

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 that will be transported on the transmission network, and of demand at individual transmission connected stations.

The *Generation Adequacy Report 2005-2011* (GAR), published by the TSO in November 2004, contains forecasts of future energy and demand for the seven-year period to 2011. Section 3.1 describes how the GAR's median peak demand forecast is adjusted to determine the transmission peak forecasts used in this Forecast Statement.

3.1 BASIS OF DEMAND FORECASTS

The peak demand forecasts in the GAR relate to total electricity demand in Ireland. This Forecast Statement 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 generation⁴ reduces 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. Due to its variable energy source, wind generation cannot be relied on to reduce local demand on the grid. However, when in production, it reduces available capacity for other generators wishing to connect in the same area. Therefore in the separate analysis of opportunities for new demand and generation, all embedded wind generators, both existing and those with signed connection offers are modelled explicitly. The other generation types are not modelled explicitly. Therefore, in determining forecast transmission peak flow⁵, an estimate of the demand met by non-wind embedded generation is deducted from the GAR peak projections. This deduction explains why the demand forecast in Table 3-1 differs from that published in the GAR.

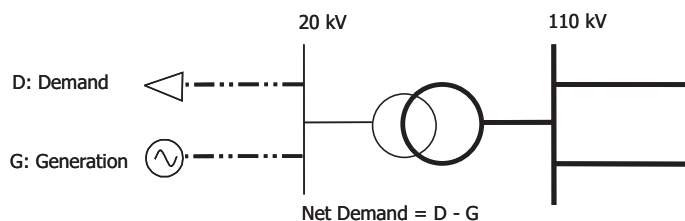


Figure 3-1 Embedded Generation reduces Demand at Transmission Interface Station

⁴ Generation connected to the distribution system or at a directly connected customer's site.

⁵ The transmission peak flows could be further reduced by embedded wind generation.

3.2 FORECASTS OF TRANSMISSION PEAKS

Table 3-1 presents the forecasts of transmission demand for the seven years 2005 to 2011. 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 night valley.

- 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 2005 forecast of 4,543 MW is the maximum demand projected to occur in winter 2005/06. The influence of demand-side management programmes on the winter peaks is discussed in Section 3.2.1.
- 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 night valley (SNV) in this Forecast Statement. Demand at SNV is typically about one-third of the annual maximum demand. These 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.

Table 3-1 Transmission Demand Forecast (MW)

Year	Summer Peak	Summer Night Valley	Winter Peak
2005	3,634	1,499	4,543
2006	3,789	1,563	4,736
2007	3,940	1,625	4,925
2008	4,098	1,691	5,123
2009	4,256	1,756	5,320
2010	4,412	1,820	5,515
2011	4,541	1,873	5,676

3.2.1 Demand-Side Management

Many factors have an impact on the electricity usage pattern, including weather, competition from other energy sources, and demand-side management (DSM). DSM is the term used to

describe the modification of normal demand patterns, usually through the use of financial incentives.

ESB's Winter Demand Reduction Incentive tariff (WDRI) is a DSM scheme that encourages industrial users who are customers of ESB to reduce their consumption at the time of winter peak. The demand forecasts in the GAR and in this Forecast Statement assume that ESB's industrial customers partaking in WDRI reduce the natural demand by 50 MW at time of winter peak.

In 2003, ESB National Grid introduced a new DSM scheme called WPDRS (Winter Peak Demand Reduction Scheme). It allowed participating customers to reduce their electricity costs by limiting their consumption at peak hours during the period from November 2003 to February 2004. The scheme is estimated to have reduced the 2003/04 winter peak demand by 80 MW.

It is assumed that this level of DSM totalling 130 MW between the two schemes will continue, hence it has been included in the peak demand forecast model.

It should be noted that WPDRS was also offered in winter 2004/05 and information since the data freeze estimates that the winter peak was reduced by 100 MW, a greater reduction than the 80 MW in winter 2003/04. If this level of participation in the scheme is maintained the winter peak forecasts could be reduced by a further 20 MW.

3.2.2 Peak Out-turn for Winter 2004/05

The peak demand in winter 2004/05 was 4,269 MW. At the time of peak the production from embedded wind generation was 100 MW. If there had been no wind generation, as was assumed in forecasting peak transmission flows, this figure would have been 4,369 MW. This compares reasonably well with the transmission peak forecast for winter 2004/05 of 4,409 MW presented in *Forecast Statement 2004-2010*.

3.3 COMPARISON WITH PREVIOUS DEMAND FORECAST

Table 3-2 compares the peak transmission forecasts in this Forecast Statement with those given in *Forecast Statement 2004-2010*. The current demand forecasts reflect an average increase in annual peak of 3.8% over the period 2005 to 2011. This is the same as last year's forecast average annual increase to 2010. As indicated in Table 3-2, there is no significant change in the annual peak forecasts between the two Forecast Statements.

Table 3-2 Comparison of Demand Forecast with *Forecast Statment 2004 - 2010* (MW)

	2005	2006	2007	2008	2009	2010	2011
<i>Forecast Statement 2005-2011</i>	4,543	4,736	4,925	5,123	5,320	5,515	5,676
<i>Forecast Statement 2004-2010</i>	4,572	4,760	4,944	5,136	5,327	5,517	
Change	-29	-24	-19	-13	-7	-2	

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 at 220 kV stations.

Table C-1 in Appendix C, lists the forecast demand at each interface station at time of summer peak, summer night valley and winter peak for 2005, 2008 and 2011. The power factor for each station is given for the summer and winter peaks.

Demand forecasts include the current best estimates of requirements for the small number of directly connected customers. 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 basis. However, when analysing the capacity for new demand in a particular area, the MIC values of local customers are assumed to ensure the contracted MIC is reserved.

Demand figures for stations interfacing with the distribution system are calculated by allocating the forecast of system demand, net of the directly connected demand customers' figures, to the interface stations in proportion to their historical demand levels. Account is taken of transfers between stations as agreed with the DSO.

The peak transmission forecasts in Table 3-1 include transmission losses. Transmission losses account for the difference between the peak transmission forecasts and the sum of the forecasts at each interface station in Appendix C. Demand projections for stations that interface with the distribution system are inclusive of distribution losses.

Although demand-side management schemes are expected to reduce some industries' demands over winter peak hours, their normal demand levels are included in the demand forecasts shown in Table C-1 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 2004. The profiles indicate that the average peak in summer is about 80% of the winter peak demand.



Figure 3-2 Weekly Peak Values for Year 2004

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 2004 as well as profiles for typical summer and winter weekdays and for the minimum demand day. The profiles, with demand levels ranging from approximately 1,500 MW to 4,300 MW, indicate that the power system deals with a wide variation in demand throughout the year. Even within the day demand variations are substantial. The demand in the winter peak day in Figure 3-3 shows a variation of almost 100% from night valley to peak. A number of points on this range, the winter peak (WIN), typical summer peak (SMR) and summer night valley (SNV) demands, are examined in the analysis undertaken for this Forecast Statement.

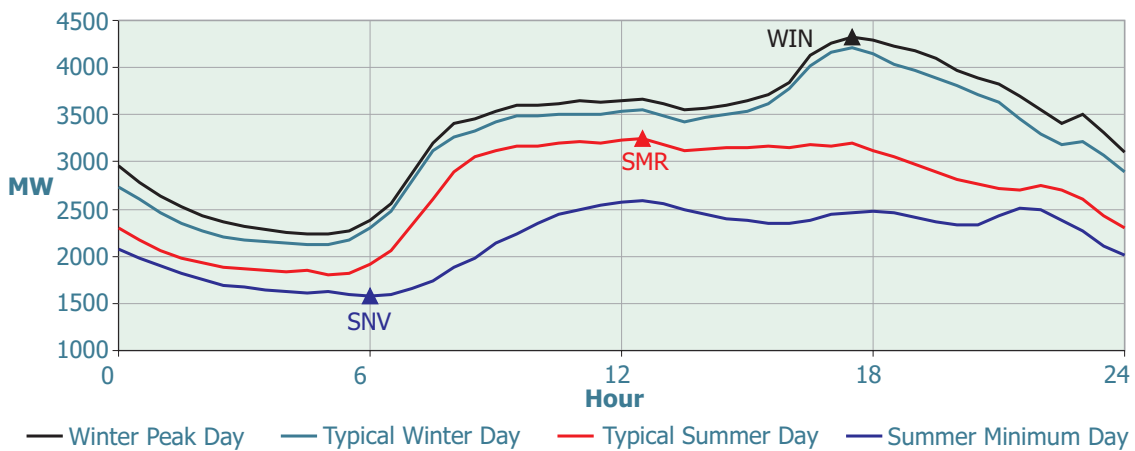


Figure 3-3 Daily Demand Profiles for Year 2004

