Generation Adequacy Report
on the electricity supply-demand balance in France
CONTENTS

Synopsis 3
Introduction 4

PART ONE:
OVERALL SUPPLY–DEMAND BALANCE IN MAINLAND FRANCE 5

1 Consumption forecasts 5
   1.1. Recent trends 5
   1.2. Energy forecasts 8
      1.2.1. Methodology 8
      1.2.2. Three scenarios 9
      1.2.3. Annual energy forecasts 11
      1.2.4. Generation Adequacy Report consumption forecasts in relation to… 11
   1.3. Power level forecasts 13
      1.3.1. Power demand 13
      1.3.2. Load management 14

2 Generation facilities outlook 15
   2.1. Overview of existing generation facilities 15
   2.2. Nuclear thermal generation 15
      2.2.1. Existing facilities 15
      2.2.2. Future developments 16
   2.3. Centralised conventional thermal generation 17
      2.3.1. Existing facilities 17
      2.3.2. Environmental regulations 18
      2.3.3. Prospects 19
   2.4. Decentralised thermal generation 20
      2.4.1. Overview 20
      2.4.2. Combined Heat and Power facilities 20
      2.4.3. Thermal plants running on Renewable Energy Sources 21
   2.5. Hydraulic generation 21
      2.5.1. Existing facilities 21
      2.5.2. Regulatory context 22
   2.6. Wind power 22
   2.7. Three prospective scenarios 23
      2.7.1. Common assumptions for thermal generation 23
      2.7.2. Three different scenarios for RES development 23
      2.7.3. Supply side scenarios recap 25

3 Exchange hypotheses 26
   3.1. Interconnections with neighbouring systems 26
   3.2. Energy exchanges 26
   3.3. Exchanges and security of supply in the French system 28

4 Generation adequacy measurement 30
   4.1. Adequacy criterion 30
   4.2. Associated shortfall outlook 30
   4.3. Risk perception 31
   4.4. Link with the markets 32

5 Generation adequacy in the coming years 33
   5.1. Methodology 33
      5.1.1. LOLE calculation 33
      5.1.2. Identifying capacity needs 33
      5.1.3. Soundness of proposed capacity expansion regarding major uncertainties 33
      5.1.4. Energy balance sheets 34
   5.2. Medium term–up to 2010 34
      5.2.1. Capacity needs 34
      5.2.2. Energy balance sheets 36
   5.3. Long term – 2010 to 2016 37
      5.3.1. Capacity needs 37
      5.3.2. Energy balance sheets 39

6 Conclusion 40

PART TWO:
REGIONAL SUPPLY–DEMAND BALANCES 41

1 The Provence Alps Côte d’Azur (PACA) region 42
   1.1. Background 42
      1.1.1. Demand 42
      1.1.2. Generation 43
      1.1.3. Transmission network 44
   1.2. Security of supply 45
      1.2.1. In the eastern part of the PACA region 45
      1.2.2. Tavel–Realtor congestion 47
   1.3. Conclusion 48
Western France 49
2.1. Background 49
  2.1.1. Demand 49
  2.1.2. Generation 49
  2.1.3. Transmission System 50
2.2. Security of supply 51
  2.2.1. Voltage control 51
  2.2.2. Line capacity in Southern Brittany 51
  2.2.3. Line capacity in Northern Brittany 52
  2.2.4. Line capacity in Vendée 53

Ile de France region 54
3.1. Background 54
  3.1.1. Consumption 54
  3.1.2. Generation 54
  3.1.3. Transmission system 55
3.2. Security of supply 55
  3.2.1. Active power restrictions 55
  3.2.2. Voltage control 55
3.3. Conclusion 55

PART THREE: INSULAR SYSTEMS 56

Corsica 56
1.1. Demand 56
1.2. Supply 57
  1.2.1. Thermal generation 57
  1.2.2. Hydro-electric generation 57
  1.2.3. Other renewable generation 57
  1.2.4. Links with other countries 57
1.3. Requirements 58

French overseas départements and Mayotte 58
2.1. Demand 58
2.2. Supply 59
  2.2.1. Installed capacity in 2005 59
  2.2.2. Development prospects 60
2.3. Requirements 61
Synopsis

Under the terms of the Law of 10th February 2000, RTE is required to draw up a multi-annual Generation Adequacy Report on the electricity supply-demand balance in France. The present 2005 edition has been compiled in close conjunction with the working group in charge of PPI (Programmation Pluriannuelle des Investissements de production électrique, or Long-term Investment Programmes) at the French Directorate for Energy Demand and Markets, DIDEME. The purpose of RTE’s Generation Adequacy Report is to quantify the additional electric generating facilities that need to be commissioned in the years ahead. It is based on various scenarios for the development of supply and demand, adopted on 1st January 2005, and covers the period 2006–2016.

Three different consumption forecast scenarios have been used. All include a substantial drop in consumption by the Eurodif plant between 2010 and 2015. The two upper scenarios (called R1 and R2) fall within current trends, with annual growth of 1.7% and 1.5% until 2010 and a slowing down thereafter; they can be considered as equally likely to occur in the short-term. The low consumption growth scenario (R3) is intended to depict a context of environmental commitments. It is based on the assumption that demand side management initiatives will have an immediate impact, which makes it rather unlikely in the short-term. The low consumption growth scenario (R3) is intended to depict a context of environmental commitments. It is based on the assumption that demand side management initiatives will have an immediate impact, which makes it rather unlikely in the short-term. The low consumption growth scenario (R3) is intended to depict a context of environmental commitments. It is based on the assumption that demand side management initiatives will have an immediate impact, which makes it rather unlikely in the short-term.

Up until 2016, France’s fleet of generating facilities will be determined by a number of changes: the re-commissioning of three of EDF’s fuel-oil-fired units, the expected arrival of the EPR in 2012, and the definitive shutdown by 2015 of coal-fired plants that do not meet the requirements imposed by environmental regulations. In the field of renewable energy sources (RES), three different scenarios are considered. The main difference between them is the way wind generating facilities develop. Under the “Low RES” hypothesis it grows by 1,500 MW. Meanwhile, the “High RES” scenario, which includes the Government’s target of covering 21% of domestic consumption with renewable energy by 2013, sees wind generation expand by 14,000 MW. Under the median scenario, the figure of 4,000 MW of wind generating capacity by 2010 seems to reflect estimates deemed realistic by players in the sector. According to consumption growth and RES development hypotheses adopted there will be a need for additional capacities between 2008 and 2010. When reference scenario “R2” is combined with the “Low RES” hypothesis, some 1,200 MW of new capacities are needed by 2010. Under the high demand scenario “R1”, 1,500 MW of additional capacity is needed by summer 2008 if the necessary level of security of supply is to be maintained throughout that winter. Under the same scenario, even taking account of the potential 4,000 MW supplied by wind farms, the capacity needed would be 1,700 MW by 2010.

All of the simulations carried out for the period 2010-2016 show that the electric system is entering a new period in its development, in which regular investment in generating facilities is needed to maintain the security of supply. Beyond 2010, a further 1,000 MW of new capacity will be required each year, if demand side management initiatives are not put into practice. In all cases, the generating installations that need to be developed must be a combination of peak facilities (such as combustion turbines) and mid merit facilities (such as combined cycle gas turbines or CCGTs). The requirements estimated above are based on a specific criterion, according to which the risk of a shortfall in the electricity supply, referred to as the Loss of Load Expectation or LOLE, must not exceed three hours per year on average—consistent with one shortfall every ten years. This criterion is part of a probabilistic approach, and meeting it does not necessarily guarantee that there will be no power cuts in the event of an unusually cold spell of weather. Although the LOLE limit has not yet been exceeded, difficult situations have already been encountered in the recent past. Lastly, the Generation Adequacy Report details specifically what new generating capacities are required to strengthen the security of supply to the Provence Alps Côte d’Azur (PACA) and Brittany regions, as well as in insular systems.

(1) It was announced in May 2005 that a fourth unit would also be re-commissioned, but this has not been taken into account in the present report.
Introduction

Purpose of the Generation Adequacy Report

Under the terms of Article 6 of the Law of 10th February 2000 concerning the modernisation and development of public service electricity, the transmission system operator is required to draw up a multi-annual Generation Adequacy Report, no less than once every two years and subject to the scrutiny of the State.

The purpose of the Generation Adequacy Report is to evaluate the amount of new generation facilities that must be commissioned in the future in order to maintain security of supply for all French territories. The information it contains is used by the Ministry for Energy2 to make final decisions on investment planning control through the PPI (standing for Programmation Pluriannuelle des Investissements, or Long-term Investment Programme). The PPI has been enforced by the above cited law, and is aimed at specifying the fuel mix of generating facilities with respect to French energy policy targets.

Two reports were completed by RTE, in 2001 and 2003 respectively. This third report was carried out in the first semester 2005, in close conjunction with the working group in charge of preparing a PPI report for Parliament. It covers the period from 2005 through 2016.

Methodology and contents

This report is broken down into three parts, dealing with:

- the overall supply–demand balance in mainland France:
  Assessing generation adequacy typically involves forecasting domestic electricity consumption and exchanges between France and neighbouring countries, and comparing them with known developments in generation facilities. Since electricity cannot be stored, and both demand and supply are subject to random variations, under adverse circumstances available generation may not be able fully to satisfy demand, thereby leading to some customers being cut off. Security of supply can be measured by the risk of such “shortfall situations” arising. A quantitative criterion can be set out to define an acceptable level of risk. The amount of new generation facilities must comply with this criterion.

  Chapters one to three respectively describe hypotheses for consumption, known developments in generation facilities and exchanges. The choice of the adequacy criterion and what it physically means is discussed in chapter four. Chapter five includes an estimate of the new facilities that need to be commissioned, in addition to those that have already been decided upon.

- specific situations of some importing areas inside France:
  Whereas the overall supply-demand balance focuses on consumption and generation, security of supply may also be affected by transmission network limitations. Three areas merit special attention, since they import energy: the PACA (Provence-Alpes-Côte d’Azur) region, Western France, and Ile de France, the region around Paris.

- the supply-demand balance of insular systems:
  the island of Corsica and some other French overseas territories have their own insular electric systems. Generation Adequacy in each of them is assessed by their operators: Electricité de Mayotte, for Mayotte Island, and EDF–Systèmes Electriques Insulaires, for all the others.

Warnings about confidentiality requirements

For the purposes of drafting this Generation Adequacy Report, RTE has used information supplied directly by players involved in the French electrical system.

Due to the fact that this information should remain confidential, the presentation of certain hypotheses and results has been restricted. Some detailed elements have therefore been omitted, or figures aggregated.
PART ONE: OVERALL SUPPLY–DEMAND BALANCE IN MAINLAND FRANCE

Consumption forecasts

All the data presented in this chapter refer to gross domestic consumption. They include transmission and distribution losses, but do not include consumption by auxiliaries in power stations, or consumption by pumps in pumped storage facilities.

1.1 Recent trends

Annual energy consumption levels and maximum loads recorded over recent years are listed in the table below:

<table>
<thead>
<tr>
<th>Year</th>
<th>Gross Consumption (TWh)</th>
<th>Maximum load (GW)</th>
</tr>
</thead>
<tbody>
<tr>
<td>2001</td>
<td>448.7</td>
<td>79.6 (December 17th)</td>
</tr>
<tr>
<td>2002</td>
<td>449.9</td>
<td>79.5 (December 10th)</td>
</tr>
<tr>
<td>2003</td>
<td>466.8</td>
<td>83.1 (January 9th)</td>
</tr>
<tr>
<td>2004</td>
<td>477.3</td>
<td>80.1 (December 22nd)</td>
</tr>
</tbody>
</table>

As regards maximum loads, a new record of 86.0 GW was reached on 28th February 2005. These raw data do not show the actual underlying consumption trends. The high degree of volatility which can be observed, especially in the case of maximum loads, can be ascribed to two main factors:

- High sensitivity to climatic conditions in winter, mainly due to widespread use of electric heating: Demand for electricity rises by approximately 1,500 MW for every 1°C drop in the outside temperature. Annual consumption may vary by as much as a dozen TWh, between very cold and very mild winters.

- Load management:
In order to mitigate power peak excursions on extreme cold spells, load management has long been a feature of the French electrical landscape. The first means that appeared, and still the most important in respect of power demand reduction, relies on a price signal: within the price schedules EJP (standing for Effacement en Jour de Pointe: peak day load shedding) or Tempo, prices are set at a very high level for 22 periods of 18 hours each year from 1st November through 31st March, and much lower at other times. Peak days are decided by the supplier, with just one day’s notice to consumers. These price schedules are now available exclusively to non-eligible consumers (mainly in the Residential sector). In 2005, power demand can be reduced by 3,000 MW by activating the EJP signal.

Eligible consumers entered into new contracts with their suppliers by the turn of 2000. Although EJP type provisions were not continued in these new contracts, power demand reduction is still possible from some consumers, at the request of the supplier. The maximum reduction that can be achieved in this way is estimated at 1,500 MW, as experienced on 28th February 2005.
Dependence on these two parameters can clearly be seen on daily load curves. Load curves on Wednesday 12th and 26th of January 2005 are plotted on the next chart. The same week days, just two weeks apart, should exhibit similar consumption patterns over the day. The difference observed is mainly due to outside temperatures:

- -1.2°C on 26th, which can be considered as a cold day: during four out of the past ten winters, the temperature never fell below that value; however, it was not the coldest day of last winter (-3.0°C recorded on 28th February);
- +7.4°C on 12th, which was not unusually mild: the temperature rose to or above that level nine days on average during each month of January alone over the last ten winters;
- load shedding was not necessary on 12th. EJP was activated on 26th, reducing demand by up to 3 GW from 7 a.m. onwards.
Climate sensitivity is now well established in summer too, increasing year on year with the rising use of air conditioning equipment.

Unlike in winter, when temperature sensitivity is fairly even throughout the day, sensitivity in summer is higher in the afternoon, when it is close to 500 MW/°C, than at night or early morning.

Nonetheless, the statistical dispersion of power demand in summer remains well behind that seen in winter. Not only do loads vary less for each degree of temperature, but the range of temperatures experienced is narrower: a +5 °C deviation from the daily average in summer is almost as uncommon as a –8 °C deviation from the daily average in winter.

Bearing in mind these considerations, a sound assessment of consumption trends needs to adjust raw data to take account of the influence of the weather and load management. To do this, an outside temperature reference has to be set. The hourly power demand actually measured (including the power reduction achieved by activating any load management schemes) is converted into what it would have been under this reference temperature.

The chosen reference, called “normal temperature”, is the expected outside temperature for each day of the year.

Once adjusted to take account of the weather and load management, consumption figures showed annual growth of 1.6% to 1.7% in 2003 and 2004, equivalent to an increase of 7 to 8 TWh per year.

(5) Due to climate change, a new “normal temperature” time series for the coming years was fixed in October 2003.
As will be seen in the next section, the consumption forecast process relies on detailed knowledge of end-use consumption. The following table provides consumption data for the main end-use sectors, adjusted for weather and load management and taking account of the leap year effect (for 2004):

<table>
<thead>
<tr>
<th></th>
<th>2001</th>
<th>2002</th>
<th>2003</th>
<th>2004</th>
</tr>
</thead>
<tbody>
<tr>
<td>Adjusted domestic consumption</td>
<td>444.4</td>
<td>453.6</td>
<td>461.0</td>
<td>468.5</td>
</tr>
<tr>
<td>Industry</td>
<td>136.0</td>
<td>135.7</td>
<td>134.5</td>
<td>137.6</td>
</tr>
<tr>
<td>Commercial</td>
<td>108.6</td>
<td>112.6</td>
<td>114.1</td>
<td>115.4</td>
</tr>
<tr>
<td>Residential</td>
<td>131.1</td>
<td>135.0</td>
<td>138.5</td>
<td>141.3</td>
</tr>
<tr>
<td>Energy (including Eurodif)</td>
<td>30.0</td>
<td>30.2</td>
<td>33.3</td>
<td>33.8</td>
</tr>
<tr>
<td>Transport</td>
<td>9.1</td>
<td>9.2</td>
<td>9.0</td>
<td>9.1</td>
</tr>
<tr>
<td>Losses</td>
<td>29.6</td>
<td>30.9</td>
<td>31.6</td>
<td>31.4</td>
</tr>
</tbody>
</table>

1.2 Energy forecasts

1.2.1. Methodology

Electricity consumption is driven by a wide range of factors: economic activity, demography, user behaviour, technological advances, market sharing of energy sources, etc.

To take account of these various factors, RTE’s long term forecasts are based on a detailed breakdown of consumption:

- to begin with, total consumption is divided into industry, residential and commercial sectors;
- within these sectors, further divisions are made into different sub-sectors of activity (iron and steel, chemical, etc.) and electricity end-uses (heating, lighting, engines, etc.);
- for each sub-sector or end-use, one key driver is identified (usually industrial output for industry sub-sectors, number and category of houses for residential end-uses, floor area or employed workforce for commercial end-uses, etc.). Consumption in each sub-sector or for each end-use is estimated as the product of this key driver and an energy intensity value (e.g. the number of kWh used to produce one ton of steel, or to heat one house, etc.).

The current energy intensity values are derived from known current consumption and driver values. Their expected future values include technological advances, at a pace which may vary according to energy prices and energy/environmental regulations.

Forecasts on the key drivers are drawn up in such a manner that they are consistent with macroeconomic (namely GDP) and demographic (total population, employed workforce, number of households) indicators. They include end-use energy switching from or to electricity. Total domestic consumption forecasts take the form of the sum of each sub-sector or end-use consumption forecast.

Uncertainties are attached to all these factors. In order to obtain a plausible range for future electricity consumption, three possible scenarios are outlined for social and political developments, leading to three sets of parameters for sub-sectors and end-uses, and then three electricity consumption scenarios.

Common underlying background:

All forecasts are drawn up on the basis of:

- a steady 2.3% annual growth in GDP through to 2020,
- a rise in the population to 62.7 million people by 2020,
- an employed workforce of 28.5 million people in 2020 (leading to a 4% unemployment rate),
- a rise in the number of households to 28.1 million in 2020,
stability in relative end-users prices for gas and electricity, thereby leading to little change in market shares in end-uses where both can compete.

The decisive drivers:

- **Industry:** Although industrial output growth is set at the same 1.3% per year rate for the three scenarios, sub-sector growth rates differ from one to another, as do energy efficiency improvements. The possible relocation outside France of some large energy consuming industries is not taken into account.

- **Commercial sector:** There are different scenarios depending on the development of energy regulation for buildings and their impact on heating requirements and air conditioning development.

- **Residential sector:** The main differences arise in the structure of new housing (individual houses vs. apartment buildings), evolution of energy regulations for buildings and their impact on heating requirements, air conditioning development, domestic appliances consumption.

*Demand Side Management (DSM):*

The effects of actions taken to curb demand, which are already contributing to the observed drop in growth rates, are expressly taken into account in energy forecasts. They are described differently depending on the scenario used. In the industrial sector, DSM actions are often undertaken spontaneously if economic profitability is achieved rapidly. Use of efficient processes (such as variable speed engines) as well as improvements in specific processes will occur under any scenario.

In the residential and commercial sectors, demand is curbed largely due to regulatory measures, involving electrical appliances labelling (based on energy efficiency), and energy regulations for buildings.

**One particular sector: the energy sector**

Within the energy sector, one particular consumer merits special attention, namely the uranium enrichment plant operated by Eurodif, which is by far the largest one in France. Eurodif has announced that the currently operated plant based on gaseous diffusion will be decommissioned around 2012, and replaced by a new one using centrifuge technology. Switching to this process will lead to a steep decline in energy consumption, worth approximately three years of consumption growth in all other sectors.

**1.2.2. Three scenarios**

As in previous “Generation Adequacy” reports, three consumption scenarios have been drawn up. They differ from each other in terms of social, economical, and political factors.

*“Reference” scenario R2*

In broad terms, scenario R2 assumes that the behaviour of the Government and economic and social players will not undergo any drastic change.

The Government remains deeply involved in energy and environment matters – as has been highlighted in the POPE Law (standing for: “loi Programme fixant les Orientations de Politique Énergétique” – the law enacting French Energy Policy) dated 13th July 2005. Energy regulations are set to be reinforced, notably for buildings, moving a step further every five years. Regulatory requirements are assumed to be properly implemented.

For each sub-sector and end-use, the most likely outcome, according to past trends and on-going technological advances, is assumed for energy intensity improvement.

Scenario R2 will be taken as the reference scenario for the “Generation Adequacy Report”.
“Market oriented” scenario R1
Under scenario R1, the Government is assumed to play a less far-reaching role in the development of the national economy and in the fields of energy and the environment. Decisions regarding energy end-use are made in a market oriented way, sometimes detrimental to environmental issues. As an example, it is assumed that 72% of new lodgings to be built through 2020 will be individual houses, which are more energy consuming, rather than 60% under scenario R2. At the same time, less stringent monitoring of regulatory measures will lead to a mere 15% drop in unitary heating requirements between 2002 and 2020, instead of a 20% drop under scenario R2.

“Environmentally concerned” scenario R3
Conversely, under scenario R3, the Government pays greater attention to environment related issues, and intervenes heavily in the quest for improved energy efficiency. Energy conservation schemes are actively promoted, for electricity as well as for fossil fuels.
### 1.2.3. Annual energy forecasts

The annual energy forecasts for scenarios R1, R2 and R3 are provided in the following table. Figures refer to energy demand expected under “normal” weather conditions, without application of any load management scheme.

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>R1</td>
<td>515</td>
<td>534</td>
<td>569</td>
<td></td>
<td></td>
<td></td>
<td>1.7%</td>
<td>1.3%</td>
</tr>
<tr>
<td>R2</td>
<td>453.6</td>
<td>461.0</td>
<td>468.5</td>
<td>508</td>
<td>522</td>
<td>552</td>
<td>1.5%</td>
<td>1.1%</td>
</tr>
<tr>
<td>R3</td>
<td>494</td>
<td>499</td>
<td>518</td>
<td></td>
<td></td>
<td></td>
<td>1.2%</td>
<td>0.7%</td>
</tr>
</tbody>
</table>

* AAGR: Average Annual Growth Rate – not including Eurodif consumption

### 1.2.4. Generation Adequacy Report-consumption forecasts in relation to...

#### ... historical trends:

The rise in average annual consumption reached 10 TWh per year in the 1980s (not including Eurodif consumption). Since the beginning of the 1990s, the pace has slowed down to 7 to 8 TWh per year.

<table>
<thead>
<tr>
<th>Domestic consumption trend since 1950</th>
</tr>
</thead>
</table>

Under scenario R1, the same pace is maintained through 2010. It is only slightly lower under scenario R2. At the opposite end of the scale, scenario R3 exhibits a sudden drop to less than 5 TWh per year in the coming years.
... economic growth:
Continuing the trend highlighted in the recent past years, consumption growth is slower than GDP growth in all three scenarios.

... Government forecasts:
In June 2004, the DGEMP published a business-as-usual scenario projecting energy supply and use until 2030 (“Scenario Tendanciel à l’horizon 2030”, available on the web site www.industrie.gouv.fr). This scenario only takes account of policies which have already been put in place, or those that are expected with certainty. As such, it is not intended to be predictive, but rather to stand as a benchmark in evaluating new policies.

Forecasts for electricity consumption in 2010 are the same under the “Scenario tendanciel” and scenario R1 of the “Generation Adequacy Report”. Beyond that timeframe, the DGEMP’s forecasts, considering no further moves towards improved energy efficiency, are higher.
The impact of DSM measures under each scenario has been evaluated against 2020 annual consumption:

### Estimates of consumption savings arising from DSM by 2020 (TWh)

<table>
<thead>
<tr>
<th>TWh</th>
<th>R1</th>
<th>R2</th>
<th>R3</th>
</tr>
</thead>
<tbody>
<tr>
<td>Buildings regulation</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Resid. Comm. Ind.</td>
<td>6</td>
<td>2</td>
<td>-</td>
</tr>
<tr>
<td>Technological advances</td>
<td>9</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Production output</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>TOTAL</td>
<td>17</td>
<td>25</td>
<td>55</td>
</tr>
</tbody>
</table>

### previous “Generation Adequacy Report” forecasts:

Any comparison with the forecasts contained in the 2003 “Generation Adequacy Report” publication is difficult due to the changing outside reference temperature. Once the previous forecasts are translated into the current temperature reference, 2010 figures for scenarios R1 and R2 appear about 4 TWh higher than expected in the previous Report. This upward revision is mainly due to the growth observed between 2002 and 2004.

### 1.3 Power level forecasts

#### 1.3.1. Power demand

More than annual energy consumption, the main challenge when attempting to ensure the security of supply is to match power demand during winter cold spells. Power consumption forecasts are drawn up on the basis of typical load curves for each sector, which convert annual energy forecasts for that sector into power for every time slot throughout the year; then, for each time slot, total power demand is obtained by summing up all the sectors.

For reference scenario R2, the resulting power levels at peak time are given in the table below:

### Forecasts for peak power load (Scenario R2)

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Normal temperature peak</td>
<td>76.6</td>
<td>77.6</td>
<td>84.0</td>
<td>88.5</td>
<td>92.3</td>
</tr>
<tr>
<td>1/10 chance peak</td>
<td>87.2</td>
<td>88.2</td>
<td>95.2</td>
<td>100.1</td>
<td>104.1</td>
</tr>
</tbody>
</table>

- Figures refer to half-hourly points and so are consistent with data available on RTE's website.
- The “normal temperature peak” corresponds to the forecast (or climate and load management-adjusted values, for 2003 and 2004) under “normal” climatic conditions at 7 p.m. on a mid-January working day.
- The “1/10 chance peak” is the level which has a 10% chance of being reached or exceeded at some point during the winter, depending on cold spells. This value provides a more realistic picture of the supply that needs to be developed to meet it.
- None of these data take account of any reduction arising from the activation of load management schemes.
The forecasts drawn from scenarios R1 and R3 are grouped together in the following table:

<table>
<thead>
<tr>
<th>Consumption forecasts</th>
</tr>
</thead>
<tbody>
<tr>
<td>--------------------------------</td>
</tr>
</tbody>
</table>

### 1.3.2. Load management

As previously mentioned, power demand may currently be reduced by up to 4.5 GW by activating load management schemes (3 GW from non-eligible customers under EJP price schedules, and a further 1.5 GW from eligible customers). By the end of the 1990s, EJP activation was leading to reductions of more than 6 GW. Subsequently, the first stage in the process of opening the market up to competition had the effect of reducing the effectiveness of load management schemes.

The gradual opening of the market to other consumers, which took place on 1st July 2004 for professionals and is scheduled for 1st July 2007 for all others, might reduce the impact of EJP still further. However, it remains to be seen what kind of offers new suppliers can and will make to these customers, and how attractive they will be to existing EJP price schedule holders.

On the other hand, part of the lost reduction capability could be regained, through different steps:

- commercial agreements between consumers and their suppliers: should electricity prices become very high at peak times, load reduction (rather than building new peak facilities) may prove economically efficient once again;
- large consumers submitting “upward offers” on the Balancing Mechanism (BM); although possible, this step has not been used in practice until now;
- direct agreement between a consumer and RTE for load reduction at RTE’s request, as mentioned in Article 4 of the Law dated 9th August 2004.

Considering all the uncertainties involved, a prudent assumption has been made for this “Generation Adequacy Report”: demand reduction capability will continue to fall, reaching 3 GW in 2010, and will stabilise thereafter.
Generation facilities outlook

All generating capacity figures given in this section relate to net capacity, excluding consumption by power stations auxiliaries. This ensures consistency with the demand figures provided in the previous section.

2.1 Overview of existing generation facilities

As of 1st January 2005, the total installed capacity of generating facilities sited in France stood at 116.7 GW. However, for reasons that will be explained later, some of these facilities cannot be operated, or at least not at full rated power levels. The table below provides a breakdown of global figure into four main types of generation, depending also on what grid facilities are connected to (either the Public Transmission Grid, or distribution networks; it should be remembered that, in France, the Public Transmission Grid covers all voltage levels higher than 45 kV):

<table>
<thead>
<tr>
<th>Installed and operated capacity as of 1st January 2005 (GW)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Installed capacity</td>
</tr>
<tr>
<td>Nuclear Thermal: 63.4</td>
</tr>
<tr>
<td>Conventional Thermal: 27.5</td>
</tr>
<tr>
<td>Wind: 0.4</td>
</tr>
<tr>
<td>Hydro: 25.4</td>
</tr>
<tr>
<td>Total: 116.7</td>
</tr>
<tr>
<td>Of which:</td>
</tr>
<tr>
<td>Connected to Transmission Grid:</td>
</tr>
<tr>
<td>Nuclear Thermal: 63.4</td>
</tr>
<tr>
<td>Conventional Thermal: 24.0</td>
</tr>
<tr>
<td>Wind: e</td>
</tr>
<tr>
<td>Hydro: 24.0</td>
</tr>
<tr>
<td>Total: 111.4</td>
</tr>
<tr>
<td>Operated capacity</td>
</tr>
<tr>
<td>Nuclear Thermal: 63.3</td>
</tr>
<tr>
<td>Conventional Thermal: 21.1</td>
</tr>
<tr>
<td>Wind: 0.4</td>
</tr>
<tr>
<td>Hydro: 25.4</td>
</tr>
<tr>
<td>Total: 110.2</td>
</tr>
</tbody>
</table>

The following sections will provide information on current status and projections for each type of generation, with the “Conventional Thermal” category broken down further into “centralised” (mainly large plants) and “de-centralised” categories.

2.2 Nuclear thermal generation

2.2.1. Existing facilities

The majority of French nuclear generation comes from 58 units, all based on the same PWR (“Pressurised Water Reactor”) technology. These units were commissioned between 1977 and 1999. Their rated power varies from 900 MW for the oldest to 1,500 MW for the newest. Altogether they provide a capacity of 63.13 GW.

The main question regarding these units relates to the duration of their working lives. In France, unlike in other countries, there has been no regulatory limit set on that duration: licences are granted by the Nuclear Safety Authority after each refuelling outage, once compliance with safety requirements is ascertained.

→
Despite this uncertainty, the most common thinking is that they may be operated for at least forty years. This thinking is supported by the current technical condition of the installations, and the assumption that the tightening of safety requirements which occurs every ten years will be economically achievable. Assuming the units have a working lifetime of 40 years (at least), decommissioning should not start until the early 2020s.

In addition to the PWR fleet, the FBR (Fast Breeder Reactor) prototype Phenix, commissioned in 1973, is still in operation. However, it is now used as a laboratory for research and development (in the field of transmutation of long-life radio nuclides) rather than as a generating facility. The maximum authorised output for these experiments is 125 MW, less than its 233 MW rated power. It will be decommissioned in 2008.

2.2.2. Future developments

No existing nuclear units are expected to have their power ratings upgraded in the next few years.

The building of a new EPR (European Pressurised water Reactor) type nuclear unit was announced in 2004. Rated 1,600 MW, it will be sited at Flamanville, and should be commissioned in 2012. This project has to be considered with the replacement of existing nuclear units in mind, and is intended to ensure that tried and tested EPR technology is available prior to 2020. As continued commitment to the nuclear option is a cornerstone of French energy policy, highlighted in the POPE乐观 Law dated 13th July, completion of this project looks quite certain.
2.3 Centralised conventional thermal generation

2.3.1. Existing facilities

Centralised facilities are considered to be those units, usually of large size and connected to the Public Transmission Grid, which are scheduled to maintain the balance between electricity supply and demand within the European electric system as a whole. This category includes all coal- and fuel-oil-fired units larger than 100 MW, Combined Cycle Gas Turbines (CCGT) and Open Cycle Gas Turbines (OCGT - used as peaking facilities) along with a few dual fired (furnace gas/fuel-oil) units.

According to this definition, installed centralised conventional thermal capacity stood at 19.0 GW, as of 1st January 2005.

Operated capacity at that time was however much lower. Indeed, as a response to the over-capacity that built up in the late 1980s, several fuel oil- and coal-fired units were taken out of service. Some of them were decommissioned immediately, but others have simply been kept on stand-by, as a reserve which could be brought back into operation if necessary. Since re-commissioning notice is longer than one year, and none were engaged in this process on January 1st 2005, these idle units cannot be operated in 2005. Their total capacity, which is still accounted for in “installed capacity”, amounts to 6.1 GW.

Most of the centralised conventional thermal facilities are ageing. With the exception of 1.1 GW of CCGT, which were just in the process of being commissioned at the beginning of 2005, and some OCGT built during the 1990s, all the others are now more than twenty years old.
2.3.2. Environmental regulations

The fate of ageing conventional thermal units depends greatly on environmental regulations, which are becoming increasingly stringent. New emissions limits on air pollutants (sulphur dioxide SO\textsubscript{2} and nitrogenous oxides NO\textsubscript{x}) are particularly important. The limits are laid down in the Order dated 30th July 2003, which transposes European Directives 2001/80/EC (known as the Large Combustion Plants directive - LCP) and 2001/81/EC (National Emission Ceilings) into French law.

The main purpose of this legislation is to bring emission limits for existing plants (e.g.: commissioned before 2002) into line with those permitted for new plants: 400 mg/Nm\textsuperscript{3} SO\textsubscript{2}, 400 mg/Nm\textsuperscript{3} NO\textsubscript{x}. Additional abatement devices need to be installed in units built before 1985, to ensure that they comply with the limits and to enable them to continue operating beyond 2008. However, some exceptions are allowed for, of which two are of particular interest:

- less stringent limits (1,800 mg/Nm\textsuperscript{3} SO\textsubscript{2}, 900 mg/Nm\textsuperscript{3} NO\textsubscript{x}) may be imposed on coal-fired units, providing they are operated for no more than 20,000 hours starting from 1st January 2008 and are stopped no later than 31st December 2015. This opens up the possibility of postponing the decommissioning of old facilities, for which abatement investments would not prove cost effective.

- for fuel oil-fired facilities which will not operate for more than 2,000 hours per year (which is the case for peak facilities), limits are not set on concentrations of pollutants in exhaust gases, but rather on the quantities emitted each year: for a 600 MW rated unit, caps are set at 735 t/year SO\textsubscript{2} and 1,155 t/year NO\textsubscript{x}. In practice, these caps will reduce average annual generation by the facilities concerned to under 1,000 hours per year, even if they use fuel oil with lower sulphur content than at present.

The total capacity of facilities operated in 2005 which are potentially concerned by the first exception stands at 7.7 GW (from the total of 12.9 GW in operation, the following are discounted: 1.1 GW of new CCGT which comply with new regulations, 3.3 GW of fuel-oil fired units, which will opt for the second exception, and 0.8 GW of OCGT which are not concerned by this regulation). Operators made their decision in June 2004: only 3.2 GW will be retrofitted to comply with new limits; the remaining 4.5 GW will be restricted to 20,000 hours of operation from 1st January 2008 onwards.

As regards “idle” units, in light of this environmental regulation, as well as the costs incurred in rehabilitating units which have not been run for more than ten years, it is deemed that only four fuel-oil fired units, for a total amount of 2.5 GW, may be brought back into operation as peak facilities (second exception).

CO₂ emissions permits place new restrictions on the operation of conventional thermal plants. However, they are not deemed to result in more stringent limits than those imposed by the Large Combustion Plants Directive.

2.3.3. Prospects

Centralised conventional thermal operated capacity will develop as units are commissioned (or re-commissioned) and decommissioned. Decommissioning decisions will be influenced greatly by environmental regulations, as discussed above. They may also be influenced by other considerations, with the effect that many units will be decommissioned earlier than would be strictly necessary under regulations. On the basis of information provided by operators, RTE has drawn up the following time schedule for plant closure:

- 1,350 MW from 2005 through summer 2009 (mainly units capped by the 20,000 hours LCP credit, which will be stopped for other reasons before this credit is exhausted*)
- 1,000 MW from summer 2010 through summer 2012 (units capped by the LCP credit, which will be stopped for credit exhaustion)
- 2,450 MW from summer 2013 through to the end of 2015 (including 2,100 MW of coal-fired units capped by the LCP credit; it should be noted that, to allow operation beyond 2013, annual average generation duration between 2008 and 2013 may not exceed 3,000 hours, which is rather less than the generation times observed the last few years).

Decommissioning dates are very uncertain, since operators are not required to give RTE much notice of such decisions, and may even adapt their strategy depending on market developments. The indicative agenda given above is a plausible one, consistent with all known information to date, but it cannot be considered as certain.

(∗) of which 480 MW were permanently shut down during the first half of 2005.
Conversely, re-commissioning of idle units will raise operated capacity. RTE has been advised that three fuel-oil-fired units, totalling 2.0 GW, are to be brought back into operation, one each year between summer 2006 and summer 2008.(10)

Moreover, several operators have publicly announced plans to build new capacity in France, mainly based on natural gas technology (CCGT). However, at the beginning of 2005, there is no certainty that they will proceed to completion.

2.4 Decentralised thermal generation

2.4.1. Overview

As a definition, decentralised thermal generation involves all other facilities which do not fall into the “centralised” category discussed above. Total installed and (supposedly) operated capacity amounts to 8.5 GW as of 1st January 2005, of which 3.5 GW are embedded in distribution networks. It includes all conventional thermal facilities on Corsica (284 MW), where there is no Public Transmission Grid.

Most of the decentralised thermal facilities located on the mainland are operated without taking account of market prices or the supply – demand balance. These are mainly:

- units which benefit from “compulsory purchase”: a contract agreed with the “Public Service Operator” ensures that all the power generated will be sold at a guaranteed price; a large number of Combined Heat and Power (CHP) facilities are granted this kind of contract.
- units burning non-commercial fuels (such as forestry or paper industry by-products, refinery gas, and so on), where generation is driven by fuel availability.

Their production can then be considered as inevitable. However, since purchase prices are more profitable in periods extending from 1st November through 31st March, power output is higher in winter, when demand for electricity is itself higher.

The only exception concerns Diesel groups, all embedded in distribution networks, which can be started up at RTE’s request. They are used as peak facilities, in the same way as “centralised” OCGT. Their cumulative capacity is close to 800 MW.

2.4.2. Combined Heat and Power facilities

CHP expansion has been impressive between 1998 and 2002, with the commissioning of nearly 4 GW of new facilities, most of them burning natural gas. This can be explained by favourable regulatory rules, notably “compulsory purchase” by the Public Service Operator, and the as yet underexploited potential both in industrial sites and in association with district heating networks. However, the pace of development has slowed in recent years, with a mere 150 MW of new facilities commissioned in 2002 and 2003.

In the years ahead, development of CHP will be led by the PPI (standing for Programmation Pluriannuelle des Investissements – Long Term Investment Programme) Order dated 7th March 2003, which sets a range of 250 to 1,000 MW to be commissioned between 1st January 2003 and 1st January 2007. Given the recent trend and the lack of new incentives, the Generation Adequacy Report is based on the lower end of this range. Moreover, “compulsory purchase” is now dependent on a more stringent global energy efficiency criterion, which is deemed to limit further development.
“Compulsory purchase” agreements have a twelve year duration. Most of them will terminate around 2010, and there is no certainty that they may be renewed or prolonged.

### 2.4.3. Thermal plants running on Renewable Energy Sources

Renewable Energy Sources (RES) used in thermal power generation include biomass (wood, etc.), bio-gas (landfill gas, or gas resulting from the methanisation process), and municipal waste (50% of its calorific content is conventionally assumed to originate in renewable sources).

According to European directive 2001/77/EC (which promotes RES power generation), France aims to have RES generation cover 21% of its domestic electricity consumption by the year 2010. This target is included in the POPE 11 Law dated 13th July 2005.

In the mean time, the PPI Order dated 7th March 2003 sets development objectives for each kind of generation: 50 to 100 MW for bio-gas, 200 to 400 MW for biomass, and 100 to 200 MW for waste, to be commissioned between 1st January 2003 and 1st January 2007.

Considering that development had lagged behind objectives, and as a complement to “compulsory purchase” for small-scale facilities, the Ministry of Industry issued a call for tenders for units larger than 12 MW. Fourteen projects were declared successful in early 2005, for a cumulative capacity of 232 MW (216 MW biomass – mainly wood – and 16 MW bio-gas).

In 2003, 3.3 TWh were generated from waste, 1.3 TWh from biomass and 0.4 TWh from bio-gas. As half of the waste used is considered renewable, 2003 thermal RES generation is estimated at 3.4 TWh.

The long term capability of thermal RES has been explored on the basis of economically available resources. 8.2 TWh in 2010 and 12 TWh in 2016 seem to be the highest achievable output. Turning this potential output into reality will require government support.

### 2.5 Hydraulic generation

#### 2.5.1. Existing facilities

Hydro-electric facilities have not changed greatly in the last 20 years. The total installed capacity amounts to 25.4 GW. Average annual producible energy from natural water inflows is 70 TWh\(^1\); dispersion around this average figure, depending on rain- and snow-falls, is relatively wide: up to +/- 10 TWh. Due to inevitable production losses (overflows, machinery failures, etc.), expected annual generation is 67.5 TWh, with current equipment and under existing operating regulations.

Pumped Storage facilities provide supplementary generation, by taking water pumped and stored at an earlier time when electricity prices were lower, and using it to drive turbines when prices are high.

There are virtually no plans to develop large power installations, with the exception of one on the Romanche river (Alps). However, this project involves replacing old equipment (more than a century old for some stations), and will yield only moderate gains in terms of power capacity and annual producible energy. Consequently, the 200 to 1,000 MW target set by the PPI Order for commissioning of hydro plants between 2003 and 2007 will prove difficult to achieve.

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(11) POPE stands for “loi Programme fixant les Orientations de Politique Energétique” – the law enacting French Energy Policy

(12) average annual energy which would be generated from natural inflows if installations were always operated under optimal conditions.
2.5.2. Regulatory context

The above mentioned POPE Law emphasises the importance of hydroelectricity both as a form of RES generation (which must cover 21% of national consumption by 2010) and for its fast moving capability (thus improving the security of electricity supply).

However, the French parliament is also set to debate another piece of legislation, concerning water and the aquatic environment. This Water Law may impact hydroelectric generation in three ways:

- A rise in the so-called “reserved flows” to be maintained in the natural river bed\(^{(13)}\): now set at 1/40 of the average annual natural flow (module), they may be lifted up to 1/10 from 2013 on (or when licenses are renewed, if sooner). With no changes to existing installations, it would result in a 3 TWh loss of annual producible energy.
- Limits on flow variations: water inflows are usually stored during periods of low demand, and then released at a higher rate during peak demand periods; limits on daily downstream flow variations might have negative consequences for available capacity at peak time.
- A ban on new constructions along rivers (or part of rivers) which have not been equipped up to now: part of the (low) expansion potential would be frozen.

2.6 Wind power

Wind power generation is still limited in France, with installed capacity less than 400 MW as of 1st January 2005. France still has high potential in this field, especially in areas located along the Mediterranean coast and the Channel.

Since thermal RES and hydroelectric capabilities are limited, wind power is essential if the country is to reach or even get close to the 21% RES target. With a view to making substantial developments in wind power capabilities, RTE has undertaken a study on how to accommodate this kind of generation in the French electric system. The study’s conclusions are presented in Appendix 1.

One important point is that, although there can be no guarantee on the output of wind generators, installing them does reduce the amount of thermal generating capacity needed to achieve the same security of supply. In this respect, it can be said that wind generators provide capacity credit.

This capacity credit is close to the average winter load factor of wind generators (around 30%, i.e. installing 1 GW of wind generators saves 300 MW of thermal facilities) when there are few wind generators. It decreases as installed wind capacity rises, but still remains around 20% when installed wind capacity lies in the range of 15 to 20 GW.

It should be emphasised that these results are established for the French mainland system and are based on:

- Wind conditions: wind speeds in the Mediterranean and the Channel areas are not correlated; within the latter, correlation between western (Brittany) and eastern (Nord-Picardie) regions is poor. Geographically balanced development across these areas will allow for inter-regional compensation;
- The electric system: the amount of thermal facilities required to achieve an acceptable level of security of supply depends heavily on power demand volatility, which is high in winter due to outside temperature sensitivity. Adding wind generators provides some power, thus reducing thermal capacity requirements. It also means that the demand to be covered by thermal facilities is more volatile, thus requiring additional thermal capacity. However, since there is no correlation between outside temperature and wind speed in winter, this volatility is moderately increased. This increase in volatility is negligible for just a few installed
wind generators, and becomes slightly more acute as installed wind generation is in the range of 10 to 20 GW.

These conclusions do not apply in other systems, such as those in French overseas territories (or other European systems) where geographical concentration leads to a more widespread statistical dispersion of wind generators’ output, and where the statistical dispersion due to other random events is less marked: in those cases, the capacity credit of wind power is much lower.

The PPI Order dated 7th March 2003 sets a target of between 2,000 et 6,000 MW of new generators to be completed between 2003 et 2007. Two support mechanisms have been introduced to achieve this goal:

- “compulsory purchase” at guaranteed prices: until 2005, all wind farms less than 12 MW were covered by this scheme; under the POPE Law, this cap will be removed and all wind farms located in newly-created “Zones de Développement de l’Eolien” (Wind energy development areas) will be eligible;
- the Government issuing call for tenders for wind farms greater than 12 MW: a first call for tender has gone out for 500 MW offshore installations, and a second one for 500 MW onshore wind farms; both are pending.

### 2.7 Three prospective scenarios

The above considerations indicate that future prospects for nuclear and centralised conventional thermal generation are fairly clear, at least until 2010. Uncertainties on the supply side mainly stem from decentralised generation (thermal RES, wind power) whose development requires public support, and to a lesser extent, from hydropower, depending on changes to the regulatory framework.

#### 2.7.1. Common assumptions for thermal generation

Hypotheses regarding centralised thermal generation are unique, and based on the most plausible outcome outlined in paragraphs 2.2.2. et 2.3.3.

- Nuclear generation: 58 REP remaining in operation through 2016 at least, Phenix shutdown in 2008, and commissioning of one EPR unit in 2012,
- Conventional thermal generation: re-commissioning of 3 fuel-oil fired units (2,000 MW) from 2006 to 2008, gradual phasing out of 4,800 MW coal-fired units from 2005 to 2015.

A unique hypothesis has also been made for CHP, despite uncertainty about whether the “compulsory purchase” scheme will be renewed beyond 2010. It has been considered that at that time installations will be fully amortised, so that operation will be profitable as long as earnings recoup operating and maintenance costs. If the supply–demand balance is tight, prices on power markets will be high enough to support extended operation; if not, some CHP capacity might be shut down, but in such a situation of overcapacity, these closures would not result in a need for additional capacity.

#### 2.7.2. Three different scenarios for RES development

Uncertainties regarding the development of RES are considered on the basis of three supply scenarios, which will be detailed in this section.

The “Low RES” scenario only takes account of capacity developments that can be considered as certain:

- wind power: between now and 2010, capacity already in place or under construction in 2005 will be increased by the addition of 1,000 MW resulting from the Government’s two calls for tender;
biomass: projects declared successful from the calls for tender are the only new facilities to be commissioned between now and 2010;
- hydro power: no significant capacity addition or withdrawal is expected; however, although equipment is stable, it is assumed that the rise in “reserved flows” will lower annual producible energy by 3 TWh/year from 2013 onwards.

The “Low RES” scenario will be considered as the reference supply scenario for evaluating capacity requirements in this “Generation Adequacy Report”.

Under the “High RES” scenario, precedence is given to RES generating 21% of domestic electricity consumption, if not by 2010 then within a few years of that date. Such a scenario calls for substantial governmental support.

Under this scenario, thermal RES generation as a whole (including half of generation from municipal waste) climbs to 8.3 TWh in 2010, and 11.9 TWh in 2015.

The main expansion is expected in wind power generation, with milestones of 12 GW installed in 2010, and 14 GW in 2013; subsequently, as the 21% RES goal is reached, the pace of growth slows down, leading to 16 GW in 2020. Production amounts to 28 TWh in 2010, 33 TWh in 2016, in accordance with a generation capability of 2,300 hours of full power equivalent per year.

For hydro-electric generation, the impact of the rise in “reserved flows” is softened; moreover, new small hydro schemes are assumed to expand along rivers that have not, until now, been equipped with installations.

The “Medium RES” scenario is intended to provide a more plausible picture of RES development in the short term, according to observed on-going developments. In the longer term, the final goal of having 21% of domestic consumption coming from RES will actually be reached, but at a later date, by the turn of 2020.

Under this scenario, thermal RES generation in 2010 is expected to be 5.6 TWh, meaning that additional capacity, in the same order of magnitude as that involved in the first Government calls for tender, has to be decided and commissioned in the meantime; the expected capacity for 2016 stands at 6.1 TWh.

Installed wind power capacity is expected to reach 4 GW in 2010, producing 9 TWh/year. These figures lie within the range of current forecasts made by operators. Thereafter, capacity expands to 12.5 GW in 2016 (producing 29 TWh/year), and to 14 GW (33 TWh/year) in 2020.

Concerning hydropower, equipment is assumed to remain unchanged until 2010; subsequently, the drop in producible energy induced by the rise in “reserved flows” is assumed to be offset by some new small scale developments.
2.7.3. Supply side scenarios recap

The following tables recap hypotheses that will be used under each scenario, looking at both operated capacity (not accounting for “idle” facilities) and annual producible energy.

<table>
<thead>
<tr>
<th>Operated capacity forecasts (GW)</th>
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<tbody>
<tr>
<td>(GW)</td>
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<tr>
<td>Low</td>
</tr>
<tr>
<td>Nuclear</td>
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<td>63.3</td>
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<td>12.9</td>
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<td>Decentralised th. of which RES</td>
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<tr>
<td>8.5</td>
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<tr>
<td>1.0</td>
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<tr>
<td>Wind power</td>
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<tr>
<td>Hydro</td>
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<td></td>
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<tr>
<td>Producible energy forecasts (TWh/year)</td>
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<td>---------------------------------</td>
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<td>(TWh)</td>
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<td>3.4</td>
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<tr>
<td>Wind power</td>
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<td>0.3</td>
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<tr>
<td>Hydro*</td>
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</tbody>
</table>

*: excluding Pumped storage stations – in 2003, actual generation
Exchange hypotheses

3.1 Interconnections with neighbouring systems

The development of electricity exchange capacities between countries allows for solidarity in three key areas:

- greater security for national electric systems, more able to deal with contingencies affecting generation facilities or grids: in the event of an incident, automatic systems can help to a certain extent, by channelling emergency supply from interconnected countries to the affected area.
- sharing of operational reserves: each system contributes to these reserves in proportion to its size, thus cutting the operating costs of national generation fleets.
- optimum use of generating facilities: by establishing a network of generating units, operators are able to dispatch least cost units which are available to meet the overall demand, at any given time; units with lower generating costs therefore run almost continuously; to satisfy basic demand across the entire interconnected area; the units which cost more to run are only used to meet peaks in demand.

The French electric system is solidly interconnected with those of neighbouring countries. At the beginning of 2005, the nominal export capacity on all borders was approximately 14 GW. Not all of this nominal capacity is always available for commercial trading, depending on where electricity is injected into the system and whether certain installations are unavailable: Net Transfer Capacities (NTC) for each border and each hour of the next day, as well as forecasts for the coming weeks and years, are published daily on the RTE website (www.rte-france.com).

There are currently two borders on which exchange capacities are deemed insufficient, and which RTE and its counterparts plan to strengthen:

- the Franco-Belgian border: RTE and ELIA have jointly decided to strengthen the interconnection by adding a second circuit to the existing 400 kV line between (near Lille) and Avelgem (Belgium). Work is expected to be completed by the end of November 2005.
- the Franco-Spanish border: the maximum NTC of 1,400 MW (and often less, notably in summer) is very low, given the size of the French and Iberian electric systems, and particularly in view of the substantial operating contingencies that can affect them. In addition, the European Commission has identified the need for improved transit capacities between France and Spain as a priority. A project to strengthen the link in the Eastern Pyrenees has been put forward, which would take the NTC to 2,600 MW. The plan was opened to Public Debate in 2004. Consultations are continuing.

3.2 Energy exchanges

France has won a leading position as an exporting country in Europe since the mid-1980s.

Part of these exports come from firm commitments, either foreign stakes in French facilities or long term supply contracts with foreign counterparts, most of them agreed by the end of the 1980s for twenty years or more. However, an increasingly large por-
tion comes from short term transactions, which have developed since market liberalisation in Europe. The short-term markets provide a means of comparing generating supply available in different locations for very narrow timeframes (within the day, or even shorter), when operating conditions are relatively clear. The transactions agreed on these markets are those that serve to equalize supply prices everywhere the most efficiently, as long as transmission capacities allow the necessary power to be actually transmitted. It is perfectly possible for the resulting exchange flows to be in the opposite direction to transactions agreed several weeks, months or even years beforehand, as is the case with the long-term contracts signed in the 1990s.

The dynamic nature of short-term exchanges is highlighted by the total volume of commercial trading involving France (sum of imports and exports, both counted positively, resulting from any kind of commercial contract): this volume rose from 107.8 TWh in 2002 to 113.2 TWh in 2003, and 118.7 TWh in 2004, whereas the export balance (difference between exports and imports) fell.

Commercial flows across interconnections thus appear to be determined by the relative competitiveness of the generating facilities available at any given time on interconnected systems, rather than by commercial obligations contained in previously agreed contracts.

The fact that France tends to export more electricity than it imports indicates that it has competitive generating facilities, which exceed strict national requirements. The drops observed in 2003 and 2004 were partly due to temporary factors (the effect of climatic factors on national demand, poor water availability); however, they were also partly due to structural causes: the stability of inevitable generation and facilities with very low generating costs, which are increasingly monopolized by rising national consumption.
3.3 Exchanges and security of supply in the French system

The ability of neighbouring systems to help maintain security of supply in France depends not only on interconnection capacities, but also on available generation capacity abroad.

Stakes in French generating facilities or long term supply contracts have guaranteed foreign counterparts a 3 GW supply from France since the 1990s and through to 2010. Accordingly, these foreign counterparts have not found it necessary to build the same capacity in their own countries.

However, each electric system is subject to random events, and has to install sufficient capacity to cope with adverse contingencies. Random events in foreign systems are only partly correlated with those of the French one. Of course, climatic conditions (especially cold spells) are usually roughly similar between neighbouring countries, but temperature sensitivity in foreign systems is much less marked than in France. Other random events, such as hydro flows or wind speeds, are less correlated across the continent, and some others, like thermal plant outages, are not correlated at all.

The fact that these random events do not produce adverse outcomes at the same time means that, statistically, when the system margin (available generation, minus demand) is reduced in France, most often there is some available generation capacity left somewhere abroad. Considering the nature of random events and their impact in terms of power variation and their correlation over the European systems, available capacity abroad when the French system margin is close to nil is estimated at 3 GW, with a standard deviation of 3 GW.

When combining both sets of data, that is to say:
- the (steady) ability to find, on average, 3 GW from neighbouring systems when there is no generating capacity left in France,
- a firm (inherited) commitment to export 3 GW,

it appears that, when security of supply is endangered in the French system, the exchange balance can be set at zero. To be more precise, it is statistically possible on average that the system can be balanced, but it cannot be taken as certain in all circumstances: in the event of a shortfall in France, there is a 50% chance of finding power to import, and even a 20% chance of finding up to 3 GW; conversely, there is also a 20% chance of having to export 3 GW.

This brief analysis is supported by empirical observation. Over the last four years, margins in the French system were sometimes reduced to unusual levels. The actual exchange balance in four such situations is given below (more detailed information on each of these situations is available in Appendix 2):
- in August 2003, when the possibility of cutting off the load in France was considered, net exports of 3 GW had to be maintained,
- during the cold spell of December 2001, the exchange balance switched to (very low) import for a few hours,
- during the less severe cold spell of March 2004, exports fell to almost 1 GW for a few hours; the price level at that time was reasonable, suggesting that imports could have been made if necessary,
- and then, during the cold spell of late February - early March 2005, when the situation in France was very tight, the exchange balance showed imports up to 3 GW.
In the future, import capability at extreme peaks will obviously depend on developments in the supply–demand balance in all neighbouring systems. However, an in-depth analysis of all these systems (something like a Generation Adequacy Report at European scale) is beyond the scope of the present Generation Adequacy Report, which focuses exclusively on the French system. An assumption has therefore been made: the prevalent conditions in 2005 (i.e.: the ability to cancel exports, on average) will continue until 2015.

It appears plausible that margins will remain steady abroad, if not in each individual system, then at least over a sample of systems. Concerns about security of supply have arisen in many European countries, and it may be expected that, if they worsen, countermeasures will be undertaken to restore margins to the current level. Conversely, it would be imprudent to expect larger margins abroad, since surplus capacity puts downward pressure on prices, leading operators to withdraw some of it (by means of permanent shut-down, or mothballing).

This assumption is consistent with the findings of the UCTE as published in the “System Adequacy Forecast” Report (available on the UCTE website at www.ucte.org): margins at UCTE scale are seen as remaining steady until at least 2010.
4. Generation adequacy measurement

4.1 Adequacy criterion

As electricity cannot be stored and both supply and demand are subject to random variations, it is rigorously impossible to guarantee that consumers’ demand can be fully met at any time and in any circumstance. When a combination of particularly unfavourable random events occurs and causes available generation to fall below total demand, the only way to maintain the balance between production and consumption is to cut off a part of demand: such situations are referred to as “shortfall situations”.

Adding supply resources reduces the risk of “shortfall situations” occurring. Customer dissatisfaction (measured by the frequency or duration of shortfall situations, or unsupplied energy) falls, whilst the cost of installing new facilities, which is ultimately passed on to consumers, increases. Determining the appropriate or adequate level of generating capacity involves deciding between costs and security of supply. Since the security of supply is the same for all consumers (improved security cannot be bought by individual consumers), this decision clearly has to be made at the Government’s discretion.

The adequacy criterion used in the present Generation Adequacy Report, with approbation from DGEMP, is the average duration of shortfall situations, also known as Loss Of Load Expectation (LOLE). Supply is adequate when LOLE stands at 3 hours per year.

This criterion is the same as in the 2003 Generation Adequacy Report. It is equivalent to the one historically used by EDF.

4.2 Associated shortfall outlook

Shortfall situations are those where the System Operator is led to disconnect some consumers without notice, in order to maintain actual consumption in balance with available generation. Load shedding with consumers’ consent is considered a normal way of balancing supply and demand and does not account for a “shortfall situation”.

Consumers are only disconnected as a last resort, when all regular or emergency steps have failed. It is only done after:
- all upward offers submitted to the Balancing Mechanism are called upon,
- the system Reserves, except Primary Reserve, are exhausted,
- so-called “emergency means” are required: calling for remaining surplus system reserves in neighbouring systems, in agreement with the TSOs concerned; reducing voltage on distribution networks; overloading thermal units; running hydro facilities at full power.

The daily pattern of French system consumption in winter peaks at around 7 p.m. (see §1.1). Although the load at that moment is usually 3 GW higher than in the morning, the risk of a shortfall occurring at the evening peak is not much higher. Indeed, the evening peak is:
- quite short, allowing for full power use of hydro plants with small or medium capacity reservoirs, and consistent with efficient use of emergency means,
- not synchronous with evening peaks in neighbouring systems (one hour later than in...
Germany, Belgium or Italy; one hour earlier than in Spain), thus increasing capability of assistance from those countries.

Accordingly, it is considered that, if supply is sufficient to match the morning peak demand with regular operational means, unless a large unit trips in the afternoon, emergency means will enable operators to meet the evening peak without disconnecting any consumers.

So, when disconnection proves unavoidable, it will last for a duration of at least 5 to 6 hours per day (3 to 4 hours in the morning, 2 hours in the evening), climbing to 16 or 18 hours on the worst days. The average disconnected load is estimated at 2 GW.

Such situations are likely to be encountered mainly during cold spells which last for several consecutive days. Depending on the outside temperature, the availability of thermal units and river flows, loss of load will occur from one to a dozen days (between 3 and 4 on average), usually working days in the same week or spanning two consecutive weeks. The average duration of a shortfall situation stands at approximately 30 hours.

Consequently, the generation adequacy criterion (LOLE at 3 hours/year) translates into a 10% probability that (at least) one shortfall situation will be encountered during one year. In other words, if supply is always tailored so as to meet the criterion exactly, shortfall situations will be experienced every ten years on average.

Notably, this equivalence (3 hours/year – return time of 10 years) applies specifically to the electric system in mainland France. The main random events in this system (e.g. cold spells, droughts, and even large thermal unit outages) have fairly long time characteristics.

This implies that shortfall situations tend to accumulate in episodes of several consecutive days. These episodes must be infrequent, so as to keep LOLE at 3 hours/year on average\(^\text{17}\). In French overseas territories, where the main random event (Diesel or OCGT outage) has a much shorter time characteristic, shortfall episodes usually last one or two days. If the same 3 hours/year criterion is used, they will occur more frequently than on the continent.

### 4.3 Risk perception

Shortfall situations are the only ones which actually affect consumers, but they are not the only source of concern about security of supply.

Indeed, in order to appreciate the risk incurred at a given time a few hours or a few days in advance, one needs to consider the possibility that other adverse random events (temperatures lower than forecasts, unit trips) might materialise in the meantime, thereby turning a tight but still manageable situation into a shortfall one. As soon as a non-negligible risk is detected, alerts must be activated. In many cases, the worst will not happen. Alerts are therefore more frequent than actual disconnections.

As an example, every day for the peak hour of the following day, a 4.5 GW margin (in winter - a 3.5 GW in summer) is needed to overcome contingencies\(^\text{18}\). If there are insufficient upward offers on the BM (these account for most of the margin), RTE displays alerts to BM participants. Combined with the 3 hours/year LOLE criterion, the expected annual number of hours where margin requirements are not fulfilled due to lack of supply over Europe is estimated at 12; the probability of encountering such a situation at least once within one year lies in the range of 35% to 40%.

\(^{17}\) Wind generation has a shorter time characteristic (large variations in wind speeds often occur 24 hours apart). However, simulations conducted with wind generation installed capacity up to 12.5 GW have shown that, to achieve the same LOLE of 3 hours/year, the probability of a shortfall situation is just slightly higher at 11%.

\(^{18}\) The margin requirement is sized so that the probability of having to call upon emergency means is less than 1% at the morning peak, and 4% at the evening peak, in winter.
The longer the prediction times involved, the greater the uncertainty in meteorological forecasts and the higher the probability of plant outages. Consequently, for longer notice periods (three days, one week, etc.), the frequency of alerts will still be higher.

The cold spell experienced in February – March 2005 illustrates the difference between perceived risk and actual conditions. Energy suppliers issued warnings calling on French consumers to decrease their consumption, numerous TV reports and newspaper articles dramatically highlighted the tight situation and raised questions about generation adequacy. However, with important but local exceptions (Corsica, where load curtailment was actually activated – see part III – and the Provence Alps Côte d’Azur region, where emergency means, the last step before load curtailment, were used – see part II), real time power margins always remained at comfortable levels.

Although power outages are actually uncommon when using the 3 hours per year LOLE criterion, repetitive alerts may induce a feeling of poor security of supply.

4.4 Link with the markets

According to market principles, generating facilities which are necessary for the security of supply will only be maintained or developed if they yield sufficient revenues to cover at least operating and maintenance costs. This should be the case in particular for those peak facilities which are used on average barely more than 3 hours per year (load curtailment and emergency means use duration).

According to the latest of the DGEMP’s periodic studies on electricity generation costs, which is available on the website www.industrie.gouv.fr, the annual fixed costs of an OCGT (capital and operating and maintenance costs) amount to 43 €/kW. If such facilities yielded income only during the 3 hours (annual average) where they are used, prices would have to climb 14,000 €/MWh at these times to make the investment profitable. In fact, they yield income over a somewhat longer period: suppliers have to make decisions on buying power from hours to days before the time of supply; the risk of incurring a negative imbalance (where their clients consume more than they are generating and/or have already purchased from third parties), and having to pay for it19, result in preventive buying; such buying, which will most often be seen as unnecessary afterwards, tends to push prices upwards more than 3 hours per year. Nevertheless, even assuming price spikes lasting 15 to 20 hours per year, an average price of 2,000 to 3,000 €/MWh over these 15 to 20 hours would be necessary to pay off OCGT investment. If market prices were to attain such high levels for such long periods, the 3 hours per year LOLE would be easily achieved.

Market surveys however do not support this condition. Clearly, the probability of shortfall situations has been less in past years than it is expected to be in the future, but the difference in prices between what has been recorded and what would be necessary is substantial: since Powernext was created, the threshold of 1,000 €/MWh has been reached for a period of 7 hours, in August 2003; the average of the 70 highest hourly prices between late November 2001 and April 2005 (three and a half years) is just over 300 €/MWh.

There is no evidence that the market mechanisms implemented until now will be able to sustain the investments in generating capacity needed to ensure the desired security of supply.
5 Generation adequacy in the coming years

5.1 Methodology

5.1.1. LOLE calculation

An assessment of generation adequacy for the coming years is based on comparisons between projected demand (as stated in chapter 1), generation capacity (chapter 2), and accounting for exchanges (chapter 3). It is conducted through system simulations, each of them covering a one year period, with different combinations of the main random events to which the French supply–demand system is subject: outside temperatures, hydro flows, wind speeds, thermal plants outages. The number of simulations (almost 500) is high enough to provide statistically significant results, both on LOLE (and other shortfall parameters: the probability of encountering at least one “shortfall situation” during the year, unsupplied energy), and on the energy balance sheet (annual generation from each unit, or its operating duration).

5.1.2. Identifying capacity needs

The need for new facilities to comply with the adequacy criterion (3 hours per year, as stated in chapter 4) is evaluated on the basis of the most likely demand scenario (R2), with only fairly certain generation development (Low RES).

If simulations show that LOLE is less than 3 hours per year, then generation capacity is sufficient. If not, additional facilities are needed: new simulations are carried out with them, until LOLE is reduced to the required 3 hours per year.

The annual operating duration of fuel-oil-fired units, as well as of coal-fired units capped with the 20,000 hours credit which are intended to be operated beyond 2013, is also measured. If these exceed compulsory limits (set respectively at 1,000 and 3,000 hours per year), the facilities to be added must then be appropriate for operating more than 3,000 hours per year.

Facilities which must run more than 3,000 hours per year have been modelled, conventionally, as CCGT. It should be noted that coal-fired units would also be appropriate with respect to system operation. The additional capacity needed (if any) to comply with adequacy criterion has been modelled as OCGT: this is also a conventional representation for supply means which have to be run for short periods each year. Load shedding or even pumped storage facilities would be suitable as well.

5.1.3. Soundness of proposed capacity expansion regarding major uncertainties

The soundness of the above determined capacity addition has to be tested in the light of uncertainties surrounding both the growth in demand and supply side developments.

On the first point, the test is conducted by combining the higher demand growth scenario “R1” with supply scenario “Low RES”. 
Since uncertainties on the supply side mainly arise from RES generation, the second test is conducted by combining the reference demand scenario “R2” with the supply scenario “Medium RES”.

5.1.4. Energy balance sheets

Simulations also provide energy balance sheets. Energy balances are heavily dependent on the ranking order in which facilities are called upon to meet demand. For the purposes of this report, it has been assumed that coal-fired units and CCGT (including mid-merit additional facilities) in France and abroad will remain broadly in the same range. It should be emphasised that this is just one of the possible outcomes resulting from developments in CO2 and fuel prices. If gas prices rise only moderately, a high CO2 price would make CCGT more competitive, leading to fewer TWh produced from coal-fired generating facilities, balanced by higher French CCGT generation and fewer exports; a low CO2 price or a widening spread between coal and natural gas prices would lead to the opposite.

Three main topics are addressed:

- international exchanges: export balances are compared to interconnection capacity so as to detect possible limitations on the latter (notably in combination of low demand “R3” and “High RES” scenarios).

5.2 Medium term – up to 2010

5.2.1. Capacity needs

I) Identification of needs:

With demand scenario “R2” and supply scenario “Low RES”, the risk of shortfall is slightly above the acceptable level as early as the winter of 2009/10. To comply with the adequacy criterion at that time, 1,200 MW of additional supply capacity will be needed. In other words, it will not be enough just to commission the already planned 2.0 GW of fuel-oil-fired units, 1.1 GW of new wind farms and 0.2 GW of thermal RES plants.

Simulations for the preceding years, with the same supply and demand scenarios, show that LOLE always remains below 3 hours per year. Consequently, this additional supply capacity shall be installed (at least) by the end of summer 2009, to be in operation during winter 2009/10.

To prevent excessively long annual operation for units subject to environmental constraints (3,000 hours per year for coal-fired plants which are capped with the 20,000 hours credit and are intended to remain in operation beyond 2013, 1,000 hours per year for fuel-oil-fired units), 600 MW have to be of the mid-merit type.
II) Soundness regarding higher consumption growth:

If demand “R1” and supply “Low RES” scenarios materialised, adequacy criterion would not be met as early as winter 2008/09: LOLE would then climb up to nearly 6 hours, and shortfall probability close to 15%. Adding 1,200 MW by summer 2009, as recommended in the combination “R2–Low RES”, would barely be enough to prevent further deterioration of LOLE the following year.

Complying with adequacy criterion throughout the period would require 1,500 MW of additional capacity to be installed by summer 2008, with a further 100 MW (on top of the 1,200 MW already identified) by summer 2009, of which half should be mid-merit facilities.

Since the deadline is close, there are few available steps that could be taken; however, there are some options:

- postpone decommissioning of two 250 MW coal-fired units beyond 2008; the LCP 20,000 hours credit may allow operation until 2010 or 2011; this option would allow an extra two or three years for commissioning new mid-merit facilities for 500 MW;
- re-commission the last currently idle fuel-oil-fired unit in 2008’;
- commission new OCGT;
- expand load shedding capacity; however, this option, as well as the previous two, would not provide a totally satisfying solution to coal- and fuel-oil fired units utilisation limits;
- allow a faster pace for RES development; merely reaching the “Medium RES” pace would reduce the need for other palliative measures to 500 MW; only peak facilities (or load shedding) would then be necessary.

III) Sensitivity to the pace of RES development:

Combining reference demand scenario “R2” and “Medium RES” supply scenario provides information on how RES development pace may change the need for thermal facilities.

In comparison to “Low RES”, “Medium RES” yields an extra 300 MW thermal RES generation and 2,500 MW installed wind power in 2010. This amount is enough to satisfy the adequacy criterion in winter 2009/10, but only just: new supply resources will be needed in summer 2010.

Obligations arising from the LCP directive (the 20,000 hours credit for coal-fired units, for fuel oil – fired units) are fulfilled.

The combination of low demand “R3” and fast developing “High RES” scenarios results in no need for additional thermal plants.

(21) EDF indicated on 25th May 2005 that it intends to re-commission the fourth fuel-oil-fired unit in 2008, whilst commissioning 250 MW of new OCGT both in 2007 and 2008.
IV) Summary of capacity results for 2010:

<table>
<thead>
<tr>
<th>Low R1</th>
<th>Medium R1</th>
<th>Low R2</th>
<th>Medium R2</th>
<th>High R3</th>
</tr>
</thead>
<tbody>
<tr>
<td>Shortfall probability</td>
<td>21.9%</td>
<td>15.8%</td>
<td>13.6%</td>
<td>10.1%</td>
</tr>
<tr>
<td>Unsupplied energy</td>
<td>20.4 GWh</td>
<td>12.8 GWh</td>
<td>9.9 GWh</td>
<td>5.7 GWh</td>
</tr>
<tr>
<td>LOLE</td>
<td>8.8 h</td>
<td>5.8 h</td>
<td>4.8 h</td>
<td>3.1 h</td>
</tr>
</tbody>
</table>

Capacity requirements in relation to installed capacity under the supply scenario:
- 2.8 GW of which: mid-merit facilities: 1.5 GW
- 1.7 GW of which: peak facilities: 0.8 GW

Capacity need above requirement in “R2 – Low RES” scenario:
- 1.6 GW

5.2.2. Energy balance sheets
I) Summarised annual energy balance sheets:

<table>
<thead>
<tr>
<th>TWh</th>
<th>2004</th>
<th>2010</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Low R1</td>
<td>Medium R1</td>
</tr>
<tr>
<td>Domestic consumption</td>
<td>477.2</td>
<td>515.0</td>
</tr>
<tr>
<td>Consumption by pumps</td>
<td>7.3</td>
<td>7.6</td>
</tr>
<tr>
<td>Export balance</td>
<td>62.1</td>
<td>51.8</td>
</tr>
<tr>
<td>DEMAND</td>
<td>546.6</td>
<td>574.4</td>
</tr>
<tr>
<td>Nuclear</td>
<td>426.8</td>
<td>428.5</td>
</tr>
<tr>
<td>Coal</td>
<td>23.2</td>
<td>22.9</td>
</tr>
<tr>
<td>Fuel-oil and OCGT</td>
<td>1.8</td>
<td>2.5</td>
</tr>
<tr>
<td>Gas and thermal decentralised</td>
<td>26.2</td>
<td>32.0</td>
</tr>
<tr>
<td>Added facilities</td>
<td>-</td>
<td>7.2</td>
</tr>
<tr>
<td>Hydro*</td>
<td>64.5</td>
<td>73.1</td>
</tr>
<tr>
<td>Other RES</td>
<td>4.1</td>
<td>8.2</td>
</tr>
<tr>
<td>SUPPLY</td>
<td>546.6</td>
<td>574.4</td>
</tr>
<tr>
<td>RES/Consumption ratio</td>
<td>12.5%</td>
<td>14.0%</td>
</tr>
<tr>
<td>CO₂ emissions (MtCO₂)</td>
<td>32.8</td>
<td>38.3</td>
</tr>
</tbody>
</table>

*: including pumped storage facilities production
II) RES/Consumption ratio:

“Low RES” scenario barely enables the ratio of RES generation to domestic consumption to stabilise at its present value. The apparent improvement which can be seen in the above table should not be misleading: the 2004 ratio is unusually low, due to the drought which occurred that year.

“Medium RES” marks the beginning of the upturn to reach the 21% target. Only under the “High RES scenario” does the ratio actually get close to the target.

III) Exchanges:

Export balance figures are close to each other in both “Low RES” and “Medium RES” scenarios. They are slightly lower than those recorded in recent years (despite unfavourable figures for outside temperature and hydro flows in 2003 and 2004). The reason for this is that some coal-fired units, with fairly high utilisation rates at present, will either be decommissioned or will have restrictions placed on their operation as a result of environmental regulations. Newly built facilities are scarce, and those which are to be re-commissioned, running on high cost fuel-oil, are less competitive and also subject to operation restrictions.

The combination of low demand growth “R3” and “High RES” supply scenarios results in a much higher export figure. The substantial amount of inevitable production together with the very slow rate of growth in consumption under these scenarios mean that cheap generation capacity is made available for European markets: nuclear, and also unrestricted coal-fired units, and CCGT. Nonetheless, this level of exports does seem feasible with expected 2010 interconnections.

5.3 Long term – 2010 to 2016

5.3.1. Power requirements

I) Identification of needs:

Considering reference demand scenario “R2”, and taking into account only fairly certain generation developments as in the “Low RES” scenario, an additional capacity as great as 7.3 GW is needed by the end of summer 2015. In other words, commissioning one EPR unit in 2012 (on top of 2.0 GW of re-commissioned fuel-oil fired units, 1.1 GW of wind generators, and 0.2 GW of thermal RES, all of them connected before 2010) will not be enough to provide the desired level of security of supply.

To prevent fuel-oil fired units from operating more than 1,000 hours per year, at least 4.5 GW has to be of base-load or mid-merit type, the remainder (2.8 GW) being of peaking type.

II) Soundness regarding uncertainties related to Eurodif process change and commissioning of EPR:

Within the 2010 to 2016 period, two major events will notably influence the supply–demand balance in the French system: these are, on the one hand, the change in the uranium enrichment process in the Eurodif plant, and on the other hand, the commissioning of the EPR unit.

At this point in time, so early on, the currently projected dates of these events cannot be considered as certain. Extra capacity requirements have therefore been tested against alternative dates: 1 year anticipation or 1 year postponement from the announced closure date (2012) of the Eurodif gaseous diffusion plant,
and 1 or 2 years’ postponement from the announced date (also 2012) on which the EPR is to be commissioned.

According to the basic hypothesis, the extra capacity would be provided through a three-phase schedule: first, in 2010 and 2011, the addition of 1,000 MW each year (following the 1,200 MW to be commissioned by summer 2009); then, a pause in 2012 and 2013; and finally, the addition of 2,000 MW in both 2014 and 2015, to match consumption growth and compensate for the decommissioning of the last coal-fired units affected by the 31st December 2015 deadline.

However, adding a steady 1,000 MW each year over the entire period would be sufficient to cope with uncertainties on the timing of both Eurodif gaseous diffusion plant closure and commissioning of the EPR unit. This would also limit the risks associated with an earlier than expected exhaustion of the 20,000 hours credit imposed on many coal-fired units, which may materialise in the event of adverse contingencies (such as droughts, long cold spells, etc.) before 2015.

iii) Soundness regarding higher consumption growth:

Soundness is tested by combining high consumption growth scenario R1 and the “Low RES” supply scenario. The additional capacity needed to comply with the 3 hours per year LOLE requirement is estimated at 10 GW by summer 2015, of which at least 6 GW will have to be of base-load or mid-merit type. That represents 3 GW more than in the reference consumption scenario.

iv) Sensitivity to the pace of RES development:

Under the “Medium RES” scenario, there are 0.5 GW of thermal RES, 0.6 GW of hydro facilities, and 11 GW of wind power more than under the “Low RES” scenario, in 2016. The additional capacity that needs to be commissioned by summer 2015 is then limited to 3.4 GW, under R2 consumption scenario. RES generation replaces 3.9 GW of conventional thermal units.

Under low growth consumption R3 scenario and the “High RES” supply scenario combination, no capacity addition is necessary before 2016.

V) Summary of capacity results for 2016:

<table>
<thead>
<tr>
<th></th>
<th>Low R1</th>
<th>Medium R1</th>
<th>Low R2</th>
<th>Medium R2</th>
<th>High R3</th>
</tr>
</thead>
<tbody>
<tr>
<td>Shortfall probability</td>
<td>89%</td>
<td>55%</td>
<td>67%</td>
<td>32%</td>
<td>3%</td>
</tr>
<tr>
<td>Unsupplied energy</td>
<td>248 GWh</td>
<td>71 GWh</td>
<td>104 GWh</td>
<td>28 GWh</td>
<td>1.2 GWh</td>
</tr>
<tr>
<td>LOLE</td>
<td>77 h</td>
<td>25 h</td>
<td>38 h</td>
<td>12 h</td>
<td>0.7 h</td>
</tr>
<tr>
<td>Capacity needs</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>of which: mid-merit</td>
<td>10.2 GW</td>
<td>6.3 GW</td>
<td>7.3 GW</td>
<td>3.4 GW</td>
<td></td>
</tr>
<tr>
<td>facilities</td>
<td>6.2 GW</td>
<td>2.6 GW</td>
<td>4.5 GW</td>
<td>0.5 GW</td>
<td></td>
</tr>
<tr>
<td>of which: peak</td>
<td>4.0 GW</td>
<td>3.7 GW</td>
<td>2.8 GW</td>
<td>2.9 GW</td>
<td></td>
</tr>
<tr>
<td>facilities</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
5.3.2. Energy balance sheets

I) Summarised annual energy balance sheets for 2016:

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<th>TWh</th>
<th>2004</th>
<th>2016</th>
</tr>
</thead>
<tbody>
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<td>Low R1</td>
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<tr>
<td>Domestic consumption</td>
<td>477.2</td>
<td>541.0</td>
</tr>
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<td>Consumption by pumps</td>
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<td>7.7</td>
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<td>601.9</td>
</tr>
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<td>Nuclear</td>
<td>426.8</td>
<td>448.7</td>
</tr>
<tr>
<td>Coal</td>
<td>23.2</td>
<td>16.6</td>
</tr>
<tr>
<td>Fuel-oil and OCGT</td>
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<td>3.1</td>
</tr>
<tr>
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<td>32.1</td>
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</tr>
<tr>
<td>Hydro*</td>
<td>64.5</td>
<td>70.1</td>
</tr>
<tr>
<td>Other RES</td>
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<td>8.2</td>
</tr>
<tr>
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<td>601.9</td>
</tr>
<tr>
<td>RES/Consumption ratio</td>
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<td>12.7%</td>
</tr>
<tr>
<td>CO₂ emissions (MtCO₂)</td>
<td>32.8</td>
<td>39.6</td>
</tr>
</tbody>
</table>

* : including pumped storage facilities’ production

II) RES/Consumption ratio:

Not surprisingly, under the “Low RES” scenario, the gap goes on widening between the achieved value of the RES/Domestic consumption ratio and the 21% target. Achievement under “Medium RES” scenario still remains slightly below target.

III) Exchanges:

Export balances are similar where RES generation is not developed in the same order of magnitude as they were in 2010; in fact, they show a downward trend throughout the 2010 – 2016 period, with a discontinuity in 2012 and 2013, due to the closure of the Eurodif plant and the commissioning of the EPR.

If RES develops in line with the “Medium RES” scenario, and consumption grows as stated in reference scenario R2, then exports will climb to the level reached in 2004.

Finally, under the combination of low consumption growth scenario R3 and the “High RES” supply scenario, exports remain at a very high level throughout the period 2010 – 2016, close to 80 TWh per year. As this latter figure represents the average of expected exports, there is a risk that interconnection capacity will be saturated in some circumstances (such as high hydro flows, mild winters, higher than normal availability of nuclear units).

IV) CO₂ emissions:

CO₂ emissions arising from the whole electricity sector (including decentralised generation) in 2016 can vary from one to two depending on RES development. It is worth noting that, even in the worst case (“R1” – “Low RES” combination) emissions do not inflate greatly from their 2004 level. Moreover, these levels are all low in comparison with the bulk of energy related emissions in France.

■
Under the median demand growth scenario, some 1,200 MW of new capacity is needed as early as 2009, and 1,000 MW per year thereafter, to maintain the desired level of security of supply.

This result is along the same lines as those seen in the previous Generation Adequacy Report. The forecast issued then indicated that a further 3,000 MW would be required by 2010. Since then, a decision has been taken to re-commission three fuel-oil-fired units. This, along with the completion of several small scale projects not taken into account two years ago, is the reason for much of the reduction in the amount of new capacities needed.

These capacities must be partly provided by mid merit facilities.

Merely introducing more peak facilities alone (such as combustion turbines, fuel-oil units or load shedding) would lead to operation time for fuel-oil-fired units in excess of the regulatory restrictions they must comply with.

More sustained growth in demand serves to force the shortfall risk above desired levels as early as winter 2008/09.

Additional supply (possibly including load shedding) of between 1,500 and 1,600 MW would be needed from the summer of 2008, in order to maintain the security of supply at an acceptable level.

Looking at the short-term, there is a similar probability that either demand scenario R1 or R2 will occur. It would therefore be prudent to enlarge supply by the summer of 2008. The options of postponing the decommissioning or re-commissioning of certain units may be suitable in this case.

Moderate growth in supply of energy from renewable sources, which is supposed to satisfy 21% of electricity consumption by around 2020, would be enough to cover the need for new capacity detected up to 2010.
The national study carried out in the first section of the Generation Adequacy Report was concerned mainly with the supply-demand balance, without considering any network restrictions. Yet the security of supply to each consumer is also dependent on the consistency of the network, with regard to the respective locations where electrical energy is generated and consumed.

The Transmission System’s capability is mainly limited in two ways for safe operation: first, the load of any of the individual components (lines, transformers) must not exceed its thermal rating, and the voltage level at any point on the Transmission System has to be maintained within mandatory boundaries. These requirements have to be fulfilled even in the wake of the failure of any single transmission component or any generating unit (“N-1” rule) and in some instances, in the wake of a dual failure (“N-2”).

The purpose of this second part is not, however, to carry out a detailed examination of all the constraints likely to affect networks: this is done in the “Transmission System Development Plan”. This section is concerned only with problems affecting the security of supply to consumers, which can be resolved either by strengthening the Public Transmission System, or by developing generating facilities at properly chosen sites.

Our assessment covers three geographical zones:

- Île de France,
- Provence-Alpes-Côte d’Azur (PACA),
- and a Western Zone, covering the administrative region of Brittany and two départements in the administrative region of Pays de Loire: Loire Atlantique and Vendée.

These three zones all consume more electricity than they generate. In addition, the latter two are outlying areas supplied from the national network.
I. The Provence Alps Côte d’Azur (PACA) region

I.1. Background

1.1.1. Demand

Electricity consumption in the PACA region rose to 34.2 TWh in 2003, 8.0% of total French final consumption. It is spread very unevenly over the region, with the three coastal départements accounting for some 82% (with the Bouches du Rhône consuming almost half of the total).

Sectoral breakdown is also uneven: industry, heavily developed in the area around Marseille (Fos–Berre lagoon), accounts for half of demand in the Bouches du Rhône; conversely, in the Var and Alpes Maritimes départements, the Commercial and Residential sectors are highly prominent.

In recent years, consumption growth has been slightly lower in PACA than in France as a whole. This global observation nonetheless conceals a substantial disparity between the eastern coastal départements, where growth has been around 3% per year (which reflects a strong growth in population), and the Bouches du Rhône département, where the weight of the industrial sector and its lack of dynamism have resulted in slower growth in demand.

Despite a warm summer climate and the development of tourist activities, the consumption peak is still in winter, as is the case in all regions of France.

There is strong sensitivity to climatic conditions: 150 MW/°C in winter, 70 MW/°C in summer. EJP load shedding accounts for 300 MW. On 28th February 2005, demand for power reached 6.9 GW.

Consumption forecasts have been established in line with those made for the country as a whole (see Part One). They are based on the
same demographic prospects, broken down and applied to the region.

Given the heterogeneous nature of the demand structure, the scenarios have been projected not only generally for the entire PACA region, but also more specifically for the eastern PACA region (Alps Maritimes and Var). This distinction is all the more necessary in that growth in this latter area is set to be influenced by the Demand Side Management project known as the “Plan EcoEnergie”, put together with the plans to strengthen the 400 kV network (see inset).

### 1.1.2. Generation

Two large thermal power stations are sited near Marseille: Gardanne (810 MW, coal-fired units), and Martigues (750 MW, fuel-oil-fired units). The fate of some units is uncertain, due to national environmental regulations, as well as to operating constraints linked to the local context (limits on their use in case of pollution peaks) and their age.

There are also a number of decentralised thermal generating units present in the region, with a cumulative power rating of 500 MW. These are mainly sited in the industrial areas of Fos–Berre lagoon. It is not certain what will become of them when the compulsory purchase contracts expire, around 2010.

<table>
<thead>
<tr>
<th>AAGR</th>
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</tr>
</thead>
<tbody>
<tr>
<td>R1</td>
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<tr>
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<td>1.8%</td>
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<tr>
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<td>1.2%</td>
<td>0.8%</td>
<td>0.7%</td>
<td>1.2%</td>
<td>0.8%</td>
</tr>
</tbody>
</table>

AAGR: Average Annual Growth Rate
The region is also home to one of France’s biggest hydroelectric installations, on the Durance river. Eleven plants, connected to one another by a system of canals, form a continuous chain from the huge reservoir at Serre-Ponçon to the Berre lagoon. This installation can generate up to 1,500 MW, and can be started up quickly when needed (e.g. if a generating unit or a transmission system component trips).

However, its operation is subject to some restrictions. Part of them originate from the fact that the downstream end of the installation does not run alongside the natural bed of the river (emptying into the Rhone river), but diverts fresh water flows into the naturally salted Berre lagoon. Annual amounts of fresh water and associated silt have already been restricted since the beginning of the 1990s, meaning that about two thirds of the water arriving at the two plants further downstream (Salon and Saint Chamas) has to flow into the Rhone. Another restriction relates to flow variations in the natural bed of the river, the speed of which is limited. Therefore, the ability of the upstream chain of plants to change their power output at short notice is dependent on the possibility of diverting extra-flows to the Berre lagoon. Now, there is also the possibility of more stringent limitations on fresh water and silt amounts at Berre lagoon. If this were to prohibit the operator from diverting water into it, either temporarily (due to quota exhaustion) or indefinitely (decommissioning of Salon and Saint Chamas plants due to poor economic results), the power output modulation capability of the whole Durance installation would be reduced, with highly negative implications for security of supply in the PACA region and beyond.

A number of other hydroelectric plants are sited in the region, notably in the area surrounding Nice (on the Var, Tinée and Roya rivers – almost 300 MW installed capacity), and on tributaries of the Durance (around 100 MW). The three plants located further downstream (700 MW) on the Rhone river also fall within the region’s territory; however, whilst they are located within the territory of the administrative region, their position on the western border means their output is classed as external production, from an electrical point of view.

1.1.3. Transmission network

Most of the power is drawn from the 400 kV national transmission network, at the Tavel station (near Avignon).

The high consumption density area is supplied by a double circuit 400 kV line connecting Tavel to Réalort (near Marseille), Néoules (near Toulon) and then Broc Carros (near Nice); until now, one circuit has been operated at 225 kV along the end section running between Néoules and Broc Carros.

Further north is another line, which does not have the same homogeneity: its western sec-
tion, a double circuit 400 kV line (with one circuit operated at 225 kV until now) connects Tavel to Boutre, where it hooks up with the 225 kV network collecting the output from plants further upstream on the Durance river; at its eastern end, this line only consists of one 225 kV line (along with another 150 kV line with much lower transfer capacity) linking Sainte Tulle to Lingostière (near Nice).

The 225 kV lines along the upper part of the Durance river do not allow significant imports, as when the Durance plants generate electricity, the flows tend to balance out near Serre-Ponçon. The 225 kV interconnector with Italy barely allows anything more to be imported from the Italian network.

1.2 Security of supply

The favourable location of the hydroelectric facilities means that the voltage levels can be controlled without major difficulty. Limits on the power that can be delivered are determined mainly by the lines’ transit capacity. These limits can be looked at across two geographical areas that fit together:

- firstly the eastern part of the PACA region (east of Néoules and Boutre, i.e. the entire Alpes Maritimes département and the eastern half of the Var), whose supply comes from two lines with asymmetrical capacities (southern section: dual 400/225 kV circuit line from Néoules; northern section: 225 and 150 kV lines from Sainte Tulle);

- then almost all of the PACA region, whose supply crucially depends on the Tavel – Réaltor line, which is naturally the most heavily loaded section in the southern network chain.

1.2.1. In the eastern part of the PACA region

1) The current situation

Risks associated with one single component failure:

Among all the failures that can affect either generating units or transmission system components within this area, the most worrying is the possible tripping of the 400 kV line Néoules–Broc Carros. If power demand in eastern PACA was greater than 2,000 MW when a trip occurred, the reallocation of electrical flows through the remaining lines would generate overflows which could not be maintained for more than one minute; the system operator would then have no time to undertake any corrective measures, so the unavoidable consequence of the trip would be a total black-out across the whole eastern PACA region. To prevent such a situation, consumption has to be maintained below 2,000 MW, possibly by curtailing part of the customers’ load.

Around 7 p.m. on 28th February 2005, the system operator had to call upon “emergency means” (running Alpes Maritimes hydro facilities at maximum output, 5% voltage drop on distribution networks throughout Alpes Maritimes and eastern Var), the last step before load curtailment. Such a consumption level was reached in 2005 due to an exceptional cold spell; in the future, owing to continuous growth in consumption, it may be encountered more frequently. For lower consumption levels, overflows on the remaining lines after the 400 kV Néoules–Broc Carros line trips can be tolerated for more than one minute: the system operator can take other steps to bring flows back within tolerable limits. However, since there are few actions that can be taken, load curtailment is necessary as a corrective measure if demand is too high (approximately...
1,500 MW in winter). Such situations are currently encountered 1,500 hours per year.

Other line trips would also lead to corrective load curtailment, notably the 225 kV Néoules–Trans–Biançon–Broc Carros link, for consumption levels currently encountered 1,200 hours per year.

Although corrective load curtailment will remain rare since line reliability is pretty high, the use of this measure contravenes one of RTE’s main self-imposed operating rules: the “N-1 Rule” stipulates that the loss of a 400 kV line must not have any impact on supply to consumers. Nowhere else in France is the “N-1 Rule” breached in this way for 1,500 hours per year.

**Risks associated with a dual component failure**

Generally speaking, dual circuit line failure is highly uncommon in France. Nevertheless, it is more common in the PACA area, which suffers more from forest fires than any other region: indeed, in the event of a fire beneath overhead lines, these lines have to be shut down to enable fire fighters to intervene safely.

When the dual circuit 400/225 kV Néoules–Broc Carros line is unavailable, the maximum load which can be transmitted to the eastern PACA region is 800 MW. In 2005, East PACA consumption exceeds this threshold more than 7,000 hours per year: this means that, if a fire breaks out under this line, load curtailment is inevitable. Such a situation has already occurred, on 6th July 2001.

In the same way, without the dual circuit 400 kV Réaltor–Néoules line, no more than 1,150 MW can be transmitted to East PACA, a level which is currently exceeded 3,500 hours per year. The fire which broke out near Draguignan in late July 2003 led to load curtailment during peak hours on the 29th and 30th of the month.

**II) Planned transmission system reinforcement:**

Connecting Boutre to Broc Carros with a 400 kV line will ease the current situation considerably. This project, usually termed “BBC”, has been under study for more than twenty years. However, it has come up against strong local opposition and has been altered significantly over the years. Its current configuration is the result of a Government ruling dated 5th July 2000, which ordered the construction of one single circuit 400 kV line between Boutre and Broc Carros, and the simultaneous dismantling of both the existing 225 and 150 kV lines east of Sainte Tulle.

The public inquiry concerning the 400 kV line took place in the autumn of 2004. The project is expected to be officially approved in the second half of 2005, allowing commissioning by the end of 2007.

When the reinforcement work is completed, and if no other work is carried out, the most worrying potential problem for security of supply in East PACA is the tripping of the new 400 kV BBC line itself, which would create higher loads on the southern axis lines. Whereas these loads remain tolerable with the consumption levels foreseen for the next coming years, they will turn into overloads in the longer term: the “N-1 Rule” requirement will no longer be met by the turn of 2020, under the low consumption growth scenario R3.

The risks of curtailment on dual circuit faults (fires) also disappear in the next few years, but return in force around 2020, once again under the R3 consumption scenario: more than 3,000 hours per year for faults affecting the dual circuit line Realtor–Néoules fault and 2,000 hours per year for the Neoules–Broc Carros line.
The same risk levels would be reached by, or even prior to, 2015 under consumption scenarios R2 or R1. In order to maintain a sound level of security of supply for a sustained period in East PACA, consumption growth has to be quickly curbed. This is why in its ruling dated 5th July 2000, the Government decided, along with the “BBC” 400 kV line creation, to launch a Demand Side Management programme called “Plan Eco-Energies” dedicated to Alpes Maritimes and Var départements. Further transmission system reinforcement work or generating capacity requirements within the eastern PACA region will depend heavily on the success of this programme.

1.2.2. Tavel–Realtor congestion

I) Current situation

Risks associated with one single component failure
The potential tripping of one Tavel-Realtor circuit, resulting in increased flows on the remaining circuit, is the most worrying single component fault for security of supply to the entire PACA region, more than any local generating unit trip. With all thermal and hydro plants running, load curtailment becomes necessary after one Tavel Realtor circuit fault (as a corrective measure) when PACA consumption exceeds 6,900 MW. This level was approached on 28th February 2005. Taking into consideration all random events related to consumption and the availability of generating units, there are currently a few dozen hours per year when the “N-1 Rule” requirements are not met.

For lower consumption levels, flows on the remaining circuit can be restored to below indefinitely tolerable levels by increasing generation within the PACA region. However, this will only be possible if some rapidly-mobilisable generating capacity is kept aside as an upward system reserve: notably the Durance and Verdon hydro plants, and also the Gardanne and Martigues thermal units. Given the time needed to start up these thermal units (several hours), they must be preventively started and run at partial load, even if they are not needed for the national supply-demand balance. This is the case for the fuel-oil groups at Martigues, currently for several hundred hours per year. In the 1990s, Gardanne’s coal-fired units had to be run for several thousand hours, while some available nuclear power stations elsewhere in France were not operated at full power.

Risks associated with a dual component failure
The probability that a fire breaks out under the Tavel – Realtor line is quite as high as under other lines in PACA. From June through September, operation of thermal units is very often forced to avoid (or at least limit) load curtailment as a consequence of dual circuit outage.

On Friday 6th May 2005, a fire broke out under the Tavel - Realtor line in the evening and so both circuits of the Tavel - Realtor line had to be shut down. All thermal units were out of operation at that time (normal situation at the very start of the weekend, a period when consumption is low). This resulted in a power cut of 1,200 MW, which was spread across the entire PACA region.

II) Foreseeable situation

The “BBC” reinforcement project, which is needed to solve security of supply problems to East PACA, will also help to ease congestion on the Tavel–Realtor line: flows out of Tavel will be distributed much more evenly between the northern (via Boutre) and southern (via Realtor) axes. Once the “BBC” project is completed, and assuming that genera-
ting capacity within the PACA region remains the same as at present, (no commissioning/decommissioning of thermal units, no extra restrictions on Durance hydro plants), the “N-1 Rule” requirements could be met easily, until 2010 under high growth demand scenario R1, or until 2013 under the reference demand scenario.

Beyond these timeframes, it will be necessary to increase the transmission system’s capability to import power into PACA, or to commission new generating capacity within the PACA region itself, either nearby or east of Realtor.

Today, the conditions are right for developing such generating facilities around Fos. Generally speaking, industrial sites are more suited to the installations of generating units than empty green-field sites; they offer more possibilities in terms of logistical and technical support. In particular, the construction of a second LNG terminal will ensure easy access to natural gas. Consequently, it is no surprise that a number of projects to construct CCGTs in this zone have been unveiled.

The capacity that the network will be able to take on, however, is currently limited to 900 MW, in addition to the existing generating facilities. For capacities beyond that, it will be necessary to create a 400 kV level across the Fos zone, which is currently only covered by a 225 kV network.

### 1.3 Conclusion

Security of supply within the PACA region is currently a source of concern. Over the last five years, three load curtailments have occurred, all related to fires beneath overhead dual circuit lines. In addition, a situation was encountered last winter which almost resulted in load curtailment, due to high consumption. This level of risk exposure is unique in France.

In order to bring security of supply back to the French average, the planned 400 kV Boutre – Broc Carros line needs to be completed as quickly as possible.

Commissioning new generating facilities around Fos/Marseille by the turn of 2010 would help sustain local generation, subject to a range of uncertainties (keeping older units in operation, cogeneration facilities with “compulsory purchase” contracts, hydro plants downstream on the Durance), which is nonetheless essential for the security of supply in the PACA region.
2.1 Background

2.1.1. Demand

Consumption in the six départements forming the “Western France” area reached 28.7 TWh in 2003, that is 6.7% of total final electricity consumption in France. It is quite evenly distributed over the territory. Over the last ten years, consumption has grown faster than in the rest of France, slightly in the Côtes d’Armor and Finistère départements, more significantly in the four others, and particularly in Vendée.

Sensitivity to the outside temperature in winter is high, with an increase in consumption of 150 MW for a decrease of 1°C in temperature (1/10 of the total French sensitivity, while western France consumption is only 1/15 of total French consumption). Load management schemes (EJP) are widespread, with demand reduction of 350 MW (more than 1/10 of the amount for the whole of France). Power demand of 6,050 MW was recorded at 9 a.m. on 28th February 2005.

Demand forecasts are slightly higher than the national average. This is mainly due to demographic factors, in Residential and Commercial sectors. Prospects are also more positive for industrial consumption, since the food industry, more dynamic, accounts for a higher proportion of the region’s activity.

<table>
<thead>
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<th>AAGR 2003/10</th>
<th>AAGR 2010/15</th>
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<td>1.9%</td>
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<tr>
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<td>1.6%</td>
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</tr>
<tr>
<td>R3</td>
<td>1.2%</td>
<td>0.8%</td>
<td>0.7%</td>
</tr>
</tbody>
</table>

2.1.2. Generation

The main power station in the area is located in Cordemais, on the Loire river estuary, just downstream from Nantes. It has:

- two coal-fired units rated 580 MW each, which are being operated in 2005, and which will comply with environmental regulations from 2008 onwards,
- and two fuel-oil fired units, rated 685 MW each; one of them is being operated in 2005, the other, currently idle, will be re-commissioned in summer 2007.

Five open-cycle gas turbines (OCGT), with a combined rated output of 480 MW, are sited in the more westerly département of Finistère, at Brennilis and Dirinon. Since they run on expensive light fuel-oil, they are operated only at peak
times, or when transmission system capacity is saturated.

The last large facility within the area is the tidal plant of La Rance. Its rated power is 240 MW, but since power output depends on tides, there is no guarantee of output at peak times.

Decentralised generation accounts for a relatively modest part of the region’s generating fleet:
- about 300 MW in thermal facilities, either installed on industrial sites connected to the Public Transmission System, or connected to Distribution networks (municipal waste, small scale CHP)
- 30 MW in hydro plants
- about 60 MW as of 1st January 2005 in wind power (installed capacity), mainly in the Finistere département.

Regarding wind power, “Western France” (especially the départements of Finistere and Cotes d’Armor) has high potential, resulting in a number of development projects in the years 2000 through 2003. However, due to strong local opposition, only a few reached completion. Any attempt to forecast the amount of installed capacity in this region, even for 2010, is difficult.

Finally, even under the most favourable plant availability conditions, generation barely reaches 2,500 MW, a long way below normal consumption levels.

2.1.3. Transmission System

Power generated in the rest of France (and Europe) is made available to “Western France” along a dual circuit 400 kV line forming a bow between Launay–Domloup–Cordemais. This bow is firmly connected to the national Public Transmission System, via three dual circuit lines (Distre–Cordemais, Les Quintes–Domloup, Menuel–Launay).

Power is delivered to sub areas from this bow:
- to Southern Brittany, from Cordemais, through one dual circuit 400 kV line (to La Martyre), and a rack of five 225 kV lines,
- to Northern Brittany, mainly from Domloup, via a single circuit 400 kV line (to Plaine Haute), coupled with 225 kV lines connected to Domloup and Launay,
- to the Vendee area, via one single circuit 225 kV line connected to Cordemais.
2.2 Security of supply

Since power is generated some distance from the place of consumption, voltage control is the biggest issue to be dealt with in “Western France”.

Restrictions on transmission capacity also arise from the thermal capacity of lines, mainly from the 400 kV bow to sub-areas:

- Southern Brittany, due to high flows on 225 kV lines between Nantes and Lorient,
- Northern Brittany, which is only supplied by 225 kV lines in the absence of the 400 kV Domploupl-Plaine Haute line,
- and Vendee.

2.2.1. Voltage control

Voltage control problems are encountered across a large part of the Western France region, even spilling over the boundaries of the six départements covered. To overcome these problems, in addition to local generating units, RTE also has specific compensation measures at its disposal: two synchronous compensators installed at Cheviré, south of Nantes (physically, these are the 250 MW alternators of an old power station, shut down in the mid-1980s), which run almost continuously; the alternator at the most recent TAC at Brennilis, which can be disconnected from the turbine, is also frequently used as a synchronous compensator.

Despite the use of these devices, Cordemais thermal units are very often called upon for voltage control, even when their active power generation is not necessary. And despite this, the limits on the power that could be supplied by the network (as it was until summer 2004) were determined by voltage, and not by active power transit capacities.

To ease these restrictions, in 2002 RTE launched a programme to strengthen voltage drop compensation facilities: capacitor banks, installed in the autumn of 2004, and Static Reactive Power Compensators (which serve the same purpose as alternators used as synchronous compensators), which are set to be installed in the autumn of 2005. These moves to strengthen the network, which offer total reactive power of 700 MVar, have been designed to maximise the transit capacity of the existing lines.

2.2.2. Line capacity in Southern Brittany

I) Current situation:

More than 60% of power transmitted westwards from Cordemais goes through the five 225 kV lines. Flows on these lines are quite high in relation to their capability. When consumption exceeds 6,300 MW in the “Western France” area, the loss of one of these lines leads to overloading on neighbouring ones that can be tolerated for less than one minute. This would in turn inevitably lead to a black-out, requiring targeted power cuts as a preventive measure.

For lower consumption levels, the system operator can take other steps to reduce overflows. However, these steps, either on the generation side (starting up previously unused OCGTs in the Finistere département) or on the transmission system side (substation switching) are limited: when consumption exceeds 5,400 MW in the “Western France” area, load curtailment (as a corrective measure) is unavoidable.

Such levels of consumption should only be achieved very rarely until 2010, but much more frequently thereafter.

II) Foreseeable situation:

The network solution to this problem involves creating a 400 kV injection near Lorient, offering a priority path for power on the 400 kV
lines leaving Cordemais. A decision has already been taken to build a 400/225 kV substation in the Morbihan area, and the public consultation process has been launched. It should be completed by 2010.

Once this 400 kV injection is completed, restrictions reappear on the same lines, but at higher consumption levels, 15% above current ones.

New generating capacity would also help solve the capacity problems affecting lines in Southern Brittany, providing it is sited at the right end of the affected lines. Assuming some 800 MW of new facilities are completed in the Lorient area, the consumption thresholds at which load curtailment is required will be raised by 30%. Security of supply, with respect to “N-1 Rule” requirements, would then be guaranteed through 2020 and beyond, even under the R1 high growth consumption scenario. In addition, this generation would significantly reduce transmission losses, and provide reactive power where it is needed most to control voltage drops.

Generation facilities located at the opposite end of affected lines, in the Cordemais area, would be of less interest; they may even exacerbate restrictions, if they are connected to the 225 kV lines. The same is true for the neighbouring area of Montoir, which may nonetheless look attractive for CCGT operators, considering the immense LNG terminal nearby.

2.2.3. Line capacity in Northern Brittany

I) Current situation:

The Northern Brittany zone (which covers most of the Côtes d’Armor département and the built-up areas of Saint-Malo and Dinard) is supplied by a single circuit 400 kV line, and two 225 kV lines which meet near La Rance, to the east. With the network full, power on the 225 kV Plaine Haute-La Martyre line flows in a westerly direction.

The crucial incident here would obviously be the loss of the 400 kV line. In this case, the flow is reversed on the Plaine Haute–La Martyre, but overloading appears on the eastern 225 kV lines. Due to the need to control overloading on the Launay-Rance line, a phase transformer was installed at the La Rance substation in 2002, to rebalance the flows between the two 225 kV lines from the east. Nonetheless, this will be insufficient after 2010: the overall transit capacity will be too low.

II) Foreseeable situation:

Possible solutions involve strengthening either the 400 kV network (doubling up the existing line to Plaine Haute, from Domloup or Launay), or the 225 kV network.

Installing generating facilities in the Saint-Brieuc region could also improve the security of supply to the Northern Brittany area. With the current network, the capacity for hosting base or mid merit facilities is limited: beyond 600 MW, evacuation restrictions would lead to major operating constraints (numerous reductions in power at off-peak times).

However, peak installations (open cycle combustion turbines), with low unit power ratings and only used during peak periods, could be incorporated without difficulty. By 2010, such facilities will be needed to maintain the national supply - demand balance (see Part One). For this purpose, the facilities could be located anywhere in France. Installing them in the Côtes d’Armor region would make them most useful, as they would ease the risks associated with faults on the 400 kV Domloup–Plaine Haute line. Installing 150 MW of combustion turbines in the Northern Brittany region would satisfy 15% of additional consumption in the zone,
which represents 7 (under scenario R1) to 10 (under scenario R2) years of growth.

Any decentralised generation, whether wind or renewable thermal (it is noticeable that none of the projects adopted in the first biomass-biogas tender is located in Western France) would also help strengthen the security of supply to the Northern Brittany region.

2.2.4. Line capacity in Vendée

i) The current situation:

The high level of consumption in the Vendée results in high transits on the 225 kV lines, both the one that crosses the département itself (Cheviré–Merlatière–Sirmière–Beaulieu), and the one that runs alongside it in the east (Niort–Cholet–Cheviré).

ii) Foreseeable situation:

Given the existing level of constraints, RTE has already decided to install a Phase Transformer in 2006, to control flows along the Niort–Cholet link.

In the medium-term, this solution will be completed by the addition of more substantial new installations, based on a 400 kV injection, either in or very near the Vendée département.

Alternative solutions involving the development of new generating facilities in the area do not appear to offer the same crucial advantages. Built in the north near Cheviré or Cordemais, they would have only a limited impact (as would reactivating the fourth unit at Cordemais). Further south, the ability of the existing network to take on new capacities is limited.
3.1 Background

3.1.1. Consumption

Electricity consumption in the Ile de France region amounted to 64.4 TWh in 2003, which represents 15% of final electricity consumption in France. More than 80% of consumption in the region is in the Residential and Commercial Sectors. Recently, it has been developing at almost the same rate as national consumption.

At 7 p.m. on 28th February 2005, demand for power reached 14.5 GW.

Growth forecasts for the region are identical to national forecasts. In terms of peak loads, they result in an annual increase of approximately 200 MW.

3.1.2. Generation

Since April 2005, the Paris region has had only the following centralised generating facilities:

- the plant at Vitry, made up of two 250 MW coal-fired units, which will be subject to a 20,000 hour operating credit from 2008,
- the plant at Porcheville, made up of two 585 MW fuel-oil fired units currently in service, and another two units in reserve; one of these two units will be returned to service by the summer of 2006,
- and two combustion turbines, of 200 and 130 MW

Three 250 MW coal-fired units were decommissioned between spring 2003 and spring 2005.
Decentralised thermal generation, on the other hand, developed strongly at the turn of the millennium, mainly due to the development of cogeneration. The capacity connected to the Public Transmission System reached 750 MW in 2005, and 500 MW of that has in fact been connected since 2000. The total power rating of installations connected to the distribution networks is evaluated at 500 MW.

With barely more than 3,000 MW of installed and operated power, Ile de France is one of the French regions in which demand coverage is lowest.

### 3.1.3. Transmission system

The 400 kV network forms a strongly meshed loop around Paris towards which a number of radial lines converge. Whilst there are relatively few generating facilities installed in the region itself, within a radius of 200 kilometres around the city there are no fewer than six nuclear power stations (Paluel, Penly, Nogent, Belleville, Dampierre, Saint-Laurent) and the conventional thermal plant at Le Havre.

Consumers are supplied by the 225 kV network, which is fed by a number of 400 / 225 kV substations located on the 400 kV ‘loop’. This 225 kV network takes the form of another concentric loop within the previous one, and includes axial lines that converge towards the city of Paris in the centre.

### 3.2 Security of supply

#### 3.2.1. Active power constraints

Rising consumption means that the existing 400/225 kV transforming installations need to be gradually strengthened. The decommissioning of the 250 MW coal-fired units, all of which were connected at 225 kV, means that this strengthening has had to be undertaken slightly more quickly. A transforming substation was therefore created in the north-east of Paris in 2000. Plans were also unveiled recently for a new substation in the south-west of the city.

In addition to flows supplying local needs, the 400 kV network also carries power from north to south and vice versa. This varies depending on generation schedules (unavailability of southern/northern nuclear units), and exchanges with the United Kingdom, Belgium or Germany. In certain extreme circumstances, these flows may result in overloading on some 400 kV lines. However, such situations should remain rare, and can be resolved by activating the fuel-oil-fired units at Porcheville if necessary.

#### 3.2.2. Voltage control

As in all zones that import large quantities of electricity, it can prove difficult to maintain regular voltage levels. In this respect, the shutting down of coal-fired units can only exacerbate the problem. Conversely, the impending reactivation of a fuel-oil-fired unit at Porcheville is a positive development. RTE is looking closely at this issue, and is considering installing extra facilities (capacitor banks) to compensate if necessary.

### 3.3 Conclusion

The security of supply to the Ile de France region does not appear to be at risk in the short to medium-term. Even the problem of maintaining regular voltage levels can be managed by installing extra compensatory facilities. Installing new generating facilities, although they can only improve the security of supply, does not appear absolutely necessary at present.
PART THREE:
INSULAR SYSTEMS

Note: Generation Adequacy Reports for insular electric systems have been conducted by EDF and Electricité de Mayotte. The information given below is taken from these reports.

Corsica

The situation in Corsica is already extremely strained, as demonstrated by the cold spell that occurred in late February and early March 2005, which resulted in “revolving” power cuts. In the short-term, the situation is expected to be improved when the AC link with Sardinia enters service.

1.1 Demand

In 2004, energy consumption amounted to 1,823 GWh (1,840 GWh after adjustment for climatic factors), and the maximum peak load was 405 MW. Over the last ten years, average annual energy growth was 3.8%.

The Residential and small Commercial sectors account for 73% of demand. Sensitivity to temperatures is extremely high in relative terms: 15 MW°C, in winter.

Consumption forecasts for the next decade put annual growth rates at between 2.4 and 3.8%. They take account of Demand Side Management efforts by the various partners concerned (the Corsican local government authorities, ADEME, EDF-GDF Services Corse), and also specific actions to promote gas instead of electric heating in urban areas supplied by gas.

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<thead>
<tr>
<th>Scenario</th>
<th>2004</th>
<th>2010</th>
<th>2015</th>
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<tr>
<td><strong>MEDIAN SCENARIO</strong></td>
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<tr>
<td>ENERGY (GWH)</td>
<td>1,840</td>
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<td>2,537</td>
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<tr>
<td>EXTREME LOAD (MW)</td>
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<td>550</td>
<td>620</td>
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<tr>
<td><strong>UPPER SCENARIO</strong></td>
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<tr>
<td>ENERGY (GWH)</td>
<td></td>
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<td>2,773</td>
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<tr>
<td>EXTREME LOAD (MW)</td>
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<td>675</td>
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<td><strong>LOWER SCENARIO</strong></td>
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<tr>
<td>ENERGY (GWH)</td>
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<td>2,374</td>
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<tr>
<td>EXTREME LOAD (MW)</td>
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<td>583</td>
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1.2 Supply

Total installed power in Corsica at the end of 2004 was 457 MW. To that total must be added the 50 MW provided by the SACOI link, and shortly the extra 50 MW from the SARCO link expected for the end of 2005.

1.2.1. Thermal generation

In 2005, the island’s thermal facilities consist of base or semi-base diesel units, which account for 209 MW, and peak combustion turbines which provide 75 MW. These installations are sited at Vazzio (near Ajaccio) and Lucciana (near Bastia).

Given the more stringent environmental regulations, there are plans to decommission all of the diesel units in two stages: firstly, those which are not equipped with denitrification systems (i.e. 133 MW) as early as the end of 2010, followed by those which are or soon will be (76 MW) in 2012. The combustion turbines, which are used for less than 500 hours per year, should remain in service until at least 2015.

1.2.2. Hydro-electric generation

The total installed power rating of Corsica’s hydro-electric plants in 2005 is 155 MW. The main installations are located in three valleys, each with reservoirs, which guarantee satisfactory availability in terms of power and energy at peak consumption times in winter. This fleet will be reinforced by the 55 MW Rizzanese facility, which is due to enter service in 2010, and whose annual output is estimated at 80 GWh.

There are also prospects for the development of small scale hydro facilities, raising the existing 2005 capacity of 20 MW to 25 MW by 2010, and 30 MW by 2015.

1.2.3. Other renewable generation

The wind generating capacity installed on Corsica amounts to 18 MW, spread across three sites which entered service between 2000 and 2003. A number of projects are being discussed, which could conceivably raise installed capacity to 80 MW by 2010, and 100 MW by 2015.

The development of other renewable energy sources does not appear to be significant.

1.2.4. Links with other countries

The Corsican electric system can also take off power via the 200 kV DC SACOI link (Sardinia-Corsica-Italy). The power guaranteed under contractual agreements is 20 MW, but the amount actually taken off is usually closer to the maximum technical limit of 50 MW.

The introduction of an AC link with Sardinia (SARCO), with a capacity of 50 MW, is expected for the end of 2005.
### 1.3 Requirements

On these bases, by applying the same adjustment criterion as that used for mainland France, namely a LOLE of 3 hours per year, the Generation Adequacy Report indicates the following requirements:

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<td>Base</td>
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<td>70</td>
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</table>

Under the median scenario, a further 280 MW of new facilities, in addition to the Rizzanese and SARCO installations, must enter service by 2015. More than 200 MW are made necessary by the decision to decommission the existing diesel units. A possible upgrading of the SARCO link (up to 80 MW at first, and 100 MW later) could be part of the solution.

### 2 French overseas départements and Mayotte

#### 2.1 Demand

Growth in consumption is sustained in all French overseas départements and territories: on average over the last five years, annual consumption growth has been 4.5% in Martinique and Guadeloupe, almost 6% in Reunion Island and over 10% in Mayotte. The main reason for the growth is rapid demographic expansion (annual population growth of 0.6% in Martinique, 0.8% in Guadeloupe, 1.4% in Reunion Island, 2% in Guyana and over 3% in Mayotte). It is also partly due to rising living standards, which have seen increasing numbers of households acquire electrical appliances.

Demand side management efforts, focusing on the development of the ECODOM label for building insulation, the use of low consumption bulbs, servo-control of electric water heaters (running during off-peak periods) and the installation of solar-powered water heaters, are helping to limit growth in energy consumption and peak loads. An assessment of the programmes already undertaken shows that the evening peak load has been reduced by about 20 MW over the five last years, in each of the départements of Reunion, Martinique and Guadeloupe.

The growth forecasts given below take account of continued demand side management initiatives.
### Generators, installation capacity in 2005

<table>
<thead>
<tr>
<th></th>
<th>Installed capacity</th>
<th>Bagasse coal</th>
<th>Diesel</th>
<th>Combustion Turbine</th>
<th>Hydro-electric</th>
<th>Wind</th>
<th>Geothermic</th>
</tr>
</thead>
<tbody>
<tr>
<td>Reunion Island</td>
<td>514</td>
<td>159</td>
<td>125</td>
<td>103</td>
<td>121</td>
<td>6</td>
<td></td>
</tr>
<tr>
<td>Guadeloupe</td>
<td>390</td>
<td>59</td>
<td>174</td>
<td>112</td>
<td>19</td>
<td>16</td>
<td></td>
</tr>
<tr>
<td>Martinique</td>
<td>377</td>
<td>7 *</td>
<td>280</td>
<td>89</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Guyana</td>
<td>246</td>
<td>72</td>
<td>60</td>
<td>114</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Saint-Pierre</td>
<td>21</td>
<td></td>
<td>21</td>
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</tr>
<tr>
<td>Miquelon</td>
<td>5.8</td>
<td>5.2</td>
<td></td>
<td></td>
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<td>0.6</td>
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<tr>
<td>Mayotte</td>
<td>38.5</td>
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</tbody>
</table>

* for Martinique, this is a municipal waste incineration plant

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### Prospects for consumption growth in French overseas départements and Mayotte

<table>
<thead>
<tr>
<th></th>
<th>Energy supplied in 2004 (GWh)</th>
<th>Peak load in 2004 (MW)</th>
<th>2010 demand (GWh)</th>
<th>Peak 2010 (MW)</th>
<th>demand (GWh)</th>
<th>Peak 2015 (MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Reunion Island</td>
<td>2,191</td>
<td>370</td>
<td>2,876</td>
<td>480</td>
<td>3,348</td>
<td>563</td>
</tr>
<tr>
<td>Guadeloupe</td>
<td>1,450</td>
<td>225</td>
<td>1,782</td>
<td>273</td>
<td>2,025</td>
<td>311</td>
</tr>
<tr>
<td>Martinique</td>
<td>1,381</td>
<td>218</td>
<td>1,697</td>
<td>269</td>
<td>1,929</td>
<td>306</td>
</tr>
<tr>
<td>Guyana</td>
<td>677</td>
<td>103</td>
<td>839</td>
<td>127</td>
<td>1,006</td>
<td>152</td>
</tr>
<tr>
<td>Saint-Pierre</td>
<td>36.9</td>
<td>9</td>
<td>Practically stable</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Miquelon</td>
<td>5.7</td>
<td>1.6</td>
<td>Practically stable</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Mayotte</td>
<td>139</td>
<td>25.8</td>
<td>243</td>
<td>37.0</td>
<td>319</td>
<td>48.6</td>
</tr>
</tbody>
</table>

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**2.2 Supply**

#### 2.2.1. Installed capacity in 2005

There are several types of thermal generating facilities commonly installed in France’s overseas départements and territories. The units are driven:

- by a steam turbine, with the steam produced by burning bagasse (cane sugar residue) or coal: five units of this type are installed in Reunion Island, and two in Guadeloupe,
- by diesel engines,
- or by internal combustion turbines.

The bagasse – coal units and the slow diesel units are intended for base load operation; the fast or semi-fast diesel units are intended for mid-merit operation; and the combustion turbines are intended for peak operation.

Hydro-power is developed to varying extents, depending on local possibilities. It is strongly developed in Guyana, where generation by the Petit-Saut installation covers almost two thirds of energy demand during a normal year; water availability nonetheless varies considerably from one year to the next. In Reunion Island, the main plants have fairly low capacity reservoirs, so generation is concentrated at peak consumption times (daily lock-full).

In addition to these installations, there are also some wind power and geothermic facilities (the Bouillante plant), mainly in Guadeloupe.
2.2.2. Development prospects

The fate of existing units:
New environmental regulations, including new restrictions on emissions of nitrogen oxides by diesel engines and combustion turbines, are due to come into force in 2010. They will only apply to installations that operate for more than 500 hours per year. Most of the combustion turbines used as peak facilities may therefore not be concerned. Conversely, the question is raised about rehabilitation or decommissioning on most of the diesel units, notably the oldest ones:

- 125 MW at the Port power station, in Reunion Island,
- 150 MW at Jarry Nord in Guadeloupe,
- 110 MW at Bellefontaine in Martinique,
- 70 MW at Dégrad des Cannes in Guyana.
A decision is expected by late 2005.

The projects decided upon:
Current projects that have been decided upon concern:

- a new 51 MW bagasse - coal unit at the plant at Gol, Reunion Island, due to enter service in 2006,
- a 40 MW combustion turbine at the new site at Galion, in Martinique, also due to enter service in 2006.

Potential renewable projects:
There are significant possibilities for developing wind power in the West Indies and Reunion Island. The quality of wind conditions is less favourable in Guyana and Mayotte:

<table>
<thead>
<tr>
<th></th>
<th>2005</th>
<th>2010</th>
<th>2015</th>
</tr>
</thead>
<tbody>
<tr>
<td>Reunion Island</td>
<td>6</td>
<td>40</td>
<td>60</td>
</tr>
<tr>
<td>Guadeloupe</td>
<td>20</td>
<td>40</td>
<td>60</td>
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<tr>
<td>Martinique</td>
<td>1</td>
<td>12</td>
<td>20</td>
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<td>Guyana</td>
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<td>5</td>
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<tr>
<td>Mayotte</td>
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There are a number of hydro-power projects in the pipeline for Reunion Island, with the overequipment of the existing facility on the Rivière de l’Est (East River), and the so-called ’Basculement des eaux Est-Ouest’ or “East-West water switching” project, combining pumping with turbines (10 MW available at peak times); the latter project is highly likely to be completed in 2008. In Guyana, small scale projects could add about 10 MW. In the other French overseas départements, the potential for development looks low.

The proven geothermal resources in Guadeloupe enable installation of up to 20 or 30 MW new facilities. However, there are too many uncertainties surrounding the timing of projects to take them into account.

Photovoltaic solar generation, which receives more substantial support from the public authorities than in mainland France, should also sharply increase: there are plans to install 2 MWp each year from 2005 onwards in each of the départements of Reunion Island, Guadeloupe and Martinique, as well as 1 MWp per year in Guyana.
2.3 Requirements

The capacity needs for 2010 are heavily dependent on the possible decommissioning of diesel units. Assuming these units are upgraded to meet environmental regulation requirements, capacity needs evolve over time as follows:

### Additional generating capacities required for French overseas départements and territories (MW) - Scenario without decommissioning

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<td><strong>Reunion Island</strong></td>
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<td><strong>Guyana</strong></td>
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<td><strong>Saint-Pierre-et-Miquelon</strong></td>
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The more urgent needs to meet growing demand appear in Reunion Island (where, in addition to the 51 MW unit at Gol B due to come on line in 2006, a further 80 MW will be required prior to 2010), and in Guadeloupe (40 MW of base load facilities in 2009) and in the island of Mayotte (where the very rapid consumption growth is set to require an additional 5 to 10 MW of capacity per year).

If diesel units are decommissioned in 2010, new facilities will be required by that time to compensate, leading to the following time-schedule of capacity addition:

### Additional generating capacities required for French overseas départements and territories (MW) - Scenario with decommissioning

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France has some of the most promising wind generation potential, second only to the United Kingdom in Europe. The best locations lie in the north of the country, in Brittany and along the western Mediterranean coast. Wind generation is a source of renewable energy that the Government is seeking to promote, with the aim of reaching its target of having 21% of energy needs met by renewable sources by 2010.

With a view to strongly developing wind generation in France, RTE has conducted a study aimed at characterising wind generation and the way it can be integrated into the existing electric system. For this study, total installed wind power capacity has been fixed at 10 GW, made up of generators rated between 1.5 and 2 MW each. The geographical distribution over the French territory was derived from connection applications received by RTE in March 2003. Wind generation time series were drawn up from wind speed series available from 1950 onwards.

### A1.1 Generation features

**Generation capacity is greater in winter than in summer, which reflects demand for electricity.**

Average annual generation amounts to 23.2 TWh, equivalent to 2,320 hours at full power. The load factor, defined as the ratio between average output and installed capacity, stands at 26.5%.

The seasonal pattern shows a substantial difference between winter months, with an average load factor of 32% in January, and summer, with a minimal load factor of 20% in August. In this respect, it should be noted that heat waves are accompanied by a very marked drop in wind generation. On the other hand, average wind generation during extreme cold spells is no different from a normal winter day. This observation is important in evaluating the extent to which wind facilities are able to help maintain the balance between supply and demand. However, it contradicts the widely held view that there is a correlation between winter anticyclonic conditions that are propitious for extreme cold spells and the lack of wind. It seems that extreme cold spells may occur under varied climatic conditions, many of which are accompanied by high winds.

Production intermittency may be offset by having facilities dispersed widely across the country.

Intermittency is the most prominent feature of wind generation, and must not be confused with poor predictability. Intermittency means that part of generation is not controlled (generation is inevitable, in the same way as run-of-river hydro power). It also means that periods of low and high generation do not necessarily coincide with fluctuations in demand. The intermittent nature of wind generation is peculiar, in that the level of power produced varies frequently.

The concept of “generation dispersal” is defined as the statistical compensation of the cumulative generation of a set of wind farms subject to partially or totally de-correlated wind conditions. This means that, whereas half the time an isolated wind farm does not usually produce more than 15% of its rated power, having facilities dispersed across France places average daily production at between 20% and 40% of the total installed power rating, with the same probability. France has three regions where wind conditions are almost entirely de-correlated, and this means that wind generation can be spread out, thereby substantially reducing the effects of its intermittency.
Natural variability in wind speeds causes the level of wind generation to vary on both a local and national scale. For 10 GW of installed capacity, a 2,000 MW drop in output from one day to the next is expected to occur one day out of ten, and a 4,000 MW drop on one day out of a hundred – which means once each winter on average. Such variations are in the same order of magnitude as variations in demand induced by outside temperatures.

### A1.2 Integration into the electric system

**Wind generation contributes to the security of the supply-demand balance.**

Despite intermittency, wind farms participate in maintaining the supply-demand balance, helping to adjust the entire generating fleet by a fraction of the total installed wind capacity. This is known as capacity credit, and is defined as the power rating of a conventional generating facility that can be replaced by wind farms whilst maintaining the same quality of supply, i.e. an annual LOLE equal to 3 hours per year.

For a better understanding of these figures, it may be useful to go back to the principles that determine the sizing of the adequate thermal generating fleet: facilities have to be installed in sufficient quantity so that the difference between available generation and demand (i.e. the margin) remains positive in almost all possible operating situations, even the most difficult (low available generation, high demand). The capacity that needs to be installed therefore depends not only on average generation and demand, but also on the deviation from these average values. However, thermal and wind generating facilities do not contribute to these “deviations” in quite the same way:

- thermal generating units rarely suffer breakdowns,
- wind farms may be geographically well-spaced out and may be subject to different wind conditions at any given time, but anyway the intermittent nature of the wind results in substantial fluctuations in the power generated, producing significant deviations from average figures.

In mathematical terms, the statistical dispersion is measured using standard deviation:

- the expected available power of 2 thermal units of 1,600 MW each, whose probability of breakdown is 3% can be calculated at 3,104 MW, with a standard deviation of 386 MW,
- the available power of a 10 GW wind farm has the same expectation but its standard deviation cannot be less than 1,500 MW, even under the most favourable geographical spread,
- the margin of the French electric system at winter peaks shows a high standard deviation, mainly due to the high degree of sensitivity to outside temperatures: around 6,000 MW. Adding thermal or wind generation facilities tends to increase it further; since uncontrollable risk factors such as temperature fluctuations, unit availability and wind speeds can be considered as independent, the variances (squares of standard deviations) are added together. As a result, the standard deviation for the margin is increased:
- just 12 MW after addition of two thermal units of 1,600 MW each,
- but 185 MW after adding 10 GW of wind generating facilities.

With the same expectation and a higher dispersion of margin, maintaining an identical level of security of supply requires more generating facilities to be installed in the case of wind farms.

Two other consequences can be derived:

- the more intermittency is offset by having widely dispersed wind farms subject to different wind conditions (meaning lower standard deviation for wind production), the closer the capacity credit will remain to the average power level,
- the more the electric system in question is subject to major uncontrollable risk factors (meaning higher standard deviation for margin, which justifies installing more thermal generating facilities), the higher the capacity credit of a wind farm of a given size.

As far as long term planning of capacity is concerned, the capacity credit does not affect all thermal generating facilities in the same way. Since wind generation occurs throughout the year (albeit with marked seasonal modulation), it almost exclusively replaces base-load facilities, whose installed power rating can be roughly reduced by the annual average wind output. This reduction may exceed the total thermal power facilities replaced; in this case, the requirement for peak facilities would be increased: these peak facilities would be useful for short periods each year, on days when there is no wind or when other contingencies affect the system adversely.

**Balancing facilities are needed to compensate for the irregular nature of wind generation.**

Acting in advance and in real-time when necessary, RTE must guarantee that there is always a sufficient number of facilities to be able to overcome any uncontrollable or unforeseen risk factors that may affect the supply and demand for electricity. Incorporating 10 GW of installed wind power into the French electric system would raise the margin required to guarantee the security of the system by several hundred MW. This rise is actually quite moderate, since generating margins are already calculated to deal with sudden and substantial upturns in demand for electricity (mainly in winter, due to inaccurate weather and temperature forecasts), and the risk that power stations (many of them of large size) may suffer unexpected outages.

This need for extra margin could mean that, right from the daily preparation phase, RTE may need to order some thermal units to be started up and operated at intermediate power, so that they are able to raise their output if wind farm output is lower than expected. The total power output of the units started up must then be compensated for by a matching drop in the output of other thermal units, in order to maintain the supply-demand balance. It is worth emphasising the importance of having accurate forecasts for wind conditions, and therefore wind generation, which will be crucial in determining what balancing resources are required.

For more short term fluctuations (several hours), hydro-electric units, which can be called upon very quickly, will have to be set aside to compensate, either upward or downward, for irregularities and forecasting errors that may affect wind generation.

Lastly, on a minute-by-minute basis, the reserves permanently available from units in operation to allow automatic frequency regulation (“primary and secondary regulation”) are sufficient to absorb any rapid fluctuations in wind generation, provided the generating facilities are sufficiently dispersed.

**In conclusion**

In France, wind facilities could reach 6 to 7 GW with no particular need for to develop the transmission network, provided they are sited in suitable locations. Up to 10 GW, the supply-demand balance can be managed without
having to greatly increase the facilities required to guarantee system security. However, reaching the target of 14 GW that would enable France to produce 21% of its electricity from renewable sources, is a new challenge. It will require major progress in the field of weather forecasts, and extremely close co-ordination between European transmission system operators. It seems clear that if this objective is to be achieved, the French transmission network and interconnections between European countries will have to be strengthened.

### A1.4 What about our European neighbours?

The issue of massive investment in wind generation has already been raised in a number of European countries, particularly Germany and Denmark. The debate has often led to claims that, if not actually alarmist, are at least highly critical of the performance of wind farms, from the point of view of network stability, connection costs, voltage disruption and the failure to participate in system services. Whilst these technical considerations are not covered in the Generation Adequacy Report, the opinions expressed are often very critical of the substantial extra costs incurred as a result of poor predictability and the lack of guarantees on wind farms’ output.

The reasons for the widely varying views are to be found in the specific features of each electric system. For example, wind generating facilities in northern European countries tend to be grouped quite closely, and are therefore unable to compensate one another at times when there is little wind. In Denmark, for example, the generation distribution curve is quite similar to what would be observed for a single French département, in that 40% of the time, generation does not exceed 15% of installed power. Under these conditions, the contribution of wind farms to the security of the supply - demand balance is deemed to be negligible, if not zero.

Unlike France, in Germany the risk factors that determine the volume of reserves needed are quite limited, if wind power is discounted. Electric heating is less heavily developed than in France, meaning that demand tends to vary less, whilst the thermal generating fleet only has very few large units with power ratings of over 1 GW, thereby reducing the risk of loss of load. Moreover, Germany does not have many hydro-electric balancing facilities. Under these conditions, fluctuations and forecasting errors for a very large fleet of wind generating facilities become the predominant uncontrollable risk factor, requiring a significant increase in reserves.

In Spain, where the installed power reached 8 GW at the end of December 2004, wind generating facilities are dispersed about as widely as could be the case in France. Moreover, the country has hydro-electric installations that can provide flexible and effective balancing capacity. The Spanish are continuing to develop their wind generation facilities, and are expected to have an installed fleet of 13 GW by 2010.

The British are in a similar position. Wind conditions are the most favourable in Europe and cover almost all of the country, offering particularly good possibilities for dispersing generating facilities. Under these conditions, the UK Government plans to have 10 GW of output from renewable sources covering 10% of electricity demand by 2010, with a further 10 GW of wind capacity to be developed between 2010 and 2020.

This brief tour of Europe serves to emphasise that the issue of incorporating wind generating facilities into an electric system on a massive scale depends mainly on the specific conditions in each country: quality of wind conditions, possibilities for dispersing facilities, hydro-electric resources, weight of risk factors in the electric system. In this respect, France is far better suited to the development of wind generation than Germany or Denmark.
In recent years, there have been four periods when generation margins in France have been reduced. For a day that is representative of each of these episodes, the following graphs depict the hourly exchange capacities across all borders (exports from France are counted positively – left-hand scale), and the prices observed on the exchanges places in France (Powernext) and Germany (EEX) for the same points in time (right-hand scale, logarithmic):

**A2.1 December 2001**

**System status**
Central and southern Europe was in the grip of an extremely cold spell, from which the UK and north-western France were spared the worst: the average temperature in France on 17th December was -1.2°C. Hydro-electric power supplies were very low. The number of thermal units unavailable in France was unusually high for the time of year.

**Market conditions**
Very high prices were observed on EEX (Powernext had only just been set up, and its prices were less representative), suggesting that there was barely any remaining accessible and available power in Western Europe.

The exchange balance was just balanced out at consumption peaks.

**A2.2 August 2003**

**System status**
All of Europe was in the grip of a heat wave, with increased consumption for air-conditioning and substantial reductions in thermal generation due to the lack of cooling sources.

**Market conditions**
Prices reached 1,000 €/MWh on Powernext (a level not seen since) and exceeded 200 €/MWh on EEX. Again, it is reasonable to assume that there was barely any remaining accessible and available power in Western Europe.

Despite heavy strain on the French electric system, an export balance of 3 GW had to be maintained, as suppliers had to honour previously agreed commitments.
**A2.3 February - March 2004**

**System status**
Temperatures were low for the time of year (around 6°C below the norm in France). Hydro-electric supplies and the number of thermal units unavailable were both normal.

**Market conditions**
There was no particular strain on prices, either on EEX (60 €/MWh on average for the “peak” period between 8 a.m. and 8 p.m.), or on Powernext (47 €/MWh). There were still some reasonably-priced resources available in Europe.

The exchange balance was balanced out at the morning peak; France could quite probably have imported large quantities if necessary.

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**A2.4 February - March 2005**

**System status**
Temperatures were low for the time of year (around 6°C below the norm in France). Hydro-electric supplies and the number of thermal units unavailable were both normal.

**Market conditions**
Prices were significantly higher than during the same period the previous year (“peak” approaching 100 €/MWh on both EEX and Powernext), throughout the week. It seems probable that not all European resources were in use.

France imported large amounts of electricity: up to 3 GW on Monday 28th February, and 2 GW on Friday 4th March.
Supply - demand simulations

The simulations cover a full year period running from September to August. This ensures that a realistic and economically relevant model can be established for the contribution made by major hydro-electric installations, which fill up during the spring and summer as the snows melt and are emptied during the winter. An examination of the 2010 timeframe therefore covers the time between September 2009 and August 2010, with the most critical period being January 2010.

Under the basic principle of simulations, the various generating facilities are ranked according to their operating cost; for each hourly period studied, they are called upon from the cheapest to the most expensive until total demand, i.e. domestic consumption and exports, is satisfied. So-called “inevitable” generation (e.g. run-of-river hydro-electric or wind power or most of decentralised thermal generation), which do not depend on price conditions, are considered as having a zero cost and are ranked first.

A3.1 Probabilistic approach

Gaining a representative view of future possibilities means not just projecting the structure of supply and demand, but also taking account of the main risk factors that can affect the electric system. This gives a probabilistic overview of the way that the supply-demand balance will be achieved for each timeframe, which may be interpreted statistically by expectation results.

For the purpose of this Generation Adequacy Report, a set of 456 possible future scenarios has been simulated for each timeframe observed, combining risk factors such as climatic conditions, water resources, the availability of thermal facilities and wind generation.

A3.2 Supply model

A3.2.1 High power thermal generation (nuclear, coal, fuel-oil, combustion turbines)

Each generating unit is characterised by its power rating, its unavailability hypotheses and its operating cost. The unavailability hypotheses make a distinction between scheduled unavailability, which may for example be the result of outages for maintenance or refuelling, and unscheduled unavailability due to risk factors.

Given the power rating of the largest units (1,300 MW or 1,450 MW), the hypotheses adopted regarding the availability of the nuclear fleet in winter are very important (number of units subject to scheduled outages).

A3.2.2 Hydro-electric generation

The hydro-electric fleet is described in great detail, since five hundred installations are represented, with their up- and downstream chains. Management of reservoirs at the valley heads is modelled, as under real operating conditions, by deciding on the use of available water reserves where they maximise the savings made over other generating facilities.
A3.2.3 Other decentralised generating facilities

Distinctions are made between cogeneration load profiles according to whether the installations have compulsory purchase contracts, or whether they were installed to supply heating networks or industrial activities.

For generating methods such as biomass, incineration plants or various other types of installation, often relatively unknown and which altogether represent only a low volume of energy, the contribution is modelled by using a constant power band throughout the year.

A3.2.4 Load shedding

Under the hypothesis adopted, it is assumed that by activating load shedding, domestic consumption can be reduced by 3 GW. In the simulations, this is modelled by a very high cost load shedding group, which is therefore only called upon when supply–demand balance is tight.

A3.3 Exchange model

Exchanges are represented on the basis of a foreign market principle, where a specific demand is expressed, and generating units available in France compete with fictitious units located in other countries.

These foreign units are modelled exactly like real French units, with power ratings and generating costs that reflect the power volumes available on the markets at different price levels. Some are subject to unavailability, as a way of representing the risk factors that affect neighbouring electric systems. The total volume of fictitious units exceeds foreign demand (outside France) by 4 GW. Their available power expectation is based on foreign demand, so that power exported from France, in situations where all available French generating facilities are running, has an expectation of zero and a standard deviation of around 3 GW.

Hour by hour, the difference between foreign demand and generation by the fictitious units, started up as needed according to their cost, corresponds to French exports.

Power / cost combinations are determined by in-depth analysis of daily data from the period 2003-2004, related to the generating programmes of French units on the one hand, and exchange programmes on the other.

A3.4 Risks

For the three scenarios simulating possible developments in generating facilities and the three demand scenarios, the probabilistic approach used involved simulating 456 possible future situations, combining risk factors such as climatic conditions, water resources, the availability of thermal facilities and wind generation.

A3.4.1 Climatic risk factors

Outside temperatures have a noticeable impact on electricity consumption. A set of 114 average daily temperature values likely to be encountered in the period up to 2010 was put together, based on records covering the period between September 1888 and August 2002, corrected so that daily averages are adjusted to the normal reference temperature.

A3.4.2 Hydro-electric risk factors

The main uncontrollable factor that affects hydro-electric generation concerns natural supplies of water to installations. Data on water
resources are presented in the form of weekly water flows to each of the 500 installations that make up the hydro-electric generating fleet. Four different combinations of hydro and outside temperature data sets were constructed.

**A3.4.3 Thermal unit availability risk factors**

Availability of each thermal unit each week is drawn at random, in such a way that it respects, on average, its prescribed rate of unscheduled unavailability.

**A3.4.4 Wind risk factors**

Fifty-three annual generating journals were created, based on wind speeds at a height of 10 metres, either measured directly by meteorological stations (years 1993 to 2002), or resulting from NCEP/NCAR reanalyses (from 1950 to 1992). The correlation between wind speeds and temperatures was taken into account for associating the corresponding journals of uncontrollable factors. In particular, the aim was to take account of the fact that very frequently, the absence of wind coincides with very high temperatures in summer.

**A3.5 The results of the simulations**

The simulations gave rise to two main sets of results:

**A3.5.1 Shortfall outlook**

The security of the supply-demand balance is evaluated by calculating a “shortfall outlook”. This includes the probability of shortfalls occurring (number of shortfalls compared with number of scenarios simulated), the expected duration of shortfalls (in hours), and the expected amount of unsupplied energy (in gigawatt hours).

**A3.5.2 Energy balance sheets**

The simulations also indicate exchange balances, and expected annual energy generation in the nuclear, coal, oil and wind sectors. The tables appearing in this document only show results in terms of annual expectation figures (average generation for all the scenarios simulated).

These results depend on the ranking order in which the various generating facilities in France are called upon (materialised by generating costs), and also the position in this ranking order of the fictitious facilities representing available offers on foreign markets outside France. Changes to some of the parameters that determine this order, notably prices of natural gas, coal and per tonne of CO₂, are quite unpredictable. Consequently, the energy results are subject to some degree of uncertainty, and are provided only as an indication.
Generation Adequacy Report

on the electricity supply-demand balance in France

2005 EDITION