European Bank for Reconstruction and Development

Development of the electricity carbon emission factors for Russia

Baseline Study for Russia

- Final Report -
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Utilised Data Sources
<table>
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<th>Acronym</th>
<th>Description</th>
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<tr>
<td>CCGT</td>
<td>Combined Cycle Gas Turbine</td>
</tr>
<tr>
<td>CDM</td>
<td>Clean Development Mechanism</td>
</tr>
<tr>
<td>CHP</td>
<td>Combined heat and power</td>
</tr>
<tr>
<td>CM</td>
<td>Combined Margin</td>
</tr>
<tr>
<td>CO₂</td>
<td>Carbon dioxide</td>
</tr>
<tr>
<td>CPP</td>
<td>Condensing power plant</td>
</tr>
<tr>
<td>EBRD</td>
<td>European Bank for Reconstruction and Development</td>
</tr>
<tr>
<td>EFA</td>
<td>Energy Forecasting Agency</td>
</tr>
<tr>
<td>EUR</td>
<td>Euro (currency)</td>
</tr>
<tr>
<td>GHG</td>
<td>Greenhouse gas</td>
</tr>
<tr>
<td>GTU</td>
<td>Gas turbine unit</td>
</tr>
<tr>
<td>GW</td>
<td>Gigawatt</td>
</tr>
<tr>
<td>GWh</td>
<td>Gigawatt hour</td>
</tr>
<tr>
<td>HPP</td>
<td>Hydropower plant</td>
</tr>
<tr>
<td>IE</td>
<td>Independent Entity</td>
</tr>
<tr>
<td>IPS</td>
<td>Integrated Power System</td>
</tr>
<tr>
<td>JI</td>
<td>Joint Implementation</td>
</tr>
<tr>
<td>km</td>
<td>Kilometre</td>
</tr>
<tr>
<td>kV</td>
<td>Kilo volt</td>
</tr>
<tr>
<td>kVA</td>
<td>Kilo volt ampere</td>
</tr>
<tr>
<td>kWh</td>
<td>Kilowatt hour</td>
</tr>
<tr>
<td>LEC</td>
<td>Levelised Electricity Cost</td>
</tr>
<tr>
<td>LI</td>
<td>Lahmeyer International</td>
</tr>
<tr>
<td>MED</td>
<td>Ministry of Economic Development</td>
</tr>
<tr>
<td>MoM</td>
<td>Minutes of the Meeting</td>
</tr>
<tr>
<td>MS</td>
<td>Microsoft</td>
</tr>
<tr>
<td>MVA</td>
<td>Mega volt ampere</td>
</tr>
<tr>
<td>MW</td>
<td>Megawatt</td>
</tr>
<tr>
<td>MWh</td>
<td>Megawatt hour</td>
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<tr>
<td>NPP</td>
<td>Nuclear power plant</td>
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<tr>
<td>PSH</td>
<td>Pumped storage hydropower plant</td>
</tr>
<tr>
<td>RES</td>
<td>Renewable Energy System</td>
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<tr>
<td>SO-CDU</td>
<td>System Operator – Central Dispatching Unit</td>
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<tr>
<td>SRMC</td>
<td>Short Run Marginal Cost</td>
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<tr>
<td>t</td>
<td>Metric tonne</td>
</tr>
<tr>
<td>TPP</td>
<td>Thermal power plant</td>
</tr>
<tr>
<td>UES</td>
<td>Unified Electricity System</td>
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<tr>
<td>UNFCCC</td>
<td>United Nations Framework Convention on Climate Change</td>
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1 INTRODUCTION

The project “Development of the electricity carbon emission factors for Russia” was assigned by the European Bank for Reconstruction and Development (EBRD) to the Consultant Lahmeyer International with Perspectives as subcontractor on 16 July 2009.

It is a Baseline Study with the overall goal to calculate reliable carbon emission factors for Russia for the period from 2009 to 2020. These electricity carbon emission factors for the Russian electricity systems shall facilitate to derive the baseline scenario of future Joint Implementation (JI) project activities since the EBRD considers financing a large number of investment projects that will lead to energy efficiency improvements in terms of greenhouse gas (GHG) emissions reductions.

As per the work schedule the project was divided into three major work packages:

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<td>Development of Power System Simulation Model &amp; Baseline Studies</td>
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<td>Work Package III:</td>
<td>Validation by Accredited Independent Entity</td>
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The study includes a thorough data review and analysis under a long term perspective. This was executed in order to reliably simulate the development of Russia’s electricity systems. Official data has been made available with support by the Ministry of Economic Development (MED), Moscow, Russia, which also acts as National Focal Point for Joint Implementation.

A detailed list of the utilised data sources including their origin is provided in the annex.

With regard to the structure of the present Baseline Study, the following approach according to Figure 1-1 was pursued.

![Figure 1-1: Structure of the Baseline Study](image)

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Accordingly, Chapter 2 analyses and describes the present state of the seven existing territorial electricity systems in Russia, thus assessing the required input data for the calculation of the carbon emission factors. Correspondingly, historic power generation and transmission capabilities in the respective systems are outlined. Further on, a demand analysis is conducted by assessing the overall load profiles vs. the expected electricity demand development for the period under consideration. Regarding the supply side the related subchapters deal with the analysis of official investment programs in order to facilitate a demand-supply-balancing. The envisaged electricity systems’ expansion plan is highlighted as well in this context.

For the sake of clarity, above mentioned data analysis is conducted separately for each electricity system under consideration.

Whereas the previous analysis forms the input data, Chapter 3 describes in detail the underlying calculation method in terms of data throughput. Since the resulting carbon emission factors shall facilitate to determine the baseline scenario for future JI project activities in Russia, their calculation has to be in full accordance with the official guidelines and calculation tools published by the United Nations Framework Convention on Climate Change (UNFCCC).

After having determined the applicable calculation method, the overall setup of the developed Power System Simulation Model is presented in detail in the following subchapter. Special emphasis is placed on the embedded dispatch analysis within the Model in order to facilitate the forecast of the most probable energy mix for the period between 2009 and 2020.

Chapter 4 presents the corresponding carbon emission factors for each electricity system after having simulated the power generation dispatch which was described previously.

The output of the Power System Simulation Model comprises:
- The forecasted load duration curves representing the future electricity demand;
- The forecasted energy mix representing the future electricity supply; and
- The resulting carbon emission factors for each electricity system.

This information is presented on an annual basis.

Finally, Chapter 5 concludes the present study by summing up major project results and providing recommendations concerning the future application of the Power System Simulation Model in consideration of continuous updating of the Model and its utilisation by the users.
2 ANALYSIS AND DEVELOPMENT OF THE TERRITORIAL ELECTRICITY SYSTEMS

In the following a thorough analysis of the present state of Russia’s seven territorial electricity systems is described as carried out in the study. The analysis results serve as input parameters for the developed Power System Simulation Model in order to calculate the corresponding carbon emission factors as outlined in Chapter 3. The seven Integrated Power Systems (IPS) in Russia are the following:

(i) Electricity System IPS Center
(ii) Electricity System IPS East
(iii) Electricity System IPS North West
(iv) Electricity System IPS Siberia
(v) Electricity System IPS South
(vi) Electricity System IPS Urals
(vii) Electricity System IPS Volga

For the sake of clarity, the geographical extent of the above mentioned electricity systems is provided in Figure 2-1 below.


Figure 2-1: Integrated Power Systems in Russia
In the following subchapters the current state and future development of all seven IPS is provided with regard to:

- Historic power generation and transmission;
- Demand analysis and forecast;
- Analysis of investment programs.

It is noted that above mentioned structure remains unaltered throughout the analysis of the seven IPS.
2.1 Electricity System IPS Center

2.1.1 Historic Power Generation and Transmission

Due to the densely populated most western part of Russia (see Figure 2-1) the IPS Center is one of the largest integrated power systems in Russia pertaining to the installed capacity of power plants. The overall capacity of all integrated power plants excluding plants which operate in isolated networks amounted to roughly 45.8 GW in 2009.

In order to provide a more detailed insight, Figure 2-2 presents the structure of the power plants operating in IPS Center according to their power plant technology.

As shown in Figure 2-2 the share of conventional thermal power plants (TPP) amounts to 70% (32.2 GW) whereas nuclear power plants (NPP) amount to almost one third (11.8 GW) of installed capacity in IPS Center. Renewable energy sources (RES) in IPS Center are only represented by hydropower generation which plays however a comparatively minor role in electricity supply when compared to the other IPS in Russia.

Concerning overall power generation approximately 230,000 GWh were produced in IPS Center in 2007. Such as for the installed capacity, thermal power plants accounted for the lion’s share by supplying roughly two thirds (64%) of generated power, followed by the base load operated nuclear power plants which amounted to a share of 35% in power generation.

![Figure 2-2: (a) Installed Capacity and (b) Power Generation in IPS Center](image)

Regarding the electricity transmission infrastructure in the territorial electricity systems, Russia’s grids are divided into several high voltage classes in order to support the integral functioning of the overall Unified Electricity System (UES) operated by the national system operator.

Hence, the high-voltage transmission grids in the European part of Russia are mainly formed by 500 to 750 kV transmission lines, such as in the IPS Center.

By contrast 1,150 kV transmission lines exist most commonly in the Asian part of Russia due to the long distances which have to be bypassed. However, 500 kV grids are operated as well in these regions.

Generally speaking, Russia’s high-voltage transmission systems serve as important backbone of the country’s electricity supply as their main objective is:
• Provision of reliable supply of the integrated power plants’ output to the distribution network substations;
• Linking of the overall power supplies due to the joint operation of all seven Integrated Power Systems (IPS) within the UES which is controlled centrally by the national system operator JSC “SO-CDU of UES”;
• Electricity exports and imports to other IPS’ as well as to electricity systems of neighbouring countries.

Bearing in mind above mentioned high-voltage classes, the transmission lines as presented in Table 2-1 are operated within IPS Center. For the sake of completeness Table 2-1 furthermore provides an insight into the installed capacity of transformers of different voltage classes operating at step-down substations within IPS Center.

<table>
<thead>
<tr>
<th>Length of transmissions grids [thousands km]</th>
</tr>
</thead>
<tbody>
<tr>
<td>IPS</td>
</tr>
<tr>
<td>-----</td>
</tr>
<tr>
<td>Center</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Transformer capacity of different voltage classes at step-down substations [thousand MVA]</th>
</tr>
</thead>
<tbody>
<tr>
<td>IPS</td>
</tr>
<tr>
<td>-----</td>
</tr>
<tr>
<td>Center</td>
</tr>
</tbody>
</table>

With regard to historic electricity losses, the most recent official figure was published in 2006 and amounted to 8.7% of the overall electricity output within the Russian UES. The corresponding value adds up to 21,345 GWh in total whereas the largest share of the electricity losses was caused by variable load losses. When focusing in particular on electricity losses occurred in the currently assessed IPS Center such losses amounted to 5,333 GWh in total. Accordingly, this value results in the comparatively highest electricity losses among all seven IPS analysed in this present study.

2.1.2 Demand Analysis and Forecast
After having analysed the historic power generation and transmission of the IPS Center this subchapter deals with most recent demand figures and forecasts in order to reliably estimate future energy demand in the analysed electricity system. Afterwards respective investment programs are assessed in a subsequent step in order to aim for an overall demand supply balancing.
Hence, a comprehensive electricity demand analysis was carried out which was based on official data being publicly available by the national system operator JSC “SO-CDU of UES” for each Russian IPS. The analysis’ results are summarised in a detailed fact sheet which is depicted in Figure 2-3 thereafter.

**Figure 2-3: Demand Analysis and Forecast of IPS Center**
Figure 2-3 is structured as follows: It generally presents hourly load and generation curves which occurred in the IPS Center during an exemplary working day in Summer and Winter 2009.

Both charts on top show the hourly load curve which is covered by the respective hourly generation curve provided directly below. It is obvious that the overall load in summer tends to be lower than in winter where for instance the use of additional heating appliances increases the overall electricity demand. Furthermore two peaks may be observed throughout the daily pattern: the first in the morning at around 9 a.m. and the second peak in the early evening at around 6 p.m.

In addition, an insight into the overall import/export pattern of IPS Center is also presented in the lower half of Figure 2-3. Correspondingly, IPS Center operates as net exporting system, i.e. overall power generation is higher than the occurring load. Moreover, power exports generally increase during winter time due to the higher consumer’s demand in conjunction with a higher load factor of the operated power plants.

Further on, special emphasis is placed on both charts at the bottom of Figure 2-3. The development of the overall electricity demand in IPS Center is provided therein which has been based on official data provided by the Energy Forecasting Agency (EFA), Moscow. Accordingly, an average annual growth rate of 2.7% in the IPS Center was projected for the period from 2009 until 2020. This value hence serves as important input parameter for the simulation of the future electricity demand in the respective electricity system and is therefore incorporated into the developed Power System Simulation Model, see Chapter 3.2.

Moreover, cross-border imports and exports are also provided in the bottom charts implying that the IPS Center remains a stable net exporting grid throughout the period under consideration, both to other Russian IPS as well as to neighbouring electricity systems.

Having thoroughly analysed the current and future electricity demand in the IPS Center the following subchapter accordingly deals with the electricity supply side in order to adequately cover the forecasted demand.

2.1.3 Analysis of Investment Programs

In order to sufficiently cover the expected electricity demand in IPS Center as outlined in Chapter 2.1.2, new generation capacities have to come online within the electricity system.

In order to schedule their implementation, both the expected increase of the peak load representing the future electricity demand and the retirement schedule of already operating power plants have to be considered. Their development for the IPS Center for the period from 2009 until 2020 is presented in Figure 2-4. The figure has been derived by analyzing official investment programs in Russia being published by EFA. On the left-hand side, it can be seen that the currently installed generation capacities cannot cover the expected peak demand in the system beyond the year 2013.

It is moreover noted that the dashed line above the peak demand curve in Figure 2-4 (a) includes an additional 10% security margin in order to account for potential uncertainties. With reference to the expected peak demand including the security margin, new generation capacities would already be required by 2012 under consideration of the envisaged power plant retirement schedule.

Expected power generation bottlenecks may thus only be avoided by additional investments in new constructions of generation facilities which are described subsequently.

Accordingly, Figure 2-4 (b) summarises the official capacity expansion plan for the IPS Center.

**Side Note on Russia’s Investment Program:**
According to the official investment program published by EFA, major investments will be undertaken by generating companies and power grid companies in line with strongly required support by federal funds.

The currently approved investment plan has announced the overall sum of 11,616.3 billion rubles (~ 295 billion EUR) for the years 2006 to 2020 for investments in the construction of new power plants. Moreover, capital requirements for investments in electricity infrastructure projects, such as the construction of new transmission lines, were estimated at 9,078.3 billion rubles (~ 231 billion EUR) in total.

Continuing with the analysis of Figure 2-4 the implementation of above the mentioned investment program results in a capacity increase of 10 GW until 2013 (22 GW until 2020) in the IPS Center in order to avoid potential bottlenecks and to meet the consumer’s demand regarding power supply security. In view of new power plant technologies to be implemented, capacity additions of renewable energy sources which amount to 1 GW in total until 2020 are envisaged.

Summing up, the herein presented capacity expansion plan forms the basis for the simulation of the foreseen energy generation mix in the IPS Center between 2009 and 2020. Consequently, the corresponding carbon emission factors will be calculated by applying the data analysed in this present chapter as input. In this context it is further noted that the underlying methodology for the simulation of the future energy supply scenario in IPS Center and its corresponding carbon emission factors is described in detail in Chapter 3.
2.2 Electricity System IPS East

2.2.1 Historic Power Generation and Transmission

The eastern electricity system of Russia can be characterized as the part which has relatively low density in population (see Figure 2-1). This fact also reflects the lack of urban agglomeration, the scarcity of industrial ventures and consequently shows less installed capacity of power plants than in other electricity systems. The overall capacity of all integrated power plants within the IPS, hence excluding all plants which operate in isolated networks, amounted to only 7 GW in 2009.

In order to provide a more detailed insight Figure 2-5 provides the structure of the power plants operating in IPS East subdivided into power plant technology.

In this figure it can be seen that the share of conventional thermal power plants amounts to 51% (3.5 GW) whereas nuclear power may be disregarded as it amounts to less than 1 GW (0.7%) of installed capacity in IPS East. Furthermore, hydropower generation forms the second backbone in IPS East as its share in installed capacity amounts to 3.3 GW (48%).

Concerning overall power generation approximately 40,000 GWh were produced in IPS East in 2007. As for the installed capacity, thermal power plants accounted for the largest part (64%) of generated power, followed by the hydro power stations at a rate of 33% (13,200 GWh).

Nuclear power is ranked third as it only amounts to 3% of the system’s power generation.

![Figure 2-5: (a) Installed Capacity and (b) Power Generation in IPS East](image)

The high-voltage transmission grids in the IPS East are mainly formed by 110 kV to 500 kV transmission lines with the ones of 230 kV having the largest extent.

In opposition to that transmission lines in the range of 750 kV and 1,150 kV are not operated. This may be explained primarily by geographical circumstances and the few metropolitan areas.

For the sake of completeness Table 2-2 furthermore provides an insight into the installed capacity of transformers of different voltage classes operating at step-down substations within IPS East.
Table 2-2: Length of Transmission Grids and Transformer Capacities in IPS East

<table>
<thead>
<tr>
<th>IPS</th>
<th>110 kV</th>
<th>220 kV</th>
<th>330 kV</th>
<th>500 kV</th>
<th>750 kV</th>
<th>1150 kV</th>
<th>TOTAL</th>
</tr>
</thead>
<tbody>
<tr>
<td>East</td>
<td>8.3</td>
<td>10.5</td>
<td>-</td>
<td>3.0</td>
<td>-</td>
<td>-</td>
<td>21.7</td>
</tr>
</tbody>
</table>

Transformer capacity of different voltage classes at step-down substations [thousand MVA]

<table>
<thead>
<tr>
<th>IPS</th>
<th>110 kV</th>
<th>220 kV</th>
<th>330 kV</th>
<th>400 kV</th>
<th>500 kV</th>
<th>750 kV</th>
<th>TOTAL</th>
</tr>
</thead>
<tbody>
<tr>
<td>East</td>
<td>7.0</td>
<td>6.6</td>
<td>-</td>
<td>-</td>
<td>4.5</td>
<td>-</td>
<td>18.2</td>
</tr>
</tbody>
</table>

With regard to historic electricity losses, the most recent official figure was published in 2006 and amounted to 8.7% of overall electricity output within the Russian UES. The corresponding value accordingly added up to 21,345 GWh in total whereas the largest share of the electricity losses was caused by variable load losses. Compared to the overall losses of 21,435 GWh of the Russian UES in the year 2006 (latest available figure, see also Chapter 2.1.2) the electricity losses occurred in the same period in IPS East amounted to only 403 GWh.

2.2.2 Demand Analysis and Forecast

After having analysed the historic power generation and transmission of the IPS East the following subchapter deals with most recent demand figures and forecasts in order to reliably estimate future energy demand in the analysed electricity system. Afterwards respective investment programs will be assessed in a subsequent step in order to aim for an overall demand supply balancing.

Hence, a comprehensive electricity demand analysis was carried out which is based on official data being publicly available by the national system operator JSC “SO-CDU of UES” for each Russian IPS. The analysis’ results are summarised in a detailed fact sheet which is depicted in Figure 2-6 thereinafter.
Figure 2-6: Demand Analysis and Forecast of IPS East
Figure 2-6 is structured as follows: It generally presents hourly load and generation curves which occurred in the IPS East during an exemplary working day in Summer and Winter 2009.

The uppermost chart of each season shows the hourly load curve which is covered by the respective hourly generation curve provided directly below. It is obvious that the overall load in summer tends to be lower than in winter caused by additional heating appliances which increase the overall electricity demand. Furthermore in winter three peaks may be observed throughout the daily pattern, the first during the night at around 3 a.m., the next peak at midday and the third one around 3 p.m.

In addition, an insight into the overall import/export pattern of IPS East is also presented in the lower half of Figure 2-6. According to the figures power exports generally increase during winter time due to the higher consumer’s demand in conjunction with a higher load factor of the operated power plants.

Further on, special emphasis is placed on both charts at the bottom of Figure 2-6. The development of the overall electricity demand in IPS East is provided therein which has been based on official data provided by EFA. Consequently, an average annual growth rate of 2.9% in the IPS East was projected for the period from 2009 until 2020. This value is considered as an important input parameter for the simulation of the future electricity demand in the respective electricity system. It is thus incorporated into the developed Power System Simulation Model, see Chapter 3.2.

The cross-border imports and exports in the bottom chart indicate that the IPS East is expected to constitute an increasing net exporting grid throughout the period under consideration. Between 2009 and 2013 a constant growth can be observed, followed by a sudden rise between 2014 and 2015. From then on the cross-border exports are expected to remain stable with some little growth.

Having thoroughly analysed the current and future electricity demand in the IPS East the following subchapter accordingly deals with the electricity supply side in order to adequately cover the forecasted demand.

### 2.2.3 Analysis of Investment Programs

In order to sufficiently cover the expected electricity demand in IPS East as outlined in Chapter 2.2.2 new generation capacities have to come online within the electricity system.

In doing so both the expected increase of the peak load representing the future electricity demand and the retirement schedule of already operating power plants have to be considered. Figure 2-7 has been derived by analyzing official investment programs in Russia being published by EFA. The figure presents both developments for the IPS East for the period from 2009 until 2020. It can be seen that the currently installed generation capacities cannot cover the expected peak demand in the system already beyond 2013.

For the sake of clarity it is moreover noted that the dashed line above the peak demand curve in Figure 2-7 (a) includes an additional 10% security margin in order to account for potential uncertainties. With reference to the expected peak demand including the security margin, new generation capacities would already be required by 2012 under consideration of the envisaged power plant retirement schedule.

Expected power generation bottlenecks may thus only be avoided by additional investments in new constructions of generation facilities which are described subsequently.
Figure 2-7: (a) Demand Supply Balancing and (b) Capacity Expansion Plan for IPS East

Figure 2-7 (b) hence summarises the official capacity expansion plan for the IPS East.

Accordingly, the implementation of above mentioned investment program results in a capacity increase of 1 GW until 2012 (6 GW until 2020) in the IPS East in order to avoid potential bottlenecks and to meet the consumer’s demand regarding power supply security. Capacity additions of conventional thermal plant constitute the largest share, implying some 3.6 GW until 2020.

Summing up, the herein presented capacity expansion plan forms the basis for the simulation of the foreseen energy mix in the IPS East between 2009 and 2020. Accordingly, the corresponding carbon emission factors will be calculated by applying the data analysed in this present chapter as input. In this context it is further noted that the underlying methodology for the simulation of the future energy supply scenario in IPS East and its corresponding carbon emission factors will be described in detail in Chapter 3.
2.3 Electricity System IPS North West

2.3.1 Historic Power Generation and Transmission

The name of the IPS North West already describes the location of this electricity system within Russia. There is a high density in population, especially in the agglomeration of St. Yet, the system is of comparatively average size and therefore its overall capacity of all integrated power plants amounted to 17.9 GW in 2009. Again, plants which operate in isolated networks are excluded.

In order to provide a more detailed insight Figure 2-8 provides the structure of the power plants operating in IPS North West according to the different power plant technology.

The share of conventional thermal power plants amounts to 52% (9.2 GW), followed by nuclear power (32%) and hydropower plants (16%) with an installed capacity of 5.8 GW and 2.8 GW respectively.

In terms of the overall power generation approximately 83,300 GWh were produced in IPS North West in 2007. Conventional thermal power plants generated the largest share of 45% (37,600 GWh) while base load operating nuclear power plant operated almost equally with 33,800 GWh of total power output. The lowest contribution stemmed from hydropower plants contributing to some 14% (11,900 GWh) of grid power output.

![Figure 2-8: (a) Installed Capacity and (b) Power Generation in IPS North West](image)

High-voltage transmission grids in Northwest Russia mainly consist of transmission lines in the range of 110 kV to 330 kV. In total, the length of the transmission lines amounts to 40,400 km which is rather average when compared to other systems.

Bearing in mind the high-voltage classes as determined in Chapter 2.1.1, the following transmission lines are operated within IPS North West. Table 2-3 furthermore provides an insight into the installed capacity of transformers of different voltage classes operating at step-down substations within IPS North West.
Table 2-3: Length of Transmission Grids and Transformer Capacities in IPS North West

<table>
<thead>
<tr>
<th>IPS</th>
<th>110 kV</th>
<th>220 kV</th>
<th>330 kV</th>
<th>500 kV</th>
<th>750 kV</th>
<th>1150 kV</th>
<th>TOTAL</th>
</tr>
</thead>
<tbody>
<tr>
<td>North West</td>
<td>28,9</td>
<td>5,4</td>
<td>5,7</td>
<td>0,1</td>
<td>0,4</td>
<td>-</td>
<td>40,4</td>
</tr>
</tbody>
</table>

Transformer capacity of different voltage classes at step-down substations [thousand MVA]

<table>
<thead>
<tr>
<th>IPS</th>
<th>110 kV</th>
<th>220 kV</th>
<th>330 kV</th>
<th>400 kV</th>
<th>500 kV</th>
<th>750 kV</th>
<th>TOTAL</th>
</tr>
</thead>
<tbody>
<tr>
<td>North West</td>
<td>25,1</td>
<td>6,9</td>
<td>17,5</td>
<td>2,6</td>
<td>-</td>
<td>2,0</td>
<td>54,1</td>
</tr>
</tbody>
</table>

Regarding electricity losses the most recent official figure was published in 2006 and amounted to 8.7% of overall electricity output within the Russian UES. The corresponding value accordingly added up to 21,345 GWh in total whereas the largest share of the electricity losses was caused by variable load losses. However, when focusing in particular on electricity losses occurred in the currently assessed IPS North West such losses amounted to 2,932 GWh in total.

2.3.2 Demand Analysis and Forecast

After having analysed the historic power generation and transmission of the IPS East the following subchapter deals with most recent demand figures and forecasts in order to reliably estimate future energy demand in the analysed electricity system. Afterwards corresponding investment programs will be assessed in a subsequent step in order to aim for an overall demand supply balancing.

For this reason a comprehensive electricity demand analysis was carried out which is based on official data being released to the public by the national system operator JSC “SO-CDU of UES” for each Russian IPS. The analysis’ results are summed up in a detailed fact sheet which is depicted in thereinafter.
Figure 2-9: Demand Analysis and Forecast of IPS North West
Figure 2-9 is structured as follows: It generally presents hourly load and generation curves which occurred in the IPS North West during an exemplary working day in summer and winter 2009. The topmost chart of each season shows the hourly load curve which is covered by the corresponding hourly generation curve provided directly below. It is obvious that the overall load in summer tends to be lower than in winter. Accordingly, in winter one peak may be observed throughout the daily pattern, occurring around midday between 10 and 11 a.m. In summer a similar development of the curve may be observed.

In addition, an insight into the overall import/export pattern of IPS North West is also presented in the lower half of Figure 2-9. IPS North West reveals considerable fluctuations, however, still operating as a net exporting system. Moreover, power exports generally increase during winter time due to the higher consumer’s demand in conjunction with a higher load factor of the operated power plants.

Further on, special emphasis is placed on both charts at the bottom of Figure 2-9. The development of the overall electricity demand in IPS North West is provided therein which has been based on official data provided by EFA. Accordingly, an average annual growth rate of 2.3% in the IPS North West was projected for the period under consideration. This value is considered as an important input parameter for the simulation of the future electricity demand in the respective electricity system. It is incorporated into the developed Power System Simulation Model, see Chapter 3.2.

Moreover, an overview on the development of cross-border exports are also provided in the bottom charts implying that IPS North West remains a stable net exporting grid to neighbouring electricity systems.

Having thoroughly analysed the current and future electricity demand in the IPS North West hitherto, the following subchapter accordingly deals with the electricity supply side in order to adequately cover the forecasted demand.

2.3.3 Analysis of Investment Programs

In order to sufficiently cover the expected electricity demand in IPS North West as outlined previously, new generation capacities have to come online within the electricity system. In doing so both the expected increase of the peak load representing the future electricity demand and the retirement schedule of already operating power plants have to be considered. Accordingly, Figure 2-10 has been derived by analyzing official investment programs in Russia being published by EFA. The figure presents both developments for the IPS North West for the period from 2009 until 2020. It can be seen that the currently installed generation capacities cannot cover the expected peak demand in the system beyond the year 2014.

For the sake of clarity it is moreover noted that the dashed line above the peak demand curve in Figure 2-10 (a) includes an additional 10% security margin in order to account for potential uncertainties. With reference to the expected peak demand including the security margin, new generation capacities would already be required by 2013 under consideration of the envisaged power plant retirement schedule.

Expected power generation bottlenecks may thus only be avoided by additional investments in new constructions of generation facilities which are described subsequently.
Figure 2-10 (a) Demand Supply Balancing and (b) Capacity Expansion Plan for IPS North West

Figure 2-10 (b) summarises the official capacity expansion plan for the IPS North West. Regarding further background information of above mentioned investment program, see also the respective side note included in Chapter 2.1.3.

Continuing with the analysis of Figure 2-10 the implementation of above mentioned investment program results in a capacity increase of 3.7 GW until 2014 (10 GW until 2020) in the IPS North West in order to avoid potential bottlenecks in power supply. Furthermore, new constructions of CHP power plants adding up to a total installed capacity of 3.2 GW until 2020 are planned in the respective system.

Summing up, the herein presented capacity expansion plan forms the basis for the simulation of the foreseen energy mix in the IPS North West between 2009 and 2020. Accordingly, the corresponding carbon emission factors will be calculated by applying the data analysed in this present chapter as input. In this context it is further noted that the underlying methodology for the simulation of the future energy supply scenario in IPS North West and its corresponding carbon emission factors will be described in detail in Chapter 3.
2.4 Electricity System IPS Siberia

2.4.1 Historic Power Generation and Transmission

IPS Siberia is large in size and has some agglomeration centres with areas of high population. At the same time there are extraordinary climate and geographical conditions. The overall capacity of all integrated power plants, thus excluding plants which operate in widely scattered isolated networks, amounted to roughly 36 GW in 2009.

In order to provide a more detailed insight Figure 2-11 provides the structure of the power plants operating in IPS Siberia according to power plant technology.

The lion’s share of installed capacity belongs to thermal power plants adding up to 52% (19.1 GW), followed by hydropower plants which form roughly 46% (16.5 GW) of installed capacity. Nuclear power plants being integrated in the IPS are only represented by marginal capacity as they account for just 0.5% (0.2 GW) in IPS Siberia.

In 2007 the power generation in IPS Siberia summed up to approximately 190,000 GWh. Hydropower plants contributed the largest share of generated power with 101,700 GWh in total, being followed by thermal power plants which amounted to 47% respectively. The actual power output of nuclear power plants was negligible.

Figure 2-11: (a) Installed Capacity and (b) Power Generation in IPS Siberia

Regarding electricity transmission infrastructure IPS Siberia bears some differences when compared to other electricity systems since the operation of transmission lines at lower high-voltage levels is more common than in the other Russian electricity systems.

Table 2-4 furthermore provides an insight into the installed capacity of transformers of different voltage classes operating at step-down substations within IPS Siberia.
### Table 2-4: Length of Transmission Grids and Transformer Capacities in IPS Siberia

<table>
<thead>
<tr>
<th>Length of transmissions grids [thousands km]</th>
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<tbody>
<tr>
<td>IPS</td>
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<tr>
<td>------</td>
</tr>
<tr>
<td>Siberia</td>
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</tbody>
</table>

<table>
<thead>
<tr>
<th>Transformer capacity of different voltage classes at step-down substations [thousand MVA]</th>
</tr>
</thead>
<tbody>
<tr>
<td>IPS</td>
</tr>
<tr>
<td>------</td>
</tr>
<tr>
<td>Siberia</td>
</tr>
</tbody>
</table>

Regarding overall electricity losses in the IPS Siberia, the most recent official figure was published in 2006 and amounted to 8.7% of overall electricity output within the Russian UES. However, when focusing in particular on electricity losses occurred in the currently assessed IPS Siberia such losses amounted to 3,241 GWh in total resulting in comparatively high losses among the seven IPS.

#### 2.4.2 Demand Analysis and Forecast

After having analysed the power generation and transmission capabilities of the IPS Siberia the following subchapter deals with most recent demand figures and forecasts in order to reliably estimate future energy demand in the analysed electricity system. Afterwards respective investment programs will be assessed in a subsequent step in order to aim for an overall demand supply balancing.

Hence, a comprehensive electricity demand analysis was carried out which is based on official data being publicly available by the national system operator JSC “SO-CDU of UES” for each Russian IPS. The analysis’ results are summarised in a detailed fact sheet which is depicted in Figure 2-12 thereinafter.
Figure 2-12: Demand Analysis and Forecast of IPS Siberia
Accordingly, Figure 2-12 is structured as follows: It generally presents hourly load and generation curves which occurred in the IPS Siberia during an exemplary working day in summer and winter 2009.

The uppermost charts show the hourly load curve which is covered by the respective hourly generation curve provided directly below. It is obvious that the overall load in summer is significantly lower than in winter due to additional heating appliances which increase the overall electricity demand. Accordingly, in the exemplary winter day two peaks occur: the first at 6 a.m. in the morning and the second at around 3 p.m. in the afternoon. However there are hardly any considerable fluctuations throughout the day time.

In addition, an insight into the overall import/export pattern of IPS Siberia is also presented in the lower half of Figure 2-12. Correspondingly, IPS Siberia is to be considered as a net importing system, as the occurring load is higher than the overall power generation. Moreover, power exports clearly increase during winter time due to the higher consumer’s demand.

Further on, special emphasis is placed on both charts at the bottom of Figure 2-12.

The development of the overall electricity demand in IPS Siberia is provided therein which has been based on official data provided by EFA. Accordingly, an average annual growth rate of 2.3% in the IPS Siberia was projected for the period from 2009 until 2020. This value hence serves as important input parameter for the simulation of the future electricity demand in the respective electricity system and is therefore incorporated into the developed Power System Simulation Model, see Chapter 3.2.

Moreover, cross-border imports and exports are also provided in the bottom charts implying that IPS Siberia develops as exporting system to neighbouring grids starting late in 2018 though.

Having thoroughly analysed the current and future electricity demand in the IPS Siberia the following subchapter accordingly deals with the electricity supply side in order to adequately cover the forecasted demand.

2.4.3 Analysis of Investment Programs

In order to sufficiently cover the expected electricity demand in IPS Siberia as outlined in Chapter 2.4.2 new generation capacities have to come online within the electricity system.

In doing so both the expected increase of the peak load representing the future electricity demand and the retirement schedule of already operating power plants have to be considered. Accordingly, Figure 2-13 has been derived by analyzing official investment programs in Russia being published by EFA. The figure presents both developments for the IPS Siberia for the period from 2009 until 2020. It can be seen that the currently installed generation capacities cannot cover the expected peak demand in the system beyond the year 2015.

For the sake of clarity it is moreover noted that the dashed line above the peak demand curve in Figure 2-13 (a) includes an additional 10% security margin in order to account for potential uncertainties. With reference to the expected peak demand including the security margin, new generation capacities would already be required by 2012 under consideration of the envisaged power plant retirement schedule.

Expected power generation bottlenecks may thus only be avoided by additional investments in new constructions of generation facilities which are described subsequently.
Figure 2-13 (b) summarises the official capacity expansion plan for the IPS Siberia.

Regarding Figure 2-13 (b) the implementation of above mentioned investment program results in a capacity increase of 31 GW until 2020 in total in order to avoid potential bottlenecks and to meet the consumer’s demand regarding power supply security. Hence, renewable energy sources are not represented with in the capacity expansion plan besides new hydropower plants adding up to some 9.6 GW of additionally installed capacity until 2020.

Summing up, the herein presented capacity expansion plan forms the basis for the simulation of the foreseen energy mix in the IPS Siberia between 2009 and 2020. Accordingly, the corresponding carbon emission factors will be calculated by applying the data analysed in this present chapter as input. In this context it is further noted that the underlying methodology for the simulation of the future energy supply scenario in IPS Siberia and its corresponding carbon emission factors will be described in detail in Chapter 3.
2.5 Electricity System IPS South

2.5.1 Historic Power Generation and Transmission

The IPS South is located in the most south-western part of Russia covering mainly the Caucasus and constitutes one of the smallest integrated power systems in Russia pertaining to its overall installed capacity. Consequently, overall capacity of all integrated power plants within the system amounted to roughly 16.5 GW in 2009.

In order to provide a more detailed insight Figure 2-14 provides the structure of all power plants jointly operating in IPS South according to power plant technology.

Hence, the share of conventional thermal power plants (TPP) amounts to 54% (9 GW) whereas hydropower plants amount to just over one third (5.6 GW) of installed capacity. Compared to the other IPS in Russia nuclear power plays a comparatively small role amounting to an installed capacity of just 2 GW in total.

Concerning overall power generation approximately 67,000 GWh were produced in IPS South in 2007. As for the installed capacity thermal power plants accounted for the majority by supplying more than half (61%) of the generated power followed by hydropower generation (28%) and nuclear power generation (11%) at last.

![Figure 2-14: (a) Installed Capacity and (b) Power Generation in IPS South](image)

Regarding the electricity transmission infrastructure operating in IPS South the same high-voltage classes as already outlined in Chapter 2.1.1 exist.

Concerning the high-voltage classification the following transmission lines are operated within IPS South. Moreover, Table 2-5 provides an insight into the installed capacity of transformers of different voltage classes operating at step-down substations within IPS South.
Regarding overall electricity losses in the IPS South the corresponding value of electricity losses in Russia added up to 21,345 GWh in total in 2006. However, when focusing in particular on electricity losses occurred in the currently assessed IPS South such losses amounted to 2,025 GWh only. These losses accordingly present a rather low value having a part of less than 10% in the aggregated electricity losses of Russia.

### 2.5.2 Demand Analysis and Forecast

After having analysed historic power generation and transmission of IPS South the following subchapter deals with most recent demand figures and forecasts in order to reliably estimate future energy demand in the analysed electricity system.

Afterwards respective investment programs will be assessed in a subsequent step in Chapter 2.5.3 in order to aim for an overall demand supply balancing.

Hence, a comprehensive electricity demand analysis was carried out which is based on official data being publicly available by the national system operator JSC “SO-CDU of UES” for each Russian IPS. The analysis’ results are summarised in a detailed fact sheet which is depicted in Figure 2-15 thereinafter.
Figure 2-15: Demand Analysis and Forecast of IPS South
Accordingly, Figure 2-15 is structured as follows: It generally presents hourly load and generation curves which occurred in the IPS South during an exemplary working day in summer and winter 2009.

Both charts in the top show the hourly load curve which is covered by the respective hourly generation curve provided directly below. Hence, overall load in summer tends to be lower than in winter when overall electricity demand is increased.

Furthermore, two peak loads may be observed throughout the typically daily pattern in winter, the first in the morning at around 10 a.m. and the second in early evening at around 6 p.m.

In addition, an insight into the overall import/export pattern of IPS South is also presented in the lower half of Figure 2-15. Accordingly, IPS South operates as net importing system, i.e. the occurring load is higher than overall power generation. It is further obvious that power imports increase during summer due to the higher consumer's demand, e.g. by increased utilisation of air-conditioning units.

Special emphasis is also placed on both charts at the bottom of Figure 2-15.

The development of overall electricity demand in IPS South is provided therein which has been based on official data provided by EFA. Accordingly, an average annual growth rate of roughly 3% in IPS South was projected for the period from 2009 until 2020. This value hence serves as important input parameter for the simulation of the future electricity demand in the respective electricity system and is therefore incorporated into the developed Power System Simulation Model, see Chapter 3.2.

Moreover, cross-border imports and exports are also provided in the bottom charts implying that the IPS South operates as net exporting grid towards foreign electricity systems.

Having thoroughly analysed the current and future electricity demand in the IPS South the following subchapter accordingly deals with the electricity supply side in order to adequately cover the forecasted demand.

2.5.3 Analysis of Investment Programs

In order to sufficiently cover the expected electricity demand in IPS South as outlined previously new generation capacities have to come online within the electricity system.

In doing so both the expected increase of the peak load representing the future electricity demand and the retirement schedule of already operating power plants have to be considered simultaneously. Figure 2-16 has been derived by analyzing official investment programs in Russia being published by EFA. The figure thus presents both developments for IPS South for the period from 2009 until 2020. It can be seen that the currently installed generation capacities cannot cover the expected peak demand in the region beyond the year 2014.

By contrast new generation capacities would already be required by 2013 when comparing to the expected peak demand including the security margin, see dashed line in Figure 2-16 (a).

Expected power generation bottlenecks may thus only be avoided by additional investments in new constructions of generation facilities which are described subsequently.
Figure 2-16: (a) Demand Supply Balancing and (b) Capacity Expansion Plan for IPS South

Figure 2-16 (b) summarises the official capacity expansion plan for the IPS South. In this context reference is made to the side note dealing with additional background information of the official Russian investment program which is included in Chapter 2.1.3.

Continuing with the analysis of Figure 2-16 (b) the implementation of above mentioned investment program in IPS South results in a capacity increase of almost 4 GW until 2014 (8.75 GW until 2020) in order to avoid potential bottlenecks and to meet the consumer’s demand. Hence especially combined cycle power plants are expected to replace the retired power plants whose capacity addition amounts to 4.2 GW until 2020.

Summing up, the herein presented capacity expansion plan forms the basis for the simulation of the foreseen energy mix in the IPS South between 2009 and 2020. The corresponding carbon emission factors will be calculated by applying the data analysed in this present chapter as input to the Power System Simulation Model. In this context it is further noted that the underlying methodology for the simulation of the future energy supply scenario in IPS South and its corresponding carbon emission factors will be described in detail in Chapter 3.
2.6 Electricity System IPS Urals

2.6.1 Historic Power Generation and Transmission

The IPS Urals is located in central Russia its most eastern European part. Together with IPS Center and IPS Siberia, the IPS Urals is one of the largest integrated power systems in Russia with view to overall installed capacity. Consequently, overall capacity of all integrated power plants within the system amounted to approximately 40 GW in 2009.

In order to provide a more detailed insight Figure 2-17 provides the structure of all power plants which operate in IPS South according to power plant technology. Hence, the structure of installed capacity differs significantly compared to other Russian electricity systems. The share of conventional thermal power plants thus amounts to 94% (37 GW) whereas hydropower and nuclear plants only play a marginal role in terms of installed capacity. Hydropower adds up to 1.8 GW and nuclear power to 0.6 GW in total.

Regarding power generation some 222,500 GWh were produced in the IPS Urals. Accordingly, thermal power plants accounted for almost all (96%) of the generated power, followed by hydropower and nuclear power generation which supply roughly 2% of overall generated power each.

![Figure 2-17: (a) Installed Capacity and (b) Power Generation in IPS Urals](image)

Regarding the electricity transmission infrastructure operating in IPS Urals the high-voltage classification as already determined in Chapter 2.1.1 is in place.

Hence, the following transmission lines are operated within IPS Urals. Moreover, Table 2-6 provides an insight into the installed capacity of transformers of different voltage classes operating at step-down substations within IPS Urals.
Table 2-6: Length of Transmission Grids and Transformer Capacities in IPS Urals

<table>
<thead>
<tr>
<th>IPS</th>
<th>110 kV</th>
<th>220 kV</th>
<th>330 kV</th>
<th>500 kV</th>
<th>750 kV</th>
<th>1150 kV</th>
<th>TOTAL</th>
</tr>
</thead>
<tbody>
<tr>
<td>Urals</td>
<td>76.0</td>
<td>19.8</td>
<td>-</td>
<td>11.6</td>
<td>-</td>
<td>0.1</td>
<td>107.5</td>
</tr>
</tbody>
</table>

Transformer capacity of different voltage classes at step-down substations [thousand MVA]

<table>
<thead>
<tr>
<th>IPS</th>
<th>110 kV</th>
<th>220 kV</th>
<th>330 kV</th>
<th>400 kV</th>
<th>500 kV</th>
<th>750 kV</th>
<th>TOTAL</th>
</tr>
</thead>
<tbody>
<tr>
<td>Urals</td>
<td>77.4</td>
<td>45.3</td>
<td>-</td>
<td>-</td>
<td>34.6</td>
<td>-</td>
<td>157.3</td>
</tr>
</tbody>
</table>

As already done for the other electricity systems a brief overview concerning overall electricity losses in the IPS Urals is provided.

According to Chapter 2.1 the corresponding value of electricity losses added up to 21,345 GWh in total in 2006.

However, when focusing in particular on electricity losses occurred in the currently assessed IPS Urals such losses amounted to 2,562 GWh. These losses accordingly represent an average value compared with the other IPS, having a part of roughly 12% within the aggregated electricity losses of Russia.

2.6.2 Demand Analysis and Forecast

The following subchapter accordingly deals with most recent demand figures and forecasts of the IPS Urals in order to reliably estimate future energy demand in the analysed electricity system.

Afterwards respective investment programs will be assessed in a subsequent step in Chapter 2.6.3 in order to aim for an overall demand supply balancing.

Hence, a comprehensive electricity demand analysis was carried out which is based on official data being publicly available by the national system operator JSC “SO-CDU of UES” for each Russian IPS. The analysis’ results are summarised in a detailed fact sheet which is depicted in Figure 2-18 thereinafter.
Figure 2-18: Demand Analysis and Forecast of IPS Urals
Figure 2-18 generally presents hourly load and generation curves which occurred in the IPS Urals during an exemplary working day in summer and winter 2009. Both charts in the top accordingly show the hourly load curve which is covered by the respective hourly generation curve provided directly below. Hence, overall load in summer is clearly lower than in winter when overall electricity demand is increased.

Furthermore, two peak loads may be observed throughout the exemplary load curve in winter, the first in the morning at around 7 a.m. and the second in late afternoon at around 4 p.m.

In addition, an insight into an exemplary import/export pattern of IPS Urals is also presented in the lower half of Figure 2-18. Accordingly, IPS Urals operated in both modes, i.e. importing power during early morning and exporting power during the rest of the day.

Special emphasis is also placed on both charts at the bottom of Figure 2-18. The development of overall electricity demand in IPS Urals is provided therein which has been based on official data provided by EFA. Accordingly, an average annual growth rate of roughly 2.2% in IPS Urals was projected for the period from 2009 until 2020. This value hence serves as important input parameter for the simulation of the future electricity demand in the respective electricity system and is therefore incorporated into the developed Power System Simulation Model, see Chapter 3.2.

Moreover, cross-border imports and exports are also provided in the bottom charts implying that the IPS Urals operates as stable net exporting system towards foreign electricity systems.

After having thoroughly analysed the current and future electricity demand in the IPS Urals the following subchapter accordingly deals with the electricity supply side in order to cover the forecasted demand.

2.6.3 Analysis of Investment Programs

In order to adequately cover the expected electricity demand in IPS Urals as outlined in the previous subchapter new generation capacities have to come online within the system. In doing so both the expected increase of the peak load representing the future electricity demand and the retirement schedule of already operating power plants have to be considered simultaneously. Figure 2-19 has been derived by analyzing official investment programs in Russia as already done previously for the other IPS. The figure thus presents both developments for IPS Urals for the period under consideration. It can be seen that the currently installed generation capacities cannot cover the expected peak demand in the region already beyond the year 2011. By contrast new generation capacities would already be required by today when comparing to the peak demand which includes a 10% security margin, see the dashed line in Figure 2-19 (a) accordingly.

Expected power generation shortages may only be avoided by urgently needed investments in new constructions of generation facilities within IPS Urals which are described in the following.
Accordingly, Figure 2-19 (b) summarises the official capacity expansion plan for the IPS Urals. However, reference is made in this context to the side note which deals with additional background information of the official Russian investment program included in Chapter 2.1.3.

Continuing with the analysis of Figure 2-19 (b), the implementation of above mentioned investment program in IPS Urals results in a capacity increase of almost 3 GW until 2011 and some considerable 28 GW until 2020 in order to bridge occurring power shortages. In doing so, in particular new combined cycle power plants (CCGT) are expected to replace already retired power plants. The overall capacity addition of such CCGTs in the IPS Urals accordingly amounts to more than 16 GW until 2020.

Summing up, the herein presented capacity expansion plan forms the basis for the simulation of the foreseen energy mix in the IPS Urals between 2009 and 2020. Accordingly, the corresponding carbon emission factors will be calculated by applying the data analysed in this present chapter as input to the Power System Simulation Model. It is furthermore noted that the underlying methodology for the simulation of the future energy supply scenario in IPS Urals and its corresponding carbon emission factors will be described in detail in Chapter 3.
2.7 Electricity System IPS Volga

2.7.1 Historic Power Generation and Transmission

Being stretched along the Volga region the correspondent IPS Volga is located in the southern part of European Russia. Overall capacity of the integrated power plants within the system amounted to almost 21 GW in 2009.

In order to give a more detailed insight Figure 2-20 provides the structure of all power plants which are integrated within IPS Volga according to power plant technology.

Hence, the share of conventional thermal power plants amounts to 47% (10 GW) whereas hydropower plants amount to just approximately one third (6.8 GW) of installed capacity. Nuclear power plants have a share of 20% in the installed capacity amounting to 4.1 GW in total.

Regarding overall power generation approximately 102,000 GWh were produced in IPS Volga in 2007. In the Volga IPS, TPPs accounted for 52% of total power generation, NPPs for 30% and the HPPs for 19% accordingly.

![Figure 2-20: (a) Installed Capacity and (b) Power Generation in IPS Volga](image)

Regarding the electricity transmission infrastructure operating in IPS Volga the same high-voltage classes as already outlined in Chapter 2.1.1 exist.

With reference to there mentioned high-voltage classification the following transmission lines are operated within IPS Volga. Moreover, Table 2-7 provides an insight into the installed capacity of transformers of different voltage classes operating at step-down substations within the Volga IPS.
Table 2-7: Length of Transmission Grids and Transformer Capacities in IPS Volga

<table>
<thead>
<tr>
<th>Length of transmissions grids [thousands km]</th>
</tr>
</thead>
<tbody>
<tr>
<td>IPS</td>
</tr>
<tr>
<td>------</td>
</tr>
<tr>
<td>Volga</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Transformer capacity of different voltage classes at step-down substations [thousand MVA]</th>
</tr>
</thead>
<tbody>
<tr>
<td>IPS</td>
</tr>
<tr>
<td>------</td>
</tr>
<tr>
<td>Volga</td>
</tr>
</tbody>
</table>

Regarding overall electricity losses in the IPS Volga the total value of electricity losses added up to 21,345 GWh in Russia in 2006.

However, when focusing in particular on electricity losses occurred in the currently assessed IPS Volga such losses amounted to 1,720 GWh only. Accordingly, these losses results in the lowest value among all seven IPS analysed within this study, thus having a part of only 8% in the aggregated electricity losses of total Russia.

2.7.2 Demand Analysis and Forecast

After having analysed historic power generation and transmission of IPS Volga the following subchapter deals with most recent demand figures and forecasts in order to reliably estimate future energy demand in the analysed electricity system.

Afterwards respective investment programs will be assessed in a subsequent step in Chapter 2.7.3 in order to aim for an overall demand supply balancing.

Hence, a comprehensive electricity demand analysis was carried out which is based on official data being publicly available by the national system operator JSC “SO-CDU of UES” for each Russian IPS. The analysis’ results are summarised in a detailed fact sheet which is depicted in Figure 2-21 thereinafter.
Figure 2-21: Demand Analysis and Forecast of IPS Volga
Figure 2-21 presents hourly load and generation curves which occurred in the IPS Volga during an exemplary working day in summer and winter 2009.

Both charts in the top show the hourly load curve which is covered by the respective hourly generation curve provided directly below. Hence, overall load in summer tends to be lower than in winter when overall electricity demand is increased.

Furthermore, two peak loads may be observed throughout the typically daily pattern in winter, the first in the morning at around 8 a.m. and the second in early evening at around 5 p.m.

In addition, an insight into the overall import/export pattern of IPS Volga is also presented in the lower half of Figure 2-21. IPS Volga operated as net exporting system on that exemplary day, i.e. overall power generation was higher than the occurring load. It is further on obvious that power exports increased during winter.

Special emphasis is also placed on both charts at the bottom of Figure 2-21. The development of overall electricity demand in IPS Volga is provided therein which has been based on official data provided by EFA. Accordingly, an average annual growth rate of approximately 2.5% in IPS Volga was projected for the period from 2009 until 2020. This value hence serves as important input parameter for the simulation of the future electricity demand in the respective electricity system and is therefore incorporated into the developed Power System Simulation Model, see Chapter 3.2.

Moreover, cross-border imports and/or exports are also provided in the bottom charts implying that the IPS Volga remains a stable net exporting grid towards foreign electricity systems.

Having thoroughly analysed the current and future electricity demand in the IPS Volga the following subchapter accordingly deals with the electricity supply side in order to adequately cover the forecasted demand.

2.7.3 Analysis of Investment Programs

In order to sufficiently cover the expected electricity demand in IPS Volga as outlined previously new generation capacities have to come online within the system.

In doing so both the expected increase of the peak load representing the future electricity demand and the retirement schedule of already operating power plants have to be considered simultaneously. Figure 2-22 has been derived by analyzing official investment programs in Russia being published by EFA. The figure thus presents both developments for IPS Volga for the period from 2009 until 2020. It can be seen that the currently installed generation capacities cannot cover the expected peak demand in the region beyond the year 2013.

By contrast new generation capacities would already be required before 2013 when comparing to the expected peak demand including the security margin, see the dashed line in Figure 2-22 (a).

Expected power generation bottlenecks may thus only be avoided by additional investments in new constructions of generation facilities which are described subsequently.
Continuing with the analysis of Figure 2-22 (b) the implementation of above mentioned investment program in IPS Volga results in a capacity increase of almost 1 GW until 2013 (~ 6 GW until 2020) in order to avoid potential bottlenecks in power supply:

For IPS Volga an increase of annual electricity demand of 31% in 2020 in total is officially forecasted. However, only 8% of capacity expansion will be added to grid within the same time period. Further on, no major imports are officially expected. This fact leads to significant load shedding since the installed power plants cannot cover the entirety of the load. Since the objective of this study is to provide a forecast of the most probable development of the carbon emission factors, LI took into account that the scheduled retirement of existing power units with a total rated power of 5.21 GW will be postponed for several years, of those 3.2 GW even until the end of the forecasting period in 2020. With this adaptation the operation of IPS Volga is feasible without major amounts of unserved load.

Summing up, the herein presented capacity expansion plan forms the basis for the simulation of the foreseen energy mix in the IPS Volga between 2009 and 2020. Accordingly, the corresponding carbon emission factors will be calculated by applying the data analysed in this present chapter as input to the Power System Simulation Model. In this context it is further noted that the underlying methodology for the simulation of the future energy supply scenario in IPS Volga and its corresponding carbon emission factors will be described in detail in Chapter 3.
3 CALCULATION METHODOLOGY

Having thoroughly analysed the required input data for the calculation of the carbon emission factors per IPS in the previous chapter, the calculation methodology of the developed Power System Simulation Model is presented hereinafter.

Since the calculated carbon emission factors should facilitate the determination of baseline scenarios for the future development of Joint Implementation project activities in Russia, their calculation has to comply with official UNFCCC requirements, i.e. in particular a publicly available calculation tool.

Consequently, the structure of this present chapter first outlines the applicable UNFCCC “Tool to calculate the emission factor for an electricity system”2 in its most recent version 02 dated 16 October 2009 and the applicable calculation method chosen by the Consultant.

Secondly, the setup and underlying calculation principles of the developed Power System Simulation Model, which was programmed in MS EXCEL, are explained in detail to provide a comprehensive insight into the assumptions and especially the processing of the analysed data.

It is noted that the subsequently described calculation methodology was presented to and approved by the assigned Accredited Independent Entity (AIE), TÜV SÜD3. In this regard the calculation methodology was also presented to and confirmed by MED during the intermediate meeting in Moscow.4

3.1 UNFCCC Calculation Method

The UNFCCC “Tool to calculate the emission factor for an electricity system, version 02” (in the following referred to as the UNFCCC Tool) was basically developed in the context of project activities under the Clean Development Mechanism (CDM). However, since the official UNFCCC CDM Baseline & Monitoring Methodologies and their related Methodological Tools are also applicable under the JI scheme, said UNFCCC Tool provides in the following the official calculation method.

3.1.1 General Calculation Methodology

The general methodology for the calculation of carbon emission factors applicable under the JI hence consists of a combination of the “Operating Margin” emission factor (OM) and the “Build Margin” emission factor (BM) in order to adequately estimate emissions in absence of a CDM or JI project activity.

For the calculation of the OM four different approaches can be used accordingly. Based on the data available and as mutually agreed with MED and TÜV SÜD in its role as Accredited Independent Entity, the simple adjusted OM is selected to calculate the carbon emission factors for Russia. This calculation method accordingly allows for a separate consideration of low-cost/must-run power plants in the electricity systems, which are defined as:

- Power plants with low marginal generation costs; and/or

---

2 Refer to UNFCCC (http://cdm.unfccc.int/index.html)
3 An initial meeting was held on 12 January 2010 followed by conference calls.
4 Minutes of Meeting (MoM) were prepared dated 11 February 2010.
• Power plants that are dispatched independently of the daily or seasonal load.

Typically low-cost/must-run power plants include nuclear power plants, hydropower plants and other renewable power generation facilities. However, in the case of the Russian electricity systems, a major share of conventional thermal power plants are operated as must-run power plants as well since they supply heat in combined heat and power (CHP) operation mode for district heating purposes during the winter period.

Within the simple adjusted OM such low-cost/must-run power plants are considered separately if their contribution to total grid generation is equal or higher than 50%.

Accordingly, the simple adjusted OM is calculated using the following equation:

\[
EF_{\text{grid,OM-adj},y} = (1 - \lambda_y) \cdot \frac{\sum_{m} EG_{m,y} \times EF_{EL,m,y}}{\sum_{m} EG_{m,y}} + \lambda_y \cdot \frac{\sum_{k} EG_{k,y} \times EF_{EL,k,y}}{\sum_{k} EG_{k,y}}
\]

Where:
- \( EF_{\text{grid,OM-adj},y} \) Simple adjusted operating margin \( \text{CO}_2 \) emission factor in year \( y \) \([\text{t}\text{CO}_2/\text{MWh}]\);
- \( \lambda_y \) Factor expressing the percentage of time when low-cost/must-run power plants are on the margin in year \( y \) \(%\);
- \( EG_{m,y} \) Net quantity of electricity generated and delivered to the grid by power unit \( m \) in year \( y \) \([\text{MWh}]\);
- \( EG_{k,y} \) Net quantity of electricity generated and delivered to the grid by low-cost/must-run power unit \( k \) in year \( y \) \([\text{MWh}]\);
- \( EF_{EL,m,y} \) \( \text{CO}_2 \) emission factor of power unit \( m \) in year \( y \) \([\text{t}\text{CO}_2/\text{MWh}]\);
- \( EF_{EL,k,y} \) \( \text{CO}_2 \) emission factor of power unit \( k \) in year \( y \) \([\text{t}\text{CO}_2/\text{MWh}]\).

The crucial parameter \( \lambda_y \), which allows for a differentiation between low-cost/must-run power units and other dispatchable power units, is obtained as follows:

\[
\lambda_y = \frac{\text{Number of hours low–cost/must–run sources are on the margin in year } y}{8760 \text{ hours per year}}
\]

Further on, the BM has been calculated. It assumes that recently built power plants are indicative for future capacity additions to a respective electricity system. It shall thus represent recent developments within the electricity system, especially in which the installed generation capacity is increasing.

In accordance with UNFCCC requirements the sample group of power plants comprising the build margin consists of either:

(i) The set of five power units that have been built most recently; or

(ii) The set of power capacity additions in the electricity system that comprise 20% of the system generation and that have been built most recently,
whichever comprises the larger annual power generation.

The BM is accordingly calculated as follows:

\[
EG_{\text{grid,BM},y} = \frac{\sum_mE_{G,m,y} \times EF_{EL,m,y}}{\sum_mE_{G,m,y}}
\]

Where:

- \( EF_{\text{grid,BM},y} \): Build Margin CO\(_2\) emission factor in year \( y \) [tCO\(_2\)/MWh];
- \( EG_{m,y} \): Net quantity of electricity generated and delivered to the grid by power plant \( m \) in year \( y \) [MWh];
- \( EF_{EL,m,y} \): CO\(_2\) emission factor of power unit \( m \) in year \( y \) [tCO\(_2\)/MWh].

After having calculated the OM and BM carbon emission factor, the overall carbon emission factor which constitutes the applicable baseline scenario in a respective electricity system is defined as the Combined Margin (CM) and calculated as per the following equation:

\[
EG_{\text{grid,CM},y} = EF_{\text{grid,OM},y} \times w_{OM} + EF_{\text{grid,BM},y} \times w_{BM}
\]

Accordingly, the CM carbon emission factor is derived by combining the OM and BM under consideration of respective weighing factors. In accordance with the UNFCCC Tool the weighing factors \( w_{OM} \) and \( w_{BM} \) are determined to be equal by default where \( w_{OM} = 0.5 \) and \( w_{BM} = 0.5 \). However, other weighing factors can be applied within the Model (e.g. for wind and solar power projects.)

As outlined above the UNFCCC calculation guideline forms the backbone for the setup and moreover the calculation mode of the developed Power System Simulation Model. The Model’s structure is presented in the following subchapter, whereas special emphasis is placed on the required dispatch analysis in order to forecast the most realistic power supply scenario per electricity system for the period under consideration.

### 3.1.2 Statements regarding Specific Issues defined in the UNFCCC Tool

Regarding some specific detailed issues for the calculation of the emission factors, the UNFCCC Tool provides options or encourages the user to provide an own approach. In the following, statements are made regarding the different issues:

**Retrofits:**

In case of a retrofit, the user may replace an existing power generation unit by adding the retrofitted power generation unit again into the list of power plants (including improved efficiency/capacity). However, to avoid double counting of capacity additions resulting from retrofits within the BM, the original commissioning date of the specific power generation unit remains unchanged.
Reference: UNFCCC Tool, p. 14: “As a general guidance, a power unit is considered to have been built at the date when it started to supply electricity to the grid.”

Reference: UNFCCC Tool, p. 15: “Capacity additions from retrofits of power plants should not be included in the calculation of the build margin emission factor.”

**JI (CDM) projects:**
The Model offers the option to mark TPP, HPP and RES power plants as JI projects. These marked power generation units are considered specifically within the identification of the units for the BM within the ex-post calculation (see Chapter 3.2).

Reference: UNFCCC Tool, p. 14 and p. 15: “Power plant registered as CDM project activities should be excluded from the sample group $m$. However, if the group of power units, not registered as CDM project activity, identified for estimating the build margin emission factor includes power unit(s) that is(are) built more than 10 years ago then: (i) Exclude power unit(s) that is (are) built more than 10 years ago from the group; and (ii) Include grid connected power projects registered as CDM project activities, which are dispatched by dispatching authority to the electricity system.”

**BM procedure (5 power plants vs. 20%):**
The data for Russia demonstrate that the “20%-condition” applies in all situations, i.e. the last five power generation units do not produce more electricity than at least 20% of the entire energy system. However, in order to comply with the UNFCCC Tool, the Model checks if the “20%-condition” overrules the “5 power plants-condition”. In detail, the following stepwise procedure is applied in the Model:

1) Identify power plants for the BM according to the UNFCCC Tool (“20%-condition”), excluding power plants registered under JI.

2) Check “20%-condition” vs. “5 power plants-condition”.

3) Check commissioning date of identified power plants. If older than 10 years follow approach provided by the UNFCCC Tool regarding power plants registered under JI by adding JI projects to the BM and eliminating the oldest of the other power generation units, until “20%-condition” is met.

4) If “20%-condition” is still not met, extend to power plants with commissioning date after collapse of the Soviet Union and thus the establishment of individually dispatched power systems in 1992.

A warning related to step 4 alerts the user of the Model in order to notify the user that the provided procedure of the UNFCCC Tool does not result in a reasonable determination of the BM and therefore suggests the above described deviation.

The above described procedure is taken into account for both ex-post and ex-ante calculation of emission factors (see also Chapter 3.2).³

**References:**
UNFCCC Tool, p. 2: “The build margin is the emission factor that refers to the group of prospective power plants whose construction and future operation would be affected by the proposed CDM project activity.”

³ Due to the aggregation of NPP, HPP and RES power units within the ex-ante calculation, JI registered projects are not considered specifically for the BM identification in the ex-ante calculation mode.
UNFCCC Tool, p. 14 and p. 15: “Power plant registered as CDM project activities should be excluded from the sample group m. However, if the group of power units, not registered as CDM project activity, identified for estimating the build margin emission factor includes power unit(s) that is(are) built more than 10 years ago then: (i) Exclude power unit(s) that is (are) built more than 10 years ago from the group; and (ii) Include grid connected power projects registered as CDM project activities, which are dispatched by dispatching authority to the electricity system.”

UNFCCC Tool, p. 14, footnote 6: “If this approach does not reasonably reflect the power plants that would likely be built in the absence of the project activity, project participants are encouraged to submit alternative proposals for consideration by the CDM Executive Board.”

Consideration of imports:
The Model is based on the principle that all emissions are counted for one electricity system which are actually emitted within this very electricity system. This means, that electricity exports are added to the load and their respective emissions are counted within the considered electricity system. Following this principle electricity imports are counted with zero emissions.

Reference:
UNFCCC Tool, p. 4: “[…] determine the CO₂ emission factor(s) for net electricity imports […] [with] 0 tCO₂/MWh” (option (a))
This rule is applied for intra-Russian as well as cross-border imports.

Aggregation and distinction of power plants:
In order to reduce complexity due to the large amount of power generation units installed in the Russian electricity systems, similar power generation units at one site are clustered as one power plant according to their technology, capacity, fuel and efficiency. Since this clustering is based on the rules stipulated in the UNFCCC Tool the so derived power plants are called “UNFCCC power plants” within this Baseline Study.

Reference:
UNFCCC Tool, p. 1: “A power plant/unit is a facility that generates electric power. Several power units at one site comprise one power plant […]”

Consideration of offgrid power plants:
In order to forecast the grid emission factor of Russia’s unified electricity systems (see also Chapter 2) offgrid power plants are not considered.

Reference:
UNFCCC Tool, p. 4: “Project participants may choose between the following two options to calculate the operating margin and build margin emission factor: Option 1: Only grid power plants are included in the calculation”.

Fuels:
For the net calorific values as well as the fuel emission factors the corresponding IPCC default values are used.
In case a power unit utilises more than one fuel, only the fuel type with the lowest CO₂ emission factor is considered.
Reference:
UNFCCC Tool, p. 20 + p. 21: “IPCC default values at the lower limit of the uncertainty at a 95% confidence interval as provided in table 1.2 [and table 1.4] of Chapter 1 of Vol. 2 (Energy) of the 2006 IPCC Guidelines on National GHG Inventories.”
UNFCCC Tool, p. 8: “Where several fuel types are used in the power unit, use the fuel type with the lowest CO₂ emission factor […].”

Utilisation of sources:
Generally, only official and/or publicly available data has been used for the calculation of the emission factors. However, in order to evaluate the quality of the data, these data have been cross-checked with Lahmeyer International's internal information.

3.2 Setup of the Power System Simulation Model
After having described the theoretical fundamentals of the carbon emission factor calculation defined by the UNFCCC Tool, the present chapter focuses on the structure as well as on the principles of the Power System Simulation Model. Whereas the UNFCCC Tool provides guidance for the calculation of the carbon emission factor ex post, the purpose of the present study consists in applying such guidance by elaborating a forecast of the most probable development of the carbon emission factors of the Russian power systems.
Subchapter 3.2.1 gives a detailed overview on the general structure of the Power System Simulation Model whereas in the subsequent subchapters underlying principles of the calculation mode are explained.

3.2.1 General Structure
The UNFCCC stipulated a guideline on how to calculate historic carbon emission factors of electricity grids actually realised. The UNFCCC Tool thus defines rules for the calculation of those grid emission factors ex post, i.e. all values concerning historic grid loads, power plant operation data (e.g. annual generation, total amount of CO₂ emissions), commissioning and retirement of power units are already existent and serve as input parameters for the calculation.
However, the objective of the present study is to provide a forecast on the most probable development of the grid emission factors of the Russian power systems. This forecast is further on referred to as "ex ante" calculation in order to distinguish it from the ex post calculation as described above.
The result of this study shall furthermore not only be limited to the forecast of the grid emission factors, but also focuses on the Model which enables the user to recalculate the emission factor on an ongoing basis. As already described the guidelines of the UNFCCC Tool refer to past years and do not aim for forecasted values. Nevertheless, the Power System Simulation Model seeks to calculate binding grid emission factors. Due to this fact, the Consultant decided in accordance with the Client and the assigned Independent Entity to integrate the ex post calculation into the Model, which enables the exact calculation of historic grid emission factors in accordance with the UNFCCC rules. This basic structure of the Model is shown in Figure 3-1.
The Model disposes of a dynamic carbon emission factor calculation which is used for ex post calculation and ex ante (in terms of a forecast) calculation. The difference thus relies in the nature of the input parameters. Since for historic years all input parameters already exist, they have to be implemented into the Model and the Model computes the exact carbon emission factor based on the input values. For the forecast (ex ante) the required input parameter are not realised yet by contrast.

For this reason, the Power System Simulation Model takes into account official forecasts of the development of the power system, such as installed capacity, technologies, efficiencies, fuels, dispatch behaviour, commissioning and retirement of power units, forecasts for domestic electricity demand as well as imports and exports. As a function of these parameters the Power System Simulation Model simulates the operation of the power system with all its units. The results of this simulation represent the input parameters for the consecutive calculation of the carbon emission factor following the approach provided by the UNFCCC Tool as described above. In other words: The Power System Simulation Model generates input parameters for the future which are required to calculate the carbon emission factor. The calculation of the ex ante carbon emission factor is then conducted with the same equations and structure as the Model utilises for the ex-post calculation.

The principal structure of the Power System Simulation Model’s data processing is shown in Figure 3-2:
As described earlier, the Model requires several input parameters concerning the characteristics of existing as well as to be commissioned power units until 2020. Additionally, information regarding the electricity demand (e.g. hourly load curves, annual electricity demand) as well as the import/export profile is needed in order to forecast the entire load of the power system for each hour of the forecasted year. This electric load has to be supplied by the means of all generating units available. In doing so, the generation of nuclear power plants (NPP), hydropower plants (HPP), pumped-storage hydropower plants (PSH) and renewable energy plants (RES) is deducted from the entire load. The resulting residual load has to be covered by the conventional thermal power plants (TPP), resulting in the “Thermal Residual Load”. A detailed description of this process and the generation profiles of each type of power plant technology is given in the next subchapter.

By utilising information about planned maintenance and forced outage rates of each power unit, the maintenance schedule is computed. In parallel, the Model defines the merit order of the thermal power plants according to their generation costs on a qualitative basis (for a detailed description see next subchapter).

As a function of all these information, the dispatch of the thermal power plants is performed while respecting operation restrictions, such as must-run, spinning reserve operation as well as technical minima of the power units.

As a result of the dispatching the annual generation and the herewith associated emissions are calculated. According to the rules of the Simple Adjusted OM calculation (see Chapter 3.1), thermal power plants are distinguished between low-cost/must-run plants and other plants. Since the generation of nuclear as well as hydropower plants represents a low-cost source of energy, their generation is considered as low-cost/must-run generation. The same approach is applied for renewable energy plants. As their power output cannot be dispatched, they represent must-run generation. The emissions of the low-cost/must-run power plants are thus divided by the sum of the entire low-cost/must-run generation in order to calculate the second term of the carbon...
emission factor equation according to the Simple Adjusted OM method. This process is depicted schematically in Figure 3-3.

Further on, based on the commissioning years of the respective power units, the Model looks back into the history of the recently commissioned power units in order to calculate the Build Margin (BM) emission factor. In line with the UNFCCC Tool, the most recent power units which in sum generate more than 20% of the annual entire generation of the power system are identified. The emissions and the generation of these power plants are taken into account when calculating the BM emission factor according to the principles described in Chapter 3.1.

Consequently, the Combined Margin emission factor is calculated as the weighted average (see Chapter 3.1) of the Operating and the Build Margin emission factor.

The approach stipulated above considers the supply-side carbon emission factors. Furthermore, the Model offers the option to compute the demand-side carbon emission factors in accordance with the CDM “Tool to calculate baseline, project and/or leakage emissions from electricity consumption, version 01”. Supply-side carbon emission factors are converted by applying technical loss figures of the electricity system.

### 3.2.2 Forecast of Residual Load supplied by Thermal Power Plants

In order to forecast the electric load for a future year, the Model requires two input parameters: Firstly, the hourly load profile for one year (“base year”) is needed. Secondly, the forecast of the entire annual generation is needed. The respective forecasts are on the basis of consumption at “sent-out” level. “Sent-out” refers to the respective busbars of the power plants. This means, that actual losses consumed in the electrical grid (“technical losses”) as well as non-technical losses, e.g. theft of energy, are already incorporated i.e. deducted in these forecasts. The hourly load curve of the base year is scaled with the annual consumptions at sent-out level in order to get a forecast of the load curve for the corresponding year. With this approach, not only the targeted annual energy demand is met but also the characteristic consumption patterns are transcribed to the future years, in particular the time and the height of peak load.

Intra-Russian as well as cross-border imports and exports are separately given as hourly load profiles for the base year. According to the evaluated official documents provided by the Russian Energy Forecasting Agency (EFA) the intra-Russian imports/exports patterns will stay the same until 2020. Nonetheless, according to EFA’s forecasting documents the cross-border
imports/exports will evolve until 2020. This forecasted development is taken into account by adding the difference compared to the base year as a base component on the intra-Russian imports/export pattern.

For the purpose of this study, 2009 is regarded as base year because this year represents the last historic year, for which most of the data is available as exact realised values or at least as exact values for the first half year with prognostic continuation for the entire year. Nonetheless, the Model is designed in that way, that users can change the base year to a year for the period under consideration, e.g. to 2012. This ensures that the now calculated emission factor forecast based on official forecast data of the power system from 2009 can be continuously updated with later official data, which will be more precise since the actually forecasted year will be closer and less uncertainty will prevail in these official forecasts.

As the final objective of this study is the evaluation of carbon emission factors, non-emitting power plants are looked at on an aggregated basis. This approach is plausible due to several aspects: Since nuclear power plants (NPP) can hardly be ramped up and down, their generation represents base load generation. By this reason, their officially forecasted power generation for future years is modelled so as to provide constant base load power during the entire year. For this reason, they can be aggregated as a “single big” virtual nuclear power plant. The same can be applied for renewable energy sources: Since their share in installed capacity is very low (< 0.1%) the shape of their generation has only a marginal influence on the generation of the other power plants.

The objective of pumped-storage hydro power plants is to perform peak-shaving in order to allow for a more economical operation of thermal power plants. Since the levelised electricity costs of peaking power plants are always rather expensive, PSH plants can thus enable economies by flattening the residual load for the thermal plants. By reason of the daily seasonality of peak and off-peak times (daily load pattern), PSH plants are typically operated to provide for a day-night shifting. Within this context, PSH plants are thus modelled in that way to reduce the annual load during peak times. Based on officially forecasted annual generation and charging values, these values are broken down to their respective daily values and then put into the daily load curve whenever peak times (and off-peak times respectively) occur while respecting their maximum rated capacity. Figure 3-4 shows an exemplary operation of a PSH plant for one day.

![Figure 3-4: Pumped-storage hydro power plant production and charge for a sample day](image-url)
The operation of hydro power plants is similar to the one of pumped-storage hydro power plants. Since their primary energy is there anyways (renewable character) and its accession can be controlled very easily, hydro power plants represent optimal peaking power plants. Hence, hydro power plants are dispatched so as to flatten the load curve in order to reduce peaks. Besides river barrage HPPs there are also run-of-the-river HPPs (mostly smaller) without storages capabilities. These plants provide base load generation throughout the day. Based on information regarding their dispatch characteristics, the base component accounts for 20% - 84% and the peaking component for 80% - 16% in terms of daily generation, depending on the respective electricity system. The amounts of base and peak component have been taken from official data provided by EFA. Figure 3-5 shows the daily operation of hydro power plants on a sample day.

![Figure 3-5: Hydro power plant production for a sample day](image)

Due to seasonal variations in the hydrology of the water intakes of the HPPs, information about the intra-annual distribution of hydro power production of the largest Russian HPP operator RusHydro are utilised to resolve the annual amount of hydro power generation on seasonal basis (spring, summer, autumn, winter).

![Figure 3-6: Relation of load curves for one sample week](image)
Following the approach described in the previous subchapter, the generation of NPPs, RES, HPPs and PSHs is deducted from the entire grid load. The so formed load curve is called “residual load curve”. The residual load curve in conjunction with the entire load curve and the curves which are considered for the transfer from the entire to residual load are demonstrated in Figure 3-6. This residual load has then to be supplied by thermal power plants. Their operational behaviour is described in the following two subchapters.

3.2.3 Maintenance Scheduling

In general, power unit unavailability consists of two different kinds of outages: Planned outage and forced outage. Planned outage is the annual maintenance period in which general repair and general overhauls are made. Forced outage is the uncertain, not schedulable unavailability of power units. In order to simulate the carbon emission factor with the dispatch calculation, the consideration of future power unit availability is strictly necessary. The rules for the forecast of planned outages in this study are defined as follows:

- 30% of the units, beginning at the largest capacity, are planned to be serviced during low electricity demand months. In order to identify a low electricity demand period, a moving average over the hourly electricity consumption for the next three months is calculated and the minimum consumption hour identified. In this hour the intensive service period will start. In that period the above mentioned largest units are served. All other units will be serviced throughout the year. The duration of the planned maintenance will be 10% of the year, namely 876 hours.

In order to simulate the uncertain forced outage the following assumptions are made:

- The longer one specific power unit is available, the larger is the possibility that a forced outage will occur. Once the unit is unavailable this will be the case at least for the next 4 days. Afterwards the possibility rises that the unit will become available again the longer the unit is unavailable.

Within the Model, first the planned maintenance schedule is set and afterwards the simulation of random outages is run, based on the already set planned maintenance periods. The result is an assembly of power unit availabilities on an hourly solution.

3.2.4 Merit Order & Power Plant Dispatching

The operation of the power plants is determined by economic as well as technical criteria. Whereas the generation hierarchy is determined mainly by economic parameters, the actual operation of so ordered power units follow technical rules.

The economic criterion consists in always supplying the instantaneous electricity demand with economically optimal combination of the available power plants. This objective is realised in the so-called “merit order” principle which orders the power plants according to their incremental cost of power generation. For calculating the emission factor by simulating the operation of the power system the Short Run Marginal Costs (SRMC) are considered on a qualitative basis. The merit order curve first considers the type of fuel, since the fuel expenditures make up for the largest cost component in SRMC. Secondly, the sizes of the power units are taken into account. Since large-scale power units are able to allow for economies of scale, their incremental cost of power generation or Levelised Electricity Cost (LEC) is lower than a similar power unit with a smaller installed capacity.

Hence, the installed capacity constitutes the second criterion within the setup of the merit order curve. The third criterion takes into account the average efficiency of the power units, which determines how efficient the fuel is used in order to generate electricity.

For the calculation of the emissions in an hour h of specific power plant j two separate plant efficiencies are taken into account. The ambient conditions determine essentially the efficiency of
the combustion process as well as the turbine operation. However, the main driver of the efficiency is constituted by the temperature. Bearing in mind the large temperature differences in Russia due to the continental climate, the Model reflects these circumstances by the application of a specific efficiency during summer as well as a specific efficiency during winter. Moreover, combined heat and power plants have to extract a specific amount of steam for supplying district heating. Since a lower amount of hot steam can be used for electricity generation, the efficiency increases. The efficiencies of each power unit are either taken from technical data sheets or have been provided by official entities.

The technical criteria consist in a set of different restrictions which influence the operation of the power units:

Firstly, must-run restrictions force the power unit to always generate its rated power output because of combined heat and power mode for instance. Depending on the type of turbine they have either a fixed ratio of heat generation towards electricity generation (i.e. backpressure turbine) or they are condensing power plants with a flexible point of extraction (i.e. extraction condensing turbine). Since backpressure turbines either produce heat and electricity in fixed operation mode, they are obliged to also generate their rated electricity output. Extraction condensing turbines are more flexible because the point of steam extraction out of the turbine may be altered. Hence, they are not forced to always run at their electrical rated power. Nevertheless, since the heat demand in Russia is high during winter, both types of turbines have to produce their maximum heat output and thus run electrically at 100% of their rated power. During summer, heat demand is lower but still existing. By this reason, the backpressure turbines still have to run at 100% of their rated electric power whereas the condensing extraction turbines are not forced any more to produce their maximum heat output. They can keep the steam inside the turbine and use it for electricity production which enables a higher electric efficiency. During summer their electric must-run capacity counts for 40%.

The second technical restriction is composed by the technical minimum of each power unit. No thermal power unit can reduce its electric output to ranges around zero. The respective technically minimal output depends on the fuel. Coal units can reduce their power down to 50% of their rated capacity, gas units down to 30% of their rated capacity.

The third technical criterion consists in the spinning reserve. Power systems require balancing power. Hydropower plants and pumped storage hydropower plants can supply secondary and tertiary reserve power, depending on the delay in which power is needed. However, for a stable operation of a power system primary reserve power is needed within seconds or even smaller intervals. In this context the spinning masses of conventional thermal power turbines represent goods means in order to balance electric power. By regulating the amount of steam that is flowing from the boiler into the turbine, the electrical power can be equilibrated. Thermal power plants represent thus the backbone of the power systems’ frequency control. Due to this fact, the Model considers an operation of all thermal power units at maximum 90% of their rated electric power. Only in case the load increases the thermal power plants are operated up to their rated capacity.

### 3.2.5 Monte Carlo Simulation

Since the simulation of the forced outage of each power unit is described by stochastic processes, the actual availability of a specific power unit \( j \) in a specific hour \( h \) of the year is not deterministic. In other words: In each simulation run the availability of the unit \( j \) in the hour \( h \) can change as a function of the defined stochastic processes. Every simulation run could constitute a possible state, which will be realised in reality with a specific probability. The availability of each power unit thus influences the resulting carbon emission factor.
In order to describe the most probable operation of the power systems for forecasting the most probable development of the carbon emission factors, a Monte Carlo Simulation is performed. The Monte Carlo Simulation simulates a sufficiently high number of possible operations of the power system as well as the carbon emission factors. With this interrelation, frequencies can be calculated that describe the probability of the development of the carbon emission factors.

In the course of the development of the Power System Simulation Model it has been found out, that the impact of the availabilities of the power units on the actual development of the carbon emission factors is relatively low.

Especially the Operating Margin is hardly influenced by the units’ availabilities. In few cases the availabilities can change the annual generation of single power units in that way, that the composition of the Build Margin changes. In these specific cases the Build Margin can deviate from the value realised in the majority of the cases. However, these deviations are relatively seldom. The maximum deviation of the Combined Margin emission factor of 14.02% occurs in IPS East in year 2012 whereas the standard deviation in all Russian IPS accounts for 0.76%. Due to this observation it has been found that the number of one hundred simulation runs per system per year is sufficient in order to calculate the most probable development of the annual carbon emission factors.

The described value which is realised in the majority of the cases is expressed by the median of the distribution of the one hundred simulations. Nevertheless, for the sake of completeness the corresponding minimum and maximum values are presented in order to provide an overview on possible ranges of the corresponding carbon emission factors.
4 POWER GENERATION DISPATCH AND CORRESPONDING CARBON EMISSION FACTORS

Whereas the Chapter 3 focussed on the methodology of the dispatch analysis as well as on the rules of the computation of the carbon emission factors, this present chapter presents the results of the conducted power system simulations and calculations.

For each Russian electricity system, firstly the forecasted electricity demand and particularly its load curve are presented followed by a description of how this demand is satisfied. For this purpose exemplary daily generation dispatch profiles are shown as well as the development of the annual energy generation mix.

With this information about the future operation of the respective electricity system, the corresponding carbon emission factors have been calculated. These are presented in the third subchapter for each electricity system.
4.1 Electricity System IPS Center

4.1.1 Forecasts Load Duration Curves
The load curves of future years have been forecasted following the methodology described in Chapter 3. Exemplarily, the simulated load curve of 2012 is depicted in Figure 4-1.

![Figure 4-1: (a) Forecasted hourly load curve for 2012 inclusive imports/exports and (b) corresponding hourly load duration curve of IPS Center](image)

Annual as well as daily and weekly seasonal patterns can be observed. Correspondingly, the load in summer months is lower compared to the one during winter. Depending on daytime as well as on the weekday the mean grid load accounts for approximately 20,000 – 25,000 MW, whereas the value rises up to 25,000 – 35,000 MW during winter time. Peak load occurs on 21 December 2012 at 6 p.m., when the hourly load amounts to 42,703 MW.

The depicted values represent the “domestic” load of clients within the IPS Center as well as intra-Russian and cross-border imports/exports. Since the development of the technical & non-technical losses within the IPS Center is already included in the figure for the annual electricity demand which is used in order to scale future power demands, the stated figures above are on so-called “sent-out level”. Hence, their amounts have actually to be generated by the power plants of IPS Center. This value represents thus the basis of electricity generation when calculating the grid emission factor of the IPS Center.

4.1.2 Forecasted Energy Mix
According to the methodology described in Chapter 3, the previously depicted load has served as input parameter into the power system simulation which then dispatched the power units following their merit order as well as spinning reserve restrictions. In Figure 4-2 the dispatch for 15 June 2012 is given.
It can be seen, that nearly half of the power is supplied by nuclear power plants. An hourly average of 5 GWh/h to 7 GWh/h is generated by combined heat and power plants (CHP). The output of those two as well as of the 200 MW power plants, which supply approximately 2 GWh/h, the 150 MW and the 600 MW power plants represent base load generation, since their power output is very constant throughout the entire day. The power plant Kostroma GRES (K-1200-240) with its rated capacity of 1,200 MW runs on spinning reserve during daytime but reduces its power output in the night. Also the 300 MW plants run at spinning reserve during peak times and reduce power output in hours of lower load. The pumped storage hydropower plants reduce the daily peak load between 10 a.m. and 3 p.m. and charge during 1 a.m. and 7 a.m. The other hydropower plants are dispatched in a manner in order to flatten daily load to a maximum extent. Hence, they generate approximately 200 – 600 MWh/h between 9 a.m. and 6 p.m. Altogether, 562 GWh of electricity are produced during the sample day shown in Figure 4-2.

In the annual comparison of energy generation mixes, it can be seen that the share of coal fired power plants rises from 27 TWh to 60 TWh significantly (+ 125%) due to the commissioning of new coal fired power plants. The generation of gas fired units remains approximately constant at 113 TWh until 2016. Thereafter, its share rises up to 130 TWh in 2020. Until 2012 the output of nuclear power plants ranges from 80 – 90 TWh and rises up to 105 TWh afterwards. Since no major hydro power plants are either commissioned or decommissioned, the HPP share stays at a constant level of 1.5 TWh. Consequently, the shares in power output (in terms of electric TWh) remain also relatively constant with coal around 20% (+8% in 2020 compared to 2009), gas approximately 42% (-7% in 2020 compared to 2009), and nuclear power around 37%, hydropower making up for only 0.5 – 0.7%.
4.1.3 Corresponding Carbon Emission Factors

Following the UNFCCC Tool, the previously described energy generation mix has been taken into account together with the corresponding efficiencies of the respective power units as well as the fuel carbon emission factors in order to compute the development of the annual grid emission factors. The results for IPS Center are depicted in Figure 4-3:

![Figure 4-3: Results of Monte Carlo Simulation: (a) Distribution (median, min, max) for Combined Margin Emission Factor and (b) Forecasted Development for Combined, Operating & Build Margin Emission Factors for IPS Center](image)

The Operating Margin emission factor starts at 0.740 t CO$_2$/MWh in 2009 and rises constantly with some detentions until it reaches the level of 0.782 t CO$_2$/MWh in 2020. Since the Operating Margin represents the emission factor of the actual operation of the power system, this increase reflects the increased share of coal-fired power plants in the fuel mix (see Figure 4-2).

The Build Margin emission factor represents all newly commissioned power units. The tendency of the Build Margin is upwards. However, this increase is attenuated by the comparatively low-emission gas-fired as well as zero-emission nuclear power units that are going to be built. Their lower emissions decrease the Build Margin to a value between 0.400 to 0.500 t CO$_2$/MWh, resulting in 0.459 t CO$_2$/MWh in 2020.

The Combined Margin takes into account both the Operating and the Build Margin emission factors. Since its value corresponds to exactly the average of both, the Combined Margin results in 0.576 t CO$_2$/MWh in 2009. Throughout the consideration period the Combined Margin increases only slightly up to 0.621 t CO$_2$/MWh in 2020.

The corresponding annual carbon emission factors for the IPS Center are listed in Table 4-1 differentiated between the Combined Margin, Operating Margin and Build Margin.

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4.2 Electricity System IPS East

4.2.1 Forecasted Load Duration Curves
The load curves of future years have been forecasted following the methodology described in Chapter 3. Exemplarily for the IPS East, the forecasted load curve of 2013 is depicted in Figure 4-4.

![Figure 4-4: (a) Forecasted hourly load curve for 2013 inclusive imports/exports and (b) corresponding hourly load duration curve of IPS East](image)

Typical annual as well as daily and weekly seasonal patterns can be observed. Correspondingly, the load in summer months is lower compared to the one during winter. Depending on daytime as well as on the weekday the mean grid load counts for approximately 2,500 – 4,000 MW, whereas the value rises up to 4,000 – 6,000 MW during winter time. Peak load occurs on 28.12.2013 at 12 a.m., when the hourly load counts for 5,993 MW.

The depicted values represent the “domestic” load of clients within the IPS East as well as intra-Russian and cross-border (via tie-lines abroad) imports/exports. Since the development of the technical & non-technical losses within the IPS East is already included in the figure for the annual electricity demand which is used in order to scale future power demands, the stated figures above are on so-called “sent-out level”. Hence, their amounts have actually to be generated by the power plants of IPS East. This value represents thus the basis of electricity generation when calculating the grid emission factor of the IPS East.

4.2.2 Forecasted Energy Mix
According to the methodology described in Chapter 3, the previously depicted load has served as input parameter into the power system simulation which then dispatched the power units following their merit order as well as spinning reserve restrictions. In Figure 4-5 the dispatch for 13.05.2013 is given.
The graph on the left shows that some little contribution to the base load comes from renewable energy sources while nuclear power plants are just represented insignificantly with 23 MWh/h. Additionally it can be seen that about 1,000 MWh/h are supplied by combined heat and power plants (CHP) and another 1,000 MWh/h are generated by 800 MW power plants. The output of those three power plant types (RES, CHP and 800 MW) represents base load generation, since their generation is very constant throughout the entire day. The Eastern hydro power plants are used to follow daily load and generate 600 to 1,600 MWh/h. The additional generation is exported into other IPSs and cross-border countries. During the depicted day 80.2 GWh are generated in total.

In the annual comparison of energy mixes it can be seen that the share of coal fired power plants decreases in 2010 and then rises almost constantly until 2015. In 2015 the coal energy generation strongly increases about 10 TWh to almost 40 TWh. The generation of gas fired units increase from 1.6 TWh in 2009 to 4.8 TWh in 2020. During the observation period the hydropower plant output rises from 9 TWh by 75%, the small portion of NPP by 150% and the generation by RES from 0.45 TWh in 2009 by more than 100% in 2020.

### 4.2.3 Corresponding Carbon Emission Factors

Following the UNFCCC Tool the previously described fuel mix has been taken into account together with the corresponding efficiencies of the respective power units as well as the fuel carbon emission factors in order to compute the development of the annual carbon emission factors. The results for IPS East are depicted in Figure 4-6:
The Operating Margin emission factor starts at a value of 0.994 t CO$_2$/MWh in 2009. After decreasing in 2010, it rises again. From 2014 onwards it remains rather stable, resulting in a value of 1.015 t CO$_2$/MWh in 2020.

The Build Margin considers all newly commissioned power units. In 2009 the BM only consists of 5 units, whereas 4 units are zero-emission hydropower plants. The significant increase in 2011 is caused by the commissioning of a large-scale, emission-intensive coal-fired power plant. After 2011 the BM remains fairly constant throughout the consideration period. The minimum value is reached in 2010 amounting to 0.262 t CO$_2$/MWh, whereas a peak occurs in 2012 at a value of 0.979 t CO$_2$/MWh.

The Combined Margin takes into account both the Operating and the Build Margin emission factors. Whereas in 2010 the Combined Margin results in its minimum value at 0.559 t CO$_2$/MWh, it then increases to 0.968 t CO$_2$/MWh in 2012. The Combined Margin then remains fairly constant, resulting in 0.962 t CO$_2$/MWh in 2020.

The corresponding annual carbon emission factors for the IPS East are listed in Table 4-2 differentiated between the Combined Margin, Operating Margin and Build Margin.

### Table 4-2: Annual Carbon Emission Factors for IPS East

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<td>0.916</td>
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</table>
4.3 Electricity System IPS North West

4.3.1 Forecasted Load Duration Curves

The load curves of future years have been forecasted following the methodology described in Chapter 3. Exemplarily, the forecasted load curve of 2014 is depicted in Figure 4-7.

![Figure 4-7: (a) Forecasted hourly load curve for 2014 inclusive imports/exports and (b) corresponding hourly load duration curve of IPS North West](image)

Typical annual as well as daily and weekly seasonal patterns can be observed. Correspondingly, the load in summer months is lower compared to the one during winter. Depending on daytime as well as on the weekday the mean grid load counts for approximately 8,000 – 11,000 MW, whereas the value rises up to 12,000 – 15,000 MW during winter time. Peak load occurs on 21.12.2014 at 5 p.m., when the hourly load counts for 15,867 MW. During the winter time a more fluctuating day-night variation can be observed.

The depicted values represent the “domestic” load of clients within the IPS North West as well as intra-russian (via tie-lines between neighbouring Russian IPSs) and cross-border (via tie-lines abroad) imports/exports. Since the development of the technical & non-technical losses within the IPS North West is already included in the figure for the annual electricity demand which is used in order to scale future power demands, the stated figures above are on so-called “sent-out level”. Hence, their amounts have actually to be generated by the power plants of IPS North West. This value represents thus the basis of electricity generation when calculating the grid emission factor of the IPS North West.

4.3.2 Forecasted Energy Mix

According to the methodology described in Chapter 3, the previously depicted load has served as input parameter into the power system simulation which then dispatched the power units following their merit order as well as spinning reserve restrictions. In Figure 4-8 the dispatch for 24.12.2014 is given.
It can be seen, that approximately 5 GWh/h is supplied by nuclear power plants and about 1.7 GWh/h by the combined cycle gas turbines (CCGT). Another 4.8 GWh/h are generated by combined heat and power plants (CHP). These power plants as well as the 300 MW are used to support base load generation, since their generation is very constant throughout the entire day. The 200 MW power plants and the gas turbine units (GTU) are switched on during daytime in order to cover the elevated load. One the one hand, the hydropower plants are used to follow the daily load in peak periods, on the other hand, they are also providing base load power. Altogether, 348 GWh of electricity are generated during the forecasted day.

In the annual comparison of energy mixes it can be seen that the share of coal fired power plants rises from 0.8 TWh to 11.1 TWh significantly, due to the commissioning of new coal power plants. The generation of gas fired units first decrease from 47 to 43 TWh until 2011, but after that year its share rises constantly to 56 TWh in 2020. The nuclear power plant generation is rising constantly from 38 TWh to 47 TWh. Since no major hydropower plants are either commissioned or decommissioned, the HPP share stays at a constant level of 12.2 TWh.

4.3.3 Corresponding Carbon Emission Factors

Following the UNFCCC Tool, the previously described fuel mix has been taken into account together with the corresponding efficiencies of the respective power units as well as the fuel carbon emission factors in order to compute the development of the annual grid emission factors. The results for IPS North West are depicted in Figure 4-9:
Figure 4-9: Results of Monte Carlo Simulation: (a) Distribution (median, min, max) for Combined Margin Emission Factor and (b) Forecasted Development for Combined, Operating & Build Margin Emission Factors for IPS North West

The Operating Margin starts at 0.492 t CO₂/MWh in 2009. It decreases until 2014 (0.389 t CO₂/MWh) and then increases again to 0.482 t CO₂/MWh in 2020. Since the Operating Margin represents the emission factor of the actual operation of the power system, this increase reflects the rising share of coal-fired power plants in the fuel mix (see Figure 4-8).

The Build Margin emission factor considers all newly commissioned power units. Whereas the Build Margin comprises 10 power units in 2009, this figure increases to 20 units in 2020. The development of the Build Margin remains rather stable beginning with a value of 0.405 t CO₂/MWh in 2009 and then resulting in 0.423 t CO₂/MWh in 2020.

The Combined Margin takes into account both the Operating and the Build Margin emission factor. Since its value corresponds to exactly the average of both, the actual Combined Margin starts at 0.448 t CO₂/MWh in 2009, then decreases slightly. It finally results in a value of 0.453 t CO₂/MWh in 2020.

The corresponding annual carbon emission factors for the IPS North West are listed in Table 4-3 differentiated between the Combined Margin, Operating Margin and Build Margin.

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4.4 Electricity System IPS Siberia

4.4.1 Forecasted Load Duration Curves

Exemplarily for the IPS Siberia, the load curves of 2015 are depicted in Figure 4-10.

![Figure 4-10: (a) Forecasted hourly load curve for 2015 inclusive imports/exports and (b) corresponding hourly load duration curve of IPS Siberia](image)

Typical annual as well as daily and weekly seasonal patterns can be observed. Correspondingly, the load in summer months is lower compared to the one during winter. Depending on daytime as well as on the weekday the mean grid load counts for approximately 20,000 – 24,000 MW which is a small variation from day to night compared to other IPS, whereas the value rises up to 26,000 – 35,000 MW during winter time. Peak load occurs on 22.12.2015 at 3 p.m., when the hourly load counts for 34,846 MW.

The depicted values represent the “domestic” load of clients within the IPS Siberia as well as intra-russian (via tie-lines between neighbouring Russian IPS) and cross-border (via tie-lines abroad) imports/exports. Since the development of the technical & non-technical losses within the IPS Siberia is already included in the figure for the annual electricity demand which is used in order to scale future power demands, the stated figures above are on so-called “sent-out level”. Hence, their amounts have actually to be generated by the power plants of IPS Siberia. This value represents thus the basis of electricity generation when calculating the grid emission factor of the IPS Siberia.

4.4.2 Forecasted Energy Mix

According to the methodology described in Chapter 3, the previously depicted load has served as input parameter into the power system simulation which then dispatched the power units following their merit order as well as spinning reserve restrictions. In Figure 4-11 the dispatch for 18.03.2015 is given.
It can be seen, that about 9 GWh/h are supplied by combined heat and power plants (CHP). Another 6 GWh/h are generated by 800 MW power plants and 2 GWh/h by the 600 MW power plants. The output of those three power plant types represents base load generation, since their generation is very constant throughout the entire day. The Siberian hydropower plants are used to follow daily load and generate 10 GWh to 13 GWh every hour.

In the annual comparison of energy mixes it can be seen that the share of coal fired power plants decreases in the first three years from around 90 to 79 TWh and then rises from 91 TWh to 158 TWh significantly (+74%) due to the commissioning of new coal power plants. The generation of gas fired units remains approximately constant at 20 TWh until 2020. From 2009 until 2020 the hydropower plant output rises from 85 TWh to 111 TWh. Starting with about 45% coal fired generation and 45% hydropower generation, the fuel shares (in terms of electric TWh) shifts to coal from about 45% up to 55% and hydropower drops from about 45% down to 38% while the smaller portion of gas fired power plants decreases slightly from 10% to 7%.

4.4.3 Corresponding Carbon Emission Factors
Following the UNFCCC Tool, the previously described fuel mix has been taken into account together with the corresponding efficiencies of the respective power units as well as the fuel carbon emission factors in order to compute the development of the annual grid emission factors. The results for IPS Siberia are depicted in Figure 4-12:
Figure 4-12: Results of Monte Carlo Simulation: (a) Distribution (median, min, max) for Combined Margin Emission Factor and (b) Forecasted Development for Combined, Operating & Build Margin Emission Factors for IPS Siberia

The Operating Margin emission factor starts at 1.038 t CO$_2$/MWh in 2009 and decreases slightly to a value of 0.910 t CO$_2$/MWh in 2020. Since the Operating Margin represents the emission factor of the actual operation of the power system, this decrease reflects the decreasing share of low-efficient coal-fired power plants and the increasing share of new high-efficient coal-fired power plants in the fuel mix (see Figure 4-11).

The Build Margin emission factor considers all newly commissioned power units. Since almost exclusively high-efficient coal-fired power units as well as hydro power units are going to be built, their lower emissions result in a slightly lower Build Margin when compared to the Operating Margin. Starting with 0.968 t CO$_2$/MWh in 2009, it decreases to a value of 0.877 t CO$_2$/MWh in 2020.

The Combined Margin Emission factor takes into account both the Operating and the Build Margin emission factor. Since its value corresponds to exactly the average of both, the Combined Margin results in 1.003 t CO$_2$/MWh in 2009. It hence decreases during the period under consideration, amounting to 0.893 t CO$_2$/MWh in 2020.

The corresponding annual carbon emission factors for the IPS Siberia are listed in Table 4-4 differentiated between the Combined Margin, Operating Margin and Build Margin.

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4.5 Electricity System IPS South

4.5.1 Forecasted Load Duration Curves
Following the methodology described in Chapter 3, for the IPS South exemplarily the forecasted load curve of 2016 is depicted in Figure 4-13.

![Forecasted hourly load curve for 2016 inclusive imports/exports and corresponding hourly load duration curve of IPS South](image)

Figure 4-13: (a) Forecasted hourly load curve for 2016 inclusive imports/exports and (b) corresponding hourly load duration curve of IPS South

Typical annual as well as daily and weekly seasonal patterns can be observed in the IPS South as well. Correspondingly, the load in summer months is lower compared to the one during winter. Depending on daytime as well as on the weekday the mean grid load counts for approximately 7,000 – 11,000 MW, whereas the value rises up to 9,000 – 15,000 MW during winter time. Peak load occurs on 18.12.2016 at 6 p.m., when the hourly load counts for 15,154 MW.

The depicted values represent the “domestic” load of clients within the IPS South as well as intra-Russian (via tie-lines between neighbouring Russian IPS) and cross-border (via tie-lines abroad) imports.exports. Since the development of the technical & non-technical losses within the IPS South is already included in the figure for the annual electricity demand which is used in order to scale future power demands, the stated figures above are on so-called “sent-out level”. Hence, their amounts have actually to be generated by the power plants of IPS South. This value represents thus the basis of electricity generation when calculating the grid emission factor of the IPS South.

4.5.2 Forecasted Energy Mix
The previously depicted load has served as input parameter into the power system simulation which then dispatched the power units following their merit order as well as spinning reserve restrictions. In Figure 4-14 the dispatch for 08.01.2016 is shown.
It can be seen, that constantly 2.8 GWh/h are supplied by nuclear power plants (NPP). Another 3 GWh/h are generated by combined cycle gas turbine (CCGT) power plants and in sum 2.7 – 3.6 GWh/h by the CHP, 300 MW and 200 MW power plants. The output of these power plants except the 200 MW plants represents base load generation. The output of the 200 MW power plants as well as of some CHP plants represent mid load generation, since, they are running at spinning reserve during daytime but diminish their power output in low-load periods. As in the Siberian system the hydropower plants in the IPS South are used to follow the daily load. The gap between the generation and load is covered with import from other neighbouring Russian IPS and cross-border imports. Between 1,200 MWh/h to 2,300 MWh/h are imported during the day.

In the annual comparison of energy mixes it can be seen that the share of hydropower plants decreases constantly during the calculated period from 29% in 2009 down to 22% in 2020. The actual generation of gas fired units oscillates around 40 TWh annually. However, since the growing energy demand will be covered more and more by new NPPs, the share of gas fired power plants decreases from 60% down to 44%. The portion of nuclear power generation increases almost constantly from 8 TWh to 31 TWh which is equal to a share of 11 to 32%. The coal power plant, which will be commissioned in 2014, is going to supply 2.1 TWh annually, counting for 2.1 – 2.6% of the entire annual generation.

4.5.3 Corresponding Carbon Emission Factors

According to the UNFCCC Tool, the previously described fuel mix has been taken into account together with the corresponding efficiencies of the respective power units as well as the fuel carbon emission factors in order to compute the development of the annual grid emission factors. The results for IPS South are depicted in Figure 4-15:
The Operating Margin emission factor starts with a maximum of 0.542 t CO$_2$/MWh in 2009. Throughout the consideration period the Operating Margin emission factor then decreases to a minimum of 0.449 t CO$_2$/MWh in 2020.

The Build Margin emission factor considers all newly commissioned power units. The Build Margin emission factor decreases, starting at 0.210 t CO$_2$/MWh in 2009 to a value of 0.169 t CO$_2$/MWh in 2010. From 2011 onwards the BM increases to 0.345 t CO$_2$/MWh in 2014 and then decreases again slightly.

The Operating and the Build Margin emission factor are both taken into account by the Combined Margin emission factor. Since its value corresponds to exactly the average of both, the Build Margin brings down the actual Operating Margin emission factor. It results in a Combined Margin of 0.376 t CO$_2$/MWh in 2009, with a peak of 0.428 t CO$_2$/MWh in 2014. The Combined Margin again decreases and amounts to 0.375 t CO$_2$/MWh in 2020.

The corresponding annual carbon emission factors for the IPS South are listed in Table 4-5 differentiated between the Combined Margin, Operating Margin and Build Margin.

Table 4-5: Annual Carbon Emission Factors for IPS South

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</table>
4.6 Electricity System IPS Urals

4.6.1 Forecasted Load Duration Curves
As for all other systems the forecast load duration curves follow the methodology described in Chapter 3. For the IPS Urals the forecasted load curve of 2017 is depicted in Figure 4-16.

![Figure 4-16: (a) Forecasted hourly load curve for 2017 inclusive imports/exports and (b) corresponding hourly load duration curve of IPS Urals](image)

Depending on daytime as well as on the weekday the mean grid load counts for approximately 23,000 – 30,000 MW during summer time whereas the value rises to 43,000 MW during winter time. Peak load occurs on 15.12.2017 at 5 p.m. when the hourly load counts for 42,847 MW.

The depicted values including intra-russian (via tie-lines between neighbouring Russian IPSs) as well as cross-border (via tie-lines abroad) imports/exports represent the “domestic” load of clients within the IPS Urals. Since the development of the technical & non-technical losses within the IPS Urals is already included in the figure for the annual electricity demand which is used in order to scale future power demands, the stated figures above are on so-called “sent-out level”. Hence, their amounts have actually to be generated by the power plants of IPS Urals. This value represents thus the basis of electricity generation when calculating the grid emission factor of the IPS Urals.

4.6.2 Forecasted Energy Mix
The previously depicted load has served as input parameter into the power system simulation which then dispatched the power units following their merit order as well as spinning reserve restrictions. In Figure 4-17 the dispatch for 19.01.2017 is shown.
The mix of power plant types (with ten different plant types) in the IPS Urals is varying considerably compared to the other systems. It can be seen, that constantly 1.2 GWh/h are supplied by nuclear power plants (NPP) as a base load. Such as the nuclear power the CHP (about 10.3 GWh/h), 800 MW (1.4 GWh/h), 600 MW (1.7 GWh/h) and even 500 MW (2.6 GWh/h) work as base load generators and do not vary their power output over the day. The combined cycle gas turbine (CCGT) power plants (9.3 – 13.6 GWh/h) and 300 MW power plants (4.7 – 5.9 GWh/h) are used to follow the daily load as well as the 200 MW and 150 MW units and hydropower plants. The difference between the generation and load is covered with import/export from other neighbouring Russian IPS and cross-border imports.

In the annual comparison of energy mixes it can be seen that the share of coal fired plants increases during the calculated period from 41 to 90 TWh, whereas the generation of gas fired units starting with 183 TWh in 2009 first decreases until 2015 (172 TWh) and then increases again to an annual energy generation of about 194 TWh. The small share of nuclear power output increases almost constantly from 3.7 to 10.3 TWh and the hydropower plant generation keeps relatively constant in the consideration period at 4.9 – 5.4 TWh. Hence, due to a constant generation of hydropower plants and a marginal rise of gas fired power plants (+6%) their fuel share (in terms of electric TWh) decreases from 78% to 65% while the shares of coal and nuclear power energy are rising from 17% to 30% and from 1.6% to 3.4% respectively.

### 4.6.3 Corresponding Carbon Emission Factors

According to the UNFCCC Tool, the previously described fuel mix has been taken into account together with the corresponding efficiencies of the respective power units as well as the fuel carbon emission factors in order to compute the development of the annual carbon emission factors. The results for IPS Urals are depicted in Figure 4-18:
The Operating Margin represents the carbon emission factor of the actual operation of the power system. It hence starts at 0.639 t CO$_2$/MWh in 2009 and increases insignificantly until 2012 to a maximum of 0.648 t CO$_2$/MWh, then again decreasing to a minimum of 0.592 t CO$_2$/MWh in 2020. The Build Margin emission factor considers all newly commissioned power units. Because particularly emission-intensive coal-fired power units are commissioned in 2012 the Build Margin increases, starting at 0.512 t CO$_2$/MWh in 2009 up to 0.650 t CO$_2$/MWh in 2012. Beyond that the Build Margin slightly decreases and results in a value of 0.544 t CO$_2$/MWh in 2020.

The Combined Margin takes into account the Operating Margin and Build Margin. Since its value corresponds to exactly the average of both, the Combined Margin results in a value of 0.576 t CO$_2$/MWh in 2009. Due to the increasing Build Margin particularly in 2012 the Combined Margin increases as well. However, it remains almost unaltered at the end of the consideration period amounting to 0.568 t CO$_2$/MWh in 2020.

The corresponding annual carbon emission factors for the IPS Urals are listed in Table 4-6 differentiated between the Combined Margin, Operating Margin and Build Margin.

Table 4-6: Annual Carbon Emission Factors for IPS Urals

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4.7 Electricity System IPS Volga

4.7.1 Forecasted Load Duration Curves

For the IPS Volga the forecasted load curve of 2019 by following the methodology as described in Chapter 3 is depicted in Figure 4-19.

![Figure 4-19: (a) Forecasted hourly load curve for 2019 inclusive imports/exports and (b) corresponding hourly load duration curve of IPS Volga](image)

Depending on daytime as well as on the weekday the mean grid load counts for approximately 11,000 – 16,000 MW during summer time whereas the value rises up to 15,000 – 23,000 MW during winter time. Peak load occurs at the end of the year as it can also be noticed in other systems on 17.12.2019 at 9 a.m. when the hourly load counts for 23,409 MW.

The depicted values including intra-Russian (via tie-lines between neighbouring Russian IPS) as well as cross-border (via tie-lines abroad) imports/exports represent the “domestic” load of clients within the IPS Volga. Since the development of the technical & non-technical losses within the IPS Volga is already included in the figure for the annual electricity demand which is used in order to scale future power demands, the stated figures above are on so-called “sent-out level”. Hence, their amounts have actually to be generated by the power plants of IPS Volga. This value represents thus the basis of electricity generation when calculating the grid emission factor of the IPS.

4.7.2 Forecasted Energy Mix

The previously depicted load has served as input parameter into the power system simulation which then dispatched the power units following their merit order as well as spinning reserve restrictions. In Figure 4-20 the dispatch for 31.07.2019 is shown.
It can be seen that nuclear power plants (NPP), combined cycle gas turbine (CCGT), combined heat and power plants (CHP) as well as the 200 MW power plants are generating in sum about 11,000 MWh/h to cover the base load. The additional generation covers the demand from other neighbouring Russian IPS and cross-border countries.

In the annual comparison of energy mixes it can be seen that the share of gas fired plants increases during the observation period from 56 TWh to 85 TWh, whereas energy generation of nuclear and hydropower plants remains more or less constant (NPP: +2.6%, HPP: -2.0%). The fuel shares of gas (in terms of electric TWh) increases from 52% in 2009 to 61% in 2020 while NPP energy decreases from 28% to 23% and HPP from 19% to 13%.

4.7.3 Corresponding Carbon Emission Factors

According to the UNFCCC Tool, the previously described fuel mix has been taken into account together with the corresponding efficiencies of the respective power units as well as the fuel carbon emission factors in order to compute the development of the annual grid emission factors. The results for IPS Volga are depicted in Figure 4-21:
The Operating Margin represents the emission factor of the actual operation of the power system. It hence starts at 0.525 t CO\textsubscript{2}/MWh in 2009 and increases slightly to a maximum of 0.549 t CO\textsubscript{2}/MWh in 2012. It then decreases to a value of 0.467 t CO\textsubscript{2}/MWh in 2020.

The Build Margin emission factor considers all newly commissioned power units. Caused by the proposed commissioning of gas-fired power plants, their emissions continuously increase the Build Margin from 0.187 t CO\textsubscript{2}/MWh in 2009 up to 0.433 t CO\textsubscript{2}/MWh in 2020.

As already explained for the other IPS, the Combined Margin takes into account both the Operating and the Build Margin emission factor. Since its value corresponds to exactly the average of both, the Build Margin brings down the actual Operating Margin emission factor. It results in a Combined Margin of 0.356 t CO\textsubscript{2}/MWh in 2009. Due to the increasing Build Margin the Combined Margin follows this development, resulting finally in 0.450 t CO\textsubscript{2}/MWh in 2020.

The corresponding annual carbon emission factors for the IPS Volga are listed in Table 4-7 differentiated between the Combined Margin, Operating Margin and Build Margin.

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</tr>
<tr>
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<td>0.359</td>
<td>0.362</td>
<td>0.387</td>
<td>0.375</td>
<td>0.380</td>
<td>0.385</td>
<td>0.382</td>
<td>0.422</td>
<td>0.442</td>
<td>0.446</td>
<td>0.450</td>
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<tr>
<td>OM</td>
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<td>0.537</td>
<td>0.549</td>
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<td>0.512</td>
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<td>0.513</td>
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<tr>
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<td>0.188</td>
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<td>0.242</td>
<td>0.248</td>
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<td>0.408</td>
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</table>
5 CONCLUSION

Based on the previously elaborated results, this final chapter compiles the project’s main findings and provides recommendations on how to best proceed with the continuous utilisation of the elaborated Power System Simulation Model with special focus on the future development of the analysed electricity systems.

The Consultant identified official data sources to be applied in order to establish a comprehensive data base for the setup of the required Power System Simulation Model. In this context applicable grid boundaries were determined in accordance with the official administrative organisation of the national Russian dispatch centre, since the structure of power generation differs considerably from region to region.

In a subsequent step, a dynamic Model was developed which enables the simulation of future developments in above mentioned electricity systems. The underlying methodology is based on already installed and to be built power generation units, transmissions systems and import/export load patterns. Official investment programs were incorporated in order to model the expected system expansion plan under consideration of the overall electricity demand.

By conducting a dispatch analysis based on economic dispatch rules, the most realistic energy demand and supply scenario for each electricity system was simulated on an annual basis for the period from 2009 until 2020. These scenarios accordingly serve as basis for the calculation of the corresponding carbon emissions factors.

According to Table 5-1 the following electricity carbon emission factors for each electricity system in Russia (IPS) were calculated on an annual basis. Moreover, the development of the annual carbon emission factors is depicted graphically in Figure 5-1.

The overall carbon emission factors for entire Russia as listed in Table 5-1 have been calculated as follows. The OM, BM and CM have been calculated by weighing each annual carbon emission factor for an electricity system according to the ratio of power generation in the respective electricity system, divided by overall power generation in entire Russia. However, the overall carbon emission factors for Russia shall be considered for information purposes only since their calculation deviates from the UNFCCC Tool.
Table 5-1: Carbon Emission Factors for Russia for 2009 – 2020

<table>
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<tr>
<th></th>
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<td>0.330</td>
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</tr>
</tbody>
</table>

Figure 5-1: Development of Carbon Emission Factors for each IPS
Above described carbon emission factors are applicable for supply-side projects. However, for demand-side projects the corresponding demand-side carbon emission factors have to be taken into account. In accordance with the UNFCCC “Tool to calculate baseline, project and/or leakage emissions from electricity consumption” (Version 01), they are derived from the supply-side carbon emission factors by considering the average technical transmission and distribution losses of the electricity systems.

In the following the demand-side carbon emission factors for the Russian IPS for the period from 2009 until 2020 are depicted.

### Table 5-2: Demand-Side Carbon Emission Factors for Russia for 2009 – 2020

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</table>

### Figure 5-2: Development of Demand-Side Carbon Emission Factors for each IPS

![Graph showing the development of demand-side carbon emission factors for each IPS from 2009 to 2020.](image)
Regarding the results which were elaborated in the course of the Baseline Study, the following recommendations concerning the further utilisation of the developed Power System Simulation Model are made.

It is noted that the data sources utilised for the derivation of above presented carbon emission factors represent the current level of information, being either published or having made available by official entities in Russia.

However, in particular due to the uncertain character of any type of official forecast it is strongly recommended to continuously monitor potential updates of any official data source. In this context reference is made to the ex post calculation option of the Power System Simulation Model, see Section 3.2. It allows the user to calculate accurate carbon emission factors on an annual basis by incorporating most recent retroactive grid data.
ANNEX

Utilised Data Sources
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<th>SOURCE</th>
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<td>• Ministry of Fuel and Energy, Ukraine (Refer to <a href="http://www.mpe.energy.gov.ua">http://www.mpe.energy.gov.ua</a>)</td>
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<td></td>
<td>• EBRD Studies</td>
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<td>• Platt’s International Data Base (Refer to <a href="http://www.platts.com">http://www.platts.com</a>)</td>
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<td></td>
<td>• Lahmeyer International’s Analysis</td>
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<td>• Installed/available capacity per unit</td>
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<td>• Scheduled decommissioning year per unit</td>
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<td>• Rules of low-cost/must-run power plants</td>
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<td>• Lahmeyer International’s Analysis</td>
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<td>• Energy Balance Forecast for 2009 to 2015 and 2020</td>
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<td>• Lahmeyer International’s Analysis</td>
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<tr>
<td>• Scenarios for the Power Generation Development up to 2030</td>
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<tr>
<td>• Investment Programs for commissioning of new units</td>
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| All data processed in the study are provided in the Annex to the Minutes of the Meeting with MED dated 11 February 2010.