# Chapter 8
# Energy Scenario Results

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**Abstract** Results for the 5.0 °C, 2.0 °C and 1.5 °C scenarios for ten world regions in regard to energy-related carbon-dioxide emissions, final-, primary-, transport- and heating demand and the deployment of various supply technologies to meet the demand. Furthermore, the electricity demand and generation scenarios are provided. The key results of a power sector analysis which simulates further electricity supply with high shares of solar- and wind power in one hour steps is provided. The ten world regions are divided into eight sub-regions and the expected development of loads, capacity-factors for various power plant types and storage demands are provided. This chapter contains more than 100 figures and tables.

This chapter provides a condensed description of the energy scenario results on a global scale, for each of the ten world regions. The descriptions include a presentation of the calculated energy demands for all sectors (power and heat/fuels for the following sectors: industry, residential and other, and transport) and of supply strategies for all the technologies considered, from 2015 to 2050. The results of the model-based analyses of hourly supply curves and required storage capacities are also discussed based on key indicators. Graphs, tables, and descriptions are provided in a standardized way to facilitate comparisons between scenarios and between regions.

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The following global summary of the regional results is presented in the same structure as that used for individual regions. Consistent with the regional results, these tables do not include the demand and supply details for the bunker fuels used in international aviation and navigation. Section 8.2 outlines a global demand and supply scenario for renewable bunker fuels in the long term, including estimates of additional $CO_2$ emissions from fossil bunker fuels between 2015 and 2050.

## 8.1 Global: Long-Term Energy Pathways

### *8.1.1 Global: Projection of Overall Energy Intensity*

Combining the assumptions for the power, heat, and fuel demands for all sectors produced the overall final energy intensity (per $ GDP) development shown in Fig. 8.1. Compared with the 5.0 °C case based on the Current Policies Scenario of the IEA, the alternative scenarios follow more stringent efficiency levels. The 1.5 °C Scenario represents an even faster implementation of efficiency measures than the 2.0 °C Scenario. The 1.5 °C Scenario involves the decelerated growth of energy services in all regions, to avoid any further strong increase in fossil fuel use after 2020. The global average intensity drops from 2.4 MJ/$GDP in 2015 to 1.25 MJ/$GDP in 2050 in the 5.0 °C case compared with 0.65 MJ/$GDP in the 2.0 °C Scenario and 0.59 MJ/$GDP in the 1.5 °C Scenario. The average final energy consumption decreases from 46.3 GJ/capita in 2015 to 28.4 GJ/capita in 2050 in the 2.0 °C Scenario and to below 26 GJ/capita in the 1.5 °C Scenario. In the 5.0 °C case, it increases to 55 GJ/capita.

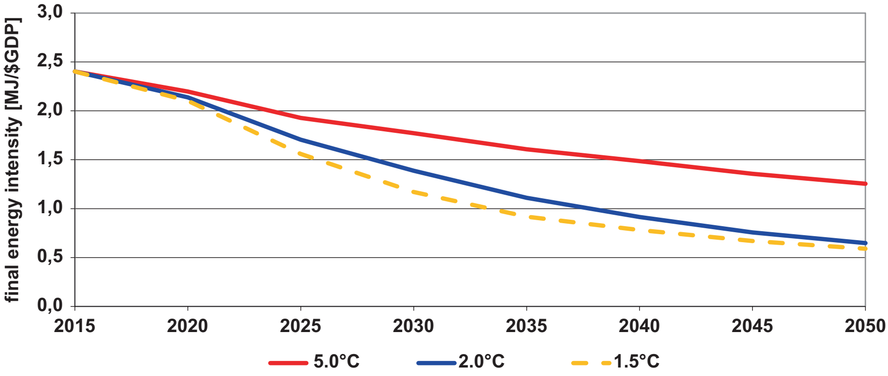


**Fig. 8.1** Global: projection of final energy (per $ GDP) intensity by scenario

### 8.1.2 Global: Final Energy Demand by Sector (Excluding Bunkers)

Combining the assumptions for population growth, GDP growth, and energy intensity produced the future development pathways for the global final energy demand shown in Fig. 8.2 for the 5.0 °C, 2.0 °C, and 1.5 °C Scenarios. In the 5.0 °C Scenario, the total final energy demand will increase by 57% from 342 EJ/year in 2015 to 537 EJ/year in 2050. In the 2.0 °C Scenario, the final energy demand will decrease by 19% compared with the current consumption and reach 278 EJ/year by 2050, whereas the final energy demand in the 1.5 °C Scenario will reach 253 EJ, 26% below the 2015 demand. In the 1.5 °C Scenario, the final energy demand in 2050 is 9% lower than in the 2.0 °C Scenario. The electricity demand for 'classical' electrical devices (without power-to-heat or e-mobility) will increase from around 15,900 TWh/year in 2015 to 23,800 TWh/year (2.0 °C) or to 23,300 TWh/year (1.5 °C) by 2050. Compared with the 5.0 °C case (37,000 TWh/year in 2050), the efficiency measures in the 2.0 °C and 1.5 °C Scenarios will save 13,200 TWh/year and 13,700 TWh/year, respectively, by 2050.

Electrification will lead to a significant increase in the electricity demand by 2050. In the 2.0 °C Scenario, the electricity demand for heating will be about

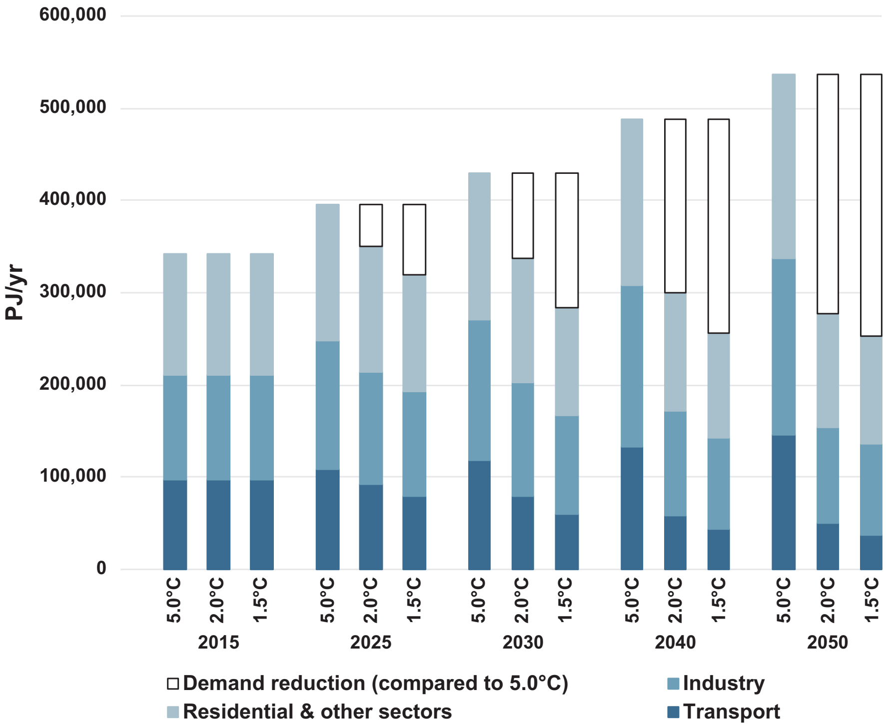


Fig. 8.2 Global: projection of total final energy demand by sector in the scenarios (without non-energy use or heat from combined heat and power [CHP] autoproducers)

12,600 TWh/year due to electric heaters and heat pumps, and in the transport sector there will be an increase of about 23,400 TWh/year due to increased electric mobility. The generation of hydrogen (for transport and high-temperature process heat) and the manufacture of synthetic fuels (mainly for transport) will add an additional power demand of 18,800 TWh/year The gross power demand will thus rise from 24,300 TWh/year in 2015 to 65,900 TWh/year in 2050 in the 2.0 °C Scenario, 34% higher than in the 5.0 °C case. In the 1.5 °C Scenario, the gross electricity demand will increase to a maximum of 65,300 TWh/year in 2050.

The efficiency gains in the heating sector could be even larger than in the electricity sector. In the 2.0 °C and 1.5 °C Scenarios, a final energy consumption equivalent to about 85.7 EJ/year and 95.4 EJ/year, respectively, is avoided through efficiency gains by 2050 compared with the 5.0 °C Scenario (Figs. 8.3, 8.4, 8.5, and 8.6).

### *8.1.3 Global: Electricity Generation*

The development of the power system is characterized by a dynamically growing renewable energy market and an increasing proportion of total power coming from renewable sources. In the 2.0 °C Scenario, 100% of the electricity produced globally will come from renewable energy sources by 2050. 'New' renewables—mainly wind, solar, and geothermal energy—will contribute 83% of the total electricity generation. Renewable electricity's share of the total production will be 62% by 2030 and 88% by 2040. The installed capacity of renewables will reach about 9500

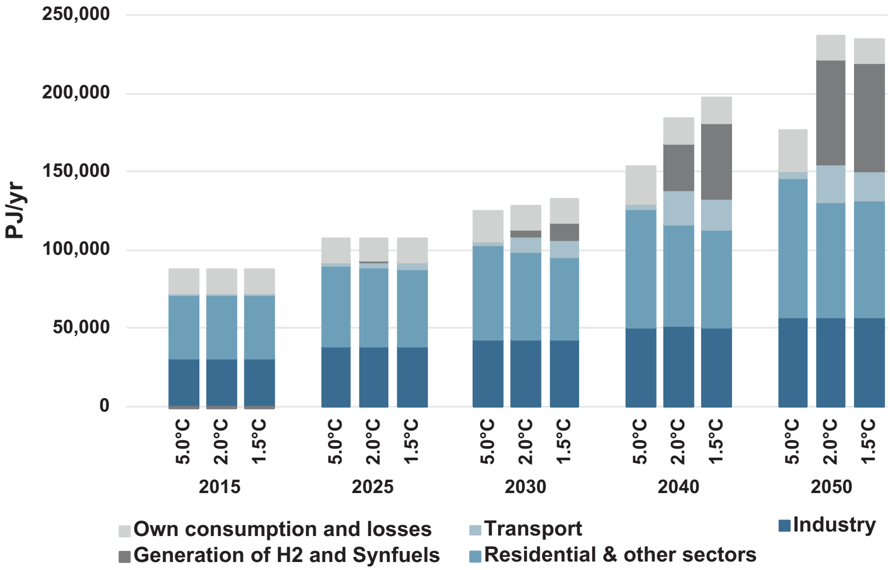


**Fig. 8.3** Global: development of gross electricity demand by sector in the scenarios

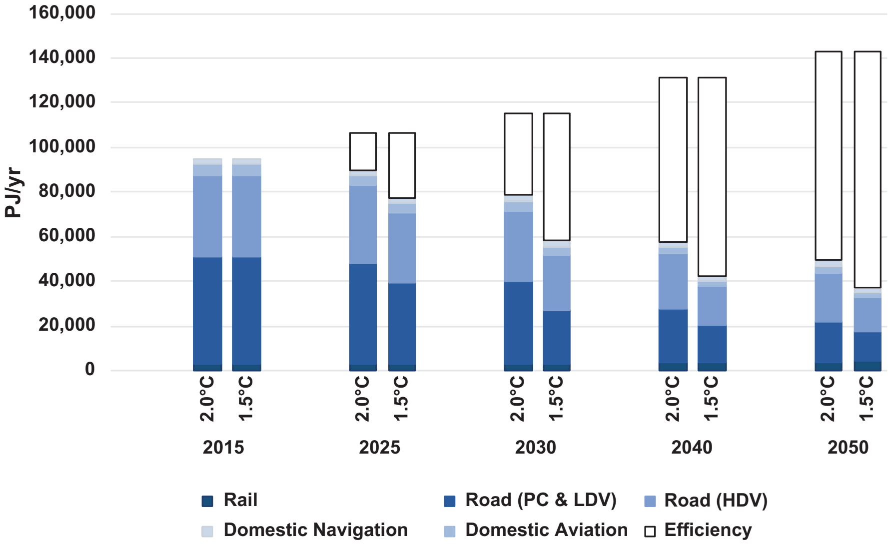


**Fig. 8.4** Global: development of final energy demand for transport by mode in the scenarios


**Fig. 8.5** Global: development of heat demand by sector in the scenarios

GW by 2030 and 25,600 GW by 2050. The share of renewable electricity generation in 2030 in the 1.5 °C Scenario is assumed to be 73%. The 1.5 °C Scenario indicates a generation capacity from renewable energy of about 25,700 GW in 2050.

Table 8.1 shows the development of different renewable technologies in the world over time. Figure 8.7 provides an overview of the global power-generation

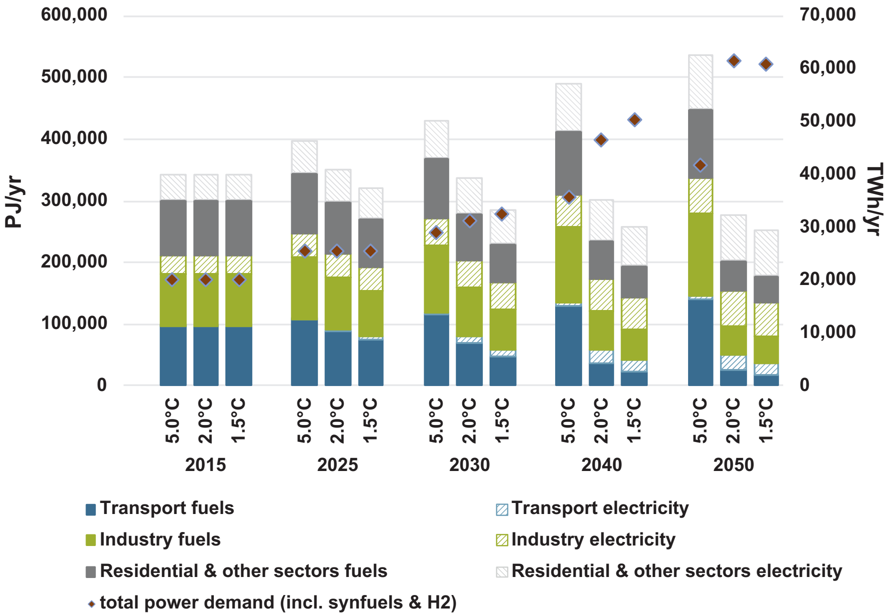


**Fig. 8.6** Global: development of the final energy demand by sector in the scenarios

**Table 8.1** Global: development of renewable electricity-generation capacity in the scenarios

| in GW | (°C) | 2015 | 2025 | 2030 | 2040 | 2050 |
|---|---|---|---|---|---|---|
| Hydro | 5.0 | 1202 | 1420 | 1558 | 1757 | 1951 |
| | 2.0 | 1202 | 1386 | 1416 | 1473 | 1525 |
| | 1.5 | 1202 | 1385 | 1415 | 1471 | 1523 |
| Biomass | 5.0 | 112 | 165 | 195 | 235 | 290 |
| | 2.0 | 112 | 301 | 436 | 617 | 770 |
| | 1.5 | 112 | 350 | 498 | 656 | 798 |
| Wind | 5.0 | 413 | 880 | 1069 | 1395 | 1790 |
| | 2.0 | 413 | 1582 | 2901 | 5809 | 7851 |
| | 1.5 | 413 | 1912 | 3673 | 6645 | 7753 |
| Geothermal | 5.0 | 14 | 20 | 26 | 41 | 62 |
| | 2.0 | 14 | 49 | 125 | 348 | 557 |
| | 1.5 | 14 | 53 | 147 | 356 | 525 |
| PV | 5.0 | 225 | 785 | 1031 | 1422 | 2017 |
| | 2.0 | 225 | 2194 | 4158 | 8343 | 12,306 |
| | 1.5 | 225 | 2829 | 5133 | 10,017 | 12,684 |
| CSP | 5.0 | 4 | 13 | 20 | 39 | 64 |
| | 2.0 | 4 | 69 | 361 | 1346 | 2062 |
| | 1.5 | 4 | 92 | 474 | 1540 | 1990 |
| Ocean | 5.0 | 0 | 1 | 3 | 9 | 22 |
| | 2.0 | 0 | 22 | 82 | 307 | 512 |
| | 1.5 | 0 | 22 | 80 | 295 | 450 |
| Total | 5.0 | 1971 | 3285 | 3902 | 4899 | 6195 |
| | 2.0 | 1971 | 5604 | 9478 | 18,243 | 25,584 |
| | 1.5 | 1971 | 6644 | 11,420 | 20,980 | 25,723 |

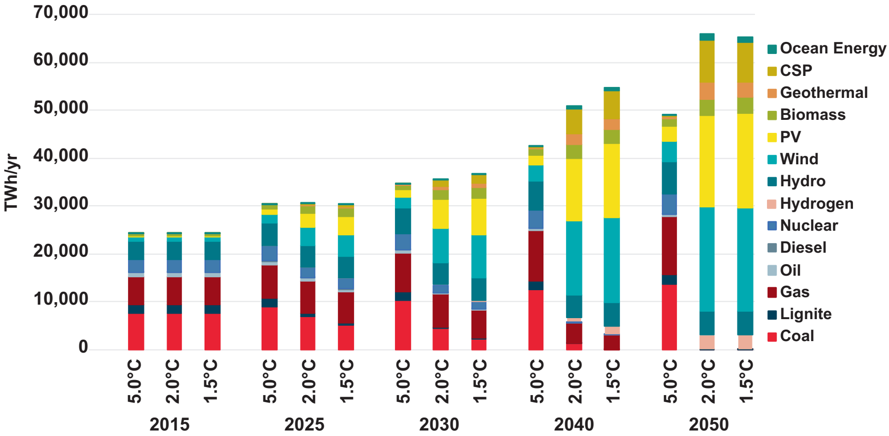


**Fig. 8.7** Global: development of electricity-generation structure in the scenarios

structure. From 2020 onwards, the continuing growth of wind and photovoltaic (PV), up to 7850 GW and 12,300 GW, respectively, will be complemented by up to 2060 GW of solar thermal generation, and limited biomass, geothermal, and ocean energy in the 2.0 °C Scenario. Both the 2.0 °C Scenario and 1.5 °C Scenario will lead to a high proportion of variable power generation (PV, wind, and ocean) of 38% and 46%, respectively, by 2030 and 64% and 65%, respectively, by 2050.

### *8.1.4 Global: Future Costs of Electricity Generation*

Figure 8.8 shows the development of the electricity-generation and supply costs over time, including the $CO_2$ emission costs, in all scenarios. The calculated average electricity generation costs in 2015 (referring to full costs) were around 6 ct/kWh. In the 5.0 °C case, the generation costs will increase until 2050, when they reach 10.6 ct/kWh. The generation costs will also increase in the 2.0 °C and 1.5 °C Scenarios until 2030, when they will reach 9 ct/kWh, and then drop to 7 ct/kWh by 2050. In both alternative scenarios, the generation costs will be around 3.5 ct/kWh lower than in the 5.0 °C Scenario by 2050. Note that these estimates of generation costs do not take into account integration costs such as power grid expansion, storage, or other load-balancing measures.

In the 5.0 °C case, the growth in demand and increasing fossil fuel prices will cause the total electricity supply costs to increase from today's $1560 billion/year to around $5500 billion/year in 2050. In both alternative scenarios, the total supply costs will be $5050 billion/year in 2050. Therefore, the long-term costs for electricity supply in both alternative scenarios are about 8% lower than in the 5.0 °C Scenario as a result of the estimated generation costs and the electrification of heating and mobility.

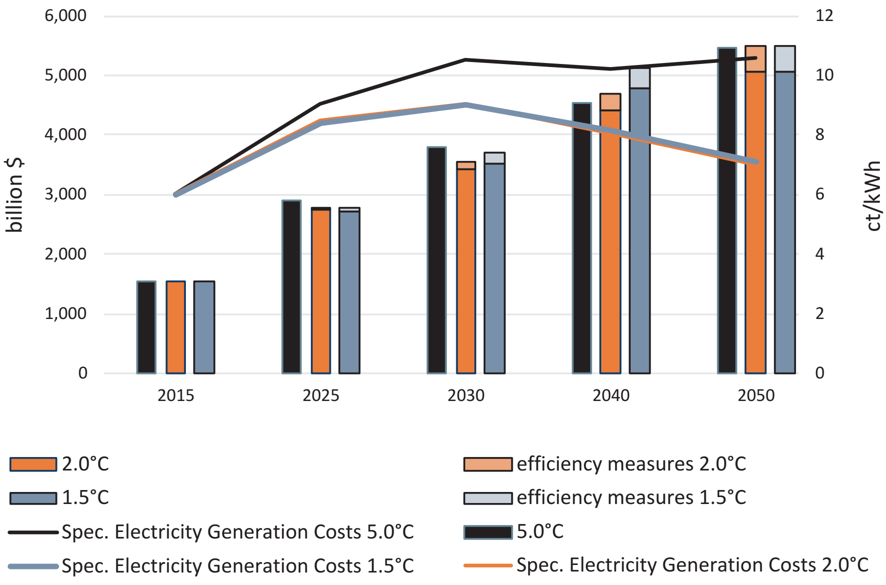


**Fig. 8.8** Global: development of total electricity supply costs and specific electricity generation costs in the scenarios

Compared with these results, the generation costs (without including $CO_2$ emission costs) will increase in the 5.0 °C case to only 7.9 ct/kWh. The generation costs will increase in the 2.0 °C Scenario until 2030 to 7.7 ct/kWh and to a maximum of 8.1 ct/kWh in the 1.5 °C Scenario. Between 2030 and 2050, the costs will decrease to 7 ct/kWh. In the 2.0 °C Scenario, the generation costs will be, at maximum, 0.1 ct/kWh higher than in the 5.0 °C Scenario and this will occur in 2040. In the 1.5 °C Scenario, the generation costs will be, at maximum, 0.5 ct/kWh higher than in the 5.0 °C Scenario, again by around 2040. In 2050, the generation costs in the alternative scenarios will be 0.8–0.9 ct/kWh lower than in the 5.0 °C case. If the $CO_2$ costs are not considered, the total electricity supply costs in the 5.0 °C case will rise to about $4150 billion/year in 2050.

### 8.1.5 Global: Future Investments in the Power Sector

In the 2.0 °C Scenario, around $49,000 billion in investment will be required for power generation between 2015 and 2050—including for additional power plants to produce hydrogen and synthetic fuels and for the plant replacement costs at the end of their economic lifetimes. This value will be equivalent to approximately $1360 billion per year on average, and is $28,600 billion more than in the 5.0 °C case ($20,400 billion). An investment of around $51,000 billion for power generation will be required between 2015 and 2050 in the 1.5 °C Scenario. On average, this will be an investment of $1420 billion per year. In the 5.0 °C Scenario, the

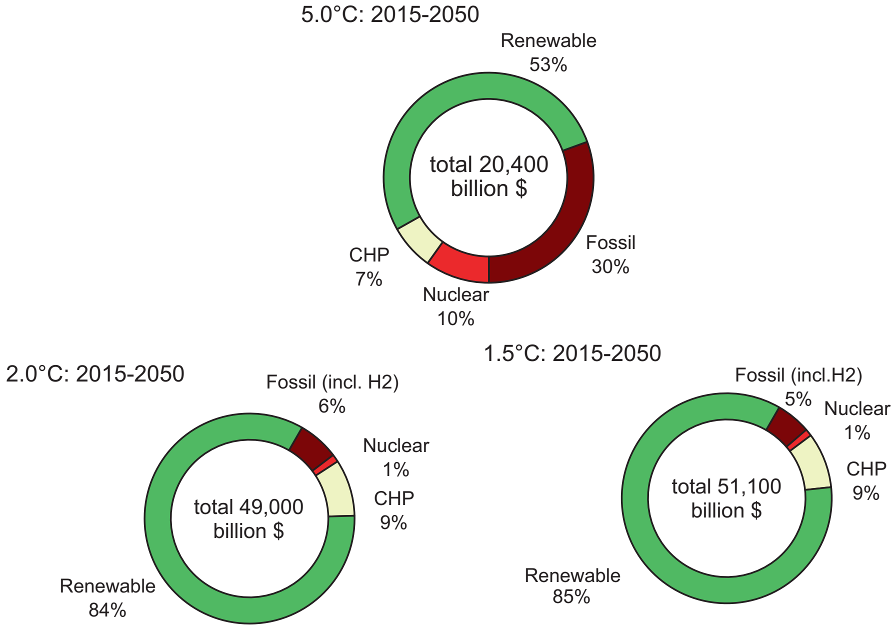


**Fig. 8.9** Global: investment shares for power generation in the scenarios

investment in conventional power plants will comprises around 40% of total cumulative investments, whereas approximately 60% will be invested in renewable power generation and co-generation (Fig. 8.9).

However, in the 2.0 °C (1.5 °C) Scenario, the world will shift almost 94% (95%) of its total energy investment to renewables and co-generation. By 2030, the fossil fuel share of the power sector investment will predominantly focus on gas power plants that can also be operated with hydrogen.

Because renewable energy has no fuel costs, other than biomass, the cumulative fuel cost savings in the 2.0 °C Scenario will reach a total of $26,300 billion in 2050, equivalent to $730 billion per year. Therefore, the total fuel cost savings in the 2.0 °C Scenario will be equivalent to 90% of the additional energy investments compared to the 5.0 °C Scenario. The fuel cost savings in the 1.5 °C Scenario will add up to $28,800 billion, or $800 billion per year.

### *8.1.6 Global: Energy Supply for Heating*

The final energy demand for heating will increase in the 5.0 °C Scenario by 59%, from 151 EJ/year in 2015 to around 240 EJ/year in 2050. In the 2.0 °C Scenario, energy efficiency measures will help to reduce the energy demand for heating by 36% in 2050, relative to that in the 5.0 °C Scenario, and by 40% in the 1.5 °C Scenario. Today, renewables supply around 20% of the global final energy demand for heating. The main contribution is from biomass. Renewable energy will provide 42% of the world's total heat demand in 2030 in the 2.0 °C Scenario and 56% in the 1.5 °C Scenario. In both scenarios, renewables will provide 100% of the total heat demand in 2050.

Figure 8.10 shows the development of different technologies for heating worldwide over time, and Table 8.2 provides the resulting renewable heat supply for all scenarios. Until 2030, biomass will remain the main contributor. In the long-term, the growing use of solar, geothermal, and environmental heat will lead to a biomass share in total heating of 33% in the 2.0 °C Scenario and 30% in the 1.5 °C Scenario.

Heat from renewable hydrogen will further reduce the dependence on fossil fuels in both scenarios. Hydrogen consumption in 2050 will be around 15,900 PJ/year in

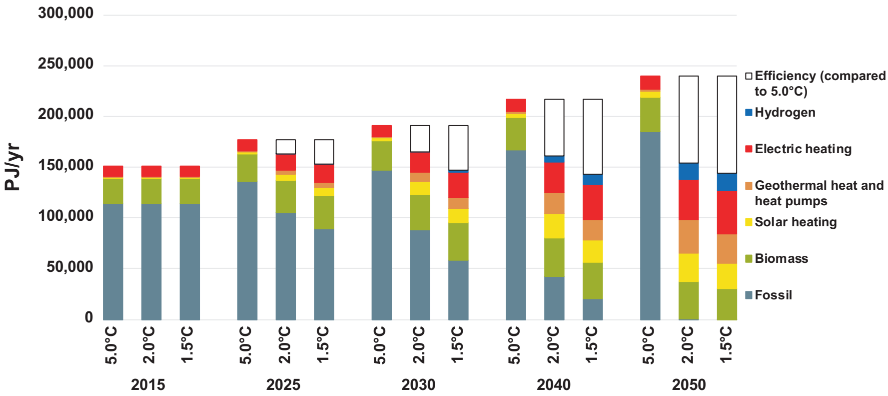


**Fig. 8.10** Global: development of heat supply by energy carrier in the scenarios

**Table 8.2** Global: development of renewable heat supply in the scenarios (excluding the direct use of electricity)

| in PJ/year | (°C) | 2015 | 2025 | 2030 | 2040 | 2050 |
|---|---|---|---|---|---|---|
| Biomass | 5.0 | 25,470 | 27,643 | 28,878 | 31,568 | 34,564 |
| | 2.0 | 25,470 | 32,078 | 35,134 | 38,187 | 37,536 |
| | 1.5 | 25,470 | 33,493 | 36,927 | 36,385 | 30,151 |
| Solar heating | 5.0 | 1246 | 2091 | 2754 | 4353 | 6220 |
| | 2.0 | 1246 | 6485 | 12,720 | 23,329 | 27,312 |
| | 1.5 | 1246 | 7656 | 14,153 | 21,665 | 24,725 |
| Geothermal heat and heat pumps | 5.0 | 563 | 804 | 925 | 1293 | 1823 |
| | 2.0 | 563 | 4212 | 8956 | 21,115 | 33,123 |
| | 1.5 | 563 | 4615 | 10,288 | 20,031 | 29,123 |
| Hydrogen | 5.0 | 0 | 0 | 0 | 0 | 0 |
| | 2.0 | 0 | 193 | 508 | 5670 | 15,877 |
| | 1.5 | 0 | 180 | 1769 | 10,461 | 17,173 |
| Total | 5.0 | 27,278 | 30,538 | 32,557 | 37,214 | 42,608 |
| | 2.0 | 27,278 | 42,967 | 57,318 | 88,301 | 113,848 |
| | 1.5 | 27,278 | 45,944 | 63,137 | 88,542 | 101,172 |

the 2.0 °C Scenario and 17,200 PJ/year in the 1.5 °C Scenario. The direct use of electricity for heating will also increase by a factor of 4.2–4.5 between 2015 and 2050 and will have a final share of 26% in 2050 in the 2.0 °C Scenario and 30% in the 1.5 °C Scenario (Table 8.2).

### 8.1.7 Global: Future Investments in the Heating Sector

The roughly estimated investments in renewable heating technologies up to 2050 will amount to around $13,230 billion in the 2.0 °C Scenario (including investments for plant replacement after their economic lifetimes)—approximately $368 billion per year. The largest share of this investment is assumed to be for heat pumps (around $5700 billion), followed by solar collectors and geothermal heat use. The 1.5 °C Scenario assumes an even faster expansion of renewable technologies. However, the lower heat demand (compared with the 2.0 °C Scenario) will result in a lower average annual investment of around $344 billion per year (Table 8.3, Fig. 8.11).

### 8.1.8 Global: Transport

The energy demand in the transport sector will increase in the 5.0 °C Scenario by 50% by 2050, from around 97,200 PJ/year in 2015 to 145,700 PJ/year in 2050. In the 2.0 °C Scenario, assumed technical, structural, and behavioural changes will reduce the energy demand by 66% (96,000 PJ/year) by 2050 compared with the 5.0 °C Scenario. Additional modal shifts, technology switches, and a reduction in

**Table 8.3** Global: installed capacities for renewable heat generation in the scenarios

| in GW | (°C) | 2015 | 2025 | 2030 | 2040 | 2050 |
|---|---|---|---|---|---|---|
| Biomass | 5.0 | 10,215 | 10,180 | 9938 | 9423 | 8997 |
| | 2.0 | 10,215 | 10,202 | 9456 | 7875 | 5949 |
| | 1.5 | 10,215 | 10,418 | 9568 | 7073 | 4141 |
| Geothermal | 5.0 | 5 | 7 | 7 | 8 | 4 |
| | 2.0 | 5 | 85 | 181 | 492 | 656 |
| | 1.5 | 5 | 101 | 200 | 433 | 551 |
| Solar heating | 5.0 | 378 | 615 | 781 | 1175 | 1652 |
| | 2.0 | 378 | 1685 | 3198 | 5722 | 6575 |
| | 1.5 | 378 | 1993 | 3555 | 5286 | 5964 |
| Heat pumps | 5.0 | 89 | 126 | 144 | 199 | 270 |
| | 2.0 | 89 | 497 | 906 | 1821 | 2857 |
| | 1.5 | 89 | 514 | 967 | 1726 | 2430 |
| Total[a] | **5.0** | **10,688** | **10,928** | **10,871** | **10,805** | **10,923** |
| | **2.0** | **10,688** | **12,469** | **13,741** | **15,910** | **16,036** |
| | **1.5** | **10,688** | **13,026** | **14,290** | **14,517** | **13,086** |

[a]Excluding direct electric heating

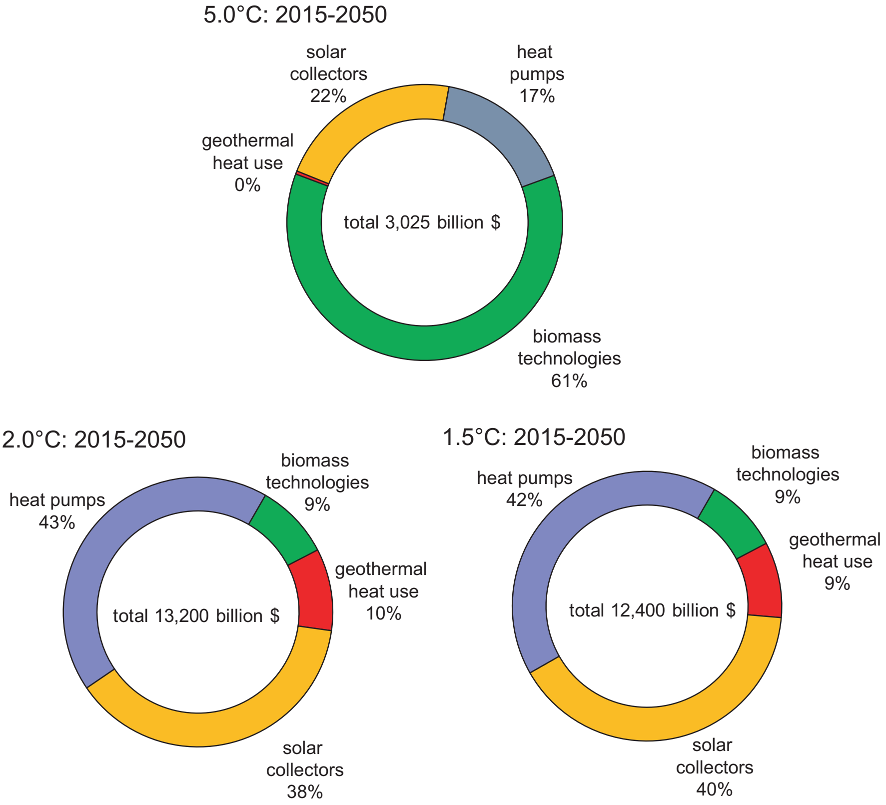


**Fig. 8.11** Global: development of investment in renewable heat-generation technologies in the scenarios

the transport demand will lead to even higher energy savings in the 1.5 °C Scenario of 74% (or 108,000 PJ/year) in 2050 compared with the 5.0 °C case (Table 8.4, Fig. 8.12).

By 2030, electricity will provide 12% (2700 TWh/year) of the transport sector's total energy demand in the 2.0 °C Scenario, whereas in 2050, the share will be 47% (6500 TWh/year). In 2050, around 8430 PJ/year of hydrogen will be used in the transport sector, as a complementary renewable option. In the 1.5 °C Scenario, the annual electricity demand will be about 5200 TWh in 2050. The 1.5 °C Scenario also assumes a hydrogen demand of 6850 PJ/year by 2050.

Biofuel use is limited in the 2.0 °C Scenario to a maximum of around 12,000 PJ/year Therefore, by around 2030, synthetic fuels based on power-to-liquid will be introduced, with a maximum amount of 5820 PJ/year in 2050. Because of the lower overall energy demand by transport, biofuel use will be reduced in the 1.5 °C Scenario to a maximum of 10,000 PJ/year The maximum synthetic fuel demand will amount to 6300 PJ/year.

**Table 8.4** Global: projection of transport energy demand by mode in the scenarios

| in PJ/year | (°C) | 2015 | 2025 | 2030 | 2040 | 2050 |
|---|---|---|---|---|---|---|
| Rail | 5.0 | 2705 | 2708 | 2814 | 3024 | 3199 |
| | 2.0 | 2705 | 2875 | 3149 | 3520 | 3960 |
| | 1.5 | 2705 | 2932 | 3119 | 3559 | 4087 |
| Road | 5.0 | 85,169 | 94,755 | 102,556 | 116,449 | 127,758 |
| | 2.0 | 85,169 | 79,975 | 68,660 | 48,650 | 40,089 |
| | 1.5 | 85,169 | 67,579 | 48,949 | 34,055 | 28,859 |
| Domestic aviation | 5.0 | 4719 | 6544 | 7745 | 9080 | 9176 |
| | 2.0 | 4719 | 4732 | 4239 | 3291 | 2640 |
| | 1.5 | 4719 | 4461 | 3612 | 2361 | 1845 |
| Domestic navigation | 5.0 | 2130 | 2304 | 2392 | 2537 | 2663 |
| | 2.0 | 2130 | 2303 | 2388 | 2512 | 2601 |
| | 1.5 | 2130 | 2301 | 2383 | 2506 | 2601 |
| Total | 5.0 | 94,723 | 106,310 | 115,506 | 131,091 | 142,796 |
| | 2.0 | 94,723 | 89,886 | 78,436 | 57,973 | 49,290 |
| | 1.5 | 94,723 | 77,274 | 58,063 | 42,482 | 37,392 |

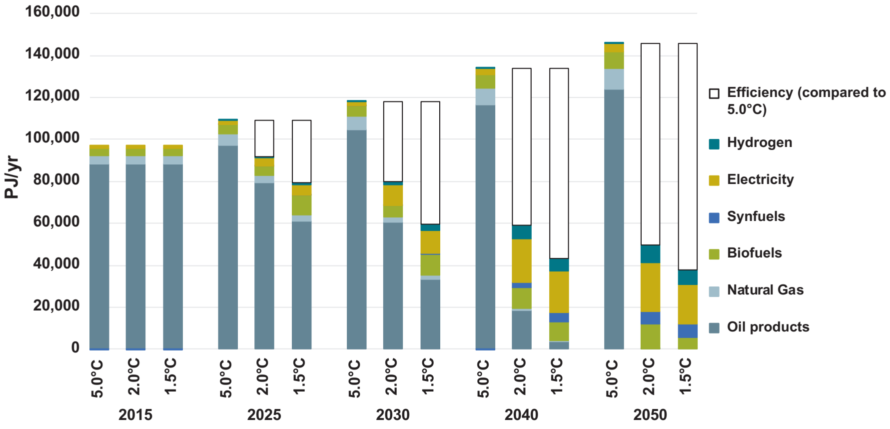


**Fig. 8.12** Global: final energy consumption by transport in the scenarios

### *8.1.9 Global: Development of $CO_2$ Emissions*

In the 5.0 °C Scenario, the annual global energy-related $CO_2$ emissions will increase by 40%, from 31,180 Mt. in 2015 to more than 43,500 Mt. in 2050. The stringent mitigation measures in both alternative scenarios will cause annual emissions to fall to 7070 Mt. in 2040 in the 2.0 °C Scenario and to 2650 Mt. in the 1.5 °C Scenario, with further reductions to almost zero by 2050. In the 5.0 °C Scenario, the cumulative $CO_2$ emissions from 2015 until 2050 will add up to 1388 Gt. In contrast, in the 2.0 °C and 1.5 °C Scenarios, the cumulative emissions for the period 2015–2050 will be 587 Gt and 450 Gt, respectively.

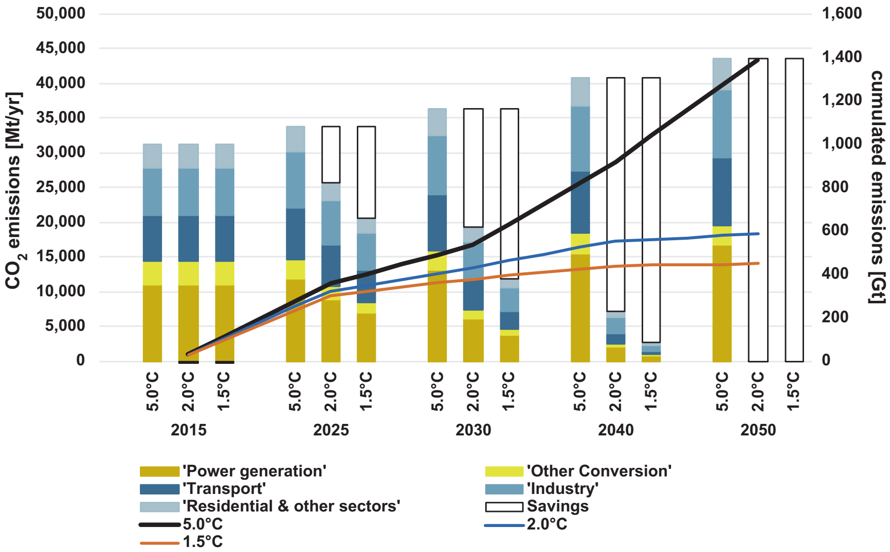


**Fig. 8.13** Global: development of $CO_2$ emissions by sector and cumulative $CO_2$ emissions (since 2015) in the scenarios ('Savings' = lower than in the 5.0 °C Scenario)

Thus, the cumulative $CO_2$ emissions will decrease by 58% in the 2.0 °C Scenario and by 68% in the 1.5 °C Scenario compared with the 5.0 °C case. A rapid reduction in annual emissions will occur in both alternative scenarios. In the 2.0 °C Scenario, the reduction will be greatest in 'Power generation', followed by the 'Residential and other' and 'Transport' sectors (Fig. 8.13).

### *8.1.10 Global: Primary Energy Consumption*

The levels of primary energy consumption based on the assumptions discussed above in the three scenarios are shown in Fig. 8.14. In the 2.0 °C Scenario, the primary energy demand will decrease by 21%, from around 556 EJ/year in 2015 to 439 EJ/year in 2050. Compared with the 5.0 °C Scenario, the overall primary energy demand will decrease by 48% by 2050 in the 2.0 °C Scenario (5.0 °C: 837 EJ in 2050). In the 1.5 °C Scenario, the primary energy demand will be even lower (412 EJ in 2050) due to the lower final energy demand and lower conversion losses.

Both the 2.0 °C and 1.5 °C Scenarios aim to rapidly phase-out coal and oil. This will cause renewable energy to have a primary energy share of 35% in 2030 and 92% in 2050 in the 2.0 °C Scenario. In the 1.5 °C Scenario, renewables will have a primary energy share of more than 92% in 2050 (this will includes non-energy consumption, which will still include fossil fuels). Nuclear energy will be phased-out in both the 2.0 °C and 1.5 °C Scenarios. The cumulative primary energy consumption of natural gas in the 5.0 °C Scenario will be 5580 EJ, the cumulative coal consump-

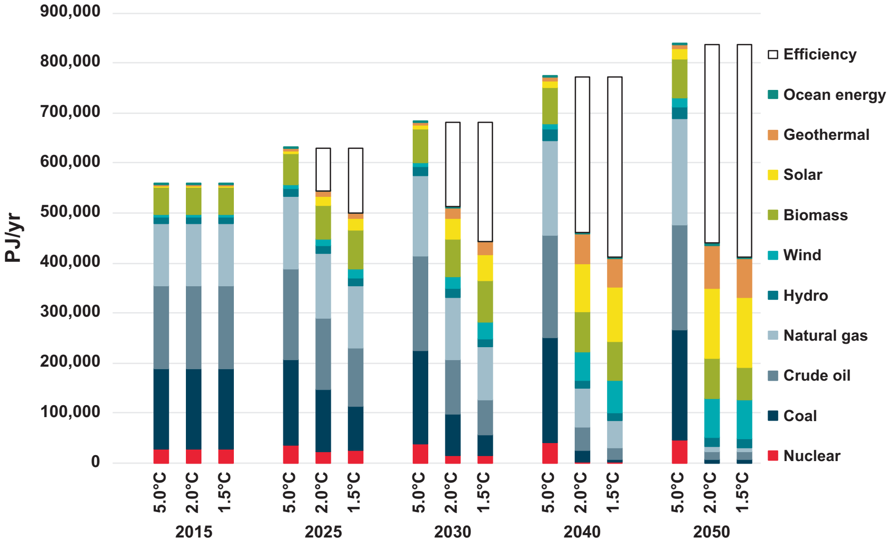


**Fig. 8.14** Global: projection of total primary energy demand (PED) by energy carrier in the scenarios

tion will be about 6360 EJ, and the crude oil consumption will be 6380 EJ. In the 2.0 °C Scenario, the cumulative gas demand will amount to 3140 EJ, the cumulative coal demand to 2340 EJ, and the cumulative oil demand to 2960 EJ. Even lower fossil fuel use will be achieved in the 1.5 °C Scenario: 2710 EJ for natural gas, 1570 EJ for coal, and 2230 EJ for oil.

## 8.2 Global: Bunker Fuels

Bunker fuels for international aviation and navigation are separate categories in the energy statistics. Their use and related emissions are not usually directly allocated to the regional energy balances. However, they contribute significantly to global greenhouse gas (GHG) emissions and pose great challenges regarding their substitution with low-carbon alternatives. In 2015, the annual bunker fuels consumption was in the order of 16,000 PJ, of which 7400 PJ was for aviation and 8600 PJ for navigation. Between 2009 and 2015, bunker fuel consumption increased by 13%. The annual $CO_2$ emissions from bunker fuels accounted for 1.3 Gt in 2015, approximately 4% of global energy-related $CO_2$ emissions. In the 5.0 °C Scenario, the development of the final energy demand for bunker fuels is assumed to be that of the IEA World Energy Outlook 2017 Current Policies scenario. This will lead to a further increase of 120% in the demand for bunker fuels until 2050 compared with that in the base year, 2015. Because no substitution with 'green' fuels is assumed, $CO_2$ emissions will rise by the same order of magnitude.

Although the use of hydrogen and electricity in aviation is technically feasible (at least for regional transport) and synthetic gas use in navigation is an additional option under discussion, this analysis uses a conservative approach and assumes that bunker fuels are only replaced by biofuels or synthetic liquid fuels. Figure 8.15 shows the 5.0 °C and two alternative bunker scenarios, which are defined in consistency to the scenarios for each world region. For the 2.0 °C and 1.5 °C Scenarios, we assume the limited use of sustainable biomass potentials and the complementary central production of power-to-liquid synfuels. In the 2.0 °C Scenario, this production is assumed to take place in three world regions: Africa, the Middle East, and OECD Pacific (especially Australia), where synfuel generation for export is expected to be the most economic. The 1.5 °C Scenario requires even faster decarbonisation, and therefore follows a more ambitious low-energy pathway. This will lead to a faster build-up of the power-to-liquid infrastructure in all regions, which in the long term, will also be used for limited 'regional' bunker fuel production to maintain the utilization of the existing infrastructure. Therefore, the production of bunker fuels is assumed to occur in more regions, with lower exports from the supply regions mentioned above, in the 2.0 °C Scenario. Another assumption is that, consistent with the regional 1.5 °C Scenarios, the biomass consumption for energy supply will decrease in the long term, whereas power-to-liquid will continue to increase as the main option for international aviation and navigation. Finally, the expansion of the power-to-liquid infrastructure for the generation of bunker fuel will be closely associated with the assumed development of regional synthetic fuel demand and generation for transportation in each world region. Figure 8.15 also shows the resulting cumulative $CO_2$ emissions from bunker fuel consumption between 2015 and 2050, which amount to around 70 Gt in the 5.0 °C case, 30 Gt in the 2.0 °C Scenario, and 21 Gt in the 1.5 °C Scenario. Table 8.5 provides more-detailed data for the three bunker fuel scenarios.

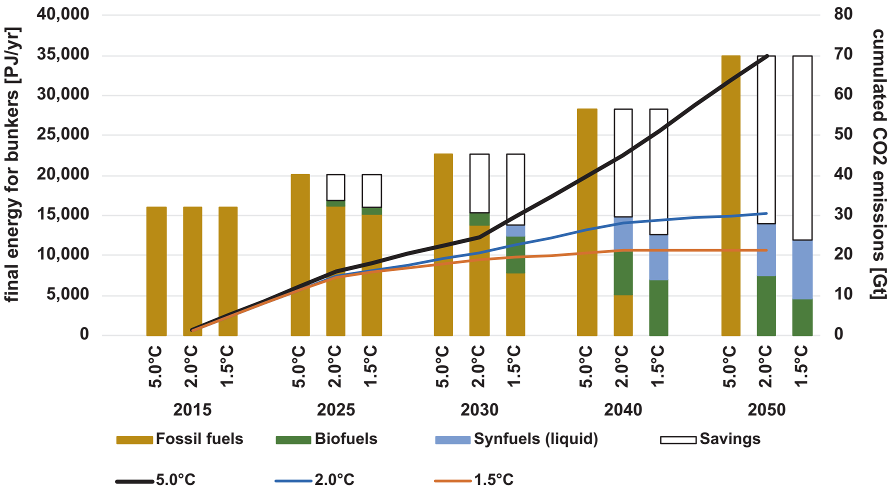


**Fig. 8.15** Global: scenario of bunker fuel demand for aviation and navigation and the resulting cumulative $CO_2$ emissions

**Table 8.5** Global: projection of bunker fuel demands for aviation and navigation by fuel in the scenarios

| World bunkers 5.0 °C scenario | Unit | 2015 | 2020 | 2025 | 2030 | 2035 | 2040 | 2045 | 2050 |
|---|---|---|---|---|---|---|---|---|---|
| Total final energy consumption | **PJ/year** | **15,985** | **17,976** | **20,090** | **22,593** | **25,443** | **28,293** | **31,462** | **34,987** |
| thereof aviation | PJ/year | 7408 | 8385 | 9431 | 10,674 | 12,097 | 13,537 | 15,148 | 16,950 |
| thereof navigation | PJ/year | 8576 | 9591 | 10,658 | 11,919 | 13,346 | 14,756 | 16,314 | 18,037 |
| fossil fuels | PJ/year | 15,985 | 17,976 | 20,090 | 22,593 | 25,443 | 28,293 | 31,462 | 34,987 |
| biofuels | PJ/year | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| synthetic liquid fuels | PJ/year | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Primary energy demand | | | | | | | | | |
| crude oil | PJ/year | 17,663 | 19,754 | 21,956 | 24,558 | 27,506 | 30,423 | 33,650 | 37,220 |
| $CO_2$ emissions | **Mt/year** | **1296** | **1450** | **1611** | **1802** | **2018** | **2232** | **2468** | **2730** |
| World bunkers 2.0 °C Scenario | **unit** | **2015** | **2020** | **2025** | **2030** | **2035** | **2040** | **2045** | **2050** |
| Total final energy consumption | **PJ/year** | **15,985** | **17,538** | **16,836** | **15,274** | **15,053** | **14,826** | **14,483** | **14,014** |
| thereof aviation | PJ/year | 7408 | 8594 | 8418 | 7713 | 7602 | 7487 | 7314 | 7077 |
| thereof navigation | PJ/year | 8576 | 8944 | 8418 | 7561 | 7451 | 7339 | 7169 | 6937 |
| fossil fuels | PJ/year | 15,985 | 17,270 | 16,180 | 13,748 | 10,537 | 5189 | 3621 | 0 |
| biofuels | PJ/year | 0 | 268 | 657 | 1526 | 3146 | 5417 | 6381 | 7430 |
| synthetic liquid fuels | PJ/year | 0 | 0 | 0 | 0 | 1370 | 4220 | 4481 | 6584 |
| Assumed regional structure of synthetic bunker production | | | | | | | | | |
| Africa | PJ/year | 0 | 0 | 0 | 0 | 846 | 2607 | 2768 | 4067 |
| Middle East | PJ/year | 0 | 0 | 0 | 0 | 183 | 564 | 598 | 879 |
| OECD Pacific | PJ/year | 0 | 0 | 0 | 0 | 341 | 1050 | 1115 | 1638 |
| Primary energy demand | | | | | | | | | |
| crude oil | PJ/year | 17,663 | 18,978 | 17,683 | 14,943 | 11,391 | 5580 | 3872 | 0 |
| biomass | PJ/year | 0 | 400 | 952 | 2150 | 4369 | 7420 | 8623 | 9907 |
| RES electricity demand for PtL | TWh/year | 0 | 0 | 0 | 0 | 961 | 2880 | 3058 | 4375 |

(continued)

**Table 8.5** (continued)

| World bunkers 5.0 °C scenario | Unit | 2015 | 2020 | 2025 | 2030 | 2035 | 2040 | 2045 | 2050 |
|---|---|---|---|---|---|---|---|---|---|
| $CO_2$ emissions | **Mt/year** | **1296** | **1391** | **1296** | **1095** | **835** | **409** | **284** | **0** |
| World bunkers 1.5 °C Scenario | **unit** | **2015** | **2020** | **2025** | **2030** | **2035** | **2040** | **2045** | **2050** |
| Total final energy consumption | **PJ/year** | **15,985** | **17,538** | **15,995** | **13,747** | **12,795** | **12,602** | **12,311** | **11,912** |
| thereof aviation | PJ/year | 7408 | 8594 | 7997 | 6942 | 6462 | 6364 | 6217 | 6016 |
| thereof navigation | PJ/year | 8576 | 8944 | 7997 | 6805 | 6334 | 6238 | 6094 | 5896 |
| fossil fuels | PJ/year | 15,985 | 17,538 | 15,179 | 7836 | 2559 | 0 | 0 | 0 |
| biofuels | PJ/year | 0 | 0 | 816 | 4536 | 6398 | 6931 | 5540 | 4527 |
| synthetic liquid fuels | PJ/year | 0 | 0 | 0 | 1375 | 3839 | 5671 | 6771 | 7385 |
| Assumed regional structure of synthetic bunker production | | | | | | | | | |
| Africa | PJ/year | 0 | 0 | 0 | 717 | 2002 | 2863 | 3093 | 2882 |
| Middle East | PJ/year | 0 | 0 | 0 | 155 | 433 | 619 | 669 | 873 |
| OECD Pacific | PJ/year | 0 | 0 | 0 | 289 | 836 | 1265 | 1622 | 1697 |
| OECD North America | PJ/year | 0 | 0 | 0 | 213 | 568 | 798 | 924 | 977 |
| OECD Europe | PJ/year | 0 | 0 | 0 | 0 | 0 | 126 | 262 | 557 |
| Eurasia | PJ/year | 0 | 0 | 0 | 0 | 0 | 0 | 200 | 400 |
| Primary energy demand | | | | | | | | | |
| crude oil | PJ/year | 17,663 | 19,273 | 16,589 | 8517 | 2766 | 0 | 0 | 0 |
| biomass | PJ/year | 0 | 0 | 1182 | 6389 | 8885 | 9495 | 7486 | 6035 |
| RES electricity demand for PtL | TWh/year | 0 | 0 | 0 | 964 | 2693 | 3870 | 4621 | 4896 |
| $CO_2$ emissions | **Mt/year** | **1296** | **1413** | **1216** | **624** | **203** | **0** | **0** | **0** |

The production of synthetic fuels will cause significant additional electricity demand and a corresponding expansion of the renewable power generation capacities. In the case of liquid bunker fuels, these additional renewable power generation capacities will amount to 1100 GW in the 2.0 °C Scenario and more than 1200 GW in the 1.5 °C Scenario if a flexible utilization rate of 4000 full-load hours per year can be achieved. However, such a situation will require high amounts of electrolyser capacity and hydrogen storage to allow not only flexibility in the power system, but also high utilization rates of the downstream synthesis processes (e.g., via Fischer-Tropsch plants). Other options for renewable synthetic fuel production are solar thermal chemical processes, which directly use high-temperature solar heat.

## 8.3 Global: Utilization of Solar and Wind Potential

The economic potential, under space constraints, of utility solar PV, concentrated solar power (CSP), and onshore wind was analysed with the methodology described in Sect. 3.3 of Chap. 3.

The 2.0 °C Scenario utilizes only a fraction of the available economic potential of the assumed suitable land for utility-scale solar PV and concentrated solar power plants. This estimate does not include solar PV roof-top systems, which have significant additional potential. India (2.0 °C) will have the highest solar utilization rate of 8.5%, followed by Europe (2.0 °C) and the Middle East (2.0 °C), with 5.9% and 4.6%, respectively.

Onshore wind potential has been utilized to a larger extent than solar potential. In the 2.0 °C Scenario, space-constrained India will utilize more than half of onshore wind, followed by Europe with 20%. This wind potential excludes offshore wind, which has significant potential but the mapping for the offshore wind potential was beyond the scope of this analysis (Table 8.6).

The 1.5 °C Scenario is based on the accelerated deployment of all renewables and the more ambitious implementation of efficiency measures. Therefore, the total installed capacity of solar and wind generators by 2050 is not necessarily larger than it is in the 2.0 °C Scenario, and the utilization rate is in the same order of magnitude. The increased deployment of renewable capacity in OECD Pacific (Australia), the Middle East, and OECD North America (USA) will be due to the production of synthetic bunker fuels from hydrogen to supply global transport energy for international shipping and aviation.

**Table 8.6** Economic potential within a space-constrained scenario and utilization rates for the 2.0 °C and 1.5 °C scenarios

| | SOLAR | Installed capacity by 2050 | | | | Utilization rate | | WIND | Installed capacity by 2050 | | Utilization rate | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | 2.0 °C | | 1.5 °C | | 2.0 °C | 1.5 °C | | 2.0 °C | 1.5 °C | 2.0 °C | 1.5 °C |
| Economic Potential within available space | Tech. space potential | PV | CSP | PV | CSP | | | Onshore wind | | | | |
| | [GW] | [GW] | | | | [%] | | [GW] | [GW] | | [%] | |
| OECD North America | 445,954 | 1688 | 208 | 1816 | 236 | 0.4% | 0.5% | 86,846 | 847 | 833 | 1.0% | 1.0% |
| Latin America | 148,664 | 317 | 66 | 425 | 79 | 0.3% | 0.3% | 29,736 | 220 | 237 | 0.7% | 0.8% |
| OECD Europe | 14,364 | 793 | 54 | 918 | 57 | 5.9% | 6.8% | 2873 | 577 | 636 | 20.1% | 22.1% |
| Middle East | 24,451 | 881 | 252 | 742 | 216 | 4.6% | 3.9% | 470 | 455 | 434 | 96.8% | 92.4% |
| Africa | 914,180 | 767 | 247 | 930 | 257 | 0.1% | 0.1% | 190,711 | 485 | 509 | 0.3% | 0.3% |
| Eurasia | Not available | 658 | 22 | 657 | 34 | | | Not available | 564 | 544 | | |
| Non-OECD-Asia | 44,064 | 1065 | 274 | 1005 | 224 | 3.0% | 2.8% | 4740 | 515 | 506 | 10.9% | 10.7% |
| India | 1323 | 1257 | 209 | 1129 | 209 | 8.5% | 7.7% | 1974 | 1139 | 983 | 57.7% | 49.8% |
| China | 176,916 | 1756 | 762 | 1772 | 614 | 1.4% | 1.3% | 17,848 | 1180 | 1345 | 6.6% | 7.5% |
| OECD Pacific | 124,178 | 665 | 57 | 745 | 67 | 0.6% | 0.7% | 24,447 | 244 | 303 | 1.0% | 1.2% |

## 8.4 Global: Power Sector Analysis

The long-term global and regional energy results were used to conduct a detailed power sector analysis with the methodology described in Sect. 3.5 of Chap. 3. Both the 2.0 °C and 1.5 °C Scenarios rely on high shares of variable solar and wind generation. The aim of the power sector analysis was to gain insight into the power system stability for each region (subdivided into up to eight sub-regions) and to gauge the extent to which power grid interconnections, dispatch generation services, and storage technologies are required. The results presented in this chapter are projections calculated from publicly available data. Detailed load curves for some of the sub-regions and countries discussed in this chapter were not available and, in some cases, the relevant information is classified. Therefore, the outcomes of the [R]E 24/7 model are estimates and require further research with more detailed localized data, especially regarding the available power grid infrastructure. Furthermore, power sector projections for developing countries, especially in Africa and Asia, assume unilateral access to energy services for the residential sector by 2050, and they require transmission and distribution grids in regions where there are none at the time of writing. Further research—in cooperation with local utilities and government representatives—is required to develop a more detailed understanding of power infrastructure needs.

### *8.4.1 Global: Development of Power Plant Capacities*

The size of the global market for renewable power plants will increase significantly under the 2.0 °C Scenario. The annual market for solar PV power must increase from close to 100 GW in 2017 (REN21-GSR 2018) by a factor of 4.5 to an average of 454 GW by 2030. The onshore wind market must expand to 172 GW by 2025, about three times higher than in 2017 (REN21-GSR 2018). The offshore wind market will continue to increase in importance within the renewable power sector. By 2050, offshore wind installations will increase to 32 GW annually—11 times higher than in 2017 (GWEC 2018). Concentrated solar power plants will play an important role in dispatchable solar electricity generation for the supply of bulk power, especially for industry, and will provide secured capacity to power systems. By 2030, the annual CSP market must increase to 78 GW, compared with 3 GW in 2020 and only 0.1 GW in 2017 (REN21-GSR2018) (Table 8.7).

In the 1.5 °C Scenario, the phase-out of coal and lignite power plants is accelerated and a total capacity of 618 GW—equivalent to approximately 515 power stations[1]—must end operation by 2025. The replacement power must come from a variety of renewable power generators, both variable and dispatchable. The annual market for solar PV must be around 30% higher in 2050 than it was in 2025, as in the 2.0 °C Scenario. While the onshore wind market also has an accelerated trajectory

[1] Assumption: average size of one coal power plant side contains multiple generation blocks, with a total of 1200 MW on average for each location.

**Table 8.7** World: average annual change in the installed power plant capacity

| Global power generation: average annual change of installed capacity [GW/a] | 2015–2025 | | 2026–2035 | | 2036–2050 | |
|---|---|---|---|---|---|---|
| | 2.0 °C | 1.5 °C | 2.0 °C | 1.5 °C | 2.0 °C | 1.5 °C |
| Hard coal | 2 | −107 | −96 | −119 | −68 | −12 |
| Lignite | −25 | −34 | −16 | −9 | −3 | −1 |
| Gas | 41 | 70 | 44 | 72 | −199 | −28 |
| Hydrogen-gas | 1 | 17 | 12 | 57 | 240 | 246 |
| Oil/diesel | −18 | −32 | −29 | −28 | −6 | −2 |
| Nuclear | −15 | −27 | −23 | −24 | −7 | −10 |
| Biomass | 24 | 40 | 26 | 29 | 25 | 21 |
| Hydro | 19 | 10 | 7 | 7 | 7 | 8 |
| Wind (onshore) | 121 | 307 | 273 | 333 | 242 | 158 |
| Wind (offshore) | 16 | 64 | 75 | 91 | 64 | 45 |
| PV (roof top) | 170 | 413 | 368 | 437 | 399 | 324 |
| PV (utility scale) | 57 | 138 | 123 | 146 | 133 | 108 |
| Geothermal | 5 | 16 | 22 | 24 | 28 | 23 |
| Solar thermal power plants | 9 | 57 | 93 | 109 | 102 | 85 |
| Ocean energy | 4 | 10 | 20 | 20 | 28 | 23 |
| Renewable fuel based co-generation | 13 | 31 | 27 | 31 | 25 | 20 |

under the 1.5 °C Scenario as well, the offshore wind market is assumed to be almost identical to that in the 2.0 °C pathway because of the longer lead times for these projects. The same is assumed for CSP plants, which are utility-scale projects and significantly higher deployment seems unlikely in the time remaining until 2025.

### *8.4.2 Global: Utilization of Power-Generation Capacities*

On a global scale, in the 2.0 °C and 1.5 °C Scenarios, the shares of variable renewable power generation will increase from 4% in 2015 to 39% and 47%, respectively, by 2030, and to 64% and 60%, respectively, by 2050. The reason for the variations in the two cases is their different assumptions regarding efficiency measures, which may lead to lower overall demand in the 1.5 °C Scenario than in the 2.0 °C Scenario. During the same period, dispatchable renewables—CSP plants, biofuel generation, geothermal energy, and hydropower—will remain around 32% until 2030 on a global average and decrease slightly to 29% in the 2.0 °C Scenario (and to 27% in the 1.5 °C Scenario) by 2050. The shares of dispatchable conventional generation—mainly coal, oil, gas, and nuclear—will decline from a global average of 60% in 2015 to only 14% in 2040. By 2050, the remaining dispatchable conventional gas power plants will have been converted to operate with hydrogen and synthetic fuels, to avoid stranded investments and to achieve higher quantities of dispatch power capacity. Table 8.8 shows the increasing shares of variable renewable power

**Table 8.8** Global: power system shares by technology group

| Power generation structure in 10 world regions | | 2.0 °C | | | 1.5 °C | | |
|---|---|---|---|---|---|---|---|
| World | | Variable renewables | Dispatch renewables | Dispatch fossil | Variable renewables | Dispatch renewables | Dispatch fossil |
| OECD North America | 2015 | 7% | 35% | 58% | 7% | 41% | 52% |
| | 2030 | 48% | 30% | 23% | 59% | 27% | 15% |
| | 2050 | 68% | 19% | 13% | 68% | 21% | 11% |
| Latin America | 2015 | 3% | 63% | 34% | 3% | 62% | 35% |
| | 2030 | 24% | 51% | 25% | 36% | 61% | 3% |
| | 2050 | 39% | 45% | 16% | 40% | 46% | 13% |
| Europe | 2015 | 15% | 47% | 38% | 15% | 47% | 38% |
| | 2030 | 44% | 44% | 12% | 51% | 39% | 10% |
| | 2050 | 67% | 28% | 4% | 69% | 27% | 4% |
| Middle East | 2015 | 0% | 12% | 88% | 0% | 13% | 87% |
| | 2030 | 51% | 19% | 31% | 56% | 18% | 27% |
| | 2050 | 81% | 19% | 0% | 70% | 16% | 13% |
| Africa | 2015 | 2% | 26% | 73% | 2% | 17% | 81% |
| | 2030 | 47% | 21% | 32% | 52% | 13% | 35% |
| | 2050 | 73% | 27% | 0% | 64% | 15% | 21% |
| Eurasia | 2015 | 1% | 35% | 63% | 1% | 35% | 63% |
| | 2030 | 36% | 43% | 21% | 40% | 46% | 14% |
| | 2050 | 69% | 23% | 7% | 65% | 25% | 10% |
| Non-OECD Asia | 2015 | 1% | 35% | 64% | 1% | 35% | 64% |
| | 2030 | 26% | 35% | 39% | 36% | 34% | 30% |
| | 2050 | 52% | 28% | 19% | 55% | 28% | 17% |
| India | 2015 | 4% | 32% | 64% | 4% | 32% | 64% |
| | 2030 | 45% | 26% | 29% | 60% | 21% | 19% |
| | 2050 | 72% | 27% | 1% | 58% | 26% | 16% |
| China | 2015 | 6% | 35% | 59% | 6% | 21% | 73% |
| | 2030 | 30% | 24% | 46% | 39% | 30% | 31% |
| | 2050 | 49% | 47% | 5% | 49% | 42% | 9% |
| OECD Pacific | 2015 | 4% | 34% | 61% | 4% | 34% | 61% |
| | 2030 | 40% | 31% | 30% | 45% | 29% | 27% |
| | 2050 | 71% | 26% | 2% | 64% | 22% | 14% |
| Global average | 2015 | 4% | 35% | 60% | 4% | 34% | 62% |
| | 2030 | 39% | 32% | 29% | 47% | 32% | 21% |
| | 2050 | 64% | 29% | 7% | 60% | 27% | 13% |

Note: Variable renewable generation shares in long term energy pathways and power sector analysis differ due to different calculation methods. The power sector analysis results are based on the sum of up to eight sub-regional simulations, while the long term energy pathway is based on the regional average generation excluding variations in solar and wind resources within that region generation—solar PV and wind power—under the 2.0 °C and 1.5 °C Scenarios over the entire modelling period. The main difference between the two scenarios is the time horizon until variable renewable power generation is implemented, with more rapid implementation in the 1.5 °C Scenario. Again, increased variable shares—mainly in the USA, the Middle East region, and Australia—will produce synthetic fuels for the export market, as fuel for both renewable power plants and the transport sector.

Table 8.9 provides an overview of the capacity factor developments by technology group for the 2.0 °C and 1.5 °C Scenarios. The operational hours shown are the result of [R]E 24/7 modelling under the *'Dispatch case'*, which assumes that the highest priority is given to the dispatch of power from variable sources, followed by dispatchable renewables. Conventional power generation will only provide power for electricity demand that cannot be met by renewables and storage technologies. Only imports via interconnections will be assigned a lower priority than conventional power. The reason that interconnections are placed last in the supply cascade is the high level of uncertainty about whether these interconnections can actually be implemented in time. Experience with power grid projects—especially transmission lines—indicates that planning and construction can take many years or fail entirely, leaving large-scale utility-based renewable power projects unbuilt.

**Table 8.9** Global: capacity factors for *variable* and *dispatchable* power generation

| Utilization of variable and dispatchable power generation: | | 2015 | 2020 | 2020 | 2030 | 2030 | 2040 | 2040 | 2050 | 2050 |
|---|---|---|---|---|---|---|---|---|---|---|
| World | | | 2.0 °C | 1.5 °C | 2.0 °C | 1.5 °C | 2.0 °C | 1.5 °C | 2.0 °C | 1.5 °C |
| Capacity factor – average | [%/yr] | 49.5% | 37% | 37% | 33% | 31% | 34% | 30% | 33% | 31% |
| Limited dispatchable: fossil and nuclear | [%/yr] | 58.7% | 34% | 34% | 24% | 16% | 25% | 10% | 17% | 9% |
| Limited dispatchable: renewable | [%/yr] | 36.9% | 45% | 45% | 42% | 36% | 58% | 31% | 39% | 34% |
| Dispatchable: fossil | [%/yr] | 42.9% | 28% | 28% | 19% | 15% | 33% | 15% | 19% | 19% |
| Dispatchable: renewable | [%/yr] | 43.1% | 56% | 56% | 54% | 47% | 42% | 39% | 51% | 43% |
| Variable: renewable | [%/yr] | 14.6% | 14% | 14% | 28% | 26% | 28% | 26% | 29% | 27% |

On the global level, the average capacity factor across all power-generation technologies is around 45%. For this analysis, we created five different power plant categories based on their current usual operation times and areas of use:

- **Limited dispatchable fossil and nuclear power plants**: coal, lignite, and nuclear power plants with limited ability to respond to changes in demand. These power plants are historically categorized as 'baseload power plants'. Power systems dominated by renewable energy usually contain high proportions of variable generation, and therefore quick reaction times (to ramp up and down) are required. Limited dispatchable power plants cannot deliver these services and are therefore being phased-out.
- **Limited dispatchable renewable systems** are CSP plants with integrated storage and co-generation systems with renewable fuels (including geothermal heat). They cannot respond quickly enough to adapt to minute-by-minute changes in demand, but can still be used as dispatch power plants for 'day ahead' planning.
- **Dispatchable fossil fuel power plants** are gas power plants that have very quick reaction times and therefore provide valid power system services.
- **Dispatchable renewable power plants** are hydropower plants (although they are dependent on the climatic conditions in the region where the plant is used), biogas power plants, and former gas power plants converted to hydrogen and/or synthetic fuel. This technology group is responsible for most of the required load-balancing services and is vital for the stability of the power system, as storage systems, interconnections, and, if possible, demand-side management.
- **Variable renewables** are solar PV plants, onshore and offshore wind farms, and ocean energy generators. A sub-category of ocean energy plants—tidal energy plants—is very predictable.

Table 8.9 shows the development of the utilization of limited and fully dispatchable power generators—both fossil and renewable fuels—and variable power generation. In the 2.0 °C Scenario, conventional power generation in the baseload mode—currently with an annual operation time of around 6000 h per year or more—will decline sharply after 2030 and the annual operation time will be halved, whereas medium-load and dispatch power plants will predominate. The system share of dispatchable renewables will remain around 45%–50% throughout the entire modelling period.

### *8.4.3 Global: Development of Load, Generation, and Residual Load*

Table 8.10 shows the development of the maximum and average loads for the 10 world regions, the average and maximum power generation in each region in megawatts, and the residual loads under both alternative scenarios. The residual load in

**Table 8.10** Global: load, generation, and residual load development

| Power generation structure in 10 world regions | | 2.0 °C | | | | 1.5 °C | | | |
|---|---|---|---|---|---|---|---|---|---|
| World | | Max demand [GW] | Max generation [GW] | Max residual load [GW] | Max load development (Base 2020) [GW] | Max demand [GW] | Max generation [GW] | Max residual load [GW] | Max load development (Base 2020) [GW] |
| OECD North America | 2020 | 753 | 723 | 57 | 100% | 755 | 989 | 58 | 100% |
| | 2030 | 864 | 1159 | 145 | 115% | 919 | 1532 | 194 | 122% |
| | 2050 | 1356 | 2779 | 469 | 180% | 1362 | 2900 | 496 | 180% |
| Latin America | 2020 | 218 | 214 | 30 | 100% | 218 | 274 | 18 | 100% |
| | 2030 | 343 | 377 | 74 | 157% | 312 | 418 | 25 | 143% |
| | 2050 | 533 | 601 | 154 | 244% | 550 | 696 | 122 | 252% |
| OECD Europe | 2020 | 574 | 584 | 121 | 100% | 574 | 583 | 125 | 100% |
| | 2030 | 620 | 718 | 95 | 108% | 639 | 936 | 104 | 111% |
| | 2050 | 862 | 1530 | 417 | 150% | 900 | 1727 | 448 | 157% |
| Middle East | 2020 | 174 | 181 | −29 | 100% | 174 | 180 | −26 | 100% |
| | 2030 | 229 | 297 | −20 | 132% | 237 | 346 | −13 | 136% |
| | 2050 | 551 | 1164 | −67 | 317% | 522 | 1018 | −161 | 300% |
| Africa | 2020 | 164 | 125 | 47 | 100% | 164 | 135 | 37 | 100% |
| | 2030 | 280 | 261 | 101 | 171% | 296 | 305 | 105 | 181% |
| | 2050 | 875 | 1363 | 647 | 534% | 915 | 1562 | 412 | 559% |
| Eurasia | 2020 | 257 | 163 | 107 | 100% | 257 | 171 | 106 | 100% |
| | 2030 | 316 | 332 | 147 | 123% | 330 | 416 | 139 | 129% |
| | 2050 | 630 | 1338 | 271 | 245% | 632 | 1296 | 275 | 246% |

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| Non-OECD Asia | 2020 | 248 | 135 | 122 | 100% | 248 | 133 | 124 | 100% |
| | 2030 | 415 | 389 | 256 | 167% | 423 | 465 | 296 | 171% |
| | 2050 | 935 | 1459 | 728 | 377% | 841 | 1394 | 656 | 339% |
| India | 2020 | 288 | 266 | 44 | 100% | 288 | 249 | 61 | 100% |
| | 2030 | 493 | 624 | 112 | 171% | 491 | 861 | 148 | 170% |
| | 2050 | 1225 | 1880 | 854 | 425% | 1207 | 1865 | 558 | 419% |
| China | 2020 | 957 | 935 | 74 | 100% | 953 | 946 | 57 | 100% |
| | 2030 | 1233 | 1249 | 173 | 129% | 1219 | 1613 | 179 | 128% |
| | 2050 | 1967 | 2724 | 1415 | 206% | 1990 | 3203 | −609 | 209% |
| OECD Pacific | 2020 | 354 | 322 | 47 | 100% | 354 | 318 | 47 | 100% |
| | 2030 | 308 | 468 | 21 | 87% | 318 | 544 | 36 | 90% |
| | 2050 | 410 | 997 | 196 | 116% | 471 | 1140 | 173 | 133% |

this analysis is the load remaining after variable renewable power generation. Negative values indicate that the power generation from solar and wind exceeds the actual load and must be exported to other regions, stored, or curtailed. In each region, the average generation should be on the same level as the average load. The maximum loads and maximum generations shown do not usually occur at the same time, so surplus production of electricity can appear and this should be exported or stored as much as possible. In rare individual cases, solar or wind generation plants can also temporarily reduce their output to a lower load, or some plants can be shut down. Any reduced generation from solar and wind in response to low demand is defined as *curtailment*.

Figure 8.16 illustrates the development of the maximum loads across all 10 world regions under the 2.0 °C and 1.5 °C Scenarios. The most significant increase appears in Africa, where the maximum load surges over the entire modelling period by 534% in response to favourable economic development and increased access to

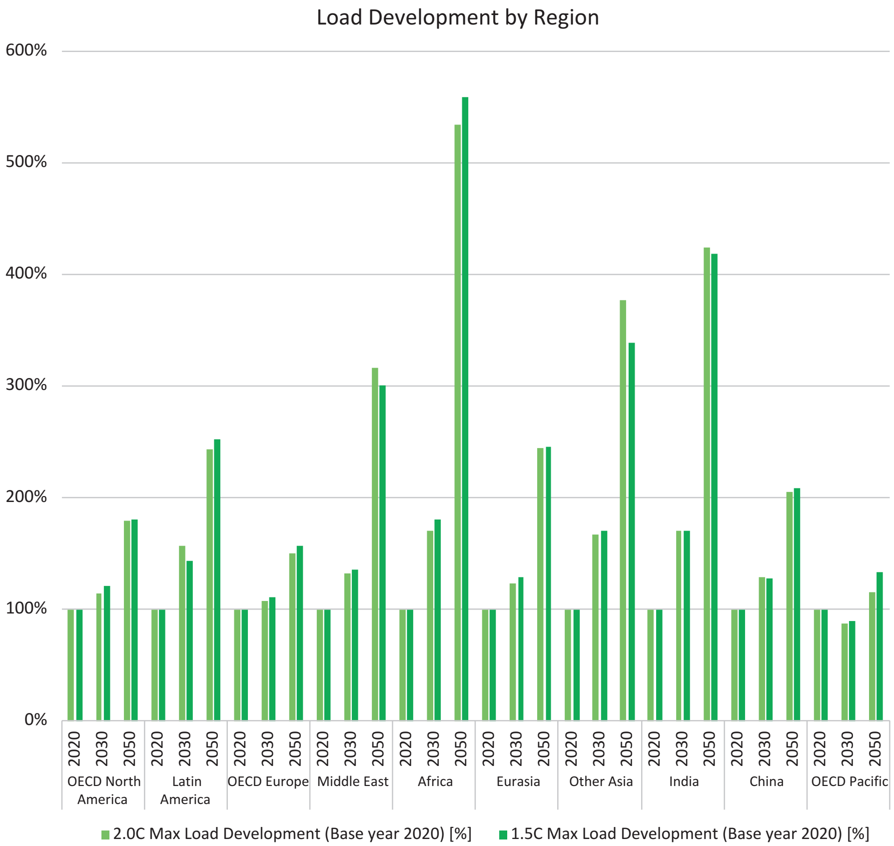


**Fig. 8.16** Development of maximum load in 10 world regions in 2020, 2030, and 2050 in the 2.0 °C and 1.5 °C scenarios

energy services by households. In OECD Pacific, efficiency measures will lead to a reduction in the maximum load to 87% of the base year value by 2030 and will increase to 116% by 2050 with the expansion of electric mobility and the increased electrification of the process heat supply in the industry sector. The 1.5 °C Scenario has slightly higher loads in response to the accelerated electrification of the industry, heating, and business sectors, except in three regions (the Middle East, India, and Non OECD Asia), where early action on efficiency measures will lead to an overall lower demand at the end of the modelling period, with the same GDP and population growth rates.

### *8.4.4 Global System-Relevant Technologies—Storage and Dispatch*

The global results of introducing system-relevant technologies are shown in Table 8.8. The first part of this section documents the required power plant markets, the changes and configurations of power-generation systems, and the development of loads in response to high electrification rates in the industry, heating, and transport sectors. The next step in the analysis documents the storage and dispatch demands and possible technology utilization. It is important to note that the results presented here are not cost-optimized. The mixture of battery storage and pumped hydropower plants with hydrogen- and synthetic-fuel-based dispatch power plants presented here represents only one option of many.

Significant simplification is required for the computer simulations of large regions, to reduce the data volumes (and calculation times) or simply because there is not yet any data, because several regions still have no electricity infrastructure in place. Detailed modelling requires access to detailed data. Although the modelling tools used for this analysis could be used to develop significantly more-detailed regional analyses, this is beyond the scope of this research.

The basic concept for the management of power system generation is based on four principles:

1. Diversity;
2. Flexibility;
3. Inter-sectorial connectivity;
4. Resource efficiency.

*Diversity* in the locally deployed renewable power-generation structure. For example, a combination of onshore and offshore wind with solar PV and CSP plants will reduce storage and dispatch demands.

*Flexibility* involves a significant number of fast-reacting dispatch power plants operated with fuels produced from renewable electricity (hydrogen and synthetic fuels). The existing gas infrastructure can be further utilized to avoid stranded investments, and the actual fuel production can also be used—with some technical limitations—for load management, which again will reduce the need for storage technologies.

*Inter-sectorial connectivity* involves the connection of the heating (including process heat) and transport sectors. Neither the transport sector nor the heating sector will undergo complete electrification. To supply industrial process heat, the capacity of co-generation plants—operated with bio-, geothermal, or hydrogen fuels—will be increased by a factor of 2.5 in the 1.5 °C Scenario. Co-generation heating systems with heat storage capacities and heat pumps operated with renewable electricity will lead to more flexibility in the management of both load and demand. However, an analysis of the full potential for these heating systems was not within the scope of this project, so they have not been included in the modelling. Further research with localized data is required.

*Resource efficiency* In addition to energy and GHG modelling, a resource assessment of selected metals has been undertaken (see Chap. 11). A variety of technologies—especially storage technologies—can be used to reduce the pressure on resource requirements, namely for cobalt and lithium for batteries and electric mobility and the silver required for solar technologies. Therefore, the choice of storage technologies has taken the specific requirements for metals into account.

Table 8.11 shows the storage volumes (in GWh per year) required to avoid the curtailment of variable renewable power generation and the utilization of storage capacities for batteries and pumped hydro for charging with variable renewable electricity in the calculated scenarios. The total storage throughput, including the hydrogen production and the amount of hydrogen-based dispatch power plants, is also shown.

Pumped hydropower will remain the backbone of the storage concept until 2030, when batteries start to overtake pumped hydropower by volume. The model does not distinguish between different battery or pumped hydro technologies. Hydrogen-based dispatch will remain the largest contributor to systems services after 2030 until the end of the modelling period.

### 8.4.5 Global: Required Storage Capacities for the Stationary Power Sector

The world market for storage and dispatch technologies and services will increase significantly in the 2.0 °C Scenario. The annual market for new hydro pump storage plants will grow on average by 6 GW per year to a total capacity of 244 GW in 2030. During the same period, the total installed capacity for batteries will grow to 12 GW, requiring an annual market of 1 GW. Between 2030 and 2050, the energy service sector for storage and storage technologies must accelerate further. The

**Table 8.11** Global: storage and dispatch

| Storage and dispatch | | 2.0 °C | | | | | 1.5 °C | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | Required to avoid curtailment | Utilization battery -charge- | Utilization PSH -charge- | Total (incl. H2) | Dispatch H2 | Required to avoid curtailment | Utilization battery -charge- | Utilization PSH -charge- | Total (incl. H2) | Dispatch H2 |
| World | | [GWh/year] | [GWh/year] | [GWh/year] | [GWh/year] | [GWh/year] | [GWh/year] | [GWh/year] | [GWh/year] | [GWh/year] | [GWh/year] |
| OECD North America | 2020 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | 2030 | 62,369 | 341 | 192 | 1065 | 11,181 | 243,235 | 243,235 | 475 | 2405 | 11,181 |
| | 2050 | 853,401 | 21,805 | 868 | 45,331 | 238,730 | 999,704 | 999,704 | 924 | 46,766 | 238,730 |
| Latin America | 2020 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | 2030 | 0 | 0 | 0 | 0 | 34 | 1207 | 1207 | 99 | 318 | 34 |
| | 2050 | 1314 | 640 | 34 | 1347 | 127,226 | 30,526 | 30,526 | 621 | 12,875 | 127,226 |
| OECD Europe | 2020 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | 2030 | 6238 | 315 | 5265 | 11,161 | 60,223 | 38,504 | 38,504 | 20,566 | 42,827 | 60,223 |
| | 2050 | 212,060 | 30,546 | 58,368 | 177,632 | 814,585 | 301,234 | 301,234 | 72,812 | 215,641 | 814,585 |
| Middle East | 2020 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | 2030 | 18,088 | 2 | 943 | 1890 | 0 | 44,945 | 44,945 | 1469 | 2943 | 0 |
| | 2050 | 752,882 | 109 | 4636 | 9180 | 0 | 554,222 | 554,222 | 4371 | 8618 | 0 |
| Africa | 2020 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | 2030 | 4877 | 118 | 2244 | 4726 | 0 | 11,264 | 11,264 | 2672 | 5591 | 0 |
| | 2050 | 367,201 | 6514 | 8977 | 30,974 | 212,902 | 585,423 | 585,423 | 9282 | 31,210 | 212,902 |
| Eurasia | 2020 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | 2030 | 736 | 1 | 169 | 341 | 14,106 | 6031 | 6031 | 644 | 1295 | 14,106 |
| | 2050 | 296,490 | 948 | 8396 | 18,661 | 401,044 | 249,984 | 249,984 | 7258 | 16,303 | 401,044 |

(continued)

**Table 8.11** (continued)

| Storage and dispatch | | 2.0 °C | | | | | 1.5 °C | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | Required to avoid curtailment | Utilization battery -charge- | Utilization PSH -charge- | Total (incl. H2) | Dispatch H2 | Required to avoid curtailment | Utilization battery -charge- | Utilization PSH -charge- | Total (incl. H2) | Dispatch H2 |
| World | | [GWh/year] | [GWh/year] | [GWh/year] | [GWh/year] | [GWh/year] | [GWh/year] | [GWh/year] | [GWh/year] | [GWh/year] | [GWh/year] |
| Non-OECD Asia | 2020 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | 2030 | 137 | 2 | 15 | 34 | 0 | 6848 | 6848 | 311 | 646 | 0 |
| | 2050 | 171,973 | 2478 | 2261 | 9465 | 386,454 | 228,160 | 228,160 | 2943 | 8789 | 386,454 |
| India | 2020 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | 2030 | 59,399 | 52 | 2983 | 6069 | 1759 | 182,561 | 182,561 | 8577 | 17,487 | 1759 |
| | 2050 | 372,809 | 2125 | 6715 | 17,678 | 28,113 | 437,884 | 437,884 | 6595 | 17,199 | 28,113 |
| China | 2020 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | 2030 | 1102 | 19 | 394 | 827 | 2582 | 45,217 | 45,217 | 7266 | 14,957 | 2582 |
| | 2050 | 102,042 | 57,483 | 2966 | 120,899 | 623,254 | 264,729 | 264,729 | 20,885 | 60,022 | 623,254 |
| OECD Pacific | 2020 | 16 | 0 | 0 | 0 | 0 | 16 | 16 | 0 | 0 | 0 |
| | 2030 | 84,079 | 623 | 4601 | 10,403 | 831 | 146,440 | 146,440 | 6688 | 14,855 | 831 |
| | 2050 | 654,287 | 70,404 | 14,815 | 170,431 | 81,215 | 760,962 | 760,962 | 14,865 | 169,093 | 81,215 |
| Total global | 2020 | 16 | 0 | 0 | 0 | 0 | 16 | 0 | 0 | 0 | 0 |
| | 2030 | 237,026 | 1474 | 16,808 | 36,517 | 90,716 | 726,252 | 2945 | 48,767 | 103,323 | 90,716 |
| | 2050 | 3,784,459 | 193,051 | 108,037 | 601,598 | 2,913,522 | 4,412,827 | 153,528 | 140,555 | 586,516 | 2,913,522 |

battery market must grow by an annual installation rate of 22 GW, and as a result, it will overtake the global capacity of pumped hydro between 2040 and 2050. The conversion of the gas infrastructure from natural gas to hydrogen and synthetic fuels will start slowly between 2020 and 2030, with the conversion of power plants with an annual capacity of around 2 GW. However, after 2030, the transformation of the global gas industry to hydrogen will accelerate significantly, with a total of 197 GW of gas power plants and gas co-generation capacity converted each year. In parallel, the average capacity factor for gas and hydrogen plants will decrease from 29% (2578 h/year) in 2030 to 11% (975 h/year) by 2050, turning the gas sector from a supply-driven to a service-driven industry.

At around 2030, the 1.5 °C Scenario requires more storage throughput than does the 2.0 °C Scenario, but storage demands for the two scenarios will be equal at the end of the modelling period. It is assumed that this higher throughput can be managed with equally high installed capacities, leading to annual capacity factors for battery and hydro pump storage of around 5–6% by 2050 (Table 8.12).

Table 8.13 shows the average global investment costs for the battery and hydro pump storage capacities in the 2.0 °C and 1.5 °C Scenarios. Both pathways have equal storage capacities and cost projections, especially for batteries, but are highly uncertain in the years beyond 2025. Therefore, the costs are only estimates and require research.

## 8.5 OECD North America

### *8.5.1 OECD North America: Long-Term Energy Pathways*

#### 8.5.1.1 OECD North America: Final Energy Demand by Sector

Combining the assumptions for population growth, GDP growth, and energy intensity will result in the development pathways for OECD North America's final energy demand shown in Fig. 8.17 under the 5.0 °C, 2.0 °C, and 1.5 °C Scenarios. Under the 5.0 °C Scenario, the total final energy demand will increase by 10% from the current 70,500 PJ/year to 77,800 PJ/year in 2050. In the 2.0 °C Scenario, the final energy demand will decrease by 47% compared with current consumption and will reach 37,300 PJ/year by 2050. The final energy demand in the 1.5 °C Scenario will reach 33,700 PJ, 52% below the 2015 demand level. In the 1.5 °C Scenario, the final energy demand in 2050 will be 10% lower than in the 2.0 °C Scenario. The electricity demand for 'classical' electrical devices (without power-to-heat or e-mobility) will decrease from 4230 TWh/year in 2015 to 3340 TWh/year (2.0 °C) or 2950 TWh/year (1.5 °C) by 2050. Compared with the 5.0 °C case (6050 TWh/year in 2050), the efficiency measures in the 2.0 °C and 1.5 °C Scenarios will save a maximum of 2710 TWh/year and 3100 TWh/year, respectively.

Electrification will lead to a significant increase in the electricity demand by 2050. The 2.0 °C Scenario will require approximately 1400 TWh/year of electricity

**Table 8.12** Required increases in storage capacities until 2050

| | | Global storage and H2-dispatch market volume under 2 scenarios | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | | Batteries | | | Pumped hydro | | | Hydrogen -production + dispatch | |
| | | [Through-put] | Cumulative capacity | Storage technology share | [Through-put] | Cumulative capacity | Storage technology share | [Through-put] | Cumulative capacity |
| | | [GWh/year] | [GW] | [%] | [GWh/year] | [GW] | [%] | [GWh/year] | [GW] |
| 2015 | | No data | 2 | 1 | No data | 153 | 99 | | No data |
| 2030 | 2.0 °C | 1474 | 12 | 8 | 16,808 | 244 | 92 | 90,716 | 35 |
| 2030 | 1.5 °C | 2945 | 13 | 6 | 48,767 | 255 | 94 | 351,496 | 137 |
| 2050 | 2.0 °C | 193,051 | 347 | 64 | 108,037 | 267 | 36 | 2,913,522 | 2990 |
| 2050 | 1.5 °C | 153,528 | 340 | 52 | 140,555 | 278 | 48 | 2,075,533 | 3423 |

**Table 8.13** Estimated average global investment costs for batty and hydro pump storage

| Estimated storage investment costs (In $ billion) | 2015–2020 | Average annual | 2021–2030 | Average annual | 2031–2040 | Average annual | 2041–2050 | Average annual | 2015–2050 | Average annual |
|---|---|---|---|---|---|---|---|---|---|---|
| Storage | | | | | | | | | | |
| Battery | 4.8 | 0.967 | 44.5 | 4.4 | 148.1 | 14.8 | 655.8 | 65.6 | 853.3 | 24.4 |
| Hydro pump storage | 0 | 0 | 38.7 | 3.9 | 42.7 | 4.3 | 47.2 | 4.7 | 128.6 | 3.7 |
| Total | 4.8 | 0.967 | 83.2 | 8.3 | 190.8 | 19.1 | 703.0 | 70.3 | 981.9 | 28.1 |

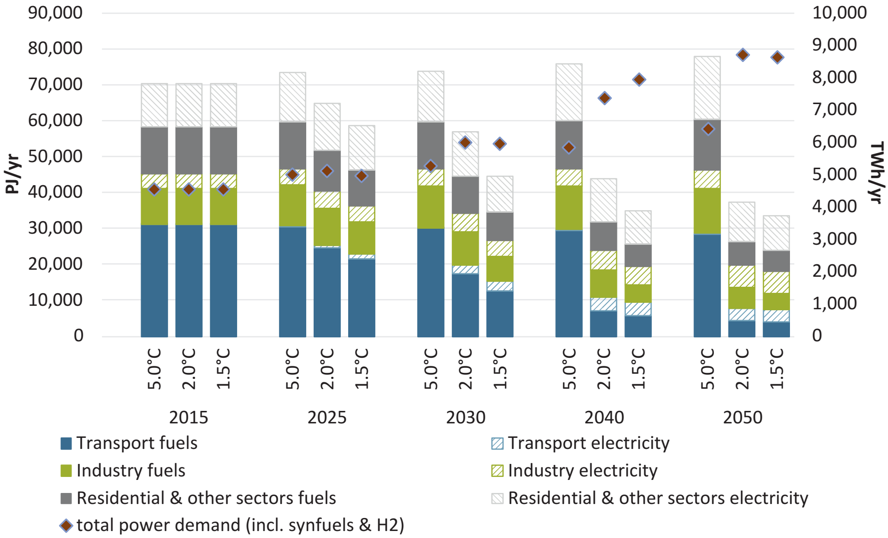


**Fig. 8.17** OECD North America: development of final energy demand by sector in the scenarios

for electric heaters and heat pumps, and in the transport sector, it will require approximately 3300 TWh/year for electric mobility. The generation of hydrogen (for transport and high-temperature process heat) and the manufacture of synthetic fuels (mainly for transport) will add an additional power demand of 3000 TWh/year. Therefore, the gross power demand will rise from 5300 TWh/year in 2015 to 9500 TWh/year in 2050 in the 2.0 °C Scenario, 30% higher than in the 5.0 °C case. In the 1.5 °C Scenario, the gross electricity demand will increase to a maximum of 9400 TWh/year in 2050 for similar reasons.

The efficiency gains in the heating sector will be similar in magnitude to those in the electricity sector. Under the 2.0 °C and 1.5 °C Scenarios, a final energy consumption equivalent to about 7000 PJ/year and 9400 PJ/year, respectively, will be avoided by 2050 through efficiency gains compared with the 5.0 °C Scenario.

### 8.5.1.2 OECD North America: Electricity Generation

The development of the power system is characterized by a dynamically growing renewable energy market and an increasing proportion of total power from renewable sources. In the 2.0 °C Scenario, 100% of the electricity produced in OECD North America will come from renewable energy sources by 2050. 'New' renewables—mainly wind, solar, and geothermal energy—will contribute 85% of the total electricity generated. Renewable electricity's share of the total production will be 68% by 2030 and 89% by 2040. The installed capacity of renewables will reach about 1880 GW by 2030 and 3810 GW by 2050. In the 1.5 °C Scenario, the share of renewable electricity generation in 2030 is assumed to be 84%. The 1.5 °C Scenario projects a generation capacity from renewable energy of about 3920 GW in 2050.

Table 8.14 shows the development of the installed capacities of different renewable technologies in OECD North America over time. Figure 8.18 provides an overview of the overall power-generation structure in OECD North America. From 2020 onwards, the continuing growth of wind and PV—to 1090 GW and 2130 GW, respectively—is complemented by up to 210 GW of solar thermal generation, as well as limited biomass, geothermal, and ocean energy, in the 2.0 °C Scenario. Both the 2.0 °C and 1.5 °C Scenarios will lead to a high proportion of variable power generation (PV, wind, and ocean) of 49% and 59%, respectively, by 2030, and 73% and 74%, respectively, by 2050.

**Table 8.14** OECD North America: development of renewable electricity generation capacity in the scenarios

| in GW | Case | 2015 | 2025 | 2030 | 2040 | 2050 |
|---|---|---|---|---|---|---|
| Hydro | 5.0 °C | 194 | 202 | 207 | 216 | 217 |
| | 2.0 °C | 194 | 199 | 202 | 206 | 206 |
| | 1.5 °C | 194 | 199 | 202 | 203 | 203 |
| Biomass | 5.0 °C | 22 | 25 | 27 | 30 | 35 |
| | 2.0 °C | 22 | 27 | 32 | 42 | 52 |
| | 1.5 °C | 22 | 35 | 39 | 43 | 45 |
| Wind | 5.0 °C | 87 | 157 | 172 | 197 | 253 |
| | 2.0 °C | 87 | 323 | 540 | 812 | 1092 |
| | 1.5 °C | 87 | 358 | 656 | 924 | 1059 |
| Geothermal | 5.0 °C | 5 | 5 | 6 | 9 | 12 |
| | 2.0 °C | 5 | 6 | 9 | 23 | 37 |
| | 1.5 °C | 5 | 5 | 8 | 25 | 37 |
| PV | 5.0 °C | 29 | 133 | 162 | 220 | 358 |
| | 2.0 °C | 29 | 534 | 991 | 1419 | 2129 |
| | 1.5 °C | 29 | 659 | 1097 | 1783 | 2269 |
| CSP | 5.0 °C | 2 | 2 | 3 | 4 | 12 |
| | 2.0 °C | 2 | 22 | 87 | 168 | 209 |
| | 1.5 °C | 2 | 39 | 148 | 257 | 236 |
| Ocean | 5.0 °C | 0 | 0 | 1 | 2 | 4 |
| | 2.0 °C | 0 | 3 | 15 | 59 | 85 |
| | 1.5 °C | 0 | 2 | 13 | 52 | 66 |
| Total | 5.0 °C | 338 | 523 | 577 | 678 | 891 |
| | 2.0 °C | 338 | 1115 | 1878 | 2729 | 3810 |
| | 1.5 °C | 338 | 1298 | 2163 | 3288 | 3916 |

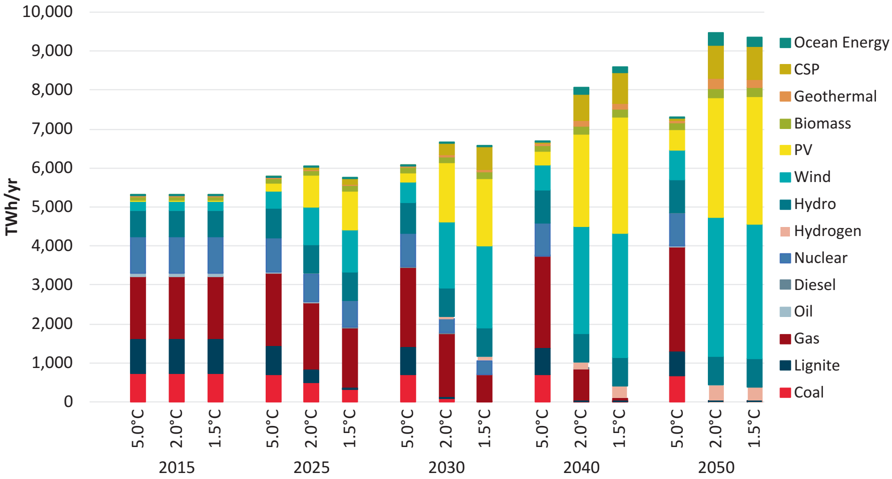


**Fig. 8.18** OECD North America: development of electricity-generation structure in the scenarios

### 8.5.1.3 OECD North America: Future Costs of Electricity Generation

Figure 8.19 shows the development of the electricity-generation and supply costs over time, including $CO_2$ emission costs, in all scenarios. The calculated electricity-generation costs in 2015 (referring to full costs) were around 4.9 ct/kWh. In the 5.0 °C case, the generation costs will increase until 2050, when they reach 10.1 ct/kWh. The generation costs in the 2.0 °C Scenario will increase in a similar way until 2030, when they reach 8.3 ct/kWh, and then drop to 6.8 ct/kWh by 2050. In the 1.5 °C Scenario, they will increase to 8.8 ct/kWh and then drop to 7.1 ct/kWh by 2050. In the 2.0 °C Scenario, the generation costs in 2050 are 3.3 ct/kWh lower than in the 5.0 °C case. In the 1.5 °C Scenario, the generation costs in 2050 are 3.1 ct/kWh lower than in the 5.0 °C case. Note that these estimates of generation costs do not take into account integration costs such as power grid expansion, storage, or other load-balancing measures.

Under the 5.0 °C case, the growth in demand and increasing fossil fuel prices will result in an increase in total electricity supply costs from today's $270 billion/year to more than $760 billion/year in 2050. In both alternative scenarios, the total supply costs in 2050 will be around $690 billion/year The long-term costs for electricity supply in 2050 will be 8%–9% lower than in the 5.0 °C Scenario as a result of the estimated generation costs and the electrification of heating and mobility.

Compared with these results, the generation costs when the $CO_2$ emission costs are not considered will increase in the 5.0 °C case to 7.5 ct/kWh. In the 2.0 °C Scenario, they will increase until 2030, when they reach 7.3 ct/kWh, and then drop to 6.8 ct/kWh by 2050. In the 1.5 °C Scenario, they will increase to 8.4 ct/kWh in 2030, and then drop to 7.1 ct/kWh by 2050. In the 2.0 °C Scenario, the generation costs will be, at maximum, 1 ct/kWh higher than in the 5.0 °C case, and this will

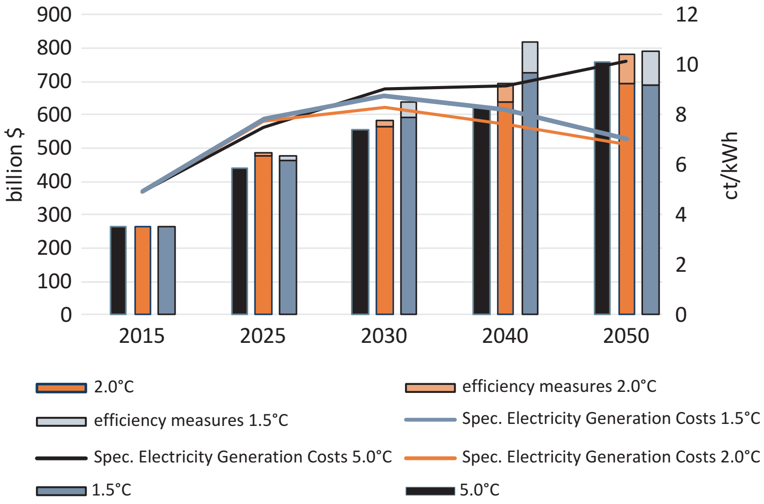


**Fig. 8.19** OECD North America: development of total electricity supply costs and specific electricity-generation costs in the scenarios

occur in 2030. In the 1.5 °C Scenario, compared with the 5.0 °C Scenario, the maximum difference in generation costs will be 2 ct/kWh in 2030. If the $CO_2$ costs are not considered, the total electricity supply costs in the 5.0 °C case will increase to $570 billion/year in 2050.

### 8.5.1.4 OECD North America: Future Investments in the Power Sector

An investment of around $7600 billion will be required for power generation between 2015 and 2050 in the 2.0 °C Scenario—including additional power plants for the production of hydrogen and synthetic fuels and investments in plant replacement after the end of their economic lifetimes. This value is equivalent to approximately $211 billion per year on average, which is $4400 billion more than in the 5.0 °C case ($3200 billion). In the 1.5 °C Scenario, an investment of around $8180 billion for power generation will be required between 2015 and 2050. On average, this is an investment of $227 billion per year. In the 5.0 °C Scenario, the investment in conventional power plants will be around 48% of the total cumulative investments, whereas approximately 52% will be invested in renewable power generation and co-generation (Fig. 8.20). However, under the 2.0 °C (1.5 °C) Scenario, OECD North America will shift almost 93% (93%) of its entire investment to renewables and co-generation. By 2030, the fossil fuel share of the power sector investment will mainly focus on gas power plants that can also be operated with hydrogen.

Because renewable energy has no fuel costs, other than biomass, the cumulative fuel cost savings in the 2.0 °C Scenario will reach a total of $3240 billion in 2050, equivalent to $90 billion per year. Therefore, the total fuel cost savings will be

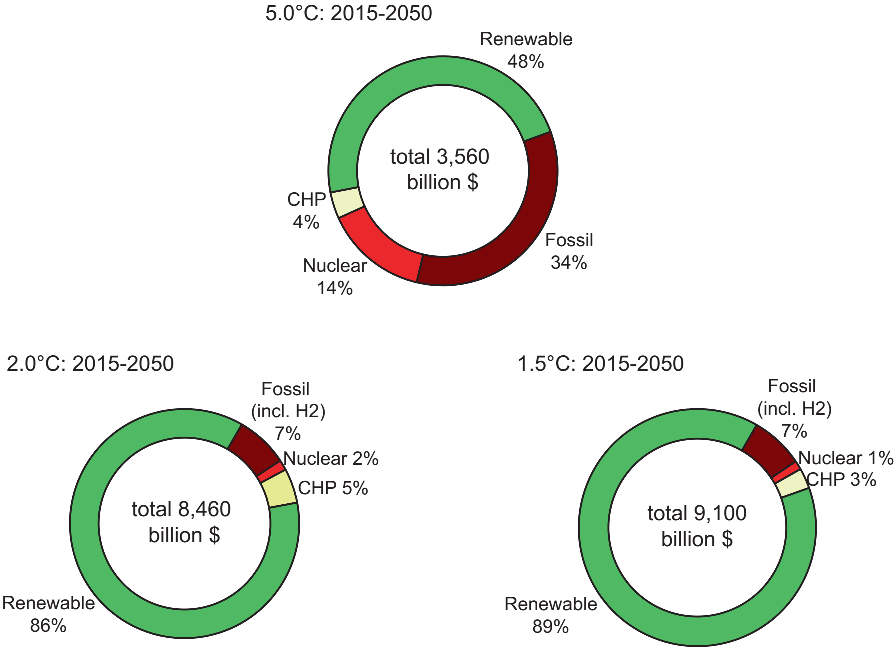


**Fig. 8.20** OECD North America: investment shares for power generation in the scenarios

equivalent to 70% of the total additional investments compared to the 5.0 °C Scenario. The fuel cost savings in the 1.5 °C Scenario will add up to $3910 billion, or $109 billion per year.

#### 8.5.1.5 OECD North America: Energy Supply for Heating

The final energy demand for heating will increases in the 5.0 °C Scenario by 32%, from 19,700 PJ/year in 2015 to 26,000 PJ/year in 2050. Energy efficiency measures will help to reduce the energy demand for heating by 27% by 2050 in the 2.0 °C Scenario relative to the 5.0 °C case, and by 36% in the 1.5 °C Scenario. Today, renewables supply around 11% of OECD North America's final energy demand for heating, with the main contribution from biomass. Renewable energy will provide 38% of OECD North America's total heat demand in 2030 in the 2.0 °C Scenario and 61% in the 1.5 °C Scenario. In both scenarios, renewables will provide 100% of the total heat demand in 2050.

Figure 8.21 shows the development of different technologies for heating in OECD North America over time, and Table 8.15 provides the resulting renewable heat supply for all scenarios. Until 2030, biomass will remain the main contributor. The growing use of solar, geothermal, and environmental heat will lead, in the long term, to a biomass share of 25% under the 2.0 °C Scenario and 19% under the 1.5 °C Scenario. Heat from renewable hydrogen will further reduce the dependence on fossil fuels under both scenarios. Hydrogen consumption in 2050 will be around

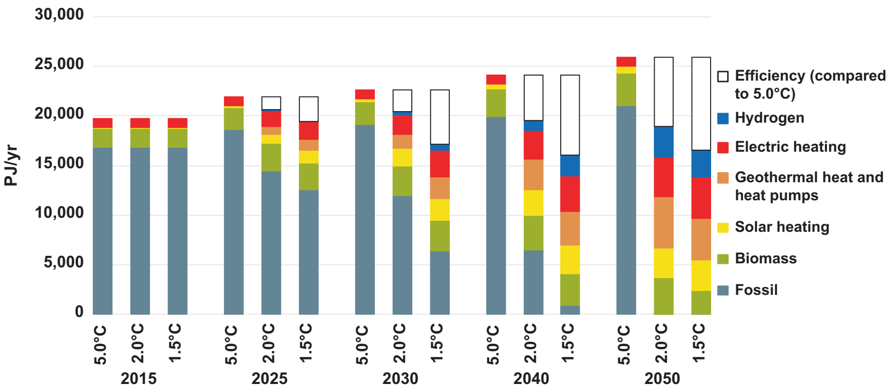


**Fig. 8.21** OECD North America: development of heat supply by energy carrier in the scenarios

**Table 8.15** OECD North America: development of renewable heat supply in the scenarios (excluding the direct use of electricity)

| in PJ/year | Case | 2015 | 2025 | 2030 | 2040 | 2050 |
|---|---|---|---|---|---|---|
| Biomass | 5.0 °C | 1868 | 2142 | 2334 | 2787 | 3279 |
| | 2.0 °C | 1868 | 2758 | 3019 | 3493 | 3686 |
| | 1.5 °C | 1868 | 2707 | 3149 | 3191 | 2378 |
| Solar heating | 5.0 °C | 107 | 210 | 277 | 451 | 695 |
| | 2.0 °C | 107 | 887 | 1772 | 2639 | 2962 |
| | 1.5 °C | 107 | 1290 | 2169 | 2839 | 3128 |
| Geothermal heat and heat pumps | 5.0 °C | 17 | 17 | 18 | 18 | 19 |
| | 2.0 °C | 17 | 875 | 1378 | 3031 | 5257 |
| | 1.5 °C | 17 | 1076 | 2185 | 3463 | 4152 |
| Hydrogen | 5.0 °C | 0 | 0 | 0 | 0 | 0 |
| | 2.0 °C | 0 | 144 | 276 | 1014 | 3045 |
| | 1.5 °C | 0 | 22 | 677 | 2100 | 2666 |
| Total | 5.0 °C | 1991 | 2369 | 2629 | 3256 | 3994 |
| | 2.0 °C | 1991 | 4664 | 6445 | 10,176 | 14,949 |
| | 1.5 °C | 1991 | 5095 | 8180 | 11,592 | 12,324 |

3000 PJ/year in the 2.0 °C Scenario and 2700 PJ/year in the 1.5 °C Scenario. The direct use of electricity for heating will also increase by a factor of 4.6–4.9 between 2015 and 2050 and will have a final energy share of 21% in 2050 in the 2.0 °C Scenario and 26% in the 1.5 °C Scenario.

### 8.5.1.6 OECD North America: Future Investments in the Heating Sector

The roughly estimated investments in renewable heating technologies up to 2050 will amount to around $2580 billion in the 2.0 °C Scenario (including investments for plant replacement after their economic lifetimes) or approximately $72 billion

**Table 8.16** OECD North America: installed capacities for renewable heat generation in the scenarios

| in GW | Case | 2015 | 2025 | 2030 | 2040 | 2050 |
|---|---|---|---|---|---|---|
| Biomass | 5.0 °C | 292 | 315 | 330 | 366 | 411 |
| | 2.0 °C | 292 | 381 | 387 | 355 | 272 |
| | 1.5 °C | 292 | 360 | 384 | 334 | 179 |
| Geothermal | 5.0 °C | 0 | 0 | 0 | 0 | 0 |
| | 2.0 °C | 0 | 17 | 30 | 44 | 52 |
| | 1.5 °C | 0 | 34 | 57 | 82 | 109 |
| Solar heating | 5.0 °C | 29 | 58 | 76 | 124 | 191 |
| | 2.0 °C | 29 | 232 | 466 | 697 | 780 |
| | 1.5 °C | 29 | 331 | 557 | 728 | 793 |
| Heat pumps | 5.0 °C | 3 | 3 | 3 | 3 | 3 |
| | 2.0 °C | 3 | 123 | 188 | 393 | 677 |
| | 1.5 °C | 3 | 143 | 292 | 479 | 568 |
| Total[a] | 5.0 °C | 324 | 375 | 410 | 494 | 605 |
| | 2.0 °C | 324 | 752 | 1071 | 1489 | 1781 |
| | 1.5 °C | 324 | 868 | 1290 | 1622 | 1649 |

[a]Excluding direct electric heating

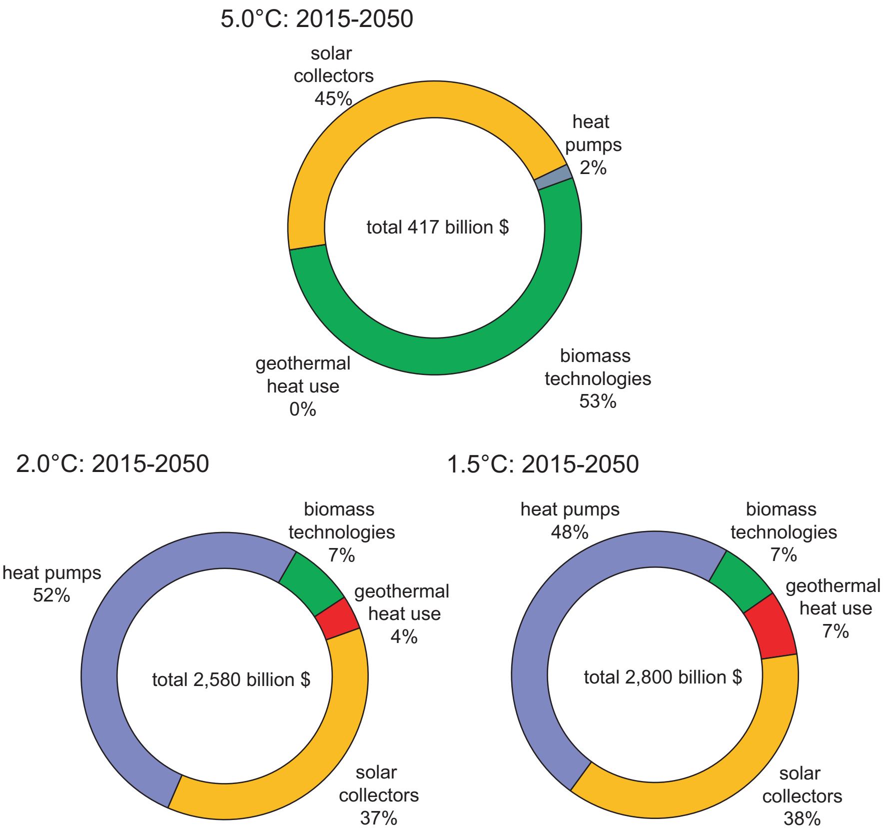


**Fig. 8.22** OECD North America: development of investments in renewable heat generation technologies in the scenarios

per year. The largest share of investment in OECD North America is assumed to be for heat pumps (around $1300 billion), followed by solar collectors and biomass technologies. The 1.5 °C Scenario assumes an even faster expansion of renewable technologies, resulting in a lower average annual investment of around $78 billion per year (Table 8.16, Fig. 8.22).

#### 8.5.1.7 OECD North America: Transport

Energy demand in the transport sector in OECD North America is expected to decrease by 8% in the 5.0 °C Scenario, from around 31,000 PJ/year in 2015 to 28,600 PJ/year in 2050. In the 2.0 °C Scenario, assumed technical, structural, and behavioural changes will save 73% (20,970 PJ/year) in 2050 compared with the 5.0 °C case. Additional modal shifts, technology switches, and a reduction in transport demand will lead to even higher energy savings in the 1.5 °C Scenario, of 74% (or 21,100 PJ/year) in 2050 compared with the 5.0 °C case (Table 8.17, Fig. 8.23).

By 2030, electricity will provide 11% (620 TWh/year) of the transport sector's total energy demand in the 2.0 °C Scenario, and in 2050, the share will be 44% (930 TWh/year). In 2050, up to 2090 PJ/year of hydrogen will be used in the transport sector as a complementary renewable option. In the 1.5 °C Scenario, the annual electricity demand will be 1030 TWh in 2050. The 1.5 °C Scenario also assumes a hydrogen demand of 2020 PJ/year by 2050.

Biofuel use is limited in the 2.0 °C Scenario to a maximum of 2540 PJ/year Therefore, around 2030, synthetic fuels based on power-to-liquid will be introduced, with a maximum amount of 270 PJ/year in 2050. Because the reduction in

**Table 8.17** OECD North America: projection of the transport energy demand by mode in the scenarios

| in PJ/year | Case | 2015 | 2025 | 2030 | 2040 | 2050 |
|---|---|---|---|---|---|---|
| Rail | 5.0 °C | 674 | 628 | 609 | 570 | 529 |
| | 2.0 °C | 674 | 660 | 655 | 523 | 516 |
| | 1.5 °C | 674 | 743 | 730 | 773 | 806 |
| Road | 5.0 °C | 26,686 | 25,691 | 24,838 | 24,222 | 23,414 |
| | 2.0 °C | 26,686 | 21,257 | 15,933 | 7731 | 5124 |
| | 1.5 °C | 26,686 | 18,612 | 11,973 | 6717 | 5251 |
| Domestic aviation | 5.0 °C | 2421 | 2978 | 3274 | 3398 | 3186 |
| | 2.0 °C | 2421 | 2309 | 2026 | 1530 | 1242 |
| | 1.5 °C | 2421 | 2167 | 1689 | 1063 | 840 |
| Domestic navigation | 5.0 °C | 461 | 482 | 493 | 514 | 535 |
| | 2.0 °C | 461 | 481 | 489 | 489 | 473 |
| | 1.5 °C | 461 | 479 | 484 | 483 | 473 |
| Total | 5.0 °C | 30,241 | 29,779 | 29,214 | 28,704 | 27,664 |
| | 2.0 °C | 30,241 | 24,707 | 19,104 | 10,273 | 7354 |
| | 1.5 °C | 30,241 | 22,000 | 14,875 | 9036 | 7370 |

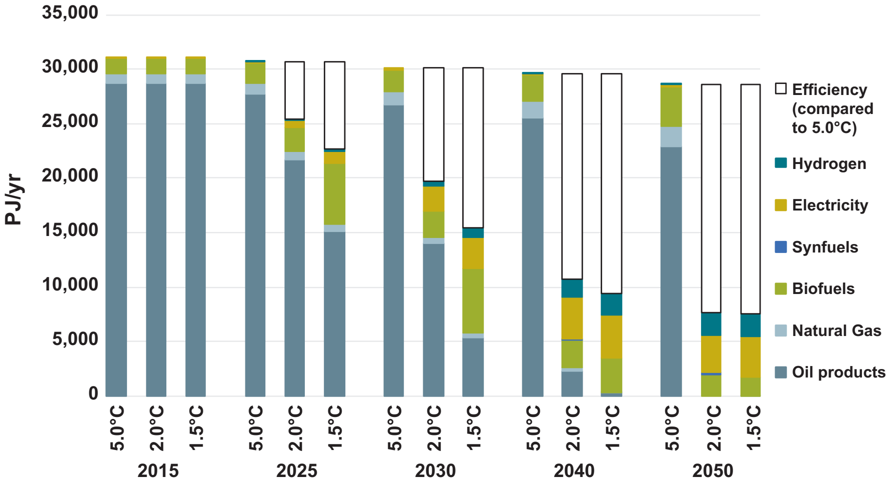


**Fig. 8.23** OECD North America: final energy consumption by transport in the scenarios

fossil fuel for transport will be faster, biofuel use will increase in the 1.5 °C Scenario to a maximum of 5900 PJ/year. The demand for synthetic fuels will decrease to zero by 2050 in the 1.5 °C Scenario because of the lower overall energy demand by transport.

### 8.5.1.8 OECD North America: Development of $CO_2$ Emissions

In the 5.0 °C Scenario, OECD North America's annual $CO_2$ emissions will decrease by 9% from 6170 Mt. in 2015 to 5612 Mt. in 2050. Stringent mitigation measures in both the alternative scenarios will lead to reductions in annual emissions to 930 Mt. in 2040 in the 2.0 °C Scenario and to 120 Mt. in the 1.5 °C Scenario, with further reductions to almost zero by 2050. In the 5.0 °C case, the cumulative $CO_2$ emissions from 2015 until 2050 will add up to 216 Gt. In contrast, in the 2.0 °C and 1.5 °C Scenarios, the cumulative emissions for the period from 2015 until 2050 will be 99 Gt and 72 Gt, respectively.

Therefore, the cumulative $CO_2$ emissions will decrease by 54% in the 2.0 °C Scenario and by 67% in the 1.5 °C Scenario compared with the 5.0 °C case. A rapid decrease in the annual emissions will occur under both alternative scenarios. In the 2.0 °C Scenario, the reduction will be greatest in 'Power generation', followed by the 'Transport' and 'Residential and other' sectors (Fig. 8.24).

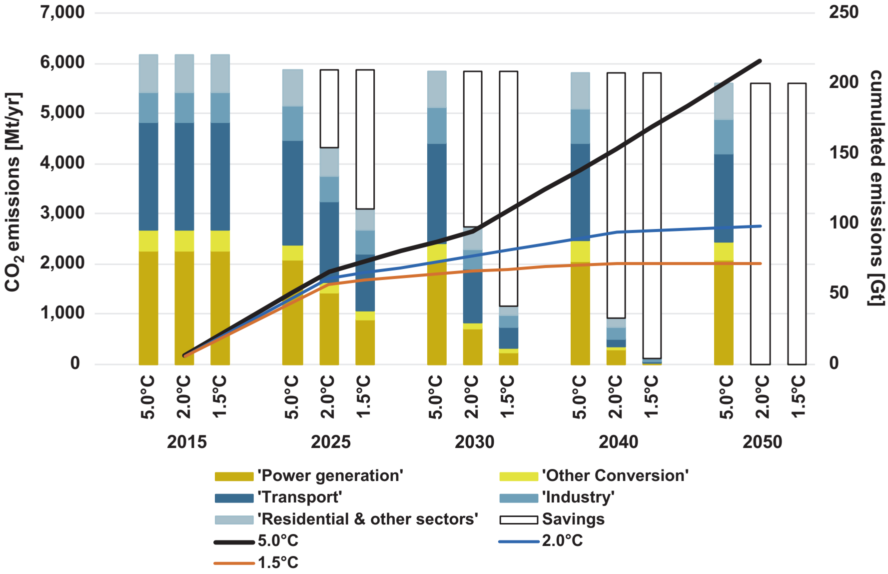


**Fig. 8.24** OECD North America: development of $CO_2$ emissions by sector and cumulative $CO_2$ emissions (after 2015) in the scenarios ('Savings' = reduction compared with the 5.0 °C Scenario)

### 8.5.1.9 OECD North America: Primary Energy Consumption

Taking into account the assumptions discussed above, the levels of primary energy consumption under the three scenarios are shown in Fig. 8.25. In the 2.0 °C Scenario, the primary energy demand will decrease by 46%, from around 111,600 PJ/year in 2015 to 60,600 PJ/year in 2050. Compared with the 5.0 °C Scenario, the overall primary energy demand will decrease by 50% by 2050 in the 2.0 °C Scenario (5.0 °C: 121,000 PJ in 2050). In the 1.5 °C Scenario, the primary energy demand will be even lower (56,600 PJ in 2050) because the final energy demand and conversion losses will be lower.

Both the 2.0 °C and 1.5 °C Scenarios aim to rapidly phase-out coal and oil. As a result, renewable energy will have a primary energy share of 34% in 2030 and 91% in 2050 in the 2.0 °C Scenario. In the 1.5 °C Scenario, renewables will have a pri-

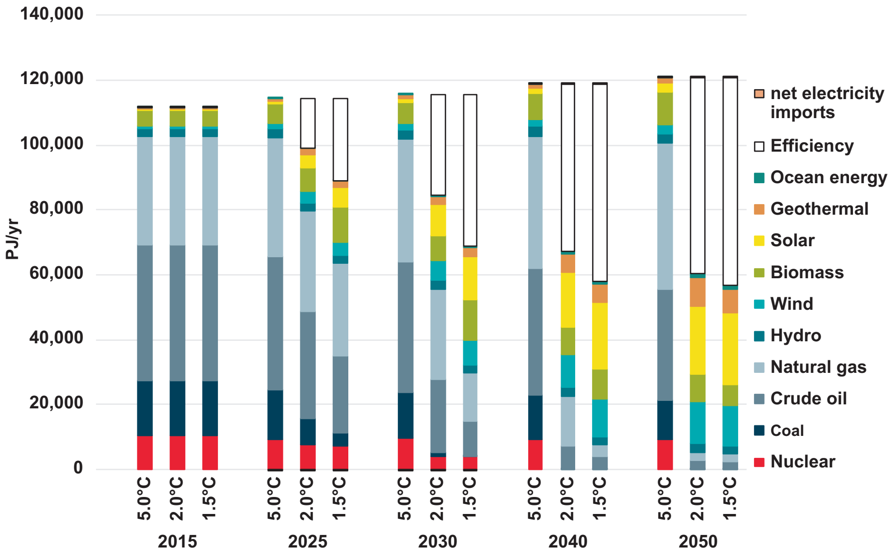


**Fig. 8.25** OECD North America: projection of total primary energy demand (PED) by energy carrier in the scenarios (including electricity import balance)

mary share of more than 91% in 2050 (including non-energy consumption, which will still include fossil fuels). Nuclear energy will be phased-out by 2040 under both the 2.0 °C and the 1.5 °C Scenarios. The cumulative primary energy consumption of natural gas in the 5.0 °C case will add up to 1290 EJ, the cumulative coal consumption to about 470 EJ, and the crude oil consumption to 1300 EJ. In contrast, in the 2.0 °C Scenario, the cumulative gas demand will amount to 730 EJ, the cumulative coal demand to 120 EJ, and the cumulative oil demand to 640 EJ. Even lower cumulative fossil fuel use will be achieved in the 1.5 °C Scenario: 480 EJ for natural gas, 80 EJ for coal, and 440 EJ for oil.

### *8.5.2 Regional Results: Power Sector Analysis*

The key results for all 10 world regions and their sub-regions are presented in this section, with standardized tables to make them comparable for the reader. Regional differences and particularities are summarized. It is important to note that the electricity loads for the sub-regions—which are in several cases also countries—are calculated (see Chap. 3) and are not real measured values. When information was available, the model results are compared with published peak loads and adapted as far as possible. However, deviations of 10% or more for the base year are in the range of the probability. The interconnection capacities between sub-regions are simplified assumptions based on current practices in liberalized power markets, and include cross-border trade (e.g., between Canada and the USA) (C2ES 2017) or within the European Union (EU). The EU set a target of 10% interconnection capacity between their member states in 2002 (EU-EG 2017). The interconnection capacities for sub-regions that are not geographically connected are set to zero for the entire modelling period, even when there is current discussion about the implementation of new interconnections, such as for the ASEAN Power Grid (ASEAN-CE 2018).

### *8.5.3 OECD North America: Power Sector Analysis*

The OECD North America region includes Canada, the USA, and Mexico, and therefore contains more than one large electricity market. Although the power sector is liberalized in all three countries, the state of implementation and the market rules in place vary significantly. Even within the USA, each state has different market rules and grid regulations. Therefore, the calculated scenarios assume the priority dispatch of all renewables and priority grid connections for new renewable power plants, and a streamlined process for required construction permits. The power sector analysis for all regions is based on technical, not political, considerations.

#### 8.5.3.1 OECD North America: Development of Power Plant Capacities

The size of the renewable power market in OECD North America will increase significantly in the 2.0 °C Scenario. The annual market for solar PV must increase from 22.76 GW in 2020 by a factor of 5 to an average of 95 GW by 2030. The onshore wind market must expand to 35 GW by 2025, an increase from around 13 GW 5 years earlier. By 2050, offshore wind generation will increase to 9.7 GW annually, by a factor of 7 compared with the base year (2015). Concentrated solar power plants will play an important role in dispatchable solar electricity generation to supply bulk power, especially for industry and industrial process heat. The annual market in 2030 will increase to 16 GW, compared with 1.7 GW in 2020. The 1.5 °C Scenario accelerates both the phase-out of fossil-fuel-based power generation and the deployment of renewables—mainly solar PV and wind in the first decade—about 5–7 years faster than the 2.0 °C Scenario (Table 8.18).

#### 8.5.3.2 OECD North America: Utilization of Power-Generation Capacities

Table 8.19 shows the increasing shares of variable renewable power generation across all North American regions. Whereas Alaska and Canada are dominated by variable wind power generation, Mexico and the sunny mid-west of the USA have significant contributions from CSP. Solar PV is distributed evenly across the entire

**Table 8.18** OECD North America: average annual change in installed power plant capacity

| Power generation: average annual change of installed capacity [GW/a] | 2015–2025 | | 2026–2035 | | 2036–2050 | |
|---|---|---|---|---|---|---|
| | 2.0 °C | 1.5 °C | 2.0 °C | 1.5 °C | 2.0 °C | 1.5 °C |
| Hard coal | −7 | −16 | −6 | −8 | −4 | 0 |
| Lignite | −14 | −18 | −7 | 0 | 0 | 0 |
| Gas | 6 | 9 | 12 | 1 | −55 | −4 |
| Hydrogen-gas | 1 | 10 | 4 | 24 | 55 | 39 |
| Oil/diesel | −5 | −7 | −3 | −4 | −1 | 0 |
| Nuclear | −4 | −9 | −10 | −10 | 0 | −1 |
| Biomass | 1 | 2 | 1 | 1 | 1 | 0 |
| Hydro | −5 | −3 | 0 | 0 | 0 | 2 |
| Wind (onshore) | 24 | 48 | 36 | 36 | 24 | 19 |
| Wind (offshore) | 2 | 19 | 11 | 19 | 10 | 3 |
| PV (roof top) | 39 | 94 | 64 | 68 | 61 | 55 |
| PV (utility scale) | 13 | 31 | 21 | 23 | 20 | 18 |
| Geothermal | 0 | 0 | 1 | 1 | 2 | 2 |
| Solar thermal power plants | 3 | 18 | 15 | 18 | 6 | 4 |
| Ocean energy | 1 | 2 | 4 | 4 | 4 | 3 |
| Renewable fuel based co-generation | 1 | 2 | 2 | 2 | 2 | 0 |

region. Onshore and offshore wind penetration is highest in rural areas, whereas solar roof-top power generation is highest in suburban regions where roof space and electricity demand from residential buildings correlate best. The south-west of the USA will have the highest share of variable renewables—mainly solar PV for residual homes and office buildings, connected to battery systems. There are no structural differences between the 2.0 °C and 1.5 °C Scenarios, except faster implementation in the latter. It is assumed that all regions will have an interconnection capacity of 20% of the regional average load, with which to exchange renewable and dispatch electricity to neighbouring regions.

Capacity factors for the five generation types and the resulting average utilization are shown in Table 8.20. Compared with the global average, North America will start with a capacity factor for limited dispatchable generation of about 10% over the global average. By 2050, the average capacity factor across all power-generation types will be 29% for both scenarios. A low average capacity factor requires flexible power plants and a power market framework that incentivizes them.

#### 8.5.3.3 OECD North America: Development of Load, Generation, and Residual Load

Table 8.21 shows the development of the maximum load, generation, and resulting residual load (the load remaining after variable renewable generation). With increased shares of variable solar PV and wind power, the minimum residual load

**Table 8.19** OECD North America and sub-regions: power system shares by technology group

| Power generation structure and interconnection | | 2.0 °C | | | | 1.5 °C | | | |
|---|---|---|---|---|---|---|---|---|---|
| OECD North America | | Variable RE | Dispatch RE | Dispatch fossil | Inter-connection | Variable RE | Dispatch RE | Dispatch fossil | Inter-connection |
| USA Alaska | 2015 | 4% | 35% | 61% | 10% | | | | |
| | 2030 | 29% | 31% | 40% | 15% | 36% | 30% | 34% | 15% |
| | 2050 | 42% | 23% | 35% | 20% | 42% | 26% | 32% | 20% |
| Canada West | 2015 | 6% | 35% | 59% | 10% | | | | |
| | 2030 | 43% | 30% | 27% | 15% | 53% | 28% | 19% | 15% |
| | 2050 | 63% | 21% | 16% | 20% | 63% | 23% | 14% | 20% |
| Canada East | 2015 | 7% | 35% | 59% | 10% | | | | |
| | 2030 | 45% | 30% | 25% | 15% | 56% | 27% | 16% | 15% |
| | 2050 | 66% | 21% | 13% | 20% | 66% | 23% | 11% | 20% |
| USA North East | 2015 | 7% | 35% | 58% | 10% | | | | |
| | 2030 | 47% | 31% | 22% | 15% | 58% | 28% | 14% | 15% |
| | 2050 | 69% | 20% | 11% | 20% | 69% | 22% | 9% | 20% |
| USA North West | 2015 | 4% | 35% | 61% | 10% | | | | |
| | 2030 | 36% | 32% | 32% | 15% | 47% | 30% | 23% | 15% |
| | 2050 | 59% | 23% | 18% | 20% | 59% | 25% | 16% | 20% |
| USA South West | 2015 | 7% | 35% | 58% | 10% | | | | |
| | 2030 | 53% | 28% | 19% | 15% | 64% | 25% | 11% | 15% |
| | 2050 | 73% | 17% | 10% | 20% | 73% | 18% | 8% | 20% |
| USA South East | 2015 | 8% | 35% | 58% | 10% | | | | |
| | 2030 | 53% | 28% | 19% | 15% | 63% | 25% | 12% | 15% |
| | 2050 | 71% | 18% | 11% | 20% | 71% | 20% | 9% | 20% |

(continued)

**Table 8.19** (continued)

| Power generation structure and interconnection | | 2.0 °C | | | | 1.5 °C | | | |
|---|---|---|---|---|---|---|---|---|---|
| OECD North America | | Variable RE | Dispatch RE | Dispatch fossil | Inter-connection | Variable RE | Dispatch RE | Dispatch fossil | Inter-connection |
| Mexico | 2015 | 5% | 35% | 61% | 10% | | | | |
| | 2030 | 37% | 30% | 32% | 15% | 46% | 28% | 26% | 15% |
| | 2050 | 56% | 23% | 22% | 20% | 55% | 25% | 19% | 20% |
| OECD North America | 2015 | 7% | 35% | 58% | | | | | |
| | 2030 | 48% | 30% | 23% | | 59% | 27% | 15% | |
| | 2050 | 68% | 19% | 13% | | 68% | 21% | 11% | |

**Table 8.20** OECD North America: capacity factors by generation type

| Utilization of variable and dispatchable power generation: | | 2015 | 2020 | 2020 | 2030 | 2030 | 2040 | 2040 | 2050 | 2050 |
|---|---|---|---|---|---|---|---|---|---|---|
| OECD North America | | | 2.0 °C | 1.5 °C | 2.0 °C | 1.5 °C | 2.0 °C | 1.5 °C | 2.0 °C | 1.5 °C |
| Capacity Factor – average | [%/yr] | 53.1% | 35% | 33% | 29% | 28% | 34% | 28% | 29% | 29% |
| Limited dispatchable: fossil and nuclear | [%/yr] | 68.6% | 40% | 10% | 28% | 2% | 20% | 6% | 10% | 10% |
| Limited dispatchable: renewable | [%/yr] | 45.9% | 46% | 57% | 37% | 39% | 59% | 36% | 36% | 35% |
| Dispatchable: fossil | [%/yr] | 39.7% | 23% | 21% | 11% | 5% | 30% | 8% | 12% | 11% |
| Dispatchable: renewable | [%/yr] | 44.0% | 52% | 68% | 49% | 52% | 47% | 44% | 49% | 45% |
| Variable: renewable | [%/yr] | 18.9% | 12% | 12% | 25% | 26% | 34% | 27% | 28% | 28% |

can become negative. If this happens, the surplus generation can either be exported to other regions, stored, or curtailed. The export of load to other regions requires transmission lines. If the theoretical utilization rate of transmission cables (= interconnection) exceeds 100%, the transport capacity must be increased. We assume that the entire load need not be exported, and that surplus generation capacities can be curtailed because interconnections are costly and require a certain level of utilization to make them economically viable. An analysis of the economic viability of new interconnections and their optimal transmission capacities is beyond the scope of this research project.

In Alaska in the 2.0 °C Scenario, for example, generation and demand are balanced in 2020 and 2030, but peak generation is substantially higher than demand in 2050. In the 1.5 °C Scenario, a significant level of overproduction is achieved by 2030. In the two scenarios, the surplus peak generation is equally high. These results have been calculated under the assumption that surplus generation will be stored in a cascade of batteries and pumped-storage hydroelectricity (PSH) or used to produce hydrogen and/or synthetic fuels. Therefore, the maximal interconnection requirements shown in this chapter represent the maximum surplus generation capacity. To avoid curtailment, these overcapacities have mainly been used for hydrogen production. Therefore, Alaska could remain an energy exporter but switch from oil to wind-generated synthetic gas and/or hydrogen.

Table 8.22 provides an overview of the calculated storage and dispatch power requirements by sub-region. To store or export the entire electricity output during

**Table 8.21** OECD North America: load, generation, and residual load development

| Power generation structure | | 2.0 °C | | | | 1.5 °C | | | |
|---|---|---|---|---|---|---|---|---|---|
| OEC D North America | | Max demand | Max generation | Max Residual Load | Max interconnection requirements | Max demand | Max generation | Max residual load | Max interconnection requirements |
| | | [GW] | [GW] | [GW] | [GW] | [GW] | [GW] | [GW] | [GW] |
| NA – USA Alaska | 2020 | 1.4 | 1.4 | 0.0 | | 1.4 | 18.8 | 0.1 | |
| | 2030 | 1.5 | 1.5 | 0.1 | 0 | 1.6 | 13.5 | 0.3 | 12 |
| | 2050 | 2.4 | 11.8 | 0.5 | 9 | 2.4 | 11.5 | 0.5 | 9 |
| NA – Canada West | 2020 | 21.1 | 21.1 | 0.0 | | 21.2 | 34.0 | 0.3 | |
| | 2030 | 23.0 | 31.2 | 5.7 | 3 | 24.5 | 39.8 | 4.6 | 11 |
| | 2050 | 37.2 | 73.1 | 15.2 | 21 | 37.3 | 76.4 | 15.3 | 24 |
| NA – Canada East | 2020 | 53.0 | 53.0 | 0.0 | | 53.1 | 117.3 | 0.8 | |
| | 2030 | 58.0 | 88.0 | 14.6 | 15 | 61.6 | 117.5 | 15.3 | 40 |
| | 2050 | 94.3 | 213.7 | 41.2 | 78 | 94.6 | 223.0 | 41.0 | 87 |
| NA – USA North East | 2020 | 258.6 | 243.6 | 29.9 | | 259.5 | 273.2 | 21.8 | |
| | 2030 | 288.5 | 355.7 | 47.7 | 20 | 304.2 | 468.8 | 63.5 | 101 |
| | 2050 | 433.0 | 853.7 | 175.3 | 246 | 434.6 | 891.6 | 176.7 | 280 |
| NA – USA North West | 2020 | 25.6 | 25.6 | 0.0 | | 25.7 | 81.1 | 2.2 | |
| | 2030 | 28.5 | 30.6 | 5.9 | 0 | 30.1 | 40.8 | 6.0 | 5 |
| | 2050 | 42.5 | 74.3 | 16.0 | 16 | 42.7 | 77.7 | 16.1 | 19 |

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| NA – USA South West | 2020 | 109.4 | 109.1 | 4.6 | | 109.8 | 167.5 | 9.3 | |
| | 2030 | 121.8 | 163.0 | 11.8 | 29 | 128.5 | 208.8 | 20.0 | 60 |
| | 2050 | 181.8 | 384.2 | 38.3 | 164 | 182.4 | 402.3 | 42.0 | 178 |
| NA – USA South East | 2020 | 217.7 | 217.7 | 0.4 | | 217.4 | 232.1 | 15.3 | |
| | 2030 | 255.8 | 372.6 | 38.0 | 79 | 270.9 | 490.7 | 64.7 | 155 |
| | 2050 | 393.3 | 890.9 | 102.6 | 395 | 394.5 | 927.6 | 122.3 | 411 |
| Mexico | 2020 | 66.6 | 51.3 | 22.3 | | | | | |
| | 2030 | 87.2 | 116.1 | 21.3 | 8 | 97.6 | 151.9 | 19.8 | 35 |
| | 2050 | 171.9 | 277.1 | 80.5 | 25 | 173.3 | 289.7 | 81.9 | 34 |

Table 8.22 OECD North America: storage and dispatch service requirements

| Storage and dispatch | | 2.0 °C | | | | | 1.5 °C | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| OECD North America | | Required to avoid curtailment [GWh/year] | Utilization battery -through-put- [GWh/year] | Utilization PSH -through-put- [GWh/year] | Total storage demand (incl. H2) [GWh/year] | Dispatch hydrogen-based [GWh/year] | Required to avoid curtailment [GWh/year] | Utilization battery -through-put- [GWh/year] | Utilization PSH -through-put- [GWh/year] | Total Storage demand (incl. H2) [GWh/year] | Dispatch Hydrogen-based [GWh/year] |
| USA Alaska | 2020 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | 2030 | 11 | 0 | 0 | 0 | 136 | 68 | 1 | 1 | 2 | 136 |
| | 2050 | 328 | 38 | 1 | 39 | 542 | 407 | 41 | 1 | 42 | 542 |
| Canada West | 2020 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | 2030 | 1011 | 14 | 7 | 21 | 1957 | 4078 | 31 | 18 | 49 | 1957 |
| | 2050 | 14,665 | 1044 | 34 | 1078 | 7776 | 17,557 | 1100 | 38 | 1137 | 7776 |
| Canada East | 2020 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | 2030 | 3014 | 38 | 20 | 58 | 4482 | 13,352 | 82 | 53 | 135 | 4482 |
| | 2050 | 42,780 | 2545 | 91 | 2636 | 18,129 | 50,077 | 2623 | 97 | 2720 | 18,129 |
| USA North East | 2020 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | 2030 | 9092 | 148 | 73 | 221 | 17,290 | 50,047 | 404 | 239 | 643 | 17,290 |
| | 2050 | 212,448 | 13,990 | 509 | 14,499 | 60,398 | 252,243 | 14,457 | 546 | 15,004 | 60,398 |
| USA North West | 2020 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | 2030 | 90 | 4 | 1 | 5 | 2394 | 1854 | 26 | 13 | 39 | 2394 |
| | 2050 | 11,806 | 1013 | 33 | 1046 | 8707 | 14,933 | 1085 | 37 | 1122 | 8707 |
| USA South West | 2020 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | 2030 | 10,722 | 121 | 68 | 189 | 6370 | 47,636 | 238 | 172 | 410 | 6370 |
| | 2050 | 172,771 | 6661 | 301 | 6962 | 22,741 | 201,316 | 6894 | 316 | 7210 | 22,741 |

| | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| USA South East | 2020 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | 2030 | 35,827 | 320 | 195 | 516 | 15,281 | 115,409 | 579 | 402 | 981 | 15,281 |
| | 2050 | 372,747 | 15,600 | 690 | 16,290 | 53,958 | 429,227 | 15,734 | 725 | 16,459 | 53,958 |
| Mexico | 2020 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | 2030 | 2604 | 37 | 18 | 55 | 7792 | 10,790 | 95 | 52 | 147 | 7792 |
| | 2050 | 25,855 | 2706 | 75 | 2781 | 32,716 | 33,945 | 2985 | 86 | 3071 | 32,716 |
| OECD North America | 2020 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | 2030 | 62,369 | 682 | 384 | 1065 | 55,702 | 243,235 | 1456 | 949 | 2405 | 55,702 |
| | 2050 | 853,401 | 43,597 | 1735 | 45,331 | 204,967 | 999,704 | 44,919 | 1846 | 46,766 | 204,967 |

each production peak would require significant additional investment. Therefore, it is assumed that not all surplus solar and wind generation must be stored, and that up to 5% (in 2030) and 10% (in 2050) of the annual production can be curtailed without significant economic disadvantage. We assume that regions with favourable wind and solar potentials, and advantages regarding available space, will use their overcapacities to export electricity via transmission lines and/or to produce synthetic and/or hydrogen fuels.

The southern part of the USA will achieve a significant solar PV share by 2050 and storage demand will be highest in this region. Storage and dispatch demand will increase in all sub-regions between 2025 and 2035. Before 2025, storage demand will be zero in all regions.

## 8.6 Latin America

### *8.6.1 Latin America: Long-Term Energy Pathways*

#### 8.6.1.1 Latin America: Final Energy Demand by Sector

Combining the assumptions on population growth, GDP growth, and energy intensity will produce the future development pathways for Latin America's final energy demand shown in Fig. 8.26 for the 5.0 °C, 2.0 °C, and 1.5 °C Scenarios. Under the 5.0 °C Scenario, the total final energy demand will increase by 70% from the current 19,200 PJ/year to 32,600 PJ/year in 2050. In the 2.0 °C Scenario, the final energy demand will decrease by 11% compared with current consumption and will reach 17,000 PJ/year by 2050. The final energy demand in the 1.5 °C Scenario will fall to 15,800 PJ in 2050, 18% below the 2015 demand. In the 1.5 °C Scenario, the final energy demand in 2050 will be 7% lower than in the 2.0 °C Scenario. The electricity demand for 'classical' electrical devices (without power-to-heat or e-mobility) will increase from 740 TWh/year in 2015 to around 1560 TWh/year in 2050 in both alternative scenarios, around 300 TWh/year lower than in the 5.0 °C Scenario (1860 TWh/year in 2050).

Electrification will lead to a significant increase in the electricity demand by 2050. In the 2.0 °C Scenario, the electricity demand for heating will be about 600 TWh/year due to electric heaters and heat pumps, and in the transport sector an increase of approximately 1700 TWh/year will be caused by electric mobility. The generation of hydrogen (for transport and high-temperature process heat) and the manufacture of synthetic fuels (mainly for transport) will add an additional power demand of 600 TWh/year. The gross power demand will thus increase from 1300 TWh/year in 2015 to 3500 TWh/year in 2050 in the 2.0 °C Scenario, 25% higher than in the 5.0 °C case. In the 1.5 °C Scenario, the gross electricity demand will increase to a maximum of 3800 TWh/year in 2050.

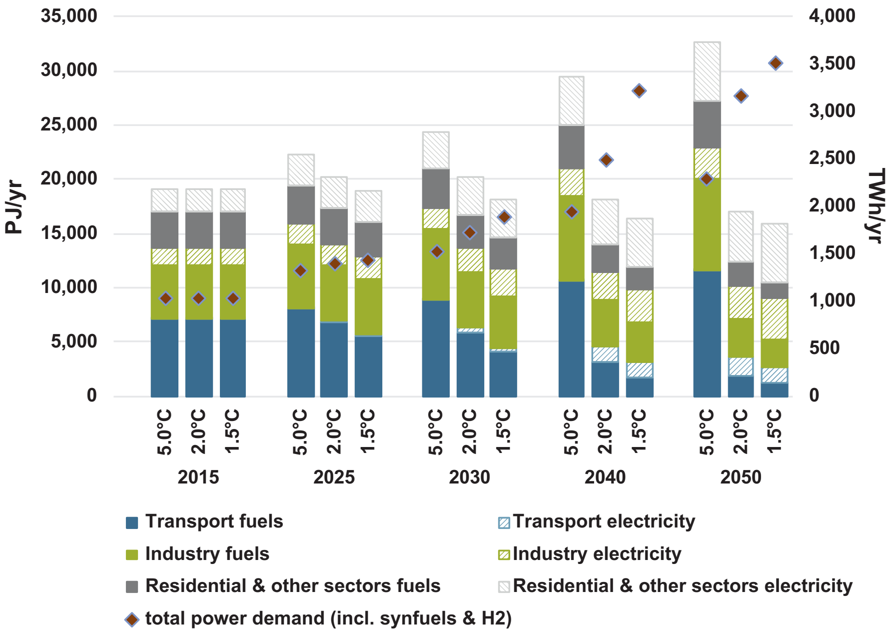


**Fig. 8.26** Latin America: development of final energy demand by sector in the scenarios

Efficiency gains in the heating sector could be even larger than in the electricity sector. Under the 2.0 °C and 1.5 °C Scenarios, a final energy consumption equivalent to about 4300 PJ/year will be avoided through efficiency gains in both scenarios by 2050 compared with the 5.0 °C Scenario.

### 8.6.1.2 Latin America: Electricity Generation

The development of the power system is characterized by a dynamically growing renewable energy market and an increasing proportion of total power coming from renewable sources. By 2050, 100% of the electricity produced in Latin America will come from renewable energy sources in the 2.0 °C Scenario. 'New' renewables—mainly wind, solar, and geothermal energy—will contribute 63% of the total electricity generation. Renewable electricity's share of the total production will be 87% by 2030 and 96% by 2040. The installed capacity of renewables will reach about 530 GW by 2030 and 1030 GW by 2050. The share of renewable electricity generation in 2030 in the 1.5 °C Scenario will be 91%. In the 1.5 °C Scenario, the generation capacity from renewable energy will be approximately 1210 GW in 2050.

Table 8.23 shows the development of different renewable technologies in Latin America over time. Figure 8.27 provides an overview of the overall power-generation structure in Latin America. From 2020 onwards, the continuing growth of wind and PV, up to 230 GW and 410 GW, respectively, will be complemented by up to 60 GW solar thermal generation, as well as limited biomass, geothermal, and

**Table 8.23** Latin America: development of renewable electricity-generation capacity in the scenarios

| in GW | Case | 2015 | 2025 | 2030 | 2040 | 2050 |
|---|---|---|---|---|---|---|
| Hydro | 5.0 °C | 161 | 200 | 222 | 269 | 302 |
| | 2.0 °C | 161 | 180 | 180 | 183 | 184 |
| | 1.5 °C | 161 | 180 | 180 | 183 | 184 |
| Biomass | 5.0 °C | 18 | 23 | 25 | 29 | 34 |
| | 2.0 °C | 18 | 43 | 57 | 75 | 89 |
| | 1.5 °C | 18 | 43 | 61 | 75 | 81 |
| Wind | 5.0 °C | 11 | 31 | 38 | 50 | 66 |
| | 2.0 °C | 11 | 56 | 95 | 199 | 234 |
| | 1.5 °C | 11 | 67 | 134 | 272 | 285 |
| Geothermal | 5.0 °C | 1 | 1 | 2 | 3 | 4 |
| | 2.0 °C | 1 | 3 | 5 | 12 | 18 |
| | 1.5 °C | 1 | 3 | 5 | 12 | 15 |
| PV | 5.0 °C | 2 | 14 | 19 | 29 | 42 |
| | 2.0 °C | 2 | 108 | 175 | 295 | 409 |
| | 1.5 °C | 2 | 133 | 237 | 529 | 537 |
| CSP | 5.0 °C | 0 | 1 | 1 | 2 | 3 |
| | 2.0 °C | 0 | 4 | 20 | 51 | 63 |
| | 1.5 °C | 0 | 4 | 20 | 76 | 78 |
| Ocean | 5.0 °C | 0 | 0 | 0 | 0 | 4 |
| | 2.0 °C | 0 | 1 | 2 | 20 | 37 |
| | 1.5 °C | 0 | 1 | 2 | 20 | 30 |
| Total | 5.0 °C | 193 | 270 | 306 | 382 | 456 |
| | 2.0 °C | 193 | 395 | 534 | 834 | 1034 |
| | 1.5 °C | 193 | 432 | 640 | 1167 | 1209 |

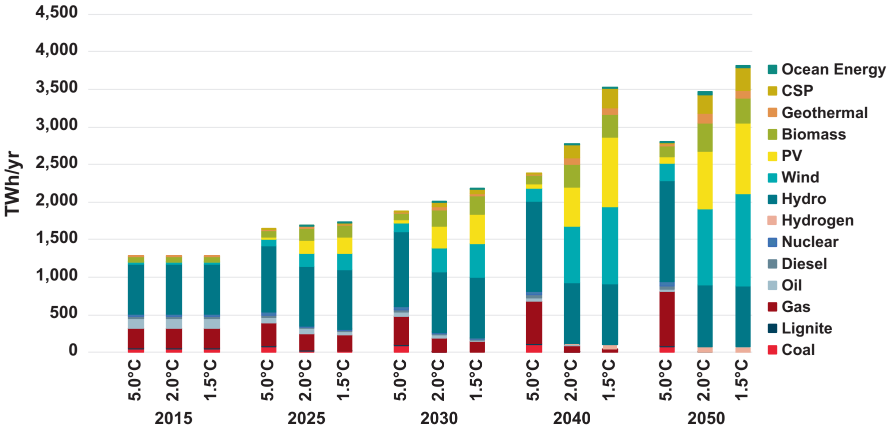


**Fig. 8.27** Latin America: development of electricity-generation structure in the scenarios

ocean energy, in the 2.0 °C Scenario. Both the 2.0 °C and 1.5 °C Scenarios will lead to a high proportion of variable power generation (PV, wind, and ocean) of 31% and 39%, respectively, by 2030, and 52% and 57%, respectively, by 2050.

#### 8.6.1.3 Latin America: Future Costs of Electricity Generation

Figure 8.28 shows the development of the electricity-generation and supply costs over time, including $CO_2$ emission costs, under all scenarios. The calculated electricity-generation costs in 2015 (referring to full costs) were around 4.5 ct/kWh. In the 5.0 °C case, the generation costs will increase until 2050, when they reach 8.3 ct/kWh. The generation costs in the 2.0 °C Scenario will increase until 2030, when they reach 7 ct/kWh, and will then drop to 5.9 ct/kWh by 2050. In the 1.5 °C Scenario, they will increase to 6.7 ct/kWh, and then drop to 5.6 ct/kWh by 2050. In the 2.0 °C Scenario, the generation costs in 2050 will be 2.4 ct/kWh lower than in the 5.0 °C case. In the 1.5 °C Scenario, the maximum difference in generation costs will be 2.6 ct/kWh in 2050. Note that these estimates of generation costs do not take into account integration costs such as power grid expansion, storage, or other load-balancing measures.

In the 5.0 °C case, the growth in demand and increasing fossil fuel prices will result in an increase in total electricity supply costs from today's $70 billion/year to more than $240 billion/year in 2050. In the 2.0 °C Scenario, the total supply costs will be $230 billion/year and in the 1.5 °C Scenario, they will be $240 billion/year in 2050. The long-term costs for electricity supply will be more than 5% lower in

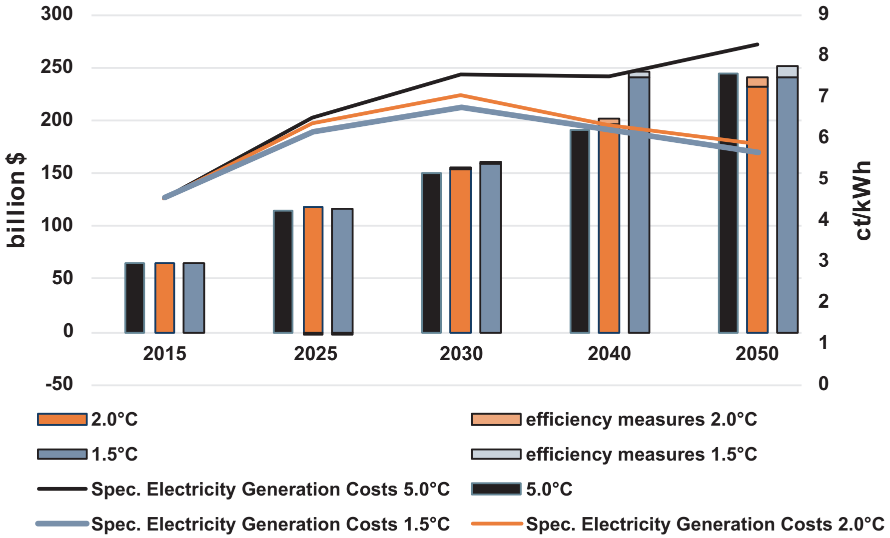


**Fig. 8.28** Latin America: development of total electricity supply costs and specific electricity-generation costs in the scenarios

the 2.0 °C Scenario than in the 5.0 °C Scenario as a result of the estimated generation costs and the electrification of heating and mobility. Further electrification and synthetic fuel generation in the 1.5 °C Scenario will result in total power generation costs that are similar to the 5.0 °C case.

Compared with these results, the generation costs when the $CO_2$ emission costs are not considered will increase in the 5.0 °C case to 7.1 ct/kWh. In the 2.0 °C Scenario, they will increase until 2030, when they will reach 6.6 ct/kWh, and then drop to 5.9 ct/kWh by 2050. In the 1.5 °C Scenario, they will increase to 6.5 ct/kWh and then drop to 5.6 ct/kWh by 2050. In the 2.0 °C Scenario, the generation costs will be maximum, at 0.25 ct/kWh higher than in the 5.0 °C case, in 2030 (0.1 ct/kWh in the 1.5 °C Scenario). The generation costs in 2050 will again be lower in the alternative scenarios than in the 5.0 °C case: 1.2 ct/kWh in the 2.0 °C Scenario and 1.5 ct/kWh in the 1.5 °C Scenario. If $CO_2$ costs are not considered, the total electricity supply costs in the 5.0 °C case will increase to about $210 billion/year in 2050.

#### 8.6.1.4 Latin America: Future Investments in the Power Sector

An investment of about $1920 billion will be required for power generation between 2015 and 2050 in the 2.0 °C Scenario, including additional power plants for the production of hydrogen and synthetic fuels and investments in plant replacement after the ends of their economic lives. This value is equivalent to approximately $53 billion per year, on average, which is $880 billion more than in the 5.0 °C case ($1040 billion). An investment of around $2190 billion for power generation will be required between 2015 and 2050 in the 1.5 °C Scenario. On average, this will be an investment of $61 billion per year. Under the 5.0 °C Scenario, the investment in conventional power plants will be around 25% of the total cumulative investments, whereas approximately 75% will be invested in renewable power generation and co-generation (Fig. 8.29).

However, under the 2.0 °C (1.5 °C) Scenario, Latin America will shift almost 94% (95%) of its entire investment to renewables and co-generation. By 2030, the fossil fuel share of the power sector investment will predominantly focus on gas power plants that can also be operated with hydrogen.

Because renewable energy has no fuel costs, other than biomass, the cumulative fuel cost savings in the 2.0 °C Scenario will reach a total of $820 billion in 2050, equivalent to $23 billion per year. Therefore, the total fuel cost savings will be equivalent to 90% of the total additional investments compared to the 5.0 °C Scenario. The fuel cost savings in the 1.5 °C Scenario will add up to $900 billion, or $25 billion per year.

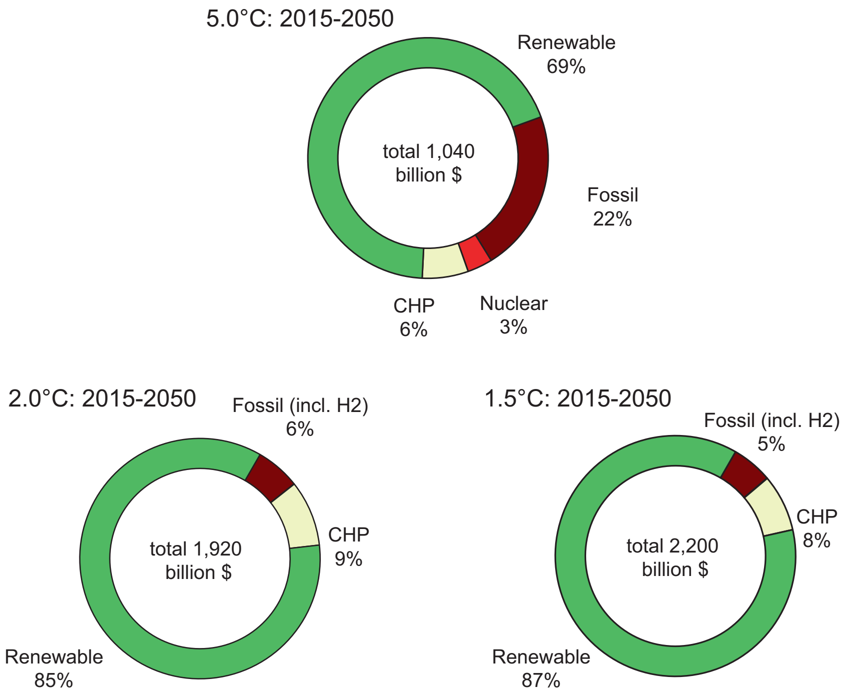


**Fig. 8.29** Latin America: investment shares for power generation in the scenarios

#### 8.6.1.5 Latin America: Energy Supply for Heating

The final energy demand for heating will increase in the 5.0 °C Scenario by 72%, from 7800 PJ/year in 2015 to 13,300 PJ/year in 2050. In the 2.0 °C and 1.5 °C Scenarios, energy efficiency measures will help to reduce the energy demand for heating by 32% in 2050, relative to that in the 5.0 °C Scenario. Today, renewables supply around 42% of Latin America's final energy demand for heating, with the main contribution from biomass. Renewable energy will provide 68% of Latin America's total heat demand in 2030 in the 2.0 °C Scenario and 75% in the 1.5 °C Scenario. In both scenarios, renewables will provide 100% of the total heat demand in 2050.

Figure 8.30 shows the development of different technologies for heating in Latin America over time, and Table 8.24 provides the resulting renewable heat supply for all scenarios. Biomass will remain the main contributor. The growing use of solar, geothermal, and environmental heat will supplement mainly fossil fuels. This will lead in the long term to a biomass share of 65% under the 2.0 °C Scenario and 50% under the 1.5 °C Scenario.

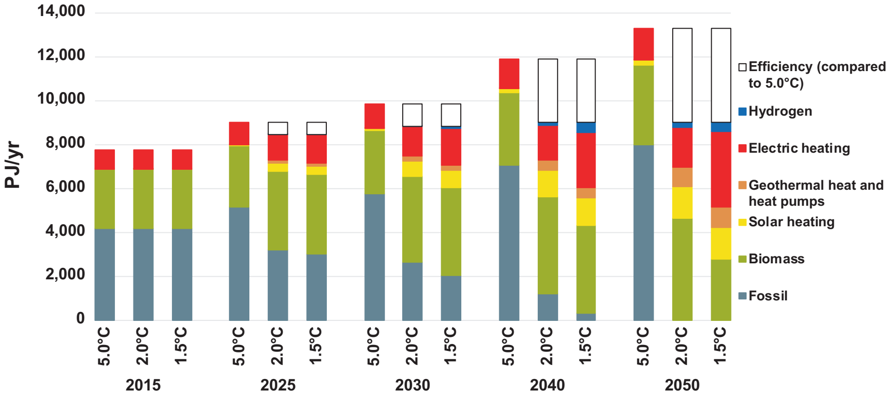


**Fig. 8.30** Latin America: development of heat supply by energy carrier in the scenarios

**Table 8.24** Latin America: development of renewable heat supply in the scenarios (excluding the direct use of electricity)

| in PJ/year | Case | 2015 | 2025 | 2030 | 2040 | 2050 |
|---|---|---|---|---|---|---|
| Biomass | 5.0 °C | 2684 | 2760 | 2888 | 3335 | 3622 |
| | 2.0 °C | 2684 | 3550 | 3895 | 4412 | 4654 |
| | 1.5 °C | 2684 | 3632 | 4007 | 4023 | 2767 |
| Solar heating | 5.0 °C | 32 | 64 | 88 | 146 | 227 |
| | 2.0 °C | 32 | 394 | 712 | 1217 | 1418 |
| | 1.5 °C | 32 | 394 | 783 | 1265 | 1445 |
| Geothermal heat and heat pumps | 5.0 °C | 0 | 0 | 0 | 0 | 0 |
| | 2.0 °C | 0 | 133 | 206 | 458 | 910 |
| | 1.5 °C | 0 | 133 | 204 | 452 | 930 |
| Hydrogen | 5.0 °C | 0 | 0 | 0 | 0 | 0 |
| | 2.0 °C | 0 | 0 | 4 | 169 | 220 |
| | 1.5 °C | 0 | 0 | 88 | 473 | 404 |
| Total | 5.0 °C | 2715 | 2824 | 2976 | 3480 | 3849 |
| | 2.0 °C | 2715 | 4077 | 4817 | 6255 | 7202 |
| | 1.5 °C | 2715 | 4159 | 5082 | 6213 | 5546 |

Heat from renewable hydrogen will further reduce the dependence on fossil fuels in both scenarios. Hydrogen consumption in 2050 will be around 200 PJ/year in the 2.0 °C Scenario and 400 PJ/year in the 1.5 °C Scenario. The direct use of electricity for heating will also increase by a factor of 2–4 between 2015 and 2050 and will attain a final energy share of 20% in 2050 in the 2.0 °C Scenario and 39% in the 1.5 °C Scenario.

#### 8.6.1.6 Latin America: Future Investments in the Heating Sector

The roughly estimated investments in renewable heating technologies up to 2050 will amount to around $580 billion in the 2.0 °C Scenario (including investments in plant replacement after their economic lifetimes), or approximately $16 billion per year. The largest share of investment in Latin America is assumed to be for solar collectors (more than $200 billion), followed by biomass technologies and heat pumps. The 1.5 °C Scenario assumes an even faster expansion of renewable technologies, but due to the lower heat demand, the average annual investment will again be around $16 billion per year (Fig. 8.31, Table 8.25).


**Fig. 8.31** Latin America: development of investments for renewable heat generation technologies in the scenarios

**Table 8.25** Latin America: installed capacities for renewable heat generation in the scenarios

| in GW | Case | 2015 | 2025 | 2030 | 2040 | 2050 |
|---|---|---|---|---|---|---|
| Biomass | 5.0 °C | 549 | 531 | 536 | 552 | 542 |
| | 2.0 °C | 549 | 730 | 742 | 657 | 603 |
| | 1.5 °C | 549 | 770 | 752 | 513 | 179 |
| Geothermal | 5.0 °C | 0 | 0 | 0 | 0 | 0 |
| | 2.0 °C | 0 | 2 | 4 | 12 | 16 |
| | 1.5 °C | 0 | 2 | 4 | 12 | 17 |
| Solar heating | 5.0 °C | 7 | 15 | 20 | 34 | 52 |
| | 2.0 °C | 7 | 91 | 164 | 281 | 327 |
| | 1.5 °C | 7 | 91 | 181 | 292 | 333 |
| Heat pumps | 5.0 °C | 0 | 0 | 0 | 0 | 0 |
| | 2.0 °C | 0 | 13 | 18 | 36 | 88 |
| | 1.5 °C | 0 | 13 | 18 | 36 | 89 |
| Total[a] | 5.0 °C | 556 | 546 | 556 | 585 | 594 |
| | 2.0 °C | 556 | 835 | 929 | 986 | 1034 |
| | 1.5 °C | 556 | 876 | 955 | 853 | 619 |

[a]Excluding direct electric heating

#### 8.6.1.7 Latin America: Transport

Energy demand in the transport sector in Latin America is expected to increase by 63% under the 5.0 °C Scenario, from around 7100 PJ/year in 2015 to 11,700 PJ/year in 2050. In the 2.0 °C Scenario, assumed technical, structural, and behavioural changes will save 69% (8090 PJ/year) by 2050 relative to the 5.0 °C Scenario. Additional modal shifts, technology switches, and a reduction in transport demand will lead to even greater energy savings in the 1.5 °C Scenario of 77% (or 9040 PJ/year) in 2050 compared with the 5.0 °C case (Table 8.26, Fig. 8.32).

By 2030, electricity will provide 6% (110 TWh/year) of the transport sector's total energy demand under the 2.0 °C Scenario, whereas in 2050, the share will be 47% (470 TWh/year). In 2050, up to 480 PJ/year of hydrogen will be used in the transport sector as a complementary renewable option. In the 1.5 °C Scenario, the annual electricity demand will be 390 TWh in 2050. The 1.5 °C Scenario also assumes a hydrogen demand of 430 PJ/year by 2050.

Biofuel use is limited in the 2.0 °C Scenario to a maximum of 1340 PJ/year Around 2030, synthetic fuels based on power-to-liquid will be introduced, with a maximum of 190 PJ/year by 2050. Due to the lower overall energy demand in transport, biofuel use will be reduced in the 1.5 °C Scenario to a maximum of 1030 PJ/year The maximum synthetic fuel demand will amount to 350 PJ/year.

#### 8.6.1.8 Latin America: Development of $CO_2$ Emissions

In the 5.0 °C Scenario, Latin America's annual $CO_2$ emissions will increase by 48%, from 1220 Mt. in 2015 to 1806 Mt. in 2050. The stringent mitigation measures in both alternative scenarios will cause the annual emissions to fall to 240 Mt. in

**Table 8.26** Latin America: projection of transport energy demand by mode in the scenarios

| in PJ/year | Case | 2015 | 2025 | 2030 | 2040 | 2050 |
|---|---|---|---|---|---|---|
| Rail | 5.0 °C | 90 | 110 | 122 | 145 | 163 |
| | 2.0 °C | 90 | 113 | 133 | 157 | 192 |
| | 1.5 °C | 90 | 130 | 145 | 163 | 224 |
| Road | 5.0 °C | 6662 | 7486 | 8102 | 9754 | 10,610 |
| | 2.0 °C | 6662 | 6424 | 5799 | 4107 | 3112 |
| | 1.5 °C | 6662 | 5196 | 3971 | 2744 | 2161 |
| Domestic aviation | 5.0 °C | 211 | 348 | 453 | 593 | 638 |
| | 2.0 °C | 211 | 228 | 213 | 175 | 139 |
| | 1.5 °C | 211 | 218 | 196 | 137 | 104 |
| Domestic navigation | 5.0 °C | 101 | 104 | 107 | 113 | 117 |
| | 2.0 °C | 101 | 104 | 107 | 113 | 117 |
| | 1.5 °C | 101 | 104 | 107 | 113 | 117 |
| Total | 5.0 °C | 7064 | 8047 | 8783 | 10,605 | 11,529 |
| | 2.0 °C | 7064 | 6868 | 6251 | 4551 | 3559 |
| | 1.5 °C | 7064 | 5648 | 4419 | 3157 | 2605 |

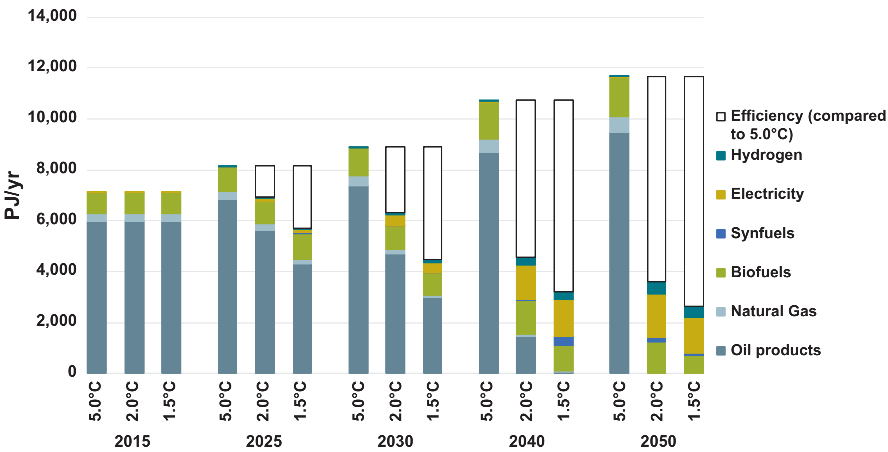


**Fig. 8.32** Latin America: final energy consumption by transport in the scenarios

2040 in the 2.0 °C Scenario and to 50 Mt. in the 1.5 °C Scenario, with further reductions to almost zero by 2050. In the 5.0 °C case, the cumulative $CO_2$ emissions from 2015 until 2050 will add up to 56 Gt. In contrast, in the 2.0 °C and 1.5 °C Scenarios, the cumulative emissions for the period from 2015 until 2050 will be 21 Gt and 17 Gt, respectively.

Therefore, the cumulative $CO_2$ emissions will decrease by 63% in the 2.0 °C Scenario and by 70% in the 1.5 °C Scenario compared with the 5.0 °C case. A rapid reduction in annual emissions will occur in both alternative scenarios. In the 2.0 °C Scenario, the reduction will be greatest in 'Power generation', followed by the 'Residential and other' and 'Industry' sectors (Fig. 8.33).

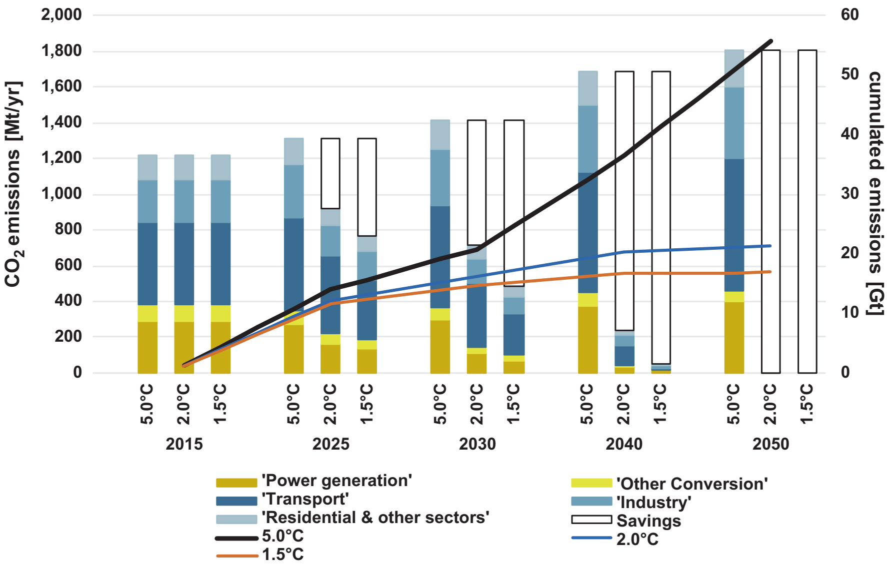


**Fig. 8.33** Latin America: development of $CO_2$ emissions by sector and cumulative $CO_2$ emissions (after 2015) in the scenarios ('Savings' = reduction compared with the 5.0 °C Scenario)

#### 8.6.1.9 Latin America: Primary Energy Consumption

The levels of primary energy consumption under the three scenarios when the assumptions discussed above are taken into account are shown in Fig. 8.34. In the 2.0 °C Scenario, the primary energy demand will decrease by 2%, from around 28,400 PJ/year in 2015 to 27,900 PJ/year in 2050. Compared with the 5.0 °C Scenario, the overall primary energy demand will decrease by 38% in 2050 in the 2.0 °C Scenario (5.0 °C: 45000 PJ in 2050). In the 1.5 °C Scenario, the primary energy demand will be even lower (25,700 PJ in 2050) because the final energy demand and conversion losses will be lower.

Both the 2.0 °C and 1.5 °C Scenarios aim to rapidly phase-out coal and oil. This will cause renewable energy to have a primary energy share of 55% in 2030 and 94% in 2050 in the 2.0 °C Scenario. In the 1.5 °C Scenario, renewables will also have a primary energy share of more than 94% in 2050 (including non-energy consumption, which will still include fossil fuels). Nuclear energy will be phased-out by 2035 under both the 2.0 °C and the 1.5 °C Scenarios. The cumulative primary energy consumption of natural gas in the 5.0 °C case will add up to 290 EJ, the cumulative coal consumption to about 60 EJ, and the crude oil consumption to 460 EJ. In contrast, in the 2.0 °C Scenario, the cumulative gas demand will amount to 130 EJ, the cumulative coal demand to 20 EJ, and the cumulative oil demand to 200

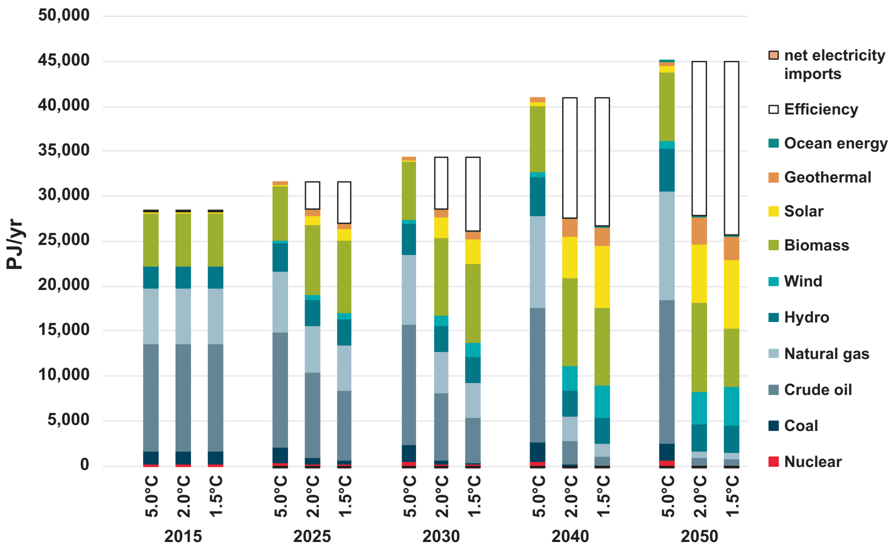


**Fig. 8.34** Latin America: projection of total primary energy demand (PED) by energy carrier in the scenarios (including electricity import balance)

EJ. Even lower fossil fuel use will be achieved in the 1.5 °C Scenario: 110 EJ for natural gas, 10 EJ for coal, and 150 EJ for oil.

### *8.6.2 Latin America: Power Sector Analysis*

The Latin American region is extremely diverse. It borders Mexico in the north and its southern tip is in the South Pacific. It also includes all the Caribbean islands and Central America. The power-generation situation is equally diverse, and the sub-regional breakdown tries to reflect this diversity to some extent. In the Caribbean, which contains 28 island nations and more than 7000 islands, the calculated storage demand will almost certainly be higher than the region's average, because a regional power exchange grid between the islands seems impractical. To calculate the detailed storage demand, island-specific analyses would be required, as has recently been done for Barbados (Hohmeyer 2015). The mainland of South America has been subdivided into the large economic centres of Chile, Argentina, and Brazil, and Central America and the northern part of South America have been clustered into two parts.

#### 8.6.2.1 Latin America: Development of Power Plant Capacities

The most important future renewable technologies for Latin America are solar PV and onshore wind, followed by CSP (which will be especially suited to the Atacama Desert in Chile) and offshore wind, mainly in the coastal areas of Brazil and Argentina. The annual market for solar PV must increase from 6.5 GW in 2020 by a factor of three to an average of 15.5 GW by 2030 under the 2.0 °C Scenario and to around 23 GW under the 1.5 °C Scenario. The onshore wind market in the 1.5 °C Scenario must increase to 15 GW by 2025, compared with the average annual onshore wind market of around 3 GW between 2014 and 2017 (GWEC 2018). By 2050, offshore wind will have increased to a moderate annual new installation capacity of around 2–3 GW from 2025 to 2050 in both scenarios. Concentrated solar power plants will be limited to the desert regions of South America, especially Chile. The market for biofuels for electricity generation will play an important role in all agricultural areas, including the Caribbean and Central America, where most geothermal resources are located (Table 8.27).

#### 8.6.2.2 Latin America: Utilization of Power-Generation Capacities

Table 8.28 shows that our modelling assumes that for the entire modelling period, there will be no interconnection capacity between the Caribbean, Central America, and South America, whereas the interconnection capacity in the rest of South America will increase to 15% by 2030 and to 20% by 2050. The shares of variable

**Table 8.27** Latin America: average annual change in installed power plant capacity

| Latin Power Generation: average annual change of installed capacity [GW/a] | 2015–2025 | | 2026–2035 | | 2036–2050 | |
|---|---|---|---|---|---|---|
| | 2.0 °C | 1.5 °C | 2.0 °C | 1.5 °C | 2.0 °C | 1.5 °C |
| Hard coal | 0 | −1 | 0 | −1 | −1 | 0 |
| Lignite | 0 | 0 | 0 | 0 | 0 | 0 |
| Gas | 4 | 2 | 1 | 6 | −9 | 5 |
| Hydrogen-gas | 0 | 1 | 1 | 4 | 11 | 14 |
| Oil/diesel | −1 | −4 | −4 | −3 | 0 | 0 |
| Nuclear | 0 | 0 | 0 | 0 | 0 | 0 |
| Biomass | 3 | 5 | 3 | 4 | 4 | 3 |
| Hydro | 2 | 0 | 0 | 0 | 0 | 0 |
| Wind (onshore) | 5 | 11 | 11 | 17 | 6 | 3 |
| Wind (offshore) | 0 | 1 | 2 | 2 | 3 | 2 |
| PV (roof top) | 9 | 18 | 14 | 25 | 9 | 8 |
| PV (utility scale) | 3 | 6 | 5 | 8 | 3 | 3 |
| Geothermal | 0 | 1 | 1 | 1 | 1 | 1 |
| Solar thermal power plants | 0 | 2 | 4 | 5 | 2 | 3 |
| Ocean energy | 0 | 0 | 1 | 1 | 2 | 2 |
| Renewable fuel based co-generation | 1 | 2 | 2 | 2 | 2 | 1 |

**Table 8.28** Latin America: power system shares by technology group

| Power generation structure and interconnection | | 2.0 °C | | | | 1.5 °C | | | |
|---|---|---|---|---|---|---|---|---|---|
| Latin America | | Variable RE | Dispatch RE | Dispatch fossil | Inter-connection | Variable RE | Dispatch RE | Dispatch fossil | Inter-connection |
| Caribbean | 2015 | 3% | 63% | 34% | 0% | | | | |
| | 2030 | 25% | 62% | 12% | 0% | 25% | 62% | 12% | 0% |
| | 2050 | 44% | 53% | 3% | 0% | 44% | 53% | 3% | 0% |
| Central America | 2015 | 2% | 64% | 35% | 0% | | | | |
| | 2030 | 21% | 64% | 14% | 0% | 21% | 64% | 14% | 0% |
| | 2050 | 40% | 58% | 2% | 0% | 40% | 58% | 2% | 0% |
| North L. America | 2015 | 2% | 64% | 34% | 10% | | | | |
| | 2030 | 20% | 41% | 39% | 15% | 20% | 41% | 39% | 15% |
| | 2050 | 30% | 40% | 30% | 20% | 30% | 40% | 30% | 20% |
| Central L. America | 2015 | 1% | 64% | 36% | 10% | | | | |
| | 2030 | 16% | 52% | 32% | 15% | 16% | 52% | 32% | 15% |
| | 2050 | 29% | 49% | 22% | 20% | 29% | 49% | 22% | 20% |
| Brazil | 2015 | 4% | 63% | 33% | 10% | | | | |
| | 2030 | 30% | 54% | 16% | 15% | 30% | 54% | 16% | 15% |
| | 2050 | 47% | 44% | 8% | 20% | 47% | 44% | 8% | 20% |
| Uruguay | 2015 | 2% | 61% | 37% | 10% | | | | |
| | 2030 | 21% | 57% | 22% | 15% | 21% | 57% | 22% | 15% |
| | 2050 | 37% | 52% | 11% | 20% | 37% | 52% | 11% | 20% |
| Argentina | 2015 | 2% | 62% | 36% | 10% | | | | |
| | 2030 | 19% | 42% | 38% | 15% | 19% | 42% | 38% | 15% |
| | 2050 | 31% | 40% | 29% | 20% | 31% | 40% | 29% | 20% |

(continued)

**Table 8.28** (continued)

| Power generation structure and interconnection | | 2.0 °C | | | | 1.5 °C | | | |
|---|---|---|---|---|---|---|---|---|---|
| Latin America | | Variable RE | Dispatch RE | Dispatch fossil | Inter-connection | Variable RE | Dispatch RE | Dispatch fossil | Inter-connection |
| Chile | 2015 | 2% | 64% | 35% | 10% | | | | |
| | 2030 | 18% | 45% | 37% | 15% | 18% | 45% | 37% | 15% |
| | 2050 | 33% | 47% | 19% | 20% | 33% | 47% | 19% | 20% |
| Latin America | 2015 | 3% | 63% | 34% | | | | | |
| | 2030 | 24% | 51% | 25% | | 24% | 51% | 25% | |
| | 2050 | 39% | 45% | 16% | | 39% | 45% | 16% | |

**Table 8.29** Latin America: capacity factors by generation type

| Utilization of variable and dispatchable power generation: | | 2015 | 2020 | 2020 | 2030 | 2030 | 2040 | 2040 | 2050 | 2050 |
|---|---|---|---|---|---|---|---|---|---|---|
| Latin America | | | 2.0 °C | 1.5 °C | 2.0 °C | 1.5 °C | 2.0 °C | 1.5 °C | 2.0 °C | 1.5 °C |
| Capacity factor – average | [%/yr] | 48.9% | 31% | 25% | 36% | 21% | 41% | 18% | 34% | 24% |
| Limited dispatchable: fossil and nuclear | [%/yr] | 73.4% | 14% | 3% | 17% | 0% | 45% | 0% | 13% | 4% |
| Limited dispatchable: renewable | [%/yr] | 26.0% | 53% | 48% | 46% | 19% | 56% | 23% | 47% | 33% |
| Dispatchable: fossil | [%/yr] | 53.2% | 24% | 11% | 31% | 2% | 37% | 6% | 31% | 11% |
| Dispatchable: renewable | [%/yr] | 45.6% | 37% | 28% | 46% | 26% | 43% | 25% | 46% | 35% |
| Variable: renewable | [%/yr] | 12.2% | 12% | 12% | 21% | 14% | 31% | 15% | 22% | 15% |

renewables are almost identical in the 2.0 °C and 1.5 °C Scenarios. The lowest rates of variable renewables are in central South America and Central America because the onshore wind potential is limited by average wind speeds that are lower than elsewhere. Compared with all the other world regions, Latin America has the highest share of dispatchable renewables, mainly attributable to existing hydropower plants.

Compared with other regions of the world, Latin America currently has a small fleet of coal and nuclear power plants, but they are operated with a high capacity factor (Table 8.29). The dispatch order for all world regions in all cases is assumed to be the same, to make the results comparable. Therefore, the capacity factors of these dispatch power plants (mainly gas) will increase at the expense of those for coal and nuclear power plants, which explains the rapid reduction in the capacity factor in 2020. Therefore, this effect is the result of the assumed dispatch order, rather than of an increase in variable power generation.

#### 8.6.2.3 Latin America: Development of Load, Generation and Residual Load

The sub-regions of Latin America are highly diverse in their geographic features and population densities, so the maximum loads in the different sub-regions vary widely. Table 8.30 shows that the sub-region with the smallest calculated maximum load is Uruguay, with only 2.3 GW, which seems realistic because the maximum

**Table 8.30** Latin America: load, generation, and residual load development

| Power generation structure | | 2.0 °C | | | | 1.5 °C | | | |
|---|---|---|---|---|---|---|---|---|---|
| | | Max demand | Max generation | Max residual load | Max interconnection requirements | Max demand | Max generation | Max residual load | Max interconnection requirements |
| Latin America | | [GW] | [GW] | [GW] | [GW] | [GW] | [GW] | [GW] | [GW] |
| Caribbean | 2020 | 14.9 | 4.9 | 10.4 | | 14.8 | 7.4 | 8.1 | |
| | 2030 | 23.4 | 23.1 | 8.9 | 0 | 21.0 | 27.5 | 1.5 | 5 |
| | 2050 | 36.6 | 38.6 | 14.8 | 0 | 36.9 | 48.4 | 6.9 | 5 |
| Central America | 2020 | 13.1 | 13.0 | 3.3 | | 13.1 | 20.0 | 0.5 | |
| | 2030 | 20.7 | 23.6 | 7.8 | 0 | 18.8 | 31.8 | 1.4 | 12 |
| | 2050 | 33.3 | 42.6 | 14.3 | 0 | 33.2 | 47.3 | 7.2 | 7 |
| North Latin America | 2020 | 37.5 | 41.5 | 1.4 | | 37.4 | 67.9 | 1.4 | |
| | 2030 | 59.1 | 76.7 | 7.1 | 11 | 53.1 | 80.9 | 5.0 | 23 |
| | 2050 | 92.9 | 117.2 | 15.8 | 9 | 94.7 | 108.3 | 24.9 | 0 |
| Central South America | 2020 | 16.8 | 9.9 | 6.9 | | 16.8 | 14.7 | 2.1 | |
| | 2030 | 26.2 | 29.4 | 5.7 | 0 | 24.1 | 39.9 | 2.3 | 14 |
| | 2050 | 42.0 | 46.3 | 11.3 | 0 | 42.9 | 59.5 | 11.5 | 5 |
| Brazil | 2020 | 99.0 | 96.4 | 5.7 | | 98.9 | 102.3 | 4.7 | |
| | 2030 | 153.8 | 150.1 | 38.4 | 0 | 140.7 | 145.2 | 9.9 | 0 |
| | 2050 | 241.0 | 247.5 | 74.1 | 0 | 250.7 | 306.1 | 45.5 | 10 |

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| Uruguay | 2020 | 2.3 | 2.9 | 0.4 | | 2.3 | 4.4 | 0.1 | |
| | 2030 | 3.4 | 4.0 | 1.1 | 0 | 3.1 | 5.3 | 0.2 | 2 |
| | 2050 | 4.9 | 6.6 | 1.7 | 0 | 5.1 | 7.8 | 1.0 | 2 |
| Argentina | 2020 | 25.5 | 26.2 | 1.0 | | 25.5 | 35.7 | 1.0 | |
| | 2030 | 40.1 | 176.4 | 3.1 | 133 | 36.6 | 176.4 | 3.6 | 136 |
| | 2050 | 56.4 | 71.8 | 14.0 | 2 | 59.4 | 82.7 | 18.2 | 5 |
| Chile | 2020 | 9.3 | 19.2 | 0.4 | | | | | |
| | 2030 | 16.5 | 21.0 | 1.7 | 3 | 15.0 | 23.5 | 1.4 | 7 |
| | 2050 | 26.1 | 30.7 | 7.7 | 0 | 27.7 | 35.5 | 7.2 | 1 |

load was 1.7 GW in 2012 according to IDB (2013). Brazil, Uruguay's direct neighbour, has the largest load of close to 100 GW, which will increase by a factor of 2.5 to around 250 GW by 2050 under both scenarios. Brazil's maximum generation will increase accordingly, without significant overproduction peaks. The calculated maximum increase in interconnection required is only 10 GW. In Argentina, peak generation matches peak demand because Argentina has one of the best wind resources in the world in Patagonia. Surplus wind power can either be exported after a significant increase in transmission capacity or, as assumed in our scenario, it can be used to produce synthetic and hydrogen fuels.

Table 8.31 provides an overview of the calculated storage and dispatch power requirements by sub-region. As indicated in the introduction to the Latin America results, the storage requirements for the Caribbean might be high because the region cannot exchange solar or wind electricity with other sub-regions. However, all other sub-regions contain either several countries or larger provinces, so they are more suited to the integration of variable electricity. Compared with other world regions, Latin America has one of the lowest storage capacities and one of the lowest needs for additional dispatch. This is because the region's installed capacity of hydropower is high. However, this research does not include a water resource assessment for hydropower plants. Droughts may increase the demand for storage and/or hydrogen dispatch.

## 8.7 OECD Europe

### *8.7.1 OECD Europe: Long-Term Energy Pathways*

#### 8.7.1.1 OECD Europe: Final Energy Demand by Sector

Combining the assumptions on population growth, GDP growth, and energy intensity produces the future development pathways for OECD Europe's final energy demand shown in Fig. 8.35 for the 5.0 °C, 2.0 °C, and 1.5 °C Scenarios. In the 5.0 °C Scenario, the total final energy demand will increase by 9%, from the current 46,000 PJ/year to 50,000 PJ/year in 2050. In the 2.0 °C Scenario, the final energy demand will decrease by 39% compared with current consumption and will reach 28,000 PJ/year by 2050. The final energy demand in the 1.5 °C Scenario will reach 25,200 PJ, 45% below the 2015 demand. In the 1.5 °C Scenario, the final energy demand in 2050 will be 10% lower than in the 2.0 °C Scenario. The electricity demand for 'classical' electrical devices (without power-to-heat or e-mobility) will decrease from 2300 TWh/year in 2015 to 2040 TWh/year by 2050 in both alternative scenarios. Compared with the 5.0 °C case (3200 TWh/year in 2050), the efficiency measures implemented in the 2.0 °C and 1.5 °C Scenarios will save 1160 TWh/year in 2050.

**Table 8.31** Latin America: storage and dispatch service requirements in the 2.0 °C and 1.5 °C Scenarios

| Storage and dispatch | | 2.0 °C | | | | | 1.5 °C | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | Required to avoid curtailment | Utilization battery -through-put- | Utilization PSH -through-put- | Total storage demand (incl. H2) | Dispatch hydrogen-based | Required to avoid curtailment | Utilization battery -through-put- | Utilization PSH -through-put- | Total storage demand (incl. H2) | Dispatch hydrogen-based |
| Latin America | | [GWh/year] | [GWh/year] | [GWh/year] | [GWh/year] | [GWh/year] | [GWh/year] | [GWh/year] | [GWh/year] | [GWh/year] | [GWh/year] |
| Caribbean | 2020 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | 2030 | 0 | 0 | 0 | 0 | 6 | 81 | 6 | 11 | 17 | 0 |
| | 2050 | 100 | 46 | 3 | 49 | 15,282 | 1816 | 534 | 59 | 594 | 1808 |
| Central America | 2020 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | 2030 | 0 | 0 | 0 | 0 | 5 | 57 | 5 | 8 | 13 | 0 |
| | 2050 | 34 | 47 | 2 | 49 | 15,010 | 1462 | 560 | 59 | 619 | 5843 |
| North Latin America | 2020 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | 2030 | 0 | 0 | 0 | 0 | 0 | 3 | 1 | 1 | 1 | 0 |
| | 2050 | 0 | 0 | 0 | 0 | 7086 | 1047 | 633 | 57 | 690 | 0 |
| Central L. America | 2020 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | 2030 | 0 | 0 | 0 | 0 | 3 | 82 | 9 | 14 | 23 | 0 |
| | 2050 | 36 | 41 | 1 | 42 | 16,031 | 2768 | 1032 | 104 | 1136 | 40 |
| Brazil | 2020 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | 2030 | 0 | 0 | 0 | 0 | 19 | 774 | 83 | 138 | 221 | 0 |
| | 2050 | 475 | 666 | 27 | 693 | 63,131 | 18,024 | 6977 | 769 | 7746 | 1103 |
| Uruguay | 2020 | 77 | 0 | 0 | 0 | 0 | 511 | 0 | 0 | 0 | 0 |
| | 2030 | 0 | 0 | 0 | 0 | 0 | 20 | 1 | 2 | 3 | 0 |
| | 2050 | 42 | 20 | 2 | 22 | 1591 | 279 | 78 | 9 | 86 | 65 |

(continued)

**Table 8.31** (continued)

| Storage and dispatch | | 2.0 °C | | | | | 1.5 °C | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | Required to avoid curtailment | Utilization battery -through-put- | Utilization PSH -through-put- | Total storage demand (incl. H2) | Dispatch hydrogen-based | Required to avoid curtailment | Utilization battery -through-put- | Utilization PSH -through-put- | Total storage demand (incl. H2) | Dispatch hydrogen-based |
| Latin America | | [GWh/year] | [GWh/year] | [GWh/year] | [GWh/year] | [GWh/year] | [GWh/year] | [GWh/year] | [GWh/year] | [GWh/year] | [GWh/year] |
| Argentina | 2020 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | 2030 | 0 | 0 | 0 | 0 | 0 | 177 | 14 | 23 | 37 | 0 |
| | 2050 | 617 | 446 | 32 | 478 | 315 | 4969 | 1727 | 180 | 1908 | 0 |
| Chile | 2020 | 2 | 0 | 0 | 0 | 0 | 2669 | 1 | 0 | 1 | 0 |
| | 2030 | 0 | 0 | 0 | 0 | 1 | 13 | 1 | 2 | 3 | 0 |
| | 2050 | 10 | 14 | 1 | 15 | 8781 | 162 | 91 | 7 | 97 | 58 |
| Latin America | 2020 | 79 | 0 | 0 | 0 | 0 | 3180 | 2 | 0 | 2 | 0 |
| | 2030 | 0 | 0 | 0 | 0 | 34 | 1207 | 121 | 197 | 318 | 1 |
| | 2050 | 1314 | 1279 | 68 | 1347 | 127,226 | 30,526 | 11,633 | 1243 | 12,875 | 8917 |

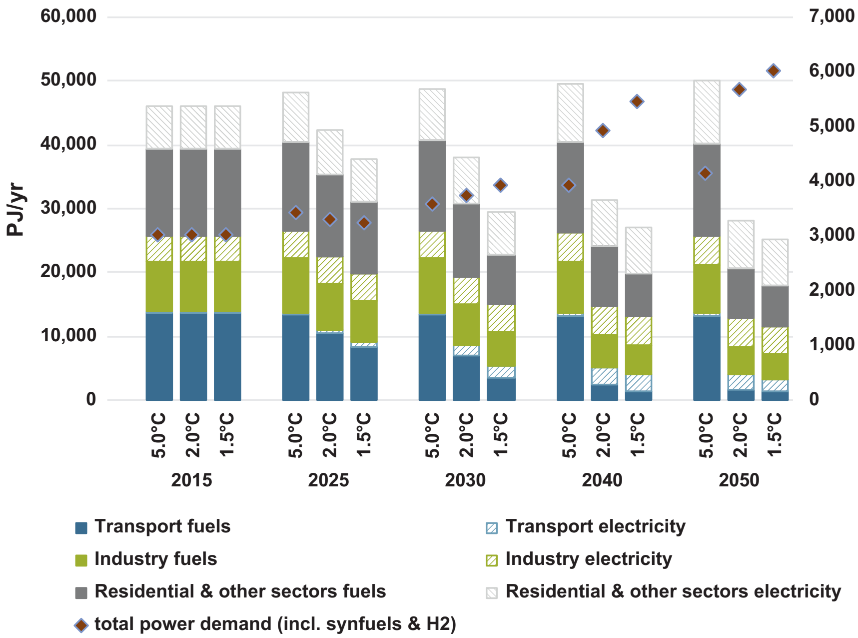


**Fig. 8.35** OECD Europe: development in three scenarios

Electrification will cause a significant increase in the electricity demand by 2050. In the 2.0 °C Scenario, the electricity demand for heating will increase to approximately 1300 TWh/year due to electric heaters and heat pumps, and in the transport sector, the demand will increase to approximately 2600 TWh/year in response to increased electric mobility. The generation of hydrogen (for transport and high-temperature process heat) and the manufacture of synthetic fuels (mainly for transport) will add an additional power demand of 1600 TWh/year The gross power demand will thus rise from 3600 TWh/year in 2015 to 6000 TWh/year by 2050 in the 2.0 °C Scenario, 28% higher than in the 5.0 °C case. In the 1.5 °C Scenario, the gross electricity demand will increase to a maximum of 6400 TWh/year by 2050.

Efficiency gains could be even larger in the heating sector than in the electricity sector. Under the 2.0 °C and 1.5 °C Scenarios, a final energy consumption equivalent to about 6200 PJ/year and 8200 PJ/year, respectively, are avoided by efficiency gains by 2050 compared with the 5.0 °C Scenario.

#### 8.7.1.2 OECD Europe: Electricity Generation

The development of the power system is characterized by a dynamically growing renewable energy market and an increasing proportion of total power from renewable sources. By 2050, 100% of the electricity produced in OECD Europe will come from renewable energy sources in the 2.0 °C Scenario. 'New' renewables—mainly wind, solar, and geothermal energy—will contribute 75% of the total electricity generation. Renewable electricity's share of the total production will be 68% by 2030 and 89% by 2040. The installed capacity of renewables will reach about 1200 GW by 2030 and 2270 GW by 2050. The share of renewable electricity generation in 2030 in the 1.5 °C Scenario is assumed to be 74%. The 1.5 °C Scenario will have a generation capacity from renewable energy of approximately 2480 GW in 2050.

Table 8.32 shows the development of different renewable technologies in OECD Europe over time. Figure 8.36 provides an overview of the overall power-generation structure in OECD Europe. From 2020 onwards, the continuing growth of wind and PV, up to 790 GW and 1000 GW, respectively, will be complemented by generation from biomass (ca. 110 GW) CSP and ocean energy (more than 50 GW each), in the 2.0 °C Scenario. Both the 2.0 °C and 1.5 °C Scenarios will lead to high proportions of variable power generation (PV, wind, and ocean) of 38% and 45%, respectively, by 2030 and 67% and 68%, respectively, by 2050.

**Table 8.32** OECD Europe: development of renewable electricity-generation capacity in the scenarios

| in GW | Case | 2015 | 2025 | 2030 | 2040 | 2050 |
|---|---|---|---|---|---|---|
| Hydro | 5.0 °C | 207 | 224 | 231 | 238 | 248 |
| | 2.0 °C | 207 | 218 | 219 | 221 | 225 |
| | 1.5 °C | 207 | 218 | 219 | 221 | 225 |
| Biomass | 5.0 °C | 40 | 51 | 56 | 60 | 65 |
| | 2.0 °C | 40 | 78 | 105 | 115 | 113 |
| | 1.5 °C | 40 | 84 | 111 | 113 | 113 |
| Wind | 5.0 °C | 138 | 216 | 254 | 296 | 347 |
| | 2.0 °C | 138 | 279 | 409 | 655 | 787 |
| | 1.5 °C | 138 | 299 | 468 | 778 | 847 |
| Geothermal | 5.0 °C | 2 | 3 | 3 | 3 | 4 |
| | 2.0 °C | 2 | 6 | 11 | 27 | 39 |
| | 1.5 °C | 2 | 6 | 11 | 27 | 39 |
| PV | 5.0 °C | 95 | 137 | 157 | 172 | 191 |
| | 2.0 °C | 95 | 264 | 422 | 745 | 996 |
| | 1.5 °C | 95 | 364 | 598 | 1028 | 1151 |
| CSP | 5.0 °C | 2 | 3 | 4 | 7 | 11 |
| | 2.0 °C | 2 | 7 | 17 | 38 | 54 |
| | 1.5 °C | 2 | 7 | 22 | 48 | 57 |
| Ocean | 5.0 °C | 0 | 1 | 1 | 4 | 8 |
| | 2.0 °C | 0 | 7 | 16 | 42 | 53 |
| | 1.5 °C | 0 | 7 | 16 | 42 | 53 |
| Total | 5.0 °C | 484 | 635 | 706 | 780 | 873 |
| | 2.0 °C | 484 | 859 | 1198 | 1842 | 2267 |
| | 1.5 °C | 484 | 985 | 1444 | 2256 | 2485 |

### 8.7.1.3 OECD Europe: Future Costs of Electricity Generation

Figure 8.37 shows the development of the electricity-generation and supply costs over time, including the $CO_2$ emission costs, in all scenarios. The calculated electricity generation costs in 2015 (referring to full costs) were around 7 ct/kWh. In the 5.0 °C case, generation costs will increase until 2050, when they will reach 10.4 ct/

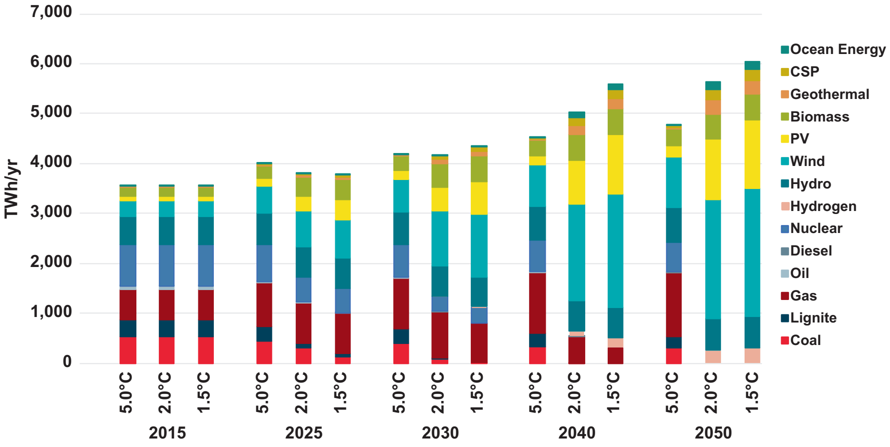


**Fig. 8.36** OECD Europe: development of electricity-generation structure in the scenarios

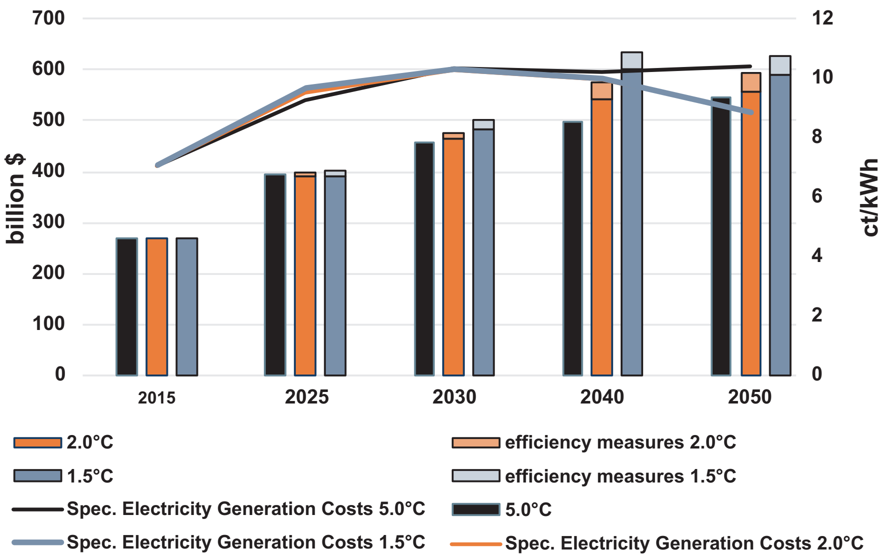


**Fig. 8.37** OECD Europe: development of total electricity supply costs and specific electricity-generation costs in the scenarios

kWh. The generation costs in both alternative scenarios will increase until 2030, when they will reach 10.3 ct/kWh, and they will drop by 2050 to 8.9 ct/kWh and 8.8 ct/kWh, respectively, 1.5–1.6 ct/kWh lower than in the 5.0 °C case. Note that these estimates of generation costs do not take into account integration costs such as power grid expansion, storage, or other load-balancing measures.

In the 5.0 °C case, the growth in demand and increasing fossil fuel prices will result in an increase in total electricity supply costs from today's $270 billion/year to more than $550 billion/year in 2050. In the 2.0 °C Scenario, the total supply costs will be $560 billion/year and in the 1.5 °C Scenario, they will be $590 billion/year The long-term costs for electricity supply will be more than 2% higher in the 2.0 °C Scenario than in the 5.0 °C Scenario as a result of the estimated generation costs and the electrification of heating and mobility. Further electrification and synthetic fuel generation in the 1.5 °C Scenario will result in total power generation costs that are 8% higher than in the 5.0 °C case.

Compared with these results, the generation costs when the $CO_2$ emission costs are not considered will increase in the 5.0 °C Scenario to 8.8 ct/kWh by 2050. In the 2.0 °C Scenario, they will increase until 2030 when they reach 9.5 ct/kWh, and then drop to 8.9 ct/kWh by 2050. In the 1.5 °C Scenario, they will increase to 9.7 ct/kWh, and then drop to 8.8 ct/kWh by 2050. In the 2.0 °C Scenario, the generation costs will reach a maximum of 1 ct/kWh higher than in the 5.0 °C case in 2030. In the 1.5 °C Scenario, the maximum difference in generation costs compared with the 5.0 °C Scenario will be 1.2 ct/kWh, which will occur in 2040. If the $CO_2$ costs are not considered, the total electricity supply costs in the 5.0 °C case will rise to about $470 billion/year in 2050.

#### 8.7.1.4 OECD Europe: Future Investments in the Power Sector

An investment of around $4900 billion will be required for power generation between 2015 and 2050 in the 2.0 °C Scenario—including additional power plants for the production of hydrogen and synthetic fuels and investments to replace plants at the ends of their economic lives. This value is equivalent to approximately $136 billion per year on average, which is $2150 billion more than in the 5.0 °C case ($2750 billion). An investment of around $5340 billion for power generation will be required between 2015 and 2050 under the 1.5 °C Scenario. On average, this will be an investment of $148 billion per year. In the 5.0 °C Scenario, investment in conventional power plants will be around 26% of the total cumulative investments, whereas approximately 74% will be invested in renewable power generation and co-generation (Fig. 8.38).

However, in the 2.0 °C (1.5 °C) Scenario, OECD Europe will shift almost 96% (97%) of its entire investments to renewables and co-generation. By 2030, the fossil fuel share of the power sector investments will predominantly focus on gas power plants that can also be operated with hydrogen.

Because renewable energy has no fuel costs, other than biomass, the cumulative fuel cost savings in the 2.0 °C Scenario will reach a total of $2340 billion in 2050,

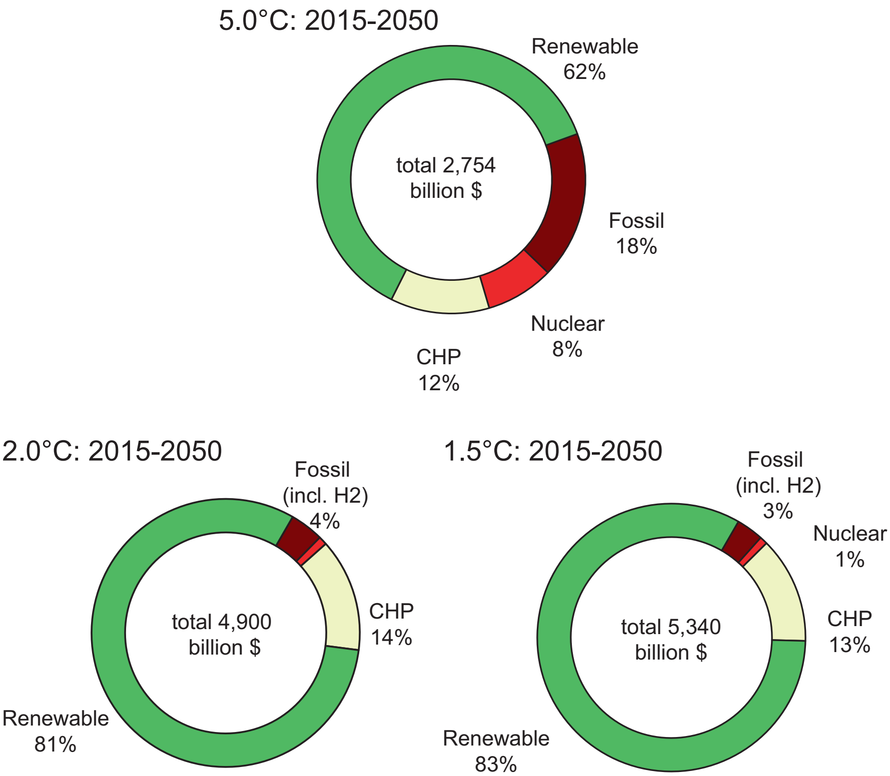


**Fig. 8.38** OECD Europe: investment shares for power generation in the scenarios

equivalent to $65 billion per year. Therefore, the total fuel cost savings will be equivalent to 110% of the total additional investments compared to the 5.0 °C Scenario. The fuel cost savings in the 1.5 °C Scenario will add up to $2600 billion, or $72 billion per year.

### 8.7.1.5 OECD Europe: Energy Supply for Heating

The final energy demand for heating will increase in the 5.0 °C Scenario by 16%, from 20,600 PJ/year in 2015 to 24,000 PJ/year in 2050. Energy efficiency measures will help to reduce the energy demand for heating by 26% in 2050 in the 2.0 °C Scenario relative to that in the 5.0 °C case, and by 34% in the 1.5 °C Scenario. Today, renewables supply around 19% of OECD Europe's final energy demand for heating, with the main contribution from biomass. Renewable energy will provide 44% of OECD Europe's total heat demand in 2030 under the 2.0 °C Scenario and 53% under the 1.5 °C Scenario. In both scenarios, renewables will provide 100% of the total heat demand in 2050.

Figure 8.39 shows the development of different technologies for heating in OECD Europe over time, and Table 8.33 provides the resulting renewable heat supply for all scenarios. Up to 2030, biomass will remain the main contributor. The growing use of solar, geothermal, and environmental heat will lead in the long term to a biomass share of 27% in the 2.0 °C Scenario and 28% in the 1.5 °C Scenario.

Heat from renewable hydrogen will further reduce the dependence on fossil fuels in both scenarios. Hydrogen consumption in 2050 will be around 1900 PJ/year in the 2.0 °C Scenario and 2200 PJ/year in the 1.5 °C Scenario. The direct use of electricity for heating will also increase by a factor of 1.5–1.6 between 2015 and 2050, and will have a final energy share of 22% in 2050 in the 2.0 °C Scenario and 23% in the 1.5 °C Scenario.

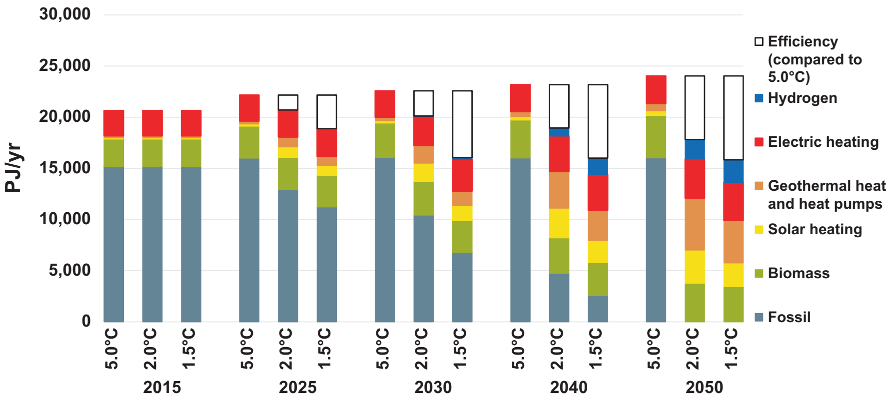


**Fig. 8.39** OECD Europe: development of heat supply by energy carrier in the scenarios

**Table 8.33** OECD Europe: development of renewable heat supply in the scenarios (excluding the direct use of electricity)

| in PJ/year | Case | 2015 | 2025 | 2030 | 2040 | 2050 |
|---|---|---|---|---|---|---|
| Biomass | 5.0 °C | 2681 | 3115 | 3343 | 3713 | 4153 |
| | 2.0 °C | 2681 | 3109 | 3295 | 3483 | 3772 |
| | 1.5 °C | 2681 | 3046 | 3096 | 3220 | 3433 |
| Solar heating | 5.0 °C | 119 | 216 | 251 | 345 | 454 |
| | 2.0 °C | 119 | 1043 | 1788 | 2904 | 3243 |
| | 1.5 °C | 119 | 1013 | 1464 | 2182 | 2327 |
| Geothermal heat and heat pumps | 5.0 °C | 203 | 291 | 336 | 479 | 717 |
| | 2.0 °C | 203 | 968 | 1731 | 3572 | 5080 |
| | 1.5 °C | 203 | 878 | 1430 | 2933 | 4147 |
| Hydrogen | 5.0 °C | 0 | 0 | 0 | 0 | 0 |
| | 2.0 °C | 0 | 0 | 1 | 788 | 1895 |
| | 1.5 °C | 0 | 0 | 162 | 1595 | 2227 |
| Total | 5.0 °C | 3003 | 3623 | 3931 | 4537 | 5325 |
| | 2.0 °C | 3003 | 5121 | 6815 | 10,748 | 13,989 |
| | 1.5 °C | 3003 | 4937 | 6152 | 9930 | 12,134 |

### 8.7.1.6 OECD Europe: Future Investments in the Heating Sector

The roughly estimated investments in renewable heating technologies up to 2050 will amount to around $2410 billion in the 2.0 °C Scenario (including investments for plant replacement at the ends of their economic lifetimes), or approximately $67 billion per year. The largest share of investments in OECD Europe is assumed to be for heat pumps (around $1200 billion), followed by solar collectors ($1080 billion). The 1.5 °C Scenario assumes an even faster expansion of renewable technologies. However, the lower heat demand (compared with the 2.0 °C Scenario) will results in a lower average annual investment of around $51 billion per year (Fig. 8.40, Table 8.34).

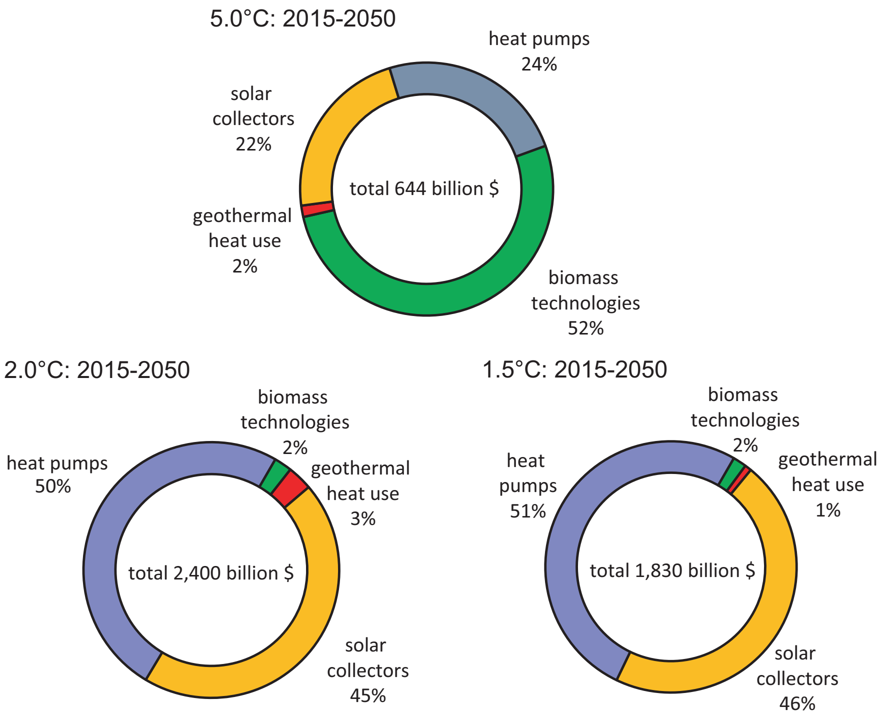


**Fig. 8.40** OECD Europe: development of investments for renewable heat-generation technologies in the scenarios

**Table 8.34** OECD Europe: installed capacities for renewable heat generation in the scenarios

| in GW | Case | 2015 | 2025 | 2030 | 2040 | 2050 |
|---|---|---|---|---|---|---|
| Biomass | 5.0 °C | 434 | 467 | 486 | 507 | 519 |
| | 2.0 °C | 434 | 407 | 339 | 293 | 289 |
| | 1.5 °C | 434 | 381 | 276 | 256 | 242 |
| Geothermal | 5.0 °C | 5 | 7 | 7 | 7 | 3 |
| | 2.0 °C | 5 | 15 | 24 | 49 | 48 |
| | 1.5 °C | 5 | 14 | 16 | 21 | 11 |
| Solar heating | 5.0 °C | 36 | 65 | 76 | 104 | 137 |
| | 2.0 °C | 36 | 298 | 510 | 790 | 885 |
| | 1.5 °C | 36 | 291 | 423 | 624 | 685 |
| Heat pumps | 5.0 °C | 29 | 40 | 46 | 62 | 84 |
| | 2.0 °C | 29 | 134 | 228 | 417 | 566 |
| | 1.5 °C | 29 | 121 | 183 | 336 | 444 |
| Total[a] | 5.0 °C | 504 | 579 | 615 | 681 | 744 |
| | 2.0 °C | 504 | 855 | 1101 | 1548 | 1789 |
| | 1.5 °C | 504 | 807 | 897 | 1237 | 1383 |

[a]Excluding direct electric heating

#### 8.7.1.7 OECD Europe: Transport

Energy demand in the transport sector in OECD Europe is expected to decrease by 3% in the 5.0 °C Scenario, from around 14,000 PJ/year in 2015 to 13,600 PJ/year in 2050. In the 2.0 °C Scenario, assumed technical, structural, and behavioural changes will save 69% (9460 PJ/year) by 2050 compared with the 5.0 °C Scenario. Additional modal shifts, technology switches, and a reduction in the transport demand will lead to even higher energy savings in the 1.5 °C Scenario of 76% (or 10,300 PJ/year) in 2050 compared with the 5.0 °C case (Table 8.35, Fig. 8.41).

By 2030, electricity will provide 18% (430 TWh/year) of the transport sector's total energy demand in the 2.0 °C Scenario, whereas in 2050, the share will be 64% (740 TWh/year). In 2050, up to 840 PJ/year of hydrogen will be used in the transport sector as a complementary renewable option. In the 1.5 °C Scenario, the annual electricity demand will be 580 TWh in 2050. The 1.5 °C Scenario also assumes a hydrogen demand of 730 PJ/year by 2050.

Biofuel use is limited in the 2.0 °C Scenario to a maximum of 600 PJ/year Therefore, around 2030, synthetic fuels based on power-to-liquid will be introduced, with a maximum amount of 130 PJ/year in 2050. Biofuel use will be reduced in the 1.5 °C Scenario to a maximum of 590 PJ/year. The maximum synthetic fuel demand will reach 170 PJ/year.

#### 8.7.1.8 OECD Europe: Development of $CO_2$ Emissions

In the 5.0 °C Scenario, OECD Europe's annual $CO_2$ emissions will decrease by 15% from 3400 Mt. in 2015 to 2876 Mt. in 2050. The stringent mitigation measures in both alternative scenarios will cause the annual emissions to fall to 570 Mt. in

**Table 8.35** OECD Europe: projection of the transport energy demand by mode in the scenarios

| in PJ/year | Case | 2015 | 2025 | 2030 | 2040 | 2050 |
|---|---|---|---|---|---|---|
| Rail | 5.0 °C | 323 | 334 | 335 | 337 | 344 |
| | 2.0 °C | 323 | 362 | 409 | 509 | 643 |
| | 1.5 °C | 323 | 383 | 458 | 453 | 400 |
| Road | 5.0 °C | 13,087 | 12,699 | 12,633 | 12,529 | 12,464 |
| | 2.0 °C | 13,087 | 10,163 | 7540 | 4196 | 3097 |
| | 1.5 °C | 13,087 | 8197 | 4404 | 3215 | 2556 |
| Domestic aviation | 5.0 °C | 300 | 397 | 448 | 485 | 474 |
| | 2.0 °C | 300 | 294 | 254 | 182 | 142 |
| | 1.5 °C | 300 | 273 | 198 | 105 | 82 |
| Domestic navigation | 5.0 °C | 227 | 236 | 240 | 248 | 259 |
| | 2.0 °C | 227 | 236 | 240 | 247 | 258 |
| | 1.5 °C | 227 | 236 | 240 | 247 | 258 |
| Total | 5.0 °C | 13,938 | 13,665 | 13,656 | 13,598 | 13,541 |
| | 2.0 °C | 13,938 | 11,055 | 8443 | 5134 | 4140 |
| | 1.5 °C | 13,938 | 9090 | 5300 | 4020 | 3296 |

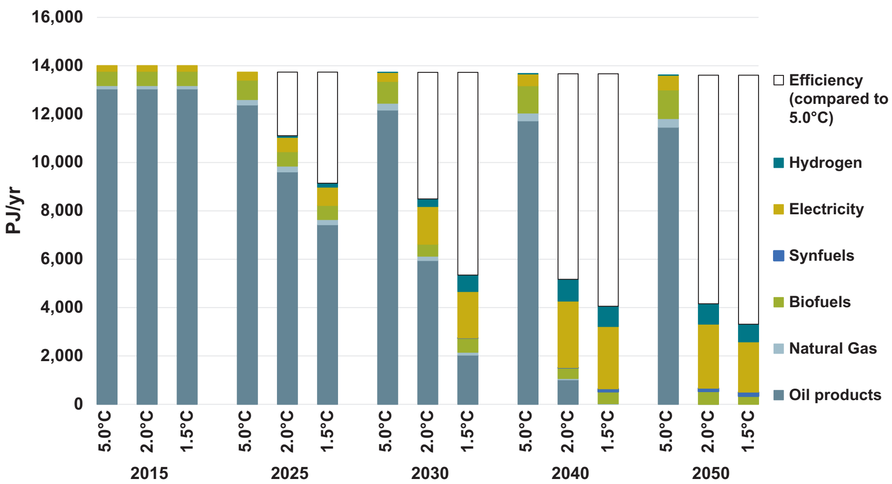


**Fig. 8.41** OECD Europe: final energy consumption by transport in the scenarios

2040 in the 2.0 °C Scenario and to 270 Mt. in the 1.5 °C Scenario, with further reductions to almost zero by 2050. In the 5.0 °C case, the cumulative $CO_2$ emissions from 2015 until 2050 will add up to 116 Gt. In contrast, in the 2.0 °C and 1.5 °C Scenarios, the cumulative emissions for the period from 2015 until 2050 will be 55 Gt and 44 Gt, respectively.

Therefore, the cumulative $CO_2$ emissions will decrease by 53% in the 2.0 °C Scenario and by 62% in the 1.5 °C Scenario compared with the 5.0 °C case. A rapid reduction in the annual emissions will occur in both alternative scenarios. In the 2.0 °C Scenario, this reduction will be greatest in 'Power generation', followed by the 'Transport' and the 'Residential and other' sectors (Fig. 8.42).

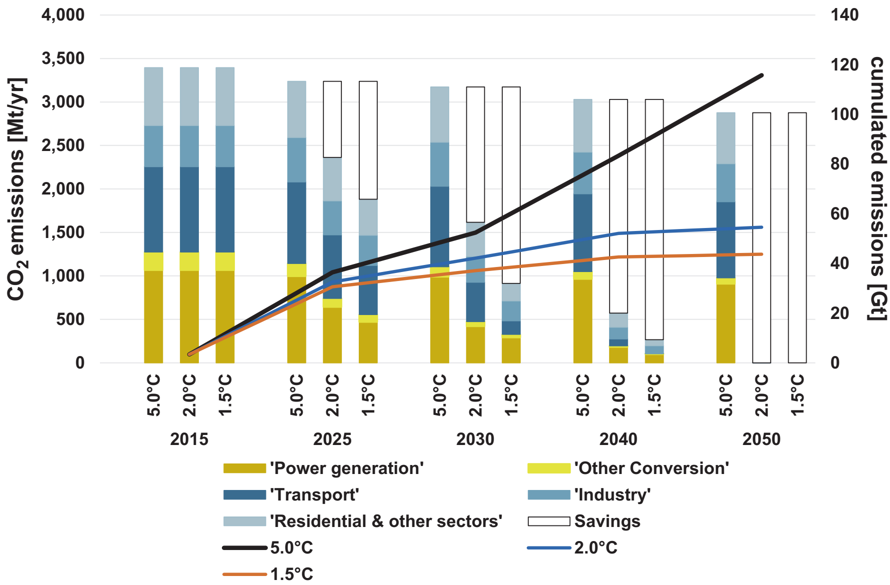


**Fig. 8.42** OECD Europe: development of $CO_2$ emissions by sector and cumulative $CO_2$ emissions (after 2015) in the scenarios ('Savings' = reduction compared with the 5.0 °C Scenario)

### 8.7.1.9 OECD Europe: Primary Energy Consumption

The levels of primary energy consumption in the three scenarios when the assumptions discussed above are taken into account are shown in Fig. 8.43. In the 2.0 °C Scenario, the primary energy demand will decrease by 44%, from around 71,200 PJ/year in 2015 to 40,100 PJ/year in 2050. Compared with the 5.0 °C Scenario, the overall primary energy demand will decrease by 43% by 2050 in the 2.0 °C Scenario (5.0 °C: 70,700 PJ in 2050). In the 1.5 °C Scenario, the primary energy demand will be even lower (39,000 PJ in 2050) because the final energy demand and conversion losses will be lower.

Both the 2.0 °C and 1.5 °C Scenarios aim to rapidly phase-out coal and oil. This will cause renewable energy to have primary energy shares of 39% in 2030 and 92% in 2050 in the 2.0 °C Scenario. In the 1.5 °C Scenario, renewables will have a primary energy share of more than 92% in 2050 (including non-energy consumption, which will still include fossil fuels). Nuclear energy will be phased-out by 2040 under both the 2.0 °C and the 1.5 °C Scenarios. The cumulative primary energy consumption of natural gas in the 5.0 °C case will add up to 670 EJ, the cumulative coal consumption to about 300 EJm, and the crude oil consumption to 660 EJ. In contrast, in the 2.0 °C case, the cumulative gas demand will amount to 420 EJ, the cumulative coal demand to 100 EJ, and the cumulative oil demand to 320 EJ. Even lower fossil fuel use will be achieved in the 1.5 °C Scenario: 340 EJ for natural gas, 70 EJ for coal, and 240 EJ for oil.

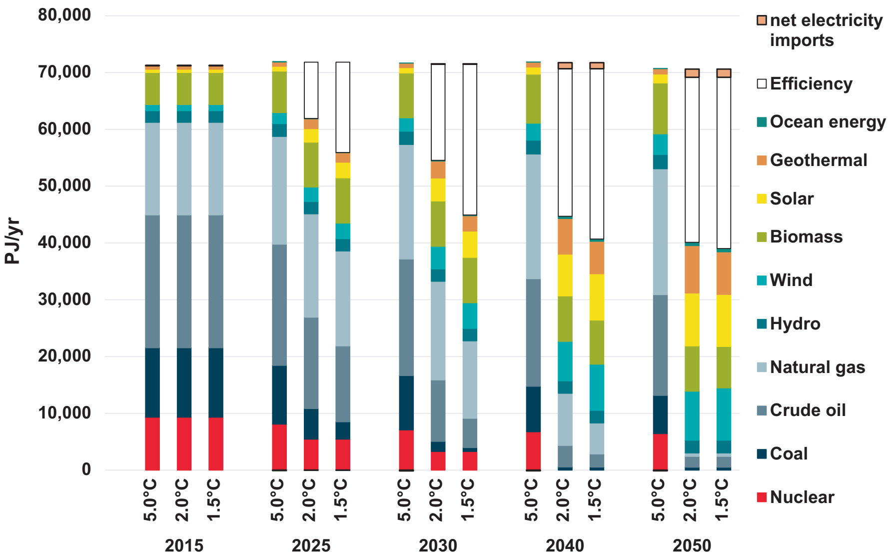


**Fig. 8.43** OECD Europe: projection of total primary energy demand (PED) by energy carrier in the scenarios (including electricity import balance)

## *8.7.2 OECD Europe: Power Sector Analysis*

The European power sector is liberalized across the EU and cross-border trade in electricity has a long tradition and is very well documented. The European Network of Transmission System Operators for Electricity (ENTSO-E) publishes detailed data about the annual cross-border trade (ENTSO-E 2018) and produces the *Ten-Year-Network Development Plan (TYNDP)*, which aims to integrate 60% renewable electricity by 2040 (TYNDP 2016). While the extent to which the power sector is liberalised and open for competition for generation and supply varies significantly across the EU, at the time of the writing of this book all 28-member states had renewable electricity and energy efficiency targets and policies to implement them. However, the OECD Europe region covers not only the EU but also neighbouring countries such as Norway, Switzerland and Turkey, which are not members of the EU, but are connected to the EU grid and are also involved in the cross-border electricity trade. The region also includes Iceland, Malta, and a significant number of islands in the coastal waters of the European continent and the Mediterranean Sea. The storage demand for all the islands and island nations cannot be calculated with a regional approach, and doing so was beyond the scope of this research. Israel is also part of OECD Europe in the IEA world regions used for this analysis. However, because of its geographic position, and to reflect current and possible future interconnections with its neighbours, Israel has been taken out of the energy balance of OECD Europe and integrated into the Middle East region.

#### 8.7.2.1 OECD Europe: Development of Power Plant Capacities

The annual market for solar PV must increase from 11 GW in 2020 by a factor of 2 to an average of 40 GW by 2030. The onshore wind market must expand to 18 GW by 2025 under the 2.0 °C Scenario. This is only a minor increase on the average European wind market of 10–14 GW between 2009 and 2016 and 16.8 GW in 2017. However, the 1.5 °C Scenario requires that the size of the onshore wind market double between 2020 and 2025. The offshore wind market for both scenarios is similar and must increase from 3 GW (GWEC 2018) in 2017 to around 10 GW per year throughout the entire modelling period until 2050. All European lignite power plants will have stopped operations by 2035, and the last hard coal power plant will have gone offline by 2040 under the 2.0 °C Scenario. The 1.5 °C pathway requires the phase-out 5 years earlier (Table 8.36).

#### 8.7.2.2 OECD Europe: Utilization of Power-Generation Capacities

The UK, Ireland, and the Iberian Peninsula are the least interconnected sub-regions of OECD Europe, and they already have relatively high shares of variable renewables, as shown in Table 8.37.

Table 8.37 shows that the Nordic countries, especially Norway and Sweden, have very high shares of hydropower, including pumped hydropower. Therefore, an increased interconnection capacity with other sub-regions by 2030 will contribute to the integration of larger shares of wind and solar in other European regions.

**Table 8.36** OECD Europe: average annual change in installed power plant capacity

| OECD Europe power generation: average annual change of installed capacity [GW/a] | 2015–2025 | | 2026–2035 | | 2036–2050 | |
|---|---|---|---|---|---|---|
| | 2.0 °C | 1.5 °C | 2.0 °C | 1.5 °C | 2.0 °C | 1.5 °C |
| Hard coal | −5 | −9 | −8 | −4 | 0 | 0 |
| Lignite | −5 | −6 | −3 | −2 | 0 | 0 |
| Gas | 2 | 1 | 0 | −5 | −22 | −19 |
| Hydrogen-gas | 0 | 1 | 2 | 6 | 14 | 14 |
| Oil/diesel | −7 | −5 | −1 | −2 | 0 | 0 |
| Nuclear | −6 | −9 | −6 | −6 | −2 | −2 |
| Biomass | 5 | 7 | 4 | 3 | 1 | 1 |
| Hydro | 1 | 0 | 0 | 0 | 0 | 0 |
| Wind (onshore) | 13 | 28 | 22 | 32 | 13 | 10 |
| Wind (offshore) | 4 | 9 | 10 | 11 | 8 | 8 |
| PV (roof top) | 16 | 43 | 30 | 42 | 25 | 21 |
| PV (utility scale) | 5 | 14 | 10 | 14 | 8 | 7 |
| Geothermal | 0 | 1 | 2 | 2 | 2 | 2 |
| Solar thermal power plants | 1 | 2 | 2 | 4 | 2 | 2 |
| Ocean energy | 1 | 2 | 3 | 3 | 2 | 2 |
| Renewable fuel based co-generation | 3 | 6 | 4 | 4 | 1 | 1 |

**Table 8.37** OECD Europe: power system shares by technology group

| Power generation structure and interconnection | | 2.0 °C | | | | 1.5 °C | | | |
|---|---|---|---|---|---|---|---|---|---|
| OECD Europe | | Variable RE | Dispatch RE | Dispatch fossil | Inter-connection | Variable RE | Dispatch RE | Dispatch fossil | Inter-connection |
| Central | 2015 | 12% | 47% | 41% | 20% | | | | |
| | 2030 | 38% | 47% | 15% | 20% | 45% | 43% | 12% | 20% |
| | 2050 | 62% | 33% | 5% | 20% | 64% | 31% | 5% | 20% |
| UK & Islands | 2015 | 25% | 47% | 28% | 10% | | | | |
| | 2030 | 63% | 31% | 6% | 20% | 71% | 25% | 5% | 20% |
| | 2050 | 84% | 15% | 2% | 20% | 85% | 13% | 2% | 20% |
| Iberian Peninsula | 2015 | 26% | 47% | 26% | 10% | | | | |
| | 2030 | 67% | 30% | 3% | 20% | 76% | 22% | 3% | 20% |
| | 2050 | 86% | 13% | 1% | 20% | 88% | 12% | 1% | 20% |
| Balkans + Greece | 2015 | 17% | 47% | 35% | 10% | | | | |
| | 2030 | 53% | 42% | 6% | 20% | 60% | 35% | 5% | 20% |
| | 2050 | 73% | 24% | 3% | 20% | 74% | 23% | 3% | 20% |
| Baltic | 2015 | 15% | 47% | 38% | 10% | | | | |
| | 2030 | 44% | 45% | 12% | 20% | 50% | 40% | 10% | 20% |
| | 2050 | 67% | 29% | 4% | 20% | 68% | 28% | 4% | 20% |
| Nordic | 2015 | 13% | 47% | 39% | 10% | | | | |
| | 2030 | 39% | 46% | 14% | 20% | 46% | 43% | 11% | 20% |
| | 2050 | 65% | 31% | 4% | 20% | 67% | 29% | 4% | 20% |

(continued)

**Table 8.37** (continued)

| Power generation structure and interconnection | | 2.0 °C | | | | 1.5 °C | | | |
|---|---|---|---|---|---|---|---|---|---|
| OECD Europe | | Variable RE | Dispatch RE | Dispatch fossil | Inter-connection | Variable RE | Dispatch RE | Dispatch fossil | Inter-connection |
| Turkey | 2015 | 10% | 47% | 42% | 5% | | | | |
| | 2030 | 35% | 48% | 17% | 5% | 40% | 44% | 16% | 5% |
| | 2050 | 59% | 35% | 6% | 5% | 60% | 34% | 6% | 5% |
| OECD Europe Central | 2015 | 15% | 47% | 38% | | | | | |
| | 2030 | 44% | 44% | 12% | | 51% | 39% | 10% | |
| | 2050 | 67% | 28% | 4% | | 69% | 27% | 4% | |

**Table 8.38** OECD Europe: capacity factors by generation type

| Utilization of variable and dispatchable power generation: | | 2015 | 2020 | 2020 | 2030 | 2030 | 2040 | 2040 | 2050 | 2050 |
|---|---|---|---|---|---|---|---|---|---|---|
| World | | | 2.0 °C | 1.5 °C | 2.0 °C | 1.5 °C | 2.0 °C | 1.5 °C | 2.0 °C | 1.5 °C |
| Capacity factor – average | [%/yr] | 45.2% | 37% | 37% | 48% | 44% | 35% | 36% | 39% | 38% |
| Limited dispatchable: fossil and nuclear | [%/yr] | 57.5% | 14% | 14% | 3% | 2% | 19% | 1% | 20% | 9% |
| Limited dispatchable: renewable | [%/yr] | 54.0% | 60% | 60% | 52% | 48% | 60% | 39% | 41% | 40% |
| Dispatchable: fossil | [%/yr] | 32.0% | 20% | 20% | 7% | 7% | 30% | 10% | 15% | 16% |
| Dispatchable: renewable | [%/yr] | 43.7% | 67% | 67% | 67% | 61% | 39% | 49% | 52% | 50% |
| Variable: renewable | [%/yr] | 22.5% | 22% | 22% | 40% | 38% | 29% | 35% | 36% | 35% |

Across the EU, it is assumed that the average interconnection capacities will increase to 20% of the regional peak load.

Both alternative scenarios assume that limited dispatchable power generation—namely coal, lignite, and nuclear—will not have priority dispatch and will be last in the dispatch queue. Therefore, the average calculated capacity factor will decrease from 57.5% in 2015 to only 14% in 2020, as shown in Table 8.38.

Table 8.38 shows that by 2020, most of the installed coal and nuclear capacity will not be required to secure power supply. Instead, dispatchable renewable power plants will fill the gap and their capacity factors will increase.

#### 8.7.2.3 OECD Europe: Development of Load, Generation, and Residual Load

The loads of the European sub-regions will not increase until 2030 in the two alternative scenarios, as shown in Table 8.39. The only exception is Turkey, which will have a constantly increasing load. This is attributed to Turkey's assumed economic development and increasing per capita electricity demand, which is currently lower than in most EU countries (WB-DB 2018). The calculated load will increase in all sub-regions between 2030 and 2050 due to the increased deployment of electric mobility. Central Europe has a very high requirement for increased transmission interconnection—or storage, see Table 8.40—because of increases in variable generation, including offshore wind in the North Sea and Baltic Sea. Central Europe,

Table 8.39 OECD Europe: load, generation, and residual load development

| Power generation structure | | 2.0 °C | | | | 1.5 °C | | | |
|---|---|---|---|---|---|---|---|---|---|
| | | Max demand | Max generation | Max residual load | Max interconnection requirements | Max demand | Max generation | Max residual load | Max interconnection requirements |
| OECD Europe | | [GW] | [GW] | [GW] | [GW] | [GW] | [GW] | [GW] | [GW] |
| Central | 2020 | 328.9 | 322.3 | 73.6 | | 328.9 | 322.3 | 77.8 | |
| | 2030 | 350.7 | 397.4 | 44.5 | 2 | 360.3 | 520.4 | 47.4 | 113 |
| | 2050 | 491.9 | 842.8 | 243.1 | 108 | 511.2 | 954.3 | 259.0 | 184 |
| UK & Islands | 2020 | 66.1 | 73.5 | 33.2 | | 66.1 | 73.4 | 33.1 | |
| | 2030 | 71.6 | 87.6 | 21.0 | 0 | 73.7 | 112.9 | 23.4 | 16 |
| | 2050 | 98.0 | 187.9 | 51.5 | 38 | 102.2 | 210.7 | 55.1 | 53 |
| Iberian Peninsula | 2020 | 47.0 | 56.1 | 10.3 | | 47.0 | 56.1 | 10.3 | |
| | 2030 | 50.8 | 62.3 | 7.3 | 4 | 52.6 | 80.8 | 7.9 | 20 |
| | 2050 | 70.8 | 133.2 | 31.7 | 31 | 74.3 | 149.4 | 34.6 | 41 |
| Balkans + Greece | 2020 | 37.9 | 38.2 | 1.4 | | 37.9 | 37.9 | 1.4 | |
| | 2030 | 39.5 | 49.3 | 6.3 | 4 | 41.6 | 63.1 | 6.8 | 15 |
| | 2050 | 55.6 | 105.4 | 24.1 | 26 | 59.8 | 117.8 | 27.5 | 30 |
| Baltic | 2020 | 4.6 | 4.5 | 0.1 | | 4.6 | 4.5 | 0.1 | |
| | 2030 | 4.9 | 6.1 | 0.7 | 1 | 5.1 | 7.9 | 0.7 | 2 |
| | 2050 | 6.8 | 13.1 | 3.2 | 3 | 7.2 | 14.7 | 3.5 | 4 |
| Nordic | 2020 | 52.0 | 50.8 | 1.3 | | 52.0 | 50.8 | 1.3 | |
| | 2030 | 54.4 | 65.9 | 8.7 | 3 | 55.2 | 86.0 | 10.4 | 20 |
| | 2050 | 71.0 | 140.3 | 30.0 | 39 | 72.6 | 158.5 | 31.0 | 55 |
| Turkey | 2020 | 37.5 | 38.5 | 0.8 | | 37.5 | 38.2 | 0.8 | |
| | 2030 | 48.4 | 49.1 | 6.9 | 0 | 50.8 | 64.4 | 7.5 | 6 |
| | 2050 | 68.2 | 107.4 | 33.1 | 6 | 73.0 | 121.5 | 37.4 | 11 |

**Table 8.40** OECD Europe: storage and dispatch service requirements

| Storage and dispatch | | 2.0 °C | | | | | 1.5 °C | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | Required to avoid curtailment | Utilization battery -through-put- | Utilization PSH -through-put- | Total storage demand (incl. H2) | Dispatch hydrogen-based | Required to avoid curtailment | Utilization battery -through-put- | Utilization PSH -through-put- | Total storage demand (incl. H2) | Dispatch hydrogen-based |
| OECD Europe | | [GWh/year] | [GWh/year] | [GWh/year] | [GWh/year] | [GWh/year] | [GWh/year] | [GWh/year] | [GWh/year] | [GWh/year] | [GWh/year] |
| Central | 2020 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | 2030 | 425 | 67 | 728 | 796 | 38,043 | 6947 | 515 | 7996 | 8511 | 139,501 |
| | 2050 | 59,495 | 28,998 | 32,425 | 61,423 | 546,511 | 99,134 | 35,542 | 48,679 | 84,222 | 549,376 |
| UK & Islands | 2020 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | 2030 | 3419 | 293 | 5808 | 6101 | 4148 | 12,239 | 440 | 13,977 | 14,417 | 13,195 |
| | 2050 | 57,089 | 9507 | 34,158 | 43,665 | 41,134 | 72,011 | 9738 | 38,301 | 48,039 | 40,932 |
| Iberian Peninsula | 2020 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | 2030 | 1688 | 186 | 2763 | 2949 | 2712 | 12,555 | 407 | 11,672 | 12,079 | 8127 |
| | 2050 | 52,580 | 7952 | 27,526 | 35,478 | 22,000 | 69,483 | 8273 | 30,928 | 39,201 | 22,448 |
| Balkans + Greece | 2020 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | 2030 | 523 | 62 | 895 | 957 | 3274 | 3699 | 172 | 3996 | 4168 | 11,349 |
| | 2050 | 19,794 | 5717 | 10,649 | 16,366 | 39,208 | 25,680 | 6267 | 12,033 | 18,300 | 42,798 |
| Baltic | 2020 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | 2030 | 27 | 2 | 41 | 42 | 482 | 190 | 7 | 174 | 181 | 1775 |
| | 2050 | 1071 | 360 | 542 | 902 | 6365 | 1504 | 413 | 677 | 1090 | 6636 |
| Nordic | 2020 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | 2030 | 149 | 16 | 274 | 291 | 6276 | 2111 | 95 | 2237 | 2332 | 23,031 |
| | 2050 | 14,144 | 4425 | 6905 | 11,330 | 80,577 | 22,171 | 5219 | 9360 | 14,580 | 78,294 |

(continued)

**Table 8.40** (continued)

| Storage and dispatch | | 2.0 °C | | | | | 1.5 °C | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | Required to avoid curtailment | Utilization battery -through-put- | Utilization PSH -through-put- | Total storage demand (incl. H2) | Dispatch hydrogen-based | Required to avoid curtailment | Utilization battery -through-put- | Utilization PSH -through-put- | Total storage demand (incl. H2) | Dispatch hydrogen-based |
| OECD Europe | | [GWh/year] | [GWh/year] | [GWh/year] | [GWh/year] | [GWh/year] | [GWh/year] | [GWh/year] | [GWh/year] | [GWh/year] | [GWh/year] |
| Turkey | 2020 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | 2030 | 8 | 4 | 21 | 25 | 5287 | 762 | 72 | 1067 | 1139 | 20,038 |
| | 2050 | 7887 | 4120 | 4348 | 8467 | 78,788 | 11,251 | 4744 | 5467 | 10,211 | 82,142 |
| OECD Europe | 2020 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | 2030 | 6238 | 630 | 10,531 | 11,161 | 60,223 | 38,504 | 1710 | 41,118 | 42,827 | 217,016 |
| | 2050 | 212,060 | 61,078 | 116,554 | 177,632 | 814,585 | 301,234 | 70,196 | 145,445 | 215,641 | 822,626 |

the Iberian Peninsula, and the UK have the highest storage demands, as shown in Table 8.40. This corresponds to the calculated results for increased interconnections. To avoid curtailment, renewably produced hydrogen will be used to store surplus generation for dispatch when required. Finding the optimal mix of battery capacity, pumped hydro capacity, hydrogen production, and expansion of transmission capacity was beyond the scope of this analysis, and further research is required on this issue.

## 8.8 Africa

### *8.8.1 Africa: Long-Term Energy Pathways*

#### 8.8.1.1 Africa: Final Energy Demand by Sector

The development pathways for Africa's final energy demand when the assumptions on population growth, GDP growth, and energy intensity are combined are shown in Fig. 8.44 for the 5.0 °C, 2.0 °C, and 1.5 °C Scenarios. In the 5.0 °C Scenario, the total final energy demand will increase by 103% from the current 23,200 PJ/year to 47,100 PJ/year in 2050. In the 2.0 °C Scenario, the final energy demand will increase at a much slower rate, by 39% compared with current consumption, and will reach

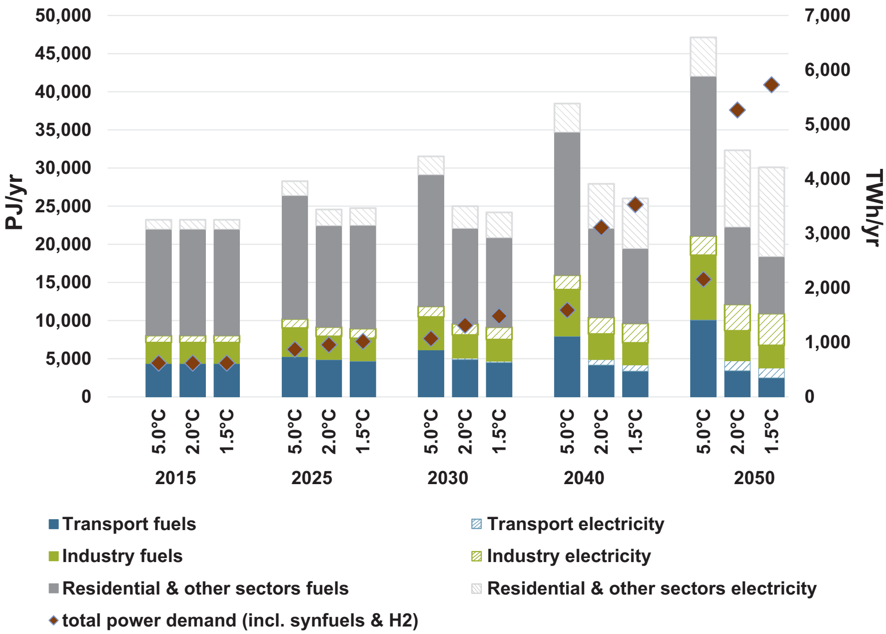


**Fig. 8.44** Africa: development of final energy demand by sector in the scenarios

32,300 PJ/year by 2050. The final energy demand under the 1.5 °C Scenario will reach 30,100 PJ, 30% above the 2015 demand level. In the 1.5 °C Scenario, the final energy demand in 2050 will be 7% lower than in the 2.0 °C Scenario. The electricity demand for 'classical' electrical devices (without power-to-heat or e-mobility) will increase from 540 TWh/year in 2015 to around 2590 TWh/year in 2050 in both alternative scenarios, which will be 590 TWh/year higher than in the 5.0 °C case. Although efficiency measures will reduce the specific energy consumption by appliances, the scenarios consider higher consumption to achieve higher living standards.

Electrification will lead to a significant increase in the electricity demand by 2050. In the 2.0 °C Scenario, the electricity demand for heating will increase to approximately 1200 TWh/year due to electric heaters and heat pumps, and in the transport sector, the demand will increase to approximately 1300 TWh/year in response to increased electric mobility. The generation of hydrogen (for transport and high-temperature process heat) and the manufacture of synthetic fuels (mainly for transport) will add an additional power demand of 1100 TWh/year The gross power demand will thus increase from 800 TWh/year in 2015 to 5700 TWh/year in 2050 in the 2.0 °C Scenario, 119% higher than in the 5.0 °C case. In the 1.5 °C Scenario, the gross electricity demand will increase to a maximum of 6300 TWh/year in 2050.

The efficiency gains in the heating sector could be even larger than in the electricity sector. In the 2.0 °C and 1.5 °C Scenarios, a final energy consumption equivalent to about 3600 PJ/year is avoided through efficiency gains by 2050 compared with the 5.0 °C Scenario.

#### 8.8.1.2 Africa: Electricity Generation

The development of the power system is characterized by a dynamically growing renewable energy market and an increasing proportion of total power from renewable sources. By 2050, 100% of the electricity produced in Africa will come from renewable energy sources in the 2.0 °C Scenario. 'New' renewables—mainly wind, solar, and geothermal energy—will contribute 92% of the total electricity generation. Renewable electricity's share of total production will be 61% by 2030 and 96% by 2040. The installed capacity of renewables will reach about 360 GW by 2030 and 2040 GW by 2050. In the 1.5 °C Scenario, the share of renewable electricity generation in 2030 is assumed to be 73%. The 1.5 °C Scenario will have a generation capacity from renewable energy of approximately 2280 GW in 2050.

Table 8.41 shows the development of different renewable technologies in Africa over time. Figure 8.45 provides an overview of the overall power-generation structure in Africa. From 2020 onwards, the continuing growth of wind and PV, up to 610 GW and 980 GW, respectively, will be complemented by up to 230 GW of solar thermal generation, as well as limited biomass, geothermal, and ocean energy, in the 2.0 °C Scenario. Both the 2.0 °C and 1.5 °C Scenarios will lead to high proportions of variable power generation (PV, wind, and ocean) of 40% and 49%, respectively, by 2030, and 71% by 2050.

**Table 8.41** Africa: development of renewable electricity-generation capacity in the scenarios

| in GW | Case | 2015 | 2025 | 2030 | 2040 | 2050 |
|---|---|---|---|---|---|---|
| Hydro | 5.0 °C | 28 | 47 | 58 | 84 | 117 |
| | 2.0 °C | 28 | 46 | 49 | 51 | 54 |
| | 1.5 °C | 28 | 46 | 48 | 51 | 54 |
| Biomass | 5.0 °C | 1 | 2 | 4 | 8 | 13 |
| | 2.0 °C | 1 | 8 | 17 | 33 | 48 |
| | 1.5 °C | 1 | 8 | 25 | 42 | 72 |
| Wind | 5.0 °C | 3 | 11 | 14 | 20 | 29 |
| | 2.0 °C | 3 | 42 | 132 | 415 | 609 |
| | 1.5 °C | 3 | 87 | 197 | 453 | 633 |
| Geothermal | 5.0 °C | 1 | 2 | 3 | 7 | 14 |
| | 2.0 °C | 1 | 7 | 16 | 33 | 64 |
| | 1.5 °C | 1 | 7 | 16 | 33 | 64 |
| PV | 5.0 °C | 2 | 17 | 27 | 52 | 89 |
| | 2.0 °C | 2 | 38 | 134 | 611 | 983 |
| | 1.5 °C | 2 | 70 | 166 | 757 | 1162 |
| CSP | 5.0 °C | 0 | 2 | 3 | 10 | 17 |
| | 2.0 °C | 0 | 0 | 1 | 80 | 235 |
| | 1.5 °C | 0 | 2 | 19 | 108 | 257 |
| Ocean | 5.0 °C | 0 | 0 | 0 | 0 | 0 |
| | 2.0 °C | 0 | 2 | 10 | 20 | 43 |
| | 1.5 °C | 0 | 2 | 10 | 20 | 43 |
| Total | 5.0 °C | 35 | 81 | 110 | 180 | 279 |
| | 2.0 °C | 35 | 144 | 359 | 1243 | 2036 |
| | 1.5 °C | 35 | 223 | 481 | 1464 | 2284 |

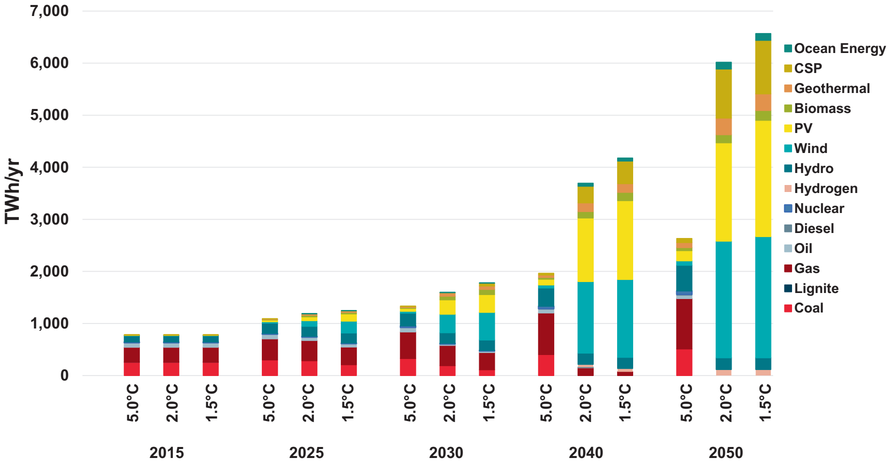


**Fig. 8.45** Africa: development of electricity-generation structure in the scenarios

### 8.8.1.3 Africa: Future Costs of Electricity Generation

Figure 8.46 shows the development of the electricity-generation and supply costs over time, including the $CO_2$ emission costs, in all scenarios. The calculated electricity-generation costs in 2015 (referring to full costs) were around 5.4 ct/kWh. In the 5.0 °C case, generation costs will increase until 2030, when they reach 11 ct/kWh, and will then stabilize at 10.8 ct/kWh by 2050. In the 2.0 °C and 1.5 °C Scenarios, the generation costs will increase until 2030, when they reach 8.4 ct/kWh and 8.2 ct/kWh, respectively. They will then drop to 5.6 ct/kWh by 2050 in both scenarios, 5.2 ct/kWh lower than in the 5.0 °C case. Note that these estimates of generation costs do not take into account integration costs such as power grid expansion, storage, or other load-balancing measures.

In the 5.0 °C case, the growth in demand and increasing fossil fuel prices will cause the total electricity supply costs to increase from today's $40 billion/year to more than $290 billion/year in 2050. In the 2.0 °C Scenario, the total supply costs will be $350 billion/year, and in the 1.5 °C Scenario, they will be $380 billion/year The long-term costs of electricity supply will be more than 23% higher under the 2.0 °C Scenario than under the 5.0 °C Scenario as a result of the estimated generation costs and the electrification of heating and mobility. Further electrification and synthetic fuel generation in the 1.5 °C Scenario will result in total power generation costs that are 34% higher than in the 5.0 °C case.

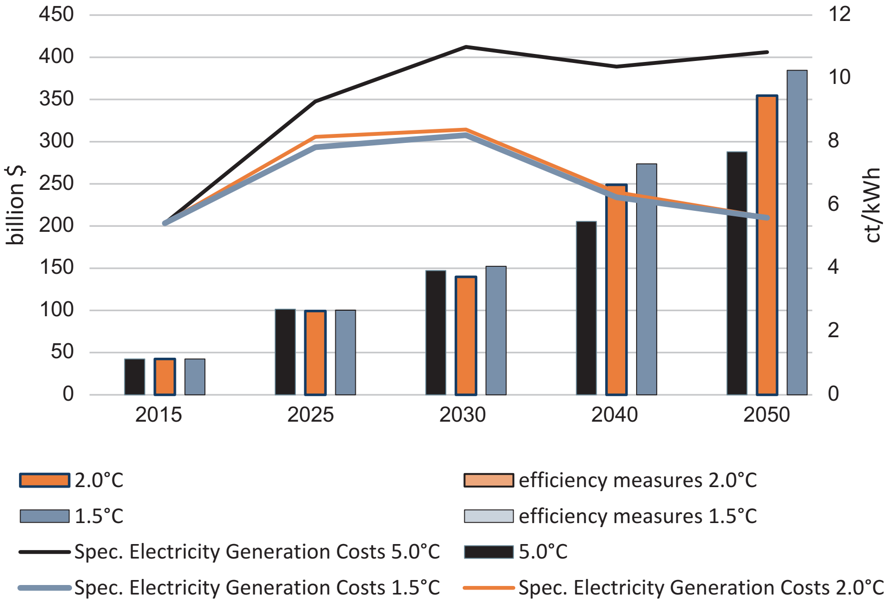


**Fig. 8.46** Africa: development of total electricity supply costs and specific electricity-generation costs in the scenarios

Compared with these results, the generation costs when the $CO_2$ emission costs are not considered will increase in the 5.0 °C case to 8.1 ct/kWh. In the 2.0 °C Scenario, they will increase until 2030, when they reach 6.8 ct/kWh, and then drop to 5.6 ct/kWh by 2050. In the 1.5 °C Scenario, they will increase to 7.2 ct/kWh and then drop to 5.6 ct/kWh by 2050. Therefore, the generation costs in both alternative scenarios are, at maximum, 2.5 ct/kWh lower than in the 5.0 °C case. If the $CO_2$ costs are not considered, the total electricity supply costs in the 5.0 °C case will increase to about \$220 billion/year in 2050.

#### 8.8.1.4 Africa: Future Investments in the Power Sector

An investment of around \$3500 billion will be required for power generation between 2015 and 2050 in the 2.0 °C Scenario—including additional power plants for the production of hydrogen and synthetic fuels and investments in plant replacement at the ends of their economic lives. This value is equivalent to approximately \$97 billion per year, on average, and is \$2590 billion more than in the 5.0 ° C case (\$910 billion). An investment of around \$3910 billion for power generation will be required between 2015 and 2050 in the 1.5 °C Scenario. On average, this is an investment of \$109 billion per year. In the 5.0 °C Scenario, the investment in conventional power plants will be around 45% of the total cumulative investments, and approximately 55% will be invested in renewable power generation and co-generation (Fig. 8.47).

However, in the 2.0 °C (1.5 °C) Scenario, Africa will shift almost 93% (94%) of its entire investments to renewables and co-generation. By 2030, the fossil fuel share of power sector investments will focus predominantly on gas power plants that can also be operated with hydrogen.

Because renewable energy has no fuel costs, other than biomass, the cumulative fuel cost savings in the 2.0 °C Scenario will reach a total of \$1510 billion in 2050, equivalent to \$42 billion per year. Therefore, the total fuel cost savings will be equivalent to 60% of the total additional investments compared to the 5.0 °C Scenario. The fuel cost savings in the 1.5 °C Scenario will add up to \$1610 billion, or \$45 billion per year.

#### 8.8.1.5 Africa: Energy Supply for Heating

The final energy demand for heating will increase in the 5.0 °C Scenario by 166%, from 7600 PJ/year in 2015 to 20,200 PJ/year in 2050. Energy efficiency measures will help to reduce the energy demand for heating by 18% in 2050 in both alternative scenarios, relative to the 5.0 °C case. Today, renewables supply around 61% of Africa's final energy demand for heating, with the main contribution from biomass. Renewable energy will provide 71% of Africa's total heat demand in 2030 under the 2.0 °C Scenario and 79% under the 1.5 °C Scenario. In both scenarios, renewables will provide 100% of the total heat demand from renewable energy in 2050.

Figure 8.48 shows the development of different technologies for heating in Africa over time, and Table 8.42 provides the resulting renewable heat supply for all scenarios. Biomass will remain the main contributor. The growing use of solar, geothermal, and environmental heat will lead, in the long term, to a reduced biomass share of 51% in the 2.0 °C Scenario and 40% in the 1.5 °C Scenario.

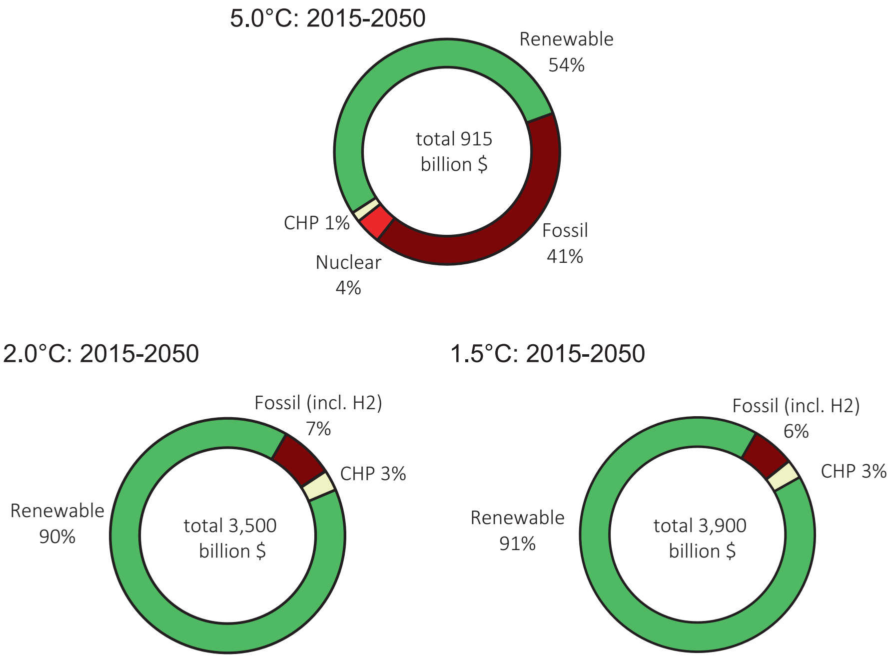


**Fig. 8.47** Africa: investment shares for power generation in the scenarios

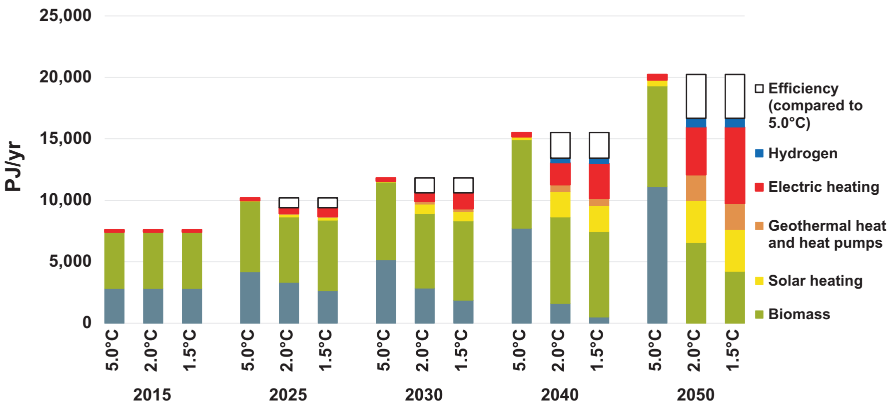


**Fig. 8.48** Africa: development of heat supply by energy carrier in the scenarios

**Table 8.42** Africa: development of renewable heat supply in the scenarios (excluding the direct use of electricity)

| in PJ/year | Case | 2015 | 2025 | 2030 | 2040 | 2050 |
|---|---|---|---|---|---|---|
| Biomass | 5.0 °C | 4586 | 5761 | 6317 | 7211 | 8203 |
| | 2.0 °C | 4586 | 5308 | 6047 | 7039 | 6551 |
| | 1.5 °C | 4586 | 5748 | 6448 | 6938 | 4222 |
| Solar heating | 5.0 °C | 7 | 37 | 86 | 228 | 481 |
| | 2.0 °C | 7 | 204 | 786 | 2066 | 3416 |
| | 1.5 °C | 7 | 203 | 783 | 2109 | 3416 |
| Geothermal heat and heat pumps | 5.0 °C | 0 | 0 | 0 | 0 | 0 |
| | 2.0 °C | 0 | 86 | 215 | 559 | 2106 |
| | 1.5 °C | 0 | 86 | 213 | 591 | 2106 |
| Hydrogen | 5.0 °C | 0 | 0 | 0 | 0 | 0 |
| | 2.0 °C | 0 | 0 | 0 | 397 | 720 |
| | 1.5 °C | 0 | 0 | 0 | 429 | 720 |
| Total | 5.0 °C | 4593 | 5797 | 6404 | 7440 | 8684 |
| | 2.0 °C | 4593 | 5598 | 7047 | 10,061 | 12,793 |
| | 1.5 °C | 4593 | 6037 | 7444 | 10,067 | 10,464 |

Heat from renewable hydrogen will further reduce the dependence on fossil fuels in both scenarios. Hydrogen consumption in 2050 will be around 720 PJ/year in both the 2.0 °C Scenario and 1.5 °C Scenario. The direct use of electricity for heating will also increase by a factor of 21–34 between 2015 and 2050, and will attain a final energy share of 23% in 2050 in the 2.0 °C Scenario and 37% in the 1.5 °C Scenario.

#### 8.8.1.6 Africa: Future Investments in the Heating Sector

The roughly estimated investments in renewable heating technologies up to 2050 will amount to around $790 billion in the 2.0 °C Scenario (including investments in plant replacement after their economic lifetimes), or approximately $22 billion per year. The largest share of investment in Africa is assumed to be for heat pumps (around $370 billion), followed by solar collectors and biomass technologies. The 1.5 °C Scenario assumes an even faster expansion of renewable technologies. However, the lower heat demand (compared with the 2.0 °C Scenario) will result in a lower average annual investment of around $21 billion per year (Table 8.43, Fig. 8.49).

**Table 8.43** Africa: installed capacities for renewable heat generation in the scenarios

| in GW | Case | 2015 | 2025 | 2030 | 2040 | 2050 |
|---|---|---|---|---|---|---|
| Biomass | 5 0 °C | 3655 | 4036 | 4100 | 3973 | 3870 |
| | 2 0 °C | 3655 | 3276 | 3063 | 2792 | 2251 |
| | 1 5 °C | 3655 | 3562 | 3069 | 2440 | 1307 |
| Geothermal | 5 0 °C | 0 | 0 | 0 | 0 | 0 |
| | 2 0 °C | 0 | 5 | 9 | 15 | 37 |
| | 1 5 °C | 0 | 5 | 8 | 15 | 37 |
| Solar heating | 5 0 °C | 1 | 7 | 16 | 44 | 92 |
| | 2 0 °C | 1 | 39 | 150 | 396 | 654 |
| | 1 5 °C | 1 | 39 | 150 | 404 | 654 |
| Heat pumps | 5 0 °C | 0 | 0 | 0 | 0 | 0 |
| | 2 0 °C | 0 | 3 | 16 | 51 | 227 |
| | 1 5 °C | 0 | 3 | 16 | 54 | 227 |
| Total[a] | 5 0 °C | 3656 | 4043 | 4116 | 4017 | 3962 |
| | 2 0 °C | 3656 | 3324 | 3239 | 3253 | 3169 |
| | 1 5 °C | 3656 | 3610 | 3244 | 2912 | 2225 |

[a]Excluding direct electric heating

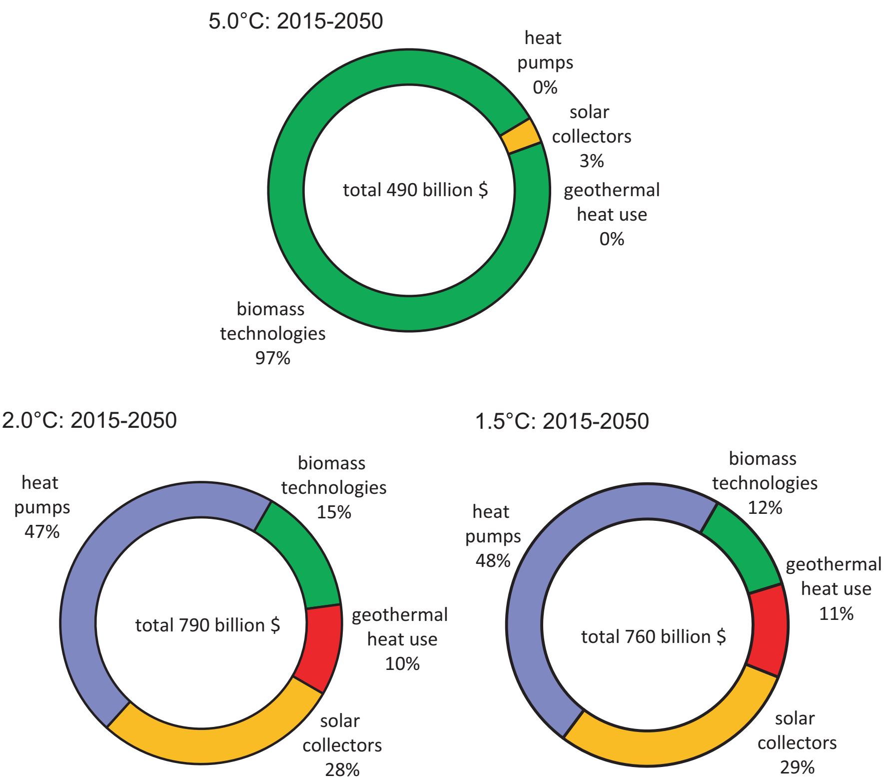


**Fig. 8.49** Africa: development of investments for renewable heat-generation technologies in the scenarios

#### 8.8.1.7 Africa: Transport

The energy demand in the transport sector in Africa is expected to increase by 131% in the 5.0 °C Scenario, from around 4400 PJ/year in 2015 to 10,100 PJ/year in 2050. In the 2.0 °C Scenario, assumed technical, structural, and behavioural changes will save 53% (5410 PJ/year) by 2050 compared with the 5.0 °C Scenario. Additional modal shifts, technology switches, and a reduction in the transport demand will lead to even higher energy savings in the 1.5 °C Scenario of 63% (or 6360 PJ/year) in 2050 compared with the 5.0 °C case (Table 8.44, Fig. 8.50).

By 2030, electricity will provide 4% (50 TWh/year) of the transport sector's total energy demand in the 2.0 °C Scenario, whereas by 2050, the share will be 28% (370 TWh/year). In 2050, up to 410 PJ/year of hydrogen will be used in the transport sector as a complementary renewable option. In the 1.5 °C Scenario, the annual electricity demand will be 360 TWh in 2050. The 1.5 °C Scenario also assumes a hydrogen demand of 340 PJ/year by 2050.

Biofuel use is limited in the 2.0 °C Scenario to a maximum of 2300 PJ/year. Therefore, around 2030, synthetic fuels based on power-to-liquid will be introduced, with a maximum amount of 700 PJ/year in 2050. With the lower overall energy demand by transport, biofuel use will be reduced in the 1.5 °C Scenario to a maximum of 1700 PJ/year The maximum synthetic fuel demand will amount to 470 PJ/year.

#### 8.8.1.8 Africa: Development of $CO_2$ Emissions

In the 5.0 °C Scenario, Africa's annual $CO_2$ emissions will increase by 126%, from 1140 Mt. in 2015 to 2585 Mt. in 2050. The stringent mitigation measures in both alternative scenarios will cause annual emissions to fall to 400 Mt. in 2040 in the

**Table 8.44** Africa: projection of transport energy demand by mode in the scenarios

| in PJ/year | Case | 2015 | 2025 | 2030 | 2040 | 2050 |
|---|---|---|---|---|---|---|
| Rail | 5.0 °C | 46 | 52 | 58 | 67 | 74 |
| | 2.0 °C | 46 | 58 | 71 | 96 | 110 |
| | 1.5 °C | 46 | 69 | 88 | 125 | 186 |
| Road | 5.0 °C | 4182 | 5000 | 5812 | 7522 | 9635 |
| | 2.0 °C | 4182 | 4688 | 4828 | 4651 | 4488 |
| | 1.5 °C | 4182 | 4493 | 4422 | 3925 | 3482 |
| Domestic aviation | 5.0 °C | 105 | 159 | 198 | 256 | 272 |
| | 2.0 °C | 105 | 114 | 110 | 90 | 71 |
| | 1.5 °C | 105 | 110 | 102 | 74 | 54 |
| Domestic navigation | 5.0 °C | 32 | 35 | 37 | 40 | 44 |
| | 2.0 °C | 32 | 35 | 37 | 40 | 44 |
| | 1.5 °C | 32 | 35 | 37 | 40 | 44 |
| Total | 5.0 °C | 4366 | 5246 | 6105 | 7885 | 10,027 |
| | 2.0 °C | 4366 | 4895 | 5045 | 4877 | 4714 |
| | 1.5 °C | 4366 | 4707 | 4648 | 4164 | 3765 |

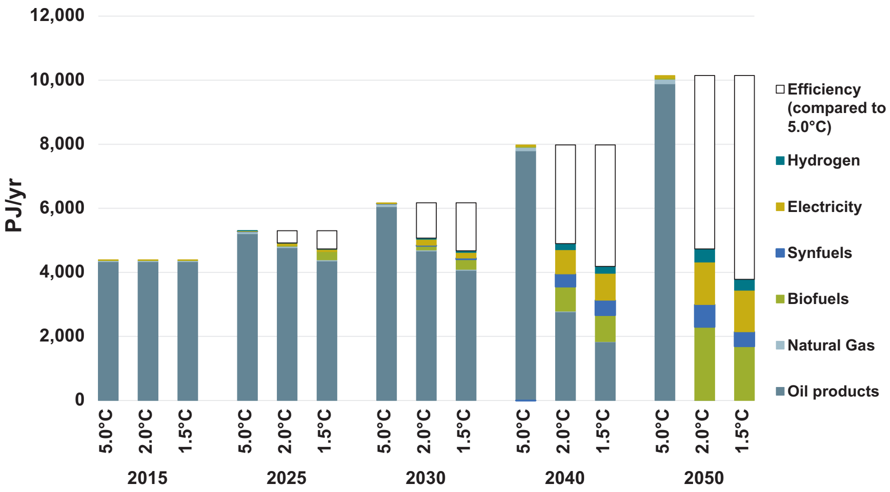


**Fig. 8.50** Africa: final energy consumption by transport in the scenarios

2.0 °C Scenario and to 200 Mt. in the 1.5 °C Scenario, with further reductions to almost zero by 2050. In the 5.0 °C case, the cumulative $CO_2$ emissions from 2015 until 2050 will add up to 66 Gt. In contrast, in the 2.0 °C and 1.5 °C Scenarios, the cumulative emissions for the period from 2015 until 2050 will be 27 Gt and 22 Gt, respectively.

Therefore, the cumulative $CO_2$ emissions will decrease by 59% in the 2.0 °C Scenario and by 67% in the 1.5 °C Scenario compared with the 5.0 °C case. A rapid reduction in annual emissions will occur in both alternative scenarios. In the 2.0 °C Scenario, this reduction will be greatest in 'Power generation', followed by the 'Industry' and 'Residential and other' sectors (Fig. 8.51).

### 8.8.1.9 Africa: Primary Energy Consumption

The levels of primary energy consumption in the three scenarios when the assumptions discussed above are taken into account are shown in Fig. 8.52. In the 2.0 °C Scenario, the primary energy demand will increase by 50% from around 33,200 PJ/year in 2015 to around 50,000 PJ/year in 2050. Compared with the 5.0 °C Scenario, the overall primary energy demand will decrease by 26% by 2050 in the 2.0 °C Scenario (5.0 °C: 67700 PJ in 2050). In the 1.5 °C Scenario, the primary energy demand will be even lower (48,000 PJ in 2050) because the final energy demand and conversion losses will be lower.

Both the 2.0 °C and 1.5 °C Scenarios aim to rapidly phase-out coal and oil. This will cause renewable energy to have a primary energy share of 56% in 2030 and 98% in 2050 in the 2.0 °C Scenario. In the 1.5 °C Scenario, renewables will have a primary energy share of more than 98% in 2050 (including non-energy consumption, which will still include fossil fuels). Nuclear energy will be phased-out by

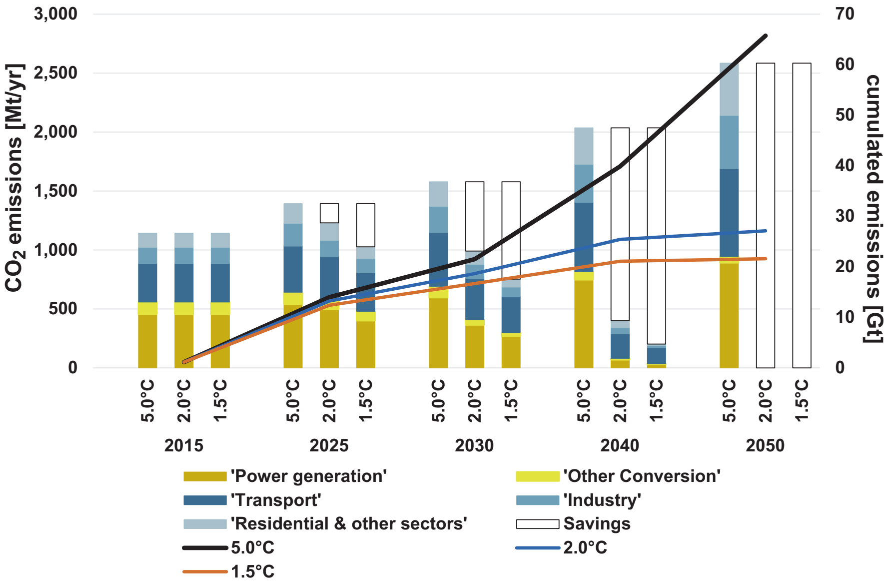


**Fig. 8.51** Africa: development of $CO_2$ emissions by sector and cumulative $CO_2$ emissions (after 2015) in the scenarios ('Savings' = reduction compared with the 5.0 °C Scenario)

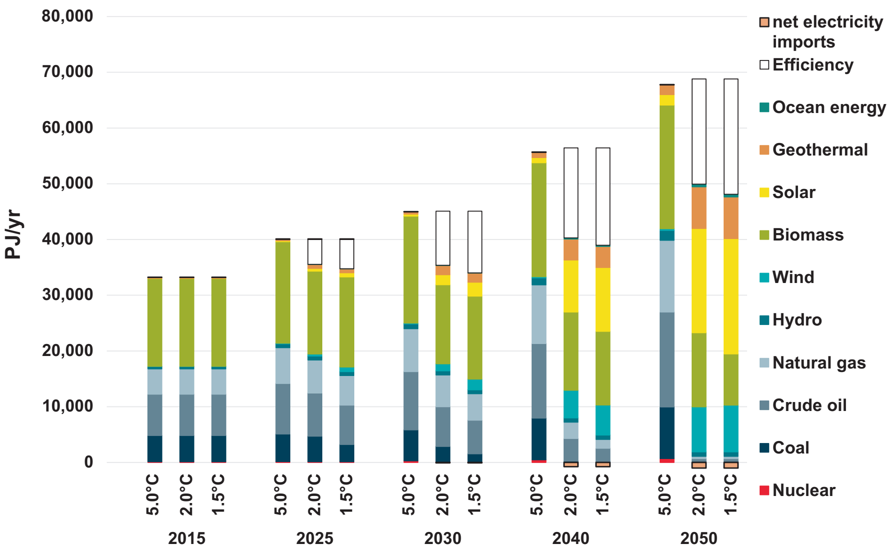


**Fig. 8.52** Africa: projection of total primary energy demand (PED) by energy carrier in the scenarios (including electricity import balance)

2035 under both the 2.0 °C Scenario and 1.5 °C Scenario. The cumulative primary energy consumption of natural gas in the 5.0 °C case will add up to 290 EJ, the cumulative coal consumption to about 210 EJ, and the crude oil consumption to 390 EJ. In contrast, in the 2.0 °C Scenario, the cumulative gas demand will amount to 130 EJ, the cumulative coal demand to 70 EJ, and the cumulative oil demand to 180 EJ. Even lower fossil fuel use will achieved in the 1.5 °C Scenario: 110 EJ for natural gas, 50 EJ for coal, and 150 EJ for oil.

## *8.8.2 Africa: Power Sector Analysis*

The African continent has 54 countries and its geographic, economic, and climatic diversity are significant. Its regional breakdown into sub-regions tries to reflect this diversity, but still requires a level of simplification. There is no pan-African power grid yet, although it is currently under discussion. The African Clean Energy Corridor (ACEC) is the most prominent regional initiative and aims to connect the Eastern Africa Power Pool (EAPP) with the Southern Africa Power Pool (SAPP). It was politically endorsed in January 2014 at the Assembly of the International Renewable Energy Agency (IRENA 2014).

### 8.8.2.1 Africa: Development of Power Plant Capacities

In 2050, Africa's most important renewable power-generation technology in both scenarios will be solar PV. In the 1.5 °C Scenario, solar PV will provide just over 40% of the total generation capacity, followed by onshore wind (with 24%), hydrogen power (15%), and CSP plants (located in the desert regions), with 10% of the total capacity. All other renewable power plant technologies will have only 2%–3% shares. The 2.0 °C Scenario will arrive at similar capacities by 2050, although the transition times in the two scenarios differ. Africa must build up solar PV and onshore wind markets equal to the market sizes in China in 2017: 50 GW of solar PV installation (REN21-GSR2018) and 23 GW of onshore wind (GWEC 2018). The market for CSP plants must reach about 1 GW per year by 2025, increasing rapidly to 3 GW per year in 2029 and 15 GW per year in 2035 (Table 8.45).

### 8.8.2.2 Africa: Utilization of Power-Generation Capacities

Africa's sub-regions are assumed to have an interconnection capacity of 5% at the beginning of the calculation period (2015). This capacity is not required for any exchange of variable electricity production, because currently, shares are only at or below 2% of the total generation capacity (Table 8.46). However, the variable generation capacity will increase rapidly towards 2030. We assume that the interconnection capacity between sub-regions will increase and that initiatives such as the African Clean Energy Corridor (ACEC) will be implemented successfully.

**Table 8.45** Africa: average annual change in installed power plant capacity

| Africa power generation: average annual change of installed capacity [GW/a] | 2015–2025 | | 2026–2035 | | 2036–2050 | |
|---|---|---|---|---|---|---|
| | 2.0 °C | 1.5 °C | 2.0 °C | 1.5 °C | 2.0 °C | 1.5 °C |
| Hard coal | 2 | 0 | −2 | −7 | −4 | 0 |
| Lignite | 0 | 0 | 0 | 0 | 0 | 0 |
| Gas | 6 | 3 | 10 | 16 | 13 | 14 |
| Hydrogen-gas | 0 | 0 | 1 | 3 | 15 | 32 |
| Oil/diesel | −1 | −2 | −2 | −2 | −1 | −1 |
| Nuclear | 0 | 0 | 0 | 0 | 0 | 0 |
| Biomass | 1 | 3 | 2 | 3 | 2 | 3 |
| Hydro | 2 | 1 | 1 | 1 | 0 | 0 |
| Wind (onshore) | 5 | 20 | 21 | 21 | 23 | 21 |
| Wind (offshore) | 0 | 2 | 5 | 10 | 7 | 4 |
| PV (roof top) | 3 | 12 | 29 | 31 | 41 | 48 |
| PV (utility scale) | 1 | 4 | 10 | 10 | 14 | 16 |
| Geothermal | 1 | 2 | 2 | 2 | 3 | 3 |
| Solar thermal power plants | 0 | 2 | 4 | 9 | 18 | 16 |
| Ocean energy | 0 | 1 | 1 | 1 | 3 | 3 |
| Renewable fuel based co-generation | 1 | 2 | 2 | 2 | 1 | 1 |

The development of average capacity factors for each generation type will follow the same trend as in most world regions. Table 8.47 shows the significant drop in the capacity factors of limited dispatchable power plants under the 1.5 °C Scenario.

### 8.8.2.3 Africa: Development of Load, Generation, and Residual Load

Table 8.48 shows that under the 2.0 °C Scenario, the transmission capacities need not exceed the assumed 25% interconnection capacity. If the exchange capacity between Africa's sub-regions is 20%—as calculated under the 1.5 °C Scenario—additional capacity will be required. Therefore, a 25% interconnection capacity seems a good target for high renewable penetration scenarios in Africa. The load in all sub-regions—from North Africa to South Africa—will increase significantly. The greatest increase is calculated for Southern Africa, with the load increasing by a factor of 7, followed by Central Africa (a factor of 6.5), East Africa (6), West Africa (5.5), and North Africa (4). The load increase in the Republic of South Africa will follow the patterns of other industrialized countries, more than doubling, due mainly to increases in electric mobility. The load increases in other parts of Africa will be first and foremost due to universal access to energy services for all households and favourable economic development.

Table 8.49 provides an overview of the calculated storage and dispatch power requirements by African sub-region. East and West Africa will require the highest battery capacity, due to the very high share of solar PV battery systems in rural and residential areas with low power grid availability. Like the Middle East, Africa is

**Table 8.46** Africa: power system shares by technology group

| | | 2.0 °C | | | | 1.5 °C | | | |
|---|---|---|---|---|---|---|---|---|---|
| Power generation structure and interconnection | | Variable RE | Dispatch RE | Dispatch fossil | Inter-connection | Variable RE | Dispatch RE | Dispatch fossil | Inter-connection |
| North Africa | 2015 | 2% | 25% | 73% | 5% | | | | |
| | 2030 | 56% | 23% | 21% | 20% | 60% | 8% | 32% | 5% |
| | 2050 | 75% | 25% | 0% | 25% | 61% | 10% | 29% | 20% |
| West Africa | 2015 | 1% | 26% | 73% | 5% | | | | |
| | 2030 | 38% | 24% | 38% | 20% | 41% | 18% | 41% | 5% |
| | 2050 | 67% | 33% | 0% | 25% | 63% | 23% | 14% | 20% |
| Central Africa | 2015 | 0% | 26% | 74% | 5% | | | | |
| | 2030 | 20% | 29% | 50% | 20% | 19% | 30% | 52% | 5% |
| | 2050 | 42% | 58% | 0% | 25% | 39% | 44% | 17% | 20% |
| East Africa | 2015 | 2% | 26% | 72% | 5% | | | | |
| | 2030 | 50% | 22% | 28% | 20% | 59% | 10% | 31% | 5% |
| | 2050 | 75% | 25% | 0% | 25% | 68% | 13% | 18% | 20% |
| Southern Africa | 2015 | 1% | 25% | 73% | 5% | | | | |
| | 2030 | 46% | 20% | 34% | 20% | 52% | 17% | 31% | 5% |
| | 2050 | 81% | 19% | 0% | 25% | 70% | 12% | 17% | 20% |
| South Africa | 2015 | 2% | 25% | 73% | 5% | | | | |
| | 2030 | 63% | 0% | 36% | 20% | 54% | 8% | 38% | 5% |
| | 2050 | 67% | 33% | 0% | 25% | 49% | 9% | 42% | 20% |
| Africa | 2015 | 2% | 26% | 73% | | | | | |
| | 2030 | 47% | 21% | 32% | | 52% | 13% | 35% | |
| | 2050 | 73% | 27% | 0% | | 64% | 15% | 21% | |

**Table 8.47** Africa: capacity factors by generation type

| Utilization of Variable and Dispatchable power generation: | | 2015 | 2020 | 2020 | 2030 | 2030 | 2040 | 2040 | 2050 | 2050 |
|---|---|---|---|---|---|---|---|---|---|---|
| Africa | | | 2.0 °C | 1.5 °C | 2.0 °C | 1.5 °C | 2.0 °C | 1.5 °C | 2.0 °C | 1.5 °C |
| Capacity factor – average | [%/yr] | **54.7%** | **33%** | **33%** | **29%** | **25%** | **40%** | **23%** | **36%** | **23%** |
| Limited dispatchable: fossil and nuclear | [%/yr] | 69.4% | 31% | 5% | 19% | 8% | 20% | 4% | 10% | 5% |
| Limited dispatchable: renewable | [%/yr] | 29.7% | 52% | 32% | 35% | 24% | 51% | 17% | 36% | 17% |
| Dispatchable: fossil | [%/yr] | 49.2% | 32% | 37% | 16% | 23% | 36% | 15% | 16% | 17% |
| Dispatchable: renewable | [%/yr] | 43.7% | 39% | 28% | 27% | 20% | 41% | 12% | 49% | 14% |
| Variable: renewable | [%/yr] | 12.2% | 12% | 12% | 38% | 28% | 34% | 27% | 35% | 27% |

**Table 8.48** Africa: load, generation, and residual load development

| Power generation structure | | 2.0 °C | | | | 1.5 °C | | | |
|---|---|---|---|---|---|---|---|---|---|
| | | Max demand | Max generation | Max residual load | Max interconnection requirements | Max demand | Max generation | Max residual load | Max interconnection requirements |
| Africa | | [GW] | [GW] | [GW] | [GW] | [GW] | [GW] | [GW] | [GW] |
| North Africa | 2020 | 23.8 | 19.3 | 8.4 | | 23.8 | 20.2 | 7.8 | |
| | 2030 | 31.0 | 33.9 | 4.2 | 0 | 34.0 | 43.6 | 6.0 | 4 |
| | 2050 | 99.3 | 161.9 | 63.6 | 0 | 109.8 | 186.1 | 28.5 | 48 |
| West Africa | 2020 | 38.7 | 19.5 | 19.7 | | 38.6 | 22.9 | 16.5 | |
| | 2030 | 64.7 | 56.7 | 25.3 | 0 | 66.5 | 58.5 | 24.5 | 0 |
| | 2050 | 214.4 | 310.3 | 164.6 | 0 | 216.1 | 355.7 | 118.0 | 22 |
| Central Africa | 2020 | 4.2 | 3.4 | 0.8 | | 4.2 | 3.9 | 0.3 | |
| | 2030 | 8.2 | 7.3 | 2.6 | 0 | 8.5 | 7.7 | 2.6 | 0 |
| | 2050 | 27.0 | 38.6 | 26.4 | 0 | 27.3 | 46.8 | 26.6 | 0 |
| East Africa | 2020 | 44.0 | 34.8 | 11.9 | | 44.0 | 39.5 | 7.0 | |
| | 2030 | 86.5 | 75.0 | 30.0 | 0 | 88.5 | 82.9 | 28.5 | 0 |
| | 2050 | 265.1 | 369.8 | 197.4 | 0 | 267.1 | 425.1 | 101.7 | 56 |
| Southern Africa | 2020 | 27.8 | 24.2 | 4.0 | | 27.7 | 25.4 | 2.3 | |
| | 2030 | 67.2 | 57.9 | 35.9 | 0 | 68.3 | 74.5 | 36.6 | 0 |
| | 2050 | 199.3 | 359.3 | 169.9 | 0 | 199.6 | 407.3 | 111.5 | 96 |
| South Africa | 2020 | 25.3 | 23.5 | 1.7 | | 25.3 | 23.5 | 2.7 | |
| | 2030 | 22.4 | 30.0 | 3.3 | 4 | 30.4 | 37.5 | 7.0 | 0 |
| | 2050 | 70.1 | 122.9 | 24.7 | 28 | 94.9 | 141.5 | 25.4 | 21 |

**Table 8.49** Africa: storage and dispatch service requirements

| Storage and dispatch | | 2.0 °C | | | | | 1.5 °C | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | Required to avoid curtailment | Utilization battery -through-put- | Utilization PSH -through-put- | Total storage demand (incl. H2) | Dispatch hydrogen-based | Required to avoid curtailment | Utilization battery -through-put- | Utilization PSH -through-put- | Total storage demand (incl. H2) | Dispatch hydrogen-based |
| Africa | | [GWh/year] | [GWh/year] | [GWh/year] | [GWh/year] | [GWh/year] | [GWh/year] | [GWh/year] | [GWh/year] | [GWh/year] | [GWh/year] |
| North Africa | 2020 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | 2030 | 1456 | 44 | 857 | 901 | 0 | 4611 | 65 | 1500 | 1565 | 0 |
| | 2050 | 59,499 | 1959 | 2904 | 4864 | 37,284 | 77,546 | 1976 | 2994 | 4969 | 2904 |
| West Africa | 2020 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | 2030 | 0 | 1 | 11 | 12 | 0 | 18 | 10 | 126 | 136 | 0 |
| | 2050 | 62,015 | 2525 | 3154 | 5679 | 41,842 | 125,281 | 2552 | 3797 | 6349 | 10,940 |
| Central Africa | 2020 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | 2030 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | 2050 | 4938 | 293 | 298 | 590 | 6107 | 10,557 | 323 | 391 | 714 | 3879 |
| East Africa | 2020 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | 2030 | 54 | 45 | 827 | 872 | 0 | 1960 | 78 | 1787 | 1865 | 0 |
| | 2050 | 104,983 | 3467 | 4976 | 8444 | 65,953 | 182,399 | 3573 | 5673 | 9246 | 6375 |
| Southern Africa | 2020 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | 2030 | 609 | 33 | 640 | 673 | 0 | 3268 | 49 | 1053 | 1102 | 0 |
| | 2050 | 110,532 | 2122 | 3371 | 5493 | 42,521 | 177,898 | 2189 | 3818 | 6008 | 19,886 |
| South Africa | 2020 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | 2030 | 2757 | 113 | 2155 | 2268 | 0 | 1407 | 46 | 877 | 923 | 0 |
| | 2050 | 25,233 | 2659 | 3245 | 5904 | 19,194 | 11,741 | 2038 | 1886 | 3924 | 0 |

(continued)

**Table 8.49** (continued)

| Storage and dispatch | | 2.0 °C | | | | | 1.5 °C | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | Required to avoid curtailment | Utilization battery -through-put- | Utilization PSH -through-put- | Total storage demand (incl. H2) | Dispatch hydrogen-based | Required to avoid curtailment | Utilization battery -through-put- | Utilization PSH -through-put- | Total storage demand (incl. H2) | Dispatch hydrogen-based |
| Africa | | [GWh/year] | [GWh/year] | [GWh/year] | [GWh/ year] | [GWh/ year] | [GWh/year] | [GWh/year] | [GWh/year] | [GWh/ year] | [GWh/year] |
| Africa | 2020 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | 2030 | 4877 | 237 | 4489 | 4726 | 0 | 11,264 | 248 | 5343 | 5591 | 0 |
| | 2050 | 367,201 | 13,026 | 17,948 | 30,974 | 212,902 | 585,423 | 12,651 | 18,558 | 31,210 | 43,984 |

one of the global renewable fuel production regions and it is assumed that all sub-regions of Africa have equal amounts of energy export potential. However, a more detailed examination of export energy is required, which is beyond the scope of this project.

## 8.9 The Middle East

### 8.9.1 The Middle East: Long-Term Energy Pathways

#### 8.9.1.1 The Middle East: Final Energy Demand by Sector

The future development pathways for the Middle East's final energy demand when the assumptions on population growth, GDP growth, and energy intensity are combined are shown in Fig. 8.53 for the 5.0 °C, 2.0 °C, and 1.5 °C Scenarios. In the 5.0 °C Scenario, the total final energy demand will increase by 133% from the current 17,100 PJ/year to around 40,000 PJ/year in 2050. In the 2.0 °C Scenario, the final energy demand will decrease by 8% compared with current consumption and will reach 15,800 PJ/year by 2050. The final energy demand in the 1.5 °C Scenario will reach 13,600 PJ, 20% below the 2015 demand level. In the 1.5 °C Scenario, the final energy demand in 2050 will be 14% lower than in the 2.0 °C Scenario. The

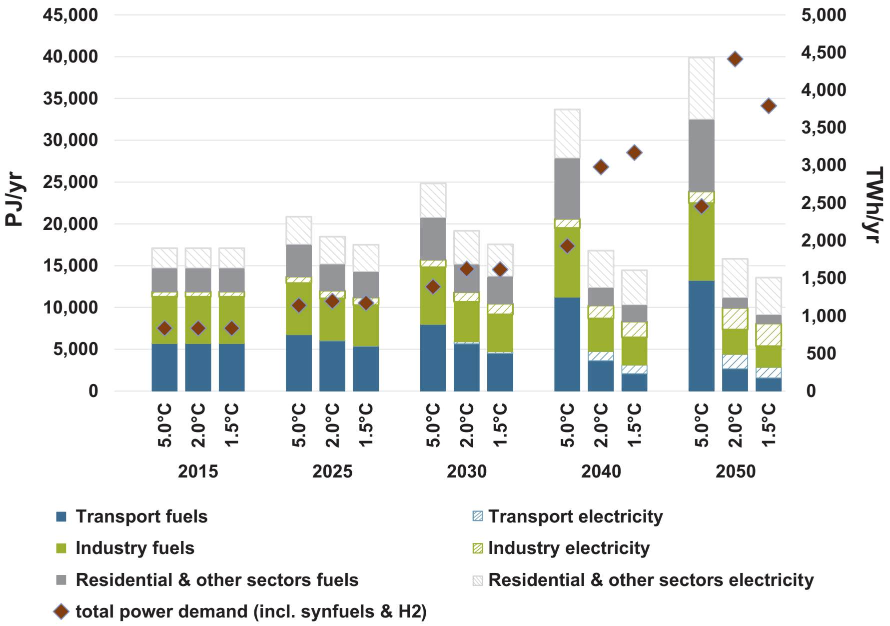


**Fig. 8.53** Middle East: development of the final energy demand by sector in the scenarios

electricity demand for 'classical' electrical devices (without power-to-heat or e-mobility) will increase from 650 TWh/year in 2015 to 1230 TWh/year (2.0 °C) and 1160 TWh/year (1.5 °C) by 2050. Compared with the 5.0 °C case (2330 TWh/year in 2050), the efficiency measures in the 2.0 °C and 1.5 °C Scenarios will save a maximum of 1100 TWh/year and 1170 TWh/year, respectively.

Electrification will lead to a significant increase in the electricity demand. In the 2.0 °C Scenario, the electricity demand for heating will rise to approximately 800 TWh/year due to electric heaters and heat pumps, and in the transport sector, the demand will rise to approximately 1700 TWh/year due to the increase in electric mobility. The generation of hydrogen (for transport and high-temperature process heat) and the manufacture of synthetic fuels (mainly for transport) will add an additional power demand of 1900 TWh/year. The gross power demand will thus rise from 1100 TWh/year in 2015 to 4700 TWh/year in 2050 in the 2.0 °C Scenario, 57% higher than in the 5.0 °C case. In the 1.5 °C Scenario, the gross electricity demand will increase to a maximum of 4100 TWh/year by 2045.

The efficiency gains could be even larger in the heating sector than in the electricity sector. In the 2.0 °C and 1.5 °C Scenarios, a final energy consumption equivalent to about 10,100 PJ/year and 10,500 PJ/year, respectively, will be avoided through efficiency gains by 2050 compared with the 5.0 °C Scenario.

#### 8.9.1.2 The Middle East: Electricity Generation

The development of the power system is characterized by a dynamically growing renewable energy market and an increasing proportion of total power from renewable sources. By 2050, 100% of the electricity produced in the Middle East will come from renewable energy sources under the 2.0 °C Scenario. 'New' renewables—mainly wind, solar, and geothermal energy—will contribute 96% of the total electricity generation. Renewable electricity's share of the total production will be 49% by 2030 and 91% by 2040. The installed capacity of renewables will reach about 430 GW by 2030 and 1910 GW by 2050. The share of renewable electricity generation in 2030 in the 1.5 °C Scenario is assumed to be 58%. In the 1.5 °C Scenario, the generation capacity from renewable energy will be approximately 1700 GW in 2050.

Table 8.50 shows the development of different renewable technologies in the Middle East over time. Figure 8.54 provides an overview of the overall power-generation structure in the Middle East. From 2020 onwards, the continuing growth of wind and PV, up to 480 GW and 1070 GW, respectively, will be complemented by up to 250 GW of solar thermal generation, as well as limited biomass, geothermal, and ocean energy, in the 2.0 °C Scenario. Both the 2.0 °C Scenario and 1.5 °C Scenario will lead to high proportions of variable power generation (PV, wind, and ocean) of 39% and 46%, respectively, by 2030, and 64% and 66%, respectively, by 2050.

**Table 8.50** Middle East: development of renewable electricity-generation capacity in the scenarios

| in GW | Case | 2015 | 2025 | 2030 | 2040 | 2050 |
|---|---|---|---|---|---|---|
| Hydro | 5.0 °C | 16 | 20 | 22 | 25 | 29 |
| | 2.0 °C | 16 | 22 | 22 | 25 | 29 |
| | 1.5 °C | 16 | 22 | 22 | 25 | 29 |
| Biomass | 5.0 °C | 0 | 0 | 1 | 3 | 7 |
| | 2.0 °C | 0 | 2 | 3 | 4 | 4 |
| | 1.5 °C | 0 | 3 | 3 | 4 | 4 |
| Wind | 5.0 °C | 0 | 4 | 9 | 23 | 49 |
| | 2.0 °C | 0 | 54 | 156 | 371 | 481 |
| | 1.5 °C | 0 | 60 | 175 | 432 | 456 |
| Geothermal | 5.0 °C | 0 | 0 | 0 | 0 | 0 |
| | 2.0 °C | 0 | 5 | 7 | 20 | 25 |
| | 1.5 °C | 0 | 5 | 7 | 20 | 21 |
| PV | 5.0 °C | 0 | 7 | 10 | 21 | 40 |
| | 2.0 °C | 0 | 76 | 187 | 560 | 1069 |
| | 1.5 °C | 0 | 92 | 236 | 587 | 928 |
| CSP | 5.0 °C | 0 | 2 | 3 | 6 | 7 |
| | 2.0 °C | 0 | 10 | 43 | 270 | 252 |
| | 1.5 °C | 0 | 10 | 47 | 342 | 216 |
| Ocean | 5.0 °C | 0 | 0 | 0 | 0 | 0 |
| | 2.0 °C | 0 | 5 | 10 | 40 | 50 |
| | 1.5 °C | 0 | 5 | 10 | 40 | 45 |
| Total | 5.0 °C | 16 | 32 | 45 | 79 | 132 |
| | 2.0 °C | 16 | 174 | 427 | 1290 | 1911 |
| | 1.5 °C | 16 | 197 | 500 | 1449 | 1699 |

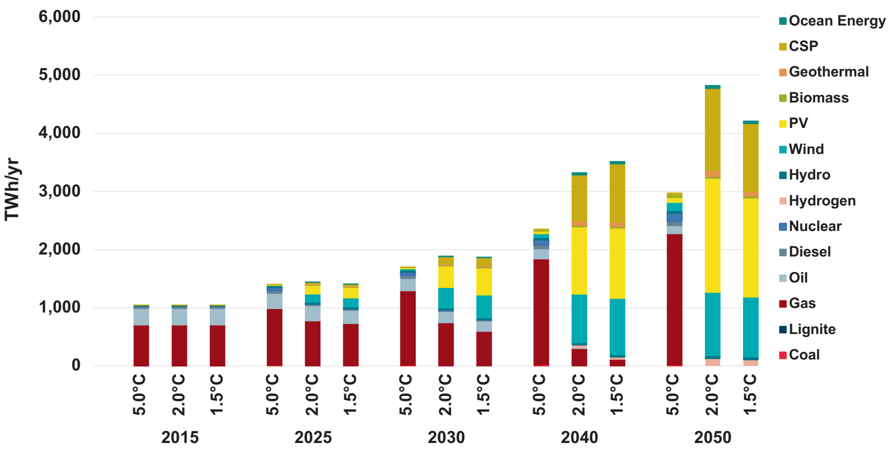


**Fig. 8.54** Middle East: development of electricity-generation structure in the scenarios

#### 8.9.1.3 The Middle East: Future Costs of Electricity Generation

Figure 8.55 shows the development of the electricity-generation and supply costs over time, including the $CO_2$ emission costs, in all scenarios. The calculated electricity-generation costs in 2015 (referring to full costs) were around 7.1 ct/kWh. In the 5.0 °C case, the generation costs will increase until 2030, when they reach 14.8 ct/kWh, and then drop to 13.7 ct/kWh by 2050. The generation costs in the 2.0 °C Scenario will increase until 2030, when they reach 11.1 ct/kWh, and then drop to 6.1 ct/kWh by 2050. In the 1.5 °C Scenario, they will increase to 10.7 ct/kWh, and then drop to 7.3 ct/kWh by 2050. In the 2.0 °C Scenario, the generation costs in 2050 will be 7.6 ct/kWh lower than in the 5.0 °C case. In the 1.5 °C Scenario, the generation costs in 2050 will be 6.4 ct/kWh lower than in the 5.0 °C case. Note that these estimates of generation costs do not take into account integration costs such as power grid expansion, storage, or other load-balancing measures.

In the 5.0 °C case, growth in demand and increasing fossil fuel prices will cause the total electricity supply costs to rise from today's $70 billion/year to more than $410 billion/year in 2050. In the 2.0 °C Scenario, the total supply costs will be $300 billion/year and in the 1.5 °C Scenario, they will be $310 billion/year. The long-term cost of electricity supply will be more than 27% lower in the 2.0 °C Scenario than in the 5.0 °C Scenario as a result of the estimated generation costs and the electrification of heating and mobility. Further demand reductions in the 1.5 °C Scenario will result in total power-generation costs that are 24% lower than in the 5.0 °C case.

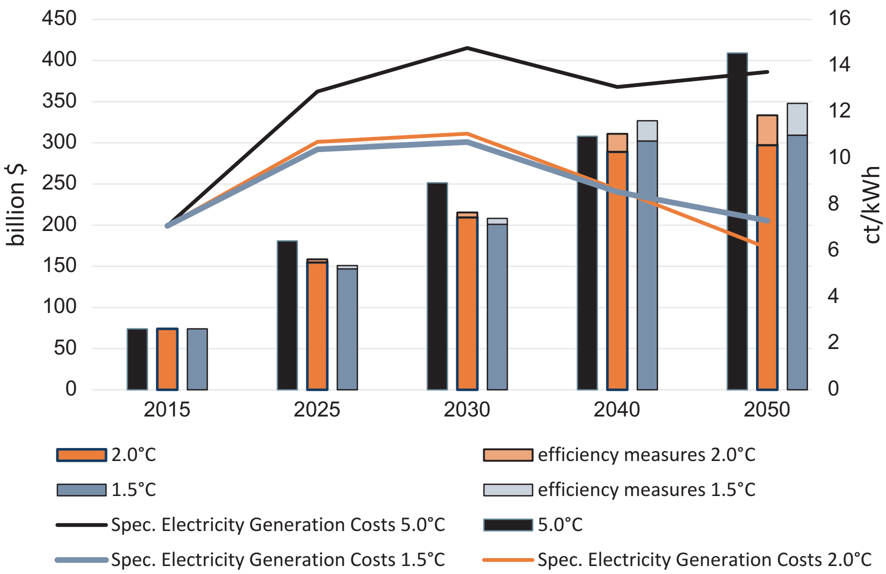


**Fig. 8.55** Middle East: development of total electricity supply costs and specific electricity-generation costs in the scenarios

The generation costs without the $CO_2$ emission costs will increase in the 5.0 °C case to 11.1 ct/kWh by 2030, and then stabilize at 10.8 ct/kWh by 2050. In the 2.0 °C Scenario and the 1.5 °C Scenario, they will increase to a maximum of 9 ct/kWh in 2030, before they drop to 6.1 ct/kWh and 7.3 ct/kWh by 2050, respectively. In the 2.0 °C Scenario, the generation costs will be 4.7 ct/kWh lower than in the 5.0 °C case and this maximum difference will occur in 2050. In the 1.5 °C Scenario, the maximum difference in generation costs compared with the 5.0 °C case will be 3.5 ct/kWh in 2050. If the $CO_2$ costs are not considered, the total electricity supply costs in the 5.0 °C case will rise to about $320 billion/year by 2050.

#### 8.9.1.4 The Middle East: Future Investments in the Power Sector

An investment of around $3450 billion will be required for power generation between 2015 and 2050 in the 2.0 °C Scenario—including additional power plants for the production of hydrogen and synthetic fuels and investments in plant replacement at the ends of their economic lives. This value will be equivalent to approximately $96 billion per year on average, and this is $2720 billion more than in the 5.0 °C case ($730 billion). An investment of around $3470 billion for power generation will be required between 2015 and 2050 in the 1.5 °C Scenario, or on average, $96 billion per year. In the 5.0 °C Scenario, the investment in conventional power plants will be around 68% of the total cumulative investments, whereas approximately 32% will be invested in renewable power generation and co-generation (Fig. 8.56). However, in both alternative scenarios, the Middle East will shift almost 94% of its entire investments to renewables and co-generation. By 2030, the fossil fuel share of power sector investment will predominantly focus on gas power plants that can also be operated with hydrogen.

Because renewable energy has no fuel costs, other than biomass, the cumulative fuel cost savings in the 2.0 °C Scenario will reach a total of $2900 billion in 2050, equivalent to $81 billion per year. Therefore, the total fuel cost savings will be equivalent to 110% of the total additional investments compared to the 5.0 °C Scenario. The fuel cost savings in the 1.5 °C Scenario will add up to $3100 billion, or $86 billion per year.

#### 8.9.1.5 The Middle East: Energy Supply for Heating

The final energy demand for heating will increase by 139% in the 5.0 °C Scenario, from 7100 PJ/year in 2015 to 17,100 PJ/year in 2050. Energy efficiency measures will help to reduce the energy demand for heating by 59% in 2050 in the 2.0 °C Scenario, relative to the 5.0 °C case, and by 62% in the 1.5 °C Scenario. Today, renewables supply almost none of the Middle East's final energy demand for heating. Renewable energy will provide 23% of the Middle East's total heat demand in 2030 in the 2.0 °C Scenario and 25% in the 1.5 °C Scenario. In both scenarios, renewables will provide 100% of the total heat demand in 2050.

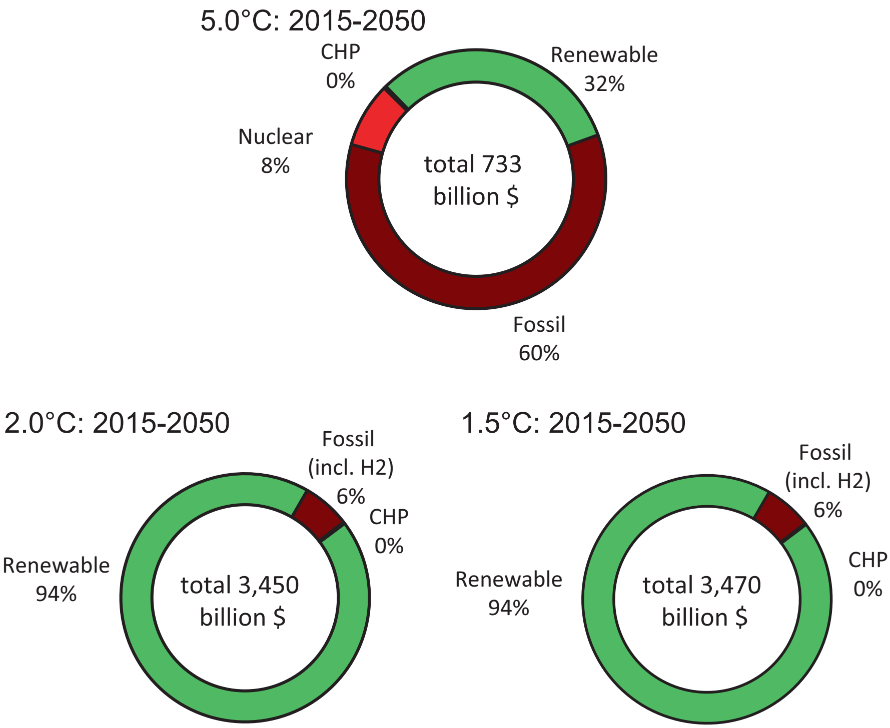


**Fig. 8.56** Middle East: investment shares for power generation in the scenarios

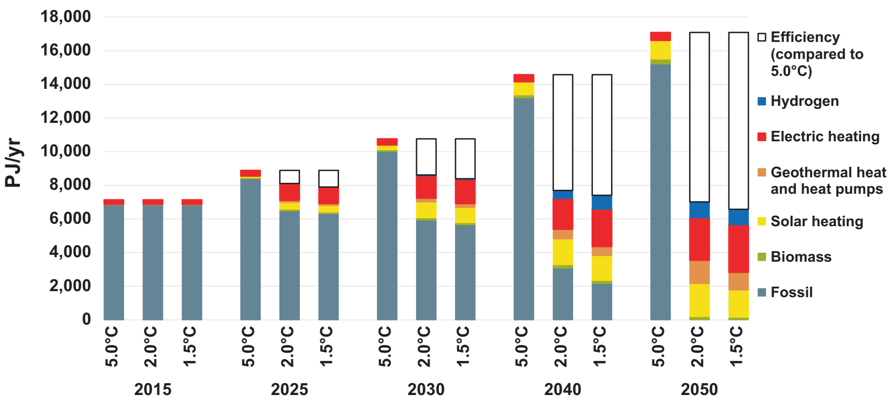


**Fig. 8.57** Middle East: development of heat supply by energy carrier in the scenarios

Figure 8.57 shows the development of different technologies for heating in the Middle East over time, and Table 8.51 provides the resulting renewable heat supply for all scenarios. The growing use of solar, geothermal, and environmental heat will

**Table 8.51** Middle East: development of renewable heat supply in the scenarios (excluding the direct use of electricity)

| in PJ/year | Case | 2015 | 2025 | 2030 | 2040 | 2050 |
|---|---|---|---|---|---|---|
| Biomass | 5.0 °C | 20 | 56 | 86 | 169 | 291 |
| | 2.0 °C | 20 | 101 | 132 | 200 | 196 |
| | 1.5 °C | 20 | 92 | 124 | 183 | 155 |
| Solar heating | 5.0 °C | 8 | 92 | 284 | 778 | 1113 |
| | 2.0 °C | 8 | 404 | 932 | 1535 | 1961 |
| | 1.5 °C | 8 | 393 | 909 | 1475 | 1619 |
| Geothermal heat and heat pumps | 5.0 °C | 0 | 0 | 0 | 0 | 0 |
| | 2.0 °C | 0 | 118 | 232 | 565 | 1387 |
| | 1.5 °C | 0 | 115 | 226 | 540 | 1057 |
| Hydrogen | 5.0 °C | 0 | 0 | 0 | 0 | 0 |
| | 2.0 °C | 0 | 0 | 51 | 488 | 946 |
| | 1.5 °C | 0 | 0 | 48 | 828 | 915 |
| Total | 5.0 °C | 28 | 149 | 370 | 947 | 1404 |
| | 2.0 °C | 28 | 624 | 1346 | 2788 | 4489 |
| | 1.5 °C | 28 | 601 | 1307 | 3025 | 3746 |

supplement electrification, with solar heat becoming the main direct renewable heat source in the 2.0 °C Scenario and 1.5 °C Scenario.

Heat from renewable hydrogen will further reduce the dependence on fossil fuels in both scenarios. Hydrogen consumption in 2050 will be around 950 PJ/year in the 2.0 °C Scenario and 920 PJ/year in the 1.5 °C Scenario. The direct use of electricity for heating will also increase by a factor of 9–10 between 2015 and 2050, and its final energy share will be 36% in 2050 in the 2.0 °C Scenario and 43% in the 1.5 °C Scenario (Fig. 8.57).

#### 8.9.1.6 The Middle East: Future Investments in the Heating Sector

The roughly estimated investments in renewable heating technologies to 2050 will amount to less than $440 billion in the 2.0 °C Scenario (including investments for plant replacement after their economic lifetimes), or approximately $12 billion per year. The largest share of investments in the Middle East is assumed to be for heat pumps (more than $200 billion), followed by solar collectors and geothermal heat use. The 1.5 °C Scenario assumes an even faster expansion of renewable technologies. However, the lower heat demand (compared with the 2.0 °C Scenario) will result in a lower average annual investment of around $10 billion per year (Table 8.52, Fig. 8.58).

**Table 8.52** Middle East: installed capacities for renewable heat generation in the scenarios

| in GW | Case | 2015 | 2025 | 2030 | 2040 | 2050 |
|---|---|---|---|---|---|---|
| Biomass | 5.0 °C | 4 | 10 | 14 | 25 | 38 |
| | 2.0 °C | 4 | 13 | 15 | 18 | 14 |
| | 1.5 °C | 4 | 12 | 15 | 17 | 13 |
| Geothermal | 5.0 °C | 0 | 0 | 0 | 0 | 0 |
| | 2.0 °C | 0 | 2 | 8 | 19 | 30 |
| | 1.5 °C | 0 | 2 | 8 | 18 | 35 |
| Solar heating | 5.0 °C | 1 | 17 | 51 | 139 | 198 |
| | 2.0 °C | 1 | 72 | 142 | 217 | 252 |
| | 1.5 °C | 1 | 71 | 139 | 209 | 206 |
| Heat pumps | 5.0 °C | 0 | 0 | 0 | 0 | 0 |
| | 2.0 °C | 0 | 12 | 17 | 43 | 122 |
| | 1.5 °C | 0 | 12 | 17 | 42 | 76 |
| Total[a] | 5.0 °C | 6 | 26 | 65 | 164 | 237 |
| | 2.0 °C | 6 | 99 | 183 | 297 | 418 |
| | 1.5 °C | 6 | 96 | 178 | 286 | 330 |

[a] Excluding direct electric heating

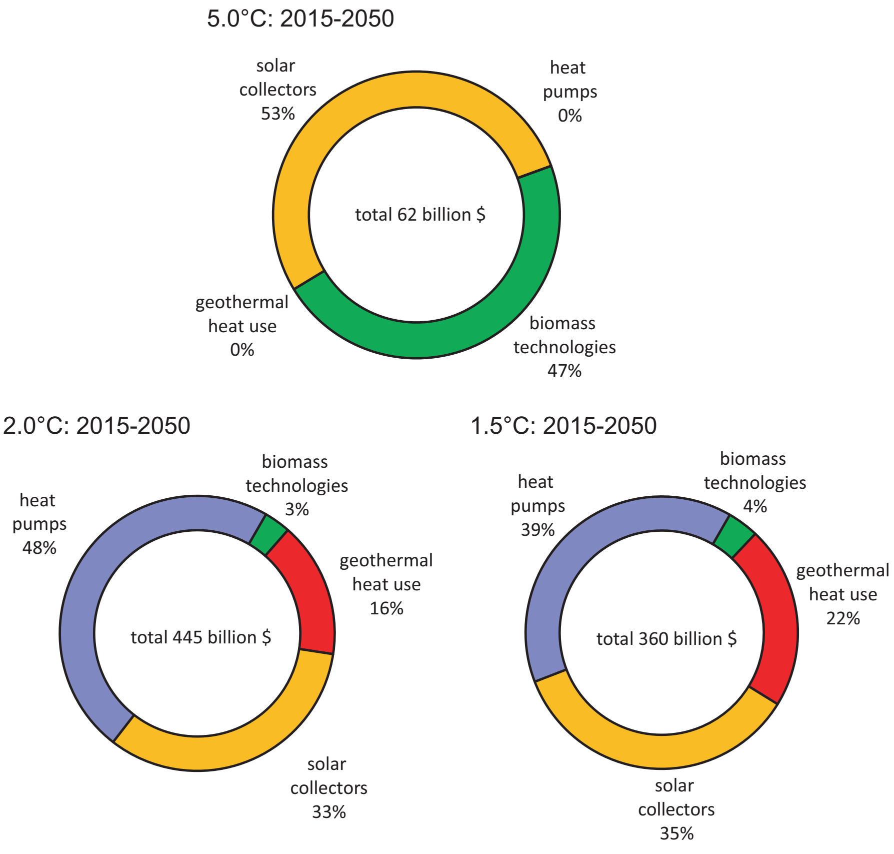


**Fig. 8.58** Middle East: development of investments for renewable heat-generation technologies in the scenarios

#### 8.9.1.7 The Middle East: transport

Energy demand in the transport sector in the Middle East is expected to increase in the 5.0 °C Scenario by 133%, from around 5700 PJ/year in 2015 to 13,300 PJ/year in 2050. In the 2.0 °C Scenario, assumed technical, structural, and behavioural changes will save 67% (8860 PJ/year) by 2050 compared with the 5.0 °C Scenario. Additional modal shifts, technology switches, and a reduction in the transport demand will lead to even higher energy savings in the 1.5 °C Scenario of 79% (or 10,400 PJ/year) in 2050 compared with the 5.0 °C case (Table 8.53, Fig. 8.59).

By 2030, electricity will provide 4% (70 TWh/year) of the transport sector's total energy demand in the 2.0 °C Scenario, whereas in 2050, the share will be 39% (480 TWh/year). In 2050, up to 620 PJ/year of hydrogen will be used in the transport sector as a complementary renewable option. In the 1.5 °C Scenario, the annual electricity demand will be 350 TWh in 2050. The 1.5 °C Scenario also assumes a hydrogen demand of 450 PJ/year by 2050.

Biofuel use is limited in the 2.0 °C Scenario to a maximum of 370 PJ/year. Therefore, around 2030, synthetic fuels based on power-to-liquid will be introduced, with a maximum consumption of 1670 PJ/year in 2050. Biofuel use in the 1.5 °C Scenario with have a maximum of 430 PJ/year. The maximum synthetic fuel demand will amount to 920 PJ/year.

**Table 8.53** Middle East: projection of transport energy demand by mode in the scenarios

| in PJ/year | Case | 2015 | 2025 | 2030 | 2040 | 2050 |
|---|---|---|---|---|---|---|
| Rail | 5.0 °C | 184 | 38 | 48 | 65 | 75 |
| | 2.0 °C | 184 | 64 | 103 | 169 | 157 |
| | 1.5 °C | 184 | 89 | 117 | 161 | 194 |
| Road | 5.0 °C | 5425 | 6613 | 7802 | 10,999 | 12,992 |
| | 2.0 °C | 5425 | 5928 | 5732 | 4510 | 4194 |
| | 1.5 °C | 5425 | 5246 | 4528 | 2899 | 2618 |
| Domestic aviation | 5.0 °C | 57 | 83 | 103 | 136 | 146 |
| | 2.0 °C | 57 | 60 | 57 | 47 | 37 |
| | 1.5 °C | 57 | 57 | 52 | 36 | 28 |
| Domestic navigation | 5.0 °C | 0 | 0 | 0 | 0 | 0 |
| | 2.0 °C | 0 | 0 | 0 | 0 | 0 |
| | 1.5 °C | 0 | 0 | 0 | 0 | 0 |
| Total | 5.0 °C | 5666 | 6734 | 7954 | 11,200 | 13,213 |
| | 2.0 °C | 5666 | 6051 | 5893 | 4726 | 4388 |
| | 1.5 °C | 5666 | 5392 | 4697 | 3096 | 2840 |

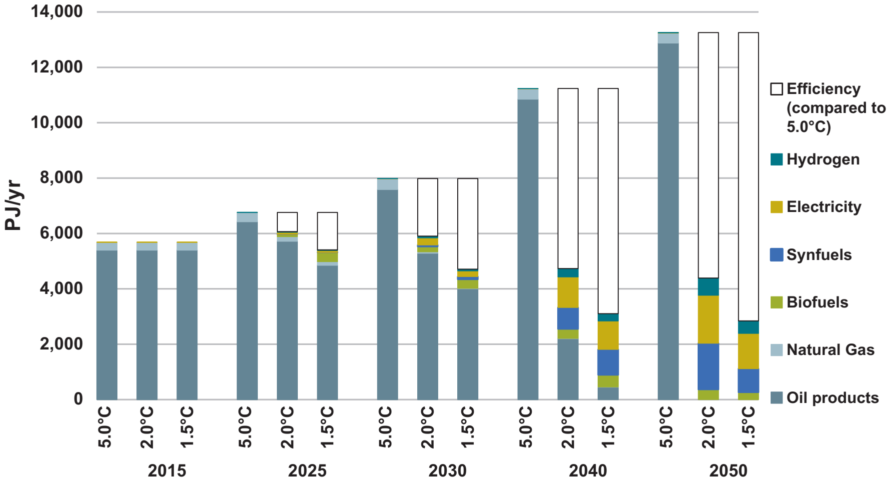


**Fig. 8.59** Middle East: final energy consumption by transport in the scenarios

### 8.9.1.8 The Middle East: Development of $CO_2$ Emissions

In the 5.0 °C Scenario, the Middle East's annual $CO_2$ emissions will increase by 76% from 1760 Mt. in 2015 to 3094 Mt. in 2050. The stringent mitigation measures in both alternative scenarios will cause the annual emissions to fall to 510 Mt. in 2040 in the 2.0 °C Scenario and to 220 Mt. in the 1.5 °C Scenario, with further reductions to almost zero by 2050. In the 5.0 °C case, the cumulative $CO_2$ emissions from 2015 until 2050 will add up to 90 Gt. In contrast, in the 2.0 °C and 1.5 °C Scenarios, the cumulative emissions for the period from 2015 until 2050 will be 38 Gt and 31 Gt, respectively.

Therefore, the cumulative $CO_2$ emissions will decrease by 58% in the 2.0 °C Scenario and by 66% in the 1.5 °C Scenario compared with the 5.0 °C case. A rapid reduction in annual emissions will occur in both alternative scenarios. In the 2.0 °C Scenario, this reduction will be greatest in 'Industry' followed by the 'Power generation' and 'Transport' sectors (Fig. 8.60).

### 8.9.1.9 The Middle East: Primary Energy Consumption

The levels of primary energy consumption in the three scenarios when the assumptions discussed above are taken into account are shown in Fig. 8.61. In the 2.0 °C Scenario, the primary energy demand will decrease by 16%, from around 30,300 PJ/year in 2015 to 25,400 PJ/year in 2050. Compared with the 5.0 °C Scenario, the overall primary energy demand will decrease by 59% by 2050 in the 2.0 °C Scenario (5.0 °C: 61,700 PJ in 2050). In the 1.5 °C Scenario, the primary energy demand will be even lower (22,300 PJ in 2050) because the final energy demand and conversion losses will be lower.

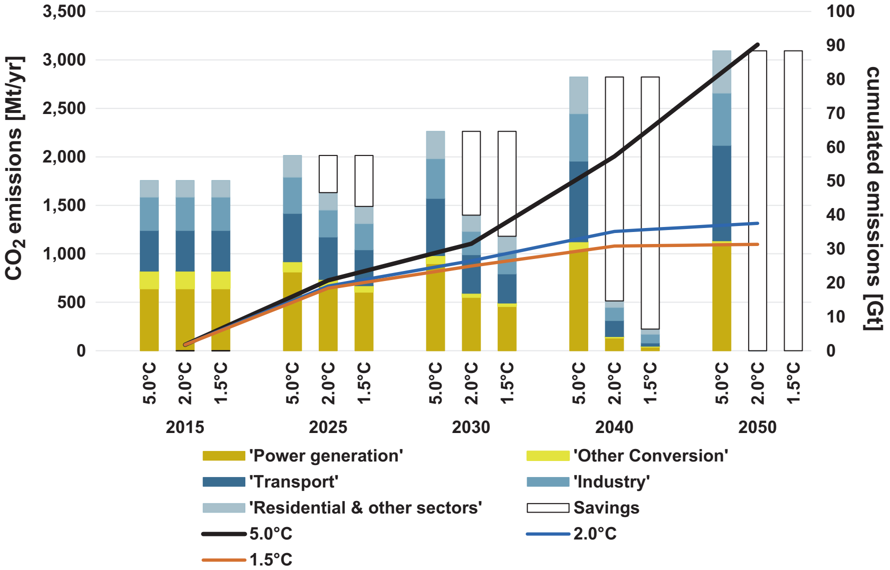


**Fig. 8.60** Middle East: development of $CO_2$ emissions by sector and cumulative $CO_2$ emissions (after 2015) in the scenarios ('Savings' = reduction compared with the 5.0 °C Scenario)

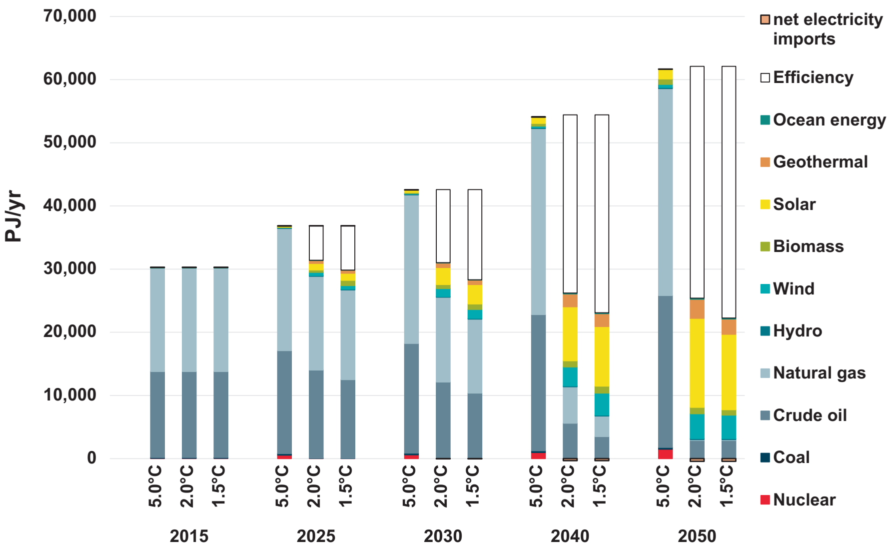


**Fig. 8.61** Middle East: projection of total primary energy demand (PED) by energy carrier in the scenarios (including electricity import balance)

Both the 2.0 °C and 1.5 °C Scenarios aim to rapidly phase-out coal and oil. This will cause renewable energy to have a primary energy share of 18% in 2030 and 88% in 2050 in the 2.0 °C Scenario. In the 1.5 °C Scenario, renewables will have a primary energy share of more than 86% in 2050 (including non-energy consumption, which will still include fossil fuels). Nuclear energy will be phased-out in 2035 in both the 2.0 °C and the 1.5 °C Scenarios. The cumulative primary energy consumption of natural gas in the 5.0 °C case will add up to 830 EJ, the cumulative coal consumption to about 10 EJ, and the crude oil consumption to 630 EJ. In the 2.0 °C Scenario, the cumulative gas demand will amount to 330 EJ, the cumulative coal demand to 1 EJ, and the cumulative oil demand to 310 EJ. Even lower fossil fuel use will be achieved in the 1.5 °C Scenario: 280 EJ for natural gas, 0.9 EJ for coal, and 270 EJ for oil.

## *8.9.2 The Middle East: Power Sector Analysis*

The Middle East has significant renewable energy potential. The region's solar radiation is among the highest in the world and it has good wind conditions in coastal areas and in its mountain ranges. The electricity market is fragmented, and policies differ significantly. However, most countries are connected to their neighbours by transmission lines. Saudi Arabia, the geographic centre of the region, has connections to most neighbouring countries. Both the 2.0 °C Scenario and the 1.5 °C Scenario assume that the Middle East will remain a significant player in the energy market, moving from oil and gas to solar, and that it will play an important role in producing synthetic fuels and hydrogen for export.

### 8.9.2.1 The Middle East: Development of Power Plant Capacities

The overwhelming majority of fossil-fuel-based power generation in the Middle East is from gas-fired power plants. Both scenarios assume that this gas capacity (in GW) will remain on the same level until 2050, but will be converted to hydrogen. The annual market for solar PV must increase to 2.5 GW in 2020 and to 28.5 GW by 2030 in the 2.0 °C Scenario, and to 35 GW in the 1.5 °C Scenario. The onshore wind market must expand to 10 GW by 2025 in both scenarios. This represents a very ambitious target because the market for wind power plants in the Middle East has never been higher than 117 MW (GWEC 2018) (in 2015). Parts of the offshore oil and gas industry can be transitioned into an offshore wind industry. The total capacity assumed for the Middle East by 2050 is 20–25 GW under both scenarios. For comparison, the UK had an installed capacity for offshore wind of 6.8 GW and Germany of 5.4 GW in 2017 (GWEC 2018). The vast solar resources in the Middle

**Table 8.54** Middle East: average annual change in installed power plant capacity

| Middle East – power generation: average annual change of installed capacity [GW/a] | 2015–2025 | | 2026–2035 | | 2036–2050 | |
|---|---|---|---|---|---|---|
| | 2.0 °C | 1.5 °C | 2.0 °C | 1.5 °C | 2.0 °C | 1.5 °C |
| Hard coal | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Lignite | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Gas | 1.5 | 7.0 | 1.9 | 6.2 | −19.1 | 3.0 |
| Hydrogen-gas | 0.0 | 0.3 | 1.5 | 1.7 | 20.3 | 24.2 |
| Oil/Diesel | −0.1 | −4.0 | −8.9 | −8.1 | −0.8 | −0.5 |
| Nuclear | −0.1 | 0.0 | −0.1 | −0.1 | 0.0 | 0.0 |
| Biomass | 0.2 | 0.3 | 0.2 | 0.1 | 0.2 | 0.0 |
| Hydro | 1.0 | 0.5 | 0.2 | 0.2 | 0.5 | 0.5 |
| Wind (onshore) | 6.5 | 19.3 | 28.3 | 35.5 | 14.7 | 7.6 |
| Wind (offshore) | 0.2 | 0.5 | 0.8 | 0.8 | 1.4 | 1.2 |
| PV (roof top) | 7.3 | 19.0 | 26.2 | 29.9 | 46.4 | 32.3 |
| PV (utility scale) | 2.4 | 6.3 | 8.7 | 10.0 | 15.5 | 10.8 |
| Geothermal | 0.6 | 0.8 | 1.1 | 1.1 | 1.0 | 0.6 |
| Solar thermal power plants | 1.3 | 5.4 | 13.1 | 20.3 | 11.4 | 3.7 |
| Ocean energy | 0.3 | 1.3 | 1.3 | 2.5 | 1.0 | 1.7 |
| Renewable fuel based co-generation | 0.0 | 0.0 | 0.1 | 0.1 | 0.0 | 0.0 |

East make it suitable for CSP plants—the total capacity by 2050 is calculated to be 252 GW (2.0 °C Scenario), equal to the gas power plant capacity in the Middle East in 2017 (Table 8.54).

#### 8.9.2.2 Middle East: Utilization of Power-Generation Capacities

In 2015, the base year of the scenario calculations, the Middle East had less than 0.5% variable power generation. Table 8.55 shows the rapidly increasing shares of variable renewable power generation across the Middle East. Israel is included in the Middle East region (as opposed to the IEA region used for the long-term scenario) to reflect its current and possible future interconnection with the regional power system. The current interconnection capacity between all sub-regions is assumed to be 5%, increasing to 20% in 2030 and 25% in 2050. Dispatchable renewables will have a stable market share of around 15%–20% over the entire modelling period in the 2.0 °C Scenario and 15%–20% in the 1.5 °C Scenario.

Average capacity factors correspond to the results for the other world regions. Table 8.56 shows that the limited dispatchable fossil and nuclear generation will drop quickly, whereas the significant gas power plant capacity within the region can increase capacity factors to take over their load and reduce carbon emissions at an early stage. The calculation results are attributed to the assumed dispatch order, which prioritizes gas over coal and nuclear.

**Table 8.55** Middle East: power system shares by technology group

| Power generation structure and interconnection | | 2.0 °C | | | | 1.5 °C | | | |
|---|---|---|---|---|---|---|---|---|---|
| Middle East | | Variable RE | Dispatch RE | Dispatch fossil | Inter-connection | Variable RE | Dispatch RE | Dispatch fossil | Inter-connection |
| Israel | 2015 | 0% | 12% | 88% | 5% | | | | |
| | 2030 | 41% | 18% | 41% | 20% | 46% | 18% | 36% | 15% |
| | 2050 | 81% | 18% | 0% | 25% | 64% | 15% | 21% | 20% |
| North-ME | 2015 | 0% | 12% | 88% | 5% | | | | |
| | 2030 | 50% | 20% | 30% | 20% | 55% | 19% | 26% | 15% |
| | 2050 | 83% | 17% | 0% | 25% | 74% | 15% | 10% | 20% |
| Saudi Arabia-ME | 2015 | 0% | 12% | 88% | 5% | | | | |
| | 2030 | 51% | 17% | 32% | 20% | 55% | 17% | 28% | 15% |
| | 2050 | 83% | 17% | 0% | 25% | 72% | 16% | 12% | 20% |
| UAE-ME | 2015 | 0% | 12% | 88% | 5% | | | | |
| | 2030 | 36% | 20% | 45% | 20% | 40% | 20% | 40% | 15% |
| | 2050 | 76% | 24% | 0% | 25% | 53% | 18% | 28% | 20% |
| East-ME | 2015 | 0% | 12% | 88% | 5% | | | | |
| | 2030 | 42% | 20% | 38% | 20% | 47% | 21% | 32% | 15% |
| | 2050 | 80% | 20% | 0% | 25% | 63% | 17% | 20% | 20% |
| Iraq-ME | 2015 | 0% | 12% | 88% | 5% | | | | |
| | 2030 | 60% | 18% | 21% | 20% | 65% | 17% | 18% | 15% |
| | 2050 | 82% | 18% | 0% | 25% | 76% | 16% | 7% | 20% |

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| Iran-ME | 2015 | 0% | 12% | 88% | 5% | | | | |
| | 2030 | 57% | 19% | 24% | 20% | 62% | 18% | 21% | 15% |
| | 2050 | 81% | 19% | 0% | 25% | 73% | 17% | 9% | 20% |
| Middle East | 2015 | 0% | 12% | 88% | | | | | |
| | 2030 | 51% | 19% | 31% | | 56% | 18% | 27% | |
| | 2050 | 81% | 19% | 0% | | 70% | 16% | 13% | |

**Table 8.56** Middle East: capacity factors by generation type

| Utilization of variable and dispatchable power generation: | | 2015 | 2020 | 2020 | 2030 | 2030 | 2040 | 2040 | 2050 | 2050 |
|---|---|---|---|---|---|---|---|---|---|---|
| Middle East | | | 2.0 °C | 1.5 °C | 2.0 °C | 1.5 °C | 2.0 °C | 1.5 °C | 2.0 °C | 1.5 °C |
| Capacity factor – average | [%/yr] | 52.6% | 45% | 43% | 27% | 24% | 34% | 21% | 29% | 25% |
| Limited dispatchable: fossil and nuclear | [%/yr] | 31.1% | 13% | 13% | 5% | 2% | 19% | 3% | 10% | 5% |
| Limited dispatchable: renewable | [%/yr] | 26.3% | 34% | 34% | 47% | 42% | 50% | 21% | 28% | 30% |
| Dispatchable: fossil | [%/yr] | 52.9% | 41% | 40% | 15% | 10% | 45% | 8% | 17% | 16% |
| Dispatchable: renewable | [%/yr] | 38.9% | 83% | 83% | 66% | 57% | 43% | 20% | 36% | 38% |
| Variable: renewable | [%/yr] | 6.6% | 12% | 12% | 24% | 23% | 27% | 23% | 29% | 25% |

#### 8.9.2.3 The Middle East: Development of Load, Generation, and Residual Load

The Middle East is assumed to be one of the exporters of solar electricity into the EU, so the calculated solar installation capacities throughout the region will be significantly higher than required for self-supply.

Table 8.57 shows a negative residual load in almost all sub-regions for every year and in both scenarios. This is attributable to substantial oversupply, so the production of renewables is almost constantly higher than the demand. This electricity has been calculated as exports from the Middle East and imports to Europe.

The Middle East will be one of three dedicated renewable energy export regions. These exports are in the form of renewable fuels and electricity. The [R]E 24/7 model does not calculate electricity exchange in 1 h steps between the world regions, and therefore the amount of electricity exported accumulates from year to year. The load curves for the Middle East and European regions are not calculated separately.

Table 8.58 provides an overview of the calculated storage and dispatch power requirements by sub-region in the Middle East. Iran and Saudi Arabia West Africa will require the highest storage capacity, due to the very high share of solar PV systems in residential areas. Like the Africa, the Middle East is one of the global renewable fuel production regions and it is assumed that all sub-regions of the Middle East have equal amounts of energy export potential. However, a more detailed examination of export energy is required, which is beyond the scope of this project.

**Table 8.57** Middle East: load, generation, and residual load development

| Power generation structure | | 2.0 °C | | | | 1.5 °C | | | |
|---|---|---|---|---|---|---|---|---|---|
| Middle East | | Max demand [GW] | Max generation [GW] | Max residual load [GW] | Max interconnection requirements [GW] | Max demand [GW] | Max generation [GW] | Max residual load [GW] | Max interconnection requirements [GW] |
| Israel | 2020 | 11.5 | 11.0 | −2.9 | | 11.5 | 11.9 | −2.9 | |
| | 2030 | 14.0 | 17.3 | −1.8 | 5 | 14.3 | 19.9 | −1.4 | 7 |
| | 2050 | 29.7 | 62.7 | −3.7 | 37 | 29.3 | 55.2 | −10.3 | 36 |
| North-ME | 2020 | 33.7 | 25.7 | −12.1 | | 33.8 | 29.4 | −11.6 | |
| | 2030 | 39.7 | 44.6 | −12.1 | 17 | 40.6 | 52.6 | −11.2 | 23 |
| | 2050 | 83.6 | 196.5 | −11.5 | 124 | 77.5 | 172.8 | −19.9 | 115 |
| Saudi Arabia-ME | 2020 | 59.5 | 45.9 | −3.4 | | 59.6 | 45.4 | −2.4 | |
| | 2030 | 72.4 | 85.9 | 2.3 | 11 | 75.1 | 99.8 | 5.6 | 19 |
| | 2050 | 173.6 | 380.9 | −21.7 | 229 | 168.6 | 334.0 | −59.4 | 225 |
| UAE-ME | 2020 | 21.2 | 29.8 | −0.4 | | 21.2 | 29.6 | 1.3 | |
| | 2030 | 26.0 | 44.1 | 2.2 | 16 | 27.0 | 50.7 | 3.4 | 20 |
| | 2050 | 62.2 | 120.2 | −7.4 | 65 | 61.3 | 105.4 | −23.4 | 67 |
| East-Middle East | 2020 | 12.0 | 23.3 | −2.5 | | 12.0 | 22.6 | −2.6 | |
| | 2030 | 14.8 | 31.3 | −1.2 | 18 | 15.1 | 35.9 | −0.8 | 22 |
| | 2050 | 32.5 | 63.4 | −3.9 | 35 | 31.2 | 55.6 | −7.2 | 32 |
| Iraq-ME | 2020 | 20.1 | 13.8 | −7.6 | | 20.2 | 13.8 | −7.3 | |
| | 2030 | 26.0 | 30.4 | −7.4 | 12 | 26.8 | 35.8 | −8.1 | 17 |
| | 2050 | 64.3 | 137.5 | −7.8 | 81 | 57.7 | 119.9 | −20.0 | 82 |
| Iran-ME | 2020 | 49.4 | 56.9 | −12.2 | | 49.4 | 56.4 | −12.2 | |
| | 2030 | 76.1 | 88.1 | −14.3 | 26 | 78.3 | 103.9 | −11.4 | 37 |
| | 2050 | 188.5 | 399.1 | −22.7 | 233 | 174.3 | 348.0 | −40.5 | 214 |

**Table 8.58** Middle East: storage and dispatch service requirements

| Storage and dispatch | | 2.0 °C | | | | | 1.5 °C | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | Required to avoid curtailment | Utilization battery -through-put- | Utilization PSH -through-put- | Total storage demand (incl. H2) | Dispatch hydrogen-based | Required to avoid curtailment | Utilization battery -through-put- | Utilization PSH -through-put- | Total storage demand (incl. H2) | Dispatch hydrogen-based |
| Middle East | | [GWh/year] | [GWh/ year] | [GWh/ year] | [GWh/ year] | [GWh/year] | [GWh/year] | [GWh/ year] | [GWh/ year] | [GWh/ year] | [GWh/year] |
| Israel | 2020 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | 2030 | 29 | 0 | 10 | 10 | 0 | 226 | 0 | 36 | 36 | 8 |
| | 2050 | 24,725 | 11 | 379 | 390 | 0 | 14,244 | 11 | 320 | 331 | 529 |
| North-ME | 2020 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | 2030 | 1164 | 0 | 193 | 194 | 0 | 3596 | 1 | 355 | 356 | 20 |
| | 2050 | 109,498 | 32 | 1409 | 1441 | 0 | 84,974 | 31 | 1434 | 1465 | 1193 |
| Saudi Arabia | 2020 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | 2030 | 3366 | 1 | 513 | 514 | 0 | 11,457 | 2 | 900 | 902 | 39 |
| | 2050 | 231,140 | 73 | 2685 | 2757 | 0 | 159,949 | 74 | 2429 | 2503 | 2624 |
| UAE | 2020 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | 2030 | 9 | 0 | 5 | 5 | 0 | 233 | 0 | 45 | 45 | 17 |
| | 2050 | 35,463 | 24 | 679 | 703 | 0 | 17,093 | 23 | 507 | 531 | 1075 |

| | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| East-ME | 2020 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | 2030 | 2 | 0 | 3 | 3 | 0 | 117 | 0 | 29 | 29 | 9 |
| | 2050 | 21,916 | 12 | 410 | 421 | 0 | 12,920 | 12 | 350 | 362 | 490 |
| Iraq | 2020 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | 2030 | 3941 | 0 | 330 | 330 | 0 | 8185 | 0 | 446 | 447 | 10 |
| | 2050 | 87,343 | 18 | 892 | 910 | 0 | 74,252 | 17 | 920 | 937 | 684 |
| Iran | 2020 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | 2030 | 9576 | 1 | 831 | 833 | 0 | 21,130 | 1 | 1127 | 1128 | 30 |
| | 2050 | 242,799 | 50 | 2508 | 2558 | 0 | 190,790 | 47 | 2443 | 2490 | 2036 |
| Middle East | 2020 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | 2030 | 18,088 | 4 | 1886 | 1890 | 0 | 44,945 | 4 | 2939 | 2943 | 132 |
| | 2050 | 752,882 | 218 | 8962 | 9180 | 0 | 554,222 | 215 | 8404 | 8618 | 8630 |

## 8.10 Eastern Europe/Eurasia

### *8.10.1 Eastern Europe/Eurasia: Long-Term Energy Pathways*

#### 8.10.1.1 Eastern Europe/Eurasia: Final Energy Demand by Sector

The future development pathways for Eastern Europe/Eurasia's final energy demand when the assumptions on population growth, GDP growth, and energy intensity are combined are shown in Fig. 8.62 for the 5.0 °C, 2.0 °C, and 1.5 °C Scenarios. In the 5.0 °C Scenario, the total final energy demand will increase by 45%, from the current 25,500 PJ/year to 37,000 PJ/year in 2050. In the 2.0 °C Scenario, the final energy demand will decrease by 25% compared with current consumption and will reach 19,100 PJ/year by 2050. The final energy demand in the 1.5 °C Scenario will reach 17,800 PJ, 30% below the 2015 level. In the 1.5 °C Scenario, the final energy demand in 2050 will be 7% lower than in the 2.0 °C Scenario. The electricity demand for 'classical' electrical devices (without power-to-heat or e-mobility) will increase from 910 TWh/year in 2015 to 1000 TWh/year (2.0 °C) or 940 TWh/year (1.5 °C) by 2050. Compared with the 5.0 °C case (1600 TWh/year in 2050), the efficiency measures in the 2.0 °C and 1.5 °C Scenarios will save a maximum of 600 TWh/year and 660 TWh/year, respectively.

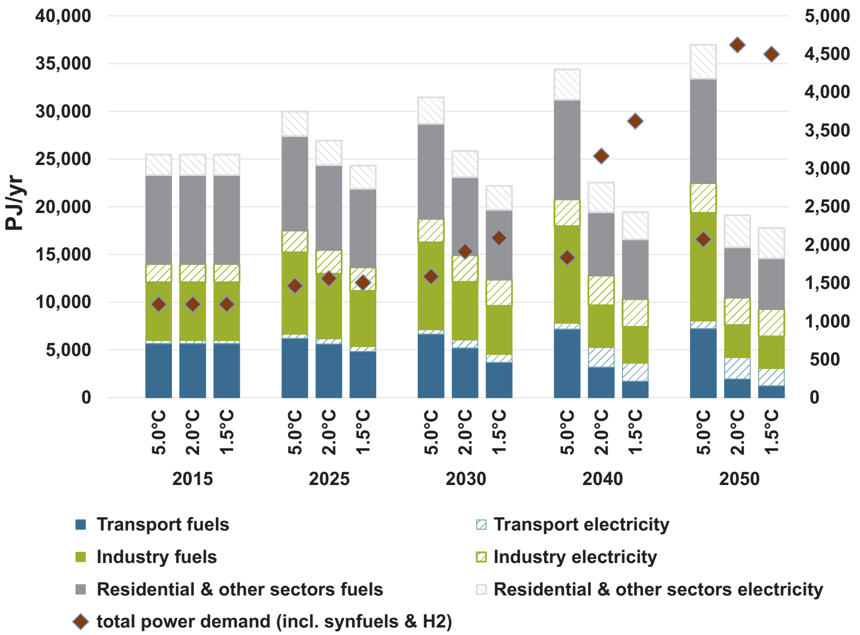


**Fig. 8.62** Eastern Europe/Eurasia: development of the final energy demand by sector in the scenarios

Electrification will lead to a significant increase in the electricity demand by 2050. In the 2.0 °C Scenario, the electricity demand for heating will be approximately 700 TWh/year due to electric heaters and heat pumps, and in the transport sector, the electricity demand will be approximately 2300 TWh/year due to increased electric mobility. The generation of hydrogen (for transport and high-temperature process heat) and the manufacture of synthetic fuels (mainly for transport) will add an additional power demand of 2300 TWh/year. Therefore, the gross power demand will rise from 1700 TWh/year in 2015 to 4900 TWh/year in 2050 in the 2.0 °C Scenario, 88% higher than in the 5.0 °C case. In the 1.5 °C Scenario, the gross electricity demand will increase to a maximum of 4800 TWh/year in 2050.

Efficiency gains could be even larger in the heating sector than in the electricity sector. In the 2.0 °C and 1.5 °C Scenarios, a final energy consumption equivalent to more than 10,700 PJ/year is avoided by 2050 compared with the 5.0 °C Scenario through efficiency gains.

#### 8.10.1.2 Eastern Europe/Eurasia: Electricity Generation

The development of the power system is characterized by a dynamically growing renewable energy market and an increasing proportion of total power from renewable sources. By 2050, 100% of the electricity produced in Eastern Europe/Eurasia will come from renewable energy sources in the 2.0 °C Scenario. 'New' renewables—mainly wind, solar, and geothermal energy—will contribute 75% of the total electricity generation. Renewable electricity's share of the total production will be 55% by 2030 and 84% by 2040. The installed capacity of renewables will reach about 560 GW by 2030 and 1900 GW by 2050. The share of renewable electricity generation in 2030 in the 1.5 °C Scenario is assumed to be 66%. In the 1.5 °C Scenario, the generation capacity from renewable energy will be approximately 1870 GW in 2050.

Table 8.59 shows the development of different renewable technologies in Eastern Europe/Eurasia over time. Figure 8.63 provides an overview of the overall power-generation structure in Eastern Europe/Eurasia. From 2020 onwards, the continuing growth of wind and PV, up to 740 GW and 820 GW, respectively, will be complemented by up to 30 GW of solar thermal generation, as well as limited biomass, geothermal, and ocean energy, in the 2.0 °C Scenario. Both the 2.0 °C Scenario and 1.5 °C Scenario will lead to a high proportion of variable power generation (PV, wind, and ocean) of 28% and 32%, respectively, by 2030, and 62% and 61%, respectively, by 2050.

**Table 8.59** Eastern Europe/Eurasia: development of renewable electricity-generation capacity in the scenarios

| in GW | Case | 2015 | 2025 | 2030 | 2040 | 2050 |
|---|---|---|---|---|---|---|
| Hydro | 5.0 °C | 98 | 107 | 112 | 123 | 136 |
| | 2.0 °C | 98 | 107 | 112 | 115 | 116 |
| | 1.5 °C | 98 | 107 | 112 | 115 | 116 |
| Biomass | 5.0 °C | 1 | 4 | 6 | 9 | 14 |
| | 2.0 °C | 1 | 21 | 45 | 64 | 96 |
| | 1.5 °C | 1 | 40 | 74 | 86 | 109 |
| Wind | 5.0 °C | 6 | 9 | 10 | 17 | 23 |
| | 2.0 °C | 6 | 70 | 176 | 469 | 744 |
| | 1.5 °C | 6 | 74 | 196 | 531 | 697 |
| Geothermal | 5.0 °C | 0 | 1 | 1 | 2 | 4 |
| | 2.0 °C | 0 | 5 | 12 | 38 | 71 |
| | 1.5 °C | 0 | 7 | 21 | 46 | 71 |
| PV | 5.0 °C | 4 | 5 | 6 | 8 | 10 |
| | 2.0 °C | 4 | 108 | 209 | 502 | 817 |
| | 1.5 °C | 4 | 132 | 294 | 678 | 821 |
| CSP | 5.0 °C | 0 | 0 | 0 | 0 | 0 |
| | 2.0 °C | 0 | 0 | 1 | 16 | 33 |
| | 1.5 °C | 0 | 0 | 1 | 22 | 34 |
| Ocean | 5.0 °C | 0 | 0 | 0 | 0 | 0 |
| | 2.0 °C | 0 | 0 | 1 | 13 | 19 |
| | 1.5 °C | 0 | 0 | 1 | 13 | 19 |
| Total | 5.0 °C | 108 | 126 | 136 | 159 | 186 |
| | 2.0 °C | 108 | 310 | 555 | 1216 | 1896 |
| | 1.5 °C | 108 | 360 | 698 | 1492 | 1869 |

#### 8.10.1.3 Eastern Europe/Eurasia: Future Costs of Electricity Generation

Figure 8.64 shows the development of the electricity-generation and supply costs over time, including the $CO_2$ emission costs, in all scenarios. The calculated electricity-generation costs in 2015 (referring to full costs) were around 4.5 ct/kWh. In the 5.0 °C case, the generation costs will increase until 2050, when they reach 10 ct/kWh. In the 2.0 °C Scenario, the generation costs will increase until 2050, when they will reach 8.6 ct/kWh. In the 1.5 °C Scenario, they will increase to 9.3 ct/kWh, and then drop to 8.8 ct/kWh by 2050. In the 2.0 °C Scenario, the generation costs in 2050 will be 1.4 ct/kWh lower than in the 5.0 °C case. In the 1.5 °C Scenario, the generation costs in 2050 will be 1.1 ct/kWh lower than in the 5.0 °C case. Note that these estimates of generation costs do not take into account integration costs such as power grid expansion, storage, or other load-balancing measures.

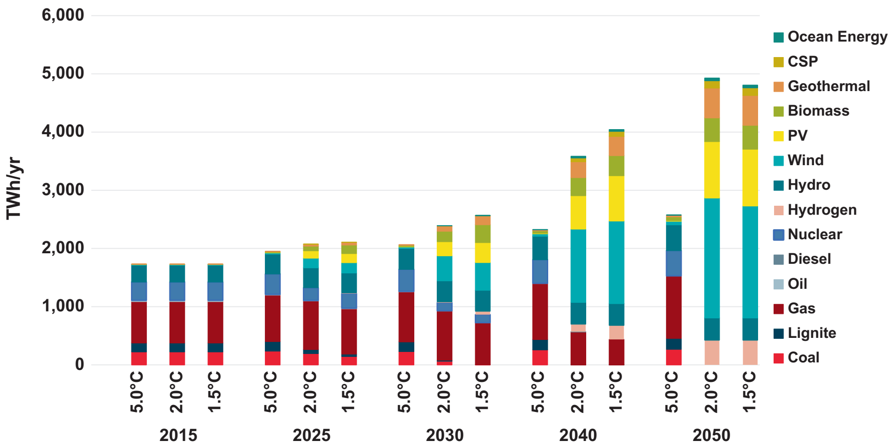


**Fig. 8.63** Eastern Europe/Eurasia: development of electricity-generation structure in the scenarios

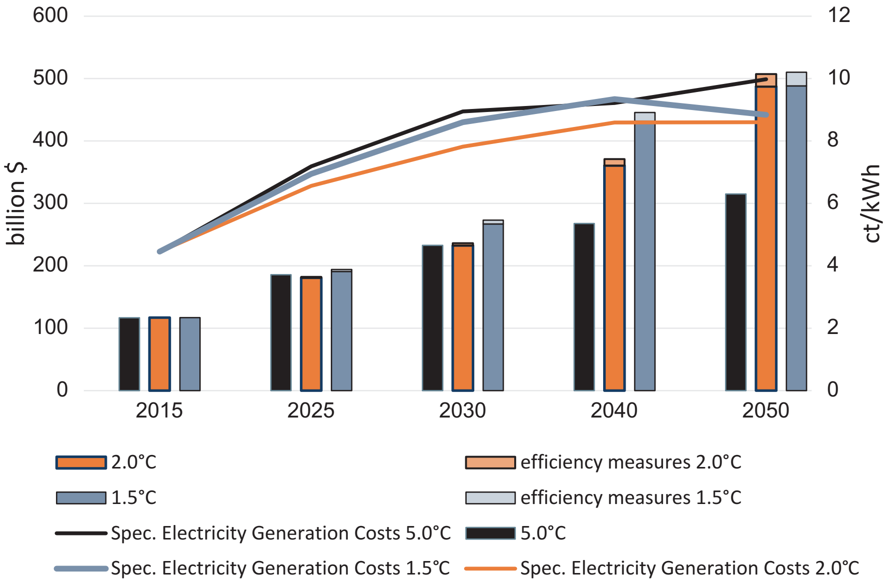


**Fig. 8.64** Eastern Europe/Eurasia: development of total electricity supply costs and specific electricity-generation costs in the scenarios

In the 5.0 °C case, the growth of demand and increasing fossil fuel prices will cause the total electricity supply costs to rise from today's $120 billion/year to more than $320 billion/year in 2050. In both alternative scenarios, the total supply costs will be $490 billion/year in 2050. The long-term costs of electricity supply will be more than 54% higher in the 2.0 °C Scenario than in the 5.0 °C Scenario as a result of the estimated generation costs and the electrification of heating and mobility. Further electrification and synthetic fuel generation in the 1.5 °C Scenario will result in total power generation costs that are 55% higher than in the 5.0 °C case.

Compared with these results, the generation costs when the $CO_2$ emission costs are not considered will increase in the 5.0 °C case to 6.9 ct/kWh. In the 2.0 °C Scenario, the generation costs will increase continuously until 2050, when they reach 8.6 ct/kWh. They will increase to 8.8 ct/kWh in the 1.5 °C Scenario. In the 2.0 °C Scenario, the generation costs will reach a maximum, at 1.7 ct/kWh higher than in the 5.0 °C case, and this will occur in 2050. In the 1.5 °C Scenario, the maximum difference in generation costs compared with the 5.0 °C case will be 2.6 ct/kWh in 2040. The generation costs in 2050 will still be 2 ct/kWh higher than in the 5.0 °C case. If the $CO_2$ costs are not considered, the total electricity supply costs in the 5.0 °C case will rise to about $240 billion in 2050.

#### 8.10.1.4 Eastern Europe/Eurasia: Future Investments in the Power Sector

An investment of around $3600 billion will be required for power generation between 2015 and 2050 in the 2.0 °C Scenario—including additional power plants for the production of hydrogen and synthetic fuels and investments in plant replacement at the end of their economic lives. This value is equivalent to approximately $100 billion per year on average, and is $2660 billion more than in the 5.0 °C case ($940 billion). An investment of around $3770 billion for power generation will be required between 2015 and 2050 in the 1.5 °C Scenario. On average, this is an investment of $105 billion per year. In the 5.0 °C Scenario, the investment in conventional power plants will be around 40% of the total cumulative investments, whereas approximately 60% will be invested in renewable power generation and co-generation (Fig. 8.65).

However, in the 2.0 °C (1.5 °C) scenario, Eastern Europe/Eurasia will shift almost 97% (98%) of its entire investments to renewables and co-generation. By 2030, the fossil fuel share of the power sector investments will predominantly focus on gas power plants that can also be operated with hydrogen.

Because renewable energy has no fuel costs, other than biomass, the cumulative fuel cost savings in the 2.0 °C Scenario will reach a total of $1730 billion in 2050, equivalent to $48 billion per year. Therefore, the total fuel cost savings will be equivalent to 70% of the total additional investments compared to the 5.0 °C Scenario. The fuel cost savings in the 1.5 °C Scenario will add up to $1900 billion, or $53 billion per year.

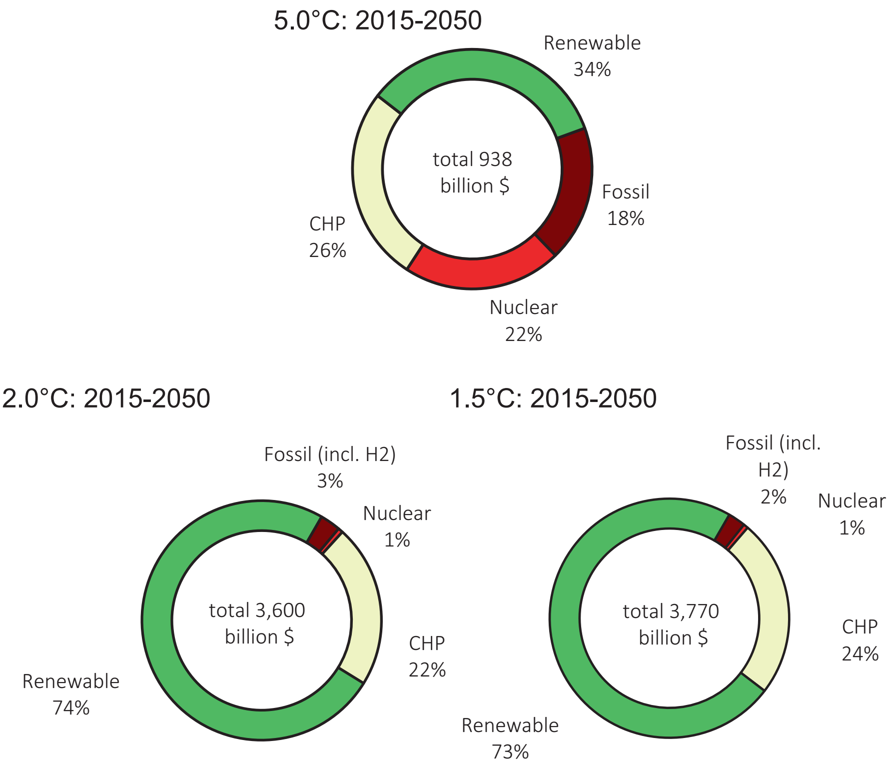


**Fig. 8.65** Eastern Europe/Eurasia: investment shares for power generation in the scenarios

### 8.10.1.5 Eastern Europe/Eurasia: Energy Supply for Heating

The final energy demand for heating will increase in the 5.0 °C Scenario by 46%, from 15,700 PJ/year in 2015 to 22,900 PJ/year in 2050. Energy efficiency measures will help to reduce the energy demand for heating by 47% in 2050 in both alternative scenarios. Today, renewables supply around 4% of Eastern Europe/Eurasia's final energy demand for heating, with the main contribution from biomass. Renewable energy will provide 29% of Eastern Europe/Eurasia's total heat demand in 2030 in the 2.0 °C Scenario and 42% in the 1.5 °C Scenario. In both scenarios, renewables will provide 100% of the total heat demand in 2050.

Figure 8.66 shows the development of different technologies for heating in Eastern Europe/Eurasia over time, and Table 8.60 provides the resulting renewable heat supply for all scenarios. Until 2030, biomass will remain the main contributor. In the long term, the growing use of solar, geothermal, and environmental heat will lead to a biomass share of 28% in both alternative scenarios.

Heat from renewable hydrogen will further reduce the dependence on fossil fuels in both scenarios. Hydrogen consumption in 2050 will be around 1900 PJ/year in the 2.0 °C Scenario and 2000 PJ/year in the 1.5 °C Scenario.

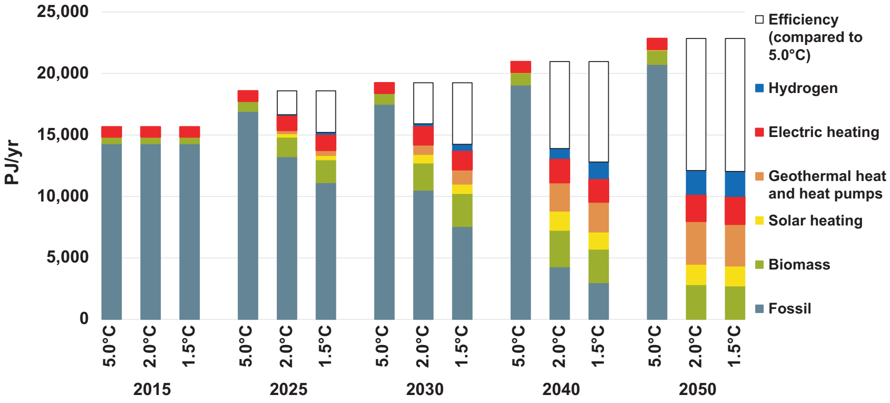


**Fig. 8.66** Eastern Europe/Eurasia: development of heat supply by energy carrier in the scenarios

**Table 8.60** Eastern Europe/Eurasia: development of renewable heat supply in the scenarios (excluding the direct use of electricity)

| in PJ/year | Case | 2015 | 2025 | 2030 | 2040 | 2050 |
|---|---|---|---|---|---|---|
| Biomass | 5.0 °C | 537 | 810 | 873 | 1005 | 1164 |
| | 2.0 °C | 537 | 1604 | 2199 | 2971 | 2819 |
| | 1.5 °C | 537 | 1869 | 2684 | 2734 | 2722 |
| Solar heating | 5.0 °C | 5 | 10 | 13 | 24 | 41 |
| | 2.0 °C | 5 | 277 | 706 | 1560 | 1662 |
| | 1.5 °C | 5 | 351 | 768 | 1395 | 1620 |
| Geothermal heat and heat pumps | 5.0 °C | 6 | 9 | 11 | 15 | 21 |
| | 2.0 °C | 6 | 265 | 780 | 2314 | 3493 |
| | 1.5 °C | 6 | 410 | 1163 | 2434 | 3393 |
| Hydrogen | 5.0 °C | 0 | 0 | 0 | 0 | 0 |
| | 2.0 °C | 0 | 42 | 152 | 795 | 1934 |
| | 1.5 °C | 0 | 155 | 494 | 1344 | 2032 |
| Total | 5.0 °C | 548 | 829 | 897 | 1044 | 1226 |
| | 2.0 °C | 548 | 2187 | 3837 | 7640 | 9908 |
| | 1.5 °C | 548 | 2786 | 5110 | 7906 | 9767 |

The direct use of electricity for heating will also increases by a factor of 2.7 between 2015 and 2050, and its final energy share will be 18% in 2050 in the 2.0 °C Scenario and 19% in the 1.5 °C Scenario.

#### 8.10.1.6 Eastern Europe/Eurasia: Future Investments in the Heating Sector

The roughly estimated investment in renewable heating technologies up to 2050 will amount to around $1070 billion in the 2.0 °C Scenario (including investments in plant replacement after their economic lifetimes), or approximately $30 billion

**Table 8.61** Eastern Europe/Eurasia: installed capacities for renewable heat generation in the scenarios

| in GW | Case | 2015 | 2025 | 2030 | 2040 | 2050 |
|---|---|---|---|---|---|---|
| Biomass | 5.0 °C | 107 | 150 | 157 | 169 | 183 |
| | 2.0 °C | 107 | 230 | 249 | 263 | 172 |
| | 1.5 °C | 107 | 241 | 252 | 230 | 162 |
| Geothermal | 5.0 °C | 0 | 0 | 0 | 1 | 1 |
| | 2.0 °C | 0 | 14 | 26 | 64 | 61 |
| | 1.5 °C | 0 | 12 | 30 | 52 | 54 |
| Solar heating | 5.0 °C | 1 | 2 | 3 | 5 | 9 |
| | 2.0 °C | 1 | 56 | 145 | 330 | 359 |
| | 1.5 °C | 1 | 74 | 163 | 300 | 352 |
| Heat pumps | 5.0 °C | 1 | 1 | 2 | 2 | 3 |
| | 2.0 °C | 1 | 25 | 64 | 184 | 248 |
| | 1.5 °C | 1 | 33 | 76 | 175 | 236 |
| Total[a] | 5.0 °C | 109 | 154 | 162 | 177 | 196 |
| | 2.0 °C | 109 | 325 | 483 | 841 | 839 |
| | 1.5 °C | 109 | 361 | 522 | 758 | 805 |

[a] Excluding direct electric heating

per year. The largest share of the investments in Eastern Europe/Eurasia is assumed to be for heat pumps (around $490 billion), followed by solar collectors and biomass technologies. The 1.5 °C Scenario assumes an even faster expansion of renewable technologies. However, the lower heat demand (compared with the 2.0 °C Scenario) will result in a lower average annual investment of around $29 billion per year (Table 8.61, Fig. 8.67).

#### 8.10.1.7 Eastern Europe/Eurasia: Transport

Energy demand in the transport sector in Eastern Europe/Eurasia is expected to increase in the 5.0 °C Scenario by 34%, from around 6000 PJ/year in 2015 to 8000 PJ/year in 2050. In the 2.0 °C Scenario, assumed technical, structural, and behavioural changes will save 48% (3840 PJ/year) by 2050 compared with the 5.0 °C Scenario. Additional modal shifts, technology switches, and a reduction in the transport demand will lead to even higher energy savings in the 1.5 °C Scenario of 62% (or 4970 PJ/year) in 2050 compared with the 5.0 °C case (Table 8.62, Fig. 8.68).

By 2030, electricity will provide 14% (240 TWh/year) of the transport sector's total energy demand in the 2.0 °C Scenario, whereas in 2050, the share will be 54% (630 TWh/year). In 2050, up to 410 PJ/year of hydrogen will be used in the transport sector as a complementary renewable option. In the 1.5 °C Scenario, the annual electricity demand will be 510 TWh in 2050. The 1.5 °C Scenario also assumes a hydrogen demand of 330 PJ/year by 2050.

Biofuel use is limited in the 2.0 °C Scenario to a maximum of 720 PJ/year Therefore, around 2030, synthetic fuels based on power-to-liquid will be intro-

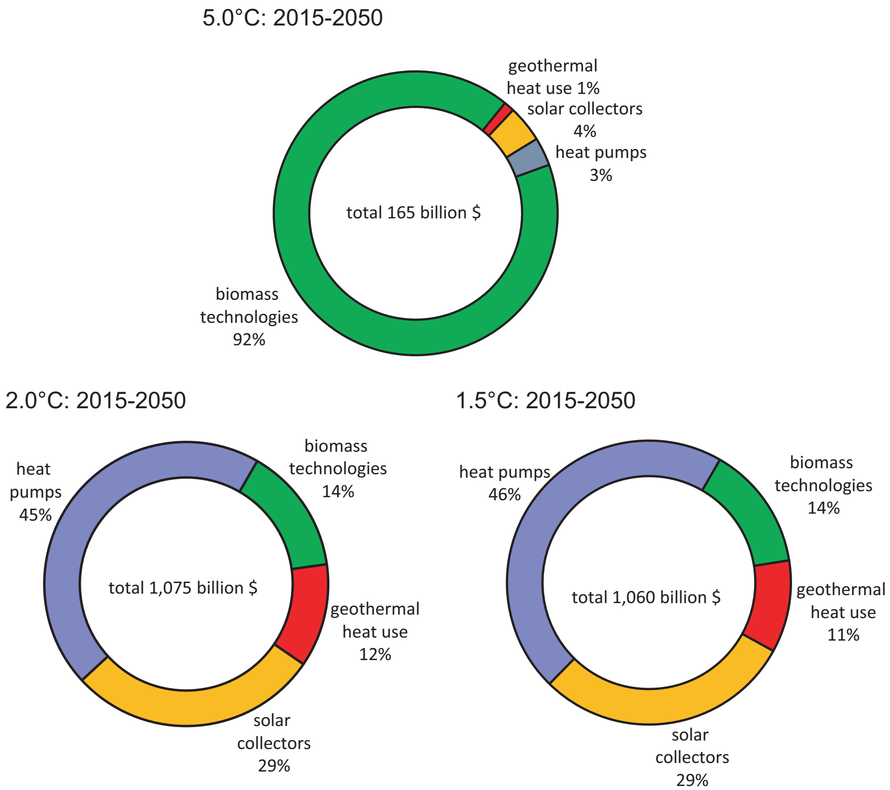


**Fig. 8.67** Eastern Europe/Eurasia: development of investments for renewable heat-generation technologies in the scenarios

duced, with a maximum amount of 880 PJ/year in 2050. With the lower overall energy demand in transport, biofuel use will also be reduced in the 1.5 °C Scenario to a maximum of 700 PJ/year The maximum synthetic fuel demand will amount to 540 PJ/year.

#### 8.10.1.8 Eastern Europe/Eurasia: Development of $CO_2$ Emissions

In the 5.0 °C Scenario, Eastern Europe/Eurasia's annual $CO_2$ emissions will increase by 14%, from 2420 Mt. in 2015 to 2768 Mt. in 2050. The stringent mitigation measures in both alternative scenarios will cause the annual emissions to fall to 590 Mt. in 2040 in the 2.0 °C Scenario and to 340 Mt. in the 1.5 °C Scenario, with further reductions to almost zero by 2050. In the 5.0 °C case, the cumulative $CO_2$ emissions from 2015 until 2050 will add up to 95 Gt. In contrast, in the 2.0 °C and 1.5 °C Scenarios, the cumulative emissions for the period from 2015 until 2050 will be 45 Gt and 36 Gt, respectively.

**Table 8.62** Eastern Europe/Eurasia: projection of transport energy demand by mode in the scenarios

| in PJ/year | Case | 2015 | 2025 | 2030 | 2040 | 2050 |
|---|---|---|---|---|---|---|
| Rail | 5.0 °C | 434 | 498 | 528 | 599 | 674 |
| | 2.0 °C | 434 | 509 | 544 | 646 | 712 |
| | 1.5 °C | 434 | 449 | 470 | 620 | 796 |
| Road | 5.0 °C | 3873 | 4321 | 4680 | 5181 | 5319 |
| | 2.0 °C | 3873 | 4336 | 4403 | 3923 | 3195 |
| | 1.5 °C | 3873 | 3593 | 2963 | 2346 | 2016 |
| Domestic aviation | 5.0 °C | 232 | 336 | 403 | 482 | 471 |
| | 2.0 °C | 232 | 247 | 228 | 188 | 150 |
| | 1.5 °C | 232 | 237 | 207 | 146 | 114 |
| Domestic navigation | 5.0 °C | 34 | 35 | 36 | 38 | 40 |
| | 2.0 °C | 34 | 35 | 36 | 38 | 40 |
| | 1.5 °C | 34 | 35 | 36 | 38 | 40 |
| Total | 5.0 °C | 4573 | 5191 | 5647 | 6301 | 6504 |
| | 2.0 °C | 4573 | 5127 | 5210 | 4795 | 4097 |
| | 1.5 °C | 4573 | 4313 | 3677 | 3150 | 2966 |

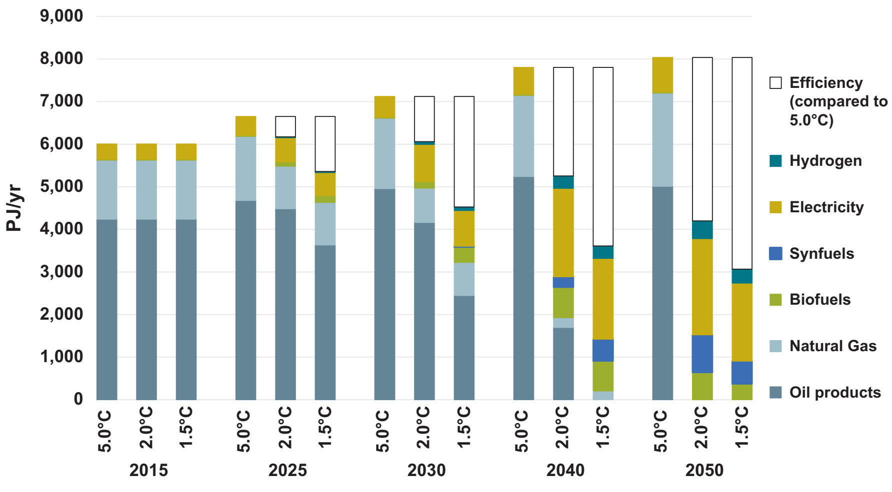


**Fig. 8.68** Eastern Europe/Eurasia: final energy consumption by transport in the scenarios

Therefore, the cumulative $CO_2$ emissions will decrease by 53% in the 2.0 °C Scenario and by 62% in the 1.5 °C Scenario compared with the 5.0 °C case. A rapid reduction in annual emissions will occur in both alternative scenarios. In the 2.0 °C Scenario, this reduction will be greatest in 'Power generation', followed by the 'Residential and other' and 'Industry' sectors (Fig. 8.69).

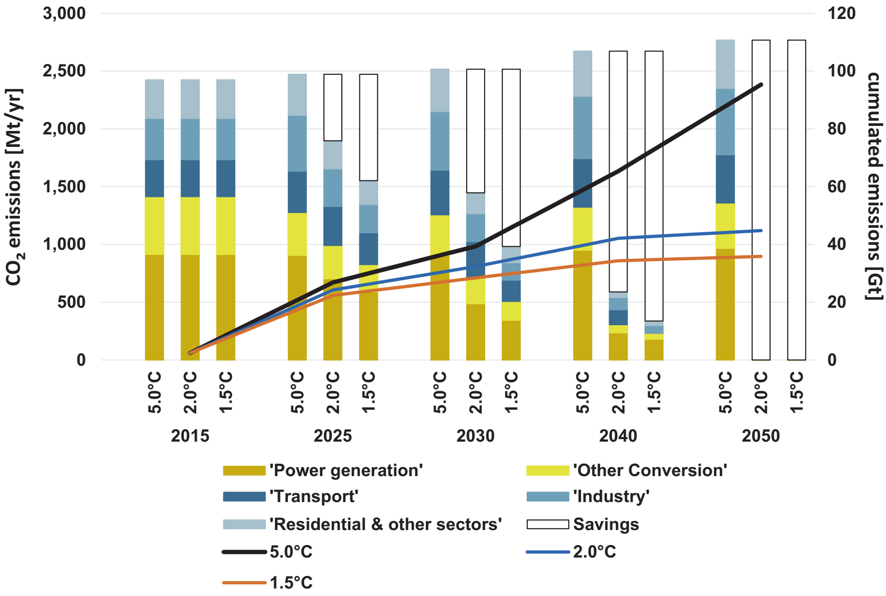


**Fig. 8.69** Eastern Europe/Eurasia: development of $CO_2$ emissions by sector and cumulative $CO_2$ emissions (after 2015) in the scenarios ('Savings' = reduction compared with the 5.0 °C Scenario)

#### 8.10.1.9 Eastern Europe/Eurasia: Primary Energy Consumption

The levels of primary energy consumption in the three scenarios when the assumptions discussed above are taken into account are shown in Fig. 8.70. In the 2.0 °C Scenario, the primary energy demand will decrease by 25%, from around 46,000 PJ/year in 2015 to 34,600 PJ/year in 2050. Compared with the 5.0 °C Scenario, the overall primary energy demand will decrease by 40% by 2050 in the 2.0 °C Scenario (5.0 °C: 57,700 PJ in 2050). In the 1.5 °C Scenario, the primary energy demand will be even lower (33,600 PJ in 2050) because the final energy demand and conversion losses will be lower.

Both the 2.0 °C and 1.5 °C Scenarios aim to rapidly phase-out coal and oil. This will cause renewable energy to have a primary energy share of 26% in 2030 and 91% in 2050 in the 2.0 °C Scenario. In the 1.5 °C Scenario, renewables will have a primary energy share of more than 90% in 2050 (including non-energy consumption, which will still include fossil fuels). Nuclear energy will be phased-out by 2040 in both the 2.0 °C Scenario and 1.5 °C Scenario. The cumulative primary energy consumption of natural gas in the 5.0 °C case will add up to 840 EJ, the cumulative coal consumption to about 290 EJ, and the crude oil consumption to 340 EJ. In contrast, in the 2.0 °C Scenario, the cumulative gas demand will amount to 510 EJ, the cumulative coal demand to 100 EJ, and the cumulative oil demand to 160 EJ. Even lower fossil fuel use will be achieved in the 1.5 °C Scenario: 450 EJ for natural gas, 70 EJ for coal, and 120 EJ for oil.

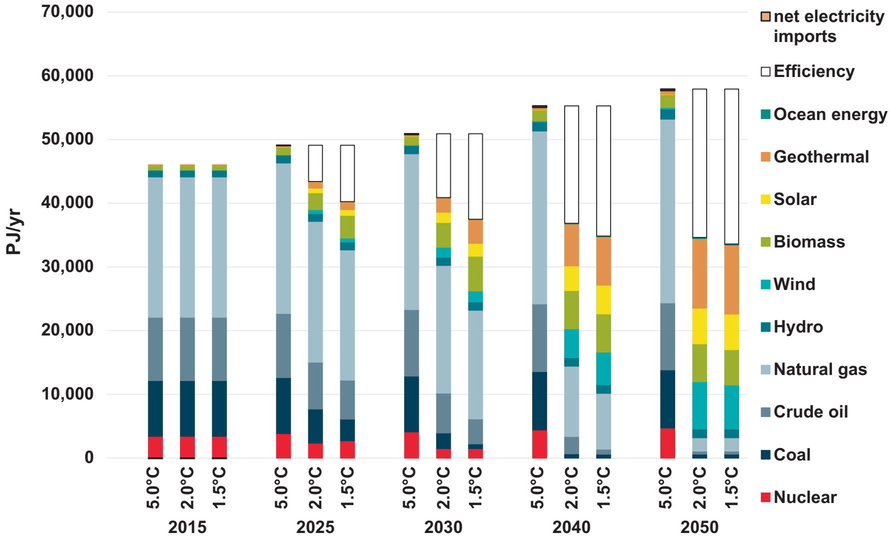


**Fig. 8.70** Eastern Europe/Eurasia: projection of total primary energy demand (PED) by energy carrier in the scenarios (including electricity import balance)

## *8.10.2 Eastern Europe/Eurasia: Power Sector Analysis*

This region sits between the strong economic hubs of the EU, China, and India. Russia, by far the largest country within this region, is an important producer of oil and gas, and supplies all surrounding countries. Therefore, Eurasia will be key in future energy developments. Its renewable energy industry is among the smallest in the world, but recent developments indicate growth in both the wind (WPM 3-2018) and solar industries (PVM 3-2018).

### 8.10.2.1 Eurasia: Development of Power Plant Capacities—2.0 °C Scenario

The northern part of Eurasia and Mongolia have significant wind potential, whereas the southern part, especially in Central Asia, has substantial possibilities for utility-scale solar power plants—both for solar PV and concentrated solar. The annual market for solar PV and onshore wind—as for all other renewable power generation technologies—must develop from a very low MW range in 2017 to a GW market by 2025. Besides solar PV and onshore wind, bioenergy has significant potential in Eurasia, especially in the European part, Russia, and the agricultural regions around the Caspian Sea (Table 8.63).

**Table 8.63** Eurasia: average annual change in installed power plant capacity

| Eurasia power generation: average annual change of installed capacity [GW/a] | 2015–2025 | | 2026–2035 | | 2036–2050 | |
|---|---|---|---|---|---|---|
| | 2.0 °C | 1.5 °C | 2.0 °C | 1.5 °C | 2.0 °C | 1.5 °C |
| Hard coal | −1 | −6 | −6 | −4 | 0 | 0 |
| Lignite | −3 | −4 | −2 | −1 | 0 | 0 |
| Gas | 4 | 1 | 0 | −2 | −17 | −5 |
| Hydrogen-gas | 0 | 2 | 2 | 4 | 20 | 17 |
| Oil/Diesel | −2 | −2 | −1 | −1 | 0 | 0 |
| Nuclear | −2 | −3 | −2 | −4 | −1 | 0 |
| Biomass | 3 | 8 | 3 | 5 | 4 | 2 |
| Hydro | 2 | 1 | 1 | 1 | 0 | 0 |
| Wind (onshore) | 7 | 20 | 26 | 28 | 24 | 21 |
| Wind (offshore) | 1 | 3 | 6 | 6 | 11 | 8 |
| PV (roof top) | 9 | 25 | 21 | 32 | 31 | 22 |
| PV (utility scale) | 3 | 8 | 7 | 11 | 10 | 7 |
| Geothermal | 1 | 3 | 2 | 4 | 4 | 3 |
| Solar thermal power plants | 0 | 0 | 1 | 1 | 1 | 2 |
| Ocean energy | 0 | 0 | 1 | 1 | 1 | 1 |
| Renewable fuel based co-generation | 2 | 7 | 4 | 7 | 5 | 3 |

#### 8.10.2.2 Eurasia: Utilization of Power-Generation Capacities

Variable power generation starts at almost zero, but increases rapidly to over 30% in most sub-regions of Eurasia, as shown in Table 8.64.

Table 8.64 shows that dispatchable renewables will experience stable market conditions throughout the entire modelling period across the whole region. Both scenarios assume that the interconnections between Eastern Europe and Russia will increase significantly, whereas the power transmission capacities for Kazakhstan, Central Asia, the area around the Caspian Sea, and Mongolia will remain low due to geographic distances.

Compared with other world regions, it will take longer for the capacity factor of the limited dispatchable power plants to drop below economic viability, as shown in Table 8.65.

Table 8.65. The capacity factor of variable renewables will rise by 2030, mainly due to increased deployment of wind and concentrated solar power with storage. The average capacity factor of the power-generation fleet will be around 35% by 2050 and will therefore be on the same level as it was 2015 in both scenarios.

#### 8.10.2.3 Eurasia: Development of Load, Generation, and Residual Load

The modelling of both scenarios predicts small increases in interconnection beyond those assumed to occur by 2030 (see Table 8.64).

**Table 8.64** Eurasia: power system shares by technology group

| Power generation structure and interconnection | | 2.0 °C | | | | 1.5 °C | | | |
|---|---|---|---|---|---|---|---|---|---|
| Eurasia | | Variable RE | Dispatch RE | Dispatch fossil | Inter-connection | Variable RE | Dispatch RE | Dispatch fossil | Inter-connection |
| Eastern Europe | 2015 | 1% | 35% | 63% | 5% | | | | |
| | 2030 | 37% | 45% | 18% | 10% | 41% | 46% | 13% | 10% |
| | 2050 | 70% | 22% | 7% | 20% | 66% | 24% | 10% | 20% |
| Russia | 2015 | 1% | 35% | 63% | 5% | | | | |
| | 2030 | 35% | 43% | 22% | 5% | 39% | 47% | 14% | 5% |
| | 2050 | 68% | 24% | 8% | 5% | 64% | 26% | 10% | 5% |
| Kazakhstan | 2015 | 2% | 35% | 63% | 5% | | | | |
| | 2030 | 44% | 42% | 14% | 5% | 49% | 42% | 9% | 5% |
| | 2050 | 80% | 16% | 4% | 5% | 77% | 18% | 5% | 5% |
| Mongolia | 2015 | 2% | 35% | 63% | 5% | | | | |
| | 2030 | 43% | 43% | 13% | 5% | 48% | 43% | 10% | 5% |
| | 2050 | 74% | 20% | 6% | 10% | 71% | 22% | 8% | 10% |
| West Caspian Sea | 2015 | 1% | 35% | 63% | 5% | | | | |
| | 2030 | 43% | 41% | 16% | 5% | 47% | 40% | 12% | 5% |
| | 2050 | 77% | 17% | 6% | 10% | 72% | 19% | 9% | 10% |
| East Caspian Sea | 2015 | 1% | 35% | 63% | 5% | | | | |
| | 2030 | 37% | 44% | 19% | 5% | 41% | 45% | 14% | 5% |
| | 2050 | 71% | 22% | 7% | 10% | 67% | 24% | 10% | 10% |

(continued)

**Table 8.64** (continued)

| Power generation structure and interconnection | | 2.0 °C | | | | 1.5 °C | | | |
|---|---|---|---|---|---|---|---|---|---|
| Eurasia | | Variable RE | Dispatch RE | Dispatch fossil | Inter-connection | Variable RE | Dispatch RE | Dispatch fossil | Inter-connection |
| Central Asia | 2015 | 0% | 35% | 64% | 5% | | | | |
| | 2030 | 18% | 50% | 31% | 5% | 23% | 50% | 27% | 5% |
| | 2050 | 43% | 39% | 18% | 5% | 38% | 37% | 26% | 5% |
| Eurasia | 2015 | 1% | 35% | 63% | | | | | |
| | 2030 | 36% | 43% | 21% | | 40% | 46% | 14% | |
| | 2050 | 69% | 23% | 7% | | 65% | 25% | 10% | |

**Table 8.65** Eurasia: capacity factors by generation type

| Utilization of variable and dispatchable power generation: | | 2015 | 2020 | 2020 | 2030 | 2030 | 2040 | 2040 | 2050 | 2050 |
|---|---|---|---|---|---|---|---|---|---|---|
| Eurasia | | | 2.0 °C | 1.5 °C | 2.0 °C | 1.5 °C | 2.0 °C | 1.5 °C | 2.0 °C | 1.5 °C |
| Capacity factor – average | **[%/yr]** | **36.8%** | **31%** | **40%** | **48%** | **47%** | **34%** | **34%** | **34%** | **34%** |
| Limited dispatchable: fossil and nuclear | [%/yr] | 43.8% | 31% | 30% | 22% | 18% | 19% | 0% | 7% | 4% |
| Limited dispatchable: renewable | [%/yr] | 39.3% | 42% | 42% | 57% | 54% | 60% | 39% | 39% | 40% |
| Dispatchable: fossil | [%/yr] | 27.6% | 18% | 17% | 7% | 6% | 31% | 8% | 12% | 15% |
| Dispatchable: renewable | [%/yr] | 38.7% | 48% | 73% | 73% | 68% | 41% | 49% | 50% | 51% |
| Variable: renewable | [%/yr] | 10.5% | 11% | 11% | 40% | 39% | 25% | 32% | 32% | 33% |

Table 8.64. However, after 2030, significant increases will be required by 2050, especially in Russia. The export of renewable electricity can also take place via existing gas pipelines with power-to-gas technologies. Between 2030 and 2050, the loads for all regions will double, due to the increased electrification of the heating, industry, and transport sectors (Table 8.66).

In Eurasia, the main storage technology for both scenarios is pumped hydro, whereas hydrogen plays a major role for the grid integration of variable generation (Table 8.67). Hydrogen production can also be used for load management, although not for short peak loads. Due to the technical and economic limitations associated with the increased interconnection via transmission lines and pumped hydro storage systems, curtailment will be higher than the scenario target (a maximum of 10% by 2050). For Eastern Europe, Kazakhstan, Mongolia, and the East Caspian Sea, the calculated curtailment will be between 10% and 14%, whereas the West Caspian Region will have the highest curtailment of 19% in the 2.0 °C Scenario and 17% in the 1.5 °C Scenario. Further research and optimization are required.

**Table 8.66** Eurasia: load, generation, and residual load development

| Power generation structure | | 2.0 °C | | | | 1.5 °C | | | |
|---|---|---|---|---|---|---|---|---|---|
| | | Max demand | Max generation | Max residual load | Max interconnection requirements | Max demand | Max generation | Max residual load | Max interconnection requirements |
| Eurasia | | [GW] | [GW] | [GW] | [GW] | [GW] | [GW] | [GW] | [GW] |
| Eastern Europe | 2020 | 32.9 | 30.8 | 3.9 | | 32.9 | 33.0 | 4.6 | |
| | 2030 | 38.1 | 45.0 | 12.4 | 0 | 40.8 | 56.2 | 14.2 | 1 |
| | 2050 | 77.2 | 179.6 | 30.9 | 71 | 77.5 | 174.3 | 31.6 | 65 |
| Russia | 2020 | 172.7 | 95.8 | 83.6 | | 172.7 | 100.6 | 81.8 | |
| | 2030 | 214.2 | 218.6 | 103.5 | 0 | 221.4 | 275.2 | 94.9 | 0 |
| | 2050 | 428.3 | 887.6 | 191.7 | 268 | 429.2 | 859.0 | 194.4 | 235 |
| Kazakhstan | 2020 | 14.7 | 18.8 | 0.9 | | 14.7 | 17.9 | 0.9 | |
| | 2030 | 17.9 | 18.6 | 8.3 | 0 | 18.9 | 23.1 | 7.7 | 0 |
| | 2050 | 34.3 | 74.5 | 14.1 | 26 | 34.4 | 72.2 | 14.4 | 23 |
| Mongolia | 2020 | 1.7 | 2.0 | 0.1 | | 1.7 | 2.0 | 0.1 | |
| | 2030 | 2.0 | 2.3 | 0.9 | 0 | 2.1 | 2.9 | 0.9 | 0 |
| | 2050 | 3.7 | 8.5 | 1.2 | 4 | 3.7 | 8.4 | 1.2 | 3 |
| West Caspian Sea | 2020 | 10.7 | 6.2 | 4.6 | | 10.7 | 6.9 | 4.2 | |
| | 2030 | 12.5 | 13.9 | 6.4 | 0 | 13.4 | 17.3 | 5.9 | 0 |
| | 2050 | 24.3 | 55.8 | 9.8 | 22 | 24.4 | 54.1 | 10.0 | 20 |
| East Caspian Sea | 2020 | 21.6 | 7.5 | 14.2 | | 21.6 | 7.8 | 13.8 | |
| | 2030 | 25.2 | 28.2 | 12.7 | 0 | 26.9 | 35.0 | 12.5 | 0 |
| | 2050 | 50.0 | 113.4 | 18.6 | 45 | 50.2 | 109.7 | 19.1 | 40 |
| Central Asia | 2020 | 2.5 | 2.3 | 0.2 | | 2.5 | 2.3 | 0.2 | |
| | 2030 | 6.0 | 5.8 | 2.8 | 0 | 6.7 | 6.5 | 3.0 | 0 |
| | 2050 | 12.0 | 18.2 | 4.2 | 2 | 12.1 | 18.2 | 4.4 | 2 |

**Table 8.67** Eurasia: storage and dispatch service requirements

| Storage and dispatch | | 2.0 °C | | | | | 1.5 °C | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | Required to avoid curtailment | Utilization battery -through-put- | Utilization PSH -through-put- | Total storage demand (incl. H2) | Dispatch hydrogen-based | Required to avoid curtailment | Utilization battery -through-put- | Utilization PSH -through-put- | Total storage demand (incl. H2) | Dispatch hydrogen-based |
| Eurasia | | [GWh/year] | [GWh/year] | [GWh/year] | [GWh/year] | [GWh/year] | [GWh/year] | [GWh/year] | [GWh/year] | [GWh/year] | [GWh/year] |
| Eastern Europe | 2020 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | 2030 | 373 | 1 | 137 | 138 | 1720 | 1674 | 2 | 317 | 319 | 5920 |
| | 2050 | 52,516 | 274 | 2626 | 2900 | 49,057 | 43,933 | 267 | 2303 | 2570 | 49,858 |
| Russia | 2020 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | 2030 | 36 | 0 | 41 | 41 | 9711 | 2290 | 3 | 517 | 520 | 33,707 |
| | 2050 | 147,854 | 1132 | 9342 | 10,474 | 282,100 | 123,490 | 1049 | 7895 | 8944 | 287,188 |
| Kazakhstan | 2020 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | 2030 | 7 | 0 | 7 | 7 | 690 | 281 | 1 | 84 | 85 | 2223 |
| | 2050 | 28,094 | 133 | 1444 | 1577 | 13,192 | 23,926 | 127 | 1271 | 1398 | 13,544 |
| Mongolia | 2020 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | 2030 | 24 | 0 | 11 | 11 | 78 | 131 | 0 | 25 | 25 | 258 |
| | 2050 | 3177 | 17 | 152 | 169 | 1997 | 2938 | 16 | 139 | 155 | 1971 |
| West Caspian Sea | 2020 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | 2030 | 163 | 0 | 78 | 79 | 472 | 882 | 1 | 173 | 174 | 1558 |
| | 2050 | 30,281 | 96 | 1207 | 1303 | 12,025 | 26,053 | 94 | 1120 | 1214 | 12,088 |
| East Caspian Sea | 2020 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | 2030 | 134 | 0 | 65 | 65 | 1125 | 773 | 1 | 170 | 170 | 3759 |
| | 2050 | 32,074 | 202 | 1785 | 1988 | 30,493 | 27,253 | 195 | 1580 | 1775 | 30,852 |

(continued)

**Table 8.67** (continued)

| Storage and dispatch | | 2.0 °C | | | | | 1.5 °C | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | Required to avoid curtailment | Utilization battery -through-put- | Utilization PSH -through-put- | Total storage demand (incl. H2) | Dispatch hydrogen-based | Required to avoid curtailment | Utilization battery -through-put- | Utilization PSH -through-put- | Total storage demand (incl. H2) | Dispatch hydrogen-based |
| Eurasia | | [GWh/year] | [GWh/year] | [GWh/year] | [GWh/year] | [GWh/year] | [GWh/year] | [GWh/year] | [GWh/year] | [GWh/year] | [GWh/year] |
| Central Asia | 2020 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | 2030 | 0 | 0 | 0 | 0 | 309 | 0 | 0 | 1 | 1 | 1090 |
| | 2050 | 2495 | 39 | 211 | 250 | 12,181 | 2391 | 39 | 207 | 245 | 12,037 |
| Eurasia Eastern Europe | 2020 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | 2030 | 736 | 2 | 339 | 341 | 14,106 | 6031 | 7 | 1287 | 1295 | 48,516 |
| | 2050 | 296,490 | 1894 | 16,767 | 18,661 | 401,044 | 249,984 | 1788 | 14,515 | 16,303 | 407,537 |

# 8.11 Non-OECD Asia

## *8.11.1 Non-OECD Asia: Long-Term Energy Pathways*

### 8.11.1.1 Non-OECD Asia: Final Energy Demand by Sector

The future development pathways for Non-OECD Asia's final energy demand when the assumptions on population growth, GDP growth, and energy intensity are combined are shown in Fig. 8.71 for the 5.0 °C, 2.0 °C, and 1.5 °C Scenarios. In the 5.0 °C Scenario, the total final energy demand will increase by 111% from the current 24,500 PJ/year to 51,800 PJ/year in 2050. In the 2.0 °C Scenario, the final energy demand will increase at a much lower rate by 16% compared with current consumption, and will reach 28,300 PJ/year by 2050. The final energy demand in the 1.5 °C Scenario will reach 25,700 PJ, 5% above the 2015 demand. In the 1.5 °C Scenario, the final energy demand in 2050 will be 9% lower than in the 2.0 °C Scenario. The electricity demand for 'classical' electrical devices (without power-to-heat or e-mobility) will increase from 830 TWh/year in 2015 to 2480 TWh/year in 2050 in both alternative scenarios. Compared with the reference case (3880 TWh/year in 2050), the efficiency measures in the 2.0 °C and 1.5 °C scenarios will save 1400 TWh/year in 2050.

Electrification will lead to a significant increase in the electricity demand by 2050. In the 2.0 °C Scenario, the electricity demand for heating will be approxi-

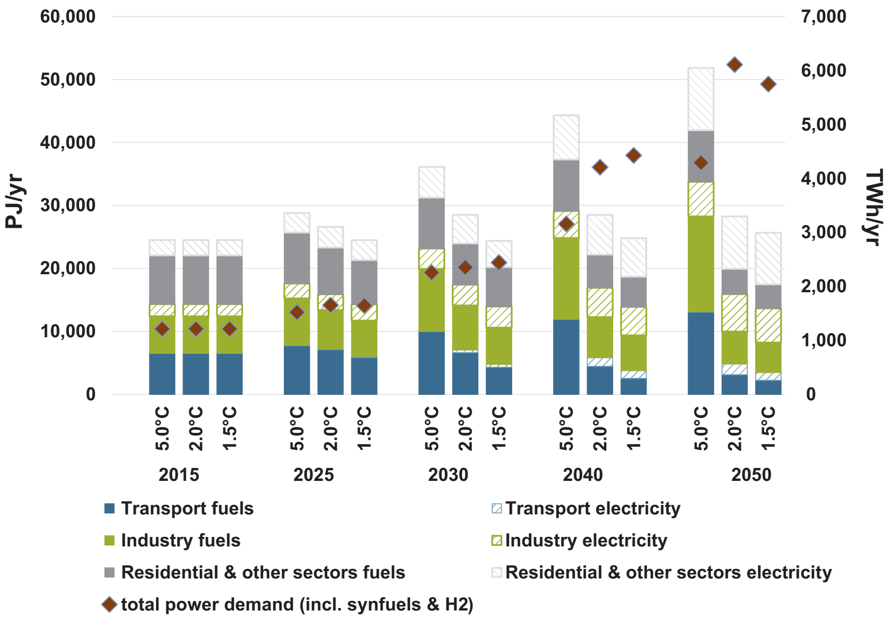


**Fig. 8.71** Non-OECD Asia: development of the final energy demand by sector in the scenarios

mately 1500 TWh/year due to electric heaters and heat pumps, and in the transport sector, the electricity demand will be approximately 1700 TWh/year due to electric mobility. The generation of hydrogen (for transport and high-temperature process heat) and the manufacture of synthetic fuels (mainly for transport) will add an additional power demand of 1700 TWh/year. Therefore, the gross power demand will rise from 1400 TWh/year in 2015 to 6400 TWh/year in 2050 in the 2.0 °C Scenario, 33% higher than in the 5.0 °C case. In the 1.5 °C Scenario, the gross electricity demand will increase to a maximum of 6000 TWh/year in 2050.

The efficiency gains in the heating sector could be even larger than those in the electricity sector. In the 2.0 °C and 1.5 °C Scenarios, a final energy consumption equivalent to about 6900 PJ/year and 8100 PJ/year, respectively, will be avoided by 2050 compared with the 5.0 °C Scenario, through efficiency gains.

#### 8.11.1.2 Non-OECD Asia: Electricity Generation

The development of the power system is characterized by a dynamically growing renewable energy market and an increasing proportion of total power from renewable sources. By 2050, 100% of the electricity produced in Non-OECD Asia will come from renewable energy sources in the 2.0 °C Scenario. 'New' renewables—mainly wind, solar, and geothermal energy—will contribute 87% of the total electricity generation. Renewable electricity's share of the total production will be 59% by 2030 and 87% by 2040. The installed capacity of renewables will reach about 610 GW by 2030 and 2430 GW by 2050. The share of renewable electricity generation in 2030 in the 1.5 °C Scenario is assumed to be 74%. In the 1.5 °C Scenario, the generation capacity from renewable energy will be approximately 2320 GW in 2050.

Table 8.68 shows the development of different renewable technologies in Non-OECD Asia over time. Figure 8.72 provides an overview of the overall power-generation structure in Non-OECD Asia. From 2020 onwards, the continuing growth of wind and PV up to 635 GW and 1280 GW, respectively, will be complemented by up to 275 GW solar thermal generation, as well as limited biomass, geothermal, and ocean energy in the 2.0 °C Scenario. Both the 2.0 °C Scenario and 1.5 °C Scenario will lead to a high proportion of variable power generation (PV, wind, and ocean) of 34% and 48%, respectively, by 2030, and 64% and 66%, respectively, by 2050.

#### 8.11.1.3 Non-OECD Asia: Future Costs of Electricity Generation

Figure 8.73 shows the development of the electricity-generation and supply costs over time, including the $CO_2$ emission costs, in all scenarios. The calculated electricity generation costs in 2015 (referring to full costs) were around 5.2 ct/kWh. In the 5.0 °C case, the generation costs will increase until 2050, when they reach 11.7 ct/kWh. The generation costs will increase in the 2.0 °C Scenario until 2030, when they will reach 8.1 ct/kWh, and will drop to 6.3 ct/kWh by 2050. In the 1.5 °C

**Table 8.68** Non-OECD Asia: development of renewable electricity-generation capacity in the scenarios

| in GW | Case | 2015 | 2025 | 2030 | 2040 | 2050 |
|---|---|---|---|---|---|---|
| Hydro | 5.0 °C | 63 | 85 | 124 | 151 | 183 |
| | 2.0 °C | 63 | 86 | 86 | 90 | 91 |
| | 1.5 °C | 63 | 86 | 86 | 90 | 91 |
| Biomass | 5.0 °C | 7 | 10 | 17 | 22 | 31 |
| | 2.0 °C | 7 | 19 | 19 | 30 | 36 |
| | 1.5 °C | 7 | 19 | 20 | 31 | 39 |
| Wind | 5.0 °C | 2 | 5 | 17 | 32 | 54 |
| | 2.0 °C | 2 | 53 | 148 | 389 | 635 |
| | 1.5 °C | 2 | 98 | 229 | 458 | 631 |
| Geothermal | 5.0 °C | 3 | 4 | 6 | 8 | 10 |
| | 2.0 °C | 3 | 6 | 23 | 50 | 63 |
| | 1.5 °C | 3 | 7 | 26 | 47 | 54 |
| PV | 5.0 °C | 3 | 9 | 26 | 44 | 70 |
| | 2.0 °C | 3 | 107 | 287 | 806 | 1282 |
| | 1.5 °C | 3 | 157 | 396 | 907 | 1256 |
| CSP | 5.0 °C | 0 | 0 | 0 | 0 | 0 |
| | 2.0 °C | 0 | 5 | 45 | 134 | 275 |
| | 1.5 °C | 0 | 5 | 45 | 110 | 224 |
| Ocean | 5.0 °C | 0 | 0 | 0 | 0 | 0 |
| | 2.0 °C | 0 | 0 | 2 | 20 | 50 |
| | 1.5 °C | 0 | 0 | 2 | 15 | 30 |
| Total | 5.0 °C | 78 | 113 | 191 | 257 | 348 |
| | 2.0 °C | 78 | 276 | 610 | 1518 | 2432 |
| | 1.5 °C | 78 | 373 | 804 | 1658 | 2325 |

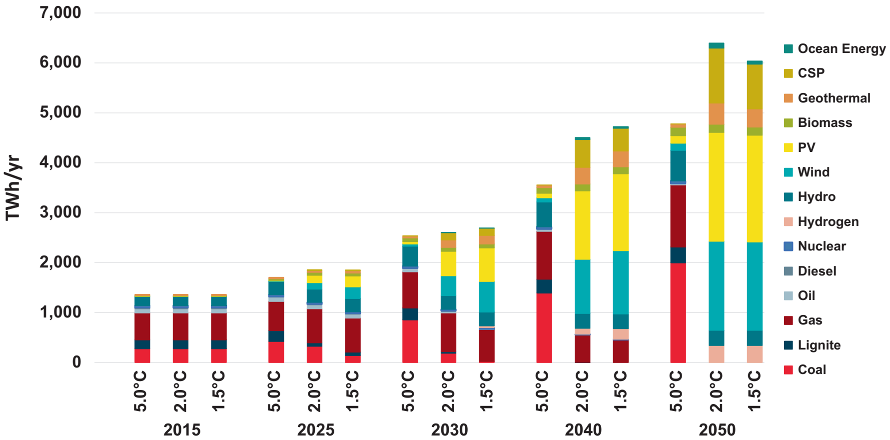


**Fig. 8.72** Non-OECD Asia: development of electricity-generation structure in the scenarios

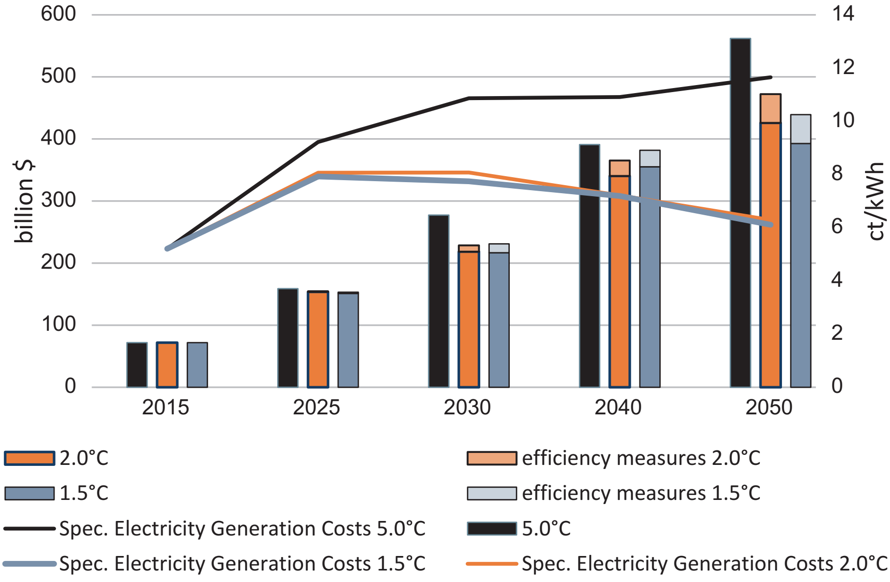


**Fig. 8.73** Non-OECD Asia: development of total electricity supply costs and specific electricity generation costs in the scenarios

Scenario, they will increase to 7.9 ct/kWh, and drop to 6.1 ct/kWh by 2050. In both alternative scenarios, the generation costs in 2050 will be around 5.5 ct/kWh lower than in the 5.0 °C case. Note that these estimates of generation costs do not take into account integration costs such as power grid expansion, storage, or other load-balancing measures.

In the 5.0 °C case, the growth in demand and increasing fossil fuel prices will cause the total electricity supply costs to rise from today's $70 billion/year to more than $560 billion/year in 2050. In the 2.0 °C Scenario, the total supply costs will be $430 billion/year and in the 1.5 °C Scenario they will be $390 billion/year. The long-term costs for electricity supply will be more than 24% lower in the 2.0 °C Scenario than in the 5.0 °C Scenario as a result of the estimated generation costs and the electrification of heating and mobility. Further reductions in demand in the 1.5 °C Scenario will result in total power generation costs that are 30% lower than in the 5.0 °C case.

Compared with these results, the generation costs when the $CO_2$ emission costs are not considered will increase in the 5.0 °C case to 7.4 ct/kWh. In the 2.0 °C Scenario, they still increase until 2030, when they reach 6.5 ct/kWh, and then drop to 6.3 ct/kWh by 2050. In the 1.5 °C Scenario, they will increase to 6.9 ct/kWh and then drop to 6.1 ct/kWh by 2050. In the 2.0 °C case, the generation costs will be maximum in 2050, and 1.1 ct/kWh lower than in the 5.0 °C, whereas they will be 1.3 ct/kWh in the 1.5 °C Scenario. If the $CO_2$ costs are not considered, the total electricity supply costs in the 5.0 °C case will increase to about $360 billion/year in 2050.

#### 8.11.1.4 Non-OECD Asia: Future Investments in the Power Sector

An investment of $4030 billion will be required for power generation between 2015 and 2050 in the 2.0 °C Scenario—including investment in additional power plants for the production of hydrogen and synthetic fuels and investments in plant replacement at the end of their economic lifetimes. This value is equivalent to approximately $112 billion per year on average, and is $2660 billion more than in the 5.0 °C case ($1370 billion). An investment of around $3950 billion for power generation will be required between 2015 and 2050 in the 1.5 °C Scenario. On average, this is an investment of $110 billion per year. In the 5.0 °C Scenario, the investment in conventional power plants will be around 55% of the total cumulative investments, whereas approximately 45% will be invested in renewable power generation and co-generation (Fig. 8.74).

However, in the 2.0 °C (1.5 °C) Scenario, Non-OECD Asia will shift almost 93% (95%) of its entire investment to renewables and co-generation. By 2030, the fossil fuel share of power sector investment will predominantly focus on gas power plants that can also be operated with hydrogen.

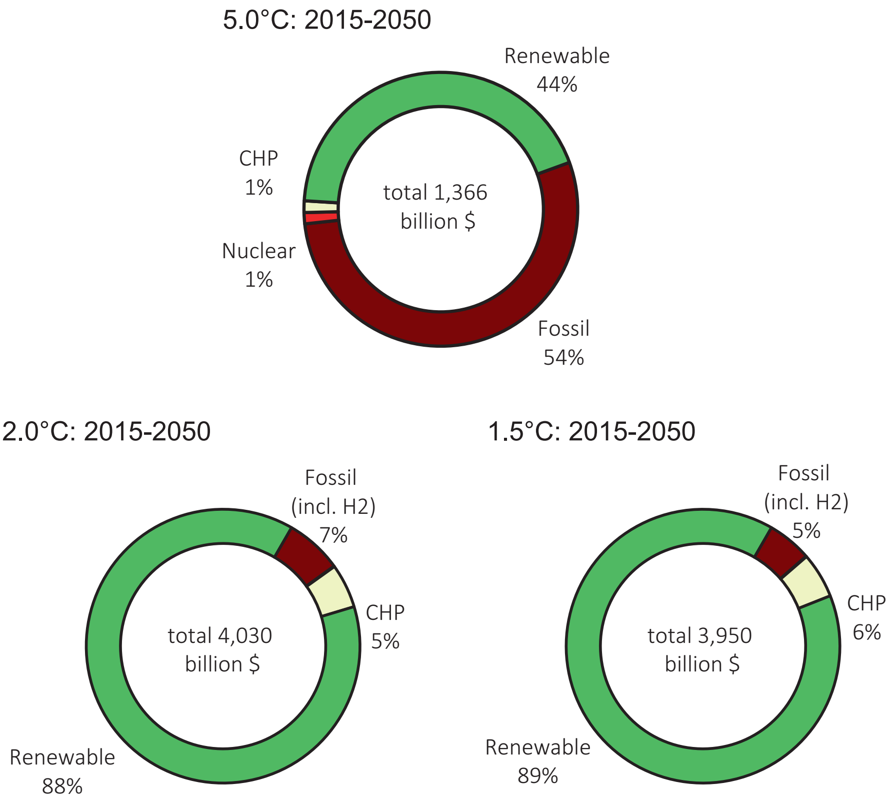


**Fig. 8.74** Non-OECD Asia: investment shares for power generation in the scenarios

Because renewable energy has no fuel costs, other than biomass, the cumulative fuel cost savings in the 2.0 °C Scenario will reach a total of $2610 billion in 2050, equivalent to $73 billion per year. Therefore, the total fuel cost savings will be equivalent to 98% of the total additional investments compared to the 5.0 °C Scenario. The fuel cost savings in the 1.5 °C Scenario will add up to $2770 billion, or $77 billion per year.

#### 8.11.1.5 Non-OECD Asia: Energy Supply for Heating

The final energy demand for heating will increase by 103% in the 5.0 °C scenario, from 10,800 PJ/year in 2015 to 21,900 PJ/year in 2050. Energy efficiency measures will help to reduce the energy demand for heating by 32% by 2050 in the 2.0 °C Scenario, relative to the 5.0 °C case, and by 37% in the 1.5 °C Scenario. Today, renewables supply around 43% of Non-OECD Asia's final energy demand for heating, with the main contribution from biomass. Renewable energy will provide 57% of Non-OECD Asia's total heat demand in 2030 in the 2.0 °C Scenario and 70% in the 1.5 °C Scenario. In both scenarios, renewables will provide 100% of the total heat demand in 2050.

Figure 8.75 shows the development of different technologies for heating in Non-OECD Asia over time, and Table 8.69 provides the resulting renewable heat supply for all scenarios. Up to 2030, biomass remains the main contributor. In the long term, the growing use of solar, geothermal, and environmental heat will lead to a biomass share of 40% in the 2.0 °C Scenario and 38% in the 1.5 °C Scenario. The heat from renewable hydrogen will further reduce the dependence on fossil fuels in both scenarios. The hydrogen consumption in 2050 will be around 900 PJ/year in the 2.0 °C Scenario and 1300 PJ/year in the 1.5 °C Scenario. The direct use of electricity for heating will also increase by a factor of 5-5.7 between 2015 and 2050. Energy for heating will have a final energy share of 34% in 2050 in the 2.0 °C Scenario and 32% in the 1.5 °C Scenario.

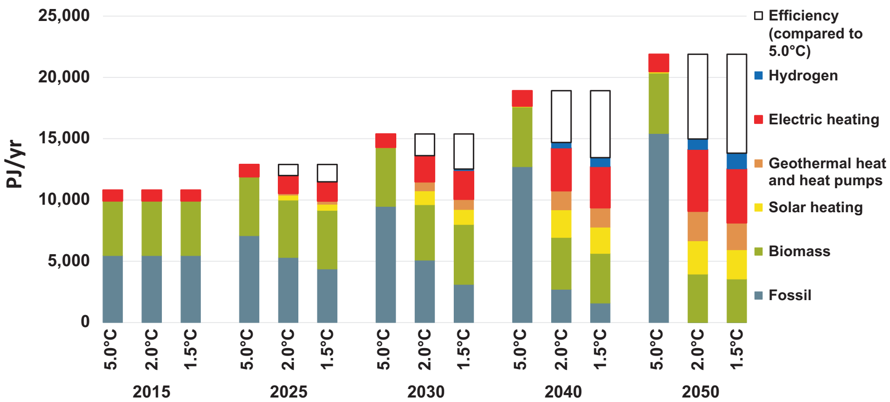


Fig. 8.75 Non-OECD Asia: development of heat supply by energy carrier in the scenarios

**Table 8.69** Non-OECD Asia: development of renewable heat supply in the scenarios (excluding the direct use of electricity)

| in PJ/year | Case | 2015 | 2025 | 2030 | 2040 | 2050 |
|---|---|---|---|---|---|---|
| Biomass | 5.0 °C | 4459 | 4800 | 4787 | 4878 | 4919 |
| | 2.0 °C | 4459 | 4680 | 4529 | 4232 | 3948 |
| | 1.5 °C | 4459 | 4772 | 4890 | 4054 | 3549 |
| Solar heating | 5.0 °C | 4 | 12 | 33 | 70 | 128 |
| | 2.0 °C | 4 | 401 | 1129 | 2252 | 2723 |
| | 1.5 °C | 4 | 509 | 1221 | 2141 | 2389 |
| Geothermal heat and heat pumps | 5.0 °C | 0 | 0 | 0 | 0 | 0 |
| | 2.0 °C | 0 | 141 | 740 | 1563 | 2410 |
| | 1.5 °C | 0 | 262 | 839 | 1587 | 2198 |
| Hydrogen | 5.0 °C | 0 | 0 | 0 | 0 | 0 |
| | 2.0 °C | 0 | 0 | 0 | 454 | 862 |
| | 1.5 °C | 0 | 0 | 133 | 735 | 1274 |
| Total | 5.0 °C | 4464 | 4811 | 4821 | 4948 | 5047 |
| | 2.0 °C | 4464 | 5222 | 6398 | 8501 | 9942 |
| | 1.5 °C | 4464 | 5542 | 7083 | 8516 | 9411 |

#### 8.11.1.6 Non-OECD Asia: Future Investments in the Heating Sector

The roughly estimated investments in renewable heating technologies up to 2050 will amount to around $1120 billion in the 2.0 °C Scenario (including investments for the replacement of plants after their economic lifetimes), or approximately $31 billion per year. The largest share of investment in Non-OECD Asia is assumed to be for solar collectors (around $480 billion), followed by heat pumps and geothermal heat use. The 1.5 °C Scenario assumes an even faster expansion of renewable technologies. However, the lower heat demand (compared with the 2.0 °C Scenario) will results in a lower average annual investment of around $28 billion per year (Table 8.70, Fig. 8.76).

#### 8.11.1.7 Non-OECD Asia: Transport

The energy demand in the transport sector in Non-OECD Asia is expected to increase in 2015 in the 5.0 °C Scenario from around 6500 PJ/year by 102% to 13,200 PJ/year in 2050. In the 2.0 °C Scenario, assumed technical, structural, and behavioural changes will save 63% (8320 PJ/year) by 2050 compared to the 5.0 °C Scenario. Additional modal shifts, technology switches, and a reduction in the transport demand will lead to even higher energy savings in the 1.5 °C Scenario of 73% (or 9660 PJ/year) by 2050 compared to the 5.0 °C case (Table 8.71, Fig. 8.77).

By 2030, electricity will provide 6% (120 TWh/year) of the transport sector's total energy demand in the 2.0 °C Scenario, whereas in 2050, the share will be 36% (480 TWh/year). In 2050, up to 650 PJ/year of hydrogen will be used in the trans-

**Table 8.70** Non-OECD Asia: installed capacities for renewable heat generation in the scenarios

| | Case | 2015 | 2025 | 2030 | 2040 | 2050 |
|---|---|---|---|---|---|---|
| Biomass | 5.0 °C | 1886 | 1925 | 1767 | 1610 | 1459 |
| | 2.0 °C | 1886 | 1850 | 1557 | 1150 | 821 |
| | 1.5 °C | 1886 | 1829 | 1693 | 1084 | 713 |
| Geothermal | 5.0 °C | 0 | 0 | 0 | 0 | 0 |
| | 2.0 °C | 0 | 4 | 18 | 51 | 73 |
| | 1.5 °C | 0 | 4 | 15 | 44 | 64 |
| Solar heating | 5.0 °C | 1 | 3 | 10 | 20 | 37 |
| | 2.0 °C | 1 | 114 | 321 | 639 | 772 |
| | 1.5 °C | 1 | 145 | 349 | 609 | 678 |
| Heat pumps | 5.0 °C | 0 | 0 | 0 | 0 | 0 |
| | 2.0 °C | 0 | 13 | 58 | 103 | 159 |
| | 1.5 °C | 0 | 27 | 70 | 110 | 144 |
| Total[a] | 5.0 °C | 1888 | 1928 | 1777 | 1631 | 1496 |
| | 2.0 °C | 1888 | 1981 | 1954 | 1944 | 1825 |
| | 1.5 °C | 1888 | 2004 | 2127 | 1847 | 1598 |

[a] Excluding direct electric heating

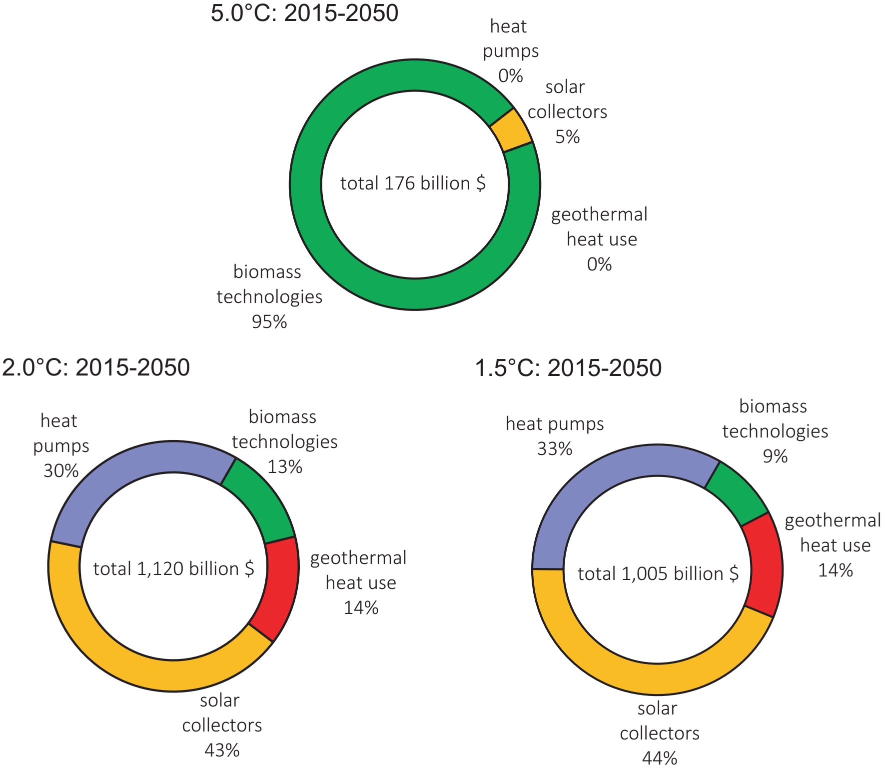


**Fig. 8.76** Non-OECD Asia: development of investments for renewable heat-generation technologies in the scenarios

**Table 8.71** Non-OECD Asia: projection of transport energy demand by mode in the scenarios

| in PJ/year | Case | 2015 | 2025 | 2030 | 2040 | 2050 |
|---|---|---|---|---|---|---|
| Rail | 5.0 °C | 76 | 81 | 81 | 83 | 83 |
| | 2.0 °C | 76 | 96 | 116 | 158 | 183 |
| | 1.5 °C | 76 | 115 | 124 | 148 | 212 |
| Road | 5.0 °C | 6023 | 7139 | 9256 | 11,061 | 12,181 |
| | 2.0 °C | 6023 | 6694 | 6489 | 5251 | 4245 |
| | 1.5 °C | 6023 | 5493 | 4217 | 3258 | 2903 |
| Domestic aviation | 5.0 °C | 225 | 353 | 447 | 581 | 621 |
| | 2.0 °C | 225 | 240 | 220 | 180 | 143 |
| | 1.5 °C | 225 | 230 | 200 | 139 | 108 |
| Domestic navigation | 5.0 °C | 196 | 216 | 227 | 246 | 267 |
| | 2.0 °C | 196 | 216 | 227 | 246 | 267 |
| | 1.5 °C | 196 | 216 | 227 | 246 | 267 |
| Total | 5.0 °C | 6521 | 7789 | 10,010 | 11,970 | 13,153 |
| | 2.0 °C | 6521 | 7246 | 7051 | 5834 | 4838 |
| | 1.5 °C | 6521 | 6053 | 4769 | 3791 | 3489 |

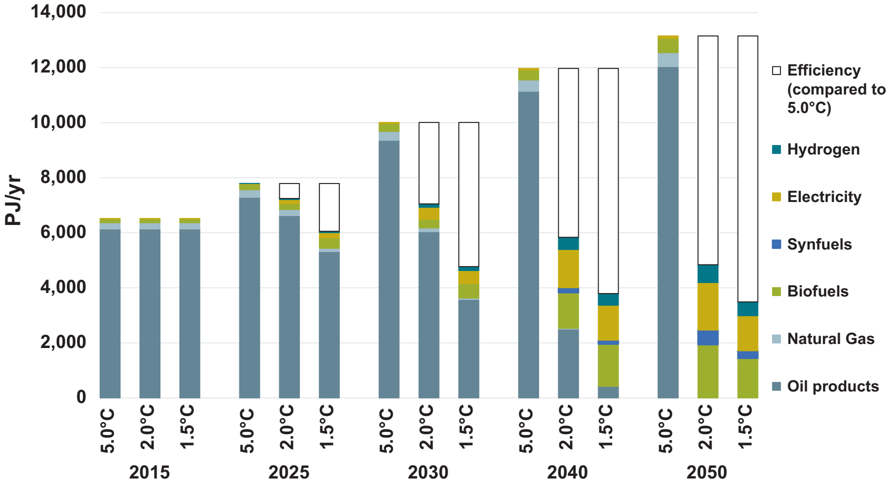


**Fig. 8.77** Non-OECD Asia: final energy consumption by transport in the scenarios

port sector as a complementary renewable option. In the 1.5 °C Scenario, the annual electricity demand will be 350 TWh in 2050. The 1.5 °C Scenario also assumes a hydrogen demand of 500 PJ/year by 2050.

Biofuel use is limited in the 2.0 °C Scenario to a maximum of 1940 PJ/year Therefore, around 2030, synthetic fuels based on power-to-liquid will be introduced, with a maximum amount of 530 PJ/year in 2050. Due to the lower overall energy demand in transport, biofuel use will be reduced in the 1.5 °C Scenario to a maximum of 1540 PJ/year. The maximum synthetic fuel demand will amount to 280 PJ/year.

#### 8.11.1.8 Non-OECD Asia: Development of $CO_2$ Emissions

In the 5.0 °C Scenario, Non-OECD Asia's annual $CO_2$ emissions will increase by 160%, from 1880 Mt. in 2015 to 4880 Mt. in 2050. The stringent mitigation measures in both alternative scenarios will cause the annual emissions to fall to 630 Mt. in 2040 in the 2.0 °C Scenario and to 330 Mt. in the 1.5 °C Scenario, with further reductions to almost zero by 2050. In the 5.0 °C case, the cumulative $CO_2$ emissions from 2015 until 2050 will add up to 121 Gt. In contrast, in the 2.0 °C and 1.5 °C Scenarios, the cumulative emissions for the period from 2015 until 2050 will be 42 Gt and 32 Gt, respectively.

Therefore, the cumulative $CO_2$ emissions will decrease by 65% in the 2.0 °C Scenario and by 74% in the 1.5 °C Scenario compared with the 5.0 °C case. A rapid reduction in annual emissions will occur in both alternative scenarios. In the 2.0 °C Scenario, this reduction will be greatest in 'Power generation', followed by the 'Residential and other' and 'Industry' sectors (Fig. 8.78).

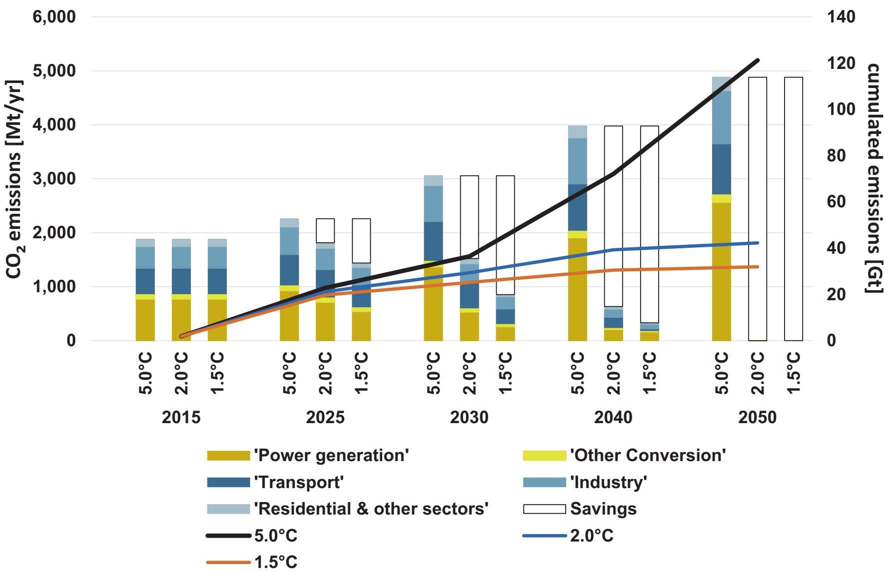


**Fig. 8.78** Non-OECD Asia: development of $CO_2$ emissions by sector and cumulative $CO_2$ emissions (after 2015) in the scenarios ('Savings' = reduction compared with the 5.0 °C Scenario)

#### 8.11.1.9 Non-OECD Asia: Primary Energy Consumption

The levels of primary energy consumption in the three scenarios when the assumptions discussed above are taken into account are shown in Fig. 8.79. In the 2.0 °C Scenario, the primary energy demand will increase by 13%, from around 38,100 PJ/year in 2015 to 43,200 PJ/year. Compared with the 5.0 °C Scenario, the overall primary energy demand will decrease by 47% by 2050 in the 2.0 °C Scenario (5.0 °C: 81600 PJ in 2050). In the 1.5 °C Scenario, the primary energy demand will be even lower (39,300 PJ in 2050) because the final energy demand and conversion losses will be lower.

Both the 2.0 °C Scenario and 1.5 °C Scenario aim to rapidly phase-out coal and oil. This will cause renewable energy to have a primary energy share of 40% in 2030 and 93% in 2050 in the 2.0 °C Scenario. In the 1.5 °C Scenario, renewables will have a primary energy share of more than 92% in 2050 (including non-energy consumption, which will still include fossil fuels). Nuclear energy will be phased out by 2045 in both the 2.0 °C Scenario and 1.5 °C Scenario. The cumulative primary energy consumption of natural gas in the 5.0 °C case will add up to 430 EJ, the cumulative coal consumption to about 530 EJ, and the crude oil consumption to 580

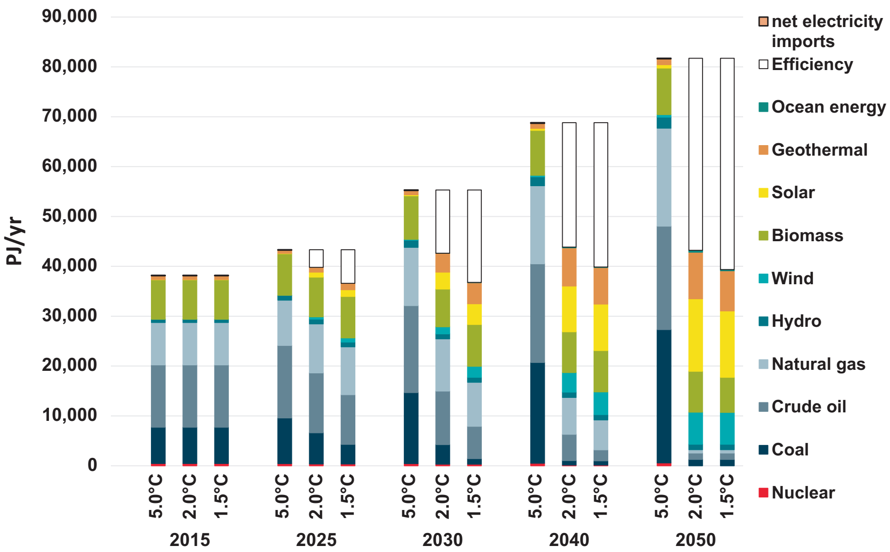


**Fig. 8.79** Non-OECD Asia: projection of total primary energy demand (PED) by energy carrier in the scenarios (including electricity import balance)

EJ. In contrast, in the 2.0 °C Scenario, the cumulative gas demand will amount to 260 EJ, the cumulative coal demand to 120 EJ, and the cumulative oil demand to 270 EJ. Even lower fossil fuel use will be achieved in the 1.5 °C Scenario: 230 EJ for natural gas, 70 EJ for coal, and 190 EJ for oil.

## *8.11.2 Non-OECD Asia: Power Sector Analysis*

Non-OECD Asia is the most heterogeneous region of all IEA world energy regions because it includes not only all the ASEAN countries (ASEAN 2018) of South East Asia, but also central and south Asian nations, as well all 16 Pacific Island states. As for the Caribbean Islands, a power system assessment—especially with regard to possible storage demand—that examines all Pacific Island states together rather than individually, is not sufficient to provide the actual required storage demand. However, with this is in mind, the ratio of solar PV generation to storage requirements does provide some indication. A specific assessment for each of the Pacific Island states is required, but is beyond the scope of this study. Indonesia and the Philippines are selected as sub-regions because they are island states with some interconnection between islands.

### 8.11.2.1 Non-OECD Asia: Development of Power Plant Capacities

Non-OECD Asia's renewable power market can be subdivided into the following categories: technologies for small and medium islands (mainly solar PV–battery systems, mini-hydro and small-scale bioenergy systems); and utility-scale solar and onshore wind for all major economies in mainland Asia or on the large islands of the Philippines and Indonesia. Several countries in this region are on the Pacific Ring of Fire and have significant geothermal energy resources. The annual market for geothermal power plants is one of the world's largest, with a projected 3–4 GW each year for almost two decades between 2025 and 2045 in both scenarios (Table 8.72).

### 8.11.2.2 Non-OECD Asia: Utilization of Power-Generation Capacities

Due to the geographic diversity and wide distribution of all sub-regions of the Non-OECD Asia region, it is assumed that there are no interconnection capacities available, and that there will not be any at the end of the modelling period (Table 8.73).

**Table 8.72** Non-OECD Asia: average annual change in installed power plant capacity

| Non-OECD-Asia power generation: average annual change of installed capacity [GW/a] | 2015–2025 | | 2026–2035 | | 2036–2050 | |
|---|---|---|---|---|---|---|
| | 2.0 °C | 1.5 °C | 2.0 °C | 1.5 °C | 2.0 °C | 1.5 °C |
| Hard coal | 2 | −6 | −7 | −4 | −1 | 0 |
| Lignite | −2 | −4 | −1 | −2 | 0 | 0 |
| Gas | 4 | 10 | 19 | 14 | −26 | −22 |
| Hydrogen-gas | 0 | 1 | 0 | 6 | 33 | 24 |
| Oil/diesel | 0 | −5 | −4 | −5 | −1 | 0 |
| Nuclear | 0 | 0 | 0 | 0 | 0 | 0 |
| Biomass | 2 | 1 | 1 | 1 | 1 | 1 |
| Hydro | 3 | 2 | 0 | 0 | 0 | 0 |
| Wind (onshore) | 4 | 21 | 20 | 24 | 26 | 20 |
| Wind (offshore) | 3 | 7 | 6 | 7 | 5 | 4 |
| PV (roof top) | 10 | 36 | 40 | 47 | 50 | 37 |
| PV (utility scale) | 3 | 12 | 13 | 16 | 17 | 12 |
| Geothermal | 0 | 3 | 4 | 4 | 2 | 1 |
| Solar thermal power plants | 1 | 6 | 9 | 8 | 17 | 13 |
| Ocean energy | 0 | 0 | 1 | 1 | 3 | 2 |
| Renewable fuel based co-generation | **1** | **2** | **1** | **1** | **1** | **1** |

In both scenarios, variable power generation will jump from only 1% today to around 25% in all sub-regions, whereas dispatchable renewables will remain stable at around 25%–30% until 2050.

Compared with other world regions, the capacity factors for limited dispatchable fossil and nuclear energy will remain relatively high until 2030, as shown in Table 8.74. The time required for variable power generation to replace fossil and nuclear generation will be greater than it is in other regions. In the 1.5 °C Scenario, all coal capacities across the region will be phased out by 2030, except for 4 GW (equivalent to 4–5 power plants), which will be off-line 5 years later.

#### 8.11.2.3 Non-OECD Asia: Development of Load, Generation, and Residual Load

Because both scenarios were calculated under the assumption that there are no interconnection capacities at the sub-regional level, more dispatch capacity will be deployed. Table 8.75 shows that only Asia North-West and Asia South-West will require some interconnection to avoid curtailment. The development of the maximum load, generation, and the resulting residual load—the load remaining after

**Table 8.73** Non-OECD Asia: power system shares by technology group

| Power generation structure and interconnection | | 2.0 °C | | | | 1.5 °C | | | |
|---|---|---|---|---|---|---|---|---|---|
| | | Variable RE | Dispatch RE | Dispatch Fossil | Inter-connection | Variable RE | Dispatch RE | Dispatch Fossil | Inter-connection |
| Asia West: Pakistan, Afghanistan, Nepal, Bhutan | 2015 | 1% | 35% | 63% | 0% | | | | |
| | 2030 | 31% | 31% | 38% | 0% | 44% | 29% | 28% | 0% |
| | 2050 | 62% | 25% | 13% | 0% | 64% | 24% | 12% | 0% |
| Sri Lanka | 2015 | 1% | 35% | 64% | 0% | | | | |
| | 2030 | 30% | 37% | 33% | 0% | 41% | 34% | 25% | 0% |
| | 2050 | 58% | 27% | 15% | 0% | 59% | 26% | 14% | 0% |
| Pacific Island State | 2015 | 1% | 35% | 64% | 0% | | | | |
| | 2030 | 29% | 34% | 37% | 0% | 39% | 30% | 30% | 0% |
| | 2050 | 55% | 25% | 20% | 0% | 55% | 25% | 20% | 0% |
| Asia North West: Bangladesh, Myanmar, Thailand | 2015 | 1% | 35% | 64% | 0% | | | | |
| | 2030 | 23% | 37% | 40% | 0% | 33% | 35% | 32% | 0% |
| | 2050 | 48% | 31% | 21% | 0% | 50% | 30% | 20% | 0% |
| Asia Central North: Viet Nam, Laos and Cambodia | 2015 | 1% | 35% | 64% | 0% | | | | |
| | 2030 | 27% | 36% | 36% | 0% | 38% | 33% | 29% | 0% |
| | 2050 | 53% | 28% | 20% | 0% | 56% | 27% | 17% | 0% |
| Asia South West: Malaysia, Brunei | 2015 | 1% | 35% | 64% | 0% | | | | |
| | 2030 | 26% | 40% | 34% | 0% | 36% | 37% | 27% | 0% |
| | 2050 | 52% | 29% | 19% | 0% | 57% | 28% | 15% | 0% |

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| Indonesia | 2015 | 1% | 35% | 64% | 0% | | | | |
| | 2030 | 21% | 34% | 45% | 0% | 31% | 35% | 35% | 0% |
| | 2050 | 47% | 30% | 23% | 0% | 48% | 30% | 22% | 0% |
| Philippines | 2015 | 1% | 35% | 64% | 0% | | | | |
| | 2030 | 34% | 34% | 32% | 0% | 48% | 30% | 22% | 0% |
| | 2050 | 63% | 23% | 13% | 0% | 65% | 22% | 13% | 0% |
| Non-OECD Asia | 2015 | 1% | 35% | 64% | | | | | |
| | 2030 | 26% | 35% | 39% | | 36% | 34% | 30% | |
| | 2050 | 52% | 28% | 19% | | 55% | 28% | 17% | |

**Table 8.74** Non-OECD Asia: capacity factors by generation type

| Utilization of variable and dispatchable power generation: | | 2015 | 2020 | 2020 | 2030 | 2030 | 2040 | 2040 | 2050 | 2050 |
|---|---|---|---|---|---|---|---|---|---|---|
| Non-OECD Asia | | | 2.0 °C | 1.5 °C | 2.0 °C | 1.5 °C | 2.0 °C | 1.5 °C | 2.0 °C | 1.5 °C |
| Capacity factor – average | [%/yr] | **55.4%** | **52%** | **53%** | **45%** | **42%** | **33%** | **33%** | **34%** | **32%** |
| Limited dispatchable: fossil and nuclear | [%/yr] | 71.4% | 52% | 53% | 44% | 33% | 31% | 13% | 25% | 0% |
| Limited dispatchable: renewable | [%/yr] | 40.5% | 61% | 61% | 59% | 56% | 58% | 53% | 45% | 49% |
| Dispatchable: fossil | [%/yr] | 50.2% | 32% | 33% | 23% | 27% | 37% | 13% | 28% | 12% |
| Dispatchable: renewable | [%/yr] | 34.4% | 75% | 75% | 74% | 69% | 41% | 58% | 53% | 51% |
| Variable: renewable | [%/yr] | 13.1% | 19% | 19% | 36% | 35% | 26% | 31% | 30% | 29% |

variable renewable generation. According to the Philippine Department of Energy, the peak demand in the Philippines in 2016 was 13.3 GW (PR-DoE 2016) (9.7 GW in Luzon, 1.9 GW in the Visayas, and 1.7 GW in Mindanao). The calculated load for the Philippines in 2020 was 16.3 GW, which seems realistic. The load will increase to 75.5 GW by 2050 under the 2.0 °C Scenario. The results for all Asian regions show a quadrupling of load by 2050.

The lack of interconnection potential between or even within most sub-regions will lead to some curtailment.

Table 8.76 shows that whereas countries on the Asian mainland will use and increase their capacity for hydro pump storage electricity, batteries will be used for most of the storage requirements of islands and island states. Where available, gas infrastructure must be converted to hydrogen-operated systems.

**Table 8.75** Non-OECD Asia: load, generation, and residual load development—2.0 °C Scenario

| Power generation structure | | 2.0 °C Max demand [GW] | 2.0 °C Max generation [GW] | 2.0 °C Max residual load [GW] | 2.0 °C Max interconnection requirements [GW] | 1.5 °C Max demand [GW] | 1.5 °C Max generation [GW] | 1.5 °C Max residual load [GW] | 1.5 °C Max interconnection requirements [GW] |
|---|---|---|---|---|---|---|---|---|---|
| Asia West: Pakistan, Afghanistan, Nepal, Bhutan | 2020 | 38.1 | 22.4 | 17.4 | | 38.1 | 22.3 | 17.5 | |
| | 2030 | 65.1 | 58.2 | 44.4 | 0 | 67.1 | 64.2 | 47.9 | 0 |
| | 2050 | 145.6 | 194.0 | 117.5 | 0 | 137.5 | 185.6 | 112.2 | 0 |
| Sri Lanka | 2020 | 5.6 | 2.7 | 3.2 | | 5.6 | 2.7 | 3.2 | |
| | 2030 | 9.0 | 8.6 | 6.3 | 0 | 9.2 | 10.5 | 6.5 | 0 |
| | 2050 | 19.7 | 31.1 | 15.2 | 0 | 18.2 | 29.7 | 14.1 | 0 |
| Pacific Island State | 2020 | 1.6 | 1.0 | 0.6 | | 1.6 | 1.0 | 0.6 | |
| | 2030 | 2.6 | 2.3 | 1.8 | 0 | 2.7 | 2.6 | 1.9 | 0 |
| | 2050 | 5.6 | 8.2 | 4.2 | 0 | 5.5 | 7.9 | 4.2 | 0 |
| Asia North West: Bangladesh, Myanmar, Thailand | 2020 | 57.8 | 18.9 | 41.8 | | 57.8 | 18.8 | 41.9 | |
| | 2030 | 97.4 | 88.8 | 67.1 | 0 | 99.6 | 101.2 | 71.5 | 0 |
| | 2050 | 218.9 | 321.0 | 171.4 | 0 | 198.1 | 306.3 | 155.8 | 0 |
| Asia Central North: Viet Nam, Laos and Cambodia | 2020 | 29.4 | 26.3 | 3.5 | | 29.4 | 26.2 | 3.6 | |
| | 2030 | 47.0 | 44.4 | 29.8 | 0 | 47.9 | 61.2 | 32.2 | 0 |
| | 2050 | 109.6 | 191.0 | 83.1 | 0 | 93.7 | 182.6 | 70.2 | 19 |
| Asia South West: Malaysia, Brunei | 2020 | 38.2 | 16.0 | 25.0 | | 38.2 | 15.1 | 25.5 | |
| | 2030 | 53.6 | 54.0 | 28.1 | 0 | 53.9 | 68.4 | 34.0 | 0 |
| | 2050 | 121.0 | 216.7 | 89.1 | 7 | 99.2 | 206.9 | 71.0 | 37 |

(continued)

**Table 8.75** (continued)

| Power generation structure | | 2.0 °C | | | | 1.5 °C | | | |
|---|---|---|---|---|---|---|---|---|---|
| | | Max demand | Max generation | Max residual load | Max interconnection requirements | Max demand | Max generation | Max residual load | Max interconnection requirements |
| | | [GW] | [GW] | [GW] | [GW] | [GW] | [GW] | [GW] | [GW] |
| Indonesia | 2020 | 60.9 | 34.3 | 26.6 | | 60.9 | 33.0 | 27.9 | |
| | 2030 | 106.7 | 99.8 | 59.9 | 0 | 108.7 | 114.5 | 77.4 | 0 |
| | 2050 | 239.4 | 363.8 | 188.3 | 0 | 218.6 | 348.2 | 173.2 | 0 |
| Philippines | 2020 | 16.3 | 13.7 | 3.9 | | | | | |
| | 2030 | 33.5 | 33.0 | 19.0 | 0 | 34.3 | 42.6 | 24.1 | 0 |
| | 2050 | 75.5 | 133.1 | 58.8 | 0 | 70.3 | 127.3 | 55.5 | 2 |

**Table 8.76** Non-OECD Asia: storage and dispatch service requirements

| Storage and dispatch | | 2.0 °C | | | | | 1.5 °C | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | Required to avoid curtailment | Utilization battery -through-put- | Utilization PSH -through-put- | Total storage demand (incl. H2) | Dispatch hydrogen-based | Required to avoid curtailment | Utilization battery -through-put- | Utilization PSH -through-put- | Total storage demand (incl. H2) | Dispatch hydrogen-based |
| Non-OECD Asia | | [GWh/year] | [GWh/year] | [GWh/year] | [GWh/year] | [GWh/year] | [GWh/year] | [GWh/year] | [GWh/year] | [GWh/year] | [GWh/year] |
| Asia West: Pakistan, Afghanistan, Nepal, Bhutan | 2020 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | 2030 | 0 | 0 | 0 | 0 | 0 | 434 | 4 | 78 | 82 | 3356 |
| | 2050 | 36,251 | 767 | 716 | 1483 | 42,533 | 37,649 | 407 | 774 | 1181 | 44,157 |
| Sri Lanka | 2020 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | 2030 | 0 | 0 | 0 | 0 | 0 | 72 | 1 | 9 | 10 | 564 |
| | 2050 | 4755 | 135 | 125 | 260 | 7380 | 5471 | 74 | 144 | 218 | 7330 |
| Pacific Island State | 2020 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | 2030 | 12 | 0 | 2 | 2 | 0 | 183 | 1 | 14 | 14 | 142 |
| | 2050 | 2178 | 44 | 43 | 87 | 2101 | 1932 | 22 | 42 | 65 | 2211 |
| Asia North West: Bangladesh, Myanmar, Thailand | 2020 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | 2030 | 0 | 0 | 0 | 0 | 0 | 194 | 1 | 27 | 28 | 6617 |
| | 2050 | 19,992 | 1114 | 824 | 1938 | 93,720 | 29,141 | 657 | 1113 | 1770 | 92,309 |
| Asia Central North: Viet Nam, Laos and Cambodia | 2020 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | 2030 | 6 | 0 | 3 | 4 | 0 | 1031 | 5 | 121 | 126 | 3346 |
| | 2050 | 26,401 | 727 | 708 | 1435 | 49,483 | 40,048 | 416 | 919 | 1335 | 45,848 |

(continued)

**Table 8.76** (continued)

| Storage and dispatch | | 2.0 °C | | | | | 1.5 °C | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | Required to avoid curtailment | Utilization battery -through-put- | Utilization PSH -through-put- | Total storage demand (incl. H2) | Dispatch hydrogen-based | Required to avoid curtailment | Utilization battery -through-put- | Utilization PSH -through-put- | Total storage demand (incl. H2) | Dispatch hydrogen-based |
| Non-OECD Asia | | [GWh/year] | [GWh/year] | [GWh/year] | [GWh/year] | [GWh/year] | [GWh/year] | [GWh/year] | [GWh/year] | [GWh/year] | [GWh/year] |
| Asia South West: Malaysia, Brunei | 2020 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | 2030 | 7 | 0 | 2 | 3 | 0 | 1036 | 5 | 120 | 125 | 4151 |
| | 2050 | 32,422 | 942 | 893 | 1835 | 59,371 | 55,862 | 610 | 1406 | 2016 | 51,750 |
| Indonesia | 2020 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | 2030 | 0 | 0 | 0 | 0 | 0 | 176 | 1 | 21 | 22 | 7391 |
| | 2050 | 11,890 | 720 | 530 | 1250 | 107,913 | 17,040 | 478 | 717 | 1195 | 107,330 |
| Philippines | 2020 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | 2030 | 112 | 3 | 22 | 25 | 0 | 3723 | 6 | 232 | 239 | 1917 |
| | 2050 | 38,084 | 507 | 670 | 1177 | 23,954 | 41,017 | 266 | 743 | 1009 | 24,126 |
| Other Asia | 2020 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | 2030 | 137 | 4 | 30 | 34 | 0 | 6848 | 23 | 622 | 646 | 27,484 |
| | 2050 | 171,973 | 4955 | 4510 | 9465 | 386,454 | 228,160 | 2930 | 5859 | 8789 | 375,061 |

# 8.12 India

## *8.12.1 India: Long-Term Energy Pathways*

### 8.12.1.1 India: Final Energy Demand by Sector

The future development pathways for India's final energy demand when the assumptions on population growth, GDP growth, and energy intensity are combined are shown in Fig. 8.80 for the 5.0 °C, 2.0 °C, and 1.5 °C Scenarios. In the 5.0 °C Scenario, the total final energy demand will increase by 201% from the current 22,200 PJ/year to 66,800 PJ/year by 2050. In the 2.0 °C Scenario, the final energy demand will increase at a much slower rate by 57% compared with current consumption and will reach 34,900 PJ/year by 2050. The final energy demand in the 1.5 °C Scenario will reach 31,900 PJ, 44% above the 2015 level. In the 1.5 °C Scenario, the final energy demand in 2050 will be 9% lower than in the 2.0 °C Scenario. The electricity demand for 'classical' electrical devices (without power-to-heat or e-mobility) will increase from 750 TWh/year in 2015 to 3200 TWh/year in 2050 in both alternative scenarios. Compared with the 5.0 °C case (4720 TWh/year in 2050), efficiency measures in the 2.0 °C and 1.5 °C Scenarios will save around 1520 TWh/year by 2050.

Electrification will lead to a significant increase in the electricity demand by 2050. In the 2.0 °C Scenario, the electricity demand for heating will be approximately 1900 TWh/year due to electric heaters and heat pumps, and in the transport sector,

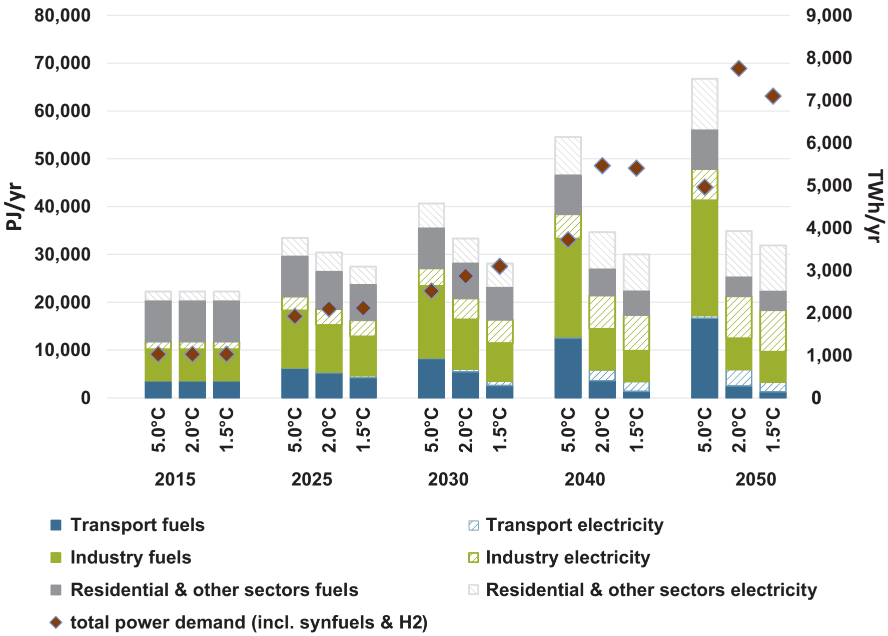


**Fig. 8.80** India: development of final energy demand by sector in the scenarios

the electricity demand will be approximately 3400 TWh/year due to electric mobility. The generation of hydrogen (for transport and high-temperature process heat) and the manufacture of synthetic fuels (mainly for transport) will add an additional power demand of 1700 TWh/year. Therefore, the gross power demand will increase from 1400 TWh/year in 2015 to 8400 TWh/year in 2050 in the 2.0 °C Scenario, 31% higher than in the 5.0 °C case. In the 1.5 °C Scenario, the gross electricity demand will increases to a maximum of 7700 TWh/year in 2050.

Efficiency gains in the heating sector could be even larger than in the electricity sector. In the 2.0 °C and 1.5 °C Scenarios, a final energy consumption equivalent to about 9500 PJ/year and 9800 PJ/year, respectively, will be avoided through efficiency gains by 2050 compared with the 5.0 °C Scenario.

#### 8.12.1.2 India: Electricity Generation

The development of the power system is characterized by a dynamically growing renewable energy market and an increasing proportion of total power from renewable sources. By 2050, 100% of the electricity produced in India will come from renewable energy sources in the 2.0 °C Scenario. 'New' renewables—mainly wind, solar, and geothermal energy—will contribute 90% of the total electricity generation. Renewable electricity's share of the total production will be 66% by 2030 and 89% by 2040. The installed capacity of renewables will reach about 1060 GW by 2030 and 3360 GW by 2050. The share of renewable electricity generation in 2030 in the 1.5 °C Scenario is assumed to be 77%. In the 1.5 °C Scenario, the generation capacity from renewable energy will be approximately 3040 GW in 2050.

Table 8.77 shows the development of different renewable technologies in India over time. Figure 8.81 provides an overview of the overall power-generation structure in India. From 2020 onwards, the continuing growth of wind and PV up to 1270 GW and 1570 GW, respectively, is complemented by up to 210 GW solar thermal generation, as well as limited biomass, geothermal, and ocean energy, in the 2.0 °C Scenario. Both the 2.0 °C Scenario and 1.5 °C Scenario will lead to a high proportion of variable power generation (PV, wind, and ocean) of 48% and 60%, respectively, by 2030, and 75% and 72%, respectively, by 2050.

#### 8.12.1.3 India: Future Costs of Electricity Generation

Figure 8.82 shows the development of the electricity-generation and supply costs over time, including the $CO_2$ emission costs, in all scenarios. The calculated electricity generation costs in 2015 (referring to full costs) were around 5.4 ct/kWh. In the 5.0 °C case, the generation costs will increase until 2040, when they reach 11 ct/kWh, and then drop to 10.7 ct/kWh by 2050. The generation costs will increase in the 2.0 °C Scenario until 2030, when they reach 8.4 ct/kWh, and then drop to 5.7 ct/kWh by 2050. In the 1.5 °C Scenario, they will increase to 7.8 ct/kWh, and then drop to 5.8 ct/kWh by 2050. In the 2.0 °C Scenario, the generation costs in 2050 will be 5 ct/kWh lower than in the 5.0 °C case. In the 1.5 °C Scenario, the generation

**Table 8.77** India: development of renewable electricity-generation capacity in the scenarios

| in GW | Case | 2015 | 2025 | 2030 | 2040 | 2050 |
|---|---|---|---|---|---|---|
| Hydro | 5.0 °C | 46 | 68 | 81 | 97 | 117 |
| | 2.0 °C | 46 | 68 | 72 | 80 | 87 |
| | 1.5 °C | 46 | 68 | 72 | 80 | 87 |
| Biomass | 5.0 °C | 8 | 13 | 16 | 20 | 25 |
| | 2.0 °C | 8 | 23 | 31 | 60 | 93 |
| | 1.5 °C | 8 | 23 | 31 | 60 | 93 |
| Wind | 5.0 °C | 25 | 82 | 119 | 185 | 246 |
| | 2.0 °C | 25 | 200 | 421 | 938 | 1273 |
| | 1.5 °C | 25 | 275 | 543 | 1002 | 1110 |
| Geothermal | 5.0 °C | 0 | 0 | 0 | 0 | 0 |
| | 2.0 °C | 0 | 3 | 8 | 42 | 68 |
| | 1.5 °C | 0 | 3 | 8 | 42 | 68 |
| PV | 5.0 °C | 5 | 115 | 198 | 345 | 545 |
| | 2.0 °C | 5 | 230 | 469 | 1090 | 1572 |
| | 1.5 °C | 5 | 365 | 648 | 1185 | 1412 |
| CSP | 5.0 °C | 0 | 0 | 1 | 1 | 2 |
| | 2.0 °C | 0 | 8 | 48 | 138 | 209 |
| | 1.5 °C | 0 | 8 | 48 | 138 | 209 |
| Ocean | 5.0 °C | 0 | 0 | 0 | 0 | 0 |
| | 2.0 °C | 0 | 1 | 11 | 33 | 59 |
| | 1.5 °C | 0 | 1 | 11 | 33 | 59 |
| Total | 5.0 °C | 84 | 279 | 415 | 648 | 936 |
| | 2.0 °C | 84 | 532 | 1061 | 2381 | 3360 |
| | 1.5 °C | 84 | 742 | 1361 | 2540 | 3037 |

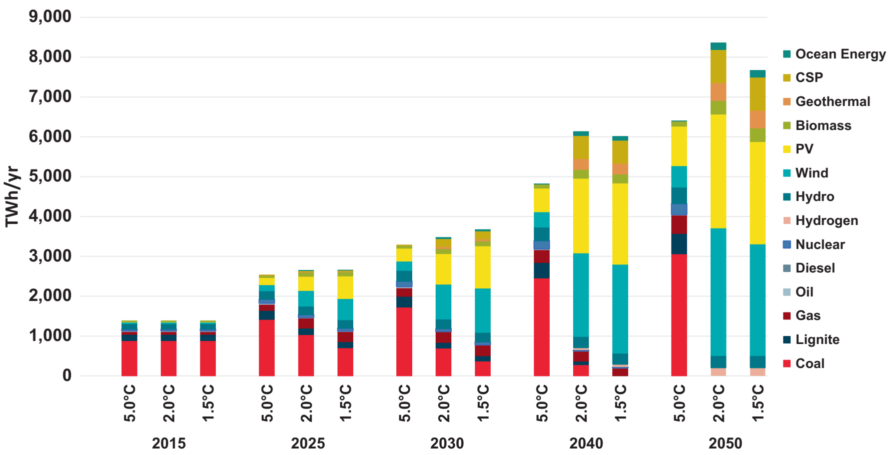


**Fig. 8.81** India: development of electricity-generation structure in the scenarios

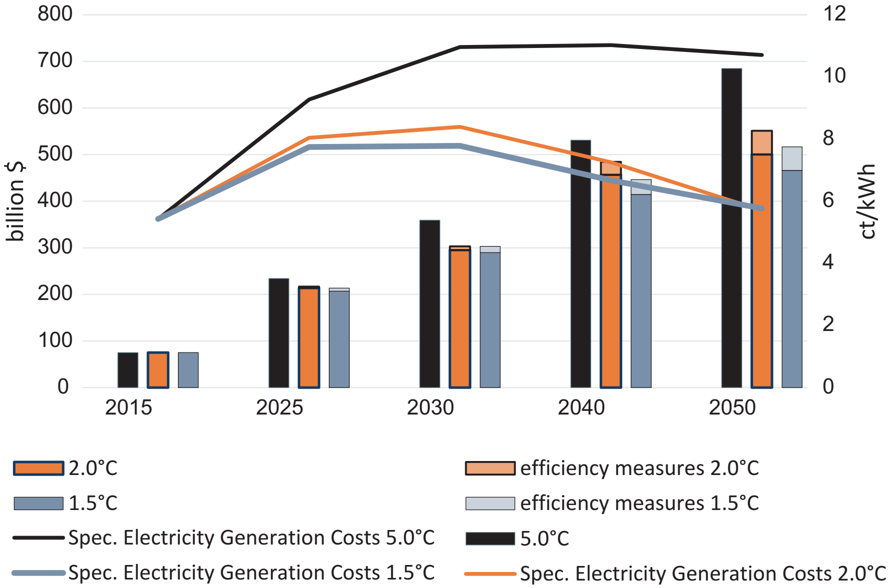


**Fig. 8.82** India: development of total electricity supply costs and specific electricity generation costs in the scenarios

costs in 2050 will be 4.9 ct/kWh lower than in the 5.0 °C case. Note that these estimates of generation costs do not take into account integration costs such as power grid expansion, storage, or other load-balancing measures.

In the 5.0 °C case, the growth in demand and increasing fossil fuel prices will cause the total electricity supply costs to rise from today's $75 billion/year to more than $690 billion/year in 2050. In the 2.0 °C case, the total supply costs will be $500 billion/year and in the 1.5 °C Scenario, they will be $470 billion/year. The long-term costs for electricity supply will be more than 27% lower in the 2.0 °C Scenario than in the 5.0 °C Scenario as a result of the estimated generation costs and the electrification of heating and mobility. Further demand reductions in the 1.5 °C Scenario will result in total power generation costs that are 32% lower than in the 5.0 °C case.

Compared with these results, the generation costs, when the $CO_2$ emission costs are not considered, will increase in the 5.0 °C case to only 6.9 ct/kWh. In both alternative scenarios, they will still increase until 2030, when they reach 6.7 ct/kWh, and then drop to around 5.8 ct/kWh by 2050. The maximum difference in generation costs will be around 1 ct/kWh in 2050. If the $CO_2$ costs are not considered, the total electricity supply costs in the 5.0 °C case will rise to about $430 billion/year in 2050.

#### 8.12.1.4 India: Future Investments in the Power Sector

An investment of around $5640 billion will be required for power generation between 2015 and 2050 in the 2.0 °C Scenario—including additional power plants for the production of hydrogen and synthetic fuels and investments in the replacement of plants after the end of their economic lifetimes. This value is equivalent to approximately $157

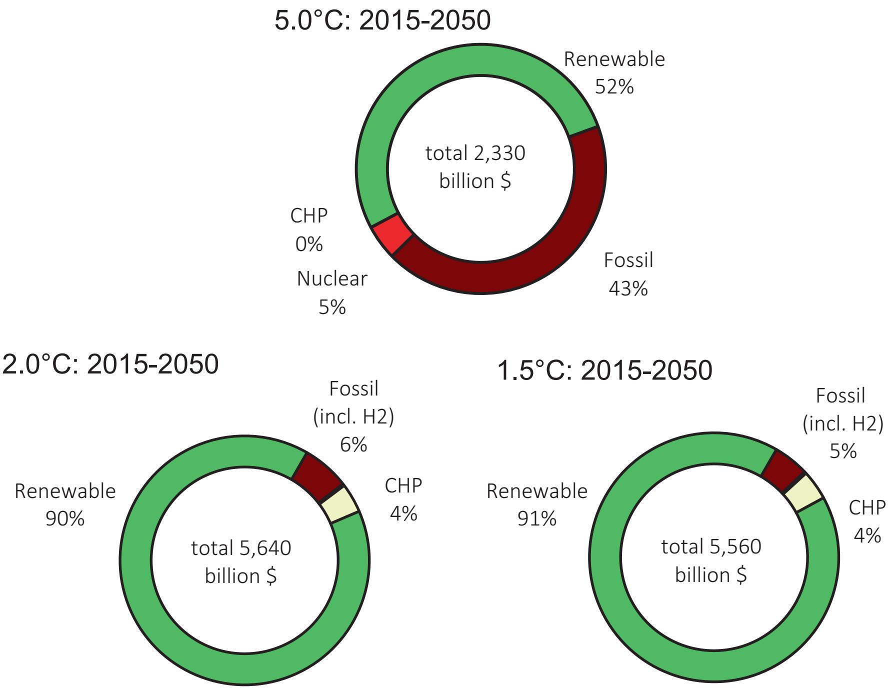


**Fig. 8.83** India: investment shares for power generation in the scenarios

billion per year on average, and is $3310 billion more than in the 5.0 °C case ($2330 billion). An investment of around $5560 billion for power generation will be required between 2015 and 2050 in the 1.5 °C Scenario. On average, this will be an investment of $154 billion per year. In the 5.0 °C Scenario, the investment in conventional power plants will be around 48% of the total cumulative investments, whereas approximately 52% will be invested in renewable power generation and co-generation (Fig. 8.83).

However, in the 2.0 °C (1.5 °C) Scenario, India will shift almost 94% (95%) of its entire investment to renewables and co-generation. By 2030, the fossil fuel share of the power sector investment will predominantly focus on gas power plants that can also be operated with hydrogen.

Because renewable energy has no fuel costs, other than biomass, the cumulative fuel cost savings in the 2.0 °C Scenario will reach a total of $3110 billion in 2050, equivalent to $86 billion per year. Therefore, the total fuel cost savings will be equivalent to 90% of the total additional investments compared to the 5.0 °C Scenario. The fuel cost savings in the 1.5 °C Scenario will add up to $3330 billion, or $93 billion per year.

#### 8.12.1.5 India: Energy Supply for Heating

The final energy demand for heating will increase in the 5.0 °C Scenario by 133%, from 11,900 PJ/year in 2015 to 27,800 PJ/year in 2050. Energy efficiency measures will help to reduce the energy demand for heating by 34% in 2050 in the 2.0 °C

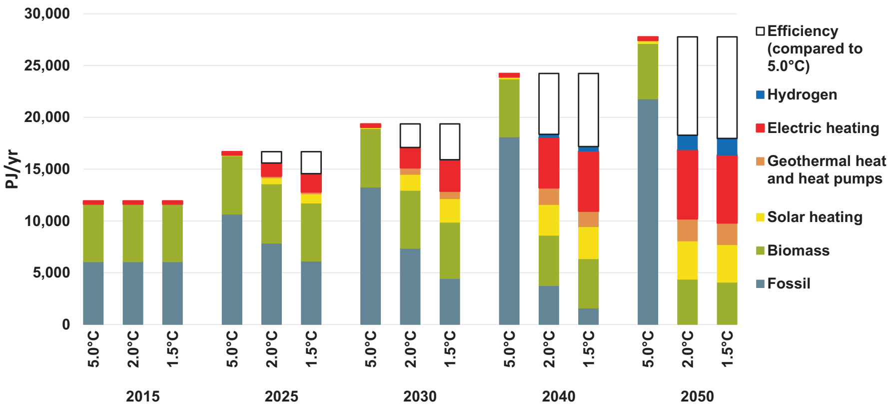


**Fig. 8.84** India: development of heat supply by energy carrier in the scenarios

**Table 8.78** India: development of renewable heat supply in the scenarios (excluding the direct use of electricity)

| in PJ/year | Case | 2015 | 2025 | 2030 | 2040 | 2050 |
|---|---|---|---|---|---|---|
| Biomass | 5.0 °C | 5544 | 5633 | 5666 | 5595 | 5341 |
| | 2.0 °C | 5544 | 5726 | 5600 | 4854 | 4366 |
| | 1.5 °C | 5544 | 5600 | 5444 | 4758 | 4078 |
| Solar heating | 5.0 °C | 28 | 77 | 115 | 200 | 310 |
| | 2.0 °C | 28 | 589 | 1537 | 2964 | 3693 |
| | 1.5 °C | 28 | 887 | 2271 | 3107 | 3626 |
| Geothermal heat and heat pumps | 5.0 °C | 0 | 1 | 1 | 1 | 2 |
| | 2.0 °C | 0 | 164 | 647 | 1627 | 2136 |
| | 1.5 °C | 0 | 189 | 725 | 1497 | 2103 |
| Hydrogen | 5.0 °C | 0 | 0 | 0 | 0 | 0 |
| | 2.0 °C | 0 | 0 | 2 | 299 | 1409 |
| | 1.5 °C | 0 | 0 | 2 | 437 | 1613 |
| Total | 5.0 °C | 5572 | 5711 | 5781 | 5796 | 5653 |
| | 2.0 °C | 5572 | 6478 | 7787 | 9743 | 11,603 |
| | 1.5 °C | 5572 | 6675 | 8442 | 9800 | 11,420 |

Scenario, relative to the 5.0 °C case, and by 35% in the 1.5 °C Scenario. Today, renewables supply around 47% of India's final energy demand for heating, with the main contribution from biomass. Renewable energy will provide 53% of India's total heat demand in 2030 in the 2.0 °C Scenario and 68% in the 1.5 °C Scenario. In both scenarios, renewables will provide 100% of the total heat demand in 2050.

Figure 8.84 shows the development of different technologies for heating in India over time, and Table 8.78 provides the resulting renewable heat supply for all scenarios. Up to 2030, biomass will remain the main contributor. In the long term, the increasing use of solar, geothermal, and environmental heat will lead to a biomass share of 38% in the 2.0 °C Scenario and 36% in the 1.5 °C Scenario.

Heat from renewable hydrogen will further reduce the dependence on fossil fuels under both scenarios. Hydrogen consumption in 2050 will be around 1400 PJ/year in the 2.0 °C Scenario and 1600 PJ/year in the 1.5 °C Scenario. The direct use of electricity for heating will also increase by a factor of about 21 between 2015 and 2050, and the electricity for heating will have a final energy share of 36% in 2050 in both alternative scenarios.

#### 8.12.1.6 India: Future Investments in the Heating Sector

The roughly estimated investments in renewable heating technologies up to 2050 amount to around $930 billion in the 2.0 °C Scenario (including investments for replacement after the economic lifetimes of the plants), or approximately $26 billion per year. The largest share of investment in India is assumed to be for solar collectors (around $490 billion), followed by heat pumps and biomass technologies. The 1.5 °C Scenario assumes an even faster expansion of renewable technologies and results in a higher average annual investment of around $29 billion per year (Table 8.79, Fig. 8.85).

#### 8.12.1.7 India: Transport

The energy demand in the transport sector in India is expected to increase in the 5.0 °C Scenario by 377%, from around 3600 PJ/year in 2015 to 17,200 PJ/year in 2050. In the 2.0 °C Scenario, assumed technical, structural, and behavioural changes will save 66% (11,280 PJ/year) by 2050 compared to the 5.0 °C Scenario. Additional modal shifts, technology switches, and a reduction in the transport demand will lead to even higher energy savings in the 1.5 °C Scenario of 81% (or 13,930 PJ/year) in 2050 compared with the 5.0 °C case (Table 8.80, Fig. 8.86).

By 2030, electricity will provide 10% (160 TWh/year) of the transport sector's total energy demand in the 2.0 °C Scenario, whereas in 2050, the share will be 58%

**Table 8.79** India: installed capacities for renewable heat generation in the scenarios

| in GW | Case | 2015 | 2025 | 2030 | 2040 | 2050 |
|---|---|---|---|---|---|---|
| Biomass | 5.0 °C | 2049 | 1923 | 1836 | 1633 | 1432 |
| | 2.0 °C | 2049 | 1954 | 1798 | 1311 | 856 |
| | 1.5 °C | 2049 | 1916 | 1756 | 1276 | 785 |
| Geothermal | 5.0 °C | 0 | 0 | 0 | 0 | 0 |
| | 2.0 °C | 0 | 2 | 9 | 32 | 38 |
| | 1.5 °C | 0 | 5 | 12 | 28 | 37 |
| Solar heating | 5.0 °C | 6 | 17 | 25 | 43 | 67 |
| | 2.0 °C | 6 | 126 | 327 | 619 | 777 |
| | 1.5 °C | 6 | 191 | 486 | 653 | 763 |
| Heat pumps | 5.0 °C | 0 | 0 | 0 | 0 | 0 |
| | 2.0 °C | 0 | 12 | 42 | 90 | 131 |
| | 1.5 °C | 0 | 11 | 46 | 82 | 129 |
| Total[a] | 5.0 °C | 2055 | 1940 | 1861 | 1676 | 1499 |
| | 2.0 °C | 2055 | 2094 | 2177 | 2052 | 1802 |
| | 1.5 °C | 2055 | 2122 | 2300 | 2039 | 1715 |

[a] Excluding direct electric heating

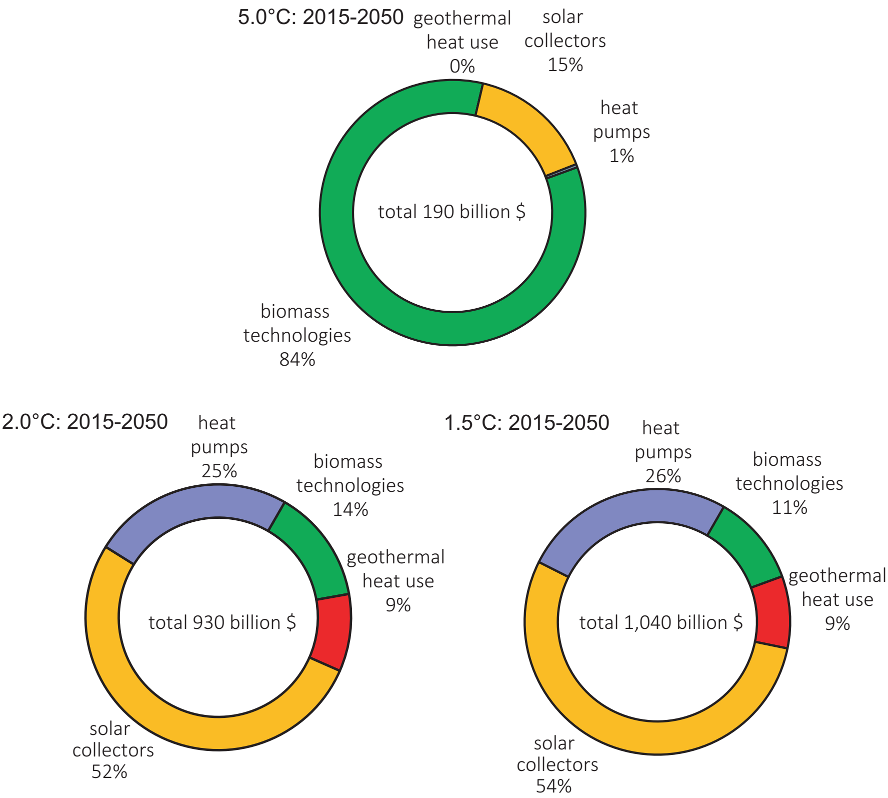


**Fig. 8.85** India: development of investments for renewable heat-generation technologies in the scenarios

(950 TWh/year). In 2050, up to 860 PJ/year of hydrogen will be used in the transport sector as a complementary renewable option. In the 1.5 °C Scenario, the annual electricity demand will be 560 TWh in 2050. The 1.5 °C Scenario also assumes a hydrogen demand of 590 PJ/year by 2050.

Biofuel use is limited in the 2.0 °C Scenario to a maximum of around 1000 PJ/year. Therefore, around 2030, synthetic fuels based on power-to-liquid will be introduced, with a maximum amount of 610 PJ/year in 2050. Due to the lower overall energy demand in transport, biofuel use will be reduced in the 1.5 °C Scenario to a maximum of 510 PJ/year. The maximum synthetic fuel demand will amount to 310 PJ/year.

#### 8.12.1.8 India: Development of $CO_2$ Emissions

In the 5.0 °C Scenario, India's annual $CO_2$ emissions will increase by 236%, from 2060 Mt. in 2015 to 6950 Mt. in 2050. The stringent mitigation measures in both alternative scenarios will cause the annual emissions to fall to 930 Mt. in 2040 in the 2.0 °C Scenario and to 200 Mt. in the 1.5 °C Scenario, with further reductions to

**Table 8.80** India: projection of transport energy demand by mode in the scenarios

| in PJ/year | Case | 2015 | 2025 | 2030 | 2040 | 2050 |
|---|---|---|---|---|---|---|
| Rail | 5.0 °C | 180 | 238 | 278 | 353 | 423 |
| | 2.0 °C | 180 | 270 | 325 | 421 | 526 |
| | 1.5 °C | 180 | 219 | 234 | 332 | 446 |
| Road | 5.0 °C | 3294 | 5861 | 7880 | 12,152 | 16,455 |
| | 2.0 °C | 3294 | 5017 | 5562 | 5301 | 5285 |
| | 1.5 °C | 3294 | 4253 | 3125 | 2977 | 2730 |
| Domestic aviation | 5.0 °C | 84 | 131 | 166 | 216 | 231 |
| | 2.0 °C | 84 | 89 | 81 | 66 | 52 |
| | 1.5 °C | 84 | 85 | 74 | 52 | 40 |
| Domestic navigation | 5.0 °C | 29 | 34 | 36 | 40 | 52 |
| | 2.0 °C | 29 | 34 | 36 | 40 | 52 |
| | 1.5 °C | 29 | 34 | 36 | 40 | 52 |
| Total | 5.0 °C | 3587 | 6263 | 8360 | 12,762 | 17,161 |
| | 2.0 °C | 3587 | 5410 | 6006 | 5828 | 5914 |
| | 1.5 °C | 3587 | 4590 | 3470 | 3401 | 3268 |

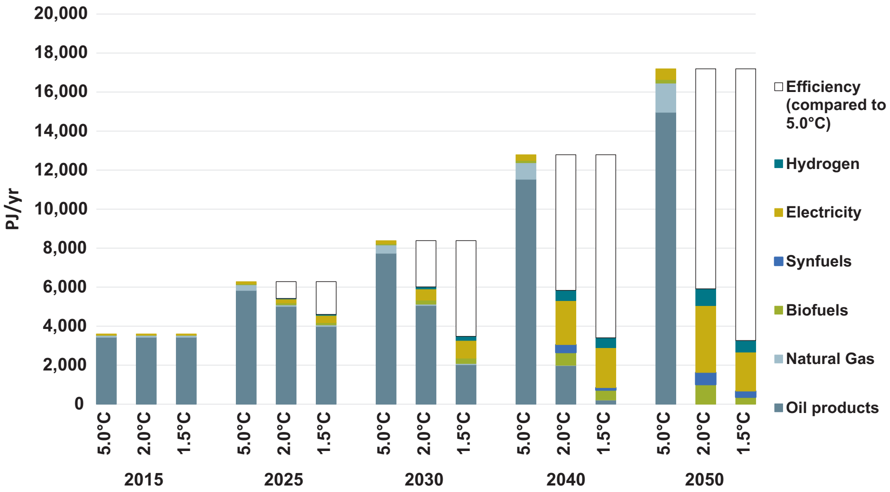


**Fig. 8.86** India: final energy consumption by transport in the scenarios

almost zero by 2050. In the 5.0 °C case, the cumulative $CO_2$ emissions from 2015 until 2050 will add up to 169 Gt. In contrast, in the 2.0 °C and 1.5 °C Scenarios, the cumulative emissions for the period from 2015 until 2050 will be 55 Gt and 38 Gt, respectively.

Therefore, the cumulative $CO_2$ emissions will decrease by 67% in the 2.0 °C Scenario and by 78% in the 1.5 °C Scenario compared with the 5.0 °C case. A rapid reduction in the annual emissions will occur in both alternative scenarios. In the

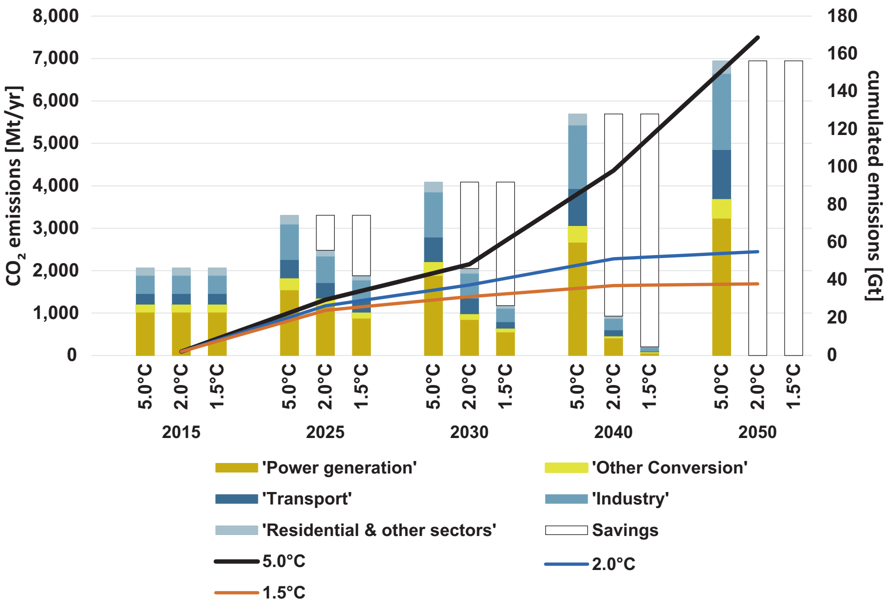


**Fig. 8.87** India: development of $CO_2$ emissions by sector and cumulative $CO_2$ emissions (after 2015) in the scenarios ('Savings' = reduction compared with the 5.0 °C Scenario)

2.0 °C Scenario, the reduction will be greatest in the 'Residential and other' sector, followed by the 'Power generation' and 'Industry' sectors (Fig. 8.87).

### 8.12.1.9 India: Primary Energy Consumption

The levels of primary energy consumption in the three scenarios when the assumptions discussed above are taken into account are shown in Fig. 8.88. In the 2.0 °C Scenario, the primary energy demand will increase by 43%, from around 35,600 PJ/year in 2015 to 50,900 PJ/year in 2050. Compared with the 5.0 °C Scenario, the overall primary energy demand will decrease by 51% by 2050 in the 2.0 °C Scenario (5.0 °C: 104,800 PJ in 2050). In the 1.5 °C Scenario, the primary energy demand will be even lower (47,100 PJ in 2050) because the final energy demand and conversion losses will be lower.

Both the 2.0 °C and 1.5 °C Scenarios aim to rapidly phase-out coal and oil. This will cause renewable energy to have a primary energy share of 40% in 2030 and 94% in 2050 in the 2.0 °C Scenario. In the 1.5 °C Scenario, renewables will have a primary energy share of more than 94% in 2050 (including non-energy consumption, which will still include fossil fuels). Nuclear energy will be phased out by 2050 in both the 2.0 °C and 1.5 °C Scenarios. The cumulative primary energy consumption of natural gas in the 5.0 °C case will add up to 160 EJ, the cumulative coal consumption to about 1180 EJ, and the crude oil consumption to 570 EJ. In contrast,

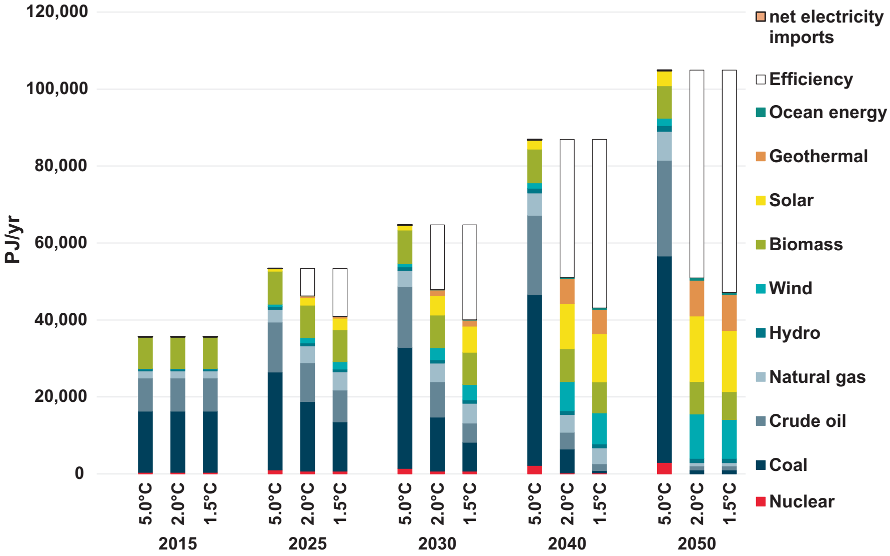


**Fig. 8.88** India: projection of total primary energy demand (PED) by energy carrier in the scenarios (including electricity import balance)

in the 2.0 °C Scenario, the cumulative gas demand will amount to 120 EJ, the cumulative coal demand to 360 EJ, and the cumulative oil demand to 220 EJ. Even lower fossil fuel use will be achieved in the 1.5 °C Scenario: 130 EJ for natural gas, 220 EJ for coal, and 150 EJ for oil.

### *8.12.2 India: Power Sector Analysis*

The electricity market in India is in dynamic development. The government of India is making great efforts to increase the reliability of the power supply and at the same time, it is developing universal access to electric power. In 2017, about 300 million Indians (RF 2018) had no power or inadequate power. In 2017, the Indian Government launched *The Third National Electricity Plan*, which covers two 5-year periods: 2017–2022 and 2022–2027. According to the International Energy Agency (IEA) Policies and Measures Database (IEA P + M DB 2018):

> […] "the plan covers short- and long-term demand forecasts in different regions and recommend areas for transmission and generation capacity additions … However, as India sets to meet its first nationally-determined contribution (NDC) under the Paris Agreement … Highlights of the plan include, that during the period 2017–22, no additional capacity of coal will be added – except for the coal power plants under construction […]".

In terms of renewable power generation, India aims to have a total capacity of 275 GW for solar and wind and 72 GW for hydro, with no further increase in the coal power plant capacity until at least 2027.

#### 8.12.2.1 India: Development of Power Plant Capacities

The Third National Electricity Plan for India is an important foundation for strengthening India's renewable power market in order to achieve the levels envisaged in both alternative scenarios. Whereas the hydropower target is consistent with the 2.0 °C and 1.5 °C targets, the solar and wind capacity of 275 GW must be reached between 2020 and 2025 for both scenarios. The annual installation rates for solar PV installations must increase to around 50 GW—the market size in China in 2017—and remain at that level until 2040 to implement either the 2.0 °C or 1.5 °C Scenario. The installation rates for onshore wind must be equally high. In 2017, 4.15 GW of new wind turbines were installed, and significant growth is required. Offshore wind and concentrated solar power plants have significant potential for selected regions of India. Both technologies are vital to achieving the 2.0 °C or 1.5 °C targets (Table 8.81).

**Table 8.81** India: average annual change in installed power plant capacity

| India power generation: average annual change of installed capacity [GW/a] | 2015–2025 | | 2026–2035 | | 2036–2050 | |
|---|---|---|---|---|---|---|
| | 2.0 °C | 1.5 °C | 2.0 °C | 1.5 °C | 2.0 °C | 1.5 °C |
| Hard coal | 7 | −7 | −6 | −7 | −15 | −6 |
| Lignite | 0 | −1 | −1 | −2 | −2 | −1 |
| Gas | 9 | 13 | 7 | 7 | −14 | 17 |
| Hydrogen-Gas | 0 | 0 | 1 | 1 | 32 | 32 |
| Oil/Diesel | 0 | −1 | −1 | −1 | 0 | 0 |
| Nuclear | 1 | 0 | 0 | 0 | −1 | −1 |
| Biomass | 2 | 2 | 2 | 2 | 4 | 4 |
| Hydro | 3 | 2 | 1 | 1 | 1 | 1 |
| Wind (onshore) | 20 | 55 | 54 | 59 | 44 | 21 |
| Wind (offshore) | 2 | 6 | 7 | 7 | 5 | 4 |
| PV (roof top) | 21 | 55 | 49 | 53 | 51 | 30 |
| PV (utility scale) | 7 | 18 | 16 | 18 | 17 | 10 |
| Geothermal | 0 | 1 | 3 | 3 | 4 | 4 |
| Solar thermal power plants | 1 | 6 | 11 | 11 | 10 | 10 |
| Ocean energy | 0 | 1 | 3 | 3 | 3 | 3 |
| Renewable fuel based co-generation | 0 | 1 | 2 | 2 | 3 | 3 |

#### 8.12.2.2 India: Utilization of Power-Generation Capacities

The division of India into five sub-regions is intended to reflect the main grid zones and it is assumed that interconnection will continue to increase to 15% in 2030 and 20% in 2050. Both scenarios aim for an even distribution of variable power plant capacities across all Indian sub-regions. By 2030, the variable power generation will reach 40% in most regions, whereas dispatchable renewables will supply about one quarter of the demand by 2030 (Table 8.82).

India's average capacity factors for the entire power plant fleet remain at around 35% over the entire modelling period, as the calculation results in Table 8.83 show. Contributions from limited dispatchable fossil and nuclear power plants will remain high until 2030 and indicate that a significant replacement of coal for electricity must occur after 2030 in the 2.0 °C Scenario. In the 1.5 °C Scenario, coal will be phased-out just after 2035.

#### 8.12.2.3 India: Development of Load, Generation, and Residual Load

Table 8.84 shows that India's load is predicted to quadruple in all five sub-regions between 2020 and 2050. Under the 2.0 °C Scenario, additional interconnection will increase—beyond the assumed 20% target—but may only be required for the western and southern sub-regions of India. However, for the 1.5 °C Scenario, interconnections must increase in four of the five regions. In the northern region, the calculated generation increases faster than the demand. This region has significant potential for concentrated solar power plants and could supply neighbouring regions.

Table 8.85 shows the storage and dispatch requirements under the 2.0 °C and 1.5 °C Scenarios. All the regions remain within the maximum curtailment target of 10%. Table 8.71 provides an overview of the calculated storage and dispatch power requirements by sub-region. Charging capacities are moderate compared with other world regions. Compared to all other world regions, hydrogen dispatch utilization is very low due to a relatively moderate increase in the gas and hydrogen capacities in India.

**Table 8.82** India: power system shares by technology group

| Power generation structure and interconnection | | 2.0 °C | | | | 1.5 °C | | | |
|---|---|---|---|---|---|---|---|---|---|
| | | Variable RE | Dispatch RE | Dispatch Fossil | Inter-connection | Variable RE | Dispatch RE | Dispatch fossil | Inter-connection |
| India-Northern Region | 2015 | 4% | 32% | 64% | 10% | | | | |
| | 2030 | 41% | 28% | 31% | 15% | 56% | 24% | 20% | 15% |
| | 2050 | 60% | 38% | 2% | 20% | 48% | 35% | 17% | 20% |
| India-North-Eastern Region | 2015 | 4% | 32% | 64% | 10% | | | | |
| | 2030 | 44% | 26% | 30% | 15% | 58% | 21% | 21% | 15% |
| | 2050 | 95% | 5% | 0% | 20% | 92% | 5% | 3% | 20% |
| India-Eastern Region | 2015 | 4% | 32% | 64% | 10% | | | | |
| | 2030 | 51% | 26% | 23% | 15% | 68% | 22% | 10% | 15% |
| | 2050 | 73% | 26% | 1% | 20% | 69% | 29% | 2% | 20% |
| India-Western Region | 2015 | 4% | 32% | 64% | 10% | | | | |
| | 2030 | 44% | 26% | 30% | 15% | 57% | 21% | 22% | 15% |
| | 2050 | 70% | 29% | 1% | 20% | 49% | 24% | 27% | 20% |
| India-Southern Region | 2015 | 4% | 32% | 64% | 10% | | | | |
| | 2030 | 48% | 23% | 29% | 15% | 60% | 18% | 22% | 15% |
| | 2050 | 78% | 21% | 1% | 20% | 62% | 19% | 19% | 20% |
| India | 2015 | 4% | 32% | 64% | | | | | |
| | 2030 | 45% | 26% | 29% | | 60% | 21% | 19% | |
| | 2050 | 72% | 27% | 1% | | 58% | 26% | 16% | |

**Table 8.83** India: capacity factors by generation type

| Utilization of variable and dispatchable power generation: | | 2015 | 2020 | 2020 | 2030 | 2030 | 2040 | 2040 | 2050 | 2050 |
|---|---|---|---|---|---|---|---|---|---|---|
| India | | | 2.0 °C | 1.5 °C | 2.0 °C | 1.5 °C | 2.0 °C | 1.5 °C | 2.0 °C | 1.5 °C |
| Capacity factor – average | [%/yr] | **60.8%** | **53%** | **57%** | **35%** | **26%** | **33%** | **30%** | **37%** | **34%** |
| Limited dispatchable: fossil and nuclear | [%/yr] | 67.7% | 57% | 61% | 48% | 38% | 37% | 27% | 37% | 12% |
| Limited dispatchable: renewable | [%/yr] | 17.1% | 24% | 26% | 38% | 34% | 58% | 39% | 44% | 42% |
| Dispatchable: fossil | [%/yr] | 44.7% | 12% | 19% | 11% | 12% | 30% | 29% | 24% | 29% |
| Dispatchable: renewable | [%/yr] | 39.8% | 60% | 68% | 57% | 45% | 40% | 52% | 65% | 57% |
| Variable: renewable | [%/yr] | 9.0% | 8% | 8% | 19% | 20% | 27% | 25% | 29% | 28% |

**Table 8.84** India: load, generation, and residual load development

| Power generation structure | | 2.0 °C | | | | 1.5 °C | | | |
|---|---|---|---|---|---|---|---|---|---|
| | | Max demand [GW] | Max generation [GW] | Max residual load [GW] | Max interconnection requirements [GW] | Max demand [GW] | Max generation [GW] | Max residual load [GW] | Max interconnection requirements [GW] |
| India-Northern Region | 2020 | 87.8 | 85.6 | 11.1 | | 87.8 | 78.2 | 19.9 | |
| | 2030 | 150.1 | 147.3 | 41.2 | 0 | 149.6 | 240.4 | 57.2 | 34 |
| | 2050 | 372.2 | 397.2 | 265.7 | 0 | 366.8 | 381.7 | 211.1 | 0 |
| India-North-Eastern Region | 2020 | 10.7 | 10.4 | 0.6 | | 10.7 | 10.4 | 0.6 | |
| | 2030 | 18.3 | 21.7 | 2.7 | 1 | 18.3 | 30.4 | 2.7 | 9 |
| | 2050 | 45.4 | 69.1 | 32.7 | 0 | 44.8 | 223.9 | 9.3 | 170 |
| India-Eastern Region | 2020 | 64.5 | 47.5 | 25.3 | | 64.5 | 38.5 | 34.2 | |
| | 2030 | 110.8 | 118.0 | 43.1 | 0 | 110.4 | 198.8 | 53.1 | 35 |
| | 2050 | 276.9 | 364.6 | 183.6 | 0 | 273.0 | 409.7 | 174.8 | 0 |
| India-Western Region | 2020 | 64.6 | 62.9 | 3.5 | | 64.6 | 62.9 | 3.5 | |
| | 2030 | 111.0 | 173.5 | 19.4 | 43 | 110.6 | 196.4 | 20.0 | 66 |
| | 2050 | 277.4 | 542.0 | 207.2 | 57 | 273.4 | 401.3 | 86.4 | 42 |
| India-Southern Region | 2020 | 60.6 | 59.1 | 3.5 | | 60.6 | 59.1 | 3.2 | |
| | 2030 | 103.0 | 163.4 | 5.2 | 55 | 102.6 | 195.0 | 15.2 | 77 |
| | 2050 | 252.8 | 507.5 | 164.8 | 90 | 249.1 | 448.0 | 76.7 | 122 |

**Table 8.85** India: storage and dispatch service requirements

| Storage and dispatch | | 2.0 °C | | | | | 1.5 °C | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | Required to avoid curtailment | Utilization battery -through-put- | Utilization PSH -through-put- | Total storage demand (incl. H2) | Dispatch hydrogen-based | Required to avoid curtailment | Utilization battery -through-put- | Utilization PSH -through-put- | Total storage demand (incl. H2) | Dispatch hydrogen-based |
| India | | [GWh/year] | [GWh/year] | [GWh/year] | [GWh/year] | [GWh/year] | [GWh/year] | [GWh/year] | [GWh/year] | [GWh/year] | [GWh/year] |
| India-Northern Region | 2020 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | 2030 | 0 | 0 | 0 | 0 | 507 | 24,533 | 57 | 3063 | 3121 | 160 |
| | 2050 | 1244 | 42 | 51 | 93 | 9873 | 734 | 38 | 51 | 89 | 8647 |
| India-North-Eastern Region | 2020 | 1 | 0 | 1 | 1.1 | 0 | 1 | 0 | 1 | 1.1 | 0 |
| | 2030 | 307 | 1 | 65 | 66 | 0 | 3862 | 8 | 471 | 478 | 0 |
| | 2050 | 4923 | 126 | 332 | 457 | 1025 | 258,992 | 219 | 1896 | 2115 | 11 |
| India-Eastern Region | 2020 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | 2030 | 1657 | 10 | 427 | 437 | 476 | 54,903 | 95 | 4933 | 5028 | 156 |
| | 2050 | 27,180 | 729 | 2154 | 2884 | 6813 | 46,793 | 1519 | 3163 | 4682 | 5715 |
| India-Western Region | 2020 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | 2030 | 29,610 | 51 | 2978 | 3028 | 448 | 41,348 | 84 | 3928 | 4012 | 310 |
| | 2050 | 174,263 | 1709 | 5618 | 7327 | 5037 | 28,209 | 1228 | 2263 | 3491 | 2020 |
| India-Southern Region | 2020 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | 2030 | 27,824 | 42 | 2496 | 2537 | 328 | 57,916 | 88 | 4759 | 4847 | 144 |
| | 2050 | 165,200 | 1643 | 5274 | 6917 | 5365 | 103,156 | 1891 | 4931 | 6822 | 2066 |
| India | 2020 | 1 | 0 | 1 | 1 | 0 | 1 | 0 | 1 | 1 | 0 |
| | 2030 | 59,399 | 104 | 5966 | 6069 | 1759 | 182,561 | 333 | 17,154 | 17,487 | 769 |
| | 2050 | 372,809 | 4248 | 13,430 | 17,678 | 28,113 | 437,884 | 4895 | 12,304 | 17,199 | 18,459 |

## 8.13 China

### *8.13.1 China: Long-Term Energy Pathways*

#### 8.13.1.1 China: Final Energy Demand by Sector

The future development pathways for China's final energy demand when the assumptions on population growth, GDP growth and energy intensity are combined are shown in Fig. 8.89 for the 5.0 °C, 2.0 °C, and 1.5 °C Scenarios. In the 5.0 °C Scenario, the total final energy demand will increase by 56% from the current 73,600 PJ/year to 114,600 PJ/year in 2050. In the 2.0 °C Scenario, the final energy demand will decreases by 26% compared with current consumption and will reach 54,400 PJ/year by 2050. The final energy demand in the 1.5 °C Scenario will reach 49,200 PJ, 33% below the 2015 demand. In the 1.5 °C Scenario, the final energy demand in 2050 will be 10% lower than in the 2.0 °C Scenario. The electricity demand for 'classical' electrical devices (without power-to-heat or e-mobility) will increase from 3470 TWh/year in 2015 to around 5230 TWh/year in both alternative scenarios

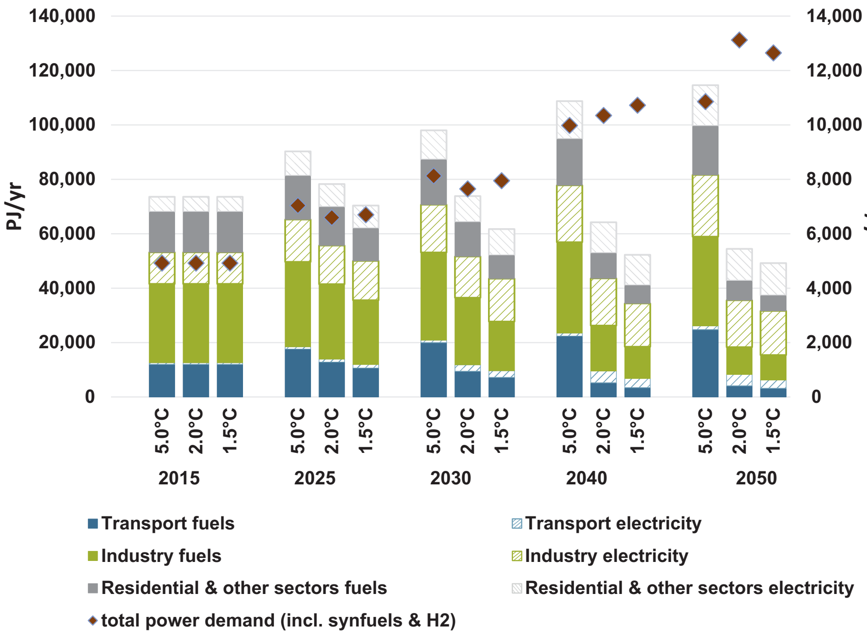


**Fig. 8.89** China: development of final energy demand by sector in the scenarios

by 2050. Compared with the 5.0 °C case (9480 TWh/year in 2050), the efficiency measures in the 2.0 °C and 1.5 °C Scenarios save around 4250 TWh/year by 2050.

Electrification will lead to a significant increase in the electricity demand by 2050. In the 2.0 °C Scenario, the electricity demand for heating will be approximately 2800 TWh/year due to electric heaters and heat pumps and in the transport sector, the electricity demand will be approximately 4200 TWh/year due to electric mobility. The generation of hydrogen (for transport and high-temperature process heat) and the manufacture of synthetic fuels (mainly for transport) will add an additional power demand of 3900 TWh/year. Therefore, the gross power demand will rise from 5900 TWh/year in 2015 to 13,800 TWh/year in 2050 in the 2.0 °C Scenario, 11% higher than in the 5.0 °C case. In the 1.5 °C Scenario, the gross electricity demand will increase to a maximum of 13,300 TWh/year in 2050.

The efficiency gains in the heating sector could be even larger than in the electricity sector. In the 2.0 °C and 1.5 °C Scenarios, a final energy consumption equivalent to about 24,400 PJ/year and 27,600 PJ/year, respectively, will be avoided through efficiency gains by 2050 compared to the 5.0 °C Scenario.

#### 8.13.1.2 China: Electricity Generation

The development of the power system is characterized by a dynamically growing renewable energy market and an increasing proportion of total power from renewable sources. By 2050, 100% of the electricity produced in China will come from renewable energy sources in the 2.0 °C Scenario. 'New' renewables—mainly wind, solar, and geothermal energy—will contribute 77% of the total electricity generation. Renewable electricity's share of the total production will be 54% by 2030 and 84% by 2040. The installed capacity of renewables will reach about 2170 GW by 2030 and 5420 GW by 2050. The share of renewable electricity generation in 2030 in the 1.5 °C Scenario is assumed to be 63%. In the 1.5 °C Scenario, the generation capacity from renewable energy will be approximately 5310 GW in 2050.

Table 8.86 shows the development of different renewable technologies in China over time. Figure 8.90 provides an overview of the overall power-generation structure in China. From 2020 onwards, the continuing growth of wind and PV, up to 1670 GW and 2220 GW, respectively, will be complemented by up to 680 GW solar thermal generation, as well as limited biomass, geothermal, and ocean energy, in the 2.0 °C Scenario. Both the 2.0 °C and 1.5 °C Scenarios will lead to a high proportion of variable power generation (PV, wind, and ocean) of 28% and 34%, respectively, by 2030, and 51% and 52%, respectively, by 2050.

**Table 8.86** China: development of renewable electricity-generation capacity in the scenarios

| in GW | Case | 2015 | 2025 | 2030 | 2040 | 2050 |
|---|---|---|---|---|---|---|
| Hydro | 5.0 °C | 320 | 395 | 424 | 477 | 525 |
| | 2.0 °C | 320 | 383 | 396 | 420 | 450 |
| | 1.5 °C | 320 | 383 | 396 | 420 | 450 |
| Biomass | 5.0 °C | 11 | 24 | 29 | 39 | 48 |
| | 2.0 °C | 11 | 57 | 101 | 158 | 195 |
| | 1.5 °C | 11 | 72 | 106 | 160 | 195 |
| Wind | 5.0 °C | 132 | 343 | 408 | 536 | 667 |
| | 2.0 °C | 132 | 428 | 678 | 1299 | 1674 |
| | 1.5 °C | 132 | 508 | 877 | 1460 | 1652 |
| Geothermal | 5.0 °C | 0 | 0 | 0 | 1 | 3 |
| | 2.0 °C | 0 | 4 | 19 | 77 | 134 |
| | 1.5 °C | 0 | 7 | 29 | 77 | 119 |
| PV | 5.0 °C | 43 | 265 | 330 | 430 | 565 |
| | 2.0 °C | 43 | 504 | 889 | 1614 | 2218 |
| | 1.5 °C | 43 | 604 | 1036 | 1781 | 2215 |
| CSP | 5.0 °C | 0 | 3 | 5 | 7 | 11 |
| | 2.0 °C | 0 | 11 | 84 | 413 | 677 |
| | 1.5 °C | 0 | 16 | 103 | 391 | 614 |
| Ocean | 5.0 °C | 0 | 0 | 0 | 1 | 1 |
| | 2.0 °C | 0 | 1 | 7 | 33 | 74 |
| | 1.5 °C | 0 | 1 | 7 | 33 | 62 |
| Total | 5.0 °C | 505 | 1029 | 1196 | 1490 | 1819 |
| | 2.0 °C | 505 | 1390 | 2175 | 4015 | 5421 |
| | 1.5 °C | 505 | 1592 | 2555 | 4322 | 5307 |

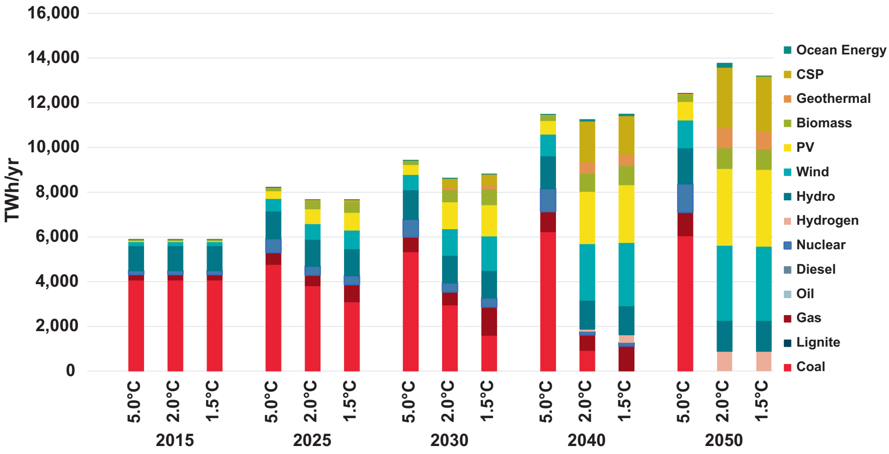


**Fig. 8.90** China: development of electricity-generation structure in the scenarios

#### 8.13.1.3 China: Future Costs of Electricity Generation

Figure 8.91 shows the development of the electricity-generation and supply costs over time, including the $CO_2$ emission costs, in all scenarios. The calculated electricity generation costs in 2015 (referring to full costs) were around 4.7 ct/kWh. In the 5.0 °C case, the generation costs will increase until 2030, when they reach 9.2 ct/kWh, and then drop to 8.8 ct/kWh by 2050. The generation costs will increase in the alternative scenarios until 2030, when they reach around 8 ct/kWh, and will then drop to 6.5 ct/kWh by 2050, 2.3 ct/kWh lower than in the 5.0 °C Scenario. Note that these estimates of generation costs do not take into account integration costs such as power grid expansion, storage, or other load-balancing measures.

In the 5.0 °C case, the growth in demand and increasing fossil fuel prices will cause total electricity supply costs to rise from today's $310 billion/year to more than $1230 billion/year in 2050. In the 2.0 °C case, the total supply costs will be $1030 billion/year and $1010 billion/year in the 1.5 °C Scenario. Therefore, the long-term costs for electricity supply will be more than 16% lower in the alternative scenarios than in the 5.0 °C case.

Compared with these results, the generation costs when the $CO_2$ emission costs are not considered will increase in the 5.0 °C case to 5.7 ct/kWh in 2030 and stabilize at 5.5 ct/kWh in 2050. In the 2.0 °C Scenario, they increase continuously until 2050, when they reach 6.6 ct/kWh. In the 1.5 °C Scenario, they will increase to 7 ct/kWh and then drop to 6.6 ct/kWh by 2050. In the 2.0 °C Scenario, the generation costs will be a maximum of 1 ct/kWh higher than in the 5.0 °C case, and this will

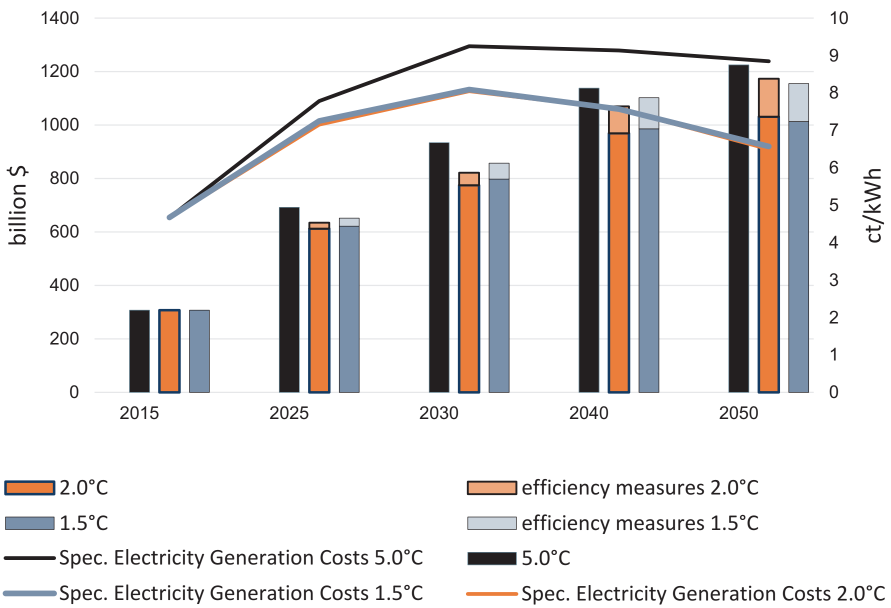


**Fig. 8.91** China: development of total electricity supply costs and specific electricity-generation costs in the scenarios

occur in 2050. In the 1.5 °C Scenario, compared to the 5.0 °C Scenario, the maximum difference in generation costs will be 1.6 ct/kWh in 2040. The generation costs in 2050 will be 1.1 ct/kWh higher than in the 5.0 °C case. If the $CO_2$ costs are not considered, the total electricity supply costs in the 5.0 °C case will rise to about $810 billion/year in 2050.

#### 8.13.1.4 China: Future Investments in the Power Sector

An investment of around $9740 billion will be required for power generation between 2015 and 2050 in the 2.0 °C Scenario—including additional power plants for the production of hydrogen and synthetic fuels and investments for plant replacement at the end of their economic lifetimes. This value will be equivalent to approximately $271 billion per year on average and will be $5680 billion more than in the 5.0 °C case ($4060 billion). An investment of around $9840 billion for power generation will be required between 2015 and 2050 in the 1.5 °C Scenario. On average, this will be an investment of $273 billion per year. In the 5.0 °C Scenario, the investment in conventional power plants will be around 29% of the total cumulative investments, whereas approximately 71% will be invested in renewable power generation and co-generation (Fig. 8.92).

However, in the 2.0 °C (1.5 °C) Scenario, China will shift almost 97% (98%) of its entire investment to renewables and co-generation. By 2030, the fossil fuel share of the power sector investment will predominantly focus on gas power plants that can also be operated with hydrogen.

Because renewable energy has no fuel costs, other than biomass, the cumulative fuel cost savings in both alternative scenarios will reach a total of more than $6200 billion in 2050, equivalent to $173 billion per year. Therefore, the total fuel cost savings will be equivalent to 110% of the total additional investments compared to the 5.0 °C Scenario.

#### 8.13.1.5 China: Energy Supply for Heating

The final energy demand for heating will increase in the 5.0 °C Scenario by 38% from 42,300 PJ/year in 2015 to 58,200 PJ/year in 2050. Energy efficiency measures will help to reduce the energy demand for heating by 42% in 2050 in the 2.0 °C Scenario, relative to the 5.0 °C case, and by 47% in the 1.5 °C Scenario. Today, renewables supply around 11% of China's final energy demand for heating, with the main contribution from biomass. Renewable energy will provide 32% of China's total heat demand in 2030 in the 2.0 °C Scenario and 46% in the 1.5 °C Scenario. In both scenarios, renewables will provide 100% of the total heat demand in 2050.

Figure 8.93 shows the development of different technologies for heating in China over time, and Table 8.87 provides the resulting renewable heat supply for all scenarios. Up to 2030, biomass will remain the main contributor. In the long term, the

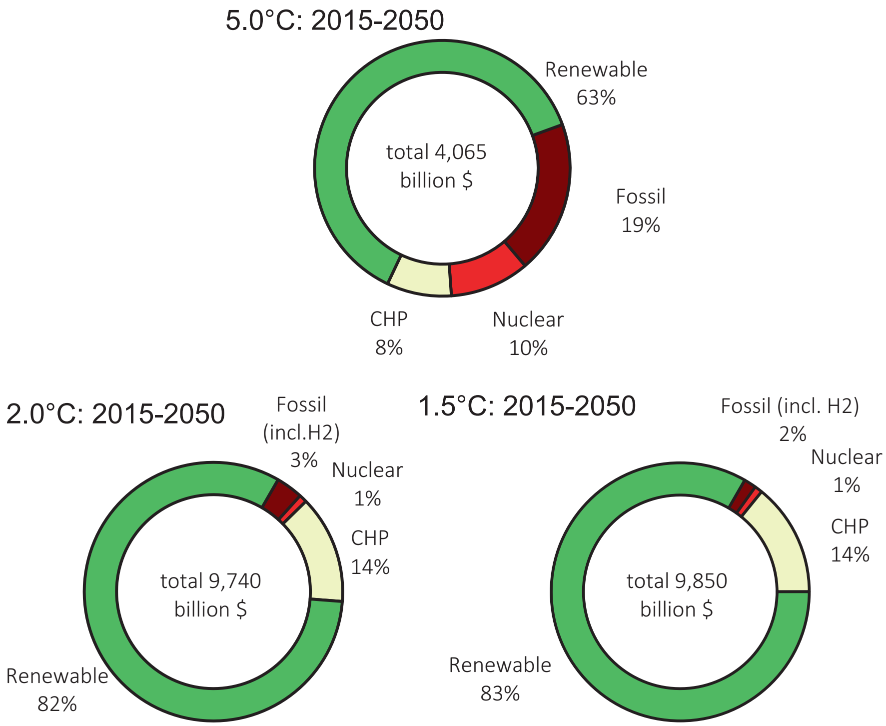


**Fig. 8.92** China: investment shares for power generation in the scenarios

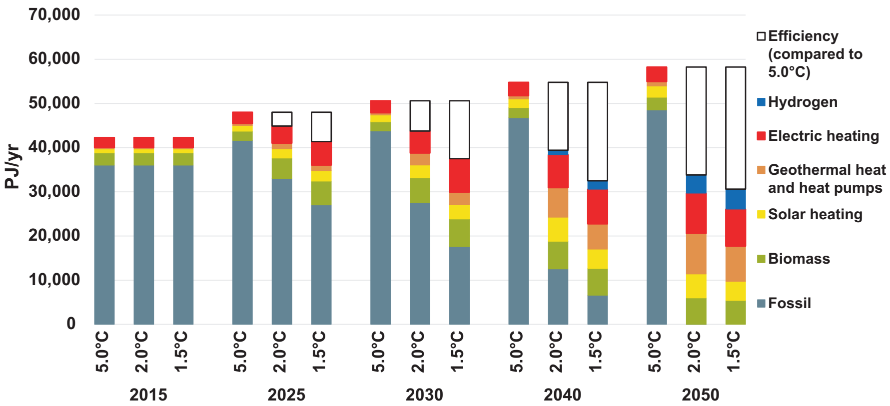


**Fig. 8.93** China: development of heat supply by energy carrier in the scenarios

growing use of solar, geothermal, and environmental heat will lead to a biomass share of 24% in both alternative scenarios.

Heat from renewable hydrogen will further reduce the dependence on fossil fuels in both scenarios. Hydrogen consumption in 2050 will be around 4100 PJ/year in

**Table 8.87** China: development of renewable heat supply in the scenarios (excluding the direct use of electricity)

| in PJ/year | Case | 2015 | 2025 | 2030 | 2040 | 2050 |
|---|---|---|---|---|---|---|
| Biomass | 5.0 °C | 2776 | 2095 | 2079 | 2291 | 2877 |
| | 2.0 °C | 2776 | 4609 | 5603 | 6254 | 5967 |
| | 1.5 °C | 2776 | 5378 | 6263 | 6055 | 5385 |
| Solar heating | 5.0 °C | 892 | 1297 | 1515 | 1962 | 2535 |
| | 2.0 °C | 892 | 2066 | 2906 | 5454 | 5417 |
| | 1.5 °C | 892 | 2364 | 3242 | 4381 | 4360 |
| Geothermal heat and heat pumps | 5.0 °C | 306 | 452 | 526 | 743 | 1026 |
| | 2.0 °C | 306 | 1304 | 2720 | 6690 | 9225 |
| | 1.5 °C | 306 | 1269 | 2884 | 5706 | 7943 |
| Hydrogen | 5.0 °C | 0 | 0 | 0 | 0 | 0 |
| | 2.0 °C | 0 | 0 | 7 | 1020 | 4118 |
| | 1.5 °C | 0 | 0 | 7 | 1890 | 4549 |
| Total | 5.0 °C | 3974 | 3844 | 4120 | 4996 | 6438 |
| | 2.0 °C | 3974 | 7978 | 11,237 | 19,417 | 24,727 |
| | 1.5 °C | 3974 | 9011 | 12,396 | 18,031 | 22,237 |

the 2.0 °C Scenario and to 4500 PJ/year in the 1.5 °C Scenario. The direct use of electricity for heating will also increase by a factor of 3.7–4 between 2015 and 2050 and electricity for heating will have a final energy share of 27% in 2050 in both the 2.0 °C Scenario and 1.5 °C Scenario.

#### 8.13.1.6 China: Future Investments in the Heating Sector

The roughly estimated investments in renewable heating technologies up to 2050 will amount to around $2780 billion in the 2.0 °C Scenario (including investments for the replacement of plants after their economic lifetimes), or approximately $77 billion per year. The largest share of investment in China is assumed to be for heat pumps (around $1200 billion), followed by solar collectors and geothermal heat use. The 1.5 °C Scenario assumes an even faster expansion of renewable technologies. However, the lower heat demand (compared with the 2.0 °C Scenario) will result in a lower average annual investment of around $67 billion per year (Table 8.88, Fig. 8.94).

#### 8.13.1.7 China: Transport

The energy demand in the transport sector in China is expected to increase in the 5.0 °C Scenario by 107% from around 12,600 PJ/year in 2015 to 26,100 PJ/year in 2050. In the 2.0 °C Scenario, assumed technical, structural, and behavioural changes will save 68% (17,840 PJ/year) by 2050 compared with the 5.0 °C Scenario.

**Table 8.88** China: installed capacities for renewable heat generation in the scenarios

| in GW | Case | 2015 | 2025 | 2030 | 2040 | 2050 |
|---|---|---|---|---|---|---|
| Biomass | 5.0 °C | 1194 | 764 | 648 | 519 | 468 |
| | 2.0 °C | 1194 | 1284 | 1214 | 921 | 578 |
| | 1.5 °C | 1194 | 1267 | 1280 | 808 | 481 |
| Geothermal | 5.0 °C | 0 | 0 | 0 | 0 | 0 |
| | 2.0 °C | 0 | 20 | 46 | 187 | 272 |
| | 1.5 °C | 0 | 20 | 42 | 139 | 161 |
| Solar heating | 5.0 °C | 281 | 409 | 478 | 618 | 799 |
| | 2.0 °C | 281 | 592 | 843 | 1546 | 1539 |
| | 1.5 °C | 281 | 688 | 956 | 1252 | 1275 |
| Heat pumps | 5.0 °C | 52 | 76 | 89 | 126 | 174 |
| | 2.0 °C | 52 | 151 | 251 | 449 | 565 |
| | 1.5 °C | 52 | 136 | 213 | 349 | 446 |
| Total[a] | 5.0 °C | 1527 | 1250 | 1214 | 1263 | 1441 |
| | 2.0 °C | 1527 | 2048 | 2355 | 3103 | 2954 |
| | 1.5 °C | 1527 | 2111 | 2491 | 2549 | 2361 |

[a] Excluding direct electric heating

Additional modal shifts, technology switches, and a reduction in transport demand will lead to even higher energy savings in the 1.5 °C Scenario of 76% (or 19,900 PJ/year) in 2050 compared with the 5.0 °C case (Table 8.89, Fig. 8.95).

By 2030, electricity will provide 21% (680 TWh/year) of the transport sector's total energy demand in the 2.0 °C Scenario, whereas in 2050, the share will be 51% (1170 TWh/year). In 2050, up to 1600 PJ/year of hydrogen will be used in the transport sector as a complementary renewable option. In the 1.5 °C Scenario, the annual electricity demand is 860 TWh in 2050. The 1.5 °C Scenario also assumes a hydrogen demand of 1100 PJ/year by 2050.

Biofuel use is limited in the 2.0 °C Scenario to a maximum of 1900 PJ/year. Therefore, around 2030, synthetic fuels based on power-to-liquid will be introduced, with a maximum amount of 560 PJ/year in 2050. Due to the lower overall energy demand in transport, biofuel use will be reduced in the 1.5 °C Scenario to a maximum of around 1400 PJ/year. The maximum synthetic fuel demand will amount to 720 PJ/year.

#### 8.13.1.8 China: Development of $CO_2$ Emissions

In the 5.0 °C Scenario, China's annual $CO_2$ emissions will increase by 25%, from 9060 Mt. in 2015 to 11,320 Mt. in 2050. The stringent mitigation measures in both alternative scenarios will cause annual emissions to fall to 1990 Mt. in 2040 in the 2.0 °C Scenario and to 760 Mt. in the 1.5 °C Scenario, with further reductions to almost zero by 2050. In the 5.0 °C case, the cumulative $CO_2$ emissions from 2015 until 2050 will add up to 392 Gt. In contrast, in the 2.0 °C and 1.5 °C Scenarios, the

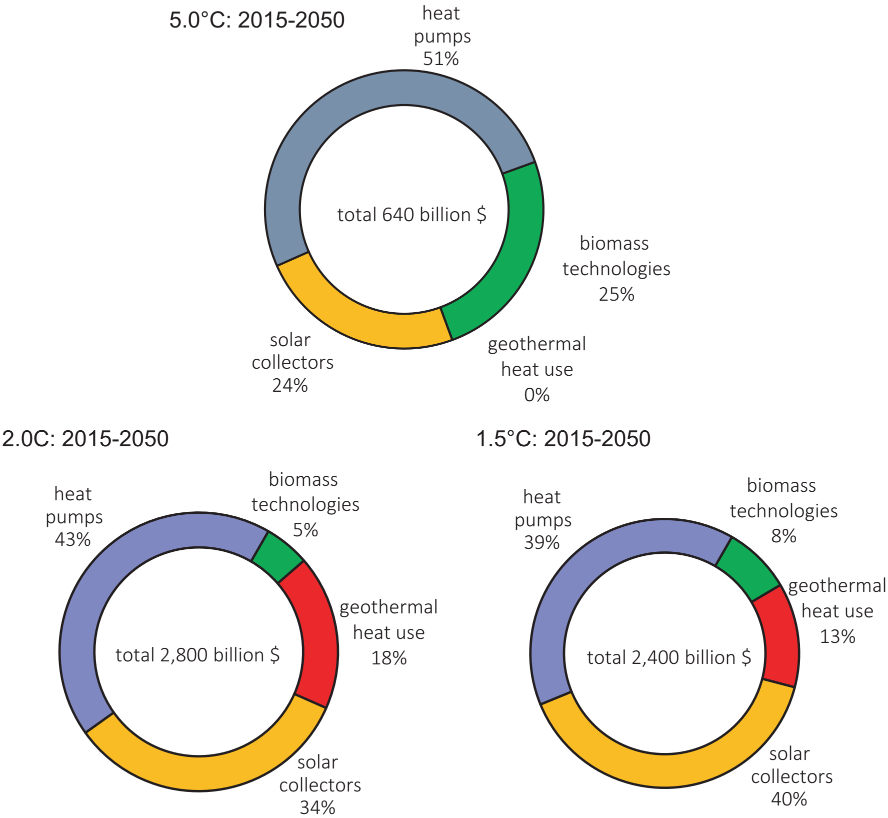


**Fig. 8.94** China: development of investments for renewable heat-generation technologies in the scenarios

cumulative emissions for the period from 2015 until 2050 will be 174 Gt and 132 Gt, respectively.

Therefore, the cumulative $CO_2$ emissions will decrease by 56% in the 2.0 °C Scenario and by 66% in the 1.5 °C Scenario compared with the 5.0 °C case. A rapid reduction in annual emissions will occur in both alternative scenarios. In the 2.0 °C Scenario the reduction will be greatest in the 'Residential and other' sector, followed by 'Power generation' and 'Transport' sectors (Fig. 8.96).

#### 8.13.1.9 China: Primary Energy Consumption

The levels of primary energy consumption in the three scenarios when the assumptions discussed above are taken into account are shown in Fig. 8.97. In the 2.0 °C Scenario, the primary energy demand will decrease by 30%, from around 125,000 PJ/year in 2015 to 87,800 PJ/year in 2050. Compared with the 5.0 °C Scenario, the

**Table 8.89** China: projection of transport energy demand by mode in the scenarios

| in PJ/year | Case | 2015 | 2025 | 2030 | 2040 | 2050 |
|---|---|---|---|---|---|---|
| Rail | 5.0 °C | 539 | 567 | 593 | 644 | 672 |
| | 2.0 °C | 539 | 589 | 637 | 687 | 762 |
| | 1.5 °C | 539 | 580 | 597 | 622 | 662 |
| Road | 5.0 °C | 10,421 | 15,629 | 17,651 | 19,664 | 22,073 |
| | 2.0 °C | 10,421 | 11,509 | 9395 | 7143 | 5894 |
| | 1.5 °C | 10,421 | 9607 | 7372 | 4576 | 4020 |
| Domestic aviation | 5.0 °C | 754 | 1234 | 1590 | 2070 | 2213 |
| | 2.0 °C | 754 | 814 | 742 | 592 | 470 |
| | 1.5 °C | 754 | 777 | 653 | 463 | 366 |
| Domestic navigation | 5.0 °C | 877 | 984 | 1035 | 1113 | 1157 |
| | 2.0 °C | 877 | 984 | 1035 | 1113 | 1157 |
| | 1.5 °C | 877 | 984 | 1035 | 1113 | 1157 |
| Total | 5.0 °C | 12,591 | 18,413 | 20,870 | 23,490 | 26,115 |
| | 2.0 °C | 12,591 | 13,895 | 11,809 | 9535 | 8284 |
| | 1.5 °C | 12,591 | 11,948 | 9657 | 6773 | 6206 |

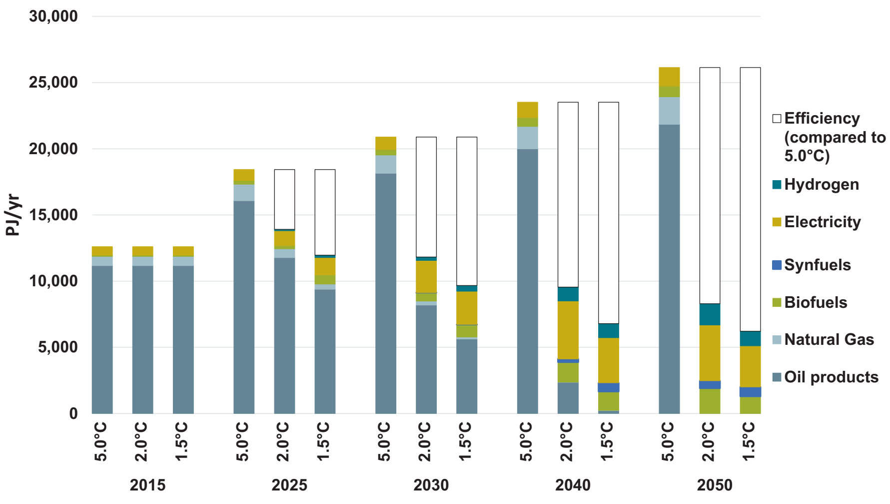


**Fig. 8.95** China: final energy consumption by transport in the scenarios

overall primary energy demand will decrease by 54% by 2050 in the 2.0 °C Scenario (5.0 °C: 192,300 PJ in 2050). In the 1.5 °C Scenario, the primary energy demand will be even lower (80,700 PJ in 2050) because the final energy demand and conversion losses will be lower.

Both the 2.0 °C and 1.5 °C Scenarios aim to rapidly phase-out coal and oil. This will cause renewable energy to have a primary energy share of 28% in 2030 and 92% in 2050 in the 2.0 °C Scenario. In the 1.5 °C Scenario, renewables will have a primary energy share of more than 91% in 2050 (including non-energy consump-

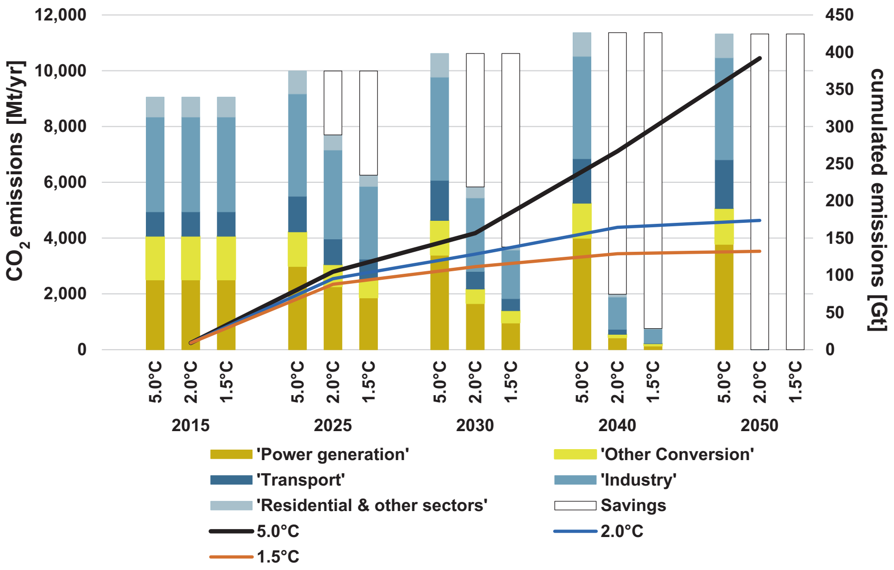


**Fig. 8.96** China: development of $CO_2$ emissions by sector and cumulative $CO_2$ emissions (after 2015) in the scenarios ('Savings' = reduction compared with the 5.0 °C Scenario)

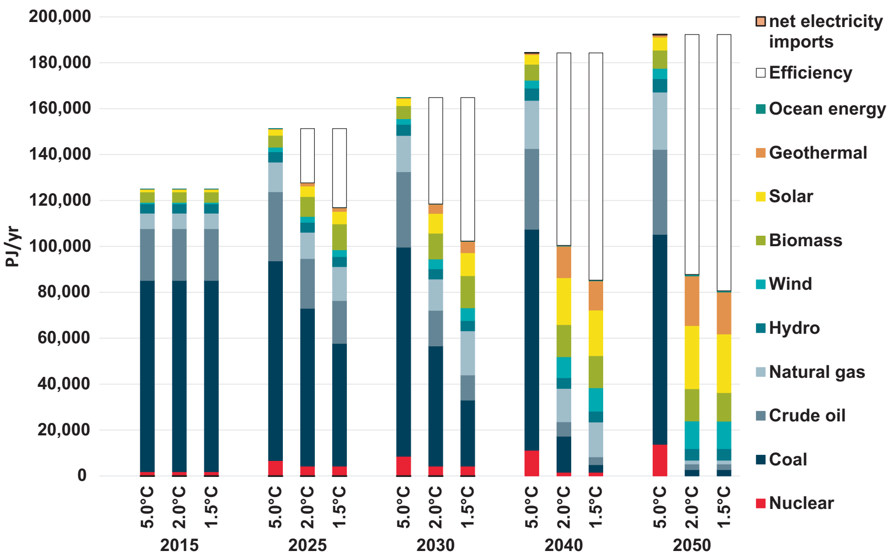


**Fig. 8.97** China: projection of total primary energy demand (PED) by energy carrier in the scenarios (including electricity import balance)

tion, which will still include fossil fuels). Nuclear energy will be phased-out by 2050 in the 2.0 °C Scenario and by 2045 in the 1.5 °C Scenario. The cumulative primary energy consumption of natural gas in the 5.0 °C case will add up to 570 EJ, the cumulative coal consumption to about 3000 EJ, and the crude oil consumption to 1080 EJ. In contrast, in the 2.0 °C Scenario, the cumulative gas demand will amount to 360 EJ, the cumulative coal demand to 1360 EJ, and the cumulative oil demand to 430 EJ. Even lower fossil fuel use will be achieved in the 1.5 °C Scenario: 440 EJ for natural gas, 930 EJ for coal, and 340 EJ for oil.

## *8.13.2 China: Power Sector Analysis*

China has by far the largest power sector of all world regions—about one quarter of the world's total electricity generation. China's National Energy Administration (NEA) released the *13th Energy Five-Year Plan (FYP)* in January 2016 (IEA RED 2016). The FYP that is in force from 2016 to 2020 introduces framework legislation that defines energy development for the next 5 years in China. In parallel to the main Energy FYP, there are 14 additional supporting FYPs, such as the Renewable Energy 13th FYP, the Wind FYP, and the Electricity FYP, which were all released at about the same time (GWEC-NL 2018). According to the Renewable Energy 13th FYP, by 2020, the total RE electricity installations will reach 680 GW, with electricity production of 1900 TWh/year This will account for 27% of electricity production. The wind power target is set to reach 210 GW by 2020, with electricity production of 420 TWh, supplying 6% of China's total electricity demand. The target for offshore wind is 5 GW by 2020 (GWEC-NL 2018). For other renewable power-generation technologies, the 2020 targets are 150 GW for solar PV, 10 GW for concentrated solar power (CSP), 15 GW for bioenergy, and 380 GW for hydropower, including 40 GW hydro pump storage (IEA-RED 2016). The renewable targets are consistent, to large extent, with both the 2.0 °C and 1.5 °C Scenarios. The onshore wind and solar PV capacities in both scenarios will increase to 50 GW and are within the current market size range. The targets for the 2.0 °C and 1.5 °C Scenarios for CSP, bioenergy, and offshore wind are slightly higher than current market volumes. However, the first decade of the 2.0 °C and 1.5 °C Scenarios will reflect the existing trends in China's power sector.

### 8.13.2.1 China: Development of Power Plant Capacities

China's solar PV and wind power markets are the largest in the world and represent about half the global annual market for solar PV (in 2017) and a third of the market for onshore wind. The continued growth of the annual renewable power market—for all technologies—for the Chinese market will continue to have a significant impact on other world regions. To implement the project's 2.0 °C Scenario, the current solar PV market in China must remain at the 2017 level, and to achieve the

**Table 8.90** China: average annual change in installed power plant capacity

| China power generation: average annual change of installed capacity [GW/a] | 2015–2025 | | 2026–2035 | | 2036–2050 | |
|---|---|---|---|---|---|---|
| | 2.0 °C | 1.5 °C | 2.0 °C | 1.5 °C | 2.0 °C | 1.5 °C |
| Hard coal | 5 | −51 | −55 | −81 | −41 | −5 |
| Lignite | 0 | 0 | 0 | 0 | 0 | 0 |
| Gas | 4 | 28 | 6 | 30 | −16 | −17 |
| Hydrogen-Gas | 0 | 0 | 1 | 3 | 24 | 38 |
| Oil/Diesel | 0 | −1 | 0 | −1 | 0 | 0 |
| Nuclear | 3 | 0 | −2 | 0 | −3 | −4 |
| Biomass | 6 | 10 | 9 | 8 | 5 | 5 |
| Hydro | 8 | 5 | 3 | 3 | 3 | 3 |
| Wind (onshore) | 31 | 65 | 46 | 64 | 36 | 29 |
| Wind (offshore) | 2 | 12 | 20 | 22 | 11 | 9 |
| PV (roof top) | 41 | 77 | 69 | 76 | 62 | 50 |
| PV (utility scale) | 14 | 26 | 23 | 25 | 21 | 17 |
| Geothermal | 1 | 4 | 5 | 6 | 8 | 6 |
| Solar thermal power plants | 1 | 13 | 34 | 29 | 40 | 30 |
| Ocean energy | 0 | 1 | 2 | 2 | 5 | 4 |
| Renewable fuel based co-generation | **4** | **9** | **10** | **9** | **8** | **8** |

1.5 °C Scenario, it must double. The onshore wind market must increase by 50% compared with 2015 for the 2.0 °C Scenario and must triple to meet the 1.5 °C trajectory. All these annual market volumes must be maintained until 2035, before a moderate reduction in the annual market sizes can occur (Table 8.90).

#### 8.13.2.2 China: Utilization of Power Generation Capacities

Across all regions, an interconnection capacity of 10% is assumed for the base year calculation. The interconnection capacity will increase to 20% by 2030, with no further increase thereafter. For the entire modelling period, it is assumed that Taiwan is not connected to any other region. Under the 2.0 °C Scenario, variable renewables will attain a share of around 30% in all sub-regions, whereas the 1.5 °C Scenario will lead to shares of over 40% in five of the seven sub-regions (Table 8.91).

Table 8.92 shows the results of the capacity factor calculations done under the assumption that variable and dispatchable power plants will have priority access to the grid and priority dispatch. The average capacity factors for limited dispatchable power plants will remain at around 30% until 2030 under the 2.0 °C Scenario. This relatively low factor indicates an overcapacity in China's power market. The curtailment rates of 20% (REW 1-2018) and more in 2017—mainly for wind farms—confirm this.

**Table 8.91** China: power system shares by technology group

| Power generation structure and interconnection | | 2.0 °C | | | | 1.5 °C | | | |
|---|---|---|---|---|---|---|---|---|---|
| China | | Variable RE | Dispatch RE | Dispatch Fossil | Inter-connection | Variable RE | Dispatch RE | Dispatch fossil | Inter-connection |
| China-North | 2015 | 7% | 35% | 58% | 10% | | | | |
| | 2030 | 32% | 21% | 47% | 20% | 43% | 29% | 28% | 20% |
| | 2050 | 53% | 43% | 4% | 20% | 53% | 37% | 9% | 20% |
| China-Northwest | 2015 | 7% | 35% | 58% | 10% | | | | |
| | 2030 | 29% | 22% | 49% | 20% | 40% | 31% | 29% | 20% |
| | 2050 | 49% | 47% | 3% | 20% | 54% | 44% | 2% | 20% |
| China-Northeast | 2015 | 6% | 35% | 60% | 10% | | | | |
| | 2030 | 34% | 24% | 43% | 20% | 45% | 31% | 24% | 20% |
| | 2050 | 54% | 43% | 4% | 20% | 54% | 45% | 2% | 20% |
| China-Tibet | 2015 | 7% | 35% | 58% | 10% | | | | |
| | 2030 | 37% | 34% | 29% | 20% | 49% | 37% | 14% | 20% |
| | 2050 | 43% | 49% | 7% | 20% | 42% | 53% | 5% | 20% |
| China-Central | 2015 | 6% | 35% | 60% | 10% | | | | |
| | 2030 | 28% | 26% | 47% | 20% | 36% | 32% | 32% | 20% |
| | 2050 | 41% | 52% | 7% | 20% | 44% | 48% | 9% | 20% |
| China-East | 2015 | 6% | 35% | 60% | 10% | | | | |
| | 2030 | 30% | 25% | 45% | 20% | 36% | 29% | 35% | 20% |
| | 2050 | 48% | 47% | 5% | 20% | 48% | 38% | 14% | 20% |

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| China-South | 2015 | 6% | 35% | 60% | 10% | | | | |
| | 2030 | 30% | 28% | 43% | 20% | 38% | 31% | 31% | 20% |
| | 2050 | 49% | 47% | 4% | 20% | 48% | 46% | 6% | 20% |
| Taiwan | 2015 | 7% | 35% | 59% | 0% | | | | |
| | 2030 | 31% | 24% | 46% | 0% | 39% | 29% | 31% | 0% |
| | 2050 | 57% | 40% | 3% | 0% | 51% | 37% | 12% | 0% |
| China | 2015 | 6% | 35% | 59% | | | | | |
| | 2030 | 30% | 24% | 46% | | 39% | 30% | 31% | |
| | 2050 | 49% | 47% | 5% | | 49% | 42% | 9% | |

**Table 8.92** China: capacity factors by generation type

| Utilization of variable and dispatchable power generation: | | 2015 | 2020 | 2020 | 2030 | 2030 | 2040 | 2040 | 2050 | 2050 |
|---|---|---|---|---|---|---|---|---|---|---|
| China | | | 2.0 °C | 1.5 °C | 2.0 °C | 1.5 °C | 2.0 °C | 1.5 °C | 2.0 °C | 1.5 °C |
| Capacity factor – average | [%/yr] | **42.0%** | **30%** | **28%** | **26%** | **21%** | **37%** | **24%** | **37%** | **26%** |
| Limited dispatchable: fossil and nuclear | [%/yr] | 39.2% | 34% | 29% | 32% | 25% | 20% | 17% | 9% | 16% |
| Limited dispatchable: renewable | [%/yr] | 47.3% | 20% | 17% | 21% | 14% | 68% | 19% | 47% | 27% |
| Dispatchable: fossil | [%/yr] | 30.7% | 28% | 40% | 46% | 34% | 24% | 37% | 11% | 37% |
| Dispatchable: renewable | [%/yr] | 59.1% | 27% | 31% | 28% | 23% | 47% | 34% | 62% | 39% |
| Variable: renewable | [%/yr] | 17.9% | 15% | 15% | 17% | 16% | 22% | 17% | 22% | 17% |

#### 8.13.2.3 China: Development of Load, Generation, and Residual Load

The load for China is calculated to continue to increase. Table 8.93 shows that the maximum load will double across all regions. However, the assumed interconnection rates of 20% are sufficient for the 2.0 °C Scenario, whereas significantly higher interconnection capacities will be required under the 1.5 °C Scenario. By 2050, all regions will have an oversupply under the 1.5 °C Scenario. This surplus electricity will be used to produce synthetic fuels and hydrogen. The [R]E 24/7 model does not interface with other world regions, so surplus generation will result in a negative residual load.

Finally, Table 8.94 provides an overview of the calculated storage and dispatch power requirements in the Chinese region. The calculated hydro pump storage increase by 2050 is consistent with the Thirteenth Five-Year Plan's requirement for 40 GW additional capacity. Furthermore, curtailment is within the acceptable range, at significantly below 10% in both scenarios by 2050. Battery capacities must increase significantly after 2030. The central, southern, and eastern sub-regions of mainland China have by far the highest storage requirements.

**Table 8.93** China: load, generation, and residual load development

| Power generation structure | | 2.0 °C | | | | 1.5 °C | | | |
|---|---|---|---|---|---|---|---|---|---|
| | | Max demand | Max generation | Max residual load | Max interconnection requirements | Max demand | Max generation | Max residual load | Max interconnection requirements |
| China | | [GW] | [GW] | [GW] | [GW] | [GW] | [GW] | [GW] | [GW] |
| China-North | 2020 | 168.7 | 168.7 | 3.6 | | 167.9 | 167.9 | 3.6 | |
| | 2030 | 215.6 | 222.5 | 22.5 | 0 | 213.0 | 292.8 | 25.8 | 54 |
| | 2050 | 364.2 | 504.4 | 246.3 | 0 | 368.2 | 587.9 | −133.4 | 353 |
| China-Northwest | 2020 | 77.4 | 80.5 | 6.1 | | 77.1 | 82.4 | 6.1 | |
| | 2030 | 95.6 | 99.5 | 11.8 | 0 | 94.5 | 126.7 | 13.3 | 19 |
| | 2050 | 135.3 | 206.2 | 114.3 | 0 | 136.9 | 246.4 | −48.1 | 158 |
| China-Northeast | 2020 | 67.8 | 67.7 | 1.9 | | 67.4 | 67.3 | 1.9 | |
| | 2030 | 83.9 | 96.3 | 12.9 | 0 | 82.7 | 126.3 | 13.8 | 30 |
| | 2050 | 133.2 | 219.9 | 103.7 | 0 | 135.0 | 255.9 | −22.8 | 144 |
| China-Tibet | 2020 | 0.8 | 0.8 | 0.0 | | 0.8 | 0.8 | 0.0 | |
| | 2030 | 1.0 | 1.0 | 0.4 | 0 | 1.0 | 1.3 | 0.2 | 0 |
| | 2050 | 2.3 | 2.4 | 1.4 | 0 | 2.4 | 2.8 | −0.9 | 1 |
| China-Central | 2020 | 208.7 | 208.7 | 5.9 | | 207.2 | 207.2 | 5.9 | |
| | 2030 | 262.7 | 260.5 | 44.9 | 0 | 258.4 | 329.5 | 34.5 | 37 |
| | 2050 | 445.3 | 536.2 | 299.8 | 0 | 451.7 | 642.0 | −218.4 | 409 |
| China-East | 2020 | 226.8 | 201.9 | 47.9 | | 225.9 | 214.1 | 31.0 | |
| | 2030 | 286.3 | 284.3 | 40.1 | 0 | 283.6 | 372.4 | 41.5 | 47 |
| | 2050 | 454.4 | 633.5 | 320.4 | 0 | 458.5 | 739.3 | −132.0 | 413 |

(continued)

**Table 8.93** (continued)

| Power generation structure | | 2.0 °C | | | | 1.5 °C | | | |
|---|---|---|---|---|---|---|---|---|---|
| | | Max demand | Max generation | Max residual load | Max interconnection requirements | Max demand | Max generation | Max residual load | Max interconnection requirements |
| China | | [GW] | [GW] | [GW] | [GW] | [GW] | [GW] | [GW] | [GW] |
| China-South | 2020 | 173.6 | 173.6 | 9.0 | | 173.6 | 173.6 | 9.0 | |
| | 2030 | 242.3 | 238.6 | 36.2 | 0 | 239.6 | 312.0 | 44.6 | 28 |
| | 2050 | 368.8 | 529.6 | 282.0 | 0 | 372.8 | 622.7 | −49.1 | 299 |
| Taiwan | 2020 | 33.0 | 33.2 | 0.0 | | | | | |
| | 2030 | 46.0 | 45.9 | 3.8 | 0 | 45.7 | 52.5 | 5.9 | 1 |
| | 2050 | 63.7 | 92.0 | 47.1 | 0 | 64.1 | 105.7 | −4.0 | 46 |

**Table 8.94** China: storage and dispatch service requirements

| Storage and dispatch | | 2.0 °C | | | | | 1.5 °C | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | Required to avoid curtailment | Utilization battery -through-put- | Utilization PSH -through-put- | Total storage demand (incl. H2) | Dispatch hydrogen-based | Required to avoid curtailment | Utilization battery -through-put- | Utilization PSH -through-put- | Total storage demand (incl. H2) | Dispatch hydrogen-based |
| China | | [GWh/year] | [GWh/year] | [GWh/year] | [GWh/year] | [GWh/year] | [GWh/year] | [GWh/year] | [GWh/year] | [GWh/year] | [GWh/year] |
| China-North | 2020 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | 2030 | 45 | 3 | 38 | 41 | 11 | 6734 | 62 | 2363 | 2425 | 0 |
| | 2050 | 14,152 | 14,255 | 641 | 14,896 | 96,848 | 39,562 | 2958 | 6350 | 9308 | 17,528 |
| China-Northwest | 2020 | 158 | 2 | 302 | 304 | 0 | 326 | 3 | 547 | 550 | 0 |
| | 2030 | 7 | 1 | 9 | 10 | 1 | 3401 | 38 | 1240 | 1278 | 0 |
| | 2050 | 12,360 | 15,511 | 661 | 16,172 | 39,433 | 31,642 | 2171 | 4847 | 7018 | 10,080 |
| China-Northeast | 2020 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | 2030 | 912 | 22 | 563 | 585 | 143 | 11,430 | 57 | 2362 | 2418 | 1 |
| | 2050 | 24,955 | 22,345 | 1465 | 23,809 | 39,793 | 49,329 | 2238 | 5393 | 7631 | 10,012 |
| China-Tibet | 2020 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | 2030 | 0 | 0 | 0 | 0 | 4 | 43 | 0 | 15 | 15 | 0 |
| | 2050 | 0 | 0 | 0 | 0 | 754 | 3 | 1 | 1 | 3 | 230 |
| China-Central Baltic | 2020 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | 2030 | 6 | 1 | 10 | 11 | 576 | 6013 | 74 | 2305 | 2379 | 1 |
| | 2050 | 4763 | 7167 | 44 | 7211 | 167,132 | 23,175 | 2609 | 4372 | 6981 | 47,112 |
| China-East | 2020 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | 2030 | 59 | 4 | 79 | 83 | 797 | 8720 | 95 | 3042 | 3137 | 0 |
| | 2050 | 17,604 | 21,928 | 1036 | 22,964 | 148,351 | 50,402 | 3884 | 8341 | 12,225 | 18,866 |

(continued)

**Table 8.94** (continued)

| Storage and dispatch | | 2.0 °C | | | | | 1.5 °C | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | Required to avoid curtailment | Utilization battery -through-put- | Utilization PSH -through-put- | Total storage demand (incl. H2) | Dispatch hydrogen-based | Required to avoid curtailment | Utilization battery -through-put- | Utilization PSH -through-put- | Total storage demand (incl. H2) | Dispatch hydrogen-based |
| China | | [GWh/year] | [GWh/year] | [GWh/year] | [GWh/year] | [GWh/year] | [GWh/year] | [GWh/year] | [GWh/year] | [GWh/year] | [GWh/year] |
| China-South | 2020 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | 2030 | 74 | 7 | 89 | 96 | 961 | 8676 | 93 | 3086 | 3179 | 0 |
| | 2050 | 21,703 | 28,028 | 1143 | 29,171 | 116,735 | 56,742 | 4139 | 9307 | 13,446 | 22,281 |
| Taiwan | 2020 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | 2030 | 0 | 0 | 0 | 0 | 89 | 202 | 5 | 121 | 126 | 0 |
| | 2050 | 6506 | 5734 | 943 | 6677 | 14,209 | 13,873 | 426 | 2985 | 3411 | 0 |
| China | 2020 | 158 | 2 | 302 | 304 | 0 | 326 | 3 | 547 | 550 | 0 |
| | 2030 | 1102 | 39 | 789 | 827 | 2582 | 45,217 | 424 | 14,533 | 14,957 | 2 |
| | 2050 | 102,042 | 114,967 | 5932 | 120,899 | 623,254 | 264,729 | 18,427 | 41,596 | 60,022 | 126,108 |

# 8.14 OECD Pacific

## *8.14.1 OECD Pacific: Long-Term Energy Pathways*

### 8.14.1.1 OECD Pacific: Final Energy demand by Sector

The future development pathways for OECD Pacific's final energy demand when the assumptions on population growth, GDP growth, and energy intensity are combined are shown in Fig. 8.98 for the 5.0 °C, 2.0 °C, and 1.5 °C Scenarios. In the 5.0 °C Scenario, the total final energy demand will decrease by 2%, from the current 20,100 PJ/year to 19,600 PJ/year in 2050. In the 2.0 °C Scenario, the final energy demand will decrease by 46% compared with current consumption and will reach 10,800 PJ/year by 2050. The final energy demand in the 1.5 °C Scenario will reach 10,200 PJ, 49% below the 2015 demand. In the 1.5 °C Scenario, the final energy demand in 2050 will be 6% lower than in the 2.0 °C Scenario. The electricity demand for 'classical' electrical devices (without power-to-heat or e-mobility) will decrease from 1520 TWh/year in 2015 to 1150 TWh/year in 2050 in both alternative scenarios. Compared with the 5.0 °C case (1890 TWh/year in 2050), the efficiency measures in the 2.0 °C and 1.5 °C Scenarios will save 740 TWh/year in 2050.

Electrification will lead to a significant increase in the electricity demand by 2050. The 2.0 °C Scenario has an electricity demand for heating of approximately 400 TWh/year due to electric heaters and heat pumps, and in the transport sector,

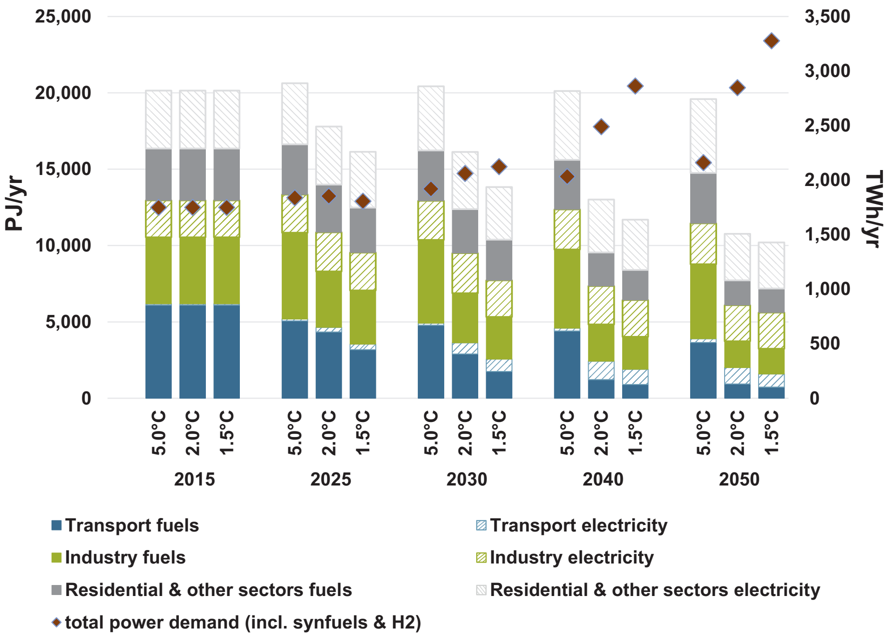


**Fig. 8.98** OECD Pacific: development of final energy demand by sector in the scenarios

the electricity demand will be approximately 1100 TWh/year due to electric mobility. The generation of hydrogen (for transport and high-temperature process heat) and the manufacture of synthetic fuels (mainly for transport) will add an additional power demand of 1000 TWh/year. Therefore, the gross power demand will rise from 1900 TWh/year in 2015 to 3000 TWh/year in 2050 in the 2.0 °C Scenario, 25% higher than in the 5.0 °C case. In the 1.5 °C Scenario, the gross electricity demand will increase to a maximum of 3400 TWh/year in 2050.

The efficiency gains in the heating sector could be even larger than in the electricity sector. In the 2.0 °C and 1.5 °C Scenarios, a final energy consumption equivalent to about 3000 PJ/year and 3100 PJ/year, respectively, will be avoided by 2050 through efficiency gains compared with the 5.0 °C Scenario.

#### 8.14.1.2 OECD Pacific: Electricity Generation

The development of the power system is characterized by a dynamically growing renewable energy market and an increasing proportion of total power coming from renewable sources. By 2050, 100% of the electricity produced in OECD Pacific will come from renewable energy sources in the 2.0 °C Scenario. 'New' renewables—mainly wind, solar, and geothermal energy—will contribute 82% of total electricity generation. Renewable electricity's share of the total production will be 60% by 2030 and 89% by 2040. The installed capacity of renewables will reach about 680 GW by 2030 and 1420 GW by 2050. The share of renewable electricity generation in 2030 in the 1.5 °C Scenario is assumed to be 68%. The 1.5 °C Scenario will have a generation capacity from renewable energy of approximately 1590 GW in 2050.

Table 8.95 shows the development of different renewable technologies in OECD Pacific over time. Figure 8.99 provides an overview of the overall power-generation structure in OECD Pacific. From 2020 onwards, the continuing growth of wind and PV, up to 320 GW and 830 GW, respectively, will complemented by up to 60 GW solar thermal generation, as well as limited biomass, geothermal, and ocean energy, in the 2.0 °C Scenario. Both the 2.0 °C and 1.5 °C Scenarios will lead to a high proportion of variable power generation (PV, wind, and ocean) of 40% and 47% by 2030, respectively, and of 68% in both scenarios by 2050.

#### 8.14.1.3 OECD Pacific: Future Costs of Electricity Generation

Figure 8.100 shows the development of the electricity-generation and supply costs over time, including the $CO_2$ emission costs, in all scenarios. The calculated electricity-generation costs in 2015 (referring to full costs) were around 8 ct/kWh. In the 5.0 °C case, the generation costs will increase until 2030, when they reach 11.1 ct/kWh, and then drop to 10.9 ct/kWh by 2050. The generation costs will increase in the 2.0 °C Scenario until 2030, when they reach 10.5 ct/kWh, and then drop to 8.3 ct/kWh by 2050. In the 1.5 °C Scenario, they will increase to 10.7 ct/kWh, and then drop to 8.5 ct/kWh by 2050. In the 2.0 °C Scenario, the generation

**Table 8.95** OECD Pacific: development of renewable electricity-generation capacity in the scenarios

| in GW | Case | 2015 | 2025 | 2030 | 2040 | 2050 |
|---|---|---|---|---|---|---|
| Hydro | 5.0 °C | 69 | 73 | 76 | 78 | 78 |
| | 2.0 °C | 69 | 76 | 78 | 82 | 84 |
| | 1.5 °C | 69 | 76 | 78 | 82 | 84 |
| Biomass | 5.0 °C | 9 | 13 | 15 | 16 | 18 |
| | 2.0 °C | 9 | 23 | 26 | 35 | 43 |
| | 1.5 °C | 9 | 23 | 29 | 42 | 47 |
| Wind | 5.0 °C | 9 | 23 | 28 | 40 | 56 |
| | 2.0 °C | 9 | 77 | 145 | 263 | 322 |
| | 1.5 °C | 9 | 84 | 198 | 335 | 384 |
| Geothermal | 5.0 °C | 2 | 4 | 5 | 7 | 11 |
| | 2.0 °C | 2 | 4 | 14 | 27 | 37 |
| | 1.5 °C | 2 | 4 | 14 | 27 | 37 |
| PV | 5.0 °C | 43 | 84 | 96 | 102 | 107 |
| | 2.0 °C | 43 | 225 | 394 | 701 | 831 |
| | 1.5 °C | 43 | 253 | 427 | 782 | 932 |
| CSP | 5.0 °C | 0 | 0 | 0 | 1 | 1 |
| | 2.0 °C | 0 | 1 | 15 | 39 | 57 |
| | 1.5 °C | 0 | 1 | 20 | 49 | 67 |
| Ocean | 5.0 °C | 0 | 1 | 1 | 2 | 4 |
| | 2.0 °C | 0 | 3 | 8 | 27 | 42 |
| | 1.5 °C | 0 | 3 | 8 | 27 | 42 |
| Total | 5.0 °C | 132 | 197 | 221 | 246 | 275 |
| | 2.0 °C | 132 | 409 | 681 | 1176 | 1416 |
| | 1.5 °C | 132 | 444 | 774 | 1345 | 1594 |

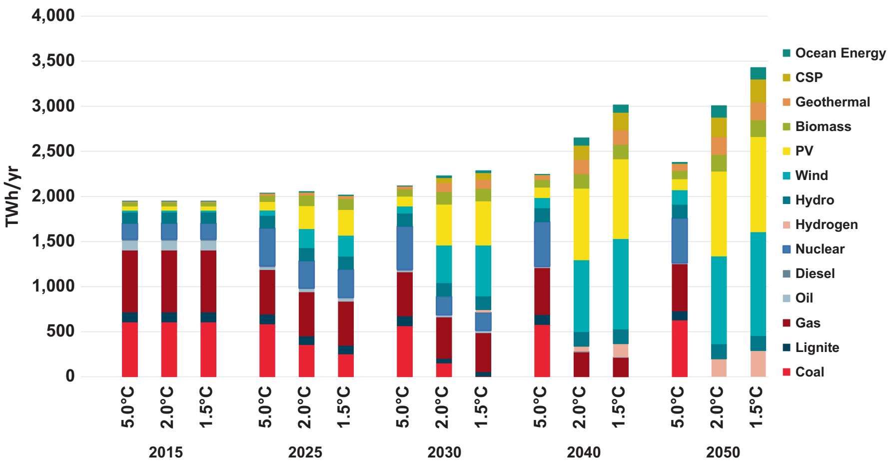


**Fig. 8.99** OECD Pacific: development of electricity-generation structure in the scenarios

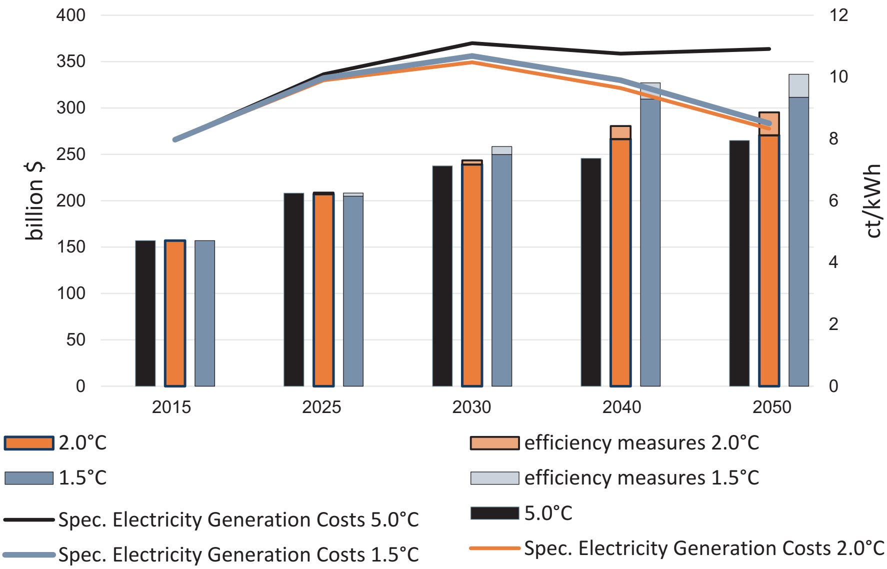


**Fig. 8.100** OECD Pacific: development of total electricity supply costs and specific electricity-generation costs in the scenarios

costs in 2050 will be 2.6 ct/kWh lower than in the 5.0 °C case, and in the 1.5 °C Scenario, this difference will 2.4 ct/kWh. Note that these estimates of generation costs do not take into account integration costs such as power grid expansion, storage, or other load-balancing measures.

In the 5.0 ° C case, the growth in demand and increasing fossil fuel prices will cause the total electricity supply costs to rise from today's $160 billion/year to more than $270 billion/year in 2050. In the 2.0 °C Scenario, the total supply costs will be $270 billion/year, and in the 1.5 °C Scenario, they will be $310 billion/year. The long-term costs for electricity supply will be only 2% higher in the 2.0 °C Scenario than in the 5.0 °C Scenario as a result of the estimated generation costs and the electrification of heating and mobility. Further electrification and synthetic fuel generation in the 1.5 °C Scenario will result in total power generation costs that are 17% higher than in the 5.0 °C case.

Compared with these results, the generation costs when the $CO_2$ emission costs are not considered will increase in the 5.0 °C case to 8.3 ct/kWh in 2050. The generation costs in the 2.0 °C Scenario will increase until 2030, when they will reach 9.3 ct/kWh, and then drop to 8.3 ct/kWh by 2050. In the 1.5 °C Scenario, they will increase to 9.9 ct/kWh, and then drop to 8.5 ct/kWh by 2050. In the 2.0 °C Scenario, the generation costs will be a maximum of 1 ct/kWh higher than in the 5.0 °C case and this will occur in 2040. In the 1.5 °C Scenario, compared with the 5.0 °C Scenario, the maximum difference in the generation costs will be 1.4 ct/kWh, again in 2040. If the $CO_2$ costs are not considered, the total electricity supply costs in the 5.0 °C case will rise to about $200 billion/year in 2050.

#### 8.14.1.4 OECD Pacific: Future Investments in the Power Sector

An investment of around \$2780 billion will be required for power generation between 2015 and 2050 in the 2.0 °C Scenario—including additional power plants for the production of hydrogen and synthetic fuels and investments in the replacement of plants at the end of their economic lifetimes. This value will be equivalent to approximately \$77 billion per year on average, and will be \$1520 billion more than in the 5.0 °C case (\$1260 billion). An investment of around \$3100 billion for power generation will required between 2015 and 2050 in the 1.5 °C Scenario. On average, this is an investment of \$86 billion per year. In the 5.0 °C Scenario, the investment in conventional power plants will be around 56% of the total cumulative investments, whereas approximately 44% will be invested in renewable power generation and co-generation (Fig. 8.101).

However, in the 2.0 °C (1.5 °C) Scenario, OECD Pacific will shift almost 93% (95%) of its entire investment to renewables and co-generation. By 2030, the fossil fuel share of the power sector investment will predominantly focused on gas power plants that can also be operated with hydrogen.

Because renewable energy has no fuel costs, other than biomass, the cumulative fuel cost savings in the 2.0 °C Scenario will reach a total of \$1420 billion in 2050, equivalent to \$39 billion per year. Therefore, the total fuel cost savings will be equivalent to 90% of the total additional investments compared to the 5.0 °C Scenario. The fuel cost savings in the 1.5 °C Scenario will add up to \$1510 billion, or \$42 billion per year.

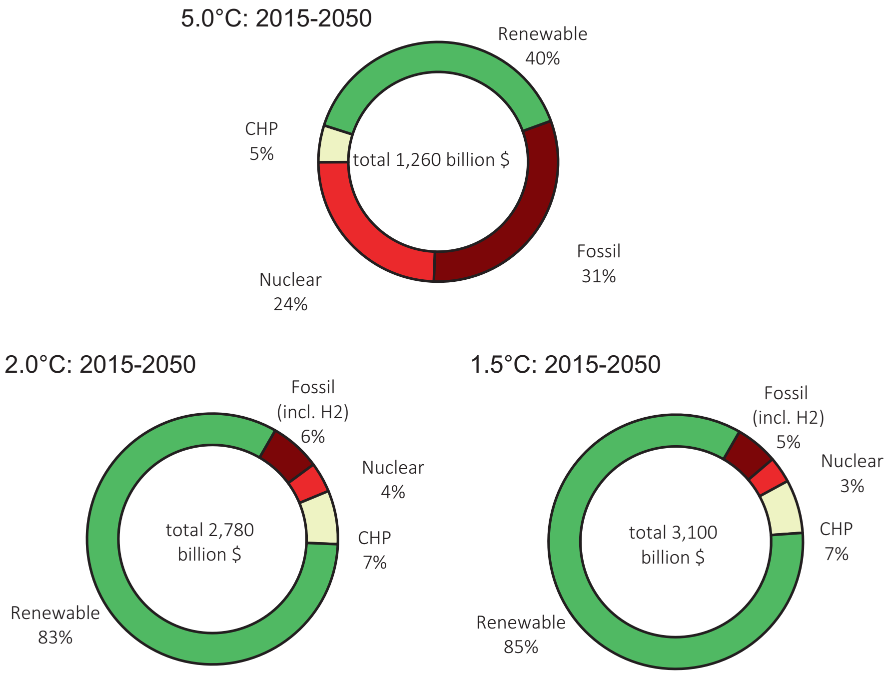


**Fig. 8.101** OECD Pacific: investment shares for power generation in the scenarios

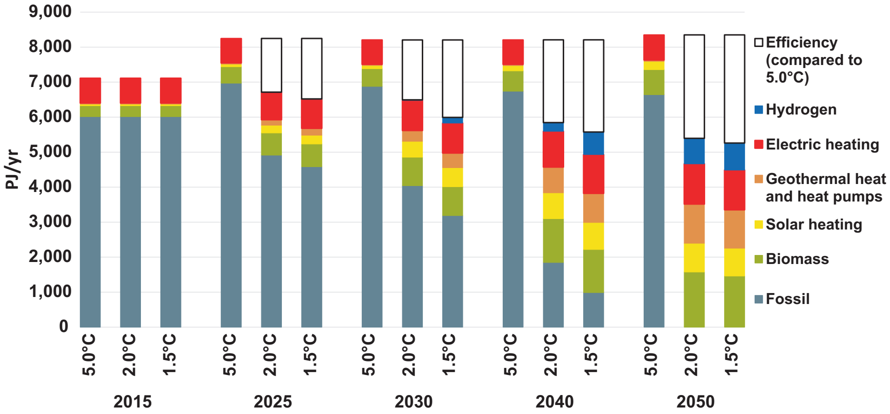


**Fig. 8.102** OECD Pacific: development of heat supply by energy carrier in the scenarios

#### 8.14.1.5 OECD Pacific: Energy Supply for Heating

The final energy demand for heating will increase in the 5.0 °C Scenario by 17%, from 7100 PJ/year in 2015 to 8300 PJ/year in 2050. Energy efficiency measures will help to reduce the energy demand for heating by 35% in 2050 in the 2.0 °C Scenario, relative to the 5.0 °C case, and by 37% in the 1.5 °C Scenario. Today, renewables supply around 7% of OECD Pacific's final energy demand for heating, with the main contribution from biomass. Renewable energy will provide 33% of OECD Pacific's total heat demand in 2030 in the 2.0 °C Scenario and 42% in the 1.5 °C Scenario. In both scenarios, renewables will provide 100% of the total heat demand in 2050.

Figure 8.102 shows the development of different technologies for heating in OECD Pacific over time, and Table 8.96 provides the resulting renewable heat supply for all scenarios. Up to 2030, biomass will remain the main contributor. The growing use of solar, geothermal, and environmental heat will lead, in the long term, to a biomass share of 37% in the 2.0 °C Scenario and of 35% in the 1.5 °C Scenario.

Heat from renewable hydrogen will further reduce the dependence on fossil fuels in both scenarios. The hydrogen consumption in 2050 will be around 700 PJ/year in the 2.0 °C Scenario and 800 PJ/year in the 1.5 °C Scenario. The direct use of electricity for heating will also increases by a factor of 1.6 between 2015 and 2050, and will achieves a final energy share of 21% in 2050 in the 2.0 °C Scenario and 22% in the 1.5 °C Scenario.

#### 8.14.1.6 OECD Pacific: Future Investments in the Heating Sector

The roughly estimated investments in renewable heating technologies up to 2050 will amount to around $530 billion in the 2.0 °C Scenario (including the investments for the replacement of plants after their economic lifetimes), or approximately $15 billion per year. The largest share of the investment in OECD Pacific is

**Table 8.96** OECD Pacific: development of renewable heat supply in the scenarios (excluding the direct use of electricity)

| in PJ/year | Case | 2015 | 2025 | 2030 | 2040 | 2050 |
|---|---|---|---|---|---|---|
| Biomass | 5.0 °C | 314 | 471 | 504 | 584 | 714 |
| | 2.0 °C | 314 | 633 | 815 | 1250 | 1579 |
| | 1.5 °C | 314 | 650 | 823 | 1229 | 1463 |
| Solar heating | 5.0 °C | 45 | 76 | 92 | 150 | 236 |
| | 2.0 °C | 45 | 221 | 452 | 737 | 819 |
| | 1.5 °C | 45 | 252 | 543 | 772 | 795 |
| Geothermal heat and heat pumps | 5.0 °C | 30 | 33 | 34 | 36 | 38 |
| | 2.0 °C | 30 | 157 | 307 | 737 | 1119 |
| | 1.5 °C | 30 | 197 | 420 | 830 | 1094 |
| Hydrogen | 5.0 °C | 0 | 0 | 0 | 0 | 0 |
| | 2.0 °C | 0 | 6 | 16 | 251 | 728 |
| | 1.5 °C | 0 | 9 | 160 | 642 | 772 |
| Total | 5.0 °C | 390 | 580 | 629 | 769 | 988 |
| | 2.0 °C | 390 | 1017 | 1591 | 2975 | 4245 |
| | 1.5 °C | 390 | 1107 | 1946 | 3473 | 4124 |

**Table 8.97** OECD Pacific: installed capacities for renewable heat generation in the scenarios

| in GW | Case | 2015 | 2025 | 2030 | 2040 | 2050 |
|---|---|---|---|---|---|---|
| Biomass | 5.0 °C | 44 | 60 | 63 | 69 | 75 |
| | 2.0 °C | 44 | 77 | 92 | 117 | 94 |
| | 1.5 °C | 44 | 79 | 91 | 113 | 80 |
| Geothermal | 5.0 °C | 0 | 0 | 0 | 0 | 0 |
| | 2.0 °C | 0 | 3 | 8 | 20 | 28 |
| | 1.5 °C | 0 | 3 | 7 | 22 | 26 |
| Solar heating | 5.0 °C | 13 | 22 | 27 | 43 | 69 |
| | 2.0 °C | 13 | 64 | 128 | 207 | 230 |
| | 1.5 °C | 13 | 73 | 152 | 215 | 224 |
| Heat pumps | 5.0 °C | 5 | 5 | 5 | 5 | 6 |
| | 2.0 °C | 5 | 11 | 23 | 54 | 74 |
| | 1.5 °C | 5 | 16 | 36 | 63 | 71 |
| Total[a] | 5.0 °C | 62 | 87 | 95 | 117 | 150 |
| | 2.0 °C | 62 | 156 | 250 | 397 | 426 |
| | 1.5 °C | 62 | 171 | 287 | 413 | 401 |

[a] Excluding direct electric heating

assumed to be for solar collectors (around \$240 billion), followed by heat pumps and biomass technologies. The 1.5 °C Scenario assumes an even faster expansion of renewable technologies, but with a similar average annual investment of around \$15 billion per year (Table 8.97, Fig. 8.103).

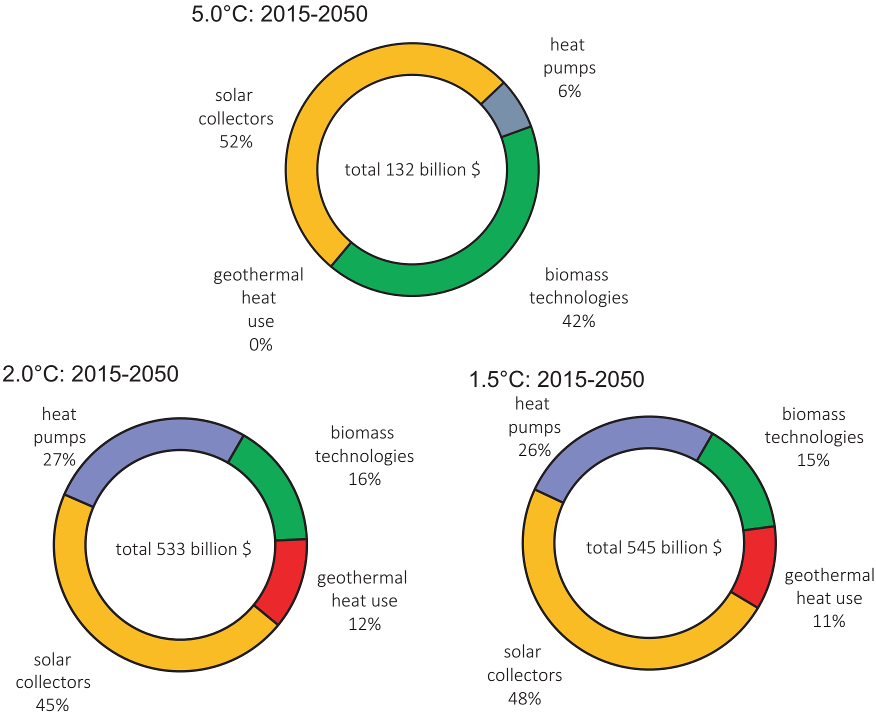


**Fig. 8.103** OECD Pacific: development of investments for renewable heat-generation technologies in the scenarios

### 8.14.1.7 OECD Pacific: Transport

Energy demand in the transport sector in OECD Pacific is expected to decrease by 37% in the 5.0 °C Scenario, from around 6200 PJ/year in 2015 to 3900 PJ/year in 2050. In the 2.0 °C Scenario, assumed technical, structural, and behavioural changes will save 49% (around 1900 PJ/year) by 2050 compared with the 5.0 °C Scenario. Additional modal shifts, technology switches, and a reduction in the transport demand will lead to even higher energy savings in the 1.5 °C Scenario of 59% (or 2300 PJ/year) in 2050 compared with the 5.0 °C case (Table 8.98, Fig. 8.104).

By 2030, electricity will provide 20% (200 TWh/year) of the transport sector's total energy demand in the 2.0 °C Scenario, whereas in 2050, the share will be 53% (300 TWh/year). In 2050, up to 480 PJ/year of hydrogen will be used in the transport sector as a complementary renewable option. In the 1.5 °C Scenario, the annual electricity demand will be 240 TWh in 2050. The 1.5 °C Scenario also assumes a hydrogen demand of 360 PJ/year by 2050.

Biofuel use is limited in the 2.0 °C Scenario and the 1.5 °C Scenario to a maximum of approximately 200 PJ/year. Therefore, around 2030, synthetic fuels based on power-to-liquid will be introduced, with a maximum amount of 270 PJ/year in 2050 in the 2.0 °C Scenario. Due to the lower overall energy demand in transport, the maximum synthetic fuel demand will amount to 210 PJ/year in the 1.5 °C Scenario.

**Table 8.98** OECD Pacific: projection of transport energy demand by mode in the scenarios

| in PJ/year | Case | 2015 | 2025 | 2030 | 2040 | 2050 |
|---|---|---|---|---|---|---|
| Rail | 5.0 °C | 158 | 162 | 163 | 162 | 161 |
| | 2.0 °C | 158 | 154 | 156 | 154 | 159 |
| | 1.5 °C | 158 | 156 | 156 | 162 | 161 |
| Road | 5.0 °C | 5515 | 4317 | 3902 | 3365 | 2614 |
| | 2.0 °C | 5515 | 3961 | 2979 | 1837 | 1456 |
| | 1.5 °C | 5515 | 2891 | 1975 | 1399 | 1123 |
| Domestic aviation | 5.0 °C | 331 | 524 | 663 | 863 | 922 |
| | 2.0 °C | 331 | 338 | 308 | 242 | 194 |
| | 1.5 °C | 331 | 307 | 240 | 147 | 109 |
| Domestic navigation | 5.0 °C | 173 | 178 | 181 | 186 | 193 |
| | 2.0 °C | 173 | 178 | 181 | 186 | 193 |
| | 1.5 °C | 173 | 178 | 181 | 186 | 193 |
| Total | 5.0 °C | 6176 | 5182 | 4908 | 4576 | 3890 |
| | 2.0 °C | 6176 | 4631 | 3624 | 2419 | 2002 |
| | 1.5 °C | 6176 | 3533 | 2551 | 1893 | 1586 |

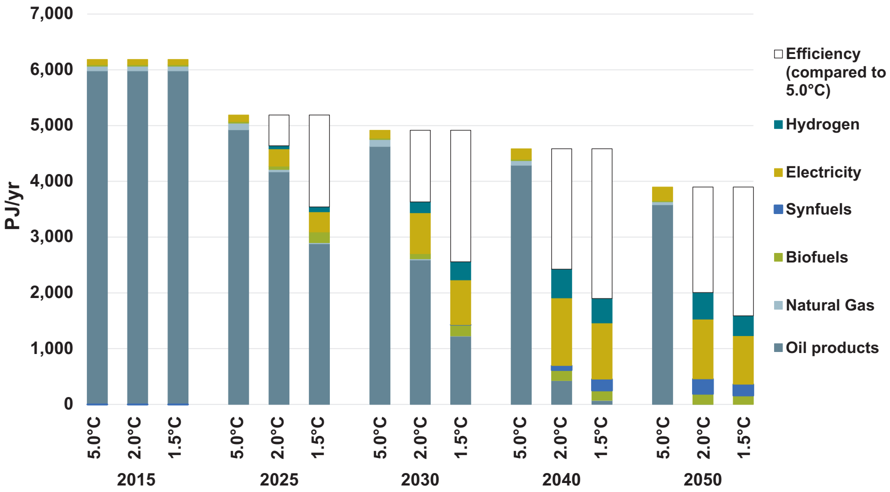


**Fig. 8.104** OECD Pacific: final energy consumption by transport in the scenarios

### 8.14.1.8 OECD Pacific: Development of $CO_2$ Emissions

In the 5.0 °C Scenario, OECD Pacific's annual $CO_2$ emissions will decrease by 21%, from 2080 Mt in 2015 to 1640 Mt in 2050. The stringent mitigation measures in both alternative scenarios will cause the annual emissions to fall to 280 Mt in 2040 in the 2.0 °C Scenario and to 160 Mt. in the 1.5 °C Scenario, with further reductions to almost zero by 2050. In the 5.0 °C case, the cumulative $CO_2$ emissions from 2015 until 2050 will add up to 67 Gt. In contrast, in the 2.0 °C and 1.5 °C Scenarios, the cumulative emissions for the period from 2015 until 2050 will be 31 Gt and 26 Gt, respectively.

Therefore, the cumulative $CO_2$ emissions will decrease by 54% in the 2.0 °C Scenario and by 61% in the 1.5 °C Scenario compared with the 5.0 °C case. A rapid reduction in the annual emissions will occur under both alternative scenarios. In the 2.0 °C Scenario, this reduction will be greatest in 'Power generation', followed by 'Transport' and 'Industry' (Fig. 8.105).

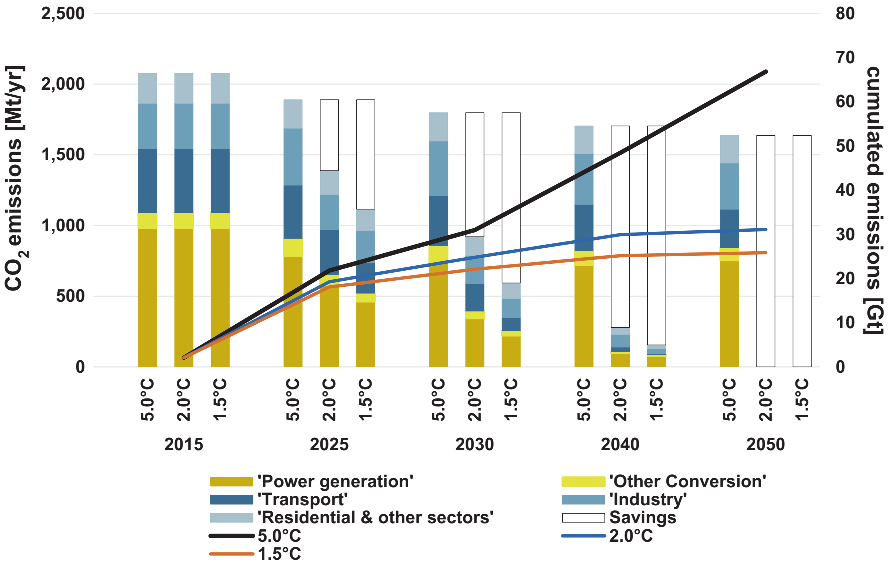


**Fig. 8.105** OECD Pacific: development of $CO_2$ emissions by sector and cumulative $CO_2$ emissions (after 2015) in the scenarios ('Savings' = reduction compared with the 5.0 °C Scenario)

#### 8.14.1.9 OECD Pacific: Primary Energy Consumption

The levels of primary energy consumption in the three scenarios when the assumptions discussed above are taken into account are shown in Fig. 8.106. In the 2.0 °C Scenario, the primary energy demand will decrease by 48%, from around 36,300 PJ/year in 2015 to 18,900 PJ/year in 2050. Compared with the 5.0 °C Scenario, the overall primary energy demand will decrease by 45% by 2050 in the 2.0 °C Scenario (5.0 °C: 34,700 PJ in 2050). In the 1.5 °C Scenario, the primary energy demand will be even lower (19,900 PJ in 2050) because the final energy demand and conversion losses will be lower.

Both the 2.0 °C Scenario and 1.5 °C Scenario aim to rapidly phase-out coal and oil. This will cause renewable energy to have a primary energy share of 33% in 2030 and 88% in 2050 in the 2.0 °C Scenario. In the 1.5 °C Scenario, renewables will have a primary energy share of more than 89% in 2050 (including non-energy consumption, which will still include fossil fuels). Nuclear energy will be phased-out in 2040 in both the 2.0 °C and 1.5 °C Scenarios. The cumulative primary energy consumption of natural gas in the 5.0 °C case will add up to 230 EJ, the cumulative coal consumption to about 300 EJ, and the crude oil consumption to 380 EJ. In contrast, in the 2.0 °C Scenario, the cumulative gas demand will amount to 150 EJ, the cumulative coal demand to 100 EJ, and the cumulative oil demand to 230 EJ. Even lower

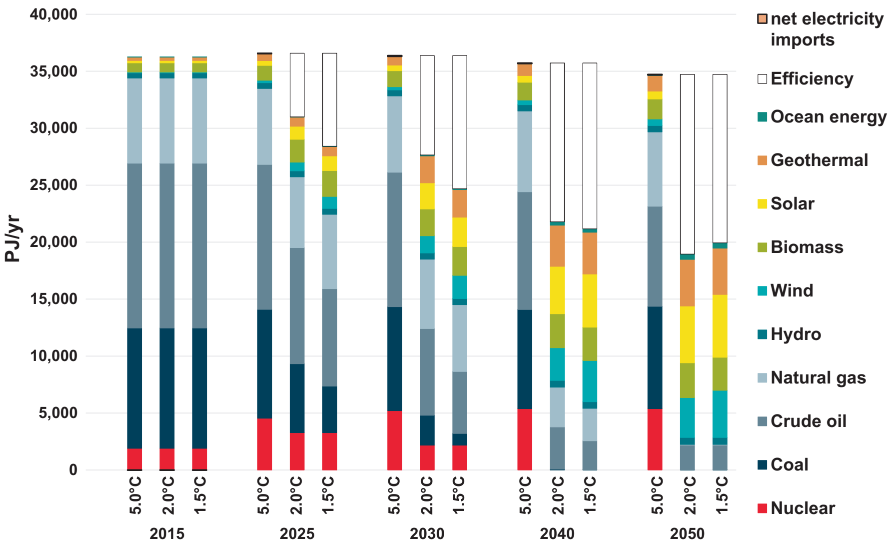


**Fig. 8.106** OECD Pacific: projection of total primary energy demand (PED) by energy carrier in the scenarios (including electricity import balance)

fossil fuel use will be achieved in the 1.5 °C Scenario: 150 EJ for natural gas, 70 EJ for coal, and 190 EJ for oil.

## 8.14.2 OECD Pacific: Power Sector Analysis

South Korea, Japan, Australia, and New Zealand form the OECD Pacific region (also referred to as OECD Asia Pacific or OECD Asia Oceania). Like Non-OECD Asia, a regional interconnected power market with regular electricity exchange is unlikely. Therefore, the region is broken down into seven sub-regions: (1) South Korea; (2) the north of Japan; (3) the south of Japan; (4) Australia's National Electricity Market (NEM) (covering the entire east coast); (5) the SWIS-NT grid region (comprising Western Australia and the Northern Territory); (6) the North Island of New Zealand; and (7) the South Island of New Zealand. The sub-regions have very different electricity policies, power-generation structures, and demand patterns. In this analysis, simplifications that may not reflect the local conditions are made to ensure that the results comparable on a global level. Therefore, the results for specific countries are only estimates.

### 8.14.2.1 OECD Pacific: Development of Power Plant Capacities

The region has significant potential for all renewables, including the dominant renewable power technologies of solar PV and onshore wind. Japan has significant geothermal power resources, and offshore wind potentials are substantial across the region. There is also potential for ocean energy across the region, although it is currently a niche technology. Australia has one of the best solar resources in the world, so concentrated solar power plants will be an important part of both scenarios in Australia. Coal and nuclear capacities will be phased-out as plants come to the end of their lifetimes. In the 1.5 °C Scenario, the last coal power plant will be phased out just after 2030.

The solar PV market will reach 8 GW in 2020 under the 2.0 °C Scenario—the same level as the actual regional market of 8.3 GW (REN21-GSR 2018) in 2017—and increase rapidly to 43 GW by 2030. The 1.5 °C Scenario requires that solar PV will achieve an equal market size by 2030 and remain at this level until 2040.

However, the onshore market must increase significantly compared with the market in 2017, which was only 0.54 GW (GWEC-NL 2018). By 2025, 12 GW of onshore wind capacity must be installed annually across the region under the 2.0 °C

**Table 8.99** OECD Pacific: average annual change in installed power plant capacity

| OECD Pacific power generation: average annual change of installed capacity [GW/a] | 2015–2025 | | 2026–2035 | | 2036–2050 | |
|---|---|---|---|---|---|---|
| | 2.0 °C | 1.5C° | 2.0 °C | 1.5 °C | 2.0 °C | 1.5 °C |
| Hard coal | −4 | −9 | −5 | −4 | −1 | 0 |
| Lignite | 0 | −1 | −2 | −2 | 0 | 0 |
| Gas | 2 | −2 | −1 | −3 | −14 | 0 |
| Hydrogen-gas | 0 | 1 | 1 | 5 | 12 | 12 |
| Oil/diesel | −3 | −2 | −2 | −2 | −1 | −1 |
| Nuclear | 0 | −5 | −3 | −3 | −2 | −2 |
| Biomass | 2 | 1 | 1 | 1 | 1 | 1 |
| Hydro | 2 | 1 | 0 | 1 | 0 | 0 |
| Wind (onshore) | 7 | 18 | 12 | 17 | 7 | 6 |
| Wind (offshore) | 1 | 4 | 5 | 5 | 2 | 2 |
| PV (roof top) | 17 | 33 | 33 | 33 | 16 | 21 |
| PV (utility scale) | 6 | 11 | 11 | 11 | 5 | 7 |
| Geothermal | 0 | 2 | 2 | 2 | 2 | 2 |
| Solar thermal power plants | 1 | 2 | 3 | 4 | 2 | 3 |
| Ocean energy | 0 | 1 | 2 | 2 | 2 | 2 |
| Renewable fuel based co-generation | **1** | **1** | **1** | **2** | **1** | **1** |

Scenario, and 17 GW under the 1.5 °C Scenario. By 2030, geothermal, concentrated solar power, and ocean energy must increase by around 2 GW each (Table 8.99).

#### 8.14.2.2 OECD Pacific: Utilization of Power Generation Capacities

The very different developments of variable and dispatch power plants in all sub-regions reflect the diversity the Pacific region. Table 8.100 shows that because there is no interconnection between the northern and southern parts of Japan, we assume that even within Japan, the separate electricity markets of the 50 Hz and 60 Hz regions will remain as they are. For Australia, it is assumed that the east- and west-coast electricity markets will have limited interconnection capacities by 2030. The North and South Islands of New Zealand are calculated to have an increased interconnection capacity by 2050.

Table 8.101 shows that for the region as a whole, the limited dispatchable power plants will retain a relatively high capacity factor, compared with other regions, until after 2020 and decrease thereafter. The average capacity factors from 2030 onwards will be consistent with all other regions.

**Table 8.100** OECD Pacific: power system shares by technology group

| Power generation structure and interconnection | | 2.0 °C | | | | 1.5 °C | | | |
|---|---|---|---|---|---|---|---|---|---|
| OECD Pacific | | Variable RE | Dispatch RE | Dispatch Fossil | Inter-connection | Variable RE | Dispatch RE | Dispatch Fossil | Inter-connection |
| South Korea | 2015 | 4% | 34% | 61% | 5% | | | | |
| | 2030 | 40% | 18% | 43% | 20% | 46% | 17% | 38% | 0% |
| | 2050 | 70% | 28% | 2% | 25% | 62% | 24% | 14% | 0% |
| Japan – North (50 Hz) | 2015 | 4% | 34% | 61% | 5% | | | | |
| | 2030 | 46% | 26% | 28% | 20% | 51% | 23% | 26% | 0% |
| | 2050 | 72% | 26% | 2% | 25% | 64% | 21% | 15% | 0% |
| Japan – South (60 Hz) | 2015 | 4% | 34% | 61% | 5% | | | | |
| | 2030 | 36% | 38% | 26% | 20% | 41% | 35% | 24% | 0% |
| | 2050 | 72% | 25% | 2% | 25% | 64% | 20% | 15% | 0% |
| Australia – East and South (NEM) | 2015 | 5% | 34% | 61% | 5% | | | | |
| | 2030 | 17% | 82% | 0% | 20% | 17% | 83% | 0% | 10% |
| | 2050 | 73% | 26% | 2% | 25% | 67% | 21% | 12% | 20% |
| Australia West and North (SWIS + NT) | 2015 | 5% | 34% | 61% | 5% | | | | |
| | 2030 | 41% | 37% | 22% | 20% | 46% | 33% | 21% | 10% |
| | 2050 | 73% | 25% | 2% | 25% | 67% | 21% | 12% | 20% |

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| New Zealand – North Island | 2015 | 5% | 34% | 61% | 5% | | | | |
| | 2030 | 39% | 61% | 0% | 20% | 45% | 55% | 0% | 10% |
| | 2050 | 77% | 22% | 2% | 25% | 70% | 18% | 12% | 20% |
| New Zealand – South Island | 2015 | 5% | 34% | 61% | 5% | | | | |
| | 2030 | 39% | 61% | 0% | 20% | 45% | 55% | 0% | 10% |
| | 2050 | 77% | 22% | 2% | 25% | 70% | 18% | 12% | 20% |
| OECD Pacific | 2015 | 4% | 34% | 61% | | | | | |
| | 2030 | 40% | 31% | 30% | | 45% | 29% | 27% | |
| | 2050 | 71% | 26% | 2% | | 64% | 22% | 14% | |

**Table 8.101** OECD Pacific: capacity factors by generation type

| Utilization of variable and dispatchable power generation: | | 2015 | 2020 | 2020 | 2030 | 2030 | 2040 | 2040 | 2050 | 2050 |
|---|---|---|---|---|---|---|---|---|---|---|
| OECD Pacific | | | 2.0 °C | 1.5 °C | 2.0 °C | 1.5 °C | 2.0 °C | 1.5 °C | 2.0 °C | 1.5 °C |
| Capacity factor – average | [%/yr] | 54.8% | 55% | 55% | 29% | 29% | 29% | 29% | 34% | 31% |
| Limited dispatchable: fossil and nuclear | [%/yr] | 65.1% | 54% | 54% | 26% | 31% | 19% | 29% | 25% | 32% |
| Limited dispatchable: renewable | [%/yr] | 42.7% | 63% | 54% | 29% | 30% | 54% | 25% | 27% | 25% |
| Dispatchable: fossil | [%/yr] | 48.6% | 48% | 50% | 20% | 23% | 35% | 21% | 19% | 26% |
| Dispatchable: renewable | [%/yr] | 43.1% | 73% | 73% | 50% | 52% | 37% | 46% | 49% | 46% |
| Variable: renewable | [%/yr] | 23.2% | 17% | 17% | 20% | 20% | 27% | 27% | 31% | 28% |

#### 8.14.2.3 OECD Pacific: Development of Load, Generation, and Residual Load

Table 8.102 shows the development of the maximum load, generation, and resulting residual load in the Pacific region. To verify the calculation results, we compared the peak demands in Australia and Japan.

The peak load for Australia's NEM was calculated to be 32.6 GW in 2020, which corresponds to the reported summer peak of 32.5 GW in the summer of 2017/2018 (AER 2018). Japan's peak demand was 152 GW in 2015 according to the Tokyo Electric Power Company (TEPCO -2018) and TEPCO predicts that it will be 136 GW in 2020, which is 11% lower.

In the long term, the Pacific region will be a renewable fuel producer for the export market. Therefore, the calculated increased interconnection capacities indicate overproduction, which will be used for international bunker fuels.

The storage and dispatch requirements for all sub-regions are shown in Table 8.103. The Pacific region has vast solar and wind resources and will therefore be one of the production hubs for synthetic fuels and hydrogen, which may be used for industrial processes, for bunker fuels, or to replace natural gas. Therefore, the storage and dispatch demand may vary significantly because they depend on the extent to which renewable fuel production is integrated into the national power sectors or used for dispatch and demand-side management. The more integrated the fuel production is, the lower the overall requirement for battery or hydro pump storage technologies. Further research is required to develop a dedicated plan to produce renewable bunker fuels in Australia.

**Table 8.102** OECD Pacific: load, generation, and residual load development

| Power generation structure | | 2.0 °C | | | | 1.5 °C | | | |
|---|---|---|---|---|---|---|---|---|---|
| OECD Pacific | | Max demand [GW] | Max generation [GW] | Max Residual Load [GW] | Max interconnection requirements [GW] | Max demand [GW] | Max generation [GW] | Max residual load [GW] | Max interconnection requirements [GW] |
| South Korea | 2020 | 86.8 | 86.8 | 1.6 | | 86.8 | 86.8 | 1.6 | |
| | 2030 | 92.3 | 145.0 | 6.6 | 46 | 94.5 | 167.5 | 14.9 | 58 |
| | 2050 | 116.4 | 298.0 | 58.3 | 123 | 134.7 | 339.9 | 62.4 | 143 |
| Japan – North (50 Hz) | 2020 | 130.6 | 97.9 | 35.1 | | 130.6 | 97.4 | 36.0 | |
| | 2030 | 79.1 | 125.0 | 4.1 | 42 | 81.6 | 145.4 | 4.1 | 60 |
| | 2050 | 106.0 | 252.2 | 49.4 | 97 | 120.1 | 288.5 | 33.9 | 134 |
| Japan – South (60 Hz) | 2020 | 83.6 | 83.6 | 3.5 | | 83.7 | 83.6 | 3.5 | |
| | 2030 | 87.5 | 126.1 | 4.8 | 34 | 90.4 | 148.0 | 11.3 | 46 |
| | 2050 | 116.2 | 287.9 | 51.2 | 121 | 132.6 | 329.3 | 38.8 | 158 |
| Australia – East and South (NEM) | 2020 | 6.7 | 7.0 | 1.2 | | 6.7 | 7.0 | 1.2 | |
| | 2030 | 4.3 | 6.4 | 3.8 | 0 | 4.4 | 6.6 | 3.9 | 0 |
| | 2050 | 5.7 | 12.6 | 2.6 | 4 | 6.4 | 14.4 | 2.5 | 5 |
| Australia West and North (SWIS + NT) | 2020 | 32.6 | 32.6 | 1.1 | | 32.6 | 32.6 | 1.1 | |
| | 2030 | 33.9 | 49.6 | 1.1 | 15 | 34.8 | 58.3 | 1.1 | 22 |
| | 2050 | 44.7 | 111.5 | 21.3 | 45 | 51.4 | 127.4 | 22.5 | 53 |
| New Zealand – North Island | 2020 | 5.5 | 5.5 | 3.9 | | 5.5 | 5.5 | 3.9 | |
| | 2030 | 5.0 | 6.9 | 0.2 | 2 | 5.1 | 8.2 | 0.2 | 3 |
| | 2050 | 6.5 | 15.9 | 3.0 | 6 | 7.5 | 18.1 | 2.1 | 9 |
| New Zealand – South Island | 2020 | 1.3 | 4.4 | 0.0 | | | | | |
| | 2030 | 1.5 | 2.1 | 0.0 | 1 | 1.5 | 2.4 | 0.0 | 1 |
| | 2050 | 2.0 | 4.8 | 0.9 | 2 | 2.2 | 5.4 | 0.6 | 3 |

Table 8.103 OECD Pacific: storage and dispatch service requirements

| Storage and dispatch | | 2.0 °C | | | | | 1.5 °C | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| OECD Pacific | | Required to avoid curtailment [GWh/year] | Utilization battery -through-put- [GWh/year] | Utilization PSH -through-put- [GWh/year] | Total Storage demand (incl. H2) [GWh/year] | Dispatch Hydrogen-based [GWh/year] | Required to avoid curtailment [GWh/year] | Utilization battery -through-put- [GWh/year] | Utilization PSH -through-put- [GWh/year] | Total storage demand (incl. H2) [GWh/year] | Dispatch hydrogen-based [GWh/year] |
| South Korea | 2020 | 0 | 0 | 0 | 0 | 70 | 0 | 0 | 0 | 0 | 51 |
| | 2030 | 13,803 | 275 | 1968 | 2242 | 241 | 27,635 | 400 | 3197 | 3596 | 890 |
| | 2050 | 156,658 | 46,248 | 8717 | 54,965 | 22,747 | 176,909 | 45,195 | 8599 | 53,793 | 16,906 |
| Japan – North (50 Hz) | 2020 | 0 | 0 | 0 | 0 | 85 | 0 | 0 | 0 | 0 | 62 |
| | 2030 | 25,236 | 357 | 2820 | 3177 | 200 | 44,298 | 418 | 3819 | 4238 | 131 |
| | 2050 | 156,580 | 32,626 | 6784 | 39,411 | 21,744 | 185,902 | 32,676 | 6917 | 39,594 | 15,831 |
| Japan – South (60 Hz) | 2020 | 0 | 0 | 0 | 0 | 121 | 0 | 0 | 0 | 0 | 88 |
| | 2030 | 21,734 | 343 | 2320 | 2663 | 303 | 37,937 | 439 | 3490 | 3929 | 774 |
| | 2050 | 199,561 | 38,310 | 8309 | 46,618 | 24,062 | 233,815 | 38,207 | 8381 | 46,588 | 17,382 |
| Australia – East and South (NEM) | 2020 | 114 | 0 | 0 | 0 | 15 | 202 | 0 | 0 | 0 | 11 |
| | 2030 | 850 | 0 | 55 | 55 | 0 | 1696 | 0 | 86 | 86 | 0 |
| | 2050 | 9375 | 1983 | 457 | 2440 | 924 | 11,304 | 1981 | 472 | 2453 | 538 |
| Australia West and North (SWIS + NT) | 2020 | 4 | 0 | 0 | 0 | 0 | 49 | 0 | 0 | 0 | 0 |
| | 2030 | 11,311 | 219 | 1621 | 1840 | 87 | 19,866 | 255 | 2289 | 2544 | 79 |
| | 2050 | 90,062 | 18,266 | 4625 | 22,891 | 8053 | 103,839 | 18,187 | 4637 | 22,824 | 5140 |

| | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| New Zealand – North Island | 2020 | 0 | 0 | 0 | 0 | 4 | 0 | 0 | 0 | 0 | 3 |
| | 2030 | 1223 | 20 | 142 | 162 | 0 | 2165 | 26 | 221 | 247 | 0 |
| | 2050 | 12,361 | 2316 | 546 | 2862 | 1090 | 14,474 | 2304 | 548 | 2852 | 779 |
| New Zealand – South Island | 2020 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | 2030 | 374 | 6 | 43 | 49 | 0 | 658 | 8 | 67 | 74 | 0 |
| | 2050 | 3733 | 695 | 164 | 859 | 328 | 4371 | 691 | 164 | 855 | 235 |
| OECD Pacific | 2020 | 118 | 0 | 0 | 0 | 295 | 251 | 0 | 0 | 0 | 215 |
| | 2030 | 84,079 | 1246 | 9157 | 10,403 | 831 | 146,440 | 1564 | 13,290 | 14,855 | 1874 |
| | 2050 | 654,287 | 140,807 | 29,623 | 170,431 | 81,215 | 760,962 | 139,369 | 29,724 | 169,093 | 59,243 |

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