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About the GECF

The Gas Exporting Countries Forum (GECF or Forum) is an intergovernmental organisation established in May 2001. It became a fully-fledged organisation in 2008, with headquarters in Doha, the State of Qatar.

As of April 2024, the GECF gathers 20 countries, including 12 full members and 8 observer members (hereafter referred to as the GECF Member Countries) from four continents. Algeria, Bolivia, Egypt, Equatorial Guinea, Iran, Libya, Nigeria, Qatar, Russia, Trinidad and Tobago, United Arab Emirates and Venezuela have the status of full members, while Angola, Azerbaijan, Iraq, Malaysia, Mauritania, Mozambique, Peru and Senegal have the status of observer members.

In accordance with the GECF Statute, the organisation aims to support the sovereign rights of its Member Countries over their natural gas resources and their abilities to develop, preserve and use such resources for the benefit of their peoples, through the exchange of experience, views, information and coordination in gas-related matters. Cooperation has been extended to technology with the establishment of the Gas Research Institute, headquartered in Algiers, the People’s Democratic Republic of Algeria.

The vision of the GECF is “to make natural gas the pivotal resource for inclusive and sustainable development”, and its mission is “to shape the energy future as a global advocate of natural gas and a platform for cooperation and dialogue, with the view to support the sovereign rights of Member Countries over their natural gas resources and to contribute to global sustainable development and energy security”.

Acknowledgements

The preparation of this Annual Gas Market Report has been made possible thanks to the efforts of the experts of the Gas Market Analysis Department (GMAD).

The Secretariat would like to thank all those who contributed to the development of this report, especially the Executive Board (EB) and Technical and Economic Council (TEC) members for their guidance, HE Eng. Mohamed Hamel, the Secretary General of the GECF, for his supervision, and GaffneyCline for its peer review of the report.

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I am delighted to present the fifth edition of the GECF Annual Gas Market Report (AGMR). The report offers a thorough review and analyses of the 2023 natural gas market developments, along with outlining short-term prospects.

The year 2023 marked a significant milestone as it represented the halfway point to the deadline of the United Nations 2030 Agenda for Sustainable Development. The United Nations Sustainable Development Goals Report revealed a worrisome lack of progress. The report highlighted that progress towards over half of the 140 targets set in 2015 is "weak and insufficient," with a third significantly off track.

Furthermore, in 2023, it became clear that the energy transitions are a gradual process rather than an immediate change, as evidenced by the record levels in coal consumption. The outcome of the Global Stocktake at COP28 emphasised the importance of ensuring that energy transitions are just, orderly, and tailored to national circumstances, capabilities, and priorities. Additionally, it also recognised the role that transitional fuels can play in facilitating the energy transition while ensuring energy security.

Thus, the year 2023 has solidly positioned natural gas as an essential element in equitable energy transitions for many decades to come.

Natural gas markets exhibited signs of rebalancing following a period of successive shocks, with spot gas prices soaring from record lows in 2020 during the COVID-19 pandemic to unprecedented highs in 2022 amidst the energy crisis in Europe. Spot gas prices witnessed a notable decline due mainly to two consecutive mild winters; yet they remain higher than historical averages. This decline in prices supported natural gas demand growth, with many countries once again favouring natural gas over other energy sources. Meanwhile, global natural gas production increased accordingly to meet the growing demand. The global LNG trade continued its upward trajectory, with the Philippines and Viet Nam joining the club of LNG importers and the commissioning of new LNG regasification capacity reaching a record high, a trend that may achieve another milestone in 2024. Moreover, there has been a significant increase in long-term LNG contracting driven by buyers’ pursuit to ensure security of gas supply, with some contracts extending even beyond 2050.

Over the short to medium term, there is expectation of rapid increase in natural gas demand, particularly in China, India, and South and Southeast Asia. Supply growth from Eurasia, the Middle East, and North America is set to play a significant role in meeting this additional demand. The natural gas markets could be significantly influenced by the commissioning of new LNG liquefaction plants. Currently, there are over 200 Mtpa of liquefaction capacity under construction worldwide. In 2024, the club of LNG exporters is anticipated to expand to include the Republic of the Congo, Mexico, Mauritania, and Senegal, with the latter two countries having recently joined the GECF. Between 2025 and 2027, 160 Mtpa out of the aforementioned capacity is expected to come online, potentially exerting downward pressure on spot gas prices. However, these developments might also stimulate natural gas demand in various price-sensitive markets, particularly in Asia, provided that investments in infrastructure are made in a timely manner.

It is worthy to recall that the GECF Global Gas Outlook, released a month ago, forecasts sustained reliance on natural gas for decades to come. According to the report, global natural gas demand is projected to increase by 34% by 2050, with its share in the energy mix expected to rise from the current 23% to 26% in 2050.

The Algiers Declaration, adopted by the 7th GECF Summit of Heads of State and Government on March 2, 2024, in Algiers, reflects member countries’ conviction that the most promising era for natural gas lies ahead. This Declaration emphasises the vital role of natural gas in advancing the United Nations Sustainable Development Goals, addressing the rising global energy demand, mitigating climate change, and ensuring universal access to affordable, reliable, sustainable, and modern energy for all. The leaders reaffirmed their determination to strengthen cooperation to ensure the reliability and resilience of natural gas systems, provide efficient and reliable natural gas supplies, and promote the role of natural gas in sustainable development and climate change mitigation and adaptation.

I would like to express my heartfelt appreciation to the GECF team for their dedication and hard work in producing the insightful AGMR 2024. I also extend my gratitude to the GECF Technical and Economic Council, the experts from Member Countries, and GaffneyCline for their comprehensive review of the report.

Eng. Mohamed HAMEL
Secretary General
# Table of Contents

<table>
<thead>
<tr>
<th>Section</th>
<th>Page</th>
</tr>
</thead>
<tbody>
<tr>
<td>Executive Summary</td>
<td>01</td>
</tr>
<tr>
<td>01 Global Perspectives</td>
<td>07</td>
</tr>
<tr>
<td>1.1 Global Economy</td>
<td>07</td>
</tr>
<tr>
<td>1.2 Energy Policies</td>
<td>13</td>
</tr>
<tr>
<td>02 Gas Consumption</td>
<td>23</td>
</tr>
<tr>
<td>2.1 Gas Consumption by Region</td>
<td>23</td>
</tr>
<tr>
<td>2.2 Gas Consumption by Sector</td>
<td>49</td>
</tr>
<tr>
<td>03 Gas Production</td>
<td>59</td>
</tr>
<tr>
<td>3.1 Gas Production by Region</td>
<td>59</td>
</tr>
<tr>
<td>3.2 Gas Production by Type</td>
<td>72</td>
</tr>
<tr>
<td>3.3 Global Upstream Developments</td>
<td>74</td>
</tr>
<tr>
<td>04 Gas Trade</td>
<td>89</td>
</tr>
<tr>
<td>4.1 Pipeline Gas Trade</td>
<td>89</td>
</tr>
<tr>
<td>4.2 LNG Trade</td>
<td>101</td>
</tr>
<tr>
<td>05 Gas Storage</td>
<td>131</td>
</tr>
<tr>
<td>5.1 Underground Gas Storage</td>
<td>131</td>
</tr>
<tr>
<td>5.2 LNG Storage</td>
<td>143</td>
</tr>
<tr>
<td>06 Energy Prices</td>
<td>147</td>
</tr>
<tr>
<td>6.1 Gas Prices</td>
<td>147</td>
</tr>
<tr>
<td>6.2 Cross Commodity Prices</td>
<td>156</td>
</tr>
<tr>
<td>Annexes</td>
<td>163</td>
</tr>
<tr>
<td>Regional Grouping</td>
<td>163</td>
</tr>
<tr>
<td>Abbreviations</td>
<td>165</td>
</tr>
<tr>
<td>References</td>
<td>168</td>
</tr>
</tbody>
</table>
### List of Figures

<table>
<thead>
<tr>
<th>Figure Number</th>
<th>Description</th>
<th>Page Number</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Global GDP growth based on purchasing power parity (2021-2025)</td>
<td>08</td>
</tr>
<tr>
<td>2</td>
<td>Global GDP growth based on market exchange rates (2021-2025)</td>
<td>08</td>
</tr>
<tr>
<td>3</td>
<td>Commodity price indices</td>
<td>11</td>
</tr>
<tr>
<td>4</td>
<td>Interest rates in major central banks</td>
<td>12</td>
</tr>
<tr>
<td>5</td>
<td>Exchange rates</td>
<td>12</td>
</tr>
<tr>
<td>6</td>
<td>Trend in global gas consumption by region</td>
<td>23</td>
</tr>
<tr>
<td>7</td>
<td>Trend in EU’s annual gas consumption</td>
<td>24</td>
</tr>
<tr>
<td>8</td>
<td>Y-o-Y variation in EU’s electricity generation by fuel in 2023</td>
<td>25</td>
</tr>
<tr>
<td>9</td>
<td>EU’s electricity mix in 2023</td>
<td>25</td>
</tr>
<tr>
<td>10</td>
<td>Trend in Germany’s annual gas consumption by sector</td>
<td>26</td>
</tr>
<tr>
<td>11</td>
<td>Monthly y-o-y variation in gas consumption in Germany’s industrial sector in 2023</td>
<td>26</td>
</tr>
<tr>
<td>12</td>
<td>Y-o-Y variation in Germany’s electricity generation by fuel in 2023</td>
<td>27</td>
</tr>
<tr>
<td>13</td>
<td>Germany’s electricity mix in 2023</td>
<td>27</td>
</tr>
<tr>
<td>14</td>
<td>Trend in Italy’s annual gas consumption by sector</td>
<td>28</td>
</tr>
<tr>
<td>15</td>
<td>Monthly y-o-y variation in gas consumption in Italy’s industrial sector in 2023</td>
<td>28</td>
</tr>
<tr>
<td>16</td>
<td>Y-o-Y variation in Italy’s electricity generation by fuel in 2023</td>
<td>29</td>
</tr>
<tr>
<td>17</td>
<td>Italy’s electricity mix in 2023</td>
<td>29</td>
</tr>
<tr>
<td>18</td>
<td>Trend in France’s annual gas consumption by sector</td>
<td>30</td>
</tr>
<tr>
<td>19</td>
<td>Monthly y-o-y variation in gas consumption in France industrial sector in 2023</td>
<td>30</td>
</tr>
<tr>
<td>20</td>
<td>Y-o-Y variation in France’s electricity generation by fuel in 2023</td>
<td>31</td>
</tr>
<tr>
<td>21</td>
<td>France’s electricity mix in 2023</td>
<td>31</td>
</tr>
<tr>
<td>22</td>
<td>Trend in Spain’s annual gas consumption by sector</td>
<td>32</td>
</tr>
<tr>
<td>23</td>
<td>Monthly y-o-y variation in gas consumption in Spain’s industrial sector in 2023</td>
<td>32</td>
</tr>
<tr>
<td>24</td>
<td>Y-o-Y variation in Spain’s electricity generation by fuel in 2023</td>
<td>33</td>
</tr>
<tr>
<td>25</td>
<td>Spain’s electricity mix in 2023</td>
<td>33</td>
</tr>
<tr>
<td>26</td>
<td>Trend in UK’s annual gas consumption by sector</td>
<td>34</td>
</tr>
<tr>
<td>27</td>
<td>Monthly y-o-y variation in gas consumption in UK industrial sector in 2023</td>
<td>34</td>
</tr>
<tr>
<td>28</td>
<td>Y-o-Y variation in UK’s electricity generation by fuel in 2023</td>
<td>35</td>
</tr>
<tr>
<td>29</td>
<td>UK’s electricity mix in 2023</td>
<td>35</td>
</tr>
<tr>
<td>30</td>
<td>Trend in the Asia Pacific annual gas consumption</td>
<td>36</td>
</tr>
<tr>
<td>31</td>
<td>Trend in China’s annual gas consumption</td>
<td>37</td>
</tr>
<tr>
<td>32</td>
<td>Y-o-Y variation in China’s power generation in 2023</td>
<td>37</td>
</tr>
<tr>
<td>33</td>
<td>China electricity mix in 2023</td>
<td>37</td>
</tr>
<tr>
<td>34</td>
<td>Trend in India’s annual gas consumption</td>
<td>38</td>
</tr>
<tr>
<td>35</td>
<td>Y-o-Y variation in India power generation in 2023</td>
<td>39</td>
</tr>
<tr>
<td>36</td>
<td>India electricity mix in 2023</td>
<td>39</td>
</tr>
<tr>
<td>37</td>
<td>Trend in Japan’s annual gas consumption</td>
<td>40</td>
</tr>
<tr>
<td>38</td>
<td>Current and forecast nuclear availability in Japan</td>
<td>40</td>
</tr>
<tr>
<td>39</td>
<td>Trend in South Korea’s natural gas consumption</td>
<td>41</td>
</tr>
<tr>
<td>40</td>
<td>Monthly HDD variation in South Korea in 2023</td>
<td>41</td>
</tr>
<tr>
<td>41</td>
<td>Trend in North America’s annual gas consumption</td>
<td>42</td>
</tr>
<tr>
<td>42</td>
<td>Trend in US natural gas consumption</td>
<td>43</td>
</tr>
<tr>
<td>43</td>
<td>Y-o-Y variation in US power generation in 2023</td>
<td>44</td>
</tr>
<tr>
<td>44</td>
<td>US electricity mix 2023</td>
<td>44</td>
</tr>
<tr>
<td>45</td>
<td>Trend in Canada’s natural gas consumption</td>
<td>44</td>
</tr>
<tr>
<td>46</td>
<td>Monthly y-o-y HDD variation in Canada in 2023</td>
<td>45</td>
</tr>
<tr>
<td>47</td>
<td>Trend in LAC’s annual gas consumption</td>
<td>46</td>
</tr>
<tr>
<td>48</td>
<td>Trend in Brazil’s annual gas consumption by sector</td>
<td>46</td>
</tr>
<tr>
<td>Figure Number</td>
<td>Description</td>
<td>Page Number</td>
</tr>
<tr>
<td>---------------</td>
<td>-----------------------------------------------------------------------------</td>
<td>-------------</td>
</tr>
<tr>
<td>100</td>
<td>Pipeline gas imports to the EU (2023 v 2022)</td>
<td>93</td>
</tr>
<tr>
<td>101</td>
<td>Net pipeline gas imports to the EU from the UK</td>
<td>93</td>
</tr>
<tr>
<td>102</td>
<td>Pipeline gas flows in North America</td>
<td>94</td>
</tr>
<tr>
<td>103</td>
<td>Net pipeline gas trade in the US</td>
<td>95</td>
</tr>
<tr>
<td>104</td>
<td>Pipeline gas imports in China by supplier</td>
<td>96</td>
</tr>
<tr>
<td>105</td>
<td>Monthly pipeline gas imports in China</td>
<td>97</td>
</tr>
<tr>
<td>106</td>
<td>Monthly pipeline gas imports in Singapore</td>
<td>98</td>
</tr>
<tr>
<td>107</td>
<td>Monthly pipeline gas imports in Thailand</td>
<td>98</td>
</tr>
<tr>
<td>108</td>
<td>Pipeline gas exports from Bolivia by importing country</td>
<td>99</td>
</tr>
<tr>
<td>109</td>
<td>Monthly pipeline gas exports from Bolivia</td>
<td>100</td>
</tr>
<tr>
<td>110</td>
<td>Trend in global LNG exports by supplier</td>
<td>101</td>
</tr>
<tr>
<td>111</td>
<td>Top 10 LNG exporting countries in 2023</td>
<td>102</td>
</tr>
<tr>
<td>112</td>
<td>Annual variation in LNG exports by country in 2023</td>
<td>102</td>
</tr>
<tr>
<td>113</td>
<td>Short-term outlook for global LNG exports by supplier</td>
<td>103</td>
</tr>
<tr>
<td>114</td>
<td>GECF's LNG exports by country (2022 &amp; 2023)</td>
<td>104</td>
</tr>
<tr>
<td>115</td>
<td>Non-GECF's LNG exports by country (2022 &amp; 2023)</td>
<td>105</td>
</tr>
<tr>
<td>116</td>
<td>Commissioning of new liquefaction capacity</td>
<td>106</td>
</tr>
<tr>
<td>117</td>
<td>FIDs in new liquefaction capacity</td>
<td>107</td>
</tr>
<tr>
<td>118</td>
<td>Trend in global liquefaction plant outages</td>
<td>109</td>
</tr>
<tr>
<td>119</td>
<td>LNG reloads by country (2022 &amp; 2023)</td>
<td>110</td>
</tr>
<tr>
<td>120</td>
<td>Global LNG imports by region</td>
<td>112</td>
</tr>
<tr>
<td>121</td>
<td>Shares of global LNG imports by region (2022 &amp; 2023)</td>
<td>112</td>
</tr>
<tr>
<td>122</td>
<td>Monthly y-o-y variation in regional LNG imports</td>
<td>113</td>
</tr>
<tr>
<td>123</td>
<td>Europe's LNG imports by country (2022 &amp; 2023)</td>
<td>114</td>
</tr>
<tr>
<td>124</td>
<td>Asia Pacific's LNG imports by country (2022 &amp; 2023)</td>
<td>115</td>
</tr>
<tr>
<td>125</td>
<td>North America's LNG imports by country (2022 &amp; 2023)</td>
<td>116</td>
</tr>
<tr>
<td>126</td>
<td>LAC’s LNG imports by country (2022 &amp; 2023)</td>
<td>117</td>
</tr>
<tr>
<td>127</td>
<td>MENA region’s LNG imports by country (2022 &amp; 2023)</td>
<td>117</td>
</tr>
<tr>
<td>128</td>
<td>Commissioning of new regasification capacity</td>
<td>118</td>
</tr>
<tr>
<td>129</td>
<td>Global LNG trade by duration</td>
<td>119</td>
</tr>
<tr>
<td>130</td>
<td>Variation in global spot/LNG trade by import country in 2023</td>
<td>120</td>
</tr>
<tr>
<td>131</td>
<td>Number of LNG export cargoes</td>
<td>120</td>
</tr>
<tr>
<td>132</td>
<td>Number of LNG cargoes by exporting country</td>
<td>121</td>
</tr>
<tr>
<td>133</td>
<td>Monthly average spot charter rate for steam turbine LNG carriers</td>
<td>122</td>
</tr>
<tr>
<td>134</td>
<td>Monthly average price of leading shipping fuels</td>
<td>123</td>
</tr>
<tr>
<td>135</td>
<td>Spot shipping costs for steam turbine LNG carriers</td>
<td>124</td>
</tr>
<tr>
<td>136</td>
<td>Growth in the global LNG carrier fleet</td>
<td>125</td>
</tr>
<tr>
<td>137</td>
<td>Global LNG carrier fleet by number of vessels (excluding FSRU and FSU)</td>
<td>126</td>
</tr>
<tr>
<td>138</td>
<td>Annual capacity additions to the global LNG fleet</td>
<td>126</td>
</tr>
<tr>
<td>139</td>
<td>Global LNG carrier fleet by capacity (excluding FSRU and FSU)</td>
<td>127</td>
</tr>
<tr>
<td>140</td>
<td>Global orderbook for LNG carriers</td>
<td>128</td>
</tr>
<tr>
<td>141</td>
<td>LNG carrier orderbook by major shipyard</td>
<td>129</td>
</tr>
<tr>
<td>142</td>
<td>Annual changes in UGS working capacity by region</td>
<td>132</td>
</tr>
<tr>
<td>143</td>
<td>UGS working capacity by technical classification</td>
<td>133</td>
</tr>
<tr>
<td>144</td>
<td>UGS in the EU</td>
<td>134</td>
</tr>
<tr>
<td>145</td>
<td>Weekly rate of UGS level changes in the EU</td>
<td>134</td>
</tr>
<tr>
<td>146</td>
<td>UGS level in the EU at different points throughout 2023</td>
<td>135</td>
</tr>
<tr>
<td>147</td>
<td>Correlation between TTF and UGS levels in the EU</td>
<td>137</td>
</tr>
<tr>
<td>148</td>
<td>Trend in gas consumption and UGS level in the EU</td>
<td>138</td>
</tr>
<tr>
<td>149</td>
<td>Trend in UGS injections and withdrawals in the EU</td>
<td>138</td>
</tr>
<tr>
<td>150</td>
<td>Global UGS status: current and future capacity</td>
<td>139</td>
</tr>
<tr>
<td>151</td>
<td>UGS in the US</td>
<td>140</td>
</tr>
<tr>
<td>152</td>
<td>Weekly rate of UGS level changes in the US</td>
<td>141</td>
</tr>
</tbody>
</table>
Table Number | Description | Page Number
---|---|---
1 | GDP growth rates (2021-2025) | 09
2 | Inflation rates (2022-2025) | 10
3 | LNG export projects targetting FID in 2024 and 2025 | 107
4 | Capacity classifications for LNG carriers | 125
5 | UGS working capacity by region and country | 131
6 | Gas storage targets in the EU in 2024 | 136
Natural gas markets started to stabilize in 2023, following a volatile period characterised by record low spot prices in 2020 during the COVID-19 pandemic and unprecedented high prices in 2021 and 2022 amidst the post-pandemic recovery and Europe’s energy crisis. Spot gas prices have significantly declined; however, they remained relatively high compared to historical averages. The decline in gas prices stimulated an increase in global gas consumption, and gas production surged accordingly to meet the growing demand. Global LNG trade continued to expand, supported by the emergence of new LNG importers and the commissioning of significant regasification capacity. During 2023, global energy policies became more favourable to natural gas, in particular a COP28 outcome acknowledged that “transitional fuels can play a role in facilitating the energy transition while ensuring energy security”, which implies new opportunities for the promotion of natural gas.

Global economy displayed resilience, navigating through a multitude of challenges
Global GDP growth, based on purchasing power parity, decreased slightly to 3.2% in 2023, impacted by high inflation, stringent monetary policies, instability within the banking sector, supply chain disruptions, economic restrictions, weakened global trade and escalating geopolitical tensions. Looking ahead to 2024, global GDP growth is projected to slow down further to 2.9% on a PPP basis, with current risks potentially exposing further downside.

Global gas consumption recovered amidst lower gas prices
Global gas consumption is estimated to have recovered by 1% to reach 4.09 tcm in 2023, with positive trends observed in many regions. In Asia, China’s gas consumption rose by 7% amidst the easing of strict COVID-19 restrictions, while in India it increased by 13% bolstered by coal-to-gas switching in power generation. Similarly, US gas consumption rose by 0.9%, driven by a phase-out of various coal power plants. In contrast, gas consumption in the EU decreased by 6%, influenced by the region’s mild winter weather, regulations on a voluntary 15% reduction in gas demand and increase in renewables energy output. In 2024, global gas demand is projected to grow by around 2%, driven by the stabilization of lower gas prices.
**All major gas consuming sectors demonstrated higher demand for natural gas**

Globally, gas consumption in power generation, industrial and residential sectors recorded increases. The lower global gas prices enhanced gas competitiveness in the power generation sector, facilitating increased coal-to-gas switching. Gas retained its share of 22% in the global power generation mix, while this sector also remained the largest gas consumer with a 44% share of global gas consumption. A slight increase of gas consumption in the industrial sector was also driven by lower gas prices and improved economic conditions in various countries. In addition, a slight increase of gas consumption in the residential sector was due to record high summer temperatures in many regions, requiring higher cooling demand.

**Global gas production recorded a slight rise, but is on a path for stronger growth**

Global gas production rose by 0.8% to 4.08 tcm in 2023. North America was at the forefront of the global production growth. China led gas production growth in Asia Pacific, whereas Qatar and the UAE drove the increase in the Middle East, while Africa, Latin America and the Caribbean kept production steady; however Eurasia and Europe experienced a significant decline. In 2024, forecast global gas production is expected to increase by around 2% to meet growing gas demand.

**Unconventional gas production continued to lead the global gas supply growth**

Unconventional gas production has consistently consolidated its position as the main driver of global gas supply growth, supported by an elevated level of investment and favourable market conditions. In 2023, unconventional gas production represented 32% of the global gas production, with shale gas and associated gas from shale oil plays being the primary contributors. The US continued its success story in development of unconventional gas resources, which represented 90% of the domestic US gas output. In addition, China followed a similar path, with unconventional gas production rising to 41% of overall gas production.

**Upstream oil and gas investment surpassed pre-pandemic levels**

The heightened focus of government policies on energy security, driven by the energy crisis in 2022, has opened up new opportunities for investment in oil and gas projects. Upstream oil and gas investment increased by 12% to reach $587 billion globally in 2023, thereby surpassing the pre-pandemic levels. However, despite an increase in exploration investment, discovered volumes in 2023 witnessed a record low, reaching only 340 bcm compared to 640 bcm in 2022.

**Emissions reduction projects gained momentum**

With the energy security concerns easing amidst the stabilisation of the gas markets, the global advocacy for reduction of GHG emissions and the further promotion of energy decarbonisation returned to the spotlight in 2023. The number of announced CCUS projects and associated overall abatement capacity significantly increased. Over 100 CCUS projects, with an aggregated capacity of circa 140 Mtpa, reached the FID stage. Additionally, blue hydrogen also strengthened its position as a potential pathway for decarbonisation.

**Pipeline gas trade continued to decline amidst the supply diversification strategy in the EU**

The European region is still the premier market for global pipeline gas trade, even as the EU countries have reduced their imports in recent years. The EU decreased its imports of pipeline gas by 24% to 155 bcm in 2023, and such volumes will likely be similar in 2024. In the meantime, pipeline gas trade in Asia Pacific continued to expand, driven by the growing gas demand in the region. In particular, China’s imports rose by 6% to reach 66 bcm, driven primarily by the escalating supply from Russia.

**Asia Pacific drove the increase in global LNG imports, with China as the top importer**

LNG imports rose by 2.5% to reach 408 Mt in 2023, surpassing the 400 Mt milestone mark. The resurgence of Asia Pacific as the premium LNG market drove this global upswing, compensating for a slight decrease in Europe. This upsurge was driven by strong demand in China, which regained its position as the top LNG importer amidst the end of COVID-19 restrictions in the country. Furthermore, the decline in spot LNG prices stimulated demand in price-sensitive markets, particularly in South and Southeast Asia. In 2024, global LNG imports are forecasted to grow by 2-2.5%, driven mainly by stronger gas demand in Asia Pacific.

**The commissioning of new liquefaction capacity fell to a two-decade low while FIDs rebounded**

The commissioning of new LNG liquefaction capacity globally hit a low of circa 4 Mtpa in 2023, the lowest since 2003. However, projections signal a rapid increase of new capacity in the short term, hitting 15 Mtpa by 2024 and 53 Mtpa by 2025, fuelled by projects that reached FID in the last five years. The surge in 2025 may initiate a potential medium-term oversupply in the LNG market, which could be exacerbated by FIDs taken on new liquefaction capacity recently, including FIDs for 32 Mtpa in 2022 and 41 Mtpa in 2023. On a positive note, the additional LNG supply may boost gas demand globally, which could help stabilize the gas markets.

**Global LNG carrier fleet expanded robustly, with a portion converted to FSRU/FSU**

The global LNG fleet reached 724 LNG carriers in 2023, with 36 new vessels entering service. Out of the total number, 672 served as active LNG carriers, while 52 were deployed as FSRUs and FSUs. The spot charter market and the cost of shipping fuels demonstrated much less volatility than in 2022, which resulted in an overall decrease in LNG shipping costs.
Underground gas storage volumes remained at a high level in the EU
With lower-than-expected heating demand amidst a warmer-than-usual winter season and voluntary gas demand reduction measures, gas storage levels in the EU were 22 bcm higher at the end of the 2022/2023 winter season, than the five-year average. As a result, there was less requirement for gas injections over the shoulder and summer seasons, resulting in downward pressure on gas prices in the region. With a delayed start to the 2023/24 winter season, gas storage levels ended 2023 with 15 bcm more than the five-year average.

Spot gas prices experienced a significant decline and reduced volatility
The gas markets experienced a bearish trend in 2023, driven by mild weather, global economic slowdown, strong LNG supply, and high storage levels in Europe and Asia. The TTF price averaged $12.90/MMBtu, marking a 66% y-o-y decrease, while the NEA spot LNG price averaged $13.47/MMBtu, representing a 59% y-o-y decline; however, spot gas prices remained higher than historical norms. In 2024, market sentiment is anticipated to remain bearish, influenced by the same factors as in 2023. Nonetheless, moderate gas demand growth in the Asia Pacific, along with increased buying activities from price-sensitive Asian countries, may provide some price support.
Global Perspectives

1.1 Global Economy

The global economy demonstrated resilience, navigating through significant challenges. In 2023, the global economic landscape had to navigate higher-than-normal inflation, stringent monetary policies, instability within the banking sector, supply chain disruptions, economic restrictions, weakened global trade and escalating geopolitical tensions. Despite these obstacles, the global economy performed better than expected, largely due to the accelerated growth of the US and China’s economies.

Global GDP growth for 2023 was 3.2% based on purchasing power parity (PPP), indicating a slight deceleration from a growth rate of 3.3% in 2022, according to Oxford Economics. Meanwhile, global GDP growth for 2023 based on market exchange rates (MER) was 2.7%.

These figures are aligned with those of other institutions including the International Monetary Fund (IMF), World Bank (WB) and United Nations (UN). In its World Economic Outlook January 2024, the IMF estimated global GDP growth for 2023 at 3.1% (based on PPP) and 2.7% (based on MER). Similarly, the World Bank, in its Global Economic Prospects for January 2024, and the United Nations, in its World Economic Situation and Prospects 2024 report, estimated the global GDP growth based on PPP for 2023 at 3%, and that based on MER at 2.6% and 2.7% respectively (Figure 1 and Figure 2).
Global Perspectives

Figure 1: Global GDP growth based on purchasing power parity (2021-2025)

Global Perspectives

was estimated at 2.5%, demonstrating stronger growth compared to the 1.9% recorded in 2022. This upturn was primarily driven by robust consumer spending and a strong labor market. In the Euro area, GDP growth was estimated at a mere 0.5% in 2023, representing a significant slowdown from the 3.5% growth recorded in the previous year. The third and fourth quarters of 2023 witnessed a marginal contraction, influenced by weak industrial activity, reduced external demand, and tight monetary policies. In China, GDP growth for 2023 was estimated at 5.2%, a notable acceleration from 3% in 2022. The rebound in the Chinese economy was bolstered by strong industrial activity. Additionally, in India, GDP growth for 2023 was estimated at 7.7%, which was higher compared to the recorded 6.5% in the previous year (Table 1).

Table 1: GDP growth rates (2021-2025)

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Source: GECF Secretariat based on data from Oxford Economics, IMF, WB and UN
Note: Data is historical for 2021-2022, preliminary estimates for 2023 and forecast for 2024-2025.

Figure 2: Global GDP growth based on market exchange rates (2021-2025)

Looking ahead, in 2024, global GDP growth based on PPP is expected to be 2.9%, the weakest level since the global financial crisis in 2008, apart from the 2020 downturn (global GDP growth based on MER is anticipated to reach 2.4%). The growth will remain below the average annual growth rate of 3.7% recorded from 2010 to 2019. This anticipated moderate deceleration will most likely be due to the delayed effects of tight monetary policies, softening labor markets, restrictive financial conditions, and ongoing weaknesses in global trade. Additionally, heightened geopolitical tensions could pose further risks, particularly if supply routes are affected, leading to significant spillover effects on energy and commodity prices. However, there are some encouraging signs, such as declining inflation and the stabilization of the banking systems. Furthermore, GDP growth in AEs and EMDEs is forecast to be 1.4% and 3.6%, respectively. In the US, growth is expected to decelerate modestly, with projected GDP growth of 2.4%. In the Euro area, GDP growth is

Advanced economies (AEs) witnessed their GDP growth decelerate sharply to 1.6% in 2023, down from 2.6% in 2022. Conversely, emerging markets and developing economies (EMDEs) demonstrated GDP growth at 4.2% in 2023, marking an improvement from 3.7% in 2022. On the regional level, the US GDP growth for 2023
In 2023, global inflation eased as the impacts of stringent monetary policies began to manifest, coupled with declining prices for energy and other commodities and the alleviation of supply chain issues. The rate of decline in inflation varies among different economies, influenced by the timing of monetary policy adjustments and the relative impact of supply and demand factors contributing to inflation. According to Oxford Economics, global inflation was estimated at 6.1% in 2023, a decrease from 8.1% in 2022. Inflation rates in the US, Euro area and UK for 2023 were estimated at 4.1%, 5.4% and 7.3%, respectively. Looking ahead, global inflation is projected to continue its downward trajectory, reaching 4.4% in 2024 and 3.3% in 2025, and will be increasingly controlled (Table 2). Specifically, in the Euro area and UK, inflation is expected to decline significantly in 2024, to reach 1.9% and 2.2% respectively, driven by the reverberating effects of tightening monetary policies and softening energy prices.

<table>
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<tr>
<td>India</td>
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<td>0.2</td>
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<td>China</td>
<td>6.7</td>
<td>5.7</td>
<td>4.6</td>
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</table>

Source: GECF Secretariat based on data from Oxford Economics

In 2023, major central banks continued their efforts to combat high inflation, with some indications of easing observed. In the first half of the year, the central banks of the US, UK and Euro area implemented consecutive interest rate increases, however, this trend shifted in the latter half of the year (Figure 4). In particular, the US Federal Reserve (Fed) raised interest rates four times last year, executing consecutive hikes of 0.25 percentage points in February, March, May and July. Following these increases, the Fed held its benchmark interest rate steady within the range of 5.25% to 5.50%. Remarkably, this was the highest rate recorded since June 2006. In the UK, the Bank of England (BOE) raised interest rates five times in 2023, with the final increase occurring in August 2023. By the year’s end, the BOE’s benchmark interest rate stood at 5.25%, marking the highest level since February 2008. In the Euro area, the European Central Bank (ECB) adjusted its key interest rates upward six times throughout the year, with Commodity prices weakened in varying degrees in 2023 but remained above their pre-pandemic levels. The average energy price index in 2023 saw a sharp y-o-y decline of 30%. This significant decrease was primarily due to the downward trend in oil, coal and gas prices. In contrast, the average non-energy price index recorded a less sharp y-o-y decline of 10%. A notable factor contributing to this trend was the significant 35% drop in the fertilizer price index compared to the previous year (Figure 3). Looking ahead to 2024, commodity prices are expected to soften further as global economic growth continues to decelerate and the pace of global trade growth slows. However, the potential for escalating geopolitical tensions and ongoing supply chain disruptions could introduce some risk premiums into commodity markets.

Figure 3: Commodity price indices

Source: GECF Secretariat based on data from World Bank Commodity Price Data
Note: Annual price indices based on nominal US dollars, 2010=100, 1960 to present. The energy price index is calculated using a weighted average of global crude oil (84.6%), gas (10.8%) and coal (4.7%) prices. The non-energy price index is calculated using a weighted average of agriculture (64.9%), metals & minerals (31.6%) and fertilizers (3.6%).
the final adjustment in September 2023. Consequently, the ECB’s benchmark interest rates for the main refinancing operations, the marginal lending facility and the deposit facility were set at 4.5%, 4.75% and 4.0%, respectively, by year-end.

Looking forward to 2024, it is anticipated that central banks will exercise significant caution before considering any reductions in interest rates.

Figure 4: Interest rates in major central banks

In 2023, the euro appreciated against the dollar, resulting in an average exchange rate of $1.0819, marking a 3% increase from the previous year. Similarly, the sterling averaged $1.2442, strengthening by 1% against the dollar compared to the previous year (Figure 5). Factors such as easing inflation and declining energy prices contributed to the support for both the euro and sterling throughout the year. In July 2023, the euro reached its highest level since February 2022 at $1.1059. Likewise, the sterling achieved its highest value since April 2022 at $1.2889. Despite the dollar’s weakening against major currencies, it was supported by the robust performance of the US economy.

Figure 5: Exchange rates

1.2 Energy Policies
1.2.1 Global Developments

After heightened energy security concerns amidst the energy crisis shadowed energy policies in 2022, the environmental agenda once again rose to the forefront in 2023. The world has become more engaged in seeking a credible solution to the energy trilemma of achieving energy security, affordability and sustainability over the past two years. There has come an understanding that any set of energy transition policies failing to address all aspects of the energy trilemma, would not be a viable solution. In 2023, reports from the 6th cycle of the IPCC assessment, the first Global Stocktake (GST) at COP28, and the UN SDG 2023 Progress Report underscored that the world is deviating from its intended trajectory in achieving collective goals, and global strategies need to be reassessed.

Although the environmental agenda has occupied a significant space of the public debate, a greater awareness about the importance of striking the accurate balance between all factors of energy trilemma was achieved. It has become widely acceptable that achieving energy security, as a means for sustainable economic development and increasing energy access, should be among top priorities for policy makers. Simultaneously, any targeted energy transition has to be affordable, as an increase in the cost of energy available to the markets would hamper the transition, due to falling economic competitiveness and dropping energy access.

It is also important to note the key developments in the alternative energy sources such as hydrogen, renewables and nuclear energy, as well as trends in carbon markets, as these can significantly impact gas markets. First, there has been a rapid increase in the number of countries incorporating hydrogen into their energy sector strategies. Second, there has been an accelerated adoption of energy policies related to renewables, to enhance energy security and meet climate goals. However, challenges such as disrupted supply chains and rising interest rates are inflating costs and testing commitments. Additionally, the extraction of critical minerals for renewables is criticized for its environmental impact, while the concentration of these supply chains in a few countries raises security issues. Third, the resurgence of nuclear power is particularly noteworthy. Previously abandoned due to safety and environmental concerns, nuclear energy is now receiving renewed support as its potential to address climate change and energy security is being re-evaluated and acknowledged. Fourth, there has been a remarkable proliferation of carbon taxes and Emission Trading Systems (ETs) worldwide. In particular, Japan launched a voluntary national market for carbon offsets in April 2023, while China’s National Climate Strategy Centre announced in September 2023 that its ETS will move from prioritizing the control over carbon intensity of coal power plants to focusing on both their carbon intensity and total emissions.
Global developments in energy policies unfolded across various international forums which are highlighted below.

1.2.1.1 COP28

The COP28 UN Climate Change Conference took place from 30 November to 13 December 2023 in Dubai, the United Arab Emirates, a distinguished GECF member country. Among the notable outcomes of COP28 was the launch of the Global Stocktake (GST), a pivotal component outlined in Article 14 of the 2015 Paris Agreement. The GST serves as a comprehensive global evaluation, assessing progress made in tackling climate change and identifying remaining challenges. The decision titled “Outcome of the first global stocktake” was adopted, with certain items of particular importance to the natural gas industry.

Item 28 acknowledges “the need for deep, rapid and sustained reductions in greenhouse gas emissions in line with 1.5°C pathways”. This calls on Parties to contribute to global efforts in a nationally determined manner, considering the Paris Agreement and individual national circumstances, pathways and approaches. It is clear that the bottom-up approach underpinning the Paris Agreement is fully respected as well as the nationally determined character of any contribution. Various global efforts may, directly or indirectly, influence gas markets.

First, the emphasis on “transitioning away from fossil fuels in the energy systems in a just, orderly, and equitable manner, accelerating action in this critical decade, so as to achieve net zero by 2050 in keeping with the science” is noteworthy. There was a vigorous debate on the path forward to achieve climate goals, with heightened emphasis on addressing the role of fossil fuels in the global energy mix. In this context, replacing phrases like “phasing-out or phasing-down of fossil fuels” with the approved term “transitioning away from fossil fuels” could be viewed as a positive signal for the gas industry. It suggests a focus on efficiently resolving the energy trilemma challenge rather than intentionally eliminating specific energy sources from the global mix.

Second, the focus on “accelerating zero- and low-emission technologies, including, inter alia, renewables, nuclear, abatement and removal technologies such as carbon capture and utilization and storage, particularly in hard-to-abate sectors, and low-carbon hydrogen production” presents promising prospects for advancing new technologies, such as CCUS and blue hydrogen, in the natural gas industry.

Third, the emphasis on “accelerating efforts towards the phase-down of unabated coal power” paves the way for the accelerated development of coal-to-gas switching on the global level.

Fourth, even the focus on “tripling renewable energy capacity globally by 2030” may be considered as encouraging to the gas industry, since natural gas serves as an ideal backup energy source for renewables, particularly notable for its intermittency.

1.2.1.2 G20

The G20 Summit was held on September 9-10, 2023, in New Delhi, India under the theme of “One Earth · One Family · One Future”. G20 leaders emphasized the importance of “exploring paths of enhanced energy security and market stability including through inclusive investments to meet the growing energy demand, in line with our sustainable development and climate goals,” as outlined in the New Delhi Declaration. They also acknowledged the necessity of facilitating low-cost energy financing options for developing countries and supported the accelerated development of global hydrogen markets from zero- and low-emission technologies. Furthermore, the leaders recognized “the importance to accelerate the development, deployment and dissemination of technologies, and the adoption of policies, to transition towards low-emission energy systems, including by rapidly scaling up the deployment of clean power generation, including renewable energy, as well as energy efficiency measures, including accelerating efforts towards phasedown of unabated coal power, in line with national circumstances and recognizing the need for support towards just transitions.” Notably, the African Union, consisting of 55 member states, was granted permanent membership in the G20.

1.2.1.3 G7

The G7 Summit took place in Hiroshima, Japan on May 19-21, 2023. During the Summit, the G7 leaders reiterated their commitment to a coordinated approach in addressing economic resilience and security, as well as the transition to clean energy economies. In addition to G7 nations, leaders from Australia, Brazil, Comoros (representing the African Union), Cook Islands (representing the Pacific Forum), India, Indonesia, South Korea and Vietnam also attended the meetings. The G7 leaders reaffirmed their shared goals of achieving net-zero emissions by 2050 and striving to limit the global temperature rise to 1.5°C. While recognizing that countries may adopt different pathways to reach these goals, the leaders stressed the need to address energy security concerns, climate change and manage geopolitical risks. In the G7 Hiroshima Leaders’ Communiqué, the
leaders also highlighted the importance of supporting investment in the gas sector, stating "the important role that increased deliveries of LNG can play, and acknowledge that investment in the sector can be appropriate in response to the current crisis and to address potential gas market shortfalls provoked by the crisis."

1.2.1.4 APEC

The Asia Pacific Economic Cooperation (APEC) Economic Leaders’ Meeting took place on November 17, 2023, in San Francisco, United States under the theme “Creating a Resilient and Sustainable Future for All”. The leaders endorsed the Golden Gate Declaration, a consensus document aimed at advancing efforts to achieve APEC economies’ ambitious sustainability and inclusion objectives. In this declaration, the leaders acknowledged that “more intensive efforts are needed for economies to accelerate their clean, sustainable, just, affordable, and inclusive energy transitions through various pathways, consistent with global net-zero greenhouse gas emissions/carbon neutrality by or around mid-century, while taking into account the latest scientific developments and different domestic circumstances. In doing so, we endeavor to unleash a new era of decent jobs, investment, economic growth, and ensure energy, security, resilience, and access in the region. We recall our commitment to rationalize and phase out inefficient fossil fuel subsidies that encourage wasteful consumption, while recognizing the importance of providing those in need with essential energy services.”

1.2.1.5 IMO

The member states of the International Maritime Organisation (IMO) reached a milestone agreement on the decarbonisation of the maritime industry on July 7, 2023. The IMO announced the adoption of new measures, including: 1) a target to achieve net-zero emissions of the global shipping industry by or around 2050, which is accompanied by indicative checkpoints of greenhouse gas emissions reductions of at least 20% by 2030, and at least 70% by 2040, all from the baseline set in 2008; 2) development of a global marine fuel standard, which will be utilized in the technical regulation and eventual reduction of the GHG intensity of shipping fuels; and 3) creation and launch of a maritime GHG emissions pricing mechanism. The details of these measures will be developed through the Marine Environment Protection Committee by 2025 and will take effect 16 months after adoption.

Looking ahead, there will be significant uncertainty with regards to future energy policies on the global level due to upcoming elections in a number of major countries and regions, including the US presidential elections, the UK and the EU parliamentary elections in 2024. Depending on their outcomes, these elections may have a significant impact on the global energy scene.

1.2.2 Regional Developments

1.2.2.1 Europe

The regional policies were focused on achieving the security of energy supply, along with the progress in the environmental agenda

After the region was hit hard by the disruption in energy supplies in 2022, the EU authorities adopted various energy regulations in 2023, which contributed to achieving a sustained level of energy security.

In February 2023, the European Council included the REPowereU plan as a part of the Recovery and Resilient Facility (RRF), which is the key instrument of the Next Generation EU Plan. This would enable the EU member states to incorporate the REPowereU in their national RRF plans and avail the key investments and reforms required to put its objectives into actions.

In February 2023, the European Commission presented the Green Deal Industrial Plan, aimed at enhancing the competitiveness of Europe’s net-zero industry and supporting a fast transition to climate neutrality. The Plan provides greater support towards the EU’s manufacturing capacity of net-zero technologies.

In March 2023, the EU prolonged its Voluntary Gas Demand Reduction regulation, which targeted decreasing gas consumption from 1 April 2023 to 31 March 2024 by at least by 15% compared to their average gas consumption in the reference period. Moreover, the regulation stipulated that member states introducing decarbonisation measures by switching from coal to gas in district heating may deduct those gas volumes from their demand-reduction obligation. This regulation contributed to easing the tight balance between gas supply and demand.

In May 2023, the Carbon Border Adjustment Mechanism (CBAM) was formally adopted by the EU, with the EC releasing its implementing regulations in August 2023. CBAM aims at reducing carbon leakage from EU imported goods and products such as fertilizers, cement and steel, and prevent offshoring of carbon emissions by moving production outside the EU.

In October 2023, CBAM entered into effect, starting with a transitional period which will run until late 2025. During this period, an importer of goods covered by CBAM is obligated to report quarterly on its embedded emissions without financial commitments. Phasing in of CBAM is accompanied by the transitional phase out of free allocation of allowances inside the EU ETS.

In November 2023, the European Council and Parliament reached a provisional agreement on the first EU regulation to curb methane emissions in the EU and globally. The regulation proposed setting a methane intensity limit on new contracts for oil, gas
and coal starting from January 2027. In addition, the regulation stipulated that new import contracts for oil, gas and coal can be concluded only if the same monitoring, reporting, and verification (MRV) obligations for methane emissions are applied to exporters to the EU as to EU producers. It also proposed a ban on routine venting and flaring by oil and gas sectors in the EU. The proposed measures would have a significant cost impact on major gas exporters to the EU.

In December 2023, the EU agreed to extend by another 12 months the emergency measures which were taken in response to the energy crisis and were due to expire on 31 December 2023. The extension covered gas solidarity measures and a market correction mechanism.

In Germany, the government approved a plan to extend the electricity and gas price caps it imposed in 2022/2023 until March 2024. The aim of the cap was to protect private households and small businesses from high energy prices.

In Italy, the government announced a revision of its energy and climate plan, updating the renewable electricity generation target from 55% to 65% by 2030. In addition, renewables are expected to account for 40% of total energy consumption.

In the UK, the state approved the Energy Act 2023, designed to transform the energy system in the country, enhance energy security, ensure affordability of residential bills and provide a licencing framework for CO₂ transportation and storage. The government amended the 2022 Energy Profit Levy by introducing the Energy Security Investment Mechanism (ESIM) and providing more incentives to the oil and gas sector to invest in new and existing projects. The UK government and the North Sea Transitional Authority (NSTA) declared their commitment to future licencing rounds that would include hundreds of new oil and gas licences.

1.2.2.2 Asia Pacific
The region was mainly concerned about the energy security, offering multiple incentives to boost domestic production

The policy agenda of major countries in Asia Pacific focused on enhancing the security of energy supply, mainly by raising the levels of domestic energy production, especially natural gas.

In China, the government focused on encouraging domestic gas production and reducing the dependence on imported gas, while prioritizing the production from unconventional sources (shale gas and CBM). In particular, the resource tax policy on shale gas was extended until the end of 2027. According to this policy, the state imposes a 30% tax relief on the 6% resource tax attributed to shale gas production. China announced the first national action plan for methane emissions mitigation, which aims to improve the methane emissions control measures gradually by 2030, especially in the areas of data monitoring and collection, creation of standardized technological practices and curbing of non-emergency gas flaring in onshore and offshore oil fields. It is worth mentioning that China is the world’s largest methane emitting country, with coal mining as the biggest source of methane emissions, and has been under considerable pressure in this regard. In addition, China introduced a new approach for liberalising natural gas prices, aiming to incentivise distributors to explore LNG imports. In terms of carbon trading, China’s carbon market has been trading for two years, covering only power generation at the moment.

In Japan, the government focused on enhancing the security of supply after the disruption that took place in 2022. They did this by launching the “Strategic Buffer LNG” framework, under which at least one LNG cargo per month will be reserved for the strategic buffer to counteract any supply issue during the peak demand period from December 2023 until February 2024. Under this framework, Japan’s Ministry of Economy, Trade and Industry (METI) is set to provide a private LNG provider a two to three-week advanced notice as to whether this reserved cargo could be released to the market or not, with a mechanism for governmental compensation if the LNG provider incurred a loss from keeping the cargo. Furthermore, Japan began carbon emission credit trading on the Tokyo Stock Exchange, considered an initial step for launching the Japanese Emission Trading Scheme (ETS) in 2024.

In India, the state adopted policies to increase domestic gas production and reduce gas price volatility. It revised a pricing mechanism for the domestically produced natural gas, adopting an oil-indexation approach linked to the monthly average of the Indian crude basket. The mechanism will be updated monthly. The target is to achieve a significant reduction in gas prices for both residential and transportation sectors. Moreover, the government worked on a program of incentives to encourage coal gasification projects, targeting reduction of natural gas imports and promoting more environmentally friendly sources of energy. In addition, India unveiled plans to provide 7.5 million complimentary cooking gas connections to households over the next three years.

In Indonesia, the government announced an ambitious target to remarkably increase its domestic gas production, targeting an uptick from 58 bcm in 2022 to 124 bcm by 2030, in line with their National Energy Plan (RUEN).

In Australia, the government focused on ensuring the stability of the domestic market by extending the previously adopted 12-month price cap until at least mid-2025, when it will be subject to review. The mechanism was introduced to reduce gas price volatility for household and small business after the unprecedented price hikes in 2022. In addition, the states approved an amendment for the Energy Safeguard Mechanism, under which facilities falling under the scope of the mechanism are obligated to reduce their emissions intensity by 4.9% annually.

In Indonesia, the government announced an ambitious target to remarkably increase its domestic gas production, targeting an uptick from 58 bcm in 2022 to 124 bcm by 2030, in line with their National Energy Plan (RUEN).
1.2.2.3 North America

Environmental policies were at the forefront in the region, with multiple initiatives for emissions reduction

In the US, key energy policies focused on implementation of the Inflation Reduction Act (IRA), adopted in 2022. This Act provided hundreds of billions of USD for clean energy development and decarbonization projects, including CCUS, hydrogen production, solar energy and energy efficiency in the form of loans, tax credits and other incentives.

In terms of oil and gas production, the US administration worked on scaling down the granting of permits for new offshore oil and gas developments. In September 2023, the National OCS Oil and Gas Leasing Program was published. The Program covers a 5-year period spanning from 1 July 2024 to 30 June 2029 and offers only a maximum of three potential oil and gas lease sales in the Gulf of Mexico area. This is the lowest number of oil and gas lease sales in history, which raised concerns in the country over the long-term security of supply.

In January 2024, the US Administration announced its decision to impose a temporary pause on the approval of US LNG export authorisations to non-FTA countries. During this temporary pause, the DOE will conduct a comprehensive review and update of the process used to approve LNG export authorisations for facilities exporting LNG to non-FTA countries, ensuring that an LNG facility is in the public interest. This reassessment will consider potential increases in energy costs for American consumers and manufacturers, the environmental impact of greenhouse gas emissions from an LNG facility and security of US natural gas supply. This decision may have a minimal impact in the short and medium term, but may affect LNG supply in the long term, largely dependent on the duration of the pause.

In addition, the US National Clean Hydrogen Strategy and Roadmap, announced in June 2023, laid down a comprehensive plan to accelerate clean hydrogen production, processing, delivery, storage, and utilisation across the US.

In Canada, the federal government announced a new system for emissions cap and trade in the oil and gas sector, to be implemented from 2026 to provide companies adequate time to adapt and acquire the needed technologies for decarbonization. The government of Alberta, Canada’s main oil and gas producing province, announced a 12% grant on the cost of capital associated with the construction of new CCUS facilities, in addition to the previously announced federal CCUS tax credit.

1.2.2.4 Latin America and the Caribbean (LAC)

Boosting the regional energy output was the main target of the energy regulations

In Argentina, the change in presidency brought a fundamental transformation to the country’s energy policy. In particular, a new bill, introducing modifications to the laws governing the energy sector, was proposed to increase the competitiveness and integration of the energy markets and lift the restrictions on the imports of natural gas. In addition, the proposal prohibits governmental interventions in setting prices for hydrocarbon products and calls for the privatization of state-owned energy companies.

In Brazil, the “gas for jobs” program was launched. It acts as a potential driver for the country’s economic growth and industrial revitalization. The program has various goals, including a rise in the country’s gas supply, optimization of its socioeconomic returns, securing of feedgas availability for petrochemical sector and integration of the low-carbon energy economy.

In Trinidad and Tobago, the energy policy focused on expanding international cooperation with neighbouring countries, including Venezuela, Suriname and Guyana, on joint development of gas fields, gas processing and LNG exports.

1.2.2.5 Africa

The policies in the region were predominately aimed at efficient economic exploitation of its vast energy resources

For the proper exploitation of its vast but untapped energy resources, Africa needs to exert considerable efforts to overcome technical, financial, environmental, and investment challenges. The energy policies were mainly focused on adopting sets of energy regulations to achieve the required levels of investment and greater energy access for consumers.

Egypt’s government worked on enhancing its gas production capabilities through offering a number of round bids for natural gas exploration and production in the Mediterranean Sea and the Nile Delta, in addition to working with international partners on expediting the development of recent discoveries.

Mauritania and Senegal emerged on the global energy scene, with their Greater Tortue Ahmeyim gas project, poised to ensure higher energy access to their populations, considerable economic growth and enhanced global energy security. Moreover, in Senegal, the government is planning to remove the energy subsidies by 2025, with the saved funds to be allocated for social projects.

South Africa’s energy policies were mostly directed towards a clean and affordable energy transition, with natural gas playing a central role in the transition from coal-fired power generation, especially in replacing the ageing and underperforming coal power plants.
2.1 Gas Consumption by Region

Global gas consumption rebounded, driven by economic development and lower gas prices, with Asia Pacific at the forefront of growth

In 2023, global gas consumption is estimated to have grown by 1.1% y-o-y to reach 4.09 tcm, with a resurgence in gas consumption in many regions (Figure 6). This followed a decline of 1.6% in 2022. Lower gas prices, and an economic rebound in various countries, boosted consumption in the industrial and power generation sectors. Furthermore, record high temperatures in many regions during the summer months bolstered gas demand for cooling. However, the warmer-than-usual winter weather placed downward pressure on gas demand, particularly affecting the residential sector.

Figure 6: Trend in global gas consumption by region

Source: GECF Secretariat based on data from Cedigaz; GECF’s estimate for 2023 and forecast for 2024
The main regional driver of the gas consumption growth was Asia Pacific. China’s consumption rose by 7% due to economic revival following the easing of strict COVID-19 lockdowns. India’s consumption increased by 13% amidst a shift from coal to gas in power generation. Similarly, the US gas consumption rose by 0.9%, driven by increased gas usage in power generation amidst a phase-out of various coal power plants. In contrast, gas consumption in the EU decreased by 7%, influenced by the region’s mild winter weather, renewal of EU regulations on a voluntary 15% reduction in gas demand and increase in wind and solar energy output.

In 2024, global gas demand is projected to grow by 1.5-2%, driven by the stabilization of gas prices at relatively low levels compared to 2022, as well as the acceleration of coal-to-gas switching. However, this forecast could vary depending on weather conditions, particularly during the winter seasons. Asia Pacific will be the primary driver of the demand surge.

2.1.1 Europe

Driven by regulatory measures, warmer winters, and a notable shift to renewable energy, the region recorded a decrease in gas consumption

2.1.1.1 European Union (EU)

The EU witnessed a significant 6% decrease in natural gas consumption, from 354 bcm in 2022 to 333 bcm in 2023 (Figure 7), amidst warmer-than-average winter temperatures, regulatory efforts to reduce gas demand and an increasing shift towards renewable energy.

![Figure 7: Trend in EU's annual gas consumption](source)

The decrease was mainly driven by the power generation sector, with a record decrease in fossil fuel power generation. In particular, gas and coal-based electricity production declined by 16% and 27%, respectively. Conversely, wind generation saw a 13% rise and surpassed gas-fired generation for the first time (Figure 8). Within the power mix, renewables held the largest share at 33%, followed by nuclear at 24%, gas at 17%, hydro at 13% and coal at 13% (Figure 9). The residential sector also witnessed a decline in demand, due to mild winter weather, while the industrial sector showed signs of recovery, spurred by a decline in gas prices.

![Figure 8: Y-o-Y variation in EU's electricity generation by fuel in 2023](source)

![Figure 9: EU's electricity mix in 2023](source)

2.1.1.1.1 Germany

The natural gas market in Germany exhibited a notable shift in consumption patterns influenced by a range of factors, including policy changes, market dynamics and environmental conditions. Total gas consumption decreased by 6% to 74 bcm in 2023 (Figure 10).
In the industrial sector, gas consumption decreased from 22.7 bcm in 2022 to 21.4 bcm in 2023, a decline of 6% y-o-y. This can be attributed to relatively high gas prices, which compelled industrial entities to scale down operations or relocate businesses (Figure 11). However, periods of lower gas prices resulted in a resurgence in industrial gas consumption, illustrating the sensitivity of the industrial sector to energy costs.

The residential sector also experienced a significant decrease in gas consumption, dropping by 3.9 bcm or 16%. This was influenced by mild winter weather conditions and the renewal of EU regulations promoting a voluntary 15% reduction in gas demand.

Similarly, the power generation sector exhibited a decrease in gas consumption from 45 bcm in 2022 to 43 bcm in 2023 (Figure 12). Furthermore, the increased output from solar, wind and hydro power reduced the need for gas in electricity production mix. The phase-out of nuclear power in Germany also had a notable impact on gas demand in Germany. While this decision initially led to an increased reliance on natural gas to compensate for the loss of nuclear capacity, it simultaneously accelerated the transition towards renewable energy sources. In the electricity mix, renewables continued to dominate with a 53% share, followed by coal at 27%, gas at 16% and hydro at 4% (Figure 13).
The residential sector saw a significant reduction in gas consumption, dropping by 3.9 bcm or 16% from the previous year. This reduction is attributed to higher temperatures. As stated by ISAC-CNR, Italy experienced a notably warmer year in 2023, with a temperature anomaly of 1.12°C above the 1991-2020 average, making it the second warmest year following 2022.

The industrial sector’s consumption decreased modestly from 11.9 bcm in 2022 to 11.4 bcm in 2023. Despite the reduction in gas prices in 2023, industrial activities recorded a second consecutive annual decline. However, a recovery was observed in Q4 2023 (Figure 15).

In the power generation sector, there was a notable decrease in gas consumption, from 25.1 bcm in 2022 to 21.1 bcm in 2023, amidst the shift in the power generation mix towards renewable sources. In the meantime, there were significant increases in the use of hydro and renewable energy sources, with an increase of 36% and 8%, respectively (Figure 16). Meanwhile, gas continued to be the dominant fuel in the power mix, accounting for 69% of the total, followed by renewables (30%), hydro (16%) and coal (5%) (Figure 17).
In the industrial sector, the consumption of natural gas decreased from 10.1 bcm in 2022 to 9.4 bcm in 2023, a reduction of 7% y-o-y. This decline was influenced by high gas prices, which led to operational cutbacks in energy-intensive industries such as the fertilizer and cement industries (Figure 19). Similarly, the residential sector saw a reduction in gas consumption, dropping by 1.4 bcm or 7% from the previous year, amidst the above-normal winter temperatures, which lessened the need for heating.

In the power generation sector, gas consumption dropped by 41%, from 5.5 bcm in 2022 to 3.2 bcm in 2023, driven by higher nuclear availability, following extensive maintenance work at various nuclear power plant sites in 2022. The government’s focus on streamlining procedures for new nuclear reactors and extending the lifespan of existing ones emphasizes the country’s commitment to nuclear energy as a cornerstone of its energy strategy. The year 2023 saw a substantial increase in nuclear energy output, from 278 TWh in 2022 to 319 TWh in 2023 (Figure 20). In France’s electricity mix, nuclear power is the dominant source, accounting for a 68% share, followed by renewables (16%), hydro (11%) and gas (6%) (Figure 21).

2.1.1.1.4 Spain

In 2023, Spain’s total gas consumption reduced from 32.8 bcm in 2022 to 29.3 bcm in 2023, a decline of 3.5 bcm or 11% y-o-y (Figure 22).
The industrial sector’s gas consumption decreased from 6.5 bcm in 2022 to 5.8 bcm in 2023, which can be attributed to high gas prices during the first quarter of the year. However, in the second half of the year, Spain witnessed a recovery in the industrial sector, primarily driven by refinery, textile, pharmaceutical, and agro-alimentary industries, with an increase of 39%, 7.4%, 4.5%, and 1.5% y-o-y, respectively (Figure 23).

Gas consumption in the power generation sector dropped by 31% from 12.4 bcm in 2022 to 8.6 bcm in 2023, which reflects the impact of declined electricity exports to France, increased renewable output and changes in Spain’s electricity production mix. In 2023, gas accounted for 23% of the electricity mix, a notable decrease from 30% in the previous year (Figure 24). Nuclear energy remained stable at 23%, while renewable energy sources, particularly solar and wind, showed significant growth, accounting for 17% and 25% of the electricity mix, respectively (Figure 25).

2.1.1.2 UK

In 2023, the United Kingdom’s total gas consumption decreased by 11% from 64.7 bcm in 2022 to 57.4 bcm in 2023. This change exemplifies the UK’s evolving energy landscape and its response to various environmental, economic, and policy factors (Figure 26).
Gas Consumption

The industrial sector’s gas consumption dropped from 2.1 bcm in 2022 to 1.7 bcm in 2023, mainly due to high gas prices (Figure 27). Companies faced challenges in maintaining operations amid rising energy costs mainly in the first and second quarter of the year.

In the residential sector, gas consumption saw a decrease from 43.4 bcm in 2022 to 40.7 bcm in 2023, driven by milder weather conditions, which led to a reduced demand for heating.

The power generation sector witnessed a significant decline in gas consumption, from 19.2 bcm in 2022 to 15 bcm in 2023. This highlights the impact of increased renewable energy output and changes in the UK’s electricity production mix. Renewable energy production, particularly from wind, continued to grow, reaching 79 TWh. This growth in renewables drove down the share of natural gas in the power generation mix (Figure 28). In the power mix, renewables take the lead, comprising 45% of the total electricity production, followed by gas at 37%, nuclear at 16%, hydro at 1% and coal at 1% (Figure 29).

In 2023, gas consumption in the region increased by 3.7% to reach 920 bcm (Figure 30). China led the growth with an increase of 28 bcm, followed by India with an increase of 8 bcm. By contrast, Japan and South Korea recorded a decline of 8 bcm and 5 bcm, respectively.
In 2024, the regional gas demand is anticipated to experience an increase, fuelled by the resurgence of the industrial sector amid declining natural gas prices. China is expected to lead demand growth in the region, driven mainly by a shift from coal to gas in the power generation sector, as lower gas prices make gas a more competitive energy source compared to other fuels. Additionally, the inauguration of new LNG receiving terminals is set to boost gas consumption in emerging countries like Indonesia, Thailand, the Philippines and Bangladesh.

2.1.2.1 China

In 2023, China witnessed a notable increase in consumption, driven by the nation’s economic recovery following the easing of COVID-19 restrictions. Total gas consumption rose by 7.6% to 397 bcm. This growth was driven by a rise in electricity demand, while hydropower production continued to operate below capacity due to drought conditions (Figure 31).

The industrial sector, particularly steel and glass manufacturing, played a pivotal role in driving gas demand, benefiting from the booming construction sector. Regional developments further emphasized China’s energy transition, with provinces like Guangdong, Hainan and Jiangsu, leading in adding gas-fired generation capacity to meet industrial and peak-shaving needs, which highlights the diverse strategies employed across the country to balance industrial demand with clean energy initiatives.

The power generation sector also observed a noticeable uptick of 10% in gas usage resulting from the drought conditions experienced throughout the year. Additionally, China’s aggressive expansion of its solar capacity demonstrates the country’s dedication to achieving its ambitious renewable energy targets. The country’s electricity output rose by 7% to 9,262 TWh, which was supported by substantial growth in gas, coal, nuclear, solar, and wind power output. Notably, the renewables sector experienced significant expansion, with solar and wind energy witnessing growth rates of 38% and 14%, respectively (Figure 32). In the meantime, coal remained the dominant fuel in the power mix, accounting for 63% of the total, followed by renewables (17%), hydro (12%), nuclear (5%) and gas (3%) (Figure 33).
Looking forward, China’s energy sector is set for a transformative shift, with wind and solar capacity projected to surpass coal capacity for the first time in 2024. This marks a significant milestone in China’s journey towards a sustainable and diversified energy mix, supported by continued capacity expansions, technological advancements, and policy frameworks.

2.1.2.2 India
In 2023, India’s natural gas market exhibited significant growth, underscored by a strategic shift towards diversifying the country’s energy mix. Total consumption of natural gas in India reached 65 bcm, marking a notable increase of 15% from the previous year (Figure 34). This rise in natural gas consumption reflects the country’s economic rebound and the increasing emphasis on cleaner energy sources, with the declining prices of natural gas making it more competitive.

The industrial sector led the consumption growth, with the fertilizer sector consuming 20.7 bcm, and the refinery and petrochemical sectors increasing by 25% and 36% y-o-y, respectively.

The electricity sector also mirrored this growth trajectory, with total production rising by 7.5% y-o-y to 1,702 TWh. The power sector’s gas consumption surged by 19% to 8.8 bcm, emphasizing natural gas’s growing importance (Figure 35). Due to the heatwave during the summer period, which boosted cooling demand, the share of gas in the electricity mix grew significantly. This was the result of the introduction of an emergency directive to address an anticipated shortfall in electricity output during peak power demand in May and June. The directive mandated that gas-fired power plants operate at full capacity during this period. Later, these measures were extended until November 2023. In the meantime, coal remained the backbone of electricity generation, despite a remarkable growth in renewable sources, like solar and wind, growing at rates of 19% and 17%, respectively. In the power mix, coal led with a 74% share, followed by renewable (13%), hydro (9%), nuclear (2%) and gas (2%) (Figure 36).

Looking ahead, India’s gas demand is projected to increase by 6% in 2024, driven by fertilizer, power generation, and industrial sectors amidst the stabilized gas prices and rising domestic production. The government’s goal is to increase the share of natural gas in India’s energy mix to 15% by 2030, alongside efforts to boost domestic production and LNG imports.

2.1.2.3 Japan
Japan’s natural gas market observed a notable trend of declining consumption in 2023, from 100 bcm in 2022 to 93 bcm in 2023, marking a 7% reduction y-o-y (Figure 37). Factors such as milder weather conditions, increased nuclear output and energy conservation efforts played significant roles in this downward trend. The city gas sector, serving residential and commercial needs and sensitive to weather and temperature fluctuations, declined as warmer temperatures reduced heating demand.
The power generation sector’s gas consumption was influenced by the operational status of nuclear reactors, which, when online, reduce the need for gas-fired electricity (Figure 38).

South Korea observed a decrease in total gas consumption to 54 bcm in 2023, marking an 8.4% decline from the previous year (Figure 39). This shift was driven by both city gas and power generation sectors, which dropped by 8.5% and 3% y-o-y, respectively.

The change in consumption patterns was partly attributed to higher nuclear output, lower coal plant utilization and milder weather conditions that subsequently influenced heating demand, with the Heating Degree Days (HDD) indicator falling by 5% in 2023 (Figure 40). January saw a unique rise in gas consumption by 6%, predominantly in the power generation sector, driven by the necessity to compensate lower nuclear output and cooler temperatures than usual. This trend, however, did not persist, with February and March seeing a decline in gas usage due to above-normal temperatures and increased output from nuclear and coal sources.

For 2024, the Korea Energy Economics Institute (KEEI) projects a rebound in gas demand, forecasting a 5.4% increase, buoyed by an improved economic growth outlook and a consequent rise in power demand. Specifically, the power sector’s gas demand is expected to recover by 4.6%, indicating a shift towards more LNG consumption due
to decreased nuclear availability and the potential for colder weather conditions. Furthermore, the KEEI report hints at a larger role for gas-fired generation in South Korea’s power mix due to firmer power demand and lower coal plants utilization. Despite an expected increase in nuclear capacity with the commissioning of new reactors, maintenance of existing reactors and transmission constraints on coal-fired generation could elevate the importance of gas-fired plants.

2.1.3 North America

Gas consumption in the region edged up, led by the US power sector’s shift to natural gas

In 2023, gas consumption in North America increased by 0.8% to reach 1,136 bcm, with the US leading the growth with an increase of 5.4 bcm. In 2024, gas demand is forecasted to remain at the same level, driven mainly by gas use in the power generation sector (Figure 41).

![Figure 41: Trend in North America’s annual gas consumption](source: GECF Secretariat based on data from Cedigaz; GECF’s estimate for 2023 and forecast for 2024)

2.1.3.1 United States (US)

In the US, the narrative around natural gas consumption and production is taking a turn towards sustained growth, as the nation continues to harness its vast shale resources. The year 2023 marked a modest uptick in total gas consumption, reaching 910 bcm, a 1% increase from the previous year (Figure 42).

![Figure 42: Trend in US natural gas consumption](source: GECF Secretariat based on data from US EIA)

The power generation sector’s demand for gas grew by 6.6%, driven by the ongoing transition from coal to gas and the growing integration of renewable energy sources necessitating flexible gas-fired power generation for grid stability. The broader electricity generation landscape in the US mirrored these shifts, with gas-fired generation continuing to hold the lion’s share and the energy mix becoming more diversified with the rise of solar and wind output. Notably, solar energy output witnessed a robust 17% increase from 2022 to 2023, underlining the country’s commitment to renewable energy expansion (Figure 43). In the power mix, gas continued to lead with a 43% share, followed by nuclear (18%), renewables (17%), coal (16%) and hydro (6%) (Figure 44).

The industrial sector, a cornerstone of gas demand, experienced a marginal increase of 0.8%, reflecting the resilience of the US manufacturing base amidst global economic fluctuations.

That contrasts with the residential and commercial sectors, where gas usage dropped by 9.3% and 6.2%, respectively, influenced by milder weather and energy efficiency gains.

The US Energy Information Administration’s (EIA) projections for 2024 paint a picture of continued ascendancy for natural gas in the energy mix. The forecasted increase in gas production is a testament to the ongoing shale revolution that has propelled the US to the forefront of global gas production. This anticipated rise in output is set to meet both domestic and international demand. The rise in natural gas consumption underscores the strategic importance of natural gas in the US energy landscape and reflects not only the technological and infrastructural advancements made by the US but also the global energy market’s increasing reliance on flexible, cleaner-burning natural gas.
2.1.3.2 Canada
The Canadian natural gas market observed a significant reduction in consumption across various sectors in 2023, culminating in an overall decrease of 11% y-o-y, bringing total gas usage down to 121.5 bcm. This shift reflects broader trends in the energy landscape, including weather conditions, sectoral demand changes and evolving energy efficiency (Figure 45).

Residential and commercial sectors experienced notable declines in gas consumption by 6% and 24%, respectively, which was influenced significantly by milder winter weather conditions, as evidenced by a 10% y-o-y decrease in Heating Degree Days (HDD) (Figure 46).

In the meantime, the industrial and power generation sectors presented a contrasting narrative, with gas consumption rising by 4.7%, underscoring the sectors’ growing reliance on natural gas amidst efforts to balance reliability and environmental considerations.

2.1.4 Latin America & the Caribbean (LAC)
The region experienced a drop in gas demand, mainly attributed to Brazil’s shift from gas to hydro power generation

In 2023, gas consumption in Latin America and the Caribbean (LAC) is estimated to have decreased by 3% to 141 bcm, with Brazil at the forefront of this decline. Looking ahead to 2024, it is anticipated that regional gas demand will fall by another 1%, mainly due to an increase in hydroelectric and renewable energy production (Figure 47).
2.1.4.1 Brazil

Brazil experienced its second consecutive year of decline in gas consumption in 2023, which dropped by 8% to reach 23 bcm (Figure 48). Most of this reduction occurred in H1 2023.

Electricity production from gas declined by 23% (1.3 bcm), attributed to increased hydroelectric production after the exceptional drought conditions of 2021. In the meantime, total electricity production grew by 5.4% y-o-y. Higher y-o-y generation from coal (+11%), hydro (+1%), solar (+89%) and wind (+18%) was recorded during the year (Figure 49). Hydro remained the dominant fuel in the Brazilian power mix with a share of 72% followed by renewables (18%), gas (6%), nuclear (3%) and coal (1%) (Figure 50).

Similarly, consumption in the industrial and automotive sectors fell by 3.7% (0.6 bcm) and 12% (0.3 bcm), respectively.

2.1.4.2 Argentina

Gas consumption in Argentina increased by 5.4% (2 bcm) in 2023 to reach 42 bcm (Figure 51). The growth in gas consumption was driven by higher use of gas in the residential, commercial and industrial sectors, which was up 19%, 18% and 1%, respectively.

Source GECF Secretariat based on data from MINISTÉRIO DE MINAS E ENERGIA and Ember
In the meantime, electricity production from gas declined by 9%, while total electricity production rose by 2% y-o-y. Higher generation from hydro (+30%), nuclear (+20%), solar (+11%) and wind (+2%) was recorded, while generation from coal dropped by 48% (Figure 52). Gas remained the dominant fuel in the Argentinian power mix with a share of 50%, followed by hydro (29%), renewables (13%), nuclear (6%) and coal (1%) (Figure 53).

**Figure 52: Y-o-Y variation in the electricity production in Argentina in 2023**

**Figure 53: Electricity mix in Argentina in 2023**

2.2.5 Africa

**The region witnessed a significant uptick in gas consumption, led by the energy needs of the electricity sector**

In 2023, gas consumption in Africa is estimated to record a growth of 4.5% compared to 2022 (8 bcm) to reach 175 bcm (Figure 54). Algeria, Nigeria and Egypt are leading the growth in the regional gas consumption, driven mainly by the electricity sector. In 2024, gas demand in Africa is forecasted to carry on rising, driven mainly by the power generation sector.

**Figure 54: Trend in Africa’s annual gas consumption**

2.2 Gas Consumption by Sector

2.2.1 Power generation

**Global electricity demand rose, fuelled by economic rebound and an ongoing shift from coal to gas, alongside a notable surge in renewable energy generation**

In 2023, the global power generation sector witnessed a 1.4% y-o-y increase in electricity consumption, totalling 28,329 TWh. This rise was attributed to the economic recovery and expansion of power grids across various countries.

Gas consumption within this sector reached 6,259 TWh, marking a modest increase from the previous year (Figure 55). This modest growth was primarily fuelled by the shift from coal to gas in various regions, spurred by a decrease in gas prices that rendered gas a more competitive option than other fuels. The sector remains the largest consumer of gas, accounting for 44% of worldwide gas usage in 2023.

Meanwhile, global renewable power generation experienced a 13% increase in 2023 compared to 2022, adding 510 TWh. Over the last five years, the output from renewables has more than doubled, spurred by enhanced policy support. Coal power generation experienced a marginal growth of 0.2% y-o-y, with an addition of 22 TWh. Hydropower production witnessed a 2.5% decrease y-o-y, reaching 4,411 TWh.

Coal continues to hold the largest share in the power generation mix at 35% in 2023, followed by natural gas (22%), renewables (16%), hydro (15%) and nuclear (9%).
2.2.2 Industrial Sector

*Global gas use in the industrial sector slightly rose, fuelled by economic growth in key regions and the fertilizer industry benefiting from reduced gas costs*

In 2023, global gas consumption in the industrial sector was estimated to have marginally increased to reach approximately 710 bcm (Figure 56). It is noteworthy that gas consumption in the industrial sector was higher than pre-pandemic levels. The key drivers of the growth are the economic recovery in China, India and the fertilizer industry as gas prices dropped, which made gas more attractive to use as feedstock. At a regional level, Africa, Asia Pacific and the Middle East recorded a growth of 6%, 1% and 0.5% y-o-y, respectively. However, Europe, North America and Latin America recorded a y-o-y decline of 0.4%, 1.4% and 4.4%, respectively.

![Figure 55: Trend in the Global Power Generation Mix](image1)

![Figure 56: Trend in annual gas consumption in the industrial sector by region](image2)

2.2.3 Residential and Commercial Sector

*Global gas consumption in the residential and commercial sectors experienced a modest increase, attributed to a mild winter weather conditions*

In 2023, global gas consumption in the residential and commercial sectors slightly grew to 826 bcm, which was higher than the pre-pandemic levels (Figure 57). The winter season was as mild as in the previous year, resulting in relatively stable natural gas consumption in these sectors. Regionally, Europe and North America experienced declines of 4.3% and 0.1%, respectively, corresponding to reductions of 8 bcm and 0.5 bcm, respectively, compared to 2022. Conversely, Africa, the Middle East and Asia Pacific experienced increases of 13%, 4%, and 1.6%, respectively.
2.2.4 Transport Sector

While the transport sector remains a niche market for gas penetration, there are varying prospects within the individual transportation modes.

On the global level, the utilisation of natural gas as a fuel for the transport sector has historically been relatively low, compared with other demand segments. In recent years, the road transport sector has accounted for around 1.5% of the global consumption of natural gas, even though this percentage share has grown annually.

2.2.4.1 Automotive industry

The two main fuel options for natural gas vehicles are compressed natural gas (CNG) and liquefied natural gas (LNG). In other segments of vehicles, CNG and LNG are growing as alternative fuel options as well. For example, CNG and LNG-fuelled engines are being utilised in agricultural machinery in Russia, coupled with penetration of LNG as a fuel for railway transport in Estonia, Russia, and Spain.

Internal combustion engines, which are fuelled by gasoline, can be easily converted to accommodate CNG instead. As such, the uptake of CNG fuel is notable in the segment of light passenger cars and medium-duty vehicles. Conversely, LNG fuel is growing in popularity for utilisation in heavy-duty engines, as are typical in trucks.

Globally, the Asia Pacific countries represent the top-ranked region for gas penetration in the transport sector. In particular, China is by far the world’s top market for natural gas vehicles, accounting for around half of the total gas consumed globally by the transport sector. Natural gas is being increasingly deployed through CNG in buses and LNG in trucks. It is estimated that there are over ten million CNG-fuelled vehicles in China, with the number of refuelling stations expected to reach 20,000 by 2025.

Other notable countries for gas consumption in the automotive industry include India, Pakistan, Bangladesh, Thailand and South Korea. Together, these nations represent around one-tenth of the total gas consumed globally by the transport sector. The Indian government is implementing measures aimed at turning the country into a gas-based economy. To this end, the national CNG initiative is expected to almost double the number of CNG refuelling stations in the country to approximately 8,000 by 2024. The long-haul trucking sector is also switching diesel engines over to LNG-fuelled engines. This drive is supported by investment in distribution and refuelling infrastructure.

Despite policies and other initiatives aimed at alternative vehicle fuels, gas uptake for transport remains low in North America and Europe, accounting for under 10% of the global total. Nevertheless, investment in gas utilisation in the transport sector in Europe is ongoing. Additions in new refuelling stations have now increased the total number of CNG refilling stations to above 4,190, while LNG refilling stations number to over 710. Germany and Italy are the major markets for natural gas vehicles in the region, accounting for around half of the refuelling infrastructure. The EU continues to push for the decarbonisation of transport on the continent, with the implementation of new policy limiting CO₂ emissions of new vehicle sales to 55% of 2021 levels by 2030, and zero by 2035.

With respect to GECF countries, in Iran, it has become government policy to promote CNG as the national transportation fuel. The National Iranian Oil Refining and Distribution Company reported that there were 2,500 CNG refilling stations in the country at the end of 2023, with plans announced to construct 400 more. The country plans to convert one million taxis to dual-fuel vehicles and have already achieved 30% of this target.

Egypt is also investing heavily in natural gas for its transport sector. The government has allocated EGP 675 million towards a new initiative aimed at the replacement of outdated vehicles with ones operating on natural gas. This scheme will run alongside the current national drive to convert 150,000 vehicles to run on natural gas, of which over 100,000 successful conversions have been achieved since 2021. In addition, there is a wide scale expansion of the refuelling capability, now reaching over 680 stations, with the target set to 1,000.

In Nigeria, the government has established the Presidential Compressed Natural Gas Initiative, aimed at introducing over 11,500 new CNG-fuelled vehicles, alongside the facilitation of 55,000 CNG conversion kits at seven such sites across the country.
There are positive and negative drivers, which may influence the penetration of gas in the automotive sector in the coming years. On the upside, many governments are implementing policies aimed at decarbonising transport industries. Such policies have already proven to encourage the increased use of natural gas and is expected to continue to be favourable to the gas industry. Conversely, the internal combustion engine market in general faces competition from electric vehicles, which may erode the market share of both gasoline-fuelled vehicles, as well as natural gas vehicles.

2.2.4.2 Maritime industry

Compared with the automotive sector, natural gas as a transport fuel has witnessed a stronger uptake within the maritime industry, where the main alternative to conventional fuel oil is LNG. However, there is growing interest in options such as methanol, ammonia, and hydrogen as well. While LNG-fuelled systems lead the way in terms of displacement of conventional fuel oils in the maritime industry, there is an increasing number of these alternative fuel options in the market, driven by an overarching initiative to decarbonise the operations of the sector.

In 2023, there were several key measures introduced towards maritime decarbonisation on both the global and regional levels. The International Maritime Organisation (IMO) continues to establish ever more stringent targets regarding the environmental impact of global shipping. The regulations of 2020 targeted the reduction of harmful compounds in the emissions of ships, with the imposition of the 0.5% sulphur cap in shipping fuels. This was followed by the IMO 2023 suite of regulations, which came into force in January 2023, and targeted the operational efficiency of maritime vessels to reduce their carbon intensity. In particular, the IMO 2023 regulations established the Efficiency Existing Ship Index (EEXI) and the Carbon Intensity Indicator (CII) as two new protocols for vessel operation, while expanding upon the existing Ship Energy Efficiency Management Plan (SEEMP).

In addition to this, in July 2023, following the 80th session of the Marine Environment Protection Committee, came the revision of the IMO Strategy for Reduction of GHG Emissions from Ships. This new measure is aimed at reducing the GHG emissions of the maritime industry to net-zero by 2050. In line with this target, there are several checkpoints along this pathway: a 20% reduction in the well-to-wake GHG emissions by 2030 compared with the base year of 2008, while striving for 30% reduction; then a 70% reduction by 2040 while striving to attain 80%. This regulation is expected to be adopted in 2025 and come into force in 2027.

Other regional-level regulatory drivers will have a notable impact on the decarbonisation of the maritime industry. The European region is particularly rigorous in its approach to the issue. As part of the FuelEU Maritime initiative, there will now be requirements on well-to-wake GHG emissions on maritime activity in the region from 2025. Specifically, the regulation aims for a 2% reduction in the well-to-wake fuel GHG intensity by 2025 relative to the base year of 2021, then a 6% reduction by 2030, towards the overall target of an 80% reduction by 2050. This is expected to function alongside the gradual inclusion of shipping in the EU’s overall Emission Trading Scheme, starting from 2024.

It is estimated that more than 98% of the total maritime fleet globally operates on conventional shipping fuels. The consequential impact of these maritime decarbonisation measures is clear, with the share of conventional fuelled ships in the global orderbook reducing to around 75%. Of these alternative fuels for maritime transport, LNG-fuelled systems are the most popular (Figure 58).

As well as having an established engine technology, LNG as a shipping fuel has several environmental advantages over conventional fuel oils. Firstly, maritime vessels, which utilise LNG-fuelled systems, may minimise GHG emissions by up to 23%. Furthermore, the use of LNG fuel may reduce the emissions of other harmful compounds, such as NOx by up to 80%, together with an almost complete elimination of SOx and other particulates.

To satisfy this growing demand for LNG fuel, the maritime industry has witnessed a commensurate expansion in the global LNG refuelling infrastructure (Figure 59). There has been a steady growth in the global capacity of LNG bunkering vessels since 2020. By late 2023, there was a significant 40% increase in the capacity of all operational vessels, when compared with the year before, reaching over 320,000 cubic metres.
Looking ahead, the global LNG refuelling capacity is expected to continue growing in the upcoming years. A further 150,000 cubic metres of capacity may be added to the global fleet beyond 2025, representing an increase of almost 45% from the current level.

The European region account for 57% of the capacity for LNG bunkering, the world’s leading region by a wide margin (Figure 60). Much of these vessels are based around Northwest Europe and the Mediterranean Sea. As the industry continues to grow, other regions have been increasing in prominence. The Asia Pacific region currently accounts for 28% of the global capacity, up from 22% in 2022, driven particularly by the commissioning of new vessels in China. Similarly, growth in the Caribbean region has led to a doubling of the share of LAC, now accounting for 9% of the global capacity.
3.1 Gas Production by Region

Global gas production rose slightly, driven by growing gas demand, with North America at the forefront of this growth.

In 2023, preliminary data suggested a 0.8% rise in global natural gas output, totalling 4.08 tcm (Figure 61). This increase predominantly occurred in North America, the Middle East and Asia Pacific, while the Eurasia, Europe and LAC regions experienced a drop, and Africa’s output remained stable compared to the previous year. Furthermore, non-GECF countries are estimated to have boosted their gas output by 2.3%, reaching 2,390 bcm.

Among the regions, North America and the Middle East recorded the most significant growth in gas production, with increases of 4.1% and 2.8%, respectively. In contrast, Eurasia and Europe witnessed reductions in their gas output, decreasing by 28 bcm.
and 19 bcm, respectively (Figure 62). On a country level, the largest increases in gas production were recorded in the US, China and Canada, with increments of 42, 9 and 8 bcm, respectively.

In 2024, with the ongoing recovery in gas demand, an increase in global gas production of around 2% is anticipated. This growth is expected to be driven by significant production increases in Eurasia, Middle East and North America, with additions of 33, 23 and 27 bcm, respectively. This upward trend will be supported by the initiation of new gas projects. In the medium term, North America and the Middle East are projected to be the primary contributors to the global increase in gas production, with Africa also potentially playing a significant role. The expansion in gas output is forecasted to be predominantly fuelled by the development of unconventional gas sources.

In 2023, Europe experienced a notable decrease in its natural gas production by 19 bcm to 214 bcm. This decline was due to reductions in output from Norway, the Netherlands and the UK, with respective decreases of 7 bcm, 5.5 bcm and 4.6 bcm (Figure 63, Figure 64 and Figure 65).

Norway’s gas production stood at the level of 126 bcm, with a 5.3% reduction in its output. The decrease in the Norwegian gas output was mainly due to the extended maintenance duration in the key producing Troll field and Kollsnes gas processing facility in the North Sea. Notably, Troll gas field recorded a 15.5% reduction in its output and accounted for 33.6 bcm of domestic gas production.

The Netherlands’ gas production stood at the level of 12.4 bcm, continuing its declining trend, with its main producing areas entering the maturity stage. The Groningen gas field, once the Europe’s largest natural gas field, officially ceased operations in 2023. This closure marked a significant milestone in the country’s energy policy, concluding a chapter that began in 1959.

The UK’s gas production dropped by 15% to reach 30.9 bcm.

In the meantime, Türkiye made significant progress in enhancing its domestic gas supply with the initiation of gas production from the Sakarya field in the Black Sea, marking a substantial step towards reducing import dependency and bolstering energy security. Additionally, several other developments across Europe, including the start of production from the Fenja field in the Norwegian Sea and the Cygnus gas field in the UK, as well as strategic plans of Romania to develop major gas fields in the Black Sea, highlight ongoing efforts to secure and expand Europe’s gas production capabilities.
3.1.2 Asia Pacific

The region witnessed a sustained production growth, led by the surge in China’s output

In 2023, gas production in the Asia Pacific region increased by 9 bcm to reach 657 bcm, representing a 16% share of global gas production. The increase in production was driven by China (8.7 bcm) and India (3.6 bcm).

3.1.2.1 China

China’s gas production increased by 4% to reach 209 bcm in 2023 (Figure 66). The country’s gas production has seen a steady increase in recent years and has the potential to continue its upward trend. Total unconventional gas production in China increased from 40 bcm in 2015 to 86 bcm in 2023, accounting for 41% of total gas output. Gas production from unconventional sources in China has become crucial in responding to the country’s energy needs. Over the years, numerous exploration and development projects have been launched to enhance unconventional production capability. In May 2023, PetroChina began extracting gas from the Tieshanpo sour gas field in the Sichuan basin. The field, known for its high sulfur content and complex geology, is undergoing development to fully exploit its reserves.

3.1.2.2 India

India witnessed a 12% rise in its annual gas production to reach 35.1 bcm in 2023 (Figure 67). This rise was predominantly driven by the encouraging government policies adopted to boost domestic production from existing and newly commissioned fields. The majority of Indian production originated from conventional gas fields (93% of the total production), with 4% coming from CBM development, recording a 9% y-o-y production growth. The Indian Directorate General of Hydrocarbons awarded exploration and development rights for 10 oil and gas blocks under the 8th round of the Open Acreage Licensing Policy (OALP) in 2023.
3.1.2.3 Australia

Gas production in Australia marginally increased by 0.2 bcm in 2023 to stand at 148.2 bcm (Figure 68). Conventional gas production dominated gas output, with 105 bcm, followed by unconventional gas production, which reached 43.2 bcm. The latter increased dramatically in recent years due to the commissioning of new liquefaction projects fed by gas production from CBM to record a compound annual growth rate (CAGR) of 19% over the last decade.

Notably in June 2023, first gas from Gorgon Stage 2 development off Western Australia was produced. This stage included the installation of 11 additional wells in the Gorgon and Jansz-Io fields and accompanying offshore production pipelines and subsea structures. Part of the produced gas is used for LNG exports for the consumers in the Asian region, while the rest is consumed domestically. In an effort to attract further investments, the Australian government is working to relax regulations to fully leverage the country’s rich unconventional gas reserves. However, a primary concern for the government amid the increase in LNG export capabilities is ensuring adequate gas supply to domestic consumers.

3.1.3 North America

The region was at the forefront of the global gas production growth, driven by the surge in output from the US and Canada

In 2023, gas production in North America increased by 51 bcm to reach 1,279 bcm, representing a 32% share of the global gas production. The increase in North American production was mainly driven by the US.

3.1.3.1 United States (US)

The US gas output increased by 4% to reach 1,064 bcm (Figure 69). The increased supply met the higher demand for feedgas by liquefaction plants. The rise in the US gas production was attributed to a surge in drilling operations in the main shale gas/oil regions, including Anadarko, Marcellus, Utica, Bakken, Eagle Ford, Haynesville, Niobrara and Permian.

The production of unconventional gas in the US witnessed a 5% rise to reach 953 bcm, which constituted 73% of the global output of unconventional gas. The leading contributors to this shale gas production were the Appalachian region, consisting of Marcellus and Utica reservoirs, and the Permian region (associated gas), which accounted for 24% and 36%, respectively, of the total output from the seven major regions.

At the end of 2023, the count of drilled but uncompleted (DUC) wells in the seven key shale oil and gas-producing regions in the US was 4,373, marking a decrease of 969 wells from December 2022. The high natural gas prices in the first half of 2023 and the increasing costs associated with drilling new wells have motivated operators to finalize and bring into operation the wells that had previously been drilled.
In 2024, the US gas production is expected to increase by 9 bcm, with much of this expansion stemming from associated gas.

![Figure 69: US gas production by type](image)

Source: GECF Secretariat based on data from Rystad Energy

3.1.3.2 Canada

With a growth of 4%, Canada’s gas output reached a solid 188.5 bcm in 2023 (Figure 70). Shale gas production has witnessed a consistent production growth since 2010, to reach more than 125 bcm in 2023, representing two thirds of Canada’s total production. Canada has been one of the countries that benefited from the shale gas revolution in the US and worked to replicate the same result. On the other hand, the conventional gas production recorded a sharp decline to stand at 35 bcm in 2023. Regionally, Province of Alberta’s gas production rose by 2% to reach 113 bcm, representing 61% of Canada’s total gas production.

![Figure 70: Canada’s gas production by type](image)

Source: GECF Secretariat based on data from Rystad Energy

3.1.4 Latin America and the Caribbean (LAC)

The regional gas production was relatively stable, with the shale gas development in Argentina gaining a great momentum

In 2023, LAC experienced a marginal decrease in natural gas production by 0.3%, to stand at the level of 161 bcm (Figure 71). This decline contrasts with localized increases in production within the region, such as in Trinidad and Tobago, which recorded a 2% rise to 28 bcm, and Peru, where production grew to 14.6 bcm from 13.7 bcm in 2022.

Overall, while 2023 saw a modest decrease in LAC’s gas production, strategic developments and discoveries across the region suggest a potential for recovery and growth in the coming years. Investments in shale and deepwater projects, along with collaborative efforts, are likely to play crucial roles in shaping the future of LAC’s natural gas industry. A notable development in 2023 was the agreement between Venezuela and Trinidad and Tobago to develop the Dragon gas field, expected to bolster LAC’s gas production capacity significantly.
3.1.4.1 Brazil

Brazil’s marketed gas production reached 20.2 bcm, mirroring last year’s level (Figure 72). In the meantime, it achieved a record in gross gas production with 55 bcm (9% rise).

3.1.4.2 Argentina

Argentina’s gas production rose by 5% to exceed 50 bcm, driven primarily by the development of the Vaca Muerta shale basin (Figure 73). Unconventional gas production accounted for 59% of the country’s total output.

3.1.5 Africa

The region continued its path toward exploitation of its vast gas resources, with new regional players entering the global gas market

In 2023, Africa’s natural gas production remained steady at 252 bcm, accounting for 6% of the global output. Despite an overall static production level, Algeria and Libya recorded increases of 5 bcm and 1 bcm, respectively, counterbalancing marginal declines from other major African producers (Figure 74).

Algeria reached its monthly record gas production in March, bolstering its LNG exports to unprecedented levels. This surge was attributed to the successful expansion in key fields like Hassi Messaoud, Hassi R’Mel, and Berkine South.

Angola witnessed a 5% growth in gas production to reach 6.5 bcm. The country has been one of the successful case studies in the field of associated gas recovery and monetization through its LNG plant in Soyo with a processing capacity of 11.4 bcm, which is considered one of the world’s first facilities supplied with associated gas.

Mozambique nearly doubled its gas production to 8.7 bcm. This development came after the country exported its first LNG cargo in November 2022, under BP’s long-term purchase and sale contract, creating a considerable margin for further growth in gas production.

Tanzania, another emerging player in the continent, worked on the economic exploitation of its considerable gas reserves, with production rising by 6% to reach 2.4 bcm.
The anticipated start-up of the Greater Tortue Ahmeyim (GTA) gas project on the Senegal-Mauritania border has been delayed to the fourth quarter of 2024. This project, expected to exploit around 425 bcm of recoverable gas, signifies a major step towards exploiting Sub-Saharan Africa’s deepwater resources.

Overall, while Africa’s gas production in 2023 remained stable, the year was marked by strategic developments and investments aimed at harnessing the continent’s considerable gas resources. These efforts, particularly in Sub-Saharan Africa, promise to elevate the continent’s role in the global gas market in the coming years, contingent on the mobilization of necessary investments and the successful implementation of planned projects.

Meanwhile, Iraq is fostering collaborations and opening opportunities for gas exploration and development. An initial agreement with Saudi Aramco to develop the Akkas gas field and the launch of the sixth licensing round for 11 exploration blocks highlighted Iraq’s commitment to meeting domestic gas needs and bolstering its petrochemical industries.

Saudi Arabia, with Aramco at the forefront, is aggressively pursuing gas production increases by 2050, focusing on both conventional and unconventional sources, including the ground-breaking Jafurah and South Ghawar projects. These efforts are part of a broader strategy to meet domestic industrial demand and support economic diversification.

**3.1.6 Middle East**

*With the startup of new gas development projects, the region was one of the drivers of the global gas production growth*

In 2023, the Middle East gas production increased by 2.8% to reach 700 bcm, with the region’s share in global gas production expanding to 17%. This growth was a result of significant contributions from Iran, Oman, Qatar and the UAE, which together added 13 bcm of gas (Figure 75). Notably, Qatar and the UAE have been focusing on leveraging their gas reserves to expand LNG export capacities through several cost-competitive projects.

**3.1.7 Eurasia**

*The region recorded a reduction in the production level, amid the geopolitical developments*

In 2023, Eurasia’s gas production was estimated at 784 bcm, representing a 3.5% decrease compared to the previous year. The region accounted for 19% of global gas production, with Russia dominating Eurasia’s gas production, followed by Turkmenistan, Uzbekistan, Azerbaijan and Kazakhstan. Gas production in Azerbaijan increased by 4% to reach 36 bcm (Figure 76). The country officially launched the Absheron gas field, a joint venture between TotalEnergies and SOCAR, currently producing 1.5 bcm at its initial phase. There are plans to boost this output to 5.5 bcm upon the completion of its multi-phase development. Meanwhile, Turkmenistan’s gas production decreased by 2% to stand at 76.8 bcm.
3.2 Gas Production by Type

Unconventional gas production has consistently consolidated its position as the main driver for the growth in global gas supply

In 2023, the landscape of global natural gas production continued to evolve. Most of the gas production remained rooted in non-associated sources, accounting for 86.3% of the total output. This dominance underscored the critical role of gas fields specifically dedicated to gas extraction in meeting global energy demands. In the meantime, associated gas, which is produced in conjunction with oil, contributed 13.7% to the global gas output, marking a marginal increase from the previous year (Figure 77). This uptick to 554 bcm in 2023 from 530 bcm in 2022 suggests a growing share of associated gas, with projections pointing towards a further increase to 582 bcm in 2024.
Unconventional gas production, particularly from shale formations, has become increasingly important, representing 32.4% of the total gas production in 2023 (Figure 79). This considerable rise, from 21.3% in 2015, mirrors the technological advancements and increased investments in unconventional gas exploration and production. Shale gas stands out as a key driver of this growth, along with associated gas from shale oil plays.

Figure 79: Global gas production by field type (conventional vs. unconventional)

Source: GECF Secretariat based on data from Rystad Energy

3.3 Global Upstream Developments

3.3.1 Exploration

Exploration activities faced several challenges, with a new record low of discoveries. In 2023, total volume of discovered gas and liquids amounted to 5 billion barrels of oil equivalent (boe). Of this, natural gas accounted for 40% (3.6 bcm), while oil constituted 60% (3 billion boe). This is compared to total discovered volume of 10.5 billion boe in 2022, with natural gas accounting for 640 bcm. This marked a more than 50% y-o-y reduction, with 2023 recording a new record low in terms of discovered volumes (Figure 80).

Figure 80: Global oil and gas volumes discovered vs exploration investment

Source: GECF Secretariat based on Rystad Energy

The low discovered volumes in 2023 led to a significant rise in the marginal cost of finding for both natural gas and oil. The cost for natural gas rose from $2.6/boe in 2022 to $5.3/boe in 2023, while the marginal cost of finding oil increased from $3.5/boe in 2022 to $8.8/boe in 2023 (Figure 81). This was driven by the disappointing results in some key offshore exploratory wells despite the increase in exploration investment to 60 billion USD in 2023.

Figure 81: Gas and oil marginal cost of finding

Source: GECF Secretariat based on Rystad Energy

Offshore discoveries continued to dominate with 74% of the total discovered volumes (3.7 billion boe), compared to 87% in 2022. Ultra deepwater prospects acquired the major stake in the offshore discoveries with 41%, followed by deepwater prospects that accounted for 30% of the offshore discoveries (Figure 82). This indicated the
additional challenges that global exploration activity was facing, with high value prospects located in more challenging geographical locations resulting in additional cost impacts incurred to explore them compared to onshore or continental shelf exploration campaigns.

On a regional basis, Asia Pacific acquired the highest share of the discovered oil and gas volumes in 2023 with 32%, due to the exploration success in offshore Indonesia and Malaysia. LAC came second with 21% of the total volume, driven by the continued success in Guyana and Suriname. This was followed by Europe, Africa and the Middle East with shares of 11%, 11% and 10%, respectively (Figure 83).

On a country level, the gas discoveries in offshore Indonesia in Larayan and Geng North fields were the most significant natural gas discoveries in 2023, followed by the major gas discoveries in the Sarawak field, offshore Malaysia. For liquid oil, the new oil discoveries offshore Guyana in the Lancetfish and Fangtooth fields and Turkey’s onshore discovery in Sehit Aybuke were the most significant. GECF Member Countries acquired 23% of the total discovered volumes in 2023, with Malaysia as the frontrunner.

Despite the challenges experienced in 2023, with the lowest recorded conventional discovered volumes, adequate level of exploration investment in 2024 is expected to revive exploration activity again, pending results from several potential exploration prospects.

3.3.2 Gas Reserves and Resources
The reduced volumes of new discoveries showed the importance of allocating adequate level of exploration investments

Global proven natural gas reserves were estimated at 206 tcm as of 2023, according to Cedigaz, with unconventional gas reserves accounting for 6% (Figure 84). Shale gas and associated gas from shale oil plays are the largest source of unconventional gas reserves in all regions and basins, with a 75% share. Shale gas reserves supported gas production in North America and Asia Pacific regions due to abundant resources in the US and China, while coalbed methane supported gas production for the LNG plants in Australia.

The Middle East continued to dominate in terms of gas reserves, accounting for 41% of global reserves, with the main contributors being Qatar, Iran and Saudi Arabia. Eurasia followed in the second place with a 32% share, mainly attributed to significant gas reserves in Russia and Turkmenistan. North America held 9% of the global reserves thanks to remarkable volumes of shale gas reserves. Other regions, in particular, Africa, Asia Pacific, LAC and Europe, accounted for 8%, 6%, 3%, and 1% of global reserves, respectively (Figure 85).

The reserve replacement ratio (RRR) for natural gas, according to Rystad, witnessed a decline to 13% in 2023, down from 19% in 2022. This was mainly driven by the disappointed results of exploration. This came after a 5% rise in the reserve replacement ratio of natural gas in 2022 (Figure 86). This showed the importance of availing adequate

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Figure 82: Classification of discovered volumes by segment
Figure 83: Regional distribution of discovered volumes in 2023

Figure 84: Classification of proven gas reserves by type
Figure 85: Regional distribution of proven gas reserves

Source: GECF Secretariat based on Rystad Energy

Source: GECF Secretariat based on Cedigaz and Enerdata

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76 | GECF Annual Gas Market Report 2024

The reserve replacement ratio (RRR) for natural gas, according to Rystad, witnessed a decline to 13% in 2023, down from 19% in 2022. This was mainly driven by the disappointed results of exploration. This came after a 5% rise in the reserve replacement ratio of natural gas in 2022 (Figure 86). This showed the importance of availing adequate
levels of upstream investments for both exploration and development to maintain the medium to long term security of supply.

Figure 86: Gas reserve replacement ratio (RRR)

Source: GECF Secretariat based on Rystad Energy

Global natural gas resources were estimated at 733 tcm in 2023, according to Enerdata, with Eurasia, LAC and North America holding the highest share with 23%, 19% and 18%, respectively. Asia Pacific, Africa, the Middle East and Europe trailed behind with 16%, 11%, 8% and 4%, respectively (Figure 87). Conventional gas resources accounted for 491 tcm and unconventional gas resources accounted for 242 tcm, with shale gas dominating.

Figure 87: Regional distribution of natural gas resources

Source: GECF Secretariat based on Enerdata

3.3.3 Developments in Decarbonisation Projects

With environmental policy rising to the forefront, emission reduction and decarbonisation projects gained a great momentum

3.3.3.1 Carbon Capture, Utilization and Storage (CCUS)

There has been a growing momentum over the use of CCUS as one of the pathways to achieve decarbonization, especially in hard-to-abate sectors. The International Panel on Climate Change (IPCC), along with other parties, have highlighted the critical need for an increased CCUS deployment to achieve net-zero. According to Global CCS Institute 2023 Status Report, over 390 carbon capture projects were announced under different stages of development as of 2023, with an aggregated capturing capacity of 360 Mtpa CO\textsubscript{2} (Figure 88). This represented a 50% y-o-y uptick in the carbon capturing capacity, with the number of announced CCUS projects more than doubling, giving a clear indication about the rising confidence in the CCUS technology capabilities to achieve a remarkable reduction in carbon emissions while balancing the economic factors, on the way to reach the just energy transition.

Figure 88: CCS/CCUS projects capacity

Source: GECF Secretariat based on data from Global CCS Institute 2023 Status Report

In 2023, there were over 40 operational facilities applying CCS/CCUS on commercial scale to industrial operations, power generation and fuel transformation, with a capturing capacity of around 49 Mtpa CO\textsubscript{2}. This represented a 14% y-o-y rise in the operational capture capacity compared to 2022. In addition, by the end of 2023, there were 204 projects in early development phase, 121 projects in advanced development and 26 projects currently under construction with aggregated capture capacity of 135,144 and 32 Mtpa, respectively.
Notably, over 100 CCUS projects reached the final investment decision (FID) stage in 2023, with aggregated capturing capacity of over 160 Mtpa. The majority of these projects are in either early or advanced development stages, with only one capture project commencing construction (Linde hydrogen plant for blue ammonia production in Texas with 1.7 Mtpa of capacity). This remarkable rise in the sanctioned CCUS projects, compared to the 19 projects taking FID in 2022, demonstrates the increased momentum for CCUS development, especially due to policy incentives such as the IRA and the 45Q tax credit in the US. In 2024, approximately 200 projects are targeting FID, with an aggregated capture capacity of 115 Mtpa.

North America led the rise in global CCUS projects capacity, with the US accounting for more than one third of global projects capacity. Europe followed in the second place, accounting for roughly one quarter of the global CCUS capacity, led by the progress in the UK and Norway.

3.3.3.2 Hydrogen Projects

In the light of the environmental pledges, the global players have struggled to find a reliable solution for decarbonization of hard-to-abate industries and heavy transportation. Low-carbon hydrogen is widely regarded as a potential solution out of this dilemma, enabling a clean energy carrier. Consequently, a remarkable rise in project announcements was seen over the past year, however few have reached FID.

According to Hydrogen Council 2023 Status Report, a staggering 1,400 low-carbon (including blue and green) hydrogen projects were announced as of the end of 2023, compared to 680 projects in 2022. Approximately 1,000 projects are planned to be in full or partial deployment by 2030. These projects are expected to have a hydrogen production capacity of up to 47 Mtpa, with blue hydrogen projects representing approximately 30% of the production capacity. About 570 billion USD of direct investment are expected to be allocated for the projects, up from 240 billion USD in 2022.

Furthermore, more than 330 projects are in feasibility studies or Front-End Development Engineering (FEED) stage, with total investments of 274 billion USD, rising from 165 projects in 2022 with total investment of 109 billion USD, highlighting the momentum behind the hydrogen economy. However, only 7% of the announced investments have secured FID, with total investments of 39 billion USD, a 17 billion USD increase from 2022 level (Figure 89).

Europe leads the way in the share of proposed hydrogen investment, with 30% of the global investment allocated for more than 540 announced projects, followed by Asia Pacific with 25%, mainly driven by the surge of new announced hydrogen projects in Australia and China. LAC accounts for 15% of the new investments, despite having a fewer number of announced projects, compared to North America that accounted for 12% of the new investments because of the higher projects capacity that need an elevated level of investments (Figure 90). Notably, China led the countries with the most projects that reached FID stage, with more than 12.5 billion USD of investments, representing 32% of the total projects with FIDs. North America accounted for 10 billion USD of FID investments, representing 25% of the total. With regards to Europe, despite having the highest share of announced hydrogen investments, it only accounted for 7.5 billion USD, representing 19% of the total FIDs investments.

![Figure 89: Classification of investments in hydrogen projects](source)

![Figure 90: Regional distribution of hydrogen investments](source)
In terms of supply, the announced projects in 2023 are expected to provide 45 Mtpa of low-carbon hydrogen by 2030, out of which green hydrogen accounts for 70% (32 Mtpa) and blue hydrogen constitutes the remaining 30% (13 Mtpa). Europe accounts for the highest volume – approximately 14 Mtpa, followed by North America and LAC, with 10 Mtpa and 6.6 Mtpa of hydrogen, respectively.

3.3.3.3 GHG Emissions Reduction

Following a challenging year for energy markets in 2022, the global advocacy for GHG emissions reduction and the promotion of decarbonization have regained momentum in 2023. CO₂ emissions constitute the primary factor driving the climate crisis, and their abatement represents the main pathway for mitigating the climate challenge. Global CO₂ emissions increased by 0.5%, reaching 40.7 Gt, a level that remains relatively high but is still lower than the peak level of 40.9 Gt recorded in 2019. Notably, emissions related to fossil fuels (including natural gas, oil and coal), which represent 90% of the global CO₂ emissions, are estimated to have risen by 1.1% in 2023, reaching a record high level of 36.8 Gt. Natural gas witnessed the smallest increase in the related global CO₂ emissions in 2023 compared to the other fossil fuels, with 0.5% y-o-y rise, reaching 7.33 Gt CO₂. This increase was primarily driven by the rise in the global consumption of natural gas.

During the same period, coal-related emissions witnessed a rise of 1.1% y-o-y, reaching 15.70 Gt CO₂, with 170 Mt increase compared to the 2022 level. This rise was primarily driven by the increased coal consumption in China and India. Oil-related emissions recorded a 1.5% y-o-y rise, reaching 11.36 Gt CO₂. This increase was primarily attributed to the recovery in the international shipping and aviation activities (Figure 91).

![Figure 91: Energy-related CO₂ emissions](source: GECF Secretariat based on data from Global Carbon Budget 2023 report)

China was responsible for 31% of total energy-related emissions, with a 4% increase in its emissions level to reach 11.9 Gt of CO₂. India also witnessed an increase in its fossil fuel emission level by 8%, culminating in 3.1 Gt of CO₂. On the other hand, the EU witnessed a remarkable 7% decline in its emission level driven by the reduction in energy consumption and retiring of some coal plants. Similarly, the US emissions dropped by 3% to reach 4.9 Gt of CO₂, driven by the increased coal-to-gas switching in power generation, while the natural gas related emissions witnessed a minor rise of 1.4%.

3.3.4 Upstream Investment in the Oil and Gas Industry

_**Upstream investment exceeded pre-pandemic levels amidst policy shifts**_

Investment in the upstream oil and gas industry has been significantly influenced by major market shocks over the past three years. Following a sharp 28% decline in 2020, upstream investment recovered with increases of 7% in 2021 and 22% in 2022. The notable surge in 2022 was driven by concerns over energy security and high energy prices. In contrast, the investment landscape in 2023 was marked by softer market fundamentals and more stable, albeit lower prices. Upstream oil and gas investment experienced a 12% y-o-y increase in 2023, reaching $587 billion, thereby surpassing the pre-pandemic levels. Notably, investment in the gas sector represents 30% of total upstream oil and gas investment.

The bulk of upstream capital expenditure was focused on production from existing fields, with costs related to the development of infrastructure, drilling and completion of wells, and modifications and maintenance on installed infrastructure accounting for 90% of upstream investment. Meanwhile, exploration activities constituted only 10%, or $60 billion (Figure 92).

In 2024, upstream oil and gas investment is projected to grow by 3% to reach $605 billion.
On a regional level, North America held the largest portion of upstream investment in 2023, with $214 billion, marking an 11% increase. This was followed by Asia Pacific and the Middle East, where investment reached $155 billion and $94 billion, respectively. Although Africa recorded the lowest regional upstream investment, it experienced the highest growth rate of 28% to reach $45 billion. In Europe, upstream investment also rose by 5% to reach $30 billion, rebounding from a marginal decline in the previous year (Figure 93).

Looking ahead to 2024, the Middle East and Europe are expected to experience the highest growth rates at 18% and 16%, respectively.

There has been a steady recovery in total investment in the oil and gas industry (including upstream, midstream and downstream segments of the gas value chain) over the past three years. However, total oil and gas investment has not yet returned to pre-pandemic levels. Total investment was $15 billion, or 2%, lower than in 2019. The pivot in government policies from focusing on energy transition to prioritizing energy security has opened some opportunities for increased investment in oil and gas projects. According to the IEA, total investment in the global oil and gas industry was projected to reach $805 billion in 2023, representing a 6% increase compared to the previous year (Figure 94). However, the impact of higher spending may have been mitigated by inflationary pressures.
Gas Production

In 2024, total investment in the oil and gas industry is expected to remain robust. The industry’s accelerated move towards decarbonization offers an opportunity for increased investment, thereby enhancing the environmental profile of natural gas. In this regard, there has been growing policy support for the adoption of CCUS technologies and hydrogen. Additionally, oil and gas companies are progressively engaging with clean energy technologies however, such investments still represent a minor fraction of their overall capital expenditure.

However, several uncertainties could potentially hinder investment in the industry. A slowdown in global economic growth and tight financing conditions could pose challenges to investment decisions. Moreover, as the energy transition advances, uncertainties regarding long-term demand, changes in environmental policies and government regulations, as well as competition for capital with renewables and other low-carbon energy sources, may complicate efforts to secure investment over the long term.

The acknowledgment that gas will play a crucial role in ensuring energy security has prompted a relaxation in some financing restrictions for oil and gas projects by banks and other financial institutions. In its May 2023 Energy Lending Policy, the European Investment Bank (EIB) recognized gas’s pivotal role in decarbonizing energy systems. The EIB committed to supporting “low-carbon power plants, including renewables and carbon capture and storage, as well as the most efficient combined heat and power projects.” Furthermore, the Bank acknowledged the ongoing role of fossil fuels within the global energy system until 2030 and noted that transitioning from oil or coal to natural gas could reduce greenhouse gas emissions in the short term.

In terms of upstream mergers and acquisitions (M&A) activity, 2023 witnessed a record surge, with deal value reaching $259 billion, marking a 60% y-o-y increase, based on estimates from Rystad Energy. The rise in global M&A activity was primarily driven by the pursuit of premium drilling inventory, as well as production and carbon-reduction objectives. North America led in announced deals, representing 65% of the total deal value, followed by South America at 17%. Europe, Asia, the Middle East and Africa each contributed less than 10%. Noteworthy transactions in October 2023 included ExxonMobil’s acquisition of Pioneer Natural Resources for $64.5 billion and Chevron’s purchase of Hess for $60 billion.
Europe represents the major market for pipeline gas trade on the global level. Specifically, this region alone accounts for over half of the global imports by pipeline. Pipeline gas is primarily supplied to the region from five countries: Algeria, Azerbaijan, Libya, Norway, and Russia. In addition, two interconnector pipelines connect the European mainland to the UK. These pipelines have the capability for bidirectional gas flows and can further bolster pipeline gas imports to the region, as dictated by prevailing market dynamics.

In 2023, the level of pipeline gas imports to the EU continued its downward trend observed in the previous year. In total, 155 bcm of pipeline gas was imported by EU countries in 2023, representing a decrease of 48 bcm from the levels imported in 2022 (Figure 95). This 24% decline was primarily driven by a reduction in imports from Russia and Norway.

Figure 95: Pipeline gas imports to the EU by supplier

Source: GECF Secretariat based on data from McKinsey and Refinitiv
In 2023, Norway remained the top supplier of pipeline gas to the EU, accounting for 54% of total pipeline gas supply, while Algeria represented 19%, and Russia 17%. There were marginal increases in the supply share from the remaining suppliers, as Azerbaijan increased from 6% in 2022 to 7% in 2023, and Libya from 1% to 2%.

Pipeline gas monthly imports were largely stable throughout 2023 (Figure 96). In 2022, the region witnessed a sharp decline in the rate of pipeline gas imports due to geopolitical developments. This culminated in the termination of gas flows through the Nordstream 1 pipeline in September 2022. In 2023, the major disruption to pipeline gas imports to the EU was due to supply-side interruption, particularly from planned and unplanned upstream outages in Norway. As a result, far less variation in the monthly rate of pipeline gas imports was achieved, reaching an average of 13 bcm over the year.

The year 2023 commenced with m-o-m decreases in January and February, as the high gas stocks in the region, coupled with ample LNG supply and muted winter demand, curbed pipeline gas imports. While the level of total imports increased in the months thereafter, supply from Norway was hampered by unplanned outages during the summer, as well as the annual maintenance program in September. However, by Q4 2023, pipeline gas supply to the region reached a more stable level.

The supply dynamics to the EU over the past two years is further underscored by the variance in pipeline gas imports by supplier from 2022 to 2023 (Figure 97). In the case of Russia, the large negative variations in the first two thirds of the year were a direct result of the loss of supply via the German and Polish routes. This trend was reversed in the latter part of 2023 by the increase in pipeline gas supply via the Turkstream pipeline. The upstream outages hampered Norwegian production during the year. Pipeline gas imports from Algeria, Azerbaijan and Libya recorded marginal variances throughout the year, which was reflected in their total supply being largely unchanged since 2022.

The pipeline gas supply from Russia and Norway has had the most significant influence on the EU market in the recent years (Figure 98). Prior to 2022, Russia was the top exporter of pipeline gas to the EU, supplying on average around 13 bcm per month during the years 2019 to 2021. As a consequence of the developments in the region in 2022, a notable decline in Russian supply occurred during that year. However, the level of exports soon stabilised from around Q4 2022, with the rate of flows reaching 2.0 bcm per month during the first half of 2023. The situation improved in the second half of the year, with the average rate of pipeline gas exports at 2.6 bcm per month in H2 2023.

Source: GECF Secretariat based on data from McKinsey and Refinitiv

Source: GECF Secretariat based on data from McKinsey and Refinitiv

Source: GECF Secretariat based on data from McKinsey and Refinitiv
The supply profile from Norway to the EU displayed much less variation within this same period. On average, 7.3 bcm per month was imported from Norway during the years 2019 to 2021. In 2022, there was a sustained effort to boost gas production and exports, which was reflected in the increased rate of flows of 7.9 bcm per month. The year 2023 was however, the lowest performing of the previous five years, with the average rate of pipeline exports reaching just 7.0 bcm per month.

With the commissioning of the Baltic Pipe in November 2022, Norway now has six entry points into the EU (Figure 99). Apart from this newly established pipeline link to Poland, however, exports from Norway recorded y-o-y declines to the other five countries in 2023. Germany remains the top market for Norwegian pipeline gas exports, even though some of the supply to Germany now flows to Poland instead. In 2023, Norway supplied 38% of its exports to Germany, 18% to Belgium and 17% to France.

As of 2023, Russian pipeline gas exports to the EU is supplied via two routes, the Turkstream pipeline and the Ukraine transit pipelines. The Turkstream pipeline accounted for 51% of total Russian flows to the EU during the year. Compared with the year before, in 2023, there was a 5% increase in gas exports via this supply route (Figure 100). In the meantime, Algeria supplies pipeline gas to southern European countries. In 2023, 22 bcm was supplied to the Italian market, representing 72% of its pipeline gas exports. However, there was a 7% y-o-y decrease in supply to Spain in 2023.

The interconnectors linking the European continent with the UK may also provide additional gas supply to the EU, primarily from regasified LNG, which is imported by the UK. Since H2 2021, the dynamics of gas demand and pricing in the regions have resulted in a sustained net flow of pipeline gas from the UK towards the EU, reaching record highs in 2022 (Figure 101). However, in 2023, the EU pipeline gas imports from the UK decreased by 38% to 12 bcm.
Barring unforeseen market developments, the pipeline gas supply to the EU in 2024 may record a similar level to 2023. Some drivers, which may prove to have an upside on supply, include the increased level of imports from Russia which started since H2 2023, and the anticipation of fewer supply outages from Norway. Furthermore, there may be additional supply to the region through agreements for the ramping up of flows from current suppliers.

4.1.2 North America

*There was growing demand for pipeline gas exports from the US to Mexico*

The North American gas market is self-contained among Canada, Mexico, and the US. In particular, the US and Canada, being producers of natural gas, do engage in cross-border pipeline gas trade, with each country having access to markets within the other. Conversely, Mexico is a net importer of pipeline gas, receiving supply from the US.

In 2023, pipeline gas supply from Canada to the US reached 81 bcm, marking a decrease of 4% (Figure 102). This was matched by a 4% increase in pipeline gas exports from the US to Canada during the period, for a total of 28 bcm. Mexico is the bigger market for pipeline gas exports from the US, receiving 64 bcm in 2023. This quantity represented an 8% increase y-o-y, in line with the increased gas demand in the country.

![Figure 102: Pipeline gas flows in North America](source: GECF Secretariat based on data from US EIA)

Mexico increased its rate of pipeline gas imports over the course of 2023 (Figure 103). In 2022, the average rate of imports was 4.9 bcm per month, similar to the level of 5.0 bcm per month during the first half of 2023. During the period July to December 2023, this rate increased noticeably to 5.6 bcm per month. On the other hand, net imports from Canada to the US remained at a stable level throughout 2023, averaging 4.4 bcm per month.

![Figure 103: Net pipeline gas trade in the US](source: GECF Secretariat based on data from US EIA)

In 2024, there may be an increase in the level of pipeline gas trade in North America. The major reason for this expansion is the imminent startup of LNG export projects in Mexico, which will boost its pipeline gas imports from the US. Conversely, the commissioning of LNG export projects in Canada may reduce the quantity of gas available for pipeline exports to the US.

4.1.3 Asia Pacific

*The share of Russian pipeline gas in China’s energy imports continued to grow*

In the Asia Pacific region, the largest importer of pipeline gas is China. In 2023, total imports to the country reached 66 bcm, which represented an increase of 6% compared with the quantity imported in 2022 (Figure 104). In comparison, this was the slowest rate of increase within the last three years, lower than the 9% growth in 2022, and the 21% jump in 2021. With China’s Covid-19 restrictions now fully lifted, there has been a resurgence in economic activity, driven by the industrial sector, and a consequent surge in gas demand.
The majority of the import volumes were supplied by Central Asian countries, specifically Turkmenistan, Kazakhstan and Uzbekistan, which together accounted for 60% of China’s pipeline gas imports in 2023. Historically, Turkmenistan has been the largest supplier of pipeline gas, having recorded over 55% of Chinese pipeline gas imports. 2023 witnessed decreases in supply from all three central Asian producers, with Kazakhstan and Uzbekistan announcing a prioritisation of domestic demand over gas exports.

In contrast, pipeline gas supply from Russia to China has been growing each year, specifically via the Power of Siberia 1 (PoS1) pipeline. In 2023, flows increased by 46% y-o-y, to reach a total of 22.7 bcm. This increase was in line with the planned ramp-up of the utilisation of this pipeline since its commissioning in 2019.

The remainder of China’s pipeline gas imports is sourced from Myanmar. In 2023, there were 3.8 bcm of imports from Myanmar, which represents a decrease of 5% y-o-y.

The year 2023 recorded new monthly highs for most of the year. Accordingly, the average rate of gas imports was 5.5 bcm per month, compared with 5.2 bcm per month in 2022 (Figure 105).

Looking ahead, 2024 will bring another phase of increases via PoS1, as Gazprom has announced a target of up to 30 bcm for the year. The pipeline is expected to attain maximum flows by 2025, by which time it can deliver up to 38 bcm. The next export project on the immediate horizon for both countries is for pipeline gas supply via the Far East Route. In this regard, PipeChina has already commenced construction on a section of the Hulin-Changchun gas pipeline, from a border town in the north-eastern Jilin province. On the Russian side, it is expected that construction of a new gas pipeline will facilitate connection with the Chinese infrastructure and the Sakhalin-Khabarovsk-Vladivostok network. Commercial deliveries via the Far East route are expected to amount to 10 bcm annually and may begin in 2027.

The contraction of supply from Kazakhstan and Uzbekistan may present a downside risk to China’s pipeline gas imports going forward. In contrast, Turkmenistan is poised to expand its export capability to China, with the acceleration of the construction of the Central Asia-China Gas Pipeline D. This is the fourth link between the nations; Lines A to C have a combined capacity of 55 bcm, while this 30 bcm Line D traverses a different route into western China.

Singapore is the second largest market for pipeline gas trade in the Asia Pacific region, importing from Indonesia and Malaysia. Over the past three years, annual declines in the quantity of pipeline gas imports to the country were recorded (Figure 106). In 2023, 6.4 bcm of pipeline gas was imported, a 22% y-o-y decrease.
Myanmar also exports pipeline gas eastward to Thailand. This is another relatively small market, with the level of pipeline imports in 2023 reaching an estimated 5.8 bcm (Figure 107). This volume was the lowest annual total in the past five years.

4.1.4 Latin America and the Caribbean (LAC)

The regional pipeline gas trade declined, but there is growth potential in the coming years

The market for pipeline trade in the LAC region is centred on gas flows in the South American continent. Specifically, Bolivia is the top supplier in the region, delivering pipeline gas to Argentina and Brazil. Additionally, Argentina currently also exports pipeline gas to Chile.

In 2023, Bolivia exported an estimated 8.2 bcm of pipeline gas, which marked a 20% decline from the level of 2022 (Figure 108). The major driver for this decrease is the reduction of imports by Argentina, amidst the burgeoning levels of domestic gas production within the country. In fact, in 2023, Bolivian pipeline gas supply to Argentina recorded 34% y-o-y decline, compared with a comparative decrease of 9% in the quantity delivered to Brazil. As a result, the Brazilian market accounted for 69% of total Bolivian pipeline gas exports in 2023.

On a monthly basis, there was a relatively stable supply of pipeline gas from Bolivia in 2023 (Figure 109). However, the level of flows was consistently less than in the two previous years.
Argentina also plays a role as a gas exporter, with pipeline links connecting the country with Chile. In recent years, the increase in indigenous gas production in Argentina has expanded the country’s capability for pipeline gas exports. The level of trade between both countries, however, remains relatively small. Argentina delivered an estimated 2.2 bcm of pipeline gas supply to Chile during 2023. This quantity represented an escalation of 23% from 2022 levels and was the highest total in the past five years.

Overall, the short to medium term prospects for pipeline gas trade in the region may be positive. In the first instance, Argentina plans to construct new gas pipeline infrastructure, targeting an increase in domestic consumption, as well as facilitating gas exports to other South American countries. The major project in development is the expansion of the Nestor Kirchner gas pipeline. In the first phase, a 570 km extension of the pipeline from the Vaca Muerta production hub to Buenos Aires was commissioned in July 2023. Subsequent development involves a $750 million expansion of the network, which will allow for the export of pipeline gas to Brazil, Bolivia and Chile.

Moreover, Venezuela stands to become an exporter of pipeline gas through two projects in different stages of development. In December 2023, the governments of Venezuela and Trinidad and Tobago signed a 30-year agreement for the production and export of natural gas. The project is estimated to deliver 1.8 bcm of pipeline gas from Venezuela’s Dragon gas field to the petrochemical industries and LNG export plant in Trinidad and Tobago. The second project of interest involves the potential revival of operations via the Antonio Ricaurte gas pipeline, but this time in reverse direction for export of Venezuelan gas to Colombia.

4.2 LNG Trade

4.2.1 LNG Supply

4.2.1.1 Global LNG Exports

The US drove the growth in global LNG exports and became the largest LNG exporter

In this report, LNG exports refer to LNG volumes delivered to importing countries, excluding deliveries via ISO containers, and do not reflect the LNG volumes loaded at an LNG export facility. As such, the LNG volumes exclude boil-off and losses during unloading, shipping and offloading. Global LNG exports include exports from LNG producing countries as well as LNG reloads.

In 2023, global LNG exports reached a new peak of 410 Mt (Figure 110), marking an increase of 2.8% (11 Mt). However, the growth rate in LNG exports decelerated compared to 2022, during which LNG exports expanded by 4.4% (17 Mt). Most of the incremental increase in global LNG exports was attributed to non-GECF countries and higher reloading activity.

The upswing in LNG exports was propelled by various factors, including the commissioning and ramp-up of new LNG projects, reduced unplanned maintenance at certain liquefaction facilities and increased availability of feedgas in some countries. In terms of market share, non-GECF countries emerged as the largest LNG exporter in 2023, accounting for 52% of global LNG exports. GECF member countries and reloads constituted 47% and 1% of the market share, respectively.
Looking at individual countries, the US surpassed Qatar to become the largest global LNG exporter in 2023, with LNG exports totalling 88 Mt (Figure 111). Qatar slipped into second position with 79 Mt, followed by Australia (79 Mt), Russia (31 Mt) and Malaysia (27 Mt). The substantial increase in global LNG exports was primarily driven by the US, with notable contributions from Algeria, Mozambique, Norway, and Indonesia (Figure 112). Conversely, Egypt, Nigeria and Russia experienced declines in their LNG exports.

In 2024, global LNG exports, including LNG reloads, are projected to increase by 2-2.5% (8-10 Mt) if LNG reloads maintain the same levels as 2023 (Figure 113). This indicates a marginally slower growth rate compared to 2023. Both GECF and Non-GECF countries are expected to drive the increase in global LNG exports, with additional 3-4 and 5-6 Mt of LNG, respectively.

Assumptions for global LNG exports in 2024:
Upside:
• Start-up and ramp-up of new liquefaction facilities in Republic of the Congo, Indonesia, Mauritania/Senegal, Mexico, Mozambique, Russia and the US: 6-7 Mt
• Increased production at the Freeport LNG facility in the US: 0.75-1 Mt
• Higher feedgas availability in Algeria and Nigeria: 1.5-2 Mt
• Lower maintenance activity at Sakhalin 2 and Yamal LNG facilities in Russia: 0.5-1 Mt

Downside: Lower feedgas availability in Australia: 1-2 Mt
Stable: LNG exports from all other countries are assumed to be at the same level as 2023

In 2025, global LNG exports are forecasted to grow by 5-6% (23-25 Mt), assuming LNG reloads remain at the same level as 2023. Non-GECF countries are expected to account for the bulk incremental increase of 15-16 Mt, with GECF MCs contributing volumes of 8-9 Mt.

Assumptions for global LNG exports in 2025:
Upside:
• Start-up and ramp-up of new liquefaction facilities in Canada, Republic of Congo, Indonesia, Mauritania/Senegal, Mexico, Qatar, Russia and the US: 22-24 Mt
• Higher feedgas availability in Algeria, Egypt, Nigeria and Trinidad and Tobago: 2-3 Mt

Downside: Lower feedgas availability in Australia: 1-2 Mt
Stable: LNG exports from all other countries are assumed to be at the same level as 2024

In 2023, LNG exports from GECF Member Countries declined by 0.6% (1.2 Mt) to reach 193 Mt, driven by lower feedgas availability and higher planned maintenance activity in some countries.

The declines in LNG exports from Egypt, Equatorial Guinea and Nigeria were influenced by lower feedgas availability. In Qatar, the drop in exports was attributed to a modest decline in the capacity utilisation of its LNG facilities. The decrease in Russia’s LNG exports was primarily attributed to higher planned maintenance activity at both the Sakhalin 2 and Yamal LNG facilities. In the meantime, the increased production at the Portovaya LNG facility partially compensated for the reduced exports from the Sakhalin 2 and Yamal LNG facilities (Figure 114).
Conversely, a notable surge in Algeria’s LNG exports was a result of increased feedgas availability and reduced unplanned maintenance at the Arzew LNG facility. In Angola, higher feedgas availability played a key role in driving up exports. Mozambique recorded an upturn in LNG exports, due to the ramp-up in production from the Coral South FLNG. Similarly, a drop in unplanned maintenance at the Peru LNG facility led to the increase in Peru’s exports.

Australia’s 2023 LNG exports remained stable, boosted by higher outputs from Ichthys, Prelude, QCLNG and Wheatstone facilities, countering decreases from Darwin, Gorgon and North West Shelf. Reduced planned maintenance at Ichthys, QCLNG and Wheatstone, along with less unplanned maintenance at Prelude, drove increases from these facilities.

4.2.1.2 Non-GECF Countries

In 2023, LNG exports from non-GECF countries experienced a significant increase of 5.7% (11 Mt) y-o-y, reaching a historic high of 211 Mt. This surge in non-GECF’s LNG exports was credited to the commissioning and ramp-up of new LNG facilities, coupled with reduced planned and unplanned maintenance activities. The US remained a major contributor to the upswing in non-GECF’s LNG exports, with Cameroon, Indonesia and Norway making lesser contributions (Figure 115). Conversely, Brunei witnessed a substantial decline, while exports from other non-GECF countries remained relatively stable.

In the US, the surge in LNG exports was driven by a ramp-up in LNG supply from the Calcasieu Pass LNG facility and lower unplanned maintenance at the Freeport LNG facility. The Freeport LNG facility was offline since June 2022 following an explosion, but gradually resumed operations in February 2023. The increase in Cameron’s LNG exports was due to lower planned maintenance activity at the Kribi FLNG facility. Meanwhile, a decline in planned and unplanned maintenance activity at the Tangguh LNG facility coupled with the commissioning of the Tangguh LNG train 3 facility drove Indonesia’s LNG exports higher. The decline in unplanned maintenance at the Snohvit LNG facility contributed to the increase in Norway’s LNG exports. Conversely, lower feedgas availability in Brunei led to a drop in its LNG exports.

In 2024, it is projected that approximately 15 Mtpa of liquefaction capacity will be brought online, primarily led by Russia, the US, Mauritania/Senegal, Mexico and the Republic of the Congo. Five new LNG export projects are expected to commence operations, including Altamira FLNG (1.4 Mtpa), Arctic LNG trains 1 (13.2 Mtpa), Congo FLNG 1 (0.6 Mtpa), GTA FLNG phase 1 (2.5 Mtpa) and the initial trains from Plaquemines LNG phase 1 (3.76 Mtpa). The commissioning of Arctic LNG train 1, GTA FLNG phase 1 and Congo FLNG has been delayed from 2023.

Looking ahead to 2025, the forecasted commissioned liquefaction capacity is expected to surge to 53 Mtpa, which may initiate a medium-term oversupply in the LNG market.
The US will spearhead the growth in new capacity additions, followed by Qatar, Russia, Canada and Mexico. Among the new projects are Arctic LNG train 2 (6.6 Mtpa), the initial trains from Corpus Christi LNG stage 3 (1.64 Mtpa), Energia Costa Azul phase 1 (3.5 Mtpa), Golden Pass LNG trains 1 and 2 (12 Mtpa), LNG Canada train 1 (14 Mtpa), the first train from Qatar LNG phase 1 expansion (8 Mtpa), the remaining trains from Plaquemines LNG phase 1 (10.02 Mtpa) and the initial trains from Plaquemines LNG phase 2 (3.76 Mtpa).

The surge in commissioning of new liquefaction capacity in 2025 may initiate a potential medium-term oversupply in the LNG market. However, we expect the additional LNG supply to boost gas demand globally, which could help stabilise the gas markets.

4.2.1.3 FIDs on New LNG Export Projects

Investment in new liquefaction capacity was dominated by the US, with additional investments expected from both the US and GECF Member Countries in the near future. In 2023, there was a recovery in final investment decisions (FIDs) in new liquefaction capacity, reaching 41 Mtpa compared to 32 Mtpa in 2022 (Figure 117). However, the total FIDs remained below the 2021 level. Despite the sharp decline in spot gas and LNG prices last year, strong long-term LNG contracting supported the rebound in FIDs. Among the four LNG export projects that received FIDs last year, three were from the US, including Plaquemines LNG phase 2 (8.8 Mtpa), Port Arthur LNG phase 1 (13.5 Mtpa) and Rio Grande LNG phase 1 (17.6 Mtpa). The only non-US project was the 0.7 Mtpa Gabon FLNG from the Republic of Gabon.

In the short term, more than 230 Mtpa of liquefaction capacity is targeting FID between 2024 and 2025 (Table 3). The US accounts for almost 50% of this capacity followed by Russia (11%), Mexico (8%), Mozambique (8%), Qatar (7%), Tanzania (4%) and the UAE (4%).

Table 3: LNG export projects targeting FID in 2024 and 2025

<table>
<thead>
<tr>
<th>Country</th>
<th>Project</th>
<th>Operator</th>
<th>Capacity (Mtpa)</th>
<th>FID Target</th>
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<tr>
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<td>Excelerate Energy</td>
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<td>Canada</td>
<td>Cedar LNG</td>
<td>Cedar LNG</td>
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<td>2024</td>
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<td>Amigo LNG</td>
<td>LNG Alliance</td>
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<td>2024</td>
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<td>Saguaro Energia LNG (Phase 1)</td>
<td>Mexico Pacific Ltd.</td>
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<td>2024</td>
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<td>Coral South FLNG 2</td>
<td>Eni</td>
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Source: GECF Secretariat based on data from Argus, ICIS LNG Edge, Refinitv, Rystad Energy and Project Updates

(*) Forecast for the commissioning of new liquefaction capacity
### Gas Trade

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</tr>
<tr>
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<td>Papua LNG</td>
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<td>3.28</td>
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</table>

Source: GECF Secretariat based on data from Argus, ICIS LNG Edge, Refinitiv, Rystad Energy and Project Updates

### 4.2.1.4 Liquefaction Plant Outages

The impact of liquefaction plant shutdowns on LNG production saw a notable decrease, mainly because of a significant drop in unplanned outages.

In 2023, the cumulative impact of scheduled maintenance, unexpected outages and various factors at liquefaction facilities worldwide amounted to 16 Mt, equivalent to 3.3% of global liquefaction capacity (Figure 118). This marked a substantial 50% decrease compared to 2022, reaching the lowest level in the past five years. The reduction was primarily driven by fewer unplanned outages, and to a lesser extent, limited effects from weather conditions, along with a decline in planned maintenance activities at certain liquefaction facilities.

Regarding the decrease in unplanned outages, the most significant decline was observed at the Freeport LNG facility in the US, which gradually resumed operations in February 2023 following an explosion in June 2022. Likewise, the Snohvit LNG facility in Norway witnessed a considerable increase in production compared to the previous year, as the facility resumed operations in May 2022 following a fire in September 2020. Additionally, the Arzew LNG facility in Algeria encountered fewer unplanned outages in 2023.

With regards to weather-related impact, no interruptions to LNG production and exports caused by storms, hurricanes, or flooding occurred in 2023. Lastly, significant reductions in planned maintenance activity were observed at liquefaction facilities in Angola, Australia, Indonesia, Qatar and the United Arab Emirates. This offset the higher planned maintenance in Russia and Trinidad and Tobago.

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**Figure 118: Trend in global liquefaction plant outages**

![Figure 118: Trend in global liquefaction plant outages](image-url)

Source: GECF Secretariat based on data from Argus, ICIS LNG Edge and Refinitiv

Note: Other refers to activities not associated with the LNG facility such as pipeline and upstream maintenance.
4.2.1.5 Global LNG Reloads

Spain maintained its position as the leading LNG re-exporter, despite a drop in its LNG reloads, while China and Indonesia recorded significant increases in their LNG reloads. In 2023, global LNG reloads expanded sharply by 18% (0.8 Mt) y-o-y to 5.4 Mt (Figure 119), which is the highest reloads since 2014. The significant expansion in LNG reloads came mainly from Brazil, China, Indonesia, Jamaica and Singapore, which offset weaker reloads from Spain. Although Spain’s LNG reloads declined last year, it retained its position as the largest LNG re-exporter globally, followed by China, Indonesia, Singapore and France.

Brazil re-exported two LNG cargoes in 2023 to Spain and to Türkiye. QatarEnergy may have facilitated the re-export to Türkiye. QatarEnergy has a six-month agreement with Brazil’s Eneva, running from October 2023 to March 2024, to utilise the Sergipe FSRU for LNG storage, thereby enhancing its trading activities. The increase in Chinese LNG reloads can be attributed to an excess of contracted LNG supply and the existence of arbitrage opportunities with neighbouring markets, considering the long-term cost of LNG supply to China. China LNG re-exports to Japan and Thailand grew substantially last year.

In Indonesia, increased domestic LNG trade and a rise in LNG re-exports to North East Asian countries, excluding China, contributed to the boost in its LNG reloads. Notably, TotalEnergies and other portfolio players or traders have agreements with Pertamina to utilize LNG tanks for storage and reloading at the Arun LNG terminal, with the eventual aim of re-exporting to other markets. Simultaneously, Jamaica experienced a surge in LNG reloads last year, primarily driven by an increase in LNG re-exports to Puerto Rico.

The Jones Act restricts the movement of goods between US ports to vessels that are owned, built, crewed and registered in the US. As there are currently no LNG vessels meeting these requirements, direct shipping of LNG from the US to Puerto Rico is not possible. Consequently, New Fortress Energy sourced LNG from Jamaica, via reloads, to supply Puerto Rico.

Similar to Indonesia, Singapore serves as a hub for portfolio players and traders engaging in LNG storage, reload and subsequent re-export to other Asia Pacific markets. The resurgence in spot LNG demand in the Asia Pacific region contributed to an increase in Singapore’s LNG reloads in 2023. In contrast, Spain experienced a decline in LNG reloads, driven by a significant drop in intra-regional LNG trade, especially to Italy and the Netherlands. The heightened LNG imports from the US in Italy and the Netherlands diminished the necessity for LNG re-exports from Spain. Additionally, Spain’s Naturgy augmented its LNG re-exports to Puerto Rico to fulfil its contractual obligations under its long-term agreement with PREPA.

4.2.2 LNG Demand

4.2.2.1 Global LNG Imports

The shift in LNG trade flows observed in 2022 ceased in 2023, as the Asia Pacific region once again emerged as the primary market for LNG and drove the increase in global LNG imports. In 2023, global LNG imports rose by 2.5% (10 Mt), surpassing the 400 Mt milestone to reach 408 Mt (Figure 120). However, this growth rate marks a notable slowdown from 2022. The increase in Asia Pacific’s LNG imports, along with stronger imports in LAC, drove the global rise, counterbalancing a slight decline in Europe. Meanwhile, LNG imports in MENA and North America remained relatively stable compared to the previous year.

Global LNG imports in 2024 are projected to rise by 2-2.5% (8-10 Mt), led by increased gas demand in the Asia Pacific, notably in China and South/Southeast Asia. Additionally, a further decline in spot LNG prices is anticipated to boost spot LNG demand in the region.
Regarding the regional distribution of global LNG imports, Asia Pacific retained its status as the largest regional market with an import share of 64.7%, followed by Europe (30.3%), LAC (2.9%), MENA (1.8%) and North America (0.3%). Compared to 2022, Asia Pacific and LAC saw an increase in their market share in global LNG imports, rising from 63.5% and 2.7%, respectively, while Europe’s share declined from 31.7% (Figure 121). Meanwhile, the market share of MENA and North America remained unchanged from 2022. The growth in the market share of Asia Pacific and LAC can be attributed to stronger LNG imports in both regions, whereas the decrease in Europe’s LNG imports led to a reduction in its market share.

The shift in LNG flows away from Asia Pacific to Europe, observed in 2022, came to a halt in 2023. During H1 2023, both regions experienced increases in LNG imports, with Europe seeing a notably larger increment compared to Asia Pacific. However, in H2 2023, there was a surge in Asia Pacific’s LNG imports, offsetting weaker imports in Europe (Figure 122). This marked a reversal in the flow shift from Asia Pacific to Europe, prompted by the growing premium of NEA spot LNG prices over the TTF prices, coupled with subdued LNG demand in Europe.

The widening price gap between the two markets resulted in Asia Pacific reclaiming its title as the premium destination for LNG, particularly from the Middle East and, to a lesser extent, from the US. Consequently, there was a partial redirection of Qatar’s LNG trade flows from Europe to Asia Pacific, which was also influenced by an increase in long-term contractual LNG supplies from Qatar to China. Regarding US LNG trade flows, exports to the Asia Pacific market experienced a significant surge during H2 2023 compared to exports to the European market.

Despite the drop in pipeline gas imports, Europe’s LNG imports declined slightly due to weaker gas consumption and high gas storage levels

In 2023, European LNG imports fell from its record high in 2022 by 1.9% (2.4 Mt) to 124 Mt, which is the region’s second-highest annual level. Despite the drop in pipeline gas imports, LNG Imports also declined due to weaker gas demand and high storage levels. The UK, France, Spain, Portugal, Türkiye and Belgium led the reduction in LNG imports, which was partially offset by stronger imports from Germany, the Netherlands, Italy and Finland (Figure 123).
In the UK, the decline in LNG imports was driven by weaker gas consumption and a drop in pipeline gas exports to mainland Europe. The weaker LNG imports in France were attributed to lower gas consumption, increased pipeline gas imports from Spain, and decreased pipeline gas exports to Belgium and Switzerland. Spain’s LNG imports declined last year due to a fall in gas consumption and reduced LNG re-exports, particularly to Italy.

Meanwhile, the fall in Portugal’s LNG imports was driven by weaker gas consumption. In Türkiye, the decrease in LNG imports was a result of higher gas production and weaker gas consumption. Furthermore, the lower LNG imports in Belgium were due to lower gas consumption and declines in pipeline gas exports to Germany and the Netherlands.

Conversely, the increase in LNG imports in Germany was driven by lower pipeline gas imports from Russia. The stronger LNG imports were facilitated by the recent start-up of three LNG import terminals in the country. In the Netherlands, weaker domestic gas production and higher pipeline gas exports to Germany boosted its LNG imports. This was also facilitated by the recent start-up of two LNG import terminals in the country. Similarly, a drop in pipeline gas imports from Russia coupled with an increase in pipeline gas exports to Slovenia boosted Italy’s LNG imports. Moreover, the start-up of the Inkoo FSRU in Finland, a joint project with Estonia, facilitated the increase in LNG imports in Finland.

4.2.2.1.2 Asia Pacific

China reclaimed its position as the world’s largest LNG importer and accounted for the bulk incremental increase in LNG imports across the Asia Pacific region

In 2023, LNG imports in the Asia Pacific region increased by 4.3% (11 Mt) y-o-y to reach 264 Mt, marking a reversal from the decline seen in 2022. However, it is worth noting that the region’s imports remained below the 2021 level of 274 Mt. The uptick in LNG imports was attributed to the resurgence in Chinese gas demand and the softening of spot LNG prices, which stimulated spot LNG demand in price-sensitive countries, particularly in South and Southeast Asia. Leading the growth in the region’s LNG imports were China, Thailand, India, Singapore, Bangladesh and the Philippines, which compensated for weaker imports from Japan and South Korea (Figure 124). Notably, the Philippines and Vietnam joined the ranks of LNG importers in 2023.

In China, the post-Covid recovery in gas consumption coupled with lower spot LNG prices boosted its LNG imports. Despite the rebound in Chinese LNG imports, it remained below the 2021 level of 80 Mt. China also reclaimed its position as the largest LNG importer, overtaking Japan. The jump in Thailand’s LNG imports was driven by a decline in domestic gas production and lower spot LNG prices. Meanwhile, the softening of spot LNG prices supported the increase in LNG imports in Bangladesh and India. In Singapore, the expansion in LNG imports was mainly attributed to the start of long-term LNG supplies under the sale and purchase agreement (SPA) between QatarEnergy and Pavilion Energy and lower pipeline gas imports.

Conversely, the drop in Japan’s LNG imports was mainly attributed to weaker gas consumption in the power sector, due to higher nuclear availability. In South Korea, the decline in gas consumption in the city gas and power sectors led to a decrease in LNG imports.

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4.2.2.1.3 North America
In 2023, North America’s LNG imports recorded a decrease of 1.7% (0.02 Mt) y-o-y, reaching a low of 1.2 Mt. This decline was driven by weaker imports from Canada and the US, which offset an increase in Mexico’s imports (Figure 125). The reduction in LNG imports from Canada and the US can be attributed to enhanced gas production in both countries. Conversely, the uptick in Mexico’s LNG imports was a result of reduced pipeline gas imports from the US.

4.2.2.1.4 Latin America and the Caribbean (LAC)
In 2023, LNG imports in LAC grew by 11% (1.15 Mt) to reach 12 Mt, marking the second-highest annual import volume in the last five years (Figure 126). Increased imports in Puerto Rico and El Salvador were facilitated by a ramp-up in recently commissioned import terminals. In Colombia, heightened gas demand in the electricity sector, prompted by reduced hydro output from the El Niño phenomenon, bolstered LNG imports. Argentina experienced a rise in LNG imports due to a decrease in pipeline gas imports. Conversely, Brazil saw a significant downturn in LNG imports attributed to reduced gas demand in the electricity sector.

4.2.2.1.5 Middle East and North Africa (MENA)
In 2023, LNG imports in the MENA region increased by 4.9% (0.4 Mt) to 7.4 Mt (Figure 127). This represented a modest recovery in the region’s LNG imports, following the decline in 2022. The stronger LNG imports in Kuwait were supported by higher gas demand, while an increase in LNG exports from Qatar boosted LNG imports in the United Arab Emirates. Jordan’s LNG imports remained unchanged from the previous year.
4.2.2.2 Start-up of New LNG Regasification Capacity

The commissioning of new LNG import capacity hit a record high, with China leading the growth and the Philippines and Vietnam joining the club of LNG importers. In 2023, 78 Mtpa of LNG regasification capacity was commissioned (Figure 128), bringing the total operational regasification capacity to 1,077 Mtpa, marking the highest capacity commissioned in a single year. The Asia Pacific region accounted for 70% of the regasification capacity commissioned last year, with Europe contributing the remaining 30%. In terms of capacity utilization, it averaged 37% in 2023, slightly down from 39% the previous year.

At a country level, China led the growth with 30 Mtpa, followed by Germany (10 Mtpa), the Philippines (10 Mtpa), Hong Kong (6 Mtpa), Türkiye (6 Mtpa) and India (5 Mtpa). Major projects that commenced operations last year include the Hong Kong FSRU (6 Mtpa) and Beijing Gas Tianjin Nangang LNG Phase 1 (5 Mtpa) in China, Elbehafen FSRU 1 (5.8 Mtpa) in Germany, Saros FSRU (5.6 Mtpa) in Türkiye, Batangas FSRU (5.3 Mtpa) and PHLNG (5 Mtpa) in the Philippines, Dhamra LNG (5 Mtpa) in India. Additionally, the Philippines and Vietnam joined the club of LNG importers last year.

In 2024, almost 130 Mtpa of regasification capacity is planned to commence operations, led by China with 49 Mtpa, followed by India (19 Mtpa), Brazil (17 Mtpa), Germany (15 Mtpa) and Vietnam (5 Mtpa). If most of these projects commence operations in 2024, it could be another record year for the commissioning of new regasification capacity. Further ahead in 2025, the planned commissioning of new regasification capacity stands at 40 Mtpa.

4.2.2.3 Trend in Global LNG Trade by Duration

Medium and long-term LNG trade continued to dominate the global LNG market, while spot and short-term LNG trade experienced a slight contraction. Spot and short-term LNG trade encompasses LNG cargoes traded under contracts of two years or less. LNG cargoes traded were categorized into spot and short-term (spot|ST) and medium-term and long-term (MT|LT) trade. However, for several cargoes, sales basis data was unavailable, leading to their classification as ‘others’. Consequently, the actual spot|ST and MT|LT trade may be higher than the data provided in this report.

In 2023, spot|ST trade declined by 2.4% (2.3 Mt) to 94 Mt (Figure 129). Similarly, the share of spot|ST trade in global LNG trade decreased by one percentage point to 23%, its lowest level in the past five years. This decline may be attributed to higher spot LNG prices compared to oil-indexed prices, making long-term oil-indexed supply more appealing than spot LNG supplies. Conversely, MT|LT LNG trade maintained its dominance in global LNG trade, with a 70% share.

The decrease in spot|ST LNG imports was primarily driven by Asia Pacific and European regions. At the country level, weaker spot|ST LNG imports were observed in Japan, Spain, South Korea, Türkiye, Taiwan and Poland (Figure 130). This drop was due to weaker gas demand in all these countries except Taiwan. Conversely, significant increases in spot|ST LNG imports were observed in China, Germany, The Netherlands, Finland, Bangladesh, India and Italy. In China, Thailand, Bangladesh and India, the sharp decline in spot LNG prices stimulated spot LNG demand in these price-sensitive markets. Meanwhile, stronger spot LNG demand in the Netherlands, Finland and Italy contributed to the rise in spot|ST LNG imports.

On the export side, the US, Algeria, Mozambique and Brunei experienced significant growth in spot|ST LNG exports. In contrast, spot|ST LNG exports from Egypt, Indonesia, Malaysia and Qatar substantially decreased.
4.2.3 LNG Shipping

4.2.3.1 LNG Shipments

The LNG shipping market continued to expand, to keep pace with demand

In 2023, the number of LNG cargoes exported globally reached 6,266 (Figure 131). This figure was just 1% (representing 56 cargoes) higher than 2022 levels and continued the overall trend of the increasing number of LNG cargoes exported annually in the past three years. The average number of LNG cargoes exported each month rose from 518 in 2022, to 522 in 2023.

On a country level, the United States was the top exporter in 2023 in terms of number of LNG shipments delivered, displacing Australia which held the top spot for the previous four years (Figure 132). Six GECF countries occupy are within the top ten spots for 2023: Qatar, Russia, Malaysia, Algeria, Nigeria and Trinidad and Tobago.

In 2023, the US delivered 123 more LNG cargoes than in the previous year, an increase of 10%. The next highest increases were recorded by Algeria with 54 cargoes, Mozambique with 38 cargoes, and Norway with 29 cargoes. Without considering Mozambique which started operations late in 2022, the highest percentage increase in LNG cargo deliveries in 2023 was observed by Norway, which exported 59% more cargoes from its Hammerfest project, compared with 2022. GECF countries Algeria, Peru and Angola followed, recording increases of 25%, 20% and 12%, respectively.

In 2024, the prospects for LNG cargo deliveries are expected to be bolstered by the increasing demand for natural gas in current and emerging markets. This will be supported by the startup of several new LNG projects during the year. However, the LNG shipping market may experience competing influences. On one hand, a wave of new LNG carriers is expected to join the global fleet. Conversely, the shipping market may become tightened by the withdrawal of several vessels, either due to increasing maritime regulations or to be repurposed as FSUs and FSRUs.
4.2.3.2 LNG Shipping Cost

The cost of shipping LNG cargoes fell, mainly driven by a stabilisation in vessel charter rates.

There are several factors which impact the cost of shipping LNG cargoes: the distance between the loading and receiving port, the cost of chartering the LNG carrier, fuel costs and the destination price of the LNG at the receiving terminal.

For LNG carriers, the steam turbine-powered vessels remain the largest segment of the global fleet, accounting for over 30% of all active carriers. The monthly average spot charter rate for steam turbine LNG carriers experienced some level of volatility throughout 2023 (Figure 133). However, contrary to the trend seen in some previous years where there were notable spikes in charter rates, the developments in 2023 generally followed the seasonal trend, while largely keeping in line with the five-year average.

Charter rates commenced the year with a continuation of the downward trend, which started in November 2022. Leading up to the start of the 2022/23 northern hemisphere winter, buyers had secured several carriers to be used as floating gas storage, especially around European ports. As the winter season progressed, and gas was taken out of storage on the continent, these floating cargoes soon discharged and returned to active duty. This alleviation of market tightness was reflected in a softening of the average charter rates, which was observed during Q1 2023. Moreover, the warmer-than-anticipated winter conditions resulted in lower gas demand, and Europe ended the season with higher-than-average levels of gas still in storage. Accordingly, in the months immediately following winter, charter rates continued to slide further, because of a reduction in inter-basin LNG flows.

By summer of 2023, a reversal of the downward trend was observed. This was driven by a growing gas demand in Asia, which prompted arbitrage opportunities between the Atlantic and Pacific basins. The tightening of the shipping markets was exacerbated by the gas storage filling regulations in the EU, as EU countries stockpiled gas to meet regional targets. Charter rates climbed in August and September, as European gas storage sites approached filled capacity. In an atypical trend, the average charter rate declined thereafter, driven by early deliveries to Europe and the discharging of floating cargoes, despite the ongoing inter-basin arbitrage. As the year ended, tempered gas demand in Asia led to higher carrier availability in the Pacific Basin, and thus led to a loosening of the shipping market. As such, 2023 concluded with a marked decline, and the December average charter rate was the lowest in the past five years.

The price of the leading shipping fuels follows a trend which is largely linked with the price of oil. Similar to the LNG carrier charter market, in 2023, the monthly average prices of shipping fuels had less volatility than in 2022, while generally returning to a level closer to the five-year average (Figure 134). The average price of shipping fuels for 2023 was $590/t, compared with the five-year average price of $483/t, and 23% lower than the average level recorded in 2022.

Due to the decline in these two key variables, as well as in the delivered price for LNG, there was an overall decrease in the spot LNG shipping cost for steam turbine carriers in 2023, when compared with the previous year (Figure 135). Considering the cost of shipping cargoes from selected regions to key demand centres globally, LNG shipping costs in 2023 were observed to have declined by up to $1.40/MMBtu on certain routes relative to the previous year. Due to the extreme market conditions, 2022 may be considered anomalous. However, even when compared with 2021, the average LNG shipping costs in 2023 were up to $0.24/MMBtu lower on certain routes.
This was due to the lower delivered LNG prices as well as lower average charter rates in 2023, despite having a higher average price of shipping fuels than in 2021.

The spot charter rate, cost of shipping fuel and the delivered destination price of LNG are the main drivers which would determine the estimates of shipping cost for spot LNG cargoes in 2024. Over the years, these factors have followed seasonal trends, with expected upticks as the market tightens closer to periods of higher demand, such as the northern hemisphere winter season. However, the LNG shipping cost remains highly sensitive to fluctuations in the market, which may arise due to a myriad of factors, including geopolitical developments, global supply-demand dynamics and increased maritime decarbonisation measures.

Table 4: Capacity classifications for LNG carriers

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</thead>
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<td>Less than 60,000</td>
</tr>
<tr>
<td>Mid-size</td>
<td>Between 60,000 and 90,000</td>
</tr>
<tr>
<td>Old Standard Carrier</td>
<td>Between 125,000 and 170,000</td>
</tr>
<tr>
<td>New Conventional Carrier</td>
<td>Between 170,000 and 200,000</td>
</tr>
<tr>
<td>Q-flex Carrier</td>
<td>Between 210,000 and 220,000</td>
</tr>
<tr>
<td>Q-Max Carrier</td>
<td>Between 260,000 and 270,000</td>
</tr>
</tbody>
</table>

Source: GECF Secretariat

Thirty-six new carriers were commissioned over the course of 2023. As such, there was a 5% increase in the size of the global fleet of LNG carriers, which continued the overall trend of an increase in the number of vessels being commissioned each year (Figure 136). This annual growth rate was higher than the 4% recorded in 2022 but was notably less than the 9% average growth rate recorded during the previous five years.

Figure 135: Spot shipping costs for steam turbine LNG carriers

Source: GECF Secretariat based on the GECF Shipping Cost Model

4.2.3.3 LNG Carrier Fleet

The global LNG carrier fleet continued to grow, but the sizeable expansion will take place within the next two years

As of end January 2024, the size of the global fleet of LNG carriers stood at 724 vessels. Of the 724 vessels, 672 vessels may be considered as “active” LNG carriers. The remaining 52 vessels in the global fleet currently serve as FSRUs and FSUs at various locations worldwide. There is a wide range of size classifications into which the active LNG carriers may be subdivided, and these are shown in Table 4.
Of the 672 active LNG carriers, 302 vessels are of the old standard sized carrier class and 295 vessels are the new conventional size class (Figure 137). The remaining 10% of the global fleet consists of LNG carriers at the upper and lower ends of the size class spectrum.

Figure 138 shows the capacity additions to the global LNG fleet each year since 2010, with the distribution by size class of the active carriers, as well as those which operate as FSUs/FSRUs.

Compared with the previous year, there was a rebound in the total LNG carrier capacity being commissioned in 2023: around 6,500,000 cubic metres of capacity was added to the global fleet, signifying an increase of 39%. In recent years, the industry has shifted toward the construction of the larger New Conventional Carriers, as opposed to the Old Standard size class. In 2023, there were 5,600,000 cubic metres of capacity commissioned in the New Conventional size class, compared with 4,400,000 cubic metres in 2022, and 8,900,000 cubic metres in 2021.

Overall, as of end January 2024, the total capacity of the global fleet of active LNG carriers reached 107,800,000 cubic metres. LNG carriers in the New Conventional size class account for the majority (48%) of the fleet, while the vessels in the Old Standard size class contribute to 42% of the fleet’s capacity (Figure 139). The ultra-large grouping of the Qatari Q-Flex and Q-Max carriers comprise almost 10% of the world’s LNG carrier capacity, while small-scale and mid-sized vessels together account for less than 2%.

Close to 100 new LNG carriers are expected to be commissioned over the course of 2024 (Figure 140). Of the newbuild projects for which the details are available, it is expected that most of these vessels will have a capacity of 174,000 cubic metres. In the coming years, there may be at least 250 LNG carriers in the New Conventional size class being launched by 2027.
South Korean shipyards remain the world’s leader for LNG carrier construction, with Hyundai Heavy Industries, Samsung Heavy Industries and Hanwha Ocean (formerly Daewoo Shipbuilding & Marine Engineering) accounting for at least three-quarters of the global orderbook (Figure 141). Qatar has been collaborating with these three South Korean majors in their upcoming phase of LNG carrier fleet expansion. QatarEnergy is advancing negotiations on the procurement of forty carriers, each with a capacity at least 170,000 cubic metres.

In the meantime, Chinese shipyards have been increasing in prominence in recent years, bolstered by lower costs for shipbuilding, as well as the unavailability of shipyard slots in South Korea. The current average level for newbuild LNG carrier construction in a South Korean shipyard has increased towards the range of $260 million, driven by the cost of steel and higher demand for shipyard slots. Conversely, Chinese shipyard costs are approximately $30 million to $40 million lower than their South Korean counterparts.
Gas Storage

5.1 Underground Gas Storage

Total capacity for underground gas storage increased, driven by China

In 2023, the total working capacity of underground gas storage (UGS) sites across the globe reached 430 bcm, which marked a 1.3% increase compared to 2022 and stresses the significance of gas storage as both a strategic energy reserve as well as a buffer to price shocks.

North America possesses 38% of the world’s working capacity for underground gas storage, followed by Europe with 26% and Eurasia with 28% (Table 5). On the country level, the US has the highest capacity with 134 bcm. This is followed by Russia with 75 bcm of capacity, Ukraine with 31 bcm, Canada with 29 bcm and Germany with 23 bcm.

Table 5: UGS working capacity by region and country

<table>
<thead>
<tr>
<th>Region</th>
<th>UGS capacity (bcm)</th>
<th>Country/subregion</th>
</tr>
</thead>
<tbody>
<tr>
<td>North America</td>
<td>163</td>
<td>USA</td>
</tr>
<tr>
<td></td>
<td>134</td>
<td>USA</td>
</tr>
<tr>
<td></td>
<td>29</td>
<td>Canada</td>
</tr>
<tr>
<td></td>
<td>104</td>
<td>EU</td>
</tr>
<tr>
<td>Europe</td>
<td>112</td>
<td>EU</td>
</tr>
<tr>
<td></td>
<td>8</td>
<td>Non-EU</td>
</tr>
<tr>
<td>Eurasia</td>
<td>119</td>
<td>Russia</td>
</tr>
<tr>
<td></td>
<td>75</td>
<td>Ukraine</td>
</tr>
<tr>
<td></td>
<td>31</td>
<td>Other Eurasia</td>
</tr>
<tr>
<td>Asia Pacific</td>
<td>29</td>
<td>China</td>
</tr>
<tr>
<td></td>
<td>21</td>
<td>China</td>
</tr>
<tr>
<td></td>
<td>8</td>
<td>Other Asia Pacific</td>
</tr>
<tr>
<td>Middle East</td>
<td>7</td>
<td>Iran</td>
</tr>
<tr>
<td></td>
<td>3</td>
<td>UAE</td>
</tr>
</tbody>
</table>

Source: GECF Secretariat based on data from Cedigaz
China continues to expand its underground gas storage infrastructure, which now stands at 21 bcm of capacity. Accordingly, the Asia Pacific region has been the primary driver in the growth of the underground gas storage sector in recent years (Figure 142). Three bcm of capacity was added in 2023, bringing the total in the Asia Pacific region to 29 bcm. In Europe, capacity increased by 2 bcm in 2023 while North America’s capacity remained unchanged.

There are three main formations which are utilised for underground gas storage sites: depleted oil or gas fields, aquifers, and salt caverns. The reinjection of gas in depleted fields is the most popular of the three due to two main reasons. Firstly, these depleted fields possess the necessary permeability and porosity required for gas storage. Secondly, the required infrastructure is already in place, such as pipelines and wells.

On the global level, the utilisation of depleted fields accounts for 81% of the total working gas capacity (Figure 143). There are over 570 such sites located around the globe, with 360 in North America and 109 in Europe.

The use of aquifers for underground gas storage accounts for 11% of the total global capacity. Aquifers store water in the same way that porous rock stores hydrocarbons. As such, depleted aquifers have proven to be ideal for underground gas storage. There are more than 80 sites, with over half of them located in North America.

The final type of underground gas storage involves the utilisation of underground rock salt caverns. This method is particularly popular in Europe and North America, and accounts for 8% of global working gas capacity. There are close to 120 salt cavern storage sites worldwide, with around half of these located in Europe.

The level of gas in storage remained at the higher end of the five-year range. The countries of the European Union operate 104 bcm of working capacity for underground gas storage. Gas storage has always represented a significant element of the European gas market, with well-defined cycles of net gas injections leading up to the peak demand time of the winter season. Gas storage has taken on increased significance in the region in recent years, which prompted the European Commission to implement legislation regarding the restocking of gas storage sites within the EU member states. Specifically, EU countries are required to fill gas storage sites to a minimum of 80% by November 1, 2022, and to a minimum of 90% by November 1 in the years 2023 to 2025.

These measures came into effect at the conclusion of the 2021/22 winter season, and thus greatly influenced the filling of underground gas storage sites during the summer months of 2022. The European Commission further imposed restrictions on its member states to curb the demand for gas, and this, along with the strong stockpiling in 2022 and the mild weather conditions, ensured that gas storage levels remained elevated as the region progressed through the winter of 2022/23 (Figure 144).

5.1.1 Europe

5.1.1.1 Underground Gas Storage in the EU

The countries of the European Union operate 104 bcm of working capacity for underground gas storage. Gas storage has always represented a significant element of the European gas market, with well-defined cycles of net gas injections leading up to the peak demand time of the winter season. Gas storage has taken on increased significance in the region in recent years, which prompted the European Commission to implement legislation regarding the restocking of gas storage sites within the EU member states. Specifically, EU countries are required to fill gas storage sites to a minimum of 80% by November 1, 2022, and to a minimum of 90% by November 1 in the years 2023 to 2025.
In January 2023, the average level of gas in storage in the EU was 83.5 bcm, representing 78% of the region’s working gas capacity. Moreover, this quantity was 19 bcm greater than the five-year historical average for the month. Sustained curbing of gas demand, as well as the warmer-than-usual winter, contributed to the widening of the delta between the current and historical storage levels, culminating in an excess of 22 bcm at the conclusion of winter.

With gas storage levels in April 2023 at the top of the five-year historical range, a smaller quantity of gas injection was required during the summer months of 2023 to meet the EU target, compared with same period in 2022. Consequently, the rate of gas restocking in 2023 was much slower than in 2022, including the five-year historical average (Figure 145). During the months April to October, the average rate of stockbuild in the EU countries was just 1.5 bcm per week in 2023, in comparison with 2.3 bcm per week in 2022, and the five-year historical average rate of 1.9 bcm per week.

The EU countries achieved the 90% minimum filling target in mid-August 2023, ahead of schedule. This enabled at least two months of lower rates of gas injection, averaging around 0.9 bcm per week, leading up to the start of winter 2023/24. From August to November, the level of gas in storage was beyond the highest point of the five-year range. Gas storage sites in the EU attained a regional high of 99.6% filled during the first week of November 2023.

The top five countries for underground gas storage capacity in the EU are Germany, Italy, Netherlands, France, and Austria. Figure 146 shows the level of gas storage in the EU at key dates in 2023. As of December 31, 2023, these five countries recorded over 80% filled capacity, with Germany and Austria having gas in storage even beyond the 90% mark.
In 2024, EU countries are obligated to fill underground gas storage sites to a minimum of 90% capacity by November 1. Additionally, the European Commission has designated storage level targets at various checkpoints through the year (Table 6).

### Table 6: Gas storage targets in the EU in 2024

<table>
<thead>
<tr>
<th>2023 Date</th>
<th>Minimum Storage Target Percentage</th>
<th>Volume (bcm)</th>
</tr>
</thead>
<tbody>
<tr>
<td>February 1</td>
<td>45%</td>
<td>47</td>
</tr>
<tr>
<td>May 1</td>
<td>27%</td>
<td>28</td>
</tr>
<tr>
<td>July 1</td>
<td>47%</td>
<td>48</td>
</tr>
<tr>
<td>September 1</td>
<td>73%</td>
<td>76</td>
</tr>
<tr>
<td>November 1</td>
<td>90%</td>
<td>94</td>
</tr>
</tbody>
</table>

Source: GECF Secretariat based on data from the European Commission and Cedigaz

#### 5.1.1.2 Relationship between Gas Prices and the Filling of UGS Sites in the EU

There is some level of correlation between the monthly variations of the gas storage level with the gas prices in the EU (Figure 147). Prior to 2022, this relationship could have been simplified into a seasonal trend whereby storage site operators replenished their stocks with lower-priced gas in the summer months, to sell during high-demand winter period when prices become elevated.

In January 2021, the TTF was below $8.00/MMBtu, and the storage level in the region stood at around the five-year historical mark. As the year progressed, gas demand rebounded amidst the recovery of the first wave of the Covid-19 pandemic. In response, gas prices rose, and eroded the incentive of storage site operators during the net injection season. As such, the rate of restocking was muted, and variation from the five-year average became increasingly negative.

In 2022, driven by the European Commission’s gas storage policy. Storage site operators were obligated to meet capacity targets, despite the soaring gas prices, and the variation of storage levels narrowed to the five-year average, closing completely by August 2022. The 2022 target of 80% storage levels was attained in September of that year, reducing the demand for gas, and prompting a decline in the TTF.

In 2023, there was less pressure on storage operators to refill gas stocks. The variation against the five-year average remained positive throughout the year, ranging from 22 bcm, down to 13 bcm by the end of 2023. Similarly, TTF displayed much less volatility, and stabilised around $12.00/MMBtu in the latter half of the year.

#### 5.1.1.3 Underground Gas Storage Balance in the EU

Due to the policies of the European Commission, a widening trend between gas storage levels and the volume of gas consumption was observed over the past three years (Figure 148). The level of gas consumption in the region is cyclical, with gas demand during the winter months being around 1.8 times the volume of gas consumed during the summer months. In 2022, the gas demand reduction measures curbed winter gas consumption by 15% y-o-y, a trend which may be expected to continue into the 2023/24 winter season. Consequently, storage levels at almost maximum capacity may be estimated to satisfy around 10 weeks of winter gas consumption in the region.
Different dynamics influenced the annual cycle of gas restocking and withdrawals over the past five years (Figure 149). The price pressure on storage operators during the summer of 2021 resulted in just 48 bcm being injected. Some 52 bcm were withdrawn during the subsequent winter, bringing the region’s average storage level to the lowest levels observed in the past five years. The gas filling policy was then fundamental to the 71 bcm of net gas injections during the summer of 2022. With just 40 bcm of withdrawals in the 2022/23 winter, the region entered the net gas injection season of 2023 at the highest level in the past five years. Only 36 bcm of stockbuild was required to meet the minimum EU target. However, the region pushed ahead to almost full capacity, recording 47 bcm of injections for the season.

5.1.2 Asia Pacific

The region is the global leader for the expansion of underground gas storage capacity

In the Asia Pacific region, China is the dominant player with respect to gas storage. In 2023, China increased its total working underground gas storage capacity by 3 bcm to reach 21 bcm, which represents 73% of the overall capacity in the region. Prior to the start of the country’s heating season, China had stockpiled around 19 bcm of gas in storage. China has a strategic goal to increase the gas storage capacity to the level of 13% of the nation’s gas consumption needs. To achieve this, the current capacity addition phases are expected to bring the national total to 40 bcm by 2025, 70 bcm by 2030 and to 80 bcm by 2035 (Figure 150).

Australia has the second largest storage capacity, at 7.2 bcm.

India is also seeking to utilise natural gas as a means of energy security. The government has announced ambitions to increase the share of natural gas in the country’s energy mix to 15% by the year 2030. In line with these plans, its natural gas transmission company GAIL, is developing the nation’s first strategic natural gas reserves. In the initial phase, depleted oil and gas fields will be repurposed as underground gas storage with a working capacity of 3 to 4 bcm.

![Figure 150: Global UGS status: current and future capacity](image-url)

Source: GECF Secretariat based on data from Cedigaz
5.1.3 North America

5.1.3.1 Underground Gas Storage in the US

The gas storage level in the US was higher than the five-year average.

The US operates 134 bcm of working capacity for underground gas storage. The US experienced a similar pattern of underground gas storage filling as the EU in recent years (Figure 151).

During the 2022/23 winter season, the adequate gas supply, along with the milder weather, diminished gas withdrawals. Accordingly, the level of gas in storage reached 10 bcm above the five-year average by April 2023. Even though the country commenced the net gas injection season with an elevated gas storage level, sustained stockbuild continued during the summer (Figure 152). The rate of net gas injections in 2023 averaged 1.6 bcm per week, consistent with the 1.4 bcm per week stored in 2022, and the five-year average rate of 1.5 bcm per week. The monthly gas storage level in the US continued to be higher than the five-year average throughout 2023. The maximum level of 109 bcm was attained by the final week of November 2023, corresponding to 81% of the country’s total working gas capacity.

Figure 151: UGS in the US

![Figure 151: UGS in the US](image)

Source: GECF Secretariat based on data from US EIA

5.1.3.2 Relationship between Gas Prices and the Filling of UGS Sites in the US

The correlation between the monthly variation of the gas storage level, with the gas prices in the US (Figure 153). Unlike the EU market, gas storage in the US is not influenced by government policy for the establishment of storage level targets. Instead, the expected market dynamics continue to prevail, whereby the price of gas has a major influence on the level of gas storage.

Figure 152: Weekly rate of UGS level changes in the US

![Figure 152: Weekly rate of UGS level changes in the US](image)

Source: GECF Secretariat based on data from US EIA

Figure 153: Correlation between HH and UGS levels in the US

![Figure 153: Correlation between HH and UGS levels in the US](image)

Source: GECF Secretariat based on data from US EIA and Refinitiv
For most of 2021 and 2022, the monthly average level of gas in storage was lower than the five-year historical average. In both years, the general trend was of a large increase in this variation with the five-year average during the summer months as HH rose, followed by a subsequent closing towards the end of each year.

For 2023 however, there was a net positive variation of the monthly average level of gas in storage over the entire duration of the year. This was greatly bolstered by the particularly low HH prices, averaging under $2.40/mmbtu during the crucial net gas injection months. Furthermore, in the months leading up to winter, with the EU countries surpassing their own gas filling obligations, demand for US LNG exports dipped, allowing operators to fill gas storage sites even further. The average level of gas in December 2023 was around 9 bcm higher than the five-year average.

5.1.3.3 Underground Gas Storage Balance in the US
The level of gas consumption in the US market is different from that of the EU due to two main factors. On the supply side, the US market is adequately satisfied by the high level of domestic gas production. Regarding demand however, gas is required during the summer months to satisfy electricity generation for cooling. Thus, the difference in the level of consumption between the summer and winter months is much smaller (Figure 154).

This domestic gas production also alleviates the necessity to fill gas storage to the maximum capacity (Figure 155). In 2023, 48 bcm of gas was injected during the summer months, which was 25% lower than the level of restocking which occurred in the previous year. Due to the high gas storage level attained during the year, and assuming an average level of gas withdrawal over the 2023/24 winter period, the US may expect to conclude the winter season at a level similar to 2023.

5.2 LNG Storage

5.2.1 Europe
LNG storage levels remained high, amidst ample LNG imports and elevated UGS levels
The EU countries together control LNG storage sites with a total capacity of 5.0 bcm equivalent. As of 2023, most of this capacity was located in Spain, which holds 2.0 bcm or 40% of the EU total (Figure 156). This is followed by France (16%), the Netherlands (8%) and Italy (7%).

This domestic gas production also alleviates the necessity to fill gas storage to the maximum capacity (Figure 155). In 2023, 48 bcm of gas was injected during the summer months, which was 25% lower than the level of restocking which occurred
In 2023, the level of LNG in storage during the first half of the year was consistently higher than in 2022, as well as the five-year historical average. Storage levels were kept elevated because of lower-than-anticipated heating demand during Q1 2023, as well as the high levels of gas in underground storage. There was a healthy rate of LNG storage level increases throughout the rest of the year, broadly in line with the five-year average. Ahead of the start of the 2023/24 winter season, LNG storage levels reached a high of 3.5 bcm in November 2023, which was 5% greater than the same period one year prior, and 7% more than the five-year average for the month (Figure 157).

Both Japan and South Korea amassed large quantities of LNG in the lead up to the 2022/23 winter season. However, the sendout of stored LNG was muted, amidst the relatively low heating demand. As the heating season ended, LNG storage levels remained high until Q3 2023, when there was a large demand for electricity for cooling to combat a heatwave in the region. LNG storage picked back up thereafter, averaging around 14 bcm during Q4 2023.

In addition, Japan’s Ministry of Economy, Trade and Industry started implementing a “Strategic Buffer LNG (SBL)” framework in December 2023 to mitigate risks of a shortfall in supply during the heating months. Under the SBL, the power generator JERA has secured a minimum of one LNG cargo each month from December 2023 to February 2024. Plans were later announced to expand this SBL scheme up to fourfold by the middle of the decade.

Countries in the Asia Pacific region invest heavily in LNG storage to boost energy security.

China’s CNOOC completed construction of a new LNG tank farm at the Binhai LNG import terminal in Jiangsu in November 2023. Each of the six LNG storage tanks has a capacity of 270,000 cubic metres, making them the largest storage units in the world. The site already contains four LNG storage tanks of 220,000 cubic metres each.

India, with the commissioning of new regasification terminals, is also building several LNG storage tanks. In total, the expansion could increase the total number of tanks in the country to 21, for a combined capacity of around 1,300,000 cubic metres.
6.1 Gas Prices

6.1.1. Gas & LNG Spot Prices

Gas and LNG spot prices experienced a significant decline but remained considerably higher than historical norms

In 2023, gas and LNG spot prices experienced a significant decline and reduced volatility, contrasting with the record highs and extreme fluctuations of the previous two years (Figure 159). Despite this downturn, spot prices stayed substantially above historical norms. While sporadic buying activity occurred in South and Southeast Asia, leading to temporary price increases, the overall trend in the gas market was bearish. This trend was attributed to several factors including subdued demand due to mild weather and a global economic downturn, a strong LNG supply, and elevated storage levels in Europe and Asia.

In Q1 2023, spot prices in Europe and Asia experienced a sharp decrease, following a bullish trend in the last quarter of 2022. Weak market fundamentals, including tepid demand driven by mild weather conditions, healthy storage levels and a robust LNG supply in both regions pressured spot prices downward. Consequently, in the first quarter of the year, TTF and NEA LNG spot prices averaged $16.85/MMBtu and $16.69/MMBtu, respectively.

In Q2 2023, this bearish trend continued, as the gas market experienced reduced tightness due to high storage levels, strong LNG supply and diminished demand with the onset of the shoulder season. Nonetheless, in June 2023, spot prices marginally increased, breaking a continuous five-month downward trajectory. TTF and NEA LNG spot prices averaged $11.35/MMBtu and $10.73/MMBtu, respectively, in the second quarter of the year.

In Q3 2023, spot prices partially recovered some of the previous months’ declines, largely due to global LNG supply concerns, sparked by strike actions at Chevron’s Gorgon and Wheatstone LNG facilities in Australia in September. TTF and NEA LNG spot prices averaged $11.85/MMBtu and $13.36/MMBtu, respectively, in third quarter of the year.
In Q4 2023, spot prices in Europe and Asia saw increases, primarily driven by heightened concerns about potential gas supply disruptions amidst the geopolitical developments in the Middle East and the damage to the Balticconnector gas pipeline, as well as by an increase in European gas demand for heating as temperatures dropped. However, in December 2023, gas and LNG spot prices in Europe and Asia reversed course, marking a notable decline after four months of continuous increases. This downward trend was largely due to bearish market fundamentals: mild winter temperatures resulted in reduced demand, and the situation was exacerbated by ample LNG supplies, a high supply of Norwegian pipeline gas and substantial storage levels in both regions. Consequently, in the fourth quarter of the year, TTF and NEA LNG spot prices averaged $12.81/MMBtu and $14.57/MMBtu, respectively.

**Figure 159: Daily gas & LNG spot prices**

Spot prices demonstrated considerably lower volatility in 2023 compared to 2022 (Figure 160). However, NBP spot prices experienced the widest volatility, with daily fluctuations ranging from -21% to 37%. In contrast, NEA LNG spot price variations were more contained, ranging from -10% to 12%. Additionally, daily fluctuations in Henry Hub spot prices varied from -26% to 24%.

The cumulative annual price variability, which represents the total of absolute daily price changes over the year, offers a clear measure of price volatility. In 2023, the annual variability of TTF and NBP spot prices was 169 and 186, respectively, a sharp decrease from 701 and 864 in 2022. In Asia, the annual variability of the NEA LNG spot price was 80, down from 389 in 2022. Consequently, spot price volatility in 2023 in both Europe and Asia was 80% lower than in 2022.

**6.1.1.1 European Spot Gas and LNG Prices**

Gas and LNG prices in Europe declined significantly, after surging to record highs in the previous year.

In 2023, the TTF spot gas price averaged $12.90/MMBtu, marking a 66% decrease from the 2022 average of $37.57/MMBtu. The NBP spot gas price also experienced a substantial reduction, averaging $12.33/MMBtu, 52% lower than the 2022 average of $25.47/MMBtu, as illustrated in Figure 161. Additionally, similar downward trends were observed across other European price benchmarks; for instance, the PSV spot gas price averaged $13.58/MMBtu in 2023, representing a 64% y-o-y decline. Furthermore, European spot LNG prices significantly decreased compared to the previous year. Despite this, they continued to be priced at a discount relative to hub prices, with the NWE and SWE LNG prices averaging $12.09 and $12.00/MMBtu, respectively, in 2023.

**Figure 161: Monthly European spot gas prices**

Spot prices demonstrated considerably lower volatility in 2023 compared to 2022 (Figure 160). However, NBP spot prices experienced the widest volatility, with daily fluctuations ranging from -21% to 37%. In contrast, NEA LNG spot price variations were more contained, ranging from -10% to 12%. Additionally, daily fluctuations in Henry Hub spot prices varied from -26% to 24%.

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In January 2023, European hub prices experienced a decline due to a combination of factors, including mild weather conditions, strong LNG deliveries, increased wind generation and healthy storage levels within the EU. The decreased supply from Norway, resulting from maintenance activities, was offset by storage withdrawals, ensuring adequate supply for the region. Then, in February 2023, heightened LNG sendout and concerted efforts to reduce gas consumption further contributed to the downward price trajectory. Despite a reduction in LNG sendout from France in March 2023, due to strike action that lasted from March 6 to April 19, affecting three of its four LNG import terminals (Fos Cavaou, Fos Tonkin, and Montoir) and resulting in the diversion of more than twenty LNG cargoes, prices continued to decline.

The market remained bearish in Q2 2023, overshadowed by bearish market fundamentals that curbed any potential price increases. Despite reduced production from Norway and unplanned maintenance at the Hammerfest LNG facility, due to a compressor failure from May 4 to 27, prices remained low. Daily TTF spot prices fell below $7.50/MMBtu by the end of May, marking the lowest level since April 2021. However, June 2023 witnessed a rise in European spot prices, driven by maintenance activities at both upstream and LNG facilities. In Norway, maintenance at the Nyhamna gas processing plant, which began on May 19, was extended until July 15 due to issues with the cooling system. Additionally, maintenance at several Norwegian gas fields was prolonged, and the Hammerfest LNG facility’s outage was extended until June 14. The reduced LNG sendout from France, along with partial maintenance at the Sabine Pass terminal in the US, also played a role in supporting prices.

In July 2023, prices once again decreased due to an increase in pipeline gas supply from Norway, as maintenance activities at various gas and LNG facilities, including the Nyhamna gas processing plant, were concluded, with operations resuming on July 15, 2023. Additionally, a surplus in the UK market balance led to enhanced flows through the IUK and BBL interconnectors. In August 2023, spot prices experienced an upick, mainly due to uncertainties caused by industrial actions in Australia and a tighter gas balance in northwest Europe, resulting from extensive maintenance work in Norway. The supply concerns stemming from the strike action in Australia and prolonged maintenance at several Norwegian gas fields led to a rise in prices in September 2023.

In October 2023, prices surged as geopolitical tensions in the Middle East intensified, raising concerns about gas supply disruptions. Bullish price movement was also driven by the potential for renewed strike action in Australia, as well as the damage to the Balticconnector between Finland and Estonia. By mid-October, daily TTF spot prices reached an 8-month peak, exceeding $16/MMBtu. However, the potential for further price increases was limited by an influx of Norwegian pipeline gas imports following the completion of annual maintenance at several facilities. The rise in European gas and LNG spot prices in November 2023 was largely driven by increased demand from the residential sector. Meanwhile, gas flows from the UK to Northwest Europe (NWE) were restricted due to maintenance on the IUK interconnector. Additionally, spot prices were pressured downward by high EU storage levels (at 95% capacity), ample Norwegian pipeline gas flows, and a strong LNG supply. The announcement by the German market operator, Trading Hub Europe (THE), regarding the sale of gas from storage to the market, also contributed to bearish sentiment. In December 2023, warmer-than-average temperatures and high wind speeds led to reduced gas demand. Additionally, a robust LNG supply, strong Norwegian gas production, and high storage levels in the EU helped to ease the market balance in the region.

6.1.1.2 Asian Spot LNG Prices

LNG prices in Asia declined significantly due to muted demand and ample LNG supply

In 2023, the average North East Asia (NEA) spot LNG price decreased by $59% to average $13.47/MMBtu compared to $33.24/MMBtu in 2022 (Figure 162). Throughout the year, Asian LNG spot prices closely followed the trends in European hub prices.

In Q1 2023, Asian LNG prices steadily declined, as above-normal seasonal temperatures coincided with healthy LNG inventories. Furthermore, buying interest remained relatively subdued. Weak market fundamentals, characterized by ample supply and lukewarm demand, continued to exert downward pressure on prices in the region.

In Q2 2023, the increased availability of nuclear power in Japan and South Korea applied additional downward pressure on prices. However, in early May, a noticeable uptick in buying activity emerged in anticipation of the upcoming summer demand, which mitigated further declines. Throughout the second quarter, weak market fundamentals persisted, with daily NEA spot LNG prices dropping below $9/MMBtu, reaching the lowest levels since May 2021.
In Q3 2023, Asian LNG spot prices witnessed an increase, stimulated by rising buying activity from LNG importers in South and Southeast Asia. The upward trend in Asian LNG prices was propelled by various factors, including potential disruptions in Australian LNG exports and increased gas demand for cooling as Japan and South Korea experienced heatwaves in August 2023. In September 2023, Asian LNG prices surged significantly due to strike actions in Australia.

In Q4 2023, daily NEA spot LNG prices climbed above $16/MMBtu. Asian LNG prices experienced a modest uptick as the market continued to be characterized by soft fundamentals, with only isolated instances of spot demand appearing in the region. Lacklustre demand in Northeast Asia and substantial storage levels further pressured prices. In December 2023, a significant decline in Asian LNG prices was mainly attributed to persistently low demand in the region, coupled with an ample supply and high inventory levels.

6.1.1.3 North American Spot Gas Prices

The Henry Hub (HH) spot gas price averaged $2.53/MMBtu in 2023, marking a 64% decrease from the 2022 average of $6.43/MMBtu. In Canada, the average Alberta Energy Company (AECO) spot gas price was $1.96/MMBtu, representing a 53% decrease from the 2022 average of $4.16/MMBtu. Monthly Henry Hub and AECO spot prices consistently remained below the levels of 2021, with the sole exception of January (Figure 163).

6.1.1.4 South American Spot Gas Prices

The South American (SA) LNG price averaged $12.16/MMBtu in 2023, marking a 61% decrease from the average price of $31.46/MMBtu recorded in 2022 (Figure 164). LNG spot prices in South America remained in line with the trends seen in European and

6.1.2. Spot and Oil-indexed Long-Term LNG Price Spreads

Oil-indexed LNG prices maintained a marginal discount to spot LNG prices in Europe and Asia

In 2023, the Oil-indexed I LNG price averaged $12.91/MMBtu, decreasing by 13% y-o-y. Similarly, the Oil-indexed II LNG price averaged $9.69/MMBtu, decreasing by 13% y-o-y (Figure 165). The average discount of Oil-indexed I price to the NEA spot LNG price narrowed significantly from $18/MMBtu in the previous year to $1/MMBtu in 2023. Similarly, the average discount of Oil-indexed II price to the NEA spot LNG price narrowed from $22/MMBtu in 2022 to $4/MMBtu in 2023.

In Europe, the Oil-indexed III price averaged $8.53/MMBtu in 2023, decreasing by 9% y-o-y (Figure 166). The average Oil-indexed III price held a discount of $3/MMBtu over the SWE LNG spot price, which was significantly lower than the discount of $22/MMBtu in 2022.
### 6.1.3. Regional Spot Gas & LNG Price Spreads

The NEA-TTF inter-basin price spread in 2023 was marginally positive, averaging $0.57/MMBtu, in contrast to the spread of -$4.33/MMBtu in 2022. Throughout January 2023, and from July to December 2023, NEA LNG spot prices consistently maintained a premium over TTF spot prices, with this premium peaking at $1.89/MMBtu in October 2023. It is noteworthy that the variation in the monthly average NEA-TTF spread remained within a narrow range of +/- $2/MMBtu throughout the year. This indicated a closer alignment between spot prices in Europe and Asia than in the previous year, as illustrated in Figure 167. This trend towards greater price convergence was mainly due to decreased gas demand and elevated gas storage levels in Europe, which placed downward pressure on TTF prices. Similarly, demand in Asia was relatively subdued, leading to a marginal price premium in the latter half of the year.

In Europe, the NBP-TTF price spread narrowed significantly with NBP trading at a marginal discount to TTF, averaging $0.57/MMBtu in 2023, compared to the average discount of $12.10/MMBtu in 2022 as shown in Figure 168. Gas markets in Northwest Europe and the UK tracked each other closely, a stark contrast to the previous year when a significant disparity was observed between the two European gas hubs. Balanced supply and demand market fundamentals ensured that both prices remained within a narrow range. Furthermore, increased regasification capacity in Northwest Europe alleviated congestion along the two interconnector pipelines from the UK to continental Europe, specifically to Belgium and the Netherlands.

The NWE LNG price traded at a discount of $0.81/MMBtu to TTF, indicating an increased availability of regasification capacity in Northwest Europe. This marked a significant shift from the previous year’s dynamics, where NWE LNG prices traded at a discount of $5.87/MMBtu due to a capacity crunch stemming from a strong influx of LNG cargoes in the region, as depicted in Figure 169.

The NWE LNG-SA LNG price spread was marginally negative, averaging -$0.07/MMBtu in 2023, compared to $0.24/MMBtu in the previous year. This indicated that NWE LNG and SA LNG spot prices maintained a strong correlation, as depicted in Figure 170. Additionally, the NEA-HH and TTF-HH spreads narrowed significantly in 2023 to $10.93/MMBtu and $10.36/MMBtu, compared to $26.81/MMBtu and $31.14/MMBtu in 2022 respectively. This narrowing was attributed to the decline in both Asian and European spot prices, as illustrated in (Figure 171 and Figure 172).

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**Figure 165: Asia: Spot and oil-indexed price spread**

![Graph showing the spread between NEA and NEA-Oil-indexed I and NEA-Oil-indexed II](image1)

Source: GECF Secretariat based on data from Argus and Refinitiv Eikon

Note: Oil-indexed I (using traditional LTC slope): 14.9% X Brent (6 0 1) + 0.5

Oil-indexed II (using 5-year historical average LTC): (2022 – 10.9%; 2023 – 11.1%) % X Brent (5 0 1) + 0.5

**Figure 166: Europe: Spot and oil-indexed price spread**

![Graph showing the spread between SWE LNG and TTF](image2)

Source: GECF Secretariat based on data from Argus and Refinitiv Eikon

Note: Oil-indexed III: Argus assessment for European LTC.

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**Figure 167: NEA-TTF price spread**

![Graph showing NEA-TTF price spread](image3)

**Figure 168: NBP-TTF price spread**

![Graph showing NBP-TTF price spread](image4)

Source: GECF Secretariat based on data from Argus and Refinitiv Eikon

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6.2. Cross Commodity Prices

6.2.1. Oil Prices

The Brent spot price averaged $83.71/bbl in 2023, witnessing a 19% decrease compared to the previous year. Similarly, the Brent month-ahead price averaged $82.22/bbl, marking a 17% decrease y-o-y as shown in Figure 173.

In January 2023, oil prices experienced a modest rebound after two consecutive months of decline. This recovery was primarily driven by the anticipated economic recovery in China following the easing of its zero-COVID policy, which fuelled optimism for higher oil demand. However, in February and March 2023, oil prices edged lower due to high US crude stocks and concerns over slowing economic growth, as well as the potential for more aggressive interest rate hikes by the US Federal Reserve. Additionally, there were worries about slower-than-expected Chinese economic growth and developments in financial markets, including the collapse of Silicon Valley Bank and issues at Credit Suisse.

In April 2023, prices rallied in response to OPEC+ announcing oil production cuts of 1.16 million b/d, set to be implemented from May 2023. Despite this, oil prices continued to experience downward pressure due to uncertainties surrounding oil demand in the two largest consuming countries, the US and China, along with ongoing macroeconomic risks.

Oil prices experienced bullish movement in Q3 2023, reaching a ten-month peak in September 2023. This uptrend was propelled by Russia and Saudi Arabia extending their voluntary supply cuts until the end of the year. Specifically, Saudi Arabia continued its voluntary reduction of 1 million barrels per day (bpd), while Russia decreased its crude exports by 300,000 bpd, a reduction from the 500,000 bpd cut in August 2023. These cuts were initially anticipated to end in October 2023.

In Q4 2023, oil prices exhibited greater volatility compared to previous months, with heightened geopolitical risks in the Middle East causing price spikes. Despite these fluctuations, oil market fundamentals remained subdued, and oil supply disruptions did not occur. However, gains in oil prices were short-lived as economic challenges persisted, leading to a lower average monthly price in October 2023. In December 2023, oil prices declined for the third consecutive month, despite OPEC+ announcing voluntary production cuts totalling 2.2 million bpd, slated to begin in early 2024. Factors such as slower economic growth and subdued global manufacturing activity contributed to the bearish market sentiment. Yet, there were bullish signals, particularly due to increased attacks on vessels in the Red Sea. These incidents forced some tankers to reroute via the Cape of Good Hope, resulting in longer shipping times and the addition of risk premiums.

Moreover, in 2023, TTF spot prices traded at an average discount of $1/MMBtu to the oil parity price. NEA LNG spot prices also maintained a $1/MMBtu discount to the oil parity price. This represented a significant shift from the previous year, when TTF and NEA LNG spot prices traded at premiums to the oil parity prices of $21/MMBtu and $16/MMBtu, respectively.
6.2.2. Coal Prices

The European API2 coal price averaged $124.80/T, marking a 55% decrease compared to the previous year. In China, the Qinhuangdao (QHG) coal price averaged $150.99/T and reflecting a 28% y-o-y decline as shown in Figure 174.

In Q1 2023, mild temperatures in Europe significantly reduced coal consumption and exerted downward pressure on prices. Additionally, lower TTF gas prices encouraged coal-to-gas switching, further diminishing demand for coal. Fuel-switching dynamics continued to significantly influence coal prices. In October 2023, European coal prices increased, mirroring gains in TTF spot prices. High TTF prices may have reversed the recent trend of coal-to-gas switching, boosting demand for coal. Moreover, while escalating tensions in the Middle East did not directly impact the coal market, the broader implications for the energy market may have affected coal prices. In December 2023, European coal prices declined for the second consecutive month, primarily due to mild temperatures reducing demand in the region. The economics of coal-to-gas fuel switching during this period favored gas. Meanwhile, in China, coal prices gained some momentum.

Throughout the year, Chinese coal prices remained higher than European coal prices, with European coal prices dropping to a monthly low of $107.50/T in May 2023. Chinese coal prices, on the other hand, reached a monthly low of $120.56/T in June 2023.

The premium of TTF spot price over the API2 parity price decreased by 71% y-o-y to $7.65/MMBtu. Similarly, the premium of NEA spot LNG price over the QHG parity price decreased by 72% y-o-y to $6.55/MMBtu.

6.2.3. Carbon Prices

The EU carbon price averaged €85.33/tCO₂ in 2023, reflecting a 5% increase y-o-y. However, the volatility of the price was lower compared to the previous year (Figure 175). Moreover, the daily EU carbon price reached a record high of €100/tCO₂ at the end of February 2023, propelled by strong buying interest from utilities and low wind generation.

After this early spike in 2023, the EU carbon price lost some momentum but remained relatively high throughout the year. The power sector’s preference for gas over coal led to reduced demand for EU Allowances (EUAs). Additionally, the distribution of over 50% of the year’s free allocation allowances exerted downward pressure on prices. The EU carbon price received support from compliance buying, particularly as the April 30, 2023 deadline for countries to surrender allowances approached. By the end of April, more than 75% of the year’s free allocation allowances had been distributed. Furthermore, gas prices continued to make gas more favorable than coal for power generation. After the annual compliance deadline passed in May 2023, demand for allowances softened, and prices faced additional downward pressure as emissions from the power sector decreased, influenced by demand reduction and strong renewables output. Notably, the European Commission’s announcement of additional allowance sales starting in July 2023 to fund the REPowerEU plan contributed to bearish market sentiment.
In June 2023, the EU carbon price were supported by higher TTF prices and improved market fundamentals, driven by increased demand for cooling due to warmer weather. Additionally, reduced wind output and limited nuclear availability supported thermal generation, thereby boosting carbon prices.

In Q3 2023, EU carbon prices experienced neutral to bearish market sentiment. The effect of lower TTF gas prices and increased renewable energy production was offset by heightened demand for cooling due to above-normal temperatures. Moreover, EU carbon prices saw a consistent decline over five months, from August to December 2023, with daily EU carbon prices hitting a 14-month low by falling below €67/tCO₂ in December 2023. This downward trend was largely due to weak industrial demand, low gas prices facilitating fuel switching, and the sale of additional EU allowances to fund the REPowerEU initiative. Predictions of above-average temperatures in the region also contributed to the price decrease.

However, the EU carbon price is projected to decrease, with an annual average of around €82/tCO₂ according to estimates from Refinitiv Eikon (as of January 22, 2024). This forecast was adjusted downward following a bearish Q4 2023, which was closely associated with weak gas market fundamentals. Additionally, expected lower industrial demand, stemming from sluggish economic growth, is likely to further impact the demand for EUAs.

6.2.4. Fuel switching

In 2023, the daily TTF spot prices generally stayed within or marginally below the range conducive to coal-to-gas switching, a notable shift from 2022, when TTF prices were consistently above the switching range for the majority of the year (Figure 176).

The average coal-to-gas switching price experienced a 41% decrease, settling at €43.17/MWh in 2023, while the TTF spot price averaged $40.67/MWh. Consequently, the TTF spot price maintained an average discount of €2.50/MWh compared to the coal-to-gas switching price, leading to an uptick in coal-to-gas switching activities in Europe throughout the year.

In January and February 2023, the monthly spread between the TTF spot price and the coal-to-gas switching price was positive. However, from March to September 2023, the spread turned negative, primarily due to the decline in TT spot prices, which was attributed to weak demand in the region. Subsequently, in Q4 2023, the spread became positive again as TTF spot prices saw some upward movement.

Looking ahead to 2024, TTF spot prices are expected to remain within the coal-to-gas switching range. Both the TTF spot prices and the average coal-to-gas switching prices are anticipated to be significantly lower than in 2023. This is expected to continue incentivizing coal-to-gas switching in the region.
## ANNEXES

### Regional Grouping

<table>
<thead>
<tr>
<th><strong>Term</strong></th>
<th><strong>Meaning</strong></th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Advanced Economies (AEs)</strong></td>
<td>Australia, Austria, Belgium, Canada, Cyprus, Czech Republic, Denmark, Estonia, Finland, France, Germany, Greece, Hong Kong, Iceland, Ireland, Israel, Italy, Japan, Korea, Latvia, Lithuania, Luxembourg, Macau (China), Malta, Netherlands, New Zealand, Norway, Portugal, Puerto Rico, San Marino, Singapore, Slovak Republic, Slovenia, Spain, Sweden, Switzerland, Taiwan (Province of China), United Kingdom, United States.</td>
</tr>
<tr>
<td><strong>Asia Pacific</strong></td>
<td>Afghanistan, Australia, Bangladesh, Bhutan, Brunei Darussalam, Cambodia, China, Cook Islands, Democratic People’s Republic of Korea, Fiji, French Polynesia, Hong Kong, India, Indonesia, Japan, Kiribati, Korea, Lao People’s Democratic Republic, Macau (China), Malaysia, Maldives, Mongolia, Myanmar, Nepal, New Caledonia, New Zealand, Pakistan, Palau, Papua New Guinea, Philippines, Samoa, Singapore, Solomon Islands, Sri Lanka, Taiwan (Province of China), Thailand, Timor-Leste, Tonga, Vanuatu and Vietnam.</td>
</tr>
<tr>
<td><strong>Emerging Markets and Developing Economies (EMDEs)</strong></td>
<td>All other countries not included in “Advanced Economies”.</td>
</tr>
<tr>
<td><strong>Eurasia</strong></td>
<td>Armenia, Azerbaijan, Belarus, Georgia, Kazakhstan, Kyrgyzstan, Moldova, Russia, Tajikistan, Turkmenistan, Ukraine and Uzbekistan.</td>
</tr>
<tr>
<td><strong>Europe</strong></td>
<td>European Union and Albania, Bosnia and Herzegovina, Gibraltar, Iceland, Montenegro, Norway, Serbia, Switzerland, Macedonia, Moldova, Türkiye and the United Kingdom.</td>
</tr>
<tr>
<td><strong>European Union</strong></td>
<td>Austria, Belgium, Bulgaria, Croatia, Cyprus, Czech Republic, Denmark, Estonia, Finland, France, Germany, Greece, Hungary, Ireland, Italy, Latvia, Lithuania, Luxembourg, Malta, Netherlands, Poland, Portugal, Romania, Slovakia, Slovenia, Spain and Sweden.</td>
</tr>
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</table>
### Abbreviations

<table>
<thead>
<tr>
<th>Abbreviation</th>
<th>Explanation</th>
</tr>
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<tbody>
<tr>
<td>ACQ</td>
<td>Annual contracted quantity</td>
</tr>
<tr>
<td>AE</td>
<td>Advanced economies</td>
</tr>
<tr>
<td>AECO</td>
<td>Alberta Energy Company</td>
</tr>
<tr>
<td>bcm</td>
<td>Billion cubic metres</td>
</tr>
<tr>
<td>bcma</td>
<td>Billion cubic metres per annum</td>
</tr>
<tr>
<td>CBAM</td>
<td>Carbon border adjustment mechanism</td>
</tr>
<tr>
<td>CBM</td>
<td>Coal bed methane</td>
</tr>
<tr>
<td>CCGT</td>
<td>Combined cycle gas turbine</td>
</tr>
<tr>
<td>CCS</td>
<td>Carbon, capture and storage</td>
</tr>
<tr>
<td>CCUS</td>
<td>Carbon capture, utilization and storage</td>
</tr>
<tr>
<td>CNG</td>
<td>Compressed natural gas</td>
</tr>
<tr>
<td>CO₂</td>
<td>Carbon dioxide</td>
</tr>
<tr>
<td>CPI</td>
<td>Consumer price index</td>
</tr>
<tr>
<td>EC</td>
<td>European Commission</td>
</tr>
<tr>
<td>ECB</td>
<td>European Central Bank</td>
</tr>
<tr>
<td>EEKI</td>
<td>Energy efficiency existing ship index</td>
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<tr>
<td>EMDE</td>
<td>Emerging markets and developing economies</td>
</tr>
<tr>
<td>EU</td>
<td>European Union</td>
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<tr>
<td>EU ETS</td>
<td>European Union emissions trading scheme</td>
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<tr>
<td>EUA</td>
<td>European Union allowance</td>
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<tr>
<td>Fed</td>
<td>Federal Reserve</td>
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<tr>
<td>FEED</td>
<td>Front end engineering design</td>
</tr>
<tr>
<td>FID</td>
<td>Final Investment decision</td>
</tr>
<tr>
<td>G7</td>
<td>Group of Seven</td>
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<tr>
<td>GDP</td>
<td>Gross domestic product</td>
</tr>
<tr>
<td>GECF</td>
<td>Gas Exporting Countries Forum</td>
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<tr>
<td>GHG</td>
<td>Greenhouse gas</td>
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<tr>
<td>Abbreviation</td>
<td>Definition</td>
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<tr>
<td>HDD</td>
<td>Heating degree days</td>
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<tr>
<td>HH</td>
<td>Henry Hub</td>
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<tr>
<td>IEA</td>
<td>International Energy Agency</td>
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<tr>
<td>IMF</td>
<td>International Monetary Fund</td>
</tr>
<tr>
<td>IMO</td>
<td>International Maritime Organization</td>
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<tr>
<td>JKM</td>
<td>Japan Korea Marker</td>
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<tr>
<td>LNG</td>
<td>Liquefied natural gas</td>
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<tr>
<td>LAC</td>
<td>Latin America and the Caribbean</td>
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<tr>
<td>LT</td>
<td>Long-term</td>
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<tr>
<td>MEA</td>
<td>Middle East and Africa</td>
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<td>MENA</td>
<td>Middle East and North Africa</td>
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<tr>
<td>METI</td>
<td>Ministry of Trade and Industry in Japan</td>
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<tr>
<td>MMBtu</td>
<td>Million British Thermal Unit</td>
</tr>
<tr>
<td>Mt</td>
<td>Million tonnes</td>
</tr>
<tr>
<td>Mtpa</td>
<td>Million tonnes per annum</td>
</tr>
<tr>
<td>MWh</td>
<td>Megawatt hour</td>
</tr>
<tr>
<td>NEA</td>
<td>North East Asia</td>
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<tr>
<td>NBP</td>
<td>National balancing Point</td>
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<tr>
<td>NDC</td>
<td>Nationally determined contribution</td>
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<tr>
<td>NGV</td>
<td>Natural gas vehicle</td>
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<tr>
<td>NZBA</td>
<td>Net-Zero Banking Alliance</td>
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<tr>
<td>OECD</td>
<td>Organization for Economic Co-operation and Development</td>
</tr>
<tr>
<td>PPAC</td>
<td>Petroleum Planning &amp; Analysis Cell</td>
</tr>
<tr>
<td>PSV</td>
<td>Punto di Scambio Virtuale (Virtual Trading Point in Italy)</td>
</tr>
<tr>
<td>QHG</td>
<td>Qinhuangdao</td>
</tr>
<tr>
<td>R-LNG</td>
<td>Regasified LNG</td>
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<tr>
<td>SA</td>
<td>South America</td>
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<tr>
<td>SPA</td>
<td>Sales and purchase agreement</td>
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<td>South West Europe</td>
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<td>T&amp;T</td>
<td>Trinidad and Tobago</td>
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<tr>
<td>TANAP</td>
<td>Trans-Anatolian Gas Pipeline</td>
</tr>
<tr>
<td>tcm</td>
<td>Trillion cubic metres</td>
</tr>
<tr>
<td>tCO₂</td>
<td>Ton of carbon dioxide</td>
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<td>TTF</td>
<td>Title Transfer Facility</td>
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<tr>
<td>TWh</td>
<td>Terawatt hour</td>
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<td>UGS</td>
<td>Underground gas storage</td>
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<tr>
<td>UAE</td>
<td>United Arab Emirates</td>
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