EX.6

R-28



# PROVIDING THE BALANCE OF POWER

ONTARIO HYDRO'S PLAN

TO SERVE CUSTOMERS'

ELECTRICITY NEEDS

## PLAN

## ANALYSIS

## PROVIDING THE BALANCE OF POWER

This "Plan Analysis" is one of a series of documents issued under the title, "Providing the Balance of Power: Ontario Hydro's Plan to Serve Customers' Electricity Needs." It provides technical details and supporting analyses for Hydro's proposed plan to meet the future electricity needs, and the alternatives that were considered. A more comprehensive discussion of the background to, and the elements of, these plans is provided in the "Demand Supply Plan" Report.

Another document, "Overview", presents in a more abbreviated and somewhat different form the main features of the proposed plan, the alternatives, and the considerations that went into their development.

A fourth document, "Environmental Analysis", analyzes the environmental impact of the Proposed Demand/Supply plan and the alternatives. These documents will be filed with the Minister of the Environment for a public hearing before the Environmental Assessment Board. Prior to that hearing, these documents will be subject to government review. As well, they will be the focus of a public information program held early in 1990.

## CONTENTS

# 1. INTRODUCTION

This report focuses on the formulation, description and analysis of the five Major Supply Cases. The rationale for selecting Candidate Plans or the Proposed Plan is provided in the Demand/Supply Report (DSP). It's recommended that the DSP Report be read first. Keeping a copy close at hand would also be useful, as there are numerous references to the DSP Report in this analysis. Definitions of many of the technical terms used in this report are provided in the glossary of the DSP Report.

There are 4 major differences between this report and the DSP Report:

- Cases and evaluation results are described for two load forecast paths that branch from the median forecast; one lies between the upper and median forecasts; the other lies between the lower and median forecasts. In all, five load forecast paths are assumed: median, branch upper, upper, branch lower and lower.

- Results are more fully presented. The DSP Report often summarizes results by five year periods. This report provides annual results. This report also provides more detailed results, such as fossil energies by fuel type, and costs under specific conditions.

- Certain aspects of plan development are covered in more detail, such as reliability, acid gas control and transmission.

- The main models used to simulate the electricity system and to carry out the economic evaluation are described.

During the formulation of plans, certain data was updated, specifically customer response to demand management initiatives, the non-utility generation forecast, hydroelectric sites and the cost of options.

The data used in this analytic work and the DSP Report were current at the time the work was carried out. Because these documents were completed at different times, there are some differences between the data used in each report. These differences are noted and explained in this report. The differences are small and would not affect the nature of the Cases developed or the results of the evaluation of the Cases.

Along with this introduction, there are eight chapters:

Chapter 2 -- System Modelling: describes the principal model used to simulate how a balanced mix of demand and supply options meet customer needs. This model receives data from many sources and, in turn, is the source of much data for subsequent evaluations in areas such as economics, finance and acid gas.

Chapter 3 -- Reliability: describes the generation reliability standard used to assess Hydro's ability to meet customer needs continually. Using two demand/supply cases, the standard is applied in a reliability analysis to find the generating reserve margin to apply in formulating all cases.

Chapter 4 -- Formulation and Description of Plans: begins with some background on how Hydro arrived at the five Cases presented in the DSP Report. However, the main purpose of this chapter is to describe how each of the five Cases respond to changes in load forecast, particularly the branch upper and branch lower forecasts. By considering load forecast changes, Hydro ensures its plans have flexibility.

Chapter 5 -- Transmission: describes the radial and inter-area transmission associated with certain sites and the sequence in which sites may be developed.

Chapter 6 -- Energy Production: describes, year by year, the energy provided by Non-Utility Generators (NUGs), the Manitoba Purchase, hydraulic, nuclear and fossil generation for all five load paths and five Cases.

Chapter 7 -- Acid Gas Control: describes acid gas control planning and the control plan assumed in the DSP Report. Energy derived from oil, natural gas and coal is presented. Energy from coal is further divided by application: e.g. low sulphur content, stations equipped with scrubbers.

Chapter 8 -- Costs: begins with the source of cost data and traces the application of those data. The principal cost model is described -- how it receives the data inputs and the many cost results that are derived from it. The principles of the allocation of present value costs and the cost risk assessment method are explained. Specific results are also presented for the branch load forecast paths.

Chapter 9 -- Financial Impact Assessment: deals with rate and borowing requirements.

# 2. SYSTEM MODELLING

## 2.0 INTRODUCTION

This chapter describes the computer modelling of the Ontario electric supply system as used for the Demand/Supply Plan. These models simulate the load to be supplied and schedule generation to supply it. They also track associated demand and supply costs, and determine acid gas emissions, coal blending and secondary nuclear sales. Additional models used for costing are discussed in Chapters 8 and 9.

## 2.1 MODELLING OVERVIEW

The primary model used for evaluation of the Demand/Supply Plans was the Load Management Strategy Testing Model (LMSTM) developed for the Electric Power Research Institute in 1984 (EPRI EA-2396, 1984). It was first used by Ontario Hydro in the preparation of the Draft Demand/Supply Planning Strategy. For the Demand/Supply Plan, the original LMSTM model was enhanced to determine fuel blending to meet acid gas limits and secondary nuclear sales.

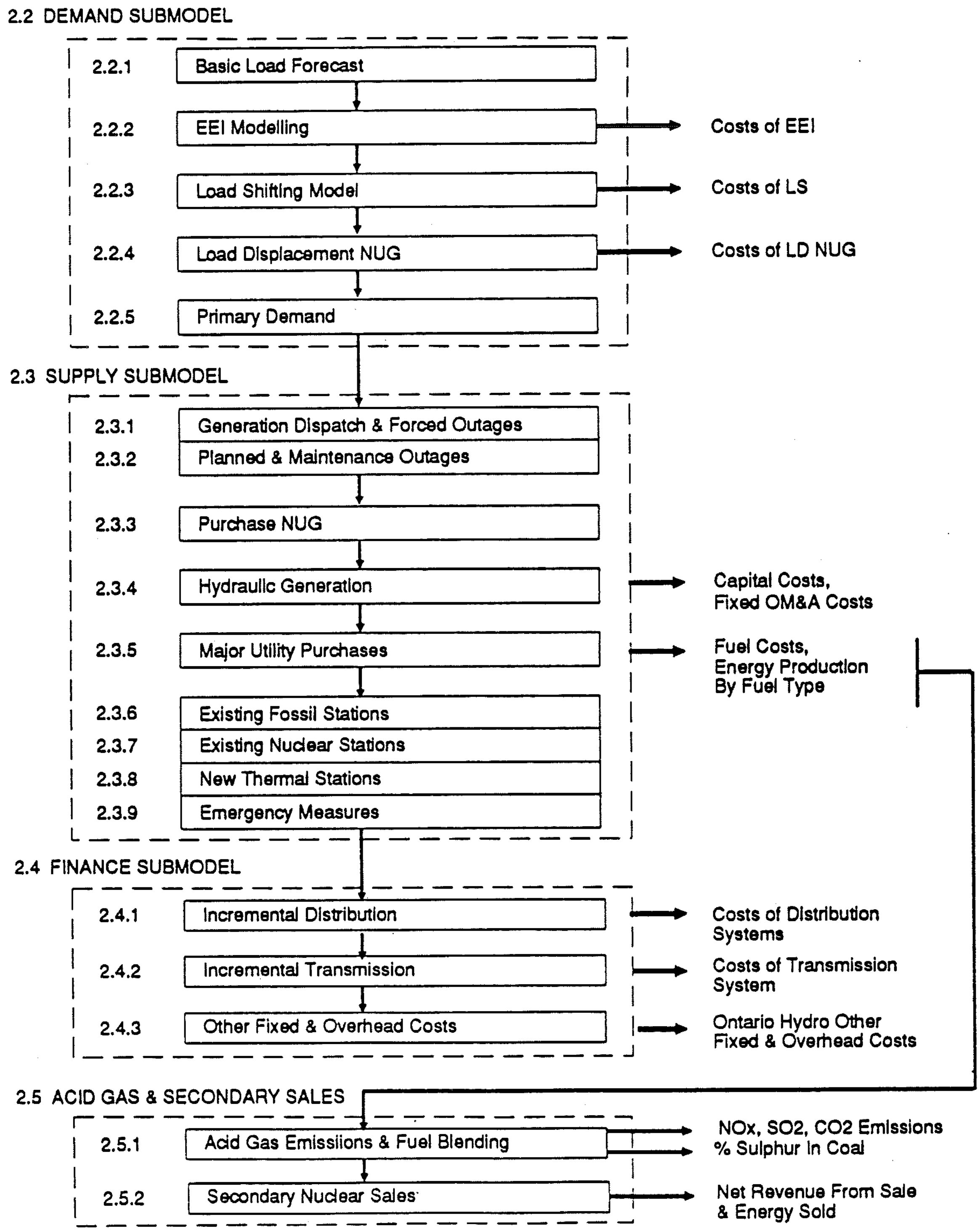
The enhanced version of LMSTM is one of several models used to analyze the plan. The primary functions of LMSTM were modelling of demand management and generation dispatch, and the calculation of fuel costs. It was also used for the calculation of costs common to all plans. The costs of new supply resources were entered directly into the Risk Assessment Model (RAM) (see Chapter 8). The corporate financial and rate impacts were also obtained separately (see Chapter 9).

LMSTM is an integrated planning model which models both demand and supply options. It consists of three submodels--demand, supply and finance. The logic flow among these submodels, and the sections of this chapter in which each submodel is described, are shown in Figure 2.1-1. A more comprehensive discussion is in the EPRI report referenced above.

The demand submodel accepts as input the basic load forecast, then subtracts the impact of demand management programs and load displacement non-utility generation, to derive the primary load forecast. This submodel also calculates the costs of demand management. This submodel is described in more detail in Section 2.2.

The supply submodel starts with the primary demand calculated in the demand submodel and the characteristics and costs of existing and new generating units. It simulates the scheduling of the production from these units; produces the capital, fixed operating and fuel costs of these units; and calculates expected energy generation by fuel type. Section 2.3 provides more detail on the supply submodel.

Figure 2.1-1
System Modelling Overview



The use of the LMSTM finance submodel is described in Section 2.4. This submodel includes the calculation of overhead and other fixed costs, transmission and distribution costs and fixed costs related to existing assets such as existing generation stations or office buildings.

Finally, acid gas emission calculations, coal blending and secondary nuclear sales are calculated, based on fuel cost and energy production by fuel type from the supply submodel.

### 2.1.1 Modelling Constraints

LMSTM has an annual resolution of demand, generation available and costs. This results in a number of constraints. The load shapes represent a seasonal pattern over a year with average load growth. As load growth from year to year changes, the relative demand across months would also change. For example, with high load growth, the December peak would be much higher than the preceding January peak. With low load growth, they would be almost the same. This changing of the seasonal pattern within a year cannot be modelled. However, it is quite small, compared to the effect of annual load growth.

The annual resolution also means that generating units may only be added as of January first of each year. Thermal units are usually scheduled to come on line in October. For modelling purposes these units were added as of the following January. In general, units with in-service dates before July first were modelled as starting the preceding January. Those with later in-service dates were modelled as starting the following January.

Starting units only in January also constrained the costing of major outages, such as rehabilitations and retubing. Therefore, the costs of these outages were modelled either as a fixed OM&A expense for shorter outages, or as a capital expense, if the duration exceeded a full year. The costs of outages spanning a year or more, such as nuclear retubing, were modelled as a capital cost and depreciated over the remaining life of the station. The costs of shorter outages were expensed as fixed OM&A.

All projects of a particular type are modelled with a similar construction expenditure pattern. These patterns actually do change with in-service date, because the underlying inflation rate is forecast to change from year to year over the planning period. This effect is insignificant, however, except for projects with long construction schedules, such as major new supply. These capital costs were used for calculation of the avoided costs. However, this constraint did not impact on the main financial analysis, because the major capital programs were modelled directly in RAM to assist with risk assessment.

Another constraint on financial modelling of capital costs is that the real discount rate cannot change over the planning period. This restriction is reflected through the calculation of the levelized capital cost, which is an Ontario Hydro modification to the original LMSTM program. The real discount rate actually varies from 6% in 1992 to 4.5% beyond 2010. A constant real discount rate of 5% was used for the calculation of all capital costs in the system modelling.

The inter-area transmission was included directly in RAM to reduce the number of system simulations required. The inter-area transmission alters the cost for a specific site for a specific type of new generation, but has no effect on other costs or demand or supply modelling. Rather than run the production simulation for each combination of new generation siting, the costs of inter-area transmission were included as part of the risk analysis and calculation of final costs.

## 2.2 DEMAND SUBMODEL

LMSTM is specifically designed for modelling the impact of demand management programs on utility load. Demand is represented by daily load shapes (24 hourly demands) for 4 typical days in each season. The typical days, or day types, represent high-demand weekdays, mid-demand weekdays, other (low-demand) weekdays, and weekends and holidays. The number of days represented by each day type in each season is shown in Figure 2.2-1. The fractional numbers of days in each type is due to averaging over the seven days of the week on which a year may start.

In this type of load representation the differences in energy demand across the day types reflect the effects of day-to-day weather variation (high-demand weekdays would reflect colder temperatures in winter and hotter temperatures in summer) and the effects of the day of the week (weekday versus weekend). If weather or day of the week alters the relative demands among the hours within a day, this is modelled by having different load shapes for each of the day types. Differences from season to season represent differences in weather over a year and influences such as the hours of sunlight, daylight savings time, and the summer vacation period.

Before proceeding it is necessary to define some terminology. The load shape is the pattern of how the demand for electricity varies from hour to hour. It must be scaled up or down from year to year by the demand or energy forecast. To illustrate, the basic loads for the three years shown for each day type on Figure 2.2-2 all have the same load shape. That is, the ratio of the load in each hour to average load for the day is the same for all three years. They differ because the load shape has been scaled by the forecast demand in each of the three years. The primary demands also shown on Figure 2.2-2 have different load shapes in the three years as a result of load reductions from efficiency improvements, load shifting and load displacement non-utility generation.

Figure 2.2-1

**Season and Day-Type Classification**
**For System Simulation**
(Number of Days in Each)

| Day Type | Season | | | | Total |
|---|---|---|---|---|---|
| | Winter | Spring | Summer | Fall | |
| HIGH Weekday | 37.51 | 20.13 | 37.82 | 20.13 | 115.59 |
| MID Weekday | 65.34 | 31.72 | 65.88 | 31.72 | 194.66 |
| LOW Weekday | 12.10 | 6.10 | 12.20 | 6.10 | 36.50 |
| WEEKEND | 6.05 | 3.05 | 6.10 | 3.05 | 18.25 |
| Total | 121.00 | 61.00 | 122.00 | 61.00 | 365.00 |

Winter = January, February, March, December
Spring = April, May
Summer = June, July, August, September
Fall = October, November

## Figure 2.2-2(a)
## Basic & Primary Load Shapes in System Simulation

WINTER

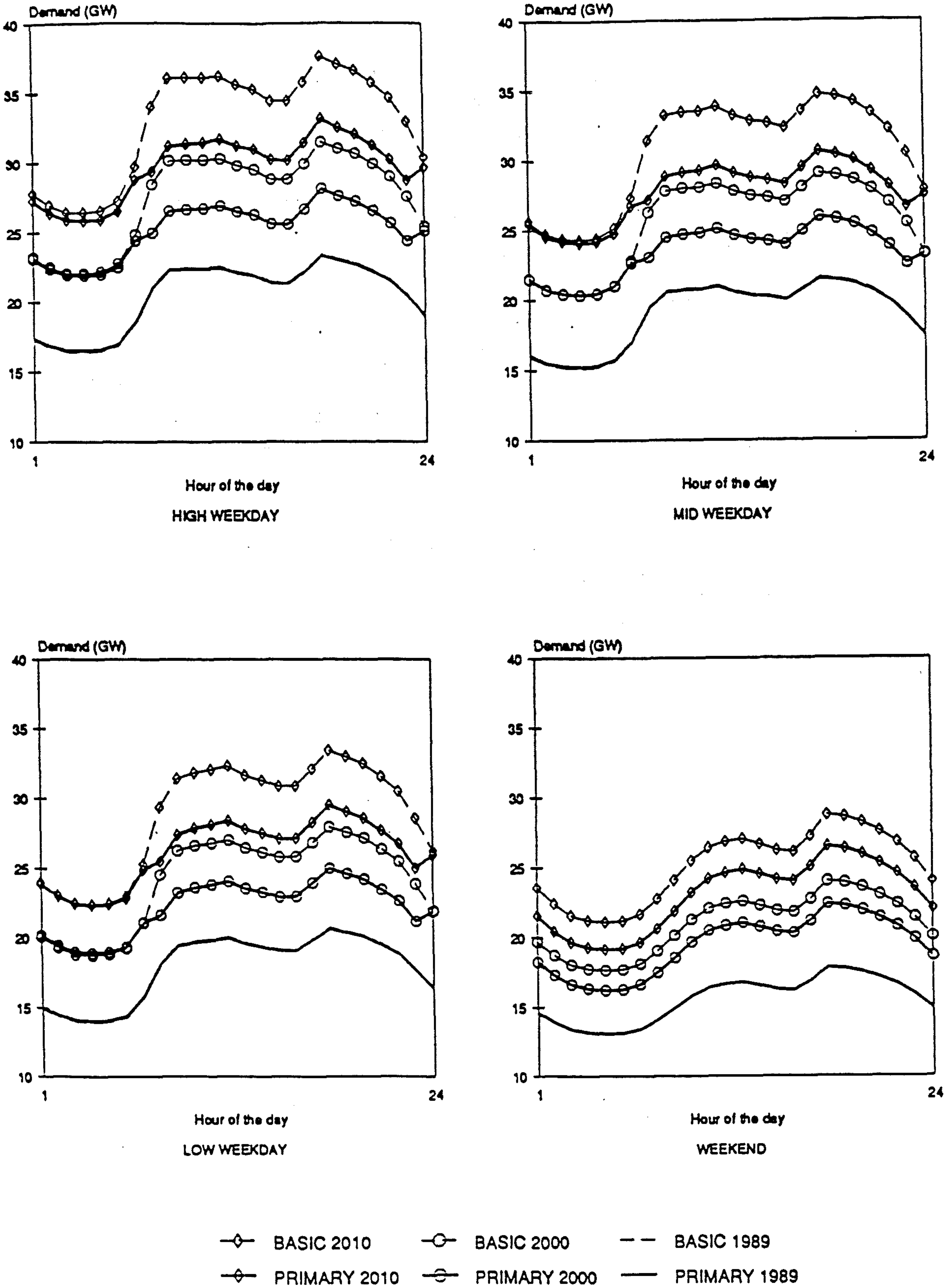
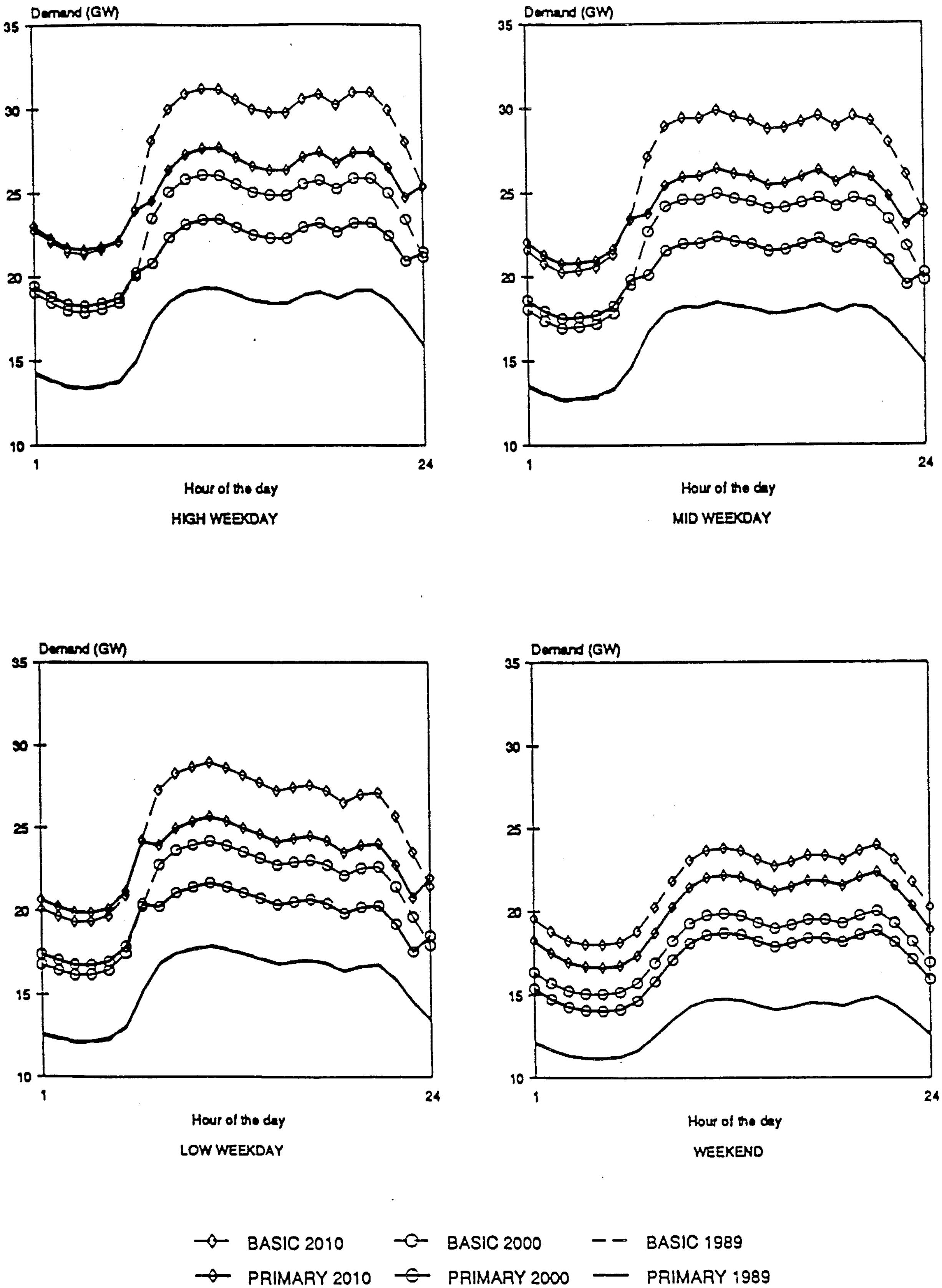


Figure 2.2-2(b)
Basic & Primary Load Shapes
in System Simulation

SPRING



## Figure 2.2-2(c)
## Basic & Primary Load Shape in System Simulation

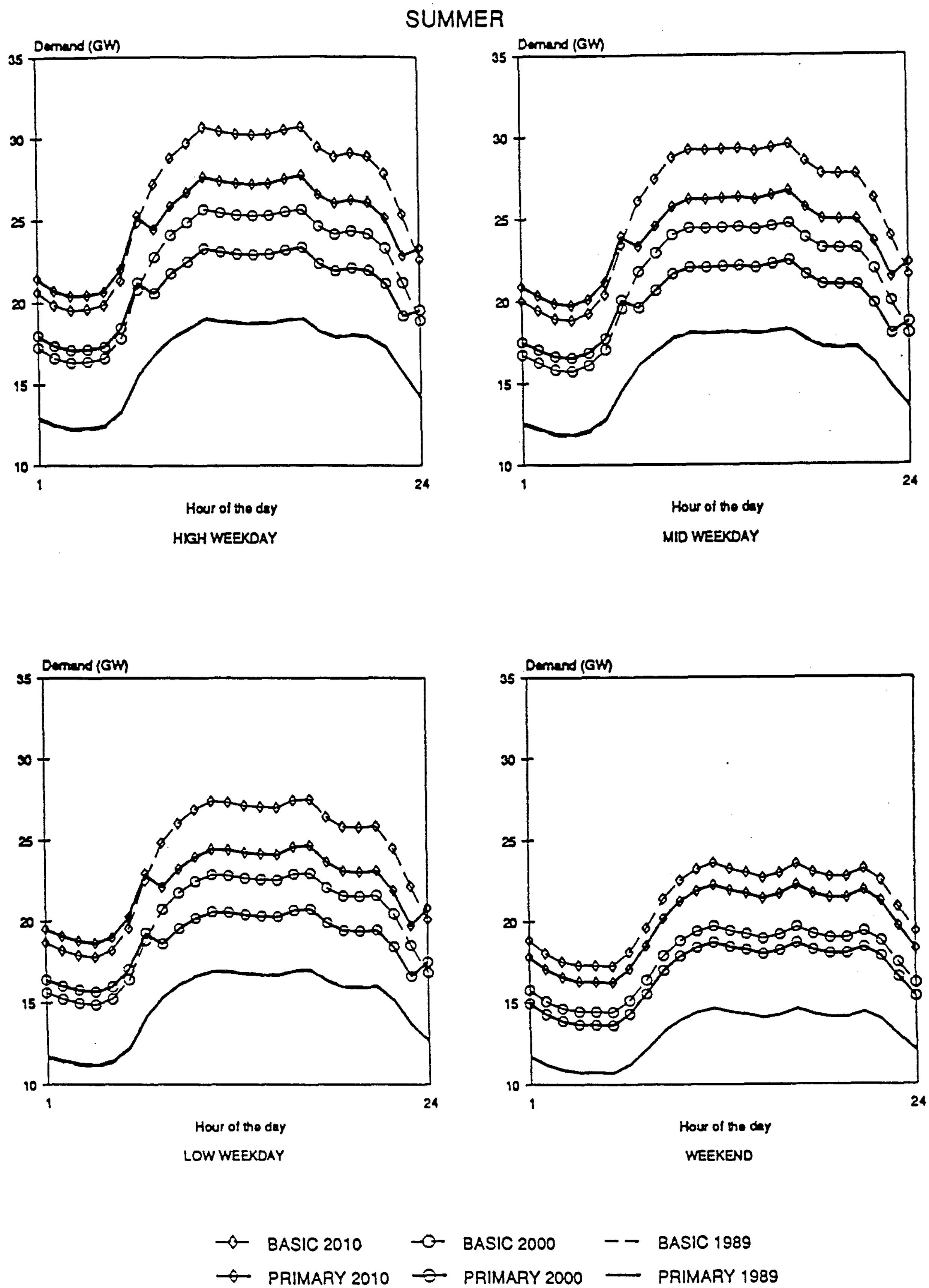
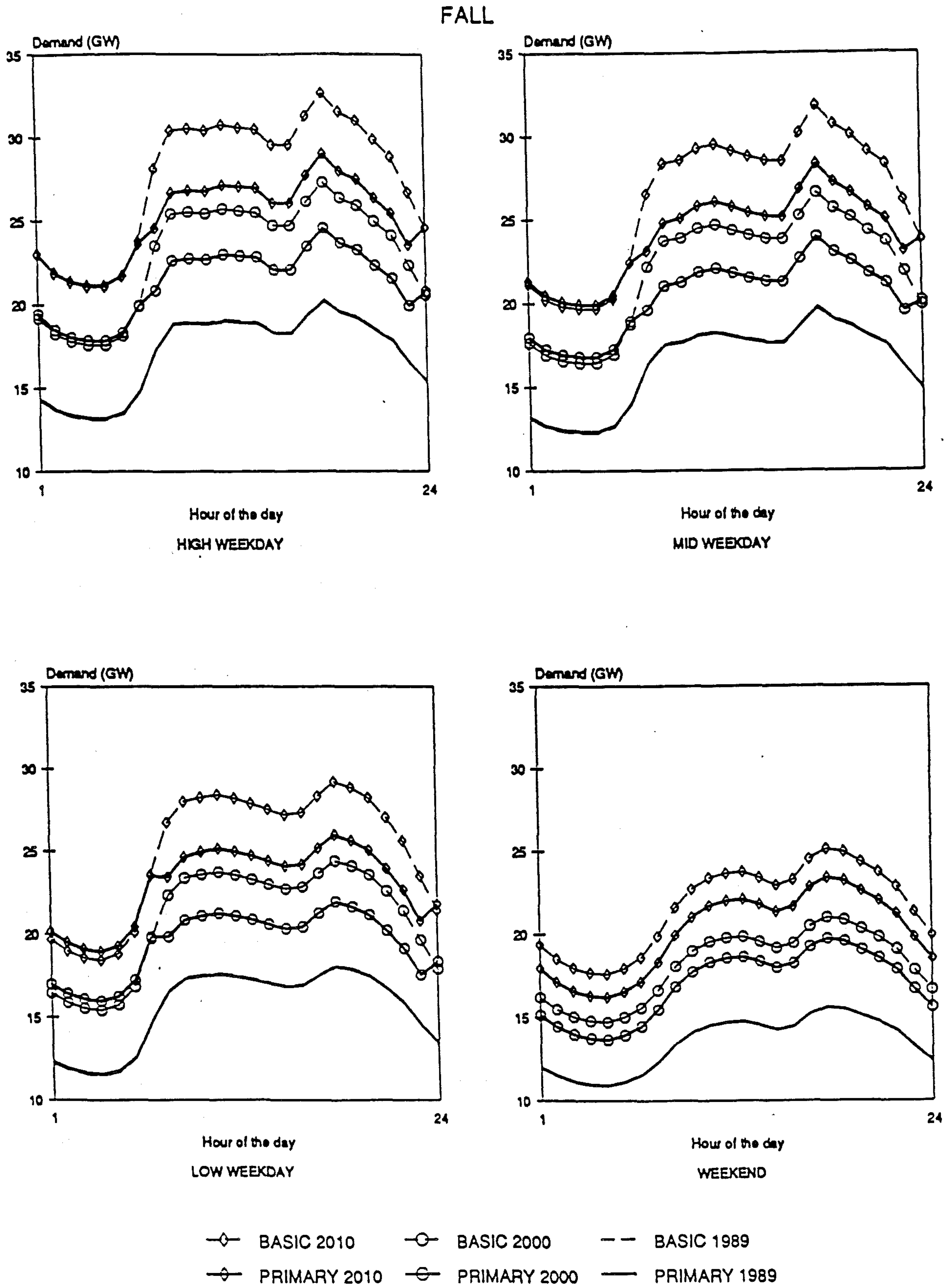


Figure 2.2-2(d)
Basic & Primary Load Shape
in System Simulation



The electricity basic demand for each day type is built from five different end-use load shapes representing different appliances or customer classes:

- residential domestic load,
- residential space heating,
- residential water heating,
- general class load (commercial & small industrial customers),
- direct customers (mainly large industrial customers).

To model demand management, the above end-use shapes were used and two other specific shapes were created:

- flat load (constant throughout the day)
- off-peak load (11 PM to 7 AM for recovering shifted load).

Demands created by adding together these various load shapes may also be grouped into customer classes:

- municipal residential
- rural residential
- general class
- direct customers.

These classes were used in this study to calculate distribution costs, which are only applicable for the loads in the first three classes.

The demand in each hour is created in stages. First, the basic load forecast is modelled as a sum of the five end-use shapes. This provides a separate estimate of basic load for each of the 384 typical hours (24 hours per day times 4 typical days times 4 seasons) (Section 2.2.1).

Next, load shapes (384 hours each) for electrical efficiency improvements (Section 2.2.2), load shifting (2.2.3) and load displacement non-utility generation (2.2.4) are created separately. Finally, these are subtracted from the basic load to create the primary load shape. This primary load is fed into the supply submodel, where it is met by supply resources.

### 2.2.1 Basic Load Forecast

The basic load forecast modelled is from the Load Forecast Report No.881212 published in April 1989. The five end-use loads were initially combined in the proportion of total system load forecast to come from each end-use. The proportion of energy consumed under these load shapes was modified to create the same one-hour December peak demand and annual energy as predicted in the load forecast. The resulting load shapes are shown in Figure 2.2-2 for 1989, 2000 and 2010.

The long-run (post 1994) basic load forecast is prepared using only one annual load shape for all years. So, basic load in LMSTM was also modelled using only one load shape for all years. The short-run forecast (up to 1994), which is also modelled in shape for all years. The short-run forecast (up to 1994), which is also modelled in LMSTM, has different load shapes so the modelling has some deviations from the load forecast in the early years. The maximum deviation is in 1989, when modelled peak demand is 0.6% higher than the forecast and energy use is 0.1% lower. After 1995, differences in both of these indicators are less than 0.03%.

### 2.2.2 Electrical Efficiency Improvements

Electrical efficiency improvements (EEI) are modelled as a load reduction from the basic load shape. They were compiled from the general class end-use shape and the residential domestic and space heating end-use shapes. The proportion of efficiency improvement modelled with each of these load shapes was determined so that the one-hour and sixteen-hour winter peaks and the annual energy reduction were as specified for the year 2000, a benchmark year in the demand management plan.

The effect of EEI programs is shown for the year 2000 in Figure 2.2-3. The load shape of EEI was not changed from year to year, but the load reduction from EEI was increased annually. Yearly peak reductions from EEI programs, as produced by the system simulation, are shown in Figure 2.2-4.

The incremental capital cost of EEI is estimated to be 900 $89/kW ($900 per kW in 1989 dollars) with Hydro offering an incentive of 351 $89/kW. After the 11-year life assumed for all EEI, the full $900 is paid by the participant. Hydro also incurs an administration OM&A cost of 350 $89/kW at the time of the first investment in EEI. This administration cost is not incurred when the equipment is replaced. All costs were escalated by the Ontario CPI.

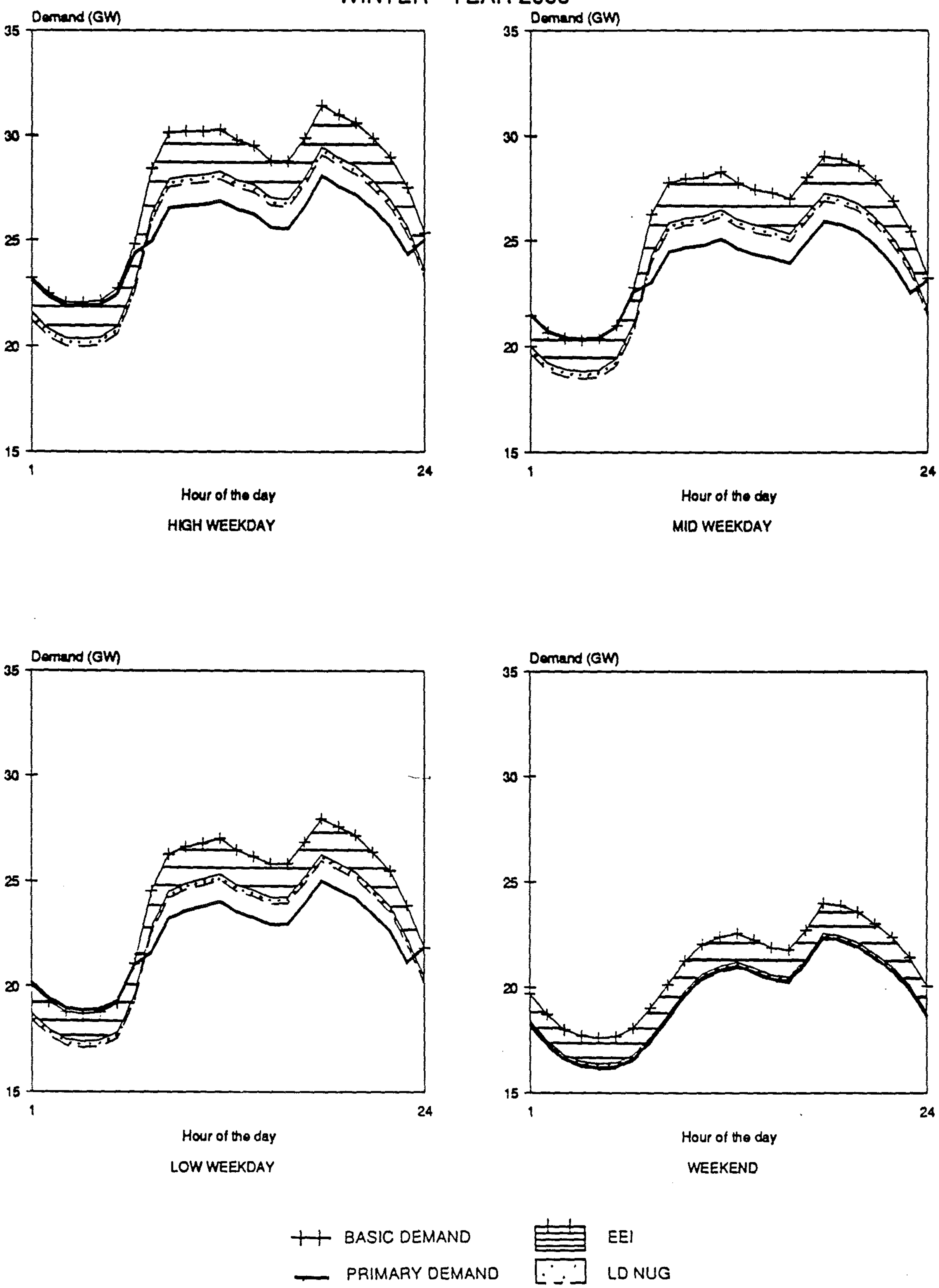
### 2.2.3 Load Shifting

Modelling load shifting is more complicated because the load must first be removed from the peak period (7 AM to 11 PM) of the three typical weekdays, and then be added to the off-peak (11 PM to 7 AM) period of these days. Some of the energy removed from the peak periods is also recovered on the weekends, which are off peak for all hours. The total amount of energy consumed is not changed as with EEI, but is only shifted to weekday nights and weekends.

Two load shapes were used to model the load removed from the peak periods--general class and direct customer load. This reflects that the majority of load shifting is expected to come from commercial and industrial customers. The proportion of the load shifting represented by each of the load shapes is shown in Figure 2.2-5. The division between these reflects the proportion of load shifting expected to come from direct customers and large users (direct customer end-use shape), versus smaller commercial, industrial and residential customers.

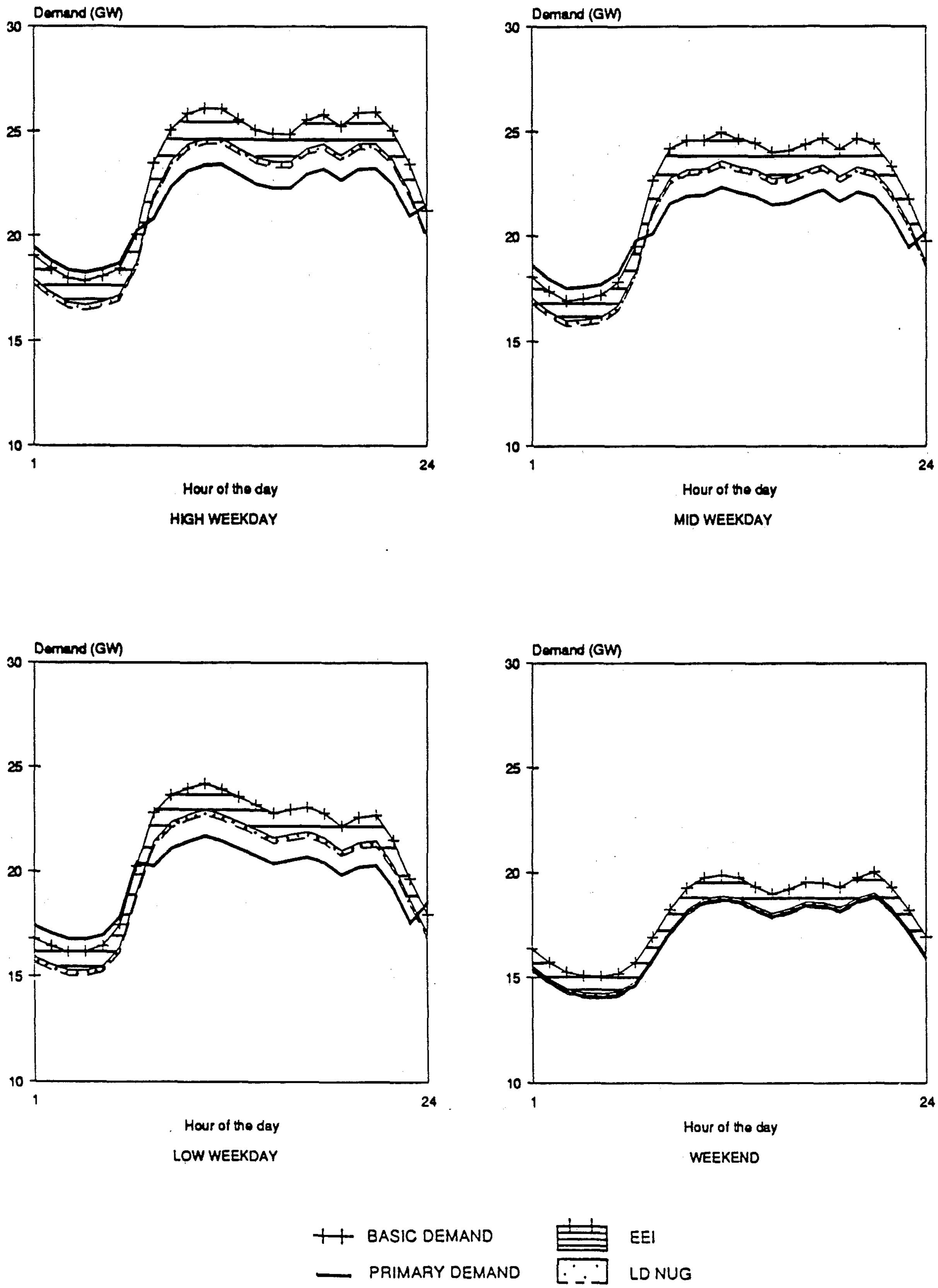
## Figure 2.2-3(a)
## Load Shape Modifications for EEI, LD NUG and LS

WINTER - YEAR 2000



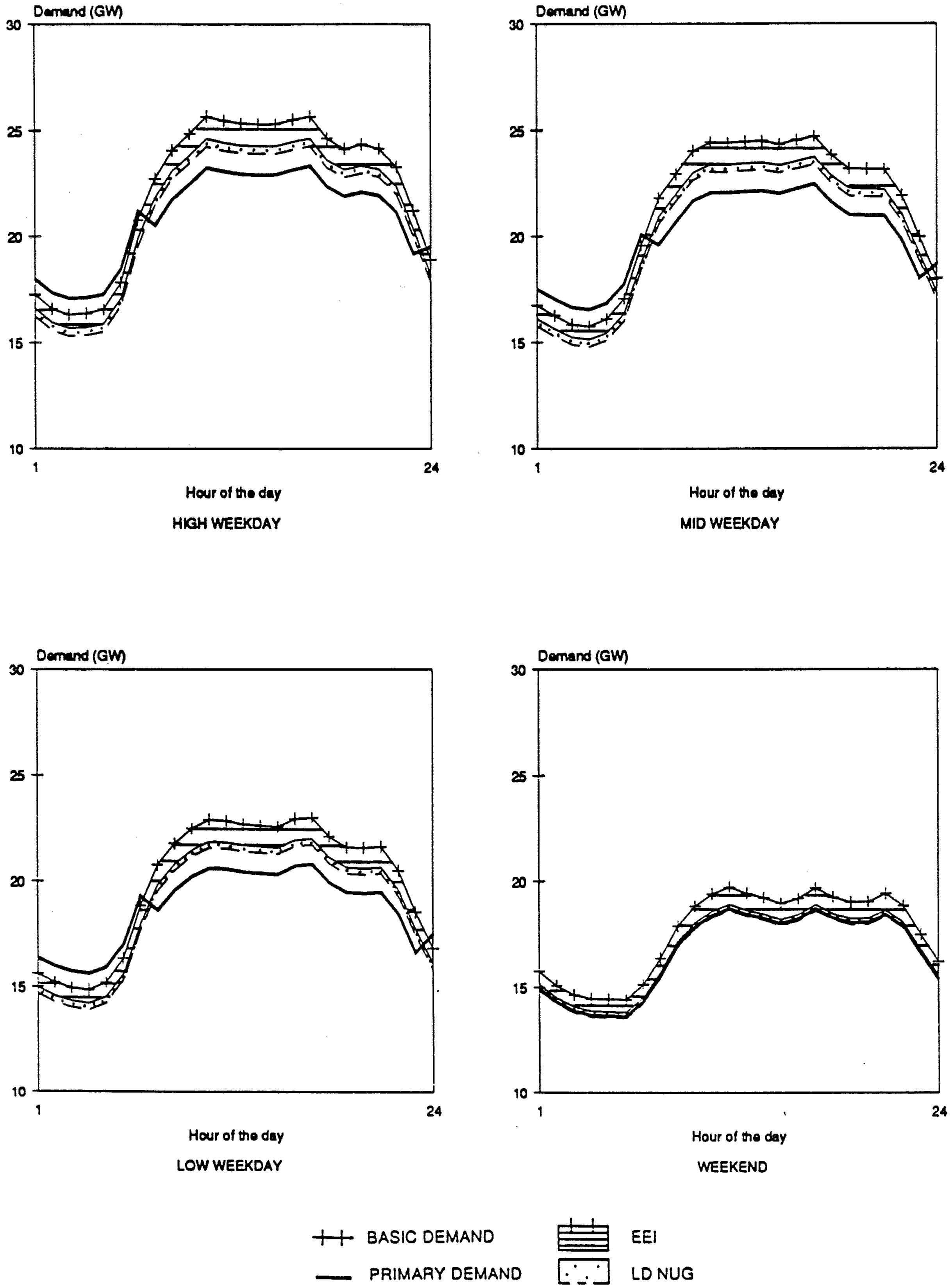
# Figure 2.2-3(b)
# Load Shape Modifications for EEI, LD NUG and LS

SPRING - YEAR 2000



## Figure 2.2-3(c)
## Load Shape Modifications for EEI, LD NUG and LS

SUMMER - YEAR 2000



# Figure 2.2-3(d)
# Load Shape Modifications for EEI, LD NUG and LS

FALL - YEAR 2000

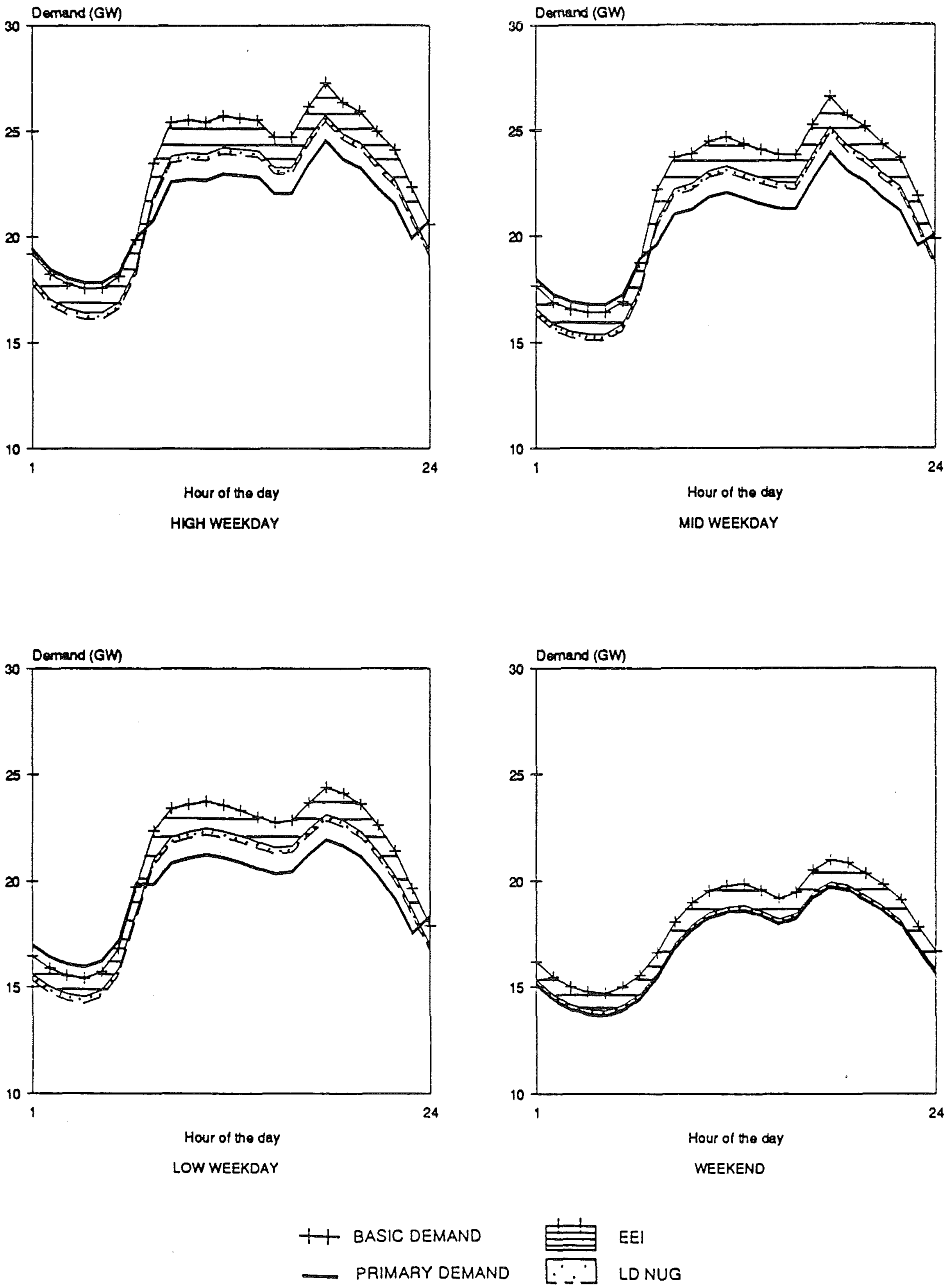


**Figure 2.2-4**

**Demand Management Savings as Produced By System Simulation**

**(Cumulative Values As Of December One-Hour Peak)**

| | LOWER LOAD FORECAST | | | | BRANCH LOWER LOAD FORECAST | | | | MEDIAN LOAD LOAD FORECAST | | | | BRANCH UPPER LOAD FORECAST | | | | UPPER LOAD FORECAST | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| YEAR | EEI (MW) | LS (MW) | LD NUG (MW) | TOTAL (MW) | EEI (MW) | LS (MW) | LD NUG (MW) | TOTAL (MW) | EEI (MW) | LS (MW) | LD NUG (MW) | TOTAL (MW) | EEI (MW) | LS (MW) | LD NUG (MW) | TOTAL (MW) | EEI (MW) | LS (MW) | LD NUG (MW) | TOTAL (MW) |
| 1989 | 14 | 78 | 23 | 115 | 14 | 81 | 23 | 118 | 14 | 81 | 23 | 118 | 14 | 81 | 23 | 118 | 14 | 84 | 23 | 121 |
| 1990 | 36 | 161 | 90 | 287 | 45 | 172 | 90 | 307 | 45 | 171 | 90 | 306 | 45 | 172 | 90 | 307 | 56 | 180 | 90 | 326 |
| 1991 | 62 | 246 | 144 | 452 | 77 | 265 | 144 | 486 | 78 | 266 | 144 | 488 | 77 | 265 | 143 | 485 | 98 | 282 | 144 | 524 |
| 1992 | 101 | 387 | 210 | 698 | 126 | 424 | 210 | 760 | 126 | 423 | 210 | 759 | 126 | 424 | 210 | 760 | 158 | 455 | 210 | 823 |
| 1993 | 146 | 519 | 272 | 937 | 183 | 581 | 275 | 1039 | 183 | 582 | 275 | 1040 | 183 | 581 | 275 | 1039 | 229 | 735 | 276 | 1240 |
| 1994 | 251 | 576 | 288 | 1115 | 314 | 656 | 300 | 1270 | 314 | 656 | 300 | 1270 | 314 | 656 | 300 | 1270 | 393 | 728 | 307 | 1428 |
| 1995 | 400 | 620 | 288 | 1308 | 500 | 717 | 325 | 1542 | 500 | 717 | 325 | 1542 | 500 | 717 | 325 | 1542 | 625 | 795 | 342 | 1762 |
| 1996 | 640 | 663 | 288 | 1591 | 779 | 765 | 240 | 1784 | 800 | 776 | 340 | 1916 | 822 | 787 | 340 | 1949 | 1000 | 870 | 362 | 2232 |
| 1997 | 880 | 707 | 288 | 1875 | 1051 | 813 | 354 | 2218 | 1100 | 836 | 354 | 2290 | 1154 | 858 | 354 | 2366 | 1375 | 946 | 369 | 2690 |
| 1998 | 1120 | 749 | 288 | 2157 | 1315 | 858 | 364 | 2537 | 1400 | 893 | 364 | 2657 | 1495 | 927 | 364 | 2786 | 1749 | 1017 | 362 | 3128 |
| 1999 | 1360 | 790 | 288 | 2438 | 1574 | 899 | 368 | 2841 | 1700 | 946 | 368 | 3014 | 1830 | 989 | 368 | 3187 | 2125 | 1100 | 355 | 3580 |
| 2000 | 1600 | 800 | 288 | 2688 | 1809 | 950 | 340 | 3099 | 2000 | 1000 | 368 | 3368 | 2185 | 1050 | 348 | 3583 | 2500 | 1200 | 348 | 4048 |
| 2001 | 1663 | 820 | 288 | 2771 | 1882 | 965 | 320 | 3167 | 2100 | 1020 | 361 | 3481 | 2314 | 1074 | 341 | 3729 | 2624 | 1220 | 341 | 4185 |
| 2002 | 1725 | 840 | 288 | 2853 | 1956 | 980 | 300 | 3236 | 2200 | 1040 | 355 | 3595 | 2447 | 1098 | 334 | 3879 | 2750 | 1240 | 334 | 4324 |
| 2003 | 1788 | 860 | 281 | 2929 | 2028 | 995 | 281 | 3304 | 2300 | 1060 | 347 | 3707 | 2580 | 1122 | 327 | 4029 | 2875 | 1260 | 327 | 4462 |
| 2004 | 1850 | 880 | 274 | 3004 | 2102 | 1010 | 274 | 3386 | 2400 | 1080 | 339 | 3819 | 2714 | 1146 | 320 | 4180 | 3000 | 1280 | 320 | 4600 |
| 2005 | 1913 | 900 | 267 | 3080 | 2177 | 1025 | 267 | 3469 | 2500 | 1100 | 332 | 3932 | 2850 | 1170 | 313 | 4333 | 3125 | 1300 | 313 | 4738 |
| 2006 | 1974 | 920 | 260 | 3154 | 2253 | 1040 | 260 | 3553 | 2600 | 1120 | 325 | 4045 | 2980 | 1194 | 306 | 4480 | 3250 | 1320 | 306 | 4876 |
| 2007 | 2038 | 940 | 253 | 3231 | 2328 | 1055 | 253 | 3636 | 2700 | 1140 | 318 | 4158 | 3134 | 1218 | 299 | 4651 | 3375 | 1340 | 299 | 5014 |
| 2008 | 2100 | 960 | 246 | 3306 | 2403 | 1071 | 246 | 3720 | 2800 | 1160 | 311 | 4271 | 3252 | 1242 | 292 | 4786 | 3500 | 1360 | 292 | 5152 |
| 2009 | 2163 | 980 | 239 | 3382 | 2476 | 1085 | 239 | 3800 | 2899 | 1180 | 303 | 4382 | 3390 | 1266 | 285 | 4941 | 3625 | 1380 | 285 | 5290 |
| 2010 | 2225 | 1000 | 232 | 3457 | 2548 | 1102 | 232 | 3882 | 3000 | 1200 | 296 | 4496 | 3532 | 1290 | 278 | 5100 | 3750 | 1400 | 278 | 5428 |
| 2011 | 2288 | 1020 | 225 | 3533 | 2619 | 1115 | 225 | 3959 | 3101 | 1221 | 290 | 4612 | 3674 | 1314 | 271 | 5259 | 3875 | 1420 | 271 | 5566 |
| 2012 | 2350 | 1041 | 218 | 3609 | 2688 | 1131 | 218 | 4037 | 3200 | 1240 | 282 | 4722 | 3819 | 1338 | 264 | 5421 | 4000 | 1440 | 264 | 5704 |
| 2013 | 2412 | 1060 | 211 | 3683 | 2755 | 1145 | 211 | 4111 | 3298 | 1260 | 275 | 4833 | 3965 | 1362 | 252 | 5579 | 4123 | 1460 | 252 | 5835 |
| 2014 | 2475 | 1080 | 204 | 3759 | 2823 | 1161 | 204 | 4188 | 3400 | 1280 | 268 | 4948 | 4117 | 1387 | 240 | 5744 | 4250 | 1480 | 240 | 5970 |

Figure 2.2-5

**Modelling of Load Shifting**
(Percent of Load Shifting From Each Group)

| Year | Direct & Large Users | General Class |
|---|---|---|
| 1989 | 100% | 0% |
| 1990 | 100% | 0% |
| 1991 | 91% | 9% |
| 1992 | 69% | 31% |
| 1993 | 55% | 45% |
| 1994 | 53% | 47% |
| 1995 | 52% | 48% |
| 1996 | 50% | 50% |
| 1997 | 47% | 53% |
| 1998 | 45% | 55% |
| 1999 | 43% | 57% |
| 2000 | 42% | 58% |
| 2001 | 42% | 58% |
| 2002 | 42% | 58% |
| 2003 | 42% | 58% |
| 2004 | 42% | 58% |
| 2005 | 42% | 58% |
| 2006 | 42% | 58% |
| 2007 | 42% | 58% |
| 2008 | 42% | 58% |
| 2009 | 42% | 58% |
| 2010 | 43% | 58% |
| 2011 | 43% | 57% |
| 2012 | 43% | 57% |
| 2013 | 43% | 57% |
| 2014 | 43% | 57% |

The costs of load shifting were approximated by assuming that all shifting comes from the implementation of TOU rates. Only the smaller customers require an investment in metering equipment by Hydro to convert them to TOU rates. All participants incur costs to shift load. The total costs by year are shown in Figure 2.2-6.

The meter conversion costs incurred by Hydro are 400 $89/meter capital and 150 $89/meter OM&A for general class customers, and 80 $89/meter capital and 100 $89/meter OM&A for residential class customers. The meters are assumed to have a 33 year life so these expenses are incurred only once per customer during the planning period.

To shift load, the participant will also have to make capital investments. For example, to shift electricity use for water heating to the off-peak demand period a tank large enough to supply hot water throughout the peak demand period must be purchased. This cost is modelled as 300 $89/kW when the shifting occurs. This equipment is replaced at this same cost every 11 years. All costs are escalated by the Ontario CPI.

The proportion of energy represented by each load shape was altered so that the demand shifted off the one-hour winter peak in the year 2000 is precisely as shown in the demand management plan. Slightly (less than 1%) more is shifted from the sixteen-hour winter peak.

Ninety-five percent of the energy removed from the peak period was added back in the weekday off-peak and five percent was recovered on weekends. The energy recovered in the weekday off-peak was added equally in each of the off-peak hours. The energy recovered on the weekend was added with the end-use load shape for that customer. The net effect of load shifting is shown in Figure 2.2-3 as the difference between the dashed line and primary demand.

### 2.2.4 Load Displacement Non-Utility Generation

There are two types of non-utility generation--"load displacement" and "purchase". Load displacement non-utility generation reduces demand much as does EEI, so it is modelled in the demand submodel. Purchase non-utility generation is modelled as a supply-side resource in the supply submodel.

The modelling of load displacement non-utility generation considers dependable demand reduction and average capacity factor (hours of operation per year). Dependable demand reduction is the amount that may be depended upon to be available at peak. This amount is modelled as being available during all hours on the winter and summer high-demand weekdays (peak days).

Figure 2.2-6

Costs of Load Shifting

| Year | Load Shifted (MW) | Participant's Costs Capital (M89$) | Participant's Costs OM&A (M89$) | Hydro Family Costs Capital (M89$) | Hydro Family Costs OM&A (M89$) |
|---|---|---|---|---|---|
| 1989 | 80 | 24.0 | 0.0 | 0.0 | 0.0 |
| 1990 | 169 | 26.7 | 0.0 | 0.0 | 0.0 |
| 1991 | 263 | 28.2 | 0.0 | 46.4 | 17.4 |
| 1992 | 421 | 47.4 | 0.0 | 49.4 | 18.5 |
| 1993 | 580 | 47.7 | 0.0 | 52.4 | 19.7 |
| 1994 | 655 | 22.5 | 0.0 | 62.8 | 29.8 |
| 1995 | 715 | 18.0 | 0.0 | 14.0 | 11.9 |
| 1996 | 775 | 18.0 | 0.0 | 14.7 | 12.5 |
| 1997 | 835 | 18.0 | 0.0 | 15.4 | 13.2 |
| 1998 | 892 | 17.1 | 0.0 | 8.0 | 3.9 |
| 1999 | 946 | 16.2 | 0.0 | 8.3 | 4.0 |
| 2000 | 1000 | 40.2 | 0.0 | 8.5 | 4.1 |
| 2001 | 1020 | 32.7 | 0.0 | 5.1 | 2.4 |
| 2002 | 1040 | 34.2 | 0.0 | 5.2 | 2.5 |
| 2003 | 1060 | 53.4 | 0.0 | 5.3 | 2.5 |
| 2004 | 1080 | 53.7 | 0.0 | 5.3 | 2.6 |
| 2005 | 1100 | 28.5 | 0.0 | 5.4 | 2.6 |
| 2006 | 1120 | 24.0 | 0.0 | 5.5 | 2.7 |
| 2007 | 1140 | 24.0 | 0.0 | 5.6 | 2.7 |
| 2008 | 1160 | 24.0 | 0.0 | 5.7 | 2.8 |
| 2009 | 1180 | 23.1 | 0.0 | 5.8 | 2.8 |
| 2010 | 1200 | 22.2 | 0.0 | 6.0 | 2.9 |
| 2011 | 1220 | 46.2 | 0.0 | 6.1 | 2.9 |
| 2012 | 1240 | 38.7 | 0.0 | 6.2 | 3.0 |
| 2013 | 1260 | 40.2 | 0.0 | 6.3 | 3.0 |
| 2014 | 1280 | 59.4 | 0.0 | 6.4 | 3.1 |

The total energy generated by non-utility generators over the year is less than would be obtained by running at the dependable demand reduction for all hours. This is modelled by reducing the amount of generation on all days other than the winter and summer peak days. The proportion of dependable capacity available on each day type is shown in Figure 2.2-7. The effect of load displacement non-utility generation is shown in Figure 2.2-3.

The cost of non-utility generation is modelled as 940 $89/kW capital cost, with Ontario Hydro offering to cover 12% of that cost. This was based on a contract under negotiation early in 1989. These capital costs are escalated by the Ontario CPI. The fixed OM&A cost was estimated as 135 $89/kW/yr. This is based on OM&A being 3% of capital cost, natural gas fuel at 2.8 $88/MCF, a heat rate of 5400 Btu/kWh and an 80% average capacity factor. As the majority of this OM&A cost is made up of gas fuel costs, it is escalated by the same rate as natural gas fuel for CTUs.

### 2.2.5 Primary Demand

The primary demand is also represented by 384 hourly demands as are the individual loads described above. As noted previously, it is created by subtracting the electrical efficiency improvement load, the load shifting load and the load displacement non-utility load from the basic demand. Primary demand is input to the supply submodel. Primary demand for the year 2000 is shown in Figure 2.2-3; primary demand in 1989, 2000 and 2010 is shown in Figure 2.2-2.

## 2.3 SUPPLY SUBMODEL

The supply submodel simulates the supply of primary demand through purchase non-utility generation, purchases from neighbouring utilities, existing and new hydraulic generation, nuclear generation, and fossil generation. The supply submodel also calculates the fuel and OM&A costs of all generation, the capital cost of new generation, and the cost of emergency measures.

The main inputs of the supply submodel are the primary forecast from the demand submodel and the characteristics of the generation system, such as rated capacity; forced outage rate; planned outage schedule (by season); and fuel, OM&A and capital (new generation only) unit costs of both new and existing generation. The main outputs are capital and OM&A costs of supply options, fuel costs, and expected energy production by fuel type.

Figure 2.2-7

**Availability of Load Displacement Non-Utility Generation**
**As Modelled in System Simulation**
(Fraction of Dependable Capacity by Day Type)

| Day Type | Season | | | |
|---|---|---|---|---|
| | Winter | Spring | Summer | Fall |
| HIGH Weekday | 1.00 | 0.70 | 1.00 | 0.70 |
| MID Weekday | 0.95 | 0.70 | 0.95 | 0.70 |
| LOW Weekday | 0.80 | 0.70 | 0.80 | 0.70 |
| WEEKEND | 0.80 | 0.70 | 0.80 | 0.70 |

### 2.3.1 Generation Dispatch and Forced Outages

To make modelling of the generation dispatch more manageable, the supply model first groups the individual units as shown in Figure 2.3-1. To improve the modelling of dispatch, and because energy production and costs are also reported in these groups, the dispatch groups are divided by fuel type.

Figure 2.3-1 also shows the loading order of the dispatch groups. Non-utility generation is used first, followed by purchases, hydraulic, nuclear, coal, gas and oil. Each is used to the maximum before the next is drawn on. The loading of generation on a typical day is shown in Figure 2.3-2.

The loading order as shown in Figure 2.3-1 is based approximately on using the lowest operating cost units first. There are exceptions, however. Hydro is obligated to buy non-utility generation at all times regardless of cost, and lignite is the first coal unit loaded until the Manitoba purchase starts. The order of gas and oil generation changes as the fuel prices change. Gas is listed first as it has the lower fuel cost until late in the planning period.

Depending on the modelling of forced outages, a dispatch group is either set at its average availability or it is represented by several different outage levels. Most of the groups are set at their average available capacity by multiplying their capacity by their average availability. These groups are then always modelled at this average availability. For example, the Lignite group has an installed capacity of 535 MW and an average availability of 92.8% (an average forced outage rate of 7.2%). This group would be modelled as always having 496 MW (535 MW * 0.928), its average available capacity.

The other dispatch groups are modelled by several different levels of outages. For example, the existing nuclear group could be modelled by four different levels of outages--19 of 20 units available, 18 of 20, 17 of 20, and 15 of 20. The existing nuclear group has 14 182 MW of installed capacity averaging 709 MW in each of 20 units. So, the four levels above would have available capacities of 13 472 MW, 12 764 MW, 12 055 MW, and 10 637 MW. The probability of each of these different levels occurring is also calculated.

Dispatch groups are modelled with different levels until up to 32 different outage states are formed by the combination of all the different outage levels of the dispatch groups. In addition to the four levels with which the nuclear is modelled in the example above, the existing coal generation may be modelled with four levels and the oil group with two levels. This results in the 32 different outage states (4 nuclear * 4 coal * 2 oil). The probability of each outage state may also be calculated.

Figure 2.3-1

System Simulation Generation Groups in Dispatch Order

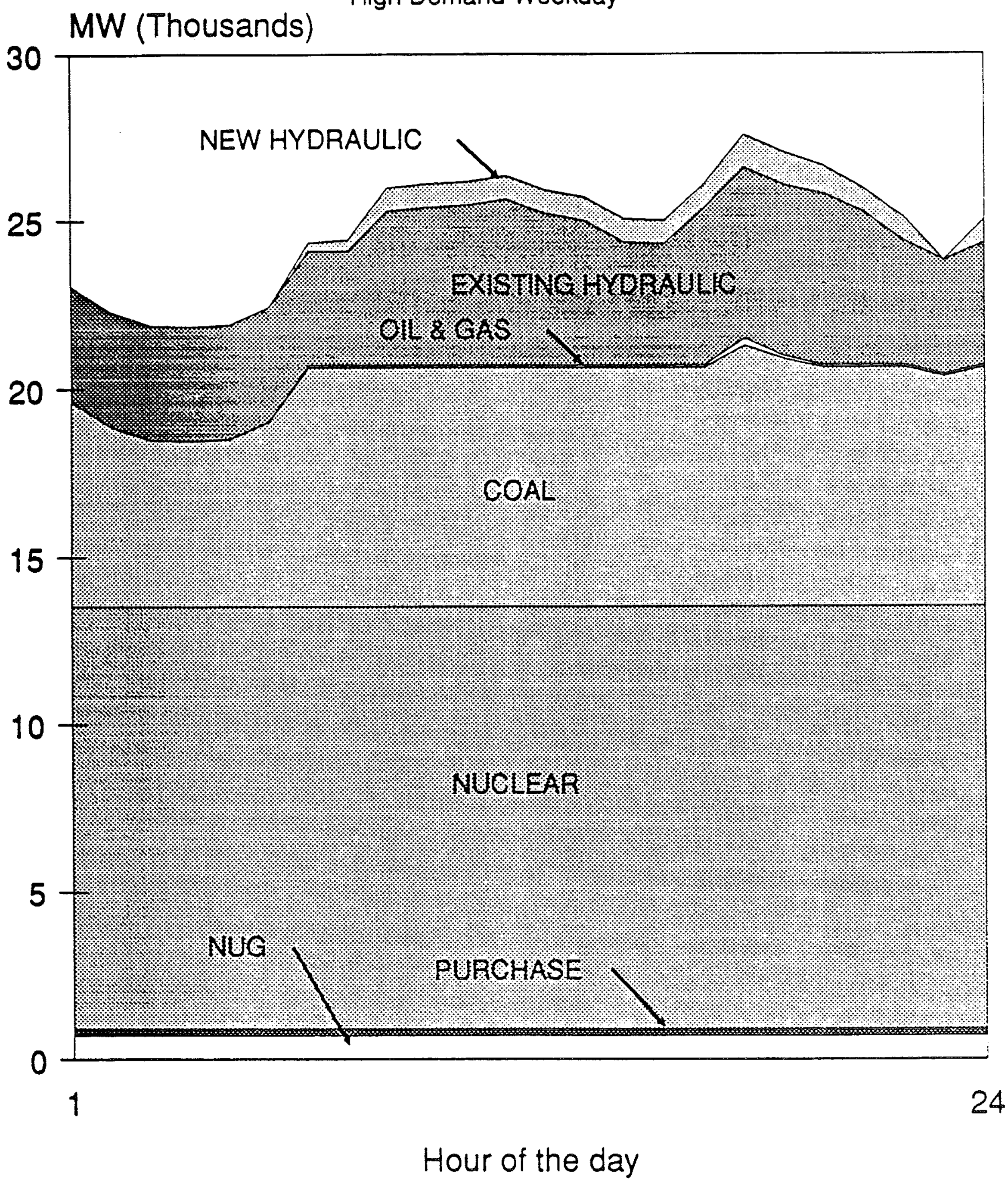
| Dispatch Order | Generation Dispatch Group | Existing Units in Group |
|---|---|---|
| 1 | Purchased Non-utility Generation | |
| 2 | Major Purchases | |
| 3 | Existing Hydraulic | |
| 4 | New Hydraulic | |
| 5 | Old Nuclear including Darlington | Pickering, Bruce, Darlington |
| 6 | New Nuclear | |
| 7 | Lignite-fired units * | Atikokan, Thunder Bay 2&3 |
| 8 | New pulverized US coal | |
| 9 | IGCC units | |
| 10 | New pulverized Western Canadian coal | |
| 11 | Existing Coal units with FGD and CPM | Lambton, Nanticoke, Lakeview |
| 12 | Existing Coal units with FGD only | |
| 13 | Existing Coal units with CPM only | |
| 14 | Other Existing Coal units | |
| 15 | Lignite-fired units * | |
| 16 | Combined Cycle units | |
| 17 | Gas-fired CTU ** | |
| 18 | Oil-fired Boiler-type units ** | Lennox |
| 19 | Oil-fired CTU | |
| 20 | Emergency Measures | Purchases, Interruptibles, Voltage |

FGD = Flue Gas Desulphurization (Scrubbers)
CPM = Combustion Process Modification (includes low NO burners)

* Changes loading order from first coal unit loaded to last coal unit loaded in 2000, because of Manitoba purchase.

** Order determined by relative costs of oil and gas. Order reverses in later years of study period.

Figure 2.3-2
Example of Generation Dispatch
Year 2000 Winter
High Demand Weekday



For each outage state, the units are dispatched for all day types in all seasons to determine the energy generation from each dispatch group. The energy produced in each state from each group is then averaged across states, based on the probabilities of the outage states. This creates the expected energy production for each dispatch group for that year. The fuel cost is then determined by multiplying the expected energy production by the unit fuel costs.

### 2.3.2 Planned and Maintenance Outages

Generation outages are classified into three categories--planned, maintenance and forced. Each is modelled differently in LMSTM. Planned outages are scheduled a year or more in advance and tend to be of durations ranging from a few weeks to two or more months. (Unit rehabilitations and retubing are longer duration planned outages. They are addressed in the sections on the specific generation types with which they are associated.) Planned outages are entered directly into LMSTM and are scheduled evenly over the Spring, Summer, and Fall seasons, so that the same amount of generation of each generation type is on planned maintenance in each of these seasons. No planned maintenance is scheduled in the Winter season.

Forced outages are unplanned and occur at random. These are modelled directly by LMSTM as described in the previous section.

Maintenance outages occur at random, but can be delayed until a lower demand period. If the unit would not have been in use in this lower demand period, then the maintenance outage has no effect on the production from this unit. For peaking generation such as Lakeview, therefore, maintenance outages do not affect energy production.

For other, non-peaking, units maintenance outages are considered to occur randomly in all hours of the year. They are modelled as planned outages in all seasons, effectively derating the unit's capacity by the expected time on maintenance outage. For example, if a unit is expected to be down on maintenance outage one day a month, then 4 days of outage would be modelled in each of Winter and Summer, and 2 days of outage would be modelled in each of Spring and Fall.

All reliability indices for existing stations are based on "1988 Forecast of Reliability Studies for Use in Corporate Planning Studies", published in March 1989. For new thermal units reliability indices are based on the Ontario Nuclear Cost Inquiry or the Thermal Cost Review.

### 2.3.3 Purchase Non-Utility Generation

Purchase non-utility generation is modelled as a single generating unit which runs continually at 80% of installed capacity, has a fuel cost equal to Ontario Hydro's purchase rate and is the first generation dispatched. The full amount of non-utility generation available is always purchased.

### 2.3.4 Hydraulic

New and existing hydraulic are modelled separately in LMSTM, but are dispatched in a similar manner. Both are dispatched within any season, using a process known as peak shaving. This type of dispatch uses hydraulic generation to create the flattest possible load shape for remaining generation to supply. This produces the lowest cost generation schedule pattern and the minimum unsupplied energy. See Figure 2.3-1, where the peaking hydraulic has been dispatched using peak shaving.

Hydraulic generation is modelled using median water flows to properly reflect the long-term average energy supply contribution of this resource. The capacities and energies used to model both the existing and new hydraulic generation are shown in Figure 2.3-3.

The modelled capacity of existing hydraulic generation available at peak is 500 MW less than the actual installed capacity. The full installed capacity is not available at peak due to physical restrictions such as seasonal and daily flow variations, maximum discharge rates and lags between upstream and downstream stations.

The site extensions at the Mattagami Complex and the developments at Little Jackfish, Niagara, and Big Chute plus Lake Gibson are modelled explicitly for capacity, energy, and in-service date. Other sites are approximated by additions of 200 MW of hydraulic capacity, with in-service dates to best match the Hydraulic Plan, and with energy availability at the average for later units in the plan. The unit availability of new hydraulic units is modelled as 93.2%, except for Niagara which is modelled at 90.0%. The modelling of the total Hydraulic Plan is shown in Figure 2.3-3.

The fuel costs of hydraulic are the water rental rates Hydro pays to the province. This rate is 3.12 $89/MWh and escalates by Ontario CPI.

### 2.3.5 Major Utility Purchases

The <u>energy production</u> from the 1000 MW purchase from Manitoba is modelled in LMSTM, but the <u>costs</u> are input directly to RAM. The Manitoba purchase was modelled in the same way as the hydraulic generation discussed above. The annual capacity and energy values of this major utility purchase are shown in Figure 2.3-4.

Figure 2.3-3

Capacity and Energy of Existing and New Hydraulic Supply
in System Simulation

EXISTING HYDRAULIC

| Year | Capacity (MW) | Energy by Season (GWh) | | | |
|---|---|---|---|---|---|
| | | Winter | Spring | Summer | Fall |
| 1989-2014 | 6500 | 11730 | 6799 | 11095 | 6011 |

NEW HYDRAULIC SUPPLY

| Year | Capacity (MW) | Energy by Season (GWh) | | | |
|---|---|---|---|---|---|
| | | Winter | Spring | Summer | Fall |
| 1990 | 0 | 0 | 0 | 0 | 0 |
| 1991 | 0 | 0 | 0 | 0 | 0 |
| 1992 | 0 | 0 | 0 | 0 | 0 |
| 1993 | 16 | 32 | 16 | 33 | 16 |
| 1994 | 16 | 32 | 16 | 33 | 16 |
| 1995 | 82 | 63 | 32 | 64 | 32 |
| 1996 | 338 | 264 | 133 | 266 | 133 |
| 1997 | 518 | 475 | 239 | 479 | 239 |
| 1998 | 518 | 475 | 239 | 479 | 239 |
| 1999 | 1068 | 819 | 413 | 826 | 413 |
| 2000 | 1068 | 952 | 480 | 960 | 480 |
| 2001 | 1268 | 1037 | 523 | 1046 | 523 |
| 2002 | 1468 | 1122 | 566 | 1132 | 566 |
| 2003 | 1668 | 1208 | 609 | 1217 | 609 |
| 2004 | 1868 | 1293 | 652 | 1303 | 652 |
| 2005 | 2068 | 1378 | 695 | 1389 | 695 |
| 2006 | 2068 | 1378 | 695 | 1389 | 695 |
| 2007 | 2068 | 1378 | 695 | 1389 | 695 |
| 2008 | 2068 | 1378 | 695 | 1389 | 695 |
| 2009 | 2268 | 1463 | 738 | 1475 | 738 |
| 2010 | 2468 | 1548 | 781 | 1561 | 781 |
| 2011 | 2668 | 1634 | 823 | 1647 | 824 |
| 2012 | 2668 | 1634 | 823 | 1647 | 824 |
| 2013 | 2668 | 1634 | 823 | 1647 | 824 |
| 2014 | 2868 | 1719 | 866 | 1733 | 867 |

## Figure 2.3-4

### Capacity and Energy of Manitoba Purchase in System Simulation

| Year | Capacity (MW) | Energy by Season (GWh) | | | |
|---|---|---|---|---|---|
| | | Winter | Spring | Summer | Fall |
| 1990-2000 | 0 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2001 | 200 | 555.12 | 277.92 | 555.84 | 277.92 |
| 2002 | 400 | 1110.24 | 555.84 | 1111.68 | 555.84 |
| 2003 | 800 | 2220.48 | 827.68 | 1519.36 | 781.68 |
| 2004-2014 | 1000 | 2775.60 | 1139.60 | 2019.20 | 1079.60 |

### 2.3.6 Existing Fossil Stations

Each fossil unit is modelled separately, even though units within stations have the same costs. Fixed OM&A are forecast from current costs and fuel costs are consistent with those used in the Thermal Cost Review. Figure 2.3-5 shows the capacities by station and by year, as used in the production simulations. Capacity reductions in later years reflect retirements.

Depending on the length of the outage involved, the costs of rehabilitating existing fossil stations are treated in one of two ways--as a fixed OM&A cost, if the outage is only several months; or as a capital cost, if the outage is modelled as one or more years in duration. The rehabilitation of Lambton was treated as planned outages with costs recovered in OM&A. The Lakeview rehabilitation costs are modelled as a capital expenditure and depreciated over the remaining life of the station. These rehabilitations and the retrofits of scrubbers (as in proposed plan median load growth) are also indicated in Figure 2.3-5.

When a unit of Lambton or Nanticoke has its combustion process modified to reduce $NO_X$, or when scrubbers are retrofit to reduce $SO_2$, the unit is retired from service and a new one is added with revised characteristics and a capital cost equal to the cost of the modification.

### 2.3.7 Existing Nuclear Stations

Pickering A and B, Bruce A and B, and Darlington are existing Hydro nuclear units. The capital cost of Darlington is explicitly modelled because it comes into service after 1989. The capital costs of the other stations are included with other existing assets (see Section 2.4). Fuel costs are based on existing nuclear fuel contract prices and are adjusted to include fuel disposal costs. Fixed OM&A is modelled as a projection of ongoing costs and has not been levelized. Large-scale fuel channel replacement (retubing) is explicitly modelled.

Retubing is modelled by removing nuclear units from service for one to three years while they are being retubed. Such outages must be modelled as 12, 24 or 36 months (1, 2, or 3 years), while the actual retubing times of individual units are 19 to 31 months. The modelling of the total retubing schedule (see Figure 2.3-6) is designed to match the actual schedule as closely as possible.

Figure 2.3-5

**Existing Fossil Station Capacity**
**As Modelled in System Simulation**
(As in Proposed Plan)

| Year | Lambton | | Nanticoke | | Lakeview | | Thunder Bay | | Lennox | | Atikokan |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | MW | Notes* | MW | Notes* | MW | Notes* | MW | Notes* | MW | Notes* | MW |
| 1989 | 2100 | | 4336 | | 2282 | | 320 | | 1674 | | 215 |
| 1990 | 2100 | | 4336 | | 2282 | | 320 | | 2232 | DMB 3 | 215 |
| 1991 | 2100 | RHB 1 | 4336 | | 1998 | RHB 5 | 320 | | 2232 | | 215 |
| 1992 | 2100 | RHB 2 | 4336 | | 1998 | RHB 6 | 320 | | 2232 | | 215 |
| 1993 | 2100 | RHB 3 | 4336 | | 1993 | RHB 1 | 320 | | 2232 | | 215 |
| 1994 | 2080 | RHB 4<br>CPM 3 & 4<br>SCR 1 & 2 | 4336 | | 1993 | RHB 2 | 420 | DMB 1 | 2232 | | 215 |
| 1995 | 2070 | CPM 1 & 2<br>SCR 3 & 4 | 4336 | | 1714 | RHB 3 & 4 | 420 | | 2232 | | 215 |
| 1996 | 2070 | | 4336 | | 1714 | RHB 7 & 8 | 420 | | 2232 | | 215 |
| 1997 | 2070 | | 4336 | | 2282 | | 420 | | 2232 | | 215 |
| 1998 | 2070 | | 4326 | CPM 1 - 4 | 2282 | | 420 | | 2232 | | 215 |
| 1999 | 2070 | | 4326 | | 2282 | | 420 | | 2232 | | 215 |
| 2000 | 2070 | | 4326 | | 2282 | | 420 | | 2232 | | 215 |
| 2001 | 2070 | | 4326 | | 2282 | | 420 | | 2232 | | 215 |
| 2002 | 2070 | | 4326 | | 1993 | RET 1 | 420 | | 2232 | | 215 |
| 2003 | 2070 | | 4326 | | 1704 | RET 2 | 420 | | 2232 | | 215 |
| 2004 | 2070 | | 4326 | | 1704 | | 420 | | 2232 | | 215 |
| 2005 | 2070 | | 4326 | | 1136 | RET 3 & 4 | 420 | | 2232 | | 215 |
| 2006 | 2070 | | 4326 | | 1136 | | 420 | | 2232 | | 215 |
| 2007 | 2070 | | 4326 | | 852 | RET 5 | 420 | | 2232 | | 215 |
| 2008 | 2070 | | 4326 | | 852 | | 420 | | 2232 | | 215 |
| 2009 | 2070 | | 4326 | | 0 | RET 6 - 8 | 420 | | 2232 | | 215 |
| 2010 | 0 | RET 1 - 4 | 4326 | | | | 420 | | 2232 | | 215 |
| 2011 | | | 4326 | | | | 420 | | 2232 | | 215 |
| 2012 | | | 4326 | | | | 420 | | 2232 | | 215 |
| 2013 | | | 3787 | | | | 420 | | 2232 | | 215 |
| 2014 | | | 2168 | | | | 420 | | 2232 | | 215 |

* RHB = Rehab of indicated units
DMB = Demothball indicated units
CPM = Modify indicated units
SCR = Retrofit scrubber on indicated units
RET = Retire indicated units

Note: Keith, Hearn A(units 1-4) and Hearn B(units 5-8) are mothballed.
In case of demothballing their capacities would be;
Keith - 256 MW, Hearn A - 391 MW, Hearn B - 788 MW
Oil-fired CTUs at existing sations have a capacity of 253 MW.

Figure 2.3-6

**Existing Nuclear Station Capacity**
**As Modelled in System Simulation**
(As in Proposed Plan)

| Year | Pickering A & B MW | Pickering A & B Notes* | Bruce A & B MW | Bruce A & B Notes* | Darlington MW | Darlington Notes* |
|---|---|---|---|---|---|---|
| 1989 | 4124 | | 6516 | | 0 | |
| 1990 | 3609 | RTB 3 | 6516 | SLR 3 & 4 | 1762 | INS 1 & 2 |
| 1991 | 3609 | RTB 4<br>SLR 5 | 6516 | SLR 1 | 2643 | INS 3 |
| 1992 | 3609 | RTB 4<br>SLR 6 | 6516 | | 3524 | INS 4 |
| 1993 | 4124 | | 6516 | | 3542 | |
| 1994 | 4124 | | 6516 | | 3524 | |
| 1995 | 4124 | | 6516 | | 3524 | |
| 1996 | 4124 | | 6516 | | 3524 | |
| 1997 | 4124 | | 6516 | | 3524 | |
| 1998 | 4124 | | 6516 | RFB 3 | 3524 | |
| 1999 | 4124 | | 6516 | | 3524 | |
| 2000 | 4124 | | 6516 | | 3524 | |
| 2001 | 4124 | | 6516 | | 3524 | |
| 2002 | 4124 | | 5747 | RTB 3 | 3524 | |
| 2003 | 4124 | | 4978 | RTB 2 & 3 | 3524 | |
| 2004 | 4124 | | 5747 | RTB 2 | 3524 | |
| 2005 | 4124 | | 5747 | RTB 2 | 3524 | |
| 2006 | 3608 | RTB 5 | 6516 | | 3524 | |
| 2007 | 3608 | RTB 5 | 5747 | RTB 1 | 3524 | |
| 2008 | 3608 | RTB 6 | 4978 | RTB 1 & 4 | 3524 | |
| 2009 | 3608 | RTB 6 | 5747 | RTB 4 | 3524 | |
| 2010 | 3608 | RTB 7 | 5656 | RTB 5 | 3524 | |
| 2011 | 2578 | RTB 7<br>RET 1 & 2 | 5656 | RTB 5 | 3524 | |
| 2012 | 2063 | RTB 8<br>RET 3 | 5656 | RTB 6 | 3524 | |
| 2013 | 2064 | RET 4 | 5656 | RTB 6 | 3524 | |
| 2014 | 2064 | | 5656 | RTB 7 | 3524 | |

* INS = In-service date of indicated units
SLR = Spacer location and relocation for indicated units
RFB = Repositioning end-fitting and bearings for indicated units
RTB = Indicated units down for retubing
RET = Retire indicated units

### 2.3.8 New Thermal Stations

All values for new fossil stations were based on the Thermal Cost Review. All 'Initial Capital' was modelled as a capital cost. All other costs excluding 'Fueling Costs', were levelized over the life of the station and included as fixed OM&A. Fuel costs are calculated in LMSTM based on expected energy generated. Unit fuel costs are as in the Thermal Cost Review.

Similarly, all values for new nuclear stations were based on the Nuclear Cost Inquiry data. Costs labelled 'Initial Capital' were included as a capital cost; used fuel management, transportation and repository costs were entered as variable operating costs. All other costs were annualized and included as fixed OM&A. Fuel costs are calculated in LMSTM based on expected energy generated. Unit fuel costs are based on Nuclear Cost Inquiry data.

As noted in Section 2.1.1 new units are constrained to start as of January 1. Also each unit is modelled with the same capital construction pattern. These patterns were developed in such a way that the sum of the patterns of the four units in a four unit station matched the supplied station construction pattern as closely as possible.

### 2.3.9 Emergency Measures

During the scheduling of generation, emergency measures are treated as the last generation loaded. The use of emergency measures is essentially the generation from this "unit". Emergency measures are emergency purchases, interruptible load cuts and voltage reductions, which add up to 2000 MW.

The cost of this energy is modelled as 11 $89/MWh above the cost of CTU oil to ensure that load is supplied by oil generation before these measures are implemented.

## 2.4 FINANCE SUBMODEL

The main financial modelling processed through LMSTM is levelizing of capital costs. This is actually performed by a modification made by Ontario Hydro to the standard LMSTM code. It uses a constant 5% real discount rate to determine the equal real dollar annual payments (required to pay for an investment over its life). All capital costs are levelized in this way. The RAM was used for the main financial results (see Chapter 8).

The financial submodel was used to model distribution system, transmission system, overhead and other fixed costs. The modelling of demand management and load displacement non-utility generation costs is described with the demand submodel (Section 2.2) and Section 2.3 (supply submodel) contains the description of generation fixed and fuel costs. Other costs used for the detailed results are described in Chapters 8 and 9.

### 2.4.1 Incremental Distribution Costs

The distribution costs for Ontario Hydro's Rural Retail System and for all of the municipal utilities are modelled to reflect the total savings of demand management regardless of the retail supplier. Distribution costs are modelled in two ways. Incremental costs are proportional to primary load growth and other costs are entered directly as cash flows as described in Section 2.4.3.

The costs associated with new investment in distribution equipment required to meet growing demand and some of the fixed operating costs of the whole distribution system are modelled. These costs are proportional to primary demand in the two residential customer classes and the general customer class. Specifically, these costs are proportional to the peak demand of each class. The direct customer class does not require distribution equipment from Hydro.

The incremental distribution costs may be divided into energy-, demand-, and customer- related costs. As demand management is not designed to alter the number of customers in Ontario only energy- and demand- related distribution costs are modelled as incremental distribution. The costs of customer-related incremental distribution are included under overhead and other fixed costs (see Section 2.4.3).

OM&A costs of incremental (post 1989) distribution system expansions are estimated as 5.46 $89/kW/yr. This OM&A cost is also applied to the existing distribution system. Incremental distribution investment has a capital cost of $228 (1989 dollars) per kW of growth in the class peak demands. These values are based on an Ontario Hydro report, 'Estimation of Incremental Capacity Costs for Municipal Utilities', Aug. 1987.

### 2.4.2 Incremental Transmission Costs

Four different types of transmission costs are defined--radial transmission, inter-area transmission, incremental load-growth transmission and existing transmission. Incremental transmission is modelled as directly proportional to peak load growth. This is distinct from inter-area transmission which is related specifically to the location of new major supply. Radial transmission is specific to particular generating stations and is modelled as part of the capital cost of each new station. The costs of inter-area and radial transmission are input directly to RAM.

Incremental load-growth transmission was modelled in the system simulation. Its costs were divided into bulk transmission, with a capital cost of 135.7 $89/kW and an OM&A cost of 4.87 $89/kW/yr; and regional transmission, with a capital cost of 124 $/kW.

Existing transmission costs were entered as overhead and other fixed costs described in Section 2.4.3.

### 2.4.3 Overhead and Other Fixed Costs

Overhead and other fixed costs are modelled as cash flows of both capital costs and fixed OM&A costs. These cash flows do not vary throughout the analysis and are input directly:

- Ontario Hydro, overhead and other fixed costs;
- Capital modification to existing generation not explicitly modelled in the supply submodel;
- Existing transmission system costs;
- Rural distribution, existing system and overhead costs; and,
- Municipal distribution, existing system and overhead costs.

These costs are shown in Figure 2.4-1.

Except for the municipal costs, all costs are based on the 1988 Ontario Hydro long-range financial plan. Municipal expenses were based on those reported in the 1987 Ontario Hydro Statistical Yearbook and then adjusted for load growth and inflation. From these values, the incremental distribution costs were subtracted to obtain the values shown in Figure 2.4-1. The costs shown for the rural retail system and for existing transmission were obtained in the same way.

## 2.5 ACID GAS AND SECONDARY NUCLEAR SALES MODELLING

An additional submodel written by Ontario Hydro starts with the LMSTM energy production and fuel cost output and determines acid gas and carbon dioxide emissions, revises the fuel cost of existing station to reflect coal blending, and estimates secondary nuclear sales.

### 2.5.1 Acid Gas Calculations and Fuel Blending

To determine emissions of $SO_2$, $NO_X$, and $CO_2$ from fossil stations the emission rates from the Thermal Cost Review were used. These are summarized in Figure 2.5-1.

Figure 2.4-1(a)

## Overhead and Other Fixed Costs in System Simulation

### Capital Costs
(Millions of Current Dollars)

| | Ontario Hydro | | | Distribution Systems | |
|---|---|---|---|---|---|
| Year | Overhead & Other Fixed Costs | Generation Capital Modifications | Transmission Other Fixed Costs | Rural Retail System | Municipal Utilities |
| 1989 | 179 | 77 | 327 | 174 | 162 |
| 1990 | 164 | 77 | 519 | 155 | 51 |
| 1991 | 148 | 120 | 486 | 170 | 43 |
| 1992 | 217 | 360 | 366 | 187 | 46 |
| 1993 | 169 | 381 | 335 | 200 | 44 |
| 1994 | 171 | 371 | 452 | 215 | 68 |
| 1995 | 181 | 470 | 459 | 238 | 129 |
| 1996 | 194 | 451 | 487 | 259 | 153 |
| 1997 | 210 | 537 | 311 | 281 | 168 |
| 1998 | 227 | 534 | 438 | 304 | 155 |
| 1999 | 247 | 538 | 478 | 326 | 107 |
| 2000 | 268 | 578 | 401 | 350 | 86 |
| 2001 | 291 | 695 | 387 | 363 | 79 |
| 2002 | 316 | 654 | 414 | 413 | 175 |
| 2003 | 344 | 691 | 592 | 442 | 157 |
| 2004 | 374 | 731 | 1082 | 482 | 148 |
| 2005 | 407 | 771 | 496 | 527 | 183 |
| 2006 | 442 | 813 | 526 | 563 | 197 |
| 2007 | 479 | 857 | 555 | 611 | 247 |
| 2008 | 518 | 910 | 587 | 659 | 263 |
| 2009 | 562 | 962 | 587 | 714 | 301 |
| 2010 | 610 | 1016 | 587 | 773 | 315 |
| 2011 | 662 | 1073 | 587 | 837 | 349 |
| 2012 | 719 | 1134 | 587 | 907 | 381 |
| 2013 | 780 | 1198 | 587 | 982 | 416 |
| 2014 * | NA | NA | NA | NA | NA |

* Capital costs in last year of planning period could not be modelled.

Figure 2.4-1(b)

Overhead and Other Fixed Costs
In System Simulation

OM&A Costs
(Millions of Current Dollars)

| Year | Ontario Hydro: Overhead & Other Fixed Costs | Ontario Hydro: Generation Capital Modifications | Ontario Hydro: Transmission Other Fixed Costs | Distribution Systems: Rural Retail System | Distribution Systems: Municipal Utilities |
|---|---|---|---|---|---|
| 1989 | 361 | 0 | 155 | 157 | 301 |
| 1990 | 384 | 0 | 166 | 169 | 326 |
| 1991 | 363 | 0 | 174 | 184 | 355 |
| 1992 | 421 | 0 | 179 | 201 | 387 |
| 1993 | 557 | 0 | 187 | 215 | 419 |
| 1994 | 577 | 0 | 192 | 234 | 455 |
| 1995 | 695 | 0 | 201 | 249 | 497 |
| 1996 | 719 | 0 | 211 | 265 | 547 |
| 1997 | 770 | 0 | 221 | 287 | 600 |
| 1998 | 823 | 0 | 233 | 309 | 658 |
| 1999 | 854 | 0 | 245 | 335 | 719 |
| 2000 | 891 | 0 | 260 | 367 | 783 |
| 2001 | 684 | 0 | 277 | 406 | 855 |
| 2002 | 738 | 0 | 297 | 442 | 934 |
| 2003 | 799 | 0 | 318 | 486 | 1020 |
| 2004 | 867 | 0 | 341 | 532 | 1111 |
| 2005 | 936 | 0 | 366 | 580 | 1210 |
| 2006 | 1010 | 0 | 392 | 635 | 1333 |
| 2007 | 1090 | 0 | 421 | 692 | 1470 |
| 2008 | 1175 | 0 | 451 | 755 | 1615 |
| 2009 | 1269 | 0 | 484 | 825 | 1785 |
| 2010 | 1371 | 0 | 519 | 901 | 1967 |
| 2011 | 1481 | 0 | 556 | 984 | 2167 |
| 2012 | 1600 | 0 | 596 | 1075 | 2386 |
| 2013 | 1728 | 0 | 640 | 1174 | 2628 |
| 2014 | 1867 | 0 | 686 | 1282 | 2845 |

Figure 2.5-1

Emission Rates for Fossil Stations
In System Simulation

| Dispatch Group | | Emission (MG/GWH) | | |
|---|---|---|---|---|
| | | SO2 | NOX | CO2 |
| Existing Coal units with FGD and CPM | | 1.64 | 1.12 | 860 |
| Existing Coal units with FGD only | | 1.64 | 1.40 | 855 |
| Existing Coal units with CPM only | - High Sulphur Coal | 16.70 | 1.36 | 825 |
| | - Low Sulphur Coal | 5.30 | 1.36 | 825 |
| | - Western Can. Coal | 2.30 | 1.36 | 930 |
| | - Natural Gas | 0.00 | 1.44 | 473 |
| Other Existing Coal units | - High Sulphur Coal | 16.70 | 1.70 | 820 |
| | - Low Sulphur Coal | 5.30 | 1.70 | 820 |
| | - Western Can. Coal | 2.30 | 1.70 | 925 |
| | - Natural Gas | 0.00 | 1.80 | 470 |
| New pulverized US coal * | | 1.64 | 0.25 | 860 |
| New pulverized Western Canadian coal * | | 2.30 | 0.15 | 930 |
| Lignite-fired units | | 4.30 | 1.30 | 935 |
| Gas-fired CTU | | 0.00 | 1.20 | 470 |
| Oil-fired Boiler-type units | | 2.80 | 1.30 | 670 |
| IGCC units | | 0.47 | 0.25 | 810 |
| Oil-fired CTU | | 1.60 | 1.90 | 0 ** |

* The emission rate for SO2 applies only after the year 2000

** Typographical error in input data file for system simulation.
Little effect on results as production from this group averages less than 1 GWh/yr.

Based on meeting the acid gas emission limits, the sulphur content of coal burned in existing, unscrubbed coal stations is then determined. The revised fuel cost is then computed based on the types of coal used. This process provides for an emission reserve--energy production could be increased by 9 TWh without exceeding the acid gas limits.

### 2.5.5 Secondary Nuclear Sales

Surplus nuclear energy production may be sold to U.S. utilities at a price higher than the incremental production cost. This is computed by first determining available surplus nuclear energy. This is equal to the maximum possible nuclear production (total nuclear capacity * 84% average nuclear availability * 8760 hours) minus actual production. Units down for retubing are not included as part of total nuclear capacity and the average availability excludes retubing outages.

The amount actually sold is a percentage of the surplus energy which decreases as the surplus increases (see Figure 2.5-2). This is multiplied by the selling price to determine revenue. The nuclear production cost is subtracted to yield net revenue or profit form the sale. The selling price is approximated as half way between the energy production costs of coal generation and nuclear generation.

## 2.6 REVIEW

The system modelling is the source of energy production by fuel type, fuel costs, and costs which are common across all plans. Other models described in Chapters 8 and 9 perform further financial modelling to calculate plan costs, assess risk, and determine corporate financial impacts. The costs of major supply options and inter-area transmission are entered directly into these other models.

The system modelling is done with a version of LMSTM modified at Ontario Hydro. LMSTM is an integrated planning model which models both demand and supply resources. System modelling is divided into four main aspects:

- demand submodel;
- supply submodel;
- finance submodel;
- acid gas & secondary nuclear sales.

The **Demand Submodel** is structured specifically for modelling the demand reductions from demand management programs. Electricity demand is modelled by 16 different typical daily load shapes (24*16 = 384 hours). This load model is specifically designed to facilitate the different effects of electrical efficiency improvements and load shifting over a day or week.

Figure 2.5-2

Secondary Nuclear Sales Assumptions
in System Simulation

| Surplus (TWh) | Percent Sold of Last TWh | Percent Sold of Total TWh |
|---|---|---|
| 1 | 70% | 70% |
| 2 | 70% | 70% |
| 3 | 60% | 67% |
| 4 | 60% | 65% |
| 5 | 50% | 62% |
| 6 | 50% | 60% |
| 7 | 50% | 59% |
| 8 | 40% | 56% |
| 9 | 40% | 54% |
| 10 | 40% | 53% |
| 11 | 40% | 52% |
| 12 | 40% | 51% |
| 13 | 40% | 50% |
| 14 | 35% | 49% |
| 15 | 35% | 48% |
| 16 | 35% | 47% |
| 17 | 35% | 46% |
| 18 | 35% | 46% |
| 19 | 35% | 45% |
| 20 | 35% | 45% |
| 21 | 35% | 44% |
| 22 | 35% | 44% |
| 23 | 35% | 43% |
| 24 | 25% | 43% |
| 25 | 25% | 42% |
| 26 | 25% | 41% |
| 27 | 25% | 41% |
| 28 | 25% | 40% |
| 29 | 25% | 40% |
| 30 | 25% | 39% |

The demand modelling starts with the basic load forecast. Demand reductions from electrical efficiency improvements, load shifting and load displacement non-utility generation are removed from the basic demand to create the primary demand.

The costs of demand management and load displacement non-utility generation are calculated in the demand submodel.

The **Supply Submodel** simulates the supply of primary demand through purchase non-utility generation, purchases from neighbouring utilities, existing and new hydraulic generation, nuclear generation, and fossil generation. It produces the expected energy production and fuel cost by fuel type. The capital and fixed costs of new supply for the financial analysis of plans are determined in other models.

Supply resources are combined into 20 different dispatch groups. For simulating dispatch these groups are either modelled at their average availability or with several different outage levels. The possible combinations of the outage levels create up to 32 outage states. Generation is dispatched in each of these states and then expected energy production by dispatch group is found by averaging across the possible states, in proportion probabilities of theses states occurring. Forced, maintenance and planned outages are all modelled in generation dispatch.

Purchased non-utility generation is dispatched first. Next, new and existing hydraulic generation, and major utility purchases (Manitoba purchase) are dispatched by peak shaving. Thermal units are dispatched in the following order: old nuclear; new nuclear; lignite (until Manitoba purchase); new coal; existing coal; lignite (after Manitoba purchase); natural gas CTUs; oil (dispatched before natural gas after 2013); existing CTUs; and, emergency measures.

The **Finance Submodel** calculates the costs of incremental distribution and incremental transmission. It also determines the overhead and other fixed costs for Ontario Hydro, rural retail, municipalities, existing transmission, and capital modifications of existing generation.

Incremental distribution costs are those due to load growth. Distribution costs due to growth in the number of customers, and other costs of the rural retail system and the municipalities, are included as overhead and other fixed costs.

Transmission costs are defined as radial, inter-area, incremental load-growth, and existing. Radial and inter-area transmission costs are determined by the major supply plan and are input directly to the financial cost models. Incremental load-growth transmission costs are calculated in the system modelling. Costs of existing transmission are entered in the overhead and other fixed costs.

**Acid Gas and Secondary Nuclear Sales** modelling determines the $SO_2$, $NO_X$, and $CO_2$ emissions using the emission rates from the Thermal Cost Review. Then the sulphur content of coal burned at existing stations is determined such that the acid gas emission limits will be met if 9 TWh more energy must be generated.

Finally, the expected sales of surplus nuclear energy are calculated. The selling price is approximated as half way between the energy production costs of coal generation and nuclear generation.

# 3. RELIABILITY

## 3.0 INTRODUCTION

To Hydro's customers, reliability means continuous, uninterrupted electricity service. Ontario Hydro, like all utilities responsible for electricity generation and transmission, strives to provide that service.

Over the past several years, the amount of energy not supplied to Hydro customers due to bulk electricity system failures has been below the limit set in Hydro's standards. Hydro provides this performance by ensuring Ontario has adequate facilities to supply demand throughout the province.

Reliability is also a function of the quality standards Hydro applies to everything it does to meet current and future electricity needs -- system design, equipment specifications and selection, construction, installation, training, planning, operation, maintenance and administration.

An interruption in electricity service can originate at a number of points -- generation, the high voltage transmission network, delivery to municipal utilities, large industrial customers and retail customers, and local distribution by municipal utilities. The focus in this analysis is on generation reliability.

## 3.1 ONTARIO HYDRO'S BULK ELECTRICITY SYSTEM

Hydro's electricity system, including some 80 generating stations and a high voltage transmission network, is integrated to allow the pooling of resources. Linkages exist within and between the East and West systems (See Figure 3-1 - Map of Ontario showing geographic location of east and west systems, plus simplified indication of where links exist between the two systems and other utilities.) As well, there are connections with neighbouring utilities in Manitoba, Quebec, New York and Michigan.

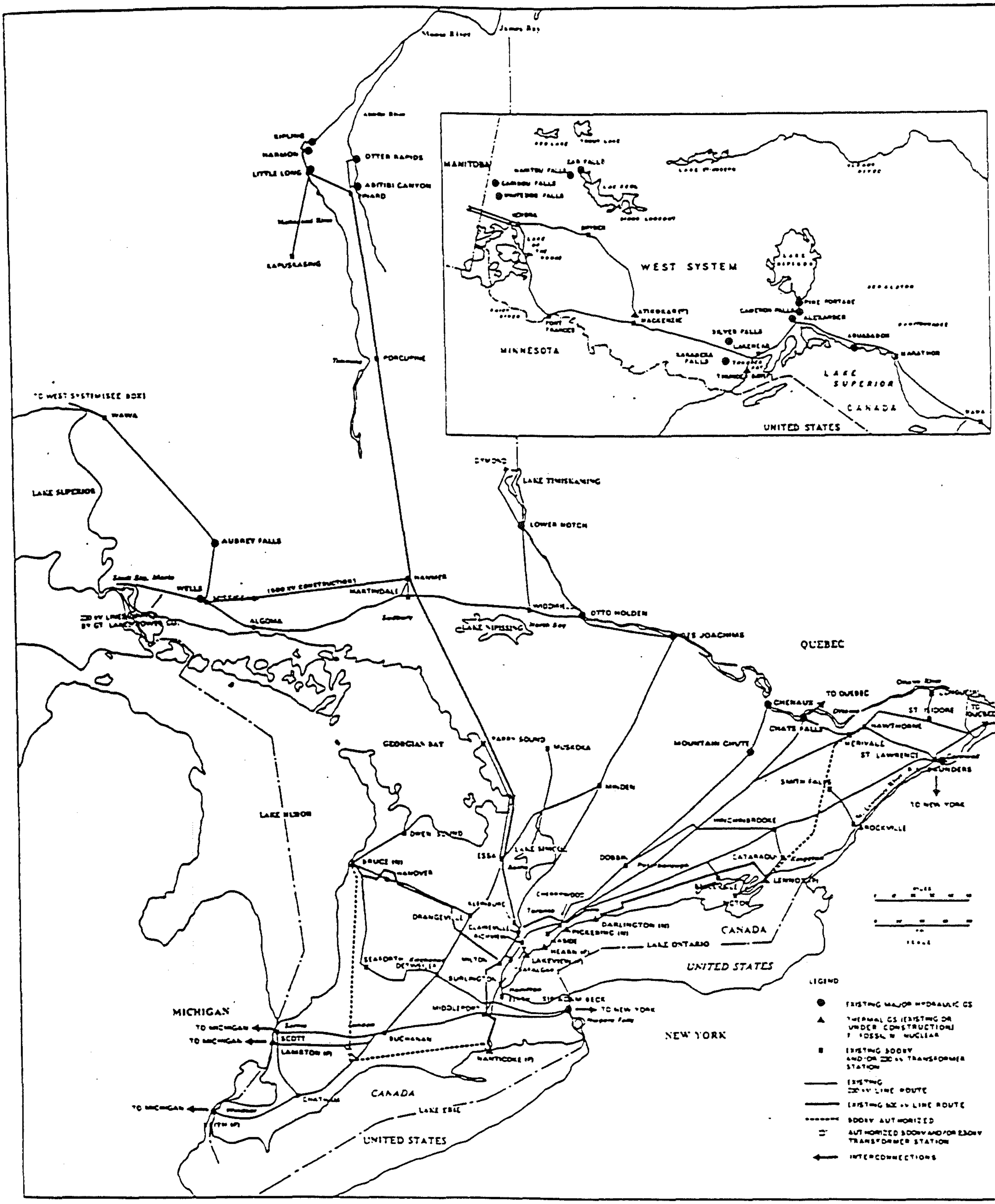
This integration allows Hydro to provide reliable electricity service with less generation than would be needed for a similarly sized unintegrated system, comprised of regional electricity generators unable to share resources.

## 3.2 A FIRST MEASURE OF PLAN EFFECTIVENESS

Reliability is a primary criterion for developing and evaluating cases. Because of its importance to customer satisfaction and its influence on plan development, it is examined early in the planning process. Two preliminary cases were selected for a

Figure 3-1

ONTARIO HYDRO
MAJOR 500 kV AND 230 kV LINE
ROUTES AND STATIONS
(AS OF MID 1987)



detailed evaluation of reliability. These are representative of cases considered in the Demand Supply Plan Report. Conclusions drawn from the results are valid for later versions of these two cases and all cases presented in Chapter 4.0, Formulation and Description of Plans.

The two cases studied were Case 6, the earlier version of Higher Fossil Case 26; and Case 8, the earlier version of the Proposed Major Supply Case. Both Cases 6 and 8 were modelled without the Manitoba purchase.

### 3.2.1 Key Generation Reliability Factors

The reliability of a particular generating station is a function of its design, age, operating history, maintenance practices, technology, fuel and size. Smaller stations, for example, tend to be more reliable than larger stations. Weather conditions can affect the performance of various stations -- a dry spell could lower water levels at a hydraulic station; cold weather could freeze a coal pile; weather inversion could trap emissions, forcing the curtailment of operations at certain stations.

Another key generation reliability factor is the difference between the actual and forecast load. These variances result when key variables such as the provincial economy deviate from the long-term forecast.

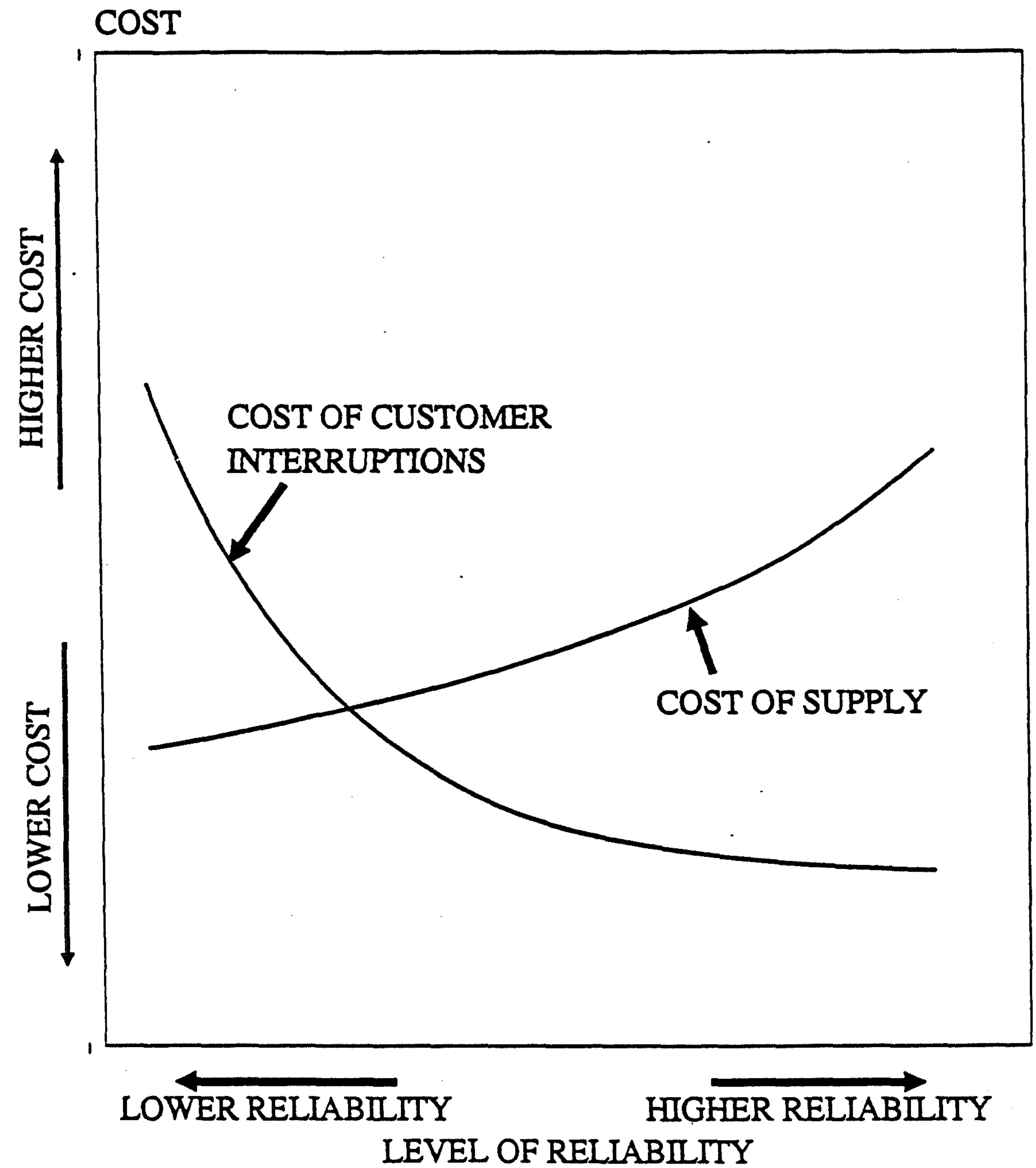
## 3.3 RELIABILITY AT WHAT COST?

Reliability carries two kinds of costs: the cost of electricity supply and the customer loss due to supply interruptions. Adding more supply facilities leads to higher customer costs for electricity service, (Figure 3-2 - Reliability Costs), but lower customer interruption costs. Reducing supply facilities leads to lower electricity service costs, but higher customer interruption costs.

Interruption costs are a function of the damages resulting from loss of electricity service. If a farmer experiences a prolonged service interruption in a summer month, for example, milk could go bad; in the winter, a service interruption could cause chicks to freeze.

In 1978, Hydro did major pioneering work to obtain cost estimates for outages affecting primary electricity users -- large farms, offices, retail trade, small industrial, large user (auto plant, steel maker), government and institutions, and residential.

FIGURE 3-2
# RELIABILITY COSTS



Since then, the cost of outages for some customers has likely gone up, due to the increasing dependency on electricity for everything from office and retail computers systems to robotics.

To determine the reliability level that minimizes total customer cost (Figure 3-3 - Total Cost of Electricity), Hydro balances the total cost of electricity, including the costs of supply and customer interruption, against the level of reliability. Typically, there is a range of reliability levels Hydro can provide at the lowest cost to the customer (Figure 3-4). Hydro chooses to operate at the top end of this range, because it provides a high level of reliability at low customer cost. For example, earlier studies on generation system reliability (the System Expansion Program Reassessment (1979)) found that a five percent increase in installed generation, results in a 60 percent decrease in unsupplied energy, at a cost of increasing customer prices by about one percent.

## 3.4 RELIABILITY CRITERION - "No more than 25 minutes..."

The current reliability criterion for generation planning states:

"Sufficient generation reserve is planned such that after allowing for interconnecting assistance and emergency operating actions, the expected annual unsupplied energy, the product of frequency, duration and magnitude of customer interruptions, caused by a deficiency of generation is less than 25 system minutes."

A system minute is the quantity of energy that is not supplied if the entire system is interrupted for one minute during annual peak demand.

Customer impact depends on how often interruptions occur, how long they last, and how much load gets interrupted. A short interruption affecting a large portion of the province, for example, could result in more unsupplied system minutes than a longer interruption in a city, simply because the provincial outage affected many more users.

To avoid or minimize a supply interruption, Hydro can:

- operate all available generating units;
- cut non-firm sales;
- cut interruptible loads;
- maximize purchases from interconnected systems;
- reduce voltage;
- reduce operating reserve to zero;
- make public appeals to reduce consumption of electricity;
- activate rotating load cuts.

FIGURE 3-3
# TOTAL COST OF ELECTRICITY

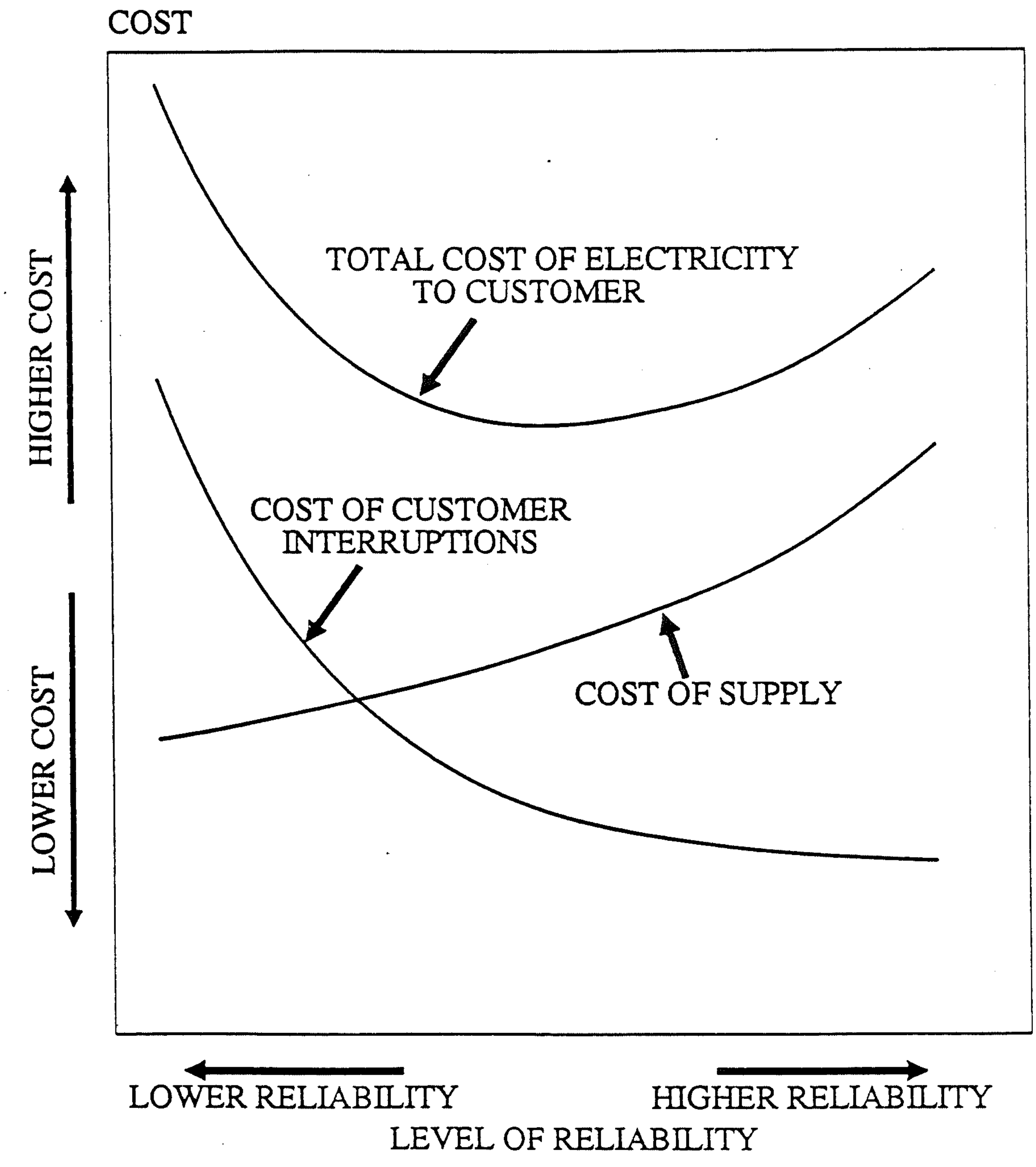
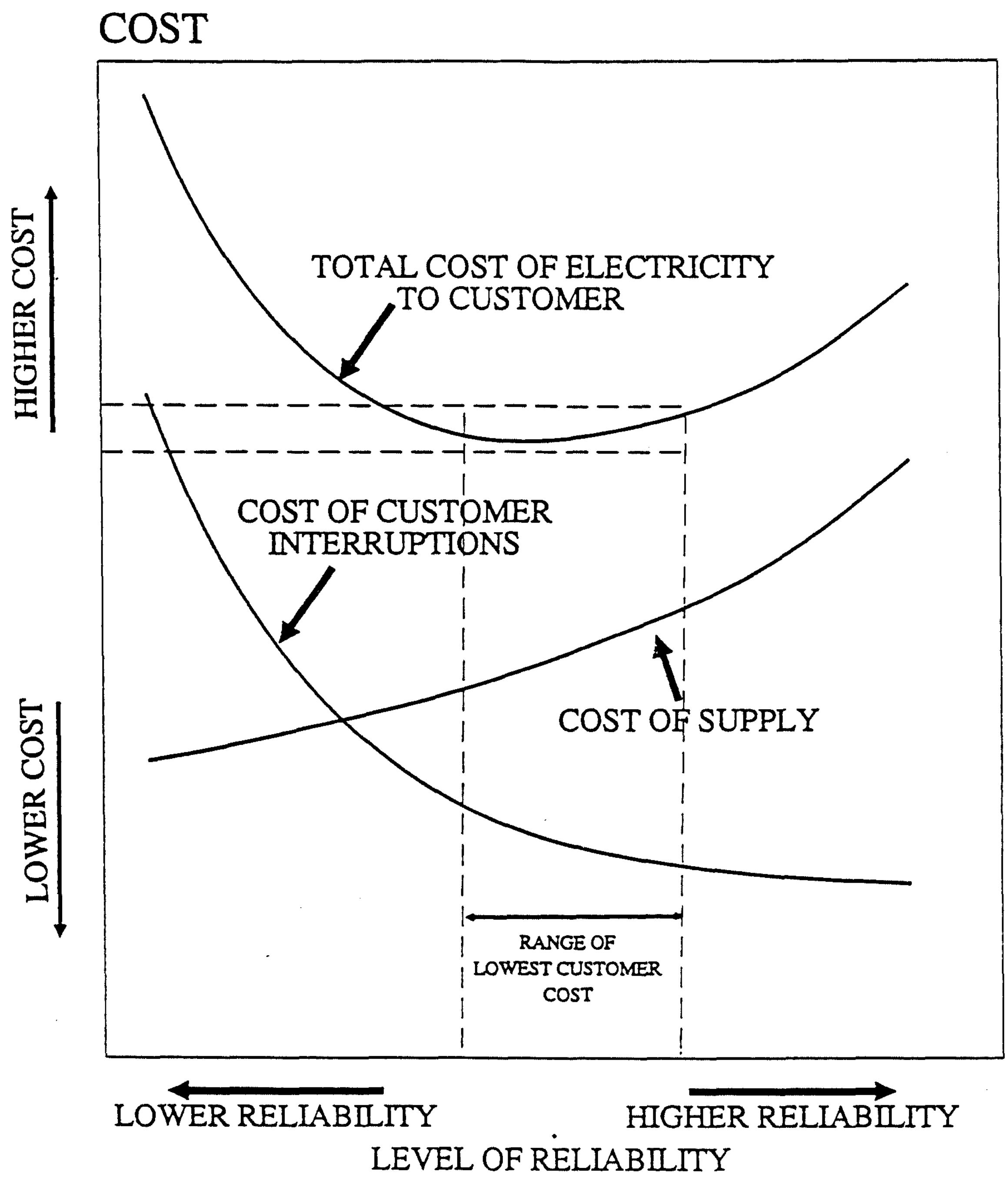


FIGURE 3-4
TOTAL CUSTOMER COST OF ELECTRICITY



The order of these steps depends on the nature of the shortage, location, duration and timing.

The last two actions, public appeals and rotating load cuts, result in unsupplied energy. Load cuts to interruptible customers are not tallied as unsupplied system minutes of energy, but are recorded.

In the last decade, some customers have experienced minimal interruptions, others have experienced extended interruptions. On a few occasions, such as in August, 1988, Hydro had to enact one or more measures to minimize supply interruptions. (For details see Section 3.5: Historical Generation Unreliability) However, the annual sum of unsupplied energy, resulting from generation deficiencies, has been below the 25 system-minute mark in each year.

## 3.5 HISTORICAL GENERATION UNRELIABILITY

The bulk electricity system unreliability data shown in Figure 3-5 includes both generation and transmission related events. The number of interruptible load cuts has increased in recent years; more than half of the interruptible load cuts in 1986-1988 were due to generation related events.

Unsupplied energy due to generation unreliability has averaged about 0.1 system-minutes per year over the last 10 years. This is well below the limit set in Hydro's standards.

### 3.5.1 Close Calls

Not indicated in Figure 3-5 is the how the available generation is needed and utilized year-round. Also not evident is the number of occasions when the system was on the brink of tallying significantly more minutes of unsupplied energy because of unplanned conditions. Figure 3-6a illustrates the generation available to meet Ontario's primary electricity demand in 1988. At several times, particularly in August, the generation system was just one contingency away, for example, turbine or generator problems, from being unable to meet demand. The actual reserve capacity for the last 6 years, after allowing for mothballed capacity, planned and forced outages is illustrated in Figure 3-6b. Figure 3-6c illustrates the actual reserve margin in percent for the past six years.

Figure 3-5

Bulk Electricity System Unreliability Data

Included in 25-minute criterion

| Voltage Reductions | Total No. of events | No. of Generation Related Events (included in Total) | Unsupplied Energy (System-minutes) |
|---|---|---|---|
| 1984 | - | - | - |
| 1985 | 1 | 0 | 1 |
| 1986 | - | - | - |
| 1987 | - | - | - |
| 1988 | 3 | 0 | 1 |

| Public Appeals | Total No. of Events | No. of Generation Related Events (included in Total) | Unsupplied Energy (System-minutes) |
|---|---|---|---|
| 1984 | - | - | - |
| 1985 | 1 | 1 | 1 |
| 1986 | - | - | - |
| 1987 | 1 | 0 | 3 |
| 1988 | 1 | 0 | 6 |

Not included in 25-minute criterion

| Capacity Interruptible Load Cuts | Total No. of Events | No. of Generation Related Events (included in total) | Unsupplied Energy (System-minutes) |
|---|---|---|---|
| 1984 | 2 | 1 | 4 |
| 1985 | 12 | 4 | 23 |
| 1986 | 6 | 3 | 35 |
| 1987 | 5 | 4 | 18 |
| 1988 | 14 | 8 | 50 |

FIGURE 3-6a
GENERATION AVAILABLE
TO MEET PRIMARY DEMAND
1988

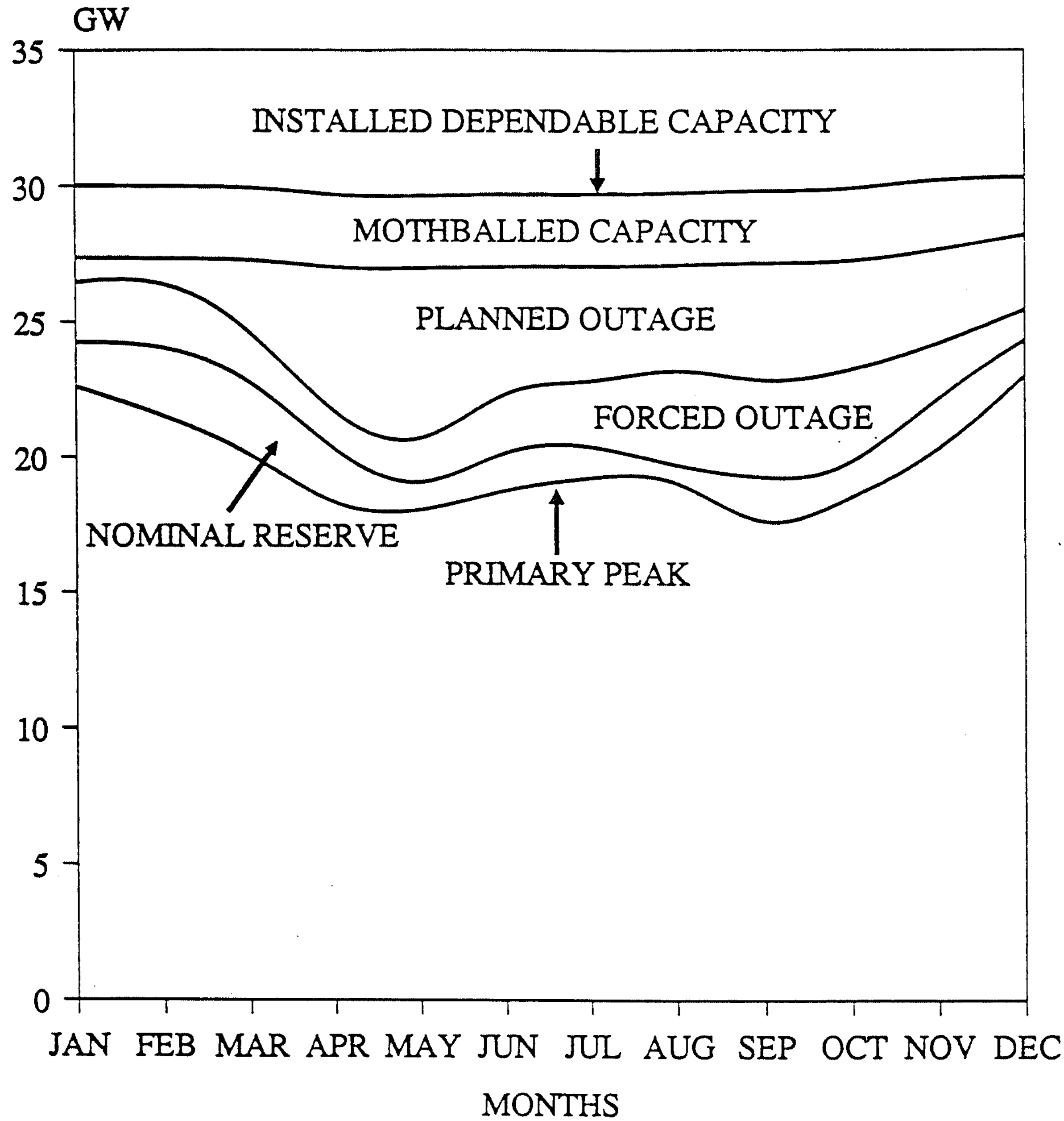


FIGURE 3-6b
GENERATION AVAILABLE
TO MEET PRIMARY DEMAND
1983 - 1988

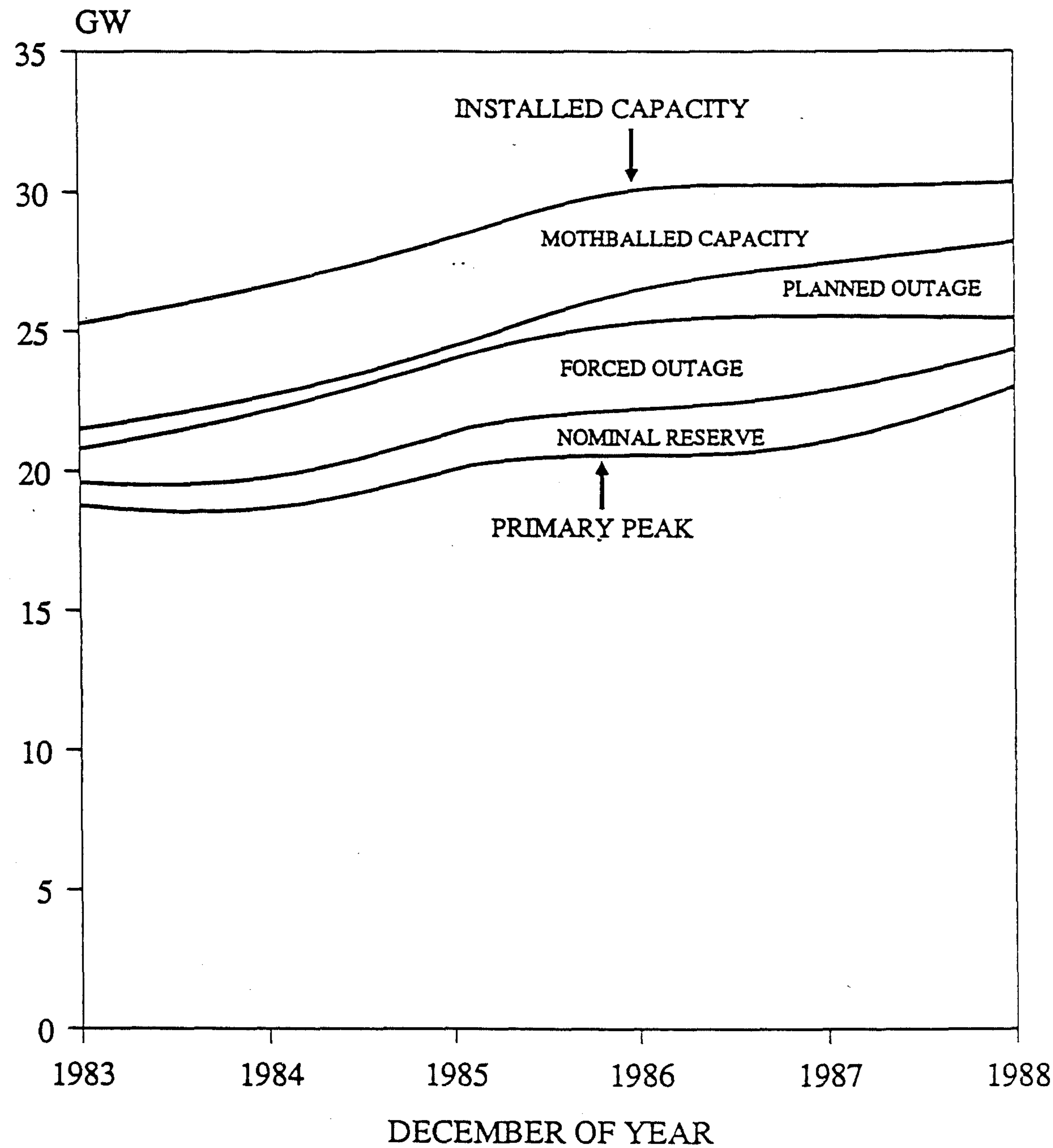
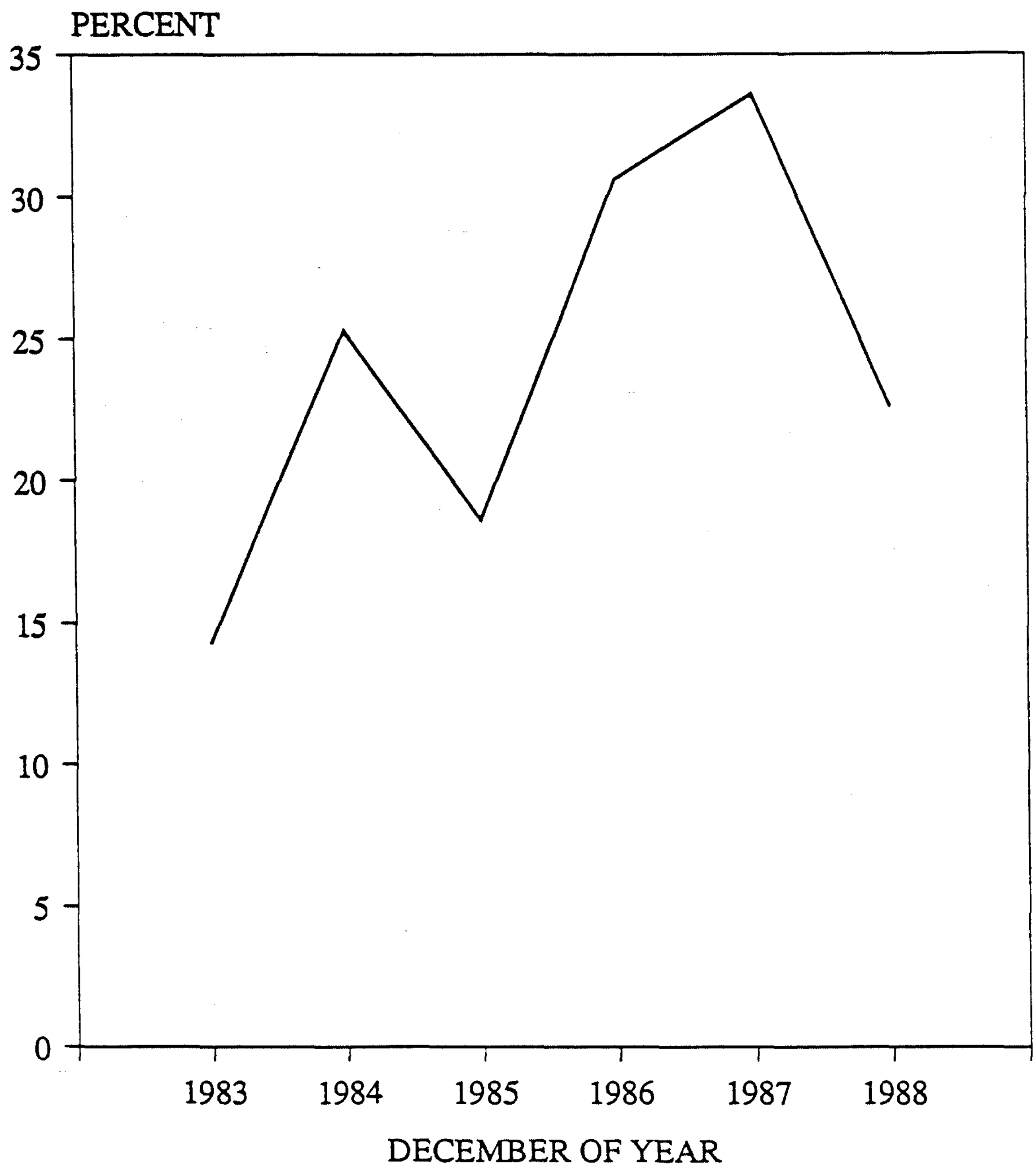


FIGURE 3-6c
HISTORICAL RESERVE MARGIN
(EXCLUDING MOTHBALLED CAPACITY)
1983 - 1988



## 3.6 MEASURING RELIABILITY

Generation reliability is estimated with a frequency and duration (F&D) analysis that compares generating capability from existing and new generating units with load and its specific characteristics. The generating capability of supply side resources and the level of customer demands are approximated by the supply and load models respectively in the F&D computations.

The supply model considers the impact of the following items:

1. Generating unit and non-utility generation reliability indices, i.e. forced outages, deratings, planned and maintenance outages;
2. Maturity of unit performances;
3. In-service date uncertainty for new units;
4. Lead time of new generating units;
5. Capacity assistance from neighbouring utilities equivalent to 700 MW of firm capacity.

The load model takes into account:

1. Variability of peak loads by day type, i.e. weekdays, weekends;
2. Daily load shapes;
3. Distribution of daily peak loads;
4. Effect of load shifting and demand management on daily load shapes;
5. Load forecast uncertainty.

Not considered in reliability calculations are:

1. "Common cause" events that would result in the shut down of several or all generating units at a station. See the following Section 3.6.1: Common cause events.
2. Catastrophic failures of generating units (failures due to normal wear and tear are considered in unit reliability indices);
3. Load forecast error beyond the range included in the uncertainty factor;
4. Strikes, shortage of major unit components;
5. Energy limitations of hydraulic generating units, e.g. low water levels or water use restrictions.

### 3.6.1 Common Cause Events

Certain events could cause several or all units at one generating station to be shut down unexpectedly. This would substantially reduce the amount of available generation and, because it is an unplanned outage, it could lead to increases in unsupplied energy, beyond those specified in the reliability criterion.

Some examples of common cause events are:

- Cooling water intake may be obstructed by fish, plants or other debris. As a result of insufficient cooling water, multiple generating units may have to be derated or even shut down.

- Generic design flaw may exist in new generating units, for example, the boiler hanger rods of Nanticoke units had to be replaced when they were put into service initially. Multiple units were taken out of service for this purpose in the mid-70s.

- Any planned or forced outage of vacuum building equipments will necessitate complete shutdown of all CANDU nuclear reactors linked to the common vacuum building. The vacuum building is one of many safety features designed to protect the public in case of accidents. One vacuum building is provided for a number of reactors; one for all eight units in Pickering NGS A & B, one each for Bruce A & B and Darlington NGSs, respectively.

## 3.7 MEETING THE RELIABILITY STANDARD

When Hydro set the 25 minute criterion in 1981, it established a method to quantify the amount of reserve margin needed to meet customer demand reliably. The calculation showed that this amount should be about 25 percent of planning firm load (PFL), depending on the data used in the reliability model. The latest estimate is 24 percent. This portion of generation is known as the "reserve margin".

Planning firm load, simply put, is total customer demand, minus that portion of capacity that is interruptible.

Since 1981, there have been some changes in system parameters such as load shape, demand management programs and outage factors of generating units. Hence, during the development of demand/supply plans, it was considered prudent to check whether the 24 percent target still provides sufficient generating reserve to meet the reliability standard. This was done by analyzing Cases 6 and 8.

These cases were selected from alternate demand/supply plans because they were representative of typical major supply plans using fossil and nuclear options. They were developed before the Manitoba Purchase option was finalized. Case 8 employs combustion turbines to satisfy near term capacity needs and nuclear stations for capacity and energy requirements in the long term. Case 6 is similar except that coal fired stations are used as instead of nuclear stations. Combustion turbines are included in both cases, when necessary, to bring the reserve margin to the desired target until base load generation is built.

The energy to be purchased from Manitoba will come from reliable hydraulic generating stations. Addition of the Manitoba purchase would not affect our reserve requirements; but in theory it should improve system reliability slightly.

The study data used in this reliability analysis are summarized here:

SUMMARY OF RELIABILITY STUDY DATA

| DATA | SOURCE OF INPUT/COMMENT |
|---|---|
| Basic Load Forecast | December 1988 forecasts. |
| Demand Management, NUG, Load Shifting, Interruptible Loads | March 1988 forecasts |
| Load Forecast Uncertainty | It is assumed that the five load forecasts: lower, branch lower, median, branch upper and upper forecasts can vary by up to 12.6 percent in 8 years from the year when the forecasts are made. |
| Generating unit data | 1988 Forecast of Reliability Indices for use in Corporate Planning Studies, Report 676 SP, March 1989. Due to data input limitations, only up to five yearly reliability indices can be used to model each of the DAFOR/DAUFOR, MOF and POF indices for each generating unit. |
| Nuclear Unit Retube Dates | February 6, 1989 proposed Schedule |
| Rehabilitation and Demothball Schedules | 1989 Business Plan Assumptions/ Acid Gas Control Reference Plan, January 1989, Report 673SP |
| Retirement Dates | End of planned life of generating station |
| Combustion Turbine Unit Forced Outage Rates | North American Electric Reliability Council, Generation Availability Data System (NERC GADS), 1983-87 Statistics |

### 3.7.1 Consequence of Inadequate Reserve

Figures 3-7a and 3-7b show what would happen to unsupplied energy and installed reserve margins, if no new capacity is added to Hydro's system after the completion of Darlington G.S. under median load forecast conditions. The level of unsupplied energy would begin to rise sharply as installed reserves begin to fall rapidly. By 2004, unsupplied energy reaches about 160 system minutes, more than six times the amount stipulated in our current reliability criterion. Contributions of economic demand management and non-utility generation were taken into account in this assessment.

Not considered in Figures 3-7a and 3-7b are two factors which would make reliability deteriorate more sharply than shown -- interruptible loads may switch to firm status when contract limits are reached; operating demands on hydraulic peaking stations during "off-peak" hours will reduce water availability, making peaking stations less able to meet peak demands.

### 3.7.2 Required Reserve

The generation reserve needed to meet the current 25 system-minute reliability criterion for Cases 6 and 8 under various load growth conditions are as tabulated in Figure 3-8 and shown in Figures 3-9a and 3-9b.

These results indicate that the required reserve, under all load forecast paths, ranges from 21 to 25% of planning firm load.

Based on the results in Figure 3-8, a target reserve level of 24% continues to be appropriate. This is also the reserve margin planned for other plans described in Chapter 4.0 - Formulation and Description of Plans.

FIGURE 3-7a
SYSTEM RELIABILITY
WITHOUT NEW CAPACITY ADDITION

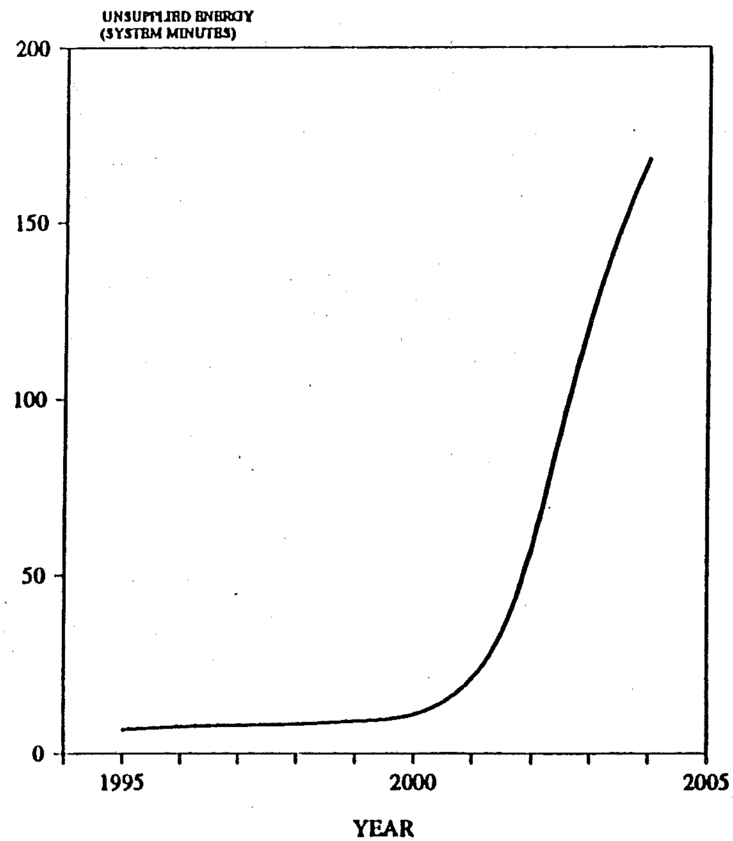



FIGURE 3-7b
SYSTEM RESERVE
WITHOUT NEW CAPACITY ADDITION

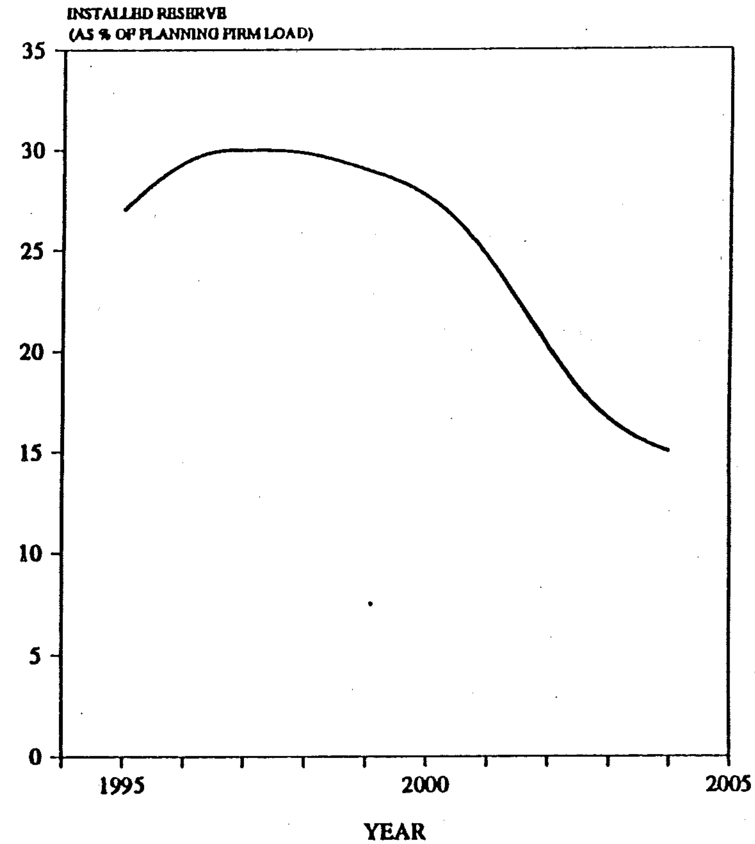


Figure 3-8

Required Reserve for Cases 6 and 8
Based on Frequency & Duration Computer Analysis

Case 6

| Load Growth | Reserve Margins (% of PFL) |
|---|---|
| Upper | 21.3 - 23.8 |
| Branch Upper | 22.6 - 25.0 |
| Median | 22.6 - 24.3 |
| Branch Lower | 22.8 - 24.6 |
| Lower | 23.9 - 25.3 |

Case 8

| Load Growth | Reserve Margins (% of PFL) |
|---|---|
| Upper | 21.5 - 22.9 |
| Branch Upper | 22.8 - 24.2 |
| Median | 22.3 - 23.9 |
| Branch Lower | 22.4 - 23.1 |
| Lower | 22.5 - 24.8 |

### 3.7.3 Key Generation System Reliability Variables

The reliability level of a generation system is dependent on two key variables: load characteristics and generation characteristics.

Load characteristics, including demand management, non-utility generation and interruptible loads, will be common for all alternative plans presented in Chapter 4.0 -- Formulation and Description of Plans.

Generation characteristics are a function of the performance of major generating units and the amount of reserve margin planned. As long as the reserve margins for any candidate demand/supply plans are maintained at levels similar to those for Cases 6 and 8, the reliability standard would be met. Specific supply options used

FIGURE 3-9a
CASE 6
REQUIRED RESERVE MARGIN

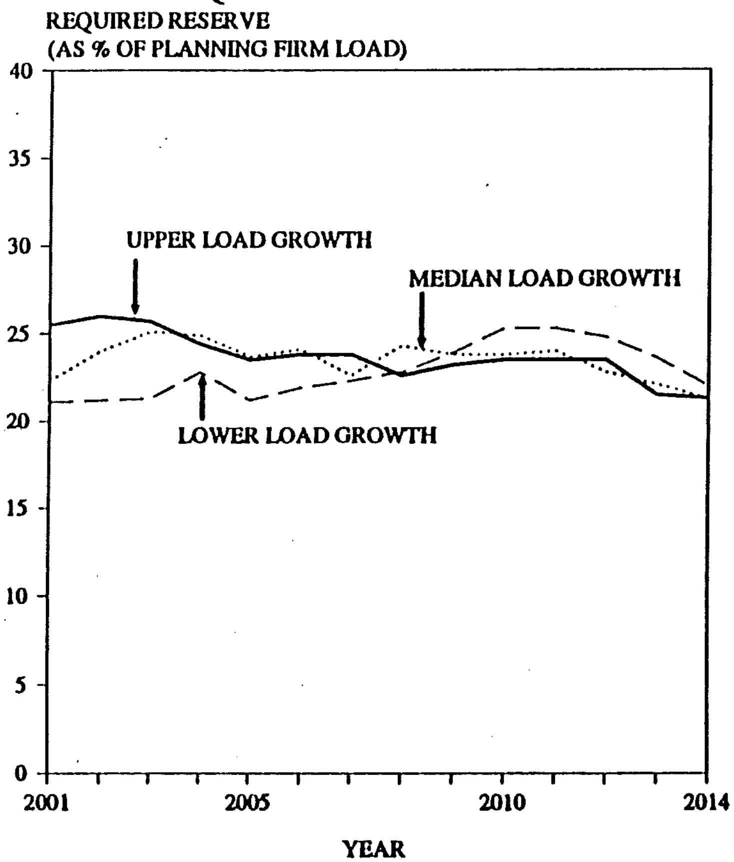
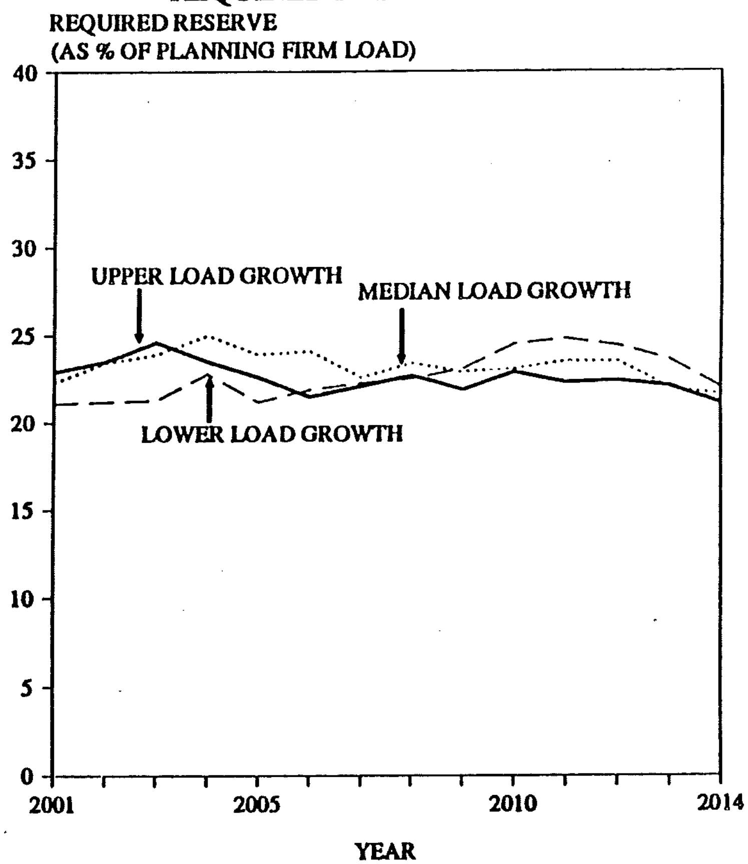



FIGURE 3-9b
CASE 8
REQUIRED RESERVE MARGIN



in each alternate plan are not critical, because reliability indices for major supply options based on fossil or nuclear technology are not significantly different.

## 3.8 PLANNED RESERVE MARGINS

If the nominal reserve margin of 24 percent of Planning Firm Load is maintained, all five demand/supply plans can meet the 25 system-minutes of unsupplied energy criterion.

The planned reserve margin may vary from the 24% level. It will drop below 24% when short lead time capacity cannot be brought on-line soon enough to reach the 24% margin. When major generating units are built, their capacity can exceed the required reserve for load growth. As a result, the reserve margin can rise above 24% for a year or more.

Actual reserve levels have varied primarily because of load growth changes. Historic reserve margins are illustrated in Figure 3-10. (The reserve margin shown is expressed as a percentage of primary demand, as this is a measurable quantity, the planning firm load cannot be measured as easily.) Margins increase when load grows less than forecast, especially if new generation had been committed and could not be delayed economically.

Figures 3-11a and 3-11b illustrate the planned reserve levels for Cases 6 and 8 under median load growth. Reserve levels fluctuate in the near term due to major rehabilitation outages. It will rise above the 24% level in the early to mid-1990's as Darlington units come into service and as demand management, non-utility generation and hydraulic programs are implemented.

In years when this activity does not occur, for example 1993, the reserve margin for Case 8 climbs to just under 35 percent. In 1995, however, rehabilitation occurs and the margin drops to a level close to the reserve standard of 24 percent.

Around the year 2000, reserve margins will fall below 24 percent before they are restored.

Overall, reserve margins for Case 6 range from a high of 34 percent to a low of about 23 percent. For Case 8, it ranges from about 34 to 20 percent.

Figures 3-12 and 3-13 illustrate the planned reserves under upper and lower growth. These more clearly illustrate how reserves can vary: below the 24 percent target when there is insufficient time to respond to load growth increases; and above the target when load growth is slow and existing and committed resources exceed the

FIGURE 3-10

# Historical Reserve Margin Levels

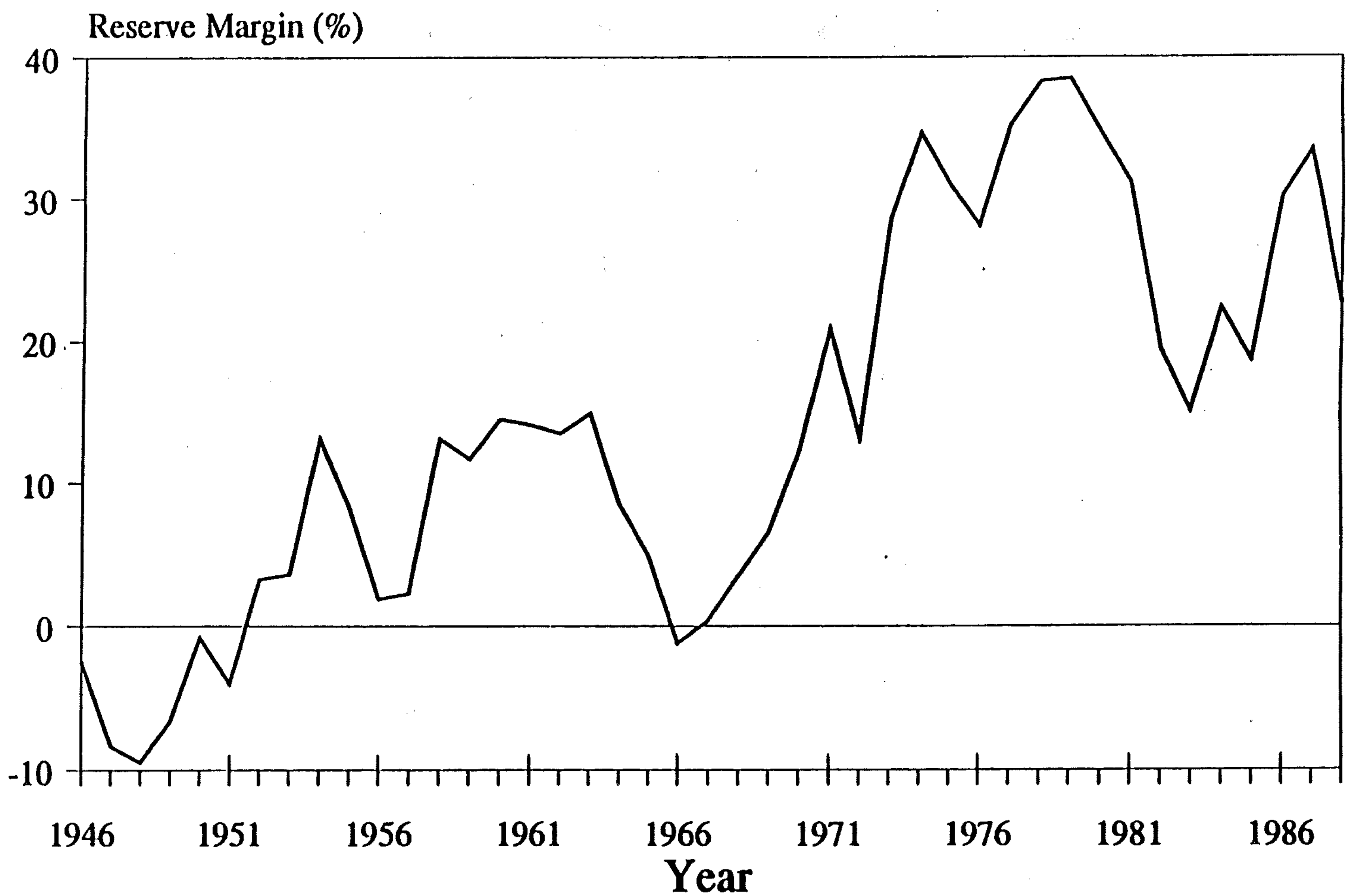


FIGURE 3-11a
1989 DEMAND SUPPLY PLAN RESERVE MARGINS
CASE 6
MEDIAN LOAD GROWTH

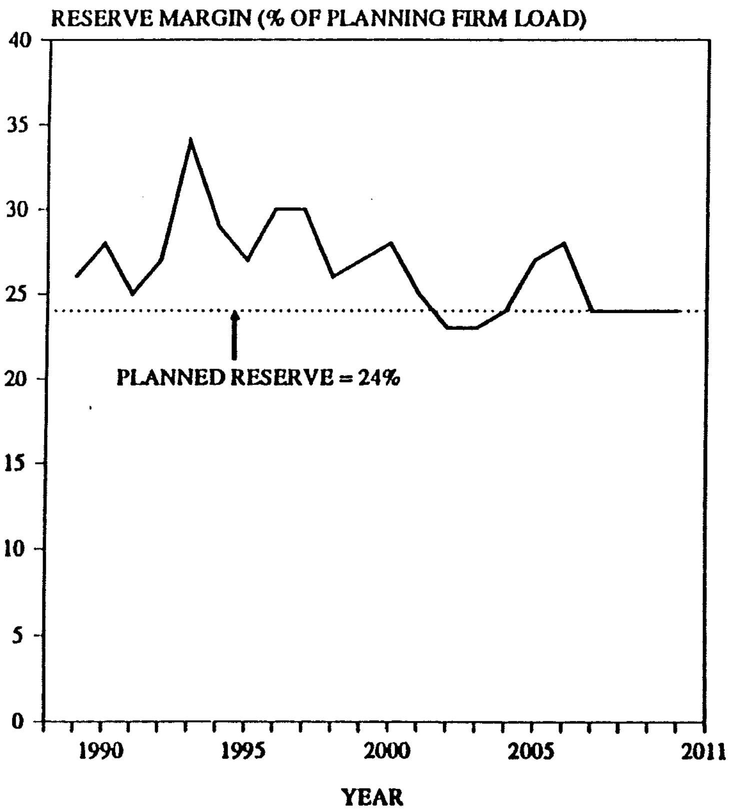
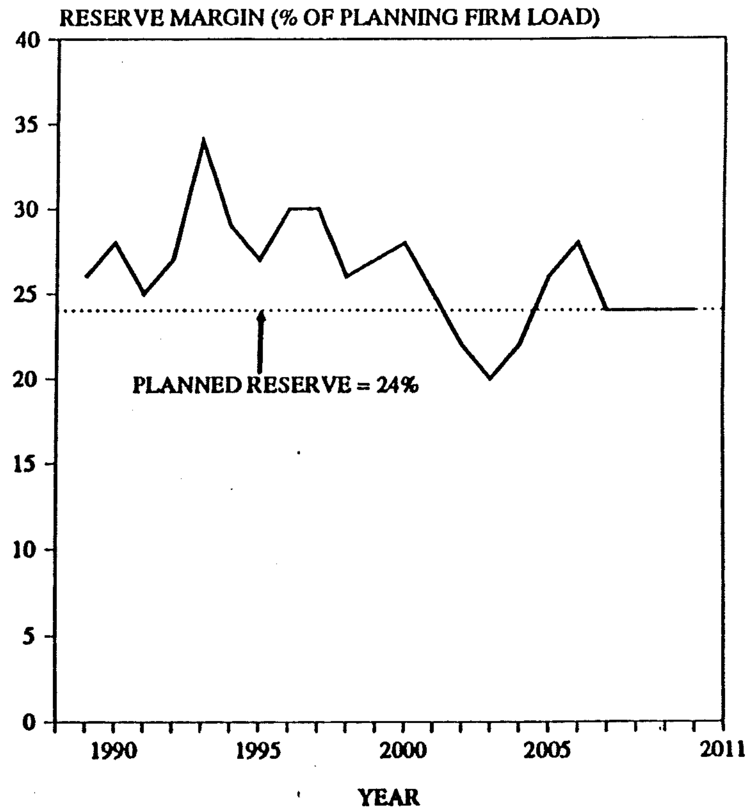



FIGURE 3-11b
1989 DEMAND SUPPLY PLAN RESERVE MARGINS
CASE 8
MEDIAN LOAD GROWTH



generation required to reliably supply electricity demand.

### 3.8.1 Comparing reserve levels with other utilities

Different utilities choose their reserve margins based on the nature of their systems, their experience, economic considerations and the reliability analysis tools considered appropriate for respective systems.

Hydro, as previously noted, expresses reserves as a percentage of planning firm load. Some other utilities measure reserves levels by "capacity margin" -- required reserve capacity expressed as a percentage of installed generation. Figure 3-14 provides the required reserve margins both as a % of PFL and % installed capacity respectively. As the installed generation is usually higher than planning firm load, the capacity margin expressed in terms of installed generation capacity is lower than reserve margin based on planning firm load.

Power systems with similar supply and demand characteristics will demonstrate similar need for reserve capacity, as indicated by the reserve margins shown in Figure 3-15 for various utilities with systems similar to Ontario Hydro.

Hydraulic generating units are usually more reliable than thermal electric generating units. Therefore, systems that are predominantly hydraulic, such as Hydro Quebec and Manitoba Hydro would require lower reserve margins.

FIGURE 3-12a
1989 DEMAND SUPPLY PLAN RESERVE MARGINS
CASE 6
UPPER LOAD GROWTH

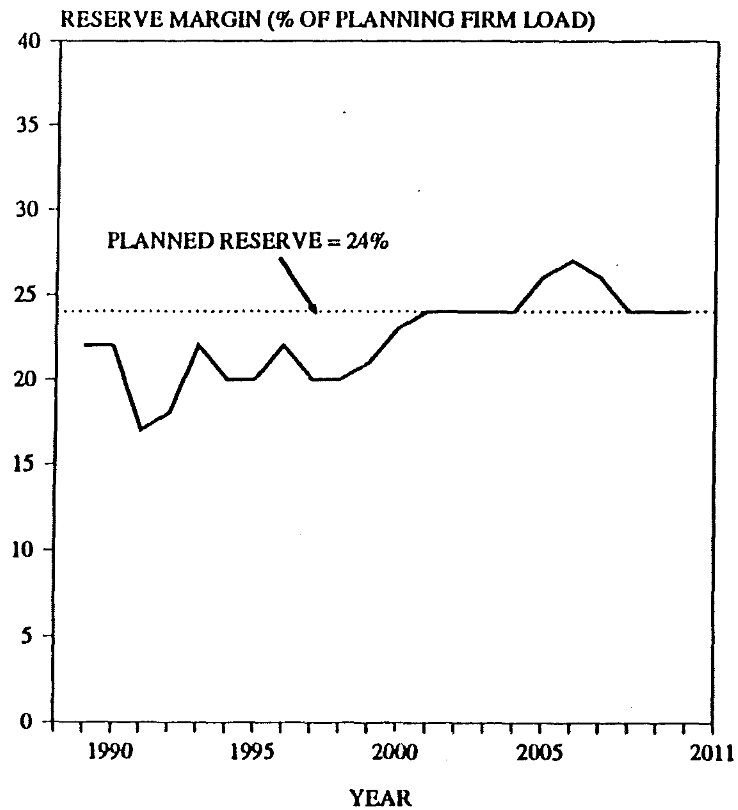



FIGURE 3-12b
1989 DEMAND SUPPLY PLAN RESERVE MARGINS
CASE 8
UPPER LOAD GROWTH

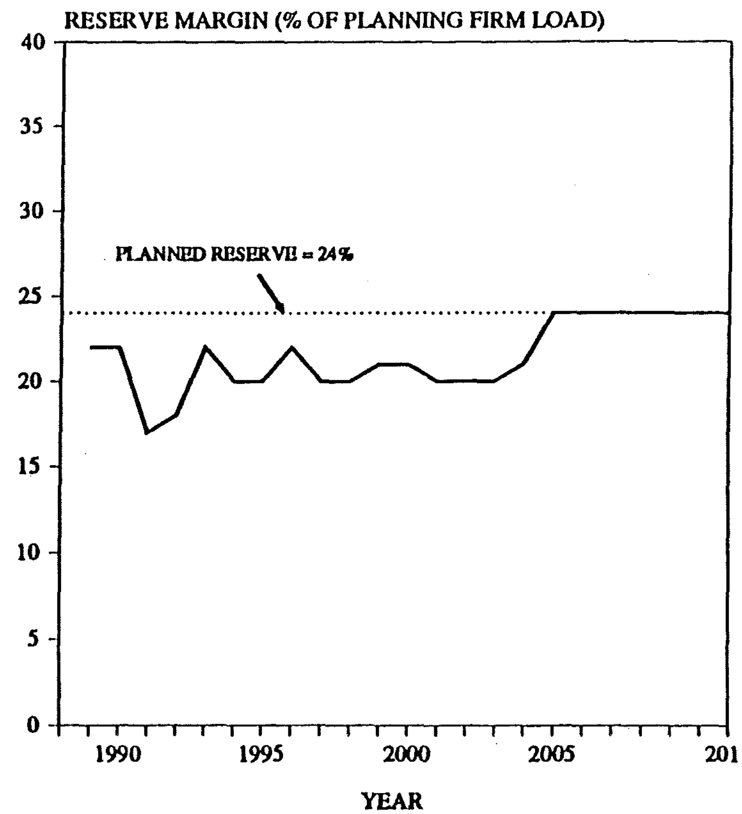


FIGURE 3-13a
1989 DEMAND SUPPLY PLAN RESERVE MARGINS
CASE 6
LOWER LOAD GROWTH

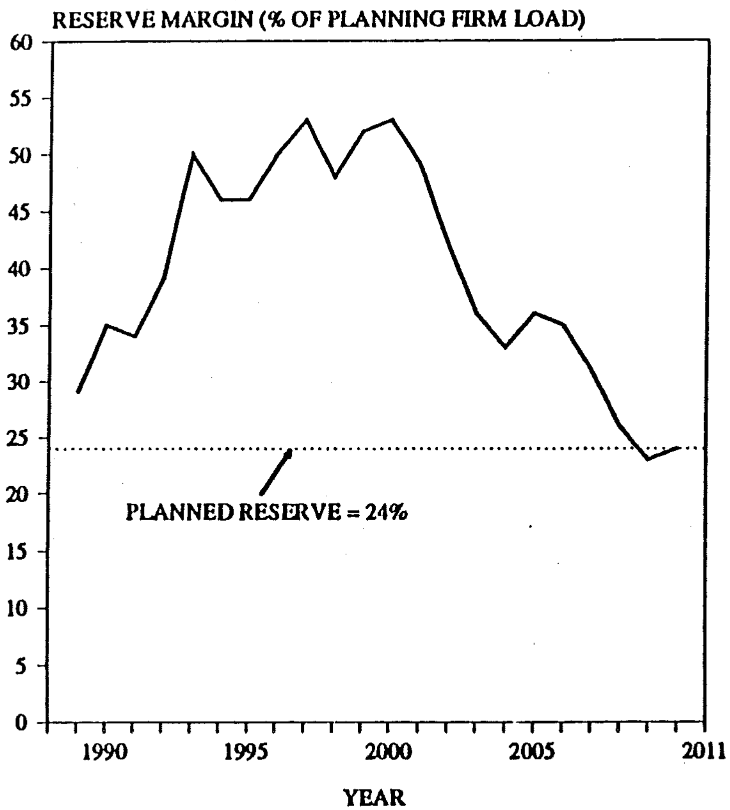



FIGURE 3-13b
1989 DEMAND SUPPLY PLAN RESERVE MARGINS
CASE 8
LOWER LOAD GROWTH

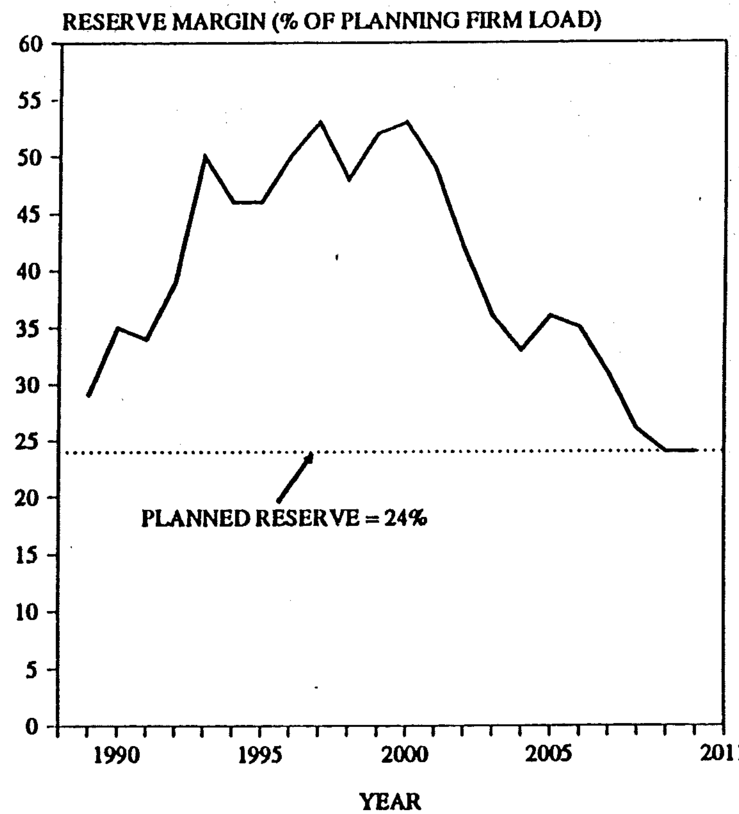


Figure 3-14

Required Reserve for Cases 6 and 8
Based on Frequency & Duration Computer Analysis

Case 6

| Load Forecast | Reserve margins (% of PFL) | Capacity margins (% of Installed Capacity) |
|---|---|---|
| Upper | 21.3 - 23.8 | 17.6 - 19.6 |
| Branch Upper | 22.6 - 25.0 | 18.0 - 19.5 |
| Median | 22.6 - 24.3 | 17.9 - 19.0 |
| Branch Lower | 22.8 - 24.6 | 17.7 - 19.0 |
| Lower | 23.9 - 25.3 | 18.5 - 19.5 |

Case 8

| Load Forecast | Reserve margins (% of PFL) | Capacity margins (% of Installed Capacity) |
|---|---|---|
| Upper | 21.5 - 22.9 | 17.3 - 17.8 |
| Branch Upper | 22.8 - 24.2 | 18.1 - 19.6 |
| Median | 22.3 - 23.9 | 18.0 - 19.5 |
| Branch Lower | 22.4 - 23.1 | 17.5 - 18.0 |
| Lower | 22.5 - 24.8 | 17.1 - 19.1 |

Figure 3-15

Reserve Margins Adopted by Various

North American Utilities

| Utility Name | Reserve Margin (% of Peak Load)* |
|---|---|
| Ontario Hydro | 24 |
| Public Service Electric & Gas of New Jersey | 22 |
| New York Power Pool | 22 |
| Philadelphia Electric | 22 |
| Delmarua Power & Light, Delaware | 22 |
| Northeast Utilities, Hartford, Conn. | 23-24 |
| Michigan Electric Coordinated Systems | 23 |
| Commonwealth Edison | 15-20 |
| New Brunswick & Nova Scotia Power | 20 |
| Hydro Quebec | 10 |
| Manitoba Hydro | 12 |

*Definition varies from utility to utility; Ontario Hydro specifies reserve margin as percentage of planning firm load.

## 3.9 REVIEW

Reserve margin provides the flexibility to handle equipment failures, load forecast errors or lower than expected demand management penetration or contribution from non-utility generation.

Ontario Hydro has a strong reliability record; albeit there were more interruptible load cuts and public appeals for reduced power consumption in recent years. In order to maintain good performance in the future, adequate reserve margins must be planned for future system expansion.

The long-term reserve margin (24% of planning firm load) used in the development of plans for the 1989 Demand/Supply Plan Study allows the system, as modified under each alternative demand/supply plan, to maintain the present reliability criterion (25 system minutes) in the long term.

While Hydro has selected a reserve target that is in the high end of the range required to meet the reliability criterion, over the long term the incremental cost of meeting that target is not significantly higher than it would be if Hydro selected a level lower in the range.

Also, providing slightly higher reserve does not lead to large increases in electricity rates charged to our customers. Provision of this extra reserve by non-capital intensive combustion turbine units (CTU) is more economic than more capital intensive coal-fuelled units, an alternative considered by the SEPR study.

Hydro's reserve levels are similar to those adopted by other similar utilities in North America.

In short, reserve margins are a form of insurance -- they carry a cost, but it is significantly below the costs that would be incurred if electricity service was unreliable.

# 4. FORMULATION AND DESCRIPTION OF PLANS

## 4.0 INTRODUCTION

The 1989 Demand/Supply Plan Report is one of the documents issued under the title "Providing The Balance Of Power: Ontario Hydro's Plan To Serve Customers' Energy Needs". It contains a relatively comprehensive discussion of the background to, and elements of, Hydro's Proposed Demand/Supply Plan to meet future needs. It also discusses some of the alternatives which were considered.

The Plan Report does not report exhaustively on all demand/supply cases which were examined since the end of 1988, when the demand/supply plan formulation and analysis process began in earnest. Rather, it presents the results of the "final" round of analysis which began in the fall of 1989 and was completed just prior to the public release of the Proposed and Candidate Plans.

Section 4.1 of this Analysis Report is provided as an overview of some of the many demand/supply cases which were considered during the earlier stages of the plan formulation and analysis process.

Chapter 15 of the Plan Report describes how cases were developed and tested the against five electricity demand paths (Upper, Branch Upper, Median, Branch Lower, and Lower forecasts). The Plan Report does not, however, present details on either the Branch Upper or Branch Lower forecasts; nor does it indicate the response of the five major supply cases to those branch forecasts. These items are covered in this chapter. The majority of this chapter (Sections 4.3 to 4.19) discusses how the need for major supply options under Branch Upper or Branch Lower forecast conditions was determined. It also indicates how the cases presented in the Plan Report would respond to these electricity demand paths.

The Plan Report contains a relatively detailed discussion of both the need for major new supply options and the resulting cases under Upper, Median, and Lower load forecasts. The vast majority of this material will <u>not</u> be repeated here. However, in some instances it was deemed useful to clarify or provide additional details on some of the assumptions and factors considered during the formulation of these demand/supply cases.

The opportunity is also taken to identify instances where data used during the formulation of demand/supply cases do not exactly match those reported in the Plan Report. These differences are shown to have no significant overall effect on the comparison and evaluation of cases.

## 4.1 PLAN FORMULATION OVERVIEW

As part of Hydro's on-going planning process there are frequent reviews and revisions of the load forecast, Demand Management and Non-utility Generation Plans, and projections of future economic conditions. Similarly, the suitability of existing and new generating technologies is constantly reassessed in light of Hydro's and others' experience with the technology, changing environmental requirements, societal preferences, and the costs, reliability, and safety of the option. Throughout the demand/supply planning process, this "changing landscape" was explicitly taken into account by frequently updating the information upon which the analysis was based, and by making corresponding adjustments to the demand/supply cases. The cycle of updating cases, analyzing them, reviewing the analysis and then adjusting cases was, and remains a continuous, iterative process.

The five major supply cases described in the Plan Report represent the most recent iterations in this process. The following few paragraphs summarize demand/supply cases which were developed, analyzed, and refined during preceding iterations of the demand/supply planning process.

### FIRST PHASE

The preliminary phase of demand/supply case formulation and analysis began in the Fall of 1988 and continued until the Spring of 1989. Much of this time was spent gathering data and improving computer simulation models used to analyze cases. Toward the latter stages of this period, as data became more refined, it became practical to begin to formulate and analyze demand/supply cases. These preliminary cases were created for two purposes.

Most importantly, they were created so that the various analysis tools and techniques could be exercised on "sample problems" to ensure that they worked effectively and efficiently to provide the required analytical results.

Secondly, the cases were created in such a way as to represent a broad range of potential major supply plans. By analyzing these using the preliminary data then available, it was possible to begin to identify those broad categories of plans which warranted further investigation.

A wide variety of cases was formulated and subjected to preliminary analysis at this time. Some of these included only nuclear additions after 2002; and some employed only CTUs to meet all future load growth. There were cases in which one or more major fossil stations (CSC-Coal or IGCC) were always added before any nuclear additions; and others were just the opposite. A number of cases were formulated in which new nuclear generation was always added very late in the planning period to study the effect of minimizing initial capital expenditures. Still other cases were designed to dramatically reduce CO2 emissions by installing more nuclear than might otherwise be required.

It was soon recognized that major supply cases which included only CTU generation were unlikely to be economic and that those which relied exclusively on new nuclear plant could not maintain system reserves at an adequate level under Upper load forecast conditions. Hence, primary consideration was given to major supply cases which featured a mixture of new fossil peaking resources (CTUs and/or CTU/CC and/or CTU/IGCC) and new baseload generation comprised of nuclear, CSC-Coal plant and/or IGCC plant.

When this analysis was performed, data on the Demand Management and Non-utility Generation Plans, the program for new hydraulic development, and the retubing and retirement schedules were not yet finalized. The probable unit sizes for new fossil stations were still being investigated and the purchase of 1000 MW from Manitoba, which now figures in all plans presented in the Plan Report, was not yet incorporated. As well, the costs associated with radial transmission and with obtaining the required approvals prior to the commitment of new generation were not fully captured at this point. Hence, although the results of this preliminary analysis were useful for indicating which general features of cases should be investigated further, the results cannot be compared directly to those presented in the Plan Report.

Because of their preliminary nature, none of the cases developed and analyzed in this first phase of the process were formally assigned case designation numbers (as in "Case 15" of the Proposed Demand/Supply Plan).

## SECOND PHASE

Before the second major phase of demand/supply case formulation and analysis was begun, the assumptions about the retirement of aging existing plant were finalized and incorporated into the models. The retirement schedule used is the same as that reported in the Plan Report. By this point, various details regarding fossil unit characteristics and costs had been compiled and submitted for review by an independent consultant as part of the Thermal Cost Review. Computer model data files were modified as needed to incorporate that information. New cases were formulated which reflected these changes as well as the insights gained during the first round of analysis.

Demand/Supply cases were developed which included mixtures of nuclear, IGCC, and CSC-Coal baseload facilities, and CTU peaking plant, either as stand-alone CTUs, or the first phase of CTU/CC or CTU/IGCC. The goal of most of the analysis performed during this phase was to determine the effect of varying the relative amounts (quantity and timing) of new peaking and baseload plant under the five load forecast paths.

Early in May, 1989 cases developed to that point and found to warrant further investigation were assigned "case numbers". Case numbers 4,5,6,7,8,and 9 were assigned arbitrarily to the then existing cases. Case numbers 1 through 3 were saved for future use, as were the numbers following 9 (in fact, case numbers 1, 2, and 3 never were used). The cases which were identified and analyzed had the following general characteristics:

| CASE NUMBER | DESCRIPTION |
|---|---|
| 4 | A mix of new nuclear baseload and CTU for peaking, with no new baseload plant prior to 2007. |
| 5 | A mix of new nuclear plus a postulated purchase of 1000 MW of power from Manitoba for baseload, with new CTUs added for peaking as needed. The dates upon which new nuclear is to be added were chosen in an attempt to minimize overall demand/supply case cost, consistent with the need to respect leadtimes required to place new major facilities into service. |
| 6 | A case with IGCCs serving all new baseload with CTUs added for peaking. |

| CASE NUMBER | DESCRIPTION |
|---|---|
| 7 | A predominantly nuclear case with the first new nuclear plant added as early as 2000. All new baseload additions are nuclear, and CTUs are added for peaking. |
| 8 | A case falling between Case 4 and Case 7, with new nuclear baseload added on a schedule which attempts to minimize overall demand/supply case costs. As well as analyzing this case under the "nominal" set of assumptions used for studying the other cases in this list, its behaviour under various changes to those assumptions was examined. These included three scenarios: imposition of more stringent acid gas control regulations; escalation of fossil fuel prices more than expected; significant delays in obtaining approvals for nuclear generation. Examination of the response to these scenarios helped to better define the degree of flexibility which cases could exhibit. |
| 9 | A case similar to Case 8, but with a 4x800 MW CSC-Coal fired station reducing the number of peaking CTUs needed after 2007. |

Analysis of the cases listed above began in the Spring of 1989 and continued through to the middle of the Summer.

## THIRD PHASE

In mid-August, a third round of data modification, case revision, and re-analysis began. This opportunity was taken to incorporate into the computer model used for case simulation and analysis, revisions to the forecast of capacity interruptible load, the non-utility generation forecast, and the future hydraulic generation program. The revised levels of load reduction and new generation, which were incorporated at that time, were eventually carried through to the final analysis and are discussed in following sections of this chapter.

The cases which were analyzed at this point were given case numbers 12, 14, 15, 16, and 18 to distinguish them from those created in previous rounds of analysis. The cases were as follows:

| <u>**CASE NUMBER**</u> | <u>**DESCRIPTION**</u> |
|---|---|
| 12 | This case was similar to Case 8 (see above) but with additional new nuclear units to reduce acid gas and CO2 emissions. |
| 14 | A case similar to Case 18, described below, but with the first major new baseload facility being a 4x800 MW CSC-Coal plant rather than a new nuclear station. |
| 15(rev 1) | Similar to Case 5, but reflecting changes necessitated by the revised hydraulic, NUG, and CIL forecasts. The then current terms of the 1000 MW purchase from Manitoba were also incorporated into this case. |
| 16 | A case similar to Case 6, but incorporating 4x800 MW CSC-Coal plants for baseload operation rather than IGCCs. |
| 18(rev 1) | A case similar to Case 8, but reflecting updated modelling data. The timing of new nuclear baseload additions reflects two objectives: minimizing overall demand/supply case cost, and reducing acid gas and CO2 emissions. |

Case numbers 10, 11, 13, 17, and 19 were not used.

## FOURTH PHASE

By the early fall of 1989, the terms of the Manitoba Purchase had become much more clear and it appeared likely that an agreement to purchase would be reached. This necessitated another iteration of case revision and re-analysis. All but one of the cases formulated and analyzed in this final phase incorporated the 1000 MW Manitoba Purchase described in the Plan Report. As it turned out, this was to be the final round of analysis before publication of the Proposed Plan.

The analysis performed at this stage explicitly considered the cost impacts of the illustrative sites described in the Plan Report. In particular, the costs of transmission required to incorporate new facilities located at defined illustrative sites, and the estimated costs of obtaining the necessary approvals for those sites, were modelled.

The cases considered during this final iteration of formulation and analysis are listed below. Note, again, that case designation numbers were not assigned on a sequential basis.

| CASE NUMBER | DESCRIPTION |
|---|---|
| 18(rev 2) | This is the same as Case 18(rev 1) but with explicit consideration of radial transmission and approval costs for defined illustrative sites. This case did not include the Manitoba Purchase. |
| 15(rev 2) | This is the Case 15 described in the Plan Report. It is essentially identical to Case 15(rev 1), but with new Manitoba Purchase terms and with the costs associated with radial transmission and illustrative site approvals incorporated. |
| 20 | Similar to Case 15(rev 2), but with the first new nuclear station replaced by a 4x660 MW unphased IGCC facility. |

| CASE NUMBER | DESCRIPTION |
|---|---|
| 21 | An all fossil case providing new IGCC plant for baseload and CTU for peaking. Similar to Case 6, but analyzed with revised data and incorporating the Manitoba Purchase. |
| 22 | This is the "Higher Nuclear" case described in Chapter 15 of the Plan Report. It is similar to Case 12. |
| 23 | This case is presented in Chapter 15 of the Plan Report. It is the case in which most new major supply requirements are provided by new nuclear generation in order to reduce $CO_2$ emissions. |
| 24 | Two versions of this case were created. The first was similar to Case 15, but with the first new nuclear station replaced by a 4x800 MW CSC-Coal fired facility. This was Case 14 with the new Manitoba Purchase terms and with explicit consideration of the illustrative siting effects on costs.<br><br>The second version of this case was similar to Case 15, but with the second new nuclear plant replaced by a 4x800 MW CSC-Coal station. This is the "Higher Fossil" Candidate Major Supply Plan (Plan 24) referred to in the Plan Report. |
| 26 | In this case, discussed in Chapter 15 of the Plan Report, all new major supply requirements are provided by new 4x800 MW CSC-Coal generation. It is similar to Case 16. |

Each of these cases was created by bringing to bear the considerable judgement and experience gained by analyzing literally hundreds of cases in the preceding phases of the analysis. This same judgement and experience was used to help determine which of the many major supply cases should be presented in the Plan Report, and which of those should be advanced as the Proposed Plan and acceptable Alternative Plans.

Of those examined in the final phase of analysis and listed immediately above, Cases 18, 20, 21, and the first version of Case 24 were not carried through to the Plan Report.

Case 18 was eliminated when it became apparent that a purchase agreement with Manitoba Hydro for 1000 MW of capacity would, in fact, be signed.

To date, the world's utilities have had relatively little experience with the IGCC option. Hydro's judgement is that this promising but new technology is not sufficiently mature to be relied upon heavily to serve near term baseload requirements. Hence, Cases 20 and 21 were not carried through to the Plan Report. Note, however, that the appearance of phased CTU/IGCC facilities (in which the conversion of CTUs to a fully fledged IGCC station is delayed) in the Proposed and Alternative Plans is indicative of Hydro's expectation that the technology will be proven as experience is gained by various other utilities.

In the earlier version of Case 24, a 4x800 MW CSC-Coal plant was provided as the first major baseload facility, followed by new nuclear stations, as required, to meet all other baseload needs. Hydro's judgement was that such a case would not adequately comply with the intent of the Demand/Supply Planning Strategy (specifically, consideration number 5.8: "Ontario Hydro will seek to maintain CANDU nuclear so that it is available for future development"). The second version of Case 24, in which a 4x800 MW CSC-Coal fired station is built after the first new nuclear station, was judged to be an acceptable alternative, and was carried through to the Plan Report.

## 4.2 STRUCTURE OF FOLLOWING SECTIONS

The chapters in the "Plan Report" were arranged to describe the various elements of the planning process in a sequence which shows their logical linkages. In general terms, that report shows how the requirement for additional demand/supply options was determined, how feasible options to meet that requirement were identified, and how plans to put these options into place in a timely manner were developed and analyzed.

The structure of the remainder of this chapter mirrors the Plan Report. For each chapter of the Plan Report, the reader will find a correspondingly numbered subsection of this chapter which supplements the information present in the Plan Report. For example, subsection 4.3 of this chapter of the Analysis Report provides details of the basic forecast which were not presented in Chapter 3 of the Plan Report.

The primary purpose of the remainder of this chapter of the Analysis Report is to present the details of the Branch Upper and Branch Lower load forecast paths and describe how the five major supply cases presented in the Plan Report respond to those branch forecasts.

## 4.3 BASIC FORECASTS

Chapter Three of the Plan Report stresses the importance of considering load forecast uncertainty when developing flexible plans to meet future electricity needs. For the Proposed and Alternative Demand/Supply Plans, this was done explicitly by developing planning cases which were capable of responding to future load growth which falls within the "bandwidth forecast".

As indicated in the Plan Report text, the bandwidth forecast for basic electrical energy needs covers 80% of the expected future outcomes for load growth. There is a 10% probability that the basic energy demand will be higher than the upper bound of the bandwidth forecast and a 10% probability that it could be less than the lower bound of the forecast range.

Five basic load forecast paths which fall within this bandwidth forecast were developed. The "Median" forecast is the most likely electricity demand in each year in the study period. The "Upper" forecast is the upper bound of the bandwidth forecast, and the "Lower" path is the lower bound of electricity demand. The Upper, Median, and Lower basic forecasts are presented in detail in Chapter 3 of the Plan Report. In addition to these three forecasts, a "Branch Upper" forecast and a "Branch Lower" forecast were developed. The Branch Upper forecast was developed to model a case in which load growth proceeds along the Median path until 1995, when demand accelerates and tends toward the Upper forecast. Similarly, the Branch

Lower forecast proceeds along the Median path until 1995, when demand is assumed to slow and tend toward the Lower forecast.

Each of the major supply cases presented in the Plan Report was tested under the five load forecast paths to ensure that the cases had adequate ability to respond to changes in electricity demand. The Upper and Lower forecast paths exercise the ability of the demand/supply cases to respond to a demand for electricity which is consistently different from that expected (Median forecast). This tests the suitability of the short term actions in the case. This also, in a sense, tests the "stamina" of the cases - their ability to respond to a prolonged onslaught of load growth which is faster or slower than expected.

The Branch Upper and Branch Lower forecasts help highlight the cases' agility:- their responsiveness to an unexpected, rapid change in demand in the mid 1990s.

Any of the demand/supply cases studied could result in an undercommitment or overcommitment of resources if demand grows faster or slower than expected after a major supply facility is commited. All cases were tested using the Branch Upper load forecast path to determine their ability to avoid or minimize long term impacts of undercommiting resources in the mid- to late- 1990s, when the Branch forecast diverges from the Median forecast. Similarly, the Branch Lower forecast path was used to test the ability of the cases to avoid or minimize the effects of overcommitments of resources.

Figure 3-10 of the Plan Report presents the detailed Basic Energy forecast for the Upper, Median, and Lower forecast cases. Figure 4.3-1 is a table which presents those three forecasts as well as the Branch Upper and Branch Lower Basic Energy forecasts used in case analyses. Figure 4.3-2 compares these five forecasts. Note that the Branch forecasts are identical to the Median forecast until after 1995 - the year in which the forecasts were assumed to diverge.

The 20-minute January Basic Peak Power forecasts which were used when formulating demand/supply cases under the five load forecast conditions are tabulated in Figure 4.3-3 of this report. This Figure corresponds to Figure 3-12 of the Plan Report. Figure 4.3-4 presents these five forecasts graphically and is analogous to Figure 3-13 of the Plan Report.

The annual average basic energy growth rates in percentage and absolute (TWh per year) terms are presented for all five load forecast paths in Figures 4.3-5 and 4.3-6, respectively. These figures correspond to Plan Report Figures 3-14 and 3-15.

The Basic forecasts presented in Figures 4.3-2 and 4.3.-4 form the starting point in the determination of the need for new demand/supply options, and in the subsequent formulation and analysis of demand/supply cases.

Figure 4.3-1: BASIC LOAD FORECAST BANDWIDTH
ANNUAL ENERGY (TWh)

| Year | Lower | Branch Lower | Median | Branch Upper | Upper |
|---|---|---|---|---|---|
| 1989 | 132 | 137 | 137 | 137 | 142 |
| 1990 | 133 | 140 | 140 | 140 | 147 |
| 1991 | 135 | 145 | 145 | 145 | 154 |
| 1992 | 137 | 151 | 151 | 151 | 162 |
| 1993 | 138 | 155 | 155 | 155 | 169 |
| 1994 | 139 | 159 | 159 | 159 | 176 |
| 1995 | 141 | 163 | 163 | 163 | 180 |
| 1996 | 141 | 163 | 165 | 167 | 185 |
| 1997 | 143 | 165 | 169 | 174 | 192 |
| 1998 | 146 | 167 | 174 | 180 | 198 |
| 1999 | 149 | 170 | 178 | 186 | 205 |
| 2000 | 153 | 172 | 184 | 194 | 212 |
| 2001 | 159 | 178 | 192 | 204 | 221 |
| 2002 | 163 | 181 | 196 | 210 | 227 |
| 2003 | 166 | 184 | 201 | 216 | 231 |
| 2004 | 167 | 185 | 202 | 219 | 234 |
| 2005 | 168 | 186 | 205 | 222 | 236 |
| 2006 | 171 | 188 | 208 | 226 | 240 |
| 2007 | 174 | 191 | 211 | 231 | 242 |
| 2008 | 178 | 193 | 214 | 234 | 245 |
| 2009 | 181 | 196 | 217 | 237 | 247 |
| 2010 | 185 | 199 | 220 | 241 | 250 |
| 2011 | 188 | 201 | 224 | 245 | 252 |
| 2012 | 191 | 204 | 227 | 249 | 255 |
| 2013 | 194 | 207 | 230 | 252 | 257 |
| 2014 | 197 | 209 | 234 | 256 | 260 |

FIGURE 4.3-2
BASIC LOAD FORECAST BANDWIDTH
ANNUAL ENERGY (TWh)

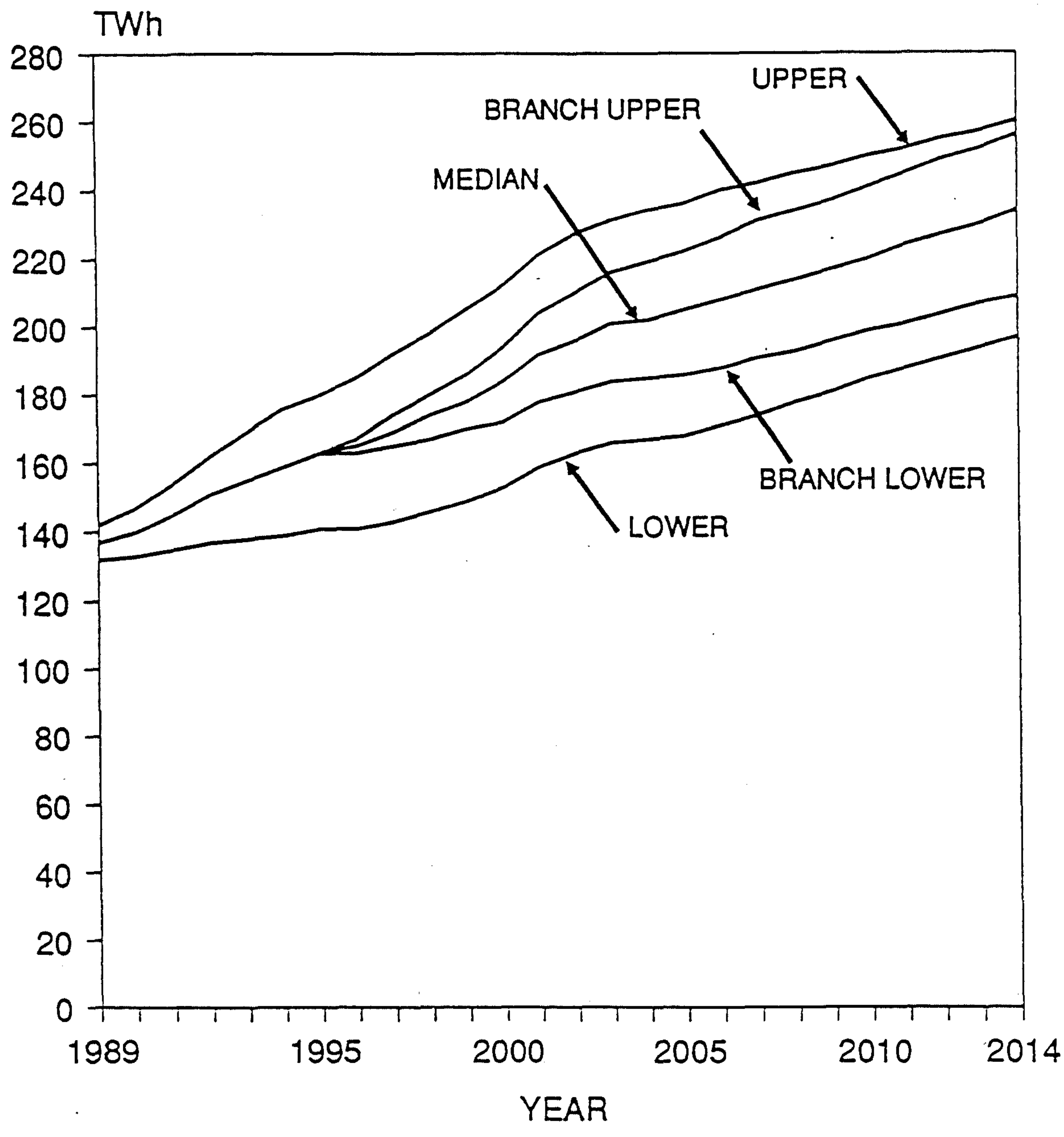


**Figure 4.3-3: BASIC LOAD FORECAST BANDWIDTH
20-MINUTE JANUARY PEAK POWER (GW)**

| Year | Lower | Branch Lower | Median | Branch Upper | Upper |
|---|---|---|---|---|---|
| 1989 | 22.7 | 23.2 | 23.2 | 23.2 | 24.0 |
| 1990 | 22.5 | 23.8 | 23.8 | 23.8 | 24.9 |
| 1991 | 22.8 | 24.5 | 24.5 | 24.5 | 26.0 |
| 1992 | 23.2 | 25.5 | 25.5 | 25.5 | 27.4 |
| 1993 | 23.5 | 26.3 | 26.3 | 26.3 | 28.7 |
| 1994 | 23.7 | 26.9 | 26.9 | 26.9 | 29.8 |
| 1995 | 23.9 | 27.5 | 27.5 | 27.5 | 30.8 |
| 1996 | 24.2 | 28.0 | 28.1 | 28.3 | 31.6 |
| 1997 | 24.2 | 28.1 | 28.7 | 29.3 | 32.6 |
| 1998 | 24.7 | 28.4 | 29.4 | 30.4 | 33.6 |
| 1999 | 25.1 | 28.8 | 30.2 | 31.5 | 34.8 |
| 2000 | 25.7 | 29.3 | 31.1 | 32.7 | 36.0 |
| 2001 | 26.6 | 30.1 | 32.3 | 34.2 | 37.4 |
| 2002 | 27.8 | 30.8 | 33.3 | 35.5 | 38.6 |
| 2003 | 28.2 | 31.4 | 34.1 | 36.5 | 39.5 |
| 2004 | 28.7 | 31.6 | 34.5 | 37.2 | 40.1 |
| 2005 | 28.6 | 31.8 | 34.9 | 37.8 | 40.6 |
| 2006 | 29.0 | 32.1 | 35.4 | 38.5 | 41.1 |
| 2007 | 29.6 | 32.5 | 35.9 | 39.2 | 41.6 |
| 2008 | 30.1 | 32.9 | 36.4 | 39.9 | 42.1 |
| 2009 | 30.7 | 33.4 | 37.0 | 40.4 | 42.5 |
| 2010 | 31.2 | 33.9 | 37.5 | 41.0 | 42.9 |
| 2011 | 31.9 | 34.3 | 38.1 | 41.7 | 43.3 |
| 2012 | 32.4 | 34.8 | 38.6 | 42.3 | 43.8 |
| 2013 | 33.0 | 35.2 | 39.2 | 43.0 | 44.2 |
| 2014 | 33.5 | 35.6 | 39.8 | 43.6 | 44.7 |

FIGURE 4.3-4
BASIC LOAD FORECAST BANDWIDTH
20-MINUTE JANUARY PEAK POWER (GW)

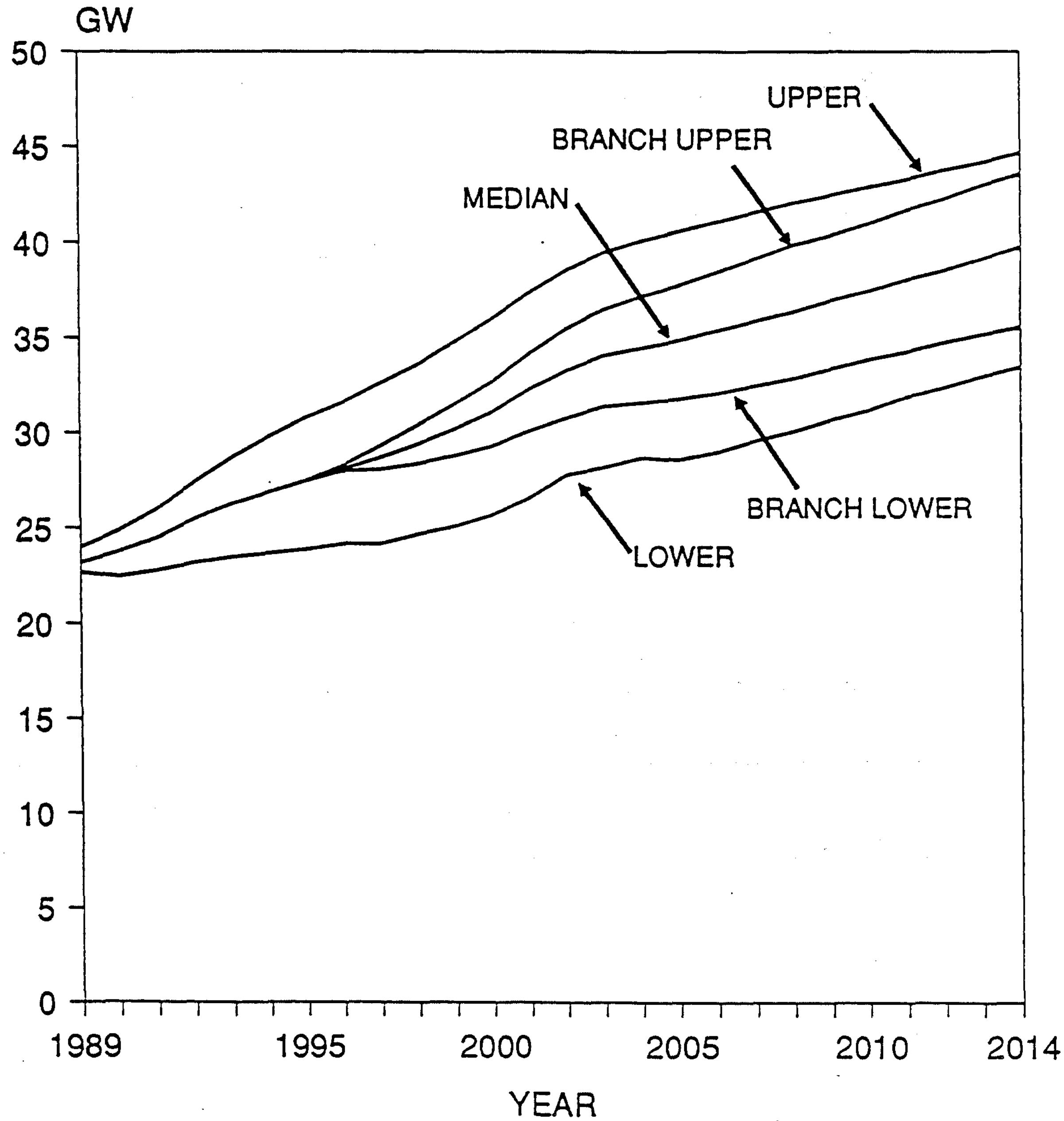


FIGURE 4.3-5
BASIC LOAD FORECAST
AVERAGE ANNUAL GROWTH RATES FOR ENERGY (%)

| PERIOD | LOWER | BRANCH LOWER | MEDIAN | BRANCH UPPER | UPPER |
|---|---|---|---|---|---|
| 1987-1995 | 1.33 | 3.18 | 3.18 | 3.18 | 4.53 |
| 1987-2000 | 1.47 | 2.40 | 2.93 | 3.36 | 4.05 |
| 1987-2010 | 1.66 | 1.98 | 2.44 | 2.84 | 3.00 |
| 1987-2014 | 1.66 | 1.88 | 2.30 | 2.65 | 2.71 |

FIGURE 4.3-6
BASIC LOAD FORECAST
AVERAGE ANNUAL ABSOLUTE GROWTH FOR ENERGY (TWh/YEAR)

| PERIOD | LOWER | BRANCH LOWER | MEDIAN | BRANCH UPPER | UPPER |
|---|---|---|---|---|---|
| 1987-2000 | 2.0 | 3.5 | 4.4 | 5.2 | 6.6 |
| 2000-2014 | 3.2 | 2.6 | 3.6 | 4.4 | 3.4 |
| 1987-2014 | 2.6 | 3.1 | 4.0 | 4.8 | 4.9 |

## 4.4 THE EXISTING SYSTEM

Prior to developing demand/supply cases, the capabilities and characteristics of all existing generating system facilities were determined. Generating units expected to retire within the 25 year planning period were identified and an estimate was made of how the existing system's capabilities were likely to change. The projected load meeting capability of the existing system and the generating unit retirement schedule upon which this was based were assumed to be the same for all five load forecast paths.

Chapter 4 of the Plan Report presents the existing system's projected load and energy meeting capability and describes how this was determined. That chapter also discusses the retirement of existing system resources.

## 4.5 REQUIREMENT FOR DEMAND/SUPPLY OPTIONS

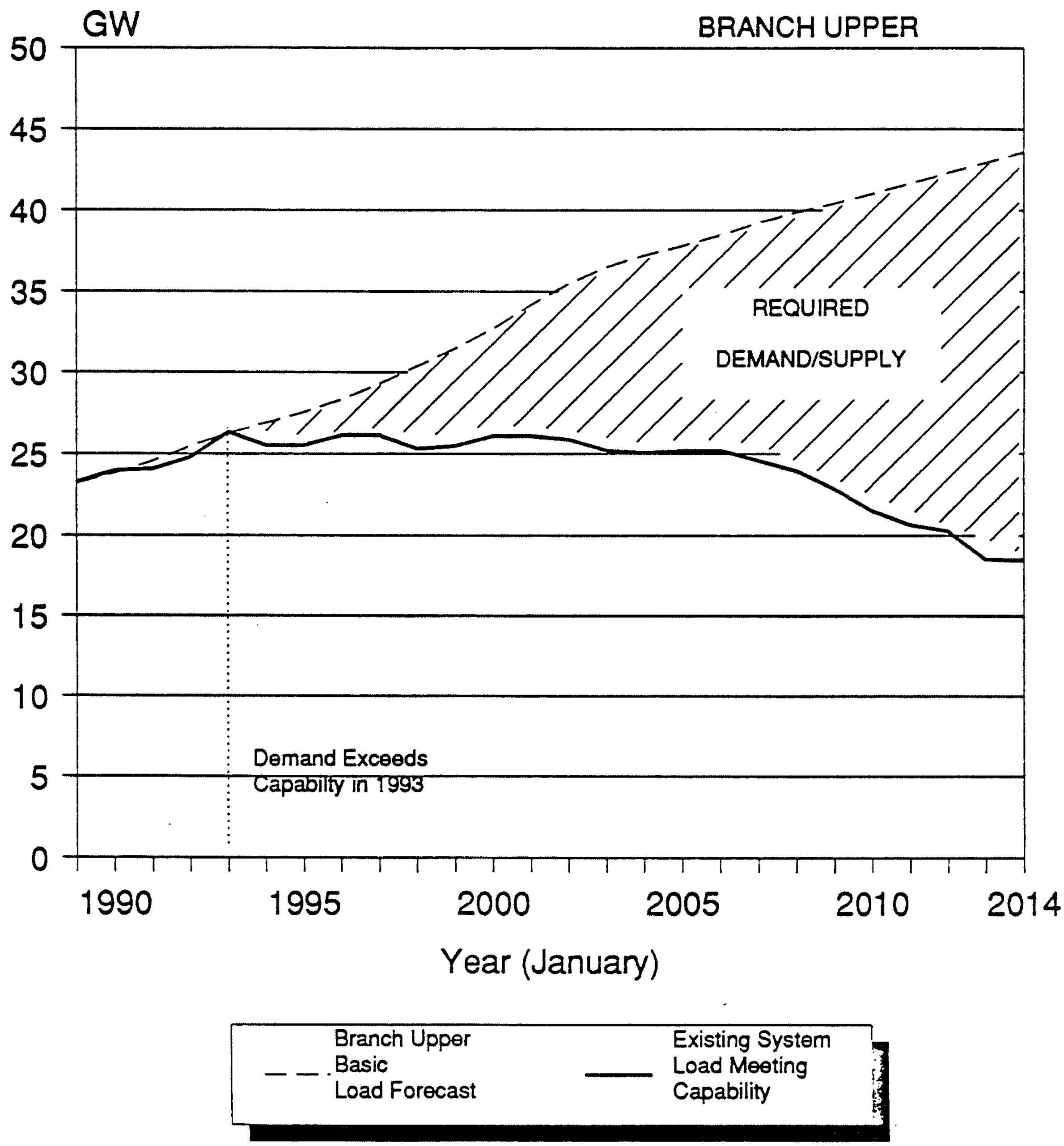
The requirement for new demand/supply options in any given year is the difference between the forecast need for electrical service and the ability of the system to serve those needs reliably. Put another way, it is the difference between the forecast basic demand in a given year and the projected load meeting capability of the existing system. Hydro's Demand/Supply Plans attempt to provide a suitable mix of demand reducing and electricity supply options to meet needs across the five load paths of the bandwidth forecast.

Figures 5-1 through 5-3 of the Plan Report show the Basic load forecast, the load meeting capability of the existing system (with allowance for retirements), and the requirement for new demand/supply options for the Upper, Median, and Lower load paths for the period to 2014. Analogous to these figures are Figure 4.5-1 for the Branch Upper forecast and Figure 4.5-2 for the Branch Lower. The year in which demand exceeds capability is 1993 for both the Branch Upper forecast and the Branch Lower forecast. This is the same year in which demand exceeds capability for the Median load forecast, which is consistent with the fact that the Median, Branch Upper, and Branch Lower forecasts are identical until after 1995.

Figure 4.5-3 presents a graph of required demand/supply in terms of load meeting capability for all five load forecasts. This curve is analogous to Figure 5-5 of the Plan Report. Figure 4.5-4 is a table of required demand/supply load meeting capability for selected years, and is analogous to Figure 5-4 of the Plan Report.

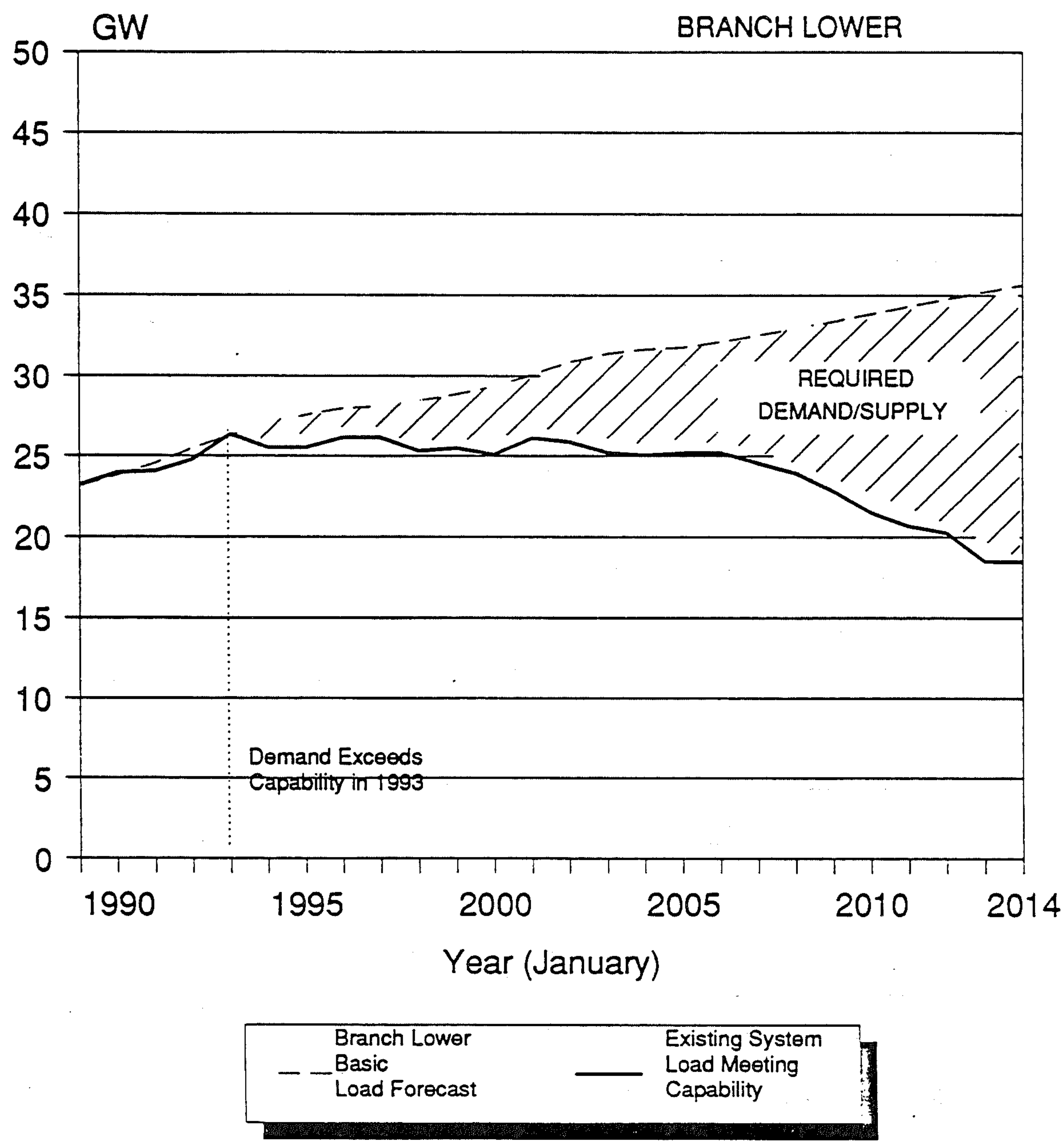
FIGURE 4.5-1

REQUIRED DEMAND/SUPPLY
20-MINUTE PEAK POWER DEMAND



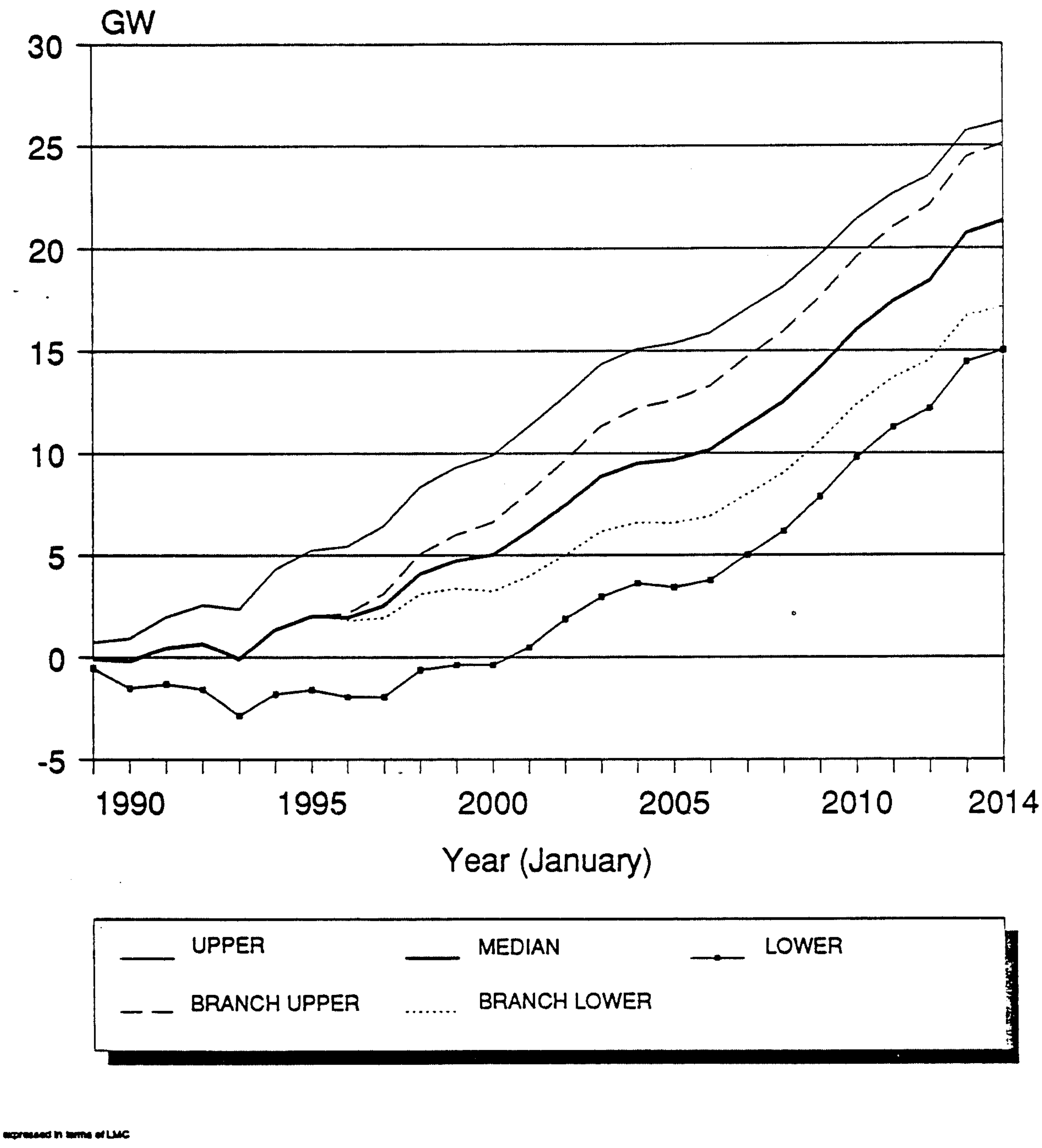

expressed in terms of LMC

# FIGURE 4.5-2
# REQUIRED DEMAND/SUPPLY
# 20-MINUTE PEAK POWER DEMAND




expressed in terms of LMC

FIGURE 4.5-3
REQUIRED DEMAND/SUPPLY
20-MINUTE PEAK POWER DEMAND



## FIGURE 4.5-4

**Requirements* for New Demand/Supply Options (GW)**

| January of Year | Lower Forecast | Branch Lower Forecast | Median Forecast | Branch Upper Forecast | Upper Forecast |
|---|---|---|---|---|---|
| 1990 | 0 | 0 | 0 | 0 | 0.9 |
| 1995 | 0 | 2.0 | 2.0 | 2.0 | 5.2 |
| 2000 | 0 | 3.2 | 5.0 | 6.6 | 9.9 |
| 2005 | 3.4 | 6.6 | 9.7 | 12.6 | 15.4 |
| 2010 | 9.8 | 12.4 | 16.0 | 19.6 | 21.4 |
| 2014 | 15.0 | 17.2 | 21.3 | 25.1 | 26.2 |

* Load-meeting capability.

Figures 4.5-5 and 4.5-6 present the Branch Upper and Branch Lower energy forecasts respectively, along with the reference energy meeting capability of the existing system (with retirements as appropriate). Similar curves for the Upper, Median, and Lower forecasts are shown in the Plan Report, Figures 5-6 through 5-8. As in the Median forecast, the required demand/supply in both branch forecasts exceeds the reference energy meeting capability of the existing system in 1993.

Figure 4.5-7 shows the need for new demand/supply options, in terms of energy demand, for all five load forecasts, and is analogous to Figure 5-10 of the Plan Report. Figure 4.5-8 shows the requirement for future energy reductions and/or new supply for a number of selected years, and is analogous to Figure 5-9 of the Plan Report.

## 4.6 COSTING CONCEPTS AND AVOIDED COSTS

This subject matter is covered in detail in Chapter 6 of the Plan Report and in Chapter 8 of this Analysis Report, and will not be discussed further here.

## 4.7 DEMAND MANAGEMENT PLAN

The Demand Management Plan contains initiatives for load reduction through electrical efficiency improvements, load shifting through time-of-use rates and direct load control, and peak clipping through capacity interruptible load contracts. To permit timely plan formulation, the relative contributions of each of these facets of demand management were estimated late in 1988. At that time, it was recognized that the degree of attainable demand management would be a function of load growth. The potential contribution of demand management to reductions in load would likely be greater in situations where basic load growth was relatively high.

The forecasts of attainable energy efficiency improvements and load shifting which were developed late in 1988 were carried through to the final round of demand/supply case formulation and analysis. The forecast of capacity interruptible load used when formulating and analyzing demand/supply cases was revised most recently in August of 1989. Figures 4.7-1 through 4.7-5 depict the levels of Demand Management assumed to be attainable for each of the five load forecasts when the final round of case formulation and analysis was undertaken. Figure 4.7-6 presents the same data on a year-by-year basis and is similar to Figure 7-22 in the Plan Report.

# FIGURE 4.5-5
# REQUIRED DEMAND/SUPPLY
# ANNUAL ENERGY DEMAND

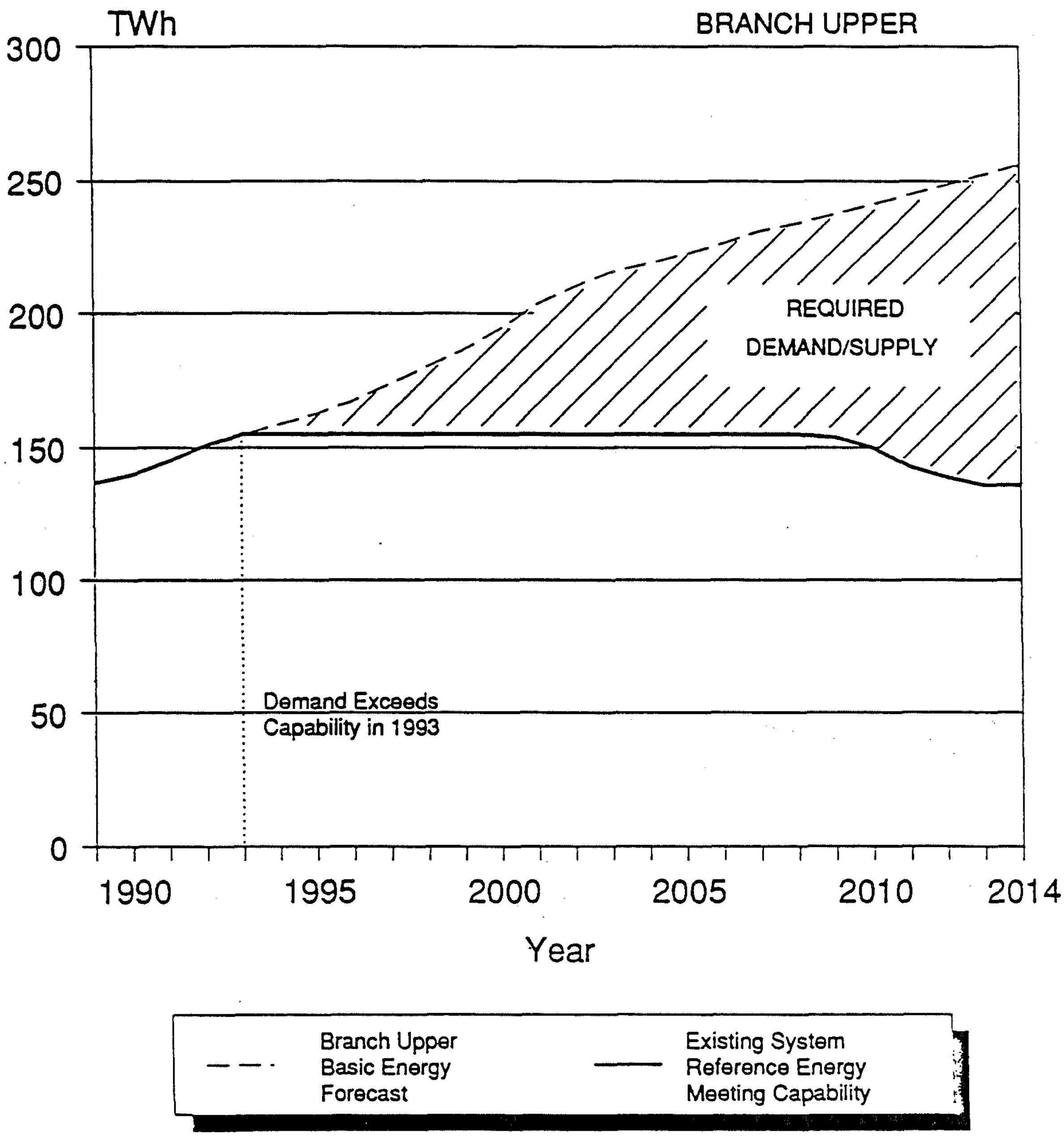


FIGURE 4.5-6
# REQUIRED DEMAND/SUPPLY
# ANNUAL ENERGY DEMAND

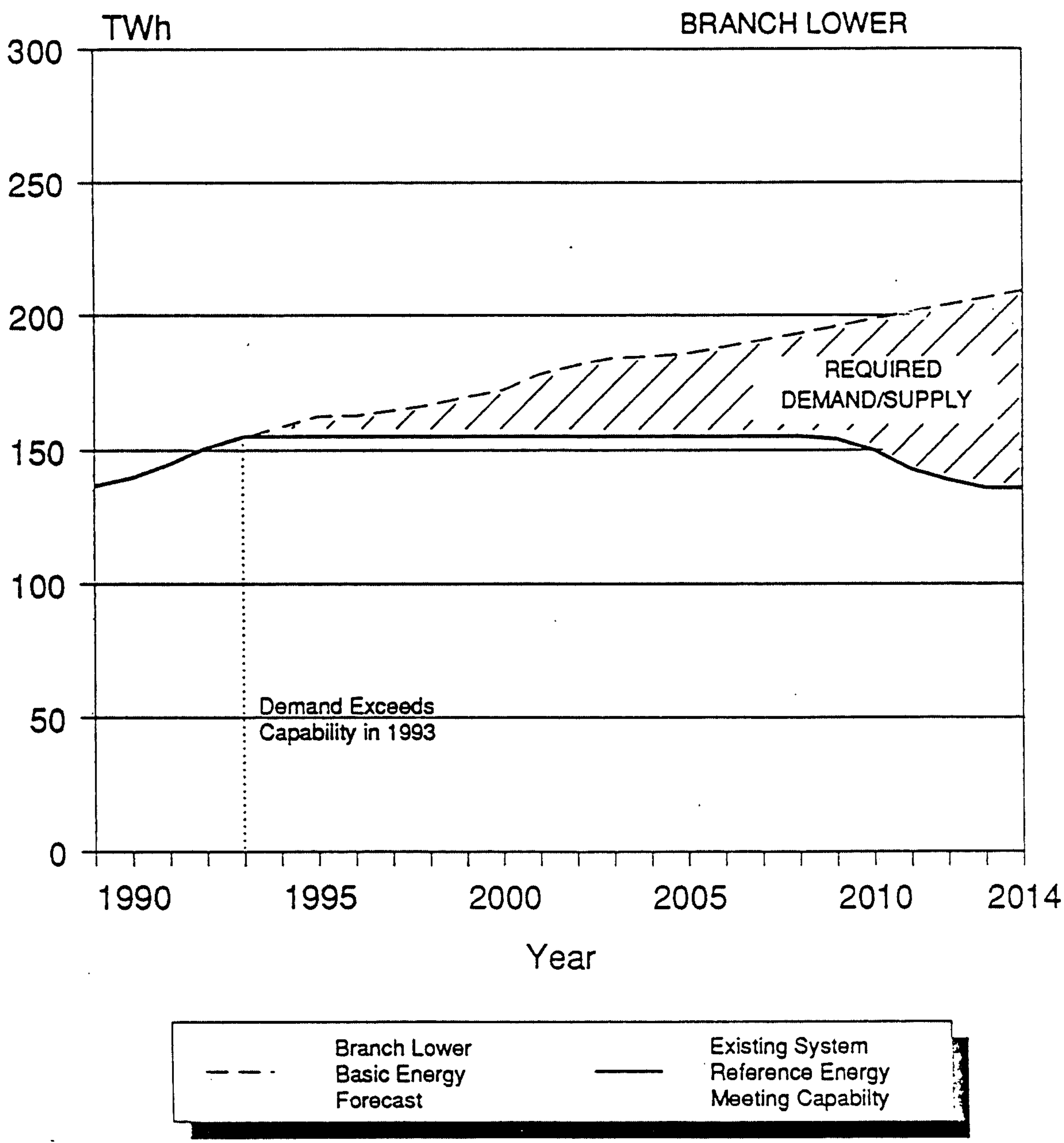


FIGURE 4.5-7

# REQUIRED DEMAND/SUPPLY ANNUAL ENERGY DEMAND

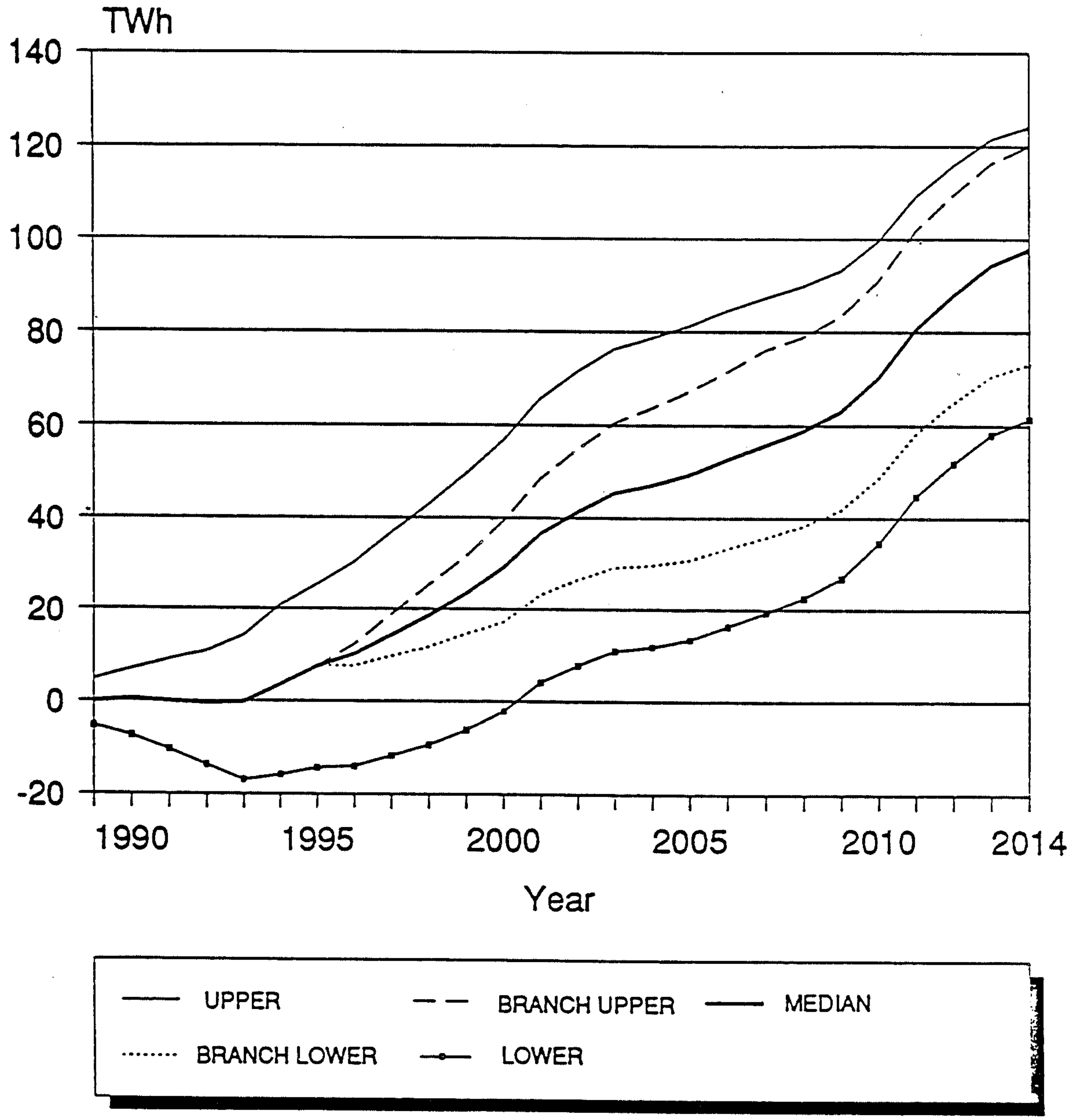


FIGURE 4.5-8

**Future Energy Requirements (TWh)**

| January of Year | Lower Forecast | Branch Lower Forecast | Median Forecast | Branch Upper Forecast | Upper Forecast |
|---|---|---|---|---|---|
| 1990 | 0 | 0 | 0 | 0 | 7 |
| 1995 | 0 | 8 | 8 | 8 | 25 |
| 2000 | 0 | 17 | 29 | 39 | 57 |
| 2005 | 13 | 31 | 50 | 67 | 81 |
| 2010 | 35 | 49 | 70 | 91 | 100 |
| 2014 | 61 | 73 | 98 | 120 | 124 |

FIGURE 4.7-1
DEMAND MANAGEMENT DATA
USED FOR ANALYSIS
LOWER LOAD FORECAST

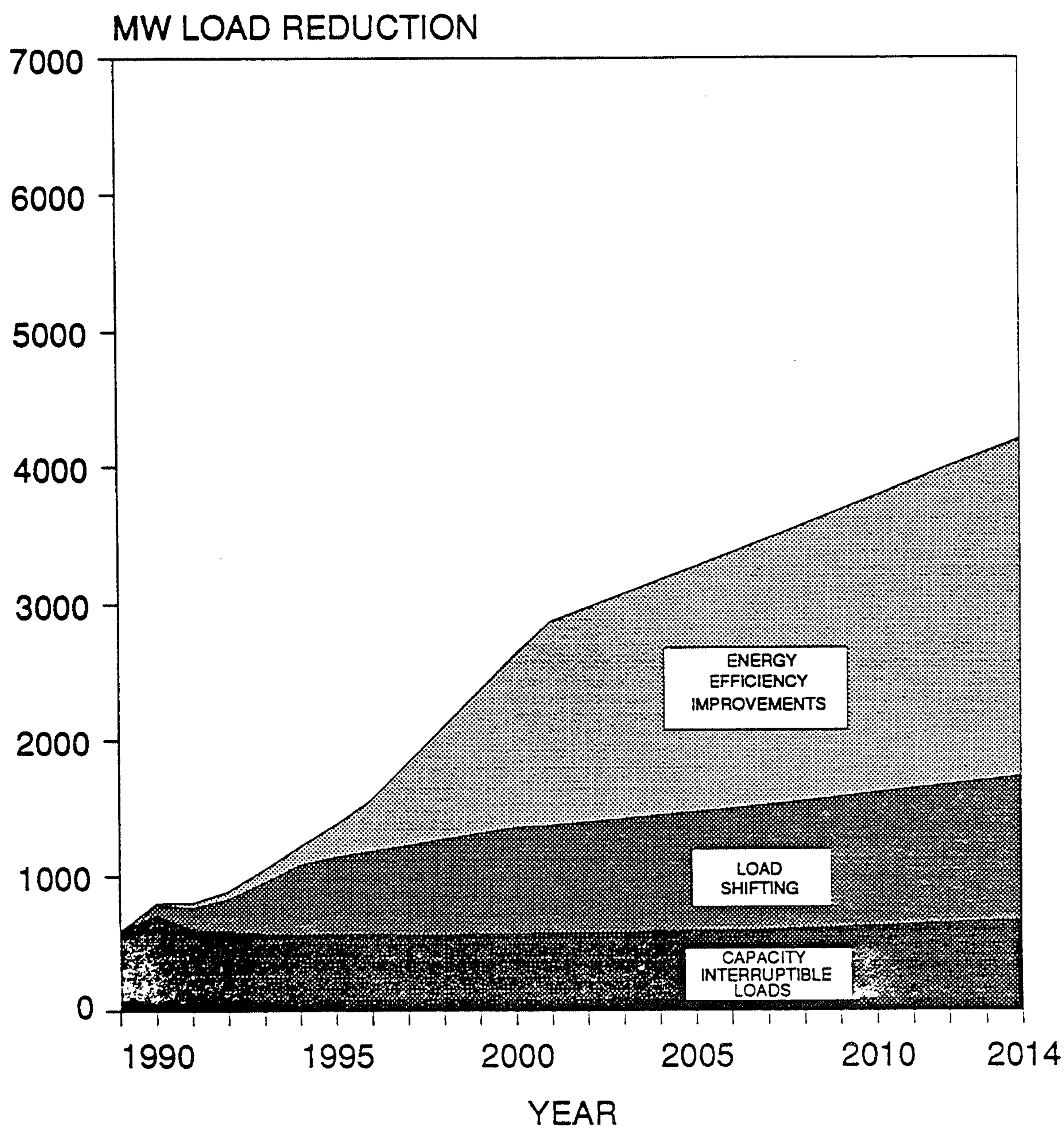
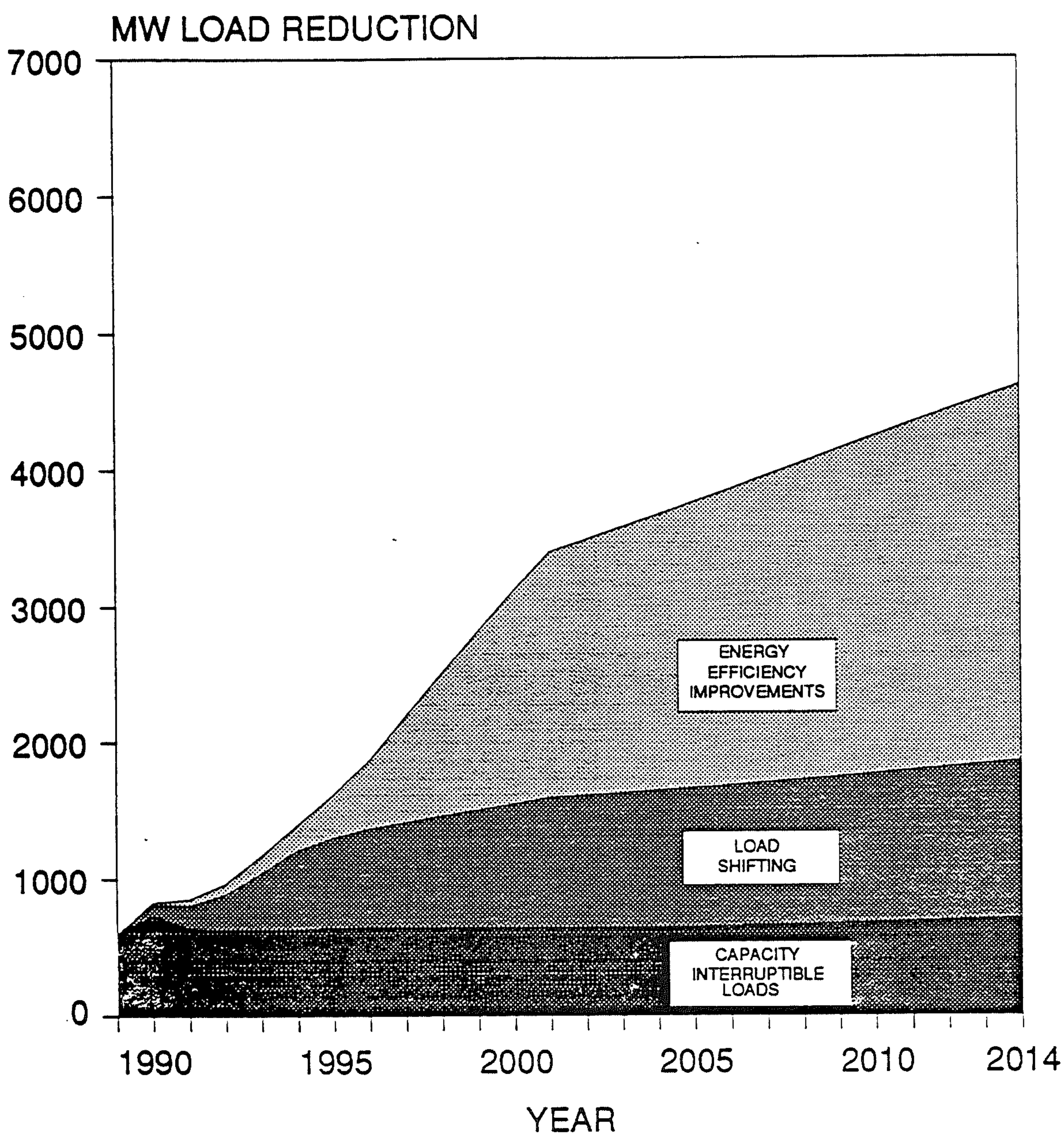


FIGURE 4.7-2
DEMAND MANAGEMENT DATA
USED FOR ANALYSIS
BRANCH LOWER LOAD FORECAST



# FIGURE 4.7-3
# DEMAND MANAGEMENT DATA USED FOR ANALYSIS MEDIAN LOAD FORECAST

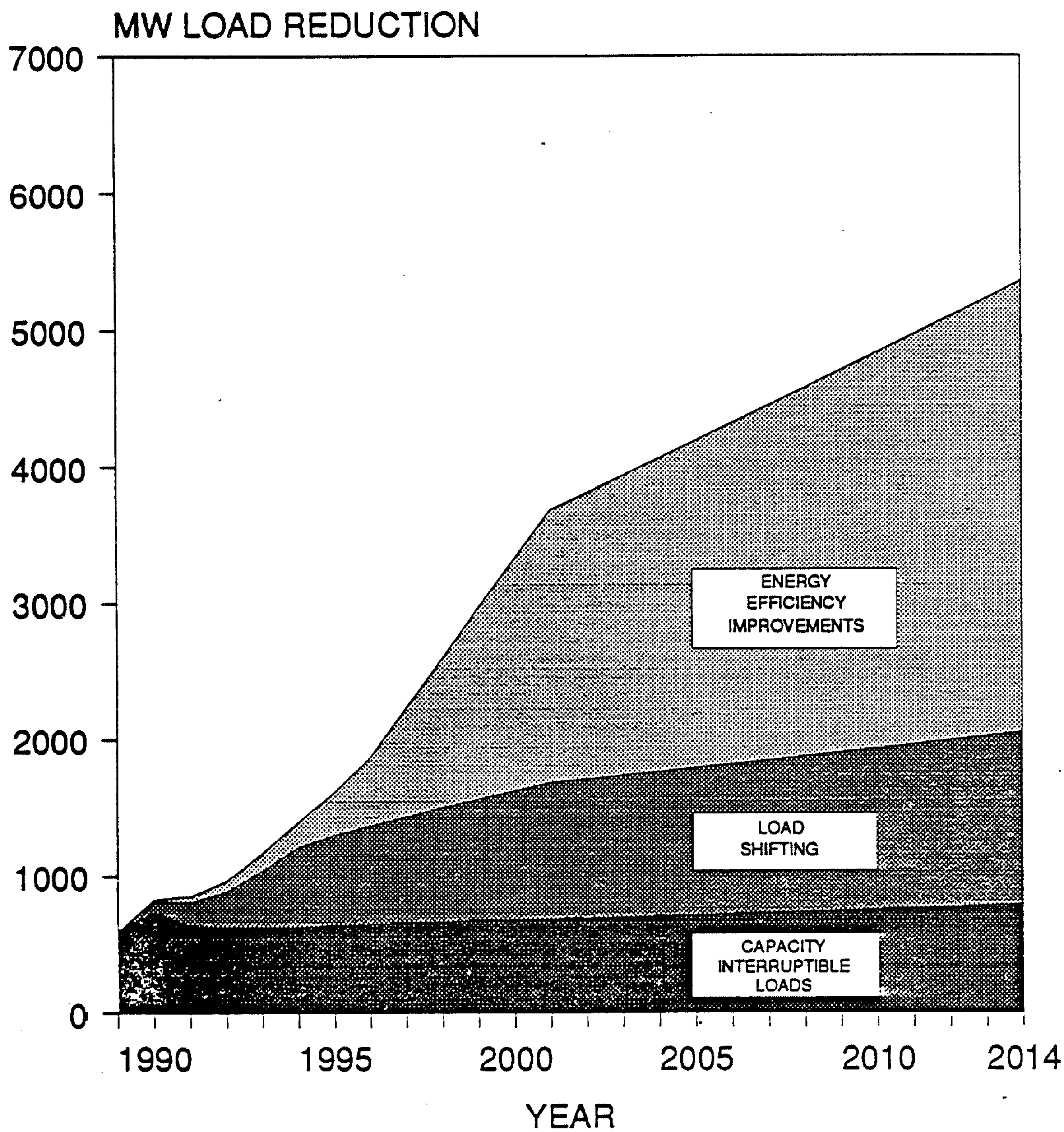
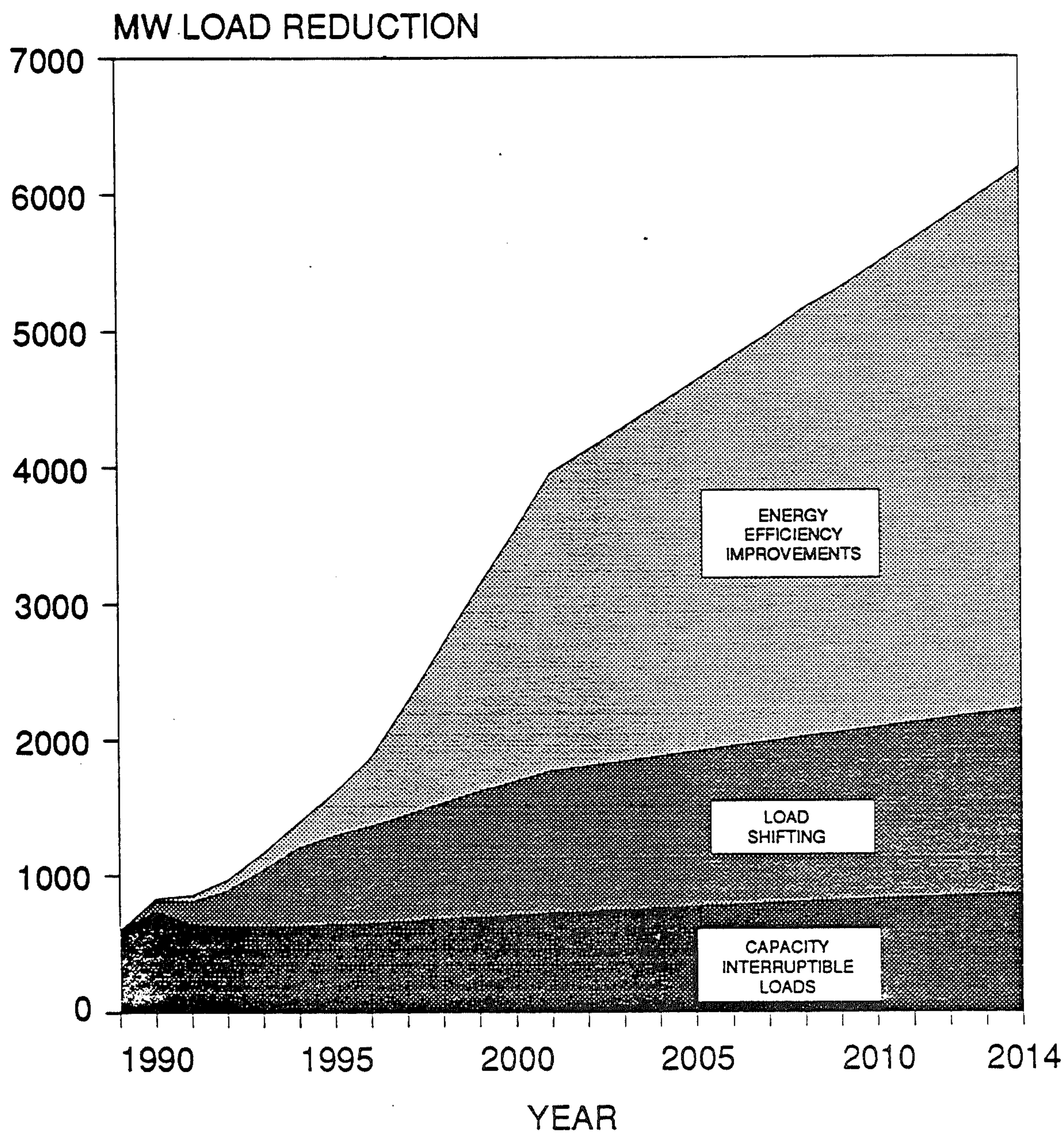


FIGURE 4.7-4
DEMAND MANAGEMENT DATA
USED FOR ANALYSIS
BRANCH UPPER LOAD FORECAST



# FIGURE 4.7-5
# DEMAND MANAGEMENT DATA USED FOR ANALYSIS UPPER LOAD FORECAST

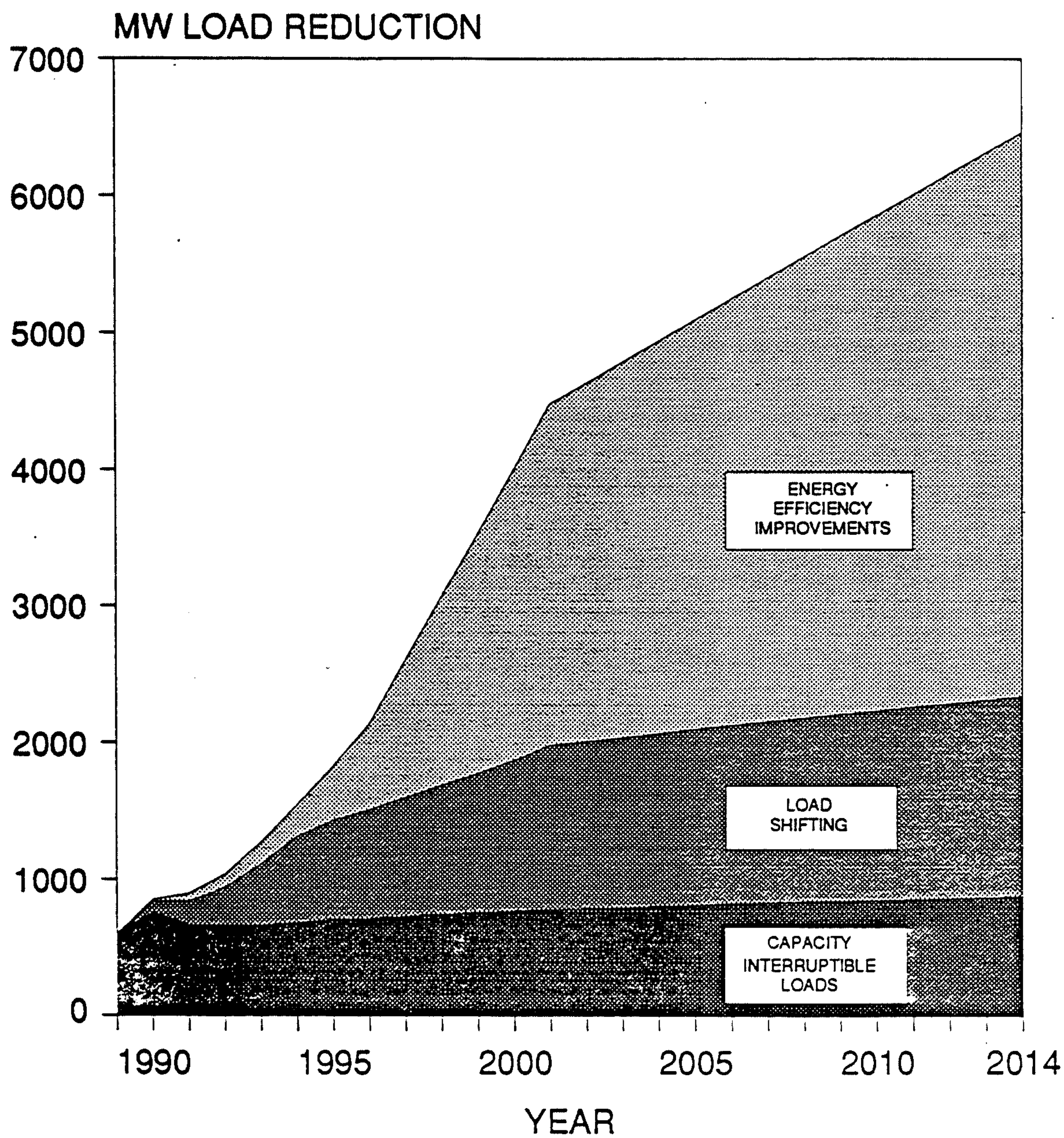


FIGURE 4.7-6

## DEMAND MANAGEMENT DATA USED IN PLAN FORMULATION

(CUMULATIVE VALUES AS OF JANUARY OF THE YEAR)

| | LOWER LOAD FORECAST | | | | BRANCH LOWER LOAD FORECAST | | | | MEDIAN LOAD FORECAST | | | | BRANCH UPPER LOAD FORECAST | | | | UPPER LOAD FORECAST | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| YEAR | EEI (MW) | LS (MW) | CIL (MW) | TOTAL (MW) | EEI (MW) | LS (MW) | CIL (MW) | TOTAL (MW) | EEI (MW) | LS (MW) | CIL (MW) | TOTAL (MW) | EEI (MW) | LS (MW) | CIL (MW) | TOTAL (MW) | EEI (MW) | LS (MW) | CIL (MW) | TOTAL (MW) |
| 1989 | 0 | 0 | 594 | 594 | 0 | 0 | 594 | 594 | 0 | 0 | 594 | 594 | 0 | 0 | 594 | 594 | 0 | 0 | 594 | 594 |
| 1990 | 14 | 77 | 709 | 800 | 14 | 80 | 735 | 829 | 14 | 80 | 735 | 829 | 14 | 80 | 735 | 829 | 14 | 83 | 758 | 855 |
| 1991 | 34 | 159 | 606 | 799 | 45 | 169 | 639 | 853 | 45 | 169 | 639 | 853 | 45 | 169 | 639 | 853 | 56 | 177 | 665 | 898 |
| 1992 | 59 | 244 | 585 | 888 | 78 | 263 | 626 | 967 | 78 | 263 | 626 | 967 | 78 | 263 | 626 | 967 | 98 | 279 | 662 | 1039 |
| 1993 | 95 | 384 | 570 | 1049 | 126 | 421 | 621 | 1168 | 126 | 421 | 621 | 1168 | 126 | 421 | 621 | 1168 | 158 | 452 | 664 | 1274 |
| 1994 | 137 | 517 | 566 | 1220 | 183 | 580 | 630 | 1393 | 183 | 580 | 630 | 1393 | 183 | 580 | 630 | 1393 | 229 | 634 | 684 | 1547 |
| 1995 | 236 | 575 | 570 | 1381 | 314 | 655 | 643 | 1612 | 314 | 655 | 643 | 1612 | 314 | 655 | 643 | 1612 | 393 | 726 | 708 | 1827 |
| 1996 | 375 | 619 | 568 | 1562 | 500 | 715 | 650 | 1865 | 500 | 715 | 650 | 1865 | 500 | 715 | 650 | 1865 | 625 | 793 | 716 | 2134 |
| 1997 | 600 | 662 | 566 | 1828 | 779 | 763 | 647 | 2189 | 800 | 775 | 656 | 2231 | 822 | 785 | 664 | 2271 | 1000 | 869 | 730 | 2599 |
| 1998 | 825 | 707 | 566 | 2098 | 1051 | 812 | 646 | 2509 | 1100 | 835 | 664 | 2599 | 1154 | 857 | 680 | 2691 | 1375 | 945 | 745 | 3065 |
| 1999 | 1050 | 748 | 568 | 2366 | 1315 | 857 | 646 | 2818 | 1400 | 892 | 671 | 2963 | 1495 | 926 | 695 | 3116 | 1750 | 1017 | 760 | 3527 |
| 2000 | 1275 | 789 | 569 | 2633 | 1574 | 899 | 645 | 3118 | 1700 | 946 | 677 | 3323 | 1831 | 989 | 706 | 3526 | 2125 | 1100 | 770 | 3995 |
| 2001 | 1500 | 800 | 574 | 2874 | 1809 | 950 | 641 | 3400 | 2000 | 1000 | 685 | 3685 | 2185 | 1050 | 721 | 3956 | 2500 | 1200 | 780 | 4480 |
| 2002 | 1575 | 820 | 578 | 2973 | 1882 | 965 | 642 | 3489 | 2100 | 1020 | 690 | 3810 | 2315 | 1074 | 732 | 4121 | 2625 | 1220 | 787 | 4632 |
| 2003 | 1650 | 840 | 582 | 3072 | 1956 | 980 | 644 | 3580 | 2200 | 1040 | 697 | 3937 | 2447 | 1098 | 744 | 4289 | 2750 | 1240 | 797 | 4787 |
| 2004 | 1725 | 860 | 586 | 3171 | 2028 | 995 | 646 | 3669 | 2300 | 1060 | 704 | 4064 | 2580 | 1122 | 756 | 4458 | 2875 | 1260 | 806 | 4941 |
| 2005 | 1800 | 880 | 589 | 3269 | 2102 | 1010 | 649 | 3761 | 2400 | 1080 | 712 | 4192 | 2714 | 1146 | 769 | 4629 | 3000 | 1280 | 817 | 5097 |
| 2006 | 1875 | 900 | 594 | 3369 | 2177 | 1025 | 652 | 3854 | 2500 | 1100 | 719 | 4319 | 2850 | 1170 | 782 | 4802 | 3125 | 1300 | 826 | 5251 |
| 2007 | 1950 | 920 | 600 | 3470 | 2253 | 1040 | 658 | 3951 | 2600 | 1120 | 727 | 4447 | 2980 | 1194 | 792 | 4966 | 3250 | 1320 | 834 | 5404 |
| 2008 | 2025 | 940 | 608 | 3573 | 2328 | 1055 | 664 | 4047 | 2700 | 1140 | 735 | 4575 | 3134 | 1218 | 806 | 5158 | 3375 | 1340 | 841 | 5556 |
| 2009 | 2100 | 960 | 617 | 3677 | 2403 | 1070 | 670 | 4143 | 2800 | 1160 | 744 | 4704 | 3252 | 1242 | 813 | 5307 | 3500 | 1360 | 847 | 5707 |
| 2010 | 2175 | 980 | 627 | 3782 | 2476 | 1085 | 677 | 4238 | 2900 | 1180 | 752 | 4832 | 3390 | 1266 | 823 | 5479 | 3625 | 1380 | 852 | 5857 |
| 2011 | 2250 | 1000 | 638 | 3888 | 2548 | 1100 | 686 | 4334 | 3000 | 1200 | 761 | 4961 | 3532 | 1290 | 833 | 5655 | 3750 | 1400 | 858 | 6008 |
| 2012 | 2325 | 1020 | 647 | 3992 | 2619 | 1115 | 693 | 4427 | 3100 | 1220 | 771 | 5091 | 3674 | 1314 | 843 | 5831 | 3875 | 1420 | 864 | 6159 |
| 2013 | 2400 | 1040 | 656 | 4096 | 2688 | 1130 | 700 | 4518 | 3200 | 1240 | 780 | 5220 | 3819 | 1338 | 854 | 6011 | 4000 | 1440 | 871 | 6311 |
| 2014 | 2475 | 1060 | 666 | 4201 | 2755 | 1145 | 707 | 4607 | 3300 | 1260 | 790 | 5350 | 3965 | 1362 | 864 | 6191 | 4125 | 1460 | 877 | 6462 |

The Demand Management forecasts presented in Figure 4.7-6 (in terms of peak power reduction) for Upper, Median, and Lower load paths are slightly lower than those reported in the Plan Report. This is because the Demand Management program is reviewed constantly and, if appropriate, modified to reflect changing expectations about attainable load reduction targets. The Demand Management Plan appearing in the Plan Report is the latest available Demand Management forecast (as of the Plan issue date). As stated in the Plan Report, these targets are not regarded by Ontario Hydro as ceilings:- if it is possible to exceed them, Hydro will do so.

Figure 4.7-7 compares the Demand Management Plan for the Median load forecast case as specified in the Plan Report with demand management projections used during the demand/supply case formulation process. Figures 4.7-8 and 4.7-9 provide a similar comparison for data pertaining to the Upper and Lower load forecast paths.

The Energy Efficiency Improvement forecasts used for demand/supply case formulation under Median and Upper load forecasts conditions differ from those reported in the Plan Report by less than 3 MW in any year, taken on a cumulative basis. For all practical purposes, these forecasts are in total agreement. Under Lower load forecast conditions, the EEI forecast used for demand/supply case formulation was less than that reported in the Plan Report by amounts growing to about 100 MW by 2001. Note, however, that by the time major supply options were determined to be needed in the Proposed Plan Lower forecast case (2009), the disagreement between the case formulation and the Plan Report EEI forecasts was nil. Therefore, the "need date" for new major supply options in the Proposed Demand/Supply Plan would not have changed even if demand/supply case formulation had proceeded based on the more recent EEI forecast.

In fact, case formulation was based on a forecast of EEI after 2009 which was slightly **more** optimistic than the forecast presented in the Plan Report. Theoretically, incorporation of the new, Plan Report EEI forecast into the Lower load forecast cases might result in post-2009 capacity additions being slightly advanced compared to the Proposed Plan. In practice, though, this would not occur. By the end of the study period, the difference between the forecasts is at most 63 MW, or only about 2.5 percent of the currently planned EEI contribution.

Differences between the forecast of load shifting presented in the Plan Report and the forecast used for demand/supply case formulation are no more than about 3 MW. Note that Figure 7-22 of the Plan Report contains a typographical error. The load reduction expected from load shifting in 1994 for the Upper load forecast case should have read 634 MW, not 735 MW.

The most notable differences between the Upper, Median, and Lower demand management forecasts which were used for demand/supply case formulation and

FIGURE 4.7-7

COMPARISON OF DEMAND MANAGEMENT DATA USED IN
PLAN ANALYSIS AND SHOWN IN THE PLAN REPORT
(VALUES AS OF JANUARY OF THE YEAR)

MEDIAN LOAD FORECAST

| | EEI | | | LS | | | CIL | | | TOTAL | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| YEAR | PLAN REPORT | ANALYSIS | DIFFER-ENCE | PLAN REPORT | ANALYSIS | DIFFER-ENCE | PLAN REPORT | ANALYSIS | DIFFER-ENCE | PLAN REPORT | ANALYSIS | DIFFER-ENCE |
| 1990 | 14 | 14 | 0 | 81 | 80 | -1 | 735 | 735 | 0 | 830 | 829 | -1 |
| 1991 | 45 | 45 | 0 | 171 | 169 | -2 | 632 | 639 | 7 | 848 | 853 | 5 |
| 1992 | 78 | 78 | 0 | 266 | 263 | -3 | 625 | 626 | 1 | 969 | 967 | -2 |
| 1993 | 126 | 126 | 0 | 423 | 421 | -2 | 621 | 621 | 0 | 1170 | 1168 | -2 |
| 1994 | 183 | 183 | 0 | 582 | 580 | -2 | 623 | 630 | 7 | 1388 | 1393 | 5 |
| 1995 | 314 | 314 | 0 | 656 | 655 | -1 | 632 | 643 | 11 | 1602 | 1612 | 10 |
| 1996 | 500 | 500 | 0 | 717 | 715 | -2 | 641 | 650 | 9 | 1858 | 1865 | 7 |
| 1997 | 800 | 800 | 0 | 776 | 775 | -1 | 652 | 656 | 4 | 2228 | 2231 | 3 |
| 1998 | 1100 | 1100 | 0 | 836 | 835 | -1 | 664 | 664 | 0 | 2600 | 2599 | -1 |
| 1999 | 1400 | 1400 | 0 | 893 | 892 | -1 | 676 | 671 | -5 | 2969 | 2963 | -6 |
| 2000 | 1700 | 1700 | 0 | 946 | 946 | 0 | 688 | 677 | -11 | 3334 | 3323 | -11 |
| 2001 | 2000 | 2000 | 0 | 1000 | 1000 | 0 | 702 | 685 | -17 | 3702 | 3685 | -17 |
| 2002 | 2100 | 2100 | 0 | 1020 | 1020 | 0 | 712 | 690 | -22 | 3832 | 3810 | -22 |
| 2003 | 2200 | 2200 | 0 | 1040 | 1040 | 0 | 724 | 697 | -27 | 3964 | 3937 | -27 |
| 2004 | 2300 | 2300 | 0 | 1060 | 1060 | 0 | 737 | 704 | -33 | 4097 | 4064 | -33 |
| 2005 | 2400 | 2400 | 0 | 1080 | 1080 | 0 | 749 | 712 | -37 | 4229 | 4192 | -37 |
| 2006 | 2500 | 2500 | 0 | 1100 | 1100 | 0 | 762 | 719 | -43 | 4362 | 4319 | -43 |
| 2007 | 2600 | 2600 | 0 | 1120 | 1120 | 0 | 775 | 727 | -48 | 4495 | 4447 | -48 |
| 2008 | 2700 | 2700 | 0 | 1140 | 1140 | 0 | 788 | 735 | -53 | 4628 | 4575 | -53 |
| 2009 | 2800 | 2800 | 0 | 1160 | 1160 | 0 | 802 | 744 | -58 | 4762 | 4704 | -58 |
| 2010 | 2899 | 2900 | 1 | 1180 | 1180 | 0 | 816 | 752 | -64 | 4895 | 4832 | -63 |
| 2011 | 3000 | 3000 | 0 | 1200 | 1200 | 0 | 830 | 761 | -69 | 5030 | 4961 | -69 |
| 2012 | 3101 | 3100 | -1 | 1220 | 1220 | 0 | 844 | 771 | -73 | 5165 | 5091 | -74 |
| 2013 | 3200 | 3200 | 0 | 1240 | 1240 | 0 | 859 | 780 | -79 | 5299 | 5220 | -79 |
| 2014 | 3298 | 3300 | 2 | 1260 | 1260 | 0 | 874 | 790 | -84 | 5432 | 5350 | -82 |

FIGURE 4.7-8

COMPARISON OF DEMAND MANAGEMENT DATA USED IN
PLAN ANALYSIS AND SHOWN IN THE PLAN REPORT
(VALUES AS OF JANUARY OF THE YEAR)

UPPER LOAD FORECAST

| | EEI | | | LS | | | CIL | | | TOTAL | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| YEAR | PLAN REPORT | ANALYSIS | DIFFER-ENCE | PLAN REPORT | ANALYSIS | DIFFER-ENCE | PLAN REPORT | ANALYSIS | DIFFER-ENCE | PLAN REPORT | ANALYSIS | DIFFER-ENCE |
| 1990 | 14 | 14 | 0 | 84 | 83 | -1 | 758 | 758 | 0 | 856 | 855 | -1 |
| 1991 | 56 | 56 | 0 | 180 | 177 | -3 | 658 | 665 | 7 | 894 | 898 | 4 |
| 1992 | 98 | 98 | 0 | 282 | 279 | -3 | 660 | 662 | 2 | 1040 | 1039 | -1 |
| 1993 | 158 | 158 | 0 | 455 | 452 | -3 | 660 | 664 | 4 | 1273 | 1274 | 1 |
| 1994 | 229 | 229 | 0 | 634 | 634 | 0 | 672 | 684 | 12 | 1535 | 1547 | 12 |
| 1995 | 393 | 393 | 0 | 728 | 726 | -2 | 696 | 708 | 12 | 1817 | 1827 | 10 |
| 1996 | 625 | 625 | 0 | 795 | 793 | -2 | 705 | 716 | 11 | 2125 | 2134 | 9 |
| 1997 | 1000 | 1000 | 0 | 870 | 869 | -1 | 724 | 730 | 6 | 2594 | 2599 | 5 |
| 1998 | 1375 | 1375 | 0 | 946 | 945 | -1 | 744 | 745 | 1 | 3065 | 3065 | 0 |
| 1999 | 1749 | 1750 | 1 | 1017 | 1017 | 0 | 765 | 760 | -5 | 3531 | 3527 | -4 |
| 2000 | 2125 | 2125 | 0 | 1100 | 1100 | 0 | 782 | 770 | -12 | 4007 | 3995 | -12 |
| 2001 | 2500 | 2500 | 0 | 1200 | 1200 | 0 | 798 | 780 | -18 | 4498 | 4480 | -18 |
| 2002 | 2624 | 2625 | 1 | 1220 | 1220 | 0 | 811 | 787 | -24 | 4655 | 4632 | -23 |
| 2003 | 2750 | 2750 | 0 | 1240 | 1240 | 0 | 826 | 797 | -29 | 4816 | 4787 | -29 |
| 2004 | 2875 | 2875 | 0 | 1260 | 1260 | 0 | 841 | 806 | -35 | 4976 | 4941 | -35 |
| 2005 | 3000 | 3000 | 0 | 1280 | 1280 | 0 | 857 | 817 | -40 | 5137 | 5097 | -40 |
| 2006 | 3125 | 3125 | 0 | 1300 | 1300 | 0 | 871 | 826 | -45 | 5296 | 5251 | -45 |
| 2007 | 3250 | 3250 | 0 | 1320 | 1320 | 0 | 884 | 834 | -50 | 5454 | 5404 | -50 |
| 2008 | 3375 | 3375 | 0 | 1340 | 1340 | 0 | 896 | 841 | -55 | 5611 | 5556 | -55 |
| 2009 | 3500 | 3500 | 0 | 1360 | 1360 | 0 | 907 | 847 | -60 | 5767 | 5707 | -60 |
| 2010 | 3625 | 3625 | 0 | 1380 | 1380 | 0 | 917 | 852 | -65 | 5922 | 5857 | -65 |
| 2011 | 3750 | 3750 | 0 | 1400 | 1400 | 0 | 928 | 858 | -70 | 6078 | 6008 | -70 |
| 2012 | 3875 | 3875 | 0 | 1420 | 1420 | 0 | 940 | 864 | -76 | 6235 | 6159 | -76 |
| 2013 | 4000 | 4000 | 0 | 1440 | 1440 | 0 | 951 | 871 | -80 | 6391 | 6311 | -80 |
| 2014 | 4123 | 4125 | 2 | 1460 | 1460 | 0 | 963 | 877 | -86 | 6546 | 6462 | -84 |

FIGURE 4.7-9
COMPARISON OF DEMAND MANAGEMENT DATA USED IN
PLAN ANALYSIS AND SHOWN IN THE PLAN REPORT
(VALUES AS OF JANUARY OF THE YEAR)

LOWER LOAD FORECAST

| | EEI | | | LS | | | CIL | | | TOTAL | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| YEAR | PLAN REPORT | ANALYSIS | DIFFER-ENCE | PLAN REPORT | ANALYSIS | DIFFER-ENCE | PLAN REPORT | ANALYSIS | DIFFER-ENCE | PLAN REPORT | ANALYSIS | DIFFER-ENCE |
| 1990 | 14 | 14 | 0 | 78 | 77 | -1 | 709 | 709 | 0 | 801 | 800 | -1 |
| 1991 | 36 | 34 | -2 | 161 | 159 | -2 | 599 | 606 | 7 | 796 | 799 | 3 |
| 1992 | 62 | 59 | -3 | 246 | 244 | -2 | 583 | 585 | 2 | 891 | 888 | -3 |
| 1993 | 101 | 95 | -6 | 387 | 384 | -3 | 566 | 570 | 4 | 1054 | 1049 | -5 |
| 1994 | 146 | 137 | -9 | 519 | 517 | -2 | 554 | 566 | 12 | 1219 | 1220 | 1 |
| 1995 | 251 | 236 | -15 | 576 | 575 | -1 | 558 | 570 | 12 | 1385 | 1381 | -4 |
| 1996 | 400 | 375 | -25 | 620 | 619 | -1 | 561 | 568 | 7 | 1581 | 1562 | -19 |
| 1997 | 640 | 600 | -40 | 663 | 662 | -1 | 566 | 566 | 0 | 1869 | 1828 | -41 |
| 1998 | 880 | 825 | -55 | 707 | 707 | 0 | 573 | 566 | -7 | 2160 | 2098 | -62 |
| 1999 | 1120 | 1050 | -70 | 749 | 748 | -1 | 580 | 568 | -12 | 2449 | 2366 | -83 |
| 2000 | 1360 | 1275 | -85 | 790 | 789 | -1 | 587 | 569 | -18 | 2737 | 2633 | -104 |
| 2001 | 1600 | 1500 | -100 | 800 | 800 | 0 | 599 | 574 | -25 | 2999 | 2874 | -125 |
| 2002 | 1663 | 1575 | -88 | 820 | 820 | 0 | 607 | 578 | -29 | 3090 | 2973 | -117 |
| 2003 | 1725 | 1650 | -75 | 840 | 840 | 0 | 616 | 582 | -34 | 3181 | 3072 | -109 |
| 2004 | 1788 | 1725 | -63 | 860 | 860 | 0 | 625 | 586 | -39 | 3273 | 3171 | -102 |
| 2005 | 1850 | 1800 | -50 | 880 | 880 | 0 | 633 | 589 | -44 | 3363 | 3269 | -94 |
| 2006 | 1913 | 1875 | -38 | 900 | 900 | 0 | 643 | 594 | -49 | 3456 | 3369 | -87 |
| 2007 | 1974 | 1950 | -24 | 920 | 920 | 0 | 655 | 600 | -55 | 3549 | 3470 | -79 |
| 2008 | 2038 | 2025 | -13 | 940 | 940 | 0 | 668 | 608 | -60 | 3646 | 3573 | -73 |
| 2009 | 2100 | 2100 | 0 | 960 | 960 | 0 | 682 | 617 | -65 | 3742 | 3677 | -65 |
| 2010 | 2163 | 2175 | 12 | 980 | 980 | 0 | 697 | 627 | -70 | 3840 | 3782 | -58 |
| 2011 | 2225 | 2250 | 25 | 1000 | 1000 | 0 | 713 | 638 | -75 | 3938 | 3888 | -50 |
| 2012 | 2288 | 2325 | 37 | 1020 | 1020 | 0 | 727 | 647 | -80 | 4035 | 3992 | -43 |
| 2013 | 2350 | 2400 | 50 | 1041 | 1040 | -1 | 742 | 656 | -86 | 4133 | 4096 | -37 |
| 2014 | 2412 | 2475 | 63 | 1060 | 1060 | 0 | 756 | 666 | -90 | 4228 | 4201 | -27 |

those presented in the Plan Report occur for capacity interruptible loads. Even so, these differences are relatively small. They are less than 3% of the current CIL forecast until the early 2000s. They grow throughout the remainder of the planning period, reaching a maximum of about 90 MW by 2014 (ie. Plan Report values exceed those used during demand/supply case formulation by up to about 90 MW).

Even for the Lower load forecast path, the basic demand between now and 2014 is forecast to grow by as much as 10.8 GW. The total of all of the differences between the two demand management forecasts identified above is small when compared to this forecast load growth. Moreover, the difference between the old and new demand management projections also represents a very small percentage of the load forecast bandwidth for which plans are designed:- a bandwidth which itself covers only about 80% of the load growth uncertainty judged to be possible. For these reasons, differences in Demand Management projections of the magnitude reported above would have no discernable influence on the validity of the cases.

## 4.8 NON-UTILITY GENERATION PLAN

Chapter 8 of the Plan Report discusses the difference between load-displacement non-utility generation and purchase non-utility generation. It also presents Figures 8-6 and 8-7, which tabulate the levels of each type of non-utility generation which are currently planned under Median load forecast conditions.

In order to facilitate timely demand/supply case formulation and analysis, it was necessary early in 1989 to obtain preliminary estimates of achievable levels of demand displacement and purchase non-utility generation. Early phases of the analysis were undertaken using these preliminary estimates.

As discussed in Section 4.2 above, the non-utility generation estimates used in the analysis were revised in August 1989. Cases formulated and analyzed after that time were all based on the non-utility generation forecasts shown in Figures 4.8-1 and 4.8-2 below. These figures present non-utility generation contributions in terms of both peak power and energy. The energy contributions from non-utility generation shown in these figures were calculated assuming an average annual capacity factor of 80%, as stated in the Plan Report text. Figure 4.8-3 shows the cumulative net induced demand displacement (in terms of MW peak power reduction) as a function of time. This figure is analogous to the bottom half of Figure 8-8 of the Plan Report. Figure 4.8-4, analogous to the top half of Figure 8-8 of the Plan Report, displays the net purchase non-utility generation contribution over time.

FIGURE 4.8-1
CUMULATIVE NET INDUCED DEMAND DISPLACEMENT NON-UTILITY GENERATION
DATA USED FOR ANALYSIS
(VALUES AS OF JANUARY OF THE YEAR)

| YEAR | LOWER | | BRANCH-LOWER | | MEDIAN | | BRANCH UPPER | | UPPER | |
|---|---|---|---|---|---|---|---|---|---|---|
| | LOAD REDUCTION (MW) | ENERGY (TWh) | LOAD REDUCTION (MW) | ENERGY (TWh) | LOAD REDUCTION (MW) | ENERGY (TWh) | LOAD REDUCTION (MW) | ENERGY (TWh) | LOAD REDUCTION (MW) | ENERGY (TWh) |
| 1990 | 23 | 0.16 | 23 | 0.16 | 23 | 0.16 | 23 | 0.16 | 23 | 0.16 |
| 1991 | 90 | 0.63 | 90 | 0.63 | 90 | 0.63 | 90 | 0.63 | 90 | 0.63 |
| 1992 | 144 | 1.01 | 144 | 1.01 | 144 | 1.01 | 144 | 1.01 | 144 | 1.01 |
| 1993 | 210 | 1.47 | 210 | 1.47 | 210 | 1.47 | 210 | 1.47 | 210 | 1.47 |
| 1994 | 275 | 1.91 | 275 | 1.93 | 275 | 1.93 | 275 | 1.93 | 276 | 1.93 |
| 1995 | 288 | 2.02 | 300 | 2.10 | 300 | 2.10 | 300 | 2.10 | 307 | 2.15 |
| 1996 | 288 | 2.02 | 325 | 2.28 | 325 | 2.28 | 325 | 2.28 | 342 | 2.40 |
| 1997 | 288 | 2.02 | 340 | 2.38 | 340 | 2.38 | 340 | 2.38 | 362 | 2.54 |
| 1998 | 288 | 2.02 | 354 | 2.48 | 354 | 2.48 | 354 | 2.48 | 369 | 2.59 |
| 1999 | 288 | 2.02 | 364 | 2.55 | 364 | 2.55 | 364 | 2.55 | 362 | 2.54 |
| 2000 | 288 | 2.02 | 368 | 2.58 | 368 | 2.58 | 368 | 2.58 | 355 | 2.49 |
| 2001 | 288 | 2.02 | 340 | 2.38 | 368 | 2.58 | 348 | 2.44 | 348 | 2.44 |
| 2002 | 288 | 2.02 | 320 | 2.24 | 361 | 2.53 | 341 | 2.39 | 341 | 2.39 |
| 2003 | 288 | 2.02 | 300 | 2.10 | 354 | 2.48 | 334 | 2.34 | 334 | 2.34 |
| 2004 | 281 | 1.97 | 281 | 1.97 | 347 | 2.43 | 327 | 2.29 | 327 | 2.29 |
| 2005 | 274 | 1.92 | 274 | 1.92 | 339 | 2.38 | 320 | 2.24 | 320 | 2.24 |
| 2006 | 267 | 1.87 | 267 | 1.87 | 332 | 2.33 | 313 | 2.19 | 313 | 2.19 |
| 2007 | 260 | 1.82 | 260 | 1.82 | 325 | 2.28 | 306 | 2.15 | 306 | 2.15 |
| 2008 | 253 | 1.77 | 253 | 1.77 | 318 | 2.23 | 299 | 2.10 | 299 | 2.10 |
| 2009 | 246 | 1.72 | 246 | 1.72 | 311 | 2.18 | 292 | 2.05 | 292 | 2.05 |
| 2010 | 239 | 1.68 | 239 | 1.68 | 303 | 2.12 | 285 | 2.00 | 285 | 2.00 |
| 2011 | 232 | 1.63 | 232 | 1.63 | 296 | 2.07 | 278 | 1.95 | 278 | 1.95 |
| 2012 | 225 | 1.58 | 225 | 1.58 | 289 | 2.03 | 271 | 1.90 | 271 | 1.90 |
| 2013 | 218 | 1.53 | 218 | 1.53 | 282 | 1.98 | 264 | 1.85 | 264 | 1.85 |
| 2014 | 211 | 1.48 | 211 | 1.48 | 275 | 1.93 | 257 | 1.76 | 257 | 1.76 |

NOTE: A capacity factor of 80% is assumed to calculate annual energy.

FIGURE 4.8-2
CUMULATIVE NET PURCHASE NON-UTILITY GENERATION
DATA USED FOR ANALYSIS
(VALUES AS OF JANUARY OF THE YEAR)

| YEAR | LOWER | | BRANCH LOWER | | MEDIAN | | BRANCH UPPER | | UPPER | |
|---|---|---|---|---|---|---|---|---|---|---|
| | CAPACITY (MW) | ENERGY (TWh) | CAPACITY (MW) | ENERGY (TWh) | CAPACITY (MW) | ENERGY (TWh) | CAPACITY (MW) | ENERGY (TWh) | CAPACITY (MW) | ENERGY (TWh) |
| 1989 | 26 | 0.18 | 26 | 0.18 | 26 | 0.18 | 26 | 0.18 | 26 | 0.18 |
| 1990 | 54 | 0.38 | 54 | 0.38 | 54 | 0.38 | 54 | 0.38 | 54 | 0.38 |
| 1991 | 81 | 0.57 | 81 | 0.57 | 81 | 0.57 | 81 | 0.57 | 81 | 0.57 |
| 1992 | 252 | 1.77 | 252 | 1.77 | 252 | 1.77 | 252 | 1.77 | 252 | 1.77 |
| 1993 | 338 | 2.37 | 338 | 2.37 | 338 | 2.37 | 338 | 2.37 | 338 | 2.37 |
| 1994 | 424 | 2.97 | 424 | 2.97 | 424 | 2.97 | 424 | 2.97 | 424 | 2.97 |
| 1995 | 461 | 3.23 | 497 | 3.48 | 497 | 3.48 | 497 | 3.48 | 535 | 3.75 |
| 1996 | 461 | 3.23 | 570 | 3.99 | 570 | 3.99 | 570 | 3.99 | 688 | 4.82 |
| 1997 | 461 | 3.23 | 642 | 4.50 | 642 | 4.50 | 642 | 4.50 | 846 | 5.93 |
| 1998 | 461 | 3.23 | 717 | 5.02 | 717 | 5.02 | 717 | 5.02 | 975 | 6.83 |
| 1999 | 461 | 3.23 | 797 | 5.59 | 797 | 5.59 | 797 | 5.59 | 1036 | 7.26 |
| 2000 | 461 | 3.23 | 883 | 6.19 | 883 | 6.19 | 883 | 6.19 | 1097 | 7.69 |
| 2001 | 461 | 3.23 | 883 | 6.19 | 974 | 6.83 | 993 | 6.96 | 1157 | 8.11 |
| 2002 | 461 | 3.23 | 883 | 6.19 | 1035 | 7.25 | 1113 | 7.80 | 1218 | 8.54 |
| 2003 | 461 | 3.23 | 883 | 6.19 | 1096 | 7.68 | 1223 | 8.57 | 1279 | 8.96 |
| 2004 | 521 | 3.65 | 883 | 6.19 | 1156 | 8.10 | 1313 | 9.20 | 1339 | 9.38 |
| 2005 | 581 | 4.07 | 883 | 6.19 | 1216 | 8.52 | 1399 | 9.80 | 1399 | 9.80 |
| 2006 | 641 | 4.49 | 883 | 6.19 | 1276 | 8.94 | 1459 | 10.22 | 1459 | 10.22 |
| 2007 | 701 | 4.91 | 883 | 6.19 | 1336 | 9.36 | 1519 | 10.65 | 1519 | 10.65 |
| 2008 | 760 | 5.33 | 883 | 6.19 | 1395 | 9.78 | 1578 | 11.06 | 1578 | 11.06 |
| 2009 | 819 | 5.74 | 883 | 6.19 | 1454 | 10.19 | 1637 | 11.47 | 1637 | 11.47 |
| 2010 | 850 | 5.96 | 914 | 6.41 | 1485 | 10.41 | 1668 | 11.69 | 1668 | 11.69 |
| 2011 | 881 | 6.17 | 945 | 6.62 | 1516 | 10.62 | 1699 | 11.91 | 1699 | 11.91 |
| 2012 | 912 | 6.39 | 976 | 6.84 | 1547 | 10.84 | 1730 | 12.12 | 1730 | 12.12 |
| 2013 | 943 | 6.61 | 1007 | 7.06 | 1578 | 11.06 | 1761 | 12.34 | 1761 | 12.34 |
| 2014 | 974 | 6.83 | 1038 | 7.27 | 1609 | 11.28 | 1792 | 12.56 | 1792 | 12.56 |

NOTE: A capacity factor of 80% is assumed to calculate annual energy.

FIGURE 4.8-3

NUG DATA USED FOR ANALYSIS

NET INDUCED DEMAND DISPLACEMENT

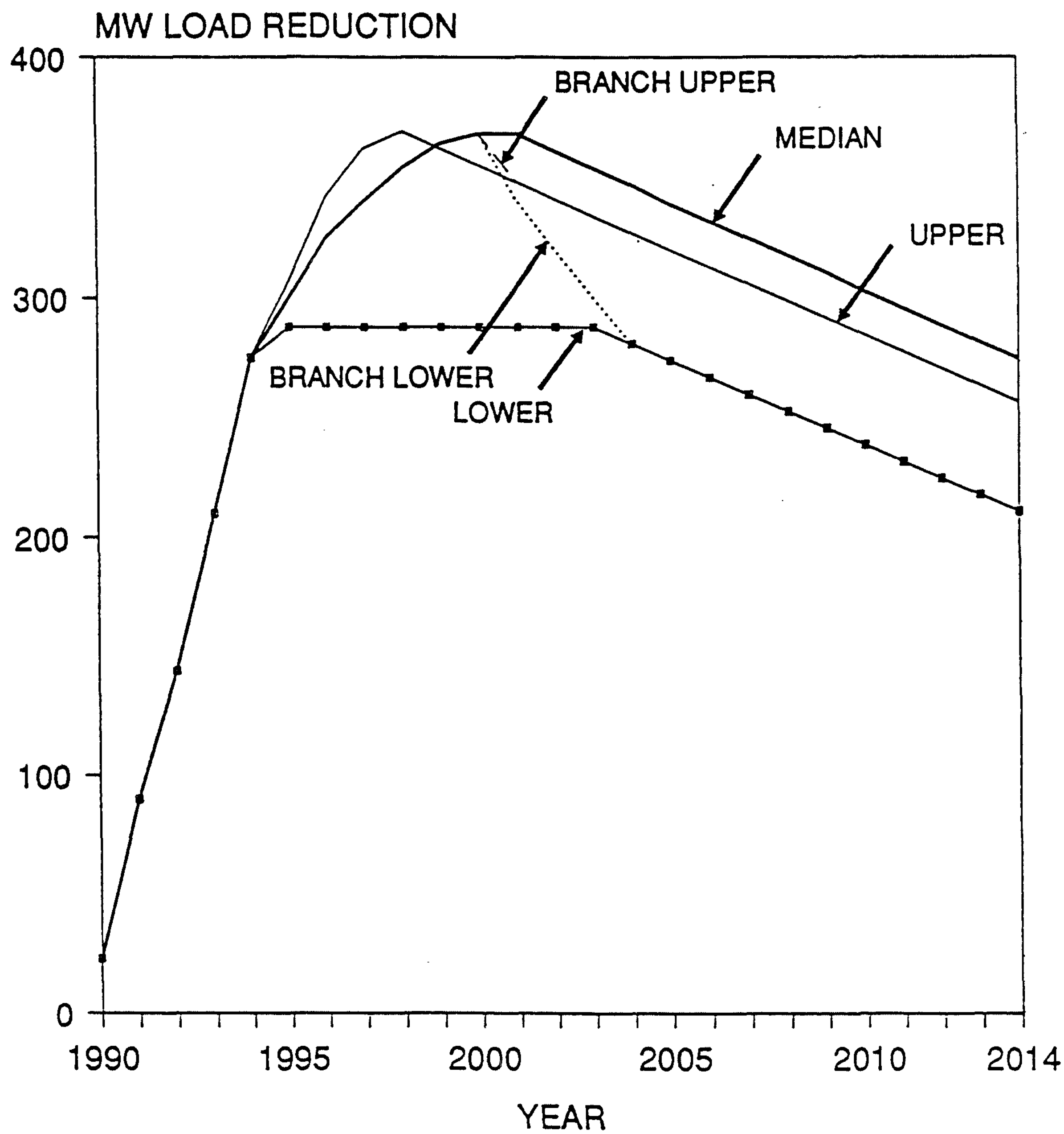
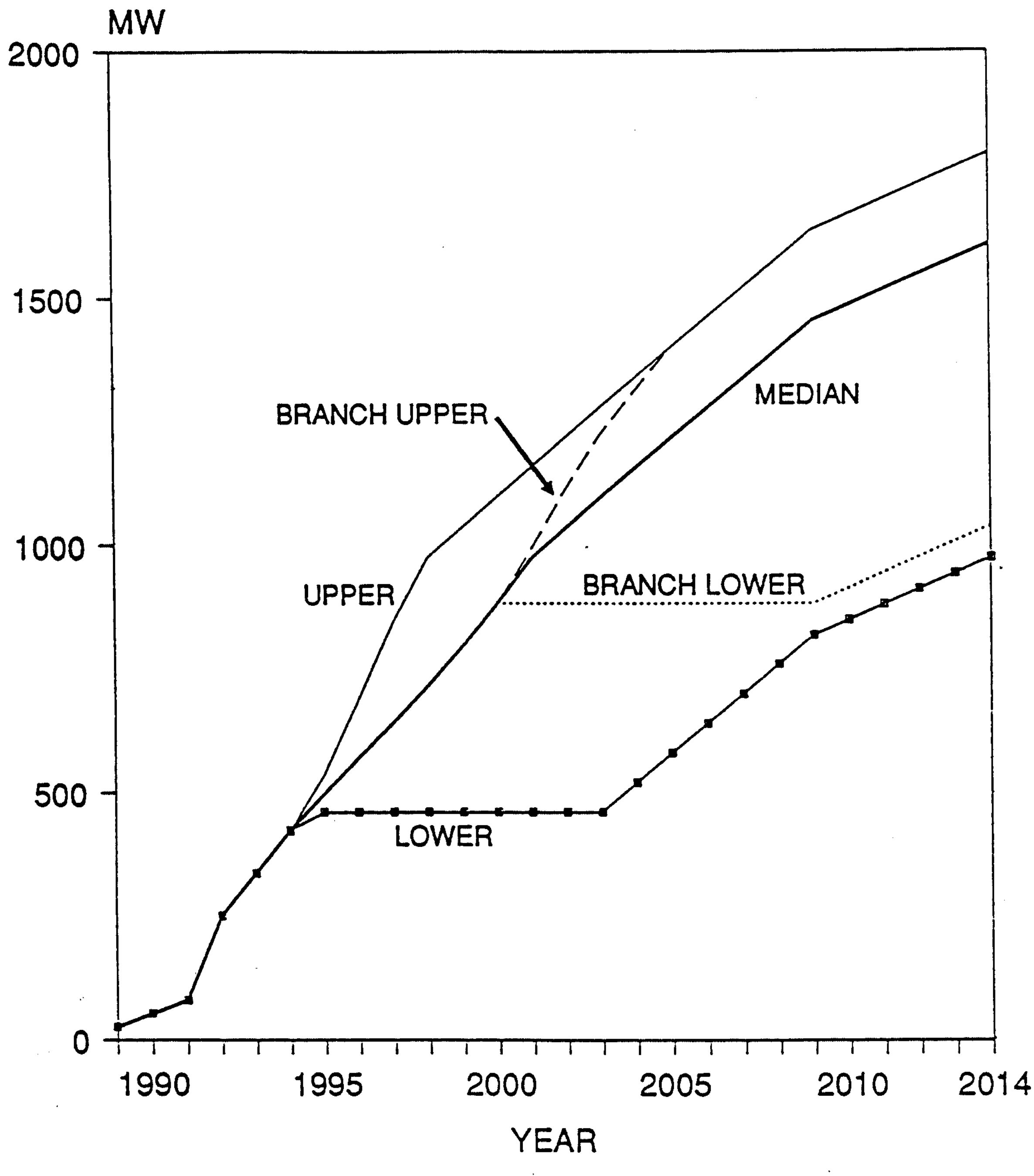


FIGURE 4.8-4
CUMULATIVE NET PURCHASE NUG CAPACITY
USED IN ANALYSIS



The current Non-utility Generation Plan (as listed in Figure 8-6 and 8-7 of the Plan Report) differs from that developed in the summer of 1989 and used for the final round of demand/supply case formulation and analysis. Figure 4.8-5 compares the two projections. The differences between the two projections for any given year are small compared to the width of the bandwidth forecast in that year. Any differences are not large enough to significantly affect the relative merits of the demand/supply cases.

## 4.9 PRIMARY AND FIRM LOAD FORECASTS

Figure 9-3 of the Plan Report presents the year-by-year forecast of the 20-minute January primary peak power demand for the Upper, Median, and Lower load paths. This primary forecast was based on the basic load forecast of December 1988, from which the power contributions of the Demand Management and Non-utility Generation Plans (as of September 1989) were subtracted. As noted previously the Demand Management and NUG contributions analyzed were based on forecasts available earlier in 1989, and are not in exact agreement with those current in the Fall of 1989. Hence, the Primary load forecast which was used in analysis is not exactly the same as that presented in the Plan Report.

Figure 4.9-1 provides the year-by-year values of the 20-minute January peak power demand used in the analysis under the five load forecast conditions. These values are not greatly different than those reported in Figure 9-3 of the Plan Report. The greatest difference is about 0.2 GW for the Lower and Median load forecast cases and 0.3 GW for the Upper. The average difference between forecasts is much less than this. Differences in primary load forecasts of this magnitude are not significant, particularly in light of the range of load growth uncertainty embodied in the bandwidth forecast.

Figure 4.9-2 presents the five primary load forecasts used during demand/supply case formulation and analyses.

Figure 4.9-3 tabulates the 20-minute January peak firm load forecast used in the final round of demand/supply case analysis for each of the five load forecast conditions. This Figure is analogous to Figure 9-8 of the Plan Report. Each of the five firm load forecasts was obtained by subtracting the Capacity Interruptible Load forecasts discussed in Section 4.7 from the primary forecasts of Figure 4.9-2. The five firm load forecasts are shown in Figure 4.9-4.

FIGURE 4.8-5

COMPARISON OF NON-UTILITY GENERATION DATA USED
IN THE MAIN PLAN REPORT AND IN PLAN FORMULATION

MEDIAN LOAD FORECAST

| | CUMULATIVE DEMAND DISPLACEMENT NUG (January of Year) | | | CUMULATIVE PURCHASE NUG (January of Year) | | |
|---|---|---|---|---|---|---|
| YEAR | PLAN REPORT | PLAN FORMULATION | DIFFERENCE | PLAN REPORT | PLAN FORMULATION | DIFFERENCE |
| 1989 | 0 | 0 | 0 | 0 | 0 | 0 |
| 1990 | 59 | 23 | -36 | 28 | 26 | -2 |
| 1991 | 102 | 90 | -12 | 55 | 54 | -1 |
| 1992 | 176 | 144 | -32 | 226 | 81 | -145 |
| 1993 | 243 | 210 | -33 | 312 | 252 | -60 |
| 1994 | 310 | 275 | -35 | 398 | 338 | -60 |
| 1995 | 334 | 300 | -34 | 471 | 424 | -47 |
| 1996 | 359 | 325 | -34 | 544 | 497 | -47 |
| 1997 | 373 | 340 | -33 | 616 | 570 | -46 |
| 1998 | 384 | 354 | -30 | 691 | 642 | -49 |
| 1999 | 391 | 364 | -27 | 771 | 717 | -54 |
| 2000 | 392 | 368 | -24 | 857 | 797 | -60 |
| 2001 | 403 | 368 | -35 | 932 | 883 | -49 |
| 2002 | 407 | 361 | -46 | 981 | 974 | -7 |
| 2003 | 411 | 354 | -57 | 1030 | 1035 | 5 |
| 2004 | 414 | 347 | -67 | 1078 | 1096 | 18 |
| 2005 | 418 | 339 | -79 | 1126 | 1156 | 30 |
| 2006 | 422 | 332 | -90 | 1174 | 1216 | 42 |
| 2007 | 426 | 325 | -101 | 1222 | 1276 | 54 |
| 2008 | 429 | 318 | -111 | 1269 | 1336 | 67 |
| 2009 | 433 | 311 | -122 | 1316 | 1395 | 79 |
| 2010 | 437 | 303 | -134 | 1360 | 1454 | 94 |
| 2011 | 441 | 296 | -145 | 1403 | 1485 | 82 |
| 2012 | 445 | 289 | -156 | 1439 | 1516 | 77 |
| 2013 | 448 | 282 | -166 | 1470 | 1547 | 77 |
| 2014 | 452 | 275 | -177 | 1497 | 1578 | 81 |

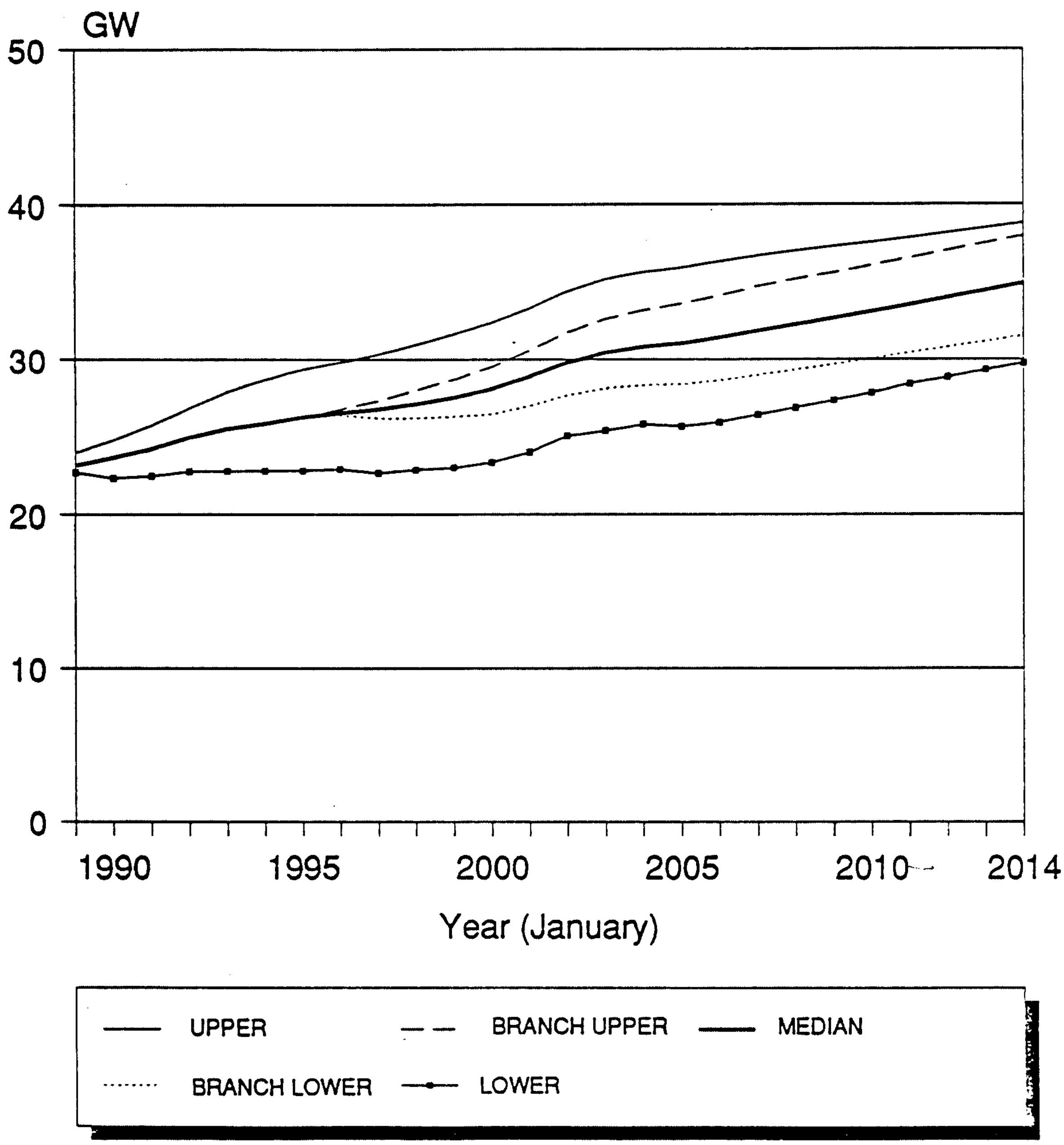
**Figure 4.9-1: PRIMARY LOAD FORECAST USED FOR ANALYSIS - JANUARY 20 MINUTE PEAK POWER DEMAND (GW)**

| Year | Lower | Branch Lower | Median | Branch Upper | Upper |
|---|---|---|---|---|---|
| 1989 | 22.7 | 23.2 | 23.2 * | 23.2 | 24.0 |
| 1990 | 22.3 | 23.7 | 23.7 | 23.7 | 24.8 |
| 1991 | 22.5 | 24.2 | 24.2 | 24.2 | 25.7 |
| 1992 | 22.8 | 25.0 | 25.0 | 25.0 | 26.8 |
| 1993 | 22.8 | 25.5 | 25.5 | 25.5 | 27.9 |
| 1994 | 22.8 | 25.8 | 25.8 | 25.8 | 28.7 |
| 1995 | 22.8 | 26.3 | 26.3 | 26.3 | 29.3 |
| 1996 | 22.9 | 26.4 | 26.6 | 26.8 | 29.8 |
| 1997 | 22.7 | 26.2 | 26.8 | 27.3 | 30.3 |
| 1998 | 22.9 | 26.2 | 27.1 | 28.0 | 31.0 |
| 1999 | 23.0 | 26.3 | 27.5 | 28.7 | 31.6 |
| 2000 | 23.4 | 26.5 | 28.1 | 29.5 | 32.4 |
| 2001 | 24.0 | 27.0 | 28.9 | 30.6 | 33.3 |
| 2002 | 25.1 | 27.7 | 29.8 | 31.8 | 34.4 |
| 2003 | 25.4 | 28.1 | 30.5 | 32.6 | 35.2 |
| 2004 | 25.8 | 28.3 | 30.8 | 33.2 | 35.7 |
| 2005 | 25.7 | 28.4 | 31.1 | 33.6 | 36.0 |
| 2006 | 25.9 | 28.6 | 31.4 | 34.2 | 36.3 |
| 2007 | 26.4 | 29.0 | 31.9 | 34.8 | 36.7 |
| 2008 | 26.9 | 29.3 | 32.3 | 35.2 | 37.0 |
| 2009 | 27.4 | 29.7 | 32.7 | 35.6 | 37.3 |
| 2010 | 27.8 | 30.1 | 33.1 | 36.1 | 37.6 |
| 2011 | 28.4 | 30.4 | 33.6 | 36.6 | 37.9 |
| 2012 | 28.8 | 30.8 | 34.0 | 37.0 | 38.2 |
| 2013 | 29.3 | 31.2 | 34.5 | 37.5 | 38.5 |
| 2014 | 29.8 | 31.5 | 35.0 | 38.0 | 38.8 |

* January 1989 Actual Primary Load was 23.1 GW.

FIGURE 4.9-2

PRIMARY LOAD FORECAST USED FOR ANALYSIS
20-MINUTE JANUARY PEAK POWER DEMAND



## FIGURE 4.9-3: FIRM LOAD FORECAST USED FOR ANALYSIS - JANUARY 20-MINUTE PEAK POWER DEMAND (GW)

| Year | Lower | Branch Lower | Median | Branch Upper | Upper |
|---|---|---|---|---|---|
| 1989 | 22.1 | 22.6 | 22.6 | 22.6 | 23.4 |
| 1990 | 21.6 | 23.0 | 23.0 | 23.0 | 24.0 |
| 1991 | 21.9 | 23.6 | 23.6 | 23.6 | 25.1 |
| 1992 | 22.2 | 24.4 | 24.4 | 24.4 | 26.2 |
| 1993 | 22.2 | 24.9 | 24.9 | 24.9 | 27.2 |
| 1994 | 22.2 | 25.2 | 25.2 | 25.2 | 28.0 |
| 1995 | 22.3 | 25.6 | 25.6 | 25.6 | 28.6 |
| 1996 | 22.3 | 25.8 | 25.9 | 26.1 | 29.1 |
| 1997 | 22.1 | 25.5 | 26.1 | 26.7 | 29.6 |
| 1998 | 22.3 | 25.6 | 26.5 | 27.3 | 30.2 |
| 1999 | 22.5 | 25.7 | 26.9 | 28.0 | 30.9 |
| 2000 | 22.8 | 25.8 | 27.4 | 28.8 | 31.6 |
| 2001 | 23.4 | 26.3 | 28.2 | 29.9 | 32.5 |
| 2002 | 24.5 | 27.0 | 29.1 | 31.0 | 33.6 |
| 2003 | 24.8 | 27.5 | 29.8 | 31.9 | 34.4 |
| 2004 | 25.2 | 27.7 | 30.1 | 32.5 | 34.9 |
| 2005 | 25.1 | 27.7 | 30.3 | 32.9 | 35.1 |
| 2006 | 25.3 | 28.0 | 30.7 | 33.4 | 35.5 |
| 2007 | 25.8 | 28.3 | 31.1 | 34.0 | 35.9 |
| 2008 | 26.3 | 28.6 | 31.6 | 34.4 | 36.2 |
| 2009 | 26.7 | 29.0 | 32.0 | 34.8 | 36.5 |
| 2010 | 27.2 | 29.4 | 32.4 | 35.3 | 36.7 |
| 2011 | 27.8 | 29.7 | 32.8 | 35.7 | 37.0 |
| 2012 | 28.2 | 30.1 | 33.3 | 36.2 | 37.3 |
| 2013 | 28.6 | 30.5 | 33.7 | 36.7 | 37.6 |
| 2014 | 29.1 | 30.8 | 34.2 | 37.1 | 38.0 |

FIGURE 4.9-4
FIRM LOAD FORECAST USED FOR ANALYSIS
20-MINUTE JANUARY PEAK POWER DEMAND

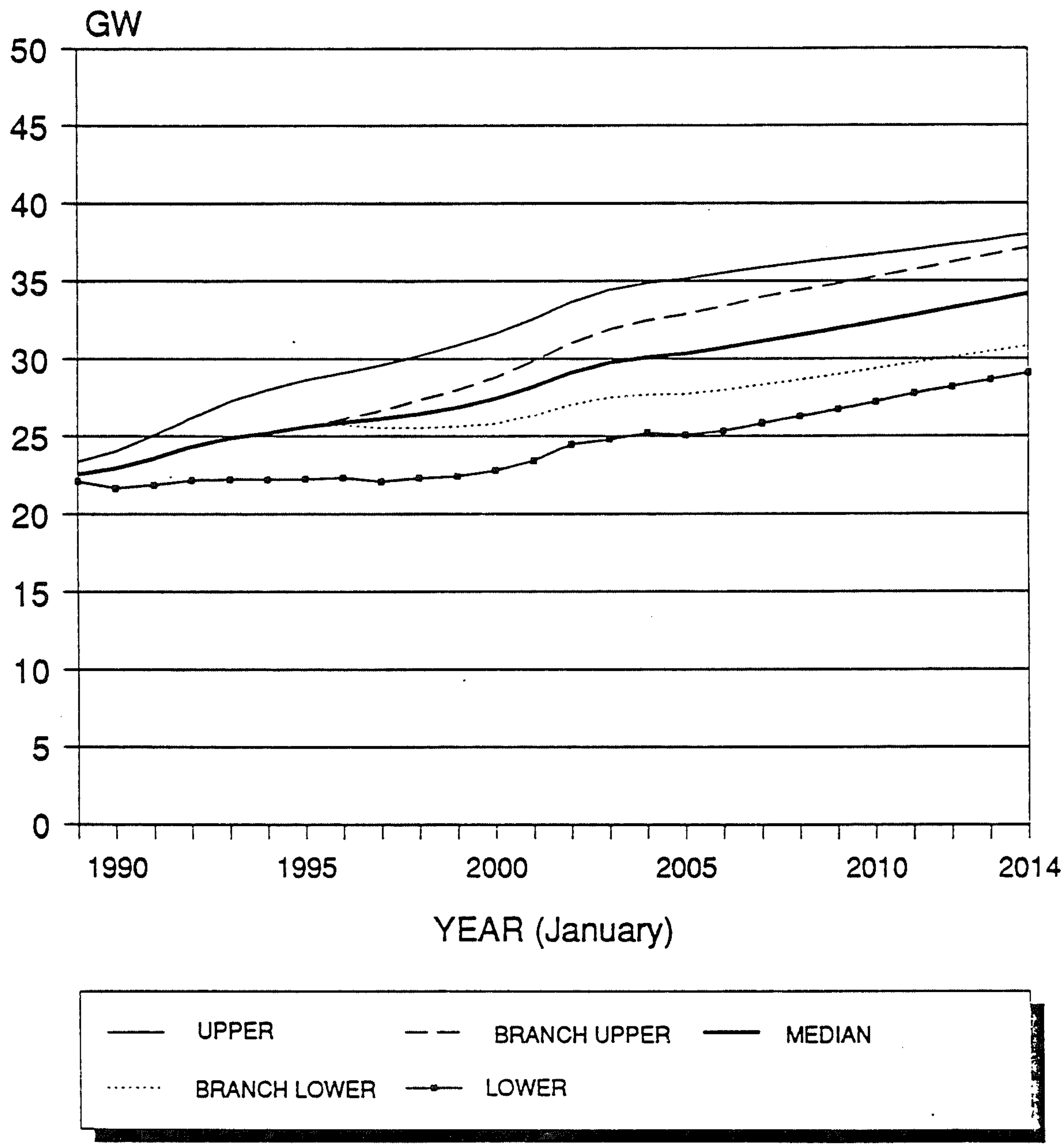


Figure 4.9-5 is a table of average year-over-year growth rates for the basic, primary, and firm forecasts used in the analysis. This figure is analogous to Figure 9-6 of the Plan Report.

## 4.10 REHABILITATION PLAN

As stated in the Plan Report, the Rehabilitation Plan used during the plan formulation process was common to all demand/supply cases and common to all five load forecasts. The Plan Report presents most of the details of the Rehabilitation Plan which are relevant to demand/supply case formulation. However, since nuclear unit retubing can have a relatively large impact on the total available generating capacity in any given year, it is documented more fully in this section.

The table in Figure 4.10-1 presents the retubing schedule which was used in demand/supply case formulation. This schedule was common to all demand/supply cases and all load forecast paths. Figure 4.10-2 is another representation of this retubing schedule which shows assumed unit outage start times and durations more clearly. Also shown in this figure is the number of megawatts assumed to be unavailable during the January peak due to retubing activity. The effect of this retubing activity has been included in the projected system Load Meeting Capability shown in Figures 4.5-1 and 4.5-2 in this Analysis Report and in Figures 4-14, 4-18, and 5-1 through 5-3 of the Plan Report.

## 4.11 REQUIREMENT FOR NEW SUPPLY

Plan Report Figures 11-1 through 11-3 present curves showing the derivation of the requirement for new supply under the Upper, Median, and Lower forecast conditions, using corporate forecasts current in September, 1989. Figures 4.11-1 through 4.11-5 below redevelop these curves for all five load forecast paths, using data employed in the fourth phase of demand/supply case formulation and analysis.

From these five curves, the requirement for new supply capacity was determined. This has been plotted for all five load forecast paths in Figure 4.11-6. This Figure is analogous to Figure 11-6 of the Plan Report. Despite the differences between the Demand Management and Non-utility Generation forecasts presented here and in the Plan Report, the calculated requirement for new supply shown in Figure 4.11-6 is in close agreement with that shown in Figure 11-6 of the Plan Report.

## FIGURE 4.9-5: AVERAGE YEAR-OVER-YEAR PEAK DEMAND GROWTH RATES

(FROM DATA USED FOR ANALYSIS)

| | Lower Load Forecast | | | Branch Lower Load Forecast | | | Median Load Forecast | | | Branch Upper Load Forecast | | | Upper Load Forecast | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Firm | Primary | Basic | Firm | Primary | Basic | Firm | Primary | Basic | Firm | Primary | Basic | Firm | Primary | Basic |
| 1988-1995 | 0.3% | 0.1% | 0.8% | 2.3% | 2.2% | 2.8% | 2.3% | 2.2% | 2.8% | 2.3% | 2.2% | 2.8% | 3.9% | 3.8% | 4.5% |
| 1988-2000 | 0.3% | 0.3% | 1.1% | 1.4% | 1.3% | 2.2% | 1.9% | 1.8% | 2.7% | 2.3% | 2.2% | 3.1% | 3.1% | 3.0% | 4.0% |
| 1988-2010 | 1.0% | 0.9% | 1.5% | 1.3% | 1.3% | 1.9% | 1.8% | 1.7% | 2.3% | 2.2% | 2.2% | 2.7% | 2.4% | 2.3% | 3.0% |
| 1988-2014 | 1.1% | 1.1% | 1.5% | 1.3% | 1.3% | 1.8% | 1.7% | 1.7% | 2.2% | 2.0% | 2.0% | 2.6% | 2.1% | 2.1% | 2.7% |

## FIGURE 4.10-1: MAJOR PLANNED FUEL CHANNEL OUTAGES - NUCLEAR STATIONS (1989-2014)

| Unit Name | Unit Capacity | Outage Type * | Outage Start | Outage Duration (months) |
|---|---|---|---|---|
| Pickering 3 | 515 | LSFCR | June 1989 | 23 |
| Bruce 3 | 769 | SLAR | February 1990 | 6 |
| Bruce 4 | 769 | SLAR | July 1990 | 10 |
| Pickering 4 | 515 | LSFCR | March 1991 | 19 |
| Bruce 2 | 769 | MAINT | May 1991 | 3 |
| Pickering 5 | 516 | SLAR | June 1991 | 5 |
| Bruce 1 | 769 | SLAR | August 1991 | 10 |
| Pickering 6 | 516 | SLAR | June 1992 | 5 |
| Bruce 2 | 769 | LSFCR | April 1993 | 31 |
| Bruce 1 | 769 | LSFCR | March 1997 | 27 |
| Bruce 3 | 769 | REFAB | July 1998 | 5 |
| Bruce 3 | 769 | LSFCR | July 2002 | 24 |
| Pickering 5 | 516 | LSFCR | April 2006 | 21 |
| Bruce 4 | 769 | LSFCR | July 2007 | 24 |
| Pickering 6 | 516 | LSFCR | January 2008 | 21 |
| Bruce 5 | 860 | LSFCR | July 2009 | 24 |
| Pickering 7 | 516 | LSFCR | October 2009 | 21 |
| Pickering 8 | 516 | LSFCR | July 2011 | 21 |
| Bruce 6 | 860 | LSFCR | July 2011 | 24 |
| Bruce 7 | 860 | LSFCR | July 2013 | 24 |

* LSFCR denotes "Large Scale Fuel Channel Replacement"
SLAR denotes "Spacer Location and Relocation"
REFAB denotes "Repositioning End-Fitting and Bearings"
MAINT denotes "Major Maintenance"

# FIGURE 4.10-2: MAJOR PLANNED/FUEL CHANNEL OUTAGES AT NUCLEAR STATIONS (1989-2014)

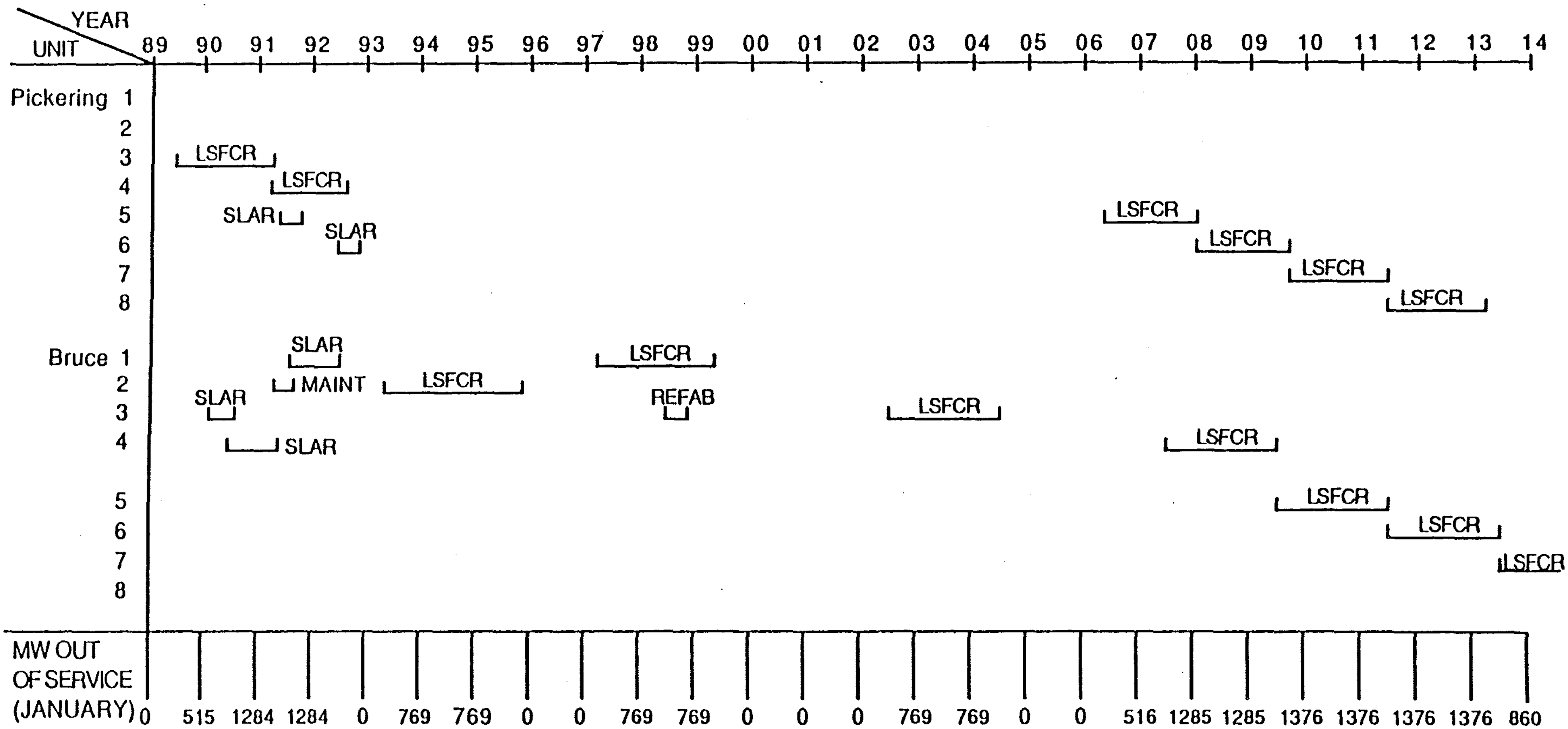


FIGURE 4.11-1

REQUIRED SUPPLY - LMC - PEAK POWER DEMAND

(DATA USED IN ANALYSIS)

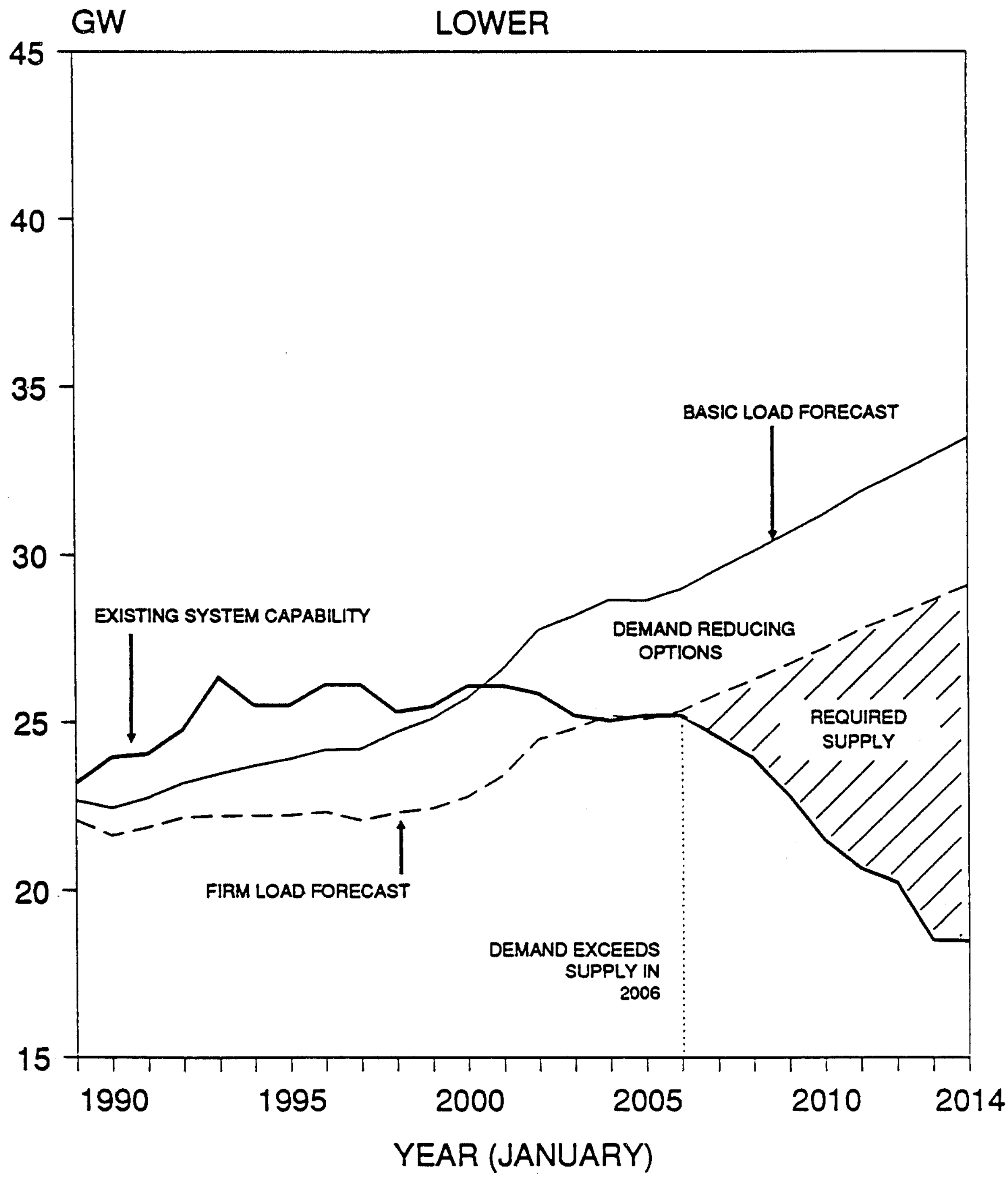


FIGURE 4.11-2

REQUIRED SUPPLY - LMC - PEAK POWER DEMAND

(DATA USED IN ANALYSIS)

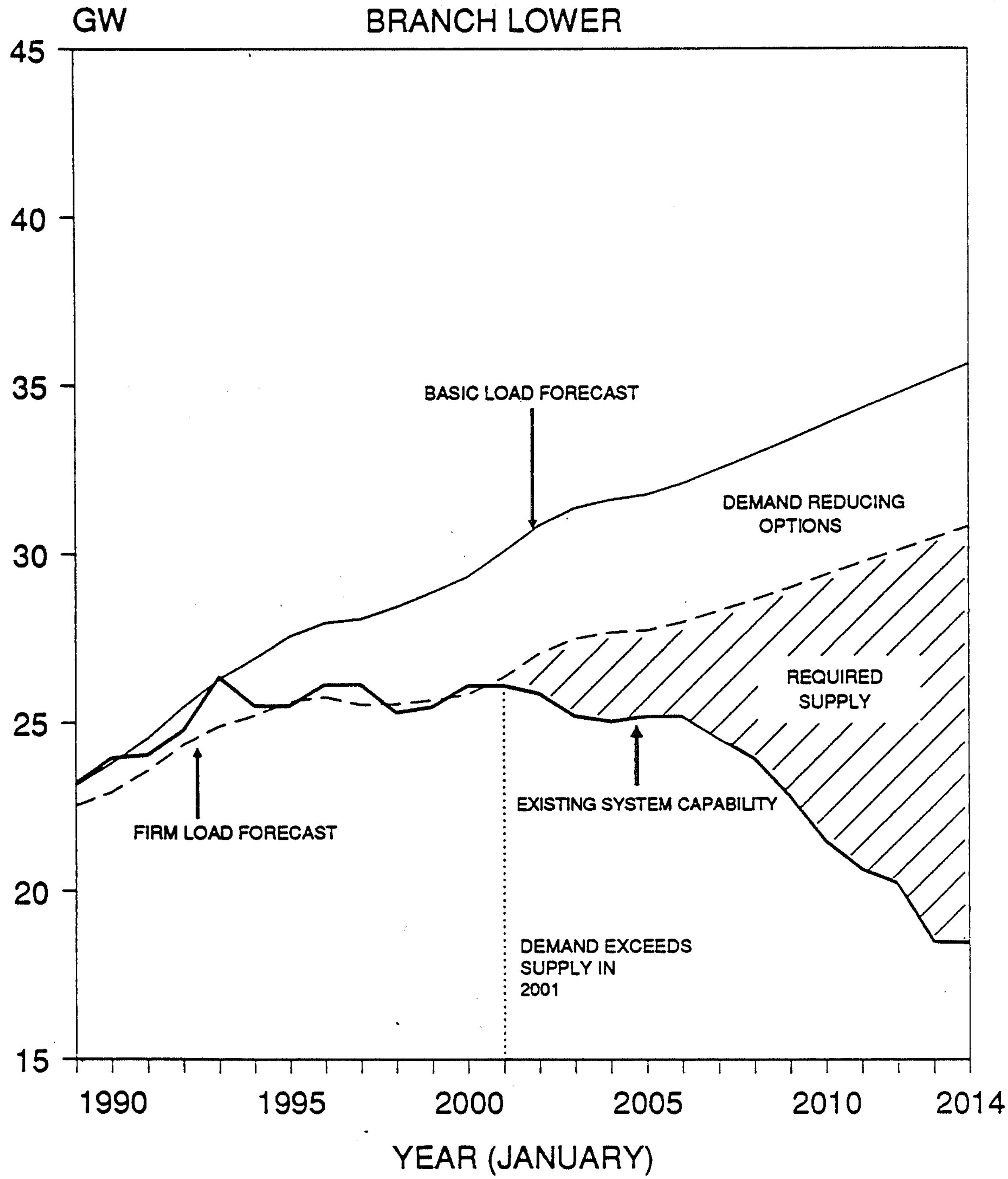


FIGURE 4.11-3

REQUIRED SUPPLY - LMC - PEAK POWER DEMAND

(DATA USED IN ANALYSIS)

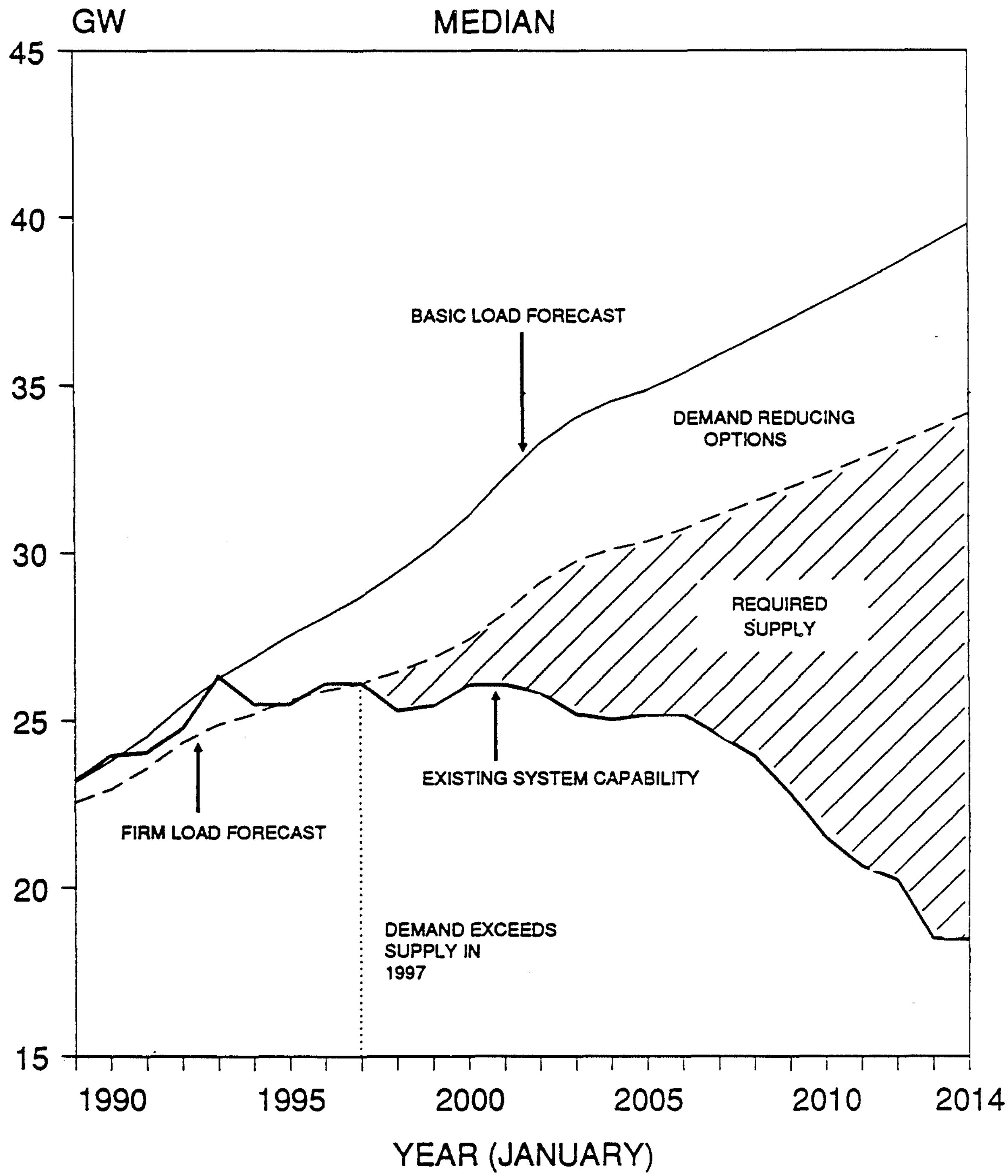


FIGURE 4.11-4

REQUIRED SUPPLY - LMC - PEAK POWER DEMAND
(DATA USED IN ANALYSIS)

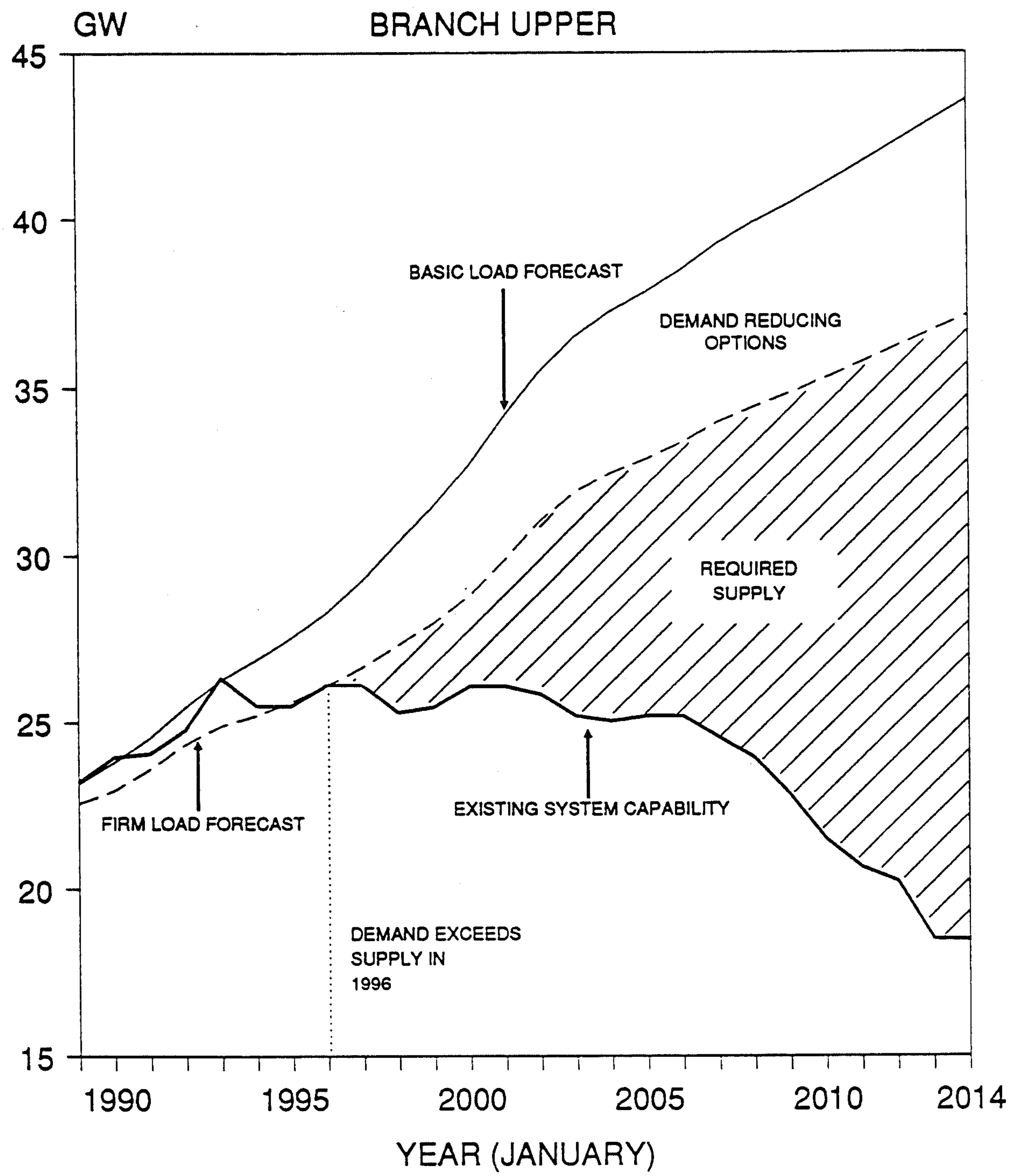


FIGURE 4.11-5

REQUIRED SUPPLY - LMC - PEAK POWER DEMAND

(DATA USED IN ANALYSIS)

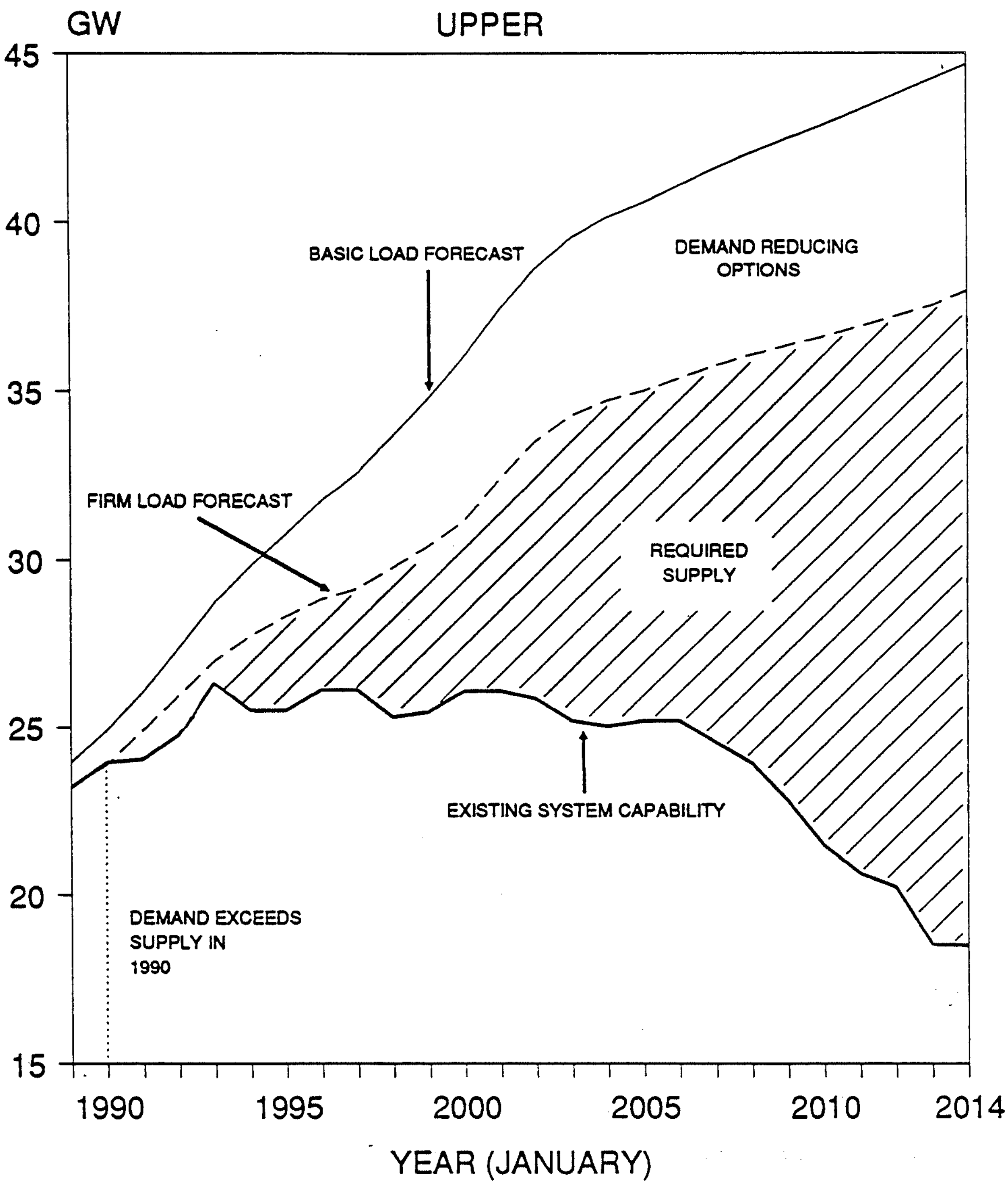
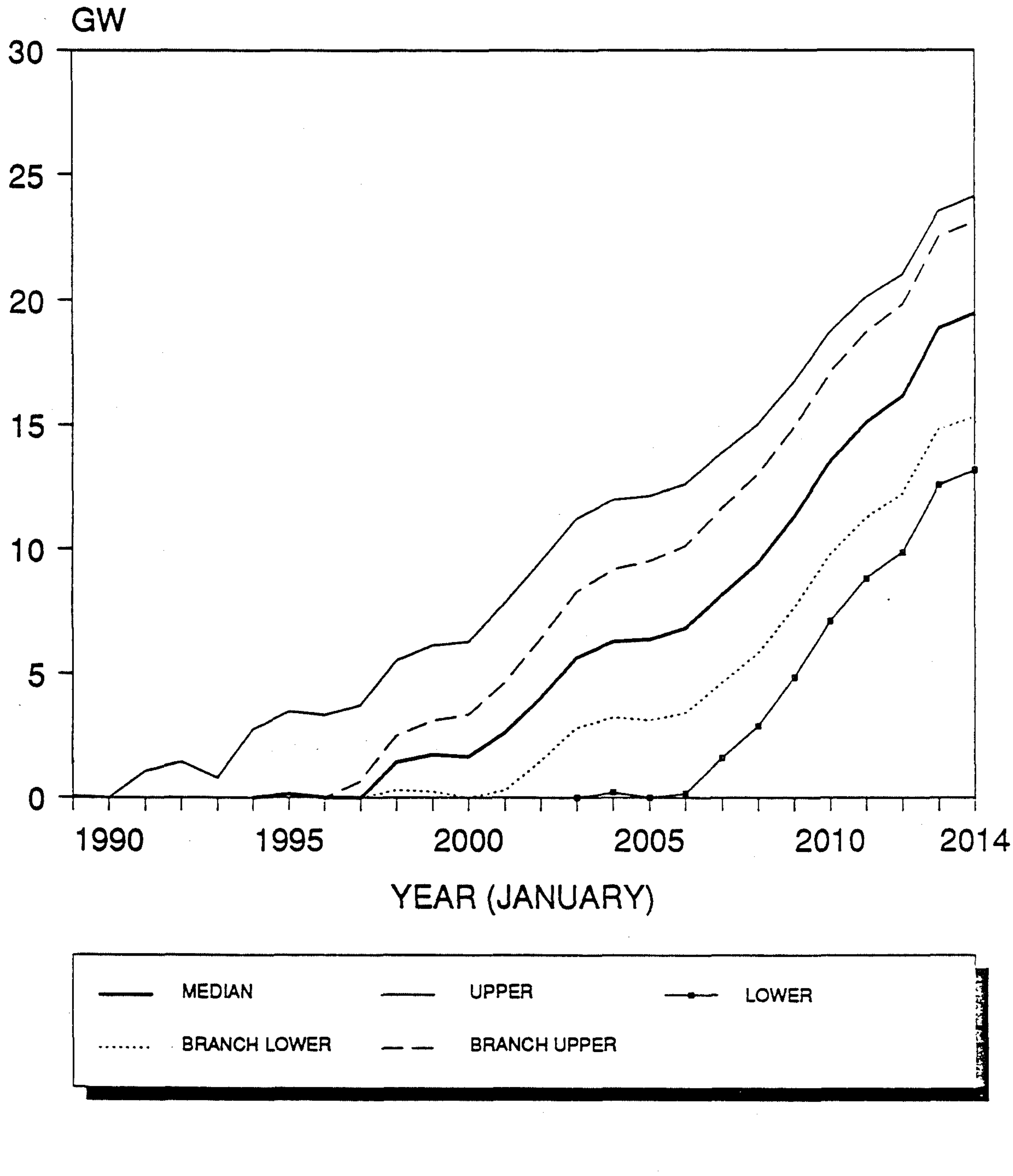


FIGURE 4.11-6

REQUIRED SUPPLY CAPACITY - PEAK POWER DEMAND

(DATA USED IN ANALYSIS)



## 4.12 THE HYDRAULIC PLAN

Chapter 12 of the Plan Report presents Ontario Hydro's proposed Hydraulic Plan. The plan presented is a relatively detailed listing of the specific hydraulic sites which will be developed by a given date, the capacity to be installed, and the energy generating capability to be realised. These details are summarised in Figure 12-7 in the Plan Report.

During demand/supply case formulation, the complete details of this hydraulic program were not finalized. For instance, until recently, the installed capacity of every site was not finalized, nor was the exact sequence of site development. In order to avoid delaying the planning process until such final details became available, demand/supply case formulation proceeded using the then current best estimates of new hydraulic generation. In fact, the projection of new hydraulic generation assumed during the final iterations of case analysis did capture the essence of what would eventually become the proposed Hydraulic Plan.

Figure 4.12-1 below shows the new hydraulic capacity and annual energy production capability which was assumed to be installed by a given date. The same hydraulic program was used throughout the final two phases of demand/supply case formulation and was common to all load forecast paths. Note that Figure 4.12-1 lists the capacity assumed to be in place by January of each given year whereas Figure 12-7 of the Plan Report quotes capacity in-service by the end of the year stated.

Figures 4.12-2 and 4.12-3 are representations of the data in Figure 4.12-1. These figures show new hydraulic capacity and annual energy producing capability, respectively which were assumed when formulating cases.

Figure 4.12-4 compares the hydraulic data used for case formulation with the now current hydraulic plan, as presented in Figure 12-7 of the Plan Report. This comparison shows that the two are generally in close agreement, although in the latter years of the study period the hydraulic capacity assumed during plan formulation differed from that in the current Hydraulic Plan by up to 84 MW. These differences have no significant effect on the applicability of the plans developed and presented in the Plan Report.

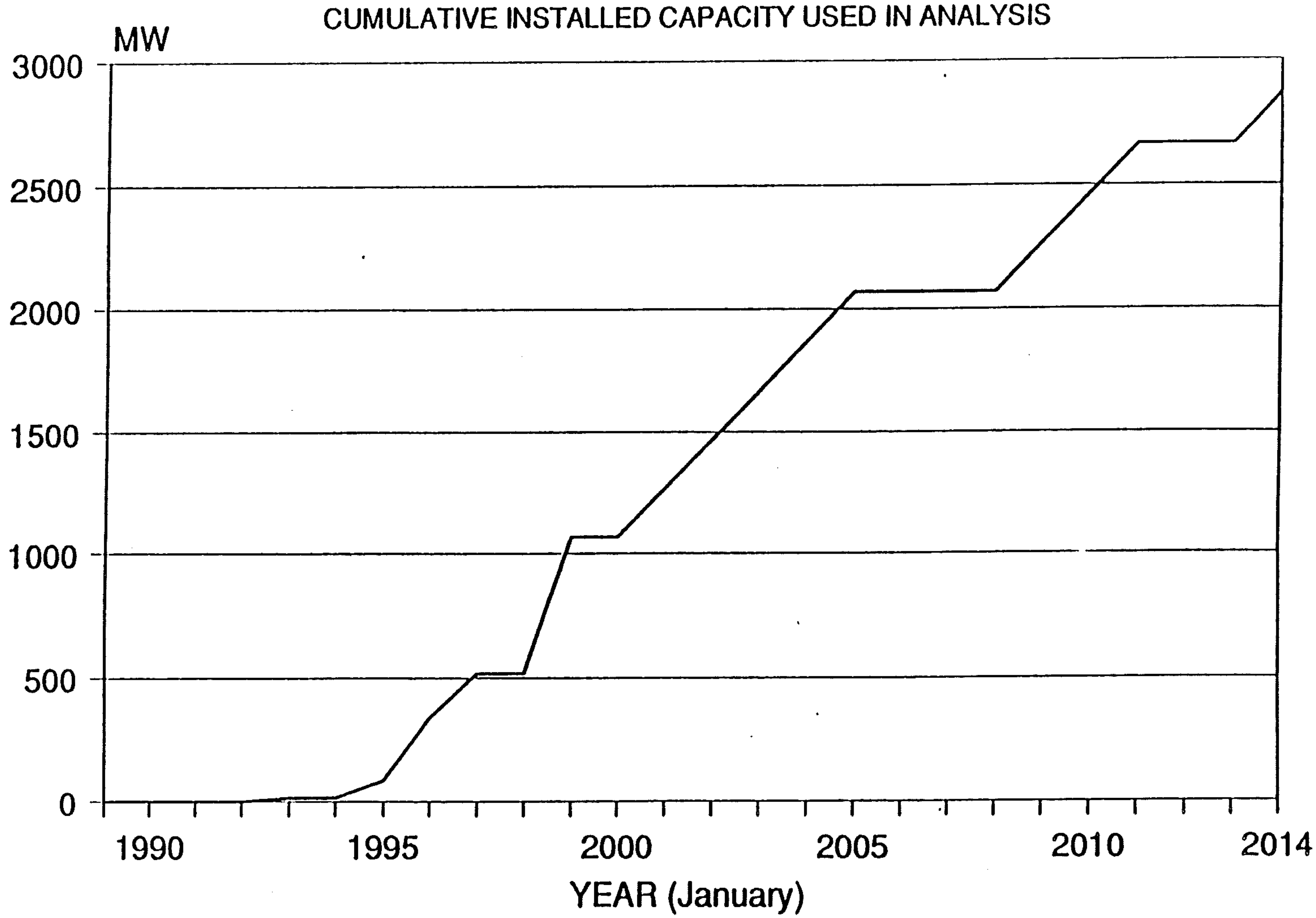
FIGURE 4.12-1: NEW HYDRAULIC PROGRAM
(DATA USED IN PLAN FORMULATION)

| YEARS | NEW CAPACITY (MW) | CUMULATIVE NEW CAPACITY (MW) | CUMULATIVE NEW ANNUAL ENERGY (TWh) |
|---|---|---|---|
| 1989 | 0 | 0 | 0 |
| 1990 | 0 | 0 | 0 |
| 1991 | 0 | 0 | 0 |
| 1992 | 0 | 0 | 0 |
| 1993 | 16 | 16 | 0.098 |
| 1994 | 0 | 16 | 0.098 |
| 1995 | 66 | 82 | 0.191 |
| 1996 | 256 | 338 | 0.796 |
| 1997 | 180 | 518 | 1.432 |
| 1998 | 0 | 518 | 1.432 |
| 1999 | 550 | 1068 | 2.872 |
| 2000 | 0 | 1068 | 2.872 |
| 2001 | 200 | 1268 | 3.129 |
| 2002 | 200 | 1468 | 3.386 |
| 2003 | 200 | 1668 | 3.643 |
| 2004 | 200 | 1868 | 3.900 |
| 2005 | 200 | 2068 | 4.157 |
| 2006 | 0 | 2068 | 4.157 |
| 2007 | 0 | 2068 | 4.157 |
| 2008 | 0 | 2068 | 4.157 |
| 2009 | 200 | 2268 | 4.414 |
| 2010 | 200 | 2468 | 4.671 |
| 2011 | 200 | 2668 | 4.928 |
| 2012 | 0 | 2668 | 4.928 |
| 2013 | 0 | 2668 | 4.928 |
| 2014 | 200 | 2868 | 5.185 |

FIGURE 4.12-2

# NEW HYDRUALIC PROGRAM

CUMULATIVE INSTALLED CAPACITY USED IN ANALYSIS



# FIGURE 4.12-3
# NEW HYDRUALIC PROGRAM ENERGY

(DATA USED IN ANALYSIS)

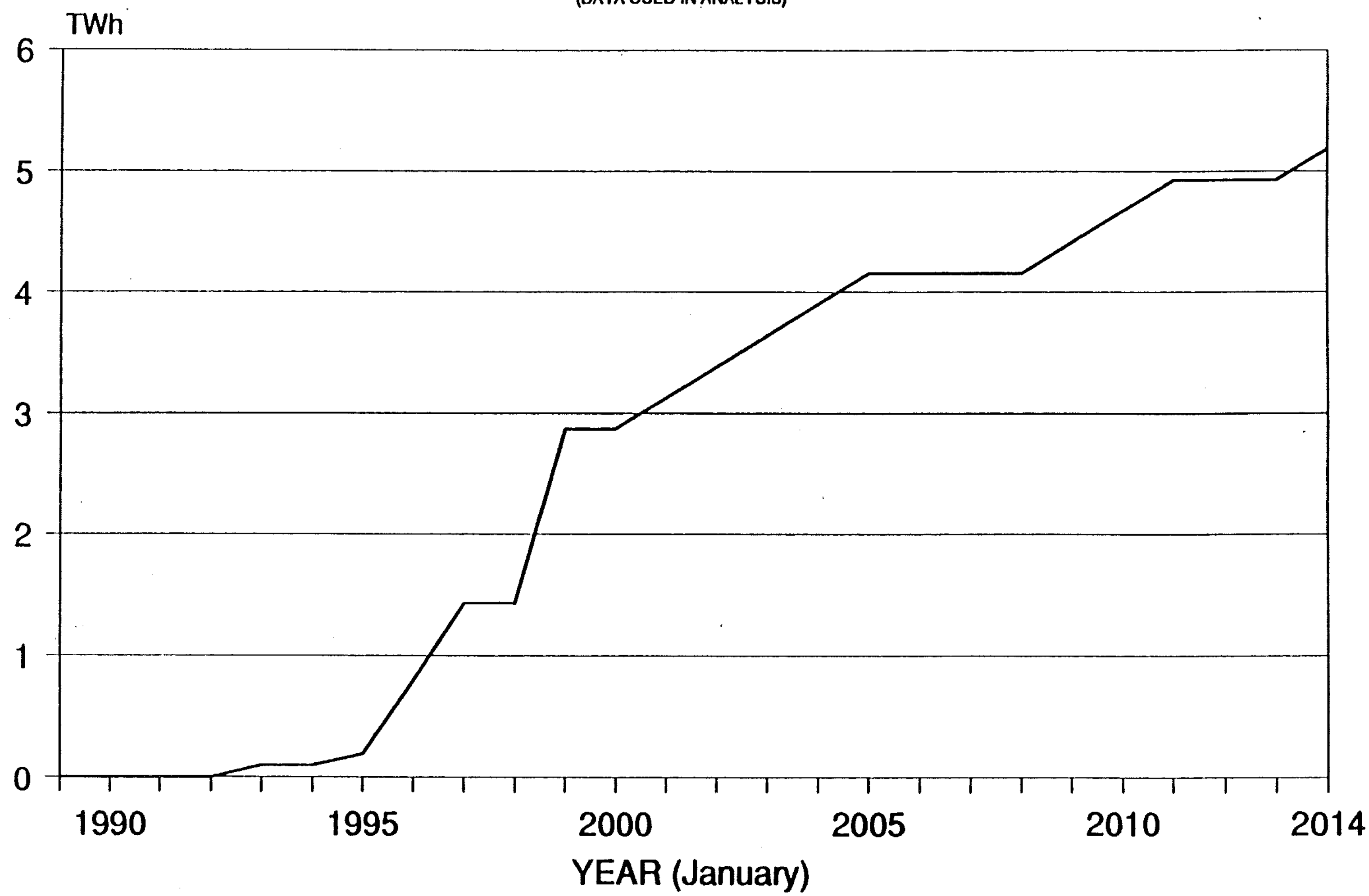


FIGURE 4.12-4

COMPARISON OF NEW HYDRAULIC PROGRAM CAPACITIES
MAIN REPORT vs PLAN ANALYSIS

| YEAR (January) | CUMULATIVE CAPACITY (MW) MAIN REPORT | ANALYSIS | DIFFERENCE (MW) |
|---|---|---|---|
| 1989 | - | 0 | 0 |
| 1990 | - | 0 | 0 |
| 1991 | - | 0 | 0 |
| 1992 | - | 0 | 0 |
| 1993 | 3 | 16 | -13 |
| 1994 | 15 | 16 | -1 |
| 1995 | 83 | 82 | 1 |
| 1996 | 333 | 338 | -5 |
| 1997 | 526 | 518 | 8 |
| 1998 | 526 | 518 | 8 |
| 1999 | 1076 | 1068 | 8 |
| 2000 | 1076 | 1068 | 8 |
| 2001 | 1209 | 1268 | -59 |
| 2002 | 1409 | 1468 | -59 |
| 2003 | 1608 | 1668 | -60 |
| 2004 | 1808 | 1868 | -60 |
| 2005 | 2008 | 2068 | -60 |
| 2006 | 2053 | 2068 | -15 |
| 2007 | 2120 | 2068 | 52 |
| 2008 | 2143 | 2068 | 75 |
| 2009 | 2241 | 2268 | -27 |
| 2010 | 2514 | 2468 | 46 |
| 2011 | 2584 | 2668 | -84 |
| 2012 | 2653 | 2668 | -15 |
| 2013 | 2718 | 2668 | 50 |
| 2014 | 2784 | 2868 | -84 |

## 4.13 REQUIREMENT FOR MAJOR SUPPLY

The need for major supply is determined by calculating the difference between the firm load forecast (see Section 4.9) and the ability of the existing system to supply that load, after the additional load meeting capability of the assumed new hydraulic additions (Section 4.12) and purchase non-utility generation (Section 4.8) are considered.

Figures 4.13-1 through 4.13-5 show how this was determined for each of the five load forecast cases. These curves are analogues of Figures 13-1 through 13-3 of the Plan Report.

Figure 4.13-6 shows the projected need for new major supply (in capacity terms) for all five load forecast paths and is analogous to Figure 13-5 in the Plan Report. These two figures are in general agreement. Any differences are insignificant compared to the uncertainty in load growth which is captured by the bandwidth forecast.

## 4.14 MAJOR SUPPLY OPTIONS

Chapter 13 of the Plan Report and Section 4.13 above identify the projected need for new major supply under the five load forecast paths considered. Chapter 14 of the Plan Report presents a full discussion of the process and rationale which Hydro employed when selecting supply options in order to meet these requirements. That discussion will not be repeated.

Chapter 14 also presents the siting and transmission considerations which were factored into the demand/supply case formulation process. These siting and transmission considerations will not be discussed further here. However, the specific illustrative sites selected for analysis and the transmission facilities required for demand/supply cases under the Branch Upper and Branch Lower forecast conditions are discussed in Chapter 5.

FIGURE 4.13-1
REQUIRED MAJOR SUPPLY - LMC - PEAK POWER DEMAND
(DATA USED IN ANALYSIS)

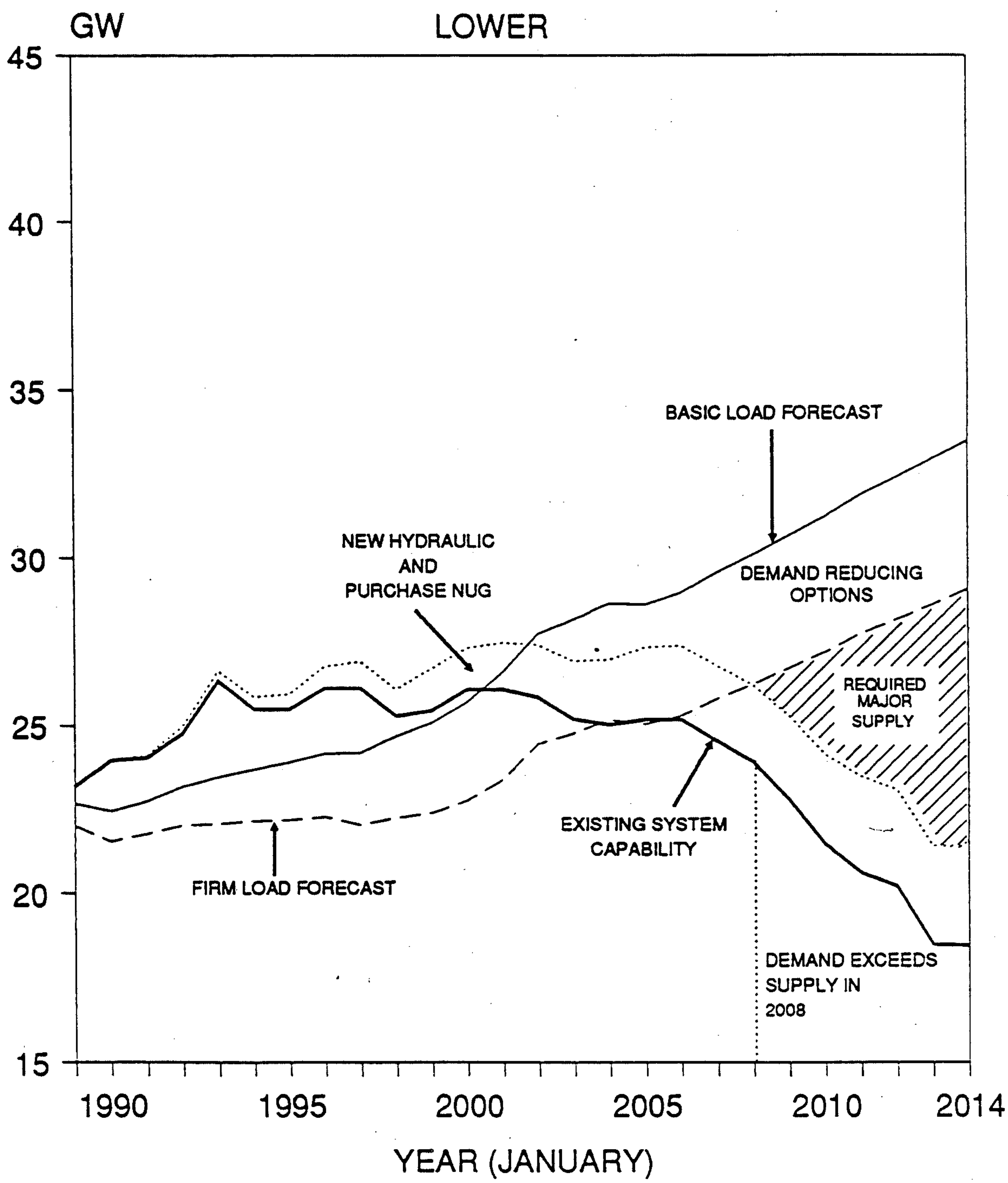


FIGURE 4.13-2
REQUIRED MAJOR SUPPLY - LMC - PEAK POWER DEMAND
(DATA USED IN ANALYSIS)

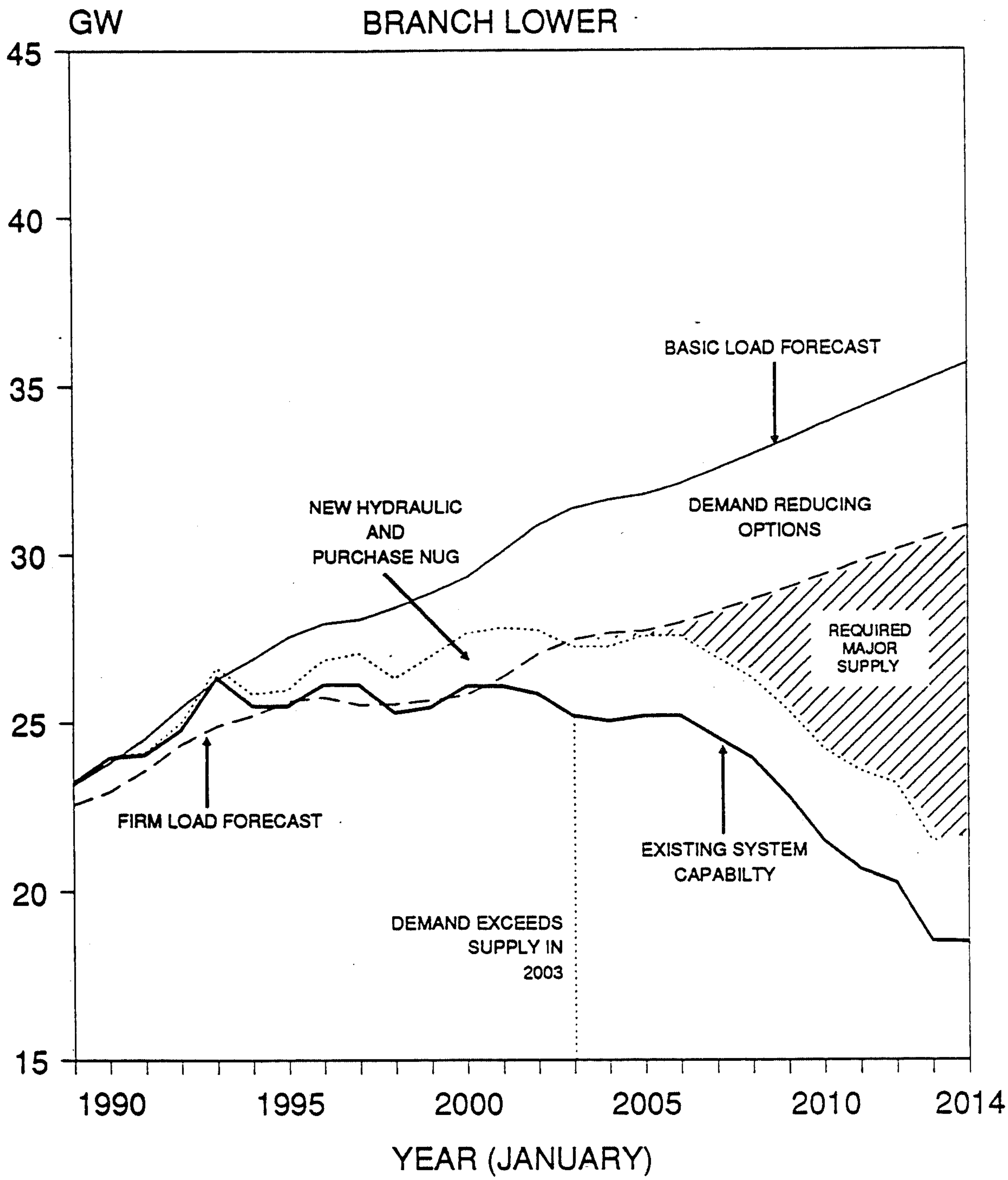


FIGURE 4.13-3
REQUIRED MAJOR SUPPLY - LMC - PEAK POWER DEMAND
(DATA USED IN ANALYSIS)

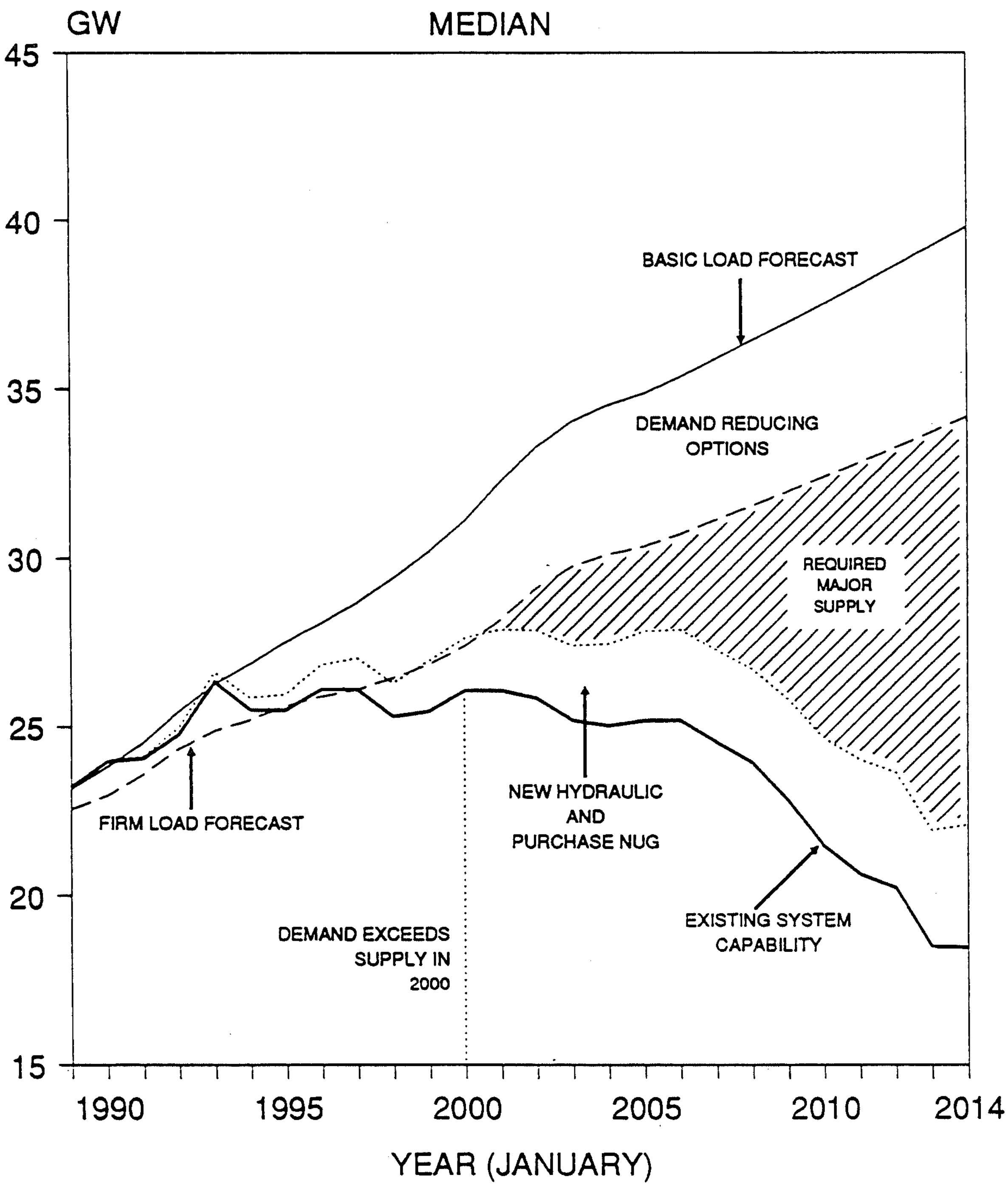


FIGURE 4.13-4

REQUIRED MAJOR SUPPLY - LMC - PEAK POWER DEMAND

(DATA USED IN ANALYSIS)

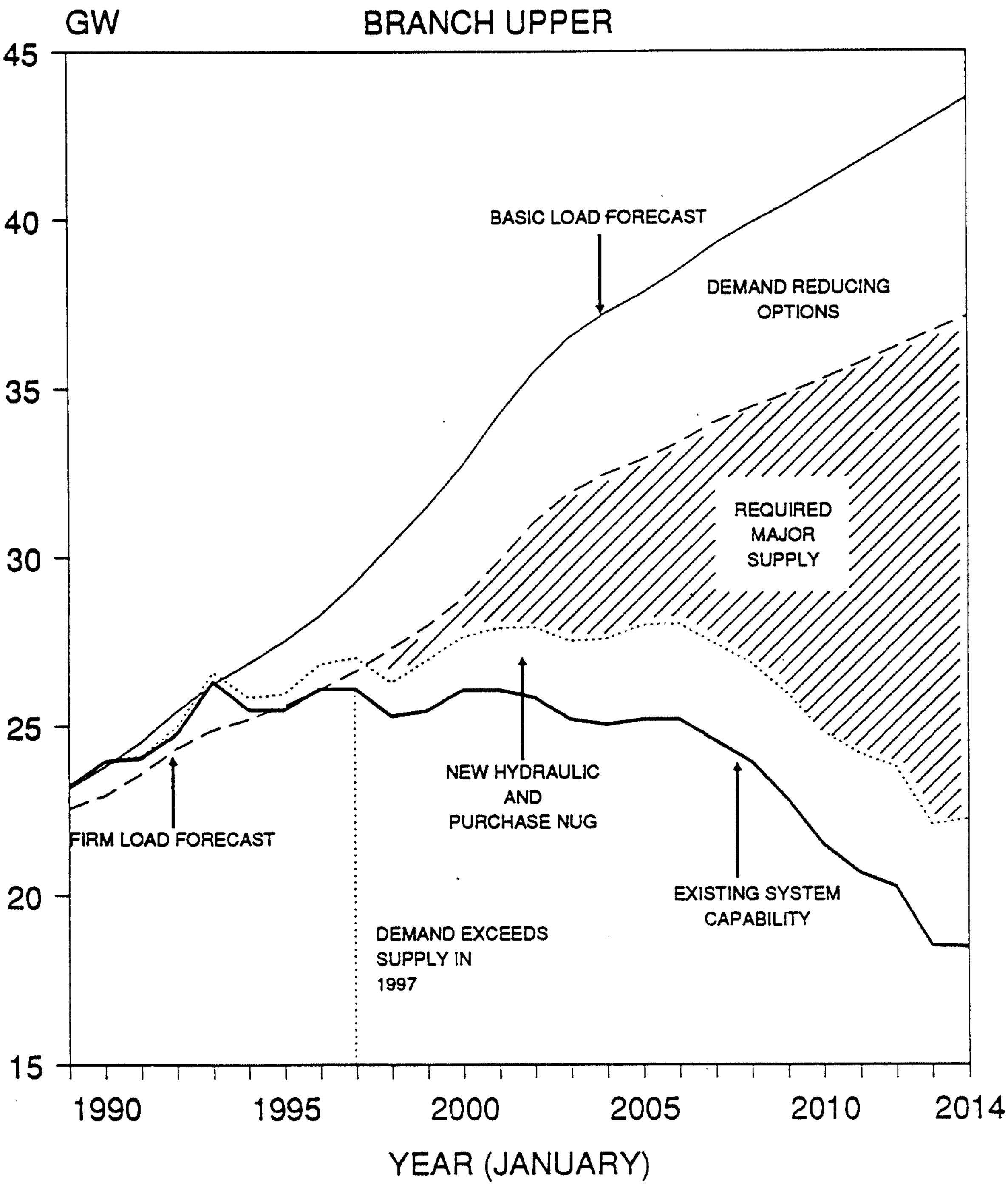


FIGURE 4.13-5
REQUIRED MAJOR SUPPLY - LMC - PEAK POWER DEMAND
(DATA USED IN ANALYSIS)

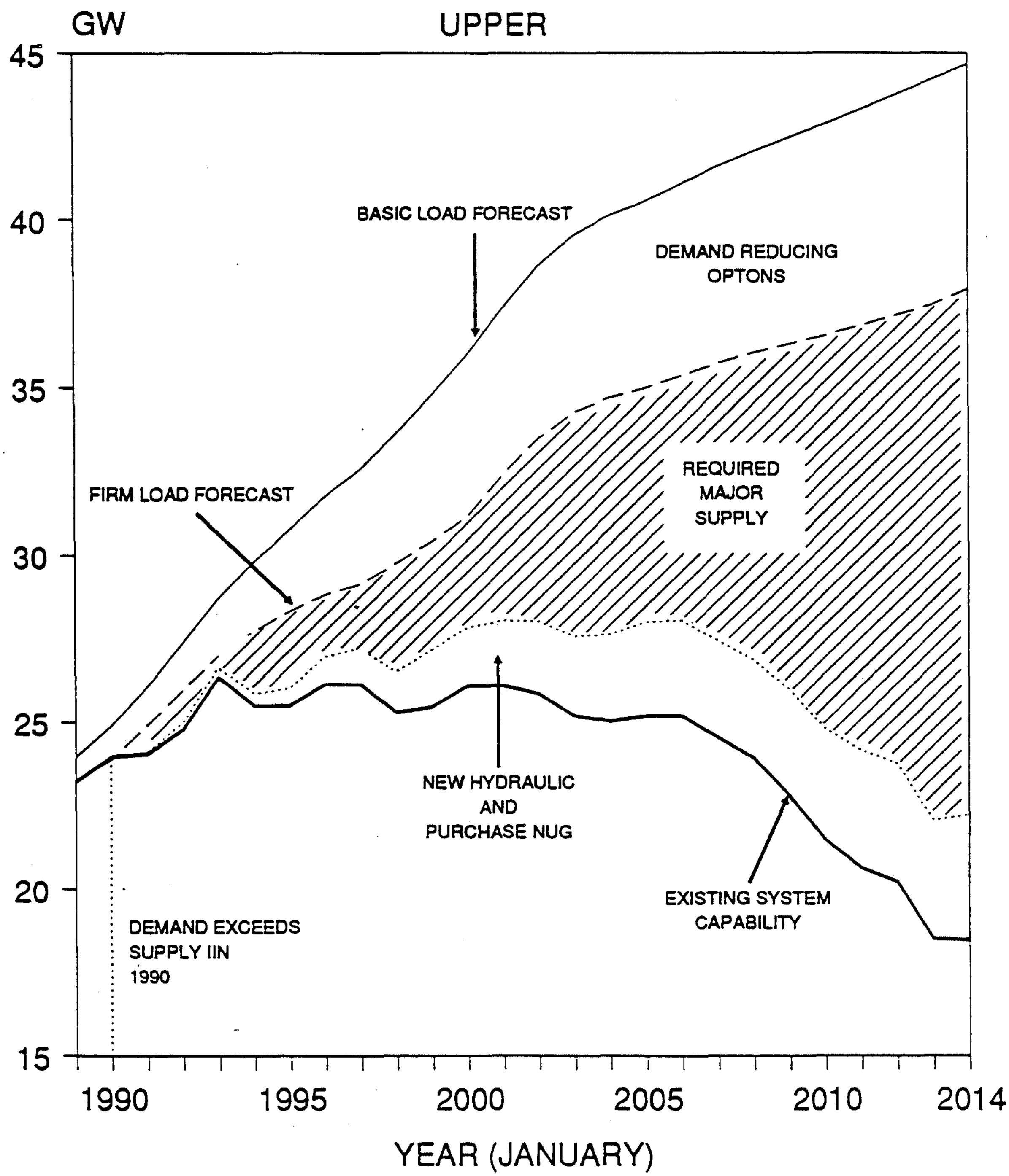
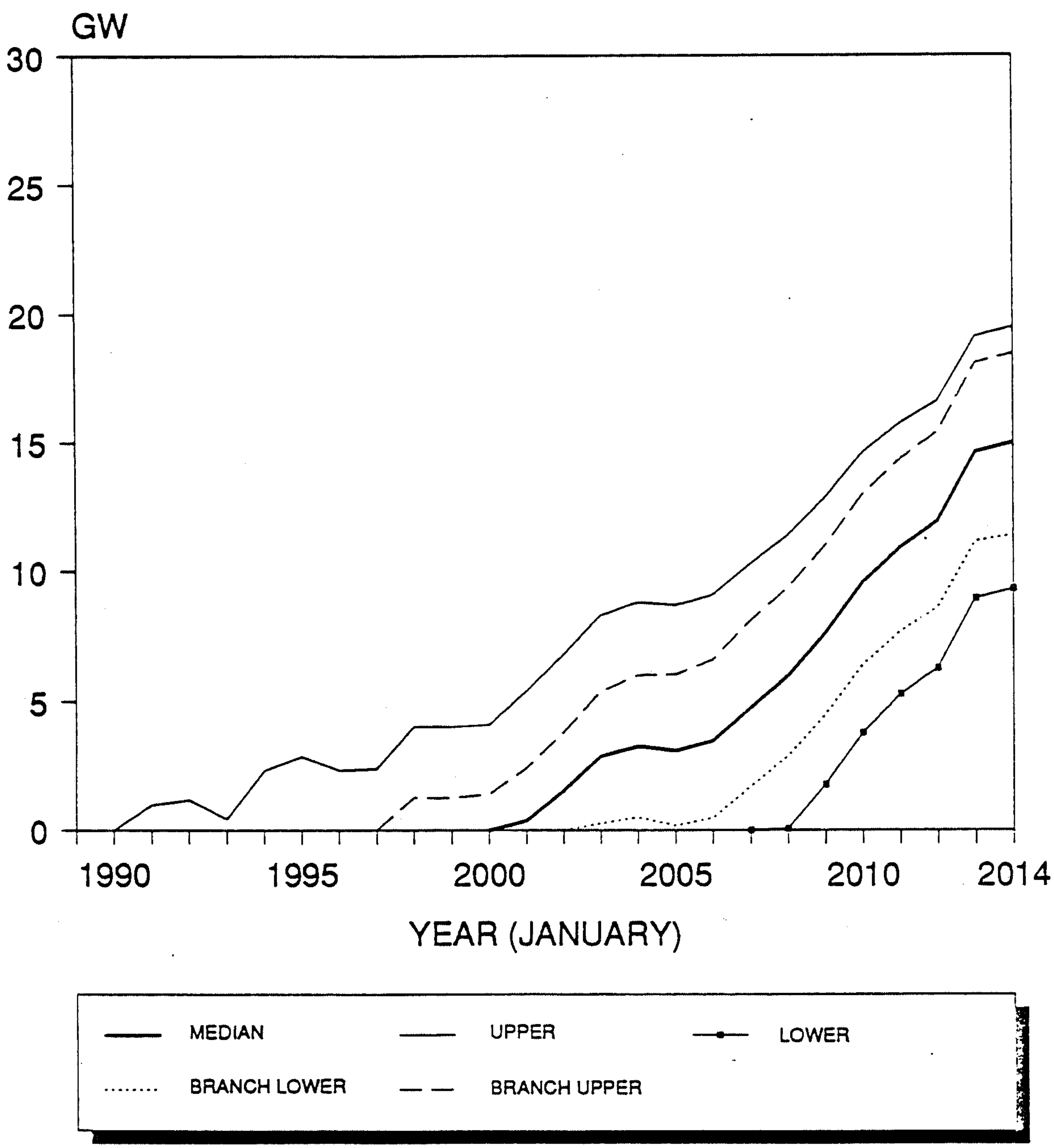


FIGURE 4.13-6
REQUIRED MAJOR SUPPLY CAPACITY - PEAK POWER DEMAND



## 4.15 MAJOR SUPPLY PLANS

When formulating demand/supply cases, it is necessary to ensure that they can respond adequately to higher or lower demand than was originally expected. That is the reason that all of the cases considered in the Demand/Supply planning process were tested against the five load path constituents of the bandwidth forecast.

One major influence on plan flexibility is the time that it takes to provide a new generating facility. This "leadtime" can be conveniently broken down into two phases: definition and acquisition. The definition phase is the period from the formulation of the intent to install a facility to the date on which that project is commited. The acquisition phase is the period from the decision to build to the in-service date.

The shorter the acquisition phase for a new facility, the closer to the need date that the commitment decision can be made. This is advantageous as there will be less uncertainty as to the eventual need for the facility.

The total leadtime (definition + acquisition) of a facility also has an important influence on plan flexibility. The longer the total leadtime of an option, the more difficult it is to respond to unexpectedly high load growth with that option.

Figure 15-6 of the Plan Report presents typical ranges of leadtimes which are projected for the options which appear in the demand/supply cases. For purposes of analysis, point estimates of the definition and acquisition leadtimes were used rather than ranges. These are tabulated in Figure 4.15-1.

Chapter 15 of the Plan Report presents the in-service dates and capacities of new facilities appearing in major supply cases. Figures 15-10, 15-13, 15-16, 15-19, and 15-22 in the Plan Report provide this detailed information for the Upper, Median, and Lower load forecast paths. Figures 4.15-2 through 4.15-6 in the following pages present the same information, supplemented by the corresponding data for the Branch Upper and Branch Lower load forecasts.

## 4.16 AVOIDED COST DETERMINATION

The subject of avoided costs is addressed fully in the Plan Report. Hence, it is not discussed in the Analysis Report.

## FIGURE 4.15-1: OPTION LEAD TIMES USED IN ANALYSES

| OPTION | DESCRIPTION | ASSUMED LEADTIMES (YEARS) * EXISTING SITES DEFINITION | CONSTRUCTION | TOTAL | NEW SITES DEFINITION | CONSTRUCTION | TOTAL | MONTHS BETWEEN UNITS IN-SERVICE |
|---|---|---|---|---|---|---|---|---|
| 1 | 4x800 MW US COAL CSC/FGD/SCR | 5.75 | 5.5 | 11.25 | 5.75 | 6.5 | 12.25 | 12 |
| 5 | 2x150 MW CTU/NC | 2 | 1.25 | 3.25 | - | - | - | 6 |
| 7 | CTU/CC (1st PHASE) | 5.75 | 2 | 7.75 | 5.75 | 3 | 8.75 | 9 |
| 8 | CTU/IGCC (1st PHASE) | 5.75 | 2 | 7.75 | 5.75 | 3 | 8.75 | 9 |
| 11 | 4x881 MW CANDU | 4.75 | 7.5 | 12.25 | 4.75 | 8.5 | 13.25 | 12 |
|  | HEARN REHABILITATION | - | - | 4 | N/A | N/A | N/A | N/A |

* CONSTRUCTION LEADTIME COVERS THE PERIOD FROM PROJECT COMMITMENT TO FIRST UNIT, FIRST POWER

# Figure 4.15-2

## MAJOR SUPPLY ADDITIONS BY 2014

## Case 15

LOWER FORECAST

Capacity Added By Year End

| Option | Station | Units | Capacity (GW) | 1990 | 1991 | 1992 | 1993 | 1994 | 1995 | 1996 | 1997 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Manitoba Purchase | | | 1.000 | | | | | | | | | 200 | | 200 | 200 | 400 | | | | | | | | | | | |
| CTU/CC | A | 1-6 | 1.008 | | | | | | | | | | | | | | | | | | | 672 | 336 | | | | |
| CTU/IGCC | A | 1-12 | 2.016 | | | | | | | | | | | | | | | | | | | | 1008 | 336 | 336 | 336 | |
| CANDU | B | 1-4 | 3.524 | | | | | | | | | | | | | | | | | | | | 881 | 881 | 881 | 881 | |
| CTU/IGCC | B | 13-14 | 0.336 | | | | | | | | | | | | | | | | | | | | | | | 336 | |
| CANDU | A | 5-6 | 1.762 | | | | | | | | | | | | | | | | | | | | | | | 881 | 881 |
| Total (GW) | | | 9.646 | | | | | | | | | | | | | | | | | | | | | | | | |

BRANCH LOWER FORECAST

Capacity Added By Year End

| Option | Station | Units | Capacity (GW) | 1990 | 1991 | 1992 | 1993 | 1994 | 1995 | 1996 | 1997 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Manitoba Purchase | | | 1.000 | | | | | | | | | 200 | | 200 | 200 | 400 | | | | | | | | | | | |
| CANDU | A | 1-4 | 3.524 | | | | | | | | | | | | | | 881 | 881 | 881 | 881 | | | | | | | |
| CTU/CC | A | 1-6 | 1.008 | | | | | | | | | | | | | | | | | | | | 1008 | | | | |
| CTU/IGCC | A | 1-12 | 2.016 | | | | | | | | | | | | | | | | | | | | 1008 | 1008 | | | |
| CANDU | B | 5-7 | 2.643 | | | | | | | | | | | | | | | | | | | | | | 881 | 881 | 881 |
| CTU/IGCC | B | 13-22 | 1.680 | | | | | | | | | | | | | | | | | | | | | | | 1680 | |
| Total (GW) | | | 11.671 | | | | | | | | | | | | | | | | | | | | | | | | |

MEDIAN FORECAST

Capacity Added By Year End

| Option | Station | Units | Capacity (GW) | 1990 | 1991 | 1992 | 1993 | 1994 | 1995 | 1996 | 1997 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Manitoba Purchase | | | 1.000 | | | | | | | | | 200 | | 200 | 200 | 400 | | | | | | | | | | | |
| CTU/CC | A | 1-6 | 1.008 | | | | | | | | | | | | 336 | 672 | | | | | | | | | | | |
| CTU/IGCC | A | 1-12 | 2.016 | | | | | | | | | | | | | 336 | | | | | | 1680 | | | | | |
| CANDU | A | 1-4 | 3.524 | | | | | | | | | | | | | | 881 | 881 | 881 | 881 | | | | | | | |
| CTU/IGCC | B | 13-24 | 2.016 | | | | | | | | | | | | | | | | | | | | 1008 | 672 | | 336 | |
| CANDU | B | 5-8 | 3.524 | | | | | | | | | | | | | | | | | | | | 881 | 881 | 881 | 881 | |
| CTU/IGCC | C | 25-26 | 0.336 | | | | | | | | | | | | | | | | | | | | | | | 336 | |
| CANDU | C | 9-10 | 1.762 | | | | | | | | | | | | | | | | | | | | | | | 881 | 881 |
| Total (GW) | | | 15.186 | | | | | | | | | | | | | | | | | | | | | | | | |

## Figure 4.15-2(Cont'd)

BRANCH UPPER FORECAST — Capacity Added By Year End

| Option | Station | Units | Capacity (GW) | 1990 | 1991 | 1992 | 1993 | 1994 | 1995 | 1996 | 1997 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Manitoba Purchase | | | 1.000 | | | | | | | | | 200 | | 200 | 200 | 400 | | | | | | | | | | | |
| CTU/CC | A | | 1.008 | | | | | | | | | | | 1008 | | | | | | | | | | | | | |
| CTU/IGCC | A | | 2.016 | | | | | | | | | | | | 1344 | 672 | | | | | | | | | | | |
| CTU/CC | B | | 1.008 | | | | | | | | | | | | | 336 | | | | 336 | 336 | | | | | | |
| CANDU | A | | 3.524 | | | | | | | | | | | | | | 881 | 881 | 881 | 881 | | | | | | | |
| CANDU | B | | 3.524 | | | | | | | | | | | | | | | | | | 881 | 881 | 881 | 881 | | | |
| CTU/IGCC | B | | 2.016 | | | | | | | | | | | | | | | | | | | 672 | | | | 1344 | |
| CANDU | C | | 3.524 | | | | | | | | | | | | | | | | | | | | 881 | 881 | 881 | 881 | |
| CTU/IGCC | C | | 1.008 | | | | | | | | | | | | | | | | | | | | | | | 336 | 672 |
| | Total (GW) | | 18.628 | | | | | | | | | | | | | | | | | | | | | | | | |

UPPER FORECAST — Capacity Added By Year End

| Option | Station | Units | Capacity (GW) | 1990 | 1991 | 1992 | 1993 | 1994 | 1995 | 1996 | 1997 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Manitoba Purchase | | | 1.000 | | | | | | | | | 200 | | 200 | 200 | 400 | | | | | | | | | | | |
| CTU | A | 1-4 | 0.672 | | | | 672 | | | | | | | | | | | | | | | | | | | | |
| CTU | B | 5-8 | 0.672 | | | | | 672 | | | | | | | | | | | | | | | | | | | |
| CTU/IGCC | A | 1-12 | 2.016 | | | | | | | | 1344 | | | 336 | 336 | | | | | | | | | | | | |
| CTU | C | 9-10 | 0.336 | | | | | | | | | | | | 336 | | | | | | | | | | | | |
| CTU/IGCC | B | 13-18 | 1.008 | | | | | | | | | | | | 672 | 336 | | | | | | | | | | | |
| CANDU | A | 1-4 | 3.524 | | | | | | | | | | | | | 881 | 881 | 881 | 881 | | | | | | | | |
| CTU/IGCC | C | 19-24 | 1.008 | | | | | | | | | | | | | 336 | 336 | | | 336 | | | | | | | |
| CANDU | B | 5-8 | 3.524 | | | | | | | | | | | | | | | | | | 881 | 881 | 881 | 881 | | | |
| CANDU | C | 9-12 | 3.524 | | | | | | | | | | | | | | | | | | | 881 | 881 | 881 | 881 | | |
| CTU/IGCC | D | 25-28 | 0.672 | | | | | | | | | | | | | | | | | | | | | | | 672 | |
| CANDU | D | 13-14 | 1.762 | | | | | | | | | | | | | | | | | | | | | | | 881 | 881 |
| | Total (GW) | | 19.718 | | | | | | | | | | | | | | | | | | | | | | | | |

# Figure 4.15-3

## MAJOR SUPPLY ADDITIONS BY 2014

### Case 22

LOWER FORECAST — Capacity Added By Year End (MW)

| Option | Station | Units | Capacity (GW) | 1990 | 1991 | 1992 | 1993 | 1994 | 1995 | 1996 | 1997 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Manitoba Purchase | | | 1.000 | | | | | | | | | 200 | | 200 | 200 | 400 | | | | | | | | | | | |
| CANDU | A | 1-4 | 3.524 | | | | | | | | | | | | | | | | | | 881 | 881 | 881 | 881 | | | |
| CANDU | B | 5-8 | 3.524 | | | | | | | | | | | | | | | | | | | | | 881 | 881 | 881 | 881 |
| CTU/IGCC | A | 1-10 | 1.680 | | | | | | | | | | | | | | | | | | | | | | | 1680 | |
| Total (GW) | | | 9.728 | | | | | | | | | | | | | | | | | | | | | | | | |

BRANCH LOWER FORECAST — Capacity Added By Year End (MW)

| Option | Station | Units | Capacity (GW) | 1990 | 1991 | 1992 | 1993 | 1994 | 1995 | 1996 | 1997 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Manitoba Purchase | | | 1.000 | | | | | | | | | 200 | | 200 | 200 | 400 | | | | | | | | | | | |
| CNADU | A | 1-4 | 3.524 | | | | | | | | | | | | 881 | 881 | 881 | 881 | | | | | | | | | |
| CTU/CC | A | 1-6 | 1.008 | | | | | | | | | | | | | | | | | | | | 1008 | | | | |
| CTU/IGCC | A | 1-12 | 2.016 | | | | | | | | | | | | | | | | | | | | 1008 | 336 | | 672 | |
| CANDU | B | 5-8 | 3.524 | | | | | | | | | | | | | | | | | | | | | 881 | 881 | 881 | 881 |
| CTU/IGCC | B | 13-16 | 0.672 | | | | | | | | | | | | | | | | | | | | | | | 672 | |
| Total (GW) | | | 11.744 | | | | | | | | | | | | | | | | | | | | | | | | |

MEDIAN FORECAST — Capacity Added By Year End (MW)

| Option | Station | Units | Capacity (GW) | 1990 | 1991 | 1992 | 1993 | 1994 | 1995 | 1996 | 1997 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Manitoba Purchase | | | 1.000 | | | | | | | | | 200 | | 200 | 200 | 400 | | | | | | | | | | | |
| CANDU | A | 1-4 | 3.524 | | | | | | | | | | | | 881 | 881 | 881 | 881 | | | | | | | | | |
| CANDU | B | 5-8 | 3.524 | | | | | | | | | | | | | | | | | 881 | 881 | 881 | 881 | | | | |
| CTU/CC | A | 1-6 | 1.008 | | | | | | | | | | | | | | | | | | | 336 | 672 | | | | |
| CTU/IGCC | A | 1-12 | 2.016 | | | | | | | | | | | | | | | | | | | | 336 | 672 | | 1008 | |
| CANDU | C | 9-12 | 3.524 | | | | | | | | | | | | | | | | | | | | | 881 | 881 | 881 | 881 |
| CTU/IGCC | B | 13-16 | 0.672 | | | | | | | | | | | | | | | | | | | | | | | 672 | |
| Total (GW) | | | 15.268 | | | | | | | | | | | | | | | | | | | | | | | | |

## Figure 4.15-3(Cont'd)

BRANCH UPPER FORECAST

Capacity Added By Year End (MW)

| Option | Station | Units | Capacity (GW) | 1990 | 1991 | 1992 | 1993 | 1994 | 1995 | 1996 | 1997 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | — | — | — | — | — | — | — | — | — | — | — | — | — | — | — | — | — | — | — | — | — | — | — | — |
| Manitoba Purchase | | | 1.000 | | | | | | | | | 200 | | 200 | 200 | 400 | | | | | | | | | | | |
| CTU/CC | A | 1-8 | 1.008 | | | | | | | | | | | 672 | 336 | | | | | | | | | | | | |
| CANDU | A | 1-4 | 3.524 | | | | | | | | | | | | 881 | 881 | 881 | 881 | | | | | | | | | |
| CTU/GCC | A | 1-12 | 2.016 | | | | | | | | | | | | | 672 | | | 336 | 336 | | | | 336 | 336 | | |
| CANDU | B | 5-8 | 3.524 | | | | | | | | | | | | | | | | | 881 | 881 | 881 | 881 | | | | |
| CANDU | C | 9-12 | 3.524 | | | | | | | | | | | | | | | | | | 881 | 881 | 881 | 881 | | | |
| CTU/GCC | B | 13-24 | 2.016 | | | | | | | | | | | | | | | | | | | | | | 672 | 1344 | |
| CTU/GCC | C | 25-36 | 0.336 | | | | | | | | | | | | | | | | | | | | | | | 336 | |
| CANDU | D | 13-14 | 1.762 | | | | | | | | | | | | | | | | | | | | | | | 881 | 881 |
| Total (GW) | | | 18.710 | | | | | | | | | | | | | | | | | | | | | | | | |

UPPER FORECAST

Capacity Added By Year End (MW)

| Option | Station | Units | Capacity (GW) | 1990 | 1991 | 1992 | 1993 | 1994 | 1995 | 1996 | 1997 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | — | — | — | — | — | — | — | — | — | — | — | — | — | — | — | — | — | — | — | — | — | — | — | — |
| Manitoba Purchase | | | 1.000 | | | | | | | | | 200 | | 200 | 200 | 400 | | | | | | | | | | | |
| CTU/NC | A | 1-4 | 0.672 | | | | 672 | | | | | | | | | | | | | | | | | | | | |
| CTU/NC | B | 5-8 | 0.672 | | | | | 672 | | | | | | | | | | | | | | | | | | | |
| CTU/GCC | A | 1-12 | 2.016 | | | | | | | | 1344 | | | 336 | 336 | | | | | | | | | | | | |
| CANDU | A | 1-4 | 3.524 | | | | | | | | | | | | 881 | 881 | 881 | 881 | | | | | | | | | |
| CTU/CC | A | 1-4 | 0.672 | | | | | | | | | | | | | 672 | | | | | | | | | | | |
| CTU/CC | B | 5-10 | 1.008 | | | | | | | | | | | | | | 336 | | | | | | 672 | | | | |
| CANDU | B | 5-8 | 3.524 | | | | | | | | | | | | | | | | 881 | 881 | 881 | 881 | | | | | |
| CANDU | C | 9-12 | 3.524 | | | | | | | | | | | | | | | | | | | 881 | 881 | 881 | 881 | | |
| CTU/GCC | B | 13-16 | 0.672 | | | | | | | | | | | | | | | | | | | | | | | 672 | |
| CANDU | D | 13-15 | 2.643 | | | | | | | | | | | | | | | | | | | | | | 881 | 881 | 881 |
| Total (GW) | | | 19.927 | | | | | | | | | | | | | | | | | | | | | | | | |

# Figure 4.15-4

## MAJOR SUPPLY ADDITIONS BY 2014

### Case 23

LOWER FORECAST

Capacity Added By Year End (MW)

| Option | Station | Units | Capacity (GW) | 1990 | 1991 | 1992 | 1993 | 1994 | 1995 | 1996 | 1997 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Manitoba Purchase | | | 1.000 | | | | | | | | | 200 | | 200 | 200 | 400 | | | | | | | | | | | |
| CANDU | A | 1-4 | 3.524 | | | | | | | | | | 881 | 881 | 881 | 881 | | | | | | | | | | | |
| CANDU | B | 5-8 | 3.524 | | | | | | | | | | | | | | | | | | | | | 881 | 881 | 881 | 881 |
| CANDU | C | 9-10 | 1.762 | | | | | | | | | | | | | | | | | | | | | | | 881 | 881 |
| CTU/GCC | A | 1-2 | 0.336 | | | | | | | | | | | | | | | | | | | | | | | 336 | |

Total (GW) 10.146

BRANCH LOWER FORECAST

Capacity Added By Year End (MW)

| Option | Station | Units | Capacity (GW) | 1990 | 1991 | 1992 | 1993 | 1994 | 1995 | 1996 | 1997 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Manitoba Purchase | | | 1.000 | | | | | | | | | 200 | | 200 | 200 | 400 | | | | | | | | | | | |
| CANDU | A | 1-4 | 3.524 | | | | | | | | | | 881 | 881 | 881 | 881 | | | | | | | | | | | |
| CANDU | B | 5-8 | 3.524 | | | | | | | | | | | | | 881 | 881 | 881 | 881 | | | | | | | | |
| CANDU | C | 9-11 | 2.643 | | | | | | | | | | | | | | | | | | | | | | 881 | 881 | 881 |
| CANDU | D | 12-13 | 1.762 | | | | | | | | | | | | | | | | | | | | | | | 881 | 881 |

Total (GW) 12.453

MEDIAN FORECAST

Capacity Added By Year End (MW)

| Option | Station | Units | Capacity (GW) | 1990 | 1991 | 1992 | 1993 | 1994 | 1995 | 1996 | 1997 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Manitoba Purchase | | | 1.000 | | | | | | | | | 200 | | 200 | 200 | 400 | | | | | | | | | | | |
| CANDU | A | 1-4 | 3.524 | | | | | | | | | | 881 | 881 | 881 | 881 | | | | | | | | | | | |
| CANDU | B | 5-8 | 3.524 | | | | | | | | | | | | | 881 | 881 | 881 | 881 | | | | | | | | |
| CANDU | C | 9-12 | 3.524 | | | | | | | | | | | | | | | | | | | | 881 | 881 | 881 | 881 | |
| CANDU | D | 13-16 | 3.524 | | | | | | | | | | | | | | | | | | | | | 881 | 881 | 881 | 881 |

Total (GW) 15.096

## Figure 4.15-4 (Cont'd)

**BRANCH UPPER FORECAST**

Capacity Added By Year End (MW)

| Option | Station | Units | Capacity (GW) | 1990 | 1991 | 1992 | 1993 | 1994 | 1995 | 1996 | 1997 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Manitoba Purchase | | | 1.000 | | | | | | | | | 200 | | 200 | 200 | 400 | | | | | | | | | | | |
| CANDU | A | 1-4 | 3.524 | | | | | | | | | | 881 | 881 | 881 | 881 | | | | | | | | | | | |
| CANDU | B | 5-8 | 3.524 | | | | | | | | | | | | | 881 | 881 | 881 | 881 | | | | | | | | |
| CANDU | C | 9-12 | 3.524 | | | | | | | | | | | | | | | | | | 881 | 881 | 881 | 881 | | | |
| CANDU | D | 13-16 | 3.524 | | | | | | | | | | | | | | | | | | | 881 | 881 | 881 | 881 | | |
| CTU/IGCC | A | 1-8 | 1.008 | | | | | | | | | | | | | | | | | | | | | | | 1008 | |
| CANDU | E | 17-18 | 1.762 | | | | | | | | | | | | | | | | | | | | | | | 881 | 881 |
| CANDU | F | 19-20 | 1.762 | | | | | | | | | | | | | | | | | | | | | | | 881 | 881 |

Total (GW) 19.628

**UPPER FORECAST**

Capacity Added By Year End (MW)

| Option | Station | Units | Capacity (GW) | 1990 | 1991 | 1992 | 1993 | 1994 | 1995 | 1996 | 1997 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Manitoba Purchase | | | 1.000 | | | | | | | | | 200 | | 200 | 200 | 400 | | | | | | | | | | | |
| CTU/NC | A | 1-4 | 0.672 | | | | 672 | | | | | | | | | | | | | | | | | | | | |
| CTU/NC | B | 5-8 | 0.672 | | | | | 672 | | | | | | | | | | | | | | | | | | | |
| CTU/IGCC | A | 1-8 | 1.344 | | | | | | | | 1344 | | | | | | | | | | | | | | | | |
| CANDU | A | 1-4 | 3.524 | | | | | | | | | | 881 | 881 | 881 | 881 | | | | | | | | | | | |
| CANDU | B | 5-8 | 3.524 | | | | | | | | | | | | | 881 | 881 | 881 | 881 | | | | | | | | |
| CANDU | C | 9-12 | 3.524 | | | | | | | | | | | | | | | | | | 881 | 881 | 881 | 881 | | | |
| CANDU | D | 13-16 | 3.524 | | | | | | | | | | | | | | | | | | | 881 | 881 | 881 | 881 | | |
| CANDU | E | 17-18 | 1.762 | | | | | | | | | | | | | | | | | | | | | | | 881 | 881 |

Total (GW) 19.544

# Figure 4.15-5

## MAJOR SUPPLY ADDITIONS BY 2014

## Case 24

LOWER FORECAST — Capacity Added By Year End (MW)

| Option | Station | Units | Capacity | (GW) | 1990 | 1991 | 1992 | 1993 | 1994 | 1995 | 1996 | 1997 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Manitoba Purchase | | | 1.000 | | | | | | | | | | 200 | | 200 | 200 | 400 | | | | | | | | | | | |
| CTU/CC | A | 1-6 | 1.008 | | | | | | | | | | | | | | | | | | | | 672 | 336 | | | | |
| CTU/IGCC | A | 1-12 | 2.016 | | | | | | | | | | | | | | | | | | | | | 1008 | 336 | 336 | 336 | |
| CANDU | A | 1-4 | 3.524 | | | | | | | | | | | | | | | | | | | | | 881 | 881 | 881 | 881 | |
| CSC COAL | A | 1-2 | 1.482 | | | | | | | | | | | | | | | | | | | | | | | | 741 | 741 |
| CTU/IGCC | B | 13-14 | 0.336 | | | | | | | | | | | | | | | | | | | | | | | | 336 | |
| | Total (GW) | | 9.366 | | | | | | | | | | | | | | | | | | | | | | | | | |

BRANCH LOWER FORECAST — Capacity Added By Year End (MW)

| Option | Station | Units | Capacity | (GW) | 1990 | 1991 | 1992 | 1993 | 1994 | 1995 | 1996 | 1997 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Manitoba Purchase | | | 1.000 | | | | | | | | | | 200 | | 200 | 200 | 400 | | | | | | | | | | | |
| CANDU | A | 1-4 | 3.524 | | | | | | | | | | | | | | | 881 | 881 | 881 | 881 | | | | | | | |
| CTU/CC | A | 1-6 | 1.008 | | | | | | | | | | | | | | | | | | | | 672 | 336 | | | | |
| CTU/IGCC | A | 1-12 | 2.016 | | | | | | | | | | | | | | | | | | | | | 1680 | 336 | | | |
| CTU/IGCC | B | 13-24 | 2.016 | | | | | | | | | | | | | | | | | | | | | | 672 | | 1344 | |
| CSC COAL | A | 1-4 | 2.223 | | | | | | | | | | | | | | | | | | | | | | | 741 | 741 | 741 |
| | Total (GW) | | 11.767 | | | | | | | | | | | | | | | | | | | | | | | | | |

MEDIAN FORECAST — Capacity Added By Year End (MW)

| Option | Station | Units | Capacity | (GW) | 1990 | 1991 | 1992 | 1993 | 1994 | 1995 | 1996 | 1997 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Manitoba Purchase | | | 1.000 | | | | | | | | | | 200 | | 200 | 200 | 400 | | | | | | | | | | | |
| CTU/CC | A | 1-6 | 1.008 | | | | | | | | | | | | | 336 | 672 | | | | | | | | | | | |
| CTU/IGCC | A | 1-12 | 2.016 | | | | | | | | | | | | | | 336 | | | | | 672 | 1008 | | | | | |
| CANDU | A | 1-4 | 3.524 | | | | | | | | | | | | | | | 881 | 881 | 881 | 881 | | | | | | | |
| CTU/IGCC | B | 13-24 | 2.016 | | | | | | | | | | | | | | | | | | | | 672 | 1008 | 336 | | | |
| CSC COAL | A | 1-4 | 2.964 | | | | | | | | | | | | | | | | | | | | | 741 | 741 | 741 | 741 | |
| CTU/IGCC | C | 25-30 | 1.008 | | | | | | | | | | | | | | | | | | | | | | 336 | | 672 | |
| CANDU | B | 5-6 | 1.762 | | | | | | | | | | | | | | | | | | | | | | | | 881 | 881 |
| | Total (GW) | | 15.298 | | | | | | | | | | | | | | | | | | | | | | | | | |

# Figure 4.15-5(cont'd)

BRANCH UPPER FORECAST — Capacity Added By Year End (MW)

| Option | Station | Units | Capacity (GW) | 1990 | 1991 | 1992 | 1993 | 1994 | 1995 | 1996 | 1997 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Manitoba Purchase | | | 1.000 | | | | | | | | | 200 | | 200 | 200 | 400 | | | | | | | | | | | |
| CTU/CC | A | 1-6 | 1.008 | | | | | | | | | | | 1008 | | | | | | | | | | | | | |
| CTU/IGCC | A | 1-12 | 2.016 | | | | | | | | | | | | 1344 | 672 | | | | | | | | | | | |
| CTU/CC | B | 7-12 | 1.008 | | | | | | | | | | | | | 336 | | | | 672 | | | | | | | |
| CANDU | A | 1-4 | 3.524 | | | | | | | | | | | | | | 881 | 881 | 881 | 881 | | | | | | | |
| CSC COAL | A | 1-4 | 2.964 | | | | | | | | | | | | | | | | | | 741 | 741 | 741 | 741 | | | |
| CTU/IGCC | B | 13-24 | 2.016 | | | | | | | | | | | | | | | | | | 336 | 672 | 336 | | | 672 | |
| CANDU | B | 5-8 | 3.524 | | | | | | | | | | | | | | | | | | | | 881 | 881 | 881 | 881 | |
| CTU/IGCC | C | 25-34 | 1.680 | | | | | | | | | | | | | | | | | | | | | | | 1008 | 672 |
| Total (GW) | | | 18.740 | | | | | | | | | | | | | | | | | | | | | | | | |

UPPER FORECAST — Capacity Added By Year End (MW)

| Option | Station | Units | Capacity (GW) | 1990 | 1991 | 1992 | 1993 | 1994 | 1995 | 1996 | 1997 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Manitoba Purchase | | | 1.000 | | | | | | | | | 200 | | 200 | 200 | 400 | | | | | | | | | | | |
| CTU/NC | A | 1-4 | 0.672 | | | | 672 | | | | | | | | | | | | | | | | | | | | |
| CTU/NC | B | 5-8 | 0.672 | | | | | 672 | | | | | | | | | | | | | | | | | | | |
| CTU/IGCC | A | 1-12 | 2.016 | | | | | | | | 1344 | | | 336 | 336 | | | | | | | | | | | | |
| CTU/IGCC | B | 13-18 | 1.008 | | | | | | | | | | | | 1008 | | | | | | | | | | | | |
| CTU/CC | A | 1-4 | 0.672 | | | | | | | | | | | | | 672 | | | | | | | | | | | |
| CANDU | A | 1-4 | 3.524 | | | | | | | | | | | | | 881 | 881 | 881 | 881 | | | | | | | | |
| CTU/CC | B | 5-10 | 1.008 | | | | | | | | | | | | | | 336 | | | 672 | | | | | | | |
| CTU/IGCC | C | 19-24 | 1.008 | | | | | | | | | | | | | | | | | 336 | | | | | | 672 | |
| CSC COAL | A | 1-4 | 2.964 | | | | | | | | | | | | | | | | | | 741 | 741 | 741 | 741 | | | |
| CANDU | B | 5-8 | 3.524 | | | | | | | | | | | | | | | | | | | 881 | 881 | 881 | 881 | | |
| CANDU | C | 9-10 | 1.762 | | | | | | | | | | | | | | | | | | | | | | | 881 | 881 |
| Total (GW) | | | 19.830 | | | | | | | | | | | | | | | | | | | | | | | | |

# Figure 4.15-6

## MAJOR SUPPLY ADDITIONS BY 2014

### Case 26

LOWER FORECAST

Capacity Added By Year End (MW)

| Option | Station | Units | Capacity (GW) | 1990 | 1991 | 1992 | 1993 | 1994 | 1995 | 1996 | 1997 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Manitoba Purchase | | | 1.000 | | | | | | | | | 200 | | 200 | 200 | 400 | | | | | | | | | | | |
| CTU/CC | A | 1-6 | 1.008 | | | | | | | | | | | | | | | | | | | 672 | 336 | | | | |
| CTU/IGCC | A | 1-12 | 2.016 | | | | | | | | | | | | | | | | | | | | 1008 | 336 | 672 | | |
| CSC COAL | A | 1-4 | 2.964 | | | | | | | | | | | | | | | | | | | | 741 | 741 | 741 | 741 | |
| CSC COAL | B | 5-6 | 1.482 | | | | | | | | | | | | | | | | | | | | | | | 741 | 741 |
| CTU/IGCC | B | 13-18 | 1.008 | | | | | | | | | | | | | | | | | | | | | | | 1008 | |

Total (GW) 9.478

BRANCH LOWER FORECAST

Capacity Added By Year End (MW)

| Option | Station | Units | Capacity (GW) | 1990 | 1991 | 1992 | 1993 | 1994 | 1995 | 1996 | 1997 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Manitoba Purchase | | | 1.000 | | | | | | | | | 200 | | 200 | 200 | 400 | | | | | | | | | | | |
| CSC COAL | A | 1-4 | 2.964 | | | | | | | | | | | | | | 741 | 741 | 741 | 741 | | | | | | | |
| CTU/CC | A | 1-6 | 1.008 | | | | | | | | | | | | | | | | | | | 336 | 672 | | | | |
| CTU/IGCC | A | 1-12 | 2.016 | | | | | | | | | | | | | | | | | | | | 1344 | 672 | | | |
| CTU/IGCC | B | 13-24 | 2.016 | | | | | | | | | | | | | | | | | | | | | 672 | 336 | 1008 | |
| CSC COAL | B | 5-7 | 2.223 | | | | | | | | | | | | | | | | | | | | | | 741 | 741 | 741 |
| CTU/IGCC | C | 25-28 | 0.672 | | | | | | | | | | | | | | | | | | | | | | | 672 | |

Total (GW) 11.699

MEDIAN FORECAST

Capacity Added By Year End (MW)

| Option | Station | Units | Capacity (GW) | 1990 | 1991 | 1992 | 1993 | 1994 | 1995 | 1996 | 1997 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Manitoba Purchase | | | 1.000 | | | | | | | | | 200 | | 200 | 200 | 400 | | | | | | | | | | | |
| CTU/CC | A | 1-6 | 1.008 | | | | | | | | | | | | 336 | 672 | | | | | | | | | | | |
| CTU/IGCC | A | 1-12 | 2.016 | | | | | | | | | | | | | 336 | | | | | 672 | 1008 | | | | | |
| CSC COAL | A | 1-4 | 2.964 | | | | | | | | | | | | | | 741 | 741 | 741 | 741 | | | | | | | |
| CTU/IGCC | B | 13-24 | 2.016 | | | | | | | | | | | | | | | | | | | 672 | 1008 | 336 | | | |
| CSC COAL | B | 5-8 | 2.964 | | | | | | | | | | | | | | | | | | | | 741 | 741 | 741 | 741 | |
| CTU/IGCC | C | 25-34 | 1.680 | | | | | | | | | | | | | | | | | | | | | 336 | 336 | 1008 | |
| CSC COAL | C | 9-10 | 1.482 | | | | | | | | | | | | | | | | | | | | | | | 741 | 741 |

Total (GW) 15.130

# Figure 4.15-6 (Cont'd)

BRANCH UPPER FORECAST

Capacity Added By Year End (MW)

| Option | Station | Units | Capacity (GW) | 1990 | 1991 | 1992 | 1993 | 1994 | 1995 | 1996 | 1997 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Manitoba Purchase | | | 1.000 | | | | | | | | | 200 | | 200 | 200 | 400 | | | | | | | | | | | |
| CTU/CC | A | 1-6 | 1.008 | | | | | | | | | | | 1008 | | | | | | | | | | | | | |
| CTU/IGCC | A | 1-12 | 2.016 | | | | | | | | | | | | 1344 | 672 | | | | | | | | | | | |
| CTU/IGCC | B | 13-18 | 1.008 | | | | | | | | | | | | | 336 | | | | 672 | | | | | | | |
| CSC COAL | A | 1-4 | 2.964 | | | | | | | | | | | | | | 741 | 741 | 741 | 741 | | | | | | | |
| CTU/CC | B | 7-12 | 1.008 | | | | | | | | | | | | | | | | | | 336 | 672 | | | | | |
| CSC COAL | B | 5-8 | 2.964 | | | | | | | | | | | | | | | | | | 741 | 741 | 741 | 741 | | | |
| CTU/IGCC | C | 19-30 | 2.016 | | | | | | | | | | | | | | | | | | | 336 | 672 | | 336 | 672 | |
| CSC COAL | C | 9-12 | 2.964 | | | | | | | | | | | | | | | | | | | | 741 | 741 | 741 | 741 | |
| CTU/IGCC | D | 31-40 | 1.680 | | | | | | | | | | | | | | | | | | | | | | | 1008 | 672 |

Total (GW) 18.628

UPPER FORECAST

Capacity Added By Year End (MW)

| Option | Station | Units | Capacity (GW) | 1990 | 1991 | 1992 | 1993 | 1994 | 1995 | 1996 | 1997 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Manitoba Purchase | | | 1.000 | | | | | | | | | 200 | | 200 | 200 | 400 | | | | | | | | | | | |
| CTU/NC | A | 1-4 | 0.672 | | | | 672 | | | | | | | | | | | | | | | | | | | | |
| CTU/NC | B | 5-8 | 0.672 | | | | | 672 | | | | | | | | | | | | | | | | | | | |
| CTU/IGCC | A | 1-12 | 2.016 | | | | | | | | 1344 | | | 336 | 336 | | | | | | | | | | | | |
| CTU/IGCC | B | 13-18 | 1.008 | | | | | | | | | | | | 1008 | | | | | | | | | | | | |
| CTU/CC | A | 1-6 | 1.008 | | | | | | | | | | | | | 672 | 336 | | | | | | | | | | |
| CSC COAL | A | 1-4 | 2.964 | | | | | | | | | | | | | 741 | 741 | 741 | 741 | | | | | | | | |
| CTU/CC | B | 5-12 | 1.008 | | | | | | | | | | | | | | 336 | | | 672 | | | | | | | |
| CTU/IGCC | C | 19-30 | 2.016 | | | | | | | | | | | | | | | | | | 336 | | | | 336 | 1344 | |
| CSC COAL | B | 5-8 | 2.964 | | | | | | | | | | | | | | | | | | 741 | 741 | 741 | 741 | | | |
| CSC COAL | C | 9-12 | 2.964 | | | | | | | | | | | | | | | | | | | 741 | 741 | 741 | 741 | | |
| CSC COAL | D | 13-14 | 1.482 | | | | | | | | | | | | | | | | | | | | | | | 741 | 741 |

Total (GW) 19.774

## 4.17 DEMAND/SUPPLY PLANS

Figures 17-16, 17-17, and 17-18 in the Plan Report provide a convenient summary of the components of the three Alternative Demand/Supply Plans under Median forecast conditions. These were created from data appearing in Appendix I of this analysis report. Figures 4.17-1 through 4.17-15 below are comparable figures based on the data used in demand/supply case formulation. Figures are provided pertaining to the three Alternative Demand/Supply Plans under all five load forecast conditions.

For any given load forecast condition, the Demand Management contribution shown in these figures is that assumed to pertain to the corresponding load path during demand/supply case formulation and presented in Section 4.7 of this Analysis Report. The non-utility generation contribution is discussed in Section 4.8.

Common Rehabilitation and Hydraulic Generation Plans were assumed for all cases under all load forecast conditions, as shown in Figures 4.17-1 through 4.17-15. The assumed contributions are discussed in Analysis Report Sections 4.10 and 4.12, respectively. The Manitoba Purchase, which is also common to the five cases presented in the Plan Report, is discussed in detail in Chapters 14 and 15 of that Report.

For details on the magnitude and timing of major supply additions (new fossil or nuclear plant), which are shown for each of the Alternative Demand/Supply Plans in Figures 4.17-1 through 4.17-15, refer to the appropriate table appearing in Section 4.15.

## 4.18 ACTION PLANS

As stated in the Plan Report, an Action Plan is a set of timely actions which must be taken to implement a Demand/Supply Plan to meet effectively the future energy needs of the province. An Action Plan was developed for each of the Candidate Demand/Supply Plans which, if approved, would allow facilities required for the Upper load forecast condition to be placed into service in a timely manner. If the actual load growth trend is below the Upper forecast, project commitments would be delayed accordingly. Therefore, the Action Plans will cater to all five of the load forecast paths considered during plan formulation and analysis. Chapter 18 of the Plan Report presents these detailed Action Plans for the three Candidate Demand/Supply Plans and describes how these were developed. This discussion will not be repeated here.

FIGURE 4.17-1
PLAN 15
DATA USED IN ANALYSIS - LOWER

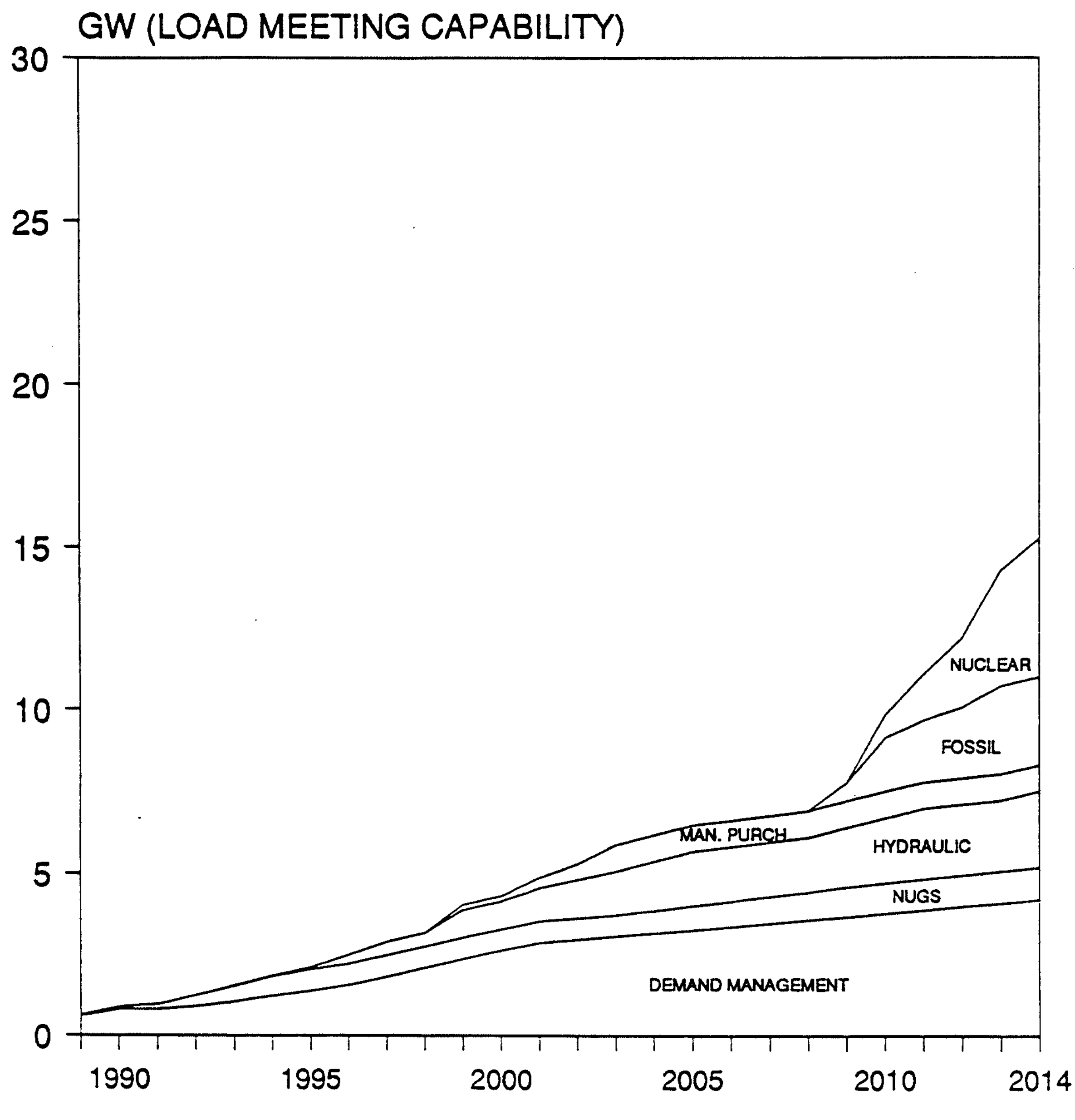


FIGURE 4.17-2

# PLAN 15

## DATA USED IN ANALYSIS - BRANCH LOWER

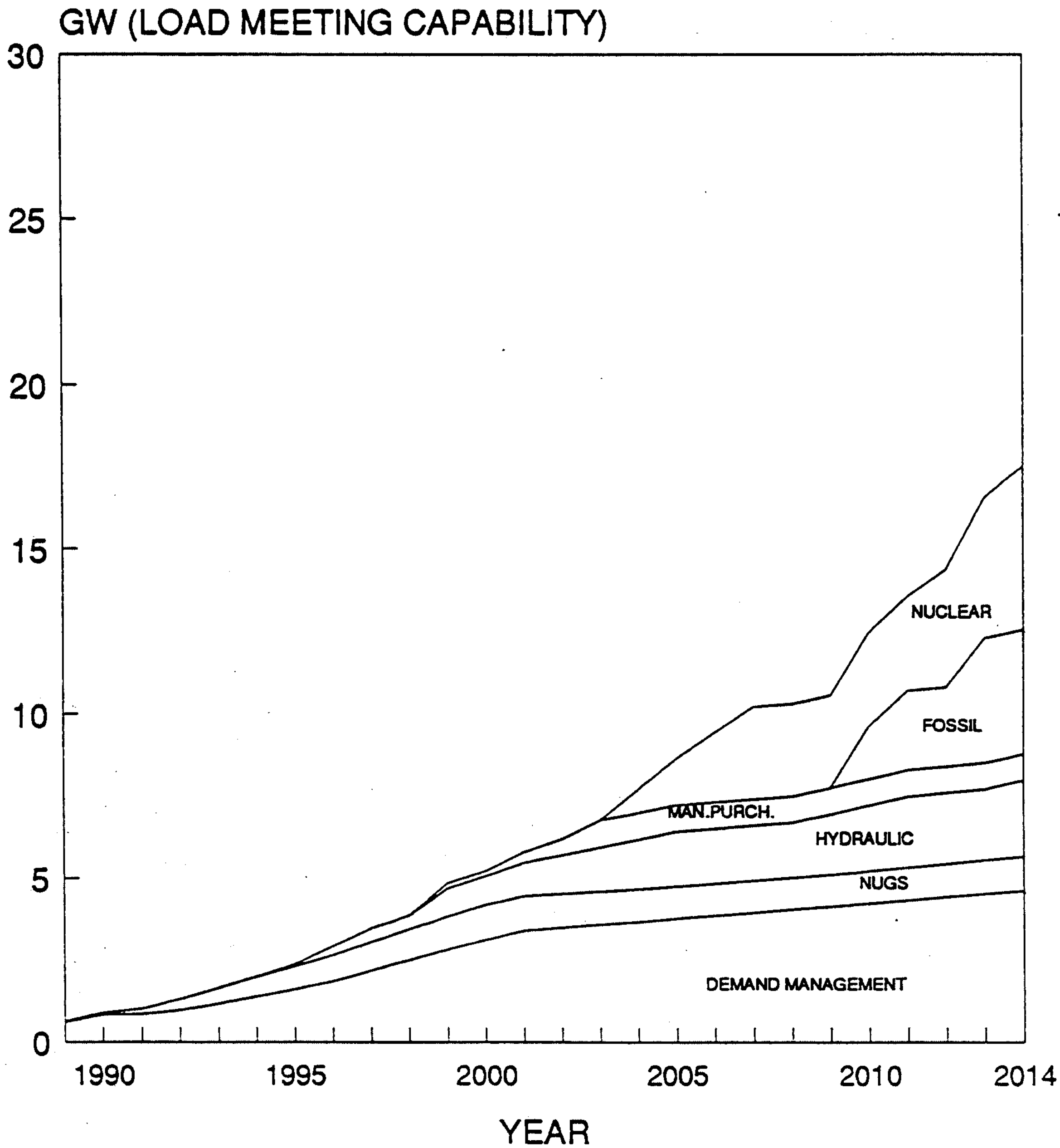


FIGURE 4.17-3
PLAN 15
DATA USED IN ANALYSIS - MEDIAN

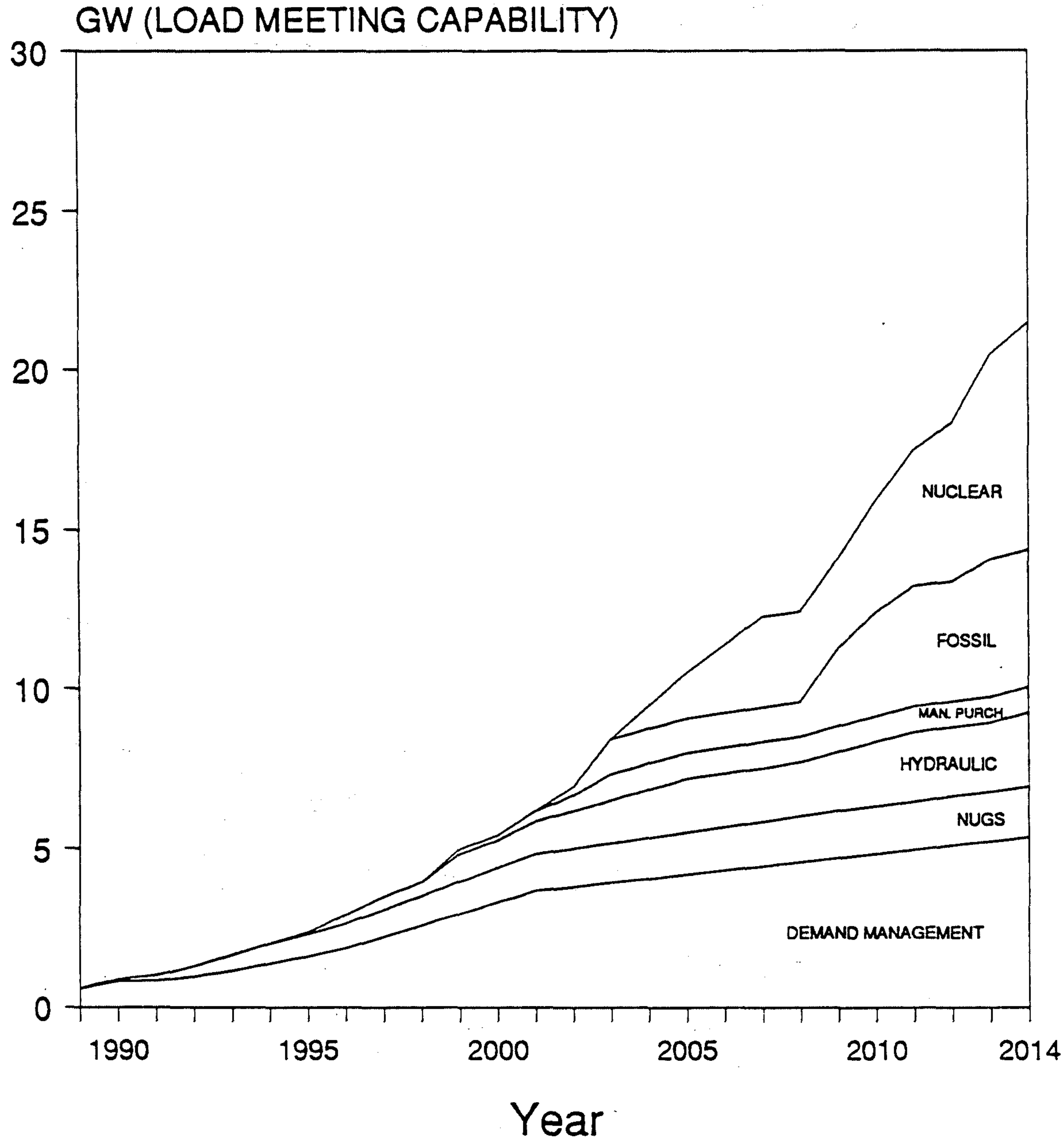


FIGURE 4.17-4
PLAN 15
DATA USED IN ANALYSIS - BRANCH UPPER

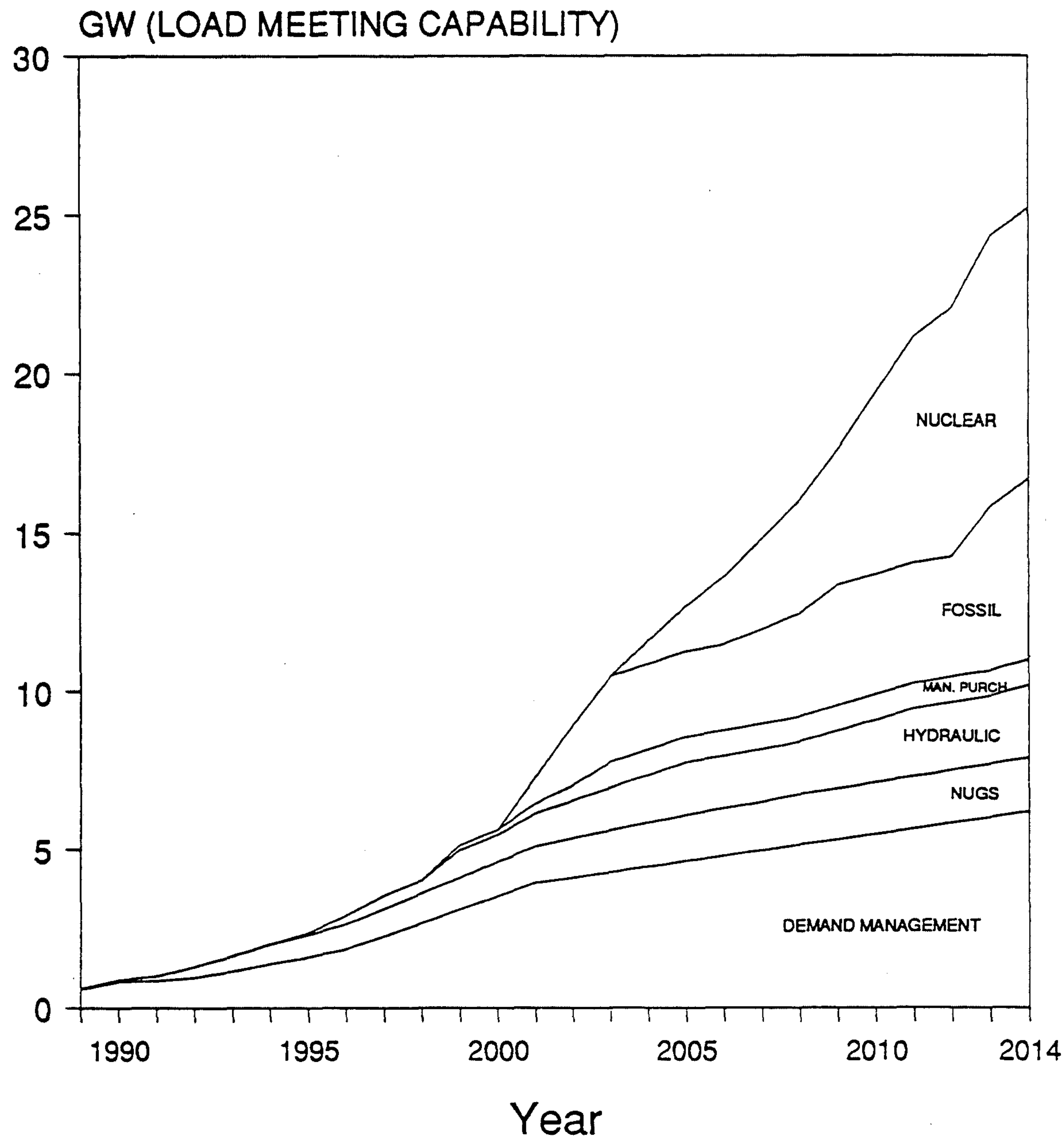


FIGURE 4.17-5
## PLAN 15
## DATA USED IN ANALYSIS - UPPER

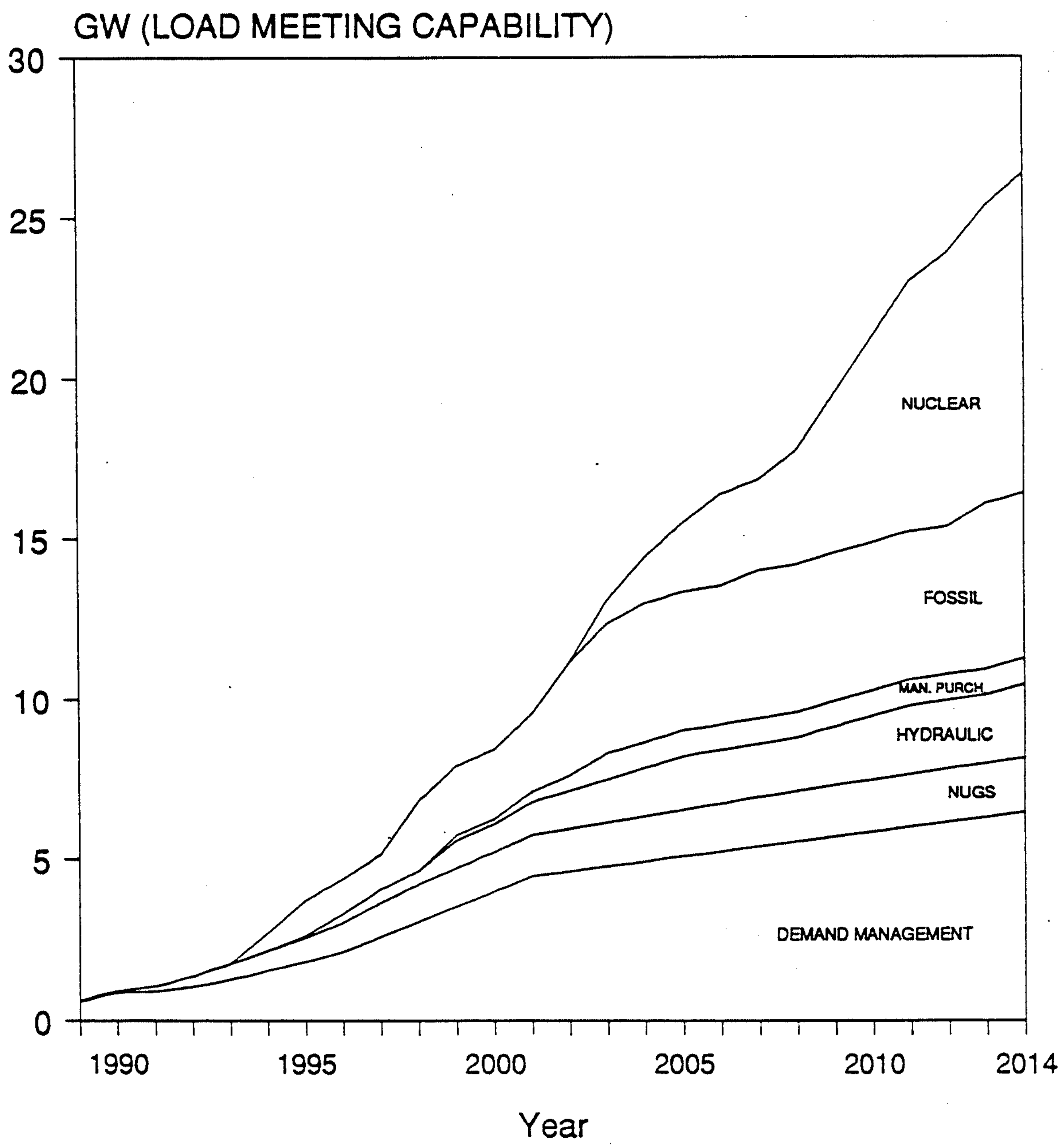


FIGURE 4.17-6
PLAN 22
DATA USED IN ANALYSIS - LOWER

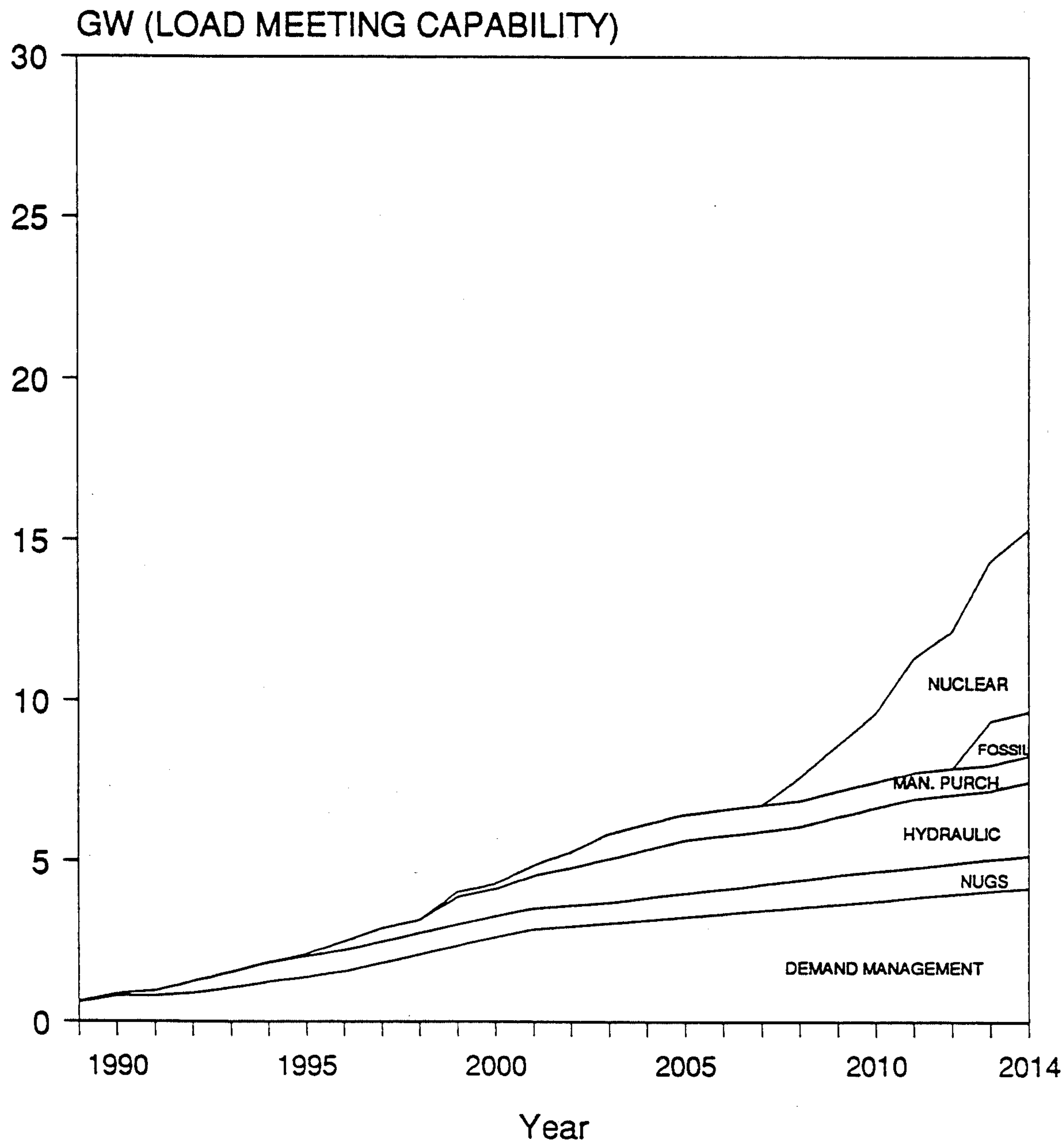


FIGURE 4.17-7
PLAN 22
DATA USED IN ANALYSIS - BRANCH LOWER

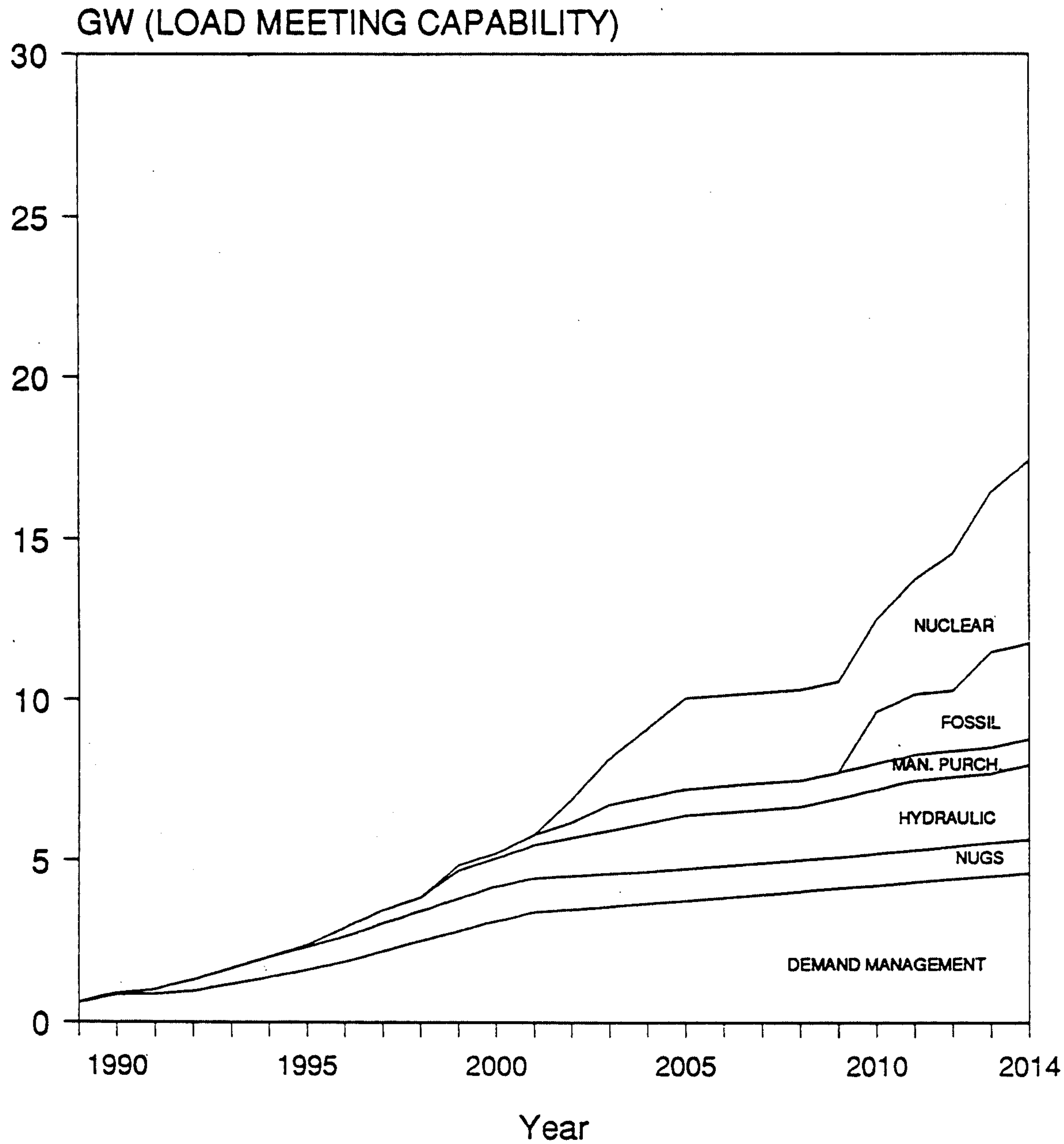


FIGURE 4.17-8

PLAN 22

DATA USED IN ANALYSIS - MEDIAN

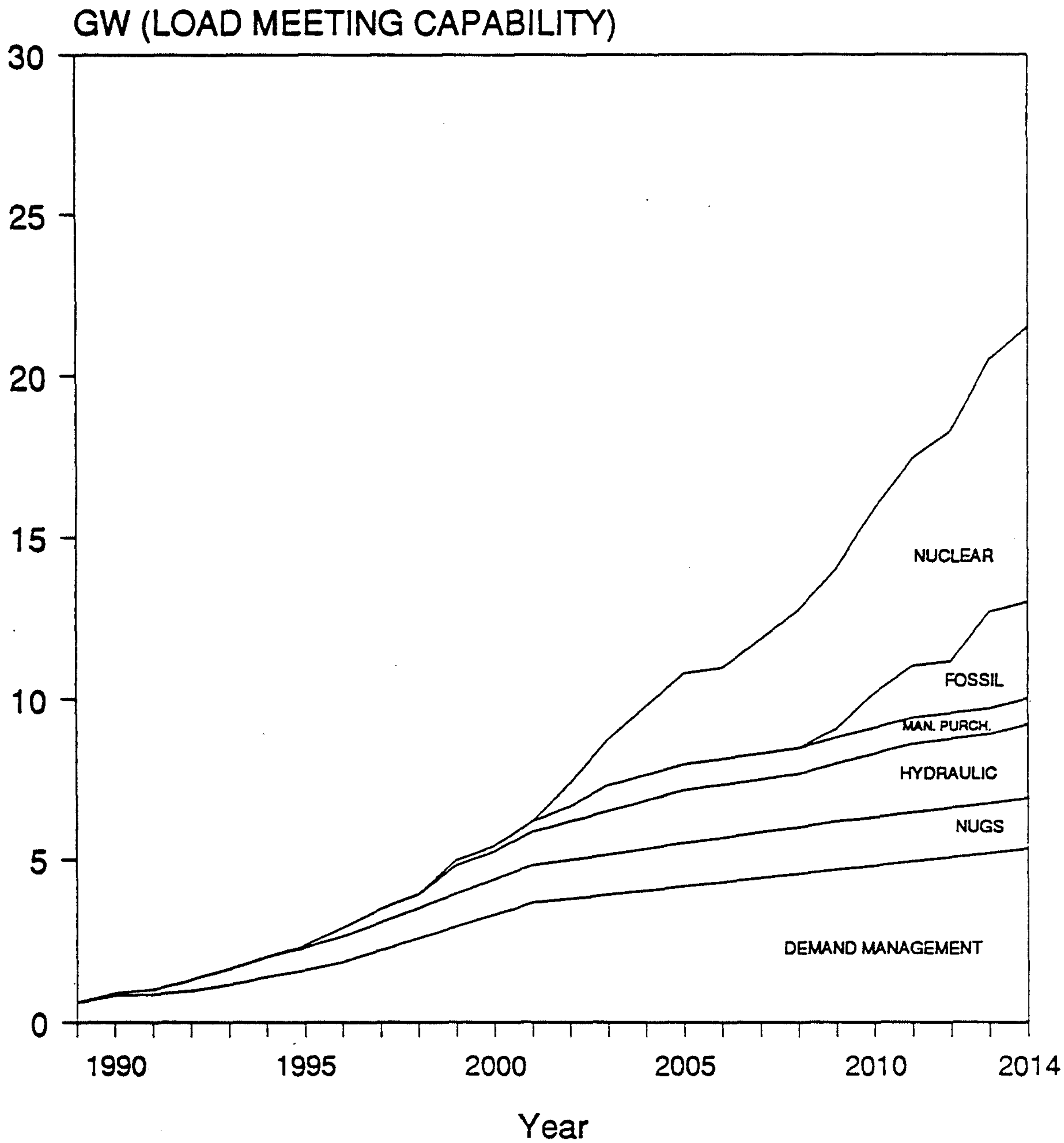


FIGURE 4.17-9

PLAN 22

DATA USED IN ANALYSIS - BRANCH UPPER

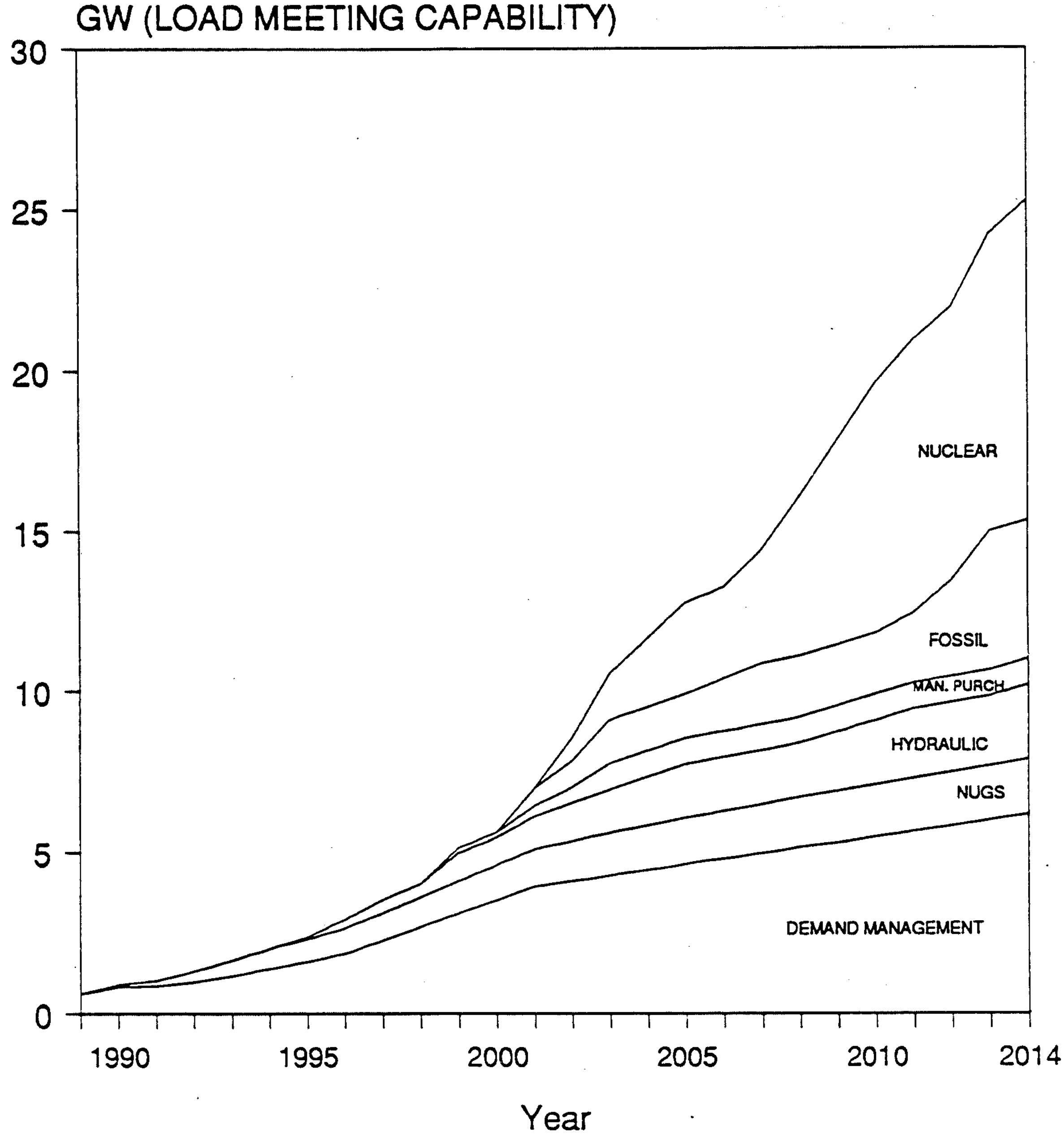


FIGURE 4.17-10
# PLAN 22
# DATA USED IN ANALYSIS - UPPER

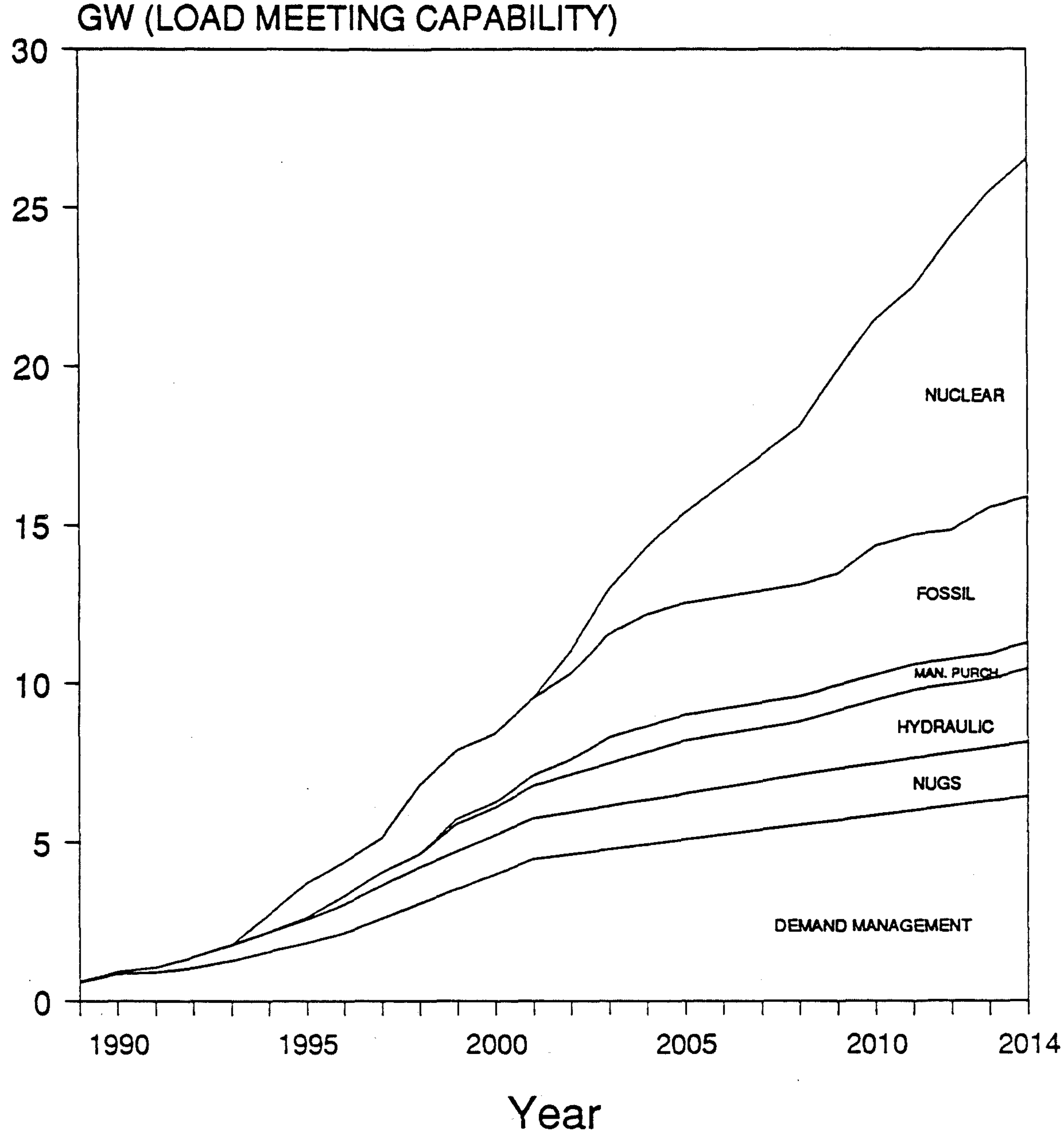


FIGURE 4.17-11

# PLAN 24
# DATA USED IN ANALYSIS - LOWER

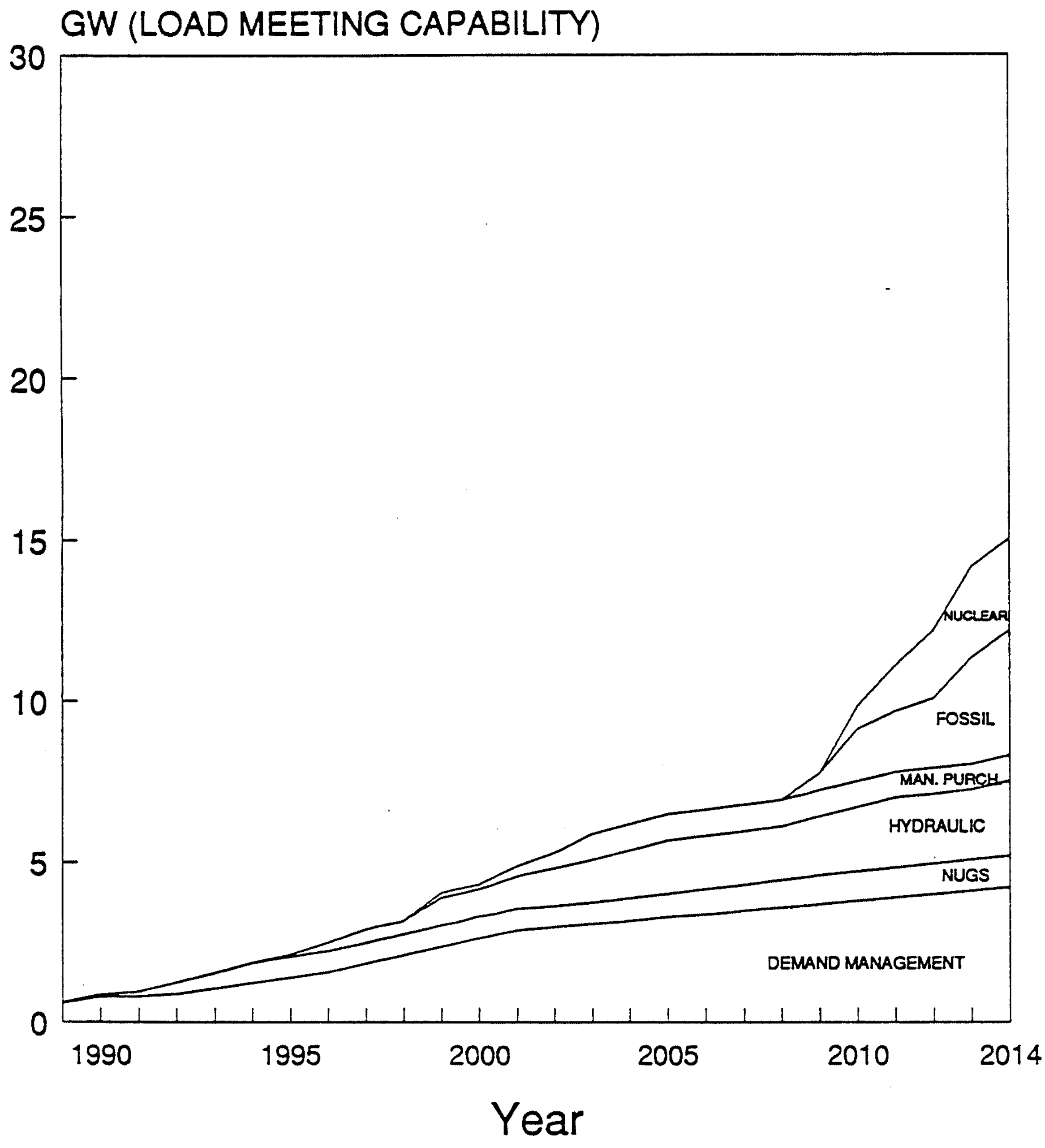


FIGURE 4.17-12
PLAN 24
DATA USED IN ANALYSIS - BRANCH LOWER

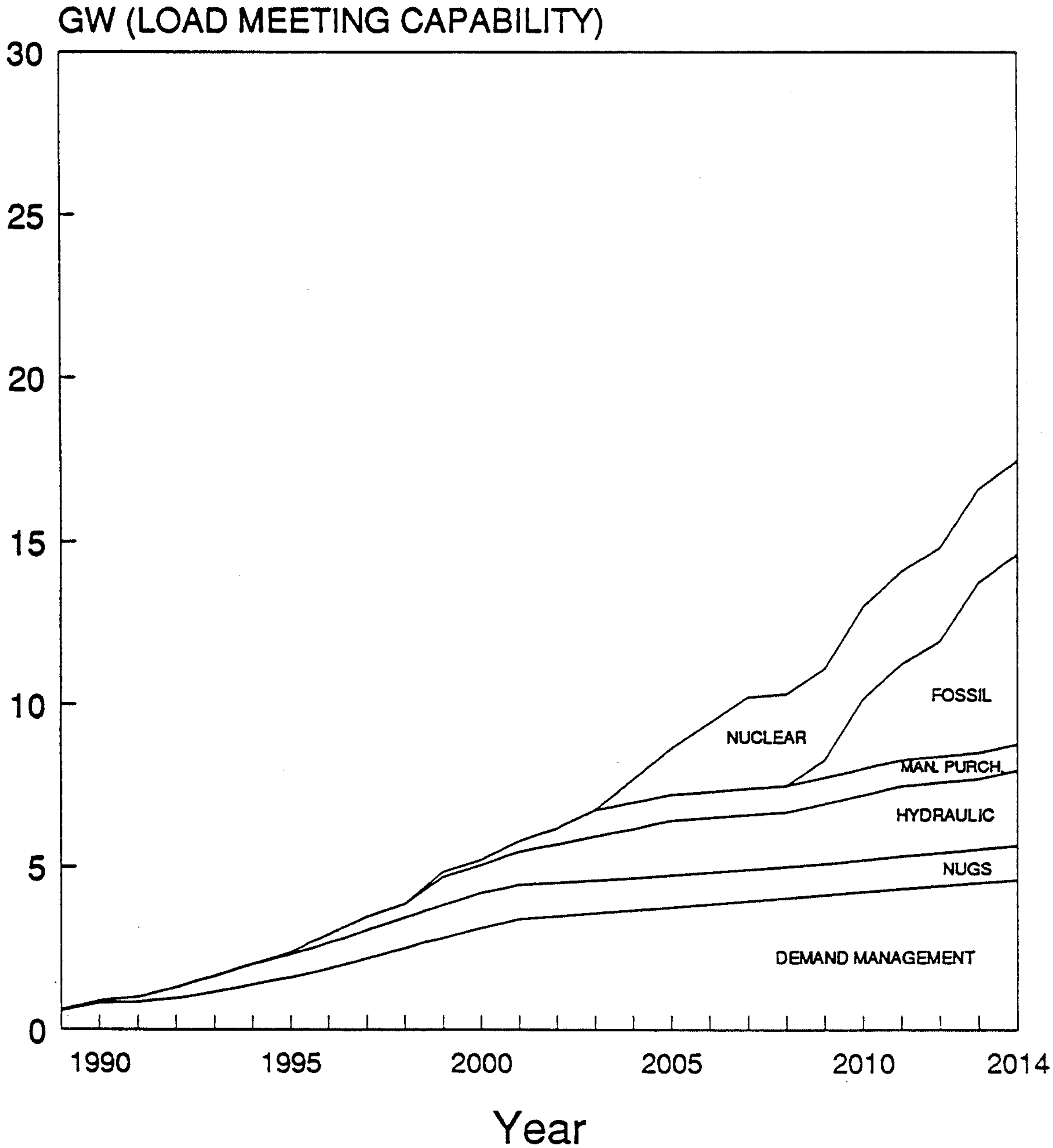


FIGURE 4.17-13
PLAN 24
DATA USED IN ANALYSIS - MEDIAN

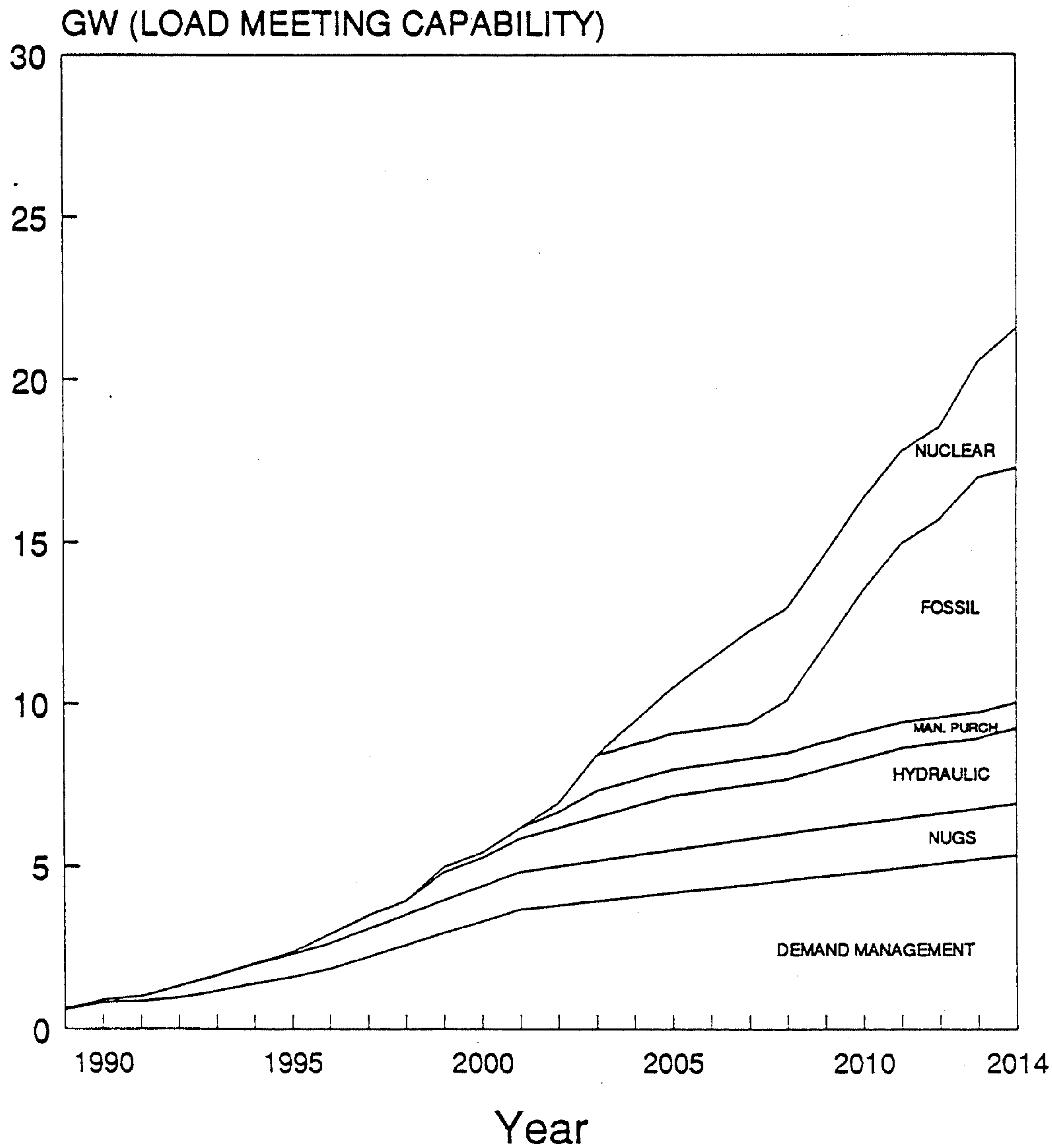


FIGURE 4.17-14

PLAN 24

DATA USED IN ANALYSIS - BRANCH UPPER

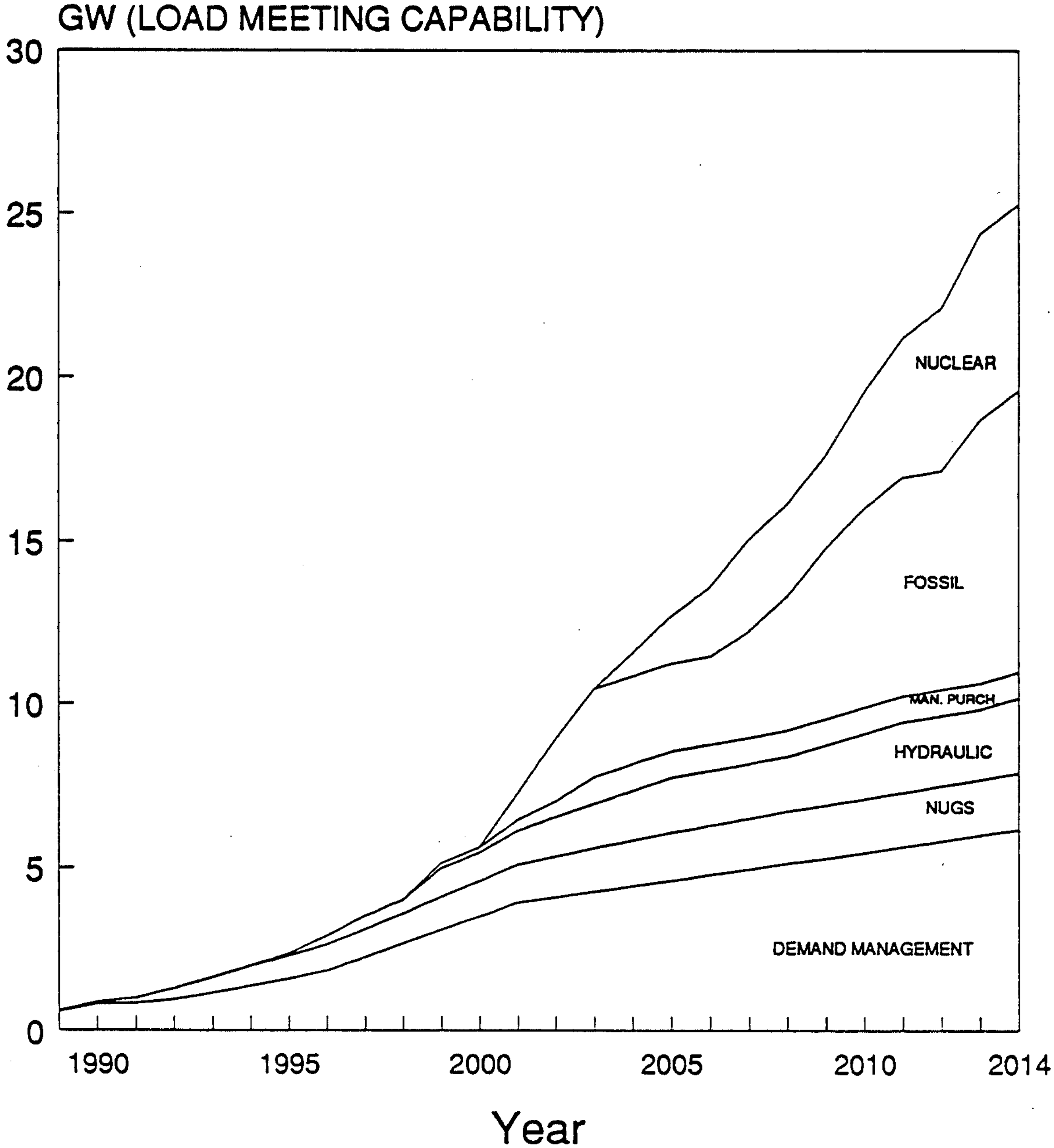
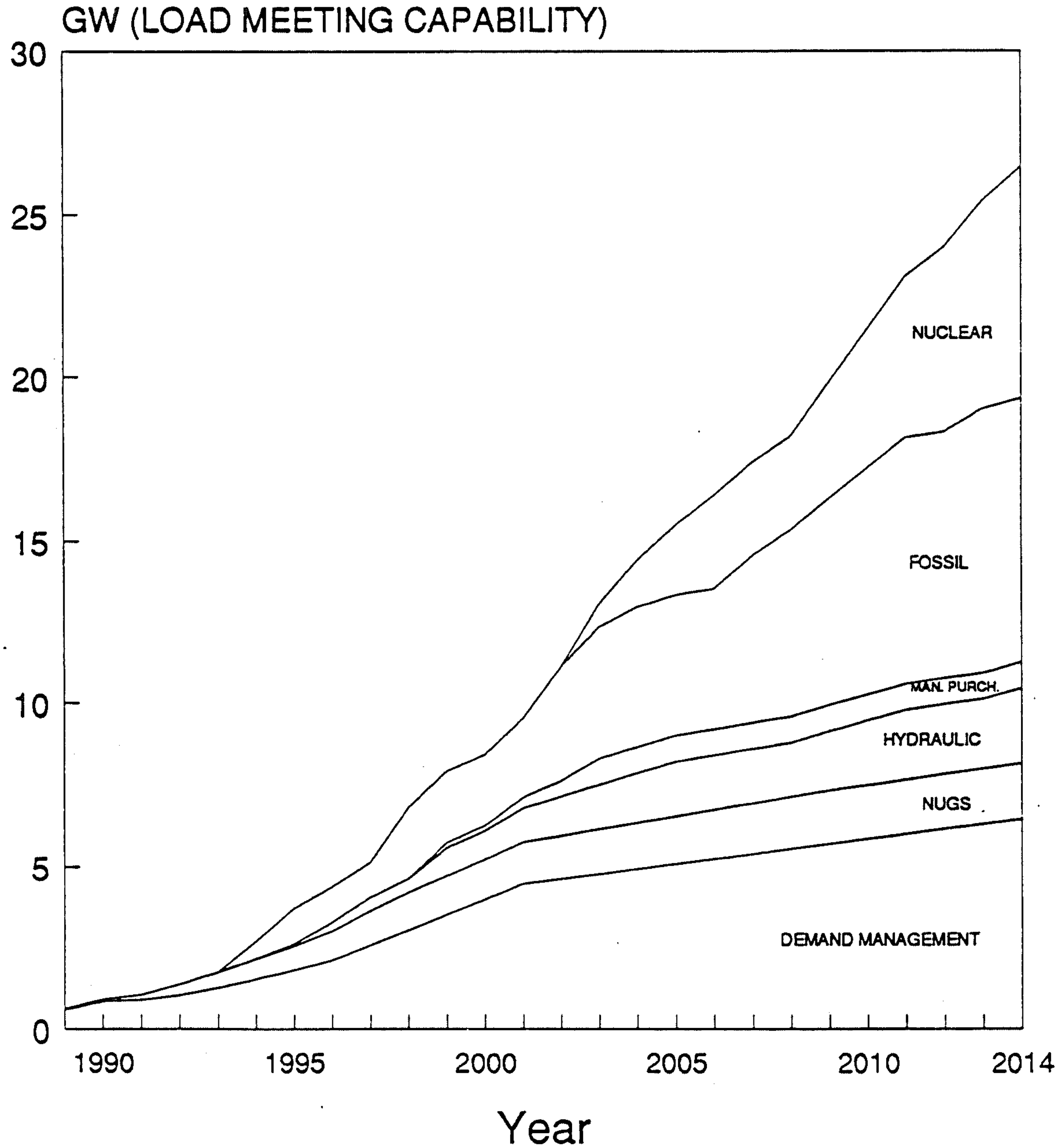


FIGURE 4.17-15
PLAN 24
DATA USED IN ANALYSIS - UPPER



## 4.19 APPROVALS

Refer to Chapter 19 of the Plan Report for a detailed description of the approvals which Ontario Hydro is seeking with respect to the Candidate Demand/Supply Plans.

## 4.20 REVIEW

The formulation of demand/supply cases began with the Basic Load Forecast and a projection of the load meeting capability of the existing system. In situations where the basic forecast exceeded the existing system's load meeting capability (LMC), the priority demand reducing options were turned to first. These options are economic electrical efficiency improvements, load shifting, demand displacement non-utility generators, and customer interruptible loads. The firm load forecast was obtained by subtracting the contributions of the demand reducing options from the basic forecast.

When the firm load forecast exceeded the LMC of the existing system, the priority supply options were then considered. These options are the economic purchase NUGs and remaining potential hydraulic developments within the province. If this was not sufficient to meet the forecast demand, it was then necessary to plan for the addition of new major supply options.

Combinations of the major supply options (utility purchases, CANDU nuclear generation, and fossil fired generation) were formulated into demand/supply cases. These cases were evaluated, modified and refined in the planning process. Dozens of cases were considered and, from these, five promising Major Supply Cases were identified and carried through for full evaluation and subsequent presentation in the DSP Report.

Demand/supply plans were devloped for the five load forecast paths (Median, Branch Upper, Upper, Branch Lower and Lower) which cover the bandwidth of the load forecast. This chapter provided details on the formulation and description of the demand/supply cases, particularly for the branch load forecast paths. The Branch Upper and Branch Lower load paths provide a means to evaluate the way in which the cases respond to changes in demand.

All cases formulated had common Demand Management, Non-Utility Generation, Rehabilitation and Hydraulic Plans. Differences between demand/supply cases arose from differences between the timing and amount of the various options used to meet the need for new major supply after the common elements were considered. Major supply options considered included Candu nuclear, CTU, CTU/CC, CTU/IGCC, and CSC-Coal. All of the Major Supply Cases presented in the Plan Report have the Manitoba Purchase in common.

This chapter also identified some differences between the data that was used when demand/supply cases were developed and the data presented in the Plan Report. The differences between data are small and would not significantly change the nature of the cases or the results of the evaluations.

# APPENDIX

This Appendix contains tables which summarize the components of the Proposed Plan and the two Alternative Plans for the Upper, Median, and Lower load forecast paths. One table is provided for each plan and each load forecast path with needs, expected demand reduction, and new supply additions expressed in terms of capacity. These are followed by similar tables expressed in terms of load meeting capability. The data in these tables describe in detail the Plans as presented in the Plan Report. Differences between data presented here and that used for demand/supply case formulation and analysis are discussed in Chapter 4 of this Analysis Report.

DEMAND / SUPPLY BALANCE - PEAK POWER (MW) - SUPPLY EXPRESSED IN CAPACITY
PROPOSED DEMAND/SUPPLY PLAN 15

MEDIAN LOAD FORECAST

| YEAR (JANUARY) | 1989 | 1990 | 1991 | 1992 | 1993 | 1994 | 1995 | 1996 | 1997 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | DEC. 2014 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| BASIC LOAD FORECAST | 23156 | 23809 | 24533 | 25463 | 26275 | 26884 | 27543 | 28099 | 28693 | 29413 | 30197 | 31111 | 32352 | 33291 | 34050 | 34530 | 34877 | 35344 | 35912 | 36443 | 36975 | 37515 | 38073 | 38644 | 39224 | 39812 | |
| EXISTING FIRM LOAD MEETING CAPABILITY | 23213 | 23970 | 24062 | 24784 | 24343 | 25510 | 25510 | 26131 | 26131 | 25310 | 25472 | 26092 | 26092 | 25859 | 25206 | 25044 | 25205 | 25205 | 24559 | 23939 | 22826 | 21482 | 20632 | 20226 | 18310 | 18489 | |
| DEMAND/SUPPLY REQUIRED - LHC | 0 | 0 | 471 | 679 | 0 | 1374 | 2033 | 1960 | 2562 | 4183 | 4725 | 5019 | 6160 | 7433 | 8844 | 9486 | 9672 | 10159 | 11353 | 12504 | 14149 | 16033 | 17421 | 18408 | 20714 | 21323 | |
| ELECTRICAL EFFICIENCY IMPROVEMENTS | 0 | 14 | 45 | 78 | 126 | 183 | 314 | 500 | 800 | 1100 | 1400 | 1700 | 2000 | 2100 | 2200 | 2300 | 2400 | 2500 | 2600 | 2700 | 2800 | 2900 | 3000 | 3100 | 3200 | 3300 | 3400 |
| LOAD SHIFTING | 0 | 81 | 171 | 266 | 423 | 582 | 656 | 717 | 776 | 836 | 893 | 946 | 1000 | 1020 | 1040 | 1060 | 1080 | 1100 | 1120 | 1140 | 1160 | 1180 | 1200 | 1220 | 1240 | 1260 | 1280 |
| DEPENDABLE LOAD DISPLACEMENT NUGS | 0 | 59 | 102 | 176 | 243 | 310 | 334 | 359 | 373 | 386 | 391 | 392 | 403 | 407 | 411 | 414 | 418 | 422 | 426 | 430 | 433 | 437 | 441 | 445 | 449 | 452 | 456 |
| PRIMARY LOAD FORECAST | 23156 | 23655 | 24215 | 24943 | 25483 | 25809 | 26239 | 26523 | 26744 | 27093 | 27513 | 28073 | 28949 | 29764 | 30399 | 30756 | 30979 | 31342 | 31766 | 32173 | 32582 | 32998 | 33432 | 33879 | 34335 | 34800 | |
| CAPACITY INTERRUPTIBLE LOADS | 725 | 735 | 632 | 635 | 621 | 623 | 632 | 641 | 652 | 664 | 676 | 688 | 702 | 712 | 724 | 737 | 749 | 762 | 775 | 788 | 802 | 816 | 830 | 844 | 859 | 874 | 890 |
| FIRM LOAD FORECAST | 22431 | 22920 | 23583 | 24318 | 24862 | 25186 | 25607 | 25882 | 26092 | 26429 | 26837 | 27385 | 28147 | 29052 | 29675 | 30019 | 30230 | 30580 | 30991 | 31385 | 31780 | 32182 | 32602 | 33035 | 33476 | 33926 | |
| SUPPLY REQUIRED - LHC | 0 | 0 | 0 | 0 | 0 | 0 | 97 | 0 | 0 | 1119 | 1365 | 1293 | 2055 | 3193 | 4469 | 4975 | 5025 | 5375 | 6432 | 7446 | 8954 | 10700 | 11950 | 12799 | 14966 | 15437 | |
| SUPPLY REQUIRED - CAPACITY | 0 | 0 | 0 | 0 | 0 | 0 | 120 | 0 | 0 | 1388 | 1693 | 1603 | 2548 | 3959 | 5542 | 6169 | 6231 | 6665 | 7976 | 9233 | 11103 | 13268 | 14818 | 15871 | 18558 | 19142 | |
| PURCHASE NUGS CAPACITY | 0 | 38 | 55 | 226 | 312 | 398 | 471 | 544 | 616 | 691 | 771 | 857 | 932 | 981 | 1030 | 1078 | 1126 | 1174 | 1222 | 1269 | 1316 | 1360 | 1403 | 1439 | 1470 | 1497 | 1522 |
| HYDRAULIC PLAN CAPACITY | 0 | 0 | 0 | 0 | 3 | 15 | 83 | 333 | 326 | 326 | 1076 | 1076 | 1209 | 1409 | 1609 | 1809 | 2008 | 2053 | 2121 | 2143 | 2241 | 2515 | 2585 | 2633 | 2718 | 2784 | 2849 |
| MAJOR SUPPLY REQUIRED - CAPACITY | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 371 | 0 | 0 | 407 | 1569 | 2903 | 3282 | 3097 | 3438 | 4633 | 5821 | 7546 | 9393 | 10870 | 11779 | 14370 | 14861 | |
| MANITOBA PURCHASE CAPACITY | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 200 | 200 | 400 | 600 | 1000 | 1000 | 1000 | 1000 | 1000 | 1000 | 1000 | 1000 | 1000 | 1000 | 1000 | 1000 | |
| NEW FOSSIL CAPACITY | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 336 | 1344 | 1344 | 1344 | 1344 | 1344 | 1344 | 3024 | 4032 | 4704 | 4704 | 5376 | 5376 | |
| NEW NUCLEAR CAPACITY | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 881 | 1762 | 2643 | 3524 | 3524 | 3524 | 4405 | 5286 | 6167 | 7929 | 8810 | |
| NEW MAJOR SUPPLY CAPACITY | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 200 | 200 | 400 | 936 | 2344 | 3225 | 4106 | 4987 | 5868 | 5868 | 7548 | 9437 | 10990 | 11871 | 14305 | 15186 | |

DEMAND / SUPPLY BALANCE - PEAK POWER (MW) - SUPPLY EXPRESSED IN CAPACITY
PROPOSED DEMAND/SUPPLY PLAN 15

UPPER LOAD FORECAST

| YEAR (JANUARY) | 1989 | 1990 | 1991 | 1992 | 1993 | 1994 | 1995 | 1996 | 1997 | 1998 | 1999 | 2000 | 2001 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| BASIC LOAD FORECAST | 23952 | 24907 | 26049 | 27356 | 28714 | 29800 | 30754 | 31752 | 32561 | 33649 | 34767 | 35978 | 37374 |
| EXISTING FIRM LOAD MEETING CAPABILITY | 23213 | 23970 | 24062 | 24784 | 26343 | 25510 | 25510 | 26131 | 26131 | 25310 | 25472 | 26092 | 26092 |
| DEMAND/SUPPLY REQUIRED - LHC | 739 | 937 | 1987 | 2572 | 2371 | 4290 | 5244 | 5621 | 6430 | 8339 | 9295 | 9886 | 11282 |
| ELECTRICAL EFFICIENCY IMPROVEMENTS | 0 | 14 | 56 | 98 | 150 | 229 | 393 | 625 | 1000 | 1375 | 1750 | 2125 | 2500 |
| LOAD SHIFTING | 0 | 84 | 188 | 282 | 455 | 725 | 728 | 795 | 870 | 954 | 1037 | 1100 | 1200 |
| DEFERRABLE LOAD DISPLACEMENT HUGS | 0 | 55 | 92 | 172 | 247 | 308 | 372 | 403 | 438 | 450 | 444 | 468 | 472 |
| PRIMARY LOAD FORECAST | 23952 | 24754 | 25713 | 26804 | 27862 | 28538 | 29261 | 29929 | 30253 | 30870 | 31536 | 32285 | 33202 |
| CAPACITY INTERRUPTIBLE LOADS | 725 | 758 | 656 | 660 | 660 | 672 | 696 | 705 | 724 | 744 | 765 | 782 | 798 |
| FIRM LOAD FORECAST | 23227 | 23996 | 25057 | 26144 | 27202 | 27866 | 28565 | 29224 | 29529 | 30126 | 30771 | 31503 | 32404 |
| SUPPLY REQUIRED - LHC | 14 | 26 | 995 | 1360 | 859 | 2356 | 3055 | 3093 | 3398 | 4816 | 5299 | 5411 | 6312 |
| SUPPLY REQUIRED - CAPACITY | 17 | 32 | 1234 | 1686 | 1065 | 2921 | 3788 | 3835 | 4214 | 5972 | 6571 | 6710 | 7827 |
| PURCHASE HUGS CAPACITY | 0 | 28 | 55 | 226 | 312 | 398 | 484 | 595 | 748 | 906 | 1035 | 1084 | 1133 |
| HYDRAULIC PLAN CAPACITY | 0 | 0 | 0 | 0 | 3 | 15 | 83 | 333 | 526 | 526 | 1076 | 1076 | 1209 |
| MAJOR SUPPLY REQUIRED - CAPACITY | 17 | 4 | 1179 | 1460 | 750 | 2508 | 3221 | 2907 | 2940 | 4540 | 4460 | 4550 | 5485 |
| MANITOBA PURCHASE CAPACITY | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 200 | 200 | 400 |
| NEW FOSSIL CAPACITY | 0 | 0 | 0 | 0 | 0 | 672 | 1344 | 1344 | 1344 | 2688 | 2688 | 2688 | 3024 |
| NEW NUCLEAR CAPACITY | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| NEW MAJOR SUPPLY CAPACITY | 0 | 0 | 0 | 0 | 0 | 672 | 1344 | 1344 | 1344 | 2688 | 2888 | 2888 | 3424 |

| YEAR (JANUARY) | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | DEC. 2014 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| BASIC LOAD FORECAST | 38622 | 39536 | 40134 | 40563 | 41079 | 41596 | 42052 | 42469 | 42870 | 43306 | 43763 | 44221 | 44678 | |
| EXISTING FIRM LOAD MEETING CAPABILITY | 25859 | 25206 | 25044 | 25205 | 25205 | 24559 | 23939 | 22826 | 21482 | 20652 | 20236 | 18510 | 18489 | |
| DEMAND/SUPPLY REQUIRED - LHC | 12763 | 14330 | 15090 | 15358 | 15874 | 17037 | 18113 | 19643 | 21388 | 22654 | 23527 | 25711 | 26189 | |
| ELECTRICAL EFFICIENCY IMPROVEMENTS | 2625 | 2750 | 2875 | 3000 | 3125 | 3250 | 3375 | 3500 | 3625 | 3750 | 3875 | 4000 | 4125 | 4250 |
| LOAD SHIFTING | 1220 | 1240 | 1260 | 1280 | 1300 | 1320 | 1340 | 1360 | 1380 | 1400 | 1420 | 1440 | 1460 | 1480 |
| DEFERRABLE LOAD DISPLACEMENT HUGS | 475 | 479 | 482 | 486 | 490 | 493 | 497 | 500 | 504 | 508 | 511 | 515 | 518 | 522 |
| PRIMARY LOAD FORECAST | 34302 | 35067 | 35517 | 35797 | 36164 | 36533 | 36840 | 37109 | 37361 | 37648 | 37957 | 38266 | 38575 | |
| CAPACITY INTERRUPTIBLE LOADS | 811 | 826 | 841 | 857 | 871 | 884 | 896 | 907 | 917 | 928 | 940 | 951 | 963 | 976 |
| FIRM LOAD FORECAST | 33491 | 34241 | 34676 | 34940 | 35293 | 35649 | 35944 | 36202 | 36444 | 36720 | 37017 | 37315 | 37612 | |
| SUPPLY REQUIRED - LHC | 7632 | 9035 | 9632 | 9735 | 10088 | 11090 | 12005 | 13376 | 14962 | 16068 | 16781 | 18805 | 19123 | |
| SUPPLY REQUIRED - CAPACITY | 9464 | 11203 | 11744 | 12071 | 12509 | 13752 | 14886 | 16586 | 18353 | 19924 | 20808 | 23318 | 23713 | |
| PURCHASE HUGS CAPACITY | 1181 | 1230 | 1279 | 1327 | 1375 | 1423 | 1471 | 1518 | 1565 | 1584 | 1603 | 1622 | 1641 | 1660 |
| HYDRAULIC PLAN CAPACITY | 1409 | 1609 | 1609 | 2008 | 2053 | 2121 | 2143 | 2241 | 2315 | 2585 | 2653 | 2718 | 2784 | 2849 |
| MAJOR SUPPLY REQUIRED - CAPACITY | 6874 | 8364 | 8856 | 8736 | 9081 | 10208 | 11272 | 12827 | 14473 | 15755 | 16552 | 18978 | 19288 | |
| MANITOBA PURCHASE CAPACITY | 600 | 1000 | 1000 | 1000 | 1000 | 1000 | 1000 | 1000 | 1000 | 1000 | 1000 | 1000 | 1000 | |
| NEW FOSSIL CAPACITY | 4368 | 5040 | 5376 | 5376 | 5376 | 5712 | 5712 | 5712 | 5712 | 5712 | 5712 | 6384 | 6384 | |
| NEW NUCLEAR CAPACITY | 0 | 881 | 1762 | 2643 | 3524 | 3524 | 4405 | 6167 | 7929 | 9691 | 10572 | 11453 | 12334 | |
| NEW MAJOR SUPPLY CAPACITY | 4968 | 6921 | 8138 | 9019 | 9900 | 10236 | 11117 | 12879 | 14641 | 16403 | 17284 | 18837 | 19718 | |

DEMAND / SUPPLY BALANCE - PEAK POWER (MW) - SUPPLY EXPRESSED IN CAPACITY
PROPOSED DEMAND/SUPPLY PLAN 15

LOWER LOAD FORECAST

| YEAR (JANUARY) | 1989 | 1990 | 1991 | 1992 | 1993 | 1994 | 1995 | 1996 | 1997 | 1998 | 1999 | 2000 | 2001 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| BASIC LOAD FORECAST | 22690 | 22463 | 22766 | 23214 | 23403 | 23723 | 23931 | 24195 | 24312 | 24710 | 25104 | 25733 | 26594 |
| EXISTING FIRM LOAD MEETING CAPABILITY | 23213 | 23910 | 24062 | 24704 | 26343 | 25510 | 25510 | 26131 | 26131 | 25310 | 25472 | 26092 | 26092 |
| DEMAND/SUPPLY REQUIRED - LMC | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 502 |
| ELECTRICAL EFFICIENCY IMPROVEMENTS | 0 | 14 | 36 | 62 | 101 | 166 | 251 | 400 | 640 | 888 | 1120 | 1360 | 1600 |
| LOAD SHIFTING | 0 | 78 | 161 | 246 | 387 | 519 | 576 | 620 | 663 | 707 | 749 | 790 | 800 |
| DEPENDABLE LOAD DISPLACEMENT NUGS | 0 | 55 | 98 | 172 | 239 | 306 | 330 | 342 | 342 | 342 | 342 | 342 | 342 |
| PRIMARY LOAD FORECAST | 22690 | 22316 | 22471 | 22734 | 22756 | 22754 | 22764 | 22833 | 22567 | 22701 | 22893 | 23231 | 23852 |
| CAPACITY INTERRUPTIBLE LOADS | 723 | 709 | 599 | 583 | 566 | 554 | 550 | 561 | 566 | 573 | 580 | 587 | 599 |
| FIRM LOAD FORECAST | 21965 | 21607 | 21872 | 22151 | 22190 | 22200 | 22206 | 22272 | 22001 | 22208 | 22313 | 22644 | 23253 |
| SUPPLY REQUIRED - LMC | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| SUPPLY REQUIRED - CAPACITY | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| PURCHASE NUGS CAPACITY | 0 | 28 | 55 | 226 | 312 | 398 | 435 | 435 | 435 | 435 | 435 | 435 | 435 |
| HYDRAULIC PLAN CAPACITY | 0 | 0 | 0 | 0 | 3 | 15 | 83 | 333 | 526 | 526 | 1076 | 1076 | 1209 |
| MAJOR SUPPLY REQUIRED - CAPACITY | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| MANITOBA PURCHASE CAPACITY | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 200 | 200 | 400 |
| NEW FOSSIL CAPACITY | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| NEW NUCLEAR CAPACITY | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| NEW MAJOR SUPPLY CAPACITY | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 200 | 200 | 400 |

| YEAR (JANUARY) | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | DEC. 2014 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| BASIC LOAD FORECAST | 27750 | 28171 | 28661 | 28630 | 28973 | 29571 | 30097 | 30667 | 31239 | 31892 | 32409 | 32960 | 33512 | |
| EXISTING FIRM LOAD MEETING CAPABILITY | 25859 | 25206 | 25044 | 25205 | 25205 | 24559 | 23939 | 22826 | 21402 | 20652 | 20236 | 18510 | 18409 | |
| DEMAND/SUPPLY REQUIRED - LMC | 1891 | 2965 | 3617 | 3425 | 3768 | 5012 | 6158 | 7841 | 9737 | 11240 | 12173 | 14450 | 15023 | |
| ELECTRICAL EFFICIENCY IMPROVEMENTS | 1663 | 1725 | 1788 | 1850 | 1913 | 1974 | 2038 | 2100 | 2163 | 2225 | 2288 | 2350 | 2412 | 2475 |
| LOAD SHIFTING | 820 | 840 | 860 | 880 | 900 | 920 | 940 | 960 | 980 | 1000 | 1020 | 1040 | 1060 | 1080 |
| DEPENDABLE LOAD DISPLACEMENT NUGS | 342 | 342 | 342 | 346 | 350 | 353 | 357 | 360 | 364 | 368 | 371 | 375 | 378 | 382 |
| PRIMARY LOAD FORECAST | 24925 | 25264 | 25671 | 25534 | 25810 | 26324 | 26762 | 27267 | 27732 | 28299 | 28730 | 29195 | 29662 | |
| CAPACITY INTERRUPTIBLE LOADS | 607 | 616 | 625 | 633 | 643 | 655 | 668 | 682 | 697 | 713 | 727 | 742 | 756 | 771 |
| FIRM LOAD FORECAST | 24318 | 24648 | 25046 | 24921 | 25167 | 25669 | 26094 | 26565 | 27035 | 27586 | 28003 | 28453 | 28906 | |
| SUPPLY REQUIRED - LMC | 0 | 0 | 2 | 0 | 0 | 1110 | 2155 | 3739 | 5333 | 6934 | 7767 | 9943 | 10437 | |
| SUPPLY REQUIRED - CAPACITY | 0 | 0 | 2 | 0 | 0 | 1376 | 2672 | 4636 | 6066 | 8598 | 9631 | 12329 | 13917 | |
| PURCHASE NUGS CAPACITY | 435 | 435 | 483 | 531 | 579 | 627 | 675 | 722 | 769 | 788 | 807 | 826 | 845 | 864 |
| HYDRAULIC PLAN CAPACITY | 1409 | 1609 | 1809 | 2008 | 2053 | 2121 | 2143 | 2241 | 2515 | 2585 | 2653 | 2718 | 2784 | 2849 |
| MAJOR SUPPLY REQUIRED - CAPACITY | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 1672 | 3602 | 5225 | 6171 | 8785 | 9288 | |
| MANITOBA PURCHASE CAPACITY | 600 | 1000 | 1000 | 1000 | 1000 | 1000 | 1000 | 1000 | 1000 | 1000 | 1000 | 1000 | 1000 | |
| NEW FOSSIL CAPACITY | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 672 | 2016 | 2352 | 2688 | 3360 | 3360 | |
| NEW NUCLEAR CAPACITY | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 881 | 1762 | 2643 | 4405 | 5286 | |
| NEW MAJOR SUPPLY CAPACITY | 600 | 1000 | 1000 | 1000 | 1000 | 1000 | 1000 | 1672 | 3897 | 5114 | 6331 | 8765 | 9646 | |

DEMAND / SUPPLY BALANCE - PEAK POWER (MW) - SUPPLY EXPRESSED IN CAPACITY
CANDIDATE DEMAND/SUPPLY PLAN 22 (HIGHER NUCLEAR)

MEDIAN LOAD FORECAST

| YEAR (JANUARY) | 1989 | 1990 | 1991 | 1992 | 1993 | 1994 | 1995 | 1996 | 1997 | 1998 | 1999 | 2000 | 2001 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| BASIC LOAD FORECAST | 23136 | 23809 | 24533 | 25463 | 26275 | 26804 | 27543 | 28099 | 28693 | 29413 | 30197 | 31111 | 32252 |
| EXISTING FIRM LOAD MEETING CAPABILITY | 23213 | 23970 | 24062 | 24784 | 26343 | 25510 | 25510 | 26121 | 26131 | 25310 | 25472 | 26092 | 26092 |
| DEMAND/SUPPLY REQUIRED - LMC | 0 | 0 | 471 | 679 | 0 | 1374 | 2033 | 1840 | 2562 | 4103 | 4725 | 5019 | 6160 |
| ELECTRICAL EFFICIENCY IMPROVEMENTS | 0 | 14 | 45 | 78 | 126 | 183 | 314 | 500 | 800 | 1100 | 1400 | 1700 | 2000 |
| LOAD SHIFTING | 0 | 81 | 171 | 264 | 423 | 582 | 656 | 717 | 776 | 836 | 893 | 946 | 1000 |
| DEPENDABLE LOAD DISPLACEMENT NUGS | 0 | 59 | 102 | 176 | 243 | 310 | 334 | 359 | 373 | 384 | 391 | 392 | 403 |
| PRIMARY LOAD FORECAST | 23136 | 23655 | 24215 | 24963 | 25463 | 25809 | 26239 | 26523 | 26744 | 27093 | 27512 | 28073 | 28849 |
| CAPACITY INTERRUPTIBLE LOADS | 725 | 735 | 632 | 625 | 621 | 623 | 632 | 641 | 652 | 664 | 676 | 688 | 702 |
| FIRM LOAD FORECAST | 22431 | 22920 | 23583 | 24318 | 24862 | 25186 | 25607 | 25882 | 26092 | 26429 | 26837 | 27385 | 28147 |
| SUPPLY REQUIRED - LMC | 0 | 0 | 0 | 0 | 0 | 0 | 97 | 0 | 0 | 1119 | 1365 | 1293 | 2055 |
| SUPPLY REQUIRED - CAPACITY | 0 | 0 | 0 | 0 | 0 | 0 | 120 | 0 | 0 | 1288 | 1693 | 1603 | 2548 |
| PURCHASE NUGS CAPACITY | 0 | 28 | 55 | 226 | 312 | 398 | 471 | 544 | 616 | 691 | 771 | 857 | 932 |
| HYDRAULIC PLAN CAPACITY | 0 | 0 | 0 | 0 | 3 | 15 | 83 | 333 | 526 | 526 | 1076 | 1076 | 1209 |
| MAJOR SUPPLY REQUIRED - CAPACITY | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 171 | 0 | 0 | 407 |
| MANITOBA PURCHASE CAPACITY | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 200 | 200 | 400 |
| NEW FOSSIL CAPACITY | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| NEW NUCLEAR CAPACITY | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| NEW MAJOR SUPPLY CAPACITY | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 200 | 200 | 400 |

| YEAR (JANUARY) | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | DEC. 2014 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| BASIC LOAD FORECAST | 33381 | 34050 | 34530 | 34877 | 35364 | 35912 | 36443 | 36975 | 37315 | 38073 | 38644 | 39224 | 39812 | |
| EXISTING FIRM LOAD MEETING CAPABILITY | 25859 | 25204 | 25044 | 25205 | 25205 | 24559 | 23939 | 22826 | 21482 | 20652 | 20236 | 18510 | 18489 | |
| DEMAND/SUPPLY REQUIRED - LMC | 7432 | 8844 | 9486 | 9672 | 10159 | 11353 | 12504 | 14149 | 16033 | 17421 | 18408 | 20714 | 21323 | |
| ELECTRICAL EFFICIENCY IMPROVEMENTS | 2100 | 2200 | 2300 | 2400 | 2500 | 2600 | 2700 | 2800 | 2900 | 3000 | 3100 | 3200 | 3300 | 3400 |
| LOAD SHIFTING | 1020 | 1040 | 1060 | 1080 | 1100 | 1120 | 1140 | 1140 | 1160 | 1200 | 1220 | 1240 | 1260 | 1280 |
| DEPENDABLE LOAD DISPLACEMENT NUGS | 407 | 411 | 414 | 418 | 422 | 426 | 430 | 433 | 437 | 441 | 445 | 449 | 453 | 456 |
| PRIMARY LOAD FORECAST | 29764 | 30399 | 30756 | 30979 | 31342 | 31766 | 32173 | 32502 | 32990 | 33432 | 33879 | 34325 | 34800 | |
| CAPACITY INTERRUPTIBLE LOADS | 712 | 724 | 737 | 749 | 762 | 775 | 788 | 802 | 816 | 830 | 844 | 859 | 874 | 890 |
| FIRM LOAD FORECAST | 29052 | 29675 | 30019 | 30230 | 30580 | 30991 | 31385 | 31780 | 32182 | 32602 | 33035 | 33476 | 33926 | |
| SUPPLY REQUIRED - LMC | 3193 | 4469 | 4975 | 5025 | 5375 | 6432 | 7446 | 8954 | 10700 | 11930 | 12799 | 14966 | 15437 | |
| SUPPLY REQUIRED - CAPACITY | 3939 | 5542 | 6169 | 6231 | 6665 | 7976 | 9233 | 11103 | 13268 | 14018 | 15871 | 18558 | 19142 | |
| PURCHASE NUGS CAPACITY | 981 | 1030 | 1078 | 1126 | 1174 | 1222 | 1269 | 1316 | 1360 | 1403 | 1439 | 1470 | 1497 | 1522 |
| HYDRAULIC PLAN CAPACITY | 1409 | 1609 | 1809 | 2008 | 2053 | 2121 | 2143 | 2241 | 2515 | 2585 | 2653 | 2718 | 2784 | 2849 |
| MAJOR SUPPLY REQUIRED - CAPACITY | 1549 | 2903 | 3282 | 3097 | 3438 | 4633 | 5821 | 7546 | 9393 | 10830 | 11779 | 14370 | 14861 | |
| MANITOBA PURCHASE CAPACITY | 600 | 1000 | 1000 | 1000 | 1000 | 1000 | 1000 | 1000 | 1000 | 1000 | 1000 | 1000 | 1000 | |
| NEW FOSSIL CAPACITY | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 336 | 1344 | 2016 | 2016 | 3696 | 3696 | |
| NEW NUCLEAR CAPACITY | 881 | 1762 | 2643 | 3524 | 3524 | 4405 | 5286 | 6167 | 7048 | 7929 | 8810 | 9691 | 10572 | |
| NEW MAJOR SUPPLY CAPACITY | 1481 | 2762 | 3643 | 4524 | 4524 | 5405 | 6286 | 7503 | 9392 | 10945 | 11826 | 14387 | 15268 | |

DEMAND / SUPPLY BALANCE - PEAK POWER (MW) - SUPPLY EXPRESSED IN CAPACITY
CANDIDATE DEMAND/SUPPLY PLAN 22 (HIGHER NUCLEAR)

UPPER LOAD FORECAST

| YEAR (JANUARY) | 1989 | 1990 | 1991 | 1992 | 1993 | 1994 | 1995 | 1996 | 1997 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | DEC. 2014 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| BASIC LOAD FORECAST | 23952 | 24907 | 26049 | 27356 | 28714 | 29800 | 30754 | 31752 | 32561 | 33649 | 34767 | 35970 | 37374 | 38622 | 39536 | 40134 | 40563 | 41079 | 41596 | 42052 | 42469 | 42870 | 43306 | 43763 | 44221 | 44678 | |
| EXISTING FIRM LOAD MEETING CAPABILITY | 23213 | 23970 | 24062 | 24784 | 26343 | 25510 | 25510 | 26131 | 26131 | 25310 | 25472 | 26092 | 26092 | 25859 | 25206 | 25044 | 25205 | 25205 | 24559 | 23939 | 23026 | 21482 | 20652 | 20236 | 18510 | 18489 | |
| DEMAND/SUPPLY REQUIRED - LHC | 739 | 937 | 1987 | 2572 | 2371 | 4290 | 5244 | 5621 | 6430 | 8339 | 9295 | 9878 | 11282 | 12763 | 14330 | 15090 | 15358 | 15874 | 17037 | 18113 | 19443 | 21388 | 22654 | 23527 | 25711 | 26189 | |
| ELECTRICAL EFFICIENCY IMPROVEMENTS | 0 | 14 | 36 | 90 | 150 | 229 | 393 | 625 | 1000 | 1375 | 1750 | 2125 | 2500 | 2625 | 2750 | 2875 | 3000 | 3125 | 3250 | 3375 | 3500 | 3625 | 3750 | 3875 | 4000 | 4125 | 4250 |
| LOAD SHIFTING | 0 | 84 | 180 | 282 | 455 | 735 | 728 | 795 | 870 | 946 | 1017 | 1100 | 1200 | 1220 | 1240 | 1260 | 1280 | 1300 | 1320 | 1340 | 1360 | 1380 | 1400 | 1420 | 1440 | 1460 | 1480 |
| DEPENDABLE LOAD DISPLACEMENT NUGS | 0 | 55 | 98 | 172 | 239 | 306 | 372 | 403 | 438 | 450 | 464 | 468 | 472 | 475 | 479 | 482 | 486 | 490 | 493 | 497 | 500 | 504 | 508 | 511 | 515 | 518 | 522 |
| PRIMARY LOAD FORECAST | 23952 | 24746 | 25707 | 26804 | 27862 | 28538 | 29261 | 29929 | 30253 | 30870 | 31536 | 32295 | 33202 | 34302 | 35067 | 35517 | 35797 | 36164 | 36533 | 36840 | 37109 | 37361 | 37648 | 37957 | 38266 | 38575 | |
| CAPACITY INTERRUPTIBLE LOADS | 725 | 750 | 650 | 660 | 660 | 672 | 696 | 705 | 724 | 744 | 765 | 782 | 798 | 811 | 826 | 841 | 857 | 871 | 884 | 896 | 907 | 917 | 928 | 940 | 951 | 963 | 976 |
| FIRM LOAD FORECAST | 23227 | 23996 | 25057 | 26144 | 27202 | 27866 | 28565 | 29224 | 29529 | 30126 | 30771 | 31503 | 32404 | 33491 | 34241 | 34676 | 34940 | 35293 | 35649 | 35944 | 36202 | 36444 | 36720 | 37017 | 37315 | 37612 | |
| SUPPLY REQUIRED - LHC | 14 | 26 | 995 | 1360 | 859 | 2356 | 3055 | 3093 | 3398 | 4816 | 5299 | 5411 | 6312 | 7632 | 9035 | 9632 | 9735 | 10088 | 11090 | 12005 | 13176 | 14962 | 16068 | 16781 | 18805 | 19123 | |
| SUPPLY REQUIRED - CAPACITY | 17 | 33 | 1234 | 1686 | 1065 | 2921 | 3788 | 3835 | 4214 | 5972 | 6571 | 6710 | 7827 | 9464 | 11203 | 11944 | 12071 | 12309 | 13752 | 14886 | 16386 | 18553 | 19924 | 20808 | 23318 | 23713 | |
| PURCHASE NUGS CAPACITY | 0 | 28 | 55 | 226 | 312 | 398 | 484 | 595 | 748 | 906 | 1035 | 1084 | 1133 | 1181 | 1230 | 1279 | 1327 | 1375 | 1423 | 1471 | 1518 | 1565 | 1584 | 1603 | 1622 | 1641 | 1660 |
| HYDRAULIC PLAN CAPACITY | 0 | 0 | 0 | 0 | 3 | 15 | 83 | 333 | 526 | 526 | 1076 | 1076 | 1209 | 1409 | 1609 | 1809 | 2008 | 2053 | 2121 | 2143 | 2341 | 2515 | 2585 | 2653 | 2718 | 2784 | 2849 |
| MAJOR SUPPLY REQUIRED - CAPACITY | 17 | 4 | 1179 | 1460 | 750 | 2508 | 3221 | 2907 | 2940 | 4540 | 4460 | 4550 | 5485 | 6874 | 8364 | 8856 | 8736 | 9081 | 10208 | 11272 | 12827 | 14473 | 15755 | 16552 | 18978 | 19288 | |
| MANITOBA PURCHASE CAPACITY | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 200 | 200 | 400 | 600 | 1000 | 1000 | 1000 | 1000 | 1000 | 1000 | 1000 | 1000 | 1000 | 1000 | 1000 | 1000 | |
| NEW FOSSIL CAPACITY | 0 | 0 | 0 | 0 | 0 | 672 | 1344 | 1344 | 1344 | 2688 | 2688 | 2688 | 3024 | 3360 | 4032 | 4368 | 4368 | 4368 | 4368 | 4368 | 4368 | 5040 | 5040 | 5040 | 5712 | 5712 | |
| NEW NUCLEAR CAPACITY | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 881 | 1762 | 2643 | 3524 | 4405 | 5286 | 6167 | 7929 | 8810 | 9691 | 11453 | 12334 | 13215 | |
| NEW MAJOR SUPPLY CAPACITY | 0 | 0 | 0 | 0 | 0 | 672 | 1344 | 1344 | 1344 | 2688 | 2888 | 2888 | 3424 | 4841 | 6794 | 8011 | 8892 | 9773 | 10654 | 11535 | 13297 | 14850 | 15731 | 17493 | 19046 | 19927 | |

DEMAND / SUPPLY BALANCE - PEAK POWER (MW) - SUPPLY EXPRESSED IN CAPACITY
CANDIDATE DEMAND/SUPPLY PLAN 22 (HIGHER NUCLEAR)

LOWER LOAD FORECAST

| YEAR (JANUARY) | 1989 | 1990 | 1991 | 1992 | 1993 | 1994 | 1995 | 1996 | 1997 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | DEC. 2014 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| BASIC LOAD FORECAST | 22690 | 22463 | 22766 | 23314 | 23403 | 23725 | 23931 | 24195 | 24312 | 24710 | 25104 | 25723 | 26594 | 27750 | 28171 | 28661 | 28630 | 28972 | 29571 | 30097 | 30667 | 31229 | 31892 | 32409 | 32960 | 33512 | |
| EXISTING FIRM LOAD MEETING CAPABILITY | 23313 | 23970 | 24062 | 24704 | 26343 | 25510 | 25510 | 26131 | 26131 | 25310 | 25472 | 26092 | 26092 | 25859 | 25206 | 25044 | 25203 | 25203 | 24559 | 23939 | 22826 | 21482 | 20652 | 20226 | 18510 | 18409 | |
| DEMAND/SUPPLY REQUIRED - LMC | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 302 | 1091 | 2965 | 3617 | 3425 | 3744 | 5012 | 6158 | 7841 | 9737 | 11240 | 12173 | 14450 | 15023 | |
| ELECTRICAL EFFICIENCY IMPROVEMENTS | 0 | 14 | 36 | 62 | 101 | 166 | 251 | 400 | 640 | 880 | 1120 | 1360 | 1600 | 1663 | 1725 | 1788 | 1850 | 1913 | 1974 | 2038 | 2100 | 2163 | 2225 | 2288 | 2350 | 2412 | 2475 |
| LOAD SHIFTING | 0 | 78 | 141 | 246 | 307 | 319 | 376 | 620 | 663 | 707 | 749 | 790 | 800 | 820 | 840 | 860 | 880 | 900 | 920 | 940 | 960 | 980 | 1000 | 1020 | 1040 | 1060 | 1080 |
| DEPENDABLE LOAD DISPLACEMENT NUGS | 0 | 55 | 98 | 172 | 219 | 306 | 330 | 342 | 342 | 342 | 342 | 342 | 342 | 342 | 342 | 342 | 346 | 350 | 353 | 357 | 360 | 364 | 368 | 371 | 375 | 378 | 382 |
| PRIMARY LOAD FORECAST | 22690 | 22316 | 22471 | 22734 | 22756 | 22754 | 22764 | 22833 | 22567 | 22781 | 22893 | 23231 | 23852 | 24925 | 25264 | 25671 | 25554 | 25810 | 26324 | 26762 | 27247 | 27732 | 28299 | 28730 | 29195 | 29662 | |
| CAPACITY INTERRUPTIBLE LOADS | 325 | 709 | 599 | 583 | 566 | 554 | 558 | 561 | 566 | 573 | 580 | 587 | 599 | 607 | 616 | 625 | 633 | 643 | 655 | 668 | 682 | 697 | 713 | 727 | 742 | 756 | 771 |
| FIRM LOAD FORECAST | 21965 | 21607 | 21872 | 22151 | 22190 | 22200 | 22206 | 22272 | 22001 | 22208 | 22313 | 22644 | 23253 | 24318 | 24648 | 25046 | 24921 | 25167 | 25669 | 26094 | 26565 | 27035 | 27586 | 28003 | 28453 | 28906 | |
| SUPPLY REQUIRED - LMC | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 2 | 0 | 0 | 1110 | 2155 | 3739 | 5553 | 6936 | 7767 | 9943 | 10417 | |
| SUPPLY REQUIRED - CAPACITY | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 2 | 0 | 0 | 1376 | 2672 | 4636 | 6886 | 8598 | 9631 | 12329 | 12917 | |
| PURCHASE NUGS CAPACITY | 0 | 28 | 55 | 226 | 312 | 398 | 435 | 435 | 435 | 435 | 435 | 435 | 435 | 435 | 435 | 483 | 531 | 579 | 627 | 675 | 722 | 769 | 788 | 807 | 826 | 845 | 864 |
| HYDRAULIC PLAN CAPACITY | 0 | 0 | 0 | 0 | 3 | 15 | 83 | 333 | 526 | 526 | 1076 | 1076 | 1209 | 1409 | 1609 | 1809 | 2008 | 2053 | 2121 | 2143 | 2241 | 2515 | 2585 | 2632 | 2710 | 2784 | 2849 |
| MAJOR SUPPLY REQUIRED - CAPACITY | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 1672 | 3602 | 5225 | 6171 | 8785 | 9288 | |
| MANITOBA PURCHASE CAPACITY | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 200 | 200 | 400 | 600 | 1000 | 1000 | 1000 | 1000 | 1000 | 1000 | 1000 | 1000 | 1000 | 1000 | 1000 | 1000 | |
| NEW FOSSIL CAPACITY | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 1600 | 1600 | |
| NEW NUCLEAR CAPACITY | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 881 | 1762 | 2643 | 4405 | 5286 | 6167 | 7048 | |
| NEW MAJOR SUPPLY CAPACITY | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 200 | 200 | 400 | 400 | 1000 | 1000 | 1000 | 1000 | 1000 | 1881 | 2762 | 3643 | 5405 | 6286 | 8767 | 9648 | |

DEMAND / SUPPLY BALANCE - PEAK POWER (MW) - SUPPLY EXPRESSED IN CAPACITY
CANDIDATE DEMAND/SUPPLY PLAN 24 (HIGHER FOSSIL)

MEDIAN LOAD FORECAST

| YEAR (JANUARY) | 1989 | 1990 | 1991 | 1992 | 1993 | 1994 | 1995 | 1996 | 1997 | 1998 | 1999 | 2000 | 2001 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| BASIC LOAD FORECAST | 23156 | 23809 | 24533 | 25383 | 26275 | 26884 | 27543 | 28099 | 28693 | 29413 | 30197 | 31111 | 32252 |
| EXISTING FIRM LOAD MEETING CAPABILITY | 23213 | 23970 | 24062 | 24704 | 26343 | 25510 | 25510 | 26131 | 26131 | 25310 | 25472 | 26092 | 26092 |
| DEMAND/SUPPLY REQUIRED - LHC | 0 | 0 | 471 | 679 | 0 | 1374 | 2033 | 1968 | 2562 | 4103 | 4725 | 5019 | 6160 |
| ELECTRICAL EFFICIENCY IMPROVEMENTS | 0 | 14 | 45 | 78 | 126 | 183 | 314 | 500 | 800 | 1100 | 1400 | 1700 | 2000 |
| LOAD SHIFTING | 0 | 61 | 171 | 266 | 423 | 502 | 656 | 717 | 776 | 836 | 893 | 946 | 1000 |
| DEPENDABLE LOAD DISPLACEMENT NUGS | 0 | 59 | 102 | 176 | 243 | 310 | 334 | 359 | 373 | 384 | 391 | 392 | 403 |
| PRIMARY LOAD FORECAST | 23156 | 23675 | 24215 | 24943 | 25483 | 25889 | 26239 | 26523 | 26744 | 27093 | 27513 | 28073 | 28849 |
| CAPACITY INTERRUPTIBLE LOADS | 725 | 735 | 632 | 625 | 621 | 623 | 632 | 641 | 652 | 664 | 676 | 688 | 702 |
| FIRM LOAD FORECAST | 22431 | 22940 | 23583 | 24318 | 24862 | 25266 | 25607 | 25882 | 26092 | 26429 | 26837 | 27385 | 28147 |
| SUPPLY REQUIRED - LHC | 0 | 0 | 0 | 0 | 0 | 0 | 97 | 0 | 0 | 1119 | 1365 | 1293 | 2055 |
| SUPPLY REQUIRED - CAPACITY | 0 | 0 | 0 | 0 | 0 | 0 | 120 | 0 | 0 | 1300 | 1693 | 1603 | 2540 |
| PURCHASE NUGS CAPACITY | 0 | 38 | 55 | 226 | 312 | 390 | 471 | 544 | 616 | 691 | 771 | 857 | 932 |
| HYDRAULIC PLAN CAPACITY | 0 | 0 | 0 | 0 | 3 | 15 | 83 | 333 | 526 | 536 | 1076 | 1076 | 1209 |
| MAJOR SUPPLY REQUIRED - CAPACITY | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 171 | 0 | 0 | 407 |
| MANITOBA PURCHASE CAPACITY | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 200 | 200 | 400 |
| NEW FOSSIL CAPACITY | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| NEW NUCLEAR CAPACITY | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| NEW MAJOR SUPPLY CAPACITY | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 200 | 200 | 400 |

| YEAR (JANUARY) | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | DEC. 2014 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| BASIC LOAD FORECAST | 33291 | 34050 | 34530 | 34877 | 35364 | 35912 | 36443 | 36975 | 37515 | 38073 | 38644 | 39224 | 39812 | |
| EXISTING FIRM LOAD MEETING CAPABILITY | 25859 | 25206 | 25044 | 25205 | 25205 | 24559 | 23939 | 22826 | 21482 | 20651 | 20236 | 18510 | 18489 | |
| DEMAND/SUPPLY REQUIRED - LHC | 7432 | 8844 | 9486 | 9672 | 10159 | 11353 | 12504 | 14149 | 16033 | 17421 | 18400 | 20714 | 21323 | |
| ELECTRICAL EFFICIENCY IMPROVEMENTS | 2100 | 2200 | 2300 | 2400 | 2500 | 2600 | 2700 | 2800 | 2900 | 3000 | 3100 | 3200 | 3300 | 3400 |
| LOAD SHIFTING | 1020 | 1040 | 1060 | 1080 | 1100 | 1120 | 1140 | 1160 | 1180 | 1200 | 1220 | 1240 | 1260 | 1280 |
| DEPENDABLE LOAD DISPLACEMENT NUGS | 407 | 411 | 414 | 418 | 422 | 426 | 430 | 433 | 437 | 441 | 445 | 449 | 452 | 456 |
| PRIMARY LOAD FORECAST | 29764 | 30399 | 30756 | 30979 | 31342 | 31766 | 32173 | 32582 | 32998 | 33432 | 33879 | 34335 | 34800 | |
| CAPACITY INTERRUPTIBLE LOADS | 712 | 724 | 737 | 749 | 762 | 775 | 788 | 802 | 816 | 830 | 844 | 859 | 874 | 890 |
| FIRM LOAD FORECAST | 29052 | 29675 | 30019 | 30230 | 30580 | 30991 | 31385 | 31780 | 32182 | 32602 | 33035 | 33476 | 33926 | |
| SUPPLY REQUIRED - LHC | 3193 | 4469 | 4975 | 5025 | 5375 | 6432 | 7446 | 8954 | 10700 | 11950 | 12799 | 14966 | 15437 | |
| SUPPLY REQUIRED - CAPACITY | 3959 | 5542 | 6169 | 6231 | 6665 | 7976 | 9233 | 11103 | 13268 | 14818 | 15871 | 18558 | 19142 | |
| PURCHASE NUGS CAPACITY | 981 | 1030 | 1078 | 1126 | 1174 | 1222 | 1269 | 1316 | 1360 | 1403 | 1439 | 1478 | 1497 | 1522 |
| HYDRAULIC PLAN CAPACITY | 1409 | 1609 | 1809 | 2008 | 2033 | 2121 | 2143 | 2241 | 2315 | 2505 | 2653 | 2710 | 2784 | 2849 |
| MAJOR SUPPLY REQUIRED - CAPACITY | 1569 | 2903 | 3282 | 3097 | 3438 | 4623 | 5821 | 7546 | 9393 | 10830 | 11779 | 14370 | 14861 | |
| MANITOBA PURCHASE CAPACITY | 600 | 1000 | 1000 | 1000 | 1000 | 1000 | 1000 | 1000 | 1000 | 1000 | 1000 | 1000 | 1000 | |
| NEW FOSSIL CAPACITY | 336 | 1344 | 1344 | 1344 | 1344 | 1344 | 2016 | 3696 | 5445 | 6858 | 7599 | 9012 | 9012 | |
| NEW NUCLEAR CAPACITY | 0 | 0 | 881 | 1762 | 2643 | 3524 | 3524 | 3524 | 3524 | 3524 | 3524 | 4405 | 5286 | |
| NEW MAJOR SUPPLY CAPACITY | 936 | 2344 | 3225 | 4106 | 4987 | 5868 | 6540 | 8220 | 9969 | 11382 | 12123 | 14417 | 15298 | |

DEMAND / SUPPLY BALANCE - PEAK POWER (MW) - SUPPLY EXPRESSED IN CAPACITY
CANDIDATE DEMAND/SUPPLY PLAN 24 (HIGHER FOSSIL)

UPPER LOAD FORECAST

| YEAR (JANUARY) | 1989 | 1990 | 1991 | 1992 | 1993 | 1994 | 1995 | 1996 | 1997 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | DEC. 2014 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| BASIC LOAD FORECAST | 23952 | 24907 | 26049 | 27356 | 28714 | 29808 | 30754 | 31752 | 32561 | 33649 | 34767 | 35978 | 37374 | 38622 | 39536 | 40134 | 40563 | 41079 | 41596 | 42052 | 42469 | 42870 | 43306 | 43763 | 44221 | 44678 | |
| EXISTING FIRM LOAD MEETING CAPABILITY | 23213 | 23970 | 24062 | 24784 | 26343 | 25510 | 25510 | 26131 | 26131 | 25310 | 25472 | 26092 | 26092 | 25859 | 25206 | 25044 | 25205 | 25205 | 24559 | 23939 | 22826 | 21482 | 20652 | 20236 | 18510 | 18489 | |
| DEMAND/SUPPLY REQUIRED - LMC | 739 | 937 | 1987 | 2572 | 2371 | 4298 | 5244 | 5621 | 6430 | 8339 | 9295 | 9886 | 11282 | 12763 | 14330 | 15090 | 15358 | 15874 | 17037 | 18113 | 19643 | 21388 | 22654 | 23527 | 25711 | 26189 | |
| ELECTRICAL EFFICIENCY IMPROVEMENTS | 0 | 14 | 36 | 58 | 158 | 229 | 393 | 625 | 1000 | 1375 | 1750 | 2125 | 2500 | 2625 | 2750 | 2875 | 3000 | 3125 | 3250 | 3375 | 3500 | 3625 | 3750 | 3875 | 4000 | 4125 | 4250 |
| LOAD SHIFTING | 0 | 84 | 200 | 322 | 455 | 735 | 728 | 795 | 870 | 946 | 1017 | 1100 | 1200 | 1220 | 1240 | 1260 | 1280 | 1300 | 1320 | 1340 | 1360 | 1380 | 1400 | 1420 | 1440 | 1460 | 1480 |
| DEPENDABLE LOAD DISPLACEMENT NUGS | 0 | 55 | 98 | 172 | 239 | 306 | 372 | 403 | 438 | 458 | 464 | 468 | 472 | 475 | 479 | 482 | 486 | 490 | 493 | 497 | 500 | 504 | 508 | 511 | 515 | 518 | 522 |
| PRIMARY LOAD FORECAST | 23952 | 24754 | 25715 | 26804 | 27862 | 28538 | 29261 | 29929 | 30253 | 30870 | 31536 | 32285 | 33202 | 34302 | 35067 | 35517 | 35797 | 36164 | 36533 | 36840 | 37109 | 37361 | 37640 | 37957 | 38266 | 38575 | |
| CAPACITY INTERRUPTIBLE LOADS | 725 | 758 | 658 | 660 | 660 | 672 | 696 | 705 | 724 | 744 | 765 | 782 | 798 | 811 | 826 | 841 | 857 | 871 | 884 | 896 | 907 | 917 | 920 | 940 | 951 | 963 | 976 |
| FIRM LOAD FORECAST | 23227 | 23996 | 25057 | 26144 | 27202 | 27866 | 28565 | 29224 | 29529 | 30126 | 30771 | 31503 | 32404 | 33491 | 34241 | 34676 | 34940 | 35293 | 35649 | 35944 | 36202 | 36444 | 36720 | 37017 | 37315 | 37612 | |
| SUPPLY REQUIRED - LMC | 14 | 26 | 995 | 1360 | 859 | 2356 | 3055 | 3093 | 3398 | 4816 | 5299 | 5411 | 6312 | 7632 | 9035 | 9632 | 9735 | 10088 | 11090 | 12005 | 13376 | 14962 | 16068 | 16781 | 18805 | 19123 | |
| SUPPLY REQUIRED - CAPACITY | 17 | 32 | 1234 | 1686 | 1065 | 3921 | 3708 | 3835 | 4214 | 5972 | 6571 | 6710 | 7827 | 9464 | 11203 | 11944 | 12071 | 12509 | 13752 | 14886 | 16586 | 18533 | 19924 | 20808 | 23310 | 23713 | |
| PURCHASE NUGS CAPACITY | 0 | 28 | 55 | 226 | 312 | 398 | 404 | 595 | 748 | 906 | 1035 | 1084 | 1133 | 1181 | 1230 | 1279 | 1327 | 1375 | 1423 | 1471 | 1518 | 1565 | 1584 | 1603 | 1622 | 1641 | 1660 |
| HYDRAULIC PLAN CAPACITY | 0 | 0 | 0 | 0 | 3 | 15 | 83 | 333 | 526 | 526 | 1076 | 1076 | 1209 | 1409 | 1609 | 1809 | 2008 | 2053 | 2121 | 2143 | 2241 | 2515 | 2585 | 2653 | 2710 | 2784 | 2849 |
| MAJOR SUPPLY REQUIRED - CAPACITY | 17 | 4 | 1179 | 1460 | 750 | 2508 | 3221 | 2907 | 2940 | 4540 | 4460 | 4550 | 5485 | 6874 | 8364 | 8856 | 8736 | 9081 | 10208 | 11272 | 12827 | 14453 | 15755 | 16552 | 18978 | 19288 | |
| MANITOBA PURCHASE CAPACITY | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 200 | 200 | 400 | 600 | 1000 | 1000 | 1000 | 1000 | 1000 | 1000 | 1000 | 1000 | 1000 | 1000 | 1000 | 1000 | |
| NEW FOSSIL CAPACITY | 0 | 0 | 0 | 0 | 0 | 672 | 1344 | 1344 | 1344 | 2688 | 2688 | 2688 | 2024 | 4360 | 5040 | 5376 | 5376 | 5376 | 6384 | 7125 | 7866 | 8607 | 9348 | 9348 | 10020 | 10020 | |
| NEW NUCLEAR CAPACITY | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 881 | 1762 | 2643 | 3524 | 3524 | 3524 | 4405 | 5286 | 6167 | 7048 | 7929 | 8810 | |
| NEW MAJOR SUPPLY CAPACITY | 0 | 0 | 0 | 0 | 0 | 672 | 1344 | 1344 | 1344 | 2688 | 2888 | 2888 | 2424 | 4960 | 6921 | 8138 | 9019 | 9900 | 10908 | 11649 | 13271 | 14893 | 16515 | 17396 | 18949 | 19830 | |

DEMAND / SUPPLY BALANCE - PEAK POWER (MW) - SUPPLY EXPRESSED IN CAPACITY
CANDIDATE DEMAND/SUPPLY PLAN 24 (HIGHER FOSSIL)

LOWER LOAD FORECAST

| YEAR (JANUARY) | 1989 | 1990 | 1991 | 1992 | 1993 | 1994 | 1995 | 1996 | 1997 | 1998 | 1999 | 2000 | 2001 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| BASIC LOAD FORECAST | 22690 | 22463 | 22766 | 23214 | 23403 | 23725 | 23921 | 24195 | 24212 | 24710 | 25104 | 25723 | 26594 |
| EXISTING FIRM LOAD MEETING CAPABILITY | 23213 | 23970 | 24062 | 24784 | 26343 | 25510 | 25510 | 26131 | 26131 | 25310 | 25472 | 26092 | 26092 |
| DEMAND/SUPPLY REQUIRED - LMC | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 502 |
| ELECTRICAL EFFICIENCY IMPROVEMENTS | 0 | 14 | 36 | 63 | 101 | 146 | 251 | 400 | 640 | 880 | 1120 | 1360 | 1600 |
| LOAD SHIFTING | 0 | 78 | 161 | 244 | 307 | 319 | 376 | 620 | 663 | 707 | 749 | 790 | 800 |
| DEPENDABLE LOAD DISPLACEMENT NUGS | 0 | 55 | 98 | 172 | 239 | 306 | 330 | 342 | 342 | 342 | 342 | 342 | 342 |
| PRIMARY LOAD FORECAST | 22690 | 22316 | 22471 | 22734 | 22756 | 22754 | 22764 | 23033 | 22567 | 22701 | 22893 | 23211 | 23852 |
| CAPACITY INTERRUPTIBLE LOADS | 725 | 709 | 599 | 583 | 566 | 554 | 558 | 561 | 566 | 573 | 580 | 587 | 599 |
| FIRM LOAD FORECAST | 21965 | 21607 | 21872 | 22151 | 22190 | 22200 | 22206 | 22272 | 22001 | 22208 | 22313 | 22644 | 23253 |
| SUPPLY REQUIRED - LMC | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| SUPPLY REQUIRED - CAPACITY | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| PURCHASE NUGS CAPACITY | 0 | 28 | 55 | 226 | 312 | 398 | 435 | 435 | 435 | 435 | 435 | 435 | 435 |
| HYDRAULIC PLAN CAPACITY | 0 | 0 | 0 | 0 | 3 | 15 | 83 | 333 | 526 | 526 | 1076 | 1076 | 1209 |
| MAJOR SUPPLY REQUIRED - CAPACITY | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| MANITOBA PURCHASE CAPACITY | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 200 | 200 | 400 |
| NEW FOSSIL CAPACITY | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| NEW NUCLEAR CAPACITY | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| NEW MAJOR SUPPLY CAPACITY | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 200 | 200 | 400 |

| YEAR (JANUARY) | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | DEC. 2014 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| BASIC LOAD FORECAST | 27730 | 28171 | 28661 | 28630 | 28973 | 29571 | 30097 | 30667 | 31239 | 31892 | 32409 | 32960 | 33512 | |
| EXISTING FIRM LOAD MEETING CAPABILITY | 25859 | 25206 | 25044 | 25205 | 25205 | 24559 | 23939 | 23426 | 21402 | 20652 | 20336 | 18518 | 18489 | |
| DEMAND/SUPPLY REQUIRED - LMC | 1891 | 2965 | 3617 | 3425 | 3768 | 5012 | 6158 | 7041 | 9757 | 11240 | 12173 | 14450 | 15023 | |
| ELECTRICAL EFFICIENCY IMPROVEMENTS | 1663 | 1725 | 1788 | 1850 | 1913 | 1974 | 2038 | 2100 | 2163 | 2225 | 2288 | 2350 | 2412 | 2475 |
| LOAD SHIFTING | 820 | 840 | 860 | 880 | 900 | 920 | 940 | 960 | 980 | 1000 | 1020 | 1040 | 1060 | 1080 |
| DEPENDABLE LOAD DISPLACEMENT NUGS | 342 | 342 | 343 | 346 | 350 | 353 | 357 | 360 | 364 | 368 | 371 | 375 | 378 | 382 |
| PRIMARY LOAD FORECAST | 24925 | 25264 | 25671 | 25554 | 25810 | 26324 | 26762 | 27247 | 27732 | 28299 | 28730 | 29195 | 29642 | |
| CAPACITY INTERRUPTIBLE LOADS | 607 | 616 | 625 | 633 | 643 | 653 | 660 | 682 | 691 | 713 | 721 | 742 | 756 | 771 |
| FIRM LOAD FORECAST | 24318 | 24648 | 25046 | 24921 | 25167 | 25669 | 26094 | 26565 | 27035 | 27586 | 28003 | 28453 | 28906 | |
| SUPPLY REQUIRED - LMC | 0 | 0 | 2 | 0 | 0 | 1110 | 2155 | 3139 | 3553 | 4934 | 7767 | 9943 | 10417 | |
| SUPPLY REQUIRED - CAPACITY | 0 | 0 | 2 | 0 | 0 | 1376 | 2672 | 4636 | 6006 | 8596 | 9631 | 12229 | 12917 | |
| PURCHASE NUGS CAPACITY | 435 | 435 | 483 | 531 | 579 | 627 | 675 | 722 | 769 | 788 | 807 | 826 | 845 | 864 |
| HYDRAULIC PLAN CAPACITY | 1409 | 1609 | 1809 | 2008 | 2053 | 2121 | 2143 | 2241 | 2515 | 2583 | 2653 | 2718 | 2784 | 2849 |
| MAJOR SUPPLY REQUIRED - CAPACITY | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 1673 | 3602 | 5225 | 6171 | 8785 | 9288 | |
| MANITOBA PURCHASE CAPACITY | 600 | 1000 | 1000 | 1000 | 1000 | 1000 | 1000 | 1000 | 1000 | 1000 | 1000 | 1000 | 1000 | |
| NEW FOSSIL CAPACITY | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 673 | 2016 | 2352 | 2688 | 4101 | 4842 | |
| NEW NUCLEAR CAPACITY | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 881 | 1762 | 2643 | 3524 | 3524 | |
| NEW MAJOR SUPPLY CAPACITY | 600 | 1000 | 1000 | 1000 | 1000 | 1000 | 1000 | 1673 | 3897 | 5114 | 6331 | 8625 | 9366 | |

DEMAND / SUPPLY BALANCE - PEAK POWER (MW) - SUPPLY EXPRESSED IN LOAD MEETING CAPABILITY
PROPOSED REFERENCE PLAN 15

| MEDIAN LOAD FORECAST YEAR (JANUARY) | 1989 | 1990 | 1991 | 1992 | 1993 | 1994 | 1995 | 1996 | 1997 | 1998 | 1999 | 2000 | 2001 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| BASIC LOAD FORECAST | 23136 | 23809 | 24533 | 25463 | 26273 | 26684 | 27543 | 28099 | 28693 | 29413 | 30157 | 31111 | 32252 |
| ELECTRICAL EFFICIENCY IMPROVEMENTS | 0 | 14 | 45 | 78 | 126 | 183 | 314 | 500 | 800 | 1100 | 1400 | 1700 | 2000 |
| LOAD SHIFTING | 0 | 81 | 171 | 266 | 423 | 382 | 656 | 717 | 776 | 836 | 893 | 946 | 1000 |
| DEPENDABLE LOAD DISPLACEMENT NUGS | 0 | 59 | 103 | 176 | 241 | 310 | 334 | 359 | 373 | 384 | 351 | 392 | 403 |
| PRIMARY LOAD FORECAST | 23136 | 23655 | 24215 | 24943 | 25483 | 25809 | 26239 | 26523 | 26744 | 27093 | 27513 | 28073 | 28849 |
| CAPACITY INTERRUPTIBLE LOADS | 715 | 735 | 632 | 625 | 621 | 623 | 632 | 641 | 652 | 664 | 676 | 688 | 702 |
| FIRM LOAD FORECAST | 22421 | 22920 | 23583 | 24318 | 24862 | 25186 | 25607 | 25882 | 26092 | 26429 | 26837 | 27385 | 28147 |
| EXISTING FIRM LOAD MEETING CAPABILITY | 23213 | 23970 | 24062 | 24784 | 26343 | 25510 | 25510 | 26131 | 26131 | 25310 | 25472 | 26092 | 26092 |
| PURCHASE NUGS LMC | 0 | 23 | 44 | 182 | 252 | 331 | 380 | 439 | 497 | 557 | 622 | 691 | 752 |
| HYDRAULIC PLAN LMC | 0 | 0 | 0 | 0 | 2 | 12 | 67 | 269 | 424 | 424 | 868 | 868 | 975 |
| MANITOBA PURCHASE LMC | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 161 | 161 | 322 |
| NEW FOSSIL LMC | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| NEW NUCLEAR LMC | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| PLANNED FIRM LOAD MEETING CAPABILITY | 23213 | 23993 | 24106 | 24966 | 26597 | 25853 | 25957 | 26839 | 27052 | 26291 | 27123 | 27812 | 28141 |
| DEMAND/SUPPLY REQUIRED - LMC | 0 | 0 | 471 | 679 | 0 | 1274 | 2033 | 1960 | 2562 | 4103 | 4725 | 5019 | 6160 |
| SUPPLY REQUIRED - CAPACITY | 0 | 0 | 0 | 0 | 0 | 0 | 130 | 0 | 0 | 1388 | 1693 | 1603 | 2548 |
| MAJOR SUPPLY REQUIRED - CAPACITY | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 171 | 0 | 0 | 407 |

| MEDIAN LOAD FORECAST YEAR (JANUARY) | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| BASIC LOAD FORECAST | 33291 | 34050 | 34530 | 34877 | 35364 | 35912 | 36443 | 36975 | 37515 | 38073 | 38644 | 39224 | 39812 |
| ELECTRICAL EFFICIENCY IMPROVEMENTS | 2100 | 2200 | 2300 | 2400 | 2500 | 2600 | 2700 | 2800 | 2900 | 3000 | 3100 | 3200 | 3300 |
| LOAD SHIFTING | 1020 | 1040 | 1060 | 1080 | 1100 | 1120 | 1140 | 1160 | 1180 | 1200 | 1220 | 1240 | 1260 |
| DEPENDABLE LOAD DISPLACEMENT NUGS | 407 | 411 | 414 | 418 | 422 | 426 | 430 | 433 | 437 | 441 | 445 | 449 | 452 |
| PRIMARY LOAD FORECAST | 29764 | 30399 | 30756 | 30979 | 31342 | 31766 | 32173 | 32582 | 32998 | 33432 | 33879 | 34335 | 34800 |
| CAPACITY INTERRUPTIBLE LOADS | 712 | 724 | 737 | 749 | 762 | 775 | 788 | 802 | 816 | 830 | 844 | 859 | 874 |
| FIRM LOAD FORECAST | 29052 | 29675 | 30019 | 30230 | 30580 | 30991 | 31385 | 31780 | 32182 | 32602 | 33035 | 33476 | 33926 |
| EXISTING FIRM LOAD MEETING CAPABILITY | 25859 | 25206 | 25044 | 25205 | 25205 | 24559 | 23939 | 22026 | 21402 | 20652 | 20236 | 18510 | 18469 |
| PURCHASE NUGS LMC | 791 | 831 | 869 | 908 | 947 | 985 | 1022 | 1061 | 1097 | 1131 | 1160 | 1185 | 1207 |
| HYDRAULIC PLAN LMC | 1136 | 1298 | 1459 | 1619 | 1636 | 1710 | 1728 | 1807 | 2028 | 2085 | 2140 | 2192 | 2245 |
| MANITOBA PURCHASE LMC | 484 | 806 | 806 | 806 | 806 | 806 | 806 | 806 | 806 | 806 | 806 | 806 | 806 |
| NEW FOSSIL LMC | 271 | 1084 | 1084 | 1084 | 1084 | 1084 | 1084 | 2439 | 3232 | 3794 | 3794 | 4335 | 4335 |
| NEW NUCLEAR LMC | 0 | 0 | 710 | 1421 | 2131 | 2842 | 2842 | 2842 | 3552 | 4263 | 4973 | 6394 | 7105 |
| PLANNED FIRM LOAD MEETING CAPABILITY | 28541 | 29225 | 29972 | 31044 | 31829 | 31987 | 31423 | 31782 | 32217 | 32731 | 33109 | 33424 | 34188 |
| DEMAND/SUPPLY REQUIRED - LMC | 7432 | 8044 | 9486 | 9672 | 10159 | 11333 | 12304 | 14149 | 16033 | 17421 | 18408 | 20714 | 21323 |
| SUPPLY REQUIRED - CAPACITY | 3959 | 5542 | 6169 | 6231 | 6665 | 7976 | 9233 | 11103 | 13260 | 14818 | 15871 | 18558 | 19142 |
| MAJOR SUPPLY REQUIRED - CAPACITY | 1569 | 2903 | 3282 | 3097 | 3438 | 4633 | 5021 | 7546 | 9393 | 10830 | 11779 | 14310 | 14861 |

DEMAND / SUPPLY BALANCE - PEAK POWER (MW) - SUPPLY EXPRESSED IN LOAD MEETING CAPABILITY
PROPOSED REFERENCE PLAN 15

UPPER LOAD FORECAST

| YEAR (JANUARY) | 1989 | 1990 | 1991 | 1992 | 1993 | 1994 | 1995 | 1996 | 1997 | 1998 | 1999 | 2000 | 2001 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| BASIC LOAD FORECAST | 23952 | 24907 | 26049 | 27356 | 28714 | 29808 | 30754 | 31753 | 32561 | 33649 | 34767 | 35978 | 37374 |
| ELECTRICAL EFFICIENCY IMPROVEMENTS | 0 | 14 | 56 | 90 | 130 | 229 | 393 | 625 | 1000 | 1375 | 1750 | 2125 | 2500 |
| LOAD SHIFTING | 0 | 84 | 188 | 290 | 483 | 735 | 728 | 795 | 870 | 946 | 1017 | 1100 | 1200 |
| DEPENDABLE LOAD DISPLACEMENT NUGS | 0. | 55 | 90 | 172 | 239 | 306 | 372 | 403 | 438 | 458 | 464 | 468 | 472 |
| PRIMARY LOAD FORECAST | 23952 | 24754 | 25715 | 26804 | 27862 | 28538 | 29261 | 29929 | 30253 | 30870 | 31536 | 32285 | 33202 |
| CAPACITY INTERRUPTIBLE LOADS | 725 | 758 | 658 | 660 | 660 | 672 | 696 | 705 | 724 | 744 | 765 | 782 | 798 |
| FIRM LOAD FORECAST | 23227 | 23996 | 25057 | 26144 | 27202 | 27866 | 28565 | 29224 | 29529 | 30126 | 30771 | 31503 | 32404 |
| EXISTING FIRM LOAD MEETING CAPABILITY | 23213 | 23960 | 24062 | 24784 | 26343 | 25510 | 25510 | 26131 | 26131 | 25310 | 25472 | 26093 | 26092 |
| PURCHASE NUGS LMC | 0 | 33 | 44 | 182 | 252 | 321 | 390 | 480 | 603 | 731 | 835 | 874 | 914 |
| HYDRAULIC PLAN LMC | 0 | 0 | 0 | 0 | 2 | 12 | 67 | 269 | 424 | 424 | 875 | 875 | 975 |
| MANITOBA PURCHASE LMC | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 161 | 161 | 323 |
| NEW FOSSIL LMC | 0 | 0 | 0 | 0 | 0 | 342 | 1084 | 1084 | 1084 | 2160 | 2160 | 2160 | 2439 |
| NEW NUCLEAR LMC | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| PLANNED FIRM LOAD MEETING CAPABILITY | 23213 | 23993 | 24106 | 24966 | 26597 | 26185 | 27051 | 27963 | 28242 | 28633 | 29503 | 30163 | 30742 |
| DEMAND/SUPPLY REQUIRED - LMC | 739 | 937 | 1987 | 2572 | 3371 | 4290 | 5244 | 5821 | 6630 | 8339 | 9295 | 9866 | 11202 |
| SUPPLY REQUIRED - CAPACITY | 17 | 33 | 1234 | 1606 | 1865 | 2931 | 3188 | 3835 | 4214 | 5972 | 6571 | 6710 | 7827 |
| MAJOR SUPPLY REQUIRED - CAPACITY | 17 | 4 | 1179 | 1440 | 750 | 2308 | 3221 | 2907 | 2940 | 4540 | 4460 | 4330 | 5485 |

| YEAR (JANUARY) | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| BASIC LOAD FORECAST | 38622 | 39536 | 40134 | 40563 | 41079 | 41596 | 42052 | 42469 | 42870 | 43306 | 43763 | 44221 | 44678 |
| ELECTRICAL EFFICIENCY IMPROVEMENTS | 2625 | 2750 | 2875 | 3000 | 3125 | 3250 | 3375 | 3500 | 3625 | 3750 | 3875 | 4000 | 4125 |
| LOAD SHIFTING | 1220 | 1240 | 1260 | 1280 | 1300 | 1320 | 1340 | 1360 | 1380 | 1400 | 1420 | 1440 | 1460 |
| DEPENDABLE LOAD DISPLACEMENT NUGS | 475 | 479 | 482 | 486 | 490 | 493 | 497 | 500 | 504 | 508 | 511 | 515 | 518 |
| PRIMARY LOAD FORECAST | 34302 | 35067 | 35517 | 35797 | 36164 | 36533 | 36840 | 37109 | 37361 | 37648 | 37957 | 38266 | 38575 |
| CAPACITY INTERRUPTIBLE LOADS | 811 | 826 | 841 | 857 | 871 | 884 | 896 | 907 | 917 | 928 | 940 | 951 | 963 |
| FIRM LOAD FORECAST | 33491 | 34241 | 34676 | 34940 | 35293 | 35649 | 35944 | 36202 | 36444 | 36720 | 37017 | 37315 | 37612 |
| EXISTING FIRM LOAD MEETING CAPABILITY | 25859 | 25206 | 25044 | 25205 | 25205 | 24559 | 23939 | 22836 | 21402 | 20652 | 20236 | 18510 | 18489 |
| PURCHASE NUGS LMC | 952 | 992 | 1031 | 1070 | 1109 | 1148 | 1186 | 1224 | 1262 | 1277 | 1293 | 1308 | 1323 |
| HYDRAULIC PLAN LMC | 1136 | 1298 | 1439 | 1619 | 1656 | 1710 | 1728 | 1807 | 2028 | 2085 | 2140 | 2192 | 2245 |
| MANITOBA PURCHASE LMC | 404 | 806 | 806 | 806 | 806 | 806 | 806 | 806 | 806 | 806 | 806 | 806 | 806 |
| NEW FOSSIL LMC | 3603 | 4065 | 4335 | 4335 | 4335 | 4606 | 4606 | 4606 | 4606 | 4606 | 4606 | 5148 | 5148 |
| NEW NUCLEAR LMC | 0 | 710 | 1421 | 2131 | 2842 | 2842 | 3552 | 4973 | 6394 | 7815 | 8526 | 9236 | 9947 |
| PLANNED FIRM LOAD MEETING CAPABILITY | 31954 | 33077 | 34097 | 35168 | 35953 | 35672 | 35819 | 36244 | 36500 | 37242 | 37607 | 37201 | 37959 |
| DEMAND/SUPPLY REQUIRED - LMC | 12763 | 14330 | 15090 | 15350 | 15874 | 17037 | 18113 | 19643 | 21308 | 22654 | 23327 | 25711 | 26189 |
| SUPPLY REQUIRED - CAPACITY | 9464 | 11203 | 11944 | 12071 | 12509 | 13732 | 14886 | 16586 | 18553 | 19924 | 20808 | 23318 | 23713 |
| MAJOR SUPPLY REQUIRED - CAPACITY | 6014 | 8364 | 8856 | 8736 | 9081 | 10208 | 11272 | 12837 | 14473 | 15755 | 16552 | 18978 | 19288 |

DEMAND / SUPPLY BALANCE - PEAK POWER (MW) - SUPPLY EXPRESSED IN LOAD MEETING CAPABILITY
PROPOSED REFERENCE PLAN 15

LOWER LOAD FORECAST

| YEAR (JANUARY) | 1989 | 1990 | 1991 | 1992 | 1993 | 1994 | 1995 | 1996 | 1997 | 1998 | 1999 | 2000 | 2001 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| BASIC LOAD FORECAST | 22690 | 23443 | 23766 | 24214 | 24503 | 24525 | 24721 | 25395 | 25212 | 25710 | 26104 | 26723 | 27394 |
| ELECTRICAL EFFICIENCY IMPROVEMENTS | 0 | 14 | 36 | 62 | 101 | 146 | 251 | 400 | 640 | 880 | 1120 | 1260 | 1600 |
| LOAD SHIFTING | 0 | 78 | 161 | 246 | 307 | 319 | 376 | 620 | 663 | 707 | 749 | 790 | 808 |
| DEPENDABLE LOAD DISPLACEMENT NUGS | 0 | 35 | 98 | 172 | 339 | 306 | 330 | 342 | 342 | 342 | 342 | 342 | 342 |
| PRIMARY LOAD FORECAST | 22690 | 23316 | 23471 | 23734 | 23756 | 23754 | 23764 | 24033 | 23567 | 23781 | 23893 | 24231 | 24652 |
| CAPACITY INTERRUPTIBLE LOADS | 725 | 709 | 399 | 583 | 566 | 554 | 550 | 561 | 566 | 573 | 580 | 587 | 599 |
| FIRM LOAD FORECAST | 21965 | 22607 | 23072 | 23151 | 23190 | 23200 | 23206 | 23472 | 23001 | 23208 | 23313 | 23644 | 24053 |
| EXISTING FIRM LOAD MEETING CAPABILITY | 23213 | 23910 | 24062 | 24764 | 24362 | 25510 | 25510 | 26131 | 26131 | 25310 | 25472 | 26092 | 26092 |
| PURCHASE NUGS LMC | 0 | 33 | 44 | 102 | 233 | 221 | 351 | 351 | 351 | 351 | 351 | 351 | 351 |
| HYDRAULIC PLAN LMC | 0 | 0 | 0 | 0 | 2 | 12 | 61 | 249 | 424 | 424 | 660 | 660 | 975 |
| MANITOBA PURCHASE LMC | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 161 | 161 | 333 |
| NEW FOSSIL LMC | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| NEW NUCLEAR LMC | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| PLANNED FIRM LOAD MEETING CAPABILITY | 23213 | 23943 | 24106 | 24866 | 24597 | 25843 | 25920 | 26750 | 26906 | 26085 | 26652 | 27472 | 27740 |
| DEMAND/SUPPLY REQUIRED - LMC | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 302 |
| SUPPLY REQUIRED - CAPACITY | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| MAJOR SUPPLY REQUIRED - CAPACITY | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |

| YEAR (JANUARY) | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| BASIC LOAD FORECAST | 27750 | 28171 | 28661 | 28630 | 28973 | 29371 | 30097 | 30667 | 31239 | 31692 | 32409 | 32960 | 33512 |
| ELECTRICAL EFFICIENCY IMPROVEMENTS | 1663 | 1725 | 1780 | 1830 | 1913 | 1974 | 2038 | 2100 | 2163 | 2225 | 2288 | 2350 | 2413 |
| LOAD SHIFTING | 820 | /840 | 860 | 880 | 900 | 920 | 940 | 960 | 980 | 1000 | 1020 | 1040 | 1060 |
| DEPENDABLE LOAD DISPLACEMENT NUGS | 342 | 342 | 342 | 346 | 350 | 353 | .357 | 360 | 364 | 368 | 371 | 375 | 378 |
| PRIMARY LOAD FORECAST | 24925 | 25264 | 25671 | 25554 | 25810 | 26124 | 26762 | 27247 | 27732 | 28299 | 28730 | 29193 | 29662 |
| CAPACITY INTERRUPTIBLE LOADS | 607 | 616 | 625 | 633 | 643 | 655 | 668 | 682 | 697 | 713 | 727 | 742 | 756 |
| FIRM LOAD FORECAST | 24318 | 24648 | 25046 | 24921 | 25167 | 25469 | 26094 | 26565 | 27035 | 27586 | 28003 | 28451 | 28906 |
| EXISTING FIRM LOAD MEETING CAPABILITY | 25859 | 25206 | 25044 | 25205 | 25205 | 24559 | 23939 | 22826 | 21402 | 20652 | 20336 | 18510 | 18489 |
| PURCHASE NUGS LMC | 351 | 351 | 390 | 420 | 467 | 506 | 544 | 583 | 620 | 635 | 651 | 666 | 681 |
| HYDRAULIC PLAN LMC | 1136 | 1298 | 1459 | 1619 | 1636 | 1710 | 1720 | 1807 | 2028 | 2085 | 2140 | 2192 | 2245 |
| MANITOBA PURCHASE LMC | 404 | 806 | 806 | 806 | 806 | 806 | 806 | 806 | 806 | 806 | 806 | 806 | 806 |
| NEW FOSSIL LMC | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 343 | 1626 | 1897 | 2168 | 2710 | 2710 |
| NEW NUCLEAR LMC | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 710 | 1421 | 2131 | 3552 | 4263 |
| PLANNED FIRM LOAD MEETING CAPABILITY | 27820 | 27661 | 27499 | 28059 | 28134 | 27582 | 27018 | 26364 | 27273 | 27494 | 28132 | 28437 | 29195 |
| DEMAND/SUPPLY REQUIRED - LMC | 1891 | 2965 | 2617 | 3425 | 3748 | 5012 | 6138 | 7041 | 9757 | 11240 | 12173 | 14450 | 15033 |
| SUPPLY REQUIRED - CAPACITY | 0 | 0 | 2 | 0 | 0 | 1376 | 2672 | 4636 | 6806 | 8596 | 9631 | 12329 | 12917 |
| MAJOR SUPPLY REQUIRED - CAPACITY | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 1673 | 3602 | 5225 | 6171 | 8703 | 9280 |

DEMAND / SUPPLY BALANCE - PEAK POWER (MW) - SUPPLY EXPRESSED IN LOAD MEETING CAPABILITY
ALTERNATIVE DEMAND/SUPPLY PLAN 32 (BIGGER NUCLEAR)

MEDIAN LOAD FORECAST

| YEAR (JANUARY) | 1989 | 1990 | 1991 | 1992 | 1993 | 1994 | 1995 | 1996 | 1997 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| BASIC LOAD FORECAST | 23156 | 23809 | 24533 | 25463 | 26215 | 26804 | 27543 | 28099 | 28693 | 29413 | 30197 | 31111 | 32252 | 33291 | 34050 | 34530 | 34877 | 35364 | 35912 | 36443 | 36975 | 37515 | 38073 | 38644 | 39224 | 39812 |
| ELECTRICAL EFFICIENCY IMPROVEMENTS | 0 | 14 | 45 | 78 | 126 | 183 | 314 | 500 | 800 | 1100 | 1400 | 1700 | 2000 | 2100 | 2200 | 2300 | 2400 | 2500 | 2600 | 2700 | 2800 | 2900 | 3000 | 3100 | 3200 | 3300 |
| LOAD SHIFTING | 0 | 61 | 171 | 266 | 423 | 502 | 656 | 717 | 776 | 836 | 893 | 946 | 1000 | 1020 | 1040 | 1060 | 1080 | 1100 | 1120 | 1140 | 1160 | 1180 | 1200 | 1220 | 1240 | 1260 |
| DEPENDABLE LOAD DISPLACEMENT NUGS | 0 | 39 | 102 | 176 | 243 | 310 | 334 | 359 | 373 | 384 | 391 | 392 | 403 | 407 | 411 | 414 | 418 | 422 | 426 | 430 | 433 | 437 | 441 | 445 | 449 | 452 |
| PRIMARY LOAD FORECAST | 23156 | 23655 | 24215 | 24943 | 25483 | 25809 | 26239 | 26523 | 26744 | 27093 | 27513 | 28073 | 28849 | 29764 | 30399 | 30756 | 30979 | 31342 | 31766 | 32173 | 32582 | 32998 | 33432 | 33879 | 34335 | 34800 |
| CAPACITY INTERRUPTIBLE LOADS | 725 | 735 | 612 | 625 | 621 | 623 | 632 | 641 | 652 | 664 | 676 | 688 | 702 | 712 | 724 | 737 | 749 | 762 | 775 | 788 | 802 | 816 | 830 | 844 | 859 | 874 |
| FIRM LOAD FORECAST | 22431 | 22920 | 23603 | 24318 | 24862 | 25186 | 25607 | 25882 | 26092 | 26429 | 26837 | 27385 | 28147 | 29052 | 29675 | 30019 | 30230 | 30580 | 30991 | 31385 | 31780 | 32182 | 32602 | 33035 | 33476 | 33926 |
| EXISTING FIRM LOAD MEETING CAPABILITY | 23213 | 23970 | 24062 | 24864 | 26343 | 25500 | 25510 | 26131 | 26131 | 25310 | 25472 | 26092 | 26092 | 25859 | 25206 | 25044 | 25205 | 25205 | 24559 | 23939 | 22626 | 21482 | 20652 | 20236 | 18510 | 18489 |
| PURCHASE NUGS LMC | 0 | 33 | 44 | 102 | 252 | 331 | 380 | 439 | 497 | 557 | 622 | 691 | 752 | 791 | 831 | 869 | 908 | 947 | 985 | 1023 | 1061 | 1091 | 1131 | 1160 | 1185 | 1207 |
| HYDRAULIC PLAN LMC | 0 | 0 | 0 | 0 | 2 | 12 | 67 | 269 | 424 | 424 | 868 | 868 | 975 | 1136 | 1298 | 1459 | 1619 | 1656 | 1710 | 1728 | 1807 | 2028 | 2085 | 2140 | 2192 | 2245 |
| MANITOBA PURCHASE LMC | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 161 | 161 | 323 | 484 | 806 | 806 | 806 | 806 | 806 | 806 | 806 | 806 | 806 | 806 | 806 | 806 |
| NEW FOSSIL LMC | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 211 | 1084 | 1626 | 1626 | 2981 | 2981 |
| NEW NUCLEAR LMC | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 710 | 1421 | 2131 | 2842 | 2842 | 3552 | 4263 | 4973 | 5684 | 6394 | 7105 | 7815 | 8526 |
| PLANNED FIRM LOAD MEETING CAPABILITY | 23213 | 23993 | 24106 | 24966 | 26597 | 25843 | 25957 | 26839 | 27052 | 26291 | 27123 | 27812 | 28141 | 28981 | 29562 | 30310 | 31381 | 31456 | 31614 | 31760 | 31745 | 32181 | 32695 | 33073 | 33490 | 34254 |
| DEMAND/SUPPLY REQUIRED - LMC | 0 | 0 | 471 | 679 | 0 | 1374 | 2031 | 1966 | 2562 | 4103 | 4725 | 5019 | 6160 | 7432 | 8844 | 9486 | 9672 | 10159 | 11353 | 12504 | 14149 | 16033 | 17421 | 18408 | 20714 | 21323 |
| SUPPLY REQUIRED - CAPACITY | 0 | 0 | 0 | 0 | 0 | 0 | 120 | 0 | 0 | 1388 | 1693 | 1603 | 2540 | 3939 | 5542 | 6169 | 6231 | 6665 | 7976 | 9233 | 11103 | 13260 | 14818 | 15871 | 18538 | 19142 |
| MAJOR SUPPLY REQUIRED - CAPACITY | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 171 | 0 | 0 | 407 | 1569 | 2903 | 3282 | 3097 | 3438 | 4833 | 5831 | 7546 | 9393 | 10830 | 11779 | 14370 | 14861 |

DEMAND / SUPPLY BALANCE - PEAK POWER (MW) - SUPPLY EXPRESSED IN LOAD MEETING CAPABILITY
ALTERNATIVE DEMAND/SUPPLY PLAN 22 (HIGHER NUCLEAR)

UPPER LOAD FORECAST

| YEAR (JANUARY) | 1989 | 1990 | 1991 | 1992 | 1993 | 1994 | 1995 | 1996 | 1997 | 1998 | 1999 | 2000 | 2001 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| BASIC LOAD FORECAST | 23952 | 24907 | 26049 | 27356 | 28714 | 29808 | 30754 | 31753 | 32561 | 33649 | 34767 | 35878 | 37374 |
| ELECTRICAL EFFICIENCY IMPROVEMENTS | 0 | 14 | 56 | 98 | 158 | 229 | 393 | 625 | 1000 | 1375 | 1750 | 2125 | 2500 |
| LOAD SHIFTING | 0 | 84 | 180 | 282 | 455 | 735 | 728 | 796 | 878 | 946 | 1017 | 1100 | 1200 |
| DEPENDABLE LOAD DISPLACEMENT NUGS | 0 | 55 | 98 | 172 | 238 | 306 | 372 | 403 | 430 | 458 | 464 | 468 | 472 |
| PRIMARY LOAD FORECAST | 23952 | 24754 | 25715 | 26804 | 27863 | 28538 | 29261 | 29929 | 30253 | 30870 | 31536 | 32185 | 33202 |
| CAPACITY INTERRUPTIBLE LOADS | 725 | 758 | 658 | 660 | 660 | 672 | 696 | 705 | 724 | 744 | 765 | 782 | 798 |
| FIRM LOAD FORECAST | 23227 | 23996 | 25057 | 26144 | 27203 | 27866 | 28565 | 29224 | 29529 | 30126 | 30771 | 31403 | 32404 |
| EXISTING FIRM LOAD MEETING CAPABILITY | 23213 | 23970 | 24062 | 24784 | 26343 | 25510 | 25516 | 26131 | 26131 | 25310 | 25472 | 26092 | 26092 |
| PURCHASE NUGS LMC | 0 | 33 | 44 | 182 | 252 | 321 | 390 | 480 | 603 | 731 | 835 | 874 | 914 |
| HYDRAULIC PLAN LMC | 0 | 0 | 0 | 0 | 2 | 12 | 61 | 269 | 424 | 424 | 868 | 868 | 975 |
| MANITOBA PURCHASE LMC | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 161 | 161 | 323 |
| NEW FOSSIL LMC | 0 | 0 | 0 | 0 | 0 | 542 | 1084 | 1084 | 1084 | 2168 | 2168 | 2168 | 2439 |
| NEW NUCLEAR LMC | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| PLANNED FIRM LOAD MEETING CAPABILITY | 23213 | 23993 | 24106 | 24966 | 26597 | 26385 | 27051 | 27963 | 28242 | 28633 | 29503 | 30163 | 30742 |
| DEMAND/SUPPLY REQUIRED - LMC | 739 | 937 | 1987 | 2372 | 2371 | 4298 | 5244 | 5621 | 6430. | 8339 | 9295 | 9886 | 11282 |
| SUPPLY REQUIRED - CAPACITY | 17 | 32 | 1234 | 1486 | 1065 | 2921 | 3788 | 3835 | 4214 | 5972 | 6571 | 6710 | 7027 |
| MAJOR SUPPLY REQUIRED - CAPACITY | 17 | 4 | 1179 | 1440 | 758 | 2500 | 3221 | 2907 | 2940 | 4540 | 4480 | 4550 | 5485 |

| YEAR (JANUARY) | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| BASIC LOAD FORECAST | 38622 | 39536 | 40134 | 40563 | 41079 | 41596 | 42052 | 42469 | 42870 | 43306 | 43763 | 44221 | 44678 |
| ELECTRICAL EFFICIENCY IMPROVEMENTS | 2625 | 2750 | 2875 | 3000 | 3125 | 3250 | 3375 | 3500 | 3625 | 3750 | 3875 | 4000 | 4125 |
| LOAD SHIFTING | 1220 | 1240 | 1260 | 1280 | 1300 | 1320 | 1340 | 1360 | 1380 | 1400 | 1420 | 1440 | 1460 |
| DEPENDABLE LOAD DISPLACEMENT NUGS | 475 | 479 | 482 | 486 | 490 | 493 | 497 | 500 | 504 | 508 | 511 | 515 | 518 |
| PRIMARY LOAD FORECAST | 34302 | 35067 | 35517 | 35797 | 36164 | 36533 | 36840 | 37109 | 37361 | 37648 | 37957 | 38266 | 38575 |
| CAPACITY INTERRUPTIBLE LOADS | 811 | 826 | 841 | 857 | 871 | 884 | 896 | 907 | 917 | 928 | 940 | 951 | 963 |
| FIRM LOAD FORECAST | 33491 | 34241 | 34676 | 34940 | 35293 | 35649 | 35944 | 36202 | 36444 | 36720 | 37017 | 37315 | 37612 |
| EXISTING FIRM LOAD MEETING CAPABILITY | 25659 | 25206 | 25044 | 25205 | 25205 | 24559 | 23939 | 22826 | 21482 | 20652 | 20236 | 18518 | 18409 |
| PURCHASE NUGS LMC | 952 | 992 | 1031 | 1070 | 1109 | 1148 | 1186 | 1224 | 1262 | 1277 | 1293 | 1308 | 1323 |
| HYDRAULIC PLAN LMC | 1126 | 1290 | 1459 | 1619 | 1656 | 1710 | 1720 | 1807 | 2028 | 2085 | 2140 | 2192 | 2245 |
| MANITOBA PURCHASE LMC | 484 | 806 | 806 | 806 | 806 | 806 | 806 | 806 | 806 | 806 | 806 | 806 | 806 |
| NEW FOSSIL LMC | 2710 | 3252 | 3523 | 3523 | 3523 | 3523 | 3523 | 3523 | 4065 | 4065 | 4065 | 4606 | 4606 |
| NEW NUCLEAR LMC | 710 | 1421 | 2131 | 2842 | 3552 | 4263 | 4973 | 6394 | 7105 | 7815 | 9236 | 9947 | 10657 |
| PLANNED FIRM LOAD MEETING CAPABILITY | 31852 | 32975 | 33995 | 35065 | 35851 | 36009 | 36156 | 36581 | 36148 | 36700 | 37776 | 37370 | 38128 |
| DEMAND/SUPPLY REQUIRED - LMC | 12763 | 14330 | 15090 | 15358 | 15874 | 17037 | 18113 | 19643 | 21360 | 22654 | 23527 | 23711 | 26189 |
| SUPPLY REQUIRED - CAPACITY | 9464 | 11203 | 11944 | 13071 | 12509 | 13752 | 14886 | 16506 | 18533 | 19824 | 20800 | 22318 | 22713 |
| MAJOR SUPPLY REQUIRED - CAPACITY | 6874 | 8344 | 8856 | 8736 | 9081 | 10208 | 11272 | 12827 | 14473 | 15755 | 16552 | 18978 | 19268 |

DEMAND / SUPPLY BALANCE - PEAK POWER (MW) - SUPPLY EXPRESSED IN LOAD MEETING CAPABILITY
ALTERNATIVE DEMAND/SUPPLY PLAN 32 (HIGHER NUCLEAR)

LOWER LOAD FORECAST

| YEAR (JANUARY) | 1989 | 1990 | 1991 | 1992 | 1993 | 1994 | 1995 | 1996 | 1997 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| BASIC LOAD FORECAST | 22690 | 22463 | 22766 | 23214 | 23403 | 23725 | 23921 | 24195 | 24212 | 24710 | 25104 | 25723 | 26394 | 27750 | 28171 | 28661 | 28630 | 28973 | 29571 | 30097 | 30667 | 31239 | 31892 | 32409 | 32960 | 33512 |
| ELECTRICAL EFFICIENCY IMPROVEMENTS | 0 | 14 | 36 | 62 | 101 | 146 | 251 | 400 | 640 | 880 | 1120 | 1360 | 1600 | 1663 | 1725 | 1788 | 1850 | 1913 | 1974 | 2038 | 2100 | 2163 | 2225 | 2288 | 2350 | 2412 |
| LOAD SHIFTING | 0 | 78 | 141 | 246 | 307 | 519 | 576 | 620 | 663 | 787 | 749 | 790 | 800 | 820 | 840 | 860 | 880 | 900 | 920 | 940 | 960 | 980 | 1000 | 1020 | 1040 | 1060 |
| DEPENDABLE LOAD DISPLACEMENT NUGS | 0 | 55 | 98 | 172 | 239 | 306 | 330 | 342 | 342 | 342 | 342 | 342 | 342 | 342 | 342 | 342 | 346 | 350 | 353 | 357 | 360 | 364 | 368 | 371 | 375 | 378 |
| PRIMARY LOAD FORECAST | 22690 | 22316 | 22471 | 22734 | 22756 | 22754 | 22764 | 22833 | 22567 | 22701 | 22893 | 23231 | 23652 | 24925 | 25264 | 25671 | 25554 | 25810 | 26324 | 26762 | 27247 | 27732 | 28299 | 28730 | 29195 | 29662 |
| CAPACITY INTERRUPTIBLE LOADS | 725 | 709 | 599 | 583 | 566 | 554 | 558 | 561 | 566 | 573 | 580 | 587 | 599 | 607 | 616 | 625 | 633 | 643 | 655 | 668 | 682 | 697 | 713 | 727 | 742 | 756 |
| FIRM LOAD FORECAST | 21965 | 21607 | 21872 | 22151 | 22190 | 22200 | 22206 | 22272 | 22001 | 22128 | 22313 | 22644 | 23053 | 24318 | 24648 | 25046 | 24921 | 25167 | 25669 | 26094 | 26565 | 27035 | 27586 | 28003 | 28453 | 28906 |
| EXISTING FIRM LOAD MEETING CAPABILITY | 23313 | 23970 | 24062 | 24784 | 26243 | 25510 | 25510 | 26131 | 26131 | 25310 | 25472 | 26092 | 26092 | 25859 | 25206 | 25044 | 25205 | 25405 | 24559 | 23919 | 22826 | 21482 | 20652 | 20236 | 18510 | 18489 |
| PURCHASE NUGS LMC | 0 | 23 | 44 | 102 | 352 | 321 | 351 | 351 | 351 | 351 | 351 | 351 | 351 | 351 | 351 | 390 | 420 | 467 | 506 | 544 | 582 | 620 | 635 | 651 | 666 | 681 |
| HYDRAULIC PLAN LMC | 0 | 0 | 0 | 0 | 2 | 12 | 67 | 269 | 424 | 424 | 868 | 868 | 975 | 1136 | 1298 | 1459 | 1619 | 1456 | 1710 | 1750 | 1808 | 2028 | 2085 | 2140 | 2192 | 2243 |
| MANITOBA PURCHASE LMC | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 141 | 161 | 322 | 484 | 806 | 806 | 806 | 806 | 806 | 806 | 806 | 806 | 806 | 806 | 806 | 806 |
| NEW FOSSIL LMC | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 1355 | 1355 |
| NEW NUCLEAR LMC | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 710 | 1421 | 2131 | 3352 | 4263 | 4973 | 5684 |
| PLANNED FIRM LOAD MEETING CAPABILITY | 23313 | 23993 | 24106 | 24886 | 26597 | 25843 | 25928 | 26750 | 26906 | 26085 | 26832 | 27472 | 27740 | 27830 | 27661 | 27699 | 28059 | 28134 | 27582 | 27729 | 27443 | 27068 | 27731 | 28096 | 28503 | 29261 |
| DEMAND/SUPPLY REQUIRED - LMC | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 502 | 1891 | 2965 | 3617 | 3625 | 3748 | 5012 | 6130 | 7841 | 9737 | 11240 | 12173 | 14430 | 15023 |
| SUPPLY REQUIRED - CAPACITY | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 2 | 0 | 0 | 1276 | 2672 | 4636 | 6886 | 8590 | 9631 | 12329 | 12917 |
| MAJOR SUPPLY REQUIRED - CAPACITY | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 1673 | 3602 | 5225 | 6171 | 8785 | 9288 |

DEMAND / SUPPLY BALANCE - PEAK POWER (MW) - SUPPLY EXPRESSED IN LOAD MEETING CAPABILITY
REFERENCE PLAN 24

| MEDIAN LOAD FORECAST | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| YEAR (JANUARY) | 1989 | 1990 | 1991 | 1992 | 1993 | 1994 | 1995 | 1996 | 1997 | 1998 | 1999 | 2000 | 2001 |
| BASIC LOAD FORECAST | 23156 | 23809 | 24533 | 25463 | 26275 | 26884 | 27543 | 28099 | 28693 | 29413 | 30197 | 31111 | 32252 |
| ELECTRICAL EFFICIENCY IMPROVEMENTS | 0 | 14 | 45 | 78 | 126 | 183 | 314 | 500 | 800 | 1100 | 1400 | 1700 | 2000 |
| LOAD SHIFTING | 0 | 81 | 171 | 266 | 423 | 582 | 656 | 717 | 776 | 836 | 893 | 946 | 1000 |
| DEPENDABLE LOAD DISPLACEMENT NUGS | 0 | 55 | 98 | 172 | 239 | 306 | 330 | 355 | 369 | 380 | 387 | 388 | 399 |
| PRIMARY LOAD FORECAST | 23156 | 23659 | 24219 | 24947 | 25487 | 25813 | 26243 | 26527 | 26748 | 27097 | 27517 | 28077 | 28853 |
| CAPACITY INTERRUPTIBLE LOADS | 725 | 735 | 632 | 625 | 621 | 623 | 632 | 641 | 652 | 664 | 676 | 688 | 702 |
| FIRM LOAD FORECAST | 22431 | 22924 | 23587 | 24322 | 24866 | 25190 | 25611 | 25886 | 26096 | 26433 | 26841 | 27389 | 28151 |
| EXISTING FIRM LOAD MEETING CAPABILITY | 23213 | 23970 | 24062 | 24784 | 26343 | 25510 | 25510 | 26131 | 26131 | 25310 | 25472 | 26092 | 26092 |
| PURCHASE NUGS LMC | 0 | 23 | 44 | 182 | 252 | 321 | 380 | 439 | 497 | 557 | 622 | 691 | 752 |
| HYDRAULIC PLAN LMC | 0 | 0 | 0 | 0 | 2 | 12 | 67 | 269 | 424 | 426 | 868 | 868 | 975 |
| MANITOBA PURCHASE LMC | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 161 | 161 | 322 |
| NEW FOSSIL LMC | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| NEW NUCLEAR LMC | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| PLANNED FIRM LOAD MEETING CAPABILITY | 23213 | 23993 | 24106 | 24966 | 26597 | 25843 | 25957 | 26839 | 27052 | 26293 | 27123 | 27812 | 28141 |
| DEMAND/SUPPLY REQUIRED - LMC | 0 | 0 | 471 | 619 | 0 | 1374 | 2033 | 1968 | 2562 | 4103 | 4725 | 5019 | 6160 |
| SUPPLY REQUIRED - CAPACITY | 0 | 0 | 0 | 0 | 0 | 0 | 125 | 0 | 0 | 1393 | 1698 | 1608 | 2553 |
| MAJOR SUPPLY REQUIRED - CAPACITY | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 176 | 0 | 0 | 412 |

| MEDIAN LOAD FORECAST | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| YEAR (JANUARY) | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 |
| BASIC LOAD FORECAST | 33291 | 34050 | 34530 | 34877 | 35364 | 35912 | 36444 | 36975 | 37515 | 38073 | 38644 | 39224 | 39812 |
| ELECTRICAL EFFICIENCY IMPROVEMENTS | 2100 | 2200 | 2300 | 2400 | 2500 | 2600 | 2700 | 2800 | 2900 | 3000 | 3100 | 3200 | 3300 |
| LOAD SHIFTING | 1020 | 1040 | 1060 | 1080 | 1100 | 1120 | 1140 | 1160 | 1180 | 1200 | 1220 | 1240 | 1260 |
| DEPENDABLE LOAD DISPLACEMENT NUGS | 403 | 407 | 410 | 414 | 418 | 422 | 426 | 429 | 433 | 437 | 441 | 444 | 448 |
| PRIMARY LOAD FORECAST | 29768 | 30403 | 30760 | 30983 | 31346 | 31770 | 32178 | 32586 | 33002 | 33436 | 33883 | 34340 | 34804 |
| CAPACITY INTERRUPTIBLE LOADS | 712 | 724 | 737 | 749 | 762 | 775 | 788 | 802 | 814 | 830 | 844 | 859 | 874 |
| FIRM LOAD FORECAST | 29056 | 29679 | 30023 | 30234 | 30584 | 30995 | 31390 | 31784 | 32188 | 32606 | 33039 | 33481 | 33930 |
| EXISTING FIRM LOAD MEETING CAPABILITY | 25859 | 25206 | 25044 | 25205 | 25225 | 24559 | 23938 | 22826 | 21482 | 20652 | 20236 | 18519 | 18489 |
| PURCHASE NUGS LMC | 791 | 831 | 869 | 908 | 947 | 985 | 1023 | 1061 | 1097 | 1131 | 1160 | 1185 | 1207 |
| HYDRAULIC PLAN LMC | 1136 | 1298 | 1459 | 1619 | 1636 | 1710 | 1728 | 1807 | 2028 | 2085 | 2140 | 2192 | 2245 |
| MANITOBA PURCHASE LMC | 484 | 806 | 806 | 806 | 806 | 806 | 806 | 806 | 806 | 806 | 806 | 806 | 806 |
| NEW FOSSIL LMC | 271 | 1084 | 1084 | 1084 | 1084 | 1084 | 1626 | 2981 | 4391 | 5531 | 6128 | 7260 | 7260 |
| NEW NUCLEAR LMC | 0 | 0 | 710 | 1421 | 2131 | 2842 | 2842 | 2842 | 2842 | 2842 | 2842 | 3552 | 4263 |
| PLANNED FIRM LOAD MEETING CAPABILITY | 28541 | 29225 | 29973 | 31044 | 31829 | 31987 | 31965 | 32324 | 32647 | 33047 | 33313 | 33514 | 34279 |
| DEMAND/SUPPLY REQUIRED - LMC | 7432 | 8044 | 9486 | 9672 | 10159 | 11353 | 12504 | 14149 | 16023 | 17421 | 18408 | 20714 | 21323 |
| SUPPLY REQUIRED - CAPACITY | 3964 | 3547 | 6174 | 6236 | 6670 | 7981 | 9239 | 11108 | 13273 | 14023 | 15876 | 18364 | 19147 |
| MAJOR SUPPLY REQUIRED - CAPACITY | 1574 | 2908 | 2287 | 3102 | 3443 | 4638 | 5827 | 7551 | 9398 | 10835 | 11784 | 14376 | 14866 |

DEMAND / SUPPLY BALANCE - PEAK POWER (MW) - SUPPLY EXPRESSED IN LOAD MEETING CAPABILITY
REFERENCE PLAN 24

UPPER LOAD FORECAST

| YEAR (JANUARY) | 1989 | 1990 | 1991 | 1992 | 1993 | 1994 | 1995 | 1996 | 1997 | 1998 | 1999 | 2000 | 2001 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| BASIC LOAD FORECAST | 23952 | 24907 | 26049 | 27356 | 28714 | 29800 | 30734 | 31752 | 32561 | 33649 | 34767 | 35970 | 37374 |
| ELECTRICAL EFFICIENCY IMPROVEMENTS | 0 | 14 | 56 | 98 | 158 | 229 | 393 | 625 | 1000 | 1375 | 1750 | 2125 | 2500 |
| LOAD SHIFTING | 0 | 84 | 180 | 282 | 455 | 735 | 720 | 795 | 870 | 946 | 1017 | 1100 | 1200 |
| DEPENDABLE LOAD DISPLACEMENT NUGS | 0 | 55 | 98 | 172 | 239 | 306 | 372 | 403 | 430 | 458 | 464 | 468 | 472 |
| PRIMARY LOAD FORECAST | 23952 | 24754 | 25715 | 26804 | 27862 | 28530 | 29261 | 29929 | 30353 | 30870 | 31536 | 32285 | 33202 |
| CAPACITY INTERRUPTIBLE LOADS | 725 | 758 | 658 | 660 | 660 | 672 | 696 | 705 | 724 | 744 | 765 | 782 | 798 |
| FIRM LOAD FORECAST | 23227 | 23996 | 25057 | 26144 | 27202 | 27866 | 28565 | 29224 | 29529 | 30126 | 30771 | 31503 | 32404 |
| EXISTING FIRM LOAD MEETING CAPABILITY | 23313 | 23970 | 24062 | 24704 | 24343 | 25510 | 25510 | 26131 | 26131 | 25310 | 25472 | 26092 | 26092 |
| PURCHASE NUGS LMC | 0 | 23 | 44 | 102 | 252 | 321 | 390 | 480 | 603 | 731 | 835 | 874 | 914 |
| HYDRAULIC PLAN LMC | 0 | 0 | 0 | 0 | 3 | 12 | 67 | 249 | 424 | 424 | 648 | 868 | 975 |
| MANITOBA PURCHASE LMC | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 161 | 161 | 323 |
| NEW FOSSIL LMC | 0 | 0 | 0 | 0 | 0 | 542 | 1084 | 1084 | 1084 | 2160 | 2168 | 2168 | 2439 |
| NEW NUCLEAR LMC | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| PLANNED FIRM LOAD MEETING CAPABILITY | 23313 | 23993 | 24106 | 24966 | 26597 | 26385 | 27051 | 27963 | 28342 | 28633 | 29583 | 30163 | 30742 |
| DEMAND/SUPPLY REQUIRED - LMC | 739 | 937 | 1987 | 2572 | 2371 | 4290 | 5244 | 5621 | 6430 | 8339 | 9295 | 9886 | 11202 |
| SUPPLY REQUIRED - CAPACITY | 17 | 32 | 1234 | 1606 | 1065 | 2921 | 3780 | 3835 | 4214 | 5972 | 6571 | 6710 | 7827 |
| MAJOR SUPPLY REQUIRED - CAPACITY | 17 | 4 | 1179 | 1460 | 750 | 2508 | 3221 | 3987 | 3940 | 4540 | 4460 | 4550 | 5485 |

| YEAR (JANUARY) | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| BASIC LOAD FORECAST | 38622 | 39536 | 40134 | 40563 | 41019 | 41596 | 42052 | 42469 | 42870 | 43306 | 43763 | 44221 | 44670 |
| ELECTRICAL EFFICIENCY IMPROVEMENTS | 2625 | 2750 | 2875 | 3000 | 3125 | 3250 | 3375 | 3500 | 3625 | 3750 | 3875 | 4000 | 4125 |
| LOAD SHIFTING | 1220 | 1240 | 1260 | 1280 | 1300 | 1320 | 1340 | 1360 | 1380 | 1400 | 1420 | 1440 | 1460 |
| DEPENDABLE LOAD DISPLACEMENT NUGS | 475 | 479 | 482 | 486 | 490 | 493 | 497 | 500 | 504 | 508 | 511 | 515 | 518 |
| PRIMARY LOAD FORECAST | 34302 | 35067 | 35517 | 35797 | 36164 | 36533 | 36840 | 37109 | 37361 | 37648 | 37957 | 38266 | 38575 |
| CAPACITY INTERRUPTIBLE LOADS | 811 | 826 | 841 | 857 | 871 | 884 | 896 | 907 | 917 | 928 | 940 | 951 | 963 |
| FIRM LOAD FORECAST | 33491 | 34241 | 34676 | 34940 | 35293 | 35649 | 35944 | 36202 | 36444 | 36720 | 37017 | 37315 | 37612 |
| EXISTING FIRM LOAD MEETING CAPABILITY | 25059 | 25206 | 25044 | 25205 | 25205 | 24559 | 23939 | 22026 | 21481 | 20652 | 20336 | 18519 | 18409 |
| PURCHASE NUGS LMC | 952 | 992 | 1031 | 1070 | 1109 | 1148 | 1186 | 1224 | 1262 | 1277 | 1293 | 1308 | 1323 |
| HYDRAULIC PLAN LMC | 1136 | 1298 | 1459 | 1619 | 1656 | 1710 | 1776 | 1807 | 2028 | 2085 | 2140 | 2192 | 2245 |
| MANITOBA PURCHASE LMC | 484 | 606 | 606 | 606 | 606 | 606 | 606 | 606 | 606 | 606 | 606 | 606 | 606 |
| NEW FOSSIL LMC | 3523 | 4065 | 4335 | 4335 | 4335 | 5148 | 5748 | 6344 | 6941 | 7539 | 7539 | 8081 | 8081 |
| NEW NUCLEAR LMC | 0 | 710 | 1421 | 2131 | 2842 | 2842 | 2842 | 3552 | 4263 | 4973 | 5684 | 6394 | 7105 |
| PLANNED FIRM LOAD MEETING CAPABILITY | 31954 | 33077 | 34097 | 35160 | 35953 | 36214 | 36248 | 36560 | 36783 | 37333 | 37691 | 37291 | 38049 |
| DEMAND/SUPPLY REQUIRED - LMC | 12763 | 14330 | 15090 | 15350 | 15834 | 17037 | 18113 | 19643 | 21388 | 22454 | 23527 | 25711 | 26189 |
| SUPPLY REQUIRED - CAPACITY | 9464 | 11203 | 11944 | 12071 | 12509 | 13752 | 14886 | 16386 | 18553 | 19924 | 20808 | 22310 | 23113 |
| MAJOR SUPPLY REQUIRED - CAPACITY | 6874 | 8364 | 8856 | 8736 | 9081 | 10208 | 11272 | 12827 | 14473 | 15735 | 16552 | 18978 | 19288 |

DEMAND / SUPPLY BALANCE - PEAK POWER (MW) - SUPPLY EXPRESSED IN LOAD MEETING CAPABILITY
REFERENCE PLAN 24

LOWER LOAD FORECAST

| YEAR (JANUARY) | 1989 | 1990 | 1991 | 1992 | 1993 | 1994 | 1995 | 1996 | 1997 | 1998 | 1999 | 2000 | 2001 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| BASIC LOAD FORECAST | 22690 | 22463 | 22766 | 23214 | 23403 | 23725 | 23931 | 24195 | 24212 | 24710 | 25104 | 25723 | 26394 |
| ELECTRICAL EFFICIENCY IMPROVEMENTS | 0 | 14 | 36 | 62 | 101 | 146 | 251 | 400 | 640 | 888 | 1120 | 1360 | 1600 |
| LOAD SHIFTING | 0 | 78 | 161 | 246 | 307 | 319 | 376 | 620 | 663 | 707 | 749 | 790 | 800 |
| DEPENDABLE LOAD DISPLACEMENT NUGS | 0 | 33 | 90 | 172 | 239 | 306 | 330 | 342 | 342 | 342 | 342 | 342 | 342 |
| PRIMARY LOAD FORECAST | 22690 | 22316 | 22471 | 22734 | 22756 | 22754 | 22764 | 22833 | 22567 | 22781 | 22893 | 23231 | 23652 |
| CAPACITY INTERRUPTIBLE LOADS | 725 | 709 | 599 | 583 | 566 | 554 | 558 | 561 | 566 | 573 | 580 | 587 | 599 |
| FIRM LOAD FORECAST | 21965 | 21607 | 21872 | 22151 | 22190 | 22200 | 22206 | 22272 | 22001 | 22208 | 22313 | 22644 | 23053 |
| EXISTING FIRM LOAD MEETING CAPABILITY | 23213 | 23970 | 24062 | 24704 | 26343 | 25510 | 25510 | 26131 | 26131 | 25310 | 25472 | 26092 | 26092 |
| PURCHASE NUGS LMC | 0 | 23 | 44 | 102 | 252 | 321 | 351 | 351 | 351 | 351 | 351 | 351 | 351 |
| HYDRAULIC PLAN LMC | 0 | 0 | 0 | 0 | 2 | 12 | 63 | 269 | 424 | 424 | 868 | 868 | 975 |
| MANITOBA PURCHASE LMC | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 161 | 161 | 323 |
| NEW FOSSIL LMC | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| NEW NUCLEAR LMC | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| PLANNED FIRM LOAD MEETING CAPABILITY | 23213 | 23993 | 24106 | 24966 | 26597 | 25843 | 25920 | 26750 | 26906 | 26085 | 26852 | 27472 | 27740 |
| DEMAND/SUPPLY REQUIRED - LMC | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 302 |
| SUPPLY REQUIRED - CAPACITY | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| MAJOR SUPPLY REQUIRED - CAPACITY | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |

| YEAR (JANUARY) | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| BASIC LOAD FORECAST | 27730 | 28171 | 28661 | 28630 | 28973 | 29571 | 30097 | 30667 | 31239 | 31892 | 32409 | 32960 | 33512 |
| ELECTRICAL EFFICIENCY IMPROVEMENTS | 1642 | 1725 | 1780 | 1850 | 1913 | 1974 | 2030 | 2100 | 2163 | 2225 | 2288 | 2350 | 2412 |
| LOAD SHIFTING | 820 | 840 | 860 | 860 | 900 | 930 | 940 | 960 | 980 | 1000 | 1020 | 1040 | 1060 |
| DEPENDABLE LOAD DISPLACEMENT NUGS | 342 | 342 | 342 | 346 | 350 | 353 | 357 | 360 | 364 | 368 | 371 | 375 | 378 |
| PRIMARY LOAD FORECAST | 24925 | 25264 | 25671 | 25554 | 25810 | 26324 | 26742 | 27247 | 27732 | 28299 | 28730 | 29195 | 29662 |
| CAPACITY INTERRUPTIBLE LOADS | 607 | 616 | 625 | 633 | 643 | 655 | 668 | 682 | 697 | 713 | 727 | 742 | 756 |
| FIRM LOAD FORECAST | 24318 | 24648 | 25046 | 24921 | 25167 | 25669 | 26074 | 26565 | 27035 | 27586 | 28003 | 28453 | 28906 |
| EXISTING FIRM LOAD MEETING CAPABILITY | 25859 | 25206 | 25044 | 25203 | 25205 | 24539 | 23939 | 22826 | 21482 | 20452 | 20236 | 18510 | 18489 |
| PURCHASE NUGS LMC | 351 | 351 | 390 | 428 | 467 | 506 | 544 | 582 | 620 | 635 | 651 | 666 | 681 |
| HYDRAULIC PLAN LMC | 1136 | 1298 | 1459 | 1619 | 1656 | 1710 | 1720 | 1807 | 2028 | 2085 | 2140 | 2192 | 2245 |
| MANITOBA PURCHASE LMC | 484 | 606 | 606 | 606 | 606 | 606 | 606 | 606 | 606 | 606 | 606 | 606 | 606 |
| NEW FOSSIL LMC | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 342 | 1426 | 1897 | 2168 | 3307 | 3905 |
| NEW NUCLEAR LMC | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 710 | 1421 | 2131 | 2842 | 2842 |
| PLANNED FIRM LOAD MEETING CAPABILITY | 27830 | 27461 | 27699 | 28059 | 28134 | 27582 | 27010 | 26564 | 27273 | 27496 | 28132 | 28324 | 28969 |
| DEMAND/SUPPLY REQUIRED - LMC | 1891 | 2965 | 3617 | 3425 | 3760 | 5012 | 6130 | 7041 | 9757 | 11340 | 12173 | 14450 | 15023 |
| SUPPLY REQUIRED - CAPACITY | 0 | 0 | 2 | 0 | 0 | 1376 | 2672 | 4636 | 6886 | 8398 | 9631 | 12329 | 12917 |
| MAJOR SUPPLY REQUIRED - CAPACITY | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 1673 | 3602 | 5223 | 6171 | 8785 | 9288 |

REVISION : NOV. 24/89

## DEMAND / SUPPLY BALANCE - ANNUAL ENERGY (TWh) FOR PLAN 15

MEDIAN LOAD FORECAST

| YEAR | 1989 | 1990 | 1991 | 1992 | 1993 | 1994 | 1995 | 1996 | 1997 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| BASIC LOAD FORECAST | 137.0 | 140.0 | 145.0 | 151.0 | 155.0 | 159.0 | 163.0 | 165.0 | 169.0 | 174.0 | 178.0 | 184.0 | 192.0 | 196.0 | 201.0 | 202.0 | 205.0 | 208.0 | 211.0 | 214.0 | 217.0 | 220.0 | 224.0 | 227.0 | 230.0 | 234.0 |
| ELECTR. EFFIC. IMPROVE. | 0.1 | 0.2 | 0.4 | 0.6 | 0.9 | 1.6 | 2.5 | 4.0 | 5.5 | 7.0 | 8.5 | 10.0 | 10.5 | 11.0 | 11.5 | 12.0 | 12.5 | 13.0 | 13.5 | 14.0 | 14.5 | 15.0 | 15.5 | 16.0 | 16.5 | 17.0 |
| LOAD SHIFTING | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| LOAD DISPLACEMENT NUGS | 0.1 | 0.8 | 1.3 | 1.8 | 2.3 | 2.5 | 2.7 | 2.8 | 2.8 | 2.9 | 2.9 | 3.0 | 3.0 | 3.0 | 3.1 | 3.1 | 3.1 | 3.2 | 3.2 | 3.2 | 3.2 | 3.3 | 3.3 | 3.3 | 3.3 | 3.4 |
| PRIMARY LOAD FORECAST | 136.8 | 139.0 | 143.3 | 148.6 | 151.8 | 155.0 | 157.8 | 158.2 | 160.7 | 164.1 | 166.6 | 171.0 | 178.5 | 182.0 | 186.4 | 186.9 | 189.4 | 191.9 | 194.3 | 196.8 | 199.3 | 201.7 | 205.2 | 207.7 | 210.2 | 213.6 |
| HYDRAULIC | 35.6 | 35.6 | 35.6 | 35.6 | 35.7 | 35.7 | 35.8 | 36.4 | 37.1 | 37.1 | 38.5 | 38.5 | 38.8 | 39.0 | 39.3 | 39.5 | 39.8 | 39.8 | 39.8 | 39.8 | 40.0 | 40.3 | 40.6 | 40.6 | 40.6 | 40.8 |
| PURCHASE NUGS | 0.3 | 0.6 | 1.7 | 2.3 | 2.9 | 3.4 | 3.8 | 4.3 | 4.8 | 5.3 | 5.9 | 6.4 | 6.7 | 7.1 | 7.4 | 7.7 | 8.0 | 8.4 | 8.7 | 9.0 | 9.3 | 9.6 | 9.8 | 10.0 | 10.2 | 10.3 |
| MANITOBA PURCHASE | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.2 | 1.4 | 1.7 | 3.3 | 5.1 | 6.8 | 7.0 | 7.0 | 7.0 | 7.0 | 7.0 | 7.0 | 7.0 | 7.0 | 7.0 | 7.0 | 7.0 |
| FOSSIL | 28.3 | 22.1 | 10.3 | 20.9 | 20.0 | 19.6 | 20.8 | 15.6 | 21.1 | 25.5 | 17.8 | 21.0 | 25.8 | 32.0 | 34.1 | 22.5 | 19.3 | 18.5 | 15.2 | 21.4 | 22.4 | 19.4 | 23.6 | 22.9 | 14.4 | 12.4 |
| NUCLEAR | 72.6 | 80.7 | 84.6 | 89.7 | 93.2 | 96.3 | 97.4 | 101.9 | 97.7 | 96.0 | 103.0 | 103.4 | 103.9 | 98.8 | 98.9 | 110.2 | 115.3 | 118.2 | 123.7 | 119.6 | 120.5 | 125.4 | 124.2 | 127.2 | 134.0 | 143.0 |
| TOTAL PRODUCTION | 136.8 | 139.0 | 143.3 | 148.6 | 151.8 | 155.0 | 157.8 | 158.2 | 160.7 | 164.1 | 166.6 | 171.0 | 178.5 | 182.0 | 186.4 | 186.9 | 189.4 | 191.9 | 194.3 | 196.8 | 199.3 | 201.7 | 205.2 | 207.7 | 210.2 | 213.6 |

## DEMAND / SUPPLY BALANCE - ANNUAL ENERGY (TWh) FOR PLAN 15

UPPER LOAD FORECAST

| YEAR | 1989 | 1990 | 1991 | 1992 | 1993 | 1994 | 1995 | 1996 | 1997 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| BASIC LOAD FORECAST | 142.0 | 147.0 | 154.0 | 162.0 | 169.0 | 176.0 | 180.0 | 185.0 | 192.0 | 196.0 | 205.0 | 212.0 | 221.0 | 227.0 | 231.0 | 234.0 | 236.0 | 240.0 | 242.0 | 245.0 | 247.0 | 250.0 | 252.0 | 255.0 | 257.0 | 260.0 |
| ELECTR. EFFIC. IMPROVE. | 0.1 | 0.3 | 0.5 | 0.8 | 1.1 | 2.0 | 3.1 | 5.0 | 6.9 | 6.7 | 10.6 | 12.5 | 13.1 | 13.7 | 14.4 | 15.0 | 15.6 | 16.2 | 16.9 | 17.5 | 18.1 | 18.7 | 19.4 | 20.0 | 20.6 | 21.2 |
| LOAD SHIFTING | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| LOAD DISPLACEMENT NUGS | 0.5 | 0.8 | 1.4 | 1.9 | 2.4 | 2.9 | 3.2 | 3.5 | 3.6 | 3.7 | 3.7 | 3.7 | 3.7 | 3.8 | 3.8 | 3.8 | 3.9 | 3.9 | 3.9 | 3.9 | 4.0 | 4.0 | 4.0 | 4.1 | 4.1 | 4.1 |
| PRIMARY LOAD FORECAST | 141.4 | 145.9 | 152.2 | 159.3 | 165.4 | 171.1 | 173.7 | 176.6 | 181.5 | 185.6 | 190.7 | 195.8 | 204.1 | 209.5 | 212.8 | 215.2 | 216.5 | 219.9 | 221.2 | 223.6 | 224.9 | 227.3 | 228.6 | 230.9 | 232.3 | 234.6 |
| HYDRAULIC | 35.6 | 35.6 | 35.6 | 35.6 | 35.7 | 35.7 | 35.8 | 36.4 | 37.1 | 37.1 | 38.5 | 38.5 | 38.8 | 39.0 | 39.3 | 39.5 | 39.8 | 39.8 | 39.8 | 39.8 | 40.0 | 40.3 | 40.6 | 40.6 | 40.6 | 40.8 |
| PURCHASE NUGS | 0.2 | 0.5 | 1.7 | 2.2 | 2.8 | 3.3 | 4.0 | 5.0 | 6.1 | 7.0 | 7.3 | 7.8 | 8.0 | 8.3 | 8.8 | 9.0 | 9.3 | 9.4 | 9.9 | 10.2 | 10.6 | 10.7 | 10.8 | 10.9 | 11.1 | 11.2 |
| MANITOBA PURCHASE | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.2 | 1.4 | 1.7 | 3.3 | 5.1 | 6.8 | 7.0 | 7.0 | 7.0 | 7.0 | 7.0 | 7.0 | 7.0 | 7.0 | 7.0 | 7.0 | 7.0 |
| FOSSIL | 32.8 | 28.6 | 27.3 | 30.6 | 32.6 | 34.3 | 35.1 | 31.0 | 30.5 | 44.6 | 39.0 | 43.4 | 48.4 | 58.0 | 52.5 | 42.9 | 37.0 | 37.4 | 38.2 | 38.6 | 28.2 | 19.7 | 16.1 | 15.6 | 11.2 | 8.9 |
| NUCLEAR | 72.8 | 81.2 | 87.6 | 90.6 | 94.3 | 97.8 | 98.8 | 104.1 | 98.9 | 96.6 | 104.5 | 104.4 | 104.7 | 99.1 | 105.6 | 116.8 | 123.5 | 126.1 | 126.3 | 127.9 | 130.1 | 149.5 | 154.1 | 156.8 | 162.4 | 166.7 |
| TOTAL PRODUCTION | 141.4 | 145.9 | 152.2 | 159.3 | 165.4 | 171.1 | 173.7 | 176.6 | 181.5 | 185.6 | 190.7 | 195.8 | 204.1 | 209.5 | 212.8 | 215.2 | 216.5 | 219.9 | 221.2 | 223.6 | 224.9 | 227.3 | 228.6 | 230.9 | 232.3 | 234.6 |

## DEMAND / SUPPLY BALANCE - ANNUAL ENERGY (TWh) FOR PLAN 15

LOWER LOAD FORECAST

| YEAR | 1989 | 1990 | 1991 | 1992 | 1993 | 1994 | 1995 | 1996 | 1997 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| BASIC LOAD FORECAST | 132.0 | 133.0 | 135.0 | 137.0 | 138.0 | 139.0 | 141.0 | 141.0 | 143.0 | 146.0 | 149.0 | 153.0 | 159.0 | 163.0 | 164.0 | 167.0 | 168.0 | 171.0 | 174.0 | 178.0 | 181.0 | 185.0 | 188.0 | 191.0 | 194.0 | 197.0 |
| ELECTR. EFFIC. IMPROVE. | 0.1 | 0.2 | 0.3 | 0.5 | 0.7 | 1.3 | 2.0 | 3.2 | 4.4 | 5.6 | 6.8 | 8.0 | 8.3 | 8.6 | 6.9 | 9.2 | 9.6 | 9.9 | 10.2 | 10.5 | 10.8 | 11.1 | 11.4 | 11.7 | 12.1 | 12.4 |
| LOAD SHIFTING | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| LOAD DISPLACEMENT NUGS | 0.5 | 0.8 | 1.4 | 1.9 | 2.4 | 2.6 | 2.7 | 2.7 | 2.7 | 2.7 | 2.7 | 2.7 | 2.7 | 2.7 | 2.7 | 2.7 | 2.8 | 2.8 | 2.8 | 2.8 | 2.9 | 2.9 | 2.9 | 3.0 | 3.0 | 3.0 |
| PRIMARY LOAD FORECAST | 131.4 | 132.0 | 133.3 | 134.6 | 134.9 | 135.1 | 136.3 | 135.1 | 135.9 | 137.7 | 139.5 | 142.3 | 148.0 | 151.7 | 154.4 | 155.0 | 155.7 | 158.3 | 161.0 | 164.7 | 167.3 | 171.0 | 173.6 | 176.3 | 179.0 | 181.6 |
| HYDRAULIC | 35.6 | 35.6 | 35.6 | 35.6 | 35.7 | 35.7 | 35.8 | 36.4 | 37.1 | 37.1 | 38.5 | 38.5 | 38.8 | 39.0 | 39.3 | 39.5 | 39.8 | 39.8 | 39.8 | 39.8 | 40.0 | 40.3 | 40.6 | 40.6 | 40.6 | 40.8 |
| PURCHASE NUGS | 0.2 | 0.5 | 1.7 | 2.2 | 2.8 | 3.0 | 3.0 | 3.0 | 3.0 | 3.0 | 3.0 | 3.0 | 3.0 | 3.0 | 3.3 | 3.6 | 3.9 | 4.3 | 4.6 | 4.9 | 5.2 | 5.3 | 5.5 | 5.6 | 5.7 | 5.8 |
| MANITOBA PURCHASE | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.2 | 1.4 | 1.7 | 3.3 | 5.1 | 6.8 | 7.0 | 7.0 | 7.0 | 7.0 | 7.0 | 7.0 | 7.0 | 7.0 | 7.0 | 7.0 | 7.0 |
| FOSSIL | 23.3 | 16.5 | 11.6 | 9.9 | 7.2 | 6.3 | 6.7 | 3.7 | 4.6 | 6.7 | 2.7 | 3.4 | 4.9 | 9.1 | 6.6 | 5.8 | 8.3 | 9.0 | 10.8 | 18.5 | 20.3 | 18.4 | 22.2 | 21.7 | 13.1 | 10.3 |
| NUCLEAR | 72.3 | 79.4 | 84.5 | 86.8 | 89.1 | 90.1 | 90.8 | 92.0 | 91.3 | 90.7 | 93.9 | 95.8 | 98.0 | 95.6 | 94.4 | 99.3 | 99.6 | 96.3 | 98.8 | 94.5 | 94.7 | 99.9 | 98.4 | 101.4 | 112.6 | 117.7 |
| TOTAL PRODUCTION | 131.4 | 132.0 | 133.3 | 134.6 | 134.9 | 135.1 | 136.3 | 135.1 | 135.9 | 137.7 | 139.5 | 142.3 | 148.0 | 151.7 | 154.4 | 155.0 | 155.7 | 158.3 | 161.0 | 164.7 | 167.3 | 171.0 | 173.6 | 176.3 | 179.0 | 181.6 |

REVISION: NOV. 24/89

DEMAND / SUPPLY BALANCE - ANNUAL ENERGY (TWh) FOR PLAN 22

| MEDIAN LOAD FORECAST | | | | | | | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| YEAR | 1989 | 1990 | 1991 | 1992 | 1993 | 1994 | 1995 | 1996 | 1997 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 |
| BASIC LOAD FORECAST | 137.0 | 140.0 | 145.0 | 151.0 | 155.0 | 160.0 | 163.0 | 165.0 | 169.0 | 174.0 | 178.0 | 184.0 | 192.0 | 196.0 | 201.0 | 202.0 | 205.0 | 208.0 | 211.0 | 214.0 | 217.0 | 220.0 | 224.0 | 227.0 | 230.0 | 234.0 |
| ELECT. EFFIC. IMPROVE. | 0.1 | 0.2 | 0.4 | 0.8 | 0.9 | 1.5 | 2.5 | 4.0 | 5.5 | 7.0 | 8.5 | 10.0 | 10.5 | 11.0 | 11.5 | 12.0 | 12.5 | 13.0 | 13.5 | 14.0 | 14.5 | 15.0 | 15.5 | 16.0 | 16.5 | 17.0 |
| LOAD SHIFTING | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| LOAD DISPLACEMENT NUGS | 0.1 | 0.8 | 1.3 | 1.6 | 2.3 | 2.5 | 2.7 | 2.8 | 2.8 | 2.9 | 2.9 | 3.0 | 3.0 | 3.0 | 3.1 | 3.1 | 3.1 | 3.2 | 3.2 | 3.2 | 3.2 | 3.3 | 3.3 | 3.3 | 3.3 | 3.4 |
| PRIMARY LOAD FORECAST | 136.8 | 139.0 | 143.3 | 148.6 | 151.8 | 156.0 | 157.8 | 158.2 | 160.7 | 164.1 | 166.6 | 171.0 | 178.5 | 182.0 | 186.4 | 186.9 | 189.4 | 191.8 | 194.3 | 196.8 | 199.3 | 201.7 | 205.2 | 207.7 | 210.2 | 213.6 |
| HYDRAULIC | 35.6 | 35.4 | 35.6 | 35.6 | 35.7 | 35.7 | 35.8 | 36.4 | 37.1 | 37.1 | 38.5 | 38.5 | 38.8 | 39.0 | 39.3 | 39.5 | 39.6 | 39.8 | 39.8 | 39.8 | 40.0 | 40.3 | 40.6 | 40.6 | 40.6 | 40.8 |
| PURCHASE NUGS | 0.3 | 0.8 | 1.7 | 2.3 | 2.9 | 3.4 | 3.8 | 4.3 | 4.8 | 5.3 | 5.9 | 6.4 | 6.7 | 7.1 | 7.4 | 7.7 | 8.0 | 8.4 | 8.7 | 9.0 | 9.3 | 9.6 | 9.8 | 10.0 | 10.2 | 10.3 |
| MANITOBA PURCHASE | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.2 | 1.4 | 1.7 | 3.3 | 5.1 | 6.8 | 7.0 | 7.0 | 7.0 | 7.0 | 7.0 | 7.0 | 7.0 | 7.0 | 7.0 | 7.0 | 7.0 |
| FOSSIL | 28.3 | 22.1 | 19.3 | 20.9 | 20.0 | 18.6 | 20.8 | 15.6 | 21.1 | 25.5 | 17.6 | 21.0 | 25.8 | 26.0 | 22.7 | 12.2 | 9.7 | 13.2 | 10.2 | 11.4 | 8.8 | 8.8 | 9.0 | 8.7 | 6.4 | 5.4 |
| NUCLEAR | 72.6 | 80.7 | 86.6 | 89.7 | 93.2 | 98.3 | 97.4 | 101.9 | 97.7 | 96.0 | 103.0 | 103.4 | 103.9 | 104.8 | 110.3 | 120.6 | 124.8 | 123.5 | 128.7 | 129.6 | 134.4 | 136.1 | 138.9 | 141.4 | 146.0 | 150.0 |
| TOTAL PRODUCTION | 136.8 | 139.0 | 143.3 | 148.6 | 151.8 | 156.0 | 157.8 | 158.2 | 160.7 | 164.1 | 166.6 | 171.0 | 178.5 | 182.0 | 186.4 | 186.9 | 189.4 | 191.8 | 194.3 | 196.8 | 199.3 | 201.7 | 205.2 | 207.7 | 210.2 | 213.6 |

DEMAND / SUPPLY BALANCE - ANNUAL ENERGY (TWh) FOR PLAN 22

| UPPER LOAD FORECAST | | | | | | | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| YEAR | 1989 | 1990 | 1991 | 1992 | 1993 | 1994 | 1995 | 1996 | 1997 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 |
| BASIC LOAD FORECAST | 142.0 | 147.0 | 154.0 | 153.0 | 169.0 | 176.0 | 180.0 | 185.0 | 192.0 | 198.0 | 205.0 | 212.0 | 221.0 | 227.0 | 231.0 | 234.0 | 236.0 | 240.0 | 242.0 | 245.0 | 247.0 | 250.0 | 252.0 | 255.0 | 257.0 | 260.0 |
| ELECT. EFFIC. IMPROVE. | 0.1 | 0.3 | 0.5 | 0.8 | 1.1 | 2.0 | 3.1 | 5.0 | 6.9 | 8.7 | 10.6 | 12.6 | 13.1 | 13.7 | 14.4 | 15.0 | 15.6 | 16.2 | 16.9 | 17.5 | 18.1 | 18.7 | 19.4 | 20.0 | 20.6 | 21.2 |
| LOAD SHIFTING | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| LOAD DISPLACEMENT NUGS | 0.5 | 0.8 | 1.4 | 1.9 | 2.4 | 2.9 | 3.2 | 3.5 | 3.6 | 3.7 | 3.7 | 3.7 | 3.7 | 3.8 | 3.8 | 3.8 | 3.9 | 3.9 | 3.9 | 3.9 | 4.0 | 4.0 | 4.0 | 4.1 | 4.1 | 4.1 |
| PRIMARY LOAD FORECAST | 141.4 | 145.9 | 152.2 | 150.3 | 165.4 | 171.1 | 173.7 | 176.6 | 181.5 | 185.6 | 190.7 | 195.8 | 204.1 | 209.5 | 212.8 | 215.2 | 216.5 | 219.9 | 221.2 | 223.6 | 224.9 | 227.3 | 228.6 | 230.9 | 232.3 | 234.6 |
| HYDRAULIC | 35.6 | 35.6 | 35.6 | 35.6 | 35.7 | 35.7 | 35.8 | 36.4 | 37.1 | 37.1 | 38.6 | 38.5 | 38.8 | 39.0 | 39.3 | 39.5 | 39.6 | 39.6 | 39.8 | 39.8 | 40.0 | 40.3 | 40.6 | 40.6 | 40.6 | 40.8 |
| PURCHASE NUGS | 0.2 | 0.6 | 1.7 | 2.2 | 2.4 | 3.3 | 4.0 | 5.0 | 6.1 | 7.0 | 7.3 | 7.6 | 8.0 | 8.3 | 8.6 | 9.0 | 9.3 | 9.6 | 9.9 | 10.2 | 10.6 | 10.7 | 10.8 | 10.9 | 11.1 | 11.2 |
| MANITOBA PURCHASE | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.2 | 1.4 | 1.7 | 3.3 | 5.1 | 6.8 | 7.0 | 7.0 | 7.0 | 7.0 | 7.0 | 7.0 | 7.0 | 7.0 | 7.0 | 7.0 | 7.0 |
| FOSSIL | 32.8 | 28.6 | 27.3 | 30.6 | 32.6 | 34.3 | 35.1 | 31.0 | 39.8 | 44.6 | 39.0 | 43.4 | 49.4 | 51.5 | 46.8 | 34.2 | 30.9 | 31.2 | 26.2 | 27.1 | 18.8 | 14.6 | 15.3 | 11.1 | 8.0 | 5.8 |
| NUCLEAR | 72.8 | 81.2 | 87.6 | 90.0 | 94.3 | 97.8 | 98.8 | 104.1 | 98.9 | 94.8 | 104.5 | 104.6 | 104.7 | 105.6 | 111.3 | 123.4 | 129.5 | 132.3 | 134.3 | 139.4 | 150.5 | 154.6 | 154.9 | 161.3 | 165.7 | 169.8 |
| TOTAL PRODUCTION | 141.4 | 145.9 | 152.2 | 150.3 | 165.4 | 171.1 | 173.7 | 176.6 | 181.5 | 185.6 | 190.7 | 195.8 | 204.1 | 209.5 | 212.8 | 215.2 | 216.5 | 219.9 | 221.2 | 223.6 | 224.9 | 227.3 | 228.6 | 230.9 | 232.3 | 234.6 |

DEMAND / SUPPLY BALANCE - ANNUAL ENERGY (TWh) FOR PLAN 22

| LOWER LOAD FORECAST | | | | | | | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| YEAR | 1989 | 1990 | 1991 | 1992 | 1993 | 1994 | 1995 | 1996 | 1997 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 |
| BASIC LOAD FORECAST | 132.0 | 133.0 | 135.0 | 137.0 | 138.0 | 139.0 | 141.0 | 141.0 | 143.0 | 146.0 | 149.0 | 153.0 | 159.0 | 163.0 | 166.0 | 167.0 | 168.0 | 171.0 | 174.0 | 178.0 | 181.0 | 185.0 | 188.0 | 191.0 | 194.0 | 197.0 |
| ELECT. EFFIC. IMPROVE. | 0.1 | 0.2 | 0.3 | 0.5 | 0.7 | 1.3 | 2.0 | 3.2 | 4.4 | 5.6 | 6.8 | 8.0 | 8.3 | 8.6 | 8.9 | 9.2 | 9.6 | 9.9 | 10.2 | 10.5 | 10.8 | 11.1 | 11.4 | 11.7 | 12.1 | 12.4 |
| LOAD SHIFTING | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| LOAD DISPLACEMENT NUGS | 0.5 | 0.8 | 1.4 | 1.9 | 2.4 | 2.6 | 2.7 | 2.7 | 2.7 | 2.7 | 2.7 | 2.7 | 2.7 | 2.7 | 2.7 | 2.7 | 2.8 | 2.8 | 2.8 | 2.8 | 2.9 | 2.9 | 2.9 | 3.0 | 3.0 | 3.0 |
| PRIMARY LOAD FORECAST | 131.4 | 132.0 | 133.3 | 134.6 | 134.9 | 135.1 | 136.3 | 135.1 | 135.9 | 137.7 | 139.5 | 142.3 | 148.0 | 151.7 | 154.4 | 155.0 | 155.7 | 158.3 | 161.0 | 164.7 | 167.3 | 171.0 | 173.6 | 176.3 | 179.0 | 181.6 |
| HYDRAULIC | 35.6 | 35.4 | 35.6 | 35.6 | 35.7 | 35.7 | 35.8 | 36.4 | 37.1 | 37.1 | 38.6 | 38.5 | 38.8 | 39.0 | 39.3 | 39.5 | 39.6 | 39.8 | 39.8 | 39.8 | 40.0 | 40.3 | 40.6 | 40.6 | 40.6 | 40.8 |
| PURCHASE NUGS | 0.2 | 0.5 | 1.7 | 2.2 | 2.8 | 3.0 | 3.0 | 3.0 | 3.0 | 3.0 | 3.0 | 3.0 | 3.0 | 3.0 | 3.3 | 3.6 | 3.9 | 4.3 | 4.6 | 4.9 | 5.2 | 5.3 | 5.5 | 5.6 | 5.7 | 5.8 |
| MANITOBA PURCHASE | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.2 | 1.4 | 1.7 | 3.3 | 5.1 | 6.8 | 7.0 | 7.0 | 7.0 | 7.0 | 7.0 | 7.0 | 7.0 | 7.0 | 7.0 | 7.0 | 7.0 |
| FOSSIL | 23.3 | 16.5 | 11.6 | 9.9 | 7.2 | 4.3 | 6.7 | 3.7 | 4.4 | 6.7 | 2.7 | 3.3 | 4.8 | 8.1 | 6.4 | 5.6 | 6.3 | 9.0 | 10.8 | 13.0 | 10.3 | 8.8 | 7.5 | 7.4 | 8.1 | 3.5 |
| NUCLEAR | 72.3 | 79.4 | 84.5 | 86.8 | 89.1 | 90.1 | 90.8 | 92.0 | 91.3 | 90.7 | 94.0 | 95.8 | 96.0 | 95.6 | 94.4 | 99.3 | 99.6 | 98.3 | 98.8 | 100.0 | 104.7 | 100.5 | 113.1 | 115.7 | 120.3 | 124.5 |
| TOTAL PRODUCTION | 131.4 | 132.0 | 133.3 | 134.6 | 134.9 | 135.1 | 136.3 | 135.1 | 135.9 | 137.7 | 139.5 | 142.3 | 148.0 | 151.7 | 154.4 | 155.0 | 155.7 | 158.3 | 161.0 | 164.7 | 167.3 | 171.0 | 173.6 | 176.3 | 179.0 | 181.6 |

REVISION : NOV. 24/89

DEMAND / SUPPLY BALANCE - ANNUAL ENERGY (TWh) FOR PLAN 24

MEDIAN LOAD FORECAST

| YEAR | 1989 | 1990 | 1991 | 1992 | 1993 | 1994 | 1995 | 1996 | 1997 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| BASIC LOAD FORECAST | 137.0 | 140.0 | 145.0 | 151.0 | 155.0 | 159.0 | 163.0 | 165.0 | 169.0 | 174.0 | 178.0 | 184.0 | 192.0 | 196.0 | 201.0 | 202.0 | 205.0 | 208.0 | 211.0 | 214.0 | 217.0 | 220.0 | 224.0 | 227.0 | 230.0 | 234.0 |
| ELECT. EFFIC. IMPROVE. | 0.1 | 0.2 | 0.4 | 0.8 | 0.9 | 1.5 | 2.5 | 4.0 | 5.5 | 7.0 | 8.5 | 10.0 | 10.5 | 11.0 | 11.5 | 12.0 | 12.5 | 13.0 | 13.5 | 14.0 | 14.5 | 15.0 | 15.5 | 16.0 | 16.5 | 17.0 |
| LOAD SHIFTING | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| LOAD DISPLACEMENT NUGS | 0.1 | 0.8 | 1.3 | 1.6 | 2.3 | 2.5 | 2.7 | 2.8 | 2.8 | 2.9 | 2.9 | 3.0 | 3.0 | 3.0 | 3.1 | 3.1 | 3.1 | 3.2 | 3.2 | 3.2 | 3.2 | 3.3 | 3.3 | 3.3 | 3.3 | 3.4 |
| PRIMARY LOAD FORECAST | 136.8 | 139.0 | 143.3 | 148.6 | 151.8 | 155.0 | 157.8 | 158.2 | 160.7 | 164.1 | 166.6 | 171.0 | 178.5 | 182.0 | 186.4 | 186.9 | 189.4 | 191.9 | 194.3 | 196.8 | 199.3 | 201.7 | 205.2 | 207.7 | 210.2 | 213.6 |
| HYDRAULIC | 35.6 | 35.6 | 35.6 | 35.6 | 35.7 | 35.7 | 35.8 | 36.4 | 37.1 | 37.1 | 38.5 | 38.5 | 38.8 | 39.0 | 39.3 | 39.5 | 39.8 | 39.8 | 39.8 | 39.8 | 40.0 | 40.3 | 40.6 | 40.6 | 40.6 | 40.8 |
| PURCHASE NUGS | 0.3 | 0.6 | 1.7 | 2.3 | 2.9 | 3.4 | 3.8 | 4.3 | 4.8 | 6.3 | 5.9 | 6.4 | 6.7 | 7.1 | 7.4 | 7.7 | 8.0 | 8.4 | 8.7 | 9.0 | 9.3 | 9.6 | 9.8 | 10.0 | 10.2 | 10.3 |
| MANITOBA PURCHASE | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.2 | 1.4 | 1.7 | 3.3 | 5.1 | 6.8 | 7.0 | 7.0 | 7.0 | 7.0 | 7.0 | 7.0 | 7.0 | 7.0 | 7.0 | 7.0 | 7.0 |
| FOSSIL | 28.3 | 22.1 | 19.3 | 20.9 | 20.0 | 19.6 | 20.8 | 15.6 | 21.1 | 25.5 | 17.8 | 21.0 | 25.8 | 32.0 | 34.1 | 22.6 | 19.3 | 18.5 | 15.2 | 21.4 | 22.4 | 25.0 | 34.8 | 40.7 | 36.7 | 34.1 |
| NUCLEAR | 72.6 | 80.7 | 86.6 | 89.7 | 93.2 | 96.3 | 97.4 | 101.9 | 97.7 | 95.0 | 103.0 | 103.4 | 103.9 | 98.8 | 98.9 | 110.2 | 115.3 | 118.2 | 123.7 | 119.6 | 120.5 | 119.8 | 113.1 | 109.4 | 115.7 | 121.3 |
| TOTAL PRODUCTION | 136.8 | 139.0 | 143.3 | 148.6 | 151.8 | 155.0 | 157.8 | 158.2 | 160.7 | 164.1 | 166.6 | 171.0 | 178.5 | 182.0 | 186.4 | 186.9 | 189.4 | 191.9 | 194.3 | 196.8 | 199.3 | 201.7 | 205.2 | 207.7 | 210.2 | 213.6 |

DEMAND / SUPPLY BALANCE - ANNUAL ENERGY (TWh) FOR PLAN 24

UPPER LOAD FORECAST

| YEAR | 1989 | 1990 | 1991 | 1992 | 1993 | 1994 | 1995 | 1996 | 1997 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| BASIC LOAD FORECAST | 142.0 | 147.0 | 154.0 | 162.0 | 169.0 | 176.0 | 180.0 | 185.0 | 192.0 | 198.0 | 205.0 | 212.0 | 221.0 | 227.0 | 231.0 | 234.0 | 236.0 | 240.0 | 242.0 | 245.0 | 247.0 | 250.0 | 252.0 | 255.0 | 257.0 | 260.0 |
| ELECT. EFFIC. IMPROVE. | 0.1 | 0.3 | 0.5 | 0.8 | 1.1 | 2.0 | 3.1 | 5.0 | 6.9 | 8.7 | 10.6 | 12.5 | 13.1 | 13.7 | 14.4 | 15.0 | 15.6 | 16.2 | 16.9 | 17.5 | 18.1 | 18.7 | 19.4 | 20.0 | 20.6 | 21.2 |
| LOAD SHIFTING | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| LOAD DISPLACEMENT NUGS | 0.5 | 0.8 | 1.4 | 1.9 | 2.4 | 2.9 | 3.2 | 3.5 | 3.6 | 3.7 | 3.7 | 3.7 | 3.7 | 3.8 | 3.8 | 3.8 | 3.9 | 3.9 | 3.9 | 3.9 | 4.0 | 4.0 | 4.0 | 4.1 | 4.1 | 4.1 |
| PRIMARY LOAD FORECAST | 141.4 | 145.9 | 152.2 | 159.3 | 165.4 | 171.1 | 173.7 | 176.6 | 181.5 | 185.6 | 190.7 | 195.8 | 204.1 | 209.5 | 212.8 | 215.2 | 216.5 | 219.9 | 221.2 | 223.6 | 224.9 | 227.3 | 228.6 | 230.9 | 232.3 | 234.6 |
| HYDRAULIC | 35.6 | 35.6 | 35.6 | 35.6 | 35.7 | 35.7 | 35.8 | 36.4 | 37.1 | 37.1 | 38.5 | 38.5 | 38.8 | 39.0 | 39.3 | 39.5 | 39.8 | 39.8 | 39.8 | 39.8 | 40.0 | 40.3 | 40.6 | 40.6 | 40.6 | 40.8 |
| PURCHASE NUGS | 0.2 | 0.5 | 1.7 | 2.2 | 2.8 | 3.3 | 4.0 | 5.0 | 6.1 | 7.0 | 7.3 | 7.6 | 8.0 | 8.3 | 8.6 | 9.0 | 9.3 | 9.6 | 9.9 | 10.2 | 10.6 | 10.7 | 10.8 | 10.9 | 11.1 | 11.2 |
| MANITOBA PURCHASE | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.2 | 1.4 | 1.7 | 3.3 | 5.1 | 6.8 | 7.0 | 7.0 | 7.0 | 7.0 | 7.0 | 7.0 | 7.0 | 7.0 | 7.0 | 7.0 | 7.0 |
| FOSSIL | 32.8 | 28.6 | 27.3 | 30.6 | 32.6 | 34.3 | 35.1 | 31.0 | 39.5 | 44.8 | 39.0 | 43.4 | 49.4 | 58.0 | 52.5 | 42.0 | 37.0 | 37.4 | 38.2 | 44.8 | 39.6 | 34.5 | 38.1 | 37.8 | 32.8 | 28.7 |
| NUCLEAR | 72.8 | 81.2 | 87.6 | 90.9 | 94.3 | 97.8 | 98.8 | 104.1 | 98.9 | 96.5 | 104.5 | 104.6 | 104.7 | 99.1 | 105.6 | 118.6 | 123.5 | 126.1 | 126.3 | 121.7 | 127.7 | 132.7 | 132.1 | 134.6 | 140.8 | 146.9 |
| TOTAL PRODUCTION | 141.4 | 145.9 | 152.2 | 159.3 | 165.4 | 171.1 | 173.7 | 176.6 | 181.5 | 185.6 | 190.7 | 195.8 | 204.1 | 209.5 | 212.8 | 215.2 | 216.5 | 219.9 | 221.2 | 223.6 | 224.9 | 227.3 | 228.6 | 230.9 | 232.3 | 234.6 |

DEMAND / SUPPLY BALANCE - ANNUAL ENERGY (TWh) FOR PLAN 24

LOWER LOAD FORECAST

| YEAR | 1989 | 1990 | 1991 | 1992 | 1993 | 1994 | 1995 | 1996 | 1997 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| BASIC LOAD FORECAST | 132.0 | 133.0 | 135.0 | 137.0 | 138.0 | 139.0 | 141.0 | 141.0 | 143.0 | 146.0 | 149.0 | 153.0 | 159.0 | 163.0 | 166.0 | 167.0 | 168.0 | 171.0 | 174.0 | 178.0 | 181.0 | 185.0 | 188.0 | 191.0 | 194.0 | 197.0 |
| ELECT. EFFIC. IMPROVE. | 0.1 | 0.2 | 0.3 | 0.5 | 0.7 | 1.3 | 2.0 | 3.2 | 4.4 | 5.6 | 6.5 | 8.0 | 8.3 | 8.6 | 8.9 | 9.2 | 9.5 | 9.9 | 10.2 | 10.5 | 10.8 | 11.1 | 11.4 | 11.7 | 12.1 | 12.4 |
| LOAD SHIFTING | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| LOAD DISPLACEMENT NUGS | 0.5 | 0.8 | 1.4 | 1.9 | 2.4 | 2.6 | 2.7 | 2.7 | 2.7 | 2.7 | 2.7 | 2.7 | 2.7 | 2.7 | 2.7 | 2.7 | 2.8 | 2.8 | 2.8 | 2.8 | 2.9 | 2.9 | 2.9 | 3.0 | 3.0 | 3.0 |
| PRIMARY LOAD FORECAST | 131.4 | 132.0 | 133.3 | 134.6 | 134.9 | 135.1 | 136.3 | 135.1 | 135.9 | 137.7 | 139.8 | 142.3 | 148.0 | 151.7 | 154.4 | 155.0 | 155.7 | 158.3 | 161.0 | 164.7 | 167.3 | 171.0 | 173.6 | 176.3 | 179.0 | 181.6 |
| HYDRAULIC | 35.6 | 35.6 | 35.6 | 35.6 | 35.7 | 35.7 | 35.8 | 36.4 | 37.1 | 37.1 | 38.5 | 38.5 | 38.8 | 39.0 | 39.3 | 39.5 | 39.8 | 39.8 | 39.8 | 39.8 | 40.0 | 40.3 | 40.6 | 40.6 | 40.6 | 40.8 |
| PURCHASE NUGS | 0.2 | 0.5 | 1.7 | 2.2 | 2.8 | 3.0 | 3.0 | 3.0 | 3.0 | 3.0 | 3.0 | 3.0 | 3.0 | 3.0 | 3.3 | 3.6 | 3.9 | 4.3 | 4.6 | 4.9 | 5.2 | 5.3 | 5.5 | 5.6 | 5.7 | 5.8 |
| MANITOBA PURCHASE | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.2 | 1.4 | 1.7 | 3.3 | 5.1 | 6.8 | 7.0 | 7.0 | 7.0 | 7.0 | 7.0 | 7.0 | 7.0 | 7.0 | 7.0 | 7.0 | 7.0 |
| FOSSIL | 23.3 | 16.5 | 11.6 | 9.9 | 7.2 | 6.3 | 6.7 | 3.7 | 4.6 | 6.7 | 2.7 | 3.4 | 4.9 | 9.1 | 8.6 | 5.6 | 8.3 | 9.0 | 10.8 | 18.5 | 20.3 | 18.4 | 22.2 | 21.7 | 18.4 | 20.1 |
| NUCLEAR | 72.3 | 79.4 | 84.5 | 86.9 | 89.1 | 90.1 | 90.8 | 92.0 | 91.3 | 90.7 | 93.9 | 95.6 | 98.0 | 95.6 | 96.4 | 99.3 | 96.6 | 98.3 | 98.8 | 94.5 | 94.7 | 99.9 | 98.4 | 101.4 | 107.3 | 107.8 |
| TOTAL PRODUCTION | 131.4 | 132.0 | 133.3 | 134.6 | 134.9 | 135.1 | 136.3 | 135.1 | 135.9 | 137.7 | 139.8 | 142.3 | 148.0 | 151.7 | 154.4 | 155.0 | 155.7 | 158.3 | 161.0 | 164.7 | 167.3 | 171.0 | 173.6 | 176.3 | 179.0 | 181.6 |

# 5. TRANSMISSION

5.0 INTRODUCTION

5.1 BACKGROUND

5.2 CRITICAL TRANSMISSION INTERFACES

5.3 TRANSMISSION REQUIREMENTS - CANDIDATE SITES

5.4 TRANSMISSION REQUIREMENTS - CANDIDATE PLANS

5.5 REVIEW

## 5.0 INTRODUCTION

This chapter discusses the transmission aspects of the major supply plans. In particular, it outlines the transmission requirements to incorporate the fossil and nuclear options being considered. The transmission required to incorporate the Non-Utility Generation (NUG) developments, the Hydraulic Program and the 1000 MW Manitoba Purchase are not covered in this chapter.

## 5.1 BACKGROUND

### Transmission Purposes

The bulk electricity transmission system (BES) is the integrated system of transmission lines and stations by which electric power is delivered from major generating stations to and between load centers and to and from interconnections with neighbouring utilities.

The purpose of the bulk transmission system is:

- to deliver power to meet forecast growth in customer demand, recognizing regional variations in rates of growth;

- to incorporate new sources of power generation or purchases into the integrated transmission network to permit economic and reliable use of such generation or purchases;

- to integrate the Hydro BES with neighbouring utilities through interconnections with these utilities to permit economic and reliability enhancements; and

- to optimize the use of available generation and purchases in accordance with changing customer demands and environmental restrictions.

The primary reasons for developing such an integrated transmission system are to permit the most economical use of resources and to maintain adequate reliability of supply to area loads in the event of anticipated station and transmission component failures.

## Planning Criteria

Transmission additions to the BES are based on the System Planning procedures for design of the Bulk Transmission System, first introduced over 20 years ago and updated regularly. These procedures take into account the more probable station and transmission component failures for which the system must remain stable with acceptable post disturbance voltage and loading levels. The procedures are based upon the Northeast Power Coordinating Council (NPCC) design and operation criteria for interconnected power systems.

## Transmission System in Year 2000

The planned development of the transmission system up to the year 2000 is contained in the System Planning Report 679SP, entitled "1989 Bulk Electricity Transmission Report" dated October 1989. The most significant component of the transmission plan is the Southwestern Ontario transmission reinforcement, which will enable the incorporation of the Bruce generation complex, and will increase the power transfer capability into the London area. Other major transmission projects include 500 kilovolt (kV) transmission from Hamilton to Toronto, Kingston and Ottawa. By the late 1990's, four 500 kV circuits will be in-service between Hamilton and Kingston.

The major transmission facilities listed in Figure 5.1 and shown in Figure 5.2, provide a strong base system for incorporating the demand and supply options under consideration in the Demand/Supply Plan Report. However, additional bulk transmission facilities will be required beyond the year 2000, to meet growth in customer demand and to incorporate new supply options, including the hydroelectric program, NUG developments, major purchases and new thermal generating stations. Both the nature and timing of these transmission facilities will be influenced by the timing, sequencing, location and choice of option of generating stations, and by the rate and magnitude of load growth.

## Transmission Classification

The transmission required to incorporate a new Ontario Hydro generating station will include radial transmission necessary to connect the site to the existing and planned BES. It may also include inter-area transmission necessary to maintain an integrated BES. The need for radial transmission is driven solely by the choice of site and its proximity to a suitable existing or planned transmission station in the integrated system. The need for inter-area transmission can also be driven by choice of sites, but is also concerned with many other factors such as security and reliabilty of load supply, geographic balancing of load and generation, cost and availability of fuel, and operational flexibility and economics. In summary, this inter-area transmission is governed by area load growth and existing capacity considerations in addition to the siting of new generation.

## Figure 5.1

### Base Case Bulk Transmission System in 2000

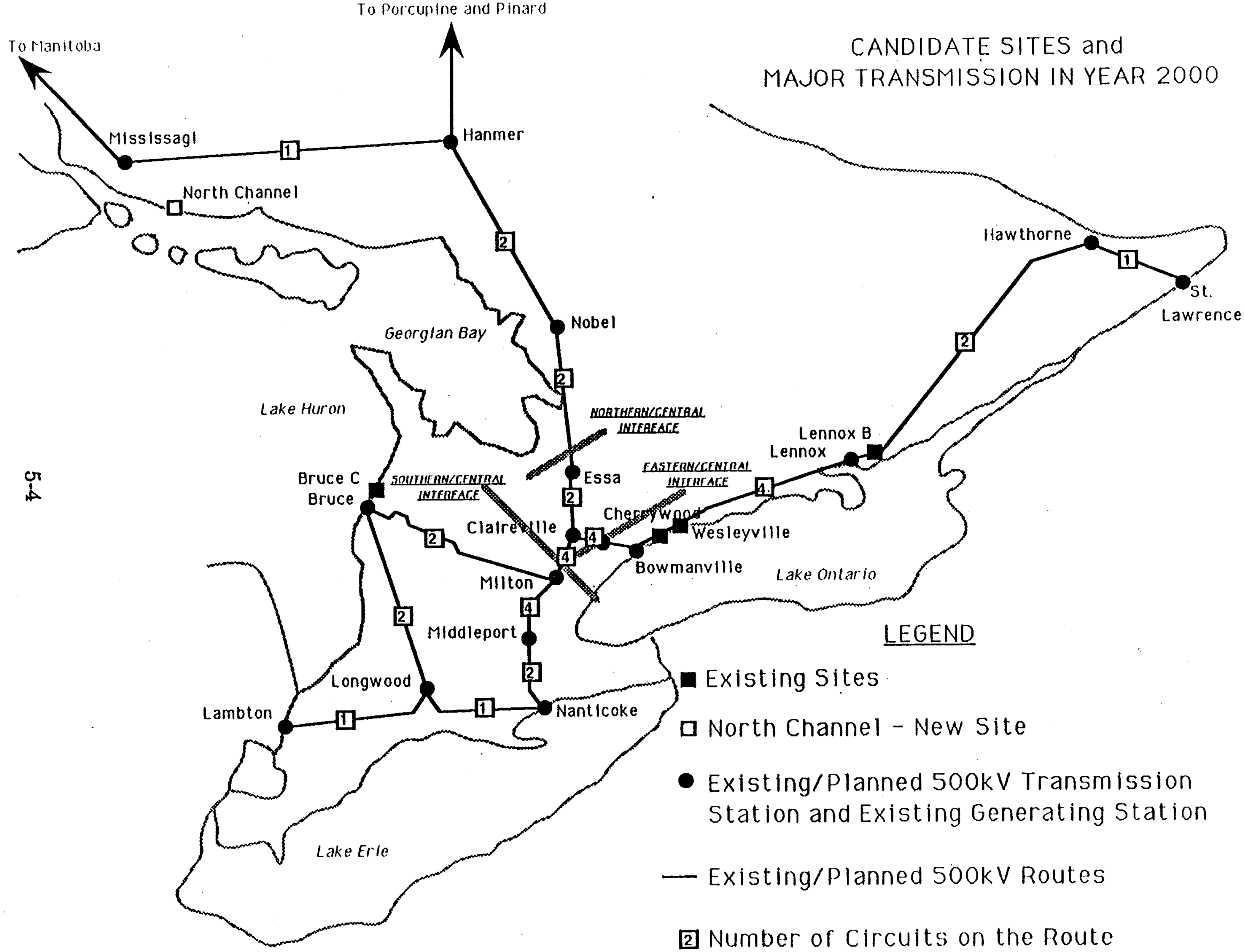
The existing system as of December 31, 1989 plus the following major additions

### 500 kV Transmission:

| | | | |
|---|---|---|---|
| 1 x 1 cct | - | Milton to Nanticoke | (1992) |
| 1 x 1 cct | - | Lennox to Hawthorne | (1992) |
| 1 x 2 cct | - | Bruce to Longwood | (1990) |
| 1 x 2 cct | - | Claireville to Cherrywood | (1993) |
| 1 x 2 cct | - | Cherrywood to Bowmanville | (1991) |
| 1 x 1 cct | - | Nanticoke to Longwood | (1991) |
| 1 x 2 cct | - | Lennox to Bowmanville | (1994) |
| 1 x 2 cct | - | Milton to Middleport | (1999) |
| 1 x 1 cct | - | Longwood to Lambton | (1996) |
| 1 x 2 cct | - | Milton to Trafalgar | (1996) |
| 1 x 1 cct | - | St.Lawrence to Hawthorne | (1998) |

FIGURE 5.2

CANDIDATE SITES and
MAJOR TRANSMISSION IN YEAR 2000



## 5.2 CRITICAL TRANSMISSION INTERFACES

In the study of large power systems, it has become necessary to identify various "critical interfaces" which define the ability of the system to deliver power from one geographic area to another. Typically, an interface consists of two or more transmission circuits which acting together, transmit power from the area on one side of the interface to the area on the other side. For the purposes of assessing the impact of the major supply plans on the need for bulk transmission reinforcements, three critical interfaces have been defined. These are:

| | |
|---|---|
| * Eastern/Central Interface | Flow into Claireville Transformer Station (TS) on the 500 kV circuits from the east |
| * Northern/Central Interface | Flow into Essa TS on the 500 kV circuits from the north |
| * Southern/Central Interface | Flow into Claireville TS on the 500 kV circuits from the southwest |

These interfaces are shown in Figure 5.2.

The following sections outline major factors which influence the loading of the critical interfaces. They also describe the impact the choice of siting and sequencing of the supply options of the Demand/Supply Plan have on the need for inter-area transmission to reinforce these interfaces.

### Eastern/Central Interface

Most of the greater Toronto area load is currently supplied radially from Cherrywood TS and Richview TS, and from stations tapped off the six 230 kV circuits crossing the city on the Finch right-of-way. These circuits are also used to carry bulk power transfers across Toronto in parallel with the 500 kV circuits on the Parkway Belt right-of-way. The high rate and magnitude of load growth in the greater Toronto area has greatly increased the loading on the 230 kV circuits on the Finch right-of-way. This is beginning to restrict Hydro's overall ability to transfer power across Toronto. In the near future, it will likely be necessary to open the 230 kV circuits on the Finch right-of-way and use these circuits only for radial load supply. This measure is a logical step in the development of the BES and was applied several years ago to the 115 kV system. Keeping the 230 kV circuits permanently open will increase the loading on the 500 kV transmission on the Parkway Belt between Cherrywood TS and Claireville TS; and, more critically render it the sole transmission path around Toronto.

Hydro plans to increase the transfer capability of the bulk transmission around Toronto by building a second 500 kV line on the existing Parkway Belt right-of-way. This transmission will be in service in 1993. Recent studies have shown that even with this reinforcement, the power transfer capability of the 500 kV transmission across Toronto would be inadequate beyond the year 2000 to fully incorporate the range of demand and supply options being evaluated for the Demand/Supply Plan.

Ontario Hydro has several sites that are available for expansion or do not presently have a station on the site. Most of these sites are on Lake Ontario, east of Toronto. Development of these sites will necessitate the transfer of large amounts of power on the existing 500 kV transmission system around Toronto. These power transfers will vary as a result of daily, weekly and monthly changes in load and generation patterns. The maximum power transfer is expected to approach 40% of the coincident system load with the establishment of just one new major generating station east of Toronto. Under these conditions a large number of customers would be exposed to total interruption of supply for prolonged periods, following a contingency resulting in the loss of all circuits on a right-of-way. A second 500 kV corridor would provide a firm transmission ring around Toronto and ensure an adequate reliability of supply. The timing of this new corridor would not only be influenced by the next new thermal generating station, if it is located east of Toronto, but also by a large purchase from Quebec. Any additional power resources or significant demand management east of Toronto, beyond either of these options, could not be incorporated without this second corridor.

The short circuit current levels on the BES, particularly in the Toronto area, have been steadily increasing as new generation and transmission have been added. The short circuit current levels can be defined as the maximum current that a circuit breaker must interrupt in order to isolate a faulted transmission line or station component from the rest of the BES. This current is many times normal load current. These levels are now approaching the point where they are among the highest experienced by any utility worldwide. The situation will be seriously aggravated by the addition of a new thermal generating station near the greater Toronto area. These very high short circuit levels have placed Ontario Hydro outside the international market provided for by most high voltage circuit breaker manufacturers. Currently, to keep the short circuit levels within the capability of available station equipment, it has been necessary to operate some of our 230 kV stations as two separate stations. Studies show that this measure, or other measures including the use of bus-tie reactors, will need to be extended to most of the BES stations in the Toronto area beyond the year 2000. While operation of a few stations in this manner poses no major problems, the widespread adoption of split station operation is a major concern. It increases operating complexities and could reduce system security and increase production costs. Additional transmission around Toronto and increased transmission redundancy will likely be required to ensure adequate security of the greater Toronto load.

Customer loads in the Regional Municipalities of York and Durham have increased by an average of 7 to 15% annually over the past five years and are expected to exceed the load meeting capability of the existing supply facilities in the area by the mid 1990s. Major transmission reinforcements will be required to maintain a reliable supply to customers in these areas. These reinforcements could be incorporated into a staged development of the proposed bulk transmission reinforcement around Toronto.

Thus, it will be necessary to reinforce the eastern/central interface to increase the reliability of load supply, to ensure security of the power system, and to permit economic utilization of system resources. One approach to this reinforcement is to build a double circuit 500 kV line on a new right-of-way from the Bowmanville SS in Newcastle Township to a new 500 kV transformer station, "Site A" TS, to be established on the existing 500 kV right-of-way between Claireville TS and Essa TS.

**Northern/Central Interface**

The existing two single circuit 500 kV transmission lines between Hanmer TS and Claireville TS, via Essa TS, provide the capability to transfer power from generation in the north to supply loads in the south, particularly during peak load and generation conditions. At other times, when northern hydraulic generation is not available, these lines provide the capability to supply loads in the north from thermal generation in the south. Hydro plans to increase the flow north and flow south transfer capability of this interface in the mid 1990s by the establishment of a switching station at Nobel near Parry Sound, and by uprating of the existing Essa to Claireville 500 kV lines. The Hanmer to Essa 500 kV lines may also need to be uprated to provide adequate transfer capability in the summer.

Even with these developments, the capability of the northern/central transmission interface will permit incorporation of no more than 2800 MW of new resources in the north. This transfer limit will be exceeded by the following northern resource developments proposed in the Demand/Supply Plan: 1000 MW firm purchase from Manitoba, with provision for an additional 500 MW economy power purchase, 1443 MW of hydraulic developments by 2004, and about 960 MW of non-utility generation developments. Additional transfer capability will be required between the Sudbury area and the Toronto area to incorporate these developments.

One of the candidate sites for the next major new thermal generating station is the North Channel area of Lake Huron. The output of this station, added to the above range of resource developments proposed for northern Ontario, would raise the level of power transfer to supply loads to the south of the northern/central interface to nearly 6000 MW. The existing and planned transmission in place by the turn of the century will not be capable of incorporating the North Channel generating station (GS). Both radial transmission to connect the generating station site to Mississagi

TS and Hanmer TS, and inter-area transmission to reinforce the northern/central interface, will be required to incorporate the new station, whether or not other developments materialize.

One approach to this inter-area transmission reinforcement is to build two single circuit 500 kV lines on a new right-of-way from Hanmer TS to "Site A", a new 500 kV transformer station to be established on the existing 500 kV right-of-way between Claireville TS and Essa TS. Also, build a single circuit 500 kV line on an existing right-of-way from "Site A" TS to Claireville TS.

**Southern/Central Interface**

The existing and planned transmission reinforcements in southern Ontario will form a strong electrical network for load supply and economic power transactions. Transmission facilities to connect Bruce GS into the London area and reinforcing the transmission between the London and Nanticoke areas will enable the incorporation of the Bruce GS into the Ontario Hydro system. Even after these new facilities are placed in service, a special protection system will still be required at Bruce GS to reject up to two generators during those times when transmission elements in southern Ontario are not available. With the present generation resource allocation in southern Ontario, the capability of the bulk transmission system in the London, Milton and Bruce triangle will be fully utilized by the turn of the century. Hence, radial and inter-area transmission will be required to incorporate additional major generation resources in this triangle prior to the retirement of the existing base load generation resources. With the present load and generation balance in this part of the Ontario Hydro system, new major generation resources are not expected to be added here until after 2008.

## 5.3 TRANSMISSION REQUIREMENTS - CANDIDATE SITES

The purpose of this section is to provide representative transmission plans for incorporation of the selected fossil and nuclear options in the Plans. Existing and identified sites are considered for illustrative purposes to ensure that cost estimates are realistic and comprehensive.

**Site Categories**

There are five site categories used in the development of major supply plans. The site categories are:

a) Existing Station/Sites - Available for Expansion

b) Existing Sites - Without Station

c) Existing Station/Sites - Available for Redevelopment

d) New Identified Sites

e) New Unidentified Sites

Candidate sites have been used for future fossil and nuclear generating facilities. The intent is not to propose actual, specific sites for generation options, but rather to illustrate that it is technically and economically feasible to site the selected options within the province. Figure 5.2 shows the geographic location of the candidate sites. Figure 5.3 indicates whether new radial and inter-area transmission are needed to incorporate each candidate site within the five site categories.

**Transmission Incorporation Requirements**

The incorporation of a generating station into the BES could require both radial and inter-area transmission facilities. The following outlines an alternative of the radial and inter-area transmission facilities required to incorporate each of the 12 identified sites and 3 new sites into the Bulk Transmission System for each supply option being considered. These are included for illustrative purposes. The precise configuration of the new transmission, including an assessment of viable alternatives and routing options, will be considered in the respective project specific environmental assessments. The facilities listed assume the candidate site is the first major supply option to be added to the Ontario Hydro system after the incorporation of Darlington 'A' nuclear generating station in 1992. The inter-area transmission facilities should not be used as building blocks for sequencing of stations. The inter-area transmission requirements of the major supply plans depend on many factors other than siting, such as timing, sequencing of siting, load growth and retirements of existing facilities. These factors are dealt with in the formulation of the transmission requirements of each major supply plan in section 5.4.

Figure 5.3
Transmission Requirements for Sites/Options

| Site | Generation Option | | Transmission Requirements Radial Yes (1) | Radial No (2) | Inter-area Yes (1) | Inter-area No (2) |
|---|---|---|---|---|---|---|
| Darlington 'B' | CANDU | | x | | x | |
| Lambton | CTU/NC (Expansion) | | | x | | x |
| | CSC (Redevelopment) | | | x | | x |
| | IGCC (Redevelopment) | | | x | | x |
| Bruce 'C' | CANDU | | x | | x | |
| Hearn | CTU/CC (Expansion) | | | x | | x |
| | CTU/CC (Redevelopment) | | | x | | x |
| Keith | CTU/CC (Expansion) | | | x | | x |
| | CTU/IGCC (Redevelopment) | (3) | | x | | x |
| Nanticoke | CTU/NC (Expansion) | | | x | | x |
| Lennox 'A' | CTU/NC (Expansion) | | | x | | x |
| Lennox 'B' | CSC (Expansion) | | x | | x | |
| | IGCC (Expansion) | | x | | x | |
| Wesleyville 'A' | CANDU | | x | | x | |
| | CSC | | x | | x | |
| | IGCC | | x | | x | |
| Wesleyville 'B' | CANDU | | x | | x | |
| | CSC | | x | | x | |
| | IGCC | | x | | x | |
| Lakeview | CTU/NC (Expansion) | (3) | | x | | x |
| | CSC (Redevelopment) | (3) | | x | | x |
| | IGCC (Redevelopment) | | | x | | x |
| North Channel | CANDU | | x | | x | |
| | CSC | | x | | x | |
| | IGCC | | x | | x | |
| New Sites | CANDU | | x | | x | |
| | CSC | | x | | x | |
| | IGCC | | x | | x | |

Notes

1 Yes - New lines and/or rights of way are required.
2 No - No new lines and/or rights of way are required. But some upgrading of existing lines and station facilities may be required.
3 Site and transmission limitations may restrict the size or number of units for these options

## a) Existing Stations/Sites - Available for Expansion

Darlington B (4 x 881 MW CANDU)

Radial - An alternative is to build two double circuit 500 kV lines (less than 1 km) on an existing right-of-way to connect the generating station into the BES at Bowmanville SS . As a minimum, it would also be necessary to build the third double circuit 500 kV line (46 km) between Bowmanville SS and Cherrywood TS on an existing right-of-way and upgrade existing facilities. This alternative would result in some energy being "locked-in" at Darlington under certain conditions.

Inter-area - New inter-area transmission, as an alternative to the third Bowmanville to Cherrywood line, would enable incorporation of this station with no locked-in energy. For example, a double circuit 500 kV line (175 km) could be built on a new right-of-way from the Bowmanville SS to a new 500 kV transformer station to be established at "Site A" on the existing 500 kV right-of-way between Claireville TS and Essa TS. As this is the preferred alternative for the incorporation of this station, it has been included in the Plan evaluations. A second major station east of Toronto could not be incorporated without this inter-area transmission.

Bruce C (4 x 881 MW CANDU)

Radial - An alternative is to build two double circuit 500 kV lines (less than 2 km) on a new right-of-way to connect the generating station into the Bruce A & B stations. Also, build a double circuit 500 kV line (150 km) on a new right-of-way to connect the generating station to "Site A" TS, a new 500 kV transformer station on the existing 500 kV right-of-way between Claireville TS and Essa TS.

Inter-area - New inter-area transmission may also be required. An alternative is to build a double circuit 500 kV line (200 km) on a new right-of-way from Longwood TS to "Site A" TS, a new 500 kV transformer station on the existing 500 kV right-of-way between Claireville TS and Essa TS.

Lambton (up to 4 x 150 MW CTU)

Radial - Some uprating of existing 230 kV and 115 kV transmission and station equipment may be required.

Inter-area - No new inter-area transmission will be required.

Hearn (up to 4 x 150 MW CTU/CC)

- Radial - Some uprating of existing 115 kV transmission and station equipment will be required.
- Inter-area - No new inter-area transmission will be required.

Keith (up to 4 x 150 MW CTU)

- Radial - No new radial transmission will be required.
- Inter-area - No new inter-area transmission will be required.

Nanticoke (up to 4 x 150 MW CTU)

- Radial - No new radial transmission will be required.
- Inter-area - No new inter-area transmission will be required.

Lennox A (up to 4 x 150 MW CTU)

- Radial - No new radial transmission will be required.
- Inter-area - No new inter-area transmission will be required.

Lennox B (4 x 800 MW US Coal CSC or 4 x 660 MW IGCC)

- Radial - An alternative is to build two short double circuit 500 kV lines on an existing right-of-way to connect the generating station into the local existing and planned 500 kV system.

- Inter-area - Inter-area transmission will also be required. An alternative of this transmission is to build the third double circuit 500 kV line (46 km) between Bowmanville SS and Cherrywood TS on an existing right-of-way.

b) **Existing Sites - Without Station**

Wesleyville A or B (4 x 881 MW CANDU or 4 x 800 MW CSC)

- Radial - An alternative is to build two double circuit 500 kV lines (less than 1 km) on an existing right-of-way to connect the generating station into the 500 kV lines between Bowmanville SS and Lennox TS and build a switching station at the site.
- Inter-area - New inter-area transmission will also be required. The preferred alternative to incorporate the 4 x 881 MW CANDU station is to build a double circuit 500 kV line (175 km) on a new right-of-way from Bowmanville SS to "Site A" TS, a new 500 kV transformer station to be established on the existing 500 kV right-of-way between Claireville TS and Essa TS. However, the first new station east of Toronto could be incorporated by the third double circuit 500 kV line (46 km) between Bowmanville SS and

Cherrywood TS on an existing right-of-way and upgrading of existing facilities. This alternative would result in some locked-in energy at Wesleyville under certain conditions. If either Wesleyville A or B is the second major station east of Toronto, then the preferred inter-area transmission alternative is a definite requirement.

c) **Existing Stations/Sites - Available for Redevelopment**

Hearn (4 x 150 MW CTU/CC)

Radial - Some uprating of existing 115 kV transmission and station equipment will be required.

Inter-area - No new inter-area transmission will be required.

Lambton (4 x 800 MW CSC Coal or 4 x 660 MW IGCC)

Radial - Some uprating of existing 230 kV transmission and station equipment will be required.

Inter-area - No new inter-area transmission will be required.

Lakeview (4 x 660 MW IGCC)

Radial - Some uprating of existing 230 kV transmission and station equipment will be required.

Inter-area - No new inter-area transmission will be required.

d) **New Identified Sites**

North Channel (4 x 881 MW CANDU or 4 x 800 MW CSC)

Radial - An alternative is to build two single circuit 500 kV lines (50 km) on a new right-of-way from the new site to the existing Mississagi TS (near Sault Ste. Marie) and two single circuit 500 kV lines (225 km) on a new right-of-way from the new site to the existing Hanmer TS at Sudbury.

Inter-area - Inter-area transmission will also be required. An alternative scheme is to build a new 500 kV single circuit line (210 km) on an existing right-of-way from Sault Ste. Marie to Sudbury and two single circuit 500 kV lines (400 km) on a new right-of-way from Hanmer TS to "Site A", a new 500 kV transformer station to be established on the existing 500 kV right-of-way between Claireville TS and Essa TS. Also, build a single circuit 500 kV line (45 km) on an existing right-of-way from "Site A" TS to Claireville TS.

### e) New Unidentified Sites in Southwestern Ontario

New Sites (4 x 881 MW CANDU or 4 x 800 MW CSC)

| | | |
|---|---|---|
| Radial | - | An alternative is to build two double circuit 500 kV lines (up to 50 km) on a new right-of-way to connect the generating station into an existing or planned transformer station. |
| Inter-area | - | New inter-area transmission will also be required. An alternative is to build a double circuit 500 kV line (200 km) on a new right-of-way from Longwood TS to "Site A", a new transformer station on the existing 500 kV right-of-way between Claireville TS and Essa TS. |

## 5.4 TRANSMISSION REQUIREMENTS - CANDIDATE PLANS

Criteria for design and evaluation of the Plans are identified in the Demand/Supply Planning Strategy Report. Major supply plans are formulated to satisfy the requirements for peak power and energy established in Chapter 13 of the Demand/Supply Plan Report. The sequence in which sites are developed influences transmission requirements.

Maintaining a regional balance between load and generation reduces, but does not eliminate, the requirement for inter-area transmission facilities. Such balance may exist at peak load times. At other times, large transfers of power in or out of the area may be required as a result of daily, weekly and monthly changes in load and generation patterns. These power transfers may stress critical transmission interfaces and require inter-area transmission reinforcements to ensure security of supply. The timing and sequencing of inter-area transmission will therefore depend on the demand and supply option chosen and its siting. The transmission facilities proposed will allow optimal use of available generation and purchases to permit economic and reliable operation of the Ontario Hydro system.

The transmission requirements for the five candidate plans are based on four transmission schemes, outlined in Figure 5.4. These transmission requirements are provided in Figure 5.5 to 5.9, using the four transmission schemes as building blocks. Figures 5.10 and 5.11 compliment this series of figures by illustrating the two siting sequences considered in developing the transmission requirements, and later, the economic evaluation of demand and supply plans. The transmission schemes are only one alternative and are provided to ensure that transmission costs are captured in the plan evaluation. The capital cost estimates have been developed using typical unit costs for new transmission and include property acquisition, engineering, overheads and contingencies. Interest charges are excluded. In all cases a typical four year cash flow is assumed to apply.

Figure 5.4
Transmission Requirements for Incorporation of Major GS's
(Station Requirements Not Included)

| Scheme ID | Description |
|---|---|
| I | Incorporation of GS at North Channel site:<br><br>Transmission Facilities Required:<br>- Hanmer TS x Mississagi TS:<br>Build the second 1-cct 500 kV line, approximately 210 km long, on an existing right-of-way<br>- North Channel GS x Mississagi TS:<br>Build two 1-cct 500 kV lines, each about 50 km long, on a new right-of-way<br>- North Channel GS x Sudbury area:<br>Build two 1-cct 500 kV lines, approximately 225 km long, on a new right-of-way<br>- Sudbury area x Toronto area (Site A):<br>Build two 1-cct 500 kV lines, approximately 400 km long, on a new right-of-way.<br>- Toronto area (Site A) x Claireville TS:<br>Build one 1-cct 500 kV line, approximately 45 km long, on an existing right-of-way. |
| II | Incorporation of GS east of Toronto<br><br>Transmission Facilities Required: |
| IIA | - Bowmanville SS x North-west of Toronto (Site A)<br>Build one 2-cct 500 kV line, approximately 175 km long, on a new right-of-way. Each circuit is to be provided with 50% series compensation. |
| IIB | - Bowmanville SS x Cherrywood TS:<br>Build 3rd 2-cct 500 kV line, approximately 46 km, on an existing approved right-of-way |
| Note: | Where the first site developed after Darlington 'A' is east of Toronto, the preferred method of incorporation for a 4x881 MW nuclear GS is by means of Scheme IIA. However, this site could be incorporated by means of the 3rd Bowmanville SS x Cherrywood TS 2-cct 500 kV line and upgrading of existing facilities with some locked-in energy. |
| III | Incorporation of GS in Southwestern Ontario<br>Site on Lake Erie<br><br>Transmission Facilities Required:<br>- New GS x Existing 500 kV Station in SWO:<br>Build two 2-cct 500 kV lines, up to 100 km long, on a new right-of-way |
| IV | Manitoba Purchase<br><br>Transmission Facilities Required:<br>- Manitoba Border x Sudbury Area:<br>Build one 1-cct 500 kV line, approximately 1000 km long, on a new right-of-way |
| Note: | This work covers only the facilities required in Ontario. New 500 kV stations will be established at Dryden, Lakehead and midpoint between Lakehead and Mississagi stations. The proposed facilities will displace indefinitely the following planned transmission projects in Northern Ontario:<br>- Birch X Marmion Lake<br>- Marmion Lake x Dryden<br>- Hanmer x Mississagi, 2nd line<br>- Northern Ontario Interconnection Stages I & II |

| Figure 5.5 |
|---|

## Case 15

08/02/90

| Transmission Facilities | Costs in 1988 $M Line | Station | In-service Year Lower | Branch Lower | Median | Branch Upper | Upper |
|---|---|---|---|---|---|---|---|
| **A) First Site - Darlington 'B'** | | | | | | | |
| Scheme I | 688 | 58 | 2013 | 2012 | 2010 | 2008 | 2008 |
| | 463 | 76 | 2015 | 2014 | 2012 | 2010 | 2010 |
| Scheme IIA | 270 | 171 | 2010 | 2004 | 2004 | 2004 | 2003 |
| Scheme IIB | 71 | 42 | 2012 | 2011 | 2009 | 2003 | 2001 |
| Scheme III | 308 | 30 | | | | | 2009 |
| Scheme IV ** | 576 | 208 | 2001 | 2001 | 2001 | 2001 | 2001 |
| **B) First Site - North Channel** | | | | | | | |
| Scheme I | 688 | 58 | 2010 | 2004 | 2004 | 2004 | 2003 |
| | 463 | 144 | 2012 | 2006 | 2006 | 2006 | 2005 |
| Scheme IIA | 270 | 103 | 2013 | 2012 | 2010 | 2008 | 2008 |
| Scheme IIB | 71 | 42 | 2012 | 2011 | 2009 | 2003 | 2001 |
| Scheme III | 308 | 30 | | | | | 2009 |
| Scheme IV ** | 576 | 208 | 2001 | 2001 | 2001 | 2001 | 2001 |

** These costs do not include the costs of deferred facilities. See Figure 5.12

Figure 5.6

Case 22

08/02/90

| Transmission Facilities | Costs in 1988 $M Line | Station | In-service Year Lower | Branch Lower | Median | Branch Upper | Upper |
|---|---|---|---|---|---|---|---|
| **A) First Site - Darlington 'B'** | | | | | | | |
| Scheme I | 688 | 58 | 2011 | 2011 | 2007 | 2007 | 2006 |
| | 463 | 76 | 2013 | 2013 | 2009 | 2009 | 2008 |
| Scheme IIA | 270 | 171 | 2008 | 2002 | 2002 | 2002 | 2002 |
| Scheme IIB | 71 | 42 | | 2013 | 2011 | 2011 | 2001 |
| Scheme III | 308 | 30 | | | | 2008 | 2009 |
| Scheme IV ** | 576 | 208 | 2001 | 2001 | 2001 | 2001 | 2001 |
| **B) First Site - North Channel** | | | | | | | |
| Scheme I | 688 | 58 | 2008 | 2002 | 2002 | 2002 | 2002 |
| | 463 | 144 | 2010 | 2004 | 2004 | 2004 | 2004 |
| Scheme IIA | 270 | 103 | 2011 | 2011 | 2007 | 2007 | 2006 |
| Scheme IIB | 71 | 42 | | 2013 | 2011 | 2011 | 2001 |
| Scheme III | 308 | 30 | | | | 2008 | 2009 |
| Scheme IV ** | 576 | 208 | 2001 | 2001 | 2001 | 2001 | 2001 |

** These costs do not include the costs of deferred facilities. See Figure 5.12.

# Figure 5.7

## Case 23

08/02/90

| Transmission Facilities | Costs in 1988 $M Line | Station | In-service Year Lower | Branch Lower | Median | Branch Upper | Upper |
|---|---|---|---|---|---|---|---|
| **A) First Site - Darlington 'B'** | | | | | | | |
| Scheme I | 688 | 58 | 2011 | 2003 | 2003 | 2003 | 2003 |
| | 463 | 76 | 2013 | 2005 | 2005 | 2005 | 2005 |
| Scheme IIA | 270 | 171 | 2000 | 2000 | 2000 | 2000 | 2000 |
| Scheme IIB | 71 | 42 | 2013 | 2012 | 2010 | 2008 | 2008 |
| Scheme III | 308 | 30 | | 2013 | 2011 | 2009/2013 | 2009 |
| Scheme IV ** | 576 | 208 | 2001 | 2001 | 2001 | 2001 | 2001 |
| **B) First Site - North Channel** | | | | | | | |
| Scheme I | 688 | 58 | 2000 | 2000 | 2000 | 2000 | 2000 |
| | 463 | 144 | 2002 | 2002 | 2002 | 2002 | 2002 |
| Scheme IIA | 270 | 103 | 2011 | 2003 | 2003 | 2003 | 2003 |
| Scheme IIB | 71 | 42 | 2013 | 2012 | 2010 | 2008 | 2008 |
| Scheme III | 308 | 30 | | 2013 | 2011 | 2009/2013 | 2009 |
| Scheme IV ** | 576 | 208 | 2001 | 2001 | 2001 | 2001 | 2001 |

** These costs do not include the costs of deferred facilities. See Figure 5.12.

## Figure 5.8

## Case 24

08/02/90

| Transmission Facilities | Costs in 1988 $M Line | Station | In-service Year Lower | Branch Lower | Median | Branch Upper | Upper |
|---|---|---|---|---|---|---|---|
| **A) First Site - Darlington 'B'** | | | | | | | |
| Scheme I | 688 | 58 | 2013 | 2012 | 2010 | 2008 | 2008 |
| | 463 | 76 | 2015 | 2014 | 2012 | 2010 | 2010 |
| Scheme IIA | 270 | 171 | 2010 | 2004 | 2004 | 2004 | 2003 |
| Scheme IIB | 71 | 42 | 2012 | 2010 | 2009 | 2003 | 2001 |
| Scheme III | 308 | 30 | | | | 2010 | 2009 |
| Scheme IV ** | 576 | 208 | 2001 | 2001 | 2001 | 2001 | 2001 |
| **B) First Site - North Channel** | | | | | | | |
| Scheme I | 688 | 58 | 2010 | 2004 | 2004 | 2004 | 2003 |
| | 463 | 144 | 2012 | 2006 | 2006 | 2006 | 2005 |
| Scheme IIA | 270 | 103 | | | 2013 | 2010 | 2009 |
| Scheme IIB | 71 | 42 | 2013 | 2012 | 2010 | 2003 | 2001 |
| Scheme III | 308 | 30 | | | | | 2013 |
| Scheme IV ** | 576 | 208 | 2001 | 2001 | 2001 | 2001 | 2001 |

** These costs do not include the costs of deferred facilities. See Figure 5.12.

## Figure 5.9

## Case 26

08/02/90

| Transmission Facilities | Costs in 1988 $M Line | Station | In-service Year Lower | Branch Lower | Median | Branch Upper | Upper |
|---|---|---|---|---|---|---|---|
| **A) First Site - Darlington 'B'** | | | | | | | |
| Scheme I | 688 | 58 | 2013 | 2012 | 2010 | 2008 | 2008 |
| | 463 | 76 | 2015 * | 2014 * | 2012 | 2010 | 2010 |
| Scheme IIA | 270 | 171 | | | 2009 | 2004 | 2003 |
| Scheme IIB | 71 | 42 | 2010 | 2011 | 2004 | 2003 | 2001 |
| Scheme III | 308 | 30 | | | | 2010 | 2009 |
| Scheme IV ** | 576 | 208 | 2001 | 2001 | 2001 | 2001 | 2001 |
| **B) First Site - North Channel** | | | | | | | |
| Scheme I | 688 | 58 | 2010 | 2004 | 2004 | 2004 | 2003 |
| | 463 | 144 | 2012 | 2006 | 2006 | 2006 | 2005 |
| Scheme IIA | 270 | 103 | | | 2013 | 2010 | 2008 |
| Scheme IIB | 71 | 42 | 2012 | 2011 | 2009 | 2003 | 2001 |
| Scheme III | 308 | 30 | | | | | 2009 |
| Scheme IV ** | 576 | 208 | 2001 | 2001 | 2001 | 2001 | 2001 |

* add $60 M for station work at southern terminal

** These costs do not include the costs of deferred facilities. See Figure 5.12.

## FIGURE 5.10

## ILLUSTRATIVE SITING AND TIMING OF OPTIONS

### Darlington B/Wesleyville B Sites Used First for CANDU/CSC Coal

| SITE | LOAD FORECAST CONDITION | CASE 23 Option | CASE 23 In-Service | CASE 22 Option | CASE 22 In-Service | CASE 15 Option | CASE 15 In-Service | CASE 24 Option | CASE 24 In-Service | CASE 26 Option | CASE 26 In-Service |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | Lower | CANDU A | 1999 | CANDU A | 2007 | CANDU A | 2009 | CANDU A | 2009 | | |
| | Branch Lower | CANDU A | 1999 | CANDU A | 2001 | CANDU A | 2003 | CANDU A | 2003 | | |
| Darlington B | Median | CANDU A | 1999 | CANDU A | 2001 | CANDU A | 2003 | CANDU A | 2003 | | |
| | Branch Upper | CANDU A | 1999 | CANDU A | 2001 | CANDU A | 2003 | CANDU A | 2003 | | |
| | Upper | CANDU A | 1999 | CANDU A | 2001 | CANDU A | 2002 | CANDU A | 2002 | | |
| | Lower | | | | | CTU/CC A | 2008 | CTU/CC A | 2008 | CTU/CC A | 2008 |
| | Branch Lower | | | CTU/CC A | 2009 | CTU/CC A | 2009 | CTU/CC A | 2008 | CTU/CC A | 2008 |
| Hearn | Median | | | CTU/CC A | 2008 | CTU/CC A | 2001 | CTU/CC A | 2001 | CTU/CC A | 2001 |
| | Branch Upper | | | CTU/CC A | 2000 | CTU/CC A | 2000 | CTU/CC A | 2000 | CTU/CC A | 2000 |
| | Upper | | | CTU/CC B | 2003 | CTU/CC B | 2002 | CTU/CC B | 2003 | CTU/CC B | 2003 |
| | Lower | | | | | | | | | | |
| | Branch Lower | | | | | | | | | | |
| Keith | Median | | | | | | | | | | |
| | Branch Upper | | | | | CTU/CC B | 2002 | CTU/CC B | 2002 | CTU/CC B | 2007 |
| | Upper | | | CTU/CC A | 2002 | CTU/CC C | 2001 | CTU/CC A | 2002 | CTU/CC A | 2002 |
| | Lower | CTU/IGCC A | 2012 | CTU/IGCC A | 2012 | CTU/IGCC B | 2012 | CTU/IGCC B | 2012 | CTU/IGCC B | 2012 |
| | Branch Lower | | | CTU/IGCC B | 2012 | CTU/IGCC B | 2012 | CTU/IGCC B | 2010 | CTU/IGCC B | 2010 |
| Lakeview | Median | | | CTU/IGCC B | 2012 | CTU/IGCC B | 2009 | CTU/IGCC B | 2008 | CTU/IGCC B | 2008 |
| | Branch Upper | CTU/IGCC A | 2012 | CTU/IGCC B | 2011 | CTU/IGCC B | 2008 | CTU/IGCC B | 2007 | CTU/IGCC C | 2008 |
| | Upper | | | CTU/IGCC B | 2012 | CTU/IGCC B | 2012 | CTU/IGCC C | 2006 | CTU/IGCC C | 2007 |
| | Lower | | | | | | | | | | |
| | Branch Lower | | | | | | | | | CTU/IGCC C | 2012 |
| Lambton | Median | | | | | CTU/IGCC C | 2012 | CTU/IGCC C | 2010 | CTU/IGCC C | 2010 |
| | Branch Upper | | | CTU/IGCC C | 2012 | CTU/IGCC C | 2012 | CTU/IGCC C | 2012 | CTU/IGCC D | 2012 |
| | Upper | CTU/NC A | 1993 | CTU/NC A | 1993 | CTU/NC A | 1993 | CTU/NC A | 1993 | CTU/NC A | 1993 |
| | Lower | | | | | | | | | | |
| | Branch Lower | | | | | | | | | | |
| Lennox A | Median | | | | | | | | | | |
| | Branch Upper | | | | | | | | | | |
| | Upper | | | | | CTU/NC C | 2001 | | | | |
| | Lower | | | | | | | | | | |
| | Branch Lower | | | | | | | | | | |
| Lennox B | Median | | | | | | | | | | |
| | Branch Upper | | | | | | | | | CTU/IGCC B | 2002 |
| | Upper | | | | | | | CTU/IGCC B | 2001 | CTU/IGCC B | 2001 |
| | Lower | | | | | | | | | | |
| | Branch Lower | | | | | | | | | | |
| Nanticoke | Median | | | | | | | | | | |
| | Branch Upper | | | | | | | | | | |
| | Upper | CTU/NC B | 1994 | CTU/NC B | 1994 | CTU/NC B | 1994 | CTU/NC B | 1994 | CTU/NC B | 1994 |

FIGURE 5.10 (CON'T)

ILLUSTRATIVE SITING AND TIMING OF OPTIONS

Darlington B/Wesleyville B Sites Used First for CANDU/CSC Coal

| SITE | LOAD FORECAST CONDITION | CASE 23 Option | CASE 23 In-Service | CASE 22 Option | CASE 22 In-Service | CASE 15 Option | CASE 15 In-Service | CASE 24 Option | CASE 24 In-Service | CASE 26 Option | CASE 26 In-Service |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | Lower | CANDU C | 2012 | | | | | | | | |
| | Branch Lower | CANDU C | 2011 | | | | | | | | |
| New Site 1 | Median | CANDU C | 2009 | CANDU C | 2010 | CANDU C | 2012 | CANDU B | 2012 | CSC COAL C | 2012 |
| | Branch Upper | CANDU C | 2007 | CANDU C | 2007 | CANDU C | 2009 | CANDU B | 2009 | CSC COAL C | 2009 |
| | Upper | CANDU C | 2007 | CANDU C | 2008 | CANDU C | 2008 | CANDU B | 2008 | CSC COAL C | 2008 |
| | Lower | | | | | | | | | | |
| | Branch Lower | CANDU D | 2012 | | | | | | | | |
| New Site 2 | Median | CANDU D | 2010 | | | | | | | | |
| | Branch Upper | CANDU D | 2008 | CANDU D | 2013 | | | | | | |
| | Upper | CANDU D | 2008 | CANDU D | 2011 | CANDU D | 2012 | CANDU C | 2012 | CSC COAL D | 2012 |
| | Lower | | | | | | | | | | |
| | Branch Lower | | | | | | | | | | |
| New Site 3 | Median | | | | | | | | | | |
| | Branch Upper | CANDU E | 2012 | | | | | | | | |
| | Upper | CANDU E | 2012 | | | | | | | | |
| | Lower | | | | | | | | | | |
| | Branch Lower | | | | | | | | | | |
| New Site 4 | Median | | | | | | | | | | |
| | Branch Upper | CANDU F | 2012 | | | | | | | | |
| | Upper | | | | | | | | | | |
| | Lower | CANDU B | 2010 | CANDU B | 2010 | CANDU B | 2012 | CSC COAL A | 2012 | CSC COAL B | 2012 |
| | Branch Lower | CANDU B | 2002 | CANDU B | 2010 | CANDU B | 2011 | CSC COAL A | 2011 | CSC COAL B | 2011 |
| North Channel | Median | CANDU B | 2002 | CANDU B | 2006 | CANDU B | 2009 | CSC COAL A | 2009 | CSC COAL B | 2009 |
| | Branch Upper | CANDU B | 2002 | CANDU B | 2006 | CANDU B | 2007 | CSC COAL A | 2007 | CSC COAL B | 2007 |
| | Upper | CANDU B | 2002 | CANDU B | 2005 | CANDU B | 2007 | CSC COAL A | 2007 | CSC COAL B | 2007 |
| | Lower | | | | | CTU/IGCC A | 2009 | CTU/IGCC A | 2009 | CTU/IGCC A | 2009 |
| | Branch Lower | | | CTU/IGCC A | 2009 | CTU/IGCC A | 2009 | CTU/IGCC A | 2009 | CTU/IGCC A | 2009 |
| Wesleyville A | Median | | | CTU/IGCC A | 2009 | CTU/IGCC A | 2002 | CTU/IGCC A | 2002 | CTU/IGCC A | 2002 |
| | Branch Upper | | | CTU/IGCC A | 2002 | CTU/IGCC A | 2001 | CTU/IGCC A | 2001 | CTU/IGCC A | 2001 |
| | Upper | CTU/IGCC A | 1997 | CTU/IGCC A | 1997 | CTU/IGCC A | 1997 | CTU/IGCC A | 1997 | CTU/IGCC A | 1997 |
| | Lower | | | | | | | | | CSC COAL A | 2009 |
| | Branch Lower | | | | | | | | | CSC COAL A | 2003 |
| Wesleyville B | Median | | | | | | | | | CSC COAL A | 2003 |
| | Branch Upper | | | | | | | | | CSC COAL A | 2003 |
| | Upper | | | | | | | | | CSC COAL A | 2002 |

FIGURE 5.11

# ILLUSTRATIVE SITING AND TIMING OF OPTIONS

## North Channel Area Site Used First for CANDU/CSC Coal

| SITE | LOAD FORECAST CONDITION | CASE 23 Option | CASE 23 In-Service | CASE 22 Option | CASE 22 In-Service | CASE 15 Option | CASE 15 In-Service | CASE 24 Option | CASE 24 In-Service | CASE 26 Option | CASE 26 In-Service |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | Lower | CANDU B | 2010 | CANDU B | 2010 | CANDU B | 2012 | | | | |
| | Branch Lower | CANDU B | 2002 | CANDU B | 2010 | CANDU B | 2011 | | | | |
| Darlington B | Median | CANDU B | 2002 | CANDU B | 2006 | CANDU B | 2009 | CANDU B | 2012 | | |
| | Branch Upper | CANDU B | 2002 | CANDU B | 2006 | CANDU B | 2007 | CANDU B | 2009 | | |
| | Upper | CANDU B | 2002 | CANDU B | 2005 | CANDU B | 2007 | CANDU B | 2008 | | |
| | Lower | | | | | CTU/CC A | 2008 | CTU/CC A | 2008 | CTU/CC A | 2008 |
| | Branch Lower | | | CTU/CC A | 2009 | CTU/CC A | 2009 | CTU/CC A | 2008 | CTU/CC A | 2008 |
| Hearn | Median | | | CTU/CC A | 2008 | CTU/CC A | 2001 | CTU/CC A | 2001 | CTU/CC A | 2001 |
| | Branch Upper | | | CTU/CC A | 2000 | CTU/CC A | 2000 | CTU/CC A | 2000 | CTU/CC A | 2000 |
| | Upper | | | CTU/CC B | 2003 | CTU/CC B | 2002 | CTU/CC B | 2003 | CTU/CC B | 2003 |
| | Lower | | | | | | | | | | |
| | Branch Lower | | | | | | | | | | |
| Keith | Median | | | | | | | | | | |
| | Branch Upper | | | | | CTU/CC B | 2002 | CTU/CC B | 2002 | CTU/CC B | 2007 |
| | Upper | | | CTU/CC A | 2002 | CTU/CC C | 2001 | CTU/CC A | 2002 | CTU/CC A | 2002 |
| | Lower | CTU/IGCC A | 2012 | CTU/IGCC A | 2012 | CTU/IGCC B | 2012 | CTU/IGCC B | 2012 | CTU/IGCC B | 2012 |
| | Branch Lower | | | CTU/IGCC B | 2012 | CTU/IGCC B | 2012 | CTU/IGCC B | 2010 | CTU/IGCC B | 2010 |
| Lakeview | Median | | | CTU/IGCC B | 2012 | CTU/IGCC B | 2009 | CTU/IGCC B | 2008 | CTU/IGCC B | 2008 |
| | Branch Upper | CTU/IGCC A | 2012 | CTU/IGCC B | 2011 | CTU/IGCC B | 2008 | CTU/IGCC B | 2007 | CTU/IGCC C | 2008 |
| | Upper | | | CTU/IGCC B | 2012 | CTU/IGCC B | 2012 | CTU/IGCC C | 2006 | CTU/IGCC C | 2007 |
| | Lower | | | | | | | | | | |
| | Branch Lower | | | | | | | | | CTU/IGCC C | 2012 |
| Lambton | Median | | | | | CTU/IGCC C | 2012 | CTU/IGCC C | 2010 | CTU/IGCC C | 2010 |
| | Branch Upper | | | CTU/IGCC C | 2012 | CTU/IGCC C | 2012 | CTU/IGCC C | 2012 | CTU/IGCC D | 2012 |
| | Upper | CTU/NC A | 1993 | CTU/NC A | 1993 | CTU/NC A | 1993 | CTU/NC A | 1993 | CTU/NC A | 1993 |
| | Lower | | | | | | | | | | |
| | Branch Lower | | | | | | | | | | |
| Lennox A | Median | | | | | | | | | | |
| | Branch Upper | | | | | | | | | | |
| | Upper | | | | | CTU/NC C | 2001 | | | | |
| | Lower | | | | | | | | | | |
| | Branch Lower | | | | | | | | | | |
| Lennox B | Median | | | | | | | | | | |
| | Branch Upper | | | | | | | | | CTU/IGCC B | 2002 |
| | Upper | | | | | | | CTU/IGCC B | 2001 | CTU/IGCC B | 2001 |
| | Lower | | | | | | | | | | |
| | Branch Lower | | | | | | | | | | |
| Nanticoke | Median | | | | | | | | | | |
| | Branch Upper | | | | | | | | | | |
| | Upper | CTU/NC B | 1994 | CTU/NC B | 1994 | CTU/NC B | 1994 | CTU/NC B | 1994 | CTU/NC B | 1994 |

FIGURE 5.11 (CON'T)

ILLUSTRATIVE SITING AND TIMING OF OPTIONS

North Channel Area Site Used First for CANDU/CSC Coal

| SITE | LOAD FORECAST CONDITION | CASE 23 Option | CASE 23 In-Service | CASE 22 Option | CASE 22 In-Service | CASE 15 Option | CASE 15 In-Service | CASE 24 Option | CASE 24 In-Service | CASE 26 Option | CASE 26 In-Service |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | Lower | CANDU C | 2012 | | | | | | | | |
| | Branch Lower | CANDU C | 2011 | | | | | | | | |
| New Site 1 | Median | CANDU C | 2009 | CANDU C | 2010 | CANDU C | 2012 | | | CSC COAL C | 2012 |
| | Branch Upper | CANDU C | 2007 | CANDU C | 2007 | CANDU C | 2009 | | | CSC COAL C | 2009 |
| | Upper | CANDU C | 2007 | CANDU C | 2008 | CANDU C | 2008 | CANDU C | 2012 | CSC COAL C | 2008 |
| | Lower | | | | | | | | | | |
| | Branch Lower | CANDU D | 2012 | | | | | | | | |
| New Site 2 | Median | CANDU D | 2010 | | | | | | | | |
| | Branch Upper | CANDU D | 2008 | CANDU D | 2013 | | | | | | |
| | Upper | CANDU D | 2008 | CANDU D | 2011 | CANDU D | 2012 | | | CSC COAL D | 2012 |
| | Lower | | | | | | | | | | |
| | Branch Lower | | | | | | | | | | |
| New Site 3 | Median | | | | | | | | | | |
| | Branch Upper | CANDU E | 2012 | | | | | | | | |
| | Upper | CANDU E | 2012 | | | | | | | | |
| | Lower | | | | | | | | | | |
| | Branch Lower | | | | | | | | | | |
| New Site 4 | Median | | | | | | | | | | |
| | Branch Upper | CANDU F | 2012 | | | | | | | | |
| | Upper | | | | | | | | | | |
| | Lower | CANDU A | 1999 | CANDU A | 2007 | CANDU A | 2009 | CANDU A | 2009 | CSC COAL A | 2009 |
| | Branch Lower | CANDU A | 1999 | CANDU A | 2001 | CANDU A | 2003 | CANDU A | 2003 | CSC COAL A | 2003 |
| North Channel | Median | CANDU A | 1999 | CANDU A | 2001 | CANDU A | 2003 | CANDU A | 2003 | CSC COAL A | 2003 |
| | Branch Upper | CANDU A | 1999 | CANDU A | 2001 | CANDU A | 2003 | CANDU A | 2003 | CSC COAL A | 2003 |
| | Upper | CANDU A | 1999 | CANDU A | 2001 | CANDU A | 2002 | CANDU A | 2002 | CSC COAL A | 2002 |
| | Lower | | | | | CTU/IGCC A | 2009 | CTU/IGCC A | 2009 | CTU/IGCC A | 2009 |
| | Branch Lower | | | CTU/IGCC A | 2009 | CTU/IGCC A | 2009 | CTU/IGCC A | 2009 | CTU/IGCC A | 2009 |
| Wesleyville A | Median | | | CTU/IGCC A | 2009 | CTU/IGCC A | 2002 | CTU/IGCC A | 2002 | CTU/IGCC A | 2002 |
| | Branch Upper | | | CTU/IGCC A | 2002 | CTU/IGCC A | 2001 | CTU/IGCC A | 2001 | CTU/IGCC A | 2001 |
| | Upper | CTU/IGCC A | 1997 | CTU/IGCC A | 1997 | CTU/IGCC A | 1997 | CTU/IGCC A | 1997 | CTU/IGCC A | 1997 |
| | Lower | | | | | | | CSC COAL A | 2012 | CSC COAL B | 2012 |
| | Branch Lower | | | | | | | CSC COAL A | 2011 | CSC COAL B | 2011 |
| Wesleyville B | Median | | | | | | | CSC COAL A | 2009 | CSC COAL B | 2009 |
| | Branch Upper | | | | | | | CSC COAL A | 2007 | CSC COAL B | 2007 |
| | Upper | | | | | | | CSC COAL A | 2007 | CSC COAL B | 2007 |

All Plans include the purchase of electricity from Manitoba. The present purchase arrangements start in 1998 at 200 MW, grow to 1000 MW by 2002, continue at that level until 2018, and conclude in 2022. The transmission required to incorporate the 1000 MW Manitoba Purchase into the Plan is included in all cases. The proposed transmission scheme to incorporate the Manitoba Purchase indefinitely delays several planned load supply transmission projects in northwestern Ontario, as well as planned inter-area transmission between northwestern and northeastern Ontario. These facilities are outlined in Figure 5.12. The net effect of the deferral of these transmission facilities is factored into the Manitoba Purchase as a benefit to Ontario Hydro.

All Plans include the same Hydraulic Program and NUG developments. The transmission required to incorporate these resources will include radial transmission to connect individual stations into the BES and inter-area transmission to ensure security and reliability of power supply, operational flexibility and economic utilization of these resources. The cost of the radial transmission is included in the cost of individual hydraulic station projects. However, the costs of the inter-area transmission have not been included. As these costs are common to all plans their exclusion does not alter the economic comparison between plans.

The four transmission schemes are common to all the candidate plans. Their in-service dates are influenced however by load growth, choice of option, geographic location and sequencing of siting. All of these influencing factors must be viewed collectively when assessing the transmission developments required by each candidate Plan.

**Load Growth**

Each Major Supply Case was tested against the bandwidth forecast, consisting of five load paths.

Under the lower load growth options, where in-service dates of major supply options are farther out in the planning time frame, transmission facilities that are freed up because of retirement of existing generating resources can be utilized to incorporate the new supply options.

Under the high load growth options, the existing and proposed transmission reinforcements are fully utilized. To incorporate the additional options required under the upper load growth, new unidentified generation sites and incorporating transmission are required. Sites to the southwest and northwest of Toronto are preferred for these upper load growth options. Incorporation of these sites would require reinforcing of the southern/central transmission interface. Because of the uncertainties associated with the siting within this geographic area and the already strained state of this transmission system, a representative transmission

# Figure 5.12

Cost and Timing of Facilities in Northern Ontario
Deferred Idefinitely by Manitoba Purchase

08/02/90

| Facility | Costs in 1988 $M Line Costs | Station Costs | In-service Year without Manitoba Purchase Lower | Branch Lower | Median | Branch Upper | Upper |
|---|---|---|---|---|---|---|---|
| 2nd Hanmer x Mississagi 500 kV | 94 | 4 | 2013 | 2009 | 2005 | 2002 | 1999 |
| Birch x Marmion Lake | 101 | 9 | 2005 | 2000 | 2000 | 2000 | 1997 |
| Marmion Lake x Dryden | 89 | 5 | 2011 | 2009 | 2005 | 2003 | 2001 |
| Northern Ontario Int. St I | 318 | 78 | 2015 | 2012 | 2006 | 2003 | 2000 |
| Northern Ontario Int. St II | 299 | 10 | 2023 | 2023 | 2015 | 2005 | 2005 |

reinforcement was specified for the planning studies. Since sites to the southwest and northwest of Toronto are not proposed to be utilized until late in the 25-year planning time frame, the transmission reinforcements specified take into account the unloading of the transmission system that would result from the retirement of existing generation resources.

### Choice of Option

The set of illustrative sites for each Case represents a feasible choice and meets the planning requirement for a geographic balance between electricity demand and supply. Darlington 'B' and North Channel are used as reference sites for CANDU stations. Wesleyville 'B' is used as a reference site for a CSC coal station. In those Cases where North Channel is not used for a nuclear station, it is a reference site for a CSC coal station. Wesleyville 'A' and Lennox 'B' are reference sites for CTU/IGCC.

### Siting - Geographic Location/Sequencing

To achieve geographic balance between load and generation, the major supply options are initially sited in eastern and northern Ontario. The inter-area transmission reinforcements triggered by this choice of site would be eastern/central and northern/central, respectively. To investigate the impact of choice of site on these inter-area transmission links, two options for the siting of the first base load station in each of the five selected Cases were chosen:

- Darlington/Wesleyville
- North Channel.

For the eastern/central reinforcement, the option chosen for the first site developed east of metro Toronto has an impact on the extent of the transmission reinforcements required, and ultimately, on the costs. The eastern/central reinforcements are designed to achieve many system goals, including the incorporation of the demand and supply options. Economical use of available resources is one of these system goals. An assessment of the resources available to the system and those options outlined in the five Cases, shows that to achieve the operational and economic objectives for the BES, the following guidelines are appropriate in determining the eastern/central transmission interface reinforcements.

| Option | Additional Generation East of metro Toronto | Transmission Reinforcements |
|---|---|---|
| fossil | less than 1500 MW | nil |
| fossil | up to 5000 MW | Scheme IIB |
| fossil | 5000 MW to 7500 MW | Scheme IIA & IIB |
| nuclear | up to 5000 MW | Scheme IIA |
| nuclear | 5000 MW to 7500 MW | Scheme IIA & IIB |

Additional generation east of Toronto beyond 7500 MW will require further reinforcement of the eastern/central interface and possible reinforcement of the southern/central interface.

For the northern/central transmission reinforcement, the impacts of the hydraulic program, non-utility generation and the Manitoba Purchase have to be considered collectively to determine the incorporation requirements for the selected option. The following resource additions in northern Ontario are expected over the 25-year planning time frame:

| Resource Addition | Installed Capability |
|---|---|
| Hydraulic Program | 2300 MW (by 2014) |
| Non-utility generation | 1340 MW (by 2014) |
| Manitoba Purchase | 1000 MW (2002 to 2018) |

Taking into account the proposed transmission reinforcements, upgrades to existing facilities and stability enhancing devices, the northern/central interface will permit only one major supply option to be incorporated at the North Channel site. For this reason, it was decided to limit the North Channel site to the base load options (nuclear, CSC coal or IGCC).

The development of a transformer station at "Site A", to terminate the northern/central and eastern/cental reinforcements in the existing 500 kV right-of-way between Claireville TS and Essa TS, is common to both of these reinforcements and is allocated for costing purposes to the first reinforcement placed in-service.

## Comparison of Cases

### Case 15 - Proposed Plan

The choice of the initial base load site, whether in eastern or northern Ontario, does not alter the total transmission reinforcements required over the 25-year planning time frame. However, the choice of first site does affect total transmission costs, due to the relative costs of the northern/central and eastern/central inter-area transmission reinforcements, the extensive radial transmission for the North Channel site and the time value of money. Under the upper load growth path, an additional site and associated incorporating transmission are required in southern Ontario.

### Case 22

The choice of initial siting does not impact the total transmission reinforcements required. Under the lower load growth path, one less inter-area transmission link is required than under the same conditions for Case 15. However, an additional site in southern Ontario and associated transmission is required under the branch upper load growth path as well as the upper load growth path.

### Case 23

The choice of initial siting does not impact the total transmission reinforcements required. An additional site in southern Ontario and associated transmission is required under all load growth paths except the lower load growth. Two additional sites are required in southern Ontario under the branch upper load growth path.

### Case 24

Under the branch upper load growth path, an additional site is required in southern Ontario when the first site utilized is in eastern Ontario. When the first site is in northern Ontario, the major transmission reinforcements between eastern and central Ontario are not required for the lower and branch lower load growth paths.

### Case 26

The major transmission reinforcements between eastern and central Ontario are not required for the lower and branch lower load growth paths. Under the branch upper load growth path, an additional site is required in southern Ontario, when the first site utilized is in eastern Ontario.

**Summary**

A major factor in determining the siting for the base load plants is the geographic balance between load and generation. To achieve this, it is preferable to limit base load expansion east of Toronto to one station at the beginning of the 25-year planning period. It is preferable to limit the North Channel development to one base load station, because of load distribution and transmission considerations. Prior to retirements of base load plants east of Toronto (2011), locations for base load stations southwest and northwest of Toronto would also be required under the upper load growth path for all Cases.

The transmission requirements to incorporate the North Channel site into the BES are approximately four times as costly as those for sites east of metro Toronto. While unit transmission costs are expected to be greatest in and around the greater Toronto area, the shorter distances and the common transmission reinforcements between the northern/central and eastern/central reinforcements more than offset the higher unit costs of the eastern/central transmission reinforcements. The lower total cost for the eastern/central transmission reinforcements is of particular significance, when comparing the impact of siting of the first base load option between eastern and northern Ontario.

## 5.5 REVIEW

The siting of generation has an impact on the nature, timing and sequence of transmission system reinforcements. The transmission required to incorporate a new Ontario Hydro generating station will include radial transmission necessary to connect the site to the existing and planned Bulk Electricity System (BES). It may also include inter-area transmission necessary to maintain an integrated BES. The inter-area transmission facilities described in this chapter are those influenced by the demand and supply options and are not meant to be a comprehensive list of the Bulk Transmission System additions required over the 25-year life of the Demand/Supply Plan.

Illustrative transmission for the incorporation of generating stations at the candidate sites is provided to ensure that transmission costs are captured in the plan evaluation. The precise configuration of the new transmission, including an assessment of viable alternatives, will be considered in the project specific environmental assessments.

Approvals sought in the Demand/Supply Plan Report include the need for radial transmission. Specific routes for this radial transmission will be assessed as part of the project specific environmental assessment for each generation development. Approvals for inter-area transmission reinforcements will be sought in separate parallel environmental assessment processes.

Consolidation of the eastern/central and northern/central inter-area transmission reinforcements into a single environmental assessment meets the incorporation requirements of the candidate plans, and offers significant advantages for the development of the integrated bulk electricity system:

- It provides the flexibility to disperse additional generation across the province (Demand/Supply Planning Strategy Element 5.4). More particularly, it enables the next new generating station to be located either on the North Channel or east of Toronto.

- It provides the opportunity for a staged development since, the in-service dates for the two transmission reinforcements are interdependent, and part of the right-of-way and facilities for the two inter-area transmission reinforcements could be common.

- It enables approvals under the Environmental Assessment Act to be sought for a total transmission development plan which is consistent with the Demand/Supply Plan.

# 6. ENERGY PRODUCTION

## 6.0 INTRODUCTION

To assess the economic and environmental impacts of demand/supply plans, it is necessary to consider:

1. energy production, and the amount of fuel required to produce that energy;
2. energy acquired through purchases from US and Canadian utilities, and non-utility generators; and
3. regulatory limits on acid gas emissions, which apply to the generating system as a whole. These limits influence the application of emission control technologies and the choice of fossil fuels, such as bituminous coal, lignite, natural gas and oil.

As noted in Chapter 4, five Cases were formulated. All five Cases require new major supply facilities.

The timing and nature of new supply additions (hydraulic, nuclear, fossil, purchases) influence the way the entire system can be operated. Hence, the pattern of energy production and fuel consumption changes between Cases.

## 6.1 OPERATING STRATEGY

Ontario Hydro generating stations are fuelled with one of five energy sources: uranium, coal, oil, gas and falling water. Each station's production is driven by the system operating strategy, which is to minimize the total cost of providing electricity to customers. This is done, whenever possible, by using the lowest cost energy sources first, provided environmental requirements and standards are met. Cost in this instance includes the variable costs of fuel and of operations. Capital costs and financing charges already incurred are not included, as they do not influence how a station is operated.

The order of generation, by least operating cost, is hydraulic, nuclear and fossil. Based on past experience and current economic considerations, it is generally best to match demand needs and generating options as follows:

1. Base load - nuclear units and hydraulic units that have limited storage capabilities,
2. Intermediate load - coal-fired units, and
3. Peak load - oil-fired, natural gas-fired and hydraulic units with storage capabilities. Hydraulic peaking stations have extra value because of their quick response to changing demand.

Electricity purchases and non-utility generation are also contracted to meet base load or intermediate load and, on some occasions, to maintain adequate operating reserves.

## 6.2 FUEL CONSUMPTION

The calculation of fuel consumption is performed with computer modelling. The model takes into account available supply facilities and their characteristics, and the characteristics of the load, as explained in Chapter 2.

Load characteristics include the effects of demand management and load displacement non-utility generation.

The model of available supply facilities includes purchases from utilities and non-utility generators, the existing system and new supply additions. Supply characteristics that influence operation include:

1. Performance of operating units such as generator outage rates,
2. Natural constraints such as water availability, and
3. Environmental constraints such as acid gas emission regulations.

By determining time of use and fuel employed, the model calculates fuel costs and emissions for every station in the plan. If the results are poor in one or both areas -- for example, acid gas emissions above regulatory limits -- the nature of the plan is revised as described in Chapter 4.

Fuel cost and emission data are used in a number of additional evaluations. Fuel consumption figures are employed to examine fuel supply implications, range of costs, electricity rates, provincial economy impact and environmental impacts (wastes, water use, mining activity, etc.). Emissions are a starting point for the environmental review.

## 6.3 ENERGY PRODUCTION RESULTS

Calculations of energy production and fuel consumption have been made for all five Cases under each of the five load forecast paths. The lower, branch lower, median, branch upper and upper load paths are discussed for each energy source: utility purchases, non-utility generation, hydraulic, nuclear and fossil.

### 6.3.1 Energy From Utility Purchases

Figure 6-1 shows the annual energy purchased from other utilities. This is assumed in all Cases and load paths.

All five Cases feature the purchase of electricity from Manitoba. The present purchase arrangements start in 1998 at 200 MW, grow to 1000 MW by 2002, continue at that level until 2018, and conclude in 2022.

The purchase begins in November 1998. However, because of the time periods used in the model, it is assumed to begin in 1999. Energy from the Manitoba Purchase reaches about 7 TW.h per year by 2003, and continues at that level to the end of the planning period.

### 6.3.2 Energy From Non-utility Generation Purchases

Figure 6-2 shows the annual energy supplied by non-utility generation purchases in all five Cases under the five load forecast paths. The estimates represent net energy purchased by Ontario Hydro. There are some non-utility generators which generate electricity to supply part or all of their own load without any net sale of power to Ontario Hydro. Because electricity produced by these "load displacement" projects has been accounted for in the primary load forecast, it is not included here.

Energy from non-utility generators increases steadily to about 3 TW.h per year by 1994 under all load paths. Thereafter, under median load forecast, energy production continues to climb, reaching about 11 TW.h per year by 2014.

Under lower load forecast, energy production levels off at about 3 TW.h per year for several years, until about 2003. Thereafter, energy production increases steadily, reaching about 7 TW.h per year by 2014.

Energy production under upper load forecast is slightly higher than under median load forecast after 1994, by about 1 TW.h per year.

After 2000, energy purchased from non-utility generators under branch lower and branch upper load forecasts begins to differ from the median load forecast. Energy under the branch lower load path levels off at about 6 TW.h per year until 2009, then rises to over 7 TW.h per year by 2014. Energy under the branch upper load path is higher than under the median load path after 2000, and reaches the same level as under the upper load path by 2005.

FIGURE 6-1

ENERGY FROM UTILITY PURCHASES
(FOR ALL CASES & LOAD FORECASTS)

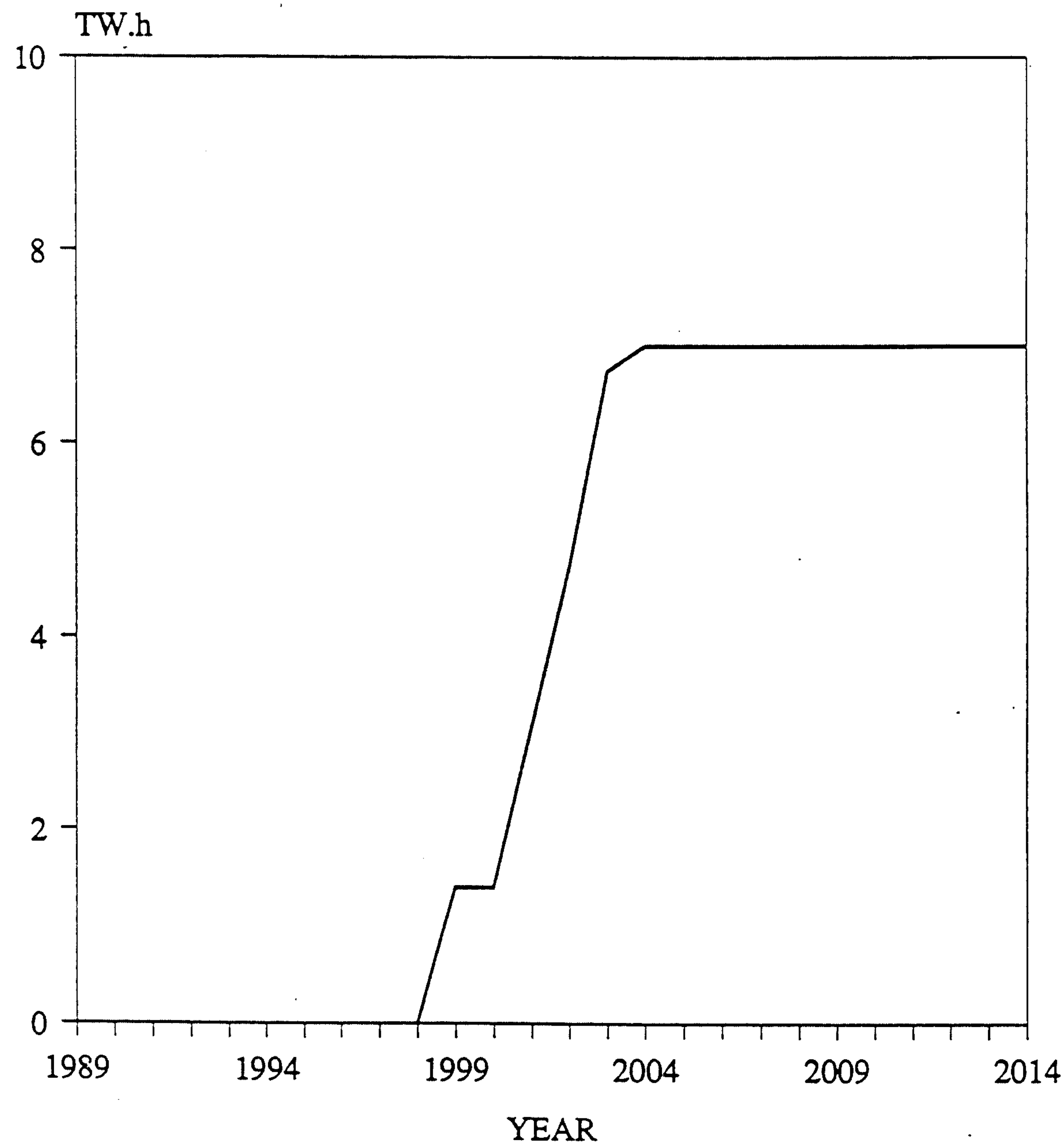
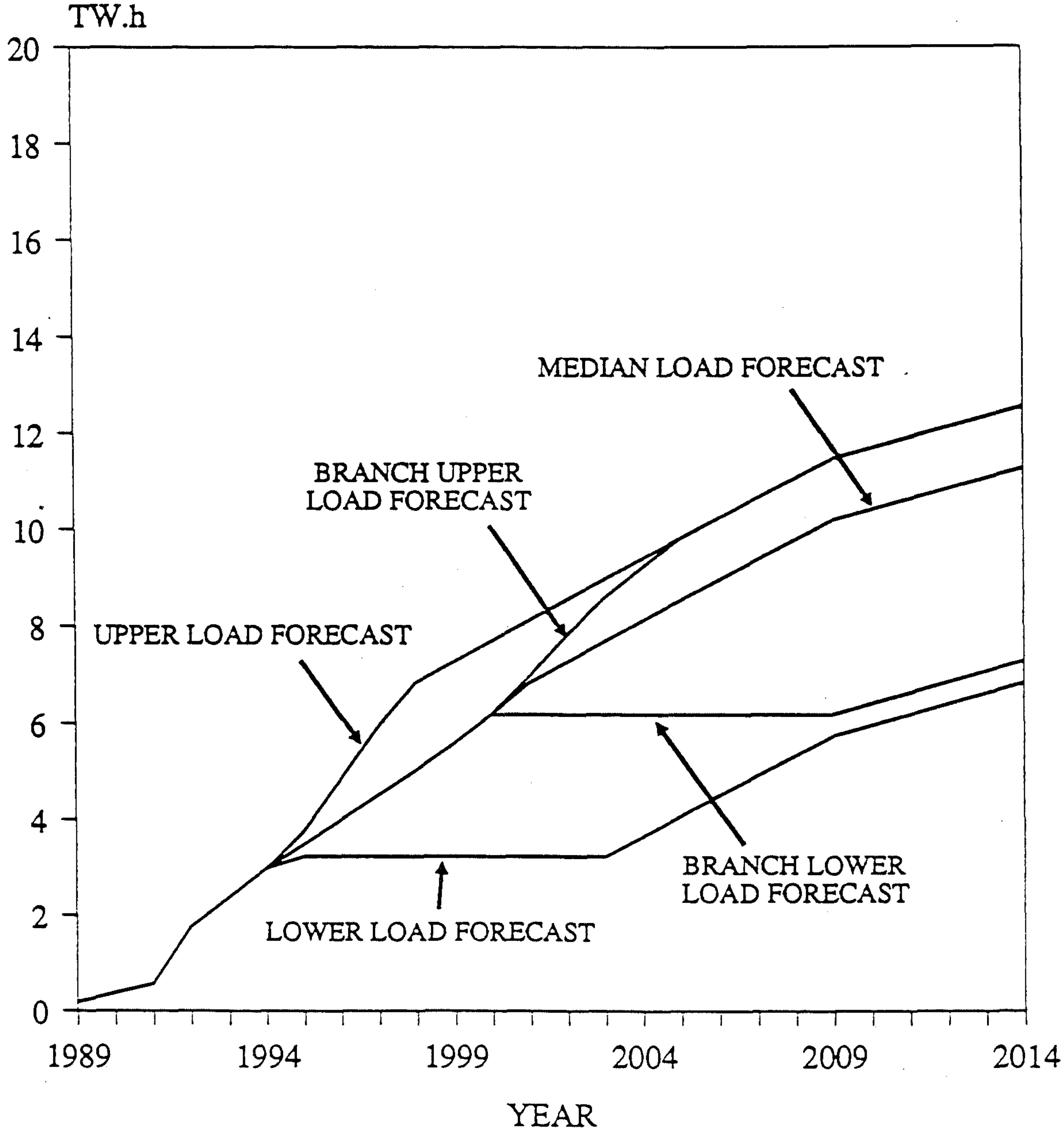


FIGURE 6-2

ENERGY FROM NON-UTILITY GENERATION (FOR ALL CASES)



### 6.3.3 Hydraulic Energy Production

Figure 6-3 shows the annual hydraulic energy production. The hydraulic development program, and the energy production it contributes, is the same for all five Cases and load forecast paths.

Annual energy production from hydraulic generation grows steadily from 36 TW.h in 1989 to about 41 TW.h per year by 2014. Under all load conditions, Ontario Hydro's operating strategy is to maximize the use of this renewable resource.

### 6.3.4 Nuclear Energy Production

Figures 6-4(a) through 6-4(e) show the annual nuclear production for the five Cases under all five load paths.

The variation between Cases under each load path is mostly due to the in-service dates for new nuclear facilities. Since nuclear stations are operated as often as possible under any load condition, all Cases have the same amount of nuclear energy production up until 1999, when Case 23 is the first to have a new nuclear facility placed in-service.

Nuclear energy production under the five load forecast paths exhibits similar patterns, but the quantity of energy produced differs. From 1989 to 1996, energy production rises as Darlington comes into service and existing nuclear units, unavailable during retubing, are returned to service.

The dips in energy production are a result of retubing one or two generating units at times and retirement of Pickering GS A units beginning in 2011. In some instances, the effects of retubing and retirements are masked by new nuclear generation coming into service.

Median Load Forecast

Under median load forecast, Cases 15, 22 and 23 produce about 140 to 160 TW.h of nuclear energy per year by 2014. Case 24 has a conventional steam cycle coal station coming into service from 2009. Nuclear production in Case 24 is therefore lower than in the other three Cases, reaching about 120 TW.h per year by 2014. Case 26 has no new nuclear generation added. Nuclear energy production gradually falls from about 100 TW.h per year in 2007 to present day levels of about 80 TW.h per year by 2014, mostly because of retirements of Pickering GS A units.

FIGURE 6-3
HYDRAULIC ENERGY PRODUCTION
(FOR ALL CASES & LOAD FORECASTS)

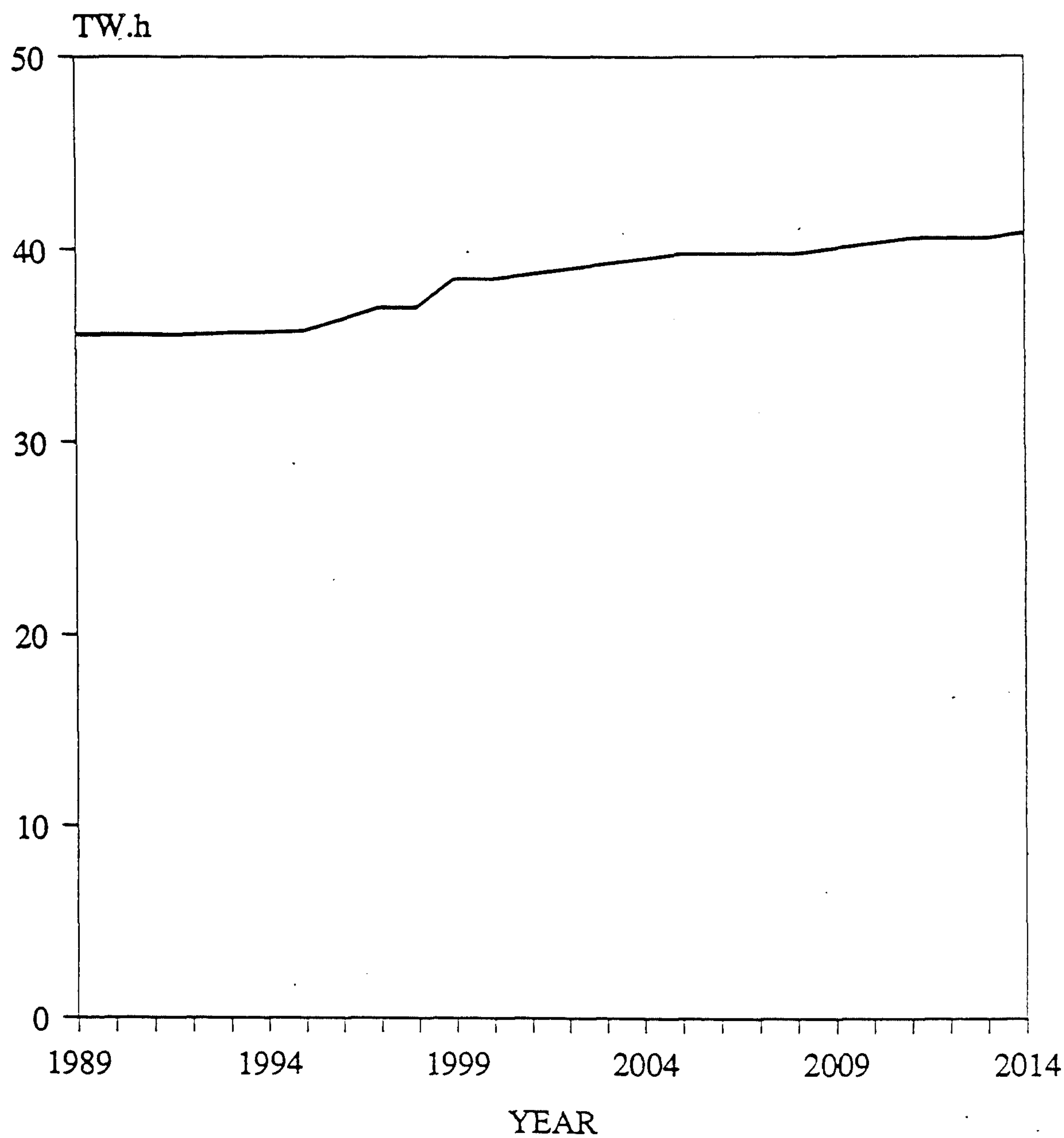


FIGURE 6-4(a)

NUCLEAR ENERGY PRODUCTION
(LOWER LOAD FORECAST)

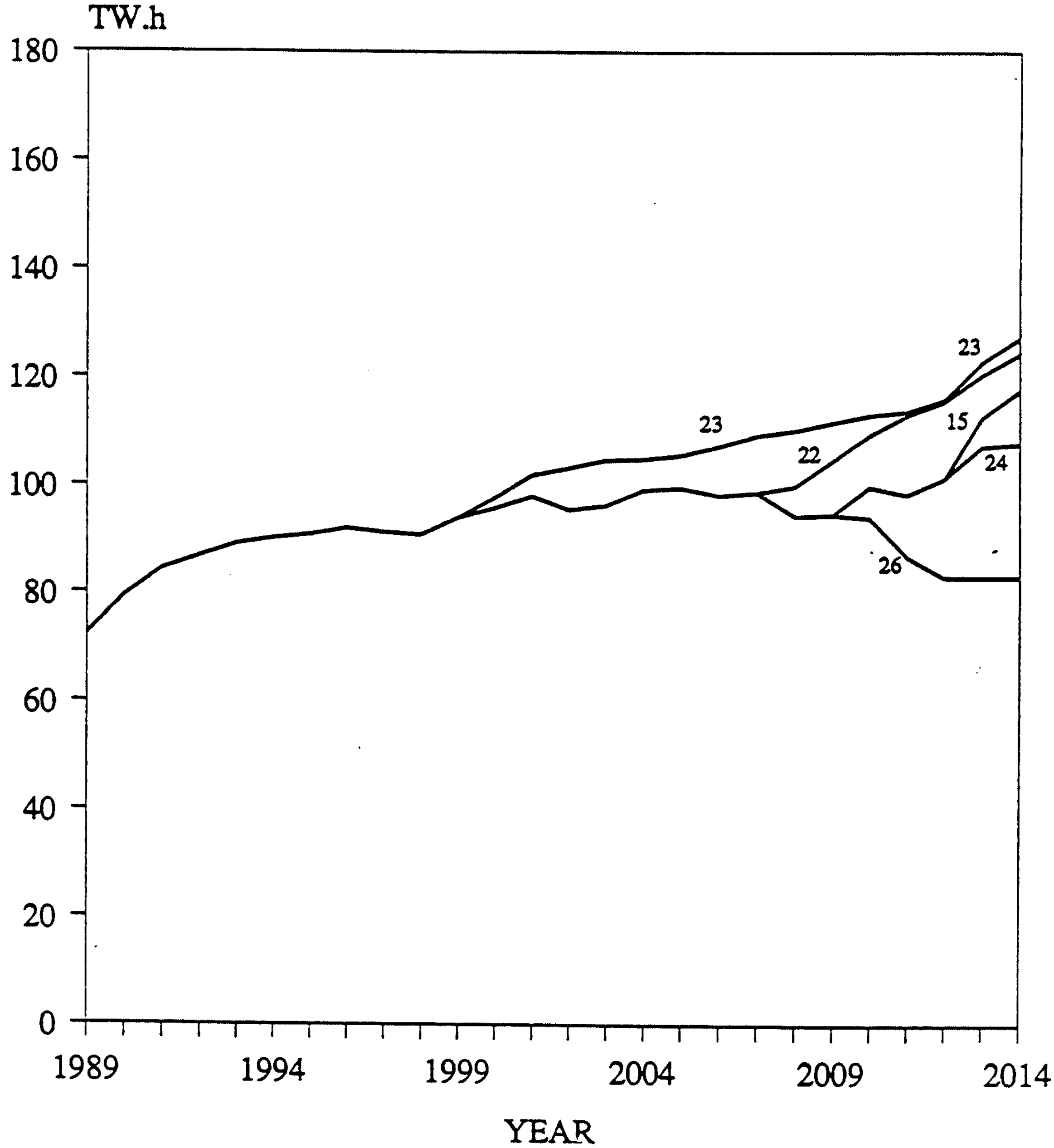


FIGURE 6-4(b)
NUCLEAR ENERGY PRODUCTION
(BRANCH LOWER LOAD FORECAST)

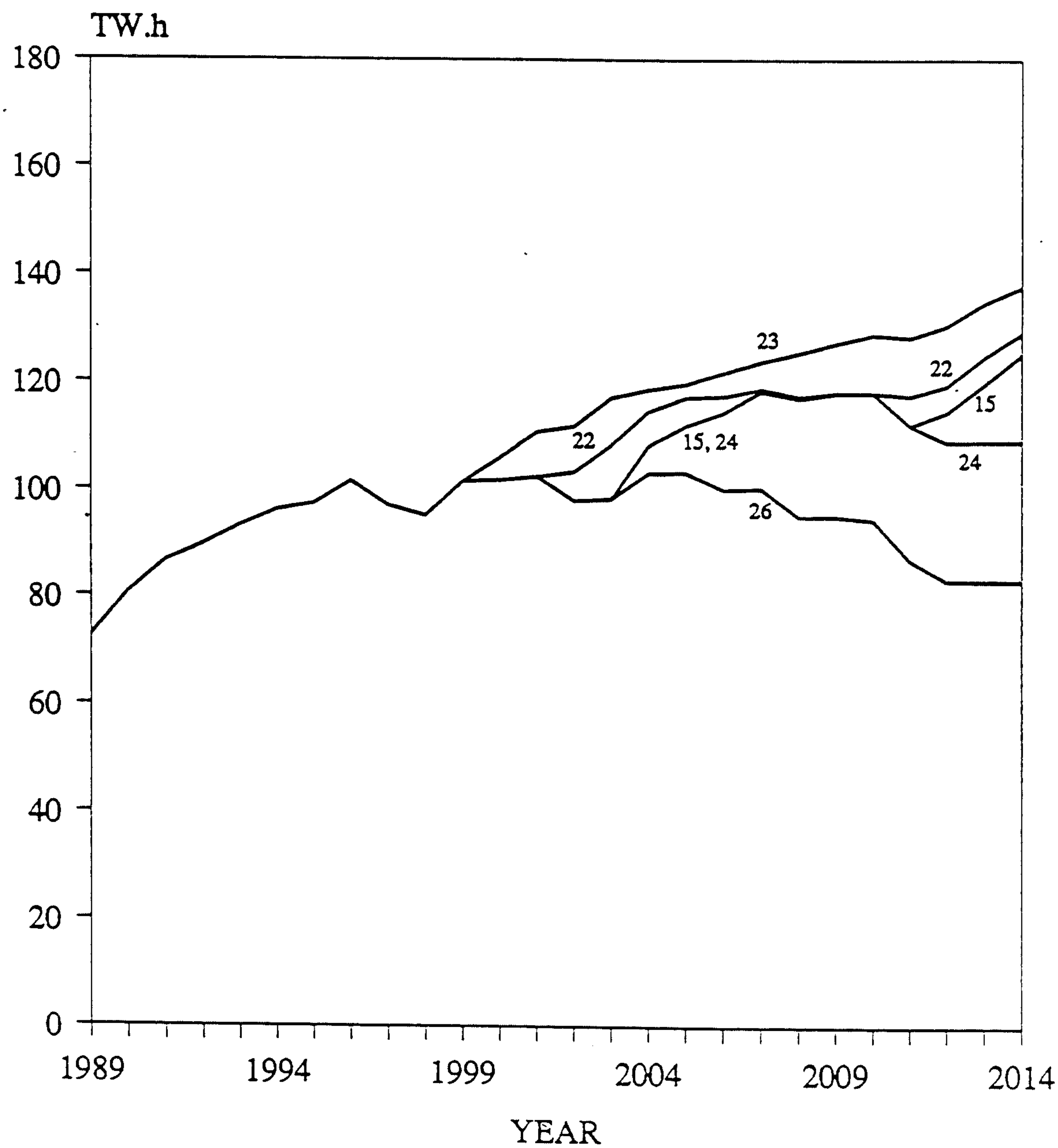


FIGURE 6-4(c)
NUCLEAR ENERGY PRODUCTION
(MEDIAN LOAD FORECAST)

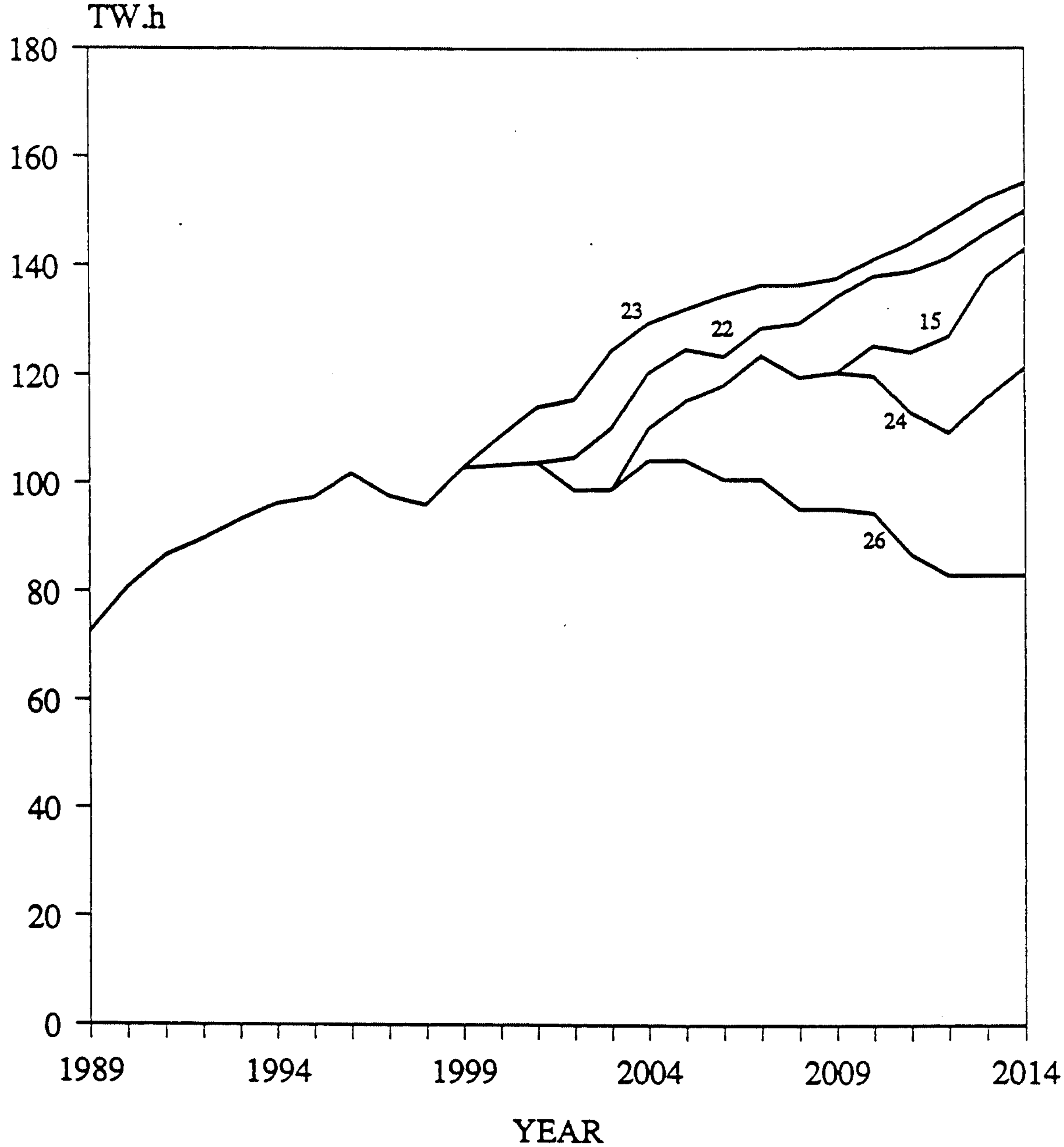


FIGURE 6-4(d)
NUCLEAR ENERGY PRODUCTION
(BRANCH UPPER LOAD FORECAST)

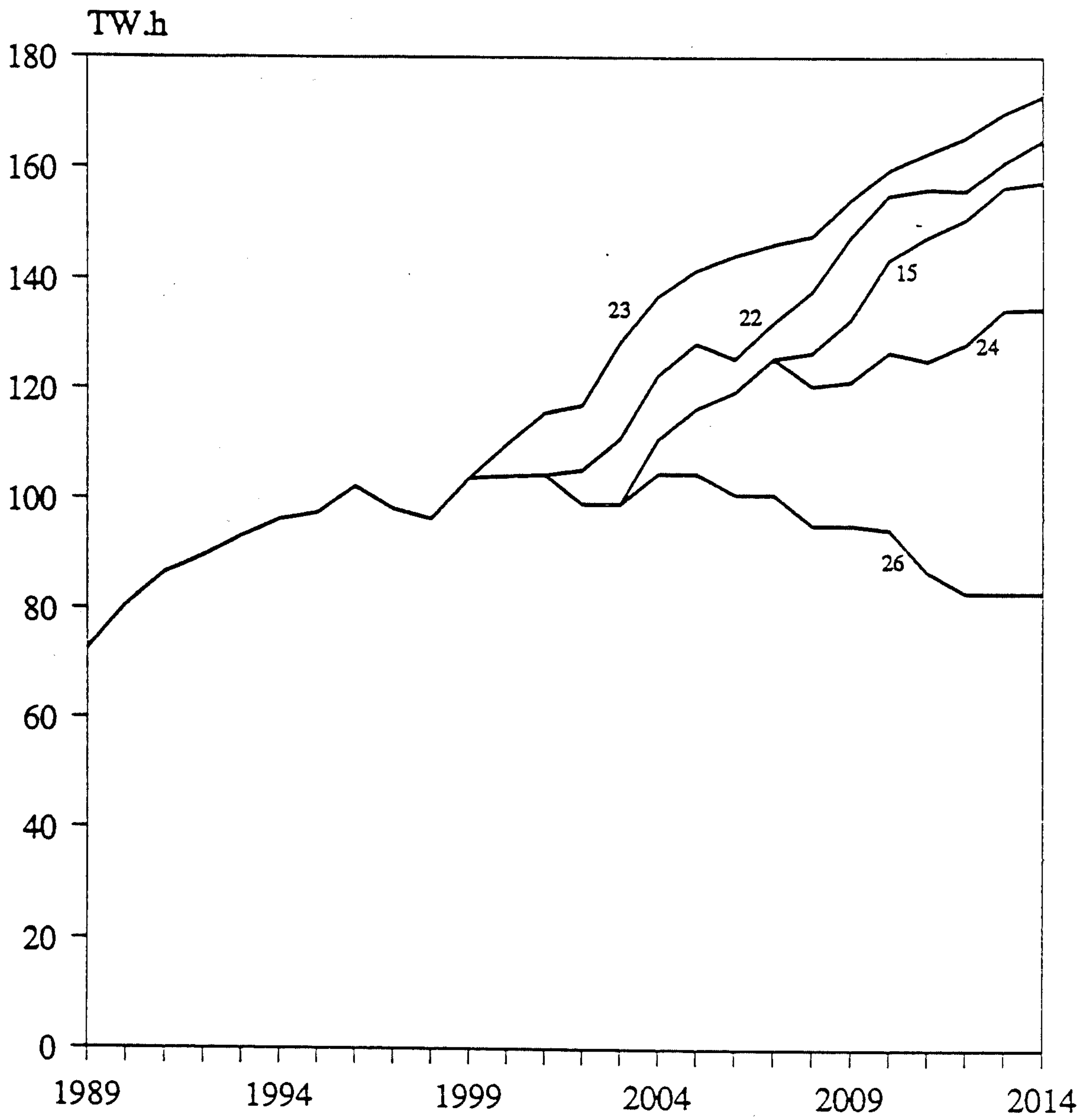
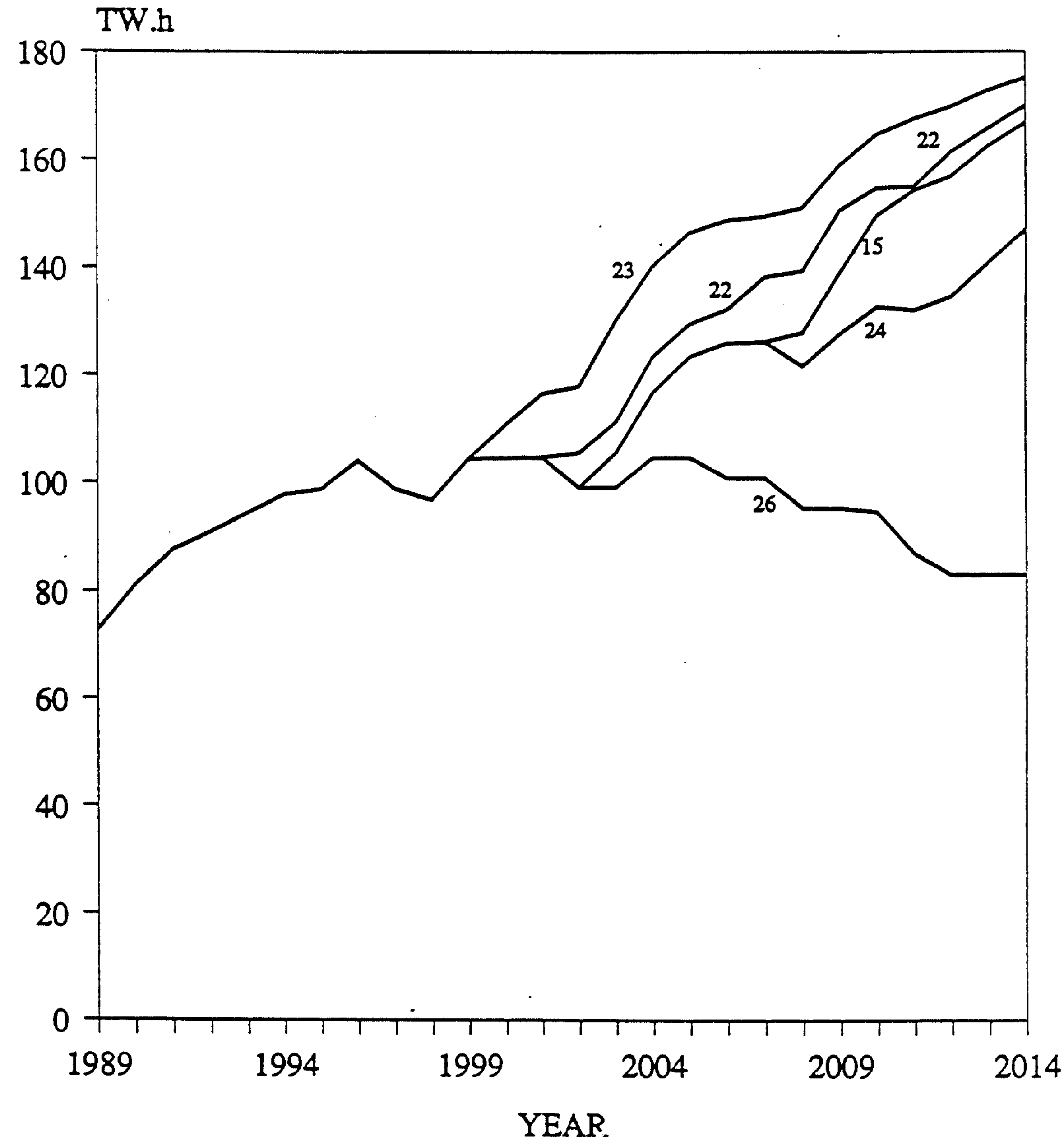


FIGURE 6-4(e)

NUCLEAR ENERGY PRODUCTION
(UPPER LOAD FORECAST)



Lower Load Forecast

Under lower load forecast, nuclear energy production rises as Darlington comes into service. Compared to other load paths, there are fewer dips in energy production because nuclear capability is not quite fully utilized in the 1990s, which masks the unavailability of units out of service for retubing.

By 2014, Cases 15, 22 and 23 produce about 120 TW.h of nuclear energy per year. Case 24 lags by 10 TW.h, reaching about 110 TW.h per year by 2014. Case 26 is the same as under the median load forecast, producing about 80 TW.h per year by 2014.

Branch Lower Load Forecast

Under branch lower load forecast, Cases 15, 22 and 23 produce about 130 TW.h of nuclear energy per year by 2014. In Case 24, energy production is 20 TW.h lower at about 110 TW.h per year. Case 26 produces the same 80 TW.h of nuclear energy per year by 2014.

Branch Upper Load Forecast

Under branch upper load forecast, Cases 15, 22 and 23 produce about 160 TW.h of nuclear energy per year by 2014. Energy production in Case 24 rises to about 130 TW.h per year and Case 26 produces the same 80 TW.h of nuclear energy per year by 2014.

Upper Load Forecast

Under upper load forecast, Cases 15, 22 and 23 produce about 170 TW.h of nuclear energy per year by 2014. Case 24 reaches about 150 TW.h per year by 2014. Case 26 remains the same as under other load forecasts, generating about 80 TW.h of nuclear energy per year by 2014.

### 6.3.5 Fossil Energy Production

Fossil energy is derived from a number of fuels: US bituminous coal, Western Canadian bituminous and lignite coal, natural gas and oil. In this section, the total fossil fuel consumption is shown. Later, in the discussion of acid gas control measures in Chapter 7, the breakdown of fossil fuel use is presented.

Fossil energy production varies more widely than the other supply options. This is because fossil generation is generally used to meet demands after contracted utility and non-utility purchases, hydraulic and nuclear generation are fully utilized. Figures 6-5(a) through 6-5(e) illustrate the annual fossil energy production for the five Cases under the five load paths.

Primarily, fossil energy production fluctuates with nuclear production -- rising during nuclear retubing, falling when nuclear comes into service. The variation in fossil energy production between Cases is due to the timing and type of supply additions. The pattern of the variation between Cases is generally similar across all load paths. The main difference under different load forecasts is the level of energy production.

Median Load Forecast

Under median load forecast, fossil energy production in all five Cases starts at about 28 TW.h per year in 1989, then drops to the 20 TW.h per year level as Darlington comes into service in the early 1990s. During the late 1990s, annual fossil energy production ranges from 16 TW.h to 26 TW.h. After 1999, the five Cases begin to exhibit different fossil production.

Case 26 has the highest fossil energy production, increasing steadily from a low of about 19 TW.h per year in 1999 to about 73 TW.h per year by 2014.

Cases 15 and 24 show similar fossil production up to 2009. Fossil energy production rises from about 19 TW.h per year in 1999 to about 34 TW.h per year by 2003. The new nuclear station coming into service in 2003 reduces fossil energy production to about 23 TW.h per year by 2009. After 2009, the two Cases diverge in their fossil production. In Case 15, a second nuclear station is added and fossil energy production falls to about 13 TW.h per year by 2014. Case 24 has a new conventional steam cycle coal station coming into service in 2009. Fossil energy production peaks at about 41 TW.h per year in 2012, then dips to 35 TW.h per year by 2014 as the second nuclear station is added.

In Case 22, fossil energy production increases from about 19 TW.h per year in 1999 to a peak of about 27 TW.h per year in 2002. As new nuclear facilities are added, fossil energy production falls to about 6 TW.h per year by 2014.

Case 23 has the lowest amount of fossil generation. The two new nuclear stations starting in 1999 and in 2002 reduce fossil production in the 2000s. Fossil energy production declines steadily from about 19 TW.h per year in 1999 to less than 1 TW.h per year by 2014.

FIGURE 6-5(a)

# FOSSIL ENERGY PRODUCTION (LOWER LOAD FORECAST)

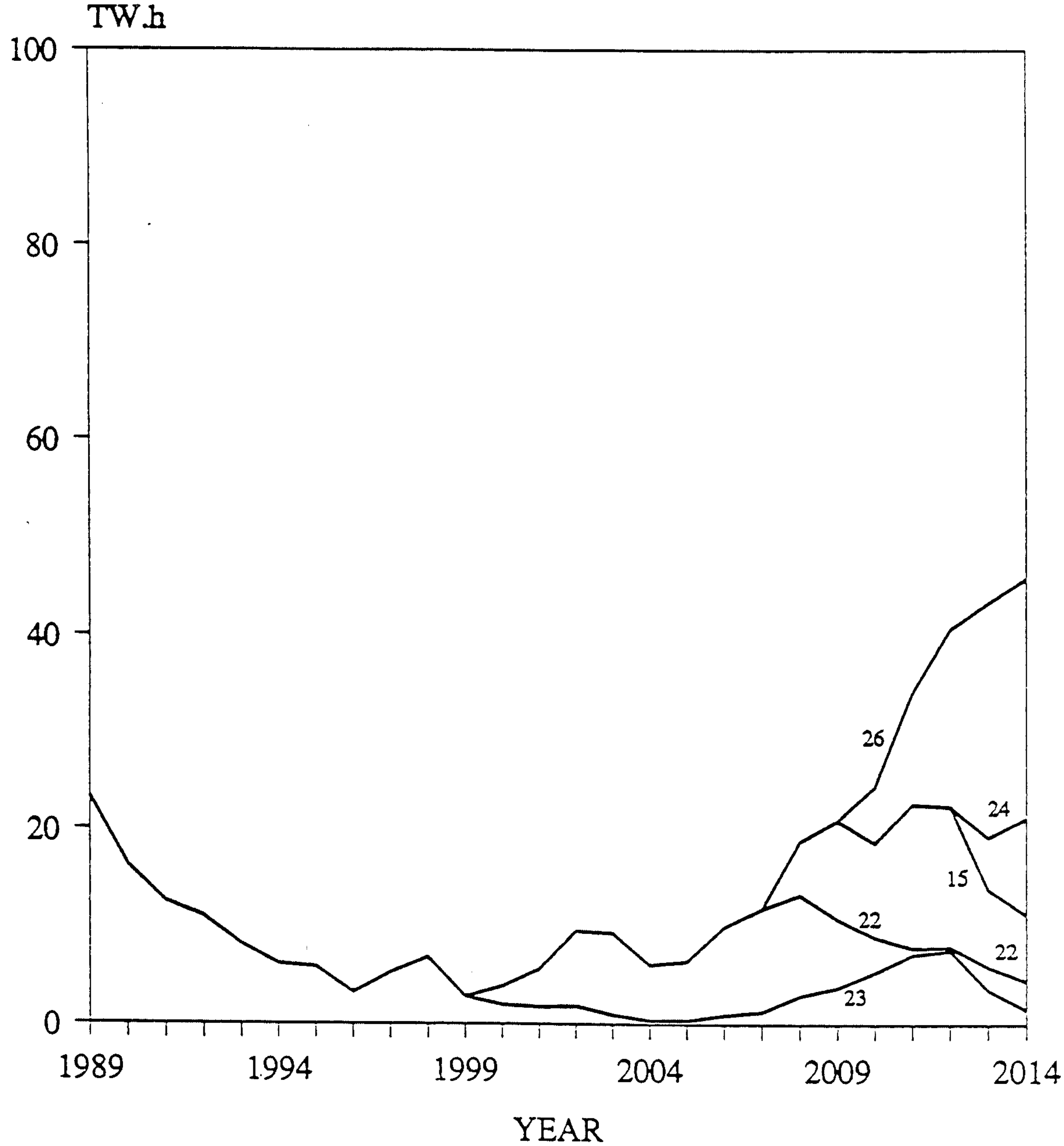


FIGURE 6-5(b)

# FOSSIL ENERGY PRODUCTION (BRANCH LOWER LOAD FORECAST)

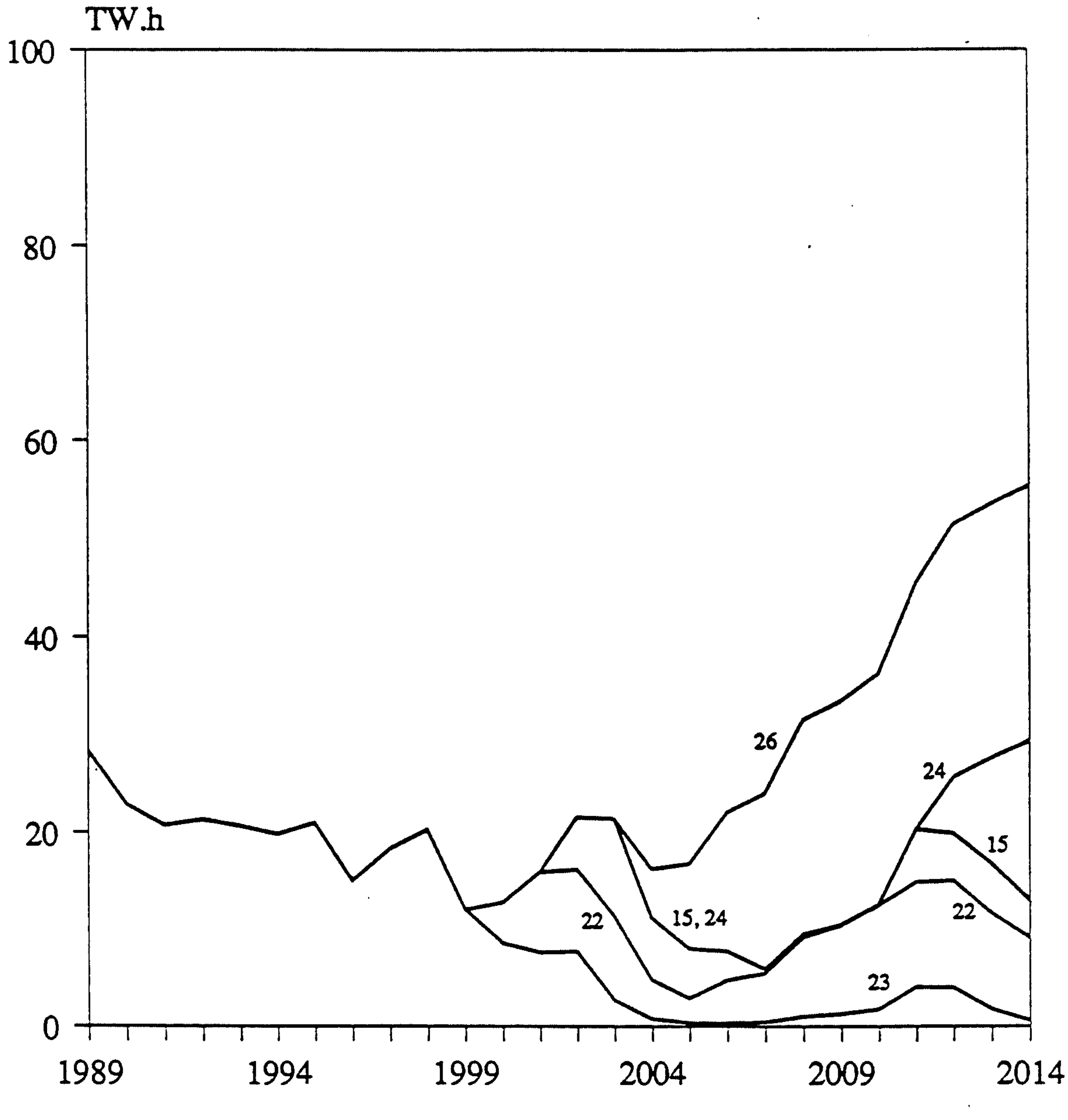


FIGURE 6-5(c)

FOSSIL ENERGY PRODUCTION
(MEDIAN LOAD FORECAST)

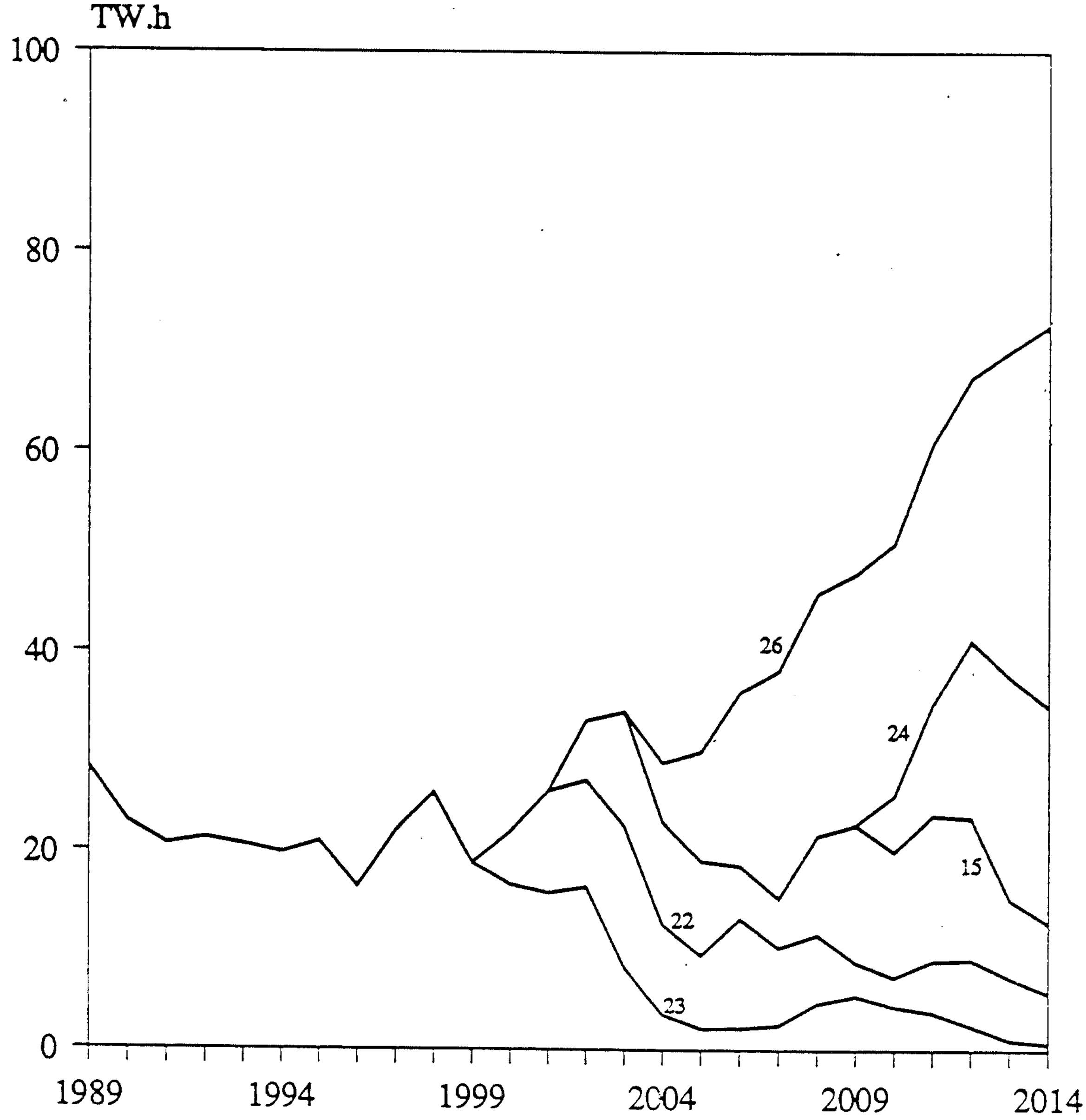


FIGURE 6-5(d)

# FOSSIL ENERGY PRODUCTION
# (BRANCH UPPER LOAD FORECAST)

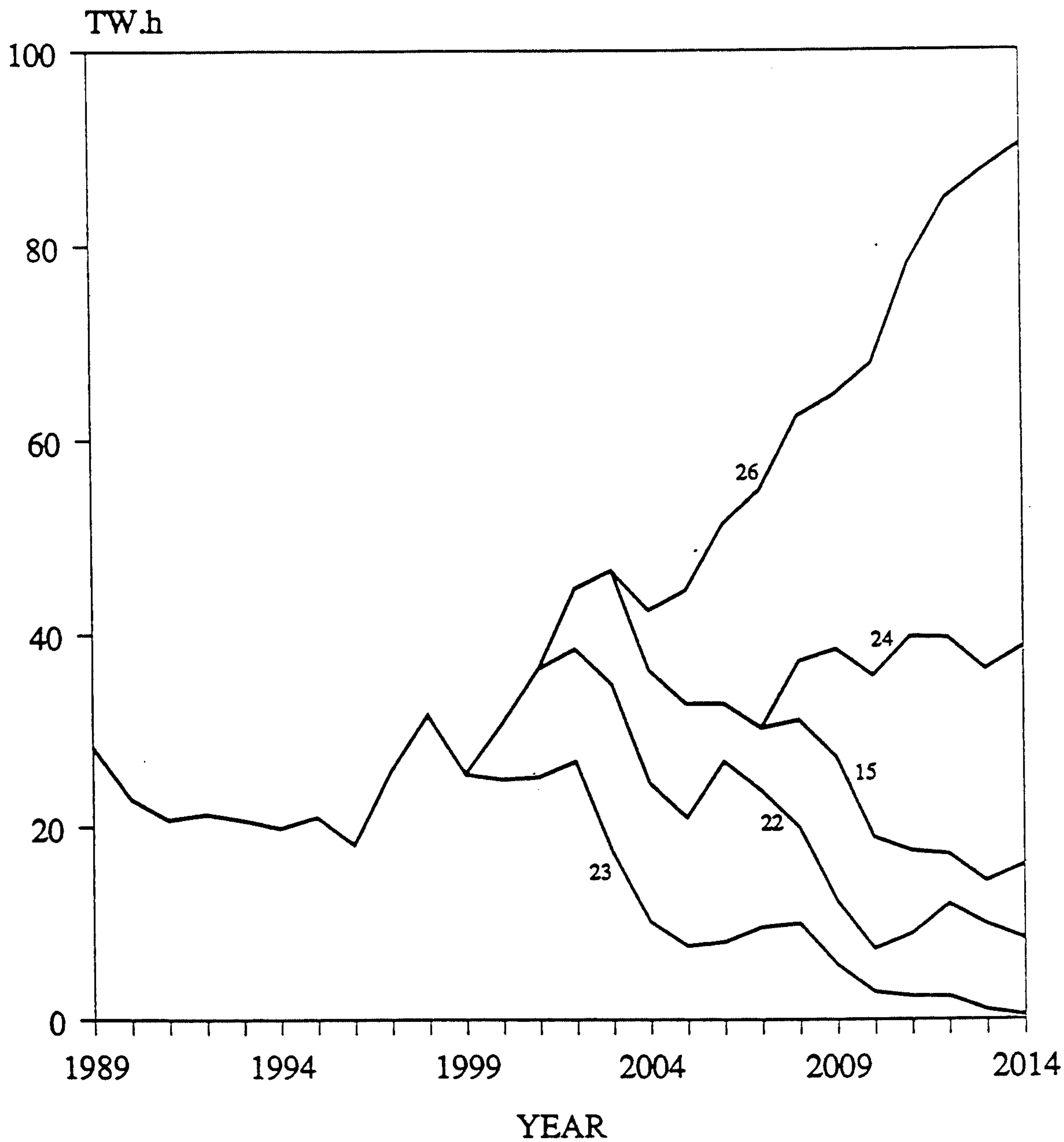
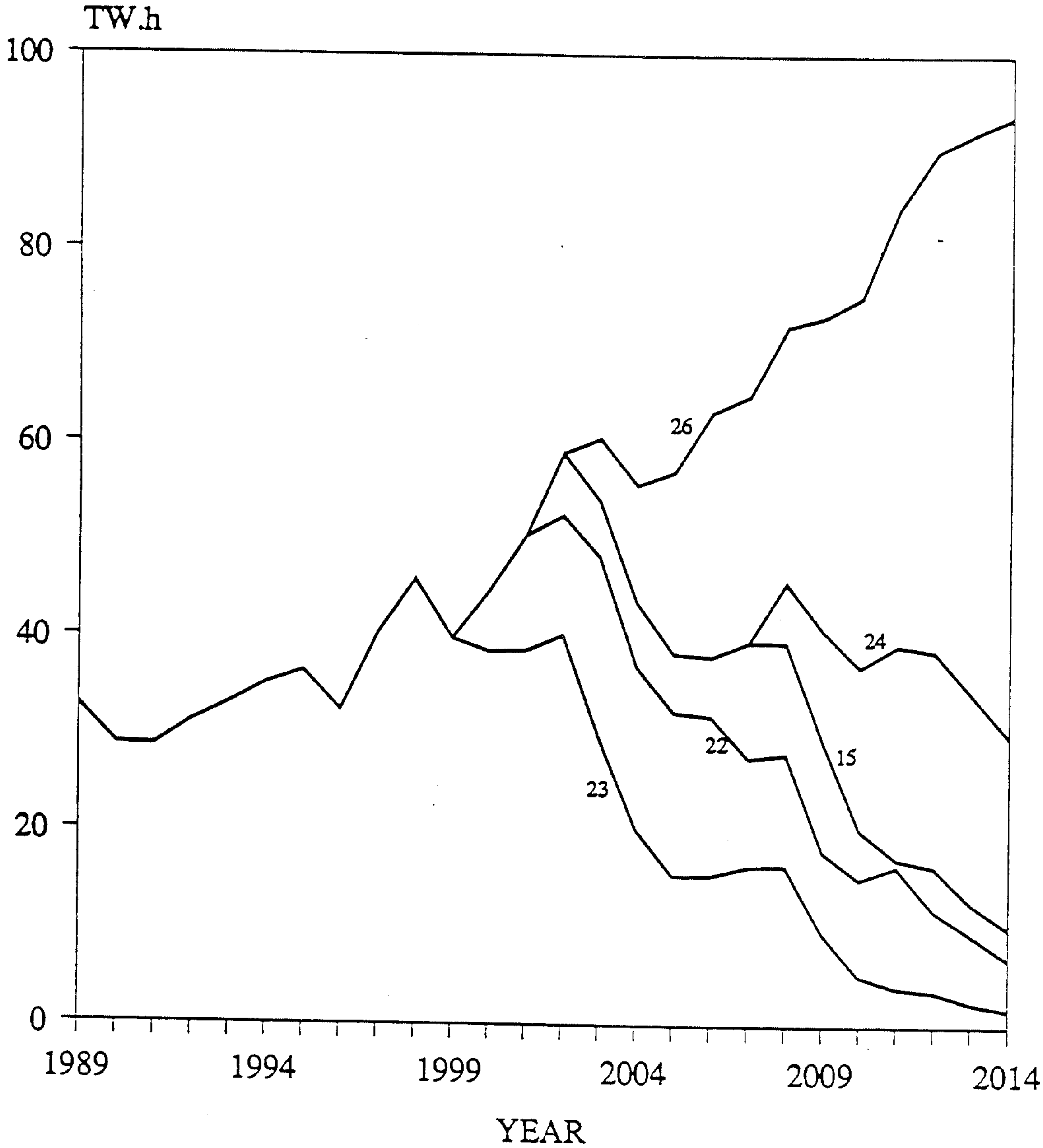


FIGURE 6-5(e)
FOSSIL ENERGY PRODUCTION
(UPPER LOAD FORECAST)



Lower Load Forecast

Under lower load forecast, fossil energy production in all five Cases starts at about 23 TW.h per year, then gradually declines to about 3 TW.h per year by 1999.

In Cases 15, 24 and 26, fossil energy production rises from about 3 TW.h in 1999 to about 21 TW.h per year by 2009. Thereafter, with the addition of major fossil generation to meet load growth and retirement needs, fossil energy production in Case 26 continues to rise to about 46 TW.h per year by 2014. In Case 24, fossil energy production is held at the 21 TW.h per year level to 2014 by the addition of new nuclear facilities. In Case 15, fossil energy production peaks at about 23 TW.h per year in 2011, then declines to about 11 TW.h per year by 2014.

In Case 22, fossil energy production increases from about 3 TW.h per year in 1999 to a peak of about 13 TW.h per year in 2008. Thereafter, new nuclear facilities are added and fossil energy production decreases to about 4 TW.h per year by 2014.

In Case 23, new nuclear facilities are added to meet load growth and retirement needs. The first new nuclear station starts in 1999, the second station in 2009 and the third station in 2011. Fossil energy production falls from about 3 TW.h per year in 1999 to a low of about 0.4 TW.h in 2004. Thereafter, fossil energy production rises gradually to about 8 TW.h per year by 2012, then falls to under 2 TW.h per year by 2014.

Branch Lower Load Forecast

Under branch lower load forecast, fossil energy production in all five Cases starts at about 28 TW.h per year and declines to about 12 TW.h per year by 1999.

In Cases 15, 24 and 26, fossil energy production rises from the low of 12 TW.h in 1999 to about 21 TW.h per year by 2003. Thereafter, fossil energy production in Case 26 rises to about 55 TW.h per year by 2014. In Cases 15 and 24, fossil energy production drops to a low of about 6 TW.h per year in 2007. Case 24 then rises to produce about 29 TW.h of fossil energy per year by 2014, while Case 15 produces about 13 TW.h per year.

In Case 22, fossil energy production falls to a low of 3 TW.h per year in 2005, and reaches about 9 TW.h per year by 2014.

In Case 23, fossil energy production declines steadily from about 12 TW.h per year in 1999 to under 1 TW.h per year by 2014.

Branch Upper Load Forecast

Under branch upper load forecast, fossil energy production also starts at about 28 TW.h per year, declines to about 18 TW.h per year by 1996, then rises to about 25 TW.h per year by 1999.

Thereafter, fossil energy production in Case 26 rises steadily, reaching over 90 TW.h per year by 2014.

In Cases 15 and 24, fossil energy production rises to a peak of 47 TW.h per year in 2003. In Case 24, fossil energy production is held steady at the 30 TW.h to 40 TW.h range, ending at about 39 TW.h per year by 2014. In Case 15, fossil energy production gradually declines to about 16 TW.h by 2014.

In Case 22, fossil energy production rises from about 25 TW.h per year in 1999 to a peak of about 38 TW.h per year in 2002, then declines to about 8 TW.h per year by 2014.

In Case 23, fossil energy production declines steadily from 25 TW.h per year in 1999 to under 1 TW.h per year by 2014.

Upper Load Forecast

Under upper load forecast, fossil energy production in all five Cases starts at about 33 TW.h per year. Fossil generation decreases for two years as the Darlington generating units are brought into service. After 1991, load growth needs dominate and fossil generation increases to about 40 TW.h per year by 1999. Thereafter, fossil energy production begins to differ among the Cases.

In Case 26, fossil energy production continues to rise from 40 TW.h per year in 1999 to about 94 TW.h per year by 2014, the highest level among all the Cases.

Fossil energy production in Cases 15 and 24 is the same as Case 26 up to 2002, when it peaks at about 59 TW.h per year. Fossil generation then declines as new nuclear facilities are brought into service between 2002 and 2014. By 2014, fossil energy production reaches about 10 TW.h per year in Case 15 and about 30 TW.h per year in Case 24.

In Case 22, fossil energy production rises from about 40 TW.h per year in 1999 to about 53 TW.h per year in 2002. Thereafter, as new nuclear generation is brought into service, fossil generation declines to about 7 TW.h per year by 2014.

In Case 23, fossil energy production decreases steadily from about 40 TW.h per year in 1999 to under 2 TW.h per year by 2014.

## 6.4 ENERGY DIVERSITY BY SOURCE AND FUEL

The portions of energy acquired from utility and non-utility purchases and hydraulic, nuclear and fossil generation are shown in Figures 6-6(a) through 6-10(e) for the five Cases under each of the five load forecast paths. The portions are expressed as a percentage of the total energy produced per year.

### 6.4.1 Common Features - Hydraulic, Non-utility Generation And Utility Purchases

There are several common features among the five Cases.

Non-utility generation purchases rise from a very small fraction of total energy in 1989 to about 5% of total energy by 2014. Non-utility generation purchases are just under 4% of total energy under the branch lower and lower load paths.

The 1000 MW Manitoba Purchase provides a small fraction of total energy production, contributing about 3% per year by 2014. Under the branch lower and lower load paths, utility purchases provide slightly under 4% of total energy.

Despite growth in the absolute quantity of hydraulic energy produced under each load path, there is not sufficient hydraulic potential to keep pace with the development of other options. Therefore, the portion of hydraulic energy production decreases with time. Hydraulic generation produces about 25% to 27% of energy needs in 1989, depending upon load forecast, and decreases to about 17% to 22% of total energy by 2014.

Together, utility and non-utility purchases and hydraulic production provide a reasonably level portion of energy across all Cases; about 27% under median load forecast, about 30% under branch lower and lower load forecasts, and about 25% under branch upper and upper load forecasts.

This leaves nuclear and fossil generation to make up the remaining portion of energy needs. The proportions of each option vary over time and between Cases.

FIGURE 6-6(a)

ENERGY DIVERSITY - CASE 23
(LOWER LOAD FORECAST)

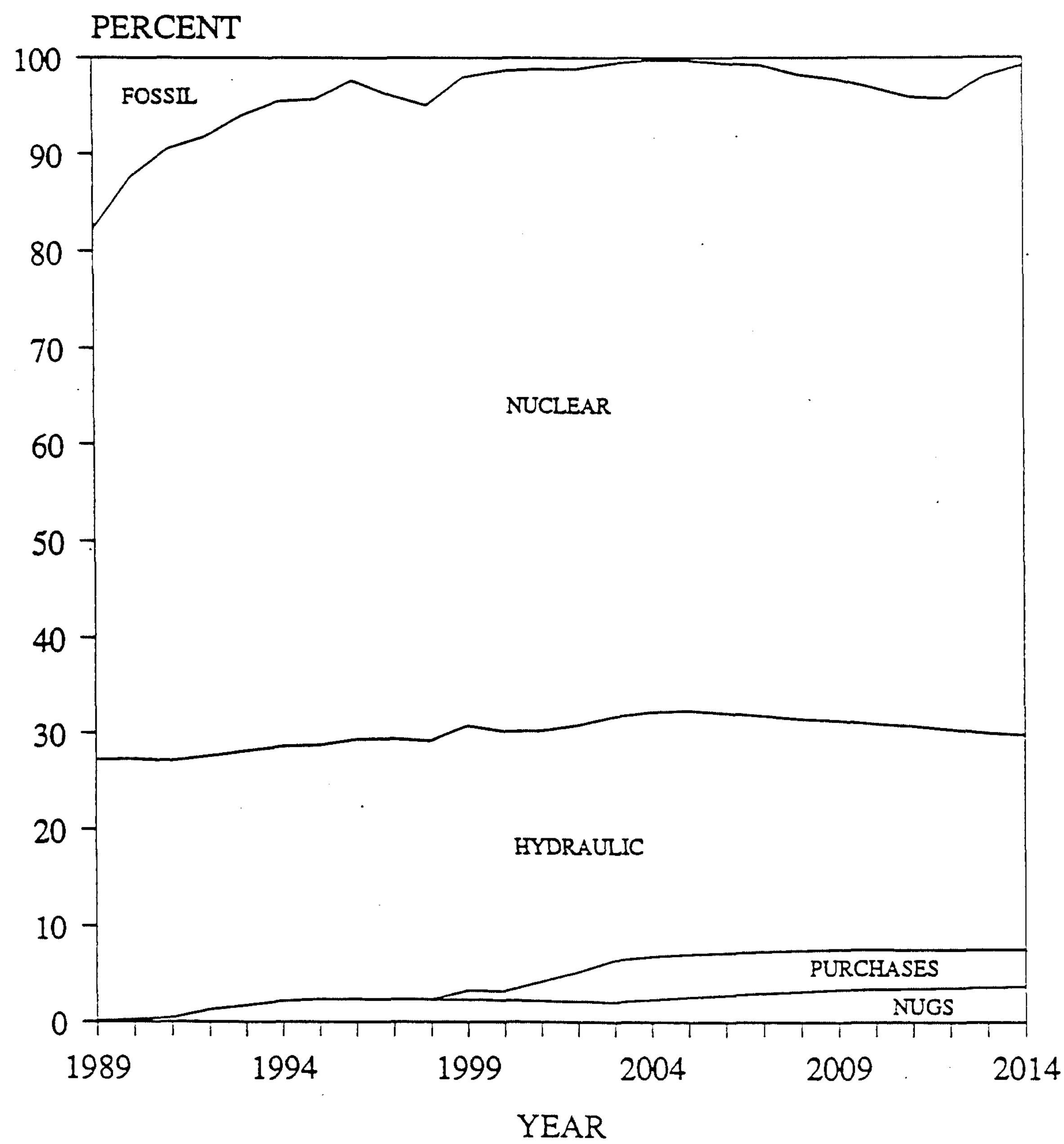


FIGURE 6-6(b)
# ENERGY DIVERSITY - CASE 23
# (BRANCH LOWER LOAD FORECAST)

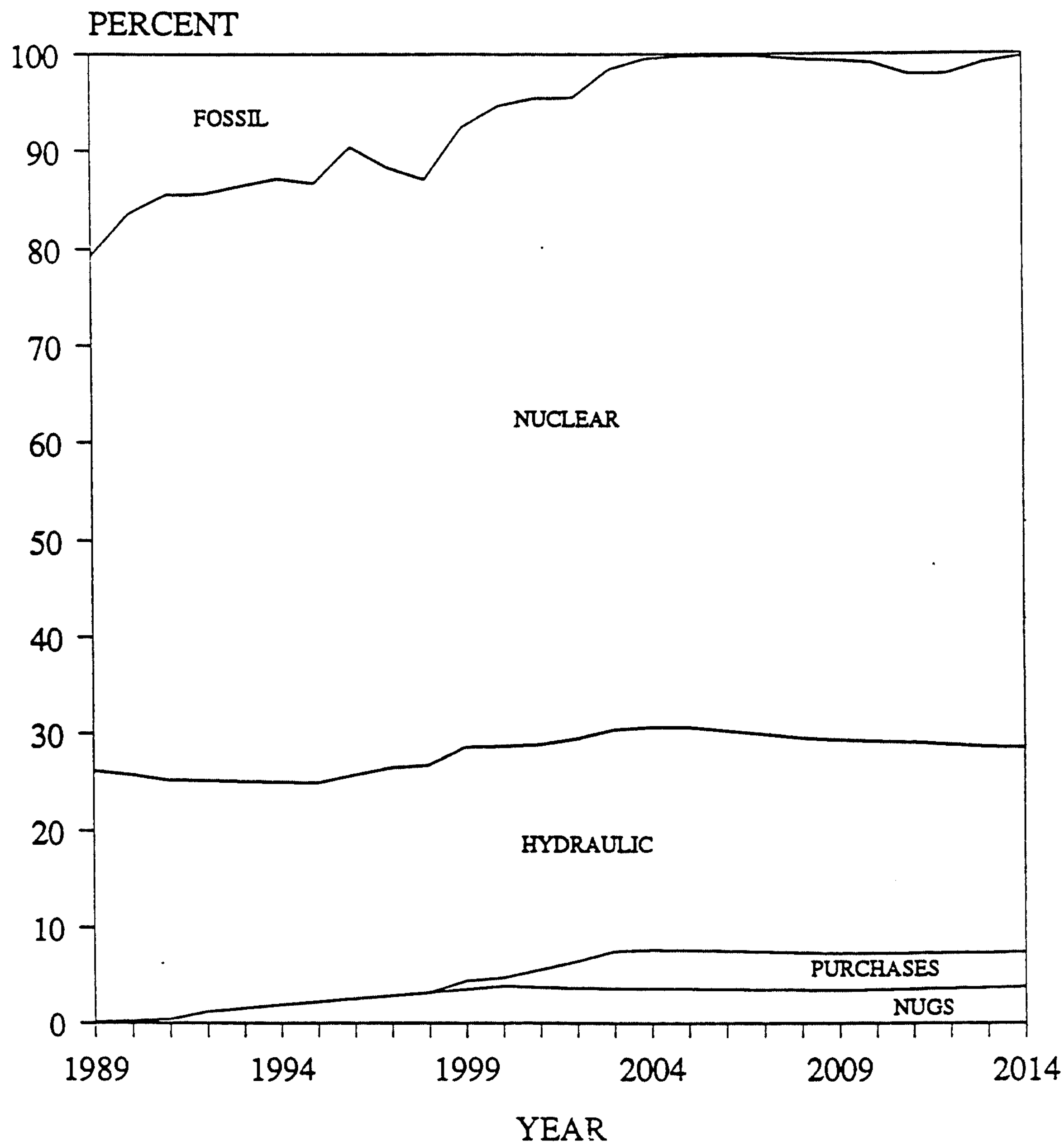


FIGURE 6-6(c)

ENERGY DIVERSITY - CASE 23
(MEDIAN LOAD FORECAST)

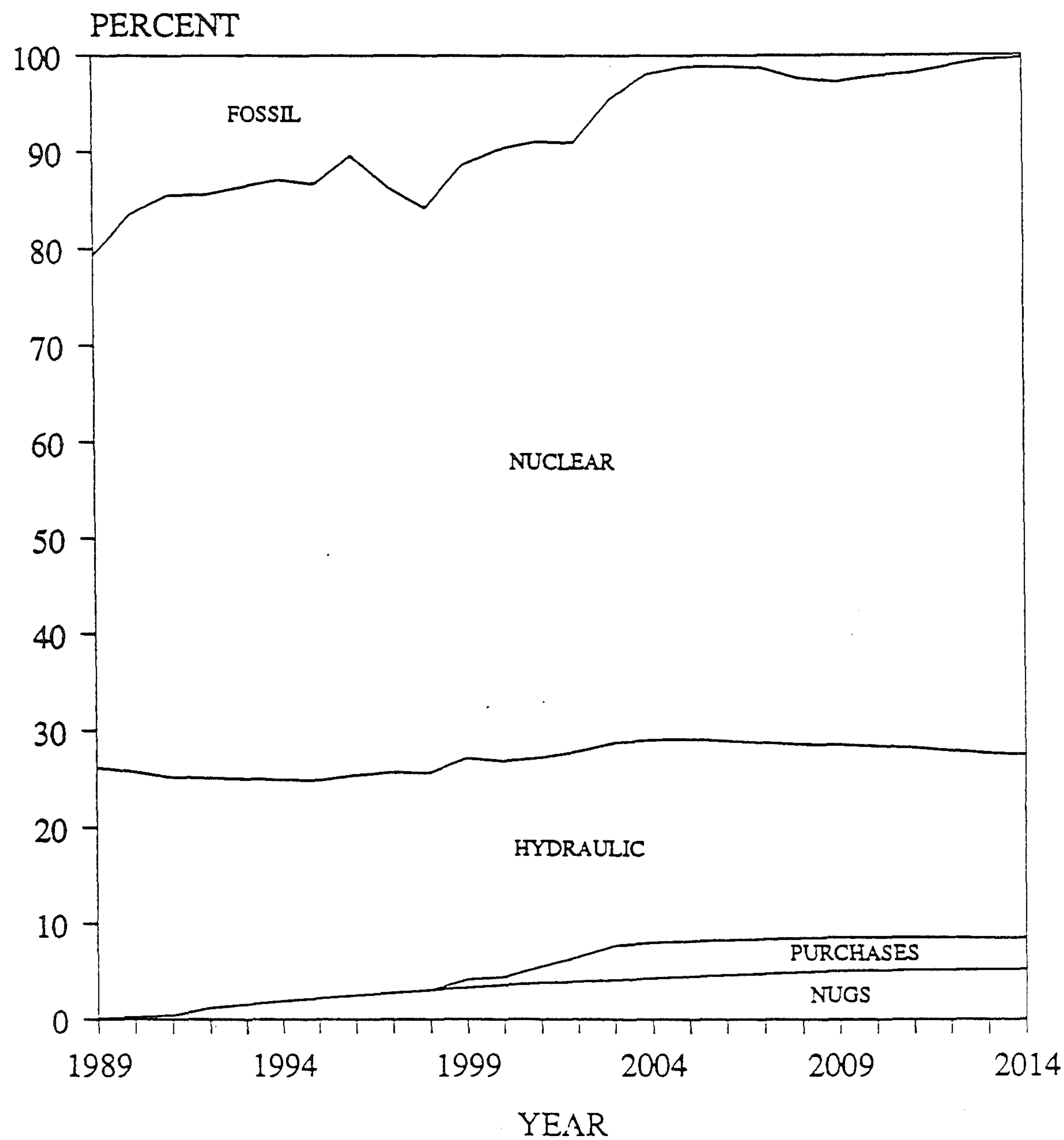


FIGURE 6-6(d)
ENERGY DIVERSITY - CASE 23
(BRANCH UPPER LOAD FORECAST)

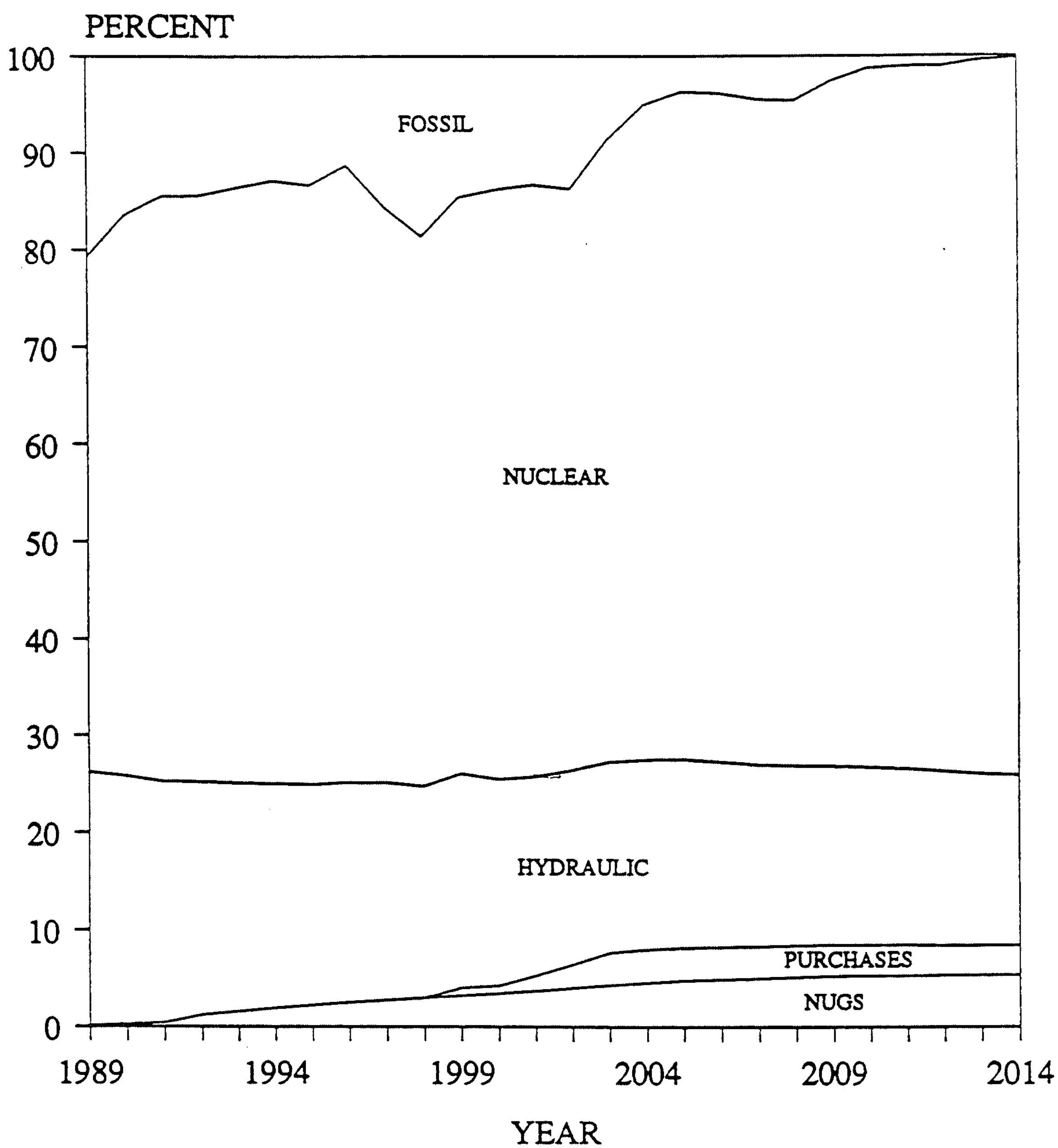


FIGURE 6-6(e)

ENERGY DIVERSITY - CASE 23

(UPPER LOAD FORECAST)

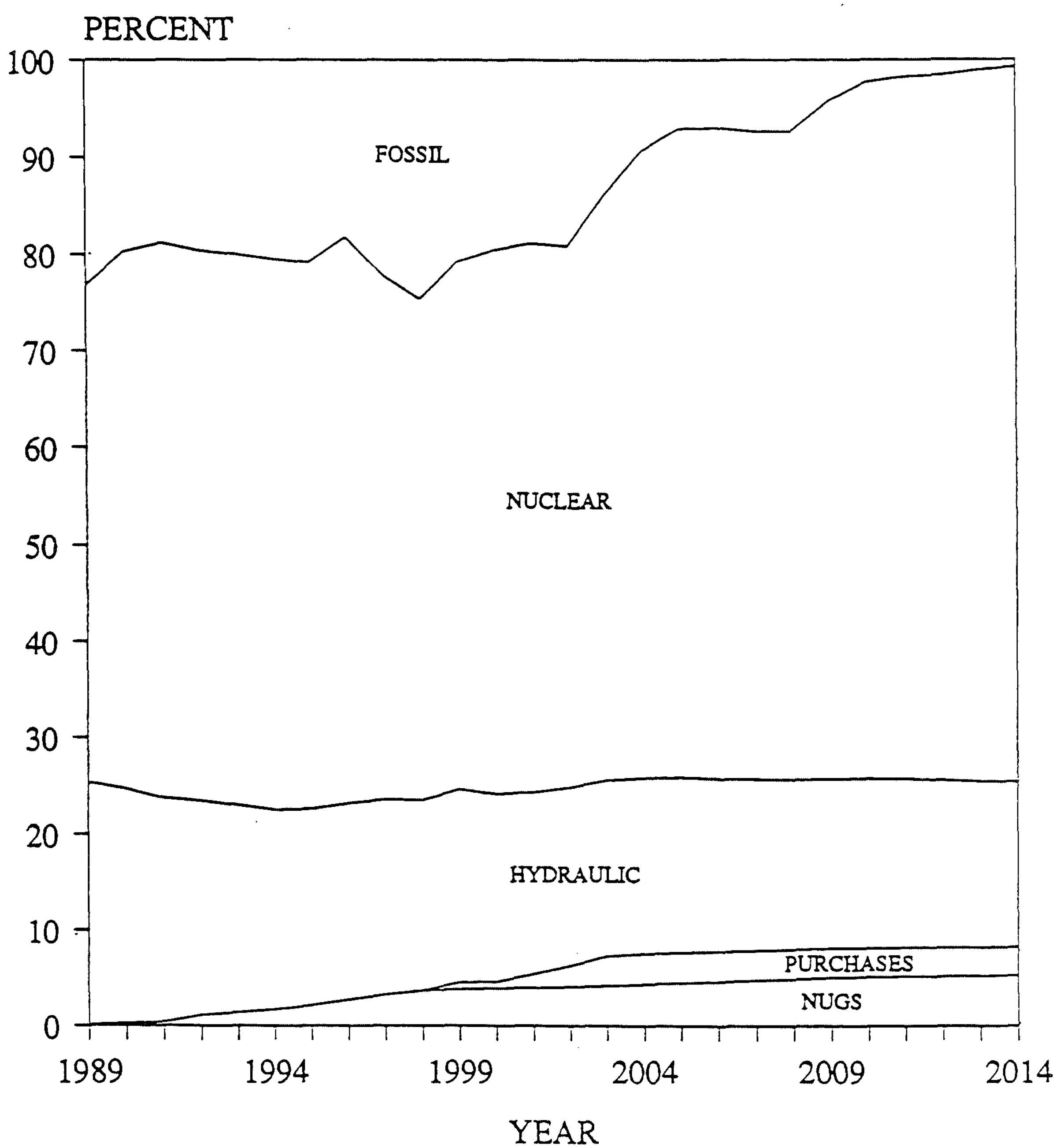


FIGURE 6-7(a)

# ENERGY DIVERSITY - CASE 22
# (LOWER LOAD FORECAST)

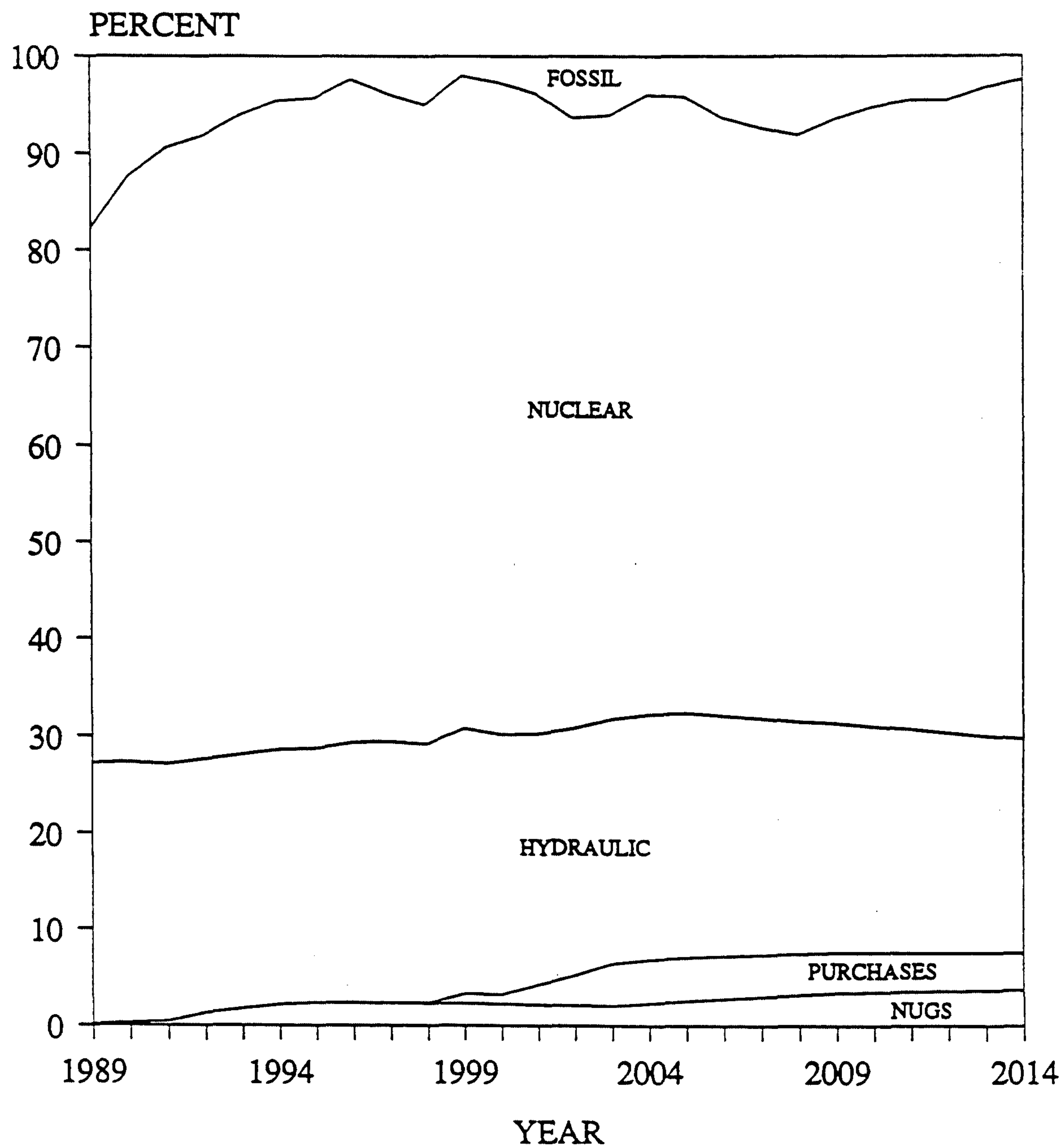


FIGURE 6-7(b)
## ENERGY DIVERSITY - CASE 22 (BRANCH LOWER LOAD FORECAST)

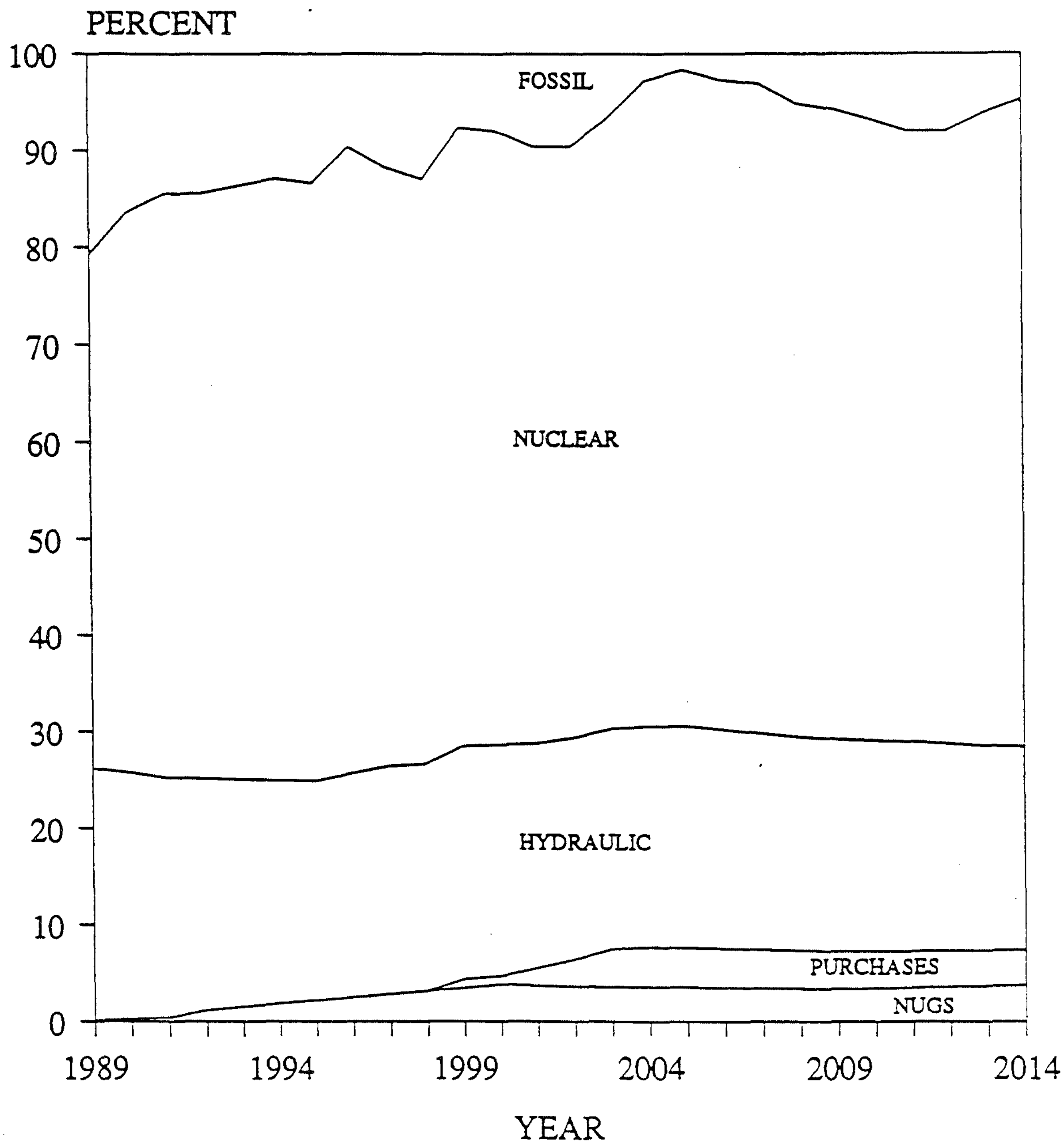


FIGURE 6-7(c)
ENERGY DIVERSITY - CASE 22
(MEDIAN LOAD FORECAST)

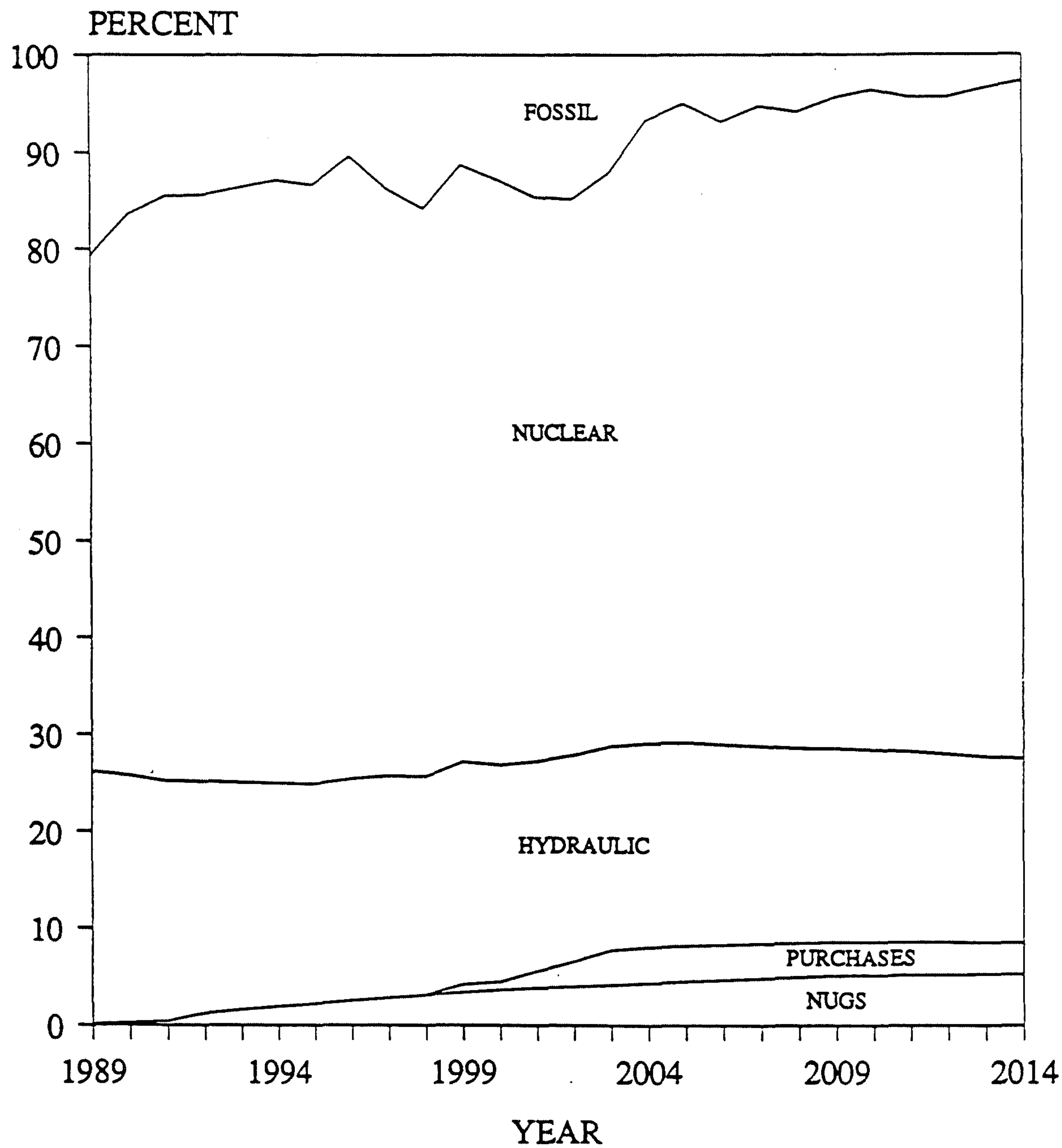


FIGURE 6-7(d)

ENERGY DIVERSITY - CASE 22
(BRANCH UPPER LOAD FORECAST)

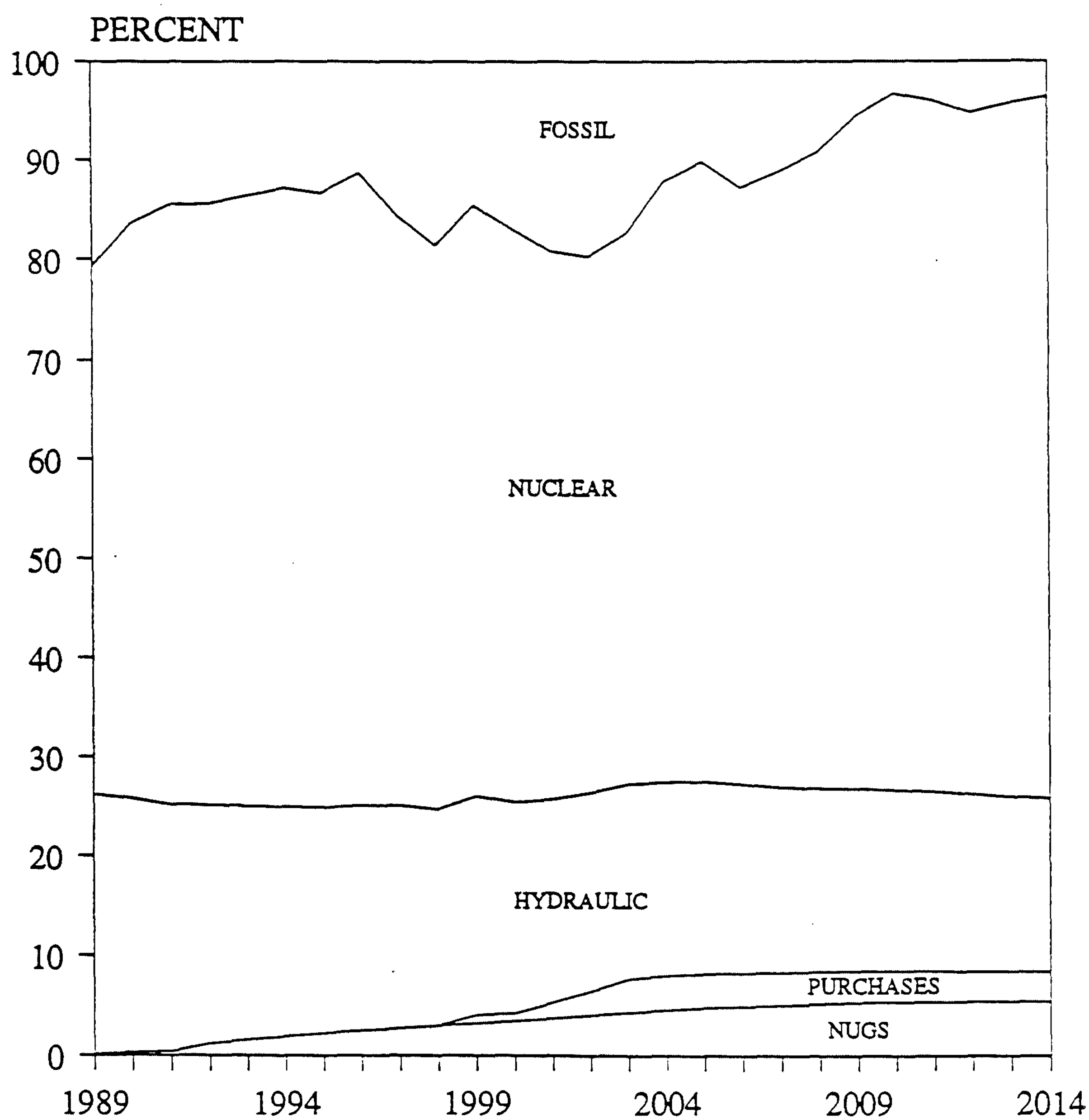


FIGURE 6-7(e)

ENERGY DIVERSITY - CASE 22

(UPPER LOAD FORECAST)

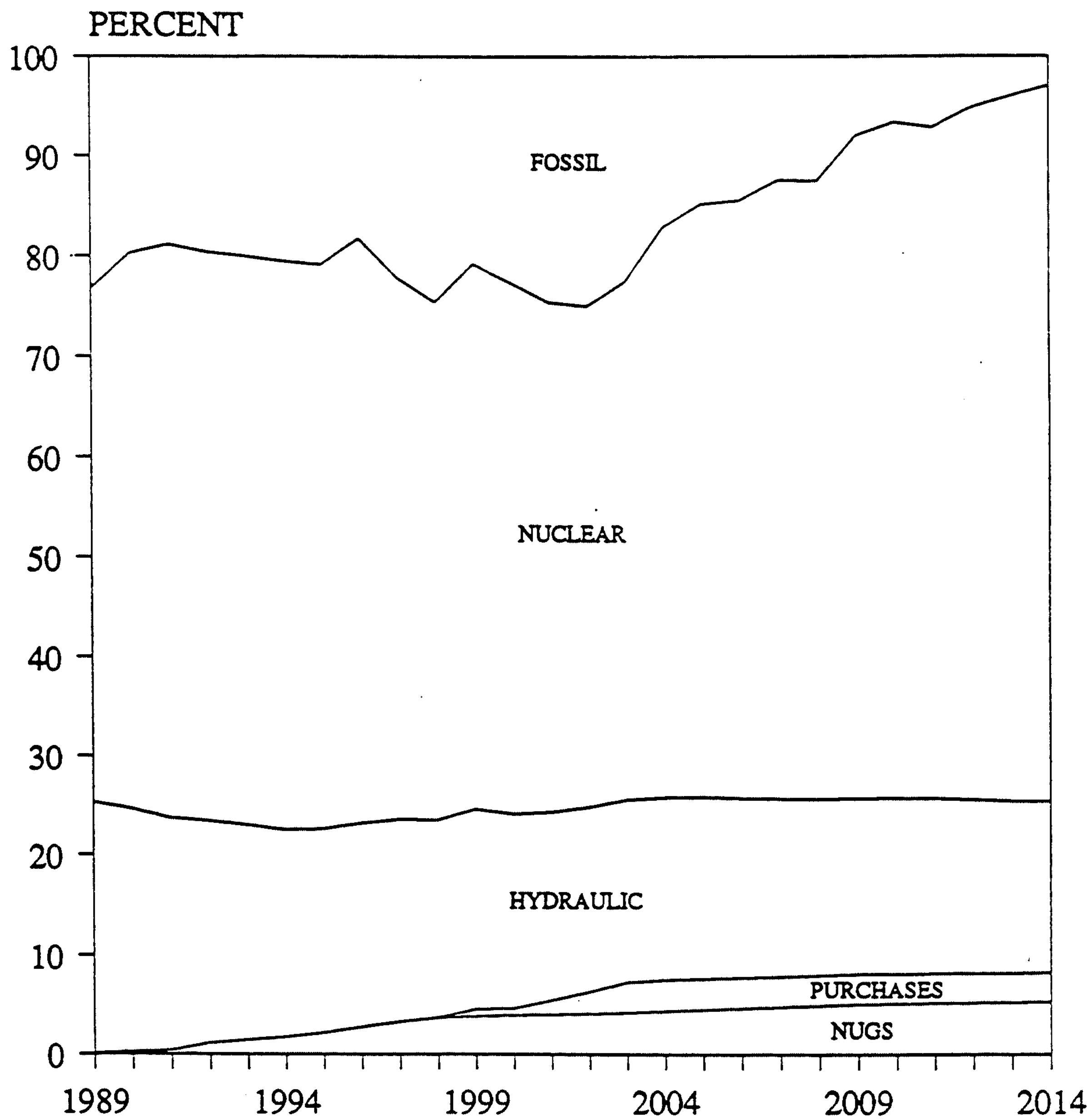


FIGURE 6-8(a)

ENERGY DIVERSITY - CASE 15
(LOWER LOAD FORECAST)

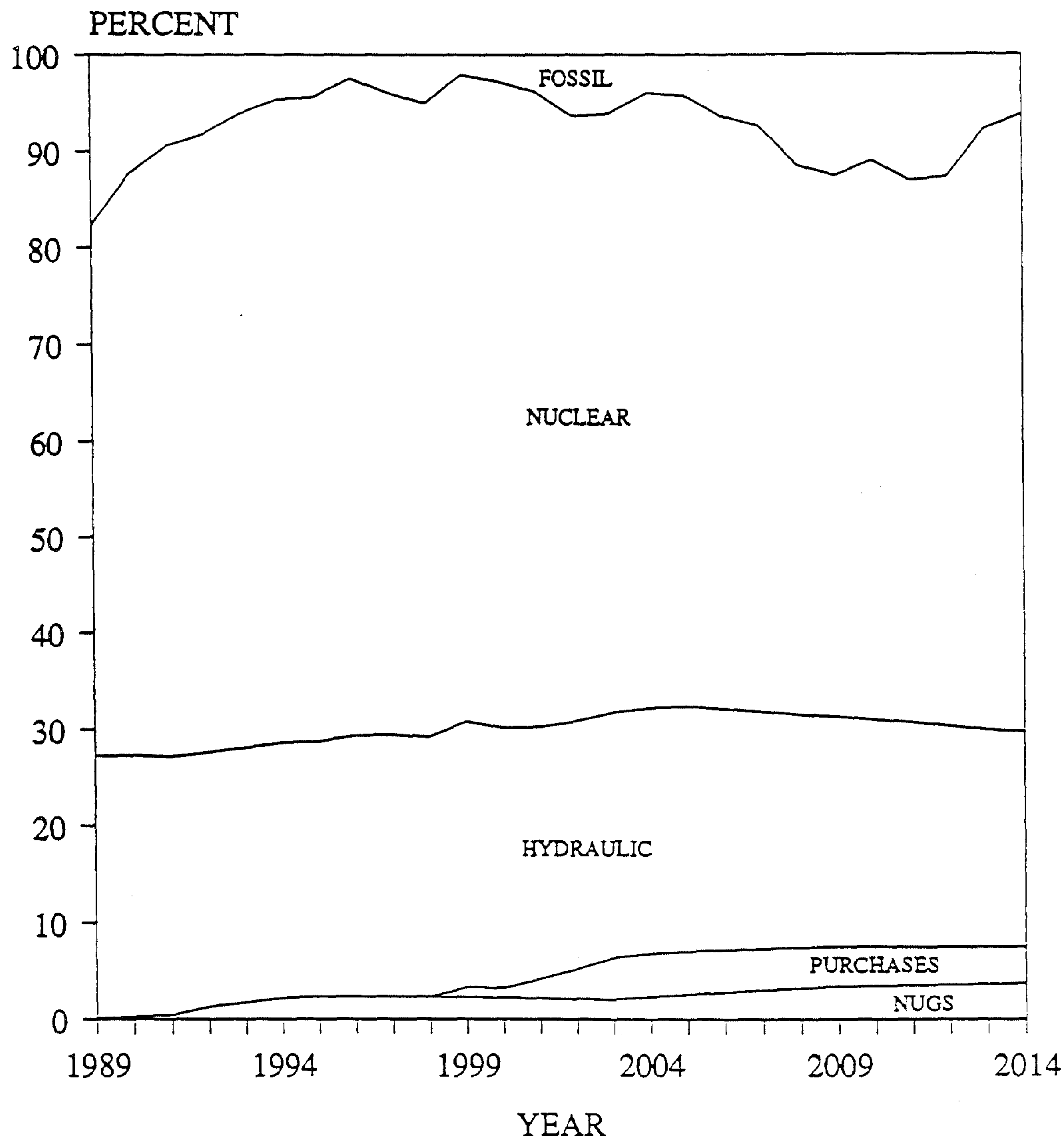


FIGURE 6-8(b)

# ENERGY DIVERSITY - CASE 15
# (BRANCH LOWER LOAD FORECAST)

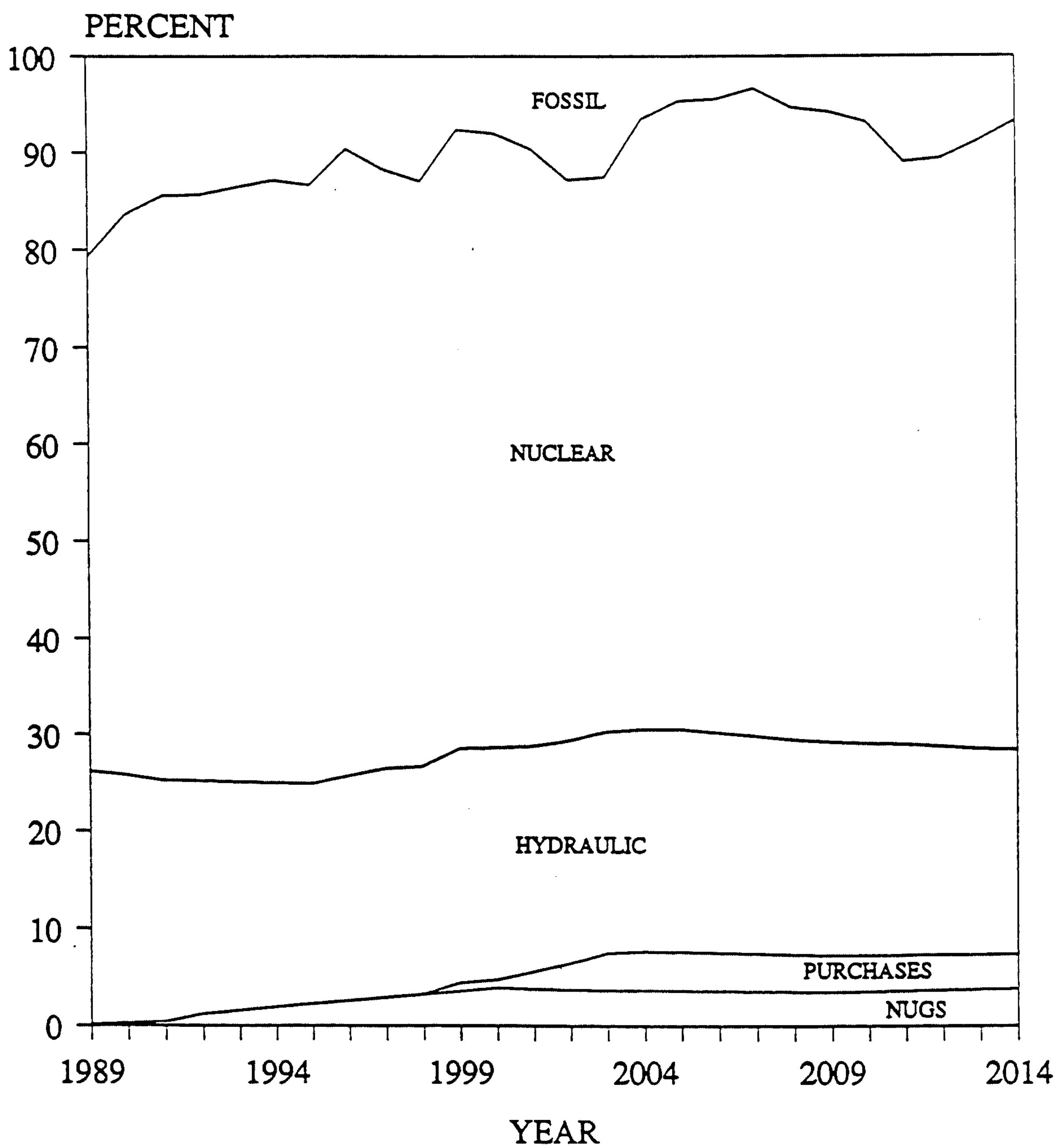


FIGURE 6-8(c)

ENERGY DIVERSITY - CASE 15

(MEDIAN LOAD FORECAST)

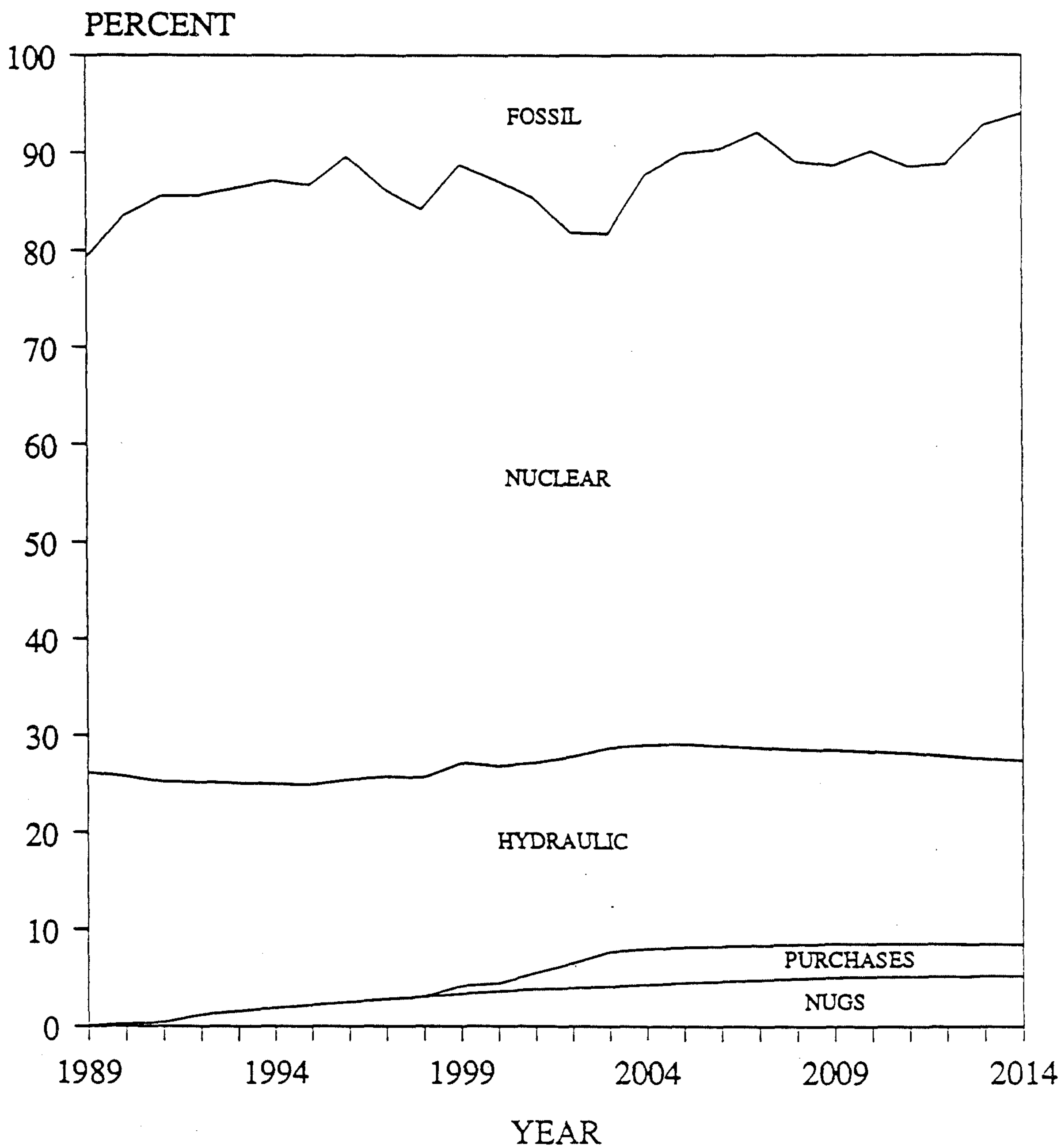


FIGURE 6-8(d)

# ENERGY DIVERSITY - CASE 15
# (BRANCH UPPER LOAD FORECAST)

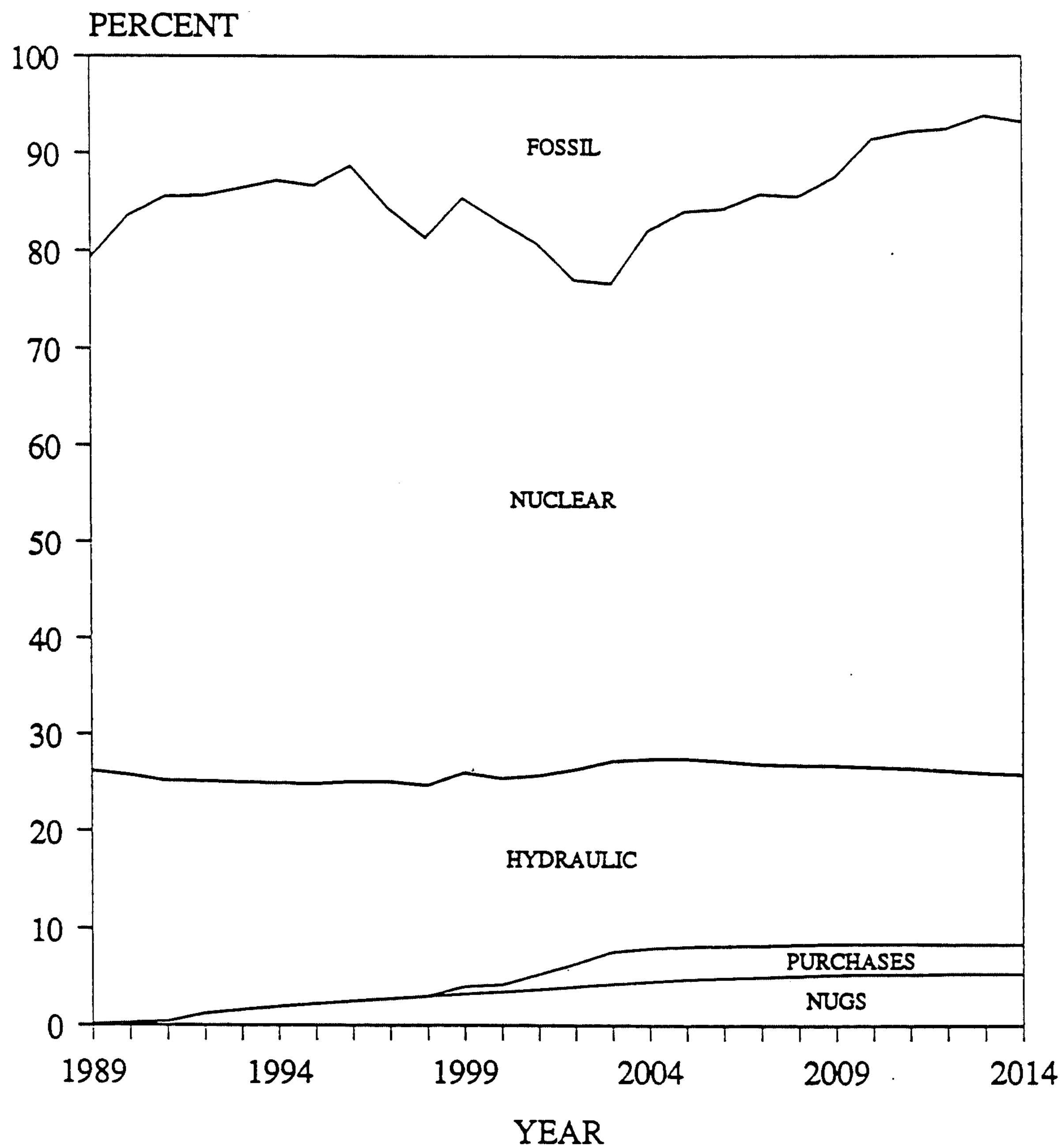


FIGURE 6-8(e)

ENERGY DIVERSITY - CASE 15
(UPPER LOAD FORECAST)

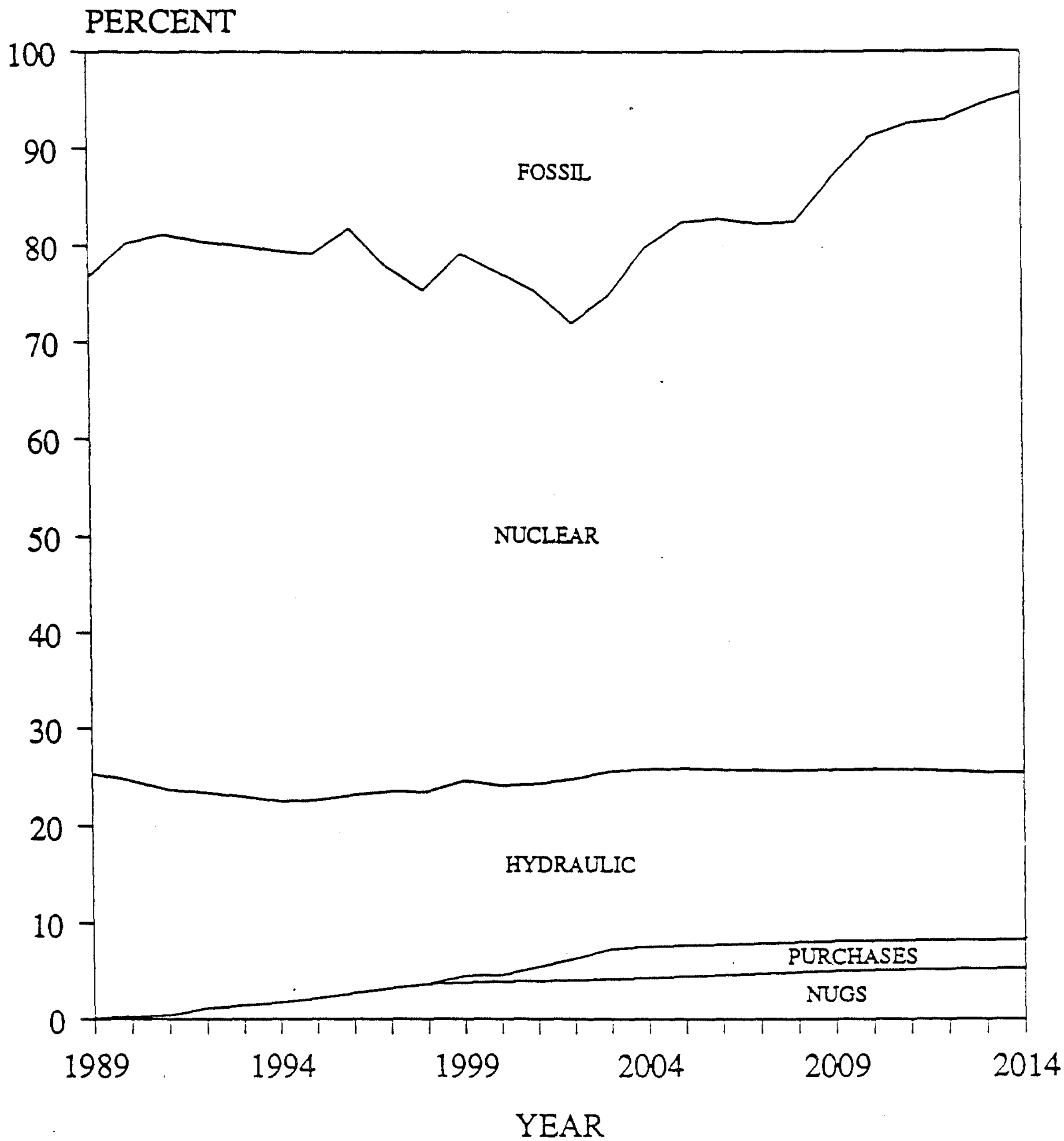


FIGURE 6-9(a)
ENERGY DIVERSITY - CASE 24
(LOWER LOAD FORECAST)

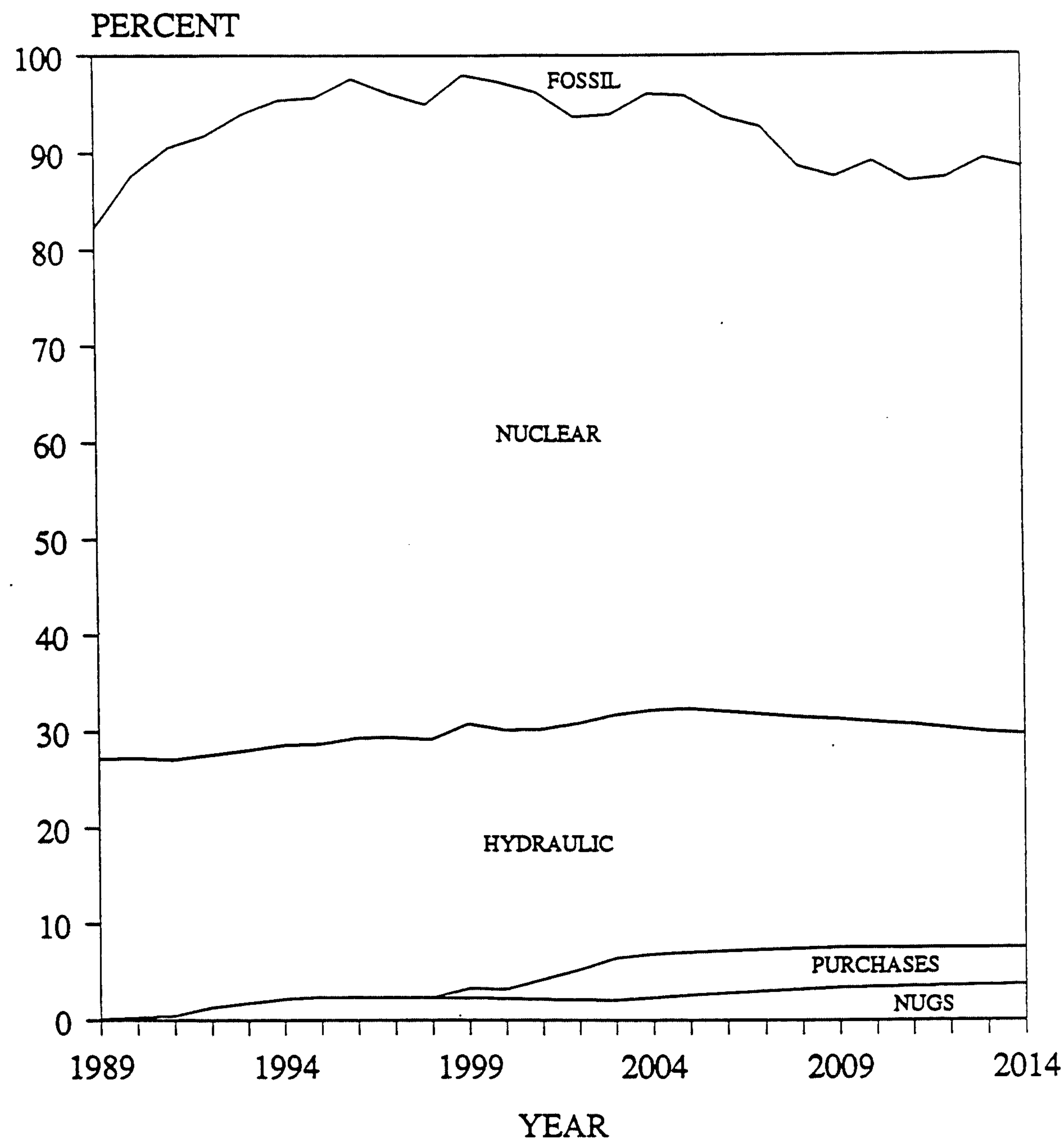


FIGURE 6-9(b)

ENERGY DIVERSITY - CASE 24
(BRANCH LOWER LOAD FORECAST)

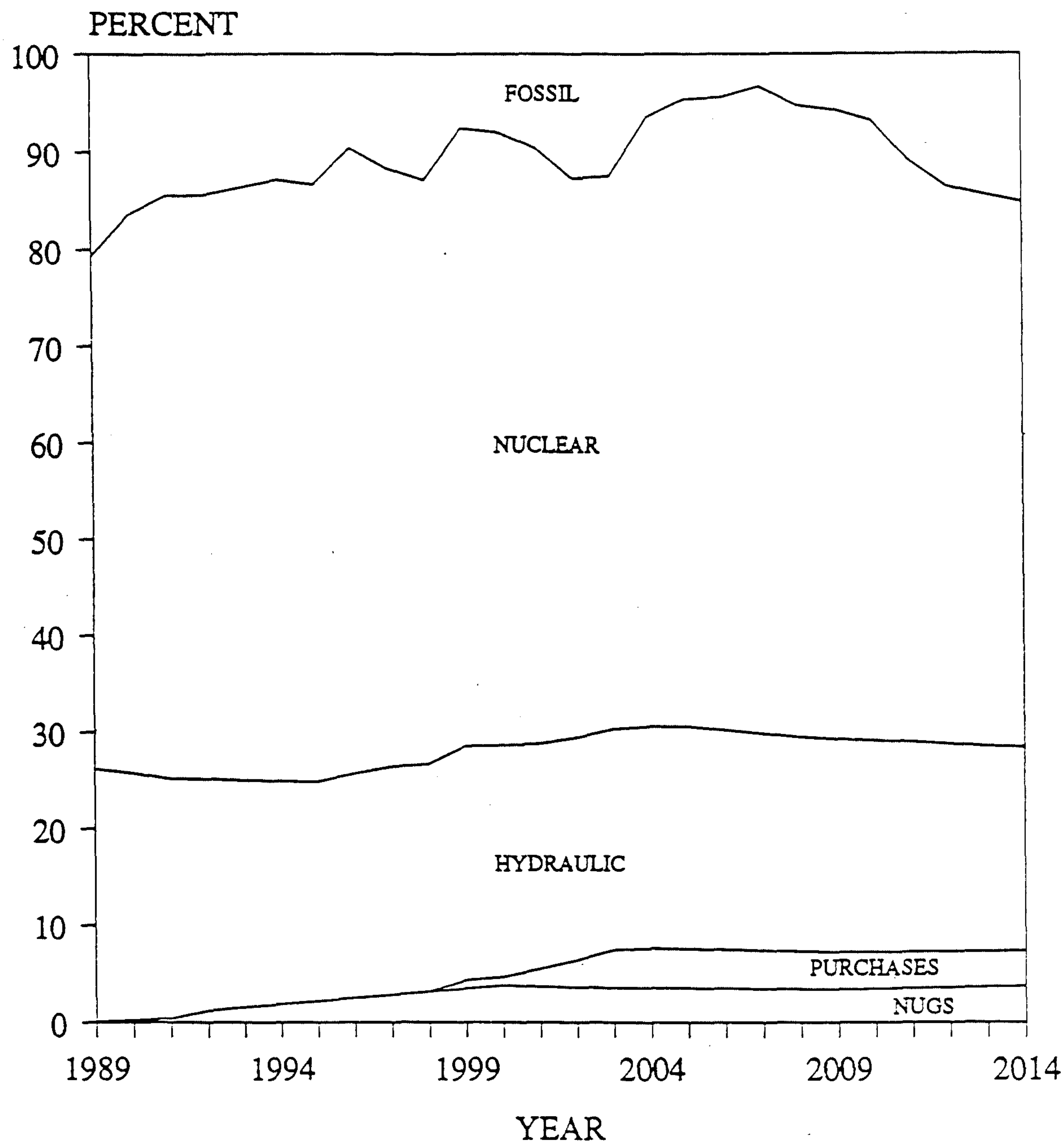


FIGURE 6-9(c)

ENERGY DIVERSITY - CASE 24
(MEDIAN LOAD FORECAST)

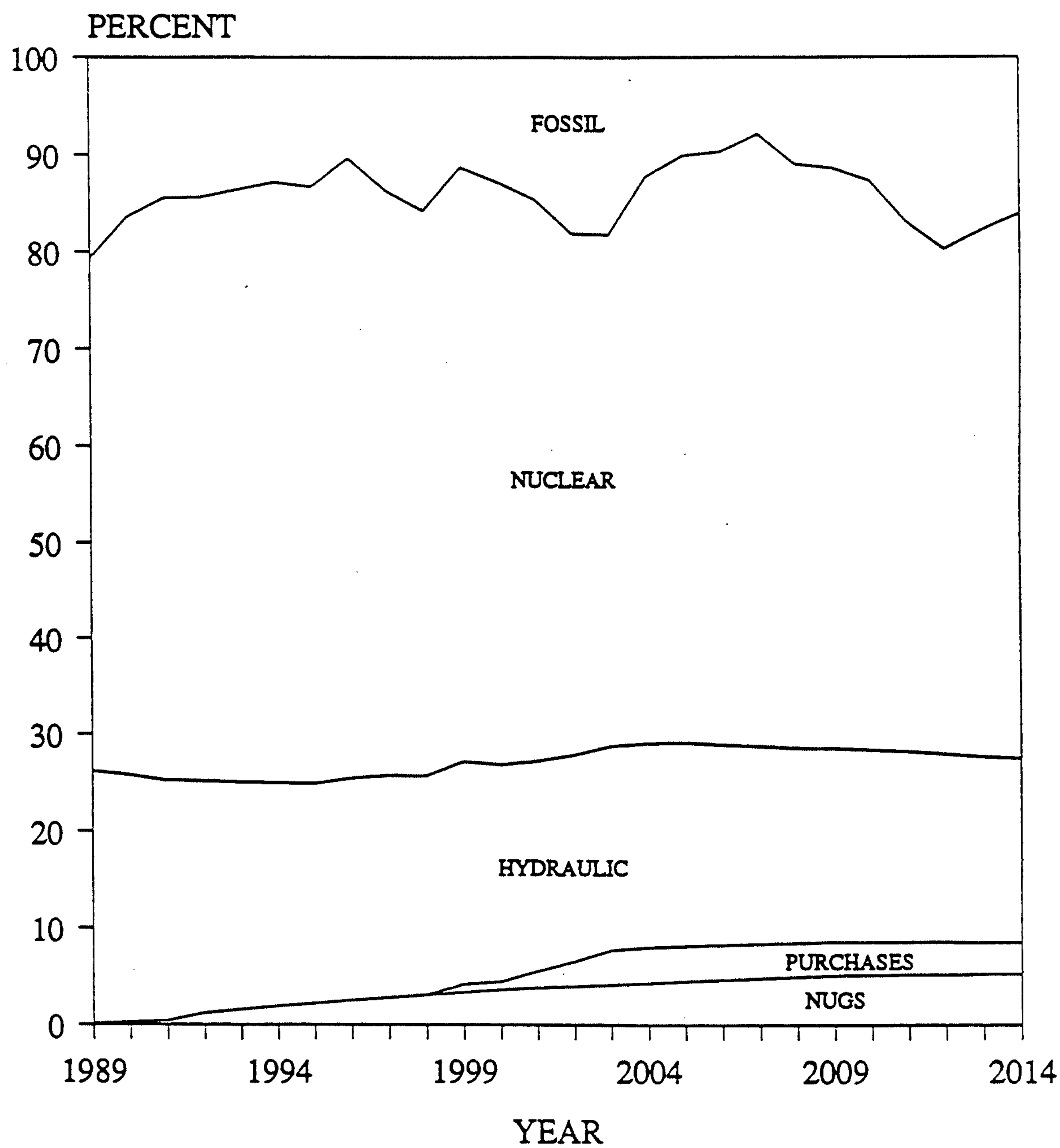


FIGURE 6-9(d)
ENERGY DIVERSITY - CASE 24
(BRANCH UPPER LOAD FORECAST)

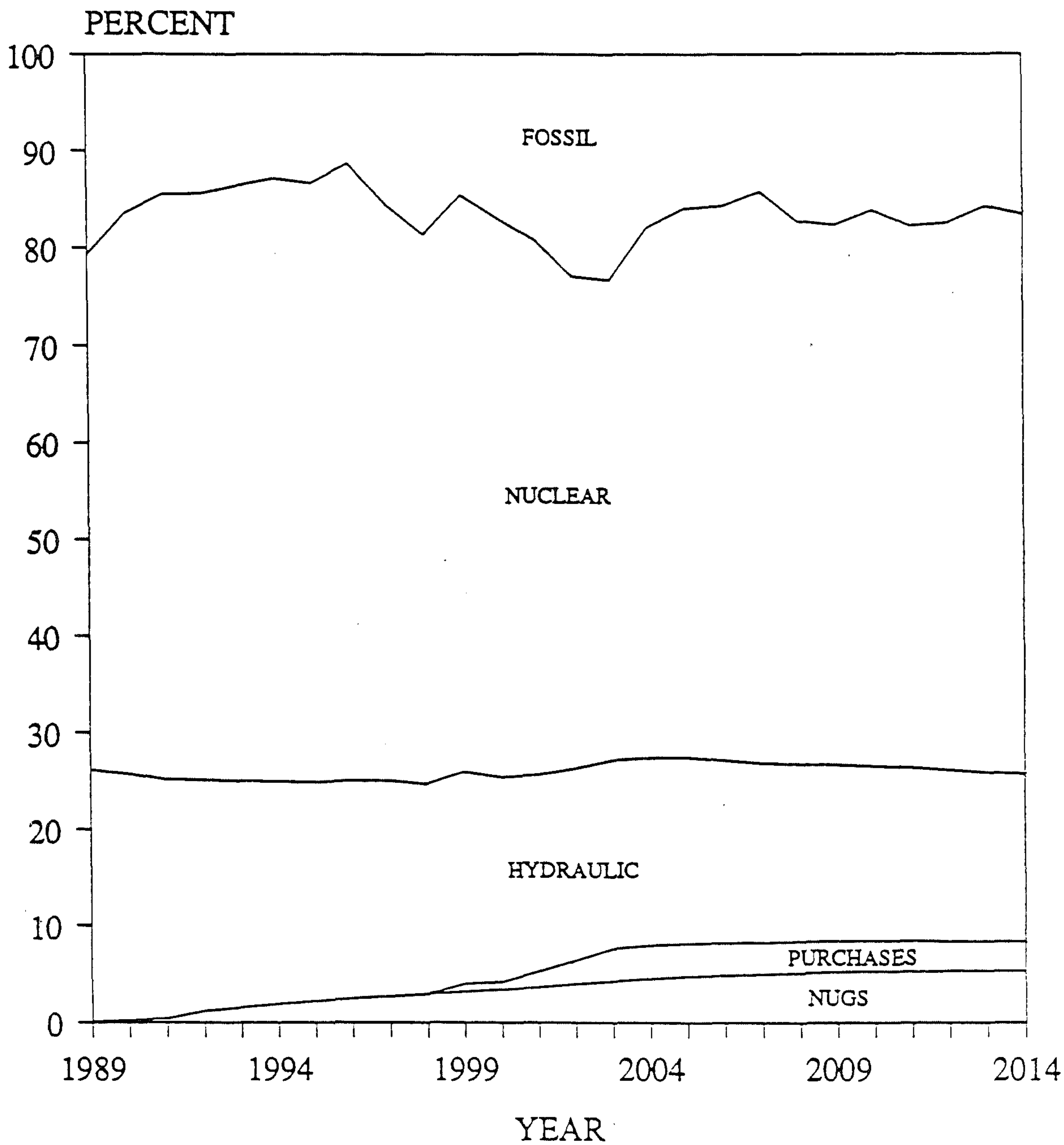


FIGURE 6-9(e)

ENERGY DIVERSITY - CASE 24
(UPPER LOAD FORECAST)

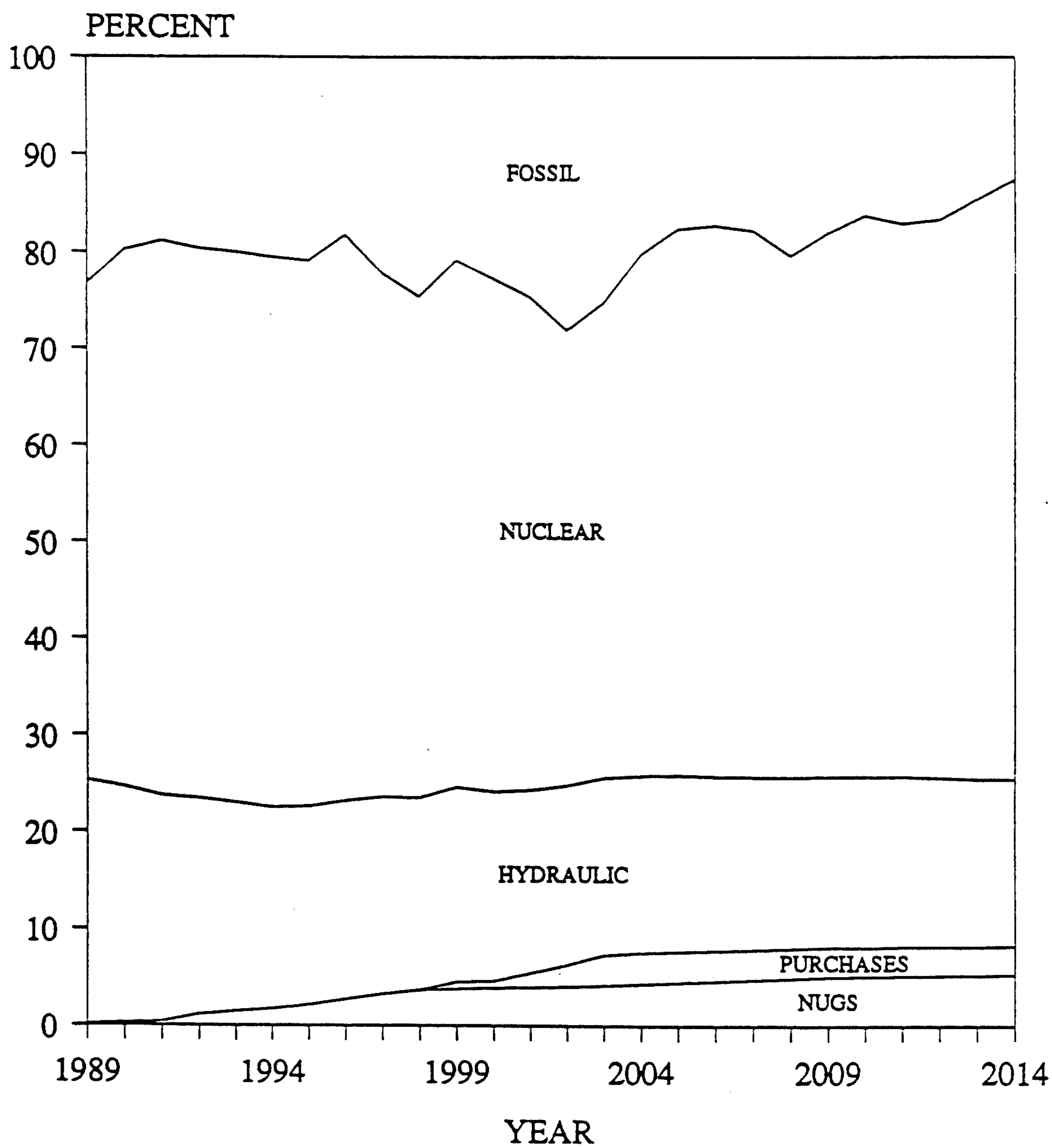


FIGURE 6-10(a)

ENERGY DIVERSITY - CASE 26
(LOWER LOAD FORECAST)

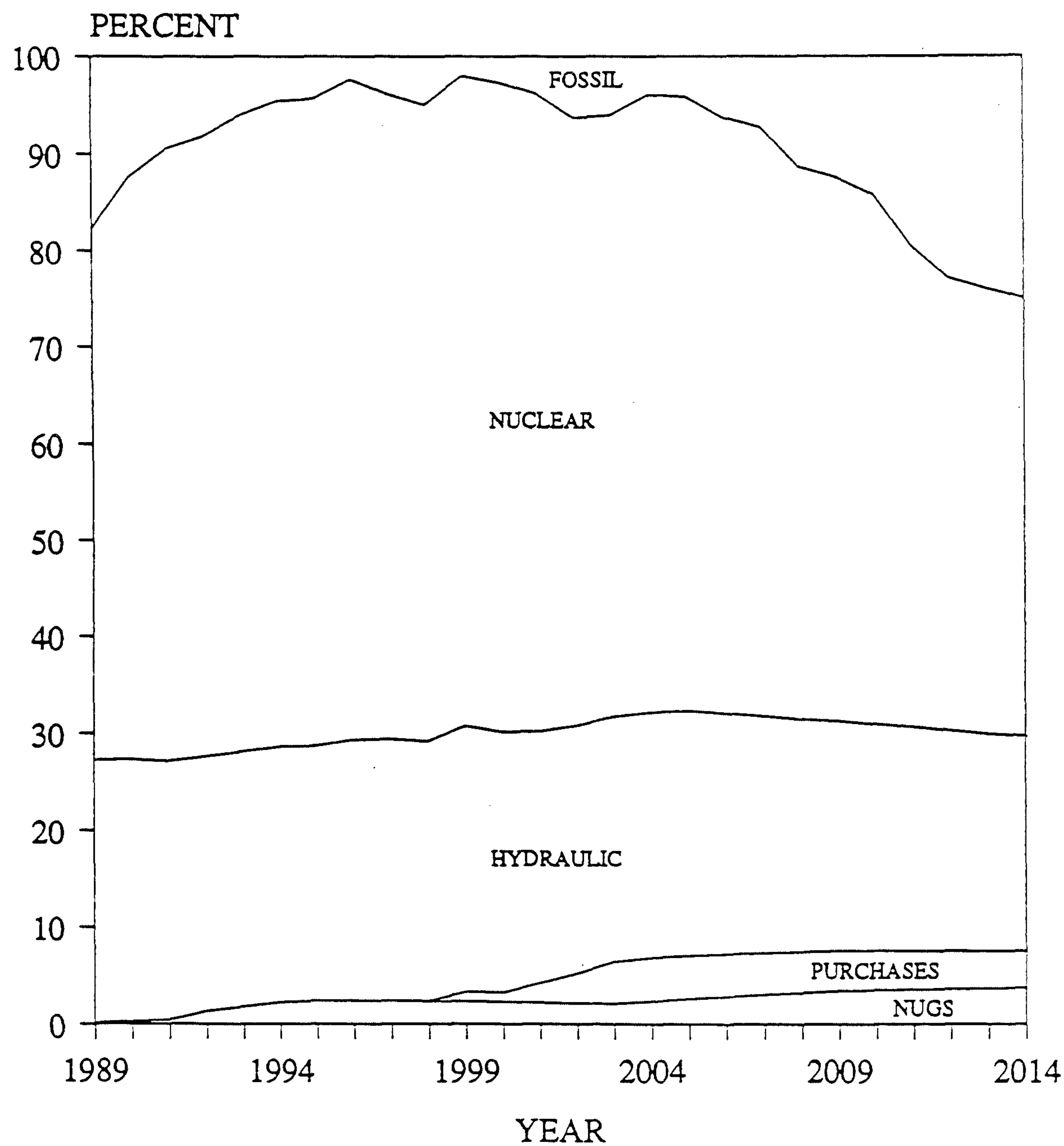


FIGURE 6-10(b)

# ENERGY DIVERSITY - CASE 26
# (BRANCH LOWER LOAD FORECAST)

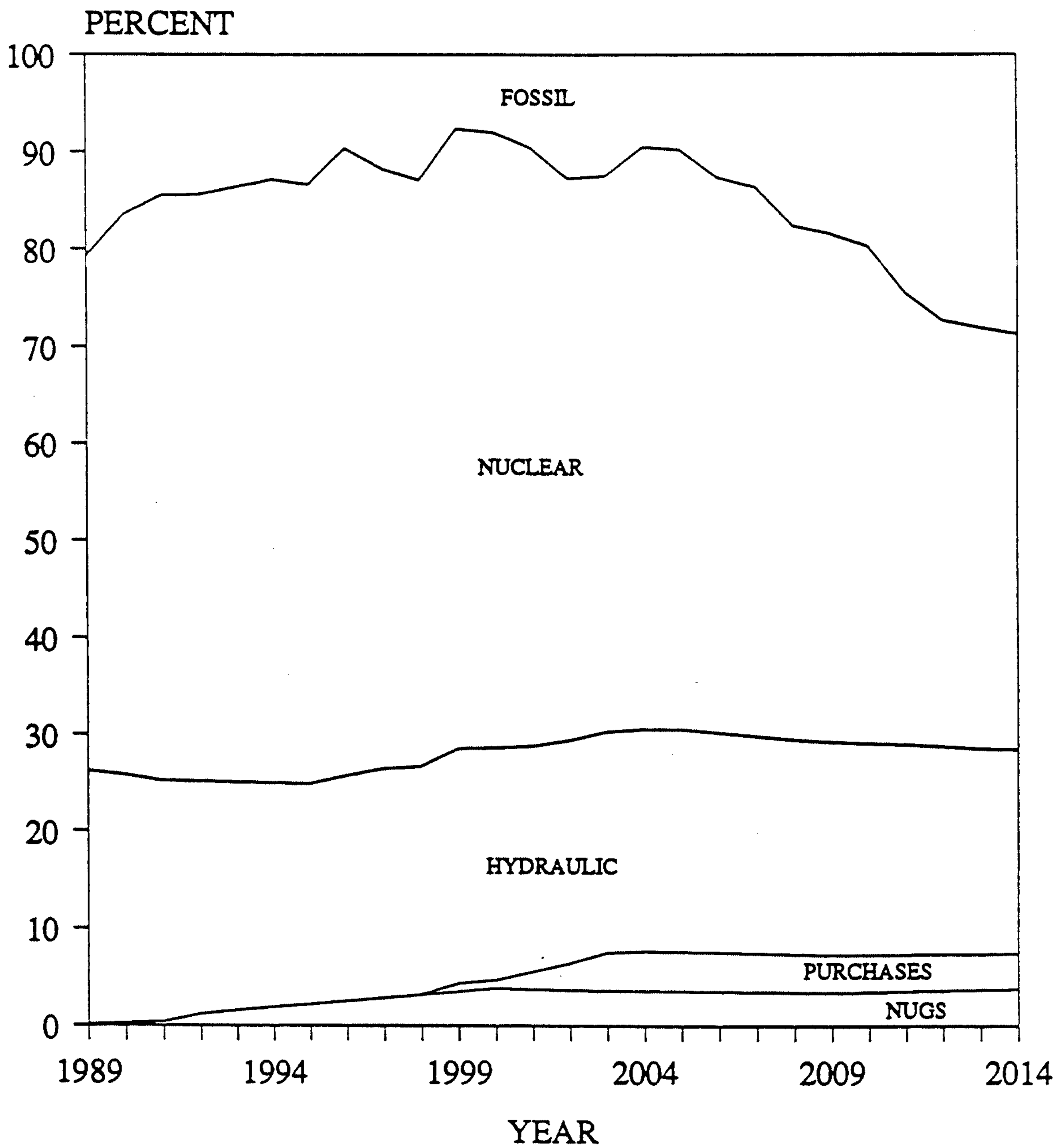


FIGURE 6-10(c)
# ENERGY DIVERSITY - CASE 26
# (MEDIAN LOAD FORECAST)

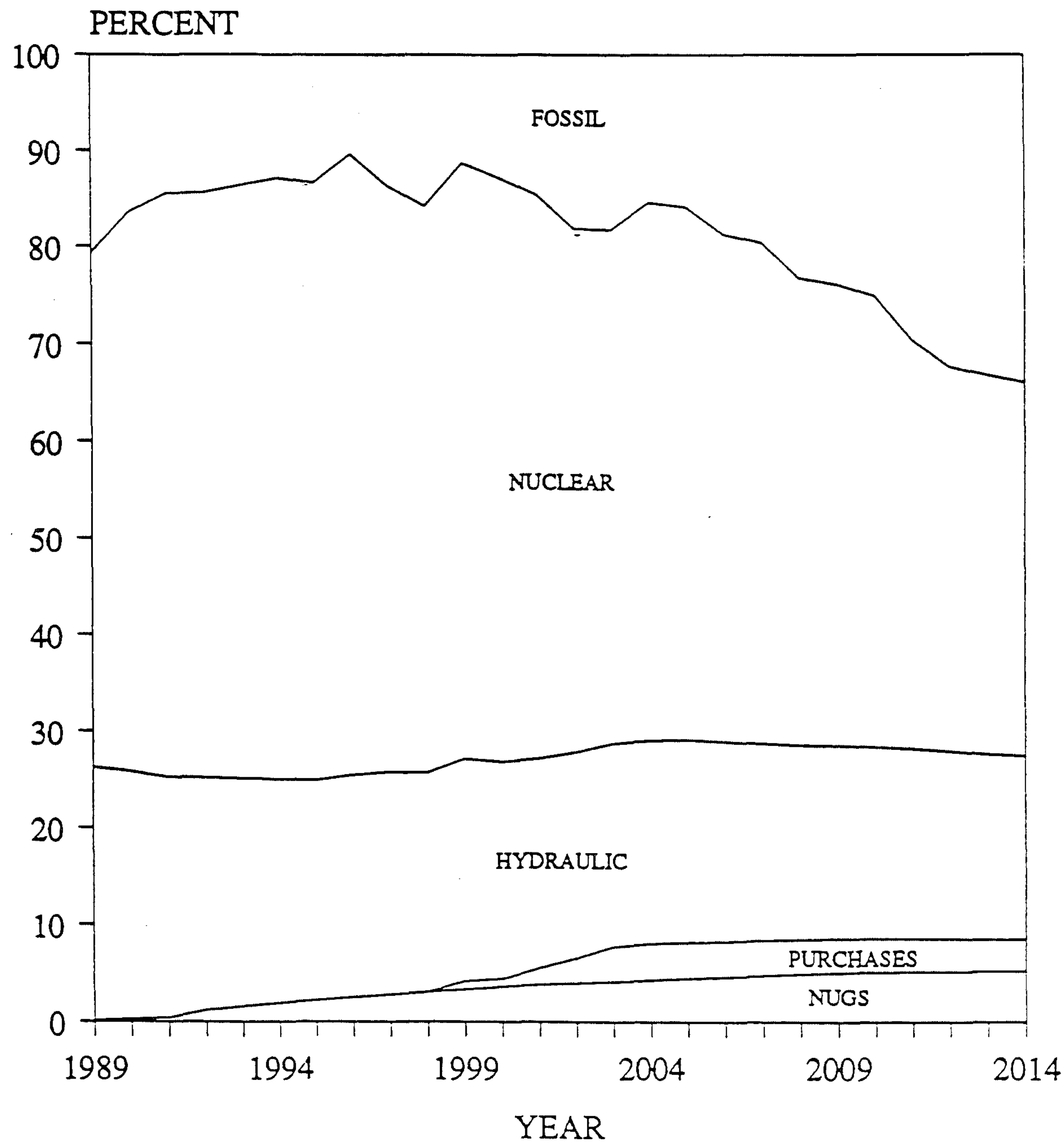


FIGURE 6-10(d)

# ENERGY DIVERSITY - CASE 26
# (BRANCH UPPER LOAD FORECAST)

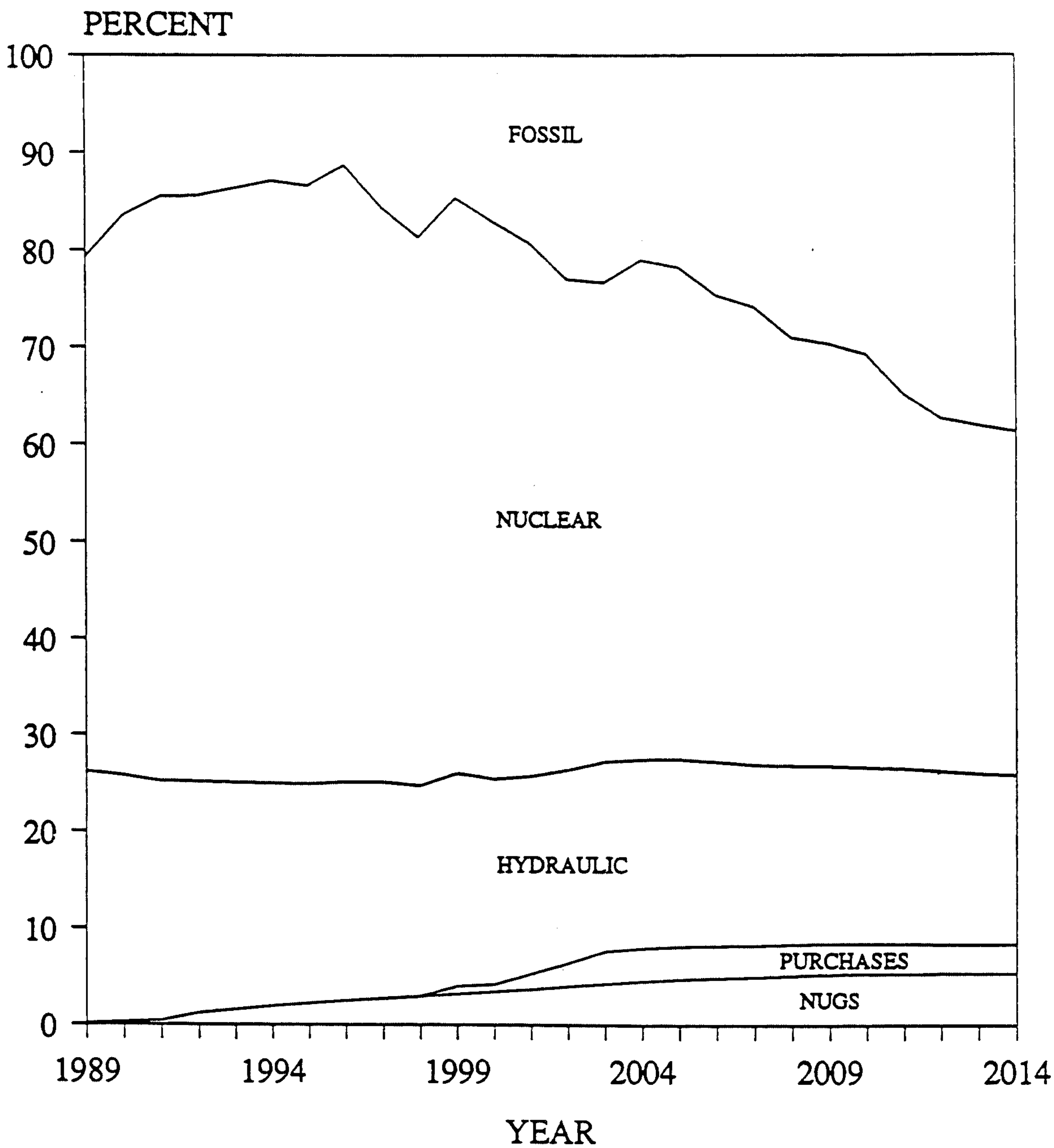
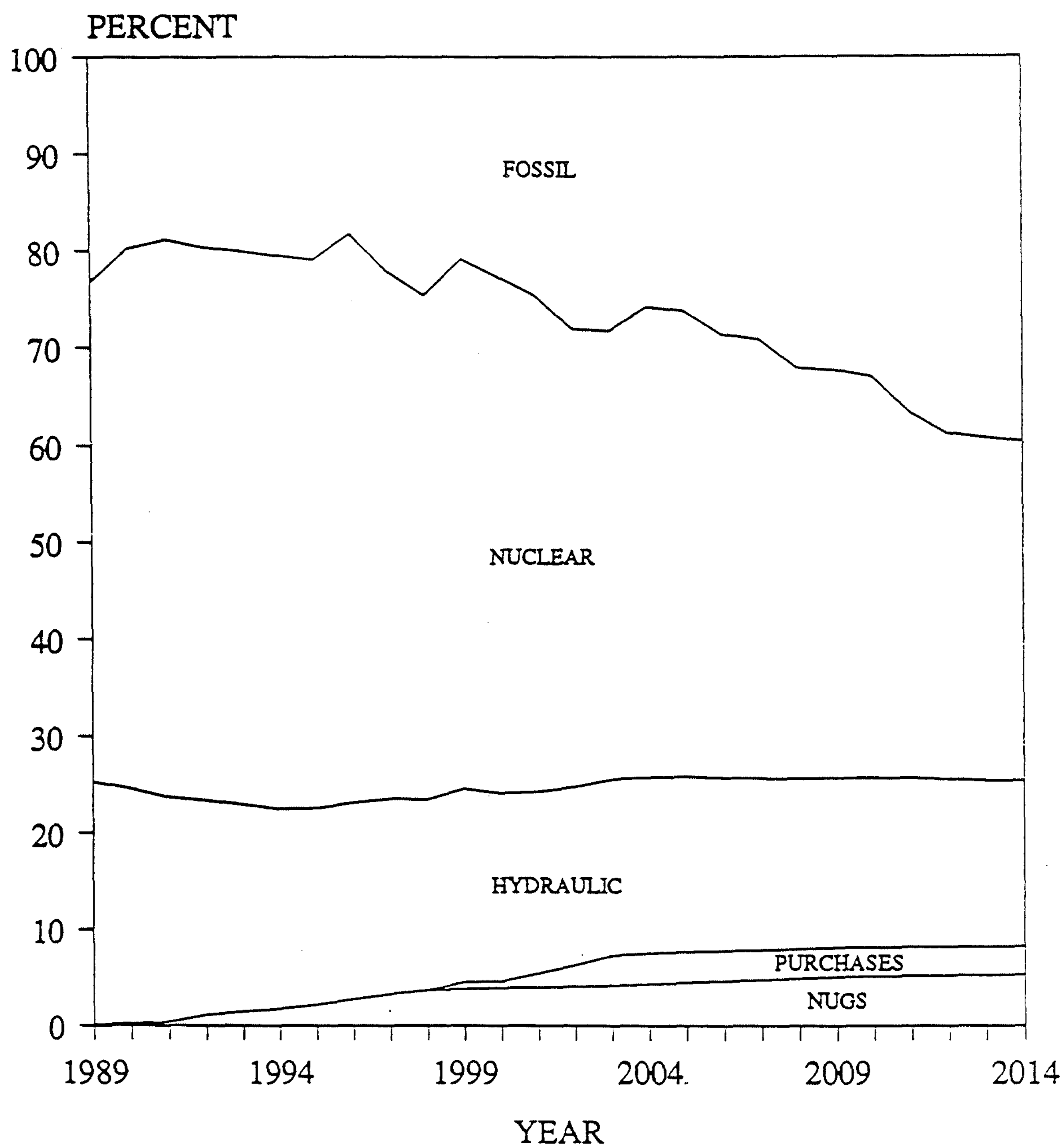


FIGURE 6-10(e)

# ENERGY DIVERSITY - CASE 26
# (UPPER LOAD FORECAST)



### 6.4.2 Mix Of Fossil And Nuclear Energy Production

Case 23

Under the five load paths, the fraction of nuclear production rises from an average of about 53% in 1989 to about 72% by 2014. Consequently, fossil energy production declines from about 21% in 1989 to less than 1% by 2014.

Cases 22 and 15

These two Cases have similar nuclear/fossil energy use trends, as well as similar portions of nuclear/fossil energy production, under common load forecasts.

Under the median, branch lower and branch upper load paths, nuclear generation supplies 53% of total energy needs in 1989. By 2014, Case 22 has 67% to 71% nuclear energy and Case 15 has 65% to 67%, depending upon load forecast. As a result, fossil energy production varies from 21% of total energy in 1989 to about 3% to 5% in Case 22, and about 6% to 7% in Case 15.

Under lower load forecast, nuclear energy production starts at 55% of total energy, and rises to about 66% by 2014. Fossil energy production declines from 18% of total energy to about 4% by 2014.

Under upper load forecast, nuclear energy production increases from 51% of total energy in 1989 to about 71% by 2014. Fossil energy production decreases from 23% of total energy in 1989 to about 3% to 4% by 2014.

Case 24

Case 24 follows the same nuclear/fossil production pattern as Cases 22 and 15. Nuclear generation in Case 24 provides a lower portion of total energy than the other two Cases, while fossil generation provides a higher portion.

Under the median, branch lower and branch upper load paths, nuclear energy production increases slightly from 53% of total energy in 1989 to about 56% to 58% by 2014, depending upon load forecast. Fossil energy production decreases from 21% of total energy in 1989 to about 15% to 17% by 2014.

Under lower load forecast, nuclear increases from 55% of total energy in 1989 to 59% by 2014, while fossil decreases from 18% of total energy to 12%.

Under upper load forecast, the nuclear portion rises from 51% in 1989 to 62% by 2014. The fossil portion declines from 23% to 13%.

Case 26

To about the turn of the century, Case 26 follows the same trends as the other Cases. After the year 2000, nuclear energy production decreases steadily and fossil generation increases.

Under median load forecast, nuclear energy production is about 39% of total energy by 2014 and fossil energy production is about 34%. Under branch lower and lower load forecasts, nuclear is about 44% of total energy, on average, and fossil is about 27%. Under branch upper and upper load forecasts, the nuclear and fossil portions are 35% and 39% respectively.

## 6.5 REVIEW

Energy production and the amount of fuel required to produce that energy are calculated using computer models, as part of the assessment of the economic and environmental impacts of demand/supply plans.

To meet the electricity demands of Ontario, purchases are made from US and Canadian utilities and non-utility generators. The balance of energy needs is supplied by Ontario Hydro's generation.

Ontario Hydro generating stations are fuelled with one of the five energy sources: uranium, coal, oil, gas and falling water. Each station's production is driven by the system operating strategy, which is to minimize the total cost of providing electricity to customers while meeting environmental requirements and standards. The order of generation, by least operating cost, is hydraulic, nuclear and fossil.

Energy production and fuel consumption estimates have been made for the five Cases under each of the five load forecast paths.

All five Cases feature the 1000 MW electricity purchase from Manitoba and hydraulic development program for all the load forecasts. Energy purchased from non-utility generators is the same in all Cases for each of the five load forecasts.

Together, utility and non-utility purchases and hydraulic generation provide about 25% to 30% of total energy requirements. Nuclear and fossil generation make up the remaining energy needs. The pattern of variation of nuclear and fossil energy mix is generally similar across all load forecasts. The main difference under different load forecast is the level of nuclear and fossil energy production.

The variation of nuclear energy production between Cases is mostly due to in-service dates for new nuclear facilities. From 1989 to 1996, nuclear production rises as Darlington comes into service and existing nuclear units, unavailable during retubing, are returned to service. Subsequently, nuclear energy production drops because of retubing one or two generating units at times and retirement of Pickering A units beginning in 2011.

Fossil energy production fluctuates with nuclear production -- rising during nuclear retubing, falling when new nuclear units come into service. The variation of fossil energy production between Cases is due to the timing and type of supply additions. Fossil energy production varies more widely than the other supply options, as fossil is generally used to meet demands after contracted utility and non-utility purchases, hydraulic and nuclear generation are fully utilized.

# 7. ACID GAS CONTROL

## 7.0 INTRODUCTION

The emission of acid gases from Ontario Hydro's fossil-fired generating stations is constrained by regulated limits imposed by the Ontario government. In order to ensure that the electricity demand in Ontario can be satisfied while remaining within the enacted regulations, Ontario Hydro must implement acid gas control measures where and when required. This chapter describes the approach for developing an acid gas control plan and the control plan assumed in the plan analysis.

## 7.1 ORIGINS OF ACID GAS EMISSIONS

Acid gas emissions are produced by the combustion of fossil fuels, such as coal, oil and natural gas. The major components of these emissions are sulphur dioxide ($SO_2$) and nitrogen oxides ($NO_X$).

Sulphur dioxide originates from the sulphur and sulphur compounds contained in the fuel. The coal and oil burnt by Ontario Hydro contains 0.3 to 2.5 percent sulphur. During combustion, 95% or more of this sulphur is released and oxidized to form $SO_2$. The balance of the sulphur is retained in the ash. Natural gas as supplied, on the other hand, contains essentially no sulphur.

At ground level, high concentrations of sulphur dioxide is detrimental to plant and animal life, and human health. As a result, the Ontario Ministry of the Environment has established ambient air quality criteria for sulphur dioxide.

Nitric oxides are formed when organic nitrogen compounds in fossil fuels oxidize during combustion, and when atmospheric nitrogen is oxidized at temperatures above 1000°C. The $NO_X$ emissions arising from atmospheric nitrogen are significantly affected by boiler design and operation.

In sunlight, nitric oxides react with volatile organic compounds (VOCs) to produce photo-oxidants, primarily ozone. At ground level, ozone affects plant and animal life. It is also thought to play a role in the further oxidation of $SO_2$ to create acid rain.

Both $SO_2$ and $NO_X$ acidify natural precipitation, thereby creating "acid rain".

## 7.2 ACID GAS EMISSION REGULATIONS

Ontario Hydro's fossil generation is constrained by limits placed on acid gas emissions. Under the Environmental Protection Act, Ontario Regulation 281/87 sets the following limits on Ontario Hydro's annual acid gas emissions:

1. To the end of 1989, emissions of sulphur dioxide and nitric oxide must not exceed 430,000 tonnes, of which no more than 370,000 tonnes may be sulphur dioxide;

2. From 1990 to the end of 1993, emissions of sulphur dioxide and nitric oxide must not exceed 280,000 tonnes, of which no more than 240,000 tonnes may be sulphur dioxide;

3. In 1994 and subsequent years, emissions of sulphur dioxide and nitric oxide must not exceed 215,000 tonnes, of which no more than 175,000 tonnes may be sulphur dioxide.

These regulations are in addition to the ambient air quality criteria. Figure 7.2-1 shows the current legislated annual acid gas emission limits and Ontario Hydro's acid gas emissions since 1982. Acid gas emissions are continually assessed so that appropriate measures can be undertaken to ensure that these regulation limits are not exceeded.

## 7.3 ACID GAS CONTROL STRATEGY

In managing acid gas emissions to protect the environment, Ontario Hydro's acid gas control policy is to:

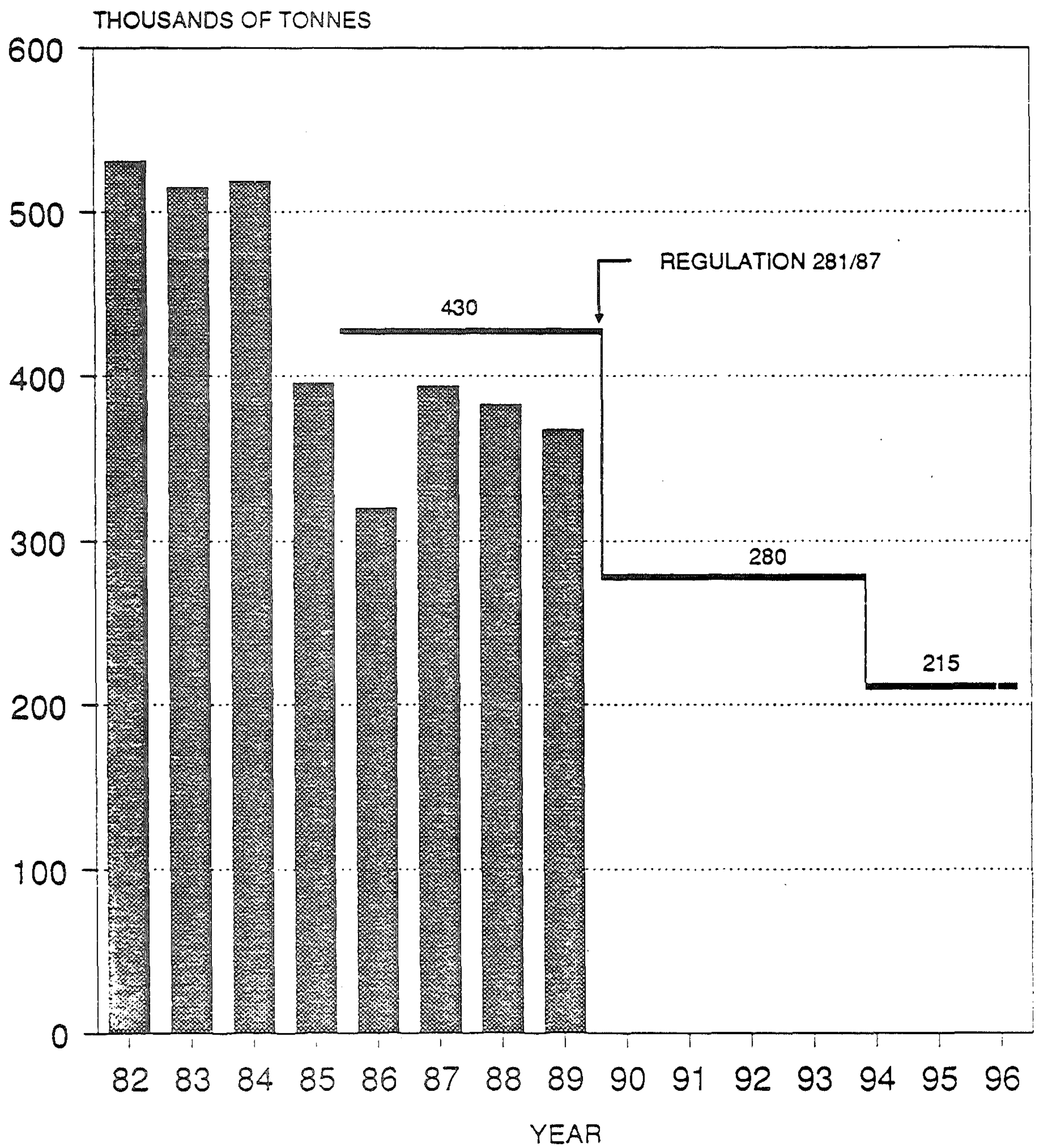
1. Meet or better government regulated limits;

2. Aim for stepped reductions in each year to 1994; and

3. Achieve reductions in a cost effective manner.

The actions selected by Ontario Hydro to meet emission regulations follow an underlying acid gas control strategy. This strategy sets out principles for implementation of acid gas control measures, consistent with Ontario Hydro's acid gas control policy.

FIGURE 7.2-1
Ontario Hydro Acid Gas
Emissions and Limits



The three elements of this strategy are:

I *Select cost effective measures on the basis of marginal cost to the system.*

Ontario Hydro selects control measures which achieve lowest marginal costs for emission reduction. In making these selections, Hydro takes into account practical constraints, such as lead time, removal efficiency, future control needs, and station retirements.

A range of control measures is utilized. Using a number of measures mitigates against the failure of one, and provides a broader base for expansion of control. As well, economic benefits may be realized through competition between comparable measures.

II *Maintain adequate flexibility to respond to deviations from expectations.*

Fossil generation needs can vary significantly if there is a change in:

a) the demand for electricity;
b) the status of other generating stations; and
c) demand management or non-utility generation.

In the past, there has been a number of circumstances which have led to significant changes in electricity production from fossil fuel generation:

1. A combination of a strong economy and hot summer weather helped create a demand for electricity in 1988 that was 4.7 TW.h higher than forecast.

2. In 1985 the outage of two units at Pickering for retubing resulted in a loss of over 7.5 TW.h of nuclear energy per year for several years.

3. Annual hydraulic generation has varied over the past 10 years from a low of 33.5 TW.h to a high of 38.8 TW.h, a range of 5.2 TW.h.

Continued variability in fossil generation use is expected. Ontario Hydro manages the acid gas implications of these uncertain fossil generation needs by maintaining the flexibility to handle a range of future conditions.

Some of this flexibility is provided by the inclusion of an acid gas planning margin. Ontario Hydro maintains an annual planning margin of at least 9 TW.h, equivalent to approximately 3 million tonnes of additional coal, or approximately the electricity production from a large nuclear unit for a year.

A planning margin is necessary because emissions must be below the regulated limit in every year, not just on average. The size of the margin is determined by balancing the costs of carrying the extra margin with the risks of having to use more expensive last minute measures to meet the emission limits. With an annual planning margin of 9 TW.h, Ontario Hydro should be able to keep acid gas emissions below the limits without having to frequently resort to last minute measures.

Since approvals for certain control options take a long time (3 years or more), some approvals are being pursued in advance of commitment dates. In February 1988, following two years of development, Ontario Hydro submitted an Environmental Assessment to the Ontario Government, which sought approval for the use of any of four different acid gas control technologies at any of its three major coal-fired stations. Approval, with certain conditions, was granted in 1989.

III *Keep sufficient options in reserve to meet unforeseen contingencies.*

Certain measures are held in reserve for use on short notice in the event of contingencies such as higher than forecast load growth and/or problems with hydraulic or nuclear units. These generally are more expensive than those in the acid gas control plan.

## 7.4 EMISSION CONTROL OPTIONS

### 7.4.1 Reduce the Use of Fossil Generation

Demand Management, non-utility generation*, hydraulic and nuclear generation, electricity imports, reducing planned sales, and transmission improvements reduce acid gas emissions by displacing fossil-fired generation.

Although demand for electricity increased over the 1970s and 1980s, it was largely met by new nuclear generation. As a result, acid gas emissions did not increase in proportion to the increase in electricity demand. As well, the nuclear generation capacity additions during this time period were able to displace existing fossil-fired generation, thereby further reducing emissions.

There can also be economic benefits associated with reductions in fossil generation. This occurs when the measure undertaken to displace fossil generation results in lower overall system costs.

### 7.4.2 Reduce the Sulphur Content in Fuel

Acid gas emissions can be reduced by burning lower sulphur coals, natural gas, or lower sulphur oil.

The two most recently constructed Ontario Hydro coal-fired stations, Atikokan TGS, and Thunder Bay TGS units 2 and 3, are designed and operated to burn low sulphur (0.4% S) lignite supplied from Western Canada. $SO_2$ emission rates from these stations are significantly lower than those from Ontario Hydro's other coal stations, which utilize higher sulphur bituminous coals.

Ontario Hydro has reduced acid gas emission rates by steadily lowering system average sulphur levels in coal, from 2.4 percent in 1976 to 1.3% in 1988. Further reductions, however, are not feasible without modification of the coal-fired stations.

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* Combustion based non-utility generation facilities will emit acid gases, but the majority will be natural gas fuelled. These are expected to emit less $NO_X$ per kW.h than Hydro's existing fossil stations because of their higher efficiency (eg. cogeneration). As well, natural gas fuelled generators emit only negligible amounts of $SO_2$.

All of the coal-fired stations in Southern Ontario are designed to burn medium to high sulphur U.S. coal*. The burning of lower sulphur coals in these stations leads to degraded precipitator performance and increased particulate emissions. The most economical way to overcome this is to utilize flue gas conditioning.

Sulphur trioxide/ammonia flue gas conditioning will be installed at three stations -- Lambton TGS, Nanticoke TGS and Lakeview TGS. Work at Lambton TGS and Nanticoke TGS will be completed in 1990, while work at Lakeview TGS will be completed from 1990 to 1994, as part of the general rehabilitation of the station. Flue gas conditioning will permit the burning of low sulphur coal at these stations, providing up to a 50 percent decrease in acid gas emissions over original design.

The use of lower sulphur fuels depends on the cost of the fuel, the cost of the station and infrastructure modifications required to burn the low sulphur fuel, and the lead-time available. A major advantage of using or switching to low sulphur fuels is the relatively short lead-time required.

Low sulphur fuel options characteristically have low capital costs and high fuelling costs. This makes them more practical for use on low capacity factor generating units or with generating units with limited remaining operating life. Fuelling costs are high because low sulphur fuels come at a premium.

### 7.4.3 Retrofit Emission Control Equipment

$SO_2$ emission control

$SO_2$ emission control equipment includes high efficiency scrubbers and injection technology. High efficiency scrubbers remove $SO_2$ from flue gases, and are up to 95% effective in reducing $SO_2$. Injection technologies, on the other hand, add chemicals during the combustion process. These chemicals combine with the $SO_2$ within the furnace, creating compounds which are then recovered. Injection technologies are up to 50% effective.

---

* Nanticoke TGS currently burns a 50:50 blend of medium sulphur U.S. coal and low sulphur Western Canadian Coal.

High efficiency scrubbers are proven and commercially available technology. While they carry a relatively high capital cost ($250 M per pair of units*), they have a relatively low operating cost ($15 M per year).

As a result, scrubbers are most cost effective when applied to high use generating units with relatively high $SO_2$ emissions and significant remaining operating lives. With high long-term use, the "low" operating costs tend to offset the "high" initial capital investment.

Scrubbers permit the use of less expensive higher sulphur coal in place of the low sulphur coal that would otherwise be used to reduce emissions. Savings on coal also offset the high initial capital investment. Savings depend on the fuel price differential between low and high-sulphur coal and the level of uncertainty in fuel price forecasts.

The retrofit of scrubbers to existing generating units takes up to a total of eight years. This includes the time required for tendering engineering, and approvals. Actual construction takes about three years.

Three scrubber processes are best suited to Ontario Hydro's coal-fired stations. All have advantages and disadvantages that will influence which option is selected for each station.

Wet Limestone Slurry Process

The most widely applied flue gas scrubbing alternative is the Wet Limestone Slurry (WLS) process. It uses limestone, mixed with water to form a slurry, as the scrubbing agent to remove $SO_2$ from the flue gas. The limestone slurry reacts with $SO_2$ to form waste by-products consisting mainly of calcium salts. The waste by-products leave the scrubber in a fluid stream, for either processing into saleable gypsum or disposal.

Advantages are: limestone is a comparatively inexpensive and abundant scrubbing agent; extensive utility operating experience; and proven reliability and availability. Disadvantages include: high capital costs and high operating costs.

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* To minimize costs and make the best use of common equipment, scrubbers are installed on pairs of generating units.

Limestone Dual Alkali Process

A variation of the WLS process is the Limestone Dual Alkali process. It uses a clear sodium sulphite/bisulphite scrubbing solution to remove the $SO_2$ from the flue gas. The spent scrubbing solution is then regenerated by reaction with a limestone slurry. The sodium sulphite solution is reused in the scrubber, while the reacted slurry is collected and disposed of as in the WLS process.

Advantages are: lower maintenance costs than WLS; high SO2 removal efficiency (above 90 percent) over a wide range of coal types; low operating costs; and operational flexibility. Disadvantages are: limited utility experience; need to purchase and store an extra scrubbing reagent; and soluble sodium salts contained in the waste material.

Lime Spray Dryer Process

A scrubber alternative with application in both utility and industrial applications is the Lime Spray Dryer Process. In this process, $SO_2$ is removed by a lime slurry sprayed into the flue gas stream. The water in this slurry evaporates within the gas stream. The reacted lime is then removed as a dry by-product.

Advantages are: reduced operating and maintenance costs; reduced potential for equipment wear; and simplified waste handling and disposal. Disadvantages include: lower $SO_2$ removal efficiency; limited commercial operating experience on high sulphur coals; high cost of lime; and high capital costs.

Injection technologies have lower capital costs and higher operating costs than high efficiency scrubbers. Thus, they are most cost effective when restricted to generating units with peaking operations.

Versus scrubbers, injection technology takes less time to implement in retrofit applications. This is largely due to the difference in construction lead times. Injection technology takes one to two years for construction versus three years for scrubbers.

The injection process best suited to Ontario Hydro's coal-fired stations is the Sorbent Furnace Injection Process:

> Sorbent Furnace Injection absorbs $SO_2$ within the boiler rather than in a specially designed scrubber. Finely ground limestone, or other reagent, is injected into the boiler, where it reacts with the $SO_2$ in the gas stream to form calcium sulphate and sulphite. This is then collected along with the flyash at the back end of the boiler.
>
> Advantages are: short lead times and low capital costs. Disadvantages are: lack of utility operating experience; low removal efficiency (about 50 percent); high operating costs; and wastes may require specialized handling.

$NO_X$ emission control

$NO_X$ control equipment includes combustion process modifications, injection technologies and Selective Catalytic Reduction (SCR).

One example of combustion process modification is the installation of low $NO_X$ burners in the boiler. Nitrogen oxide emissions from Nanticoke TGS have been reduced 35 percent by the modification of burners on all units. These modifications were carried out from 1984 to 1987.

Further improvements can be made through various combinations of new pulverisers, windbox modifications, control changes, overfire air ports and burner modifications. These measures reduce the formation of $NO_X$ by reducing the temperature of combustion and the amount of oxygen available for combustion. The cost of further combustion process modifications is about $30M for a 500 MW unit. Operating costs would be low. It is estimated that these measures would provide $NO_X$ reduction capabilities of up to 30 percent from current emission levels.

Combustion process modification can be a cost effective means of reducing total acid gas emissions in certain instances. It is particularly attractive when its use can avoid the implementation of higher cost $SO_2$ control options, or can meet a critical need for accelerated implementation of acid gas control. The latter would be a consequence of the shorter design and construction times required for this option.

Promising injection technologies such as urea injection are being developed as $NO_x$ control measures. In simple terms, chemicals are injected into the furnace where they react with the $NO_x$ produced to either form nitrogen and water or create other readily collected compounds. With these technologies, $NO_x$ reductions of 50 to 60 percent are expected. Further research on these technologies is required, however, as they have yet to be proven on the commercial scale required by Ontario Hydro.

In Selective Catalytic Reduction, ammonia is injected into the flue gas stream. The flue gas/ammonia mixture then passes over a catalyst bed in a reactor vessel, where $NO_x$ is reduced to nitrogen gas and water. SCRs offer a removal efficiency of 80 percent or greater. Capital costs are about $60 M per 500 MW unit. Operating costs will be high as they are driven by the catalyst lifetime and replacement costs. Although SCR has yet to be run on North American coals and stations, units are operating successfully in Japan and parts of Europe.

Future generating stations will be built with sufficient control equipment to mitigate their environmental impact. Thus, it is expected that any new pulverized coal station built by Hydro will have SCR units or equivalent.

## 7.5 ACID GAS CONTROL PLAN

Representative Acid Gas Control Plans were developed for use in all of the cases in the DSP. The plans combine a variety of control options into separate representative control programs for each of the five load forecasts analyzed. While each program is capable of meeting current emission regulations, the options may be reduced or supplemented as required in the future.

### 7.5.1 Formulating an Acid Gas Control Plan

In developing an acid gas control plan, the following steps are taken:

1. The annual fossil energy requirement for the plan is calculated, either by station or group of units.

2. On a year-by-year basis, the control options for each fossil unit are specified.

3. For each year of the forecast period, the combination of available control options which results in the lowest marginal cost for emission reduction, that meets the regulation and provides a 9 TW.h margin, is selected.

4. Practical constraints such as operating life and lifetime costs are taken into account. For example, scrubbers are not selected if required for only a year .

The marginal removal costs ($\$/Mg_{removed}$) for each control option vary by station, by station annual capacity factor (i.e. usage) and by year. An illustrative example of these costs are given in Figure 7.5-1 for Lambton TGS and Nanticoke TGS in the year 2000. Similar data are calculated for each year of the planning horizon. These are then used to determine the most cost effective option for reducing acid gas emissions in each year.

FIGURE 7.5-1

ILLUSTRATIVE MARGINAL COSTS
FOR ACID GAS CONTROL OPTIONS
(year 2000 $)

| OPTION | MARGINAL COST* ($\$/Mg_{removed}$) | | |
|---|---|---|---|
| | Lambton TGS | Nanticoke TGS | |
| | (70% ACF) | (31% ACF) | (13% ACF) |
| 100% Western Canadian Coal (No Loss of Capability) | 744 | 963 | 1203 |
| 100% Low Sulphur U.S. Coal | 310 | 158 | 158 |
| 50/50 Blend Western Canadian/U.S. Low Sulphur Coal | 604 | 558 | 633 |
| Scrubber High Sulphur U.S. Coal With Low $NO_x$ Burners | 217 | 708 | 2241 |
| Limestone Injection | 683 | 1677 | 3664 |
| 20% Natural Gas With 80% U.S. Low Sulphur Coal | 694 | 815 | 904 |
| 100% Natural Gas | 1685 | 2079 | 2273 |

* Relative to 1989 fuel use at stations

As shown in Figure 7.5-1, there can be significant differences in costs between the options and between stations. For example, the use of scrubbers to reduce emissions from generating stations with high annual capacity factors can be cost effective. With Lambton TGS operating at an annual capacity factor of 70 percent, the marginal removal costs of scrubbers is only 217 $\$/Mg_{removed}$. This is the lowest cost option. However, for Nanticoke TGS units, operating at an annual capacity factor of only 13 percent, scrubbers are amongst the highest cost options. At low capacity factors, the use of low sulphur coal options are the most economic (eg. 158 $/Mg$_{removed}$).

Marginal removal costs provide an indication of the relative cost effectiveness of the various options on a year by year basis. In practice, however, a control option must not only be cost effective in a particular year, but also over the entire remaining life of the station. This is especially true for options such as scrubbers, which require a significant capital expenditure. It is impractical and expensive to utilize such an option for only a year or two. Thus, in developing an acid gas control plan, the long term financial implications must be weighed against short term advantages and disadvantages.

In addition to minimizing costs, an acid gas control plan must recognize uncertainties. The plan must consider a range of possible future coal use, provide a margin to allow for uncertainty, and keep some measures in reserve for contingency response until new, more economical measures can be added to the system.

### 7.5.2 Acid Gas Control Plan Attributes

Acid gas control will be accomplished through two main options - the retrofit of control equipment to existing fossil stations, and the use of lower sulphur fuel (eg. low sulphur coal). Control equipment consists of either scrubbers or combustion process modifications (CPM) or both. These are designated major control measures as they involve capital modification to the station and require scheduling of design, construction and installation.

Figure 7.5-2 shows the Acid Gas Control Plan in-service dates for these control measures. It is assumed that scrubbers and CPM will be employed initially at Lambton TGS, followed by Nanticoke TGS, where required.

The major control measures provide economic control of acid gas emissions over the long-term. Additional acid gas reductions can be accomplished by the use of lower sulphur coals. The potential exists to obtain US coal with sulphur levels down to 0.8 percent and Western Canadian coal with sulphur levels as low as 0.3 percent. It is estimated that this additional measure will be sufficient to ensure that the regulations can be met in all load forecast cases.

The schedule for the major control measures extends to the year 2005. Beyond that date, no additional measures are planned on existing stations. This is partly due to the retirement shortly thereafter of much of the existing coal-fired capacity and its replacement with cleaner generation.

## FIGURE 7.5-2

## ACID GAS CONTROL PLAN

PLAN: ALL
PROGRAM: REFERENCE CASE

| FORECAST | GAS | 1994 | 1995 | 1996 | 1997 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| LOWER | SO2 | *L12-FGD* | | | | | | | | | | | |
| | NOx | *L12-CPM* | *L34-CPM* | | | | | | | | | | |
| DECREASING | SO2 | *L12-FGD* | *L34-FGD* | | | | | | | | | | |
| | NOx | *L12-CPM* | *L34-CPM* | | | *N14-CPM* | | | | | | | |
| MEDIAN | SO2 | *L12-FGD* | *L34-FGD* | | | | | | | | | | |
| | NOx | *L12-CPM* | *L34-CPM* | | | *N14-CPM* | | | | | | | |
| INCREASING | SO2 | *L12-FGD* | *L34-FGD* | | | | | | | *N12-FGD* | *N34-FGD* | | |
| | NOx | *L12-CPM* | *L34-CPM* | | | *N14-CPM* | | | | | | | |
| UPPER | SO2 | *L14-FGD* | | *N14-FGD* | *N58-FGD* | | | | | | | | |
| | NOx | | *L12-CPM* | *L34-CPM* | | *N12-CPM* | *N34-CPM* | | | | | | |

LEGEND: FGD - Flue Gas Desulphurization (Scrubbers)
CPM - Combustion Process Modification
L12 - Lambton TGS units 1 & 2
N14 - Nanticoke TGS units 1 to 4

1989 DEMAND/SUPPLY PLAN

Common to all Demand/Supply Plans are a number of items which affect future acid gas emissions. These include: maximum economic demand management and non-utility generation, the orderly development of remaining economic hydraulic resources, transmission improvements, and maximum use of available hydraulic and nuclear generation. Each of these reduce the amount of fossil generation required and, in turn, the production of acid gases. This leaves the retrofit of control measures, new nuclear generation, and utility purchases as the remaining options available to further reduce fossil generation.

A single representative plan for retrofits to existing facilities was applied to all plans. This is largely due to the fact that for a given load forecast, all plans are essentially the same up to the year 2000. Beyond that time there is some variation which is a result of differences in new generation brought into service. In all plans, however, all new generation will have lower acid gas emission rates than the existing generation replaced. Thus, the role of retrofits is to ensure compliance with existing regulations from now to the early 2000s.

The projected acid gas emissions are based on the Acid Gas Control Plan and an assumed fuel program. Over most years in the plan, flexibility is provided by a number of potential measures. Coal sulphur levels can be further reduced by utilizing very low sulphur coals such as Western Canadian coal. Prior to station retirement, R.L. Hearn TGS can be demothballed and operated on natural gas. Alternatively, another existing fossil station could be converted to operate on natural gas. These high cost measures remain in reserve to meet contingencies and load forecasts over and above those planned for.

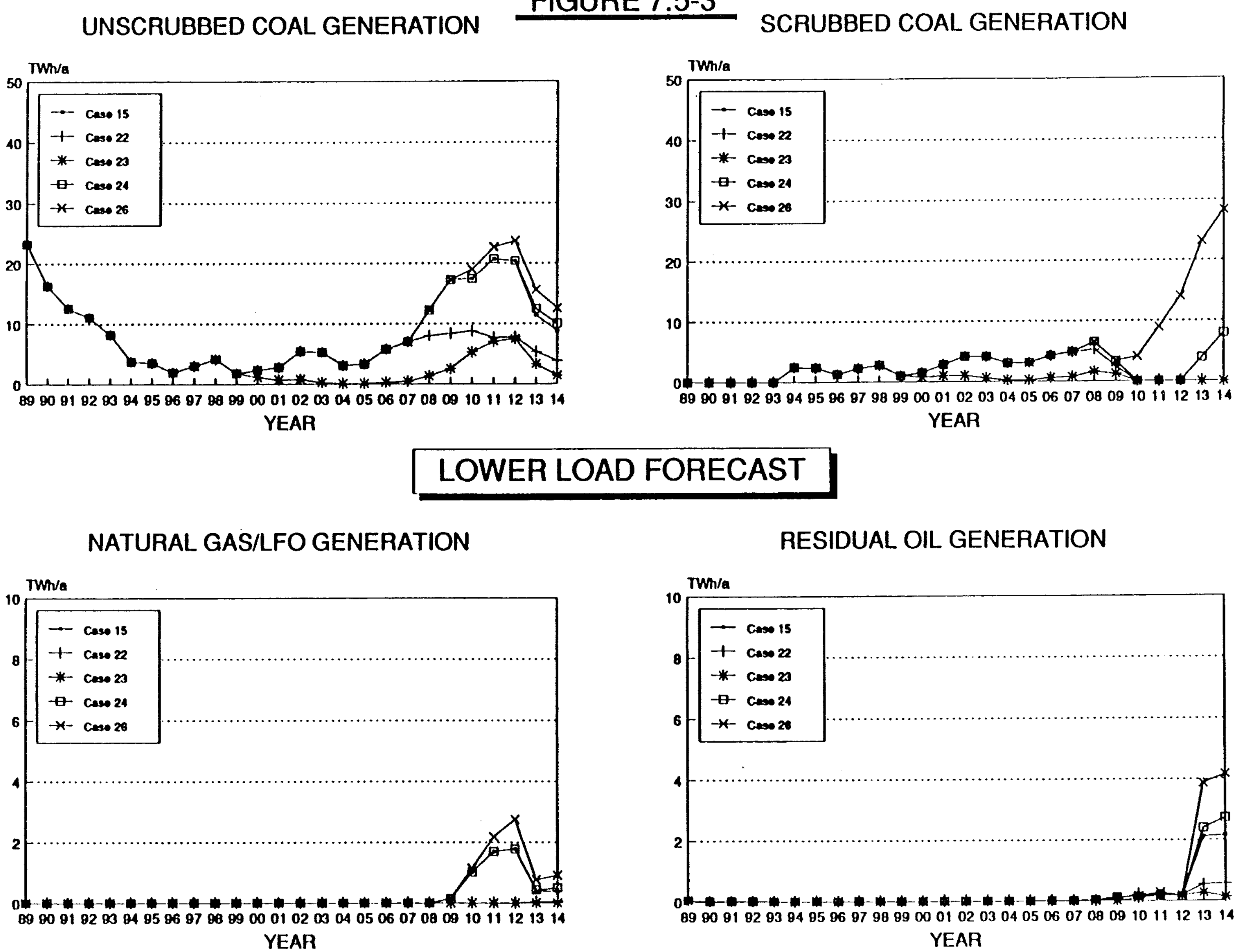
The Acid Gas Control Plan was applied to each of the Demand/Supply Plans in turn. The fossil fuel specific generation and corresponding acid gas emissions for all cases of each plan were determined and are presented in the following sections.

### 7.5.3 Fuel Specific Generation

The fossil fuel specific generation for each of the plans and load forecasts is shown in Figures 7.5-3 through 7.5-7. The fossil fuels are separated into four fuel types: scrubbed coal, unscrubbed coal, natural gas/light fuel oil (LFO), and residual oil.

Scrubbed coal refers to the coal utilized by existing fossil generating units equipped with scrubbers or new conventional steam cycle coal stations with scrubbers. It is assumed that these stations would be fuelled with a 2.5 percent sulphur US bituminous coal. Unscrubbed coal generation encompasses the

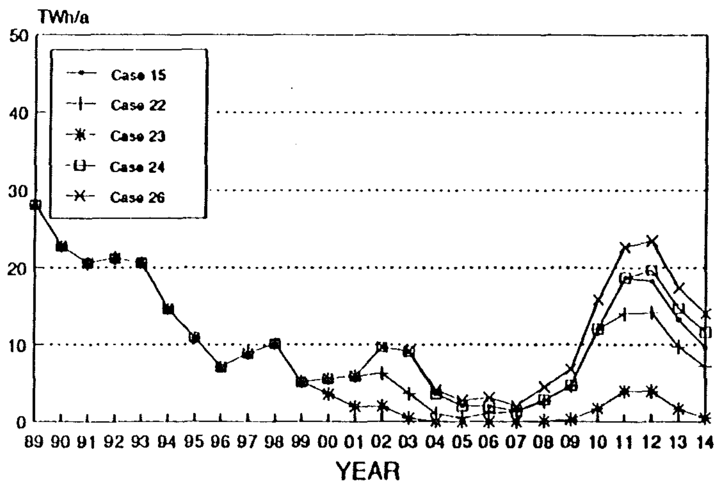
FIGURE 7.5-3


UNSCRUBBED COAL GENERATION
SCRUBBED COAL GENERATION
TWh/a
Case 15
Case 22
Case 23
Case 24
Case 26
YEAR
LOWER LOAD FORECAST
NATURAL GAS/LFO GENERATION
RESIDUAL OIL GENERATION

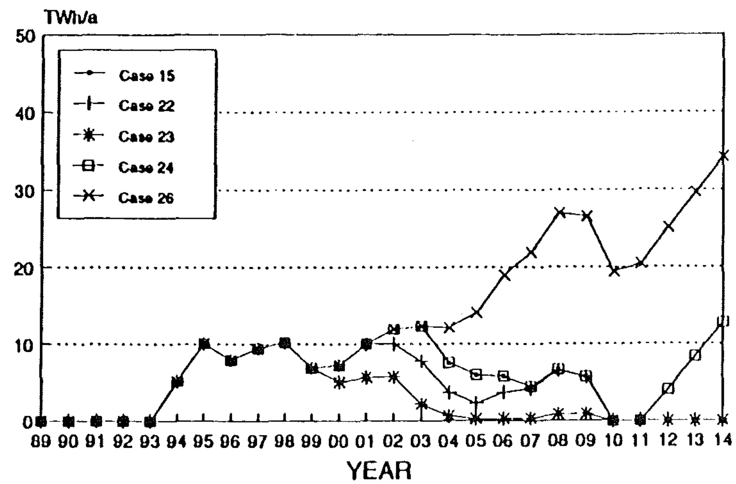
# FIGURE 7.5-4

## BRANCH LOWER FORECAST

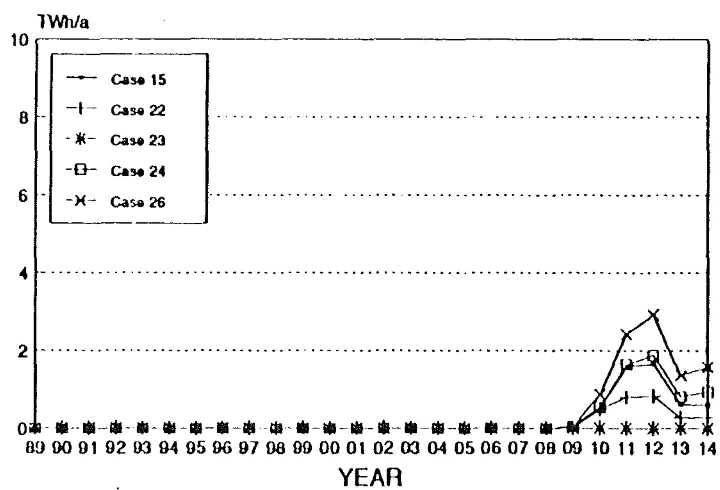
UNSCRUBBED COAL GENERATION



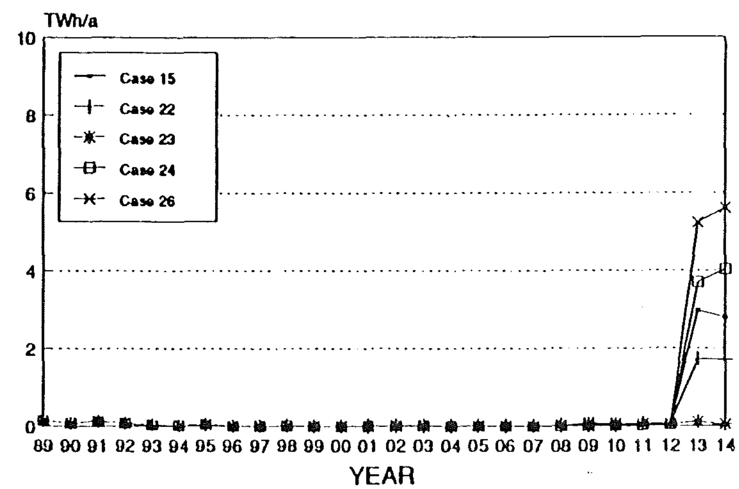

SCRUBBED COAL GENERATION




NATURAL GAS/LFO GENERATION



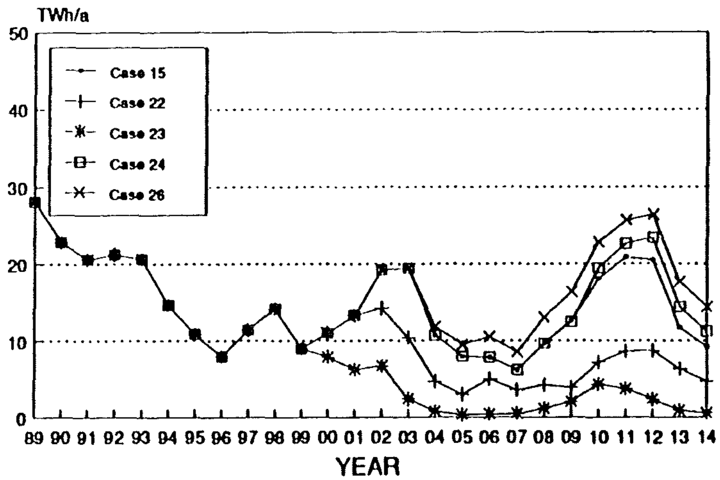

RESIDUAL OIL GENERATION



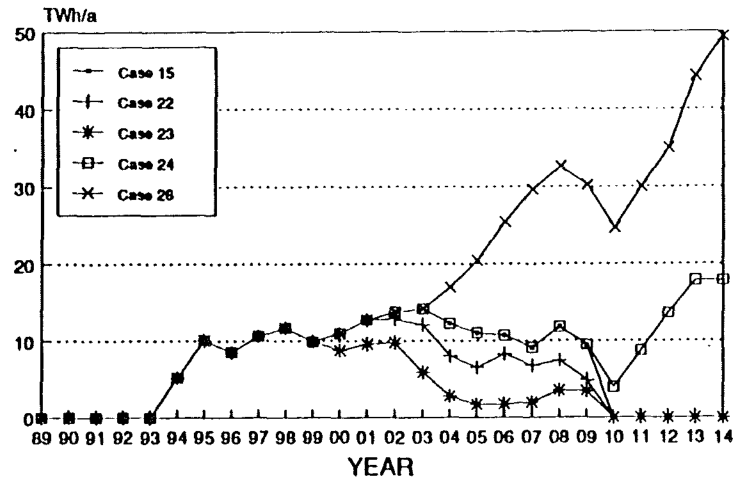
# FIGURE 7.5-5

## MEDIAN LOAD FORECAST

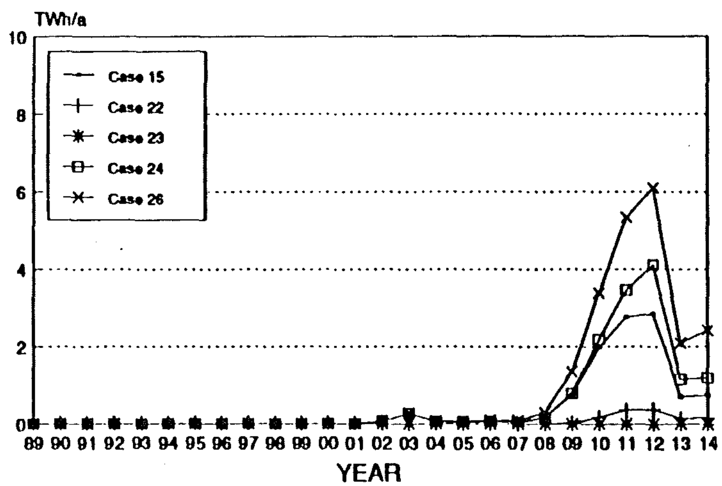
### UNSCRUBBED COAL GENERATION



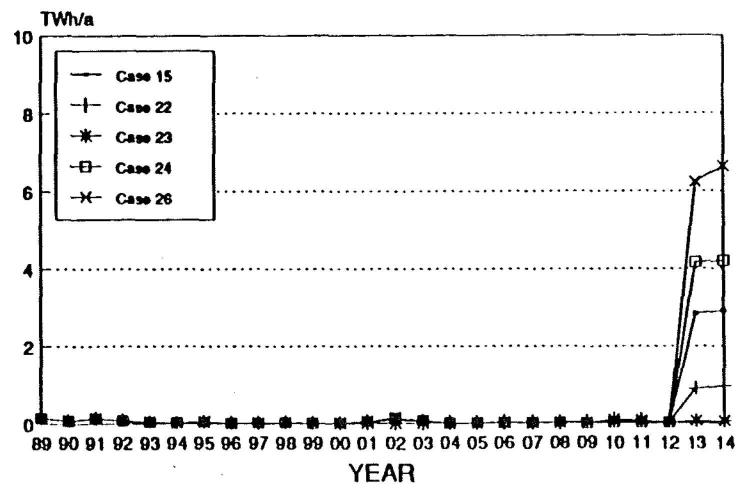

### SCRUBBED COAL GENERATION




### NATURAL GAS/LFO GENERATION

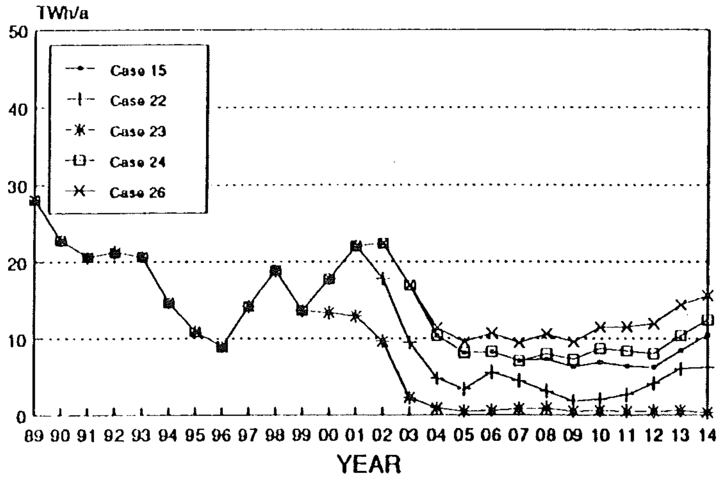



### RESIDUAL OIL GENERATION

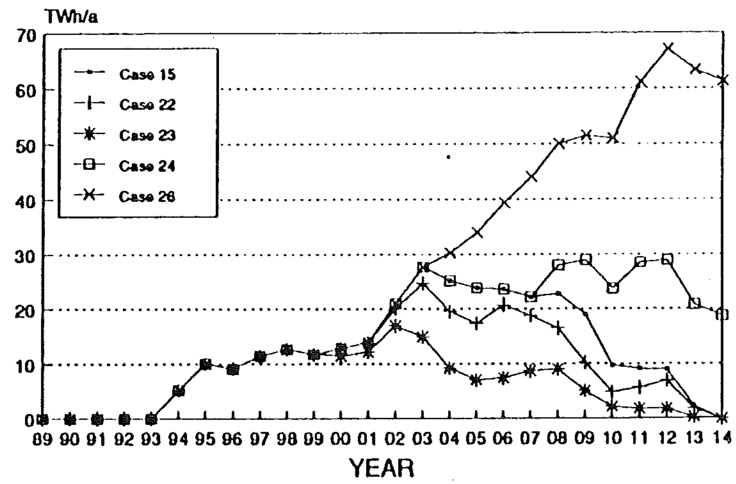


# FIGURE 7.5-6

## UNSCRUBBED COAL GENERATION

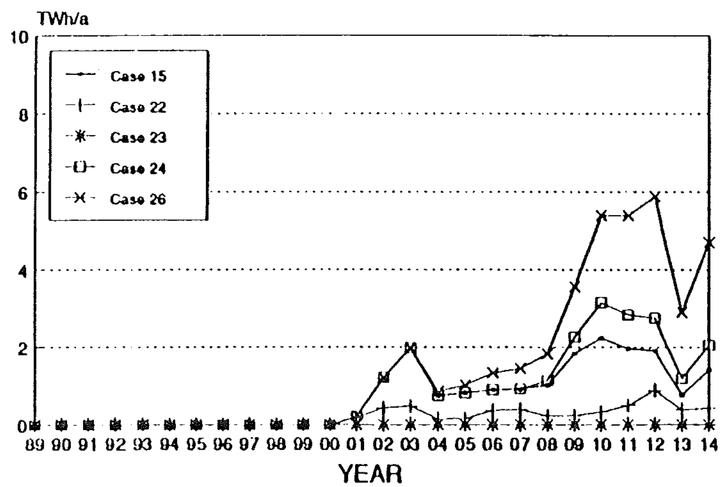



## SCRUBBED COAL GENERATION

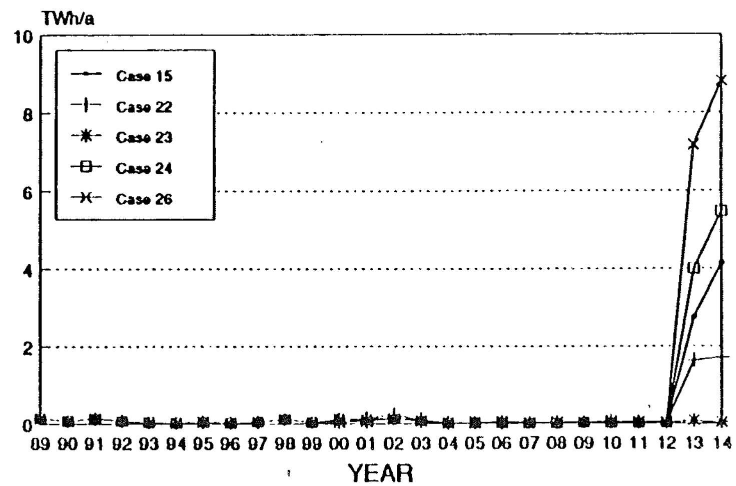



## BRANCH UPPER FORECAST

## NATURAL GAS/LFO GENERATION



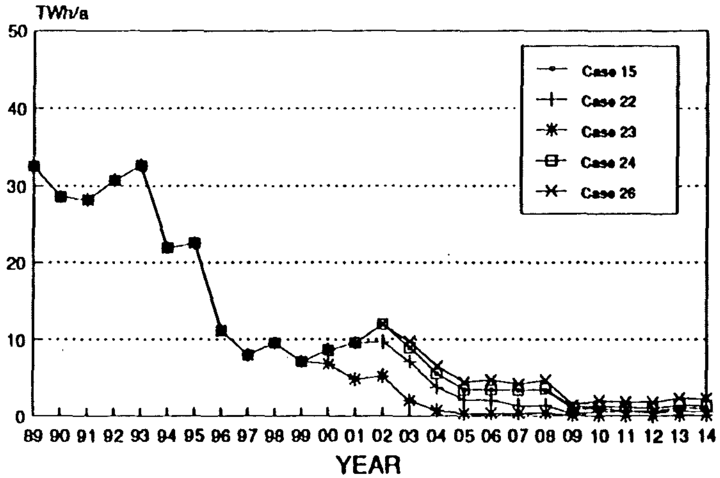

## RESIDUAL OIL GENERATION



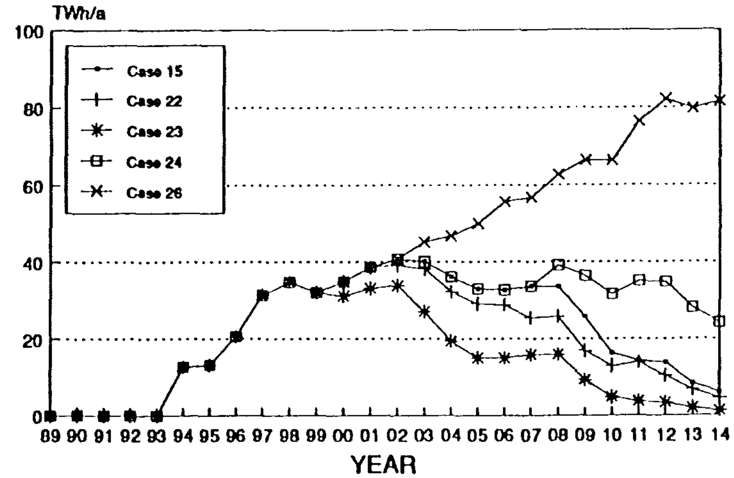
# FIGURE 7.5-7

## UPPER LOAD FORECAST

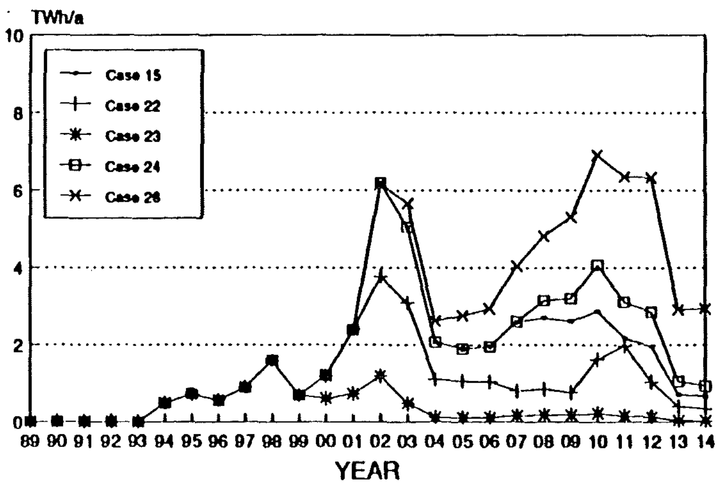
UNSCRUBBED COAL GENERATION



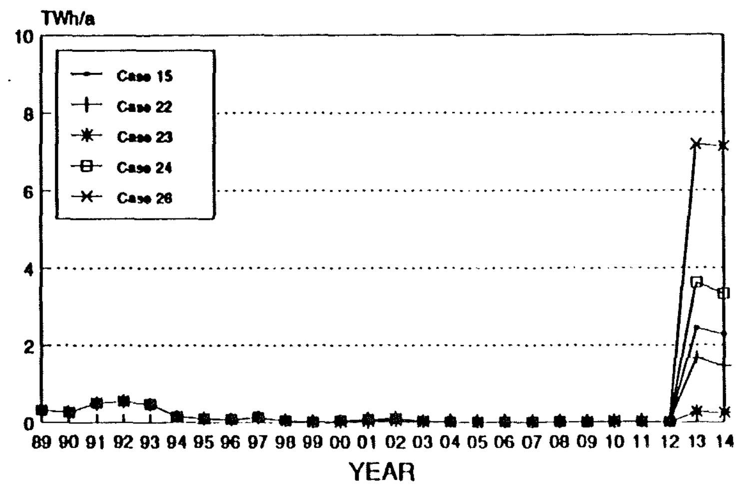

SCRUBBED COAL GENERATION




NATURAL GAS/LFO GENERATION




RESIDUAL OIL GENERATION



remaining coal used on the system. It includes both lignite and the bituminous coals used in the fossil units on the system which do not have scrubbers. Reduction in coal sulphur content for acid gas control is accomplished by adjustments in the sulphur content of the unscrubbed coal purchases. There is the potential to return R.L. Hearn TGS to service and operate it on natural gas, or to convert an other station such as Lakeview TGS to natural gas operation. In most cases, however, the consumption of this fuel is associated with new CTU and combined-cycle facilities. Residual oil generation is that generation associated with the use of Lennox TGS.

As expected, the fossil fuel specific generation is similar for all of the plans prior to the addition of new supply options. After this point, the fuel specific generation is a function of the type of generation added. Plans with new nuclear generation have the lowest fossil fuel generation and hence lowest fossil fuel requirements.

## 7.6 ANNUAL ACID GAS EMISSIONS

The estimated total annual acid gas emissions for each of the plans is shown in Figures 7.6-1 through 7.6-5. These are based on the Acid Gas Control Plan presented in section 7.5. Also shown in the figures are acid gas emissions, separated into $SO_2$ and $NO_X$. The focus of these estimates is on the long term post 1994 period.

Acid gas emissions are calculated to remain below the regulated limits in all cases. The amount by which the expected emissions are below the regulation represents the planning margin. Typically this corresponds to 9 TWh of additional fossil generation.

The Acid Gas Control Plan contains sufficient control measures to ensure the emission regulations are respected in all cases. In certain cases and under specific load forecasts, this represents more acid gas control equipment than is necessary. For example, in Case 22, branch upper load forecast, a second pair of scrubbers at Nanticoke is not required and could be eliminated. To maintain a consistent acid gas control program across all the cases, such refinements were not attempted.

The lower load forecast case for all plans does not require the retrofit of control measures to meet current acid gas emission regulations. It has been assumed for this case, however, that the installation of a single pair of scrubbers and CPM at Lambton TGS will proceed as currently envisaged.

FIGURE 7.6-1
# PROJECTED ACID GAS EMISSIONS
[Case 15]

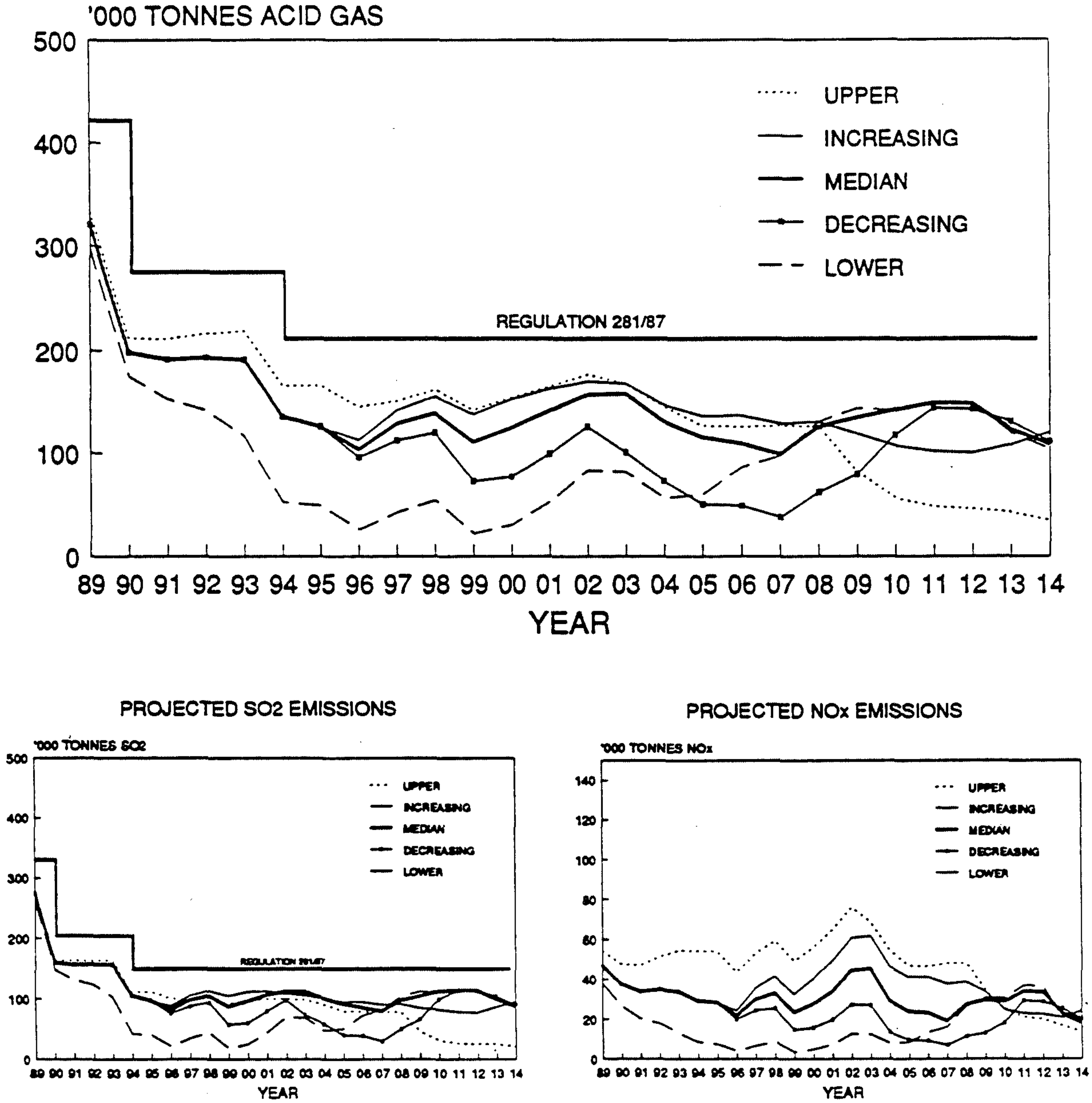


FIGURE 7.6-2
PROJECTED ACID GAS EMISSIONS
[Case 22]

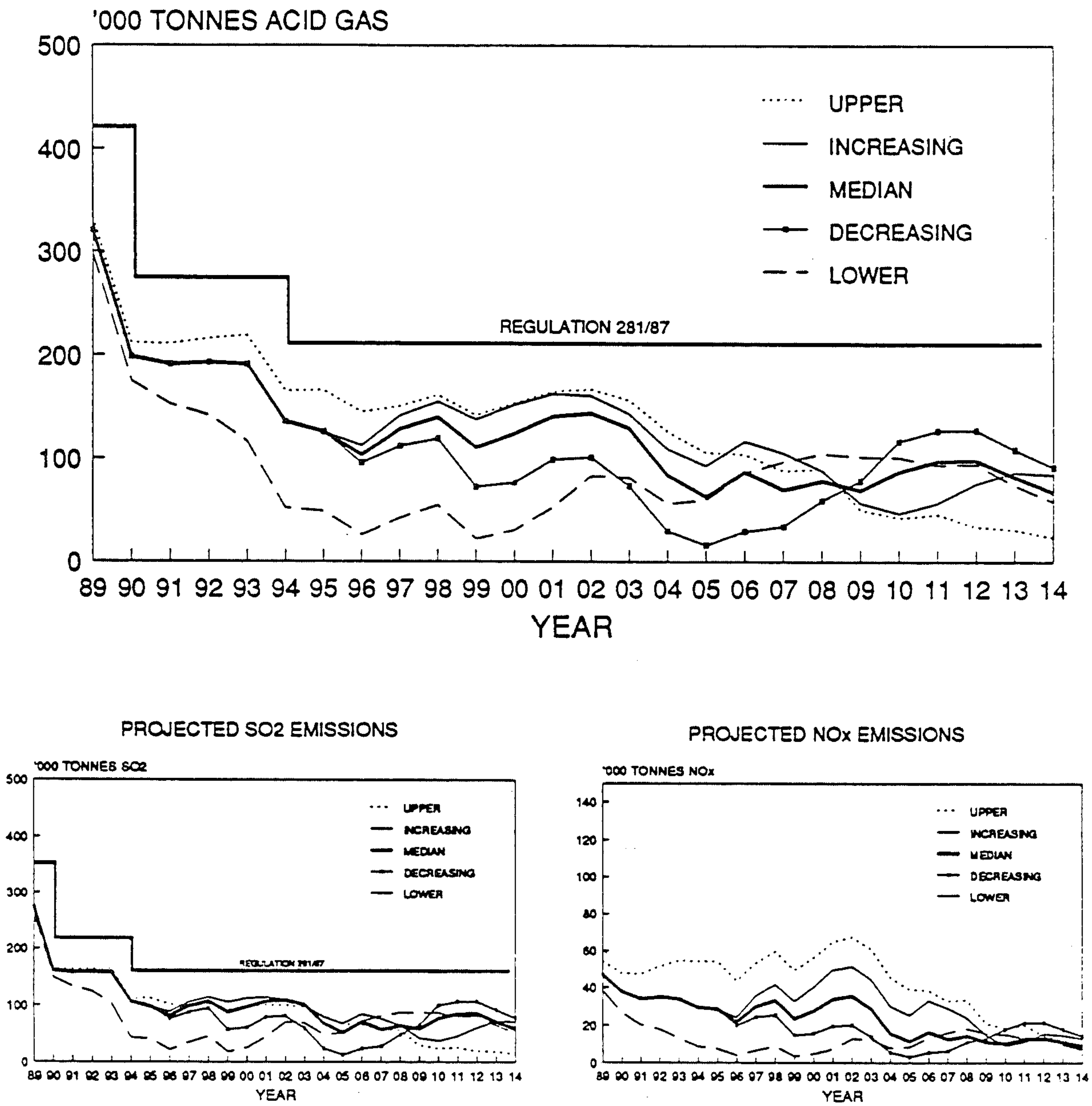
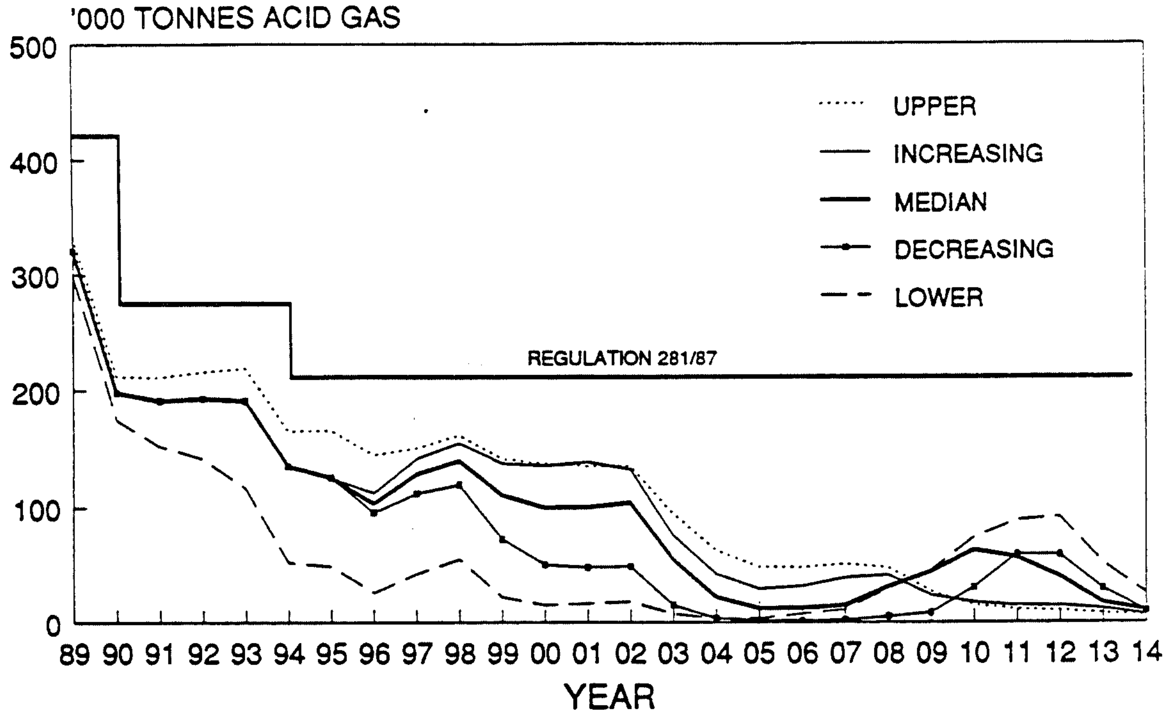


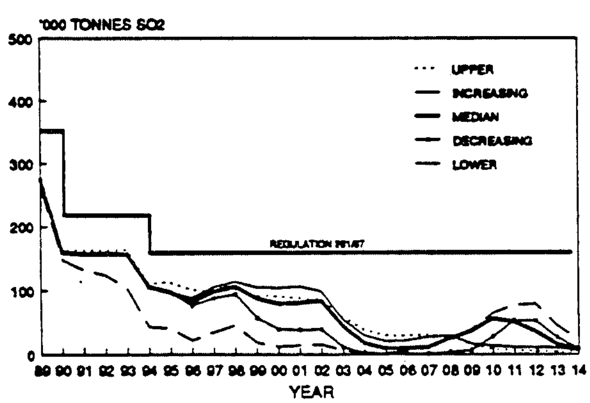
FIGURE 7.6-3

# PROJECTED ACID GAS EMISSIONS

## [Case 23]




PROJECTED SO2 EMISSIONS




PROJECTED NOx EMISSIONS

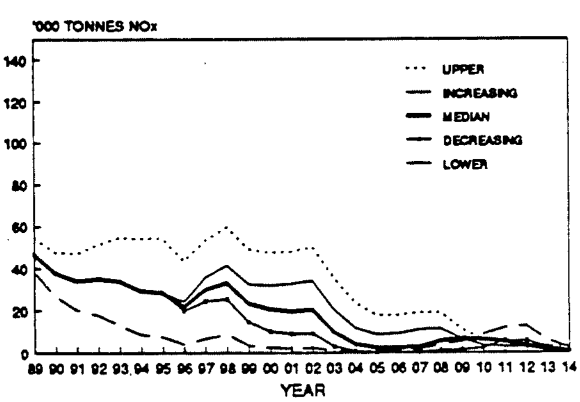


FIGURE 7.6-4

# PROJECTED ACID GAS EMISSIONS
[Case 24]

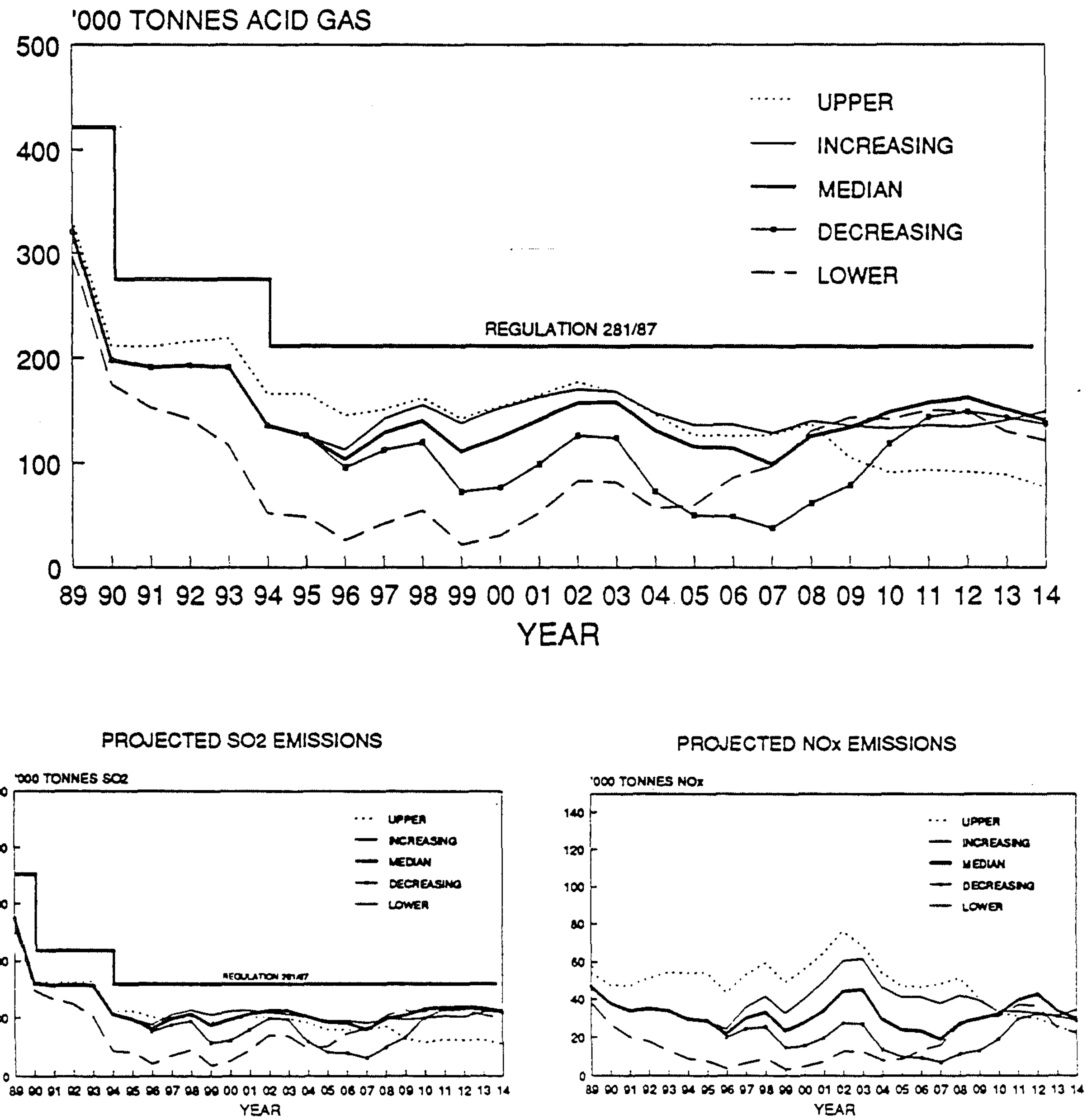
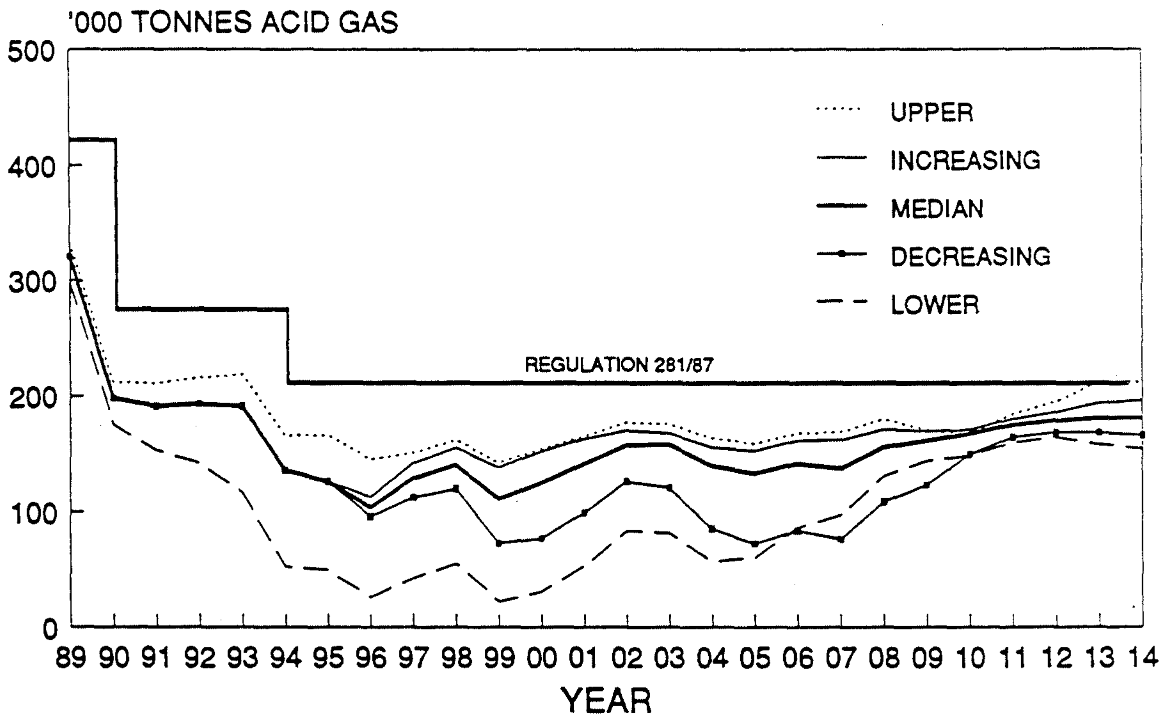
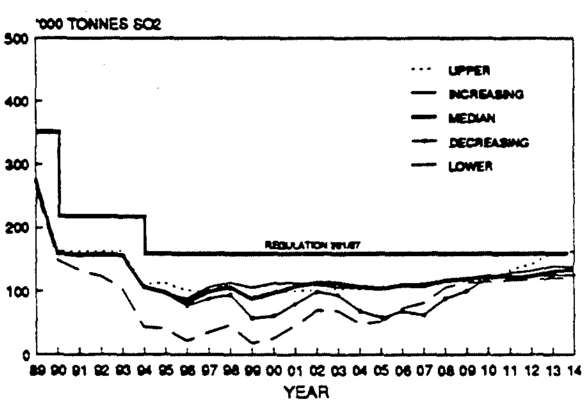


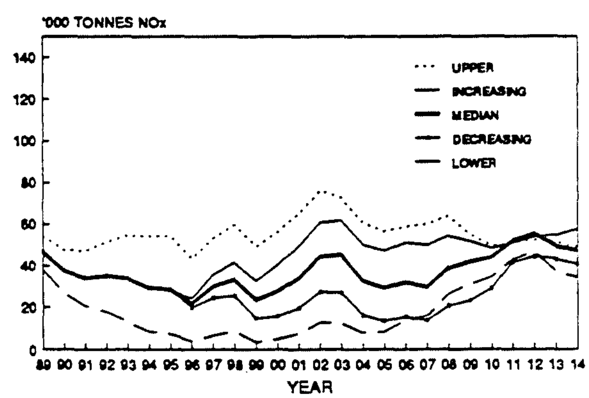
FIGURE 7.6-5
# PROJECTED ACID GAS EMISSIONS
[Case 26]




PROJECTED SO2 EMISSIONS




PROJECTED NOx EMISSIONS



The upper case requires greatly accelerated installation schedules for scrubbers and CPM at Lambton TGS and Nanticoke TGS. This would require an enormous effort by both Ontario Hydro and equipment manufacturers.

The Control Plan for the branch upper and branch lower cases is identical to the median case prior to the year 1999. This corresponds to the recognition date for the change in load forecast. This results in more acid gas control measures than is required in the branch lower load forecast case. The measures, however, are sufficient for the median and branch upper load forecast cases.

In the longer term, post 2000, acid gas emissions remain below regulated limits, through the retirement of existing fossil generation and the addition of new "cleaner" generation. This is true for all cases except Case 26. In this case, all new generation is fossil based. As a result, acid gas emissions tend to increase from the year 2005 onward. In the upper load forecast case, emissions are at the limit by the year 2014. If the 9 TW.h margin was included in the estimates, the emission limits would likely be exceeded if extraordinary measures were not undertaken. These measures could include the use of low sulphur coal in scrubbed fossil units and/or the increased use of natural gas.

## 7.7 ANALYSIS DATA

Station Emission Characteristics:

The acid gas emissions for the various plans were calculated utilizing generic emission factors for each of the fossil stations. These factors, in grams per kiloWatt-hour, are given in Figure 7.7-1. Blending of high and low sulphur coals is assumed in unscrubbed units, where advantageous.

FIGURE 7.7-1

Acid Gas Emission Factors

| Fuel/Generation Type | Emission Rates (g/kW.h) $SO_2$ | $NO_X$ |
|---|---|---|
| High Sulphur Coal | 16.70 | 1.70 |
| Low Sulphur Coal | 5.30 | 1.70 |
| Western Canadian Coal | 2.30 | 1.70 |
| Natural Gas | 0.00 | 1.80 |
| Unscrubbed Coal | 5.30 | 1.70 |
| Unscrubbed Coal with CPM | 5.30 | 1.36 |
| Scrubbed Coal | 1.64 | 1.40 |
| Scrubbed Coal with CPM | 1.64 | 1.12 |
| New Pulverized Coal Station | 1.64 | 0.25 |
| Lignite | 4.30 | 1.30 |
| CTU-Natural Gas | 0.00 | 1.20 |
| CTU-Oil | 0.00 | 1.90 |
| Combined-Cycle - Natural Gas | 0.00 | 0.80 |
| IGCC | 0.47 | 0.25 |
| Natural Gas | 0.00 | 1.20 |
| Residual Oil | 2.80 | 1.30 |

## 7.8 REVIEW

The emission of acid gases from Ontario Hydro's fossil-fired generating stations is constrained by regulated limits imposed by the Ontario government under the Environmental Protection Act. In order to ensure that the electricity demand in Ontario can be satisfied while remaining within the enacted regulations, Ontario Hydro must implement acid gas control measures where and when required.

In managing acid gas emissions to protect the environment, Ontario Hydro's acid gas control policy is to: meet or better government regulated limits; aim for stepped reductions in each year to 1994; and achieve reductions in a cost effective manner. The actions selected to meet emission regulations follow an underlying acid gas control strategy consistent with this policy. The three elements of the strategy are: select cost effective measures on the basis of marginal cost to the system; maintain adequate flexibility to respond to deviations from expectations; and keep sufficient options in reserve to meet unforeseen contingencies.

There are several control options capable of reducing acid gas emissions. Demand Management, non-utility generation, hydraulic and nuclear generation, electricity imports, reducing planned sales, and transmission improvements can reduce acid gas emissions by displacing fossil-fired generation. Acid gas emissions can be reduced by burning lower sulphur coals, natural gas, or lower sulphur oil. As well, the retrofit of emission control equipment to existing stations will reduce these emissions.

Emission control equipment includes high efficiency scrubbers and injection technology for $SO_2$ control and combustion process modifications, injection technologies and Selective Catalytic Reduction for $NO_X$ control.

Representative Acid Gas Control Plans were developed which combine a variety of control measures into separate control programs for each of the five load forecasts analyzed. While each program is capable of meeting current emission regulations, the measures may be reduced or supplemented as required in the future.

In all of the programs acid gas control is accomplished through two primary measures - the retrofit of control equipment to existing fossil stations, and the use of lower sulphur fuel (eg. low sulphur coal). Retrofits of control equipment to existing stations are designated major control measures as they involve capital modification to the station and require scheduling of design, construction and installation. The schedule for these measures extends to the year 2005. Beyond that date, no additional measures are planned on existing stations.

Acid gas emissions are calculated to remain below the regulated limits in all cases. The amount by which the expected emissions are below the regulation represents the planning margin. Typically this corresponds to 9 TWh of additional fossil generation. This is true for all cases except Case 26. In this case, all new generation is fossil based. As a result, acid gas emissions tend to increase from the year 2005 onward. In the upper load forecast case, emissions are at the limit by the year 2014.

Over most years in the plan, additional flexibility is provided by a number of potential measures. Coal sulphur levels can be further reduced by utilizing very low sulphur coals. Prior to retirement, R.L. Hearn TGS can be demothballed and operated on natural gas or another existing fossil station could be converted to operate on natural gas. These high cost measures remain in reserve to meet contingencies and load forecasts over and above those planned for.

# 8. COSTS

## 8.0 INTRODUCTION

This chapter supplements the cost information presented in Chapter 15 of the DSP Report. It explains how costs are calculated for the Demand/Supply Plans and provides more information on:

- the model used to compute plan costs
- the allocation of capital and fixed costs
- the derivation of costs of the existing system and future systems
- the sensitivity analysis of costs
- the probalility analysis for calculating expected costs
- the cumulative probability distributions of plan costs and differences relative to one another

## 8.1 COST RESULTS

This chapter also provides more details on the cost results.

For each of the five demand/supply plans described earlier in Chapter 4, costs are presented for all five load forecast paths considered in the plan formulation -- median, branch upper, upper, branch lower and lower.

Details of the sensitivity analyses that identify the significant variables to use in the probability analysis are described.

Results from the probability analysis are also shown. Cost bands are described for cases where each cost estimate, such as the discount rate, is fixed at its low, median and upper value, while all other estimates are allowed to vary. This provides additional information on the sensitivity of plan costs to certain conditions.

The next section, 8.2, describes the model used to analyze costs, its data sources, the model's capabilities and the allocation of present value costs.

The third section describes several applications of the model. In particular, there is an explanation of the calculations of the values in Figure 15-46, Cost of Ontario

Hydro New Major Supply, and Figure 15-47, Total Cost of New Demand/Supply Options and Operating the Existing System, both of the DSP Report.

The fourth section describes the sensitvity studies done to identify which cost estimates have the most significant influence in the evaluation of plan costs.

The last section contains the details on the probability analyses.

## 8.2 BUILDING THE RISK ASSESSMENT MODEL

Figure 8.2-1 presents an overview of the flow of data in and out of the Risk Assessment Model (RAM). This was used as the cost evaluation tool.

For each demand/supply case and under each load forecast path, there is a unique application of RAM. This model integrates the life cycle cost data for the options and economic values (escalation and discount rates) and carries out deterministic and probabilistic analyses for the present value cost evaluation. Central to this evaluation is the allocation of costs to the planning period, 1989 to 2014.

The following paragraphs describe the main elements and data sources of the process. As well, a description of cost allocation in RAM is provided. Specific model applications and analyses are described in Sections 8.3, 8.4 and 8.5.

### 8.2.1 Demand/Supply Plans

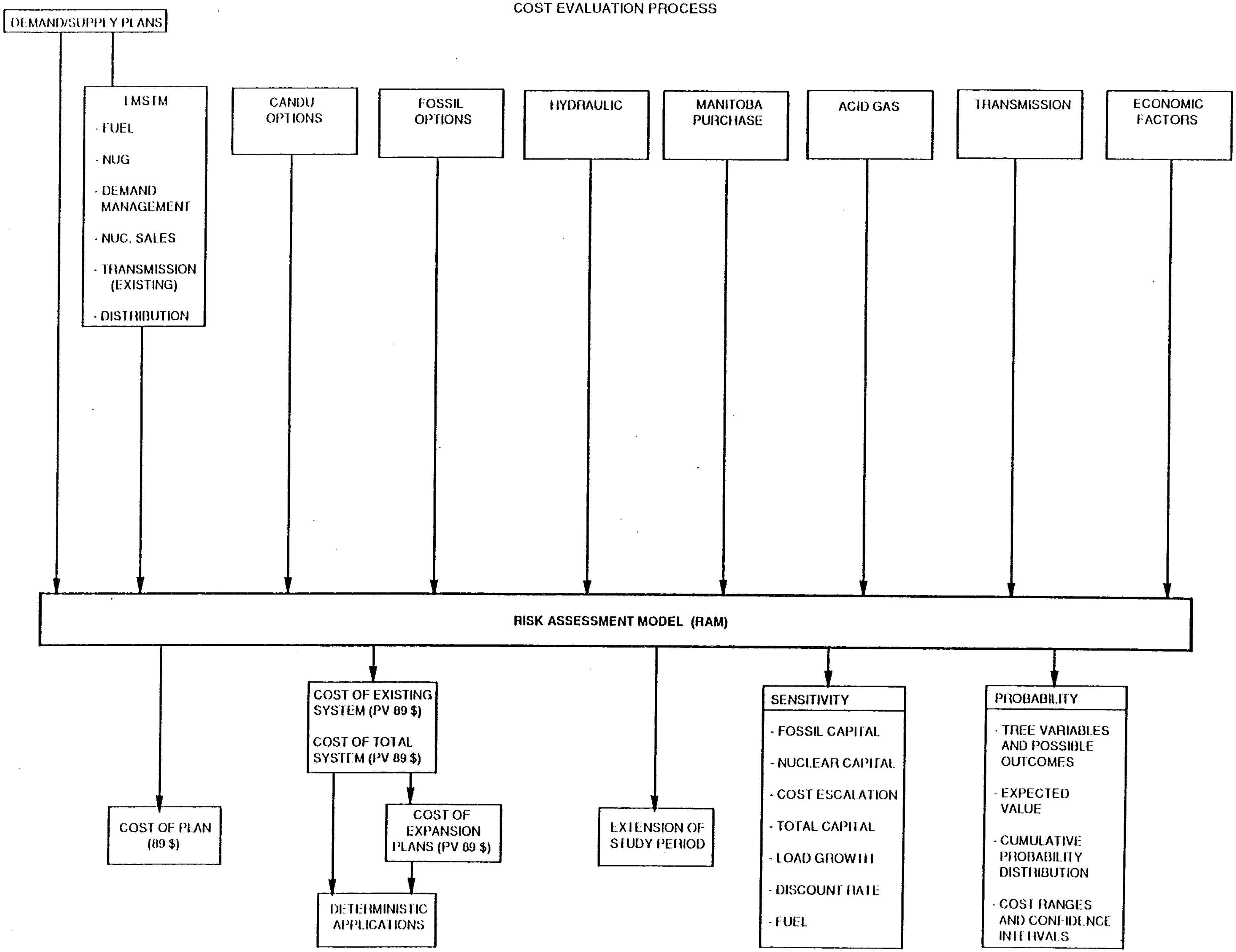
Chapter 4 defines the demand/supply cases with their specific options and in-service dates for supply options. This information is fundamental for building a cost model.

### 8.2.2 LMSTM

The production simulation model used in the development of the Plan is referred to as LMSTM. Details of this model are discussed in Chapter 2.

LMSTM provided costs of variable OM&A for nuclear, fossil and acid gas controls, hydraulic OM&A, fuel and fuel related costs and water rentals. In addition, LMSTM output is used for other capital and other operating costs, such as demand management, non-utility generation, existing and incremental growth related transmission costs, and total distribution costs.

FIGURE 8.2-1
COST EVALUATION PROCESS






F/X

### 8.2.3 CANDU Option Costs

CANDU nuclear cost data are based on the Ontario Hydro Presentations to the Ontario Nuclear Cost Inquiry (ONCI). These costs were reveiwed by an independent panel, appointed by the Ontario government. The Panel concluded that the cost estimates are complete and are appropriate for use in planning.

The life cycle costs include: capital costs for design, approval, construction, commissioning, retubing (i.e. fuel channel replacement), capital modifications during the operating life, decommissioning and associated overheads; operating, maintenance and administration (OM&A) costs for ongoing training, labour, material, purchased services, interest on inventories, overheads and the heavy water costs associated with tritium removal, upgrading and makeup; and fuel costs for acquistion and fuel waste management, including disposal. Life cycle costs include those costs attributable to the option after its assumed station life (40 years).

### 8.2.4 Fossil Option Costs

The costs of fossil options are based on the Thermal Cost Review. These costs were requested by Hydro's Board of Directors and underwent an independent expert review by consultants.

Life cycle cost categories for capital, OM&A and fuel costs are similar to those for the nuclear option. Also included are capital, OM&A and fuel related costs for acid gas controls, where appropriate.

### 8.2.5 Hydraulic Costs

Hydraulic costs are drawn from Ontario Hydro's estimates associated with each proposed development.

The cost of the Hydraulic Plan, as described in Chapter 12 of the DSP Report, is common to all demand/supply plans. Life cycle costs for the proposed projects within the Hydraulic Plan are captured in the LMSTM and RAM models. These costs include capital, OM&A and water rental charges over the assumed station service lives (90 years).

### 8.2.6 Manitoba Purchase

The cost of the Manitoba Purchase is common to all demand/supply plans. The costs included in the plans are for capacity, energy and energy credits associated with the transmission capability. The cost of capacity and energy are derived from the Manitoba-Ontario Power Transaction Agreement of December 7, 1989, and the

Electricity Sale Agreement of August 28, 1987. The energy credits are cost savings derived from the capability of the transmission lines to incorporate additional short term economy electricity sales.

### 8.2.7 Acid Gas Controls For The Existing System

Acid gas control costs are derived from Ontario Hydro's estimates.

Life cycle costs include capital costs such as design, approvals, construction, commissioning, operator training, capital modification and rehabilition during the station's operating life, and OM&A costs associated with operating the control equipment.

### 8.2.8 Transmission

Capital costs for new transmission are taken from studies described in Chapter 5. Other capital and all transmission OM&A are taken from LMSTM.

### 8.2.9 Economic Factors

Discount rates, escalation rates and their bands (i.e. low, median and upper estimates) are input to RAM. Ontario Hydro's Economic Outlook of September 1988 is the basis for the Corporate Financial Discount Rate (CFDR), the various escalation rates, Consumer Price Index (CPI) and provincial Gross Domestic Product (GDP) used in RAM.

### 8.2.10 Basic Functions of RAM

RAM was built to perform the risk assessment and calculate the costs for every individual case. More specifically, the Risk Assessment Model performs the following basic functions:

- integrate all cost data involved in the financial evaluation of the cases
- integrate all economic parameters required for financial evaluations
- provide the present value cost for each case and load forecast path (both total cost and by major cost groups), and
- perform financial sensitivity analyses and probabilistic simulations.

### 8.2.11 Allocation of Costs

One important feature performed by RAM is computing present value costs allocated to the planning period.

Present value costs are used in order to compare plans that have different patterns of expenditures for capital, OM&A, and fuel costs. Chapter 6 of the DSP Report dicusses this and other cost concepts.

The method used to allocate the present value of fixed costs recognizes that some options will have a life that ends after the planning period (1989-2014). Examples of these fixed costs are the acquisition costs of design, approval, construction, commissioning and capital modification.

The present value of fixed costs is allocated on the basis of unit-years. A unit-year is one unit operating for one year. Unit-years are used to calculate an allocation factor, which is applied to the present value of total fixed costs.

What follows is an example of the process for allocating acquisition costs attributable to a 4x881 MW CANDU station, in which units are placed in service on an annual basis beginning in January of 2004. The same process applies to the allocation of post in-service fixed costs such as capital modifications, and total fixed OM&A.

Figure 8.2-2 illustrates the calculation of the present value cost to be allocated to the planning period. The second column lists the acquisition costs, which are in 1988 dollars as expressed in ONCI. The third column lists the present value of these costs. These are calculated using specific escalation rates associated with nuclear projects and Hydro's Corporate Financial Discount Rate (CFDR). The total present value of acquisition costs in 1989 dollars is 3,550.4 M$.

A portion of this present value total for acquisition of a CANDU generating station is allocated to the planning period. The allocation is based on the ratio of the present value of unit-years within the planning period to the present value of unit-years for the entire station life. Calculating the present value of unit-years is necessary to equate the present value of life cycle expenditures to the present value of costs allocated over the station life.

The fourth column lists the unit-years for the entire life of the station. The total is 153 unit-years, which includes the effects of retubing. The fifth column is a listing of the present value factors for each year that are to be applied to the unit-years. These factors are derived using GDP as the escalation rates and CFDR as the discount rate. The procedure is similar to that used to determine the present value of a cash flow.

The sixth column is the cumulative present value total of unit-years. For example, by the end of 2006, the cumulative present value of unit-years is 1x0.466 plus 2x0.444 plus 3x0.422, which equals 2.62.

**FIGURE 8.2 - 2**

EXAMPLE OF ALLOCATING THE PRESENT VALUE ACQUISITION COSTS
OF A 4 * 881 MW CANDU GENERATING STATION

| YEAR | ACQUISITION COST 1988$M | PRESENT VALUE OF ACQUISITION COSTS '89 PV $M | UNIT YEARS | UNIT YEAR PV FACTOR (REAL/GDP) | CUMULATIVE PV OF UNIT YEARS |
|---|---|---|---|---|---|
| 1989 | 1.04 | 1.06 | | 1.023 | 0.00 |
| 1990 | 3.39 | 3.30 | | 0.968 | 0.00 |
| 1991 | 10.35 | 9.63 | | 0.917 | 0.00 |
| 1992 | 37.75 | 33.46 | | 0.871 | 0.00 |
| 1993 | 50.59 | 42.67 | | 0.826 | 0.00 |
| 1994 | 49.59 | 39.91 | | 0.781 | 0.00 |
| 1995 | 51.05 | 39.19 | | 0.739 | 0.00 |
| 1996 | 131.85 | 96.88 | | 0.700 | 0.00 |
| 1997 | 262.81 | 185.60 | | 0.665 | 0.00 |
| 1998 | 472.06 | 320.03 | | 0.631 | 0.00 |
| 1999 | 710.30 | 461.77 | | 0.599 | 0.00 |
| 2000 | 948.57 | 591.33 | | 0.567 | 0.00 |
| 2001 | 1053.10 | 630.41 | | 0.539 | 0.00 |
| 2002 | 939.28 | 540.70 | | 0.514 | 0.00 |
| 2003 | 615.47 | 340.70 | | 0.489 | 0.00 |
| 2004 | 291.97 | 155.42 | 1 | 0.466 | 0.47 |
| 2005 | 87.21 | 44.64 | 2 | 0.444 | 1.35 |
| 2006 | 27.08 | 13.34 | 3 | 0.422 | 2.62 |
| 2007 | 0.76 | 0.36 | 4 | 0.402 | 4.23 |
| 2008 | | 0.00 | 4 | 0.383 | 5.76 |
| 2009 | | 0.00 | 4 | 0.365 | 7.22 |
| 2010 | | 0.00 | 4 | 0.347 | 8.61 |
| 2011 | | 0.00 | 4 | 0.331 | 9.93 |
| 2012 | | 0.00 | 4 | 0.316 | 11.19 |
| 2013 | | 0.00 | 4 | 0.302 | 12.40 |
| 2014 | | 0.00 | 4 | 0.288 | 13.55 |
| 2015 | | 0.00 | 4 | 0.275 | 14.65 |
| 2016 | | 0.00 | 4 | 0.263 | 15.71 |
| 2017 | | 0.00 | 4 | 0.252 | 16.71 |
| 2018 | | 0.00 | 4 | 0.241 | 17.68 |
| 2019 | | 0.00 | 4 | 0.230 | 18.60 |
| 2020 | | 0.00 | 4 | 0.221 | 19.48 |
| 2021 | | 0.00 | 4 | 0.211 | 20.33 |
| 2022 | | 0.00 | 4 | 0.202 | 21.13 |
| 2023 | | 0.00 | 4 | 0.193 | 21.91 |
| 2024 | | 0.00 | 4 | 0.185 | 22.64 |
| 2025 | | 0.00 | 4 | 0.177 | 23.35 |
| 2026 | | 0.00 | 4 | 0.169 | 24.03 |
| 2027 | | | 4 | 0.162 | 24.67 |
| 2028 | | | 4 | 0.155 | 25.29 |
| 2029 | | | 4 | 0.148 | 25.89 |
| 2030 | | | 4 | 0.142 | 26.45 |
| 2031 | | | 3 | 0.136 | 26.86 |
| 2032 | | | 3 | 0.130 | 27.25 |
| 2033 | | | 3 | 0.124 | 27.62 |
| 2034 | | | 3 | 0.119 | 27.98 |
| 2035 | | | 3 | 0.114 | 28.32 |
| 2036 | | | 3 | 0.109 | 28.64 |
| 2037 | | | 4 | 0.104 | 29.06 |
| 2038 | | | 4 | 0.099 | 29.46 |
| 2039 | | | 4 | 0.095 | 29.84 |
| 2040 | | | 4 | 0.091 | 30.20 |
| 2041 | | | 4 | 0.087 | 30.55 |
| 2042 | | | 4 | 0.083 | 30.88 |
| 2043 | | | 4 | 0.080 | 31.20 |
| 2044 | | | 4 | 0.076 | 31.51 |
| 2045 | | | 1 | 0.073 | 31.58 |
| 2046 | | | | 0.070 | 31.58 |
| 2047 | | | | 0.067 | 31.58 |
| 2048 | | | | 0.064 | 31.58 |
| 2049 | | | | 0.061 | 31.58 |
| 2050 | | | | 0.058 | 31.58 |
| TOTAL | 5744.20 | 3550.40 | 153.00 | | |

TOTAL 1989 PV = 3550.4 M$
PV OF UNIT YEARS TO 2014 = 13.55
PV OF UNIT YEARS FOR STATION LIFE = 31.58
PV FACTOR FOR ALLOCATION = 43%
PV ALLOCATED ACQUISITION COST = 1523.7 M$

The cumulative present value of unit-years to the end of the planning period, 2014, is 13.55; to the end of the station life, it is 31.58. The ratio of these values, 0.429, is multiplied by the present value total of acquisition costs, resulting in an allocated present value cost of 1,523.7 M$ in 1989 dollars.

For this station, 43% of the total present value cost is allocated. This equals in $1.523 billion.

If the planning period were longer, additional fixed costs would be allocated to the period. For example, if the planning period included years up to 2045, then all of the acquisition costs for the station would be allocated.

The key result of this allocation process is that it takes into account the life cycle costs of the options. It provides a basis to compare cases that have options with different in-service dates and different service lives. Compared to a simple prorating approach, this process allocates more costs to the early years of the station's life.

The same allocation method was used for the fixed costs of all new fossil options, acid gas measures and transmission projects. The allocation of the hydraulic capital program and the Manitoba Purchase, which are common to all plans, was also calculated in a similar fashion.

To complete the calculation of a plan's present value cost, the present value of other annual costs, such as variable OM&A, and fuel and fuel related costs, are added to the allocated fixed costs.

## 8.3 DETERMINISTIC COSTS

As illustrated earlier in Figure 8.2-1, deterministic cost evaluations are one of several applications of the risk assessment models.

The deterministic applications described here include the main costs of the proposed DSP in 1989 dollars and two figures from the DSP Report: Figure 15-46, Cost of Ontario Hydro New Major Supply, and Figure 15-47, Total Cost of New Demand/Supply Options and Operating the Existing System. As well, to complement the illustration provided for median load in the latter set, similar figures are shown for the other four load forecasts.

### 8.3.1 Cost of Proposed Plan in 1989 Dollars

The magnitude of costs for main components of the Proposed Plan is presented in Figure 8.3-1 in January 1989 dollars.

The elements of the costs shown in Figure 8.3-1 are:

- Nuclear costs correspond to the capital costs of new plants;

- Fossil cost consists of the capital costs of all new options and acid gas control retrofits on existing plants;

- Purchase NUGs cover cost of purchase from planned non-utility generators;

- Demand Management and Load Displacement NUG are expenses for Ontario Hydro and participants on current and future programs;

- Manitoba Purchase comprises both the new 1,000 MW deal and the previous agreement of 200 MW;

- Hydraulic corresponds to capital costs incurred for new projects;

- Transmission cost apply to new site-specific projects (radial and inter-area); and

- Fuel consists of a portion of the total fuel bill that can be attributed to load growth beyond year 1993.

Figure 8.3-1
Proposed Demand/Supply Plan Period 1989 to 2014

| Component | 1989 Billion Dollars* |
|---|---|
| Nuclear | 19.1 |
| Fossil | 3.2 |
| Purchase NUGs | 6.2 |
| Demand Management and Load Displacement NUG | 10.3 |
| Manitoba Purchase | 3.8 |
| Hydraulic | 4.8 |
| Transmission | 2.7 |
| Fuel for Growth beyond 1993 | 10.4 |
| Total | 60.5 |

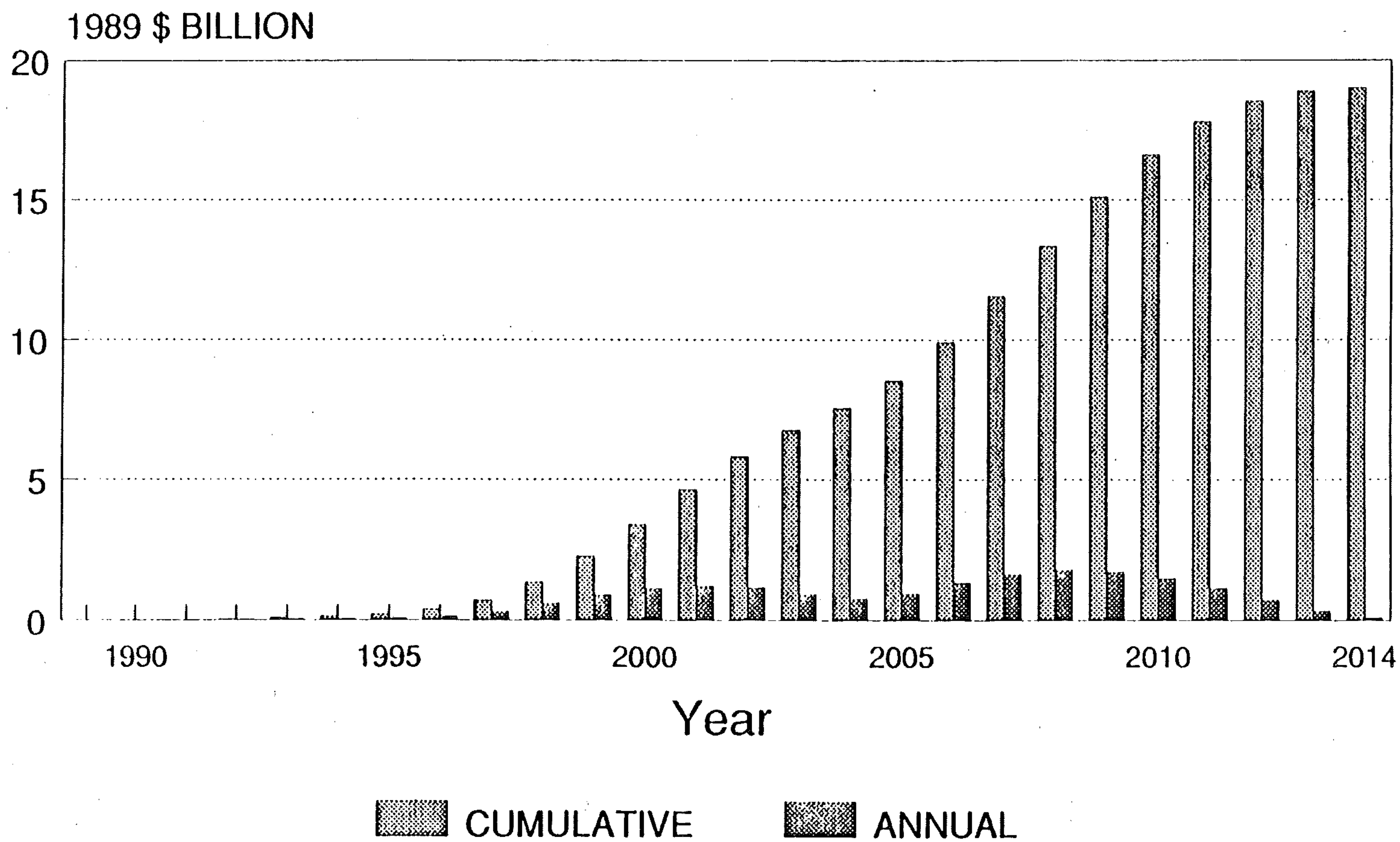
*Note: Totals were rounded.

Figures 8.3-2 through 8.3-10 show both the cumulative and annual expenses of the above components according to their planned cash flow schedules. In some instances, annual costs end before year 2014; in others, cash flows continue beyond 2014, the end of the study period.

If interest and cost escalation were subsequently added, the costs discussed in this section would be higher.

FIGURE 8.3-2

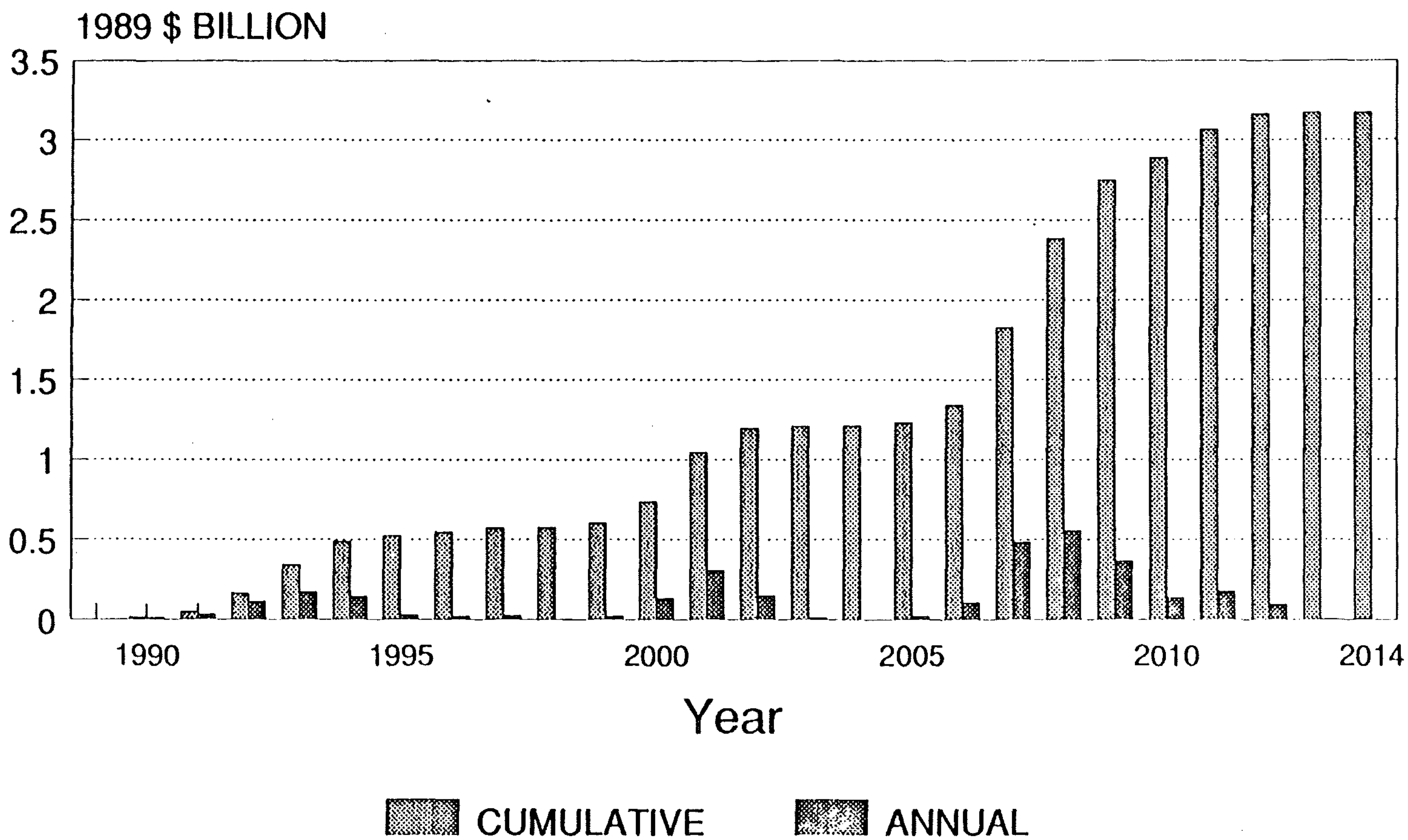
# CASE 15 - MEDIAN LOAD
## NEW NUCLEAR CAPITAL




CASH FLOW FROM 1989 TO 2014

FIGURE 8.3-3

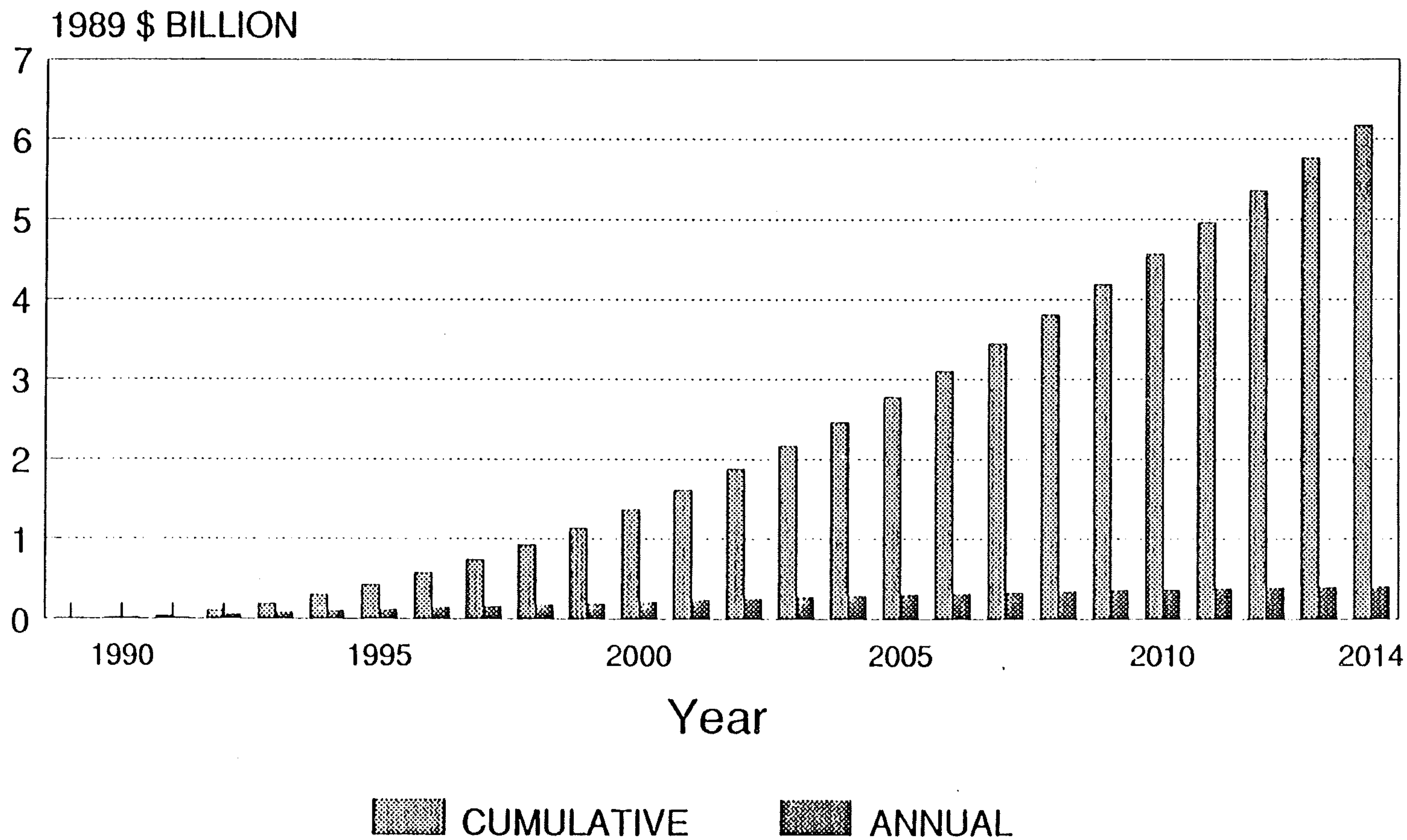
# CASE 15 - MEDIAN LOAD
## NEW FOSSIL CAPITAL




CASH FLOW FROM 1989 TO 2014

FIGURE 8.3-4

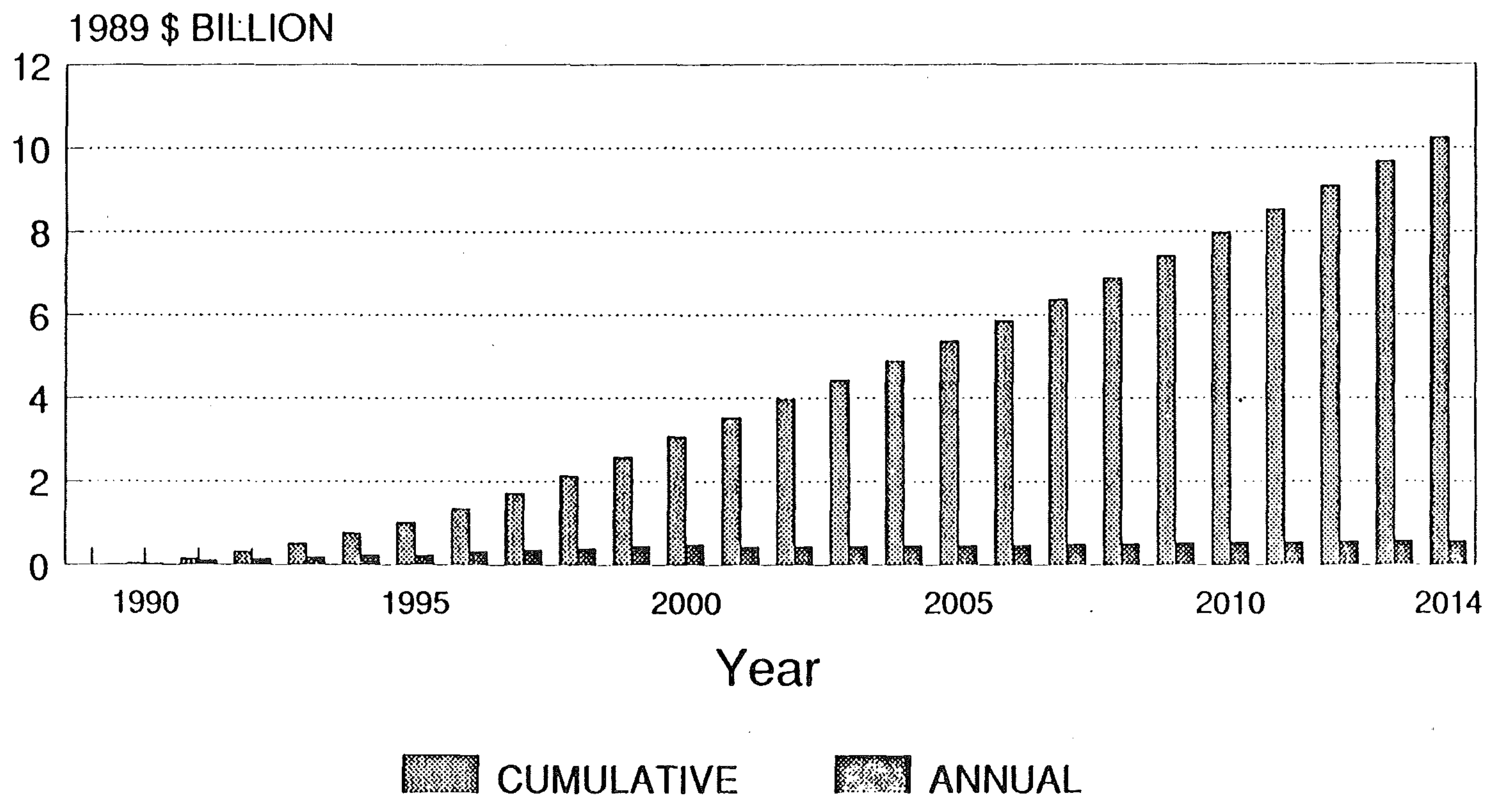
# CASE 15 - MEDIAN LOAD
## NON-UTILITY GENERATION




CASH FLOW FROM 1989 TO 2014

FIGURE 8.3-5

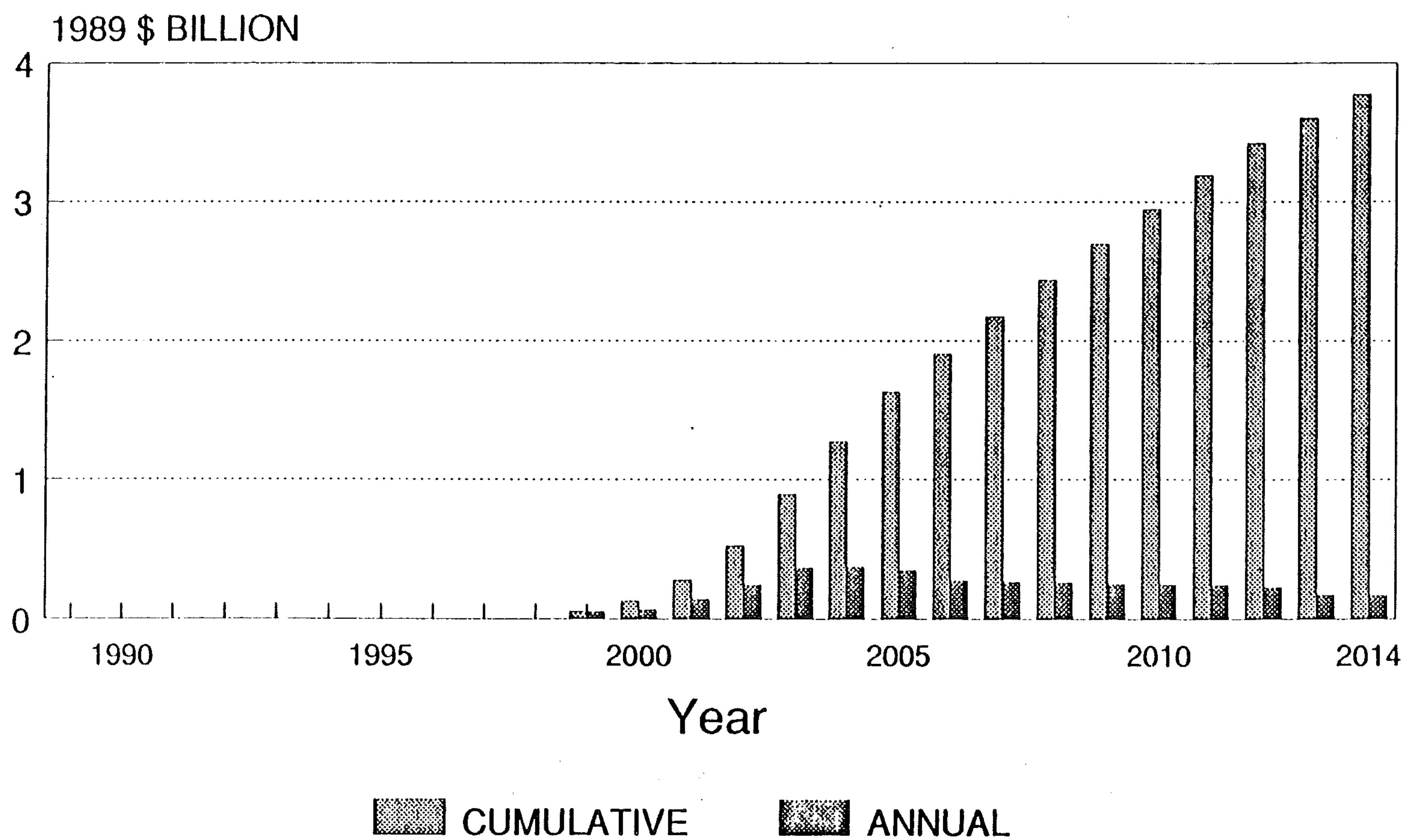
# CASE 15 - MEDIAN LOAD
## DEMAND MANAGEMENT AND LOAD DISPLACEMENT NUG




CASH FLOW FROM 1989 TO 2014

FIGURE 8.3-6

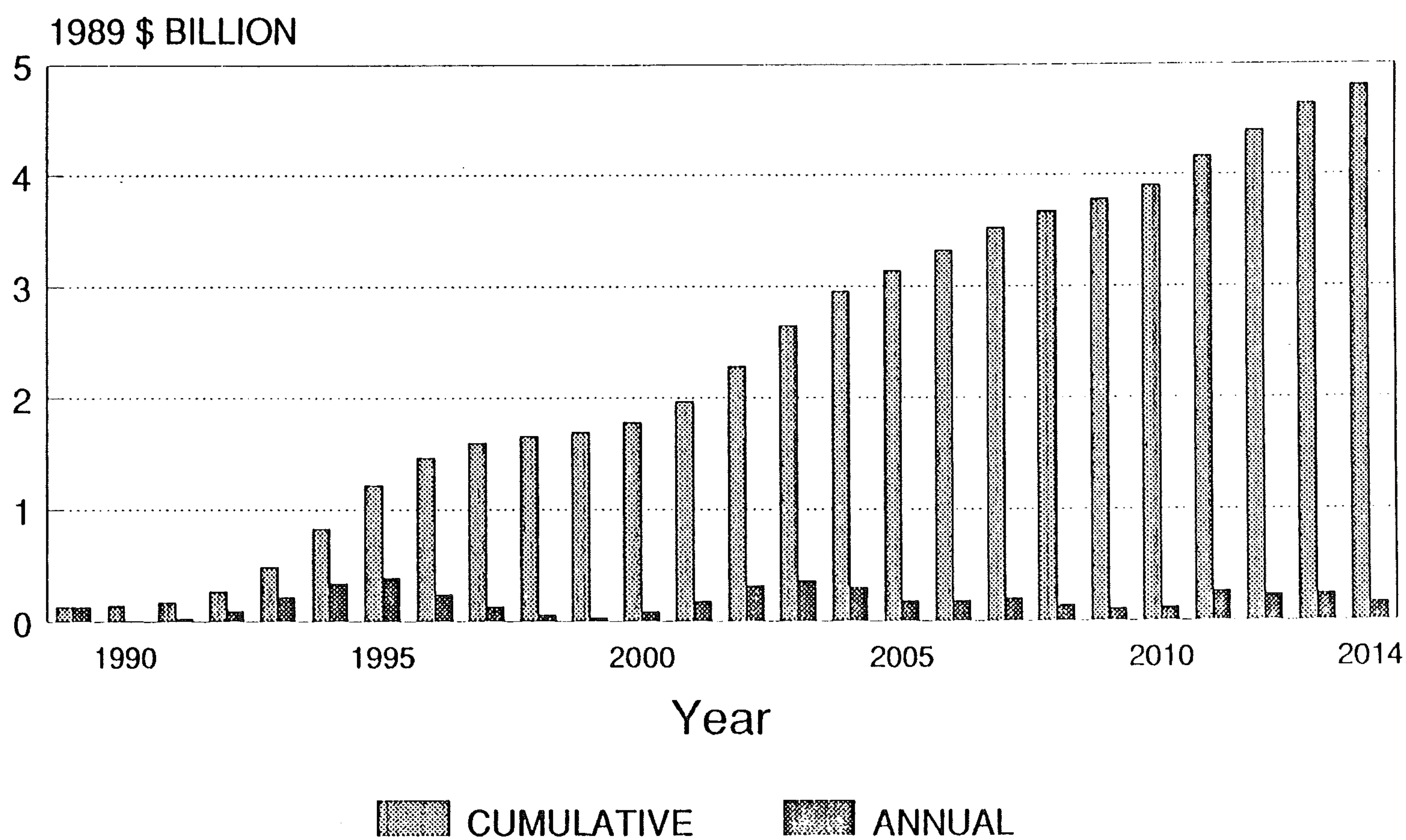
# CASE 15 - MEDIAN LOAD
## MANITOBA PURCHASE




CASH FLOW FROM 1989 TO 2014

FIGURE 8.3-7

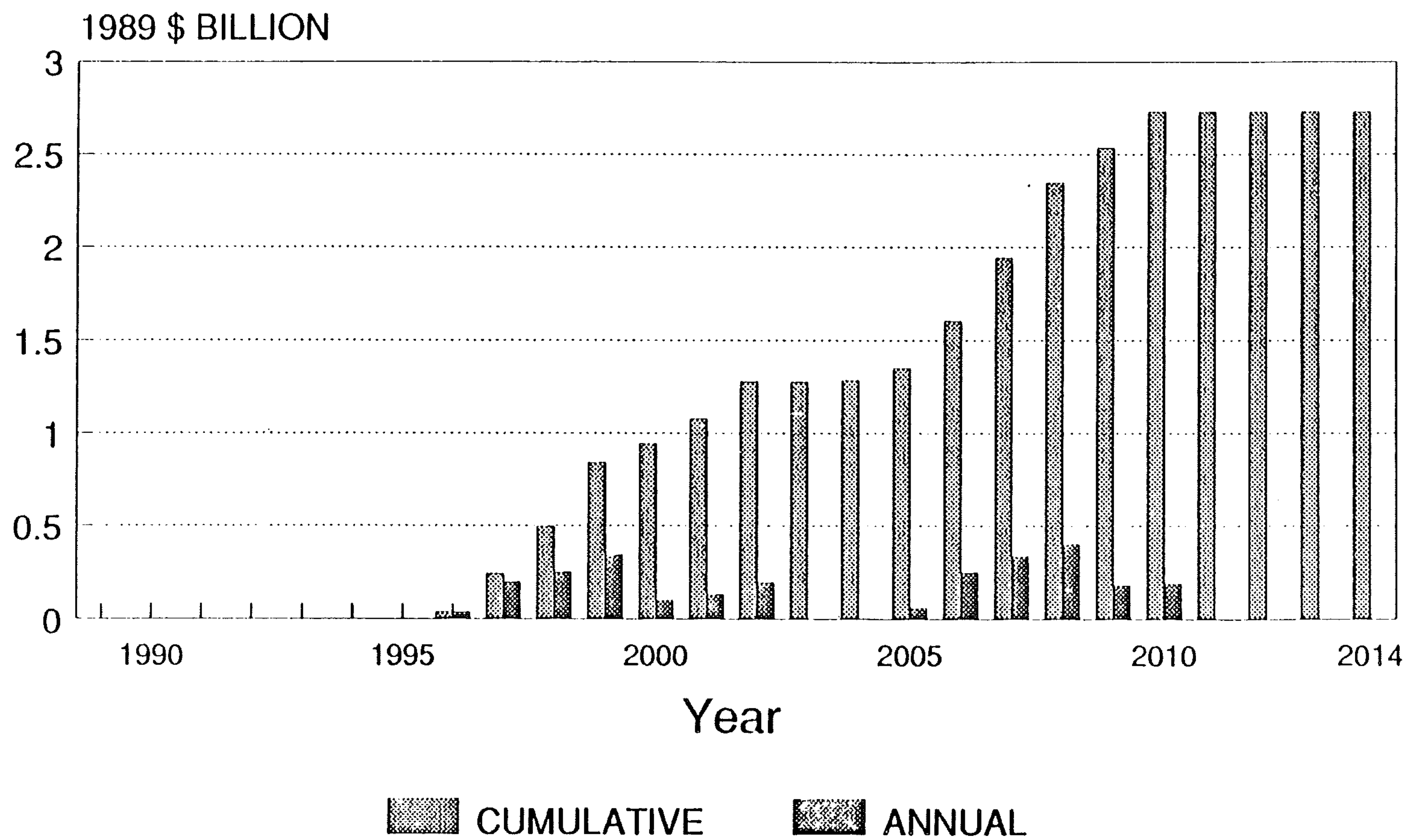
# CASE 15 - MEDIAN LOAD
## NEW HYDRAULIC CAPITAL




CASH FLOW FROM 1989 TO 2014

FIGURE 8.3-8

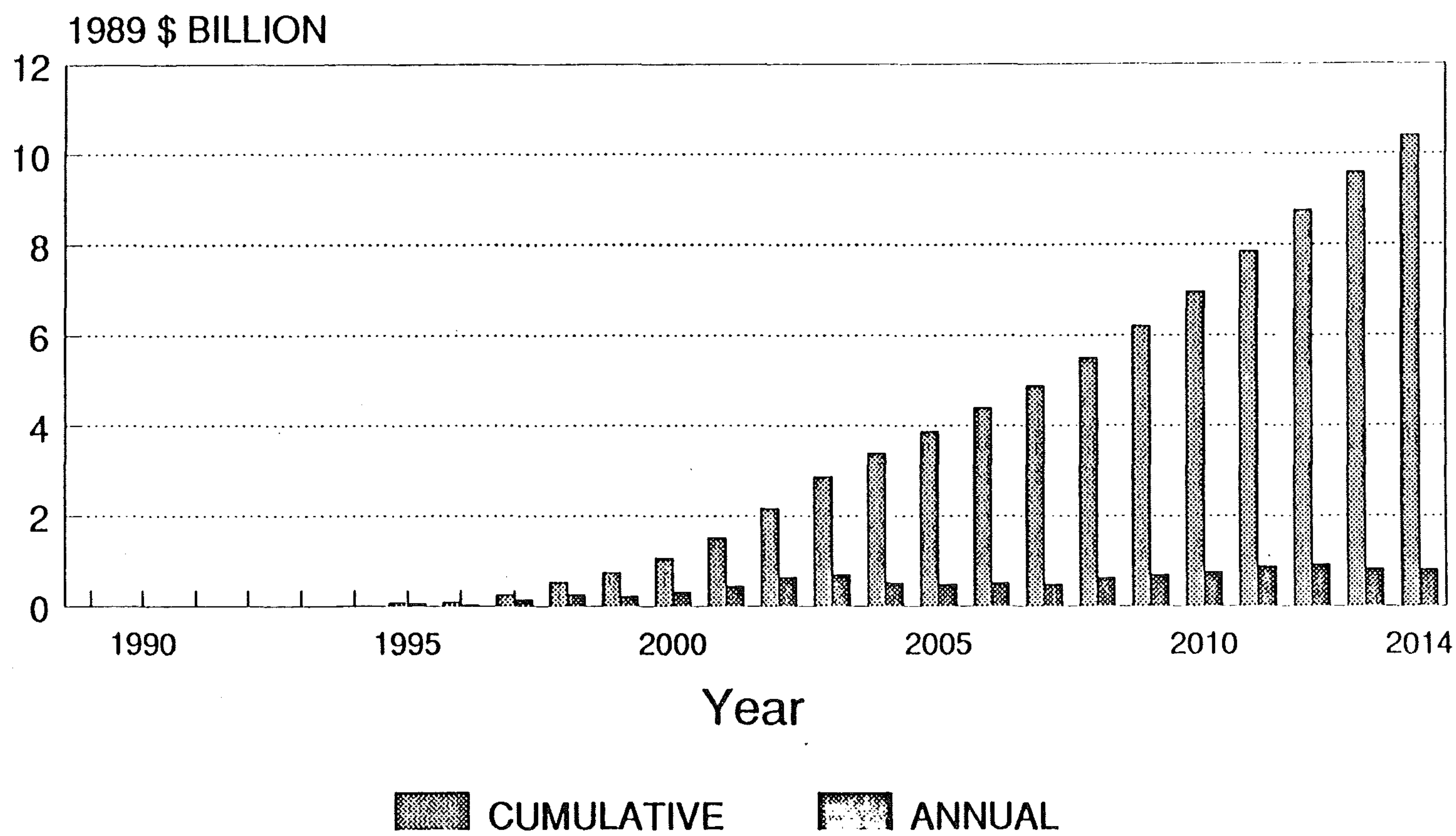
# CASE 15 - MEDIAN LOAD
## NEW SITE-SPECIFIC TRANSMISSION




CASH FLOW FROM 1989 TO 2014

FIGURE 8.3-9

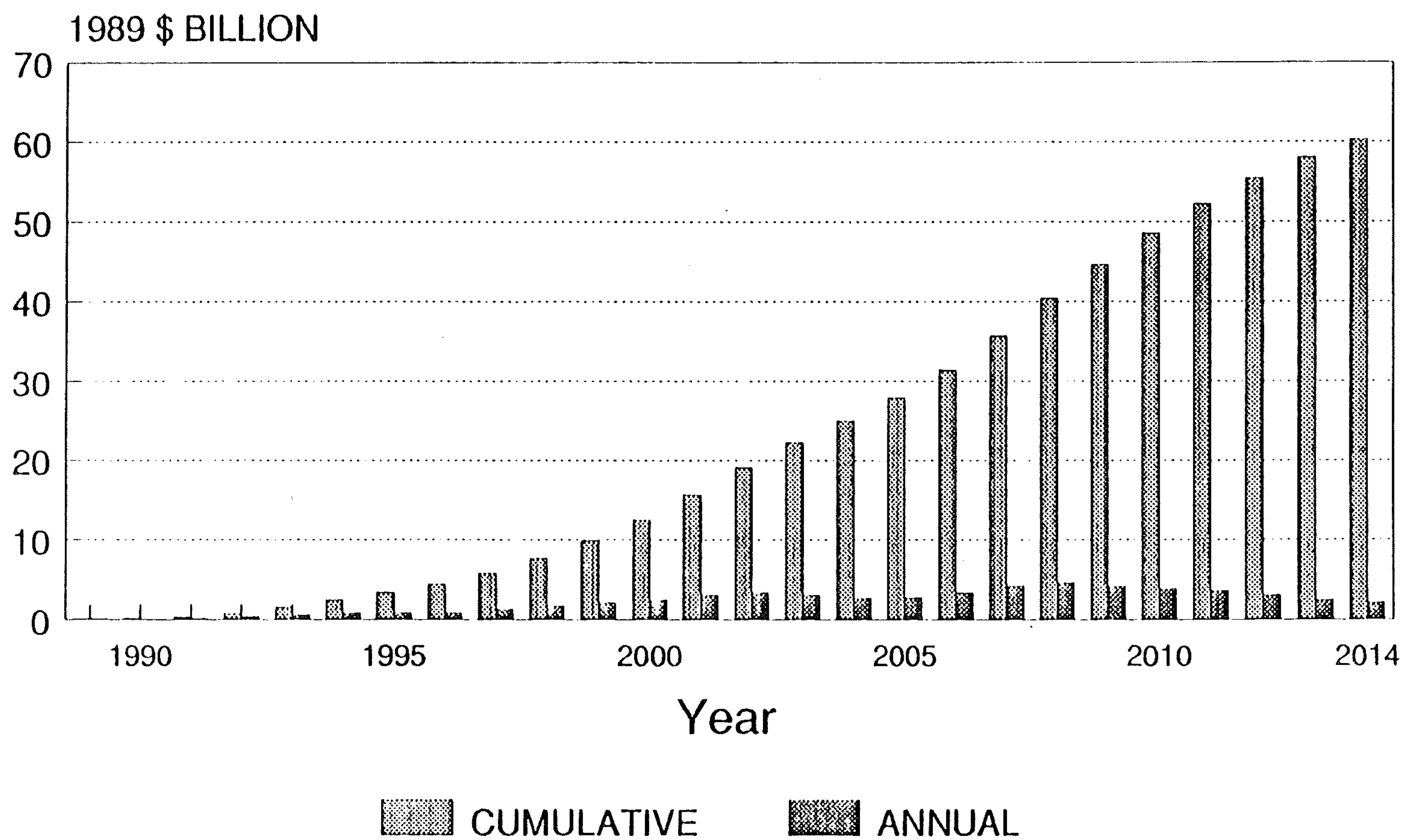
# CASE 15 - MEDIAN LOAD
## FUEL




CASH FLOW DUE TO LOAD GROWTH
BEYOND YEAR 1993

FIGURE 8.3-10

# CASE 15 - MEDIAN LOAD
## MAIN COST COMPONENTS




CASH FLOW FROM 1989 TO 2014

### 8.3.2 Cost of Existing and New Systems

Much of the total cost of one plan is common to all plans. These common elements include the Demand Management Plan, the Non-Utility Generation Plan, the Hydraulic Plan, and the Manitoba Purchase Plan. Also, common to all plans is much of the cost of operating and maintaining the existing system.

Much of the analysis of costs focuses on the difference in cost between plans. It is also useful to understand what decisions on options are driving the cost differences. This requires a division in costs by major groups and removal of common costs.

Separating the costs of the common elements is straight forward.

Separating the common costs of utilizing the existing system is more difficult because the operation of the system is dependent on what options are included in the major supply cases.

To define a common cost for the existing system Hydro used costs associated with the system when its load meeting capability closely matches the forecast customer demand. For all load forecast paths, except the lower forecast, this happens about the year 1993. For the lower load forecast, this happens about the year 2000.

Variable operating costs of the existing system in the year 1993 are extended to 2014. Annual fixed costs associated with the existing system are left unchanged. Common cost of the existing system then, is all of the costs up to 1993, and the accumulation of variable costs to 2014. For the lower load forecast path, a similar approach is applied, using 2000, the year in which load meeting capability matches demand, as the base year for extending variable operating costs.

The difference between total system costs and existing system costs represents the costs of new major supply cases. The differences in plan costs preserve the impact major supply cases have on the existing system.

Figure 8.3-11 shows the major cost groups for the existing and new systems for median load forecast. The figure is a compilation of cost information derived from data residing within RAM. The first three columns (A, B and C as indicated at the bottom of the figure) provide the data for the existing system; the remaining columns provide data for the total system costs of the five demand/supply plans evaluated. The total system is the existing system, plus the options added according to each plan.

# FIGURE 8.3-11

Section I. PRESENT VALUE FOR BASIC GROUP COSTS OF NEW AND EXISTING SYSTEMS (1989 M$ PV) - MEDIAN LOAD FORECAST

| | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Project | | EXISTING | Project | | CASE 23 | Project | | CASE 22 | Project | | CASE 15 | Project | | CASE 24 | Project | | CASE 26 |
| 2 | | | PV$M 1989 | | | PV$M 1989 | | | PV$M 1989 | | | PV$M 1989 | | | PV$M 1989 | | | PV$M 198 |
| 4 | Nuclear | Capital | 0 | Nuclear | Capital | 5165 | Nuclear | Capital | 3382 | Nuclear | Capital | 2189 | Nuclear | Capital | 1630 | Nuclear | Capital | 0 |
| 5 | | Fix OMA | 7812 | New | Fix OMA | 2553 | New | Fix OMA | 1675 | New | Fix OMA | 1063 | New | Fix OMA | 810 | New | Fix OMA | 0 |
| 6 | | Fuel | 5799 | | Fuel | 6713 | | Fuel | 6550 | | Fuel | 6383 | | Fuel | 6299 | | Fuel | 5992 |
| 9 | | Sales | 27 | | Sales | 333 | | Sales | 189 | | Sales | 119 | | Sales | 96 | | Sales | 72 |
| 11 | | Total | 13584 | | Total | 14097 | | Total | 11418 | | Total | 9536 | | Total | 8651 | | Total | 5920 |
| 13 | Fossil | Capital | 0 | Fossil | Capital | 92 | Fossil | Capital | 208 | Fossil | Capital | 517 | Fossil | Capital | 908 | Fossil | Capital | 1926 |
| 14 | | Fix OMA | 2554 | New | Fix OMA | 0 | New | Fix OMA | 25 | New | Fix OMA | 73 | New | Fix OMA | 262 | New | Fix OMA | 847 |
| 15 | | Fuel | 5726 | | Fuel | 4073 | | Fuel | 4976 | | Fuel | 6085 | | Fuel | 6598 | | Fuel | 8391 |
| 20 | | Total | 8280 | | Total | 4165 | | Total | 5208 | | Total | 6675 | | Total | 7768 | | Total | 11163 |
| 22 | AG Ctrls | Capital | 0 | AG Ctrls | Capital | 346 | AG Ctrls | Capital | 346 | AG Ctrls | Capital | 346 | AG Ctrls | Capital | 346 | AG Ctrls | Capital | 346 |
| 23 | | Fix OMA | 0 | | Fix OMA | 95 | | Fix OMA | 95 | | Fix OMA | 95 | | Fix OMA | 95 | | Fix OMA | 95 |
| 24 | | Var OMA | [Foss Fuel] | | Var OMA | [Foss Fuel] | | Var OMA | [Foss Fuel] | | Var OMA | [Foss Fuel] | | Var OMA | [Foss Fuel] | | Var OMA | [Foss Fuel] |
| 25 | | Total | 0 | | Total | 441 | | Total | 441 | | Total | 441 | | Total | 441 | | Total | 441 |
| 27 | Hydraulic | Capital | 0 | Hydraulic | Capital | 1189 | Hydraulic | Capital | 1189 | Hydraulic | Capital | 1189 | Hydraulic | Capital | 1189 | Hydraulic | Capital | 1189 |
| 28 | | Fix OMA | 1238 | New | Fix OMA | 200 | New | Fix OMA | 200 | New | Fix OMA | 200 | New | Fix OMA | 200 | New | Fix OMA | 200 |
| 29 | | Var OMA | 1526 | | Var OMA | 1609 | | Var OMA | 1609 | | Var OMA | 1609 | | Var OMA | 1609 | | Var OMA | 1609 |
| 31 | | Purch 200 | 0 | | Purch 200 | 148 | | Purch 200 | , | | Purch 200 | 148 | | Purch 200 | 148 | | Purch 200 | 148 |
| 34 | | Total | 2963 | | Total | 3146 | | Total | 3146 | | Total | 3146 | | Total | 3146 | | Total | 3146 |
| 36 | Gen Trans | Capital | 352 | Gen Trans | Capital | 1047 | Gen Trans | Capital | 1047 | Gen Trans | Capital | 1047 | Gen Trans | Capital | 1047 | Gen Trans | Capital | 1047 |
| 39 | | Other OMA | 138 | | Other OMA | 342 | | Other OMA | 342 | | Other OMA | 342 | | Other OMA | 342 | | Other OMA | 342 |
| 40 | | Total | 490 | | Total | 1389 | | Total | 1389 | | Total | 1389 | | Total | 1389 | | Total | 1389 |
| 42 | New Trans | Cap & OM | 0 | New Trans | Cap & OM | 766 | New Trans | Cap & OM | 580 | New Trans | Cap & OM | 478 | New Trans | Cap & OM | 478 | New Trans | Cap & OM | 439 |
| 45 | Distrib | Capital | 2837 | Distrib | Capital | 3322 | Distrib | Capital | 3322 | Distrib | Capital | 3322 | Distrib | Capital | 3322 | Distrib | Capital | 3322 |
| 48 | | Other OMA | 8714 | | Other OMA | 11228 | | Other OMA | 11228 | | Other OMA | 11228 | | Other OMA | 11228 | | Other OMA | 11228 |
| 49 | | Total | 11551 | | Total | 14550 | | Total | 14550 | | Total | 14550 | | Total | 14550 | | Total | 14550 |
| 51 | Fuels | Total | 14074 | Fuels | Total | 15185 | Fuels | Total | 15924 | Fuels | Total | 16867 | Fuels | Total | 17296 | Fuels | Total | 18782 |
| 53 | NUGS | Capital | | NUGS | Capital | | NUGS | Capital | | NUGS | Capital | | NUGS | Capital | | NUGS | Capital | |
| 54 | | Fix OMA | 0 | | Fix OMA | | | Fix OMA | | | Fix OMA | | | Fix OMA | | | Fix OMA | |

*Line
Cols A B C D E F G H I J K L M N O P Q R S T U V W

# FIGURE 8.3-11 (CONTINUED)

## Section I. PRESENT VALUE FOR BASIC GROUP COSTS OF NEW AND EXISTING SYSTEMS (1989 M$ PV) - MEDIAN LOAD FORECAST

| *Line / Col> | A | B | C | D | E | F | G | H | I | J | K | L | M | N | O | P | Q | R | S | T | U | V | W |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 55 | | Var OMA | 1023 | | | Var OMA | 2642 | | | Var OMA | 2642 | | | Var OMA | 2642 | | | Var OMA | 2642 | | | Var OMA | 2642 |
| 56 | | | | | | | | | | | | | | | | | | | | | | | |
| 57 | | Total | 1023 | | | Total | 2642 | | | Total | 2642 | | | Total | 2642 | | | Total | 2642 | | | Total | 2642 |
| 58 | | | | | | | | | | | | | | | | | | | | | | | |
| 59 | DM | Capital | 868 | | DM | Capital | 3103 | | DM | Capital | 3103 | | DM | Capital | 3103 | | DM | Capital | 3103 | | DM | Capital | 3103 |
| 60 | | | | | | | | | | | | | | | | | | | | | | | |
| 61 | | | | | | | | | | | | | | | | | | | | | | | |
| 62 | | Other OMA | 693 | | | Other OMA | 1552 | | | Other OMA | 1552 | | | Other OMA | 1552 | | | Other OMA | 1552 | | | Other OMA | 1552 |
| 63 | | Total | 1561 | | | Total | 4655 | | | Total | 4655 | | | Total | 4655 | | | Total | 4655 | | | Total | 4655 |
| 64 | | | | | | | | | | | | | | | | | | | | | | | |
| 65 | Other | Capital | 9244 | | Other | Capital | 9244 | | Other | Capital | 9244 | | Other | Capital | 9244 | | Other | Capital | 9244 | | Other | Capital | 9244 |
| 66 | | | | | | | | | | | | | | | | | | | | | | | |
| 67 | | | | | | | | | | | | | | | | | | | | | | | |
| 68 | | OMA | 8444 | | | OMA | 8444 | | | OMA | 8444 | | | OMA | 8444 | | | OMA | 8444 | | | OMA | 8444 |
| 69 | | | | | | | | | | | | | | | | | | | | | | | |
| 70 | | | | | | | | | | | | | | | | | | | | | | | |
| 71 | | | | | | | | | | | | | | | | | | | | | | | |
| 72 | | Total | 17688 | | | Total | 17688 | | | Total | 17688 | | | Total | 17688 | | | Total | 17688 | | | Total | 17688 |
| 73 | | | | | | | | | | | | | | | | | | | | | | | |
| 74 | Purchase | Capital | 0 | | Purchase | Capital | 1183 | | Purchase | Capital | 1183 | | Purchase | Capital | 1183 | | Purchase | Capital | 1183 | | Purchase | Capital | 1183 |
| 75 | 1000 MW | Fix OMA | | | 1000 MW | Fix OMA | | | 1000 MW | Fix OMA | | | 1000 MW | Fix OMA | | | 1000 MW | Fix OMA | | | 1000 MW | Fix OMA | |
| 76 | | | | | | | | | | | | | | | | | | | | | | | |
| 77 | | | | | | | | | | | | | | | | | | | | | | | |
| 78 | | Total | 0 | | | Total | 1183 | | | Total | 1183 | | | Total | 1183 | | | Total | 1183 | | | Total | 1183 |
| 79 | | | | | | | | | | | | | | | | | | | | | | | |
| 80 | Sales | Total | 27 | | Sales | Total | 333 | | Sales | Total | 169 | | Sales | Total | 119 | | Sales | Total | 96 | | Sales | Total | 72 |
| 81 | | | | | | | | | | | | | | | | | | | | | | | |
| 82 | | | | | | | | | | | | | | | | | | | | | | | |
| 83 | | | | | Fixed OM&A | | | | Fixed OM&A | | | | Fixed OM&A | | | | Fixed OM&A | | | | Fixed OM&A | | |
| 84 | | | | | of Existing System | | 11607 | | of Existing System | | 11607 | | of Existing System | | 11607 | | of Existing System | | 11607 | | of Existing System | | 11607 |
| 85 | | | | | | | | | | | | | | | | | | | | | | | |
| 86 | | | | | Project | TOTAL | 76330 | | Project | TOTAL | 74507 | | Project | TOTAL | 73991 | | Project | TOTAL | 74199 | | Project | TOTAL | 74823 |

There is one exception in this figure. Fixed OM&A for nuclear, fossil, acid gas controls and hydraulic are for new equipment only; and except for acid gas controls, which corresponds to new retrofits on existing plants, are labelled New Fixed OM&A. The fixed OM&A for the existing system is added separately at the bottom of the figure (line 84).

Figure 8.3-12 summarizes the cost sources for the major cost groups for Case 15, median load forecast. The first two columns link to the line number and cost groups of Figure 8.3-11. The third column describes what costs are in the cost group. The fourth column links back to the original source data provided earlier in this chapter. The fifth column links to RAM, where all data are integrated. The final column presents some comments on the data.

Figure 8.3-13 presents results when existing system costs are subtracted from the total system costs (note: the fixed OM&A for new nuclear, fossil, hydraulic, and acid gas controls on existing plants were taken directly from Figure 8.3-11). The resulting costs are the costs attributed to the Major Supply Cases for median load forecast.

# FIGURE 8.3-12

1989 Demand/Supply Plan
General Data/Source Description
Present Value of Basic Group Costs

Illustration: Case 15 - Median Load Forecast

| Line # | Cost Group | Description | Source Name | End Model | Comments |
|---|---|---|---|---|---|
| | Section I. Basic Cost Groups of Existing and New Systems | | | | |
| 4 | Nuclear Capital | Capital of new nuclear units | ONCI | RAM | Approval cost added according to specified dates. |
| 5 | Nuclear Fixed OM&A | Fixed OM&A of new nuclear units | ONCI | RAM | |
| 6 | Nuclear Fuel | Nuclear fuel of all generating units | LMSTM | RAM | |
| 9 | Nuclear Sales | Net Revenue from all nuclear sec. sales | LMSTM | RAM | |
| 11 | Nuclear Total | Sum of lines 1 through 10 | | | |
| 13 | Fossil Capital | Capital of new fossil units | TCR | RAM | Approval cost added according to specified dates. |
| 14 | Fossil Fixed OM&A | Fixed OM&A of new fossil units | TCR | RAM | |
| 15 | Fossil Fuel | Fossil fuel of all generating units | LMSTM | RAM | |
| 20 | Fossil Total | Sum of lines 13 through 19 | | | |
| 22 | AG Controls Capital | Capital of acid gas controls on existing units | ACID GAS | RAM | Cost of approval blended with the costs of capital. |
| 23 | AG Fixed OM&A | Fixed OM&A of AG controls on existing units | ACID GAS | RAM | |
| 24 | AG Var. OM&A | (combined with foss. fuel and var. OM&A) | LMSTM | RAM | |
| 25 | AG Total | Sum of lines 22 through 24 | | | |
| 27 | Hydraulic Capital | Capital of new hydraulic projects | HYDRO CAP. | RAM | |
| 28 | Hydraulic Fixed OM&A | Fixed OM&A of new hydraulic plants | LMSTM | RAM | Difference between new and existing systems. |

**Notes:**

ONCI: Ontario Nuclear Cost Inquiry
LMSTM: Load Management Strategy Testing Model
TCR: Thermal Cost Review
RAM: Risk Assessment Model

# FIGURE 8.3-12 (CONTINUED)

1989 Demand/Supply Plan
General Data/Source Description
Present Value of Basic Group Costs

Illustration: Case 15 - Median Load Forecast

| Line # | Cost Group | Description | Source Name | End Model | Comments |
|---|---|---|---|---|---|
| 29 | Hydraulic Var. OM&A | Water rentals and var. OM&A of all generating units | LMSTM | RAM | |
| 31 | Hydraulic Purchase | 5X200 MW purchase from Manitoba | LMSTM | RAM | |
| 34 | Hydraulic Total | Sum of lines 27 through 29 | | | |
| 36 | Generic Transmission Capital | Capital cost of existing system & growth-related | LMSTM | RAM | New specific projects excluded. |
| 37 | Generic Transmission Other OM&A | Total OM&A of existing system | LMSTM | RAM | New specific projects excluded. |
| 40 | Generic Trans. Total | Sum of lines 36 through 39 | | | |
| 42 | New Trans. Capital, OM&A | Total of capital and OM&A of site-specific transmission | TRANS. | RAM | New site-specific projects. |
| 45 | Distr. Capital | Capital cost charged to existing system | LMSTM | RAM | Includes municipal costs. |
| 48 | Distribution Other OM&A | Total OM&A of existing system | LMSMT | RAM | Includes municipal costs. |
| 49 | Distr. Total | Sum of lines 45 through 48 | | | |
| 51 | Fuels | Total var. OM&A all units (fuels), purch. NUGS, 5X200 MW purchase, unsupplied energy, and nuc. sec. sales. | LMSTM | RAM | All fuel and variable OM&A modeled. |
| 55 | NUGS Var. OM&A | Purchase NUGS | LMSTM | RAM | |
| 56 | NUGS Total | Sum of lines 53 through 56 | | | |

Notes:

ONCI: Ontario Nuclear Cost Inquiry
LMSTM: Load Management Strategy Testing Model
TCR: Thermal Cost Review
RAM: Risk Assessment Model

# FIGURE 8.3-12 (CONTINUED)

1989 Demand/Supply Plan
General Data/Source Description
Present Value of Basic Group Costs

Illustration: Case 15 - Median Load Forecast

| Line # | Cost Group | Description | Source Name | End Model | Comments |
|---|---|---|---|---|---|
| 59 | DM Capital | Capital cost of DM for Hydro and Participants | LMSTM | RAM | |
| 62 | DM Other OM&A | Total OM&A of DM both Hydro's and participants' | LMSTM | RAM | |
| 63 | DM Total | Sum of lines 59 through 62 | | | |
| 65 | Other Capital | Capital cost charged for other resources. Includes retubing. Excl. costs of DM, Trans., Distr., and Darlington. | LMSTM | RAM | |
| 68 | Other OM&A | Other OM&A of existing system | LMSTM | RAM | |
| 72 | Other Total | Sum of lines 65 and 68 | | | |
| 78 | Purchase Total | Total purchase cost of 1000 MW from Manitoba | MAN. PURCH. | RAM | |
| 80 | Nuc. Sales Total | Net Revenue from all nuclear sec. sales | LMSTM | RAM | (same as line no. 9) |
| 84 | Existing System Fixed OM&A Total | Total fixed OM&A of existing system (complement to that of new system) | LMSTM (special run) | RAM | Cost computed separately with LMSTM. |
| 86 | Project Total | Total Case's PV | RAM | RAM | Sum of all costs modeled. |

Section II. Costs of expansion Cases relative to estimates of Existing System

104 to 180 Values result from costs of expansion Cases net of corresponding costs for Existing System.

Notes:

ONCI: Ontario Nuclear Cost Inquiry
LMSTM: Load Management Strategy Testing Model
TCR: Thermal Cost Review
RAM: Risk Assessment Model

# FIGURE 8.3-13

Section II. PRESENT VALUE FOR BASIC GROUP COSTS OF NEW SYSTEM NET OF EXISTING COSTS (1989 M$ PV) - MEDIAN LOAD FORECAST

| | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 101 | Project | | EXISTING | Project | | CASE 23 | Project | | CASE 22 | Project | | CASE 15 | Project | | CASE 24 | Project | | CASE 26 |
| 102 | | | PV$M 1989 | | | PV$M 1989 | | | PV$M 1989 | | | PV$M 1989 | | | PV$M 1989 | | | PV$M 198 |
| 103 | | | | | | | | | | | | | | | | | | |
| 104 | Nuclear | Capital | 0 | Nuclear | Capital | 5165 | Nuclear | Capital | 3382 | Nuclear | Capital | 2189 | Nuclear | Capital | 1639 | Nuclear | Capital | 0 |
| 105 | | Fix OMA | 0 | | Fix OMA | 2553 | | Fix OMA | 1675 | | Fix OMA | 1083 | | Fix OMA | 810 | | Fix OMA | 0 |
| 106 | | Fuel | 0 | | Fuel | 914 | | Fuel | 751 | | Fuel | 584 | | Fuel | 500 | | Fuel | 193 |
| 107 | | | | | | | | | | | | | | | | | | |
| 108 | | | | | | | | | | | | | | | | | | |
| 109 | | Sales | 0 | | Sales | 306 | | Sales | 161 | | Sales | 91 | | Sales | 69 | | Sales | 45 |
| 110 | | | | | | | | | | | | | | | | | | |
| 111 | | Total | 0 | | Total | 8937 | | Total | 5969 | | Total | 3947 | | Total | 3018 | | Total | 238 |
| 112 | | | | | | | | | | | | | | | | | | |
| 113 | Fossil | Capital | 0 | Fossil | Capital | 92 | Fossil | Capital | 208 | Fossil | Capital | 517 | Fossil | Capital | 906 | Fossil | Capital | 1926 |
| 114 | | Fix OMA | 0 | | Fix OMA | 0 | | Fix OMA | 25 | | Fix OMA | 73 | | Fix OMA | 262 | | Fix OMA | 847 |
| 115 | | Fuel | 0 | | Fuel | -1653 | | Fuel | -750 | | Fuel | 360 | | Fuel | 872 | | Fuel | 2665 |
| 116 | | | | | | | | | | | | | | | | | | |
| 117 | | | | | | | | | | | | | | | | | | |
| 118 | | | | | | | | | | | | | | | | | | |
| 119 | | | | | | | | | | | | | | | | | | |
| 120 | | Total | 0 | | Total | -1560 | | Total | -518 | | Total | 950 | | Total | 2042 | | Total | 5437 |
| 121 | | | | | | | | | | | | | | | | | | |
| 122 | AG Ctrls | Capital | 0 | AG Ctrls | Capital | 346 | AG Ctrls | Capital | 346 | AG Ctrls | Capital | 346 | AG Ctrls | Capital | 346 | AG Ctrls | Capital | 346 |
| 123 | | Fix OMA | 0 | | Fix OMA | 95 | | Fix OMA | 95 | | Fix OMA | 95 | | Fix OMA | 95 | | Fix OMA | 95 |
| 124 | | Var OMA | [Foss Fuel] | | Var OMA | [Foss Fuel] | | Var OMA | [Foss Fuel] | | Var OMA | [Foss Fuel] | | Var OMA | [Foss Fuel] | | Var OMA | [Foss Fuel] |
| 125 | | Total | 0 | | Total | 441 | | Total | 441 | | Total | 441 | | Total | 441 | | Total | 441 |
| 126 | | | | | | | | | | | | | | | | | | |
| 127 | Hydraulic | Capital | 0 | Hydraulic | Capital | 1189 | Hydraulic | Capital | 1189 | Hydraulic | Capital | 1189 | Hydraulic | Capital | 1189 | Hydraulic | Capital | 1189 |
| 128 | | Fix OMA | 0 | | Fix OMA | 200 | | Fix OMA | 200 | | Fix OMA | 200 | | Fix OMA | 200 | | Fix OMA | 200 |
| 129 | | Var OMA | 0 | | Var OMA | 84 | | Var OMA | 84 | | Var OMA | 84 | | Var OMA | 84 | | Var OMA | 84 |
| 130 | | | | | | | | | | | | | | | | | | |
| 131 | | Purch 200 | 0 | | Purch 200 | 148 | | Purch 200 | 0 | | Purch 200 | 148 | | Purch 200 | 148 | | Purch 200 | 148 |
| 132 | | | | | | | | | | | | | | | | | | |
| 133 | | | | | | | | | | | | | | | | | | |
| 134 | | Total | 0 | | Total | 1620 | | Total | 1473 | | Total | 1620 | | Total | 1620 | | Total | 1620 |
| 135 | | | | | | | | | | | | | | | | | | |
| 136 | Gen Trans | Capital | 0 | Gen Trans | Capital | 696 | Gen Trans | Capital | 696 | Gen Trans | Capital | 696 | Gen Trans | Capital | 696 | Gen Trans | Capital | 696 |
| 137 | | | | | | | | | | | | | | | | | | |
| 138 | | | | | | | | | | | | | | | | | | |
| 139 | | Other OMA | 0 | | Other OMA | 204 | | Other OMA | 204 | | Other OMA | 204 | | Other OMA | 204 | | Other OMA | 204 |
| 140 | | Total | 0 | | Total | 899 | | Total | 899 | | Total | 899 | | Total | 899 | | Total | 899 |
| 141 | | | | | | | | | | | | | | | | | | |
| 142 | New Trans | Cap & OM | 0 | New Trans | Cap & OM | 766 | New Trans | Cap & OM | 580 | New Trans | Cap & OM | 478 | New Trans | Cap & OM | 478 | New Trans | Cap & OM | 439 |
| 143 | | | | | | | | | | | | | | | | | | |
| 144 | | | | | | | | | | | | | | | | | | |
| 145 | Distrib | Capital | 0 | Distrib | Capital | 485 | Distrib | Capital | 485 | Distrib | Capital | 485 | Distrib | Capital | 485 | Distrib | Capital | 485 |
| 146 | | | | | | | | | | | | | | | | | | |
| 147 | | | | | | | | | | | | | | | | | | |
| 148 | | Other OMA | 0 | | Other OMA | 2514 | | Other OMA | 2514 | | Other OMA | 2514 | | Other OMA | 2514 | | Other OMA | 2514 |
| 149 | | Total | 0 | | Total | 2998 | | Total | 2998 | | Total | 2998 | | Total | 2998 | | Total | 2998 |
| 150 | | | | | | | | | | | | | | | | | | |
| 151 | Fuels | Total | 0 | Fuels | Total | 1111 | Fuels | Total | 1651 | Fuels | Total | 2793 | Fuels | Total | 3222 | Fuels | Total | 4708 |
| 152 | | | | | | | | | | | | | | | | | | |
| 153 | NUGS | Capital | | NUGS | Capital | | NUGS | Capital | | NUGS | Capital | | NUGS | Capital | | NUGS | Capital | |
| 154 | | Fix OMA | 0 | | Fix OMA | 0 | | Fix OMA | 0 | | Fix OMA | 0 | | Fix OMA | 0 | | Fix OMA | 0 |

*Line
Col. A B C D E F G H I J K L M N O P Q R S T U V W

# FIGURE 8.3-13 (CONTINUED)

Section II. PRESENT VALUE FOR BASIC GROUP COSTS OF NEW SYSTEM NET OF EXISTING COSTS (1989 M$ PV) - MEDIAN LOAD FORECAST

| | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 155 | | Var OMA | 0 | | Var OMA | 1619 | | Var OMA | 1619 | | Var OMA | 1619 | | Var OMA | 1619 | | Var OMA | 1619 |
| 156 | | | | | | | | | | | | | | | | | | |
| 157 | | Total | 0 | | Total | 1619 | | Total | 1619 | | Total | 1619 | | Total | 1619 | | Total | 1619 |
| 158 | | | | | | | | | | | | | | | | | | |
| 159 | DM | Capital | 0 | DM | Capital | 2235 | DM | Capital | 2235 | DM | Capital | 2235 | DM | Capital | 2235 | DM | Capital | 2235 |
| 160 | | | | | | | | | | | | | | | | | | |
| 161 | | | | | | | | | | | | | | | | | | |
| 162 | | Other OMA | 0 | | Other OMA | 859 | | Other OMA | 859 | | Other OMA | 859 | | Other OMA | 859 | | Other OMA | 859 |
| 163 | | Total | 0 | | Total | 3094 | | Total | 3094 | | Total | 3094 | | Total | 3094 | | Total | 3094 |
| 164 | | | | | | | | | | | | | | | | | | |
| 165 | Other | Capital | 0 | Other | Capital | 0 | Other | Capital | 0 | Other | Capital | 0 | Other | Capital | 0 | Other | Capital | 0 |
| 166 | | | | | | | | | | | | | | | | | Fix OMA | |
| 167 | | | | | | | | | | | | | | | | | Var OMA | |
| 168 | | OMA | 0 | | OMA | 0 | | OMA | 0 | | OMA | 0 | | OMA | 0 | | OMA | 0 |
| 169 | | | | | | | | | | | | | | | | | | |
| 170 | | | | | | | | | | | | | | | | | | |
| 171 | | | | | | | | | | | | | | | | | | |
| 172 | | Total | 0 | | Total | 0 | | Total | 0 | | Total | 0 | | Total | 0 | | Total | 0 |
| 173 | | | | | | | | | | | | | | | | | | |
| 174 | Purchase | Capital | 0 | Purchase | Capital | 1183 | Purchase | Capital | 1183 | Purchase | Capital | 1183 | Purchase | Capital | 1183 | Purchase | Capital | 1183 |
| 175 | 1000 MW | Fix OMA | | 1000 MW | Fix OMA | | 1000 MW | Fix OMA | | 1000 MW | Fix OMA | | 1000 MW | Fix OMA | | 1000 MW | Fix OMA | |
| 176 | | | | | | | | | | | | | | | | | | |
| 177 | | | | | | | | | | | | | | | | | | |
| 178 | | Total | 0 | | Total | 1183 | | Total | 1183 | | Total | 1183 | | Total | 1183 | | Total | 1183 |
| 179 | | | | | | | | | | | | | | | | | | |
| 180 | Sales | Total | 0 | Sales | Total | 306 | Sales | Total | 161 | Sales | Total | 91 | Sales | Total | 69 | Sales | Total | 45 |

*Line

Cols A B C D E F G H I J K L M N O P Q R S T U V W

### 8.3.3 Cost of Ontario Hydro New Major Supply

In the DSP Report, Figure 15-46 shows the cost of Ontario Hydro new major supply for median load forecast. Figure 8.3-14 shows how these values were determined from the cost values in Figure 8.3-13. The formulas refer to coordinates in Figure 8.3-13. For example, +O104 refers to the value in Figure 8.3-13 under column O at line 104, which is 2,189 M$ (PV 1989).

Figures 8.3-15 through 8.3-19 show the costs of new major supply for the five load forecast paths. The differences between the major supply cases, relative to Case 15, are shown at the bottom of these tables. These results relate to Figure 15-49 of the DSP report, which shows the same results for the lower, median and upper load forecasts.

# FIGURE 8.3-14

**Cost of Ontario Hydro New Major Supply**
**Median Load Growth - Median Cost Estimates**
**Cost Calculation Formulas**
**Reference: Basic Group Costs (Sections I and II)**
**$1989 Million (PV) allocated to 1994-2014**

| Cost Component | Case 23 | Case 22 | Case 15 | Case 24 | Case 26 |
|---|---|---|---|---|---|
| **Nuclear** | | | | | |
| Capital | +G104 | +K104 | +O104 | +S104 | +W104 |
| OM&A | +G105 | +K105 | +O105 | +S105 | +W105 |
| **Fossil** | | | | | |
| Capital | +G113 | +K113 | +O113 | +S113 | +W113 |
| OM&A | +G114 | +K114 | +O114 | +S114 | +W114 |
| Fuel Related Costs associated with Growth beyond 1993 | +G106+G115+G124+G129-G180 | +K106+K115+K124+K129-K180 | +O106+O115+O124+O129-O180 | +S106+S115+S124+S129-S180 | +W106+W115+W124+W129-W180 |
| Bulk Transmission Cost Difference from Case 15 | +G140+G142-(O140+O142) | +K140+K142-(O140+O142) | +O140+O142-(O140+O142) | +S140+S142-(O140+O142) | +W140+W142-(O140+O142) |
| TOTAL | SUM OF ABOVE | SUM OF ABOVE | SUM OF ABOVE | SUM OF ABOVE | SUM OF ABOVE |
| Difference from Case 15 | TOTAL MINUS CASE 15'S | TOTAL MINUS CASE 15'S | BASE | TOTAL MINUS CASE 15'S | TOTAL MINUS CASE 15'S |

## FIGURE 8-1[illegible]

### Cost of Ontario Hydro New Major Supply
### Median Load Forecast - Median Cost Estimates

$1989 Million (PV) allocated to 1994-2014

| Cost Component | Case 23 | Case 22 | Case 15 | Case 24 | Case 26 |
|---|---|---|---|---|---|
| Nuclear | | | | | |
| Capital | 5,165 | 3,382 | 2,189 | 1,639 | 0 |
| OM&A | 2,553 | 1,675 | 1,083 | 810 | 0 |
| Fossil | | | | | |
| Capital | 92 | 208 | 517 | 908 | 1,926 |
| OM&A | 0 | 25 | 73 | 262 | 847 |
| Fuel-Related Costs associated with Growth beyond 1993 | (961) | (77) | 936 | 1,387 | 2,897 |
| Bulk Transmission Cost Difference from Case 15 | 287 | 101 | 0 | 0 | (40) |
| TOTAL | 7,137 | 5,314 | 4,798 | 5,006 | 5,630 |
| Difference from Case 15 | 2,339 | 516 | BASE | 208 | 832 |

# FIGURE 8.3-16

## Cost of Ontario Hydro New Major Supply
## Branch Upper Load Forecast - Median Cost Estimates

$1989 Million (PV) allocated to 1994-2014

| Cost Component | Case 23 | Case 22 | Case 15 | Case 24 | Case 26 |
|---|---|---|---|---|---|
| Nuclear | | | | | |
| Capital | 6,060 | 3,997 | 2,963 | 2,072 | 0 |
| OM&A | 3,003 | 1,984 | 1,472 | 1,027 | 0 |
| Fossil | | | | | |
| Capital | 107 | 512 | 798 | 1,383 | 2,689 |
| OM&A | 2 | 86 | 122 | 423 | 1,156 |
| Fuel-Related Costs associated with Growth beyond 1993 | 86 | 1,336 | 2,322 | 2,993 | 5,125 |
| Bulk Transmission Cost Difference from Case 15 | 249 | 82 | 0 | 33 | 0 |
| TOTAL | 9,507 | 7,996 | 7,677 | 7,931 | 8,971 |
| Difference from Case 15 | 1,830 | 319 | BASE | 254 | 1,294 |

## FIGURE 8.3-17

Cost of Ontario Hydro New Major Supply
Upper Load Forecast - Median Cost Estimates

$1989 Million (PV) allocated to 1994-2014

| Cost Component | Case 23 | Case 22 | Case 15 | Case 24 | Case 26 |
|---|---|---|---|---|---|
| Nuclear | | | | | |
| Capital | 5,946 | 4,127 | 3,438 | 2,515 | 0 |
| OM&A | 2,946 | 2,048 | 1,708 | 1,263 | 0 |
| Fossil | | | | | |
| Capital | 889 | 1,216 | 1,360 | 2,001 | 3,592 |
| OM&A | 327 | 382 | 410 | 713 | 1,609 |
| Fuel-Related Costs associated with Growth beyond 1993 | 3,072 | 4,513 | 5,276 | 5,920 | 8,204 |
| Bulk Transmission Cost Difference from Case 15 | 176 | 72 | 0 | 0 | 0 |
| TOTAL | 13,355 | 12,358 | 12,191 | 12,412 | 13,405 |
| Difference from Case 15 | 1,164 | 167 | BASE | 221 | 1,214 |

## FIGURE 8.3-18

Cost of Ontario Hydro New Major Supply
Branch Lower Load Forecast - Median Cost Estimates

$1989 Million (PV) allocated to 1994-2014

| Cost Component | Case 23 | Case 22 | Case 15 | Case 24 | Case 26 |
|---|---|---|---|---|---|
| Nuclear | | | | | |
| Capital | 4,573 | 2,529 | 1,956 | 1,723 | 0 |
| OM&A | 2,257 | 1,139 | 867 | 753 | 0 |
| Fossil | | | | | |
| Capital | 92 | 218 | 266 | 440 | 1,441 |
| OM&A | 0 | 27 | 33 | 114 | 661 |
| Fuel-Related Costs associated with Growth beyond 1993 | (1,867) | (940) | (535) | (353) | 849 |
| Bulk Transmission Cost Difference from Case 15 | 326 | 46 | 0 | 3 | (86) |
| TOTAL | 5,381 | 3,019 | 2,588 | 2,681 | 2,865 |
| Difference from Case 15 | 2,794 | 432 | BASE | 93 | 277 |

FIGURE 8.3-19

Cost of Ontario Hydro New Major Supply
Lower Load Forecast - Median Cost Estimates

$1989 Million (PV) allocated to 1994-2014

| Cost Component | Case 23 | Case 22 | Case 15 | Case 24 | Case 26 |
|---|---|---|---|---|---|
| Nuclear | | | | | |
| Capital | 2,861 | 1,212 | 624 | 510 | 0 |
| OM&A | 1,404 | 597 | 305 | 249 | 0 |
| Fossil | | | | | |
| Capital | 102 | 129 | 222 | 290 | 612 |
| OM&A | 1 | 6 | 28 | 65 | 247 |
| Fuel-Related Costs associated with Growth beyond 1993 | (229) | 456 | 970 | 1,053 | 1,516 |
| Bulk Transmission Cost Difference from Case 15 | 164 | 62 | 0 | 0 | (39) |
| TOTAL | 4,303 | 2,463 | 2,149 | 2,166 | 2,336 |
| Difference from Case 15 | 2,154 | 314 | BASE | 17 | 187 |

### 8.3.4 Total Cost of New Demand/Supply Options and Operating the Existing System

In the DSP Report, Figure 15-47 shows the total cost of new demand/supply options and operating the existing system for the median load forecast for the five cases. Figure 8.3-20 shows how these values are determined from the cost values in Figures 8.3-11 and 8.3-13.

Figures 8.3-21 through 8.3-25 show the total cost of new demand/supply options and operating the existing system under the five load forecast paths.

# FIGURE 8.3-20

**Total Cost of New Demand/Supply Options and Operating the Existing System**
**Median Load Forecast - Median Cost Estimates**
**Calculation Formulas**
**Reference: Basic Group Costs (Sections I & II)**
**$1989 Million (PV)**

| | | Case 23 | Case 22 | Case 15 | Case 24 | Case 26 |
|---|---|---|---|---|---|---|
| Cost of New D/S Options -Allocated to 1994 2014 | | | | | | |
| Nuclear | Capital | +G104 | +K104 | +O104 | +S104 | +W104 |
| | OM&A | +G105 | +K105 | +O105 | +S105 | +W105 |
| Fossil | Capital | +G113 | +K113 | +O113 | +S113 | +W113 |
| | OM&A | +G114 | +K114 | +O114 | +S114 | +W114 |
| Acid Gas Controls | | +G122+G123 | +K122+K123 | +O122+O123 | +S122+S123 | +W122+W123 |
| Manitoba Purchase | | +G178+G131 | +K178+K131 | +O178+O131 | +S178+S131 | +W178+W131 |
| Hydraulic | Capital | +G127 | +K127 | +O127 | +S127 | +W127 |
| | OM&A | +G128 | +K128 | +O128 | +S128 | +W128 |
| Load Reducing Options DM & LD-NUGs | | +G163 | +K163 | +O163 | +S163 | +W163 |
| Purchase NUGs | | +G157 | +K157 | +O157 | +S157 | +W157 |
| Transmission | | +G140+G142 | +K140+K142 | +O140+O142 | +S140+S142 | +W140+W142 |
| Distribution | | +G149 | +K149 | +O149 | +S149 | +W149 |
| Total Cost of New D/S | | SUM OF ABOVE | SUM OF ABOVE | SUM OF ABOVE | SUM OF ABOVE | SUM OF ABOVE |
| Fuel - Related Costs 1989-2014 | | | | | | |
| Cost associated with Existing Demand | | +C51-C80 | +C51-C80 | +C51-C80 | +C51-C80 | +C51-C80 |
| Cost associated with Growth beyond 1993 | | +G106+G115+G124+G129-G180 | +G106+G115+G124+G129-G180 | +O106+O115+O124+O129-O180 | +G106+G115+G124+G129-G180 | +G106+G115+G124+G129-G180 |
| Total Fuel | | SUM OF FUEL COSTS | SUM OF FUEL COSTS | SUM OF FUEL COSTS | SUM OF FUEL COSTS | SUM OF FUEL COSTS |
| Cost of Existing System - allocated to 1989 2014 | | +C5+C14+C23+C28+C36+C37+ C39+C45+C46+C48+C54+C56+C59+ C60+C62+C65+C66+C68 | +C5+C14+C23+C28+C36+C37+ C39+C45+C46+C48+C54+C56+C59+ C60+C62+C65+C66+C68 | +C5+C14+C23+C28+C36+C37+ C39+C45+C46+C48+C54+C56+C59+ C60+C62+C65+C66+C68 | +C5+C14+C23+C28+C36+C37+ C39+C45+C46+C48+C54+C56+C59+ C60+C62+C65+C66+C68 | +C5+C14+C23+C28+C36+C37+ C39+C45+C46+C48+C54+C56+C59+ C60+C62+C65+C66+C68 |
| Total Cost of New D/S Options and operating the Existing System | | GRAND TOTAL | GRAND TOTAL | GRAND TOTAL | GRAND TOTAL | GRAND TOTAL |
| Cost Differences from Case 15 | | ABOVE TOTAL MINUS CASE 15'S | ABOVE TOTAL MINUS CASE 15'S | BASE | ABOVE TOTAL MINUS CASE 15'S | ABOVE TOTAL MINUS CASE 15'S |

# FIGURE 8.3-21

Total Cost of New Demand/Supply Options and Operating the Existing System
Median Load Forecast - Median Cost Estimates
$1989 Million Present Value

| | | Case 23 | Case 22 | Case 15 | Case 24 | Case 26 |
|---|---|---|---|---|---|---|
| **Cost of New D/S Options - allocated to 1994-2014** | | | | | | |
| Nuclear | Capital | 5,165 | 3,382 | 2,189 | 1,639 | 0 |
| | OM&A | 2,553 | 1,675 | 1,083 | 810 | 0 |
| Fossil | Capital | 92 | 208 | 517 | 908 | 1,926 |
| | OM&A | 0 | 25 | 73 | 262 | 847 |
| Acid Gas Controls | | 441 | 441 | 441 | 441 | 441 |
| Manitoba Purchase | | 1,331 | 1,331 | 1,331 | 1,331 | 1,331 |
| Hydraulic | Capital | 1,189 | 1,189 | 1,189 | 1,189 | 1,189 |
| | OM&A | 200 | 200 | 200 | 200 | 200 |
| Load Reducing Options DM & LD-NUGS | | 3,094 | 3,094 | 3,094 | 3,094 | 3,094 |
| Purchase Nugs | | 1,619 | 1,619 | 1,619 | 1,619 | 1,619 |
| Transmission | | 1,665 | 1,479 | 1,378 | 1,378 | 1,338 |
| Distribution | | 2,998 | 2,998 | 2,998 | 2,998 | 2,998 |
| Total | | 20,347 | 17,641 | 16,111 | 15,868 | 14,982 |
| **Fuel - Related Costs 1989-2014** | | | | | | |
| Cost Associated with Existing Demand | | 14,046 | 14,046 | 14,046 | 14,046 | 14,046 |
| Net Cost associated with Growth beyond 1993 | | (961) | (77) | 936 | 1,387 | 2,897 |
| Total | | 13,085 | 13,969 | 14,982 | 15,433 | 16,943 |
| **Cost of Existing System - allocated to 1989-2014** | | 42,898 | 42,898 | 42,898 | 42,898 | 42,898 |
| **Total Cost of New D/S Options & operating the Existing System** | | 76,330 | 74,507 | 73,991 | 74,199 | 74,823 |
| **Cost Differences from Case 15** | | 2,339 | 516 | BASE | 208 | 832 |

# FIGURE 8.3-22

Total Cost of New Demand/Supply Options and Operating the Existing System
Branch Upper Load Forecast - Median Cost Estimates
$1989 Million Present Value

| | | Case 23 | Case 22 | Case 15 | Case 24 | Case 26 |
|---|---|---|---|---|---|---|
| Cost of New D/S Options - allocated to 1994-2014 | | | | | | |
| Nuclear | Capital | 6,060 | 3,997 | 2,963 | 2,072 | 0 |
| | OM&A | 3,003 | 1,984 | 1,472 | 1,027 | 0 |
| Fossil | Capital | 107 | 512 | 798 | 1,383 | 2,689 |
| | OM&A | 2 | 86 | 122 | 423 | 1,156 |
| Acid Gas Controls | | 717 | 717 | 717 | 717 | 717 |
| Manitoba Purchase | | 1,331 | 1,331 | 1,331 | 1,331 | 1,331 |
| Hydraulic | Capital | 1,189 | 1,189 | 1,189 | 1,189 | 1,189 |
| | OM&A | 200 | 200 | 200 | 200 | 200 |
| Load Reducing Options DM & LD-NUGS | | 3,489 | 3,489 | 3,489 | 3,489 | 3,489 |
| Purchase Nugs | | 1,824 | 1,824 | 1,824 | 1,824 | 1,824 |
| Transmission | | 2,067 | 1,900 | 1,818 | 1,851 | 1,818 |
| Distribution | | 3,277 | 3,277 | 3,277 | 3,277 | 3,277 |
| Total | | 23,265 | 20,505 | 19,199 | 18,782 | 17,689 |
| Fuel - Related Costs 1989-2014 | | | | | | |
| Cost Associated with Existing Demand | | 14,046 | 14,046 | 14,046 | 14,046 | 14,046 |
| Net Cost associated with Growth beyond 1993 | | 86 | 1,336 | 2,322 | 2,993 | 5,125 |
| Total | | 14,132 | 15,382 | 16,368 | 17,039 | 19,172 |
| Cost of Existing System - allocated to 1989-2014 | | 42,898 | 42,898 | 42,898 | 42,898 | 42,898 |
| Total Cost of New D/S Options & operating the Existing System | | 80,294 | 78,784 | 78,464 | 78,719 | 79,758 |
| Cost Differences from Case 15 | | 1,830 | 319 | BASE | 254 | 1,294 |

# FIGURE 8.3-23

Total Cost of New Demand/Supply Options and Operating the Existing System
Upper Load Forecast - Median Cost Estimates
$1989 Million Present Value

| | | Case 23 | Case 22 | Case 15 | Case 24 | Case 26 |
|---|---|---|---|---|---|---|
| **Cost of New D/S Options - allocated to 1994-2014** | | | | | | |
| Nuclear | Capital | 5,946 | 4,127 | 3,438 | 2,515 | 0 |
| | OM&A | 2,946 | 2,048 | 1,708 | 1,263 | 0 |
| Fossil | Capital | 889 | 1,216 | 1,360 | 2,001 | 3,592 |
| | OM&A | 327 | 382 | 410 | 713 | 1,609 |
| Acid Gas Controls | | 1,135 | 1,135 | 1,135 | 1,135 | 1,135 |
| Manitoba Purchase | | 1,331 | 1,331 | 1,331 | 1,331 | 1,331 |
| Hydraulic | Capital | 1,189 | 1,189 | 1,189 | 1,189 | 1,189 |
| | OM&A | 200 | 200 | 200 | 200 | 200 |
| Load Reducing Options DM & LD-NUGS | | 4,421 | 4,421 | 4,421 | 4,421 | 4,421 |
| Purchase Nugs | | 2,032 | 2,032 | 2,032 | 2,032 | 2,032 |
| Transmission | | 2,391 | 2,287 | 2,215 | 2,215 | 2,215 |
| Distribution | | 3,607 | 3,607 | 3,607 | 3,607 | 3,607 |
| **Total** | | 26,413 | 23,974 | 23,044 | 22,621 | 21,330 |
| **Fuel - Related Costs 1989-2014** | | | | | | |
| Cost Associated with Existing Demand | | 14,046 | 14,046 | 14,046 | 14,046 | 14,046 |
| Net Cost associated with Growth beyond 1993 | | 3,072 | 4,513 | 5,276 | 5,920 | 8,204 |
| **Total** | | 17,118 | 18,559 | 19,322 | 19,966 | 22,250 |
| **Cost of Existing System - allocated to 1989-2014** | | 42,898 | 42,898 | 42,898 | 42,898 | 42,898 |
| **Total Cost of New D/S Options & operating the Existing System** | | 86,428 | 85,431 | 85,264 | 85,485 | 86,477 |
| **Cost Differences from Case 15** | | 1,164 | 167 | BASE | 221 | 1,214 |

# FIGURE 8.3-24

Total Cost of New Demand/Supply Options and Operating the Existing System
Branch Lower Load Forecast - Median Cost Estimates
$1989 Million Present Value

| | | Case 23 | Case 22 | Case 15 | Case 24 | Case 26 |
|---|---|---|---|---|---|---|
| Cost of New D/S Options - allocated to 1994-2014 | | | | | | |
| Nuclear | Capital | 4,573 | 2,529 | 1,956 | 1,723 | 0 |
| | OM&A | 2,257 | 1,139 | 867 | 753 | 0 |
| Fossil | Capital | 92 | 218 | 266 | 440 | 1,441 |
| | OM&A | 0 | 27 | 33 | 114 | 661 |
| Acid Gas Controls | | 441 | 441 | 441 | 441 | 441 |
| Manitoba Purchase | | 1,331 | 1,331 | 1,331 | 1,331 | 1,331 |
| Hydraulic | Capital | 1,189 | 1,189 | 1,189 | 1,189 | 1,189 |
| | OM&A | 200 | 200 | 200 | 200 | 200 |
| Load Reducing Options DM & LD-NUGS | | 2,670 | 2,670 | 2,670 | 2,670 | 2,670 |
| Purchase Nugs | | 1,094 | 1,094 | 1,094 | 1,094 | 1,094 |
| Transmission | | 1,284 | 1,004 | 958 | 961 | 872 |
| Distribution | | 2,704 | 2,704 | 2,704 | 2,704 | 2,704 |
| Total | | 17,835 | 14,545 | 13,709 | 13,620 | 12,602 |
| Fuel - Related Costs 1989-2014 | | | | | | |
| Cost Associated with Existing Demand | | 14,046 | 14,046 | 14,046 | 14,046 | 14,046 |
| Net Cost associated with Growth beyond 1993 | | (1,867) | (940) | (535) | (353) | 849 |
| Total | | 12,179 | 13,106 | 13,511 | 13,693 | 14,895 |
| Cost of Existing System - allocated to 1989-2014 | | 42,898 | 42,898 | 42,898 | 42,898 | 42,898 |
| Total Cost of New D/S Options & operating the Existing System | | 72,912 | 70,549 | 70,118 | 70,211 | 70,395 |
| Cost Differences from Case 15 | | 2,794 | 432 | BASE | 93 | 277 |

# FIGURE 8.3-25

Total Cost of New Demand/Supply Options and Operating the Existing System
Lower Load Forecast - Median Cost Estimates
$1989 Million Present Value

| | | Case 23 | Case 22 | Case 15 | Case 24 | Case 26 |
|---|---|---|---|---|---|---|
| **Cost of New D/S Options - allocated to 1994-2014** | | | | | | |
| Nuclear | Capital | 2,861 | 1,212 | 624 | 510 | 0 |
| | OM&A | 1,404 | 597 | 305 | 249 | 0 |
| Fossil | Capital | 102 | 129 | 222 | 290 | 612 |
| | OM&A | 1 | 6 | 28 | 65 | 247 |
| Acid Gas Controls | | 227 | 227 | 227 | 227 | 227 |
| Manitoba Purchase | | 1,265 | 1,265 | 1,265 | 1,265 | 1,265 |
| Hydraulic | Capital | 1,189 | 1,189 | 1,189 | 1,189 | 1,189 |
| | OM&A | 200 | 200 | 200 | 200 | 200 |
| Load Reducing Options DM & LD-NUGS | | 1,391 | 1,391 | 1,391 | 1,391 | 1,391 |
| Purchase Nugs | | 229 | 229 | 229 | 229 | 229 |
| Transmission | | 1,002 | 901 | 839 | 839 | 800 |
| Distribution | | 3,184 | 3,184 | 3,184 | 3,184 | 3,184 |
| **Total** | | 13,054 | 10,530 | 9,702 | 9,637 | 9,343 |
| **Fuel - Related Costs 1989-2014** | | | | | | |
| Cost Associated with Existing Demand | | 10,506 | 10,506 | 10,506 | 10,506 | 10,506 |
| Net Cost associated with Growth beyond 1993 | | (229) | 456 | 970 | 1,053 | 1,516 |
| **Total** | | 10,278 | 10,962 | 11,476 | 11,559 | 12,022 |
| Cost of Existing System - allocated to 1989-2014 | | 42,354 | 42,354 | 42,354 | 42,354 | 42,354 |
| Total Cost of New D/S Options & operating the Existing System | | 65,686 | 63,846 | 63,532 | 63,549 | 63,719 |
| Cost Differences from Case 15 | | 2,154 | 314 | BASE | 17 | 187 |

### 8.3.5 Extension of the Study Period

To analyze the impact of the study period length, the evaluation period was extended ten, twenty, and thirty years. The resulting cost differences are listed here in Figure 8.3-26.

The approach followed in extending the evaluation period is essentially based on the following two simple assumptions:

- The system's structure of the case in question remains the same as of year 2014. For example, if the four generating units of a nuclear plant are in operation by the end of year 2014, then the same plant configuration remains operational during the extended period.

- The operational characteristics of the generating plant remain unchanged throughout the extension period. As well, the load, supply, and other demand factors are kept at the same level forecast for year 2014.

There are other alternative approaches. The method used was selected because of its simplicity and because it avoids having to speculate further on uncertain factors and policies beyond the original study period.

Figure 8.3-26

Cost Differences to 2014 and Beyond Relative to Case 15
Median Load Forecast
1989 $ Billion

| | To 2104 | To 2024 | To 2034 | To 2044 |
|---|---|---|---|---|
| Case 23 | 2.3 | 3.5 | 4.4 | 5.1 |
| Case 22 | 0.5 | 0.7 | 0.8 | 0.9 |
| Case 15 | Base | Base | Base | Base |
| Case 24 | 0.2 | 0.5 | 0.6 | 0.7 |
| Case 26 | 0.8 | 2.0 | 2.7 | 3.0 |

## 8.4 SENSITIVITY ANALYSIS

### 8.4.1 Examining Range of Costs in the Cases

Over a 25-year timeframe, actual costs and differences between cases will likely be different than the original most likely predictions. Hydro addresses these anticipated changes by determining total cost for all customers under a range of conditions. In doing so, Hydro determines the degree to which any case could differ from its most likely cost.

### 8.4.2 Cost Estimate Bands

Generation options have three major cost components; Capital, OM&A and Fuel; each of which can vary significantly, leading to a:

(1) large difference in a case's cost
(2) notable difference in cost between cases

Since the extremes of a cost estimate for these components tend to distort total case cost results, Hydro focuses on the confidence band--the 80% of a range between the high and low extreme estimates. Discrete values, selected on the basis of past experience and estimates of future conditions, define the low, median and upper points of a range. Figure 8.4-1 shows how these three points define the 80% "confidence band". Costs are measured along the bottom of the graph. A cost curve can be drawn through the low estimate of $80, median estimate of $100 and upper estimate of $130, since costs can fall anywhere between the estimates.

Cost estimates have components with different degrees of uncertainty. In order to have a single range for each cost estimate within the costing model, specific range predictions for each cost component were weighted by the components contribution to the option's life cycle costs developed in the ONCI and TCR. These combined ranges for capital cost, capital modifications, and OMA, were used in RAM. The RAM also uses the additional 80% confidence band estimates for the economic factors and the fuel prices, when calculating the range of present value costs for each case.

The RAM present value costs include those investments made by the municipal utilities and the customers, thereby encompassing total electricity service costs. The RAM present value calculations for costs other than Hydro's components are escalated and discounted by Hydro's financial indicators and their cost bands. Since these costs are common to all cases they do not affect the differences in the present value cost.

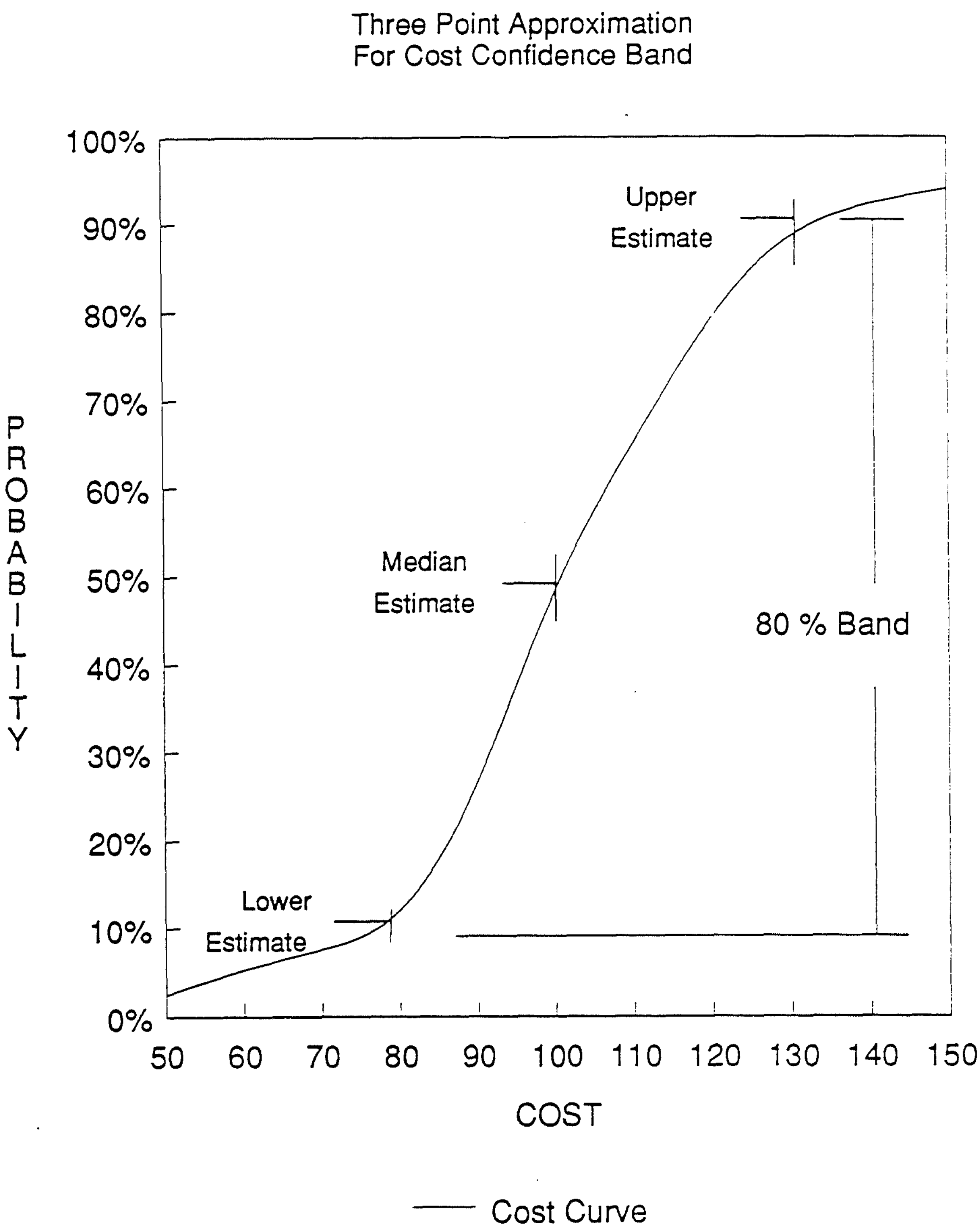

Three Point Approximation
For Cost Confidence Band
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
PROBABILITY
Upper
Estimate
Median
Estimate
Lower
Estimate
80 % Band
50
60
70
80
90
100
110
120
130
140
150
COST
Cost Curve

FIGURE 8.4-1

### 8.4.3 Cost Estimate Impacts On Case Costs

The factors requiring further study were established by examining the cost differences between cases caused by varying each individual factor independently. The RAM model was used to calculate how present value costs change in response to the cost estimate bands. The results were plotted on bar charts. When case cost components are very similar, there is very little difference in the resulting range of costs. While the length of the range can be significant,indicating an uncertainty common to all cases, the difference between cases can be insignificant.

Figure 8.4-2 shows the present value cost sensitivity to Load Forecast. The Lower and Upper load forecasts reflect the different amounts of energy to be supplied. The $20 Billion range reflects the differences in capital and operating costs necessary to meet these two load paths. While cost factors, fuel prices and economic factors may differ under different load paths, these were fixed at their median value so that the resulting range of costs represented only load path uncertainty.

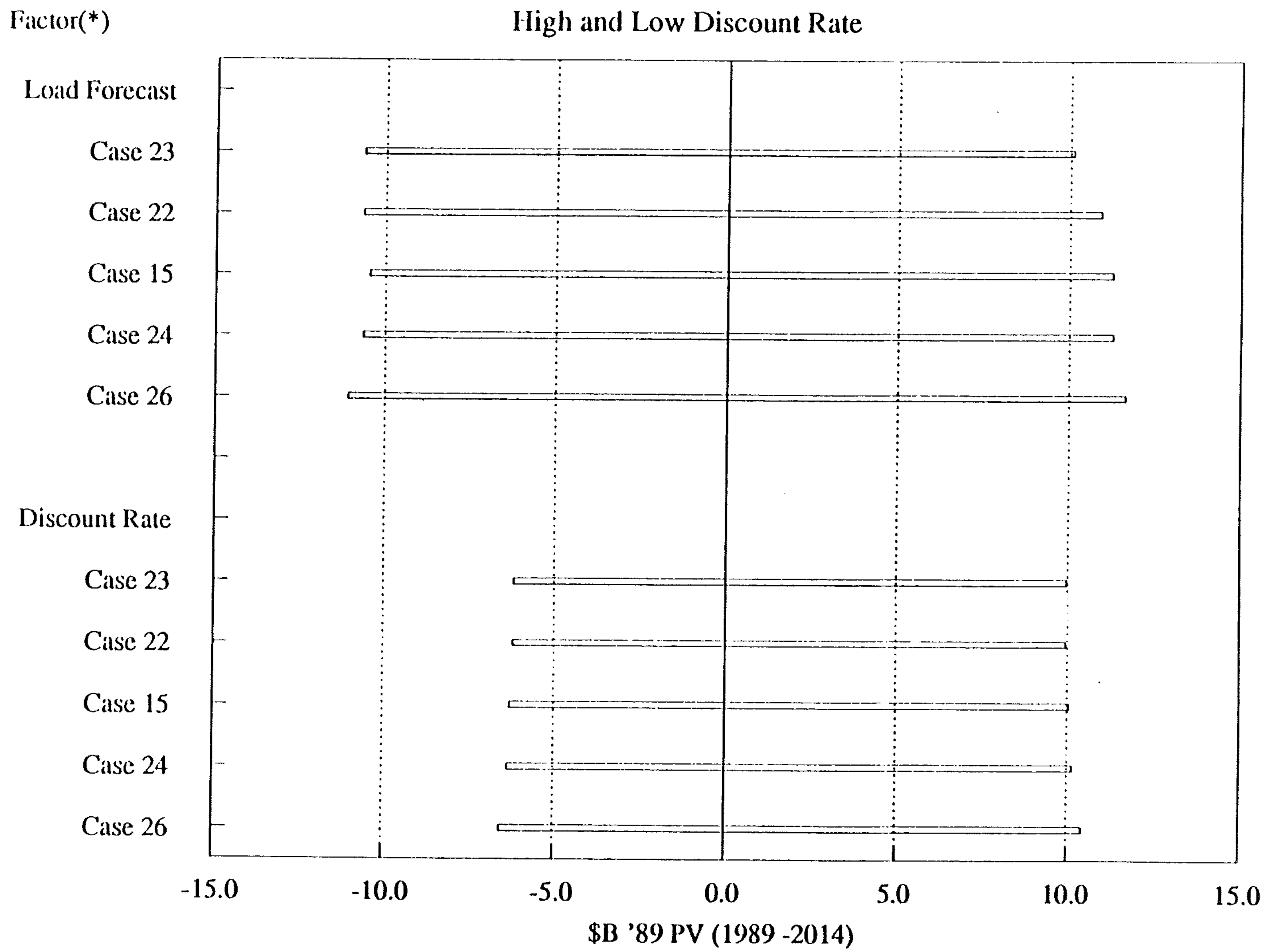
Figure 8.4-2 also shows the significant difference in present value costs when the Corporate Discount rate is varied. In order to provide real discount rate changes RAM recalculates the present value by changing the nominal discount rate by its predicted range while keeping the escalation fixed.

The significance of the discount rate to present value calculations is critical, especially when high capital options are built and financed over a long construction schedule with a high real cost of borrowing. These investments are made based on the assumtion that the higher capital cost plant will provide greater operating efficiencies, resulting in lower operating costs and system peaking fuel savings. While the future system benefits may occur, their resulting "present value" cost savings may be significantly different from those assumed in the cost evaluations.

80% Confidence Band - 10th / 90th Decile

Lower and Upper Load Forecast

High and Low Discount Rate




(*) Other Factors Fixed at Median

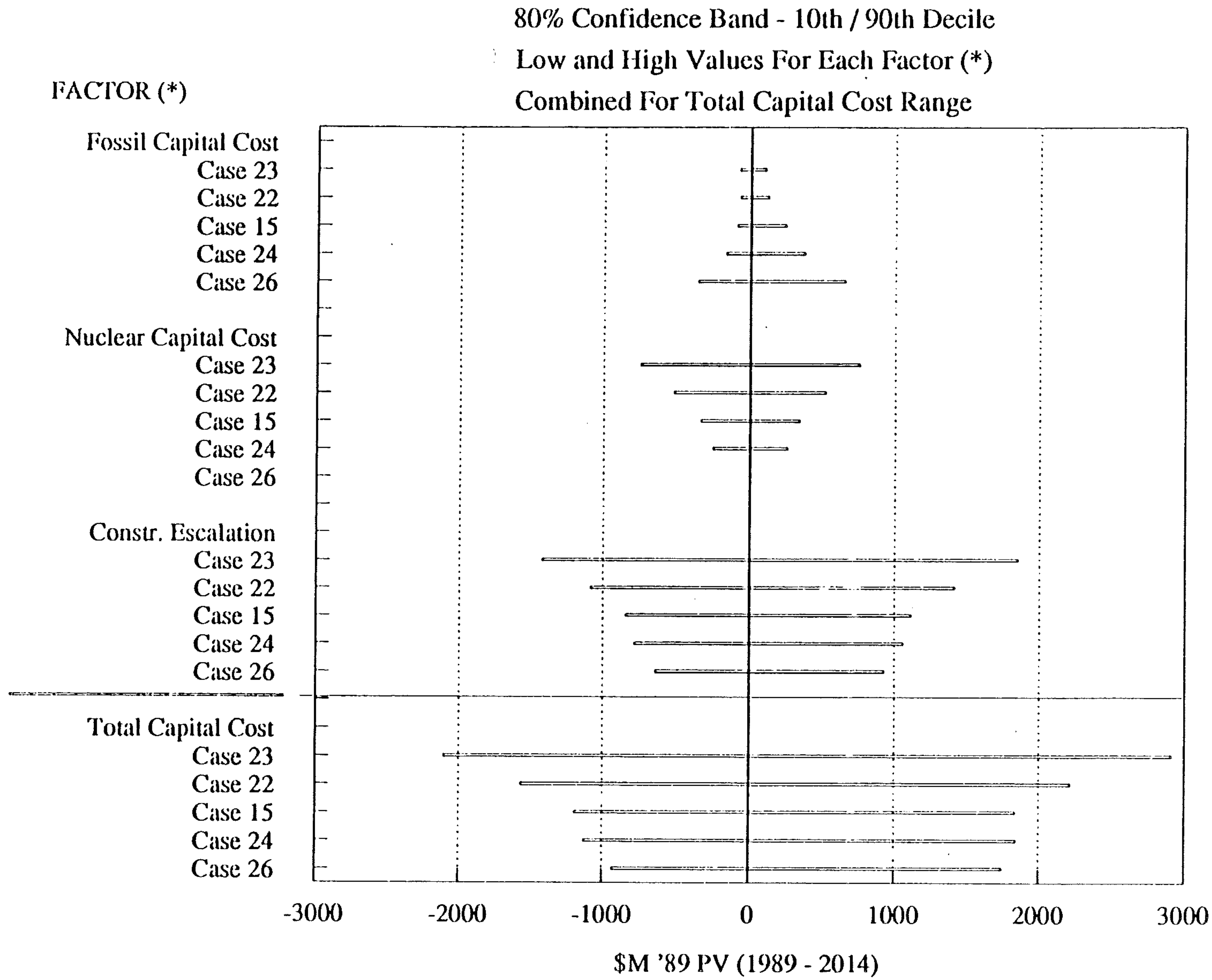
FIGURE 8.4-2

Figure 8.4-3 shows the sensitivity of base costs to the nuclear and fossil capital cost estimate bands and their construction cost escalators. In order to maintain a level of economic consistency and calculation efficiency, these cost estimates were combined. These combinations also provided a better indication of the more extreme differences between cases.

Many major components are common to all new generating options and their uncertainty is not dependent on the fuel type. For example if the nuclear option under construction were to experience higher capital costs then it is likely that similar cost pressures would also be applicable to the fossil options. Therefore, when the lower estimate for nuclear capital was used in RAM, the lower estimate for the fossil option was also used. In addition, both the nuclear and fossil construction cost escalators have many common elements such as Hydro labour and construction materials. Therefore, each options final construction costs would have similar escalation cost pressures regardless of the station type.

Figure 8.4-3 also shows the combined factor called Total Capital Costs. This range shows the cost range resulting when the three upper estimates are combined and when the three lower estimates are combined for the three components.

The uncertainty surrounding the capital cost of each option may differ, depending on a variety of factors such as newness of the technology, potential future environmental impact mitigation possibilities, Hydro past cost experience, etc. While the uncertainties have been linked, the cases have different levels of nuclear and fossil options. Their differences in response to capital and construction cost uncertainties are still captured by the degree to which each option constitutes a portion of the allocated present value costs.




(*) Other Factors Fixed at Median

FIGURE 8.4-3

Figure 8.4-4 shows the fossil and nuclear fuel cost ranges. The magnitude of these system fuel costs is highly dependent the new generating options in each case. The fossil fuel cost range reflects the significant difference in the amount of fossil fuel used by the system in each case.

Fuelling cost for nuclear options are less than for fossil options. Their cost uncertainty range is smaller, reflecting the lesser cost impact of system nuclear fuel cost within each case. While global energy pressures could cause fuel substitution, the fuel ranges are considered independent with the possibility that fossil prices can be higher while the nuclear fuel prices can be lower.

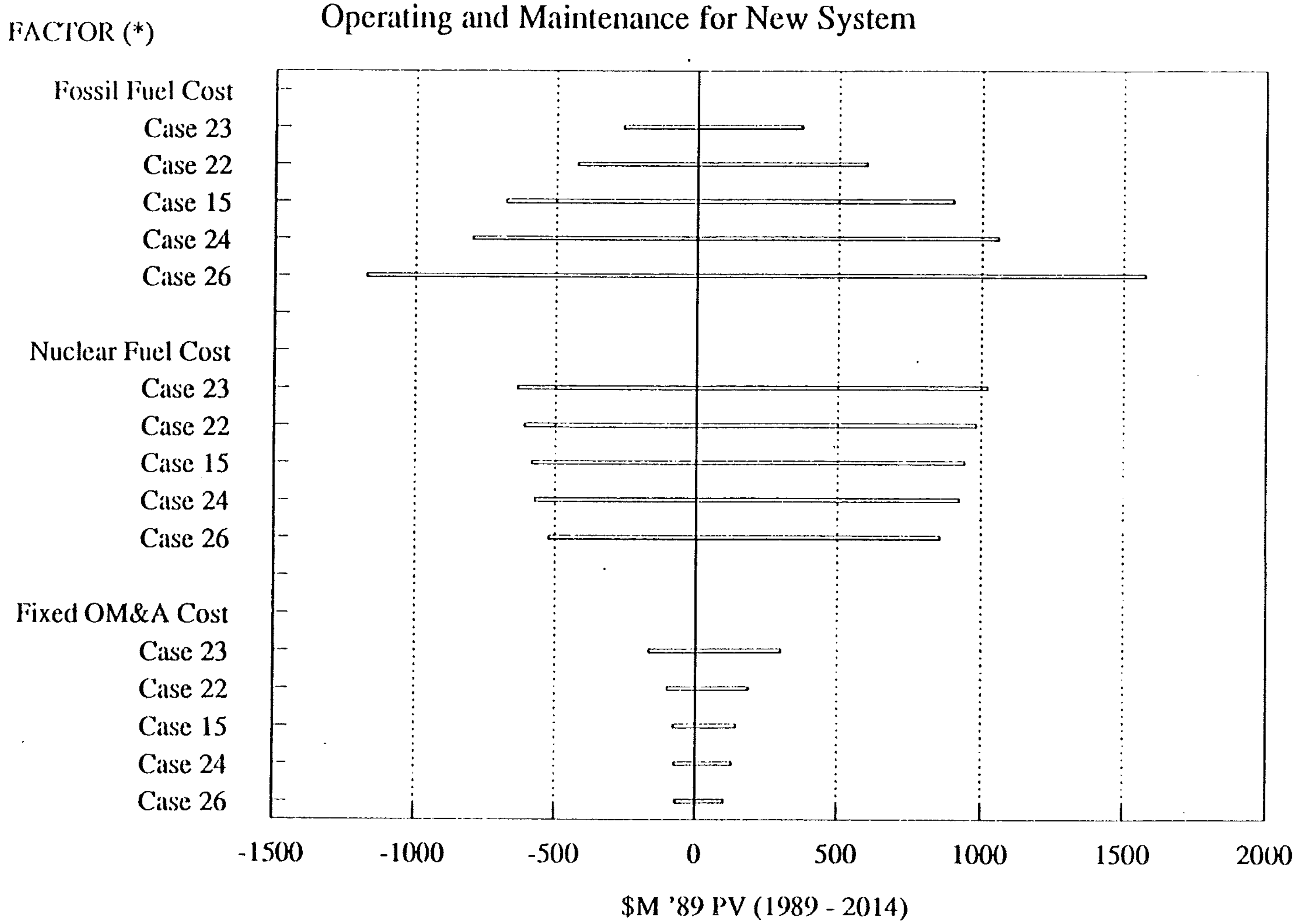
Figure 8.4-4 also indicates Fixed OMA costs uncertainty associated with the new options. These cost reflect the fixed labour and material cost for the operation and maintenance of the stations. The differences between cases reflect the higher OMA costs of the nuclear option. Many of the fixed OMA costs components are common to all Hydro generating stations therefore their uncertainty on the cost differences between cases would not be significant.

The five factors identified as having the greatest present value impact and worthy of further study with probabilistic methods were:

1. Load Forecast
2. Capital Construction Costs
3. Fossil Fuel Costs
4. Nuclear Fuel Costs
5. Cost of money (Real discount rate)

FIGURE 8.4-4

80% Confidence Band - 10th / 90th Decile
Low and High Values for Each Factor (*)
Total System Fueling Costs for Each Case
Operating and Maintenance for New System




(*) Other Factors Fixed at Median

## 8.5 PROBABILISTIC ANALYSIS

### 8.5.1 Uncertainty - Expected Costs

Probabilistic cost evaluations recognize and deal with the uncertainties surrounding the major cost factors within each case. Uncertainty introduces financial risks into the planning process. Minimizing risks generally results in an increase in costs, and minimizing costs often increases risks. One of the tools used by decision makers to balance risks with costs is the expected cost concept.

The expected cost of a case is the total cost of a case multiplied by the probability of the case's outcome. For example, Case A will have different costs depending on the load forecast. Under the median load forecast, the cost of Case A may be $20 billion. With the upper load forecast, the cost of Case A may rise to $30 billion. In the lower forecast, Case A may cost $15 billion.

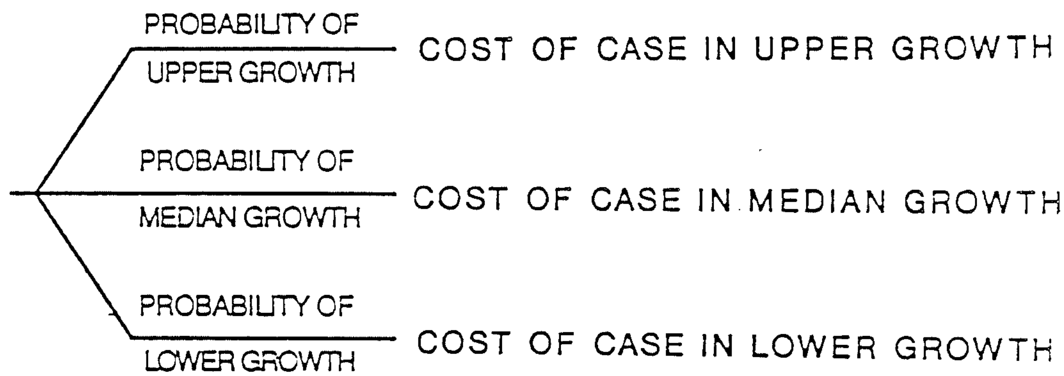
To determine the expected cost of Case A, recognizing load forecast uncertainty, the cost of Case A for the various forecasts is multiplied by the probability of the forecast. For example, if it is assumed that there is a 50% probability of median load forecast and a 25% probability of either the upper or lower forecasts, then the expected cost of Case A would be calculated as shown in Figure 8.5-1.

The resulting outcome would therefore provide Hydro with an expected cost of Case A under all three load forecast scenarios. The method can be extended to account for uncertainties in fuel costs, construction costs and discount rates, etc.

Figure 8.5-1

EXPECTED COST OF DEMAND/SUPPLY CASES

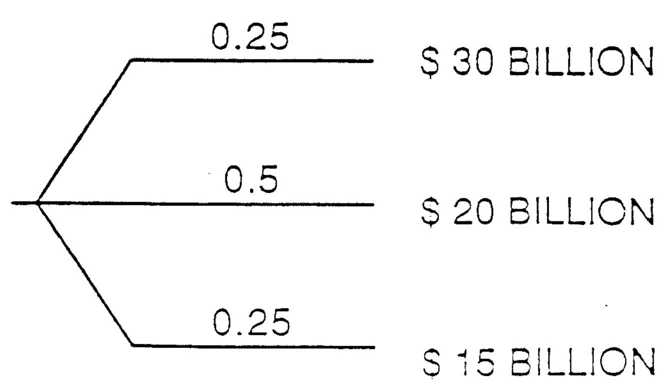
EXPECTED COST
IS THE SUM
OF THE THREE
POSSIBLE COSTS
WEIGHTED BY
THEIR
PROBABILITY




EXPECTED COST =

0.25 X 30 ÷ 0.5 X 20 ÷ 0.25 X 15

= $ 21.25 BILLION



### 8.5.2 Load Forecasts

The probabilities assigned to each one of the five load forecasts were derived from the ranges provided by the 1989 Basic Load Forecast. To these forecasts a wide range of load possibilities and likelihood are associated.

For this analysis, five load regions were determined by identifying the midpoints found between adjacent load paths. Each one of the load regions thus created contained one of the five load paths and had a probability associated with it. That probability was attributed to the corresponding load path.

The results of this analysis showed that the probabilities of each path tend to become steady by the year 2006, by which time most major capital will have been committed and spent. Those probabilities were chosen and are:

| Load Forecast | Probability |
|---|---|
| Upper | 17% |
| Branch Upper | 20% |
| Median | 26% |
| Branch Lower | 20% |
| Lower | 17% |
| Overall | 100% |

Other methods and subjective considerations may yield different measures of likelihood. Consequently, sensitivity to changes in the probabilities chosen were evaluated to check for possible impact on the ranking of Cases based on the load forecast paths alone. The results in Figure 8.5-2 show no impact on cost preference among Cases when likelihood of load forecasts is modified.

FIGURE 8.5-2

PLAN COSTS BASED ON LOAD PATH ONLY
(Millions of 1989$, Present Value)

| Load Path | Case 23 | Case 22 | Case 15 | Case 24 | Case 26 |
|---|---|---|---|---|---|
| Upper | 86428 | 85431 | 85264 | 85485 | 86477 |
| Branch Upper | 80294 | 78784 | 78464 | 78719 | 79758 |
| Median | 76330 | 74507 | 73991 | 74199 | 74823 |
| Branch Lower | 72912 | 70549 | 70118 | 70211 | 70395 |
| Lower | 65686 | 63846 | 63532 | 63549 | 63719 |

EXPECTED COST DIFFERENCES RELATIVE TO CASE 15
USING LOAD FORECAST PROBABILITIES
(Millions of 1989$, Present Value)

| LOAD | PROB | CASE 23 | CASE 22 | CASE 15 | CASE 24 | CASE 26 |
|---|---|---|---|---|---|---|
| Upper | 17% | 198 | 28 | BASE | 38 | 206 |
| Branch Upper | 20% | 366 | 64 | BASE | 51 | 259 |
| Median | 26% | 608 | 134 | BASE | 54 | 216 |
| Branch Lower | 20% | 559 | 86 | BASE | 19 | 55 |
| Lower | 17% | 366 | 53 | BASE | 3 | 32 |
| Expected Cost Differences | | 2097 | 366 | BASE | 164 | 769 |

DIFFERENCES WITH EQUAL PROBABILITY FOR LOAD PATHS
(Millions of 1989$, Present Value)

| LOAD | PROB | CASE 23 | CASE 22 | CASE 15 | CASE 24 | CASE 26 |
|---|---|---|---|---|---|---|
| Upper | 20% | 233 | 33 | BASE | 44 | 243 |
| Branch Upper | 20% | 366 | 64 | BASE | 51 | 259 |
| Median | 20% | 468 | 103 | BASE | 42 | 166 |
| Branch Lower | 20% | 559 | 86 | BASE | 19 | 55 |
| Lower | 20% | 431 | 63 | BASE | 3 | 37 |
| Expected Cost Differences | | 2056 | 350 | BASE | 159 | 761 |

### 8.5.3 Probabilities For The High, Median and Low Cost Estimates

Since there is no detailed probability distribution for each cost component, an approximation is necessary based on the lower, medium and upper estimates. This was obtained by connecting the estimates from the ONCI, TCR, and the prediction ranges in the Sept 1988 Economic Outlook.

As shown in Figure 8.5-3, the lower, median and upper estimates correspond to the 10%, 50% and 90% points along the cumulative probability distribution. In order to complete the probability distributions, the following assumtion were made:

(1) the 10% estimate is representative of the 0-20% region of the cumulative probability distribution curve;

(2) the 90% estimate is representative of the 80-100% region of the curve; and

(3) the 50% estimate is representative of the remainder of the curve.

Thus, the three probabilities associated with the three available estimates are as follows:

| Estimate | Probability |
|---|---|
| Upper | 20% |
| Median | 60% |
| Lower | 20% |

Probabilities Assigned To
Low, Median and Upper Estimates
Representing Cost Band

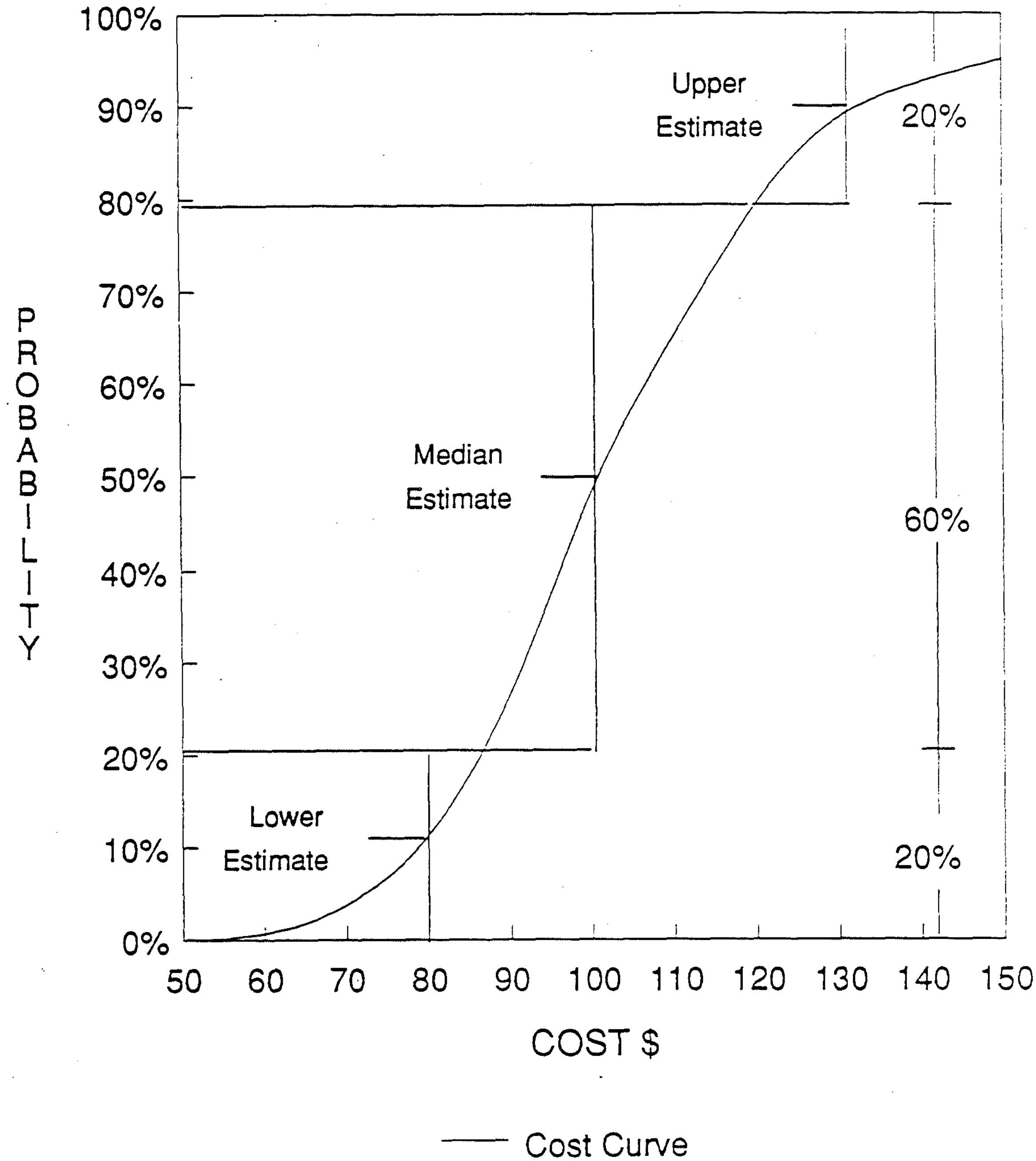



FIGURE 8.5-3

### 8.5.4 Combining the Cost Estimates and Their Probabilities

Combining the three cost estimates for the key cost components with the five possible load forecasts results in 405 ( 5 * 3 * 3 * 3 * 3 = 405) different possible combinations of estimates, resulting in an equal number of present value cost outcomes. Figure 8.5-4 illustrates how the 405 outcomes could occur. Since each component is considered independent, the path from the Load to the Capital Cost estimate could take any of the five possibilities. Similarly the path from cost component to cost component can take any of the three possibilities, resulting in the 405 possible paths.

If Case 15 is run through two different paths, as shown in Figure 8.5-5, the final expected present value costs would be different, unless by some small chance, different cost estimates resulted in exactly the same final costs.

The chance of any outcome occurring is the product of the probabilities for each path. For example, following are the probabilities associated with the path that begins with upper load forecast in Figure 8.5-5.

| | |
|---|---|
| Probability (upper load) | = 17% |
| Probability (high capital cost) | = 20% |
| Probability (median nuclear fuel cost) | = 60% |
| Probability (low fossil fuel cost) | = 20% |
| Probability (high discount rate) | = 20% |

Cumulative Probability = .17 * .20 * .60 * .20 * .20 = .000816 = .0816%

## Load and Cost Estimate Probabilities And Their Possible Outcomes

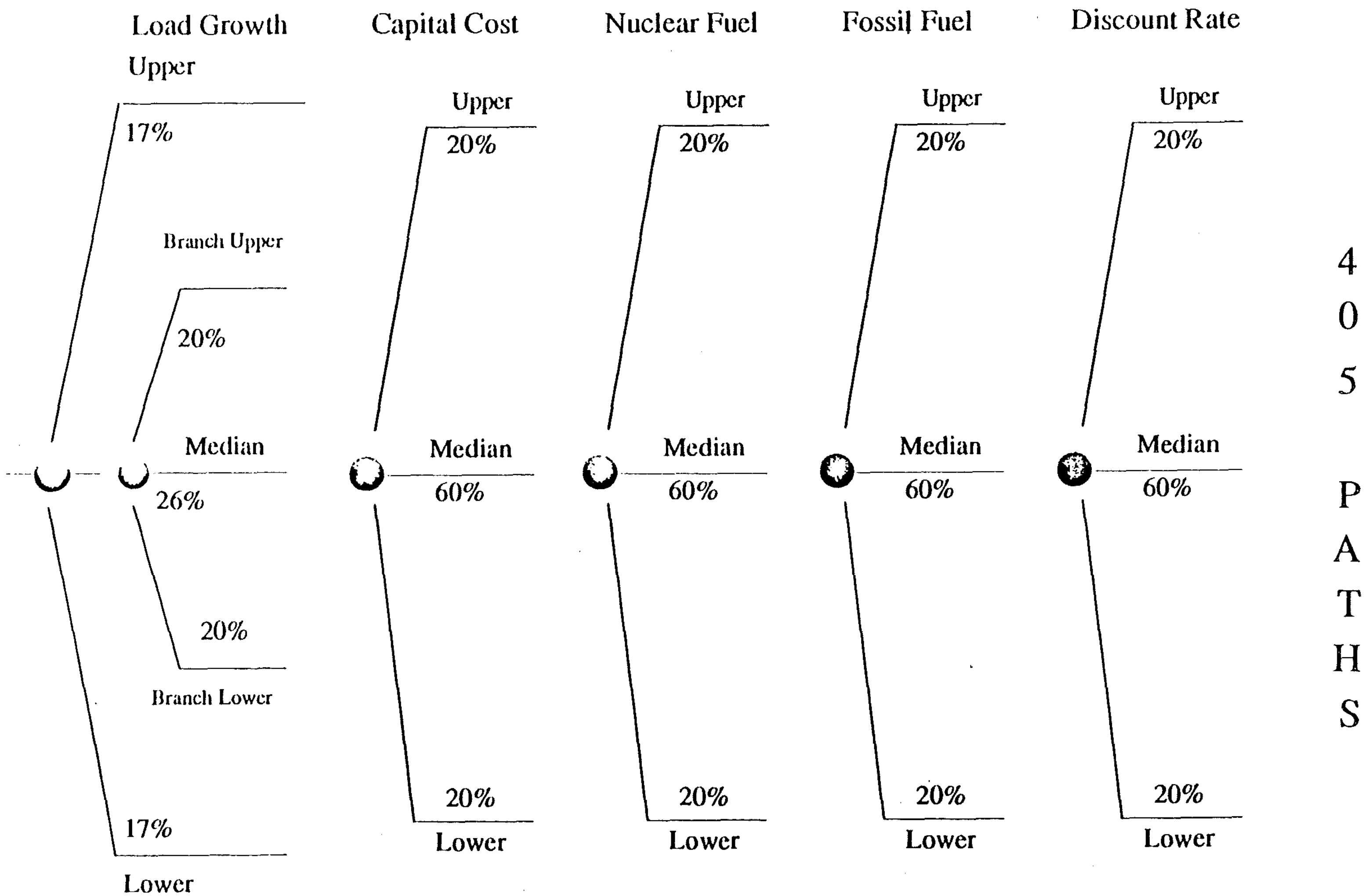



FIGURE 8.5-4

## Illustration of Path Leading To Two Possible Outcomes

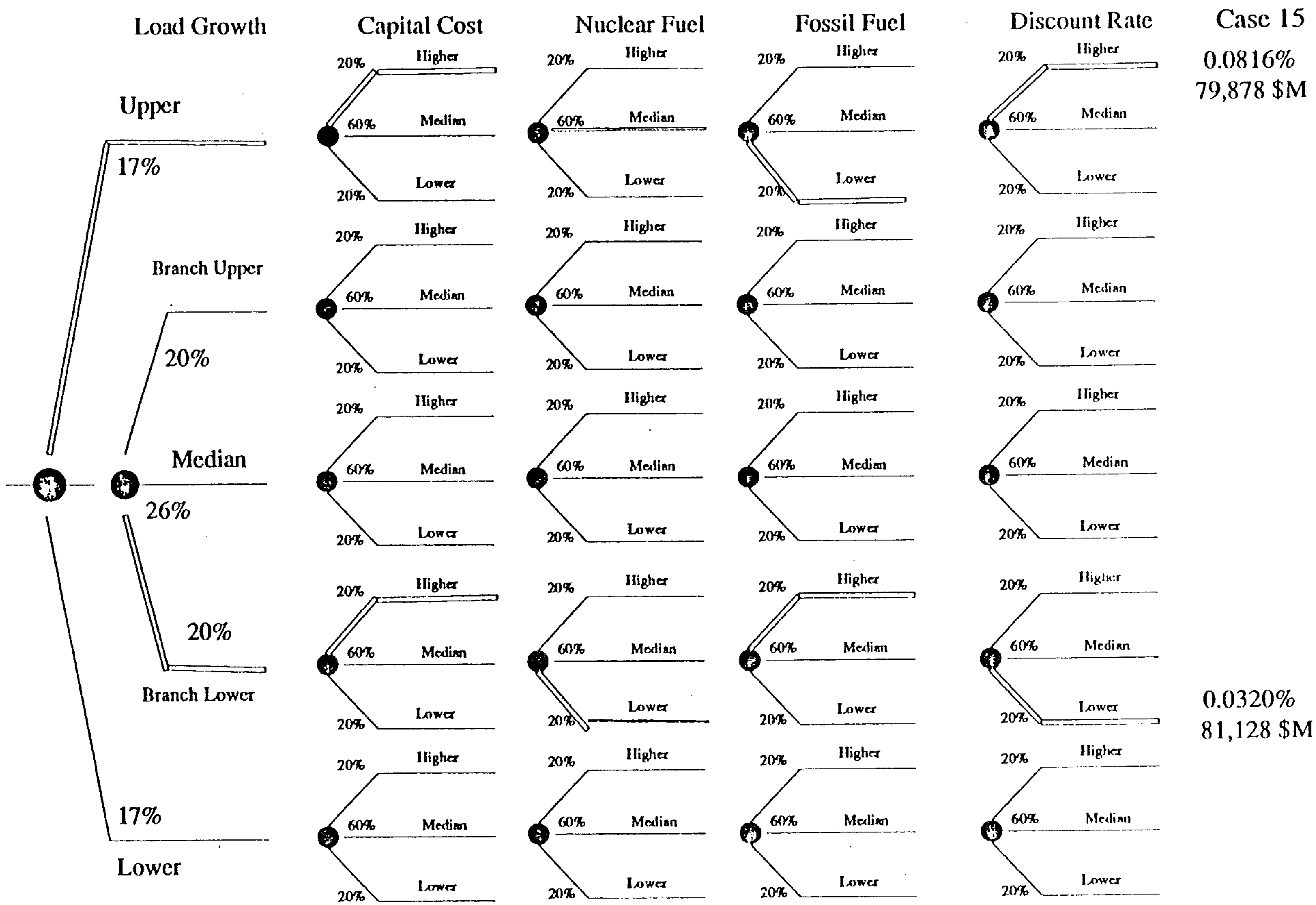



FIGURE 8.5-5

### 8.5.5 Expected Cost Results

While a path may have only a small probability, its final costs may be significantly different than the median cost. Therefore, every path in the tree is important. Figure 8.5-6 through Figure 8.5-10 shows the complete expansion of Case 15s 405 paths. At each end point is the present value cost of the RAM when the conditions on the path are modelled.

The 405 outcomes are used to determine the expected cost of the case. This is done by multiplying each outcome by the corresponding probability and then adding the results. Both the expected cost and full range of costs are considered in the evaluation of cases. Figure 8.5-11 indicates the expected values for all five cases for all five load paths. Differences from Case 15s expected cost shows its cost effectiveness under all load forecast paths. Making the load forecast probabilities equal shows no significant change in the expected cost differences.

# FIGURE 8.5-6

## TREE PATHS FOR UPPER LOAD FORECAST

| PATH # | LOAD | CAPCOST | NUCFUEL | FOSSFUEL | DISCRATE | * | ENDPOINT PROBABILITY | CASE 15 ENDPOINT '89$M PV | EXPECTED ENDPOINT ($M PV) |
|---|---|---|---|---|---|---|---|---|---|
| 1 | | | | | HIGH | * | 0.0272% | 83335 | 23 |
| 2 | | | | HIGH | MEDIAN | * | 0.0816% | 91005 | 74 |
| 3 | | | | | LOW | * | 0.0272% | 103368 | 28 |
| 4 | | | | | HIGH | * | 0.0816% | 81934 | 67 |
| 5 | | | HIGH | MEDIAN | MEDIAN | * | 0.2448% | 89443 | 219 |
| 6 | | | | | LOW | * | 0.0816% | 101549 | 83 |
| 7 | | | | | HIGH | * | 0.0272% | 80764 | 22 |
| 8 | | | | LOW | MEDIAN | * | 0.0816% | 88137 | 72 |
| 9 | | | | | LOW | * | 0.0272% | 100024 | 27 |
| 10 | | | | | HIGH | * | 0.0816% | 82449 | 67 |
| 11 | | | | HIGH | MEDIAN | * | 0.2448% | 90006 | 220 |
| 12 | | | | | LOW | * | 0.0816% | 102190 | 83 |
| 13 | | | | | HIGH | * | 0.2448% | 81048 | 198 |
| 14 | | HIGH | MEDIAN | MEDIAN | MEDIAN | * | 0.7344% | 88445 | 650 |
| 15 | | | | | LOW | * | 0.2448% | 100371 | 246 |
| 16 | | | | | HIGH | * | 0.0816% | 79878 | 65 |
| 17 | | | | LOW | MEDIAN | * | 0.2448% | 87138 | 213 |
| 18 | | | | | LOW | * | 0.0816% | 98846 | 81 |
| 19 | | | | | HIGH | * | 0.0272% | 81901 | 22 |
| 20 | | | | HIGH | MEDIAN | * | 0.0816% | 89386 | 73 |
| 21 | | | | | LOW | * | 0.0272% | 101453 | 28 |
| 22 | | | | | HIGH | * | 0.0816% | 80501 | 66 |
| 23 | | | LOW | MEDIAN | MEDIAN | * | 0.2448% | 87824 | 215 |
| 24 | | | | | LOW | * | 0.0816% | 99634 | 81 |
| 25 | | | | | HIGH | * | 0.0272% | 79330 | 22 |
| 26 | | | | LOW | MEDIAN | * | 0.0816% | 86517 | 71 |
| 27 | | | | | LOW | * | 0.0272% | 98110 | 27 |
| 28 | | | | | HIGH | * | 0.0816% | 80455 | 66 |
| 29 | | | | HIGH | MEDIAN | * | 0.2448% | 87824 | 215 |
| 30 | | | | | LOW | * | 0.0816% | 99677 | 81 |
| 31 | | | | | HIGH | * | 0.2448% | 79054 | 194 |
| 32 | | | HIGH | MEDIAN | MEDIAN | * | 0.7344% | 86262 | 634 |
| 33 | | | | | LOW | * | 0.2448% | 97858 | 240 |
| 34 | | | | | HIGH | * | 0.0816% | 77884 | 64 |
| 35 | | | | LOW | MEDIAN | * | 0.2448% | 84956 | 208 |
| 36 | | | | | LOW | * | 0.0816% | 96333 | 79 |
| 37 | | | | | HIGH | * | 0.2448% | 79569 | 195 |
| 38 | | | | HIGH | MEDIAN | * | 0.7344% | 86825 | 638 |
| 39 | | | | | LOW | * | 0.2448% | 98499 | 241 |
| 40 | | | | | HIGH | * | 0.7344% | 78168 | 574 |
| 41 | UPPER | MEDIAN | MEDIAN | MEDIAN | MEDIAN | * | 2.2032% | 85264 | 1879 |
| 42 | | | | | LOW | * | 0.7344% | 96680 | 710 |
| 43 | | | | | HIGH | * | 0.2448% | 76998 | 188 |
| 44 | | | | LOW | MEDIAN | * | 0.7344% | 83957 | 617 |
| 45 | | | | | LOW | * | 0.2448% | 95155 | 233 |
| 46 | | | | | HIGH | * | 0.0816% | 79021 | 64 |
| 47 | | | | HIGH | MEDIAN | * | 0.2448% | 86204 | 211 |
| 48 | | | | | LOW | * | 0.0816% | 97762 | 80 |
| 49 | | | | | HIGH | * | 0.2448% | 77621 | 190 |
| 50 | | | LOW | MEDIAN | MEDIAN | * | 0.7344% | 84643 | 622 |
| 51 | | | | | LOW | * | 0.2448% | 95943 | 235 |
| 52 | | | | | HIGH | * | 0.0816% | 76450 | 62 |
| 53 | | | | LOW | MEDIAN | * | 0.2448% | 83336 | 204 |
| 54 | | | | | LOW | * | 0.0816% | 94419 | 77 |
| 55 | | | | | HIGH | * | 0.0272% | 78637 | 21 |
| 56 | | | | HIGH | MEDIAN | * | 0.0816% | 85830 | 70 |
| 57 | | | | | LOW | * | 0.0272% | 97384 | 26 |
| 58 | | | | | HIGH | * | 0.0816% | 77237 | 63 |
| 59 | | | HIGH | MEDIAN | MEDIAN | * | 0.2448% | 84269 | 206 |
| 60 | | | | | LOW | * | 0.0816% | 95565 | 78 |
| 61 | | | | | HIGH | * | 0.0272% | 76067 | 21 |
| 62 | | | | LOW | MEDIAN | * | 0.0816% | 82962 | 68 |
| 63 | | | | | LOW | * | 0.0272% | 94040 | 26 |
| 64 | | | | | HIGH | * | 0.0816% | 77752 | 63 |
| 65 | | | | HIGH | MEDIAN | * | 0.2448% | 84832 | 208 |
| 66 | | | | | LOW | * | 0.0816% | 96206 | 79 |
| 67 | | | | | HIGH | * | 0.2448% | 76351 | 187 |
| 68 | | LOW | MEDIAN | MEDIAN | MEDIAN | * | 0.7344% | 83270 | 612 |
| 69 | | | | | LOW | * | 0.2448% | 94387 | 231 |
| 70 | | | | | HIGH | * | 0.0816% | 75181 | 61 |
| 71 | | | | LOW | MEDIAN | * | 0.2448% | 81964 | 201 |
| 72 | | | | | LOW | * | 0.0816% | 92862 | 76 |
| 73 | | | | | HIGH | * | 0.0272% | 77204 | 21 |
| 74 | | | | HIGH | MEDIAN | * | 0.0816% | 84211 | 69 |
| 75 | | | | | LOW | * | 0.0272% | 95469 | 26 |
| 76 | | | | | HIGH | * | 0.0816% | 75803 | 62 |
| 77 | | | LOW | MEDIAN | MEDIAN | * | 0.2448% | 82649 | 202 |
| 78 | | | | | LOW | * | 0.0816% | 93650 | 76 |
| 79 | | | | | HIGH | * | 0.0272% | 74633 | 20 |
| 80 | | | | LOW | MEDIAN | * | 0.0816% | 81343 | 66 |
| 81 | | | | | LOW | * | 0.0272% | 92125 | 25 |

# FIGURE 8.5-7

## TREE PATHS FOR BRANCH UPPER LOAD FORECAST

| PATH # | LOAD | CAPCOST | NUCFUEL | FOSSFUEL | DISCRATE | * | ENDPOINT PROBABILITY | CASE 15 ENDPOINT '89$M PV | EXPECTED ENDPOINT ($M PV) |
|---|---|---|---|---|---|---|---|---|---|
| 82 | | | | | HIGH | * | 0.0320% | 75974 | 24 |
| 83 | | | | HIGH | MEDIAN | * | 0.0960% | 83198 | 80 |
| 84 | | | | | LOW | * | 0.0320% | 94820 | 30 |
| 85 | | | | | HIGH | * | 0.0960% | 74932 | 72 |
| 86 | | | HIGH | MEDIAN | MEDIAN | * | 0.2880% | 82023 | 236 |
| 87 | | | | | LOW | * | 0.0960% | 93436 | 90 |
| 88 | | | | | HIGH | * | 0.0320% | 74127 | 24 |
| 89 | | | | LOW | MEDIAN | * | 0.0960% | 81114 | 78 |
| 90 | | | | | LOW | * | 0.0320% | 92361 | 30 |
| 91 | | | | | HIGH | * | 0.0960% | 75108 | 72 |
| 92 | | | | HIGH | MEDIAN | * | 0.2880% | 82221 | 237 |
| 93 | | | | | LOW | * | 0.0960% | 93669 | 90 |
| 94 | | | | | HIGH | * | 0.2880% | 74065 | 213 |
| 95 | | HIGH | MEDIAN | MEDIAN | MEDIAN | * | 0.8640% | 81047 | 700 |
| 96 | | | | | LOW | * | 0.2880% | 92285 | 266 |
| 97 | | | | | HIGH | * | 0.0960% | 73261 | 70 |
| 98 | | | | LOW | MEDIAN | * | 0.2880% | 80138 | 231 |
| 99 | | | | | LOW | * | 0.0960% | 91210 | 88 |
| 100 | | | | | HIGH | * | 0.0320% | 74573 | 24 |
| 101 | | | | HIGH | MEDIAN | * | 0.0960% | 81616 | 78 |
| 102 | | | | | LOW | * | 0.0320% | 92950 | 30 |
| 103 | | | | | HIGH | * | 0.0960% | 73530 | 71 |
| 104 | | | LOW | MEDIAN | MEDIAN | * | 0.2880% | 80441 | 232 |
| 105 | | | | | LOW | * | 0.0960% | 91566 | 88 |
| 106 | | | | | HIGH | * | 0.0320% | 72726 | 23 |
| 107 | | | | LOW | MEDIAN | * | 0.0960% | 79532 | 76 |
| 108 | | | | | LOW | * | 0.0320% | 90491 | 29 |
| 109 | | | | | HIGH | * | 0.0960% | 73659 | 71 |
| 110 | | | | HIGH | MEDIAN | * | 0.2880% | 80614 | 232 |
| 111 | | | | | LOW | * | 0.0960% | 91782 | 88 |
| 112 | | | | | HIGH | * | 0.2880% | 72616 | 209 |
| 113 | | | HIGH | MEDIAN | MEDIAN | * | 0.8640% | 79440 | 686 |
| 114 | | | | | LOW | * | 0.2880% | 90398 | 260 |
| 115 | | | | | HIGH | * | 0.0960% | 71812 | 69 |
| 116 | | | | LOW | MEDIAN | * | 0.2880% | 78531 | 226 |
| 117 | | | | | LOW | * | 0.0960% | 89323 | 86 |
| 118 | | | | | HIGH | * | 0.2880% | 72793 | 210 |
| 119 | | | | HIGH | MEDIAN | * | 0.8640% | 79638 | 688 |
| 120 | | | | | LOW | * | 0.2880% | 90630 | 261 |
| 121 | | | | | HIGH | * | 0.8640% | 71750 | 620 |
| 122 | -BR UPPER | MEDIAN | MEDIAN | MEDIAN | MEDIAN | * | 2.5920% | 78463 | 2034 |
| 123 | | | | | LOW | * | 0.8640% | 89246 | 771 |
| 124 | | | | | HIGH | * | 0.2880% | 70945 | 204 |
| 125 | | | | LOW | MEDIAN | * | 0.8640% | 77554 | 670 |
| 126 | | | | | LOW | * | 0.2880% | 88172 | 254 |
| 127 | | | | | HIGH | * | 0.0960% | 72258 | 69 |
| 128 | | | | HIGH | MEDIAN | * | 0.2880% | 79032 | 228 |
| 129 | | | | | LOW | * | 0.0960% | 89912 | 86 |
| 130 | | | | | HIGH | * | 0.2880% | 71215 | 205 |
| 131 | | | LOW | MEDIAN | MEDIAN | * | 0.8640% | 77857 | 673 |
| 132 | | | | | LOW | * | 0.2880% | 88528 | 255 |
| 133 | | | | | HIGH | * | 0.0960% | 70411 | 68 |
| 134 | | | | LOW | MEDIAN | * | 0.2880% | 76949 | 222 |
| 135 | | | | | LOW | * | 0.0960% | 87453 | 84 |
| 136 | | | | | HIGH | * | 0.0320% | 72170 | 23 |
| 137 | | | | HIGH | MEDIAN | * | 0.0960% | 78969 | 76 |
| 138 | | | | | LOW | * | 0.0320% | 89872 | 29 |
| 139 | | | | | HIGH | * | 0.0960% | 71127 | 68 |
| 140 | | | HIGH | MEDIAN | MEDIAN | * | 0.2880% | 77794 | 224 |
| 141 | | | | | LOW | * | 0.0960% | 88488 | 85 |
| 142 | | | | | HIGH | * | 0.0320% | 70323 | 23 |
| 143 | | | | LOW | MEDIAN | * | 0.0960% | 76885 | 74 |
| 144 | | | | | LOW | * | 0.0320% | 87413 | 28 |
| 145 | | | | | HIGH | * | 0.0960% | 71304 | 68 |
| 146 | | | | HIGH | MEDIAN | * | 0.2880% | 77992 | 225 |
| 147 | | | | | LOW | * | 0.0960% | 88720 | 85 |
| 148 | | | | | HIGH | * | 0.2880% | 70261 | 202 |
| 149 | | LOW | MEDIAN | MEDIAN | MEDIAN | * | 0.8640% | 76818 | 664 |
| 150 | | | | | LOW | * | 0.2880% | 87336 | 252 |
| 151 | | | | | HIGH | * | 0.0960% | 69456 | 67 |
| 152 | | | | LOW | MEDIAN | * | 0.2880% | 75909 | 219 |
| 153 | | | | | LOW | * | 0.0960% | 86262 | 83 |
| 154 | | | | | HIGH | * | 0.0320% | 70769 | 23 |
| 155 | | | | HIGH | MEDIAN | * | 0.0960% | 77386 | 74 |
| 156 | | | | | LOW | * | 0.0320% | 88002 | 28 |
| 157 | | | | | HIGH | * | 0.0960% | 69726 | 67 |
| 158 | | | LOW | MEDIAN | MEDIAN | * | 0.2880% | 76212 | 219 |
| 159 | | | | | LOW | * | 0.0960% | 86618 | 83 |
| 160 | | | | | HIGH | * | 0.0320% | 68921 | 22 |
| 161 | | | | LOW | MEDIAN | * | 0.0960% | 75303 | 72 |
| 162 | | | | | LOW | * | 0.0320% | 85543 | 27 |

# FIGURE 8.5-8

## TREE PATHS FOR MEDIAN LOAD FORECAST

| PATH # | LOAD | CAPCOST | NUCFUEL | FOSSFUEL | DISCRATE | * | ENDPOINT PROBABILITY | CASE 15 ENDPOINT '89$M PV | EXPECTED ENDPOINT ($M PV) |
|---|---|---|---|---|---|---|---|---|---|
| 163 | | | | | HIGH | * | 0.0416% | 71006 | 30 |
| 164 | | | | HIGH | MEDIAN | * | 0.1248% | 77673 | 97 |
| 165 | | | | | LOW | * | 0.0416% | 88371 | 37 |
| 166 | | | | | HIGH | * | 0.1248% | 70208 | 88 |
| 167 | | | HIGH | MEDIAN | MEDIAN | * | 0.3744% | 76771 | 287 |
| 168 | | | | | LOW | * | 0.1248% | 87306 | 109 |
| 169 | | | | | HIGH | * | 0.0416% | 69609 | 29 |
| 170 | | | | LOW | MEDIAN | * | 0.1248% | 76093 | 95 |
| 171 | | | | | LOW | * | 0.0416% | 86502 | 36 |
| 172 | | | | | HIGH | * | 0.1248% | 70167 | 88 |
| 173 | | | | HIGH | MEDIAN | * | 0.3744% | 76729 | 287 |
| 174 | | | | | LOW | * | 0.1248% | 87261 | 109 |
| 175 | | | | | HIGH | * | 0.3744% | 69369 | 260 |
| 176 | | HIGH | MEDIAN | MEDIAN | MEDIAN | * | 1.1232% | 75628 | 852 |
| 177 | | | | | LOW | * | 0.3744% | 86196 | 323 |
| 178 | | | | | HIGH | * | 0.1248% | 68770 | 86 |
| 179 | | | | LOW | MEDIAN | * | 0.3744% | 75149 | 281 |
| 180 | | | | | LOW | * | 0.1248% | 85392 | 107 |
| 181 | | | | | HIGH | * | 0.0416% | 69651 | 29 |
| 182 | | | | HIGH | MEDIAN | * | 0.1248% | 76145 | 95 |
| 183 | | | | | LOW | * | 0.0416% | 86570 | 36 |
| 184 | | | | | HIGH | * | 0.1248% | 68852 | 86 |
| 185 | | | LOW | MEDIAN | MEDIAN | * | 0.3744% | 75244 | 282 |
| 186 | | | | | LOW | * | 0.1248% | 85505 | 107 |
| 187 | | | | | HIGH | * | 0.0416% | 68253 | 28 |
| 188 | | | | LOW | MEDIAN | * | 0.1248% | 74565 | 93 |
| 189 | | | | | LOW | * | 0.0416% | 84701 | 35 |
| 190 | | | | | HIGH | * | 0.1248% | 69360 | 87 |
| 191 | | | | HIGH | MEDIAN | * | 0.3744% | 75836 | 284 |
| 192 | | | | | LOW | * | 0.1248% | 86212 | 108 |
| 193 | | | | | HIGH | * | 0.3744% | 68562 | 257 |
| 194 | | | HIGH | MEDIAN | MEDIAN | * | 1.1232% | 74934 | 842 |
| 195 | | | | | LOW | * | 0.3744% | 85147 | 319 |
| 196 | | | | | HIGH | * | 0.1248% | 67963 | 85 |
| 197 | | | | LOW | MEDIAN | * | 0.3744% | 74256 | 278 |
| 198 | | | | | LOW | * | 0.1248% | 84343 | 105 |
| 199 | | | | | HIGH | * | 0.3744% | 68521 | 257 |
| 200 | | | | HIGH | MEDIAN | * | 1.1232% | 74892 | 841 |
| 201 | | | | | LOW | * | 0.3744% | 85102 | 319 |
| 202 | | | | | HIGH | * | 1.1232% | 67723 | 761 |
| 203 | MEDIAN | MEDIAN | MEDIAN | MEDIAN | MEDIAN | * | 3.3696% | 73991 | 2493 |
| 204 | | | | | LOW | * | 1.1232% | 84037 | 944 |
| 205 | | | | | HIGH | * | 0.3744% | 67124 | 251 |
| 206 | | | | LOW | MEDIAN | * | 1.1232% | 73313 | 823 |
| 207 | | | | | LOW | * | 0.3744% | 83233 | 312 |
| 208 | | | | | HIGH | * | 0.1248% | 68005 | 85 |
| 209 | | | | HIGH | MEDIAN | * | 0.3744% | 74308 | 278 |
| 210 | | | | | LOW | * | 0.1248% | 84411 | 105 |
| 211 | | | | | HIGH | * | 0.3744% | 67206 | 252 |
| 212 | | | LOW | MEDIAN | MEDIAN | * | 1.1232% | 73407 | 825 |
| 213 | | | | | LOW | * | 0.3744% | 83346 | 312 |
| 214 | | | | | HIGH | * | 0.1248% | 66608 | 83 |
| 215 | | | | LOW | MEDIAN | * | 0.3744% | 72729 | 272 |
| 216 | | | | | LOW | * | 0.1248% | 82542 | 103 |
| 217 | | | | | HIGH | * | 0.0416% | 68277 | 28 |
| 218 | | | | HIGH | MEDIAN | * | 0.1248% | 74641 | 93 |
| 219 | | | | | LOW | * | 0.0416% | 84829 | 35 |
| 220 | | | | | HIGH | * | 0.1248% | 67478 | 84 |
| 221 | | | HIGH | MEDIAN | MEDIAN | * | 0.3744% | 73739 | 276 |
| 222 | | | | | LOW | * | 0.1248% | 83765 | 105 |
| 223 | | | | | HIGH | * | 0.0416% | 66879 | 28 |
| 224 | | | | LOW | MEDIAN | * | 0.1248% | 73061 | 91 |
| 225 | | | | | LOW | * | 0.0416% | 82960 | 35 |
| 226 | | | | | HIGH | * | 0.1248% | 67438 | 84 |
| 227 | | | | HIGH | MEDIAN | * | 0.3744% | 73697 | 276 |
| 228 | | | | | LOW | * | 0.1248% | 83719 | 104 |
| 229 | | | | | HIGH | * | 0.3744% | 66639 | 249 |
| 230 | | LOW | MEDIAN | MEDIAN | MEDIAN | * | 1.1232% | 72796 | 818 |
| 231 | | | | | LOW | * | 0.3744% | 82655 | 309 |
| 232 | | | | | HIGH | * | 0.1248% | 66040 | 82 |
| 233 | | | | LOW | MEDIAN | * | 0.3744% | 72118 | 270 |
| 234 | | | | | LOW | * | 0.1248% | 81850 | 102 |
| 235 | | | | | HIGH | * | 0.0416% | 66921 | 28 |
| 236 | | | | HIGH | MEDIAN | * | 0.1248% | 73113 | 91 |
| 237 | | | | | LOW | * | 0.0416% | 83028 | 35 |
| 238 | | | | | HIGH | * | 0.1248% | 66123 | 83 |
| 239 | | | LOW | MEDIAN | MEDIAN | * | 0.3744% | 72212 | 270 |
| 240 | | | | | LOW | * | 0.1248% | 81964 | 102 |
| 241 | | | | | HIGH | * | 0.0416% | 65524 | 27 |
| 242 | | | | LOW | MEDIAN | * | 0.1248% | 71534 | 89 |
| 243 | | | | | LOW | * | 0.0416% | 81159 | 34 |

# FIGURE 8.5-9

## TREE PATHS FOR BRANCH LOWER LOAD FORECAST

| PATH # | LOAD | CAPCOST | NUCFUEL | FOSSFUEL | DISCRATE | * | ENDPOINT PROBABILITY | CASE 15 ENDPOINT '89$M PV | EXPECTED ENDPOINT ($M PV) |
|---|---|---|---|---|---|---|---|---|---|
| 244 | | | | | HIGH | * | 0.0320% | 66901 | 21 |
| 245 | | | | HIGH | MEDIAN | * | 0.0960% | 73037 | 70 |
| 246 | | | | | LOW | * | 0.0320% | 82875 | 27 |
| 247 | | | | | HIGH | * | 0.0960% | 66374 | 64 |
| 248 | | | HIGH | MEDIAN | MEDIAN | * | 0.2880% | 72444 | 209 |
| 249 | | | | | LOW | * | 0.0960% | 82177 | 79 |
| 250 | | | | | HIGH | * | 0.0320% | 65977 | 21 |
| 251 | | | | LOW | MEDIAN | * | 0.0960% | 71996 | 69 |
| 252 | | | | | LOW | * | 0.0320% | 81649 | 26 |
| 253 | | | | | HIGH | * | 0.0960% | 66084 | 63 |
| 254 | | | | HIGH | MEDIAN | * | 0.2880% | 72120 | 208 |
| 255 | | | | | LOW | * | 0.0960% | 81798 | 79 |
| 256 | | | | | HIGH | * | 0.2880% | 65557 | 189 |
| 257 | | HIGH | MEDIAN | MEDIAN | MEDIAN | * | 0.8640% | 71526 | 618 |
| 258 | | | | | LOW | * | 0.2880% | 81099 | 234 |
| 259 | | | | | HIGH | * | 0.0960% | 65161 | 63 |
| 260 | | | | LOW | MEDIAN | * | 0.2880% | 71079 | 205 |
| 261 | | | | | LOW | * | 0.0960% | 80571 | 77 |
| 262 | | | | | HIGH | * | 0.0320% | 65582 | 21 |
| 263 | | | | HIGH | MEDIAN | * | 0.0960% | 71553 | 69 |
| 264 | | | | | LOW | * | 0.0320% | 81128 | 26 |
| 265 | | | | | HIGH | * | 0.0960% | 65055 | 62 |
| 266 | | | LOW | MEDIAN | MEDIAN | * | 0.2880% | 70959 | 204 |
| 267 | | | | | LOW | * | 0.0960% | 80429 | 77 |
| 268 | | | | | HIGH | * | 0.0320% | 64658 | 21 |
| 269 | | | | LOW | MEDIAN | * | 0.0960% | 70512 | 68 |
| 270 | | | | | LOW | * | 0.0320% | 79901 | 26 |
| 271 | | | | | HIGH | * | 0.0960% | 65639 | 63 |
| 272 | | | | HIGH | MEDIAN | * | 0.2880% | 71629 | 206 |
| 273 | | | | | LOW | * | 0.0960% | 81222 | 78 |
| 274 | | | | | HIGH | * | 0.2880% | 65112 | 188 |
| 275 | | | HIGH | MEDIAN | MEDIAN | * | 0.8640% | 71035 | 614 |
| 276 | | | | | LOW | * | 0.2880% | 80523 | 232 |
| 277 | | | | | HIGH | * | 0.0960% | 64715 | 62 |
| 278 | | | | LOW | MEDIAN | * | 0.2880% | 70588 | 203 |
| 279 | | | | | LOW | * | 0.0960% | 79995 | 77 |
| 280 | | | | | HIGH | * | 0.2880% | 64822 | 187 |
| 281 | | | | HIGH | MEDIAN | * | 0.8640% | 70711 | 611 |
| 282 | | | | | LOW | * | 0.2880% | 80144 | 231 |
| 283 | | | | | HIGH | * | 0.8640% | 64295 | 556 |
| 284 | BR LOWER | MEDIAN | MEDIAN | MEDIAN | MEDIAN | * | 2.5920% | 70118 | 1817 |
| 285 | | | | | LOW | * | 0.8640% | 79446 | 686 |
| 286 | | | | | HIGH | * | 0.2880% | 63899 | 184 |
| 287 | | | | LOW | MEDIAN | * | 0.8640% | 69670 | 602 |
| 288 | | | | | LOW | * | 0.2880% | 78917 | 227 |
| 289 | | | | | HIGH | * | 0.0960% | 64320 | 62 |
| 290 | | | | HIGH | MEDIAN | * | 0.2880% | 70144 | 202 |
| 291 | | | | | LOW | * | 0.0960% | 79474 | 76 |
| 292 | | | | | HIGH | * | 0.2880% | 63793 | 184 |
| 293 | | | LOW | MEDIAN | MEDIAN | * | 0.8640% | 69551 | 601 |
| 294 | | | | | LOW | * | 0.2880% | 78776 | 227 |
| 295 | | | | | HIGH | * | 0.0960% | 63396 | 61 |
| 296 | | | | LOW | MEDIAN | * | 0.2880% | 69103 | 199 |
| 297 | | | | | LOW | * | 0.0960% | 78247 | 75 |
| 298 | | | | | HIGH | * | 0.0320% | 64768 | 21 |
| 299 | | | | HIGH | MEDIAN | * | 0.0960% | 70671 | 68 |
| 300 | | | | | LOW | * | 0.0320% | 80118 | 26 |
| 301 | | | | | HIGH | * | 0.0960% | 64241 | 62 |
| 302 | | | HIGH | MEDIAN | MEDIAN | * | 0.2880% | 70077 | 202 |
| 303 | | | | | LOW | * | 0.0960% | 79420 | 76 |
| 304 | | | | | HIGH | * | 0.0320% | 63845 | 20 |
| 305 | | | | LOW | MEDIAN | * | 0.0960% | 69630 | 67 |
| 306 | | | | | LOW | * | 0.0320% | 78691 | 25 |
| 307 | | | | | HIGH | * | 0.0960% | 63951 | 61 |
| 308 | | | | HIGH | MEDIAN | * | 0.2880% | 69753 | 201 |
| 309 | | | | | LOW | * | 0.0960% | 79040 | 76 |
| 310 | | | | | HIGH | * | 0.2880% | 63424 | 183 |
| 311 | | LOW | MEDIAN | MEDIAN | MEDIAN | * | 0.8640% | 69160 | 598 |
| 312 | | | | | LOW | * | 0.2880% | 78342 | 226 |
| 313 | | | | | HIGH | * | 0.0960% | 63028 | 61 |
| 314 | | | | LOW | MEDIAN | * | 0.2880% | 68712 | 198 |
| 315 | | | | | LOW | * | 0.0960% | 77813 | 75 |
| 316 | | | | | HIGH | * | 0.0320% | 63449 | 20 |
| 317 | | | | HIGH | MEDIAN | * | 0.0960% | 69186 | 66 |
| 318 | | | | | LOW | * | 0.0320% | 78370 | 25 |
| 319 | | | | | HIGH | * | 0.0960% | 62922 | 60 |
| 320 | | | LOW | MEDIAN | MEDIAN | * | 0.2880% | 68593 | 198 |
| 321 | | | | | LOW | * | 0.0960% | 77672 | 75 |
| 322 | | | | | HIGH | * | 0.0320% | 62526 | 20 |
| 323 | | | | LOW | MEDIAN | * | 0.0960% | 68145 | 65 |
| 324 | | | | | LOW | * | 0.0320% | 77144 | 25 |

# FIGURE 8.5-10

## TREE PATHS FOR LOWER LOAD FORECAST

| PATH # | LOAD | CAPCOST | NUCFUEL | FOSSFUEL | DISCRATE | * | ENDPOINT PROBABILITY | CASE 15 ENDPOINT '89$M PV | EXPECTED ENDPOINT ($M PV) |
|---|---|---|---|---|---|---|---|---|---|
| 325 | | | | | HIGH | * | 0.0272% | 59899 | 16 |
| 326 | | | | HIGH | MEDIAN | * | 0.0816% | 65551 | 53 |
| 327 | | | | | LOW | * | 0.0272% | 74563 | 20 |
| 328 | | | | | HIGH | * | 0.0816% | 59522 | 49 |
| 329 | | | HIGH | MEDIAN | MEDIAN | * | 0.2448% | 65114 | 159 |
| 330 | | | | | LOW | * | 0.0816% | 74031 | 60 |
| 331 | | | | | HIGH | * | 0.0272% | 59240 | 16 |
| 332 | | | | LOW | MEDIAN | * | 0.0816% | 64786 | 53 |
| 333 | | | | | LOW | * | 0.0272% | 73630 | 20 |
| 334 | | | | | HIGH | * | 0.0816% | 59144 | 48 |
| 335 | | | | HIGH | MEDIAN | * | 0.2448% | 64704 | 158 |
| 336 | | | | | LOW | * | 0.0816% | 73569 | 60 |
| 337 | | | | | HIGH | * | 0.2448% | 58767 | 144 |
| 338 | | HIGH | MEDIAN | MEDIAN | MEDIAN | * | 0.7344% | 64266 | 472 |
| 339 | | | | | LOW | * | 0.2448% | 73037 | 179 |
| 340 | | | | | HIGH | * | 0.0816% | 58485 | 48 |
| 341 | | | | LOW | MEDIAN | * | 0.2448% | 63939 | 157 |
| 342 | | | | | LOW | * | 0.0816% | 72636 | 59 |
| 343 | | | | | HIGH | * | 0.0272% | 58683 | 16 |
| 344 | | | | HIGH | MEDIAN | * | 0.0816% | 64184 | 52 |
| 345 | | | | | LOW | * | 0.0272% | 72956 | 20 |
| 346 | | | | | HIGH | * | 0.0816% | 58306 | 48 |
| 347 | | | LOW | MEDIAN | MEDIAN | * | 0.2448% | 63747 | 156 |
| 348 | | | | | LOW | * | 0.0816% | 72423 | 59 |
| 349 | | | | | HIGH | * | 0.0272% | 58024 | 16 |
| 350 | | | | LOW | MEDIAN | * | 0.0816% | 63419 | 52 |
| 351 | | | | | LOW | * | 0.0272% | 72023 | 20 |
| 352 | | | | | HIGH | * | 0.0816% | 59237 | 48 |
| 353 | | | | HIGH | MEDIAN | * | 0.2448% | 64817 | 159 |
| 354 | | | | | LOW | * | 0.0816% | 73710 | 60 |
| 355 | | | | | HIGH | * | 0.2448% | 58860 | 144 |
| 356 | | | HIGH | MEDIAN | MEDIAN | * | 0.7344% | 64379 | 473 |
| 357 | | | | | LOW | * | 0.2448% | 73177 | 179 |
| 358 | | | | | HIGH | * | 0.0816% | 58579 | 48 |
| 359 | | | | LOW | MEDIAN | * | 0.2448% | 64051 | 157 |
| 360 | | | | | LOW | * | 0.0816% | 72777 | 59 |
| 361 | | | | | HIGH | * | 0.2448% | 58482 | 143 |
| 362 | | | | HIGH | MEDIAN | * | 0.7344% | 63970 | 470 |
| 363 | | | | | LOW | * | 0.2448% | 72716 | 178 |
| 364 | | | | | HIGH | * | 0.7344% | 58105 | 427 |
| 365 | LOWER | MEDIAN | MEDIAN | MEDIAN | MEDIAN | * | 2.2032% | 63532 | 1400 |
| 366 | | | | | LOW | * | 0.7344% | 72183 | 530 |
| 367 | | | | | HIGH | * | 0.2448% | 57824 | 142 |
| 368 | | | | LOW | MEDIAN | * | 0.7344% | 63204 | 464 |
| 369 | | | | | LOW | * | 0.2448% | 71783 | 176 |
| 370 | | | | | HIGH | * | 0.0816% | 58022 | 47 |
| 371 | | | | HIGH | MEDIAN | * | 0.2448% | 63450 | 155 |
| 372 | | | | | LOW | * | 0.0816% | 72102 | 59 |
| 373 | | | | | HIGH | * | 0.2448% | 57644 | 141 |
| 374 | | | LOW | MEDIAN | MEDIAN | * | 0.7344% | 63013 | 463 |
| 375 | | | | | LOW | * | 0.2448% | 71570 | 175 |
| 376 | | | | | HIGH | * | 0.0816% | 57363 | 47 |
| 377 | | | | LOW | MEDIAN | * | 0.2448% | 62685 | 153 |
| 378 | | | | | LOW | * | 0.0816% | 71169 | 58 |
| 379 | | | | | HIGH | * | 0.0272% | 58788 | 16 |
| 380 | | | | HIGH | MEDIAN | * | 0.0816% | 64325 | 52 |
| 381 | | | | | LOW | * | 0.0272% | 73148 | 20 |
| 382 | | | | | HIGH | * | 0.0816% | 58411 | 48 |
| 383 | | | HIGH | MEDIAN | MEDIAN | * | 0.2448% | 63887 | 156 |
| 384 | | | | | LOW | * | 0.0816% | 72615 | 59 |
| 385 | | | | | HIGH | * | 0.0272% | 58129 | 16 |
| 386 | | | | LOW | MEDIAN | * | 0.0816% | 63559 | 52 |
| 387 | | | | | LOW | * | 0.0272% | 72215 | 20 |
| 388 | | | | | HIGH | * | 0.0816% | 58033 | 47 |
| 389 | | | | HIGH | MEDIAN | * | 0.2448% | 63477 | 155 |
| 390 | | | | | LOW | * | 0.0816% | 72154 | 59 |
| 391 | | | | | HIGH | * | 0.2448% | 57656 | 141 |
| 392 | | LOW | MEDIAN | MEDIAN | MEDIAN | * | 0.7344% | 63040 | 463 |
| 393 | | | | | LOW | * | 0.2448% | 71621 | 175 |
| 394 | | | | | HIGH | * | 0.0816% | 57374 | 47 |
| 395 | | | | LOW | MEDIAN | * | 0.2448% | 62712 | 154 |
| 396 | | | | | LOW | * | 0.0816% | 71221 | 58 |
| 397 | | | | | HIGH | * | 0.0272% | 57572 | 16 |
| 398 | | | | HIGH | MEDIAN | * | 0.0816% | 62958 | 51 |
| 399 | | | | | LOW | * | 0.0272% | 71541 | 19 |
| 400 | | | | | HIGH | * | 0.0816% | 57195 | 47 |
| 401 | | | LOW | MEDIAN | MEDIAN | * | 0.2448% | 62520 | 153 |
| 402 | | | | | LOW | * | 0.0816% | 71008 | 58 |
| 403 | | | | | HIGH | * | 0.0272% | 56914 | 15 |
| 404 | | | | LOW | MEDIAN | * | 0.0816% | 62192 | 51 |
| 405 | | | | | LOW | * | 0.0272% | 70608 | 19 |
| | | | | TOTAL TREE EXPECTED COST | | | 100% | | 75258 |

FIGURE 8.5-11

CASE COSTS BASED ON ALL PATHS IN TREE
(Millions of 1989$, Present Value)

| Load Path | PROB | Case 23 | Case 22 | Case 15 | Case 24 | Case 26 |
|---|---|---|---|---|---|---|
| Upper | 17% | 87675 | 86667 | 86497 | 86747 | 87842 |
| Branch Upper | 20% | 81427 | 79911 | 79597 | 79889 | 81019 |
| Median | 26% | 77354 | 75502 | 74995 | 75230 | 75916 |
| Branch Lower | 20% | 73853 | 71447 | 71011 | 71116 | 71352 |
| Lower | 17% | 66504 | 64632 | 64315 | 64335 | 64527 |
| Expected Cost | | 77378 | 75623 | 75258 | 75445 | 76115 |

EXPECTED COST DIFFERENCES RELATIVE TO CASE 15
USING LOAD FORECAST PROBABILITIES
Millions of 1989$, Present Value)

| PROB | | Case 23 | Case 22 | Case 15 | Case 24 | Case 26 |
|---|---|---|---|---|---|---|
| Upper | 17% | 200 | 29 | BASE | 43 | 229 |
| Branch Upper | 20% | 366 | 63 | BASE | 58 | 284 |
| Median | 26% | 613 | 132 | BASE | 61 | 239 |
| Branch Lower | 20% | 568 | 87 | BASE | 21 | 68 |
| Lower | 17% | 372 | 54 | BASE | 4 | 36 |
| Expected Cost Differences | | 2120 | 365 | BASE | 187 | 857 |

DIFFERENCES WITH EQUAL PROBABILITY FOR LOAD PATHS
(Millions of 1989$, Present Value)

| PROB | Case 23 | Case 22 | Case 15 | Case 24 | Case 26 | |
|---|---|---|---|---|---|---|
| Upper | 20% | 236 | 34 | BASE | 50 | 269 |
| Branch Upper | 20% | 366 | 63 | BASE | 58 | 284 |
| Median | 20% | 472 | 101 | BASE | 47 | 184 |
| Branch Lower | 20% | 568 | 87 | BASE | 21 | 68 |
| Lower | 20% | 438 | 64 | BASE | 4 | 42 |
| Expected Cost Differences | | 2080 | 349 | BASE | 181 | 848 |

### 8.5.6 Cumulative Probability Distributions Explained

The total cost range for each case, representing all 405 possible outcomes, can be shown in a cumulative probability distribution graph. Cumulative probability distributions represent the probability of each possible outcome, starting from the lowest cost and ending with the highest cost. Cumulative probability distributions are derived by sorting all applicable outcomes of the probability tree and accumulating the probabilities as you move up the sorted outcomes. For example, the top chart in Figure 8.5-12 shows there is a 20% probability of the cost of Case 15 being up to $67.5 billion.

If the distribution of costs for one case is always to the left of the others, then it is considered the leading case, since always has a greater probability of costing less than the other cases.

In evaluating cases it is important to examine the <u>differences</u> between one case, for example Case 15 and all other cases. The bottom chart in Figure 8.5-12 plots the differences between each case and Case 15 for each of the 405 outcomes. These differences relative to Case 15 were taken for each of the 405 outcomes. The differences were then sorted and their associated probabilities were accumulated to produces the cumulative probability distributions. When the distribution line is to left of 0, it indicates the probability of the case costing less than Case 15; if it is to the right, it indicates the probability of the case costing more than Case 15. The bottom chart in Figure 8.5-12 shows that there is a only about 1% probability that Case 23 will cost the same or less than Case 15 when all factors are varied.

Generally, if one case dominates another by having less costly outcomes more frequently, this will be reflected when the case differences are plotted. The cumulative distributions for case costs and differences in costs are the results of different sorting operations. The two charts are also plotted on a different scale, therefore they are not directly comparable.

In addition to varying all factors, the complete probabilistic analysis involved fixing one factor while varying all the others. The three estimates for the four cost factors, Capital Cost, Nuclear Fuel, Fossil Fuel and Discount Rate, were modelled for the 5 load forecast paths producing 17 specific conditions. For example, Figure 8.5-13 shows how two Cases, 15 and 26, respond under the <u>Branch Lower</u> load forecast, while all other factors vary. The top chart shows the dominance of Case 15 over Case 26 while the bottom chart shows there is a 20% probability that Case 26 could be less than or equal to Case 15.

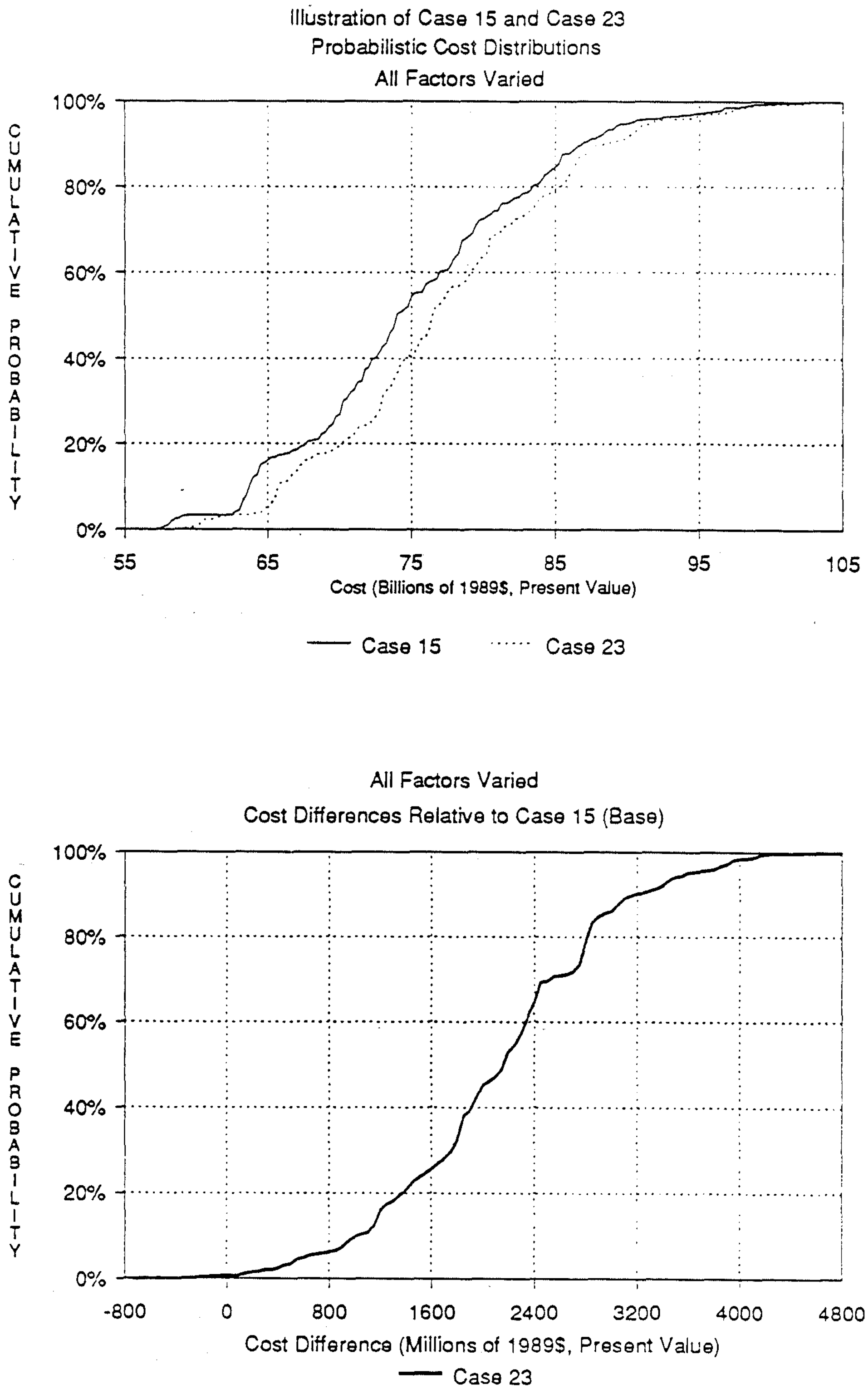


Illustration of Case 15 and Case 23
Probabilistic Cost Distributions
All Factors Varied
CUMULATIVE PROBABILITY
100%
80%
60%
40%
20%
0%
55
65
75
85
95
105
Cost (Billions of 1989$, Present Value)
Case 15
Case 23
All Factors Varied
Cost Differences Relative to Case 15 (Base)
CUMULATIVE PROBABILITY
100%
80%
60%
40%
20%
0%
-800
0
800
1600
2400
3200
4000
4800
Cost Difference (Millions of 1989$, Present Value)
Case 23


FIGURE 8.5-12

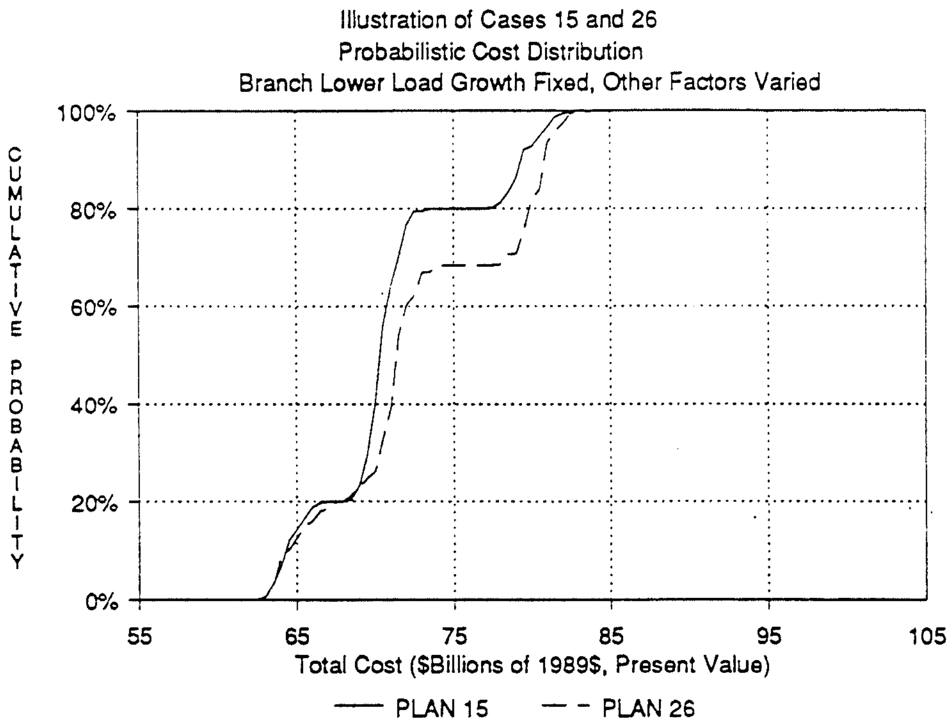


Illustration of Cases 15 and 26
Probabilistic Cost Distribution
Branch Lower Load Growth Fixed, Other Factors Varied
CUMULATIVE PROBABILITY
100%
80%
60%
40%
20%
0%
55
65
75
85
95
105
Total Cost ($Billions of 1989$, Present Value)
PLAN 15
PLAN 26

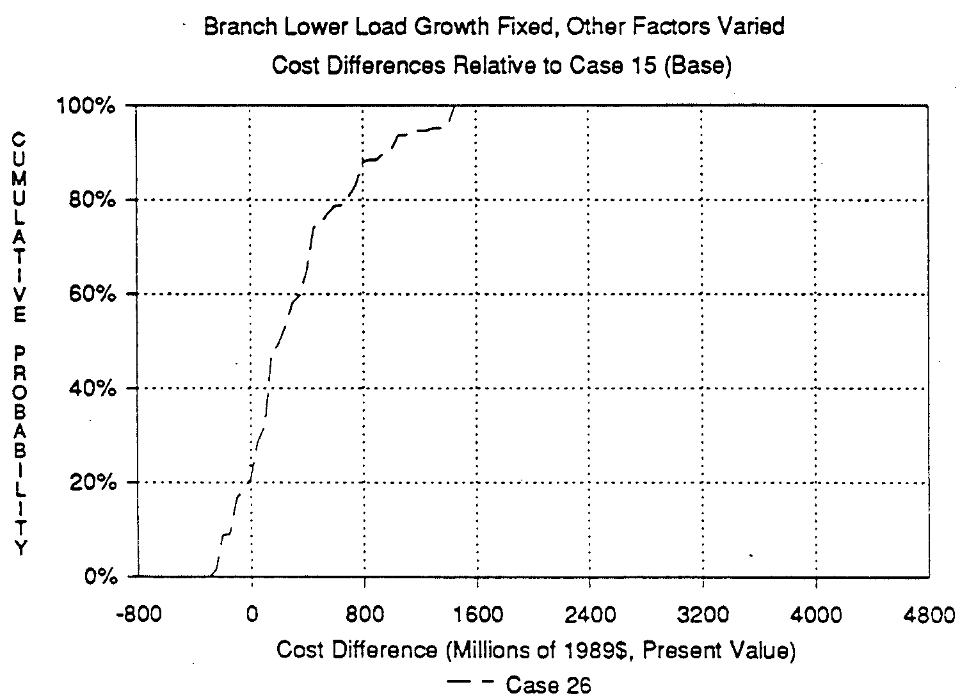
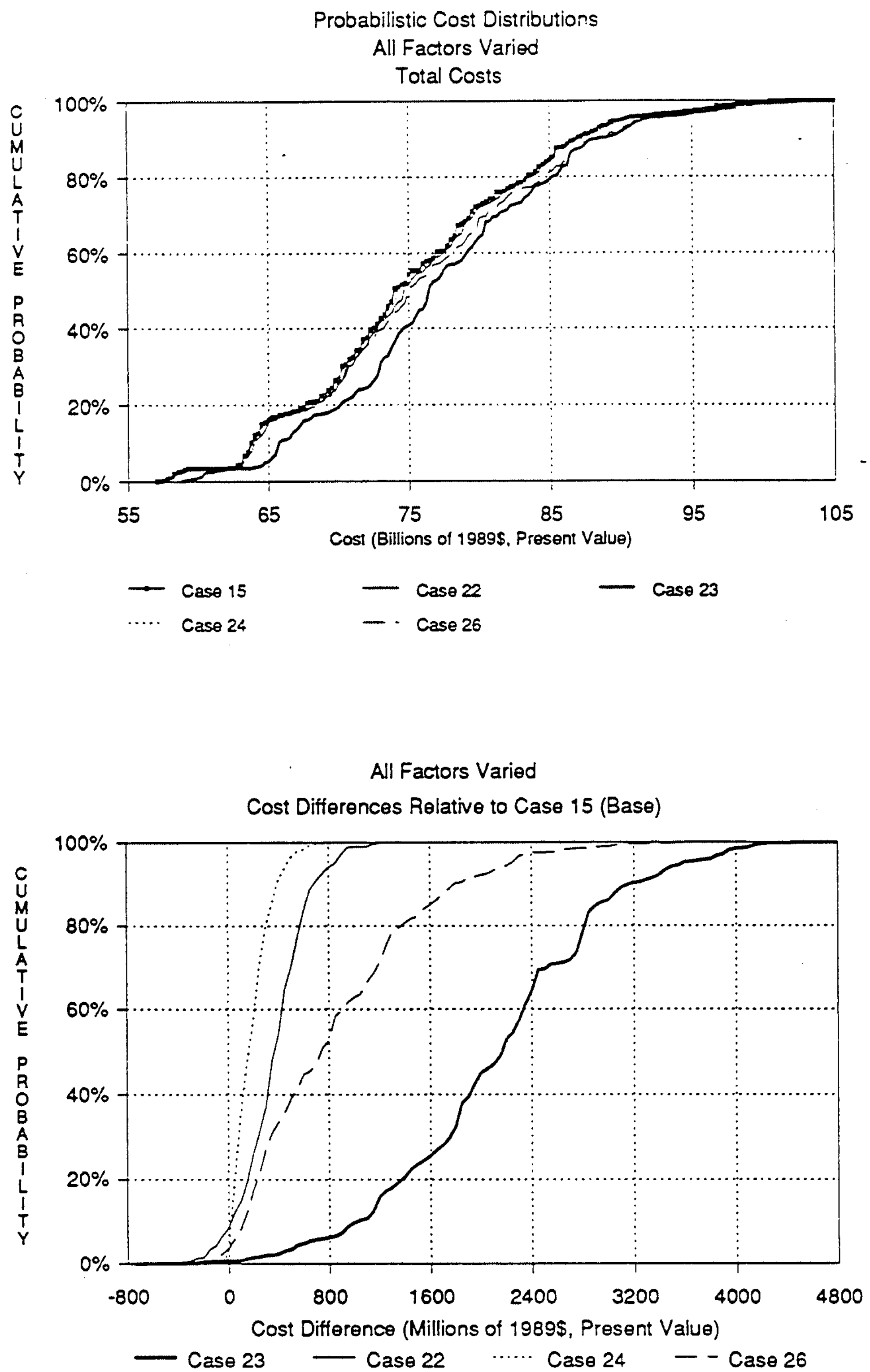

Branch Lower Load Growth Fixed, Other Factors Varied
Cost Differences Relative to Case 15 (Base)
CUMULATIVE PROBABILITY
100%
80%
60%
40%
20%
0%
-800
0
800
1600
2400
3200
4000
4800
Cost Difference (Millions of 1989$, Present Value)
Case 26

FIGURE 8.5-13

### 8.5.7 Cumulative Probabilistic Results

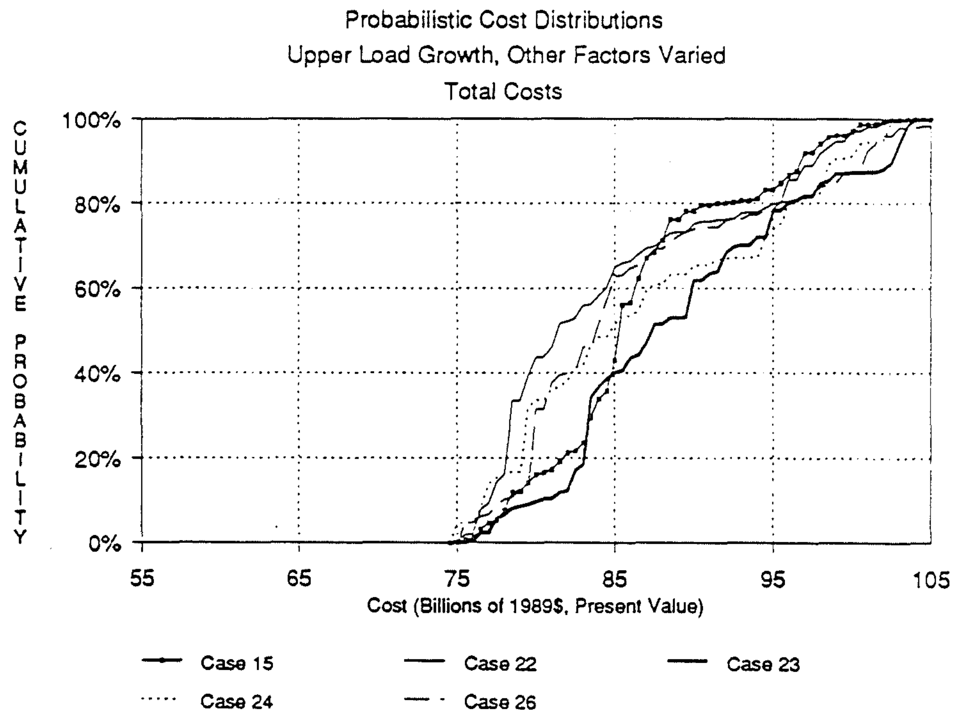
Figure 8.5-14 shows the cumulative probability distributions for each case when all five load forecasts and all cost estimates are considered. The top chart shows that Case 15 is the dominant case with lower expected costs. The bottom chart highlights the differences in costs more clearly. It shows the Case 15 only has a 8% probability of costing more than any of the other cases, when all factors are varied.

Figure 8.5-15 through Figure 8.5-31 shows how the cases respond when fixing each of the 17 specific conditions described in the last paragraph of 8.5.6. while varying all the others. Under almost all combinations of conditions, there is less than 20% probability that any case would have lower expected costs than Case 15. These occur under certain combinations of conditions which have a low probability. In addition, as cost conditions become known the actual plan could be adjusted.



Probabilistic Cost Distributions
All Factors Varied
Total Costs
CUMULATIVE PROBABILITY
100%
80%
60%
40%
20%
0%
55
65
75
85
95
105
Cost (Billions of 1989$, Present Value)
Case 15
Case 22
Case 23
Case 24
Case 26
All Factors Varied
Cost Differences Relative to Case 15 (Base)
CUMULATIVE PROBABILITY
100%
80%
60%
40%
20%
0%
-800
0
800
1600
2400
3200
4000
4800
Cost Difference (Millions of 1989$, Present Value)
Case 23
Case 22
Case 24
Case 26


FIGURE 8.5-14


Probabilistic Cost Distributions
Upper Load Growth, Other Factors Varied
Total Costs
CUMULATIVE PROBABILITY
100%
80%
60%
40%
20%
0%
55
65
75
85
95
105
Cost (Billions of 1989$, Present Value)
Case 15
Case 22
Case 23
Case 24
Case 26

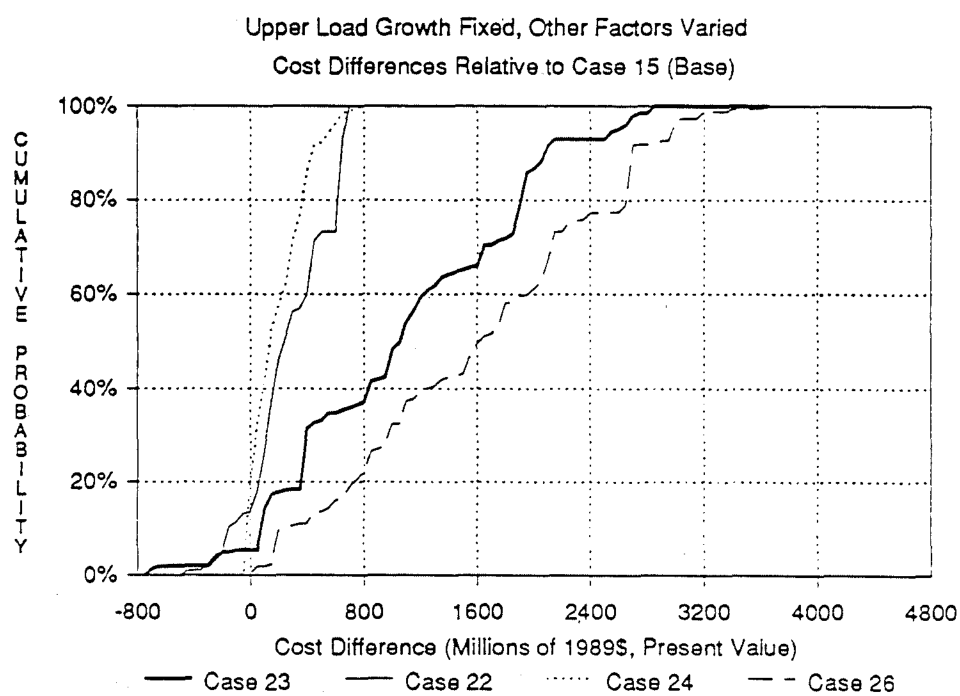
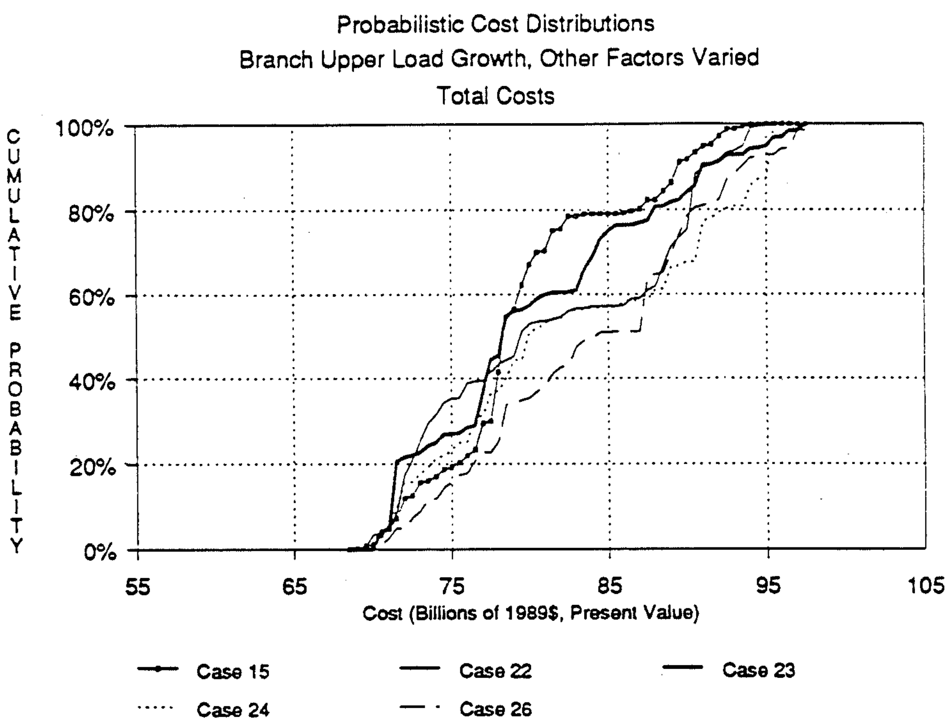

Upper Load Growth Fixed, Other Factors Varied
Cost Differences Relative to Case 15 (Base)
CUMULATIVE PROBABILITY
100%
80%
60%
40%
20%
0%
-800
0
800
1600
2400
3200
4000
4800
Cost Difference (Millions of 1989$, Present Value)
Case 23
Case 22
Case 24
Case 26

FIGURE 8.5-15


Probabilistic Cost Distributions
Branch Upper Load Growth, Other Factors Varied
Total Costs
CUMULATIVE PROBABILITY
100%
80%
60%
40%
20%
0%
55
65
75
85
95
105
Cost (Billions of 1989$, Present Value)
Case 15
Case 22
Case 23
Case 24
Case 26

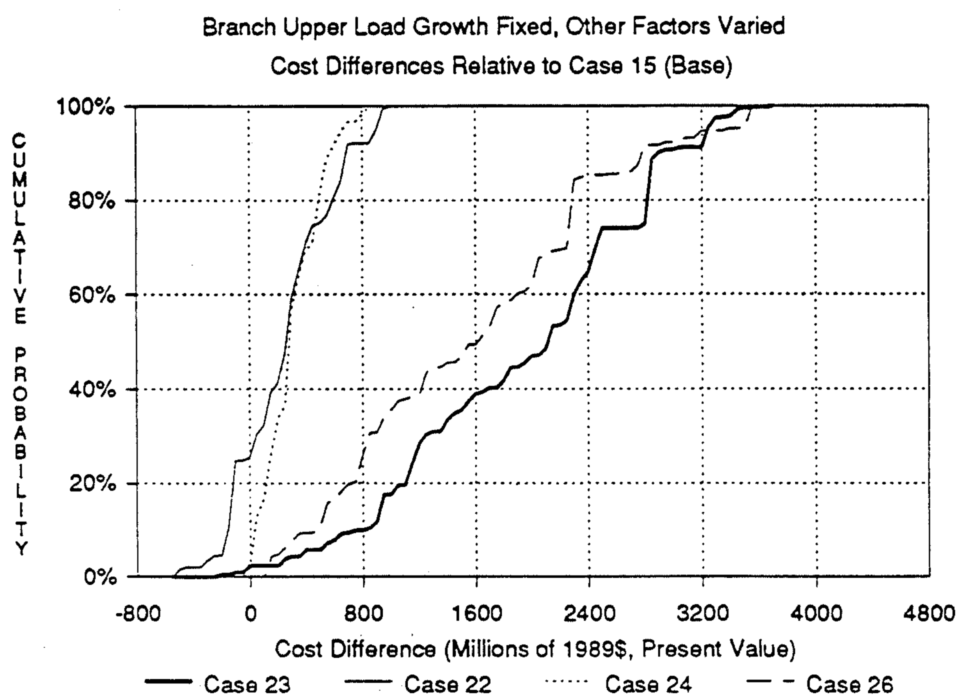
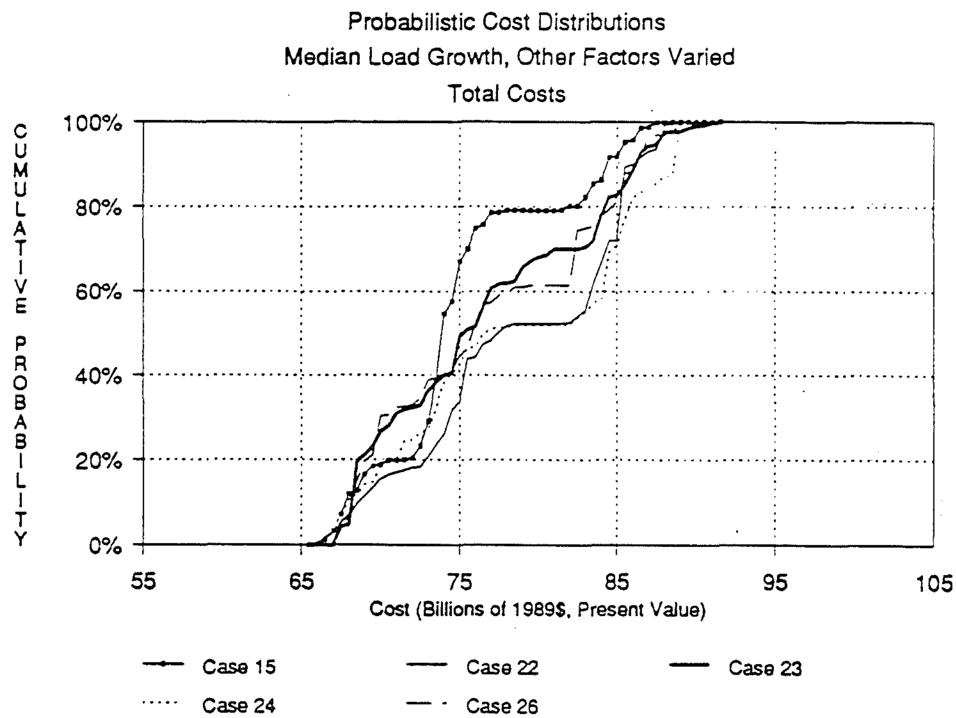
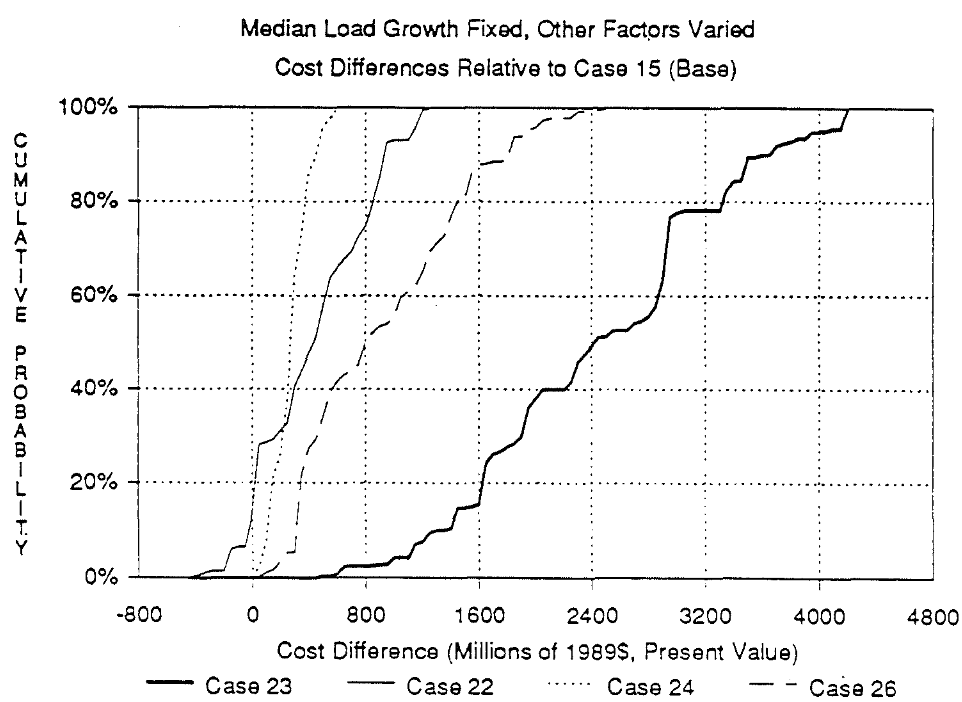

Branch Upper Load Growth Fixed, Other Factors Varied
Cost Differences Relative to Case 15 (Base)
CUMULATIVE PROBABILITY
100%
80%
60%
40%
20%
0%
-800
0
800
1600
2400
3200
4000
4800
Cost Difference (Millions of 1989$, Present Value)
Case 23
Case 22
Case 24
Case 26

FIGURE 8.5-16



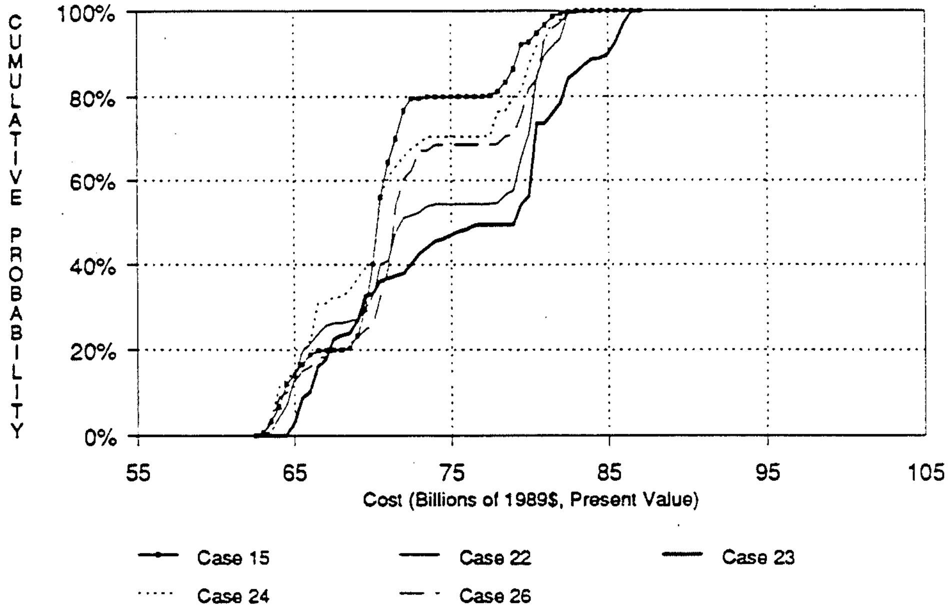
Probabilistic Cost Distributions
Median Load Growth, Other Factors Varied
Total Costs
CUMULATIVE PROBABILITY
100%
80%
60%
40%
20%
0%
55
65
75
85
95
105
Cost (Billions of 1989$, Present Value)
Case 15
Case 22
Case 23
Case 24
Case 26

Median Load Growth Fixed, Other Factors Varied
Cost Differences Relative to Case 15 (Base)
CUMULATIVE PROBABILITY
100%
80%
60%
40%
20%
0%
-800
0
800
1600
2400
3200
4000
4800
Cost Difference (Millions of 1989$, Present Value)
Case 23
Case 22
Case 24
Case 26


FIGURE 8.5-17

Probabilistic Cost Distributions
Branch Lower Load Growth, Other Factors Varied
Total Costs




Branch Lower Load Growth Fixed, Other Factors Varied
Cost Differences Relative to Case 15 (Base)

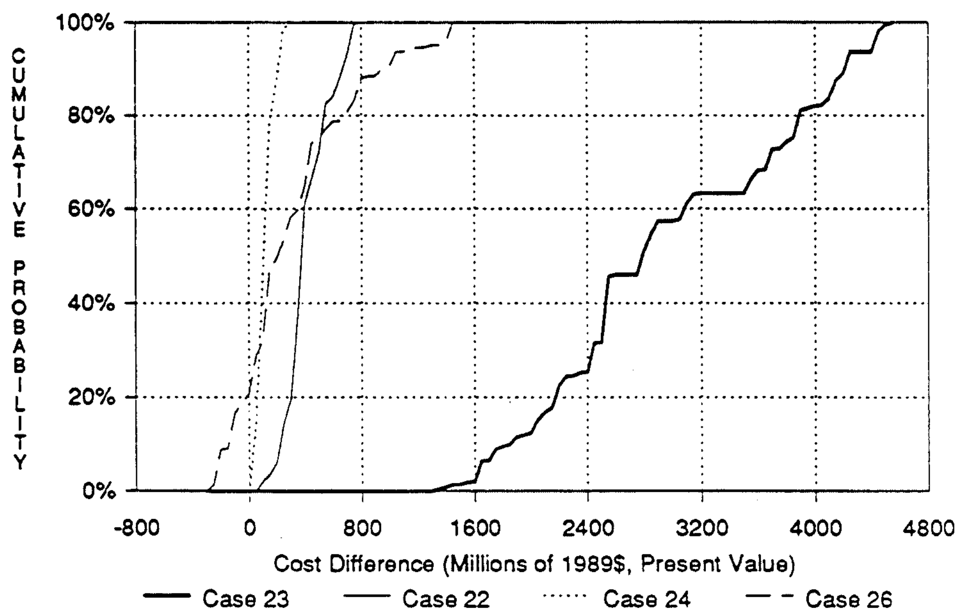
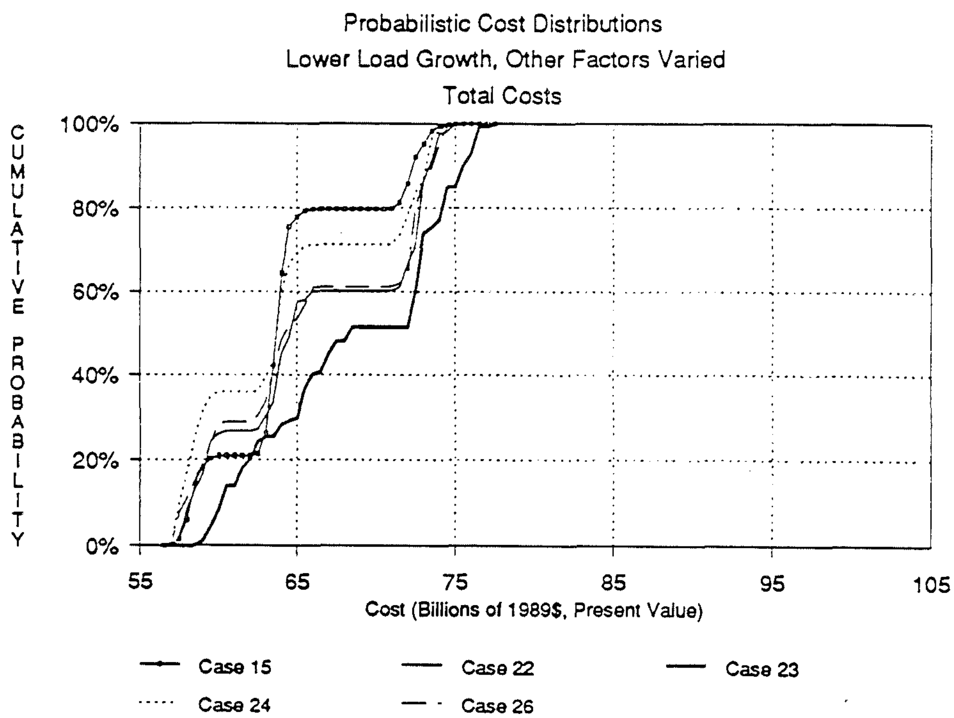
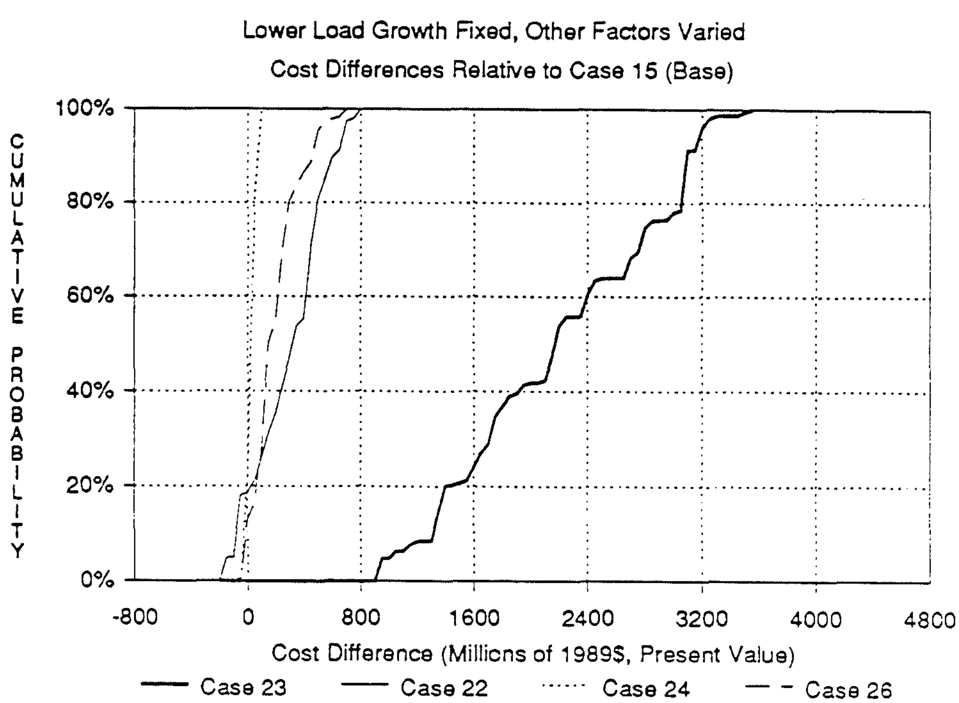



FIGURE 8.5-18

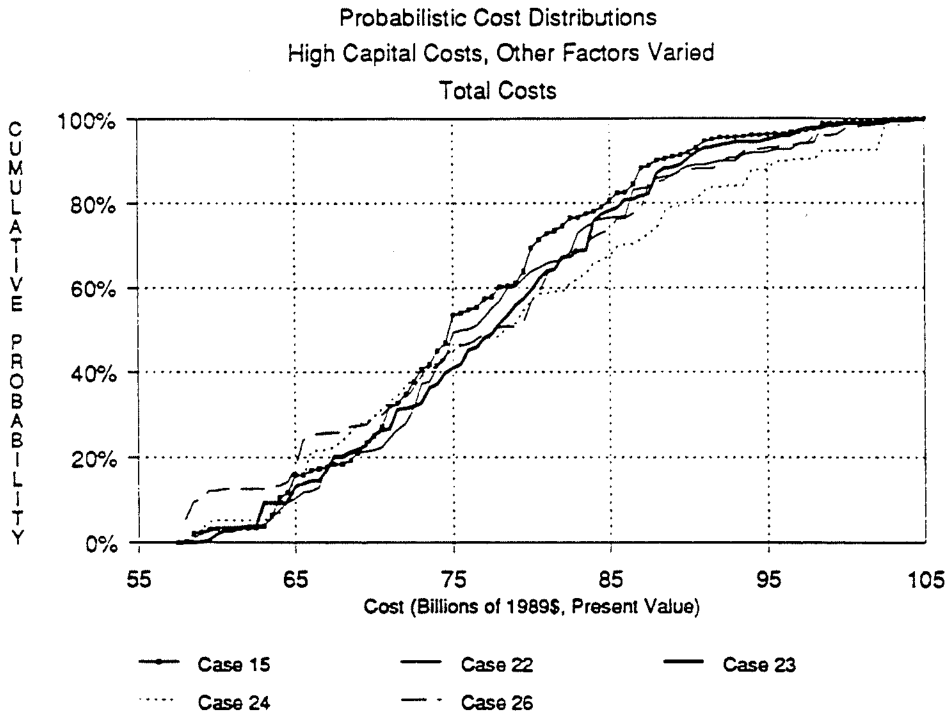


Probabilistic Cost Distributions
Lower Load Growth, Other Factors Varied
Total Costs
CUMULATIVE PROBABILITY
100%
80%
60%
40%
20%
0%
55
65
75
85
95
105
Cost (Billions of 1989$, Present Value)
Case 15
Case 22
Case 23
Case 24
Case 26

Lower Load Growth Fixed, Other Factors Varied
Cost Differences Relative to Case 15 (Base)
CUMULATIVE PROBABILITY
100%
80%
60%
40%
20%
0%
-800
0
800
1600
2400
3200
4000
4800
Cost Difference (Millions of 1989$, Present Value)
Case 23
Case 22
Case 24
Case 26


FIGURE 8.5-19


Probabilistic Cost Distributions
High Capital Costs, Other Factors Varied
Total Costs
CUMULATIVE PROBABILITY
100%
80%
60%
40%
20%
0%
55
65
75
85
95
105
Cost (Billions of 1989$, Present Value)
Case 15
Case 22
Case 23
Case 24
Case 26

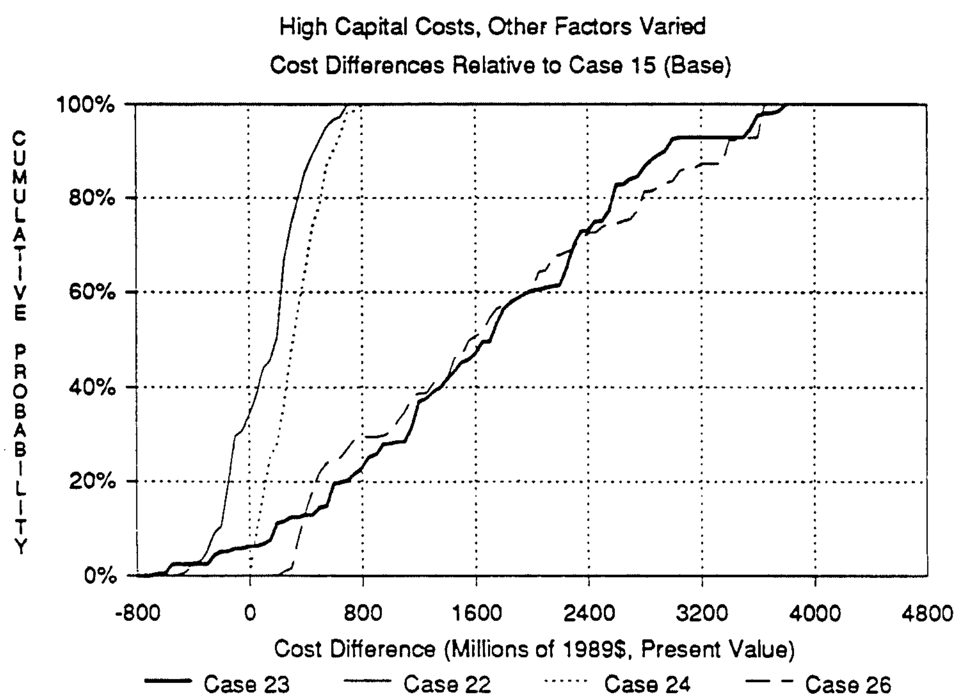
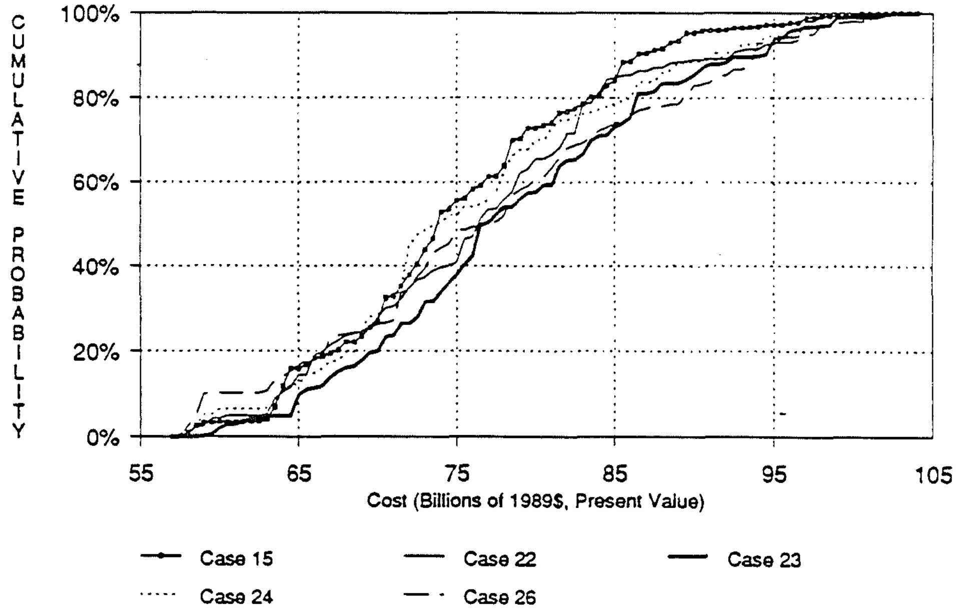

High Capital Costs, Other Factors Varied
Cost Differences Relative to Case 15 (Base)
CUMULATIVE PROBABILITY
100%
80%
60%
40%
20%
0%
-800
0
800
1600
2400
3200
4000
4800
Cost Difference (Millions of 1989$, Present Value)
Case 23
Case 22
Case 24
Case 26

FIGURE 8.5-20

Probabilistic Cost Distributions
Median Capital Costs, Other Factors Varied
Total Costs




Median Capital Costs, Other Factors Varied
Cost Differences Relative to Case 15 (Base)

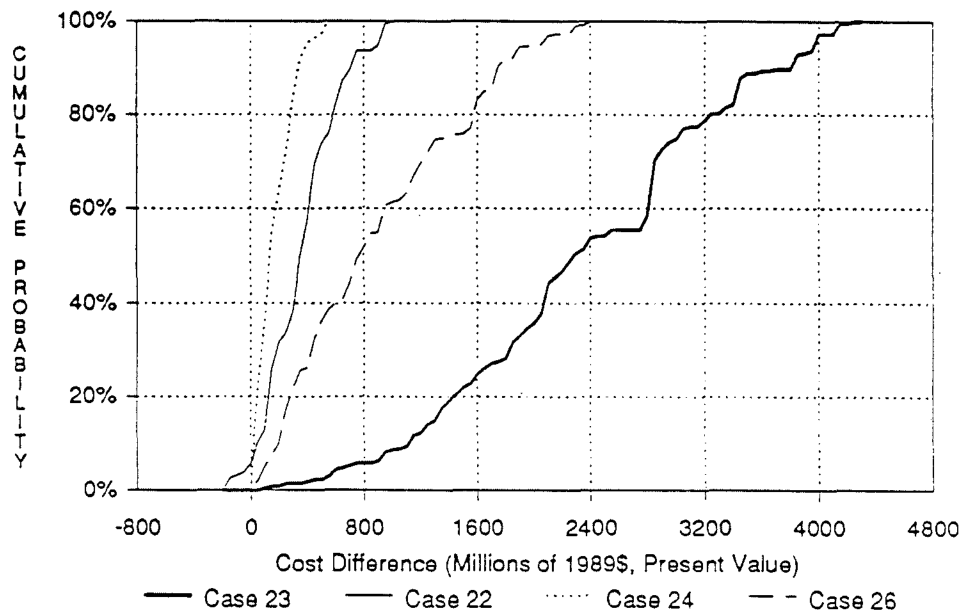



FIGURE 8.5-21

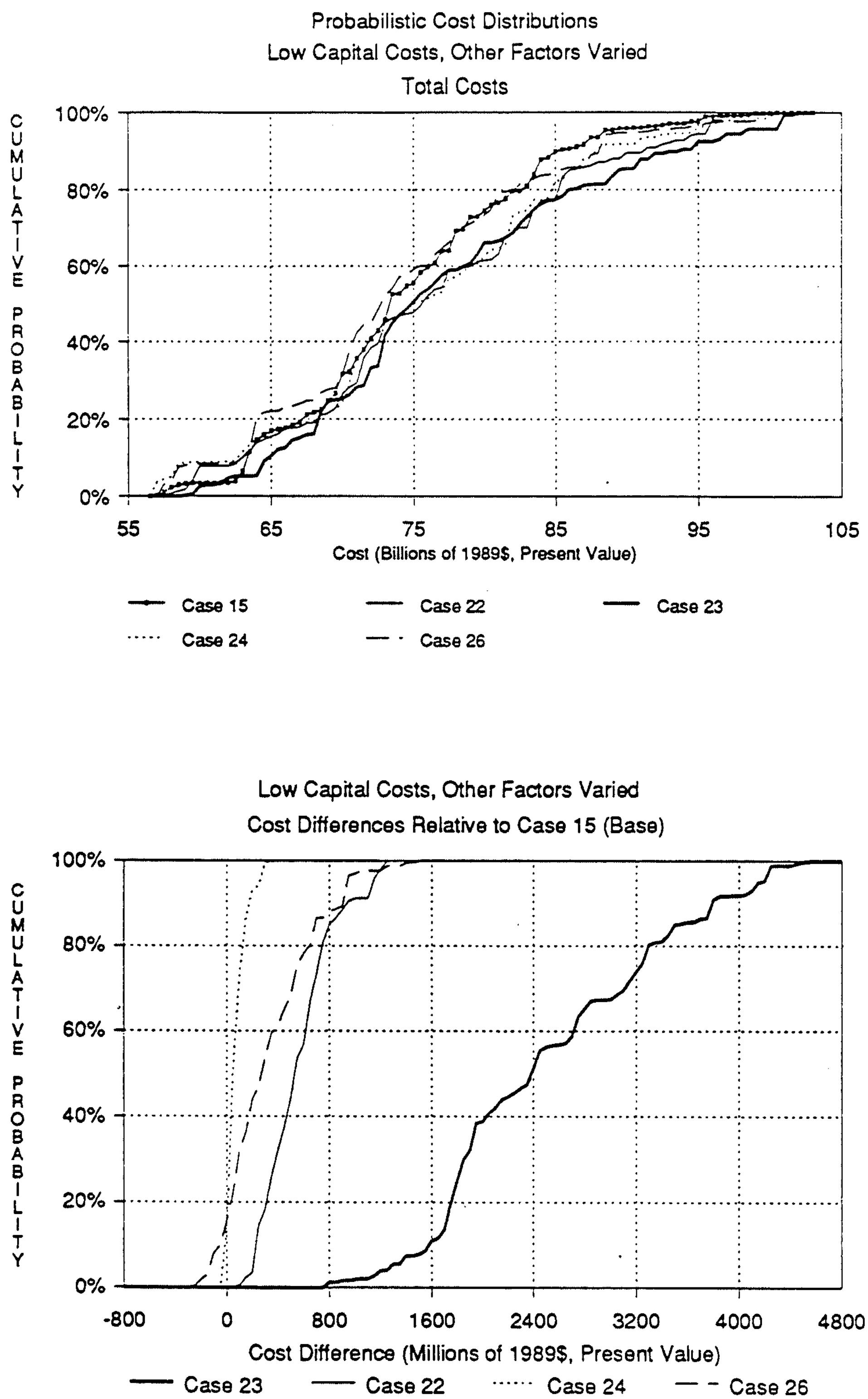
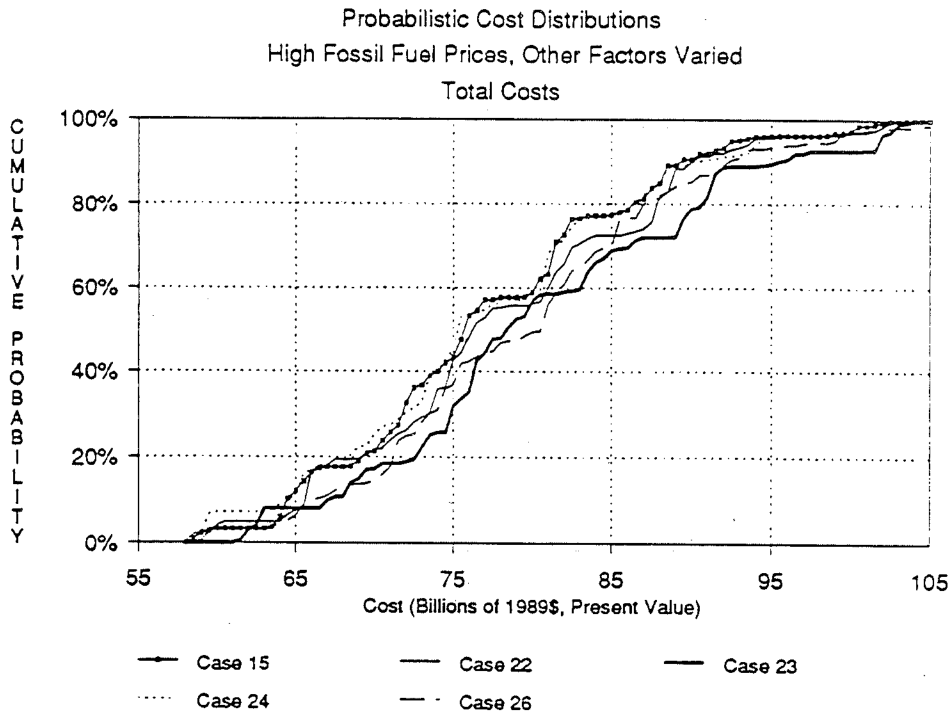
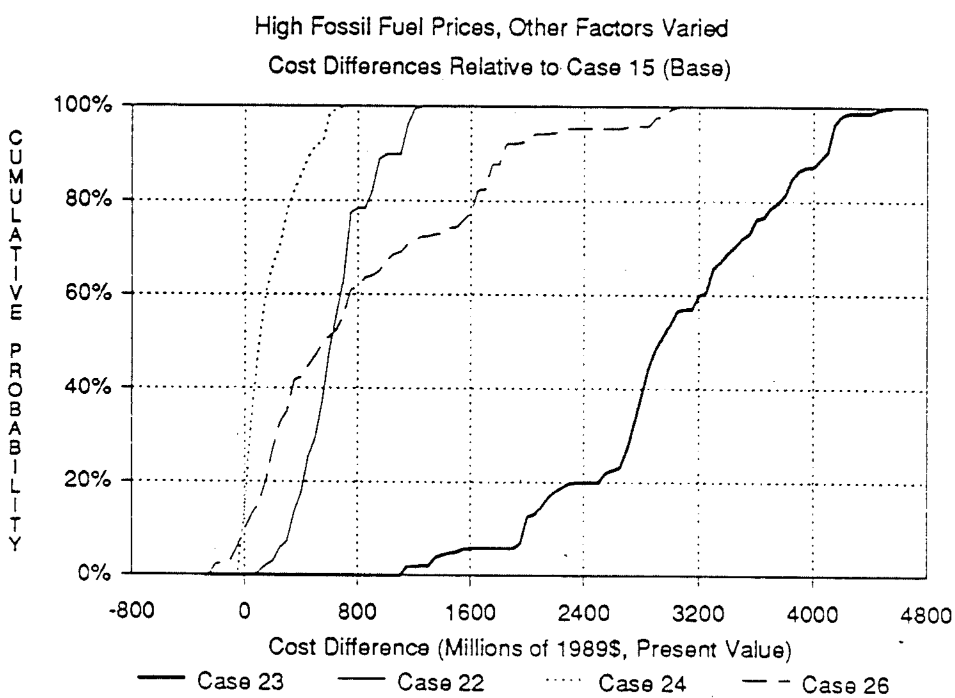

Probabilistic Cost Distributions
Low Capital Costs, Other Factors Varied
Total Costs
CUMULATIVE PROBABILITY
100%
80%
60%
40%
20%
0%
55
65
75
85
95
105
Cost (Billions of 1989$, Present Value)
Case 15
Case 22
Case 23
Case 24
Case 26
Low Capital Costs, Other Factors Varied
Cost Differences Relative to Case 15 (Base)
CUMULATIVE PROBABILITY
100%
80%
60%
40%
20%
0%
-800
0
800
1600
2400
3200
4000
4800
Cost Difference (Millions of 1989$, Present Value)
Case 23
Case 22
Case 24
Case 26

FIGURE 8.5-22

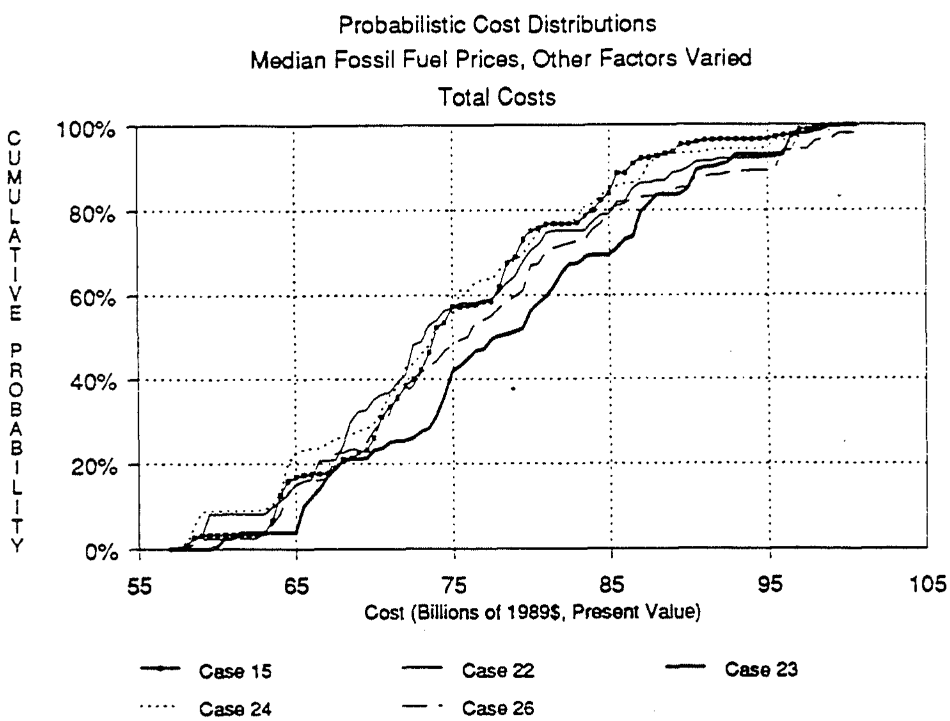


Probabilistic Cost Distributions
High Fossil Fuel Prices, Other Factors Varied
Total Costs
CUMULATIVE PROBABILITY
100%
80%
60%
40%
20%
0%
55
65
75
85
95
105
Cost (Billions of 1989$, Present Value)
Case 15
Case 22
Case 23
Case 24
Case 26

High Fossil Fuel Prices, Other Factors Varied
Cost Differences Relative to Case 15 (Base)
CUMULATIVE PROBABILITY
100%
80%
60%
40%
20%
0%
-800
0
800
1600
2400
3200
4000
4800
Cost Difference (Millions of 1989$, Present Value)
Case 23
Case 22
Case 24
Case 26


FIGURE 8.5-23


Probabilistic Cost Distributions
Median Fossil Fuel Prices, Other Factors Varied
Total Costs
CUMULATIVE PROBABILITY
100%
80%
60%
40%
20%
0%
55
65
75
85
95
105
Cost (Billions of 1989$, Present Value)
Case 15
Case 22
Case 23
Case 24
Case 26

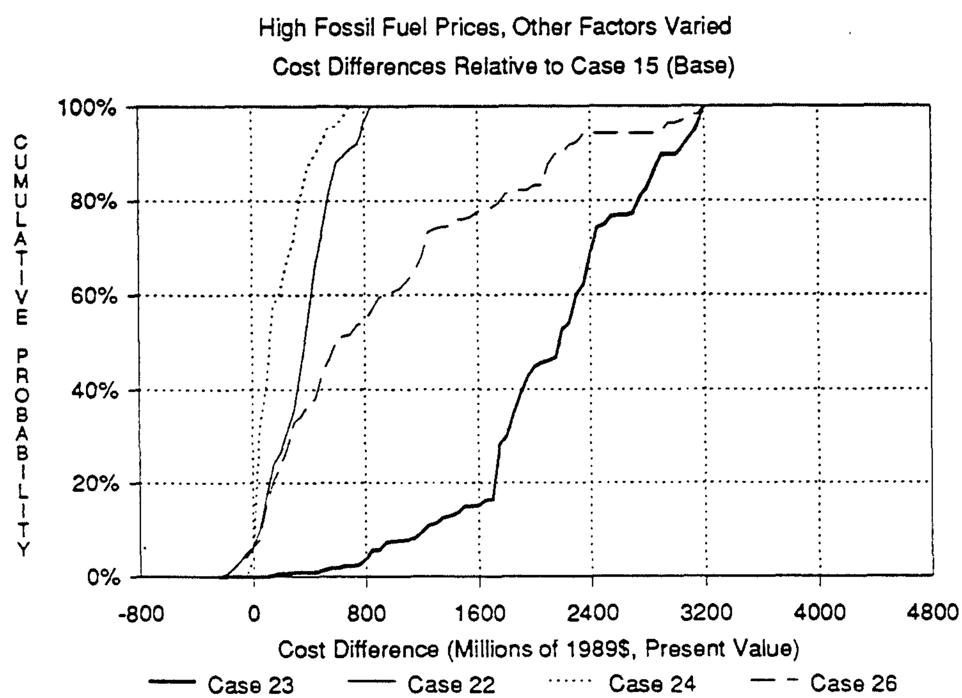
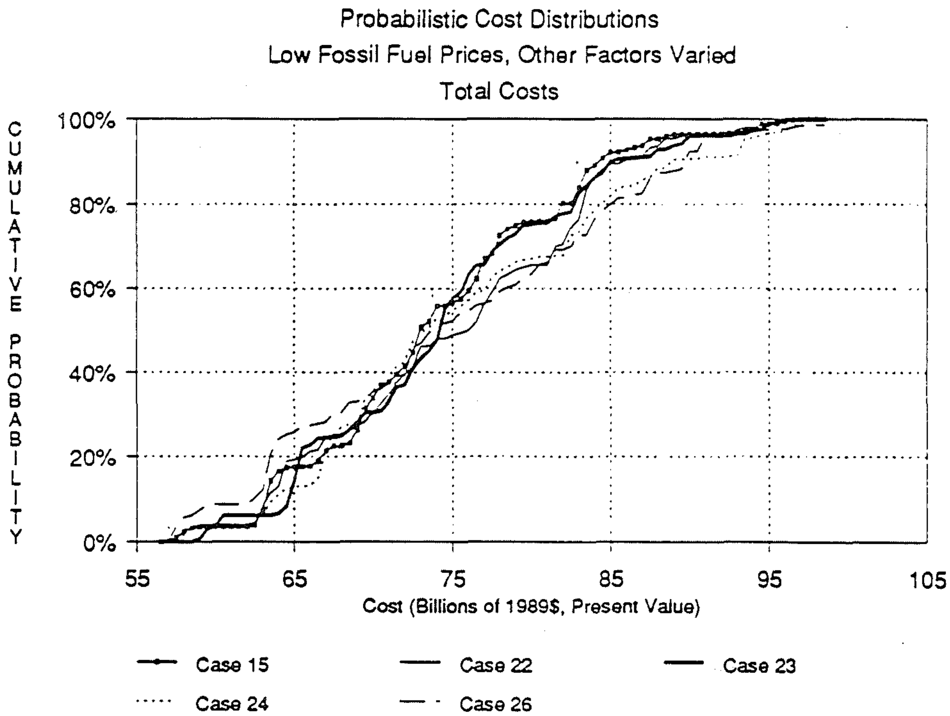

High Fossil Fuel Prices, Other Factors Varied
Cost Differences Relative to Case 15 (Base)
CUMULATIVE PROBABILITY
100%
80%
60%
40%
20%
0%
-800
0
800
1600
2400
3200
4000
4800
Cost Difference (Millions of 1989$, Present Value)
Case 23
Case 22
Case 24
Case 26

FIGURE 8.5-24


Probabilistic Cost Distributions
Low Fossil Fuel Prices, Other Factors Varied
Total Costs
CUMULATIVE PROBABILITY
100%
80%
60%
40%
20%
0%
55
65
75
85
95
105
Cost (Billions of 1989$, Present Value)
Case 15
Case 22
Case 23
Case 24
Case 26

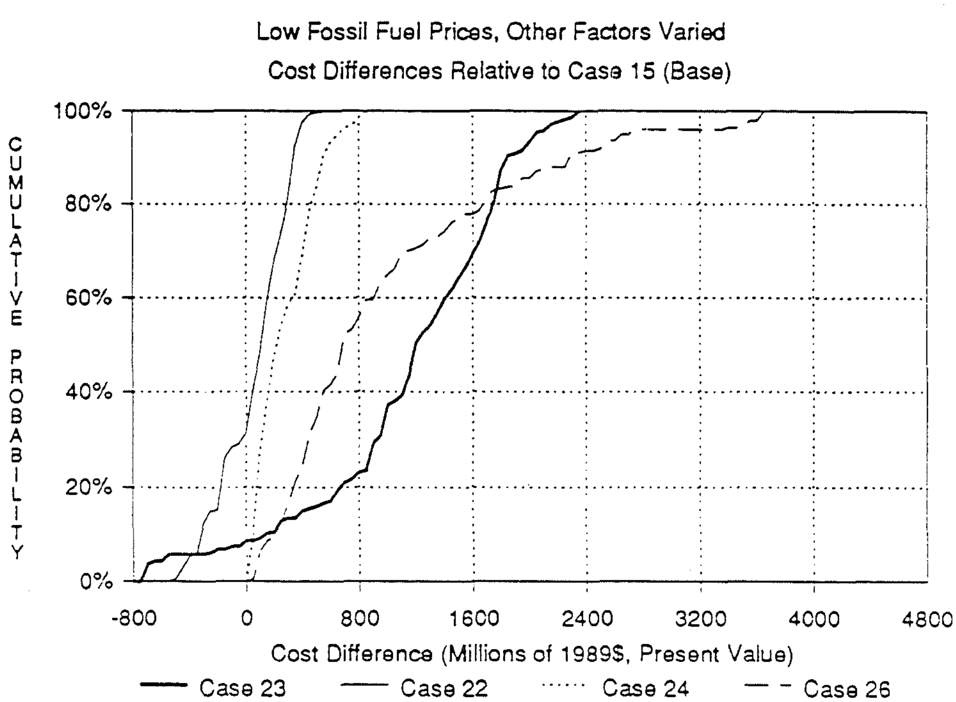
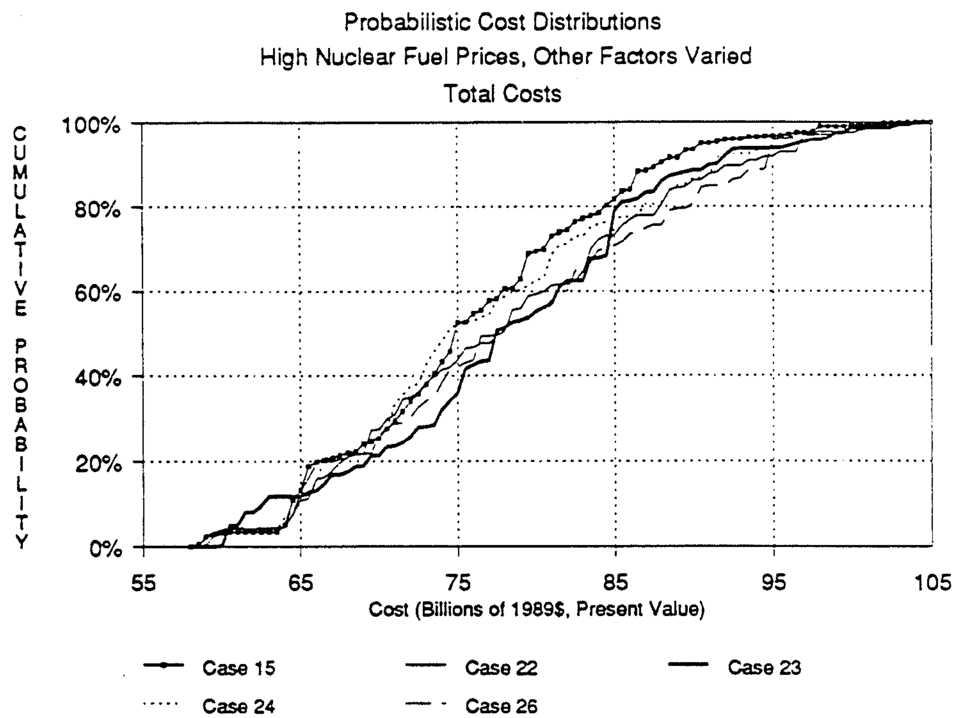

Low Fossil Fuel Prices, Other Factors Varied
Cost Differences Relative to Case 15 (Base)
CUMULATIVE PROBABILITY
100%
80%
60%
40%
20%
0%
-800
0
800
1600
2400
3200
4000
4800
Cost Difference (Millions of 1989$, Present Value)
Case 23
Case 22
Case 24
Case 26

FIGURE 8.5-25


Probabilistic Cost Distributions
High Nuclear Fuel Prices, Other Factors Varied
Total Costs
CUMULATIVE PROBABILITY
100%
80%
60%
40%
20%
0%
55
65
75
85
95
105
Cost (Billions of 1989$, Present Value)
Case 15
Case 22
Case 23
Case 24
Case 26

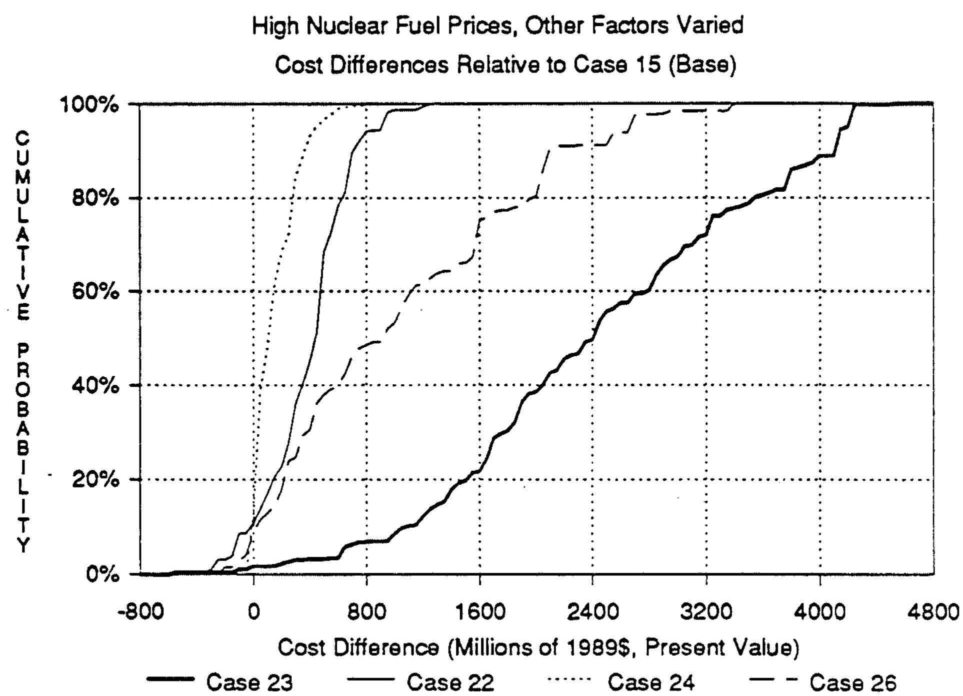
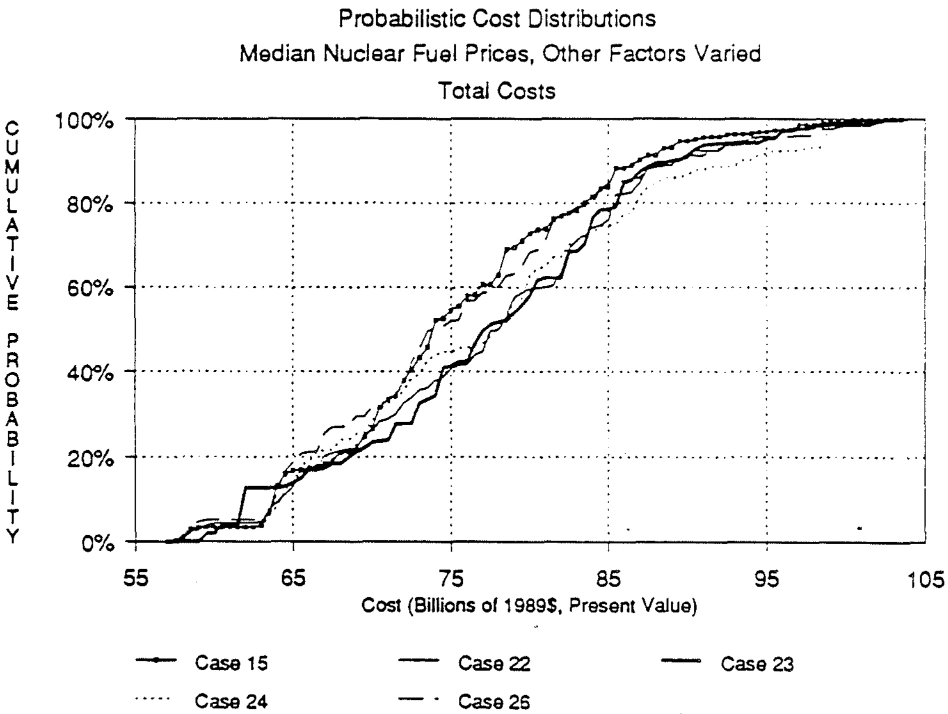

High Nuclear Fuel Prices, Other Factors Varied
Cost Differences Relative to Case 15 (Base)
CUMULATIVE PROBABILITY
100%
80%
60%
40%
20%
0%
-800
0
800
1600
2400
3200
4000
4800
Cost Difference (Millions of 1989$, Present Value)
Case 23
Case 22
Case 24
Case 26

FIGURE 8.5-26


Probabilistic Cost Distributions
Median Nuclear Fuel Prices, Other Factors Varied
Total Costs
CUMULATIVE PROBABILITY
100%
80%
60%
40%
20%
0%
55
65
75
85
95
105
Cost (Billions of 1989$, Present Value)
Case 15
Case 22
Case 23
Case 24
Case 26

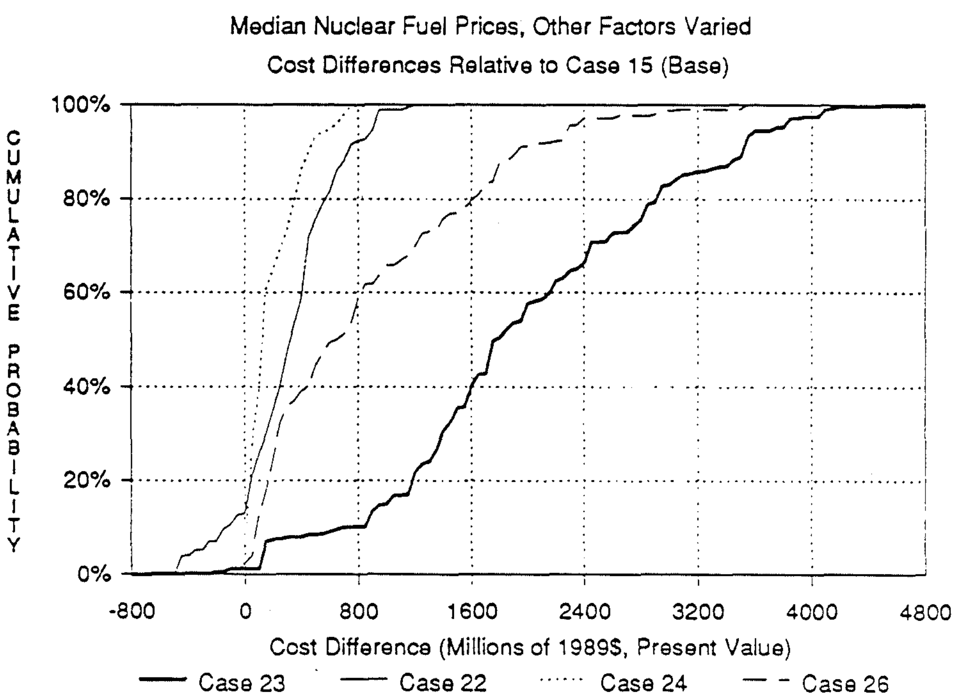
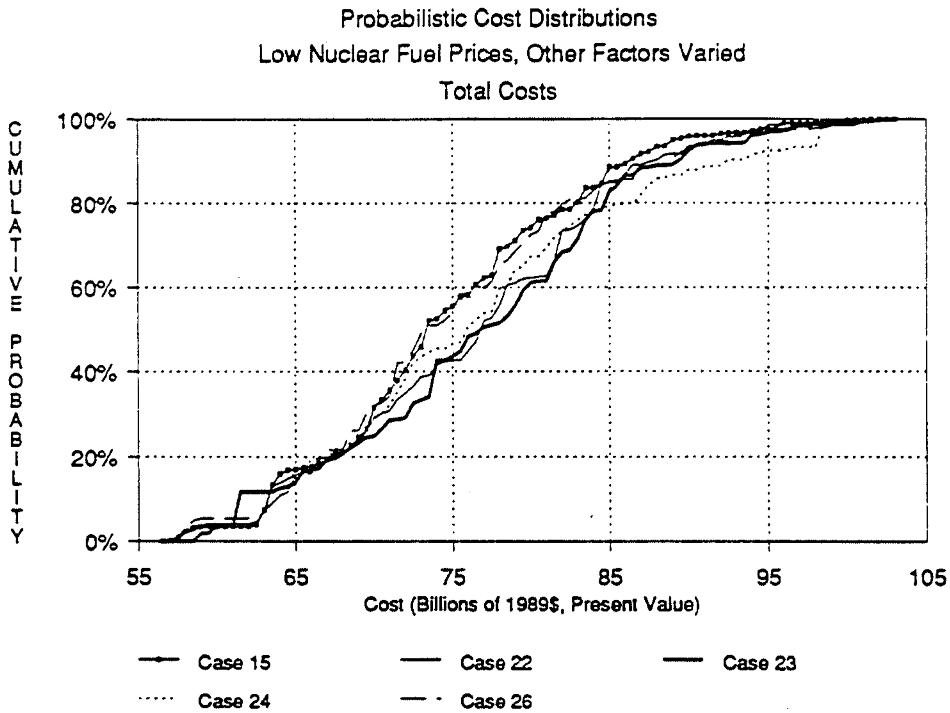

Median Nuclear Fuel Prices, Other Factors Varied
Cost Differences Relative to Case 15 (Base)
CUMULATIVE PROBABILITY
100%
80%
60%
40%
20%
0%
-800
0
800
1600
2400
3200
4000
4800
Cost Difference (Millions of 1989$, Present Value)
Case 23
Case 22
Case 24
Case 26

FIGURE 8.5-27


Probabilistic Cost Distributions
Low Nuclear Fuel Prices, Other Factors Varied
Total Costs
CUMULATIVE PROBABILITY
100%
80%
60%
40%
20%
0%
55
65
75
85
95
105
Cost (Billions of 1989$, Present Value)
Case 15
Case 22
Case 23
Case 24
Case 26

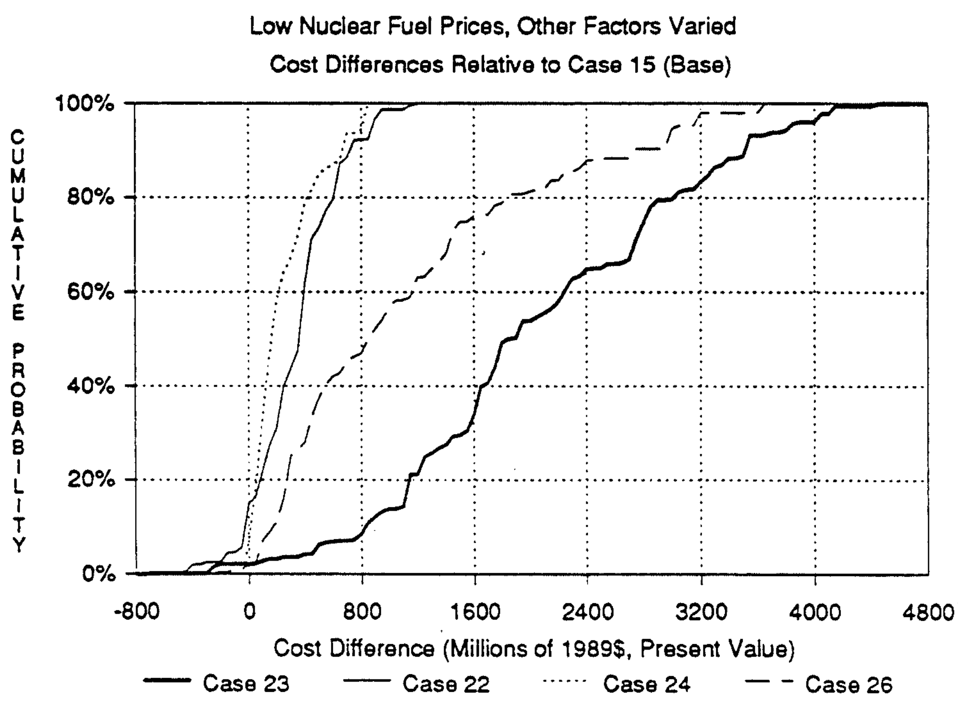
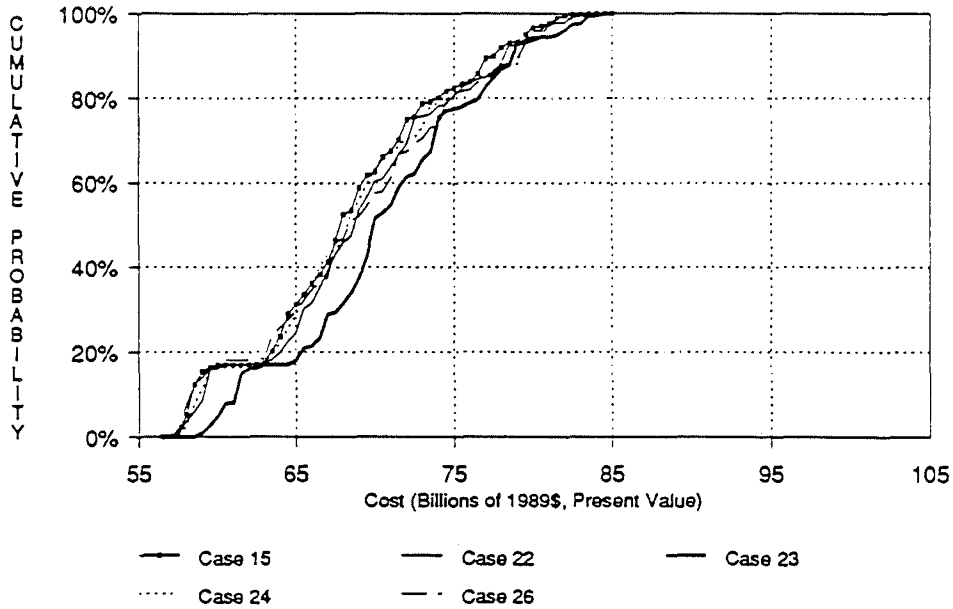

Low Nuclear Fuel Prices, Other Factors Varied
Cost Differences Relative to Case 15 (Base)
CUMULATIVE PROBABILITY
100%
80%
60%
40%
20%
0%
-800
0
800
1600
2400
3200
4000
4800
Cost Difference (Millions of 1989$, Present Value)
Case 23
Case 22
Case 24
Case 26

FIGURE 8.5-28

Probabilistic Cost Distributions
High Discount Rate, Other Factors Varied
Total Costs




High Discount Rate Fixed, Other Factors Varied
Cost Differences Relative to Case 15 (Base)

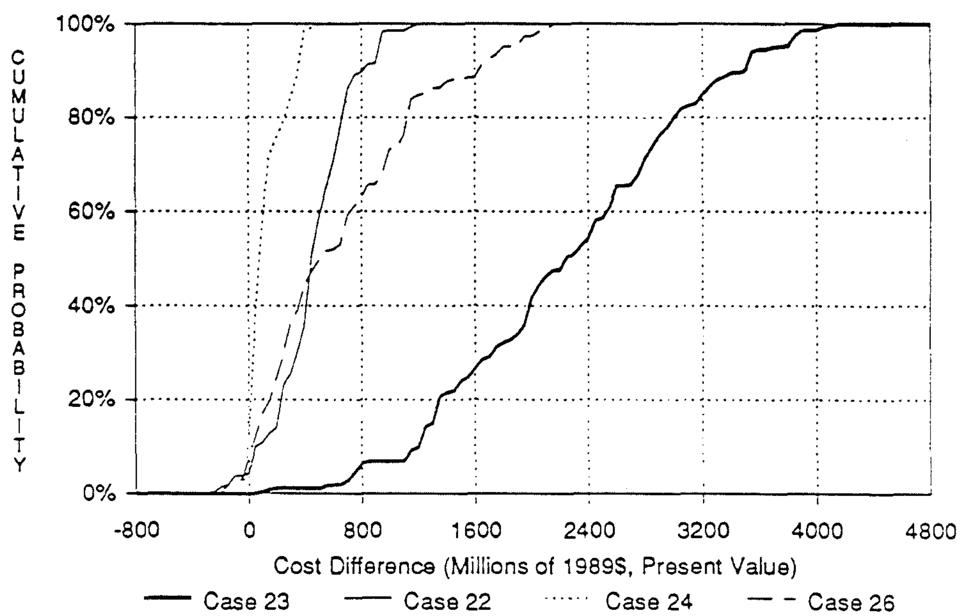
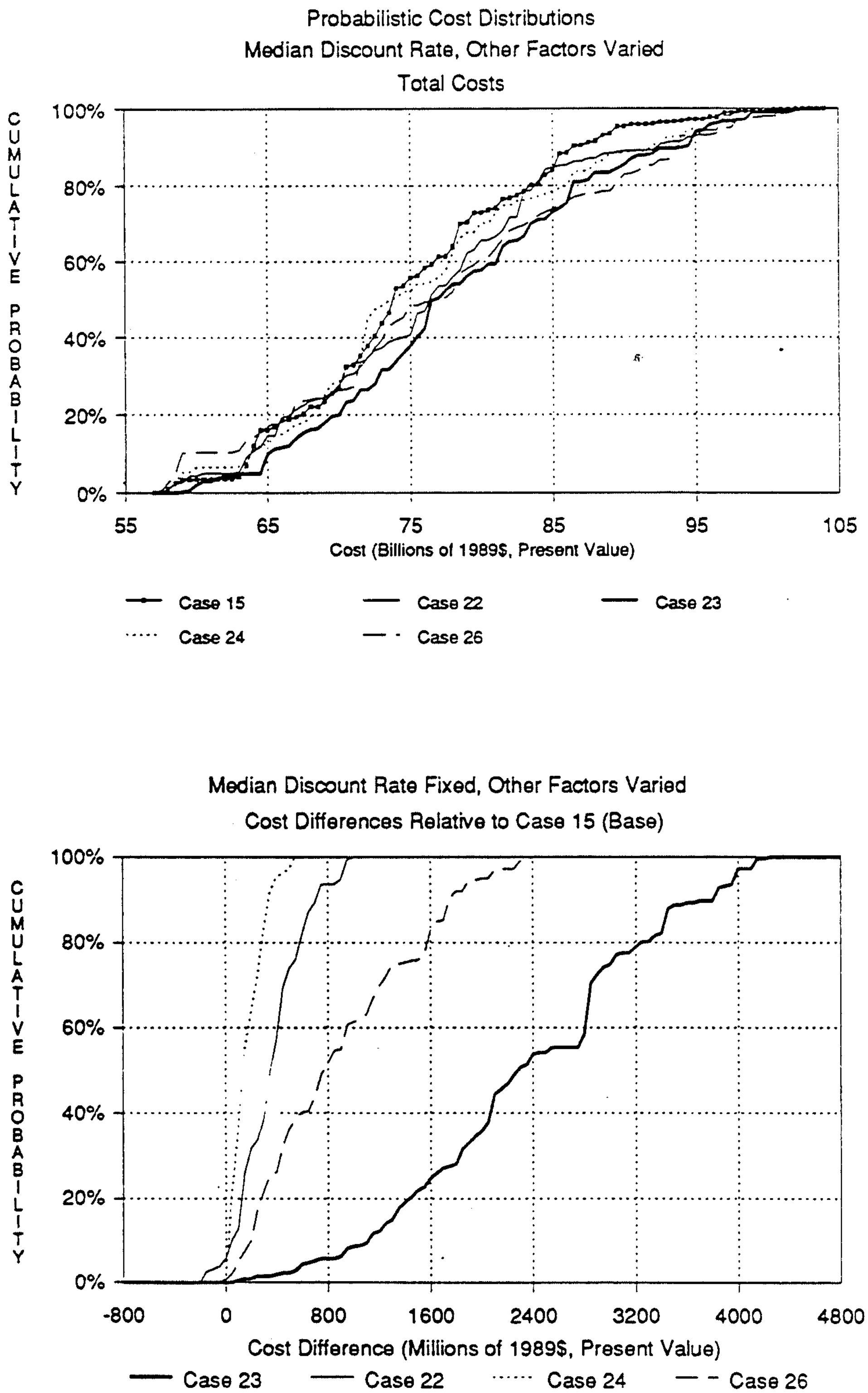
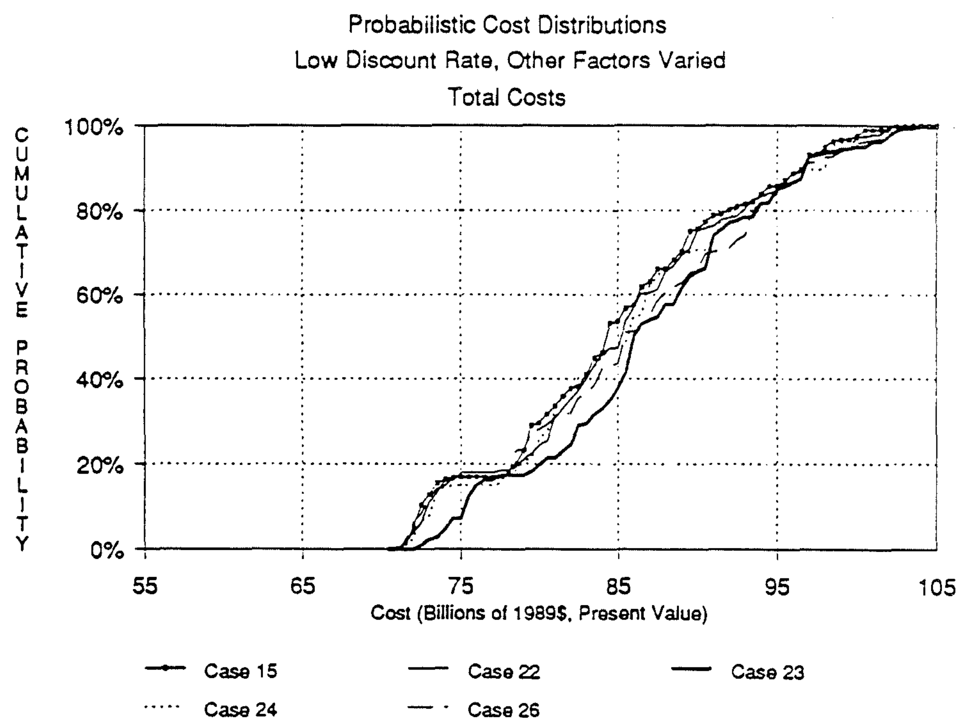



FIGURE 8.5-29



Probabilistic Cost Distributions
Median Discount Rate, Other Factors Varied
Total Costs
CUMULATIVE PROBABILITY
100%
80%
60%
40%
20%
0%
55
65
75
85
95
105
Cost (Billions of 1989$, Present Value)
Case 15
Case 22
Case 23
Case 24
Case 26
Median Discount Rate Fixed, Other Factors Varied
Cost Differences Relative to Case 15 (Base)
CUMULATIVE PROBABILITY
100%
80%
60%
40%
20%
0%
-800
0
800
1600
2400
3200
4000
4800
Cost Difference (Millions of 1989$, Present Value)
Case 23
Case 22
Case 24
Case 26


FIGURE 8.5-30


Probabilistic Cost Distributions
Low Discount Rate, Other Factors Varied
Total Costs
CUMULATIVE PROBABILITY
100%
80%
60%
40%
20%
0%
55
65
75
85
95
105
Cost (Billions of 1989$, Present Value)
Case 15
Case 22
Case 23
Case 24
Case 26

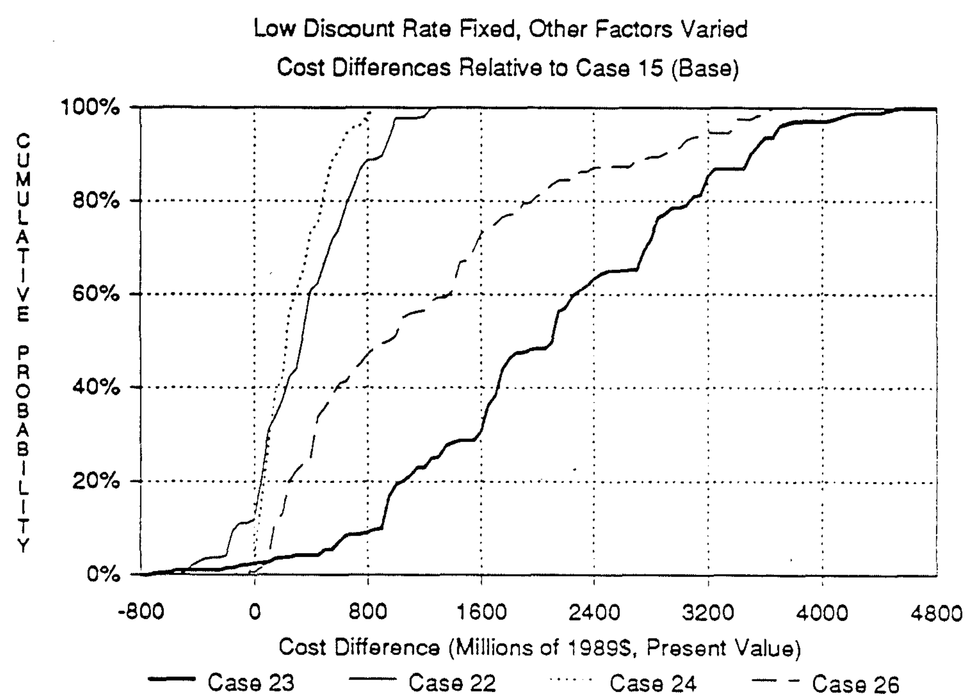

Low Discount Rate Fixed, Other Factors Varied
Cost Differences Relative to Case 15 (Base)
CUMULATIVE PROBABILITY
100%
80%
60%
40%
20%
0%
-800
0
800
1600
2400
3200
4000
4800
Cost Difference (Millions of 1989$, Present Value)
Case 23
Case 22
Case 24
Case 26

FIGURE 8.5-31

### 8.5.8 Taking Dependencies Into Account

Among 405 paths, there are some combinations of factors that have a lower probability than was assumed, because one factor is unlikely to lead to another--high capital costs would usually not result when discount rate are low. Conversely, some combinations have a higher probability than was assumed, because of dependency between factors. For example, both load forecast and discount rates are dependent on economic activity--hence a change in economic activity would lead to a corresponding change in both load forecast and discount rates.

Figure 8.5-32 shows how probabilities could change when dependencies are taken into account. Under upper load forecast, for example, the upper, median and lower probabilities for fossil fuel prices were assumed to change from 20/60/20 to 90/10/0. These changes were used to recalculate the expected costs. Case 15 was still cost effective when ranking the cases only their expected cost differences changed.

Figure 8.5-33 shows the distributions for the original independent probabilities (BASE) and the results when the probabilities for fossil fuel and the discount rate depend on the load forecast path. The results show the continued cost effectiveness of Case 15.

### 8.5.9 Summary of Risk Analysis

Figure 8.5-34 summarizes the results of the sensitivity and probabilistic analysis. The highest and lowest present value costs that occur irrespective of their probability are shown. The range between the highest and lowest shows the difference in variability within each case. The differences in the range sizes relative to Case 15 are shown. Expected cost differences relative to Case 15 and their 80% confidence band are also shown.

# Illustration of Possible Dependent Probabilities for Fossil Fuel and Discount Rate

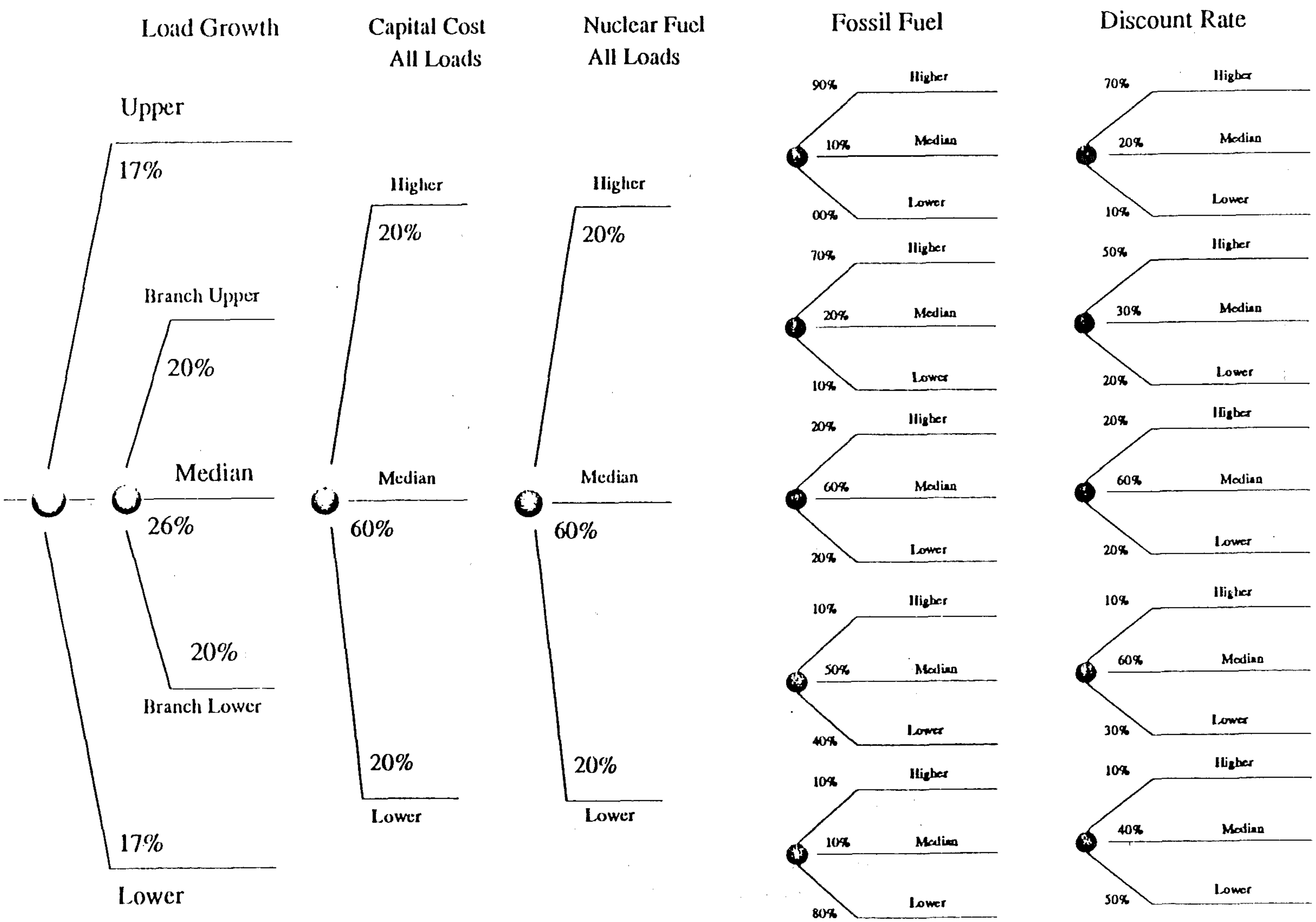
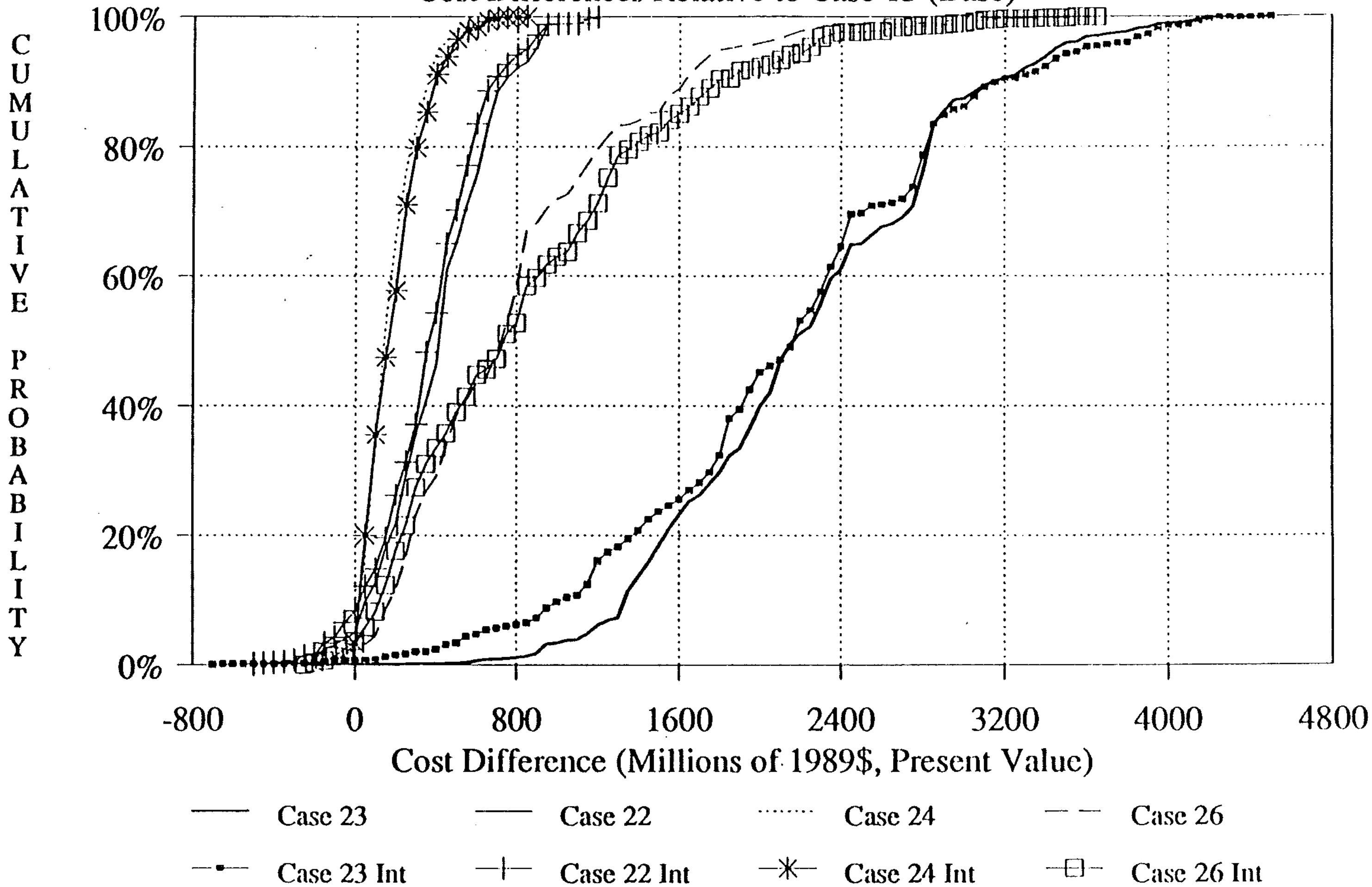



FIGURE 8.5-32

FIGURE 8.5-33
Fossil Fuel Prices and Discount Rate Interdepend on Load
Comparison to Independent Cost Difference Curves
Cost Differences Relative to Case 15 (Base)




Interdependent Cost Curves (Int) have Patterns

FIGURE 8.5-34

$ Million 1989 Present Value

| | Case 23 | Case 22 | Case 15 | Case 24 | Case 26 |
|---|---|---|---|---|---|
| Highest Cost | 104677 | 103488 | 103368 | 103908 | 106065 |
| Lowest Cost | 58673 | 57175 | 56914 | 56923 | 57013 |
| Range Size | 46004 | 46313 | 46454 | 46985 | 49052 |

Differences Relative to Case 15

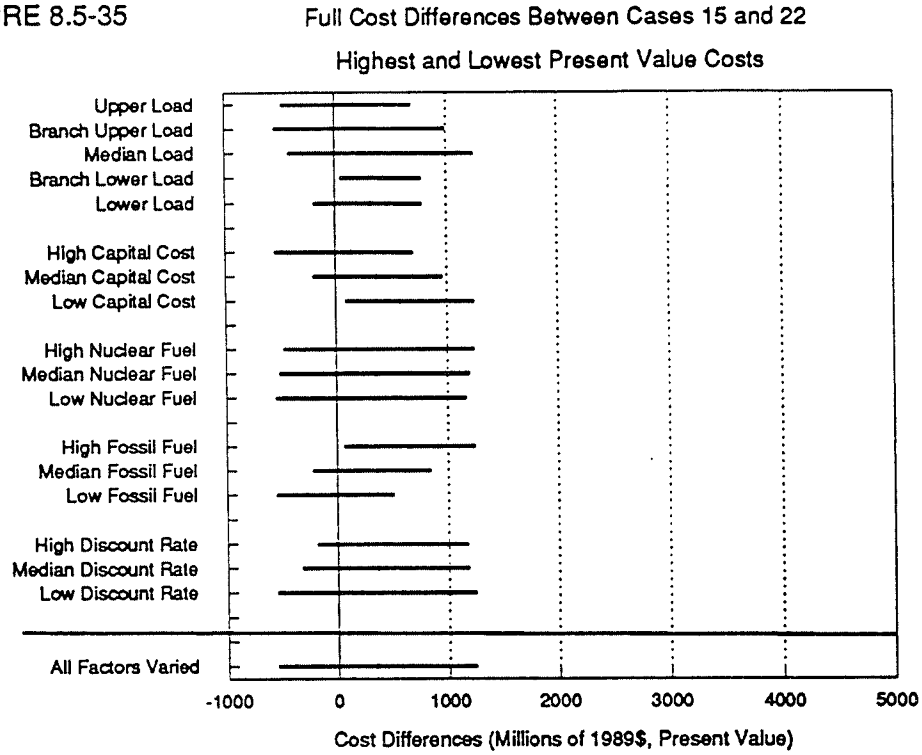
| | Case 23 | Case 22 | Case 15 | Case 24 | Case 26 |
|---|---|---|---|---|---|
| Range Differences | -450 | -141 | BASE | 531 | 2598 |
| Expected Cost Difference | 2120 | 365 | BASE | 187 | 857 |
| 80% Confidence Band for Difference | 1020-3195 | 30-690 | BASE | 30-390 | 120-1770 |

While Figure 8.5-34 shows that the range of outcomes for Case 22 and Case 23 may be less than Case 15, however these cases have much higher expected costs. All Cases have a higher expected cost than Case 15. Even when examining the 80% confidence bands, the expected cost for Case 15 is less than the confidence bands of all the other Cases.

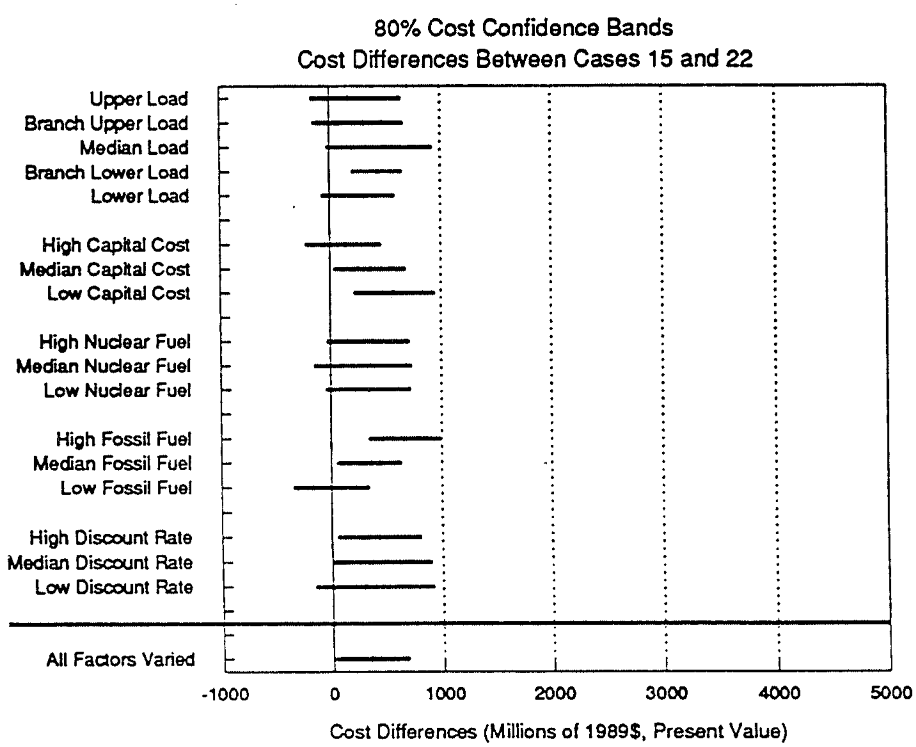
Bar charts can be used to summarize the information shown in the cumulative distribution graphs. The highest and lowest cost differences to Case 15 under each of the 17 specific conditions, outlined in 8.5.6, and the 80% confidence bands which eliminate the extreme results at each end of the ranges were plotted.

Figure 8.5-35 through Figure 8.5-38 compare the each case to Case 15 under the 17 specific conditions, while varying all the other factors. The top charts, indicating the full range of differences show that Case 15 can cost more under some combination of conditions. The lower charts for the 80% confidence band of the ranges show that the number of times when Case 15 costs more is greatly reduced. The cost penalties for Case 15, shown by the size of the few remaining ranges to the left of the 0 base line, are very small.

FIGURE 8.5-35

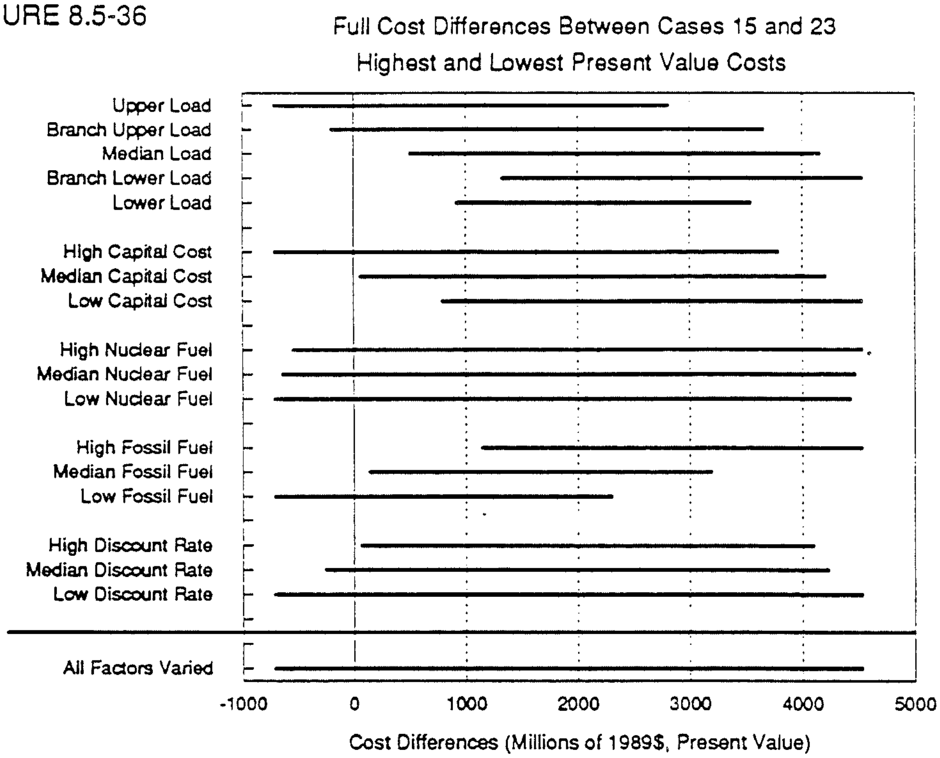


Full Cost Differences Between Cases 15 and 22
Highest and Lowest Present Value Costs
Upper Load
Branch Upper Load
Median Load
Branch Lower Load
Lower Load
High Capital Cost
Median Capital Cost
Low Capital Cost
High Nuclear Fuel
Median Nuclear Fuel
Low Nuclear Fuel
High Fossil Fuel
Median Fossil Fuel
Low Fossil Fuel
High Discount Rate
Median Discount Rate
Low Discount Rate
All Factors Varied
-1000
0
1000
2000
3000
4000
5000
Cost Differences (Millions of 1989$, Present Value)

80% Cost Confidence Bands
Cost Differences Between Cases 15 and 22
Upper Load
Branch Upper Load
Median Load
Branch Lower Load
Lower Load
High Capital Cost
Median Capital Cost
Low Capital Cost
High Nuclear Fuel
Median Nuclear Fuel
Low Nuclear Fuel
High Fossil Fuel
Median Fossil Fuel
Low Fossil Fuel
High Discount Rate
Median Discount Rate
Low Discount Rate
All Factors Varied
-1000
0
1000
2000
3000
4000
5000
Cost Differences (Millions of 1989$, Present Value)

FIGURE 8.5-36


Full Cost Differences Between Cases 15 and 23
Highest and Lowest Present Value Costs
Upper Load
Branch Upper Load
Median Load
Branch Lower Load
Lower Load
High Capital Cost
Median Capital Cost
Low Capital Cost
High Nuclear Fuel
Median Nuclear Fuel
Low Nuclear Fuel
High Fossil Fuel
Median Fossil Fuel
Low Fossil Fuel
High Discount Rate
Median Discount Rate
Low Discount Rate
All Factors Varied
-1000
0
1000
2000
3000
4000
5000
Cost Differences (Millions of 1989$, Present Value)

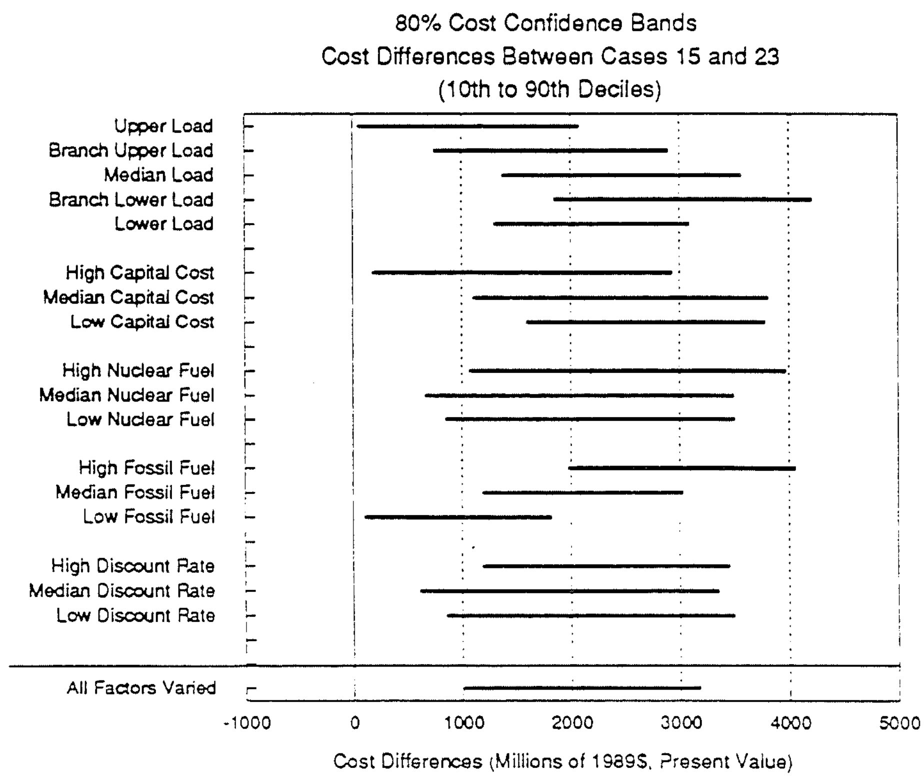
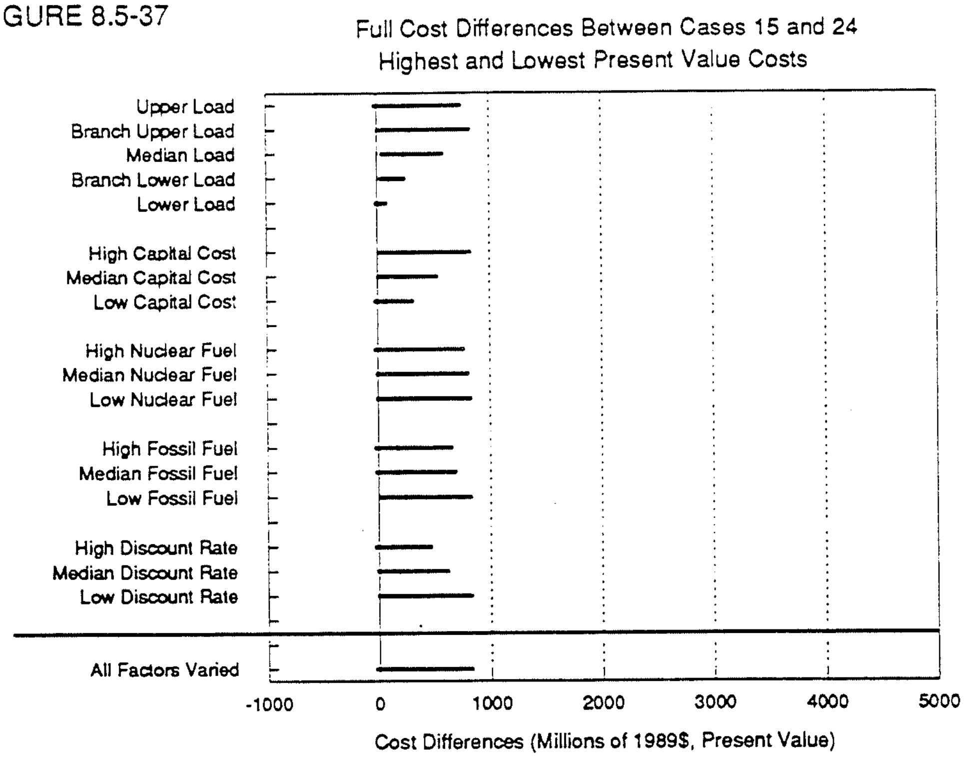
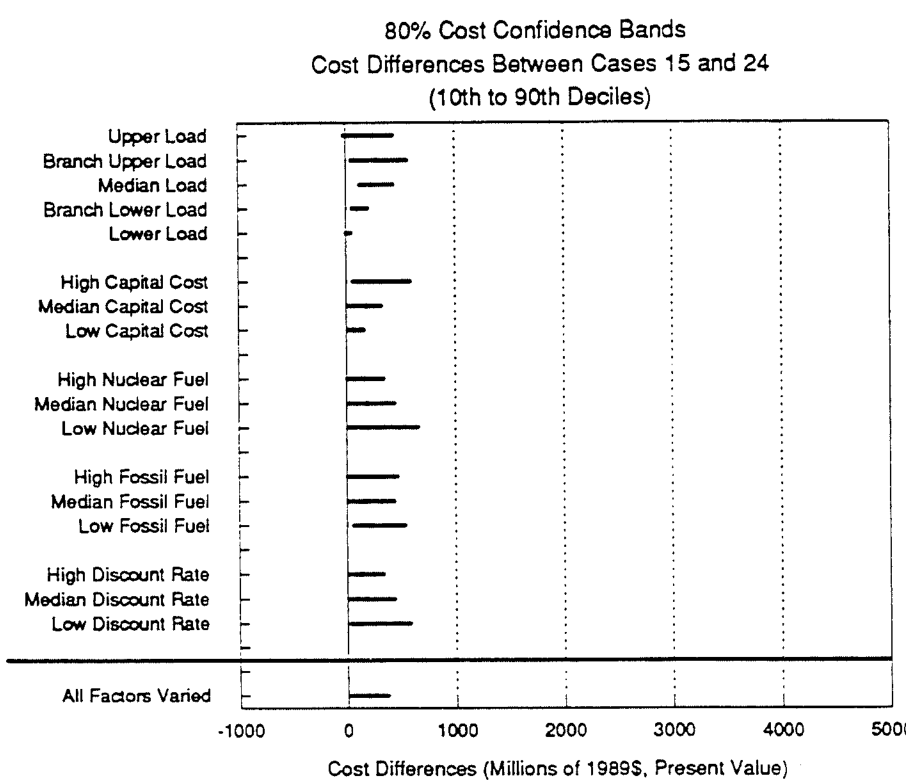

80% Cost Confidence Bands
Cost Differences Between Cases 15 and 23
(10th to 90th Deciles)
Upper Load
Branch Upper Load
Median Load
Branch Lower Load
Lower Load
High Capital Cost
Median Capital Cost
Low Capital Cost
High Nuclear Fuel
Median Nuclear Fuel
Low Nuclear Fuel
High Fossil Fuel
Median Fossil Fuel
Low Fossil Fuel
High Discount Rate
Median Discount Rate
Low Discount Rate
All Factors Varied
-1000
0
1000
2000
3000
4000
5000
Cost Differences (Millions of 1989$, Present Value)

FIGURE 8.5-37

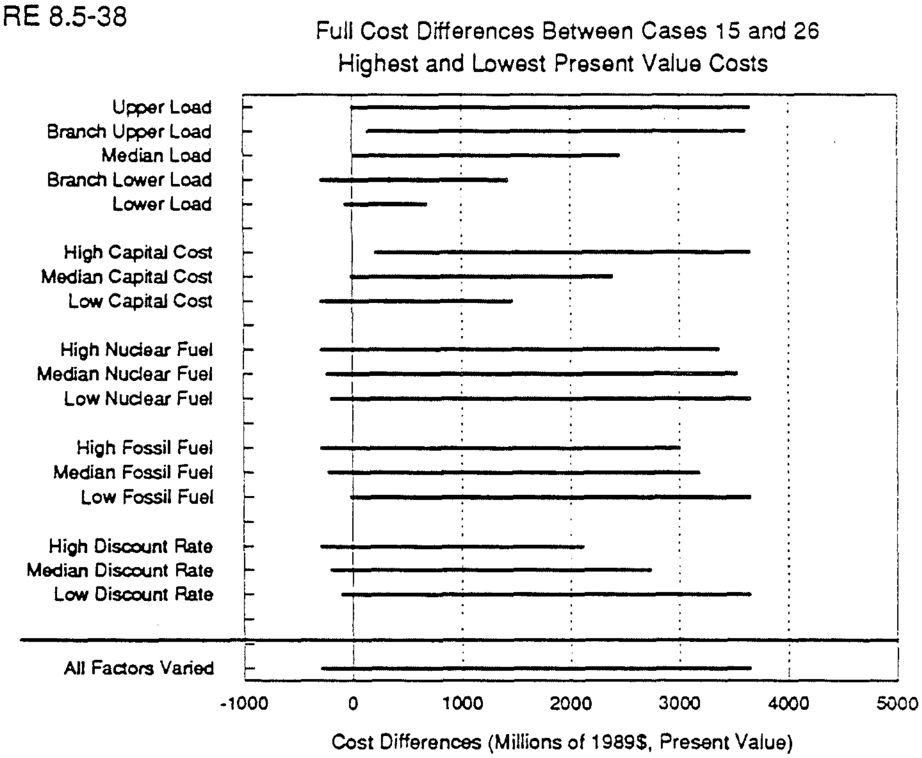


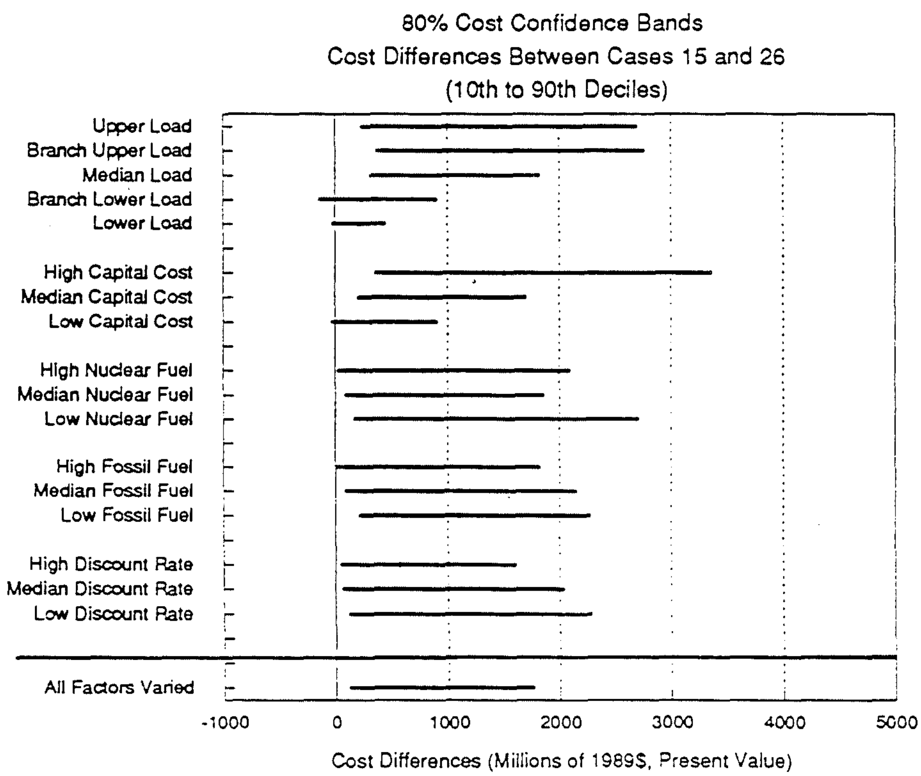
Full Cost Differences Between Cases 15 and 24
Highest and Lowest Present Value Costs
Upper Load
Branch Upper Load
Median Load
Branch Lower Load
Lower Load
High Capital Cost
Median Capital Cost
Low Capital Cost
High Nuclear Fuel
Median Nuclear Fuel
Low Nuclear Fuel
High Fossil Fuel
Median Fossil Fuel
Low Fossil Fuel
High Discount Rate
Median Discount Rate
Low Discount Rate
All Factors Varied
-1000
0
1000
2000
3000
4000
5000
Cost Differences (Millions of 1989$, Present Value)

80% Cost Confidence Bands
Cost Differences Between Cases 15 and 24
(10th to 90th Deciles)
Upper Load
Branch Upper Load
Median Load
Branch Lower Load
Lower Load
High Capital Cost
Median Capital Cost
Low Capital Cost
High Nuclear Fuel
Median Nuclear Fuel
Low Nuclear Fuel
High Fossil Fuel
Median Fossil Fuel
Low Fossil Fuel
High Discount Rate
Median Discount Rate
Low Discount Rate
All Factors Varied
-1000
0
1000
2000
3000
4000
5000
Cost Differences (Millions of 1989$, Present Value)

FIGURE 8.5-38


Full Cost Differences Between Cases 15 and 26
Highest and Lowest Present Value Costs
Upper Load
Branch Upper Load
Median Load
Branch Lower Load
Lower Load
High Capital Cost
Median Capital Cost
Low Capital Cost
High Nuclear Fuel
Median Nuclear Fuel
Low Nuclear Fuel
High Fossil Fuel
Median Fossil Fuel
Low Fossil Fuel
High Discount Rate
Median Discount Rate
Low Discount Rate
All Factors Varied
-1000
0
1000
2000
3000
4000
5000
Cost Differences (Millions of 1989$, Present Value)


80% Cost Confidence Bands
Cost Differences Between Cases 15 and 26
(10th to 90th Deciles)
Upper Load
Branch Upper Load
Median Load
Branch Lower Load
Lower Load
High Capital Cost
Median Capital Cost
Low Capital Cost
High Nuclear Fuel
Median Nuclear Fuel
Low Nuclear Fuel
High Fossil Fuel
Median Fossil Fuel
Low Fossil Fuel
High Discount Rate
Median Discount Rate
Low Discount Rate
All Factors Varied
-1000
0
1000
2000
3000
4000
5000
Cost Differences (Millions of 1989$, Present Value)

As noted previously, the probabilistic paths were modelled to their conclusion with no feedback loop to make corrections as unreasonable costs or fuel prices are experienced. The risk analysis concentrated on the results using extreme conditions, such as the estimates following their high or low values for the entire study period and linking the capital costs and the construction escalation, the uncertainty <u>differences</u> in the new major supply components in each case were emphasized. Case 15 continued to show its cost effectiveness under nearly all conditions and clearly resulted in the lowest expected costs.

## 8.6 REVIEW

For each case under each of the five load paths, there is a unique application of the Risk Assessment Model (RAM), which integrates economic values (escalation and discount rates) and cost data for the options in the supply cases.

To compare plans that have different patterns of expenditures for capital, OM&A and fuel costs, present value costs are employed. Since some options have an operating life that extends beyond the planning period, a portion of all fixed costs in some options is allocated to the study period.

Much of the cost analysis focuses on the difference in cost between plans and the decisions that drive those differences.

Since actual costs and differences between cases will likely be different than projected, Hydro determines total cost for customers under a range of conditions.

To determine what factors have the most impact on costs, Hydro examines the differences caused when individual factors are varied independently. The five factors identified as having the most impact include load forecast, captial construction costs, fossil fuel costs, nuclear fuel costs and cost of money (real discount rate).

Because of the uncertainties surrounding load growth and the major cost factors, probabilities are assigned to each of the five load paths and the lower, medium and cost estimates. Combining the three costs estimates for the key cost components with the five load forecases produces 405 possible estimates and an equal number of present value cost outcomes. Multiplying these outcomes by their corresponding probability produces the expected cost of a case.

The total cost range of a case is presented on a cumulative probability distribution graph. Differences between one case, Case 15, and all other cases, are also presented on cumulative probability distribution graphs.

When one or all factors are varied, Case 15 is the dominant case -- it has less costly outcomes more frequently than the other cases. This did not change when Hydro took into account that some combinations of factors have a higher or lower probability than was orginally assigned.

# 9. FINANCIAL IMPACT ASSESSMENT

## 9.0 INTRODUCTION

This chapter provides additional information on the impacts of the various Cases in the Demand/Supply Plan on electricity prices, borrowing requirements, and financial performance.

## 9.1 ELECTRICITY PRICES

Figure 15-52 in the Plan report illustrates the impacts on electricity prices (in percentage terms) of the various Cases, relative to Case 15, for the upper, median and lower forecasts. The values used to graph the impacts are shown in Figure 9-1.

For the first decade of the study period, there are essentially no differences in prices between the Cases (ie, price difference are generally 1% or less). From 2000 to 2009, electricity prices for Cases 22, 24 and 26 are generally within ±3% of Case 15. These differences are not considered significant, given the uncertainty inherent in estimating impacts 10 to 20 years in the future. The outlook is considerably less favourable under Case 23, with prices projected to be as much as 10 to 15% higher than Case 15.

Electricity prices charged to Ontario Hydro's primary customers are established so that total revenues, including revenues from secondary sales, recover costs and provide for a planned level of net income. In forecast terminology, the revenue to be collected from primary customers is called the "revenue requirement" (see formula below), and is defined as being equal to total costs, including net income, less secondary revenue.

Revenue requirement = OM&A + Fuel + Provincial Government levies ÷ Depreciation + Interest and foreign exchange + Net income - Secondary revenue

The percentage difference in electricity price between any two Cases in a given year is equal to the percentage difference in annual revenue requirement. (This statement is only true when comparing Cases within a particular load forecast, as projected electricity prices are also affected by load.) Differences in annual revenue requirement between the various Cases and Case 15 are provided in Figure 9-2. The impacts are expressed in 1989 dollars, which are derived from nominal dollars by dividing by an inflation index (the Ontario Consumer Price Index).

Figure 9-1 Impacts on electricity prices relative to Case 15

| (%) | 1989 | 1990 | 1991 | 1992 | 1993 | 1994 | 1995 | 1996 | 1997 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Upper | | | | | | | | | | | | | | | | | | | | | |
| Case 22 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 1 | 1 | 2 | 1 | 1 | 1 | 1 | 2 | 2 | 1 | 0 |
| Case 23 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 1 | 2 | 4 | 6 | 6 | 4 | 4 | 5 | 5 | 5 | 3 | 2 | 1 |
| Case 24 | 0 | 0 | 0 | 1 | 1 | 1 | 1 | 1 | 1 | 0 | 0 | 0 | (1) | 0 | (1) | (1) | (1) | (2) | (2) | (2) | (1) |
| Case 26 | 0 | 0 | 0 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 0 | (2) | (2) | (2) | (1) | (2) | (2) | (3) | (3) | (2) |
| Median | | | | | | | | | | | | | | | | | | | | | |
| Case 22 | 0 | 0 | 0 | 0 | 0 | 0 | (1) | (1) | (1) | 0 | 0 | 2 | 3 | 3 | 3 | 2 | 1 | 0 | 3 | 4 | 3 |
| Case 23 | 0 | 0 | 0 | (1) | (1) | (1) | (1) | 0 | 0 | 2 | 5 | 9 | 10 | 9 | 10 | 11 | 11 | 9 | 7 | 5 | 2 |
| Case 24 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 1 | 1 | 0 | 0 | 0 | 0 | (1) | 0 | 0 | 1 | (1) | (2) |
| Case 26 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 1 | 1 | 0 | (1) | (2) | (2) | (2) | (2) | (2) | (1) | (2) | (2) |
| Lower | | | | | | | | | | | | | | | | | | | | | |
| Case 22 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 2 | 4 | 6 | 5 |
| Case 23 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 1 | 3 | 7 | 10 | 12 | 14 | 13 | 12 | 11 | 9 | 4 | 1 |
| Case 24 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | (1) | (2) |
| Case 26 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | (1) | (3) | (4) |

Figure 9-2 Differences in annual revenue requirements relative to Case 15

| (1989$B) | 1989 | 1990 | 1991 | 1992 | 1993 | 1994 | 1995 | 1996 | 1997 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Upper | | | | | | | | | | | | | | | | | | | | | |
| Case 22 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.1 | 0.2 | 0.1 | 0.1 | 0.1 | 0.1 | 0.2 | 0.2 | 0.1 | 0.0 |
| Case 23 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.1 | 0.2 | 0.3 | 0.5 | 0.5 | 0.3 | 0.4 | 0.4 | 0.5 | 0.4 | 0.3 | 0.2 | 0.1 |
| Case 24 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.1 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | (0.1) | (0.1) | (0.1) | (0.2) | (0.2) | (0.2) | (0.1) |
| Case 26 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.1 | 0.1 | 0.0 | 0.0 | (0.1) | (0.2) | (0.2) | (0.1) | (0.2) | (0.2) | (0.3) | (0.3) | (0.2) |
| Median | | | | | | | | | | | | | | | | | | | | | |
| Case 22 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.1 | 0.2 | 0.3 | 0.2 | 0.2 | 0.1 | 0.0 | 0.2 | 0.4 | 0.3 |
| Case 23 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.2 | 0.3 | 0.6 | 0.7 | 0.7 | 0.8 | 0.9 | 0.9 | 0.7 | 0.6 | 0.4 | 0.2 |
| Case 24 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.1 | (0.1) | (0.2) |
| Case 26 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | (0.1) | (0.2) | (0.1) | (0.2) | (0.2) | (0.1) | (0.2) | (0.2) |
| Lower | | | | | | | | | | | | | | | | | | | | | |
| Case 22 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.1 | 0.3 | 0.4 | 0.3 |
| Case 23 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.1 | 0.2 | 0.4 | 0.6 | 0.8 | 0.9 | 0.9 | 0.8 | 0.7 | 0.6 | 0.3 | 0.1 |
| Case 24 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | (0.1) | (0.1) |
| Case 26 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | (0.2) | (0.3) |

The components of the revenue requirement differ between Cases as a result of the different planning assumptions. The main reasons for differences in the revenue requirement components are:

| | |
|---|---|
| OM&A | - is dependent on the quantity and type of new generating facilities in service (eg, a nuclear station has higher OM&A costs than a similarly-sized coal station) |
| Fuel | - is dependent on generation mix, which is influenced by the quantity and type of new generating facilities in service (eg, nuclear generation is less expensive than coal generation) |
| Provincial levies | - are dependent on the level of debt outstanding, which is influenced by cumulative capital expenditures and, therefore, by the quantity and type of new facilities in service or under construction (eg, a nuclear station costs more to build than a similarly-sized coal station) |
| Depreciation | - is dependent on the quantity and type of new facilities in service (eg, a nuclear station has higher depreciation than a similarly-sized coal station, as it costs more to build) |
| Interest/Foreign exchange | - reasons for differences are essentially the same as for depreciation, although differences in interest tend to diminish over time, as the remaining book value of the facilities (ie, the undepreciated cost) declines |
| Net income | - is dependent on the level of construction in progress and/or the value of assets in service, which is influenced by the quantity and type of new facilities in service or under construction (see section 9.3 on Financial Performance for a description of planned net income levels) |
| Secondary revenue | - is dependent on the amount of excess nuclear generation available for export, which is influenced by the quantity and type of new generating facilities in service (note: secondary revenues are essentially revenues from export sales) |

## 9.2 BORROWING

Figure 15-53 in the Plan report shows projected real annual net borrowing levels for the various Cases under upper, median and lower forecasts. The values used to graph the borrowing levels are shown in Figure 9-3. The values are expressed in 1989 dollars.

Figure 9-3 Annual Net Borrowing

| (1989$B) | 1989 | 1990 | 1991 | 1992 | 1993 | 1994 | 1995 | 1996 | 1997 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Upper | | | | | | | | | | | | | | | | | | | | | |
| Case 15 | 1.1 | 1.6 | 1.1 | 1.2 | 0.8 | 0.9 | 1.1 | 1.2 | 1.2 | 1.4 | 2.2 | 3.3 | 3.4 | 2.7 | 2.5 | 2.2 | 2.8 | 3.4 | 3.7 | 3.5 | 2.6 |
| Case 22 | 1.1 | 1.6 | 1.1 | 1.2 | 0.8 | 1.0 | 1.3 | 1.5 | 1.5 | 1.9 | 2.6 | 3.3 | 3.5 | 3.0 | 2.6 | 2.4 | 2.5 | 2.9 | 3.0 | 3.1 | 2.3 |
| Case 23 | 1.1 | 1.7 | 1.2 | 1.4 | 1.1 | 1.5 | 2.0 | 2.4 | 2.5 | 2.8 | 3.1 | 3.5 | 3.2 | 2.5 | 2.4 | 2.1 | 2.7 | 3.0 | 3.3 | 3.0 | 2.3 |
| Case 24 | 1.1 | 1.6 | 1.1 | 1.2 | 0.7 | 0.8 | 1.0 | 1.1 | 1.0 | 1.3 | 2.0 | 3.0 | 3.1 | 2.2 | 1.7 | 1.3 | 2.1 | 3.2 | 3.7 | 3.7 | 3.0 |
| Case 26 | 1.1 | 1.6 | 1.1 | 1.1 | 0.7 | 0.8 | 0.9 | 0.8 | 0.5 | 0.5 | 1.0 | 2.1 | 2.6 | 1.9 | 1.4 | 0.7 | 1.2 | 2.3 | 3.2 | 3.2 | 2.5 |
| Median | | | | | | | | | | | | | | | | | | | | | |
| Case 15 | 1.2 | 1.7 | 1.1 | 0.9 | 0.4 | 0.4 | 0.6 | 0.3 | 0.5 | 0.9 | 1.6 | 2.6 | 3.0 | 2.4 | 1.7 | 1.2 | 1.0 | 1.7 | 2.9 | 3.7 | 3.5 |
| Case 22 | 1.3 | 1.8 | 1.1 | 0.9 | 0.5 | 0.5 | 0.9 | 0.8 | 1.2 | 1.7 | 2.3 | 2.8 | 2.7 | 2.1 | 1.8 | 1.6 | 1.8 | 2.2 | 2.7 | 2.7 | 2.3 |
| Case 23 | 1.3 | 1.8 | 1.2 | 1.2 | 0.8 | 1.1 | 1.6 | 1.8 | 2.2 | 2.7 | 3.1 | 3.4 | 2.8 | 1.9 | 1.4 | 0.8 | 0.9 | 1.6 | 2.7 | 3.2 | 2.8 |
| Case 24 | 1.2 | 1.7 | 1.1 | 0.9 | 0.4 | 0.4 | 0.6 | 0.3 | 0.4 | 0.8 | 1.4 | 2.4 | 2.9 | 2.2 | 1.4 | 0.7 | 0.2 | 0.8 | 2.1 | 3.3 | 3.5 |
| Case 26 | 1.2 | 1.7 | 1.1 | 0.9 | 0.4 | 0.4 | 0.5 | 0.2 | 0.1 | 0.3 | 0.6 | 1.4 | 2.0 | 1.7 | 1.2 | 0.6 | 0.4 | 0.8 | 2.0 | 3.0 | 2.9 |
| Lower | | | | | | | | | | | | | | | | | | | | | |
| Case 15 | 1.4 | 1.9 | 1.2 | 1.1 | 0.4 | 0.4 | 0.5 | 0.1 | 0.0 | 0.2 | 0.4 | 0.9 | 0.9 | 0.5 | 0.5 | 0.5 | 0.9 | 1.8 | 2.9 | 3.7 | 3.5 |
| Case 22 | 1.4 | 1.9 | 1.2 | 1.1 | 0.4 | 0.4 | 0.5 | 0.1 | 0.0 | 0.2 | 0.5 | 1.1 | 1.3 | 1.1 | 1.3 | 1.4 | 1.9 | 2.6 | 3.0 | 3.1 | 2.5 |
| Case 23 | 1.4 | 2.0 | 1.3 | 1.2 | 0.8 | 1.0 | 1.4 | 1.3 | 1.5 | 1.7 | 1.7 | 1.7 | 1.1 | 0.3 | 0.0 | (0.2) | 0.1 | 0.9 | 2.0 | 3.0 | 3.4 |
| Case 24 | 1.4 | 1.9 | 1.2 | 1.1 | 0.4 | 0.4 | 0.5 | 0.1 | 0.0 | 0.2 | 0.4 | 0.9 | 0.9 | 0.5 | 0.4 | 0.3 | 0.7 | 1.4 | 2.4 | 3.0 | 2.6 |
| Case 26 | 1.4 | 1.9 | 1.2 | 1.0 | 0.4 | 0.3 | 0.5 | 0.1 | 0.0 | 0.2 | 0.4 | 0.9 | 0.9 | 0.4 | 0.1 | (0.2) | (0.1) | 0.4 | 1.6 | 2.7 | 2.6 |

Note: A negative value for annual net borrowing generally indicates that funds from operations (primarily net income and depreciation) exceed capital expenditures, and represents a year-over-year decline in the level of debt outstanding.

Figure 9-4 Cumulative Net Borrowing

| (1989$B) | 1989 | 1990 | 1991 | 1992 | 1993 | 1994 | 1995 | 1996 | 1997 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Upper | | | | | | | | | | | | | | | | | | | | | |
| Case 15 | 1.1 | 2.7 | 3.8 | 5.0 | 5.8 | 6.7 | 7.8 | 9.0 | 10.2 | 11.6 | 13.7 | 17.0 | 20.4 | 23.2 | 25.7 | 27.9 | 30.6 | 34.0 | 37.8 | 41.3 | 43.9 |
| Case 22 | 1.1 | 2.8 | 3.9 | 5.1 | 5.9 | 6.9 | 8.2 | 9.7 | 11.2 | 13.1 | 15.6 | 19.0 | 22.5 | 25.5 | 28.0 | 30.4 | 32.9 | 35.8 | 38.8 | 41.9 | 44.3 |
| Case 23 | 1.1 | 2.8 | 4.0 | 5.4 | 6.5 | 8.0 | 10.0 | 12.4 | 14.9 | 17.7 | 20.7 | 24.2 | 27.4 | 29.9 | 32.3 | 34.4 | 37.1 | 40.1 | 43.4 | 46.4 | 48.7 |
| Case 24 | 1.1 | 2.7 | 3.8 | 5.0 | 5.7 | 6.5 | 7.6 | 8.7 | 9.7 | 11.0 | 12.9 | 16.0 | 19.1 | 21.3 | 23.1 | 24.4 | 26.5 | 29.7 | 33.4 | 37.2 | 40.2 |
| Case 26 | 1.1 | 2.7 | 3.8 | 4.9 | 5.6 | 6.4 | 7.3 | 8.0 | 8.5 | 9.0 | 10.0 | 12.1 | 14.7 | 16.6 | 18.0 | 18.7 | 19.9 | 22.2 | 25.4 | 28.5 | 31.0 |
| Median | | | | | | | | | | | | | | | | | | | | | |
| Case 15 | 1.2 | 3.0 | 4.1 | 5.0 | 5.5 | 5.9 | 6.5 | 6.8 | 7.3 | 8.2 | 9.8 | 12.4 | 15.3 | 17.7 | 19.4 | 20.6 | 21.6 | 23.3 | 26.2 | 29.9 | 33.4 |
| Case 22 | 1.3 | 3.0 | 4.1 | 5.1 | 5.5 | 6.1 | 7.0 | 7.8 | 9.0 | 10.6 | 12.9 | 15.8 | 18.4 | 20.5 | 22.3 | 23.9 | 25.7 | 27.9 | 30.6 | 33.3 | 35.6 |
| Case 23 | 1.3 | 3.1 | 4.3 | 5.4 | 6.3 | 7.4 | 9.0 | 10.8 | 13.0 | 15.6 | 18.7 | 22.1 | 24.9 | 26.7 | 28.1 | 28.9 | 29.8 | 31.4 | 34.0 | 37.2 | 40.0 |
| Case 24 | 1.2 | 3.0 | 4.1 | 5.0 | 5.5 | 5.9 | 6.5 | 6.7 | 7.2 | 8.0 | 9.4 | 11.8 | 14.7 | 16.9 | 18.3 | 18.9 | 19.2 | 20.0 | 22.1 | 25.4 | 28.9 |
| Case 26 | 1.2 | 3.0 | 4.0 | 4.9 | 5.3 | 5.7 | 6.3 | 6.4 | 6.6 | 6.8 | 7.5 | 8.8 | 10.8 | 12.6 | 13.8 | 14.4 | 14.9 | 15.7 | 17.7 | 20.7 | 23.6 |
| Lower | | | | | | | | | | | | | | | | | | | | | |
| Case 15 | 1.4 | 3.3 | 4.5 | 5.6 | 6.0 | 6.4 | 6.9 | 7.0 | 7.0 | 7.2 | 7.6 | 8.5 | 9.4 | 10.0 | 10.5 | 11.0 | 11.9 | 13.7 | 16.6 | 20.3 | 23.8 |
| Case 22 | 1.4 | 3.3 | 4.6 | 5.6 | 6.1 | 6.4 | 6.9 | 7.0 | 7.0 | 7.2 | 7.7 | 8.8 | 10.0 | 11.1 | 12.4 | 13.8 | 15.7 | 18.3 | 21.3 | 24.4 | 26.8 |
| Case 23 | 1.4 | 3.4 | 4.7 | 5.9 | 6.7 | 7.6 | 9.0 | 10.3 | 11.8 | 13.5 | 15.1 | 16.9 | 18.0 | 18.3 | 18.2 | 18.0 | 18.1 | 19.1 | 21.1 | 24.1 | 27.5 |
| Case 24 | 1.4 | 3.3 | 4.5 | 5.6 | 6.0 | 6.4 | 6.9 | 7.0 | 7.0 | 7.2 | 7.6 | 8.5 | 9.4 | 9.9 | 10.3 | 10.6 | 11.3 | 12.7 | 15.1 | 18.0 | 20.6 |
| Case 26 | 1.4 | 3.3 | 4.5 | 5.5 | 5.9 | 6.2 | 6.7 | 6.8 | 6.8 | 6.9 | 7.4 | 8.2 | 9.1 | 9.5 | 9.6 | 9.3 | 9.2 | 9.7 | 11.2 | 13.9 | 16.5 |

Borrowing levels are expected to peak around the year 2000 and again around 2008, corresponding to the need for major new generating facilities. Annual real net borrowing levels for the various cases are generally within ±$1.5 billion of those for Case 15.

Real cumulative net borrowing levels over the twenty-year planning period are provided in Figure 9-4. Cumulative borrowings are highest for those Cases having the most nuclear generation, and lowest for those Cases using the most fossil generation, as the capital cost of nuclear generation is higher than that for fossil.

The differences in cumulative real net borrowings between the various Cases and Case 15 over the period to 2009 are:

| | Upper | | Median | | Lower | |
|---|---|---|---|---|---|---|
| | (1989$B) | (%) | 1989$B) | (%) | (1989$B) | (%) |
| Case 22 | 0.4 | 1 | 2.2 | 7 | 3.0 | 13 |
| Case 23 | 4.8 | 11 | 6.6 | 20 | 3.7 | 16 |
| Case 24 | (3.7) | (8) | (4.5) | (13) | (3.2) | (13) |
| Case 26 | (12.9) | (29) | (9.8) | (29) | (7.3) | (31) |

Real annual gross borrowing levels (net borrowing plus debt retirement) are shown in Figure 9-5. While the various Cases provide a wide range of borrowing requirements, gross annual borrowings have peak requirements that range up to twice current levels (ie, $6 billion vs $3 billion). In years when borrowing requirements are high, Ontario Hydro may have to obtain funds at interest rates closer to the upper range considered in the cost confidence analysis, and may have to accept foreign exchange risk.

## 9.3 FINANCIAL PERFORMANCE

Figure 15-54 in the Plan report illustrates Ontario Hydro's projected debt ratios for the various Cases under upper, median and lower forecasts. The debt ratio measures the extent to which assets are financed by debt, and is defined as:

$$\text{Debt ratio} = \frac{\text{Debt}}{\text{Debt + Equity}}$$

The values used to graph the debt ratios are presented in Figure 9-6.

Figure 9-5 Annual Gross Borrowing

| (1989$B) | 1989 | 1990 | 1991 | 1992 | 1993 | 1994 | 1995 | 1996 | 1997 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Upper | | | | | | | | | | | | | | | | | | | | | |
| Case 15 | 2.9 | 3.8 | 2.7 | 2.9 | 2.9 | 2.9 | 2.8 | 2.9 | 2.5 | 3.1 | 3.9 | 5.4 | 5.5 | 4.5 | 4.3 | 4.5 | 5.3 | 5.9 | 6.0 | 6.2 | 5.5 |
| Case 22 | 2.9 | 3.8 | 2.7 | 2.9 | 2.9 | 3.0 | 3.0 | 3.2 | 2.8 | 3.6 | 4.4 | 5.6 | 5.6 | 4.9 | 4.5 | 4.8 | 5.2 | 5.5 | 5.5 | 6.0 | 5.4 |
| Case 23 | 2.9 | 3.8 | 2.8 | 3.1 | 3.2 | 3.5 | 3.7 | 4.2 | 3.9 | 4.6 | 5.0 | 5.9 | 5.7 | 4.8 | 4.7 | 4.8 | 5.6 | 5.8 | 5.9 | 6.1 | 5.6 |
| Case 24 | 2.9 | 3.8 | 2.7 | 2.9 | 2.9 | 2.8 | 2.7 | 2.8 | 2.3 | 3.0 | 3.7 | 5.2 | 5.2 | 4.0 | 3.5 | 3.5 | 4.6 | 5.6 | 5.8 | 6.1 | 5.6 |
| Case 26 | 2.9 | 3.8 | 2.6 | 2.9 | 2.8 | 2.7 | 2.6 | 2.5 | 1.8 | 2.2 | 2.7 | 4.2 | 4.5 | 3.5 | 2.9 | 2.6 | 3.3 | 4.4 | 5.0 | 5.2 | 4.5 |
| Median | | | | | | | | | | | | | | | | | | | | | |
| Case 15 | 3.0 | 3.9 | 2.7 | 2.7 | 2.6 | 2.5 | 2.3 | 2.1 | 1.7 | 2.5 | 3.3 | 4.6 | 4.8 | 3.8 | 3.3 | 3.1 | 3.2 | 3.7 | 4.8 | 5.9 | 5.9 |
| Case 22 | 3.0 | 3.9 | 2.7 | 2.7 | 2.6 | 2.6 | 2.6 | 2.6 | 2.4 | 3.3 | 4.0 | 5.0 | 4.7 | 3.8 | 3.5 | 3.8 | 4.2 | 4.3 | 4.7 | 5.2 | 5.1 |
| Case 23 | 3.0 | 4.0 | 2.8 | 2.9 | 3.0 | 3.1 | 3.4 | 3.6 | 3.5 | 4.4 | 5.0 | 5.7 | 5.1 | 3.9 | 3.6 | 3.4 | 3.7 | 4.1 | 5.0 | 5.9 | 5.6 |
| Case 24 | 3.0 | 3.9 | 2.7 | 2.7 | 2.6 | 2.5 | 2.3 | 2.0 | 1.7 | 2.4 | 3.1 | 4.4 | 4.7 | 3.7 | 2.9 | 2.6 | 2.4 | 2.8 | 3.9 | 5.4 | 5.7 |
| Case 26 | 3.0 | 3.9 | 2.7 | 2.6 | 2.5 | 2.4 | 2.2 | 1.9 | 1.3 | 1.9 | 2.3 | 3.4 | 3.8 | 3.1 | 2.6 | 2.3 | 2.3 | 2.5 | 3.6 | 4.8 | 4.9 |
| Lower | | | | | | | | | | | | | | | | | | | | | |
| Case 15 | 3.1 | 4.1 | 2.8 | 2.8 | 2.6 | 2.4 | 2.3 | 1.9 | 1.2 | 1.8 | 2.2 | 3.0 | 2.7 | 1.9 | 1.8 | 2.1 | 2.6 | 3.2 | 4.1 | 5.3 | 5.3 |
| Case 22 | 3.1 | 4.1 | 2.8 | 2.8 | 2.6 | 2.4 | 2.3 | 1.9 | 1.2 | 1.8 | 2.2 | 3.1 | 3.1 | 2.5 | 2.6 | 3.1 | 3.7 | 4.1 | 4.4 | 4.9 | 4.6 |
| Case 23 | 3.1 | 4.2 | 2.9 | 3.0 | 2.9 | 3.0 | 3.2 | 3.1 | 2.8 | 3.4 | 3.6 | 4.1 | 3.3 | 2.1 | 1.8 | 2.0 | 2.3 | 2.8 | 3.6 | 5.0 | 5.5 |
| Case 24 | 3.1 | 4.1 | 2.8 | 2.8 | 2.6 | 2.4 | 2.3 | 1.9 | 1.2 | 1.8 | 2.1 | 3.0 | 2.7 | 1.9 | 1.7 | 1.9 | 2.4 | 2.8 | 3.5 | 4.5 | 4.4 |
| Case 26 | 3.1 | 4.1 | 2.8 | 2.7 | 2.5 | 2.4 | 2.2 | 1.9 | 1.2 | 1.8 | 2.1 | 2.9 | 2.7 | 1.7 | 1.4 | 1.4 | 1.6 | 1.8 | 2.7 | 4.1 | 4.2 |

Figure 9-6 Debt Ratio

| | 1989 | 1990 | 1991 | 1992 | 1993 | 1994 | 1995 | 1996 | 1997 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Upper | | | | | | | | | | | | | | | | | | | | | |
| Case 15 | 0.81 | 0.81 | 0.80 | 0.80 | 0.79 | 0.79 | 0.78 | 0.78 | 0.78 | 0.78 | 0.79 | 0.79 | 0.80 | 0.80 | 0.80 | 0.80 | 0.81 | 0.81 | 0.81 | 0.81 | 0.81 |
| Case 22 | 0.81 | 0.81 | 0.80 | 0.80 | 0.79 | 0.79 | 0.79 | 0.79 | 0.79 | 0.79 | 0.79 | 0.80 | 0.81 | 0.81 | 0.81 | 0.81 | 0.81 | 0.81 | 0.81 | 0.81 | 0.81 |
| Case 23 | 0.81 | 0.81 | 0.80 | 0.80 | 0.80 | 0.79 | 0.80 | 0.80 | 0.80 | 0.81 | 0.81 | 0.81 | 0.81 | 0.81 | 0.81 | 0.81 | 0.81 | 0.81 | 0.81 | 0.81 | 0.81 |
| Case 24 | 0.81 | 0.81 | 0.80 | 0.80 | 0.79 | 0.78 | 0.78 | 0.78 | 0.78 | 0.78 | 0.78 | 0.79 | 0.80 | 0.80 | 0.80 | 0.80 | 0.80 | 0.80 | 0.81 | 0.81 | 0.81 |
| Case 26 | 0.81 | 0.81 | 0.80 | 0.80 | 0.79 | 0.78 | 0.78 | 0.78 | 0.77 | 0.77 | 0.76 | 0.77 | 0.78 | 0.78 | 0.78 | 0.78 | 0.78 | 0.78 | 0.79 | 0.80 | 0.80 |
| Median | | | | | | | | | | | | | | | | | | | | | |
| Case 15 | 0.82 | 0.81 | 0.81 | 0.81 | 0.80 | 0.79 | 0.79 | 0.78 | 0.77 | 0.77 | 0.77 | 0.78 | 0.79 | 0.79 | 0.79 | 0.79 | 0.79 | 0.79 | 0.80 | 0.80 | 0.81 |
| Case 22 | 0.82 | 0.81 | 0.81 | 0.81 | 0.80 | 0.79 | 0.79 | 0.79 | 0.78 | 0.79 | 0.79 | 0.80 | 0.80 | 0.80 | 0.80 | 0.80 | 0.80 | 0.80 | 0.80 | 0.81 | 0.81 |
| Case 23 | 0.82 | 0.81 | 0.81 | 0.81 | 0.81 | 0.80 | 0.80 | 0.80 | 0.80 | 0.81 | 0.81 | 0.81 | 0.81 | 0.81 | 0.81 | 0.80 | 0.80 | 0.80 | 0.80 | 0.80 | 0.80 |
| Case 24 | 0.82 | 0.81 | 0.81 | 0.81 | 0.80 | 0.79 | 0.79 | 0.78 | 0.77 | 0.77 | 0.77 | 0.78 | 0.79 | 0.79 | 0.79 | 0.79 | 0.78 | 0.78 | 0.78 | 0.79 | 0.80 |
| Case 26 | 0.82 | 0.81 | 0.81 | 0.81 | 0.80 | 0.79 | 0.79 | 0.78 | 0.77 | 0.76 | 0.76 | 0.76 | 0.77 | 0.77 | 0.77 | 0.77 | 0.76 | 0.76 | 0.77 | 0.78 | 0.79 |
| Lower | | | | | | | | | | | | | | | | | | | | | |
| Case 15 | 0.82 | 0.82 | 0.82 | 0.82 | 0.82 | 0.81 | 0.80 | 0.79 | 0.78 | 0.78 | 0.77 | 0.77 | 0.77 | 0.76 | 0.76 | 0.76 | 0.75 | 0.76 | 0.77 | 0.78 | 0.79 |
| Case 22 | 0.82 | 0.82 | 0.82 | 0.82 | 0.82 | 0.81 | 0.80 | 0.79 | 0.78 | 0.78 | 0.77 | 0.77 | 0.77 | 0.77 | 0.77 | 0.77 | 0.78 | 0.79 | 0.79 | 0.80 | 0.80 |
| Case 23 | 0.82 | 0.82 | 0.82 | 0.83 | 0.82 | 0.82 | 0.81 | 0.81 | 0.81 | 0.81 | 0.81 | 0.81 | 0.81 | 0.80 | 0.79 | 0.78 | 0.77 | 0.77 | 0.77 | 0.78 | 0.79 |
| Case 24 | 0.82 | 0.82 | 0.82 | 0.82 | 0.82 | 0.81 | 0.80 | 0.79 | 0.78 | 0.78 | 0.77 | 0.77 | 0.77 | 0.76 | 0.76 | 0.75 | 0.75 | 0.75 | 0.76 | 0.78 | 0.78 |
| Case 26 | 0.82 | 0.82 | 0.82 | 0.82 | 0.82 | 0.81 | 0.80 | 0.79 | 0.78 | 0.78 | 0.77 | 0.77 | 0.77 | 0.76 | 0.75 | 0.74 | 0.73 | 0.73 | 0.74 | 0.75 | 0.76 |

The debt ratios in Figure 9-6 are based on Hydro's existing net income policy, which is currently under review. Under the existing policy, the target level of net income is based on a split interest coverage formula, and in a given year is equal to 5% of interest charged to operations (ie, net interest), plus 50% of interest capitalized. For the purposes of long-term planning, net income is established as the greater of the above interest coverage target or the statutory debt retirement (SDR) appropriation. (The SDR appropriation, as defined under the provisions of the Power Corporation Act, is the amount required to accumulate, on a sinking fund basis over 40 years, with interest at 4% per year, a sum sufficient to retire an amount of debt equal to the value of fixed assets in service.)

In general, all of Ontario Hydro's financial performance indicators do not vary significantly between the Cases. Hydro's net income policy was designed to maintain satisfactory financial performance under different planning assumptions. For all the Cases, the debt ratio is expected to remain in the 0.75 to 0.81 range throughout most of the next 20 years, rising slightly whenever major new generating stations near completion. A comparison of debt ratios between Cases generally reflects similar trends to those of borrowing levels (ie, Cases having higher borrowing levels also have higher debt ratios).

## 9.4 REVIEW

The projected outlooks for electricity prices over the next twenty years for Cases 22, 24 and 26 are not significantly different from that for Case 15. The outlook is considerably less favourable under Case 23.

Borrowing levels vary considerably between Cases, with cumulative borrowing being highest for those Cases having the most nuclear generation. Ontario Hydro's debt ratio and other financial performance indicators remain at satisfactory levels under all the Cases.