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REVIEWS

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# Prospects for Using Hydrogen in Various Branches of the World Economy as One of the Directions of Its Decarbonization

K. I. Yakubson<sup>a,\*</sup>

<sup>a</sup> Institute of Oil and Gas Problems, Russian Academy of Sciences, Moscow, 119333 Russia

\*e-mail: kris.yakubson@yandex.ru

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**Abstract**—The review deals with the state of the art and prospects for using hydrogen in various branches of the world economy: in industry (oil-refining, chemical, steel-casting, cement), on transport (road, railway, maritime, aviation), and in production and distribution of the electric and thermal power. Using hydrogen is one of efficient directions of the economy decarbonization. The possibility and efficiency of using hydrogen, ammonia, methanol, and synthetic kerosene as a fuel for internal combustion engines and gas turbines in various kinds of vehicles and in production of the electric and thermal power are evaluated. The need for long-term hydrogen storage for reducing the influence exerted on the operation of electric networks by seasonal variations in the electric power production from renewable sources is demonstrated, and the hydrogen storage methods are considered. The feasibility of various procedures for utilizing CO<sub>2</sub> formed in the course of hydrogen production by steam methane conversion at industrial enterprises using hydrogen for their own needs are analyzed.

**Keywords:** hydrogen, steam methane conversion, water electrolysis, carbon dioxide emission, decarbonization of economy

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## INTRODUCTION

Large-scale use of hydrogen in various branches of the world economy is one of the main directions of its decarbonization [1]. By the end of 2021, governments of 19 countries and European Commission, presenting the coordinated standpoint of all the EU countries, published strategies (programs) of the development of hydrogen technologies and roadmaps for their implementation [2]. For these purposes, they plan to invest \$75 bln up to 2030. Additional \$300 bln will be granted by industrial companies for implementation of more than 200 hydrogen projects in various regions of the world [2, 3]. According to the estimate of the International Energy Agency (IEA), considerably more money, up to \$1200 bln, should be invested in the development of the production and use of hydrogen in the nearest decade to make the world economy carbon-neutral by 2050 [4]. The demand for hydrogen steadily grows. Since

the 1970s, when hydrogen started to be considered as an alternative power carrier under the influence of the world oil crisis, the hydrogen production in the world increased by a factor of 5 and reached 90 mln t in 2020 [1, 4]. The major fraction of hydrogen produced in 2020 was obtained from fossil fuel: 59% by steam methane conversion, 19% by coal hydrogenation, and 0.5% by reforming of petroleum feedstock. The share of hydrogen produced by water electrolysis was less than 1%. Approximately 21% of hydrogen was obtained as a by-product from other processes, mainly from catalytic reforming of crude oil at oil refineries [1, 4]. The use of fossil fuel as the main feedstock for hydrogen production leads to large CO<sub>2</sub> emission, which reached 900 mln t in 2020 [2].

Today, virtually the whole amount of the produced hydrogen is used in processes at chemical, oil-refining, and steel-casting enterprises. Transition to low-carbon economy will stimulate the development of other fields

of using hydrogen, such as transport (surface, maritime, and air), accumulation and distribution of the electric power from renewable power sources, and production of thermal energy for cement and steel-casting industry and for heat supply for buildings [2]. This will require a considerable increase in the hydrogen production. By now, there is no coordinated estimate for the rate of the development of hydrogen energy. Comparison of the existing forecasts on the hydrogen market volume expected by 2050 shows that the existing estimates differ by several times [5]. The Hydrogen Council expects that 546 mln t of hydrogen will be produced in 2050 [6]. According to the opinion of IEA experts, published in 2020, such level of hydrogen production can be reached only by 2070; in 2050, it will be as low as 280 mln t [7, 8]. However, already in 2021, IEA in the report on the role of hydrogen technologies in ensuring zero carbon dioxide emissions by 2050, prepared for the UN Climate Change Conference [Glasgow, October 31–November 12, 2021 (COP26)], revised this forecast and suggested considerably higher targets for the growth of the hydrogen production: It should reach 212 mln t in 2030 and increase to 528 mln t by 2050 [2, 4]. 70% of the hydrogen produced in 2030 should be low-carbon: “green” obtained by water electrolysis [9] and “blue” obtained by steam methane conversion followed by capture and utilization of the CO<sub>2</sub> formed [10]. By 2050, virtually the whole amount of hydrogen used in the economy will be low-carbon. According to the forecasts, in 2030 low-carbon hydrogen will include 54% “green” and 46% “blue” hydrogen. By 2050, the share of “green” hydrogen will increase to 62%. To this end, the total capacity of electrolyzers should be increased to 850 GW by 2030 and to 3500 GW by 2050. In 2050, the planned production of 320 mln t of “green” hydrogen will involve the consumption of 15 000 TW h of electric power, of which 95% will be obtained from renewable power sources and 5%, at nuclear power plants [2, 4]. The production of 200 mln t of “blue” hydrogen, planned in 2050, will involve the consumption of 950 bln m<sup>3</sup> of natural gas and require construction of installations for capturing 1.8 bln t of CO<sub>2</sub>. Along with enormous power resources for producing low-carbon hydrogen, large amount of fresh water is required. In 2050, it will be necessary to consume 5800 mln m<sup>3</sup> of water for this purpose, which corresponds to 12% of its current consumption in power engineering [2, 4]. Under the conditions of growing deficiency of fresh water in the world [11], the development of technologies

allowing the use of saline water, including seawater, for producing hydrogen by electrolysis becomes more and more important [2, 4, 12].

The increase in the hydrogen production will be accompanied by significant changes in the structure of its consumption. In 2020, 83% of hydrogen was produced at enterprises using it for own needs in various processes (“captive” hydrogen). According to the forecasts, the share of captive hydrogen will decrease to 40% by 2030 and to 20% by 2050. The remaining hydrogen will be supplied to the market. Large-scale hydrogen use in various branches of economy will allow the CO<sub>2</sub> emissions to be decreased in total by 60 bln t in the period 2020–2050, which is 1.7 times higher than the volume of CO<sub>2</sub> emissions in the world in 2020 [13]. Up to 2030, the decrease in the emissions will be mainly determined by the scale of upgrading the hydrogen production at the existing and newly constructed enterprises of oil-refining and chemical industry. In the subsequent years, when the infrastructure for the hydrogen transportation and storage will be created, the decrease in the emissions will be determined by the rate of the decarbonization of transport and branches of the economy where electrification of processes is complicated or impossible at all, primarily of the cement and steel-casting industry [4, 8].

This review is aimed at analyzing the state of the art and prospects for using hydrogen in various branches of the world economy as the necessary condition for its decarbonization.

#### USE OF HYDROGEN IN OIL REFINING

The main oil-refining processes that use hydrogen are hydrocracking and hydrotreating (desulfurization). 40 mln t of hydrogen was consumed for these purposes in 2020 [4]. For already many years, the world leaders in oil refining are the United States and China, which in 2020 produced 769 and 648 mln t of petroleum products [14] and consumed for this purpose 7 and 12 mln t of hydrogen, respectively [4]. The main factors determining the efficiency of using hydrogen in oil refining were analyzed in a review prepared at the Argonne National Laboratory [15]. Today, hydrogen is used in the United States for the following main oil-refining processes: 32% for hydrocracking of heavy crude to obtain diesel fuel, 28% for hydrotreating of heavy crude to obtain diesel fuel with low sulfur content, 18% for catalytic cracking

of heavy crude, followed by hydrotreating, and 4%, for naphtha treatment to remove sulfur. The amount of hydrogen used for refining the same amount of crude oil at oil refineries located in different regions of the country differs significantly owing to different physicochemical properties of the crude oil being processed. The correlation between the amount of the hydrogen used and the main characteristics of the crude oil supplied to the refinery is presented. These characteristics include the crude oil type in accordance with the American Petroleum Institute (API) classification (the oil density in API degrees varied from 28.5 to 34.3), the sulfur content of oil (0.65–1.6%), and the content of liquefied petroleum gas and the ratio of gasoline and diesel fuel in the refining products produced (0.5–5.8) [15]. In the period from 2009 to 2016, the hydrogen consumption for refining of 1 t of crude oil in the United States increased by 30% and reached approximately 340 cubic feet per 1 barrel crude oil. The total hydrogen consumption by the oil-refining industry in the United States in this period increased by a factor of almost 1.5 and reached 5.8 mln t in 2016. According to the forecast, by 2030 it will reach 7.5 mln t [15]. This will be due not only to an increase in the oil extraction, but also to an increase in the share of heavy crude and in the consumption of diesel fuel compared to gasoline.

Today 45% of hydrogen consumed by the oil-refining industry in the United States is produced by steam methane conversion directly at oil refineries. Approximately 20% of hydrogen comes from catalytic reformers, and 35% is purchased on the market, where hydrogen produced by steam methane conversion presently prevails [1, 16]. The structure of hydrogen production by oil-refining industry in the EU countries is essentially different: 52% comes from catalytic reformers and only 35% is produced by steam methane conversion. In China, 10% of hydrogen comes to oil refineries from coal gasification installations [1].

The role of processes involving hydrogen in the world oil-refining industry is determined by several factors. In the XXI century, the requirements to the permissible sulfur content of organic fuel became considerably more stringent. For example, since January 1, 2017 the sulfur content of gasoline supplied to the market by oil refineries in the United States was restricted to the level 97% lower compared to gasolines produced in 2004 [17]. For the automobile transport in the United States, the use of diesel fuel of USLD grade, containing

no more than 15 ppm sulfur, was recommended since 2010 [18]. The EU requirements to the sulfur content of automobile fuel are still more stringent (no more than 10 ppm) [19]. In 2020, the permissible sulfur oxide content of ship fuel was decreased by a factor of 7, from 3.5 to 0.5% [20]. IEA experts believe that the potential of the modern hydrotreating methods for further reducing the sulfur content of organic fuels has not yet been exhausted. Therefore, by 2030 the demand for hydrogen for oil desulfurization will increase by 7% [1]. However, considerably stronger effect on the use of hydrogen in oil refining will be exerted by a decrease in the crude oil extraction [21] and by decarbonization of the world transport. According to the forecasts, already by 2040 the consumption of fossil fuels by various vehicles will decrease by a factor of 2 compared to 2020 and will amount to 50% of the total amount of the consumed energy. In 2050, the share of fossil fuels will not exceed 10% [2]. This will lead to a decrease in the demand for hydrogen in production of petroleum products. If the scenario of reaching the carbon neutrality by 2050 will be implemented, the hydrogen consumption by oil refineries can decrease to 25 mln t in 2030 and to 10 mln t by 2050. It is assumed that some of excessive facilities for hydrogen production will be used directly at oil refineries for producing synthetic hydrogen fuel and decarbonizing some high-temperature thermal operations, and also for selling to enterprises of other branches of the economy [4].

Oil refineries are the second largest localized sources of CO<sub>2</sub> emissions, being inferior only to thermal power plants. The main sources of carbon dioxide emissions at oil refineries are large stationary facilities for fuel combustion (steam boilers, process furnaces, process heaters, etc.) and numerous small sources with low CO<sub>2</sub> concentration. In total, these sources are responsible for no less than 80% of CO<sub>2</sub> emissions from a plant. The hydrogen production by steam conversion of hydrocarbons is responsible for up to 20% of CO<sub>2</sub> emissions. These emissions, which are characterized by high concentration and high pressure of CO<sub>2</sub>, are considered by Shell specialists as the most economically attractive object for utilization of CO<sub>2</sub> emissions from oil refineries [22]. In 2020, the total volume of CO<sub>2</sub> emissions from oil refineries in the world, associated with hydrogen production, was 200 mln t [2]. Radical reduction of the CO<sub>2</sub> emissions requires additional equipment of hydrogen production facilities with

systems for capturing CO<sub>2</sub> or transition to the use of electrolysis hydrogen. Expert estimates show that, in the medium term, the first alternative is more realistic. Today CO<sub>2</sub>-capturing systems are already in operation at six oil refineries (in Netherlands, France, Canada, and Japan), and 30 similar projects are at different steps of designing and implementation [1, 4]. Despite apparent advantages of using electrolysis hydrogen in oil refining, today there are only two operating installations and several projects for the construction of electrolysis installations at oil refineries, in particular, at the Royal Dutch Shell plant in Germany (REFHYNE project), where the construction of an electrolyzer of 10 MW capacity was started in 2018. This electrolyzer will be able to produce approximately 1300 t of hydrogen annually. The project is planned to be completed in December 2022 [23]. British Petroleum started implementation of a still larger-scale project for producing “green” hydrogen with a 50 MW electrolyzer at the oil refinery in Linden (Germany) [24]. Purchase of large volumes of hydrogen by oil refineries on the market (about 5 mln t in 2018 [1]) creates favorable prerequisites for the supply of “green” hydrogen, which can be produced in large volumes in the future using the electric power generated from renewable power sources [4, 25] and by nuclear power plants [2]. The scale of the production of “blue” and “green” hydrogen for oil refineries or of its purchase on the market is determined by economical criteria and by environmental regulations. Upgrade of steam reformers for the transition to “blue” hydrogen production increases the cost of the produced petroleum products by \$0.25–0.50/barrel [1]. The additional expenditure in the case of the “green” hydrogen production is still higher. IEA experts think that the state should economically stimulate the transition of oil refineries to the use of “blue” and “green” hydrogen. The following possible incentives are considered: considerable increase in the cost of CO<sub>2</sub> emission, legislative fixation of requirements to the carbon footprint of motor fuel, taking into account the whole life cycle of its production (already operates in EU countries and some of US states), preferential infrastructural credits, etc. [1, 26].

#### USE OF HYDROGEN IN CHEMICAL INDUSTRY

Chemical industry consumes 46 mln t of hydrogen, of which 33 mln t is used for ammonia production and 13 mln t, for methanol production [4]. The major fraction (65%) of hydrogen is produced at chemical

enterprises by steam methane conversion; 30%, by coal hydrogenation; and 5%, from petroleum feedstock. In China, more than a half of ammonia and almost 70% of methanol are produced using hydrogen obtained from coal. In 2018, 270 mln t of fossil fuel was consumed for the hydrogen production for chemical industry [1].

One of the main branches of chemical industry is ammonia production. Chemical products demanded in various branches of economy are produced from ammonia. About 80% of the produced ammonia (and, correspondingly, of hydrogen required for this purpose) is used for producing nitrogen fertilizers, of which urea makes up more than half [27, 28]. The present structure of using ammonia shows that the development of its production will be largely determined by the world’s demand for nitrogen fertilizers, stimulated by the main trends in the development of the world’s agriculture [29]. The world’s ammonia production in 2020 reached 175 mln t [4, 30] and increased by 17% in the past decade [31]. The production of nitrogen fertilizers increased by approximately the same factor in this period [27]. According to the forecasts, in the medium term the ammonia production will increase by approximately 1.6% annually and will reach 214 mln t by 2030 and 250 mln t by 2050 [32]. The ammonia production is accompanied by the emission of a large amount of carbon dioxide, of which 30–40% is used for urea production. Therefore, there is a trend toward combination of plants producing ammonia and nitrogen fertilizers in a common production complex [33, 34].

Along with traditional application fields, ammonia can be used as a means for hydrogen storage and transportation and as a carbon-free power carrier in power engineering and transport. In contrast to hydrogen, which is liquefied at atmospheric pressure at –250°C, ammonia becomes liquid already at –33°C or at room temperature under a pressure of 0.8 MPa. The volumetric energy density of liquid ammonia is 1.5 times higher than that of liquefied hydrogen (12.7 and 8.5 MJ L<sup>-1</sup>, respectively) and almost 3 times higher than that of compressed hydrogen at 70 MPa and 25°C. This fact considerably simplifies and cheapens the storage and transportation of liquefied ammonia compared to liquefied or compressed hydrogen. Liquefaction of NH<sub>3</sub> from the gas phase involves the consumption of only 0.1% of the energy that it bears, whereas almost half of the energy potential of gaseous hydrogen is consumed for hydrogen liquefaction and storage of liquid hydrogen

[35]. In contrast to liquefied hydrogen, the presently available infrastructure is suitable for ammonia storage and transportation [35, 36]. According to estimates of Allen Consulting experts, the cost of transporting hydrogen incorporated in ammonia using automobile and maritime transport can be 3 times lower compared to the transportation of liquefied hydrogen. In railway transportation, these values can differ by a factor of 7 [37]. The ammonia decomposition to obtain hydrogen is mainly performed as a thermal process in the presence of catalysts based on Ru and Ni. The temperature required for the efficient catalytic cracking of ammonia is 400 and 600°C for the Ru and Ni catalysts, respectively. The thermal energy consumed for the thermal decomposition of ammonia is equivalent to no less than 15% of the weight of hydrogen incorporated in it [38].

Studies performed in various countries since the 1960s demonstrated in principle the possibility of using ammonia as a motor fuel without essential upgrade of internal combustion engines both when ammonia is added to standard motor fuel and when it is used as a mixture with methane, hydrogen, and organic solvents [36, 39–41]. In addition, ammonia, both in the pure form and in a mixture with methane and hydrogen, is considered as a fuel for gas turbines [42–45]. Recently there has been active progress in studies concerning the possibility of using the existing and developing new fuel cells allowing conversion of ammonia to electric power [42]. The highest performance is shown by high-temperature solid oxide fuel cells with metal–ceramic nickel–gadolinium anode doped with cerium.

One more promising field of industrial use of ammonia and “ammonia” fuel cells is accumulation, storage, and subsequent reverse conversion of excess electric power produced by renewable power sources. The hydrogen required for ammonia synthesis is obtained from electrolysis, and nitrogen is recovered from air [44]. According to forecasts, the use of ammonia as a hydrogen-containing carbon-free fuel will start after 2030. This will lead to a considerable increase in the production of ammonia and of hydrogen required for this purpose. According to IEA forecasts, in 2050 the production of ammonia used as a fuel will exceed by approximately 10% the production of ammonia for agriculture and chemical industry. This will require approximately 50 mln t of additional hydrogen [4].

The methanol production occupies the second place in the world chemical industry with respect to

the level of using hydrogen. In the past decade, the methanol production increased by a factor of 2.5 and reached 102 mln t in 2020. According to forecasts, 140 mln t of methanol will be produced in 2050 [46, 47]. Today 55% of methanol is used as a basic product in chemical industry. The second largest field of methanol consumption (31%) is transport: 11% of methanol is consumed for the production of methyl tert-butyl ether; 3%, for the production of dimethyl ether; 14%, directly as a motor fuel or in a mixture with gasoline and diesel fuel; and 3%, for the biodiesel production [47]. According to forecasts, in the medium term the share of methanol used as a fuel will increase and will reach 38% by 2025 [47]. The large-scale experiment performed in California in the 1980–1990s stimulated wide use of methanol as a motor fuel. In that period, 15 thousand cars operating on M85 fuel (15% standard gasoline + 85% methanol) were produced and used. The emissions of unburned hydrocarbons and NO<sub>x</sub> into the atmosphere were considerably reduced without decreasing the engine operation efficiency [1]. Today, methanol is used in many countries of the world in gasoline mixtures in various concentrations and as an additive to diesel fuel. It is also used more and more frequently as a component added to gasoline jointly with ethanol, e.g., in Israel and Australia. The use of methanol as an additive to gasoline, including that containing ethanol, is regulated by national standards in many countries [46, 48–51]. The world leader in using methanol fuel on transport is China. In 2018, 1.2 mln t of methanol was consumed in China for this purpose. The methanol content of fuel mixtures used in China ranges from 5 to 100% [49]. One of the leading car producers in China, Geely Group, plans to produce annually up to 500 thousand cars operating on methanol fuel. The attractiveness of using methanol as a motor fuel is largely determined by the possibility of using the existing infrastructure, including filling stations, for its transportation and storage [46].

The electric power generation using fuel cells is a promising field of methanol application. An obvious advantage of methanol fuel cells is simple storage and transportation, compared to the hydrogen transportation. Methanol can be converted either directly to the electric power in methanol fuel cells or preliminarily to a gas mixture enriched in hydrogen for the subsequent use of this mixture in hydrogen fuel cells. A methanol fuel cell (DMFC) is one of variants of proton-exchange membrane (PEM) fuel cells using a

liquid methanol–water mixture at 80–100°C instead of gaseous hydrogen. The electric efficiency of methanol fuel cells does not exceed 40%, which restricts their application field mainly to small devices of relatively low capacity [52]. The methanol reforming system used for hydrogen production includes a combustion chamber, a vaporizer for fuel heating and evaporation, a reformer for performing the reforming reaction, and a carbon monoxide to carbon dioxide converter. Hydrogen is purified to remove harmful impurities using metal membranes based on palladium or its alloys with other metals, which ensure high purity of hydrogen and its low CO content (<10 ppm), allowing its feeding into a PEM fuel cell operating at approximately 80°C. When using high-temperature PEMs (working temperature 170°C), the requirements to the permissible content of carbon monoxide in hydrogen decrease by a factor of almost 1000. This allows the use of expensive palladium membranes for hydrogen purification to be abandoned [50, 51]. By now, several pilot projects confirming the possibility of efficient use of fuel cells whose operation is based on methanol conversion have been implemented. The possible application fields of such fuel cells are automobile industry, utilities (combined production of heat and electric power), feeding of telecommunication systems instead of diesel generators used today, and maritime transport (boats, small tourist ships, and ferries) [46].

According to IEA estimates, the hydrogen consumption by chemical enterprises by 2030 will increase by approximately 40% relative to 2019–2020 and will reach 63 mln t. By 2050, it will reach 83 mln t [2]. Today the chemical industry generates approximately 600 mln t of CO<sub>2</sub>, of which 2/3 comes from ammonia production. The CO<sub>2</sub> emission per ton of ammonia produced is 1.6–2.7 t for different enterprises. In methanol production, the CO<sub>2</sub> emission varies from 0.8 to 3.1 t of CO<sub>2</sub> per gram of methanol. The maximal levels of the specific CO<sub>2</sub> emissions are characteristic of enterprises using coal as an energy source. For example, in China the mean level of carbon dioxide emissions at ammonia plants operating on coal reaches 4.2 t of CO<sub>2</sub> per gram of ammonia. According to the forecasts, by 2025 the carbon dioxide emission in production of ammonia and methanol will increase by 3% more and will reach 635 mln t, mainly at the expense of rapidly growing methanol production. This fact makes the reduction of the CO<sub>2</sub> emissions from enterprises of this branch one

of topical and important problems of decarbonization of the world economy. IEA considers it necessary to bring the utilization of this source of the carbon dioxide emission to the levels of 70 and 540 mln t in 2030 and 2050 [2]. Several ways of solving this problem can be outlined.

A large part of carbon dioxide emissions associated with the ammonia and methanol production is due to the use of hydrogen produced by steam conversion of natural gas and coal gasification. These processes are characterized by high values of the carbon footprint: on the average, 12.4 and 19.4 kg of CO<sub>2</sub> per kilogram of H<sub>2</sub> when using natural gas and coal, respectively. Trapping and utilization of the produced CO<sub>2</sub> allow the carbon footprint to be decreased to 4.3–4.5 kg of CO<sub>2</sub> per kilogram of H<sub>2</sub> [53]. Today the cost of this hydrogen is approximately 50% higher than the cost of hydrogen produced from methane without carbon dioxide capture [4]. According to the latest forecast of the Hydrogen Council, by 2025–2030 this difference can become minimal, provided that the scale of the CO<sub>2</sub> utilization will considerably increase and the emission tax will be approximately \$35–50 per ton of CO<sub>2</sub> [3].

An increase in the production of “blue” hydrogen will also stimulate the development and commercialization of technologies for using CO<sub>2</sub> for producing highly marketable products: building materials, chemical intermediates, fuel, and polymers [54, 55]. The estimate of market prospects for these products [54] shows that the large-scale industrial use of CO<sub>2</sub> utilization technologies allows its emissions to be reduced by more than 10% by 2030. One of promising directions of CO<sub>2</sub> utilization is its injection into oil strata to increase the oil output [56]. Installations for CO<sub>2</sub> with the total capacity of 2 mln t of CO<sub>2</sub> annually operate today at three ammonia-producing plants in the United States, and this CO<sub>2</sub> is supplied to an oilfield by a special pipeline [1].

The most efficient way to reduce the CO<sub>2</sub> emissions is to abandon the use of hydrogen produced from organic feedstock in the production of ammonia and methanol and to replace this hydrogen by “green” electrolysis hydrogen whose carbon footprint is as low as 1.5 kg of CO<sub>2</sub> per kilogram of H<sub>2</sub> if using the electric power from wind and nuclear power plants [53]. Today the cost of electrolysis hydrogen is, on the average, 3 times higher than that of hydrogen produced by steam conversion of natural gas [3]. According to the estimates of Allen Consulting experts, already by 2025

this ratio will decrease to 1.5–2.0 [57]. The dynamics of the ratio between the costs of “green” hydrogen and hydrogen produced by steam methane conversion will be largely determined by the carbon dioxide emission tax. According to the forecasts, if this tax will be about \$50 per ton of CO<sub>2</sub> by 2030 and \$150 by 2040, the cost parity will be reached in the period from 2028 to 2034 [3]. Today several large projects on commercial production of “green” ammonia and methanol in EU countries, Australia, the United States, and Middle East are in the step of feasibility studies and designing [2, 58].

One of promising ways to reduce the CO<sub>2</sub> emissions in chemical industry is improvement of the existing and development of new technologies for ammonia and methanol production.

The traditional ammonia synthesis technology (Haber–Bosch process) requires large power consumption for ensuring high temperatures (450°C) and pressures (20 MPa) required for its implementation. This fact determined the interest in the development of alternative power-saving technologies for ammonia synthesis. Studies aimed at the development of electrochemical methods for ammonia production underwent the particularly active development recently, which reflects the overall trend toward decarbonization and electrification of the chemical industry [59–61]. Today the US Department of Energy finances several projects on electrochemical synthesis of ammonia, in which ammonia is produced using electrolysis hydrogen or water and membrane reactors of various designs: with conducting ceramic, alkali (hydroxide-exchange), and metal membranes [61]. In the technology suggested by CSIRO ENERGY (Australia), the ammonia synthesis is performed in a membrane reactor at a pressure of 1–3 MPa and a temperature of 450°C. A decrease in the working pressure by a factor of more than 10, compared to the standard conditions of the Haber–Bosch process, allows the power consumption to be decreased by 25% [62].

The expected increase in the methanol use in going to low-carbon economy stimulated studies on the development of the alternative methanol production technology based on CO<sub>2</sub> hydrogenation [63–65]. Because of high thermodynamic stability of CO<sub>2</sub> molecules, the efficient conversion of CO<sub>2</sub> to methanol requires additional energy and catalysts exhibiting the required selectivity and activity. The possibilities

of the CO<sub>2</sub> hydrogenation using homogeneous and heterogeneous catalysis and electrochemical and photocatalytic methods are considered from this standpoint. The main efforts of the researchers are focused on increasing the performance of the catalysts used and on searching for new catalysts, in particular, hybrid catalytic systems containing a molecular catalyst immobilized on carbon nanotubes. The cost of methanol produced from CO<sub>2</sub> using “green” electrolysis hydrogen is approximately 1.5 times higher than that of methanol produced by the traditional technology. This difference is mainly determined by the cost of hydrogen production, which will decrease in the future. Several pilot installations for methanol production by CO<sub>2</sub> hydrogenation are in operation now. The Carbon Recycling International (CRI) company (Iceland) is a technological leader in this field; it develops a project of a plant that will process annually 160 thousand tons of carbon dioxide into methanol [66].

The large-scale use of steam reforming of natural gas and of water electrolysis for hydrogen production in chemical industry has serious resource limitations. According to estimates made by IEA experts, the production of ammonia and methanol in amounts predicted by 2030 will annually require approximately 230 bln m<sup>3</sup> of natural gas (approximately 10% of the world’s demand today), 3020 TW h of additional electric power (about 11% of the world’s output today), and approximately 0.6 bln m<sup>3</sup> of water (about 1% of the total water consumption in power engineering today). The commercial implementation of these projects will require by 2030 the construction of no less than 450 installations for CO<sub>2</sub> capture, each with the annual capacity of 1 mln t of CO<sub>2</sub>, and 3500–4000 electrolyzers, each of 100 MW capacity [1]. Apparently, the production of “blue” and “green” ammonia and methanol will require major capital investments and should be stimulated by the state, especially in the initial period [1].

#### USE OF HYDROGEN IN STEEL-CASTING INDUSTRY

According to the data of the World Steel Association, the world steel production increased by a factor of almost 3 in the past two decades and reached 1869 mln t in 2019. The world leader in the steel-casting industry is China, where 996.3 mln t of steel was produced in 2019

(53.3% of the world production). The other major steel producers are significantly inferior to China: In 2019, 111.2 mln t of steel was produced in India, 87.9 mln t, in the United States, and 159.4 mln t, in the EU countries [67]. The IEA experts believe that, under the action of the growth of the population and GDP, the world demand for steel will probably continue to increase, especially owing to the economic growth in India, Southeast Asia, and Africa, even despite a gradual decrease in the demand in China [68]. According to the forecasts, by 2050 the world steel production can reach 2.5 bln t [68].

The main steel production technologies used today in the world steel-casting industry are BF–BOF (successively performed blast furnace and basic oxygen steelmaking processes) and EAF (scrap smelting in electric arc and induction furnaces). In the recent years, approximately 70% of raw steel has been produced by the BF–BOF technology and 30%, by the EAF technology [69]. This ratio varies in a wide range depending on the steel-producing country. It is 88 : 12 in China, 32 : 68 in the United States, and 58 : 42 in EU (average for 28 countries). The blast furnace process is accompanied by the formation of large amounts of CO<sub>2</sub>, on the average, 1.8 t of CO<sub>2</sub> per ton of the produced steel, of which about 60% is formed in the course of cast iron smelting in blast furnaces and 30%, in the course of coke production [70]. The CO<sub>2</sub> emissions when using EAF technology are determined virtually completely by the carbon footprint of the electric power used. For the European steel-casting industry, the average emissions are 500–600 kg of CO<sub>2</sub> per ton of steel [71, 72]. Recently some countries (India, Middle East, Iran, the United States) started to use as an EAF feedstock, along with scrap, also iron produced by direct reduction of iron ore (DRI). Today the share of the DRI–EAF technology in the world steel production is up to 7% [1]. The reductant for metallization of iron ore and DRI production is syngas produced by steam methane conversion or pure hydrogen. The replacement of metal scrap by DRI in steel casting in electric furnaces leads to an increase in the CO<sub>2</sub> emissions to 1270 kg of CO<sub>2</sub> per ton of steel in reduction of iron ore with methane and approximately to 1000 kg of CO<sub>2</sub> per ton of steel when using for this purpose hydrogen produced by water electrolysis with power from electric networks [73].

In 2020, the CO<sub>2</sub> emissions from ferrous metallurgical enterprises reached 2.4 bln t. IEA in the roadmap for reaching zero emissions by 2050 considers it necessary

to decrease them to 1.8 bln t by 2030 and to 0.2 bln t by 2050 [2]. This will require significant technological upgrade of the enterprises [74, 75]. One of primary goals of the upgrade is increasing the power efficiency of the steel production. According to IEA estimates, the power saving potential of modern technologies used in ferrous metallurgy is 20% on the average [76]. The use of the best available technologies developed by now allows this potential to be largely realized, which will lead to a 15–20% decrease in the CO<sub>2</sub> emissions [75]. Another promising way to decrease the carbon capacity of the steel production is an increase in the share of steel produced by scrap smelting in electric furnaces. According to the forecasts, 38% of steel will be produced in electric furnaces in 2030 and 46%, in 2050 [2]. Today, along with smelting in electric furnaces, the process of direct electrolysis of iron ore is being developed; it has already proved its efficiency in nonferrous metallurgy [77].

The world scrap resources have natural limitations and are distributed between steel-producing countries very nonuniformly. Therefore, it can be expected that the steel production based on DRI–EAF process will increase. According to the forecast of HSBC (Hong Kong and Shanghai Banking Corporation) experts, by 2060 the DRI production will be only 30% lower than the steel production from scrap [78]. The use of DRI in electric furnaces instead of metal scrap allows producing steel of higher quality, because DRI contains considerably smaller amounts of such harmful impurities as S, Cu, Sn, Ni, Cr, and Mo. The reduced DRI in the form of hot briquetted iron can also partially replace iron ore in cast iron production in a blast furnace. This allows the coke consumption and, correspondingly, the CO<sub>2</sub> emissions to be reduced [79]. Hydrogen plays an important role in decarbonization of ferrous metallurgy. In 2020, 5 mln t of hydrogen was used for iron production by direct reduction (DRI) [4]. According to forecasts, by 2050 approximately 60% of iron smelted in electric furnaces will be produced using iron reduced with hydrogen. This will require an increase in the hydrogen consumption to approximately 19 mln t by 2030 and 54 mln t by 2050 [2]. It is planned to use some of the produced hydrogen for reducing the CO<sub>2</sub> emissions in cast iron production. To this end, enrichment of coke gas in hydrogen and its use for iron ore reduction in a blast furnace are suggested [80]. The Japanese Ferrous Metallurgy Federation plans to prepare by 2030 a demo project on the use of this

technology with simultaneous capture of CO<sub>2</sub> from the blast furnace gas, which should lead to a 30% decrease in the CO<sub>2</sub> emissions per unit of the steel produced [1].

Today hydrogen used for steel production is obtained by steam methane conversion and coal gasification; these processes involve large CO<sub>2</sub> emissions. To accomplish the goals of decarbonization of the metallurgical industry, this hydrogen should be gradually replaced by “green” hydrogen [72–74, 75]. Its production will require large amounts of electric power generated using renewable power sources. For example, to implement the plans of decarbonization of the steel-casting industry in the EU countries and United Kingdom, the annual demand for “green” electric power will amount to 55, 143, and 183 TW h in 2030, 2040, and 2050, respectively [80]. According to the IEA estimate, complete abandonment of the use of organic fuel in hydrogen production in the world metallurgical industry will require the additional consumption of approximately 2500 TW h of the electric power annually, which corresponds to approximately 9% of the present demand for the electric power [1]. Implementation of projects on the production of “green” hydrogen for use in DRI production has already been started at several steel-casting enterprises in Austria, Sweden, and Germany [81].

#### USE OF HYDROGEN IN CEMENT PRODUCTION

Cement is one of the most demanded industrial products in the world. In production volume, it considerably surpasses steel, aluminum, other metals, wood, and plastics [82]. Its production increased by a factor of 2.4 in the past two decades: from 1.7 bln t in 2000 to 4.1 bln t in 2019 [83]. According to forecasts, the continuing growth of the population and the development of the urbanization can lead to a 12–23% increase in the cement production by 2050. In the existing technologies, about 0.6 t of CO<sub>2</sub> is formed in production of 1 t of cement [84]. Taking into account the scale of the world cement production, this makes the cement industry one of the main CO<sub>2</sub> emitters: Its share in the global CO<sub>2</sub> emissions in 2019 was approximately 7% (2.4 bln t) [85]. Therefore, the decarbonization of the cement production is one of priority goals of the program of reaching zero CO<sub>2</sub> emissions by the world economy by 2050 [2].

The cement production is a multistep process based on thermal decomposition of limestone at approximately

900°C to obtain calcium oxide, followed by its sintering with clay at 1450°C to obtain clinker, the main component of concrete. The CO<sub>2</sub> formed in these steps of the process, according to the classification of the World Business Council for Sustainable Development, is classed with direct CO<sub>2</sub> emissions from cement plants. The combustion of fossil fuel to obtain the thermal energy required for the clinker formation gives 30–40%, and thermal decomposition of limestone to CaO and CO<sub>2</sub>, 60–70% of the CO<sub>2</sub> emissions [86, 87]. The fossil fuel presently used at cement plants consists mainly of coal and petroleum coke [1]. Therefore, its replacement by alternative kinds of fuel with lower carbon content is the necessary condition for decarbonization of the cement industry. The alternative kinds of fuel considered are natural gas, biomass (including renewable organic waste of various origins), hydrogen, and electric power. Among these kinds of alternative fuel, natural gas (15%) and biomass (5%) are used today at cement plants in small volumes. In accordance with the forecast [2], already by 2040 up to 10% of the required thermal energy will be produced at cement plants by the combustion of hydrogen (in the pure form or as an additive to the fuel used), and by 2050 the share of hydrogen in the clinker production will increase to 15%. According to the forecasts, the use of hydrogen in the cement industry will reach 2 mln t in 2030 and 12 mln t by 2050 [4]. Already now one of the world largest cement producers, CEMEX, started to use hydrogen as a component of fuel mixtures at all its plants in Europe and actively introduces this technology in other countries. The company intends to reach complete decarbonization of its products by 2050 [88].

The use of alternative kinds of fuel is only one of possible ways to reduce the CO<sub>2</sub> emissions in cement production. The fuel consumption for clinker production can also be reduced by increasing the efficiency of the equipment for heat treatment of the feedstock [89] and optimizing the cement composition. Today the mean clinker content of the cement is 71%, and it is planned to be decreased to 65% by 2030 and to 57% by 2050 [2]. To this end, a part of clinker in the cement can be replaced by fly ash from coal power plants, by blast furnace slag, or by such natural minerals as volcanic ash. For example, in EU countries 80% of the blast furnace slag from metallurgical industry is presently used for the cement production [90]. According to forecasts, by 2050, in connection with virtually complete closure

of coal power plants and reduction of the use of blast furnace processes in metallurgy, the main components replacing clinker in mixed cements will be limestone and fired clay.

The above-considered directions of reducing the CO<sub>2</sub> emissions in the cement industry do not alter the principles of the clinker production by thermal decomposition of limestone. A possible alternative to the traditional technology of the clinker production is the electrochemical method being developed at the Massachusetts Institute of Technology [91]. A pH gradient is created in the electrochemical reactor as a result of water electrolysis. In the process, milled CaCO<sub>3</sub> undergoes decarboxylation at low pH at the anode, and solid calcium hydroxide Ca(OH)<sub>2</sub> precipitates at high pH at the cathode. When heated with silicon dioxide (SiO<sub>2</sub>), it forms alite, one of the main components of Portland cement. Simultaneously with solid reaction products, concentrated streams of high-purity gases arise in the reactor: a mixture of O<sub>2</sub> and CO<sub>2</sub> at the anode and H<sub>2</sub> at the cathode. The gases formed can be efficiently used for various operations at the plant, e.g., for the production of electric power using hydrogen fuel cells, or can be sold on the market. Along with process innovations, the capture and utilization of CO<sub>2</sub> will play an important role in reduction of the CO<sub>2</sub> emissions from cement enterprises. According to the IEA forecast [8], active progress in this field will start after 2030, and by 2070 80% of cement plants will be equipped with CO<sub>2</sub>-capturing installations, which will ensure 60% of the total reduction of the carbon dioxide emissions from cement enterprises.

## USE OF HYDROGEN ON VEHICLES

The world transport sector generates 24% of the global CO<sub>2</sub> emissions as a result of gasoline and diesel fuel combustion; in 2020, they amounted to 7.2 bln t. The following target levels for reducing the emissions from vehicles are indicated in the roadmap of the development of the world power engineering to reach the carbon neutrality by 2050: 5.7 bln t in 2030, 2.7 bln t in 2040, and 0.7 bln t in 2050. To this end, it is necessary to considerably change the structure of power sources used by vehicles. Today more than 90% of the required energy is obtained from organic fuel. According to the forecasts, by 2040 the share of this power source will decrease by a factor of almost 2, to

50%, and by 2050 it will become as low as 10%. The role of the electric power and alternative kinds of fuel will increase simultaneously. By 2050, the share of the electric power, hydrogen fuel, and biofuel will reach 45, 30, and 15%, respectively [3]. Hydrogen can be used as a fuel for vehicles in different forms: as alternative kind of fuel for internal combustion engines, after conversion to methanol and ammonia, and for electric power generation by fuel cells. The use of hydrogen for various kinds of vehicles has specific features determined by technological and economic factors.

*Road transport.* The road transport (passenger cars, trucks, buses, motorcycles) is responsible for 3/4 of the emissions generated by the transport sector [2]. About 60% of carbon dioxide emissions come from passenger (primarily city) transport, and 40%, from freight transport [92, 93]. The International Transport Forum predicts a significant, by a factor of more than 2, increase in the passenger and freight traffic by 2050. It is noted that the CO<sub>2</sub> emissions from vehicles by 2050 will increase by 16% even if the presently approved obligation on transport decarbonization will be fully implemented, because the expected emission reduction cannot compensate for the expected increase in the traffic [92]. The main directions of vehicle decarbonization considered today include the use of electric vehicles powered by storage batteries and hydrogen fuel cells and of cars with internal combustion engines powered by hydrogen fuel, biofuel, or synthetic fuel.

To reach the carbon neutrality of automobile transport by 2050, IEA considers it necessary to bring by the share of electric passenger cars and of trucks with low level of CO<sub>2</sub> emissions to 62 and 30%, respectively, by 2030. It is assumed that virtually all the electric passenger cars will be powered by storage batteries and that approximately 5% of trucks will use hydrogen. By 2050, the passenger transport should become fully carbon-free, and the share of using hydrogen should increase to 8%. On reaching the 90% level of freight transport decarbonization by 2050, the share of using hydrogen should reach 30%. Implementation of these plans will allow the CO<sub>2</sub> emissions from road transport to be decreased to 0.5 bln t, or by 90% relative to the year 2020. It is assumed that the electric power for charging the batteries and producing hydrogen will be generated from renewable sources [2]. According to [94], by the end of 2020 there were 34 million 804 thousand electric cars on fuel cells in the world, of which 65% were in Asia (China, Japan, South Korea),

27%, in North America, and 8%, in Europe. Only in the past 3 years their number increased by a factor of 2.7. In 2020, more than 90% of electric cars on fuel cells were used for transportation of passengers (passenger cars 75% and buses 16%) and only 9%, for transport of goods. According to Hydrogen Council's forecasts, by 2030 the number of electric passenger cars on fuel cells will increase to 10–15 mln, and that of trucks, to 500 thousands. By 2050, the number of passenger cars on fuel cells will reach 400 mln; that of buses, 5 mln; and that of trucks, 15–20 mln [3]. The market share of the road transport on fuel cells will amount to approximately 17% by 2050 [95].

The development and efficient functioning of the electric road transport requires rapid development of the corresponding infrastructure for its fueling. Today 540 hydrogen filling stations are in operation in the world. Among them, 278 are located in Asia; 190, in Europe, and 68, in North America. In the past 3 years, the number of hydrogen filling stations increased by a factor of 1.4, which is almost 2 times smaller than the rate of the growth of the world electric car fleet powered by fuel cells. According to the forecasts, the number of hydrogen filling stations will increase to 18 thousands by 2030 and to 40 thousands by 2050 [2]. The cost of the construction of hydrogen filling stations considerably exceeds the cost of construction of charging stations for electric cars and filling stations for vehicles powered by organic fuel. This is determined not only by the high cost of tanks for hydrogen storage, but also by the need for allocation of large land plots for constructing the filling stations, as their size is approximately 7 times larger than the size of land plots for traditional filling stations. Today the cost of the construction of a hydrogen filling station, depending on the volume of the hydrogen stored, is estimated at \$0.6–2 mln for tanks with a pressure of 70 MPa and \$0.15–1.6 mln for tanks with a pressure of 35 MPa [1]. The construction of filling stations at which hydrogen is stored in the liquefied form is still more expensive. The first such station has been already constructed in California by Linde [96].

Hydrogen for fueling cars can be produced directly at filling stations using renewable power sources or can be delivered by specialized automobile transport. Analysis of the economic efficiency of various methods for hydrogen delivery (in the compressed or liquefied state) has shown that the transportation of compressed hydrogen is competitive at the distances from the

production or storage sites not exceeding 130 km, whereas at longer distances the hydrogen transportation in the liquid form is less expensive [97]. The hydrogen used should contain no impurities capable of reducing the reliability of the fuel cell operation [98].

Implementation of large-scale plans on the development of the infrastructure for hydrogen supply to road transport requires major investments and state support measures [2]. When evaluating the efficiency of using electric cars powered by batteries and fuel cells for transporting passengers or goods, it is necessary to take into account the extent to which they meet the requirements to the transportation range, load, and admissible downtime, and also the availability of the infrastructure for replenishing the power resource of the electric cars. The energy of compressed hydrogen per unit weight is almost 260 kW h/kg, whereas for modern lithium-ion batteries it is 150 times lower, 260 W h/kg. Therefore, at equal range, the weight of storage batteries considerably exceeds the total weight of fuel cells and tanks with compressed hydrogen. For example, the total weight of fuel cells, tanks with hydrogen, and auxiliary battery of Xcient FC heavy truck (Hyundai), ensuring transportation of goods to a distance of 400 km, is 1 t. The weight of the battery required for this purpose is 3 t, which leads to the corresponding decrease in the weight of the transported goods [99]. The possibility of increasing the range without significantly decreasing the load capacity makes electric cars powered by fuel cells priority vehicles for long-range transportation of heavy loads [99–101]. According to the forecasts, in EU countries hydrogen fuel cells will power 5, 30, and 55% of trucks in 2030, 2040, and 2050, respectively [102]. One more important advantage of electric cars powered by fuel cells is short time required for their hydrogen filling, which usually does not exceed 15 min. Complete charging of the battery of an electric car takes today from 4 to 8 h, and with the rapid charging technology of Tesla type passenger cars this time can be decreased to 40 min [102]. This fact determines the efficiency of using fuel cells on vehicles operated intensely with minimal downtime: taxis, city buses, and small trucks (vans) [102–104].

According to the IEA forecast, wide use of fuel cells in various segments of road transport will start after 2030 [103]. As expected, by that time the total cost of the ownership of electric cars with fuel cells and batteries, taking into account all capital and

operation expenditures, will reach parity and become lower than that for cars powered by fossil fuel [105]. The use of batteries and fuel cells for decarbonization of vehicles has certain limitations with respect both to the admissible temperature and vibration levels and to the generated power, which even for heavy trucks does not exceed several hundreds of kW [98, 104]. This fact practically excludes the possibility of electrifying such kinds of off-road transport, widely used in mining and building industry, as dump trucks, loaders, bulldozers, and excavators. In particular, the operation of dump trucks requires engines of 3 MW and higher power. Experts of McKinsey & Company believe that the most efficient way of decarbonization of these vehicles is replacement of fossil fuel by hydrogen [104]. The possibility of reliable and stable operation of internal combustion engines powered by hydrogen fuel has been substantiated and confirmed by numerous studies performed during several decades [106, 107]. Presently several automobile and engine-building companies develop specialized diesel engines powered by hydrogen [108].

*Rail transport.* During already a long period, one of the main trends in the development of the world rail transport is an increase in the share of electric trains [1]. Today the electric power makes up 46% of the power consumption by rail transport. According to the forecasts, the share of electric power will increase to 65% by 2030 and to 96% by 2050, including 5% generated by fuel cells. This will allow the carbon dioxide emissions from the rail transport to be reduced from 95 mln t in 2020 to virtually zero by 2050 [2]. The traditional approach of the railway electrification involves major capital expenditure due to installation and regular repair of overhead power lines. According to data of the UK Railway Industry Association, electrification of 1 km of railways in the country costs £1.5–2.5 mln [109]. This fact determines the interest in using electric batteries and hydrogen fuel cells on railway transport. In experts' opinion, electric trains powered by fuel cells have the following main advantages [110]:

- hydrogen-powered trains can be fueled in less than 20 min and can operate for more than 18 h without refueling;
- trains powered by batteries have shorter range and longer downtime for battery charging;
- hydrogen-powered trains have lower total operation cost compared both to diesel trains and to trains powered

by electricity supplied by wire lines;

- from the economic viewpoint, it is appropriate to use electric trains powered by fuel cells primarily on nonelectrified railway routes with the range of up to 100 km, on railways with low duty (up to 10 trains daily), and on cross-border railways, because their operation does not depend on the overhead catenary voltage, which is different in many countries;

- the possible application fields of fuel cells on rail transport are considerably expanded by using fuel cells jointly with electric batteries (hybrid electric trains). In particular, the load capacity, range, and velocity of trains increase, and the power consumption decreases by approximately 30% [111];

- trains powered by fuel cells, like other types of electric trains, are characterized by considerably lower level of noise and vibration compared to trains powered by diesel fuel. Therefore, they exert no negative effect of humans, which is particularly significant for the rail transport whose routes pass near localities [112].

A train powered by hydrogen fuel cells, constructed jointly by Alstoma (France) and Siemens (Germany), is already in operation on a route between several cities in Germany (Lower Saxony). It is planned to put into operation in Germany 14 similar trains more in 2021. In 2022, hydrogen-powered trains should appear on French and British railways. The program for decarbonization of the EU economy sets ambitious tasks on using hydrogen, primarily “green,” on rail transport: Already by 2030, the share of trains powered by fuel cells should reach 40%, primarily at the expense of converting passenger trains to hydrogen fuel. This will require rapid development of the corresponding infrastructure, primarily of hydrogen holders and filling stations along railways [113].

*Maritime transport.* The maritime transport ensures 75% of the world freight transportation. In the past two decades, the total weight of cargo carried by maritime transport increased by a factor of 2: from 5984 mln t in 2000 to 11 076 mln t in 2019 [114]. If the existing rate will be preserved, the freight transportation by maritime transport can increase by a factor of almost 3 by 2050 [115]. In contrast to the road and railway transport, virtually the whole amount of energy required for the operation of maritime transport is generated by combustion of hydrocarbon fuel. In 2019, 180 mln t of fuel oil, 45 mln t of ship diesel fuel and gasoil, and 0.1 mln t of liquefied natural gas were consumed for this

purpose [8]. This led to the emission of 880 mln t of CO<sub>2</sub> in 2020, which amounted to approximately 12% of the total emissions from the transport sector [2].

In 2018, the International Maritime Organization formulated a strategy aimed at ensuring the reduction of carbon dioxide emission from maritime ships relative to 2008 by 40% in 2030 and by 70% (to approximately 300 mln t) in 2050. In the first step, in the short and medium term, the main efforts will be concentrated on implementation of technical and organizational measures to improve the energy efficiency of ships and optimize the logistics. In the second step, in the long term, along with further implementation of these measures, it is planned to gradually replace a part of hydrocarbons being burned by alternative kinds of fuel with considerably smaller carbon footprint [116, 117]. The potential effect of 22 different technical and organizational measures on the reduction of the carbon dioxide emissions in operation of maritime ships due to the reduction of the specific fuel consumption was evaluated in review [118], based on analysis of 150 published papers. Such measures include improvement of the hull design to improve its hydrodynamic characteristics, enhancement of the efficiency of power units, in particular, by using additional electric engines for operation at low velocities, a decrease in the ship velocity, etc. In most cases, the measures under consideration can ensure no more than 10–20% reduction of the CO<sub>2</sub> emissions. The technical measures become considerably more efficient when used in combination. This approach can be fully implemented in designing and constructing new ships. According to the forecasts, by 2040 the CO<sub>2</sub> emissions from newly constructed multipurpose dry-cargo ships will be 40% lower compared to the ships of the same type that are now in operation. The operation life of various types of maritime ships is 20–35 years. In 2019, 75–78% of ships carrying the heaviest loads, which are the main carbon dioxide emitters (container ships, tankers, dry-cargo ships), had the age of less than 14 years [119]. Their decommissioning and replacement by more perfect ships will require long time [120] and will largely determine the rate of the maritime fleet decarbonization.

IEA considers it necessary to reduce the CO<sub>2</sub> emissions by maritime transport by 6% annually, which allows bringing their level to 120 mln t by 2050 [2]. This is 2.5 times lower than the emission level planned by that time by the International Maritime Organization. In

accordance with the roadmap developed by IEA experts, already by 2030 17% of energy consumed by maritime ships will be generated from low-carbon kinds of fuel: ammonia (8%), hydrogen (2%), and biofuel (7%). By 2050, their share in the power consumption by maritime transport will increase to 84%, including 46% for ammonia, 17% for hydrogen, and 21% for biofuel [2]. Experts of the Organisation for Economic Cooperation and Development anticipate that the carbon dioxide emissions from maritime transport can be reduced by 80% already by 2035 by replacing 70% of fossil fuel by ammonia and hydrogen and 22%, by biofuel [121].

In all the scenarios of the maritime transport decarbonization, ammonia is given a leading role as a ship fuel. Today ammonia is already a commercial product successfully transported by maritime ships: 120 ports already have the required infrastructure, and 170 ships are properly equipped. The predicted conversion of the major fraction of maritime ships to ammonia fuel will require a considerable increase in the ammonia production. According to estimates [122], conversion of 30% of the ships that are now in operation to ammonia fuel will require increasing the production of low-carbon ammonia (“blue” and “green”) by 150 mln t annually. Simultaneously, it will be necessary to develop additional surface infrastructure for transportation, storage, and bunkering of ammonia [123]. Setting up the production of “green” ammonia directly at ports will reduce its cost for maritime ships. This approach started to be implemented in Morocco where ports promising for the production and storage of “green” ammonia have been defined. One of them is Jorf Lasfar port, where it is planned to produce 700 t of ammonia daily using renewable electric power from solar panels installed on the same site with the total capacity of 300 MW. The production of “green” ammonia required for filling all large ships passing through Morocco ports will require 280 MW h of electric power. This is less than 1% of the potential for producing renewable (wind and solar) electric energy in the country [124]. The use of ammonia as a fuel for internal combustion engines, which are now the main power units on maritime ships, requires solution of a number of technological and environmental problems. Ammonia has higher self-ignition temperature and lower laminar velocity of flame propagation compared to hydrocarbon fuel, which can lead to unstable operation of a diesel engine at low and high speeds. This can be avoided by adding

one of hydrocarbon fuels or hydrogen to ammonia [125, 126]. The ammonia combustion in internal combustion engines leads to the formation of large amounts of nitrogen oxides. They can be neutralized using standard SCR technology allowing reduction of  $\text{NO}_x$  to nitrogen and water vapor [123].

As follows from the IEA forecast, it can be expected that, in the period of up to 2050, hydrogen will be used for maritime transport decarbonization on considerably (3–4 times) smaller scale compared to ammonia [2]. This is due to a number of factors. The volumetric energy density of liquid ammonia is 2 times higher than that of liquefied hydrogen and 3.5 times higher than that of gaseous hydrogen at a pressure of 70 MPa. This will lead to the corresponding increase in the capacity of hydrogen storage tanks on board the ship and to the corresponding decrease in the available volume for carrying payload. The calculations performed in [127], based on analysis of the power consumption in more than 100 tanker journeys in a 3-year period, have shown that tanks with liquefied hydrogen can occupy 3–5% of the tanker volume, which is 2 times larger compared to the use of diesel fuel. Hydrogen liquefaction is power-consuming and expensive. Furthermore, cryogenic storage of liquid hydrogen considerably complicates its bunkering [128]. These facts gave IEA experts grounds to forecast that, on medium-range routes between ports having the required surface infrastructure, ship companies will mainly use compressed hydrogen [8]. Liquefied hydrogen, in opinion of International Council on Clean Transportation experts, can be efficiently used for large-tonnage long-range maritime transportation. The estimations of the hydrogen fuel amount required for the world largest container ships carrying cargo across the Atlantic between the United States and China, which consume daily 100 t of hydrocarbon fuel and more, allowed the following conclusions:

- about 43% of journeys can be made without increasing the area occupied by fuel tanks and without refueling on the route;
- the number of journeys without refueling can increase to 86% at 2% increase in the area for hydrogen fuel storage;
- 99% of journeys can be performed on replacement of 5% of cargo space by additional fuel tanks or with one refueling;
- medium-size container ships can perform journeys without arrangement of additional fuel tanks and without

refueling [129].

It was assumed in the calculations that the energy for power units of ships will be generated by hydrogen fuel cells, which are considered by many authors as the most efficient way of using carbon-free fuel on maritime ships [130–132].

According to the data of Global Maritime Forum, 106 pilot and demo projects aimed at decarbonization of world maritime transport are being implemented now [58], which is almost 1.5 times larger than a year before. More than 2/3 of the projects involve the use of ship fuel based on hydrogen and ammonia. The number of such projects considerably increased in the past year. For example, for large ships this number increased by a factor of 3 and 2.5, respectively. The majority of projects (71 projects) are being implemented in the EU countries, and approximately half of them are supported by the state. In the Asia–Pacific region, the leaders in the number of projects are Japan, China, and South Korea. Decarbonization of maritime transport requires large investments. According to estimates of the Global Maritime Forum, they can amount to \$40–60 bln annually in the course of the coming 30 years. The major fraction of the investments (87%) will be required for producing carbon-free fuel for maritime ships (“green” and “blue” hydrogen and ammonia) and creating the infrastructure required for its storage and bunkering; 13% will be spent for the construction of new and upgrade of existing ships [133]. Stimulation of ship companies to use carbon-free fuel requires appropriate state regulation measures on the regional and international levels [134]. In 2013, the European Commission adopted a strategy for reducing the greenhouse gas emissions from maritime transport [135]. In September 2020, the European Parliament adopted amendments requiring that ship companies should linearly reduce the annual average  $\text{CO}_2$  emissions from all their ships at least by 40% by 2030, with fines for their nonobservance. Since 2023, the European Commission plans to include maritime transport in the  $\text{CO}_2$  emission trading system (ETS EC) [136].

*Aviation transport.* Aviation transport is one of sectors of the world economy that suffered from the Covid-19 pandemic in 2020 to the greatest extent [137]. This led to the reduction of the  $\text{CO}_2$  emissions from the aviation transport from almost 1 bln t tons in 2019 to 640 mln t in 2020. According to the forecasts, already by 2025 the emissions will again reach the level of the year 2019 (950 mln t) [2]. As estimated by the Waypoint

2050 aviation expert group, the aviation passenger traffic will increase, on the average, by 3% annually and will reach 20 tln man-kilometers by 2050, which will exceed the level of the year 2019 by a factor of more than 2. If jet kerosene produced from fossil fuel will be used in aviation on the existing level, this will lead to an increase in the CO<sub>2</sub> emissions to 1.8 bln t annually [138]. The International Air Transport Association in 2016 committed to reduce by 2050 the CO<sub>2</sub> emissions from aviation transport to 325 mln t annually, or by 50% relative to the year 2005, and to reach the carbon neutrality by 2060–2065 [139]. Considerably more stringent requirements to the aviation decarbonization are indicated in the IEA roadmap: to reduce the CO<sub>2</sub> emissions to 210 mln t by 2050.

To reach this level of CO<sub>2</sub> emissions, it is necessary to decrease the use of traditional kerosene by a factor of 5: In 2050, its share in the total power consumption by aviation transport should become as low as 20–23%. According to the IEA roadmap, the leading role in the aviation fuel should be played by sustainable aviation fuel (SAF): biokerosene (45%) and hydrogen-based synthetic fuel (30%). It is anticipated that the contribution of electric storage batteries, fuel cells, and hydrogen fuel will not exceed 2%, although their introduction will start already in 2035 [2]. Along with CO<sub>2</sub>, the kerosene combustion yields water vapor, nitrogen oxides, sulfate aerosols, products of incomplete combustion of hydrocarbons, and solid particles (carbon black). Their presence in the atmosphere leads to changes in the methane and ozone content and to the formation of inversion cirrus clouds [140]. These atmospheric processes strongly influence the climate change (global warming). Their total contribution to the climate change can be several times higher than that of CO<sub>2</sub> [141, 142]. A procedure was developed [141] for quantitative estimation of the effect exerted on the climate change by the amounts of nitrogen oxides, water vapor, and inversion traces in the atmosphere by expressing them in the equivalent carbon dioxide amount, CO<sub>2</sub> eq. As has been shown, by 2050 the total amount of harmful emissions from the aviation transport, formed by kerosene combustion, can amount to 5.7 bln t of CO<sub>2</sub> eq, exceeding by a factor of 3 the forecast CO<sub>2</sub> emissions [139].

The aviation fuel based on hydrogen used in fuel cells or burned in turbine engines is characterized by virtually zero CO<sub>2</sub> emission, provided that hydrogen is produced by electrolysis using “green” electric power.

The level of CO<sub>2</sub> emissions in combustion of synthetic aviation fuel in aviation engines is determined by the carbon footprint of syngas, which is the feedstock for the Fischer–Tropsch process. In syngas production using “green” hydrogen and CO<sub>2</sub> from air, its carbon footprint is assumed to be close to zero, as for pure hydrogen fuel [143, 144]. Comparative estimation of the effect exerted on the climate change by different kinds of hydrogen aviation fuel compared to kerosene produced from petroleum feedstock was made in [141]. Hydrogen fuel cells exhibit the highest potential for reducing the negative effect on climate: this effect can be decreased by 90–75%. For hydrogen burned in aviation turbines, this decrease will amount to 75–50%, and for synthetic aviation fuel, to 60–30%. The authors state that relatively wide ranges of the estimates reflect insufficient knowledge of different factors of the effect exerted by aviation fuel on the climate change. The resultant profiles of the emissions of harmful substances from aircrafts using aviation kerosene and biofuel produced from the biomass of different origins are very close [145]. This fact suggests a significant effect of the combustion of aviation biofuel on the climate change, exceeding, in particular, the effect exerted by the combustion of hydrogen-based synthetic fuel [141].

Larger-scale, compared to IEA forecasts [2], use of hydrogen fuel in aviation will allow by 2050 not only reaching carbon neutrality of aviation transport but also reducing by 40–50% the negative effect of aviation on the climate. To this end, it is necessary that, by 2050, from 40 to 60% of aircrafts (depending on the aviation decarbonization rate) should use liquefied hydrogen as aviation fuel and the other aircrafts, synthetic hydrogen fuel and biofuel [141]. According to the program (roadmap) of the aviation transport decarbonization [141], aircrafts powered by hydrogen fuel with the range from 500 to 2000–3000 km (local, regional, and short-range aviation) will be developed and marketed in the coming 10–15 years. Today local, regional, and short-range aircrafts make up 70% of all the aircrafts in operation, and they generate approximately 30% of the CO<sub>2</sub> emissions from aviation transport. Longer time (20–25 years) will be required for the development and marketing of mid-range (7000 km) and long-range (10 000 km) aircrafts powered by hydrogen fuel. Today these types of aircrafts generate 73% of carbon dioxide emissions from aviation transport. It is anticipated that local and regional aircrafts will use electric motors

powered by hydrogen fuel cells. Short-range aircrafts will use electric motors powered by hydrogen fuel cells during horizontal flight and hydrogen-powered turbines during takeoff and climb. Mid- and long-range aircrafts will be completely powered by hydrogen turbines. In this case, it is appropriate to use fuel cells only for feeding onboard electrics. When forecasting the amount of hydrogen required for implementation of the program developed for the aviation transport decarbonization, the authors proceeded from two possible scenarios: efficient and maximal decarbonization. The amount of hydrogen required by 2040 and 2050 will be 10 and 40 mln t for the first scenario and 40 and 130 mln t for the second scenario, respectively [141]. The first scenario seems to be more realistic. The forecast hydrogen amount would be 2.5 and 7.5% of the expected level of hydrogen production in 2040 and 2050 [2].

The conversion of the major fraction of aviation transport to hydrogen fuel will require essential changes in the aircraft design. This primarily concerns the choice of the optimum design and of the number and location of liquefied hydrogen tanks on board an aircraft. Several essentially different options of hydrogen storage on board an aircraft have been suggested: arrangement of hydrogen tanks inside an aircraft or on its external surface (on airframe or wings). The arrangement of hydrogen tanks beyond the aircraft fuselage can deteriorate its aerodynamic characteristics and strengthens the requirements to the resistance of the tanks to external aerodynamic loads. The volumetric density of liquefied hydrogen is 3.8 times lower than that of aviation kerosene. This leads to the need for the corresponding increase in the total volume of onboard vessels for hydrogen storage, which may require not only significant rearrangement of the aircraft internal space but also changes in its overall size, primarily in the fuselage length [141, 146]. Also, an important problem of using hydrogen as aviation fuel is to ensure reliable thermal insulation of tanks with liquefied hydrogen to make the hydrogen loss by evaporation as low as possible. Comparative analysis of various insulation methods has shown that a plastic foam layer introduced between the external and internal walls of the hydrogen storage tank ensures the best insulation properties [147].

The first studies on evaluating the possibility of using hydrogen fuel in aviation were performed in the former Soviet Union in 1988 at the Tupolev Aviation Scientific and Technical complex. A testing laboratory

based on a TU-154V aircraft was created, and the essential features of using hydrogen as an aviation fuel were determined experimentally [148]. In the early 2000s, within the framework of the CRYOPLANE System Analysis project, the conceptual principles of the conversion from kerosene to hydrogen in aviation were formulated, and the medium- and long-range scenarios were substantiated. The project authors believe that this provided a firm basis for starting larger-scale measures aimed at introducing liquid hydrogen as an aviation fuel [149]. One of the leading aviation producers, Airbus, have already started designing several types of hydrogen-powered commercial aircrafts; their production is planned to be started in 2035 [150].

The use of hydrogen fuel in aviation will require significant upgrade of airports, which should ensure reliable hydrogen supply and storage and hydrogen fueling of aircrafts. It is anticipated that liquefied hydrogen will be delivered by specialized automobile transport to small airports serving local and regional flights [97, 141]. For large airports serving mid- and long-range flights, it is economically preferable to produce hydrogen on site using renewable power sources [151]. However, in this case facilities for storage of large volumes of liquid hydrogen should also be constructed, because the aviation fuel reserve for several-day operation should always be available at an airport. Hydrogen can be delivered from the central hydrogen storage facility to the aircraft fueling site either by special fueling trucks or by cryogenic pipelines [150, 151]. One of the most technically complex problems in the upgrade of the airport infrastructure for the conversion to hydrogen fuel is fueling of aircrafts with liquefied hydrogen. The hydrants developed for this purpose should not only exclude the hydrogen loss by evaporation but also ensure high throughput to make the aircraft fueling time as short as possible despite almost fourfold increase in the pumped hydrogen volume compared to aviation kerosene [141, 151]. Taking into account the complexity of the problem of preparing airports for serving aircrafts powered by hydrogen fuel, Airbus in 2020 launched the Hydrogen Hub in Airports program taking into account the interest of all the process participants. This concept suggests also the conversion to hydrogen fuel of all airport vehicles, whose carbon dioxide emissions amount now to 3–5% of the total carbon dioxide emissions from aviation [152]. A two-year research project on the development

of trials of processes for maintenance of hydrogen-powered aircrafts was started in 2021 on the base of the Hamburg airport (Germany) [153].

#### USE OF HYDROGEN IN POWER ENGINEERING AND BUILDING MAINTENANCE

The transition to low-carbon economy involves large-scale electrification of its different sectors. According to IEA forecasts, the world demand for the electric energy will increase from 23 230 TW h in 2020 to 60 thousand TW h in 2050. The share of renewable power sources in the total balance of the electric power generation will increase from 29% in 2020 to 61% in 2030 and 88% in 2050. The share of the generation from fossil fuel will simultaneously decrease. Whereas in 2020 power plants using coal and gas ensured 35 and 23% of the world electric power generation, by 2030 their share will decrease to 8 and 17%, respectively, and by 2050 all the coal-fired power plants will be decommissioned, and the share of electric power generation from gas fuel will become as low as 0.45%. In 2020, the electric power generation led to the emission of 12.3 bln t of CO<sub>2</sub>, of which 74% came from coal-fired power plants. The forecasted change in the power generation structure, in opinion of IEA experts, will allow the CO<sub>2</sub> emissions in this sector of world economy to be reduced virtually to zero already by 2040 [2].

One of the trends in the development of the world power engineering is the outstripping growth of the power generation using solar and wind energy, compared to other renewable power sources. In 2020, the share of the electric power generated by solar and wind facilities was 31% of the total electric power generation from renewable power sources; by 2030, it can increase to 66%, and by 2050, to 77% [2]. The electric power generated using solar and wind energy is characterized by considerable time instabilities of different scales, which can negatively affect the reliability of the electric network operation. The need for taking into account the seasonal and year-to-year variations in the wind speed and solar radiation in designing power facilities based on renewable power sources stimulated the emergence of a new rapidly developing field of science, power climatology [154]. Numerous papers in which the variability of weather conditions determining the output of solar and wind power facilities is estimated from actual data and climatic models have been published by now

[155]. Retrospective analysis of weather variations in Germany in 1990–2015 [156] has shown that the seasonal variation of the power generation by photoelectric solar facilities can reach 5 times, from the maximum in July (4.4 TW h) to the minimum in December (0.8 TW h). For the wind facilities, the difference between the maximal power output in January (8.7 TW h) and minimal in August (3.8 TW h) is 2 times smaller. Similar values of the seasonal variability of the electric power generation from various renewable power sources were obtained for the weather conditions of the United Kingdom [157]. The forecasted levels of the utilization factor of the installed capacity for a solar facility are maximal in June–July (17–18%) and minimal in December–January (2–3%). For wind facilities, this parameter varies from 50–60% in December–January to 23–25% in June–July. In designing power systems, including the infrastructure for the electric power storage, it is necessary to take into account changes in the seasonal variation of the electric power generation from renewable power sources throughout the service life of solar and wind power facilities. As shown in [158], in a 20-year period (approximate service life of wind electric generators), the wind power generation in the winter and summer times can vary by 15%. The possible level of seasonal variations in the total output of variable renewable electric power in a specific region, along with climatic characteristics of this region, depends on the ratio of the installed capacities of solar and wind power plants. For example, in Germany, where, according to data for 2015, the installed capacities of solar and wind power plants differed by only 5%, the difference between the maximal and minimal monthly production of the electric power was 25% [156]. Today the contribution of variable renewable electric power generation to the total power generation in the world is 9%. According to IEA forecasts, by 2030 and 2050 it will increase to 40 and 68%, respectively [2]. This will inevitably lead to significant fluctuations of the electric power generation within a year both in separate countries and in the world energy system as a whole.

The most efficient way to ensure stable operation of electric power systems that use variable renewable electric power is accumulation and storage of excess power and its return into the power system when the demand for the power increases. Among the available methods for electric power storage, only two methods, pumped hydroelectric and compressed-air energy

storage systems, can be used in principle for large-scale and long-term power storage. The share of pumped hydroelectric energy storage facilities in the world electric power storage volume is now 97% (159 GW). The largest facilities of this type are located in China (32 GW), Japan (28.3 GW), and the United States (22.6 GW) [159, 160]. The construction of pumped hydroelectric energy storage facilities is possible only under definite geographic conditions including the required height differential between the upper and lower reservoirs, availability of a sufficient amount of water resources, and possibility of acquisition of large land spots. In addition, it requires long time and large capital expenditure and involves environmental risks.

The main prospects for large-scale and long-term electric power storage are associated with the power conversion to hydrogen by water electrolysis [159–162]. The electrolysis technology and the equipment required for this purpose are being continuously improved, and the single and total electrolyzer capacities increase. According to the forecast of the International Renewable Energy Agency, by 2050 the main technological characteristics of the most demanded alkaline electrolyzers and polymer electrolyte membrane (PEM) electrolyzers will be considerably improved. In particular, the power consumption for producing 1 kg of H<sub>2</sub> will decrease from 47–66 kW h in 2020 to less than 42 kW h in 2050, the service life will increase by a factor of 2, to 100 000–120 000 h, and the mean capacity will increase from 1 to 10 MW [163]. If the scenario of reaching the carbon neutrality by 2050 will be implemented, the total capacity of electrolyzers will increase from 0.3 GW in 2020 to 850 GW in 2030 and 3600 GW in 2050 [2]. According to the forecast, their cost will decrease considerably with an increase in the production of electrolyzers and by 2050 will become \$130–307 per kilowatt, which is 3–5 times lower than in 2019 [163]. The cost of the wind and solar electric power will decrease simultaneously. As expected, it will be \$0.03–0.05 per kilowatt for coastal wind facilities and \$0.05–0.08 per kilowatt for maritime wind facilities. For solar photoelectric facilities, it will be \$0.02–0.08 per kilowatt, which is approximately 2–3 times lower than in 2018. By 2050, the cost of the wind and solar power can decrease by a factor of 1.5 more [164]. All these facts create favorable conditions for the large-scale production of “green” hydrogen. According to the IEA forecasts, 81 mln t of electrolysis hydrogen will be

produced in 2030, and 4 times larger amount, 322 mln t, in 2050 [4].

A large fraction of this hydrogen will be used in power engineering, which will require the creation of the developed infrastructure for hydrogen storage to smooth the seasonal fluctuations of solar and wind power generation. The underground hydrogen storage in various geological structures, primarily in reservoirs created in salt-bearing strata (salt caverns) is considered today as the most efficient method for large-scale (hundreds of thousands of m<sup>3</sup>) and long-term hydrogen storage. Salt caverns are already used for many years in the United Kingdom (three caverns of 70 thousand m<sup>3</sup> capacity each are in operation in Teesside since the early 1970s) and in the United States (a 580 thousand m<sup>3</sup> cavern in Clemens Dome and a 566 thousand m<sup>3</sup> cavern in Moss Bluff are in operation since 1983 and 2007, respectively) [165]. The practical experience of their operation has shown that the hydrogen storage in salt caverns ensures high gas tightness of the reservoir and the possibility of performing repeated cycles of hydrogen takeoff and filling at high rate with a small volume (up to 30%) of the buffer gas remaining in the cavern [166–168]. In the case of long-term (for several years) storage of a constant volume of hydrogen in salt caverns, its contamination with impurities, primarily hydrogen sulfide and methane, should be taken into account. These impurities can be formed by interaction of hydrogen with microbial communities present in the residual brine [167]. In the United States, the construction of the presently largest hydrogen holder in salt strata with the volume exceeding 1 mln m<sup>3</sup> started in Spindletop, and designing of a complex salt caverns for hydrogen storage to accumulate 1 GW of pure electric power has been initiated in Utah [169].

Salt caverns are successfully used in many countries for the methane storage. Some of them can be used for hydrogen storage without significant upgrade of the surface and well equipment. In EU countries, the share of salt caverns in the total volume of the underground methane storage is now 18%. The energy potential of methane stored in them is estimated at 206 TW h. In conversion of salt caverns to hydrogen storage, their energy potential will decrease to 50 TW h because of considerably lower volumetric energy density of hydrogen compared to methane [170]. The estimates made in [170] show that the amount of the electric power required in the EU countries to compensate for

the variability of the power generation by wind and solar power plants can reach 70 TW h in 2030 and 450 TW h in 2050, which exceeds the capacity of the existing gas holders in salt caverns. This will require construction of new hydrogen holders in salt-bearing strata in Europe. As shown in [171], the forecast capacity of hydrogen holders in salt caverns is about  $85 \times 10^3$  TW h, which is much higher than the possible deficiency. Exhausted oil and gas deposits and aquifers can also be used for underground hydrogen storage along with salt caverns [172, 173]. In EU countries, the total volume of methane stored in them is approximately 4 times larger than the methane volume in salt caverns [170]. By now, the practical experience of hydrogen storage under these conditions is insufficient. Theoretical and experimental estimates suggest possible partial hydrogen loss and its contamination due to chemical reactions with rocks and stratal waters and to diffusion and microbiological processes [172, 174, 175].

If geological structures suitable for hydrogen storage on production sites are lacking, large metal tanks arranged on the earth surface can be used for this purpose. The hydrogen pressure in such reservoirs is usually several MPa. The use of higher pressures would lead to a considerable increase in the cost of such reservoirs because of the need for using expensive materials for the construction and of hydrogen compression expenditure. Storage of compressed hydrogen in pipeline segments with sealed ends shows promise [172, 176]. The total length of such storage pipelines, which are usually located at a small depth, can reach several kilometers. When using pipes of large diameter (up to 1.4 m) and hydrogen pressure of 10 MPa, 10–12 thousand t of hydrogen can be stored in a pipeline storage facility of 1 km length [176]. The possible scale of long-term hydrogen storage in the liquefied form is considerably smaller. For example, at the Canaveral space launch site in the United States the capacity of spherical tanks for liquefied hydrogen storage is 265 t [177]. Relatively small capacity of tanks for liquefied hydrogen storage is due not only to high power consumption for liquefaction but also to problems with ensuring low loss of liquefied hydrogen through evaporation. Along with hydrogen storage in the gaseous or liquefied state, hydrogen can also be stored as a constituent of various chemical compounds (chemical hydrogen storage), primarily of ammonia and methanol [41, 50]. The volumetric hydrogen content of ammonia and methanol is 73

and 41% higher compared to liquefied hydrogen. An essential advantage of ammonia over methanol is that it contains no carbon, so that its decomposition to obtain hydrogen is not accompanied by carbon dioxide emission. Ammonia can be stored in the liquid state under relatively mild thermobaric conditions: at normal temperature and a pressure of 1 MPa or at normal pressure and a temperature of  $-33^\circ\text{C}$  [178]. Liquid organic hydrogen carriers are also considered as promising chemical compounds for hydrogen storage. They contain 5–8 wt % hydrogen, which meets the requirements to systems for chemical hydrogen storage. An important advantage of these compounds is the possibility of using for their storage and transportation the same infrastructure as for petroleum products [179].

The hydrogen storage technologies (in geological structures, in surface reservoirs, as a constituent of chemical compounds, etc.) strongly differ in the required capital expenditure and storage cost. According to the estimates [180], the underground storage of 1 kg of hydrogen in exhausted hydrocarbon deposits is approximately 8 times more expensive than in salt caverns. The most expensive method of surface hydrogen storage is its storage in the liquefied state: It is 1.6 times more expensive than the ammonia storage and more than 20 times more expensive than storage of 1 kg of compressed hydrogen.

Piston gas engines, gas turbines, and fuel cells are suitable for electric power generation using hydrogen fuel [181–183]. By now, considerable practical experience has been gained in the electric power generation by combustion of methane in a mixture with hydrogen in piston gas engines and gas turbines. There are up to 200 gas turbines using methane–hydrogen mixtures as a fuel in the world [180]. GE Global, one of the world power engineering leaders, runs 75 such turbines, of which 25 turbines operate on methane–hydrogen mixtures containing more than 50 vol % hydrogen for already more than 1 mln h. Specialists of the company experimentally confirmed the possibility of using 100% hydrogen in some types of combustion chambers that already exist or are being developed [181]. In 2018, Kawasaki company performed successful trials of a gas turbine powered by pure hydrogen at a thermal power plant in Kobe (Japan). Mitsubishi Power participates in the Netherlands in a project for the conversion of an operating 440 MW power unit at a thermal power plant to the combustion of pure hydrogen by 2025 [1]. The main environmental

problem in the conversion of gas turbines to hydrogen fuel is the formation of a large amount of nitrogen oxides, which does not allow efficient minimization of the formation of nitrogen oxides by methods used in gas turbines powered by natural gas [183]. Leading producers of gas turbines are now developing new types of combustion chambers, allowing efficient reduction of nitrogen oxide emissions when using as a fuel hydrogen or hydrogen-rich mixtures with methane [181, 184].

The efficiency of the electric power generation by gas turbines strongly depends on their capacity and load. For example, a Mitsubishi V501J gas turbine of 327 MW capacity exhibits 41 and 61.5% efficiency in operation in the open and combined cycle modes, respectively, and a Hitachi H-25 gas turbine of 32 MW capacity in the same modes exhibits 34.8 and 50.3% efficiency [185]. With a decrease in the gas turbine load to 50 and 10%, the efficiency can decrease by 20 and 60%, respectively, compared to the efficiency of the operation with complete 100% load [186]. Fuel cells are free of these drawbacks. They show equal efficiency in operation in a wide range of capacity, from tens of MW to units of kW. The efficiency of fuel cells reaches 60–65%, which is comparable with the efficiency of 1.5 GW steam–gas facilities [187, 188]. In contrast to gas turbines, fuel cells preserve high efficiency at incomplete load, which allows their use in electric network with high share of wind and solar electric power.

70900 fuel cells were produced in 2019. Most of them, 51 700 (73%), were stationary fuel cells. However, their share in the total capacity of the produced fuel cells was considerably lower, 20% (221.2 MW out of 1.13 GW). This is due to the fact that, among stationary fuel cells, those of relatively small capacity prevail. They are used in microgeneration facilities (micro heat and electric power plants) [189]. The total capacity of stationary fuel cells rapidly grew in the past years and reached approximately 2.2 GW in 2020. However, only 7% of fuel cells with the total capacity of 150 MW were hydrogen-powered [4]. The main types of fuel cells produced today are those with a solid polymer electrolyte membrane (PEMFC) and with a solid oxide electrolyte (SOFC). In 2019, 44.1 thousand PEMFCs (62% of the total number) and 22.8 thousand SOFCs (35%) with the unit capacity from several units to several tens of kW have been produced. Fuel cells with phosphoric acid electrolyte (PAFC) have the highest installed capacity, from 100 to 400 kW. Only 300 PAFCs were produced

in 2019, but their total capacity exceeded that of all the produced PEMFCs by more than 30% [189].

Cogeneration facilities used for independent power and heat supply of buildings are today the main application field of stationary fuel cells, primarily PEMFCs. The efficiency of utilization of the hydrogen energy potential by such facilities can exceed 90%. Most of these facilities (350 thousand, of which 85% use PEMFCs and 15%, SOFCs) are in operation in Japan within the framework of the ENE–FARM program [182, 190]. One of rapidly developing application fields of stationary fuel cells is power supply to consumers isolated from electric networks, e.g., of base telecommunications stations for transferring mobile telephony signals. There are more than 7 mln such stations today, and this number continues to grow with the development of telecommunications network. Fuel cells can also be used for reserve power supply to various objects requiring continuous operation, e.g., hospitals and data processing centers. Diesel electric generators powered by fossil fuel are used for this purpose today [1, 191]. The applications of fuel cells to the energy sector can be made considerably broader by combining several fuel cells in batteries (networks). This allows fuel cells to be used for power generation not only in low-capacity independent electric networks [192], but also for balancing the power consumption in regional power systems in the period of peak loads and at decreased electric power supply from solar and wind power plants [182, 188].

The efficiency of successive conversion of electric power to hydrogen, hydrogen storage, and power generation from hydrogen is estimated today at approximately 30%. According to the forecasts, enhancement of the efficiency of electrolyzers and fuel cells will lead to an increase in the overall efficiency of the electric power–hydrogen–electric power process to 42% by 2030 and to 44% by 2050 [189]. Despite major energy loss in such energy conversion, International Renewable Energy Agency experts believe that this conversion is the necessary condition for increasing the generation of renewable variable electric power [163].

Ammonia, along with hydrogen, has also high potential for decarbonization of the energy sector. Recent studies performed in Japan demonstrated the possibility of joint combustion of ammonia and coal without increasing nitrogen oxide emissions [193]. Implementation of a demo project on combustion of

coal with the addition of 20% ammonia on a 1 GW facility has been started. Its results will allow evaluation of the possibility of using this technology at operating coal-fired power plants in Japan [194]. As shown in [195], this will allow the CO<sub>2</sub> emissions to be reduced by 40 mln t by 2030, which is comparable with the effect that is planned to reach by implementing the program for the construction of new electric power plants using the most efficient systems for coal combustion. According to IEA estimate, joint combustion of coal and ammonia at all the coal-fired electric power plants that will be in operation in the world in 2030 will allow the CO<sub>2</sub> emissions to be reduced by 1.2 bln t [4]. It is assumed that the ammonia burned jointly with coal will be carbon-free [37, 195]. Its production would require 120 mln t of “green” hydrogen [1].

Various buildings are among the main consumers of electric and thermal power. These include residential buildings, offices, shops, hotels, schools, and other public spaces and business premises. Today they consume up to 30% of the final power consumption in the world, including 55% of the electric power consumption. The CO<sub>2</sub> emissions from combustion of fossil fuel used for heating buildings amount today to 3 bln t. When including the carbon footprint of external sources of the power consumed by illumination and conditioning systems and by various home appliances, this value becomes as high as 9.8 bln t [8]. IEA experts associate the main prospects for decarbonization of this sector of economy with enhancement of the energy efficiency of buildings and of the equipment and devices used, with gradual abandonment of the use of fossil fuel, and with large-scale introduction of low-carbon technologies for producing heat and electric power. According to the forecasts, the share of fossil fuel in power supply to buildings will decrease to 30% by 2030 and to 2% by 2050. The share of electric power in the energy balance of buildings will increase simultaneously: from 33% in 2020 to 50% in 2030 and 66% in 2050. It is assumed that the whole amount of the electric power used for electrification of buildings will have a minimal carbon footprint: It will be obtained from renewable power sources or from power plants equipped with carbon dioxide capturing systems [2]. The prospects for using hydrogen for decarbonization of building maintenance are determined by the possibilities of the efficient use of hydrogen as a carbon-free fuel in systems for decentralized production of electric power

and heat using fuel cells, in gas boilers for heat supply to buildings, in hybrid heat pumps, and also as a component of methane–hydrogen mixtures in the existing gas distribution networks [8, 182, 196]. Today 30% of buildings are heated with natural gas supplied through gas distribution networks. Several projects implemented recently demonstrate the possibility of using for these purposes methane–hydrogen mixtures containing up to 20% hydrogen, which do not require significant upgrade of the equipment used. This allows the CO<sub>2</sub> emissions to be reduced by 7% [196]. According to the forecasts, by 2050 the share of gases in the production of thermal energy for buildings will remain on approximately the same level, but natural gas will be virtually completely replaced by low-carbon gases (hydrogen, biogas, and synthetic methane) [1]. The efficient use of hydrogen in systems for central heating of buildings requires gas boilers powered by 100% hydrogen. Many producers have already started the production of such boilers [2, 197]. In the opinion of IEA experts, already in 2025 all the gas boilers supplied to the market should be suitable for using 100% hydrogen to reach zero CO<sub>2</sub> emissions by 2050 [2]. Hydrogen-powered boilers of lower capacity can be incorporated in hybrid systems for heat supply to building jointly with thermal pumps and fuel cells, producing additional thermal energy in the periods of peak negative centigrade temperatures [197].

The scale of using hydrogen will be determined by the development of the infrastructure required for its delivery to buildings (special pipelines and automobile transport) and by the price competition with the electric power and other low-carbon gases used for heating buildings. According to IEA experts’ estimate, hydrogen should be considered as an important additional resource for decarbonization of this sector of economy, with the leading role played by the electric power and enhancement of the energy efficiency of buildings. According to the forecasts, in 2030 the hydrogen consumption for power and heat supply to buildings will amount to 2 mln t, and by 2050 it will increase by a factor of more than 10 and reach 25 mln t, i.e., 5% of the world production level [4].

## CONCLUSIONS

Hydrogen is used today in oil-refining, chemical, and steel-casting industry. Decarbonization of the world economy will require considerable expansion of

the hydrogen application fields and the corresponding increase in the hydrogen production. According to IEA forecasts, by 2030 the hydrogen production will increase by a factor of more than 2 compared to 2020 and will reach 212 mln t, and in the next two decades it will increase to 528 mln t. The share of low-carbon (“green” and “blue”) hydrogen in the total hydrogen production will increase to reach 70% in 2030 and virtually 100% by 2050. The hydrogen consumption structure in various branches of economy will also gradually change. Already in 2030, various branches of industry will use in total only 50% of the produced hydrogen. By 2050, their share in the total hydrogen consumption will decrease to 30%. After 2030, the major fraction of the produced hydrogen, including its derivatives (ammonia, methanol, and synthetic hydrogen fuel), will be used in transport and energy sectors of the economy. Large-scale use of low-carbon hydrogen in various branches of economy will allow the CO<sub>2</sub> emissions in the period 2020–2050 to be reduced in total by 60 bln t, which amounts to 6% of the total forecast effect of the decarbonization of the world economy in this period.

The possibility of reaching the forecast production levels and using low-carbon hydrogen in various branches of the world economy is determined by the set of technological, economical, and regulation factors. An increase in the electric power generation from renewable power sources in combination with the growth of the single and total capacity of electrolyzers will allow the share of “green” hydrogen in the world hydrogen production to be increased to 28% by 2030 and to 60% by 2050. The development and improvement of technologies for capture and utilization of carbon dioxide will result in that the share of “blue” hydrogen by 2030 will amount to 50% of the total hydrogen amount produced from fossil fuel, and by 2050 its share will exceed 90%. An increase in the scale and efficiency of the production of “green” and “blue” hydrogen will be accompanied by a considerable decrease in its cost. According to the forecasts, the cost of 1 kg of “green” hydrogen will decrease from \$3.5–7.5 today to approximately \$1.5–3.5 in 2030 and \$1.0–2.5 in 2050, which will be close to the cost of “blue” hydrogen. The efficiency of using hydrogen for the decarbonization of the world economy will be largely determined by the measures of the state support and control on the national and international levels. In particular, one of topical problems is the development of standards for the main

stages of the life cycle of the hydrogen production and use.

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#### CONFLICT OF INTEREST

The author declares that he has no conflict of interest.

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