6 SUPPLY DEMAND ANALYSIS

This chapter adequacy begins with an analysis of the adequacy of system capacity to transport available supplies and meet peak day demand.

The supply-demand scenarios are then presented using forecast 1 in 2 and 1 in 20 winter peak days and 1 in 2 and 1 in 20 winters.

6.1 Adequacy of System Capacity

The transportation capacity from each of the primary injection points at Longford, Culcairn, and Iona is equal to or in excess of available supplies reported by *Participants* at each injection point. Therefore, under normal operating conditions and reliable scheduling, the system has adequate capacity to transport available supplies throughout the planning period.

Table 6.1 Adequacy of System Capacity 2002 (TJ)

Injection Point	Pipeline Capacity	Available Supply 2002
Longford	990	830
Culcairn	50	28
Iona	275	265
LNG	150	150
System w/o LNG[31]	1,280	1,123
System with LNG[32]	1,410	1,273

Table 6.1 shows the supplies available at each injection point and the relevant pipeline capacity for winter 2002. The transport capacities from each injection point exceed the available supplies throughout 2002 to 2006.

As discussed in Chapter 4, the main risks to supply for gas customers and *Participants* due to capacity constraints are:

- unplanned plant outages;
- surprise events such as unexpected higher demand due to unforeseen severe changes in weather conditions during a gas day; and
- adverse beginning of day operating conditions such as low system linepack.

[31] The system capacity is not a simple aggregate of the injection point pipeline capacities.

[32] This level of capacity is theoretical and is pushing the system to the limit. It is possible that restaging of Brooklyn compressors would be required to maintain pressures on the Ballarat Pipeline.

6.2 Peak Day Supply-Demand Analysis

6.2.1 Available Supply

Table 6.2 shows the available supplies at each injection point for the next 5 years assumed for supply-demand analysis.

The available Longford supplies are expected to be marginally lower than the reported contracted for 2002 to 2004. Not all contracted MDQ will necessarily will bid into the Market on a daily basis. In 2001 the aggregate bids from Longford varied from about 825 TJ to 835 TJ over winter. Supply of 830 TJ/d is assumed available in the supply-demand analysis for 2002 to 2004.

The expiry of the Gascor Gas Release supply contract by 2004 means that alternative supplies of at least 30 TJ/d may be sought at or near Longford. Accordingly, available Longford supplies for 2005 and 2006 are assumed to be 840 TJ/d allowing for additional contracted gas from either the Patricia Baleen field, the EGP or additional Longford supply.

Table 6.2 Available Supply (TJ)

Year	Longford	Iona	Culcairn	LNG	Total
2002	830	265	28	150	1,273
2003	830	250	28	0	1,108
2004	830	250	28	0	1,108
2005	840	250	28	0	1,118
2006	840	250	28	0	1,118

Iona supplies are comprised of UGS and toll processed gas[33]. Gas supplies from the UGS at Iona are assumed available up to the revised capacity of the UGS facility of 250 TJ/d. Some additional toll processed supply from other Otway Basin fields is available in 2002.

A conservative assumption of 28 TJ/d available supply at Culcairn has been assumed. Quantities bid into the market in winter 2001 vary from a minimum of 28 TJ to over 50 TJ/d. It is believed that quantities higher than 28 TJ/d will be made available on a non-firm basis subject to demand in NSW and linepack in the APT NSW transmission system.

LNG has an assumed capacity of 150 TJ/ on winter peak days. LNG is available in 2002 with the prospect of continued availability beyond 2002 subject to resolution of VENCorp system security reserve needs and new commercial arrangements between the LNG storage provider and Market Participants.

6.2.2 Peak Day Supply-Demand

Total system supply-demand balance is presented in Table 6.3 and Figure 6.1 for both 1in 2 and 1 in 20 peak day demand scenarios. These peak day forecasts do not include demand for gas power generation. Gas power generation is considered in section 6.2.3.

[33] And any remaining gas for injection at North Paaratte.

Aggregate available supplies are adequate to meet the forecast 1 in 2 peak days for 2002 to 2004 without LNG, however LNG or alternative supply of up to 45 TJ/d is required to meet the forecast 1 in 2 peak demand for 2005 and 2006.

The 1 in 20 peak day scenario show supply shortfalls of 49 TJ to 131 TJ/d unless LNG or an alternative supply is available from 2003.

Table 6.3 Supply - Demand (TJ)

Year	Aggregate Available Supply	1 in 2 Peak Day		1 in 20 Peak Day	
		Demand	Surplus	Demand	Surplus
2002	1,273	1,051	222	1,131	142
2003	1,108	1,075	33	1,157	-49
2004	1,108	1,107	1	1,191	-83
2005	1,118	1,139	-21	1,225	-107
2006	1,118	1,161	-43	1,249	-131

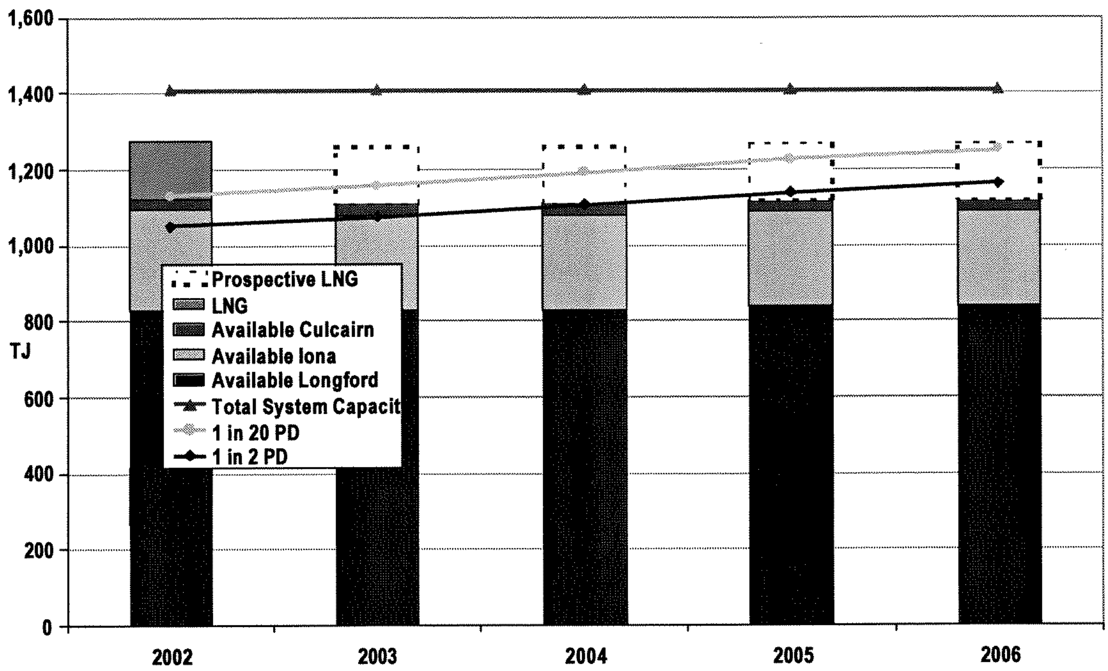

Figure 6.1 Winter Peak Day Supply - Demand

6.2.3 Gas Power Generation on Winter Peak Days

Demand for gas power generation of 100 TJ or more can normally be expected to occur in summer months, however demand of up to 150 TJ was recorded in June 2000 and maximum demand of over 100 TJ occurred in May 2001. Clearly, gas power generation in winter must be considered in supply-demand planning.

Available supplies are adequate to meet demand for gas power generation of 100 TJ or more on 1 in 2 system peak days throughout the planning period provided LNG is available.

However, on 1 in 20 peak days, LNG for gas power generation reduces from about 100 TJ in 2003 to under 20 TJ by 2006 assuming LNG remains available after 2002. Limited curtailment of load would be required under such scenarios.

Supply-demand covering gas power generation over the summer months is addressed in Chapter 1 of the monthly planning review.

6.3 Winter Supply - Demand Analysis

Load Duration Curves (LDCs) are used to assess the supply-demand outlook over the winter period. Each LDC is comprised of 365 days of simulated demand based on the forecasts sorted in descending order of demand. Supplies are stacked up in an assumed price order to assess the supply-demand outlook for a given supply scenario.

6.3.1 Depletable Resources Pricing Scenario (DRPS)

UGS and LNG are depletable resources. Either can be depleted within winter if their scarcity is not reflected by higher market bid prices. The DRPS assumes that Longford and Culcairn supplies are scheduled ahead of Iona[34], and Iona is scheduled ahead of LNG. The quantity of Culcairn gas available is assumed to be the firm contract levels (14 TJ/d in 2002 and 2003) except on high demand days where the total available is assumed to be up to 28 TJ.

Figure 6.2 depicts a 1 in 20 severe winter supply-demand scenario for 2002 using the forecast load duration curve and the available supplies in Table 6.2. Demand from gas power generation is not included in this scenario but is modelled and considered in sections 6.3.2 and 6.3.3.

[34] Iona is essentially UGS supply but some additional toll processed gas from other Otway fields may be available.

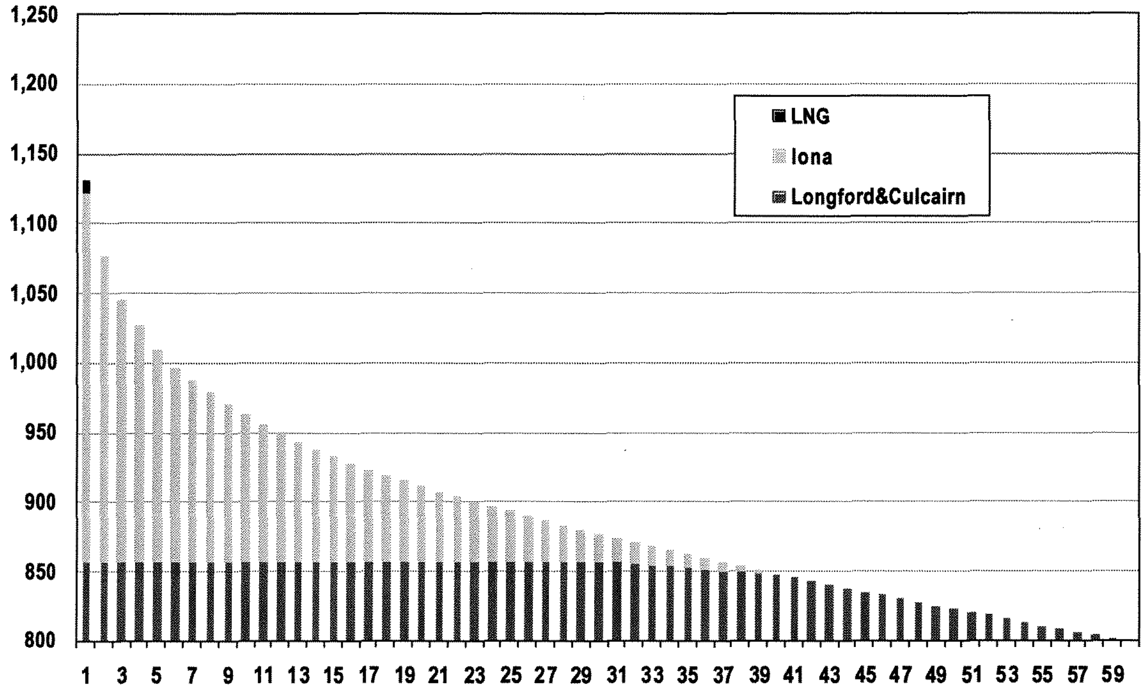

Figure 6.2 DRPS 1in 20 Winter 2002 Supply – Demand Excluding Gas Power Generation

Under the DRPS, supply is adequate to meet demand through winter 2002 excluding gas power generation by using 2.7 PJ of Iona gas over about 39 days. A needle peak shaving requirement is met by LNG on just one day.

The DRPS results for 2002 to 2006 using the supply MDQ assumptions in Table 6.2 are shown in Table 6.4.

Table 6.4 DRPS excluding Gas Power Generation Supply – Demand

Winter Supply-Demand Scenario	Iona Injections			LNG			Surplus >100TJ	Surplus >200TJ
	Peak TJ	Days	Total PJ	Peak TJ	Days	Total TJ	Days	Days
1 in 2 2002	193	28	1.7	0	0	0	363	328
1 in 20 2002	265	39	2.7	8	1	8	361	312
1 in 2 2003	217	39	2.4	0	0	0	361	313
1 in 20 2003	250	48	3.6	49	1	49	357	296
1 in 2 2004	249	58	3.9	0	0	0	354	282
1 in 20 2004	250	66	5.4	83	2	109	339	264
1 in 2 2005	250	65	5.0	21	1	21	344	271
1 in 20 2005	250	74	6.7	107	3	169	328	252
1 in 2 2006	250	72	6.2	43	2	48	333	260
1 in 20 2006	250	80	7.9	131	4	254	318	242

The results in Table 6.4 highlight a steadily increasing reliance on Iona and LNG over the planning period. Currently UGS holding capacity is about 10.7 PJ and about 500 TJ of LNG could be utilised in a given winter. Clearly, in the absence of gas power generation, UGS and LNG storage inventory and capacity are adequate to meet demand under the DRPS over the planning period.

6.3.2 Gas Power Generation

The additional winter demand from gas power generation can be quite significant and must be considered. For example, gas power generation amounted to about 7 PJ over the April to October 2001 period and exceeded 100 TJ/d on occasions. The LDC model has been used to determine the numbers of days when surplus supplies of 100 TJ or 200 TJ are available for gas power generation. The results are shown in the right hand columns of Table 6.4. Supply is adequate to meet demand including gas power generation most of the year except for the very high demand days. However, by 2006 gas available for gas power generation is restricted to under 100 TJ on about 30 days in an average winter and up to 50 days in a severe winter.

It is still necessary to ascertain if there is sufficient gas storage inventory to meet demand including that from gas power generation over the winter period.

Actual gas power generation demand in winter 2001 has been used in the following supply-demand scenarios to assess the impact of gas power generation. Although, gas demand from forecast gas power generation is expected to grow from 13 PJ in 2001 to about 16 PJ by 2006, most of this growth is associated with summer electricity peaking. The 1 in 20 winter 2002 supply-demand scenario including gas power generation is shown in Figure 6.3. Under this scenario, Iona supplies 5.3 PJ over 62 days, about double the quantity in the earlier scenario that excluded gas power generation. LNG is required for peak shaving on just one day though in a greater quantity than in the first scenario.

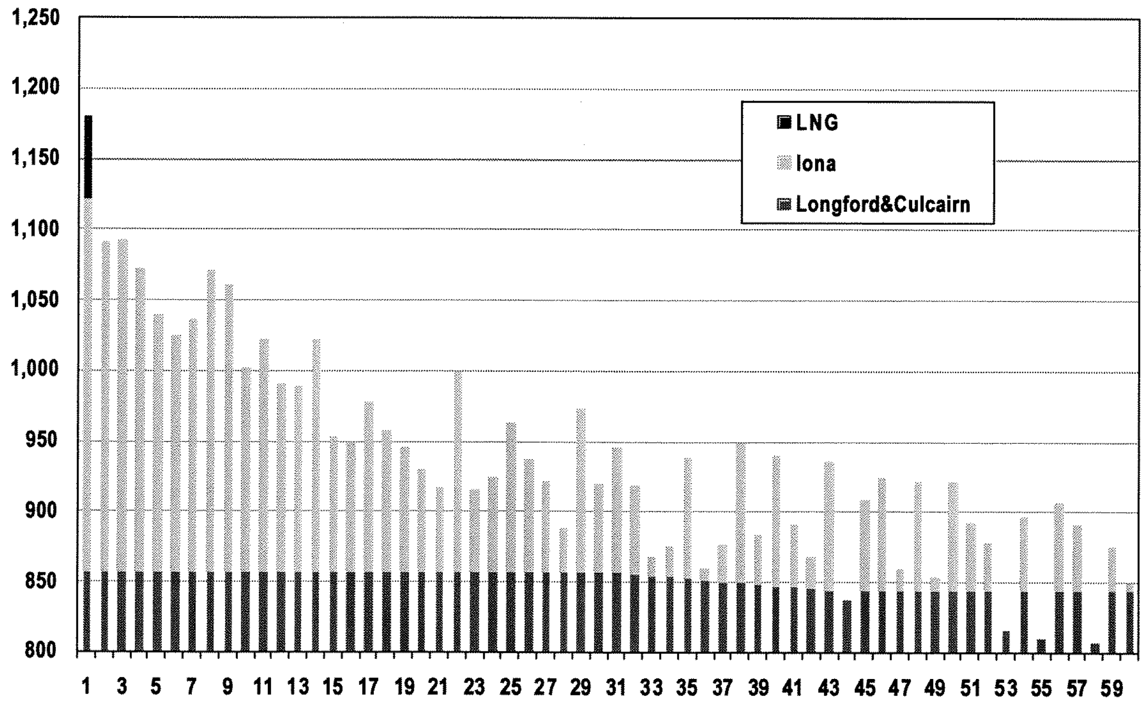

Figure 6.3 DRPS 1in 20 2002 including Gas Power Generation Supply – Demand

Assuming gas power generation in winter the medium term remains at levels similar to 2001, the results in Table 6.5 show that there is adequate storage inventory and capacity to meet demand to 2005. However, even under the strict DRP scenario, UGS and LNG storage are at risk of depletion from 2005 onwards. These risks could be easily mitigated by contracting more MDQ from Longford, Culcairn, other Otway sources, or elsewhere. Alternatively, UGS holding capacity and injection capacity could be expanded and be made available to the market.

Table 6.5 DRPS with Gas Power Generation Supply - Demand

Winter Supply-Demand Scenario	Iona Injections			LNG		
	Peak TJ	Days	Total PJ	Peak TJ	Days	Total TJ
1 in 2 2002	242	53	3.9	0	0	0
1 in 20 2002	265	62	5.3	57	1	57
1 in 2 2003	250	61	5.0	16	1	0
1 in 20 2003	250	67	6.5	98	3	113
1 in 2 2004	250	78	7.2	48	1	48
1 in 20 2004	250	86	9.0	132	6	250
1 in 2 2005	250	85	8.7	70	2	78
1 in 20 2005	250	88	10.5	156	9	382
1 in 2 2006	250	88	10.0	92	6	176
1 in 20 2006	250	95	11.9	180	12	579

6.3.3 Market Pricing Scenario (MPS)

In reality, market supply bidding is governed by supply contracts, hedging contracts, and market strategies and is not solely based on scarcity. As a result, depletable supplies such as UGS and LNG are used more liberally than that suggested by the DRPS, particularly in late autumn and the first half of winter.

To provide some indication of the impact of such market bidding strategies, actual market price and quantity bid stacks from winter 2001 have been applied to the set of demand scenarios including gas power generation. An adjustment to the bid stacks has been made to remove toll processed gas bids at Iona. The supply contracts in 2001 are similar to those reported for 2002 and 2003, so assuming LNG remains available, the 1 in 20 2002 MPS depicted in Figure 6.4 can be directly compared with the DRPS outcome in Figure 6.3.

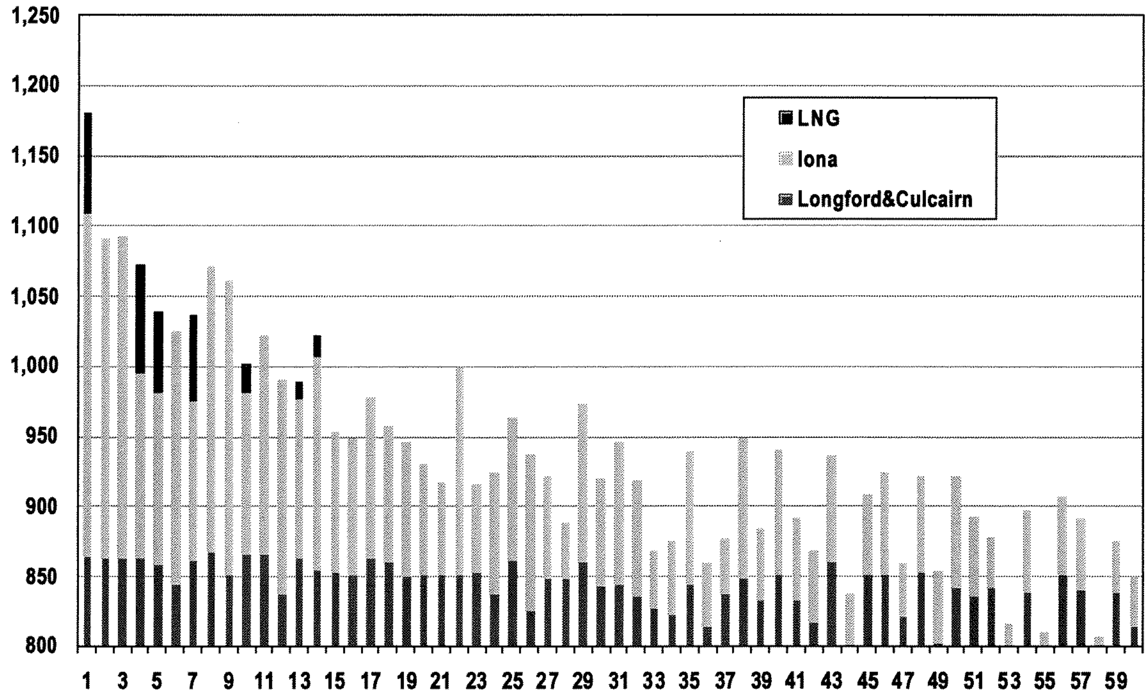

Figure 6.4 MPS 1in 20 2002 including Gas Power Generation Supply – Demand

The MPS results for 2002 to 2006 are summarised in Table 6.6. The aggregate supply quantities have been limited to the highest 100 demand days.

Table 6.6 MPS with Gas Power Generation Supply - Demand

Winter Supply Demand Scenario	Iona Injections			LNG		
	Peak TJ	Days	Total PJ	Peak TJ	Days	Total TJ
1 in 2 2002	242	100	5.1	33	5	83
1 in 20 2002	265	100	6.0	77	8	335
1 in 2 2003	250	100	5.8	55	8	207
1 in 20 2003	250	100	6.7	97	11	523
1 in 2 2004	250	100	6.9	84	10	456
1 in 20 2004	250	100	7.7	128	24	986
1 in 2 2005	250	100	7.9	110	24	899
1 in 20 2005	250	100	8.7	144	31	1645
1 in 2 2006	250	100	8.5	131	6	1344
1 in 20 2006	250	100	9.4	160	37	2190

In the MPS shown in Figure 6.3, LNG is used more frequently for peak shaving than in the DRPS because it is not always the most expensive gas bid into the market. LNG of over 300 TJ over 8 days is scheduled in this instance compared to just 57 TJ on one day in the DRPS example. Similarly, a greater quantity of gas is scheduled from Iona – some 6 PJ over the 100 highest demand days.

In the later years, Iona gas usage under the MPS is comparable but less is used than under the DRPS. This is a result of displacement of Iona gas by Culcairn gas. Up to about 50 TJ/d of Culcairn gas was offered in 2001 but this has not been assumed in the DRPS.

The main issue to note is the simulated use of LNG on a considerably greater number of days than in the DRPS. This indicates that it was not the most expensive gas available on these days. In Table 6.6, however, the LNG figures are somewhat inflated (and not are deliverable) because the probable change in bidding behaviour through winter is not included in the simulations. In a given winter, market bidding strategies should change dramatically if scarce resources such as LNG and UGS are seen as at risk of depletion. Prices should then increase accordingly and market bidding should progressively start to resemble the DRPS . The real outcome is likely to be somewhere between the DRPS and the MPS results discussed above.

In conclusion, the analysis shows that UGS and LNG remain critical supplies and appropriate market bidding strategies that reflect scarcity are required to ensure that demand can be met throughout each winter. In later years some additional MDQ from primary (non-depletable) supply points may be needed based on the scenarios analysed. A connection to the S.A. pipeline at or near Iona and availability of supply from new on-shore or off-shore Otway basin fields would greatly increase flexibility and security of supply from the SWP. An increase in UGS holding capacity in the medium term is also an option to reduce the risk of depletion during winter.

6.4 Demand Side Management

Demand side management, a virtual source of supply provided by large interruptible industrial consumers, is not included explicitly in the supply-demand analysis.

No interruptible (controllable) loads have been registered with VENCorp to date. This is not to say that industrial users will not enter into or have not already entered into commercial interruption contracts with *Market Participants*. The Government Winter 99 Contingency Projects generated a significant number of short term interruptible contracts amounting to over 40 TJ/d of interruption[35] that could be the basis of a market in DSM.

Historically, gas power generation has been interrupted when system demand had the potential to exceed system capacity. However, some gas power generation is now common on very cold winter days. In the future, demand side management of gas power generation will be driven by market forces and may depend on the relative spot prices in the Gas and Electricity markets, and in extreme circumstances, the relative VoLL levels in each market.

[35] A reasonable proportion of the interruptible loads were flexible enough to bid into a daily Market.