3 DEMAND

The flow of power on the grid is determined largely by the generation feeding into it and the demand that is drawn from it. This chapter deals with forecasts of the total peak demand on the transmission network, and of demand at individual transmission-connected stations.

The *Generation Adequacy Report 2006-2012* (GAR), published by the TSO in November 2005, contains forecasts of future energy consumption and demand for the seven-year period to 2012. Section 3.1 describes how the GAR's median peak demand forecast is adjusted to determine the transmission peak forecasts used in this Transmission Forecast Statement (TFS).

3.1 BASIS OF DEMAND FORECASTS

The peak demand forecasts in the GAR relate to total electricity demand in the Republic of Ireland. This TFS is concerned with the power that is transported on the grid from generation stations to the transmission stations interfacing with the distribution system and grid-connected demand customers.

Embedded generation[7] may reduce the net demand supplied through the transmission interface stations to which they are connected, as illustrated in Figure 3-1. There are a number of types of embedded generation: combined heat and power (CHP) schemes, wind, land-fill gas (LFG), biomass, and small hydro and thermal plants.

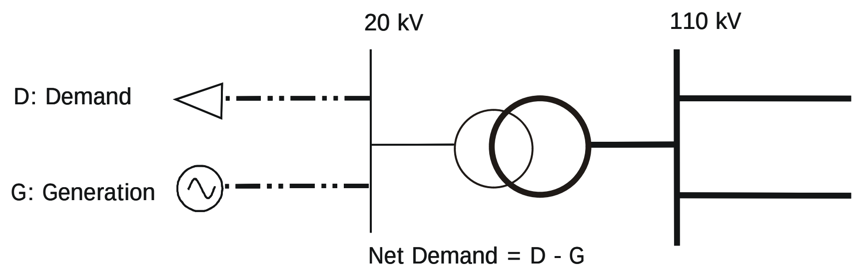

Figure 3-1 Net Demand Reduction due to Embedded Generation

Embedded non-wind generators are not modelled explicitly. In determining forecast transmission peak flow, an estimate of the demand met by non-wind embedded generation is deducted from the GAR peak projections. This deduction explains why the demand forecasts in Table 3-1 differ from those published in the GAR. All embedded wind generators, both existing and those with signed connection offers, are modelled explicitly. This is because wind generation, having a variable energy source, may at some times reduce local demand but at other times may not.

[7] Generation connected to the distribution system or at a directly-connected customer's site.

3.2 FORECASTS OF TRANSMISSION PEAKS

Table 3-1 presents the forecasts of transmission demand for the seven years 2006 to 2012. While it is difficult to accurately predict a peak demand figure for a particular year, the forecasts in Table 3-1 may be taken as indicative of a general trend in demand growth. Three demand values are presented for each year: the winter peak, the summer peak and the summer valley.

Table 3-1 Transmission Demand Forecast, MW

Year	Summer Peak	Summer Valley	Winter Peak
2006	3,803	1,711	4,754
2007	3,961	1,782	4,951
2008	4,126	1,857	5,158
2009	4,292	1,931	5,365
2010	4,453	2,004	5,566
2011	4,586	2,064	5,732
2012	4,716	2,122	5,895

The winter peak figures represent the expected annual peak demands that are forecast to occur in the October to February winter period of each year e.g., the 2006 forecast of 4,754 MW is the maximum demand projected to occur in winter 2006/07. These peak forecasts take account of the influence of demand-side management (DSM) schemes, such as the TSO's winter peak demand reduction scheme (WPDRS). In winter 2004/05, DSM accounted for approximately 120 MW of a reduction to the peak demand. This amount of DSM is assumed to continue over the next seven years.

The summer peak refers to the average peak value between March and September. This is typically 20% lower than the winter peak. While the overall grid power flow may be lower in summer than in winter, this may not be the case for flows on all circuits. In addition, the capacity of overhead lines is lower because of higher ambient temperatures, while network maintenance, normally carried out in the March to September period, can weaken the network, further reducing its capability to transport power.

The annual minimum is referred to as the summer valley in this TFS. Summer valley cases examine the impact of less demand and less generation dispatched. This minimum condition is of particular interest when assessing the capability to connect new generation. With local demand at a minimum, the connecting generator must export more of its power across the grid than at peak times. In previous Forecast Statements it was assumed that the demand at the summer valley is about one-third of the annual maximum demand. In preparation for this TFS the TSO reviewed historical summer valley demand data. TSO's analysis showed a trend over recent years of increasing summer valley demand. Based on this evidence the forecasts of summer valley demands in Table 3-1 assume a higher figure of 36% of the annual maximum demand.

3.2.1 Peak Out-turn for Winter 2005/06

The peak exported demand in winter 2005/06 was 4,679 MW. This figure is 136 MW higher than the transmission peak forecast for winter 2005/06 of 4,543 MW presented in *Forecast Statement 2005-2011*. At the time of peak the production from embedded wind generation was 82 MW, increasing the forecast error for the transmission peak. However, the energy growth for 2005 was in line with forecasts. The high peak figure indicates the difficulty in accurately predicting the maximum demand in a particular year. Peak demands may be higher or lower than forecast depending on factors such as weather conditions and customer behaviour. The TSO will monitor future peaks and adjust its forecasts accordingly if a trend indicating a higher peak to energy ratio emerges.

3.3 COMPARISON WITH PREVIOUS DEMAND FORECAST

Table 3-2 compares the winter peak transmission demand forecasts in this TFS with those given in *Transmission Forecast Statement 2005-2011*. The current demand forecasts reflect an average increase in winter peak demand of 3.7% over the period 2006 to 2012. This is similar to last year's forecast average annual increase to 2011. As indicated in Table 3-2, there is little significant change in the annual peak forecasts between the two Forecast Statements. The new peaks forecast are slightly higher than last year's forecasts.

Table 3-2 Comparison of Peak Demand Forecast with Previous Forecast Statement, MW

	2006	2007	2008	2009	2010	2011	2012
FS 2006-2012	4,754	4,951	5,158	5,365	5,566	5,732	5,895
FS 2005-2011	4,736	4,925	5,123	5,320	5,515	5,676	N/A
Difference	18	26	35	45	51	56	N/A

3.4 FORECAST DEMAND AT TRANSMISSION INTERFACE STATIONS

Transmission interface stations are the points of connection between the transmission system and the distribution system, or directly-connected customers. These are mostly 110 kV stations. In Dublin city, where the Distribution System Operator (DSO) operates the 110 kV network, the interface is usually at 220 kV stations.

Appendix C lists the forecast demands at each transmission interface station at time of winter peak, summer peak and summer valley for all years from 2006 to 2012. Demand projections at individual transmission stations are developed from the system demand forecasts on a top-down basis. The forecasting process includes regular monitoring and review of trends in consumption in all parts of the country. The allocation of the system demand forecast to each station is based pro-rata on an up-to-date measurement of actual peak demand at each station. Account is taken of planned transfers between stations as agreed with the DSO. In this way, changes in the geo-diversity of electricity consumption are captured. This process provides a station demand forecast and by extension a regional demand forecast for the short to medium term.

The system-wide demand forecasts, presented in Table 3-1, include transmission losses whereas the individual station demand forecasts do not. Transmission losses therefore account for the difference between the system-wide demand forecasts and the sum of the forecasts at each interface station in Appendix C.

Demand forecasts for the small number of directly-connected customers are the current best estimates of requirements. In some cases, the estimates may be less than contracted MIC (maximum import capacity) values, but are chosen to give a better projection of expected demand on a system-wide basis. However, when analysing the capacity for new demand in a particular area, the MIC values of local directly-connected customers are assumed to ensure that the contracted MIC is reserved.

Although demand-side management schemes are expected to reduce some industries' demands over winter peak hours, their normal demand levels are included in the winter peak demand forecasts shown in Table C-1 in Appendix C and are used in the power flow diagrams in Appendix J, as they are more indicative of general power flows.

3.5 DEMAND PROFILES

Electricity usage follows some generally accepted patterns. For example, annual peak demand occurs between 17.00 and 19.00 on winter weekday evenings, while minimum usage occurs during summer weekend night-time hours. Figure 3-2 shows the profile for the weekly peaks across the year for 2005. The profiles indicate that the average daily peak in summer is about 80% of the winter peak demand.

Figure 3-2 Weekly Peak Values for Year 2005

Figure 3-3 presents four daily demand profiles that indicate how electricity usage varies throughout the day. The demand profiles are for the day on which the annual peak occurred in 2005 as well as profiles for typical summer and winter weekdays and for the minimum demand day. The profiles, with demand levels ranging from approximately 1,660 MW to 4,650 MW, indicate that the power system deals with a wide variation in demand throughout the year. Even within the day demand variations are substantial. Figure 3-3 illustrates that on the winter peak day the peak demand is almost twice the minimum demand on that day, a variation of over 2000 MW. A number of points on this diagram, the winter peak (WP), typical summer peak (SP) and summer valley (SV) demands, are examined in the analysis undertaken for this TFS.

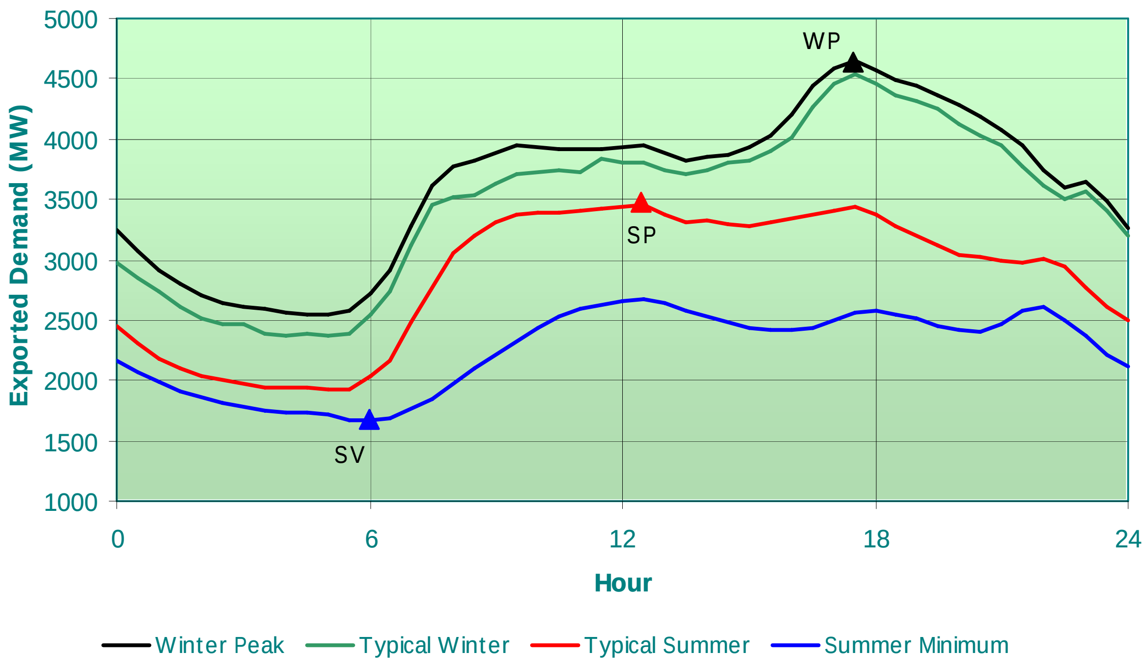

Figure 3-3 Daily Demand Profiles for Year 2005