# MODEL DOCUMENTATION
# LOAD AND DEMAND SIDE MANAGEMENT SUBMODULE

*Prepared for Energy Information Administration*
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# VOLUME I

# MODEL DESCRIPTION

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# 1. INTRODUCTION

## 1.1 PURPOSE OF THE REPORT

This report documents the Load and Demand Side Management (LDSM) submodule of the National Energy Modelling System (NEMS). The NEMS is designed as an integrated model of U.S. energy production, conversion, supply, pricing, and consumption. The LDSM is a submodule of the Electricity Market Module (EMM) of the NEMS. The EMM receives electricity demand from the NEMS demand modules, fuel prices from the NEMS fuel supply modules, expectations from the NEMS system module, and macroeconomic parameters from the NEMS macroeconomic module. Using this data, the EMM estimates the actions taken by electric utilities and nonutilities, to meet demand in the most economic manner within operational and environmental constraints.

The LDSM submodule of the EMM works in conjunction with the NEMS demand modules, and the capacity planning and dispatch modules of the EMM. This report is intended as a reference document of the LDSM submodule, for model analysts, users, and the public. The Energy Information Agency is legally obliged under Public Law 94-385, section 57.b.2. to provide adequate documentation in support of its models.

## 1.2 MODEL SUMMARY

The EMM comprises four submodules, namely, electricity capacity planning (ECP), electricity fuel dispatch (EFD), electricity finance and pricing (EFP), and load and demand side management (LDSM) submodules. As stated earlier, the LDSM submodule is designed to operate with the NEMS demand modules and the capacity and dispatch modules of the EMM. The purpose of the LDSM submodule is to explicitly incorporate utility decision-making with regards to utility-sponsored DSM into the NEMS modeling framework. Furthermore, the LDSM performs the important function of translating total electricity consumption forecasts into system load shapes needed for capacity planning.

Broadly speaking, the LDSM submodule has been designed to perform four functions:

- Translate total electricity consumption forecasts into system load shapes,
- Develop utility DSM programs for potential inclusion in future utility capacity expansion plans
- Translate census division demand data into NERC region data, and vice versa.
- Represent the impacts of intermittent technologies on load shapes.

*Alan's section 1.3*

## 1.4 MODEL ARCHIVAL CITATION AND MODEL CONTACT

- **Model Name:** Electricity Market Module (EMM)
- **Submodule Name:** Load and Demand Side Management (LDSM) submodule
- **Office:** Energy Information Administration
- **Division:** Energy Supply and Conversion Division
- **Branch:** Nuclear and Electricity Analysis Branch
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## 1.5 REPORT ORGANIZATION

The LDSM Model Documentation Report is organized in two volumes. The first volume contains a description of the submodule, while the second volume contains the actual code, as well as a comprehensive list of the variables used in the code. Volume I is organized into the following sections:

**Model Purpose**

This section describes the objective of the LDSM submodule, the level of aggregation of the data used in the model, as well as its relationship with other modules and submodules in the NEMS framework.

**Model Overview and Rationale**

This section lays down the philosophical and theoretical basis for the model, as well as outlining the fundamental assumptions in the LDSM. Alternative approaches and other models tackling the same issue of demand side management are also discussed, and the reasons for the present structure of the model are pointed out.

**Model Structure**

This section describes in greater detail, the solution algorithm of the submodule. It presents a flowchart for the sequence of operations undertaken by the LDSM, describes the database of options and end-uses developed inside the LDSM, and also lists the mathematical relationships that govern the different steps inside the LDSM.

**Appendix**

The appendices are in three distinct part, named appendices A, B, and C. The first part, titled Appendix A, contains the tables listing the set of DSM options and programs in the residential, commercial, and industrial sectors. Tables A1, A2 and A3 list the DSM programs and options in the residential and commercial sectors. These tables reflect the actual options being offered in this version of the LDSM submodule. Table A4 contains a plan of the options and programs for the industrial sector. The industrial options are not included in this version of the LDSM.

Appendix B contains the model abstract, as well as details of the input data. The computations and algorithms shown in the appendix, reflect the actual variable names and processes used in the model code. The relevant subroutines in the LDSM code are cited in the appropriate sections of Appendix B. Figure B-1 shows the communication of the LDSM with external files. Figure B-2 contains a detailed chart showing the information flows within the LDSM, as well as communication with other modules of the NEMS. Figures B-3 through B-9 contain flowcharts of different subroutines within the LDSM. Appendix C contains detailed specifications of variables used within the LDSM code.

# 2. MODEL PURPOSE

## 2.1 MODEL OBJECTIVES

The LDSM submodule is designed to be a fully integrated part of the NEMS framework. The submodule models the impact of DSM activities in terms of changes in load shapes. To do this, the LDSM submodule has a database of end-use load shapes for each of the thirteen EMM regions, being modelled in the NEMS framework. The LDSM also uses a technologies database developed jointly with the demand modules. Individual DSM options then match a base technology ("FROM" technology) to a more efficient DSM technology ("TO" technology). The energy changes and the resulting changes in load shapes (delta load shapes) are computed for each option. These constitute the unit level impact of DSM options. To compute the system level impacts, the DSM options must first be penetrated over time, and then aggregated to a form that can be competed against supply-side options. Details of these processes are given in the sections that follow.

The LDSM submodule uses stock and demand information from the demand modules at a Census Division level, and translates it into EMM region level data. The LDSM has a developed database of DSM options in the residential and commercial sectors. This information is based on a survey of existing utility practices.[1]

Using this information, the LDSM models potential changes in stock and energy consumption patterns, as a result of utility sponsored rebates, and informational DSM programs. The effect of these DSM programs is modeled in terms of changes in the load duration curves. Before these potential changes can be included as final stock changes, however, they must be selected by the ECP module, after competing against supply-side options. Thus the LDSM module pre-screens DSM options that are then sent to the ECP for final evaluation. The DSM options that are finally chosen, are then translated into changes in stock. These stock changes are then passed on to the demand modules for computation of the new stock figures.

In conclusion, the LDSM builds system load shapes from demand module data, and models utility sponsored DSM programs. The LDSM submodule has already been integrated with the EFP module, and will be fully integrated into the NEMS framework, as soon as the ECP, EFD and demand modules are ready for integration. Once this step is completed, the ECP will be able to compete DSM measures against supply side options, in order to meet the demand for electricity.

### 2.1.1 Level of Aggregation

In the LDSM, electricity generation is represented for 13 North American Electric Reliability Council (NERC) Regions and Subregions, called EMM regions. Of the 9 NERC Regions, six are represented in their entirety: ECAR, MAAC, MAIN, MAPP, SPP and ERCOT. In the Northeast Power Coordination Council (NPCC), the New England states constitute one region and New York represents another (NY). In the Southeastern Electric Reliability Council (SERC), Florida is separated from the rest of the region. The Rocky Mountain Power Area (RMP) and Arizona-New Mexico Power Area (AZN) Subcouncils have been combined into one region. The Northwest Power Pool Area (NWP) and California-Southern Nevada Power Area (CNV) form the other two regions.

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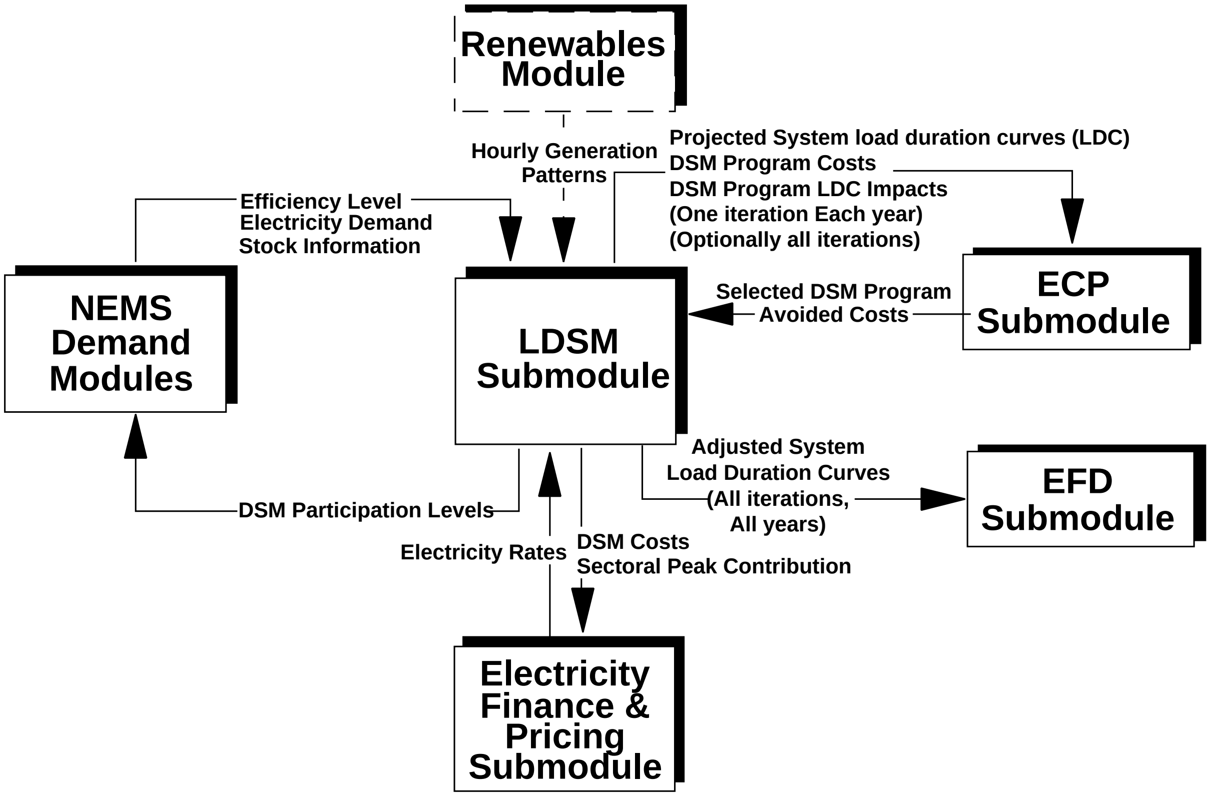
[1] The sources surveyed include data from the Bonneville Power Administration, Lawrence Berkeley Laboratories, ICF Analysis for EPA, EGUMS model documentation, and IRP reports from state commissions.

Using NERC Regions and Subregions allows for a better representation of electricity markets. Load data for electric utilities is collected by the NERC and only provided at the regional level. These data are not easily separable into census divisions because many utilities operate across state boundaries. Thus, the present structure makes comparisons of EIA and NERC forecasts possible at a regional level instead of just the national level. Only the New England Census Division corresponds exactly to a NERC Region.

## 2.2 RELATIONSHIP TO OTHER MODULES

The LDSM submodule interacts with the NEMS demand modules, and the ECP, and EFP submodules within the EMM. Hence, the LDSM is directly linked with several major modules in the NEMS modeling framework. Figure 1

**Figure 1** LDSM Linkages With Other Modules




LDSM Linkages With Other Modules

Note: Only LSDM links are shown

**Table 1. Intra-Module Linkages**

| EMM Submodule | Inputs to LDSM from Submodule | Outputs from LDSM to Submodule |
|---|---|---|
| **ECP** | • Selected DSM Programs<br>• Fraction of implementation of the selected programs<br>• Avoided Costs | • Projected System Load Duration Curves<br>• DSM Programs<br>- Delta Load Impacts<br>- DSM Costs (Equipment and Program)<br>- Maximum Possible DSM Penetration |
| **EFD** | | • Yearly Adjusted Regional System Load Duration Curves |
| **EFP** | • Electricity Rates | • Utility DSM Investment |

displays these linkages. Only the LDSM links are shown in the figure.

There are two central sets of linkages associated with the LDSM module:

- Inter-Module, i.e., with the Demand and Renewable Modules, and
- Intra-Module, i.e., with the other submodules of the EMM.

Although the LDSM works independently of these other modules, the LDSM shares common data and provides necessary data for these modules.

### 2.2.1 Intra-Module Data Linkages

The LDSM submodule is designed to be fully linked with the other EMM submodules. The LDSM submodule performs four integrating functions. The first integrating and linkage function is to supply system load duration curves to the Electricity Capacity Planning (ECP) and the Electricity Fuel Dispatch (EFD) submodules. The second key linkage function is to develop economic DSM programs (costs and load shape impacts) for consideration by the ECP submodule and to process the DSM options that are selected by the ECP. The third key linkage is the passage of avoided cost values from the ECP and electricity rates from the Electricity Finance and Pricing (EFP) to the LDSM submodule. The LDSM in turn, passes DSM program costs, and peak contribution information for each end-use sector, to the EFP module that are used to modify the financial statements and develop cost allocation algorithms. The fourth linkage function is to develop adjusted system load duration curves that account for DSM and intermittent technologies for the EFD.

Current LDSM code is equipped with the designated INCLUDE files which contain common blocks for accomplishing the aforesaid linkages. However, the actual integration of the submodule with other NEMS modules has not been completed as yet.

Table 1 lists the major linkages between the LDSM and the other EMM submodules. Table 1 and Figure 1 show that the LDSM interacts with the other EMM submodules before and after they are run. The LDSM module has, in effect, two parts. One part, which interacts with the ECP submodule of the EMM module, is run whenever the ECP submodule is run, i.e., once every year. The second part of the LDSM submodule is the part which interacts with the EFD and EFP submodules of the EMM module.

This part is run with every iteration of the NEMS.  The following subsections discuss intra-module linkages in greater detail.

#### 2.2.1.1 Linkages with the Electricity Capacity Planning Submodule

The LDSM submodule has numerous linkages with the ECP submodule.  The following discussion is divided into the outputs and inputs to the LDSM submodule.

Outputs

The outputs from the LDSM submodule to the ECP include:

- Projected Regional system load duration curves for each year in the ECP planning horizon and
- Potential DSM programs, in aggregated form

In each yearly iteration of NEMS, the LDSM obtains projections of yearly demand data from the demand modules.  The Demand modules produce electric demand estimates on a Census Division level.  The LDSM converts these data from a Census Division level to EMM regions using the "fixed shares" method. In this approach, the percentage of each census division's load allocated to an EMM region remains fixed over time, for each of the sectors in the demand modules.  (In other words, the Census division to EMM region mapping matrices do not change over time).  Utilizing these forecasts, the LDSM develops system load shapes for each of the 13 EMM regions.

These system load shapes are then discretized to obtain load duration curves (LDCs), that are input to the ECP submodule.  The LDSM allows for vast flexibility in the definition of the LDCs.  Both the number of segments and the assignment of hours to segments are inputs to the model.  Each LDC segment is discrete, and is associated with a time-of-day and seasonal definition.  The ECP submodule scales these load shapes for future years based on projected future electricity demand.  The shape of these LDCs for future years is either fixed or variable, depending on the foresight assumptions.  Under perfect foresight, the system load shape and LDC change for each future year based on end-use demand patterns.  Conversely, under both the myopic and adaptive expectations scenarios, the system load shape and LDC are scaled, based on total electricity demand, but keep the same pattern for future years.

In each yearly iteration of NEMS, the LDSM also develops aggregate DSM programs, for each EMM region for possible selection by the ECP submodule.  Examples of aggregate DSM programs that might be passed to the ECP submodule for examination include space heating, space cooling, lighting, and load management programs (check appendix A for details).  The DSM programs that are output to the ECP by the LDSM are aggregate (i.e., multiple DSM options) programs that have already passed the Total Resource Cost test.  The California Total Resource Cost test as used by the California Public Utility Commission (CPUC) in 1987 is used by the LDSM.  This test compares the total customer direct costs of an option to the utility benefits of reduced demand and energy.  More details on the test are given in later sections.  The ECP selects the least-cost mix of resource options based on data on DSM, supply and renewable options.  In effect, the DSM programs become "capacity" resources which are characterized by associated implementation and operating costs and which can be used to satisfy a portion of electricity demand in each load segment.

The specific DSM program data output to the current version of the ECP submodule are the following:

- **Potential DSM Impacts on LDCs**. These load duration curve impacts incorporate market penetration assumptions based on rebate levels, payback acceptance curves, and linear growth from current to maximum penetration levels.

- **DSM Costs**. Total utility DSM costs in present value terms, for each DSM program.[2]

Inputs

The LDSM receives three inputs from the ECP submodule:

- **Regional Avoided Costs**, and
- **Selected DSM Programs** and
- **The Fraction** of the selected DSM programs that the ECP Submodule decides to implement in the next year, expressed as a value between 0 and 1.

These inputs are described below.

Key inputs to the LDSM are forecasts of regional avoided costs derived by the ECP submodule. These avoided costs, are based on the marginal cost of producing more electricity, in case DSM measures are not promoted, and electricity consumption increases as a result. In regions where there is already surplus built capacity, the marginal costs are only the variable costs, mostly fuel cost. However, in regions where new capacity needs to be built in order to meet growth in consumption, the avoided costs include the cost of building new capacity. Hence, avoided costs in those regions are larger. It is, therefore, more beneficial for utilities in regions with high avoided costs to promote DSM measures, than it is for utilities in regions with lower avoided costs. Avoided costs are thus used to screen DSM options. Avoided cost projections are needed for each future year and LDC segment.

After the ECP submodule chooses economic DSM programs, and the level of implementation expressed as a function of the maximum possible penetration of the market, the LDSM processes the selected programs prior to passing participation levels to the NEMS demand modules, and utility DSM costs to the EFP submodule. The key function that the LDSM conducts after the ECP module is executed is to disaggregate the aggregated DSM programs into the more detailed DSM options. Tables A1 through A3, in the appendix A, give some idea of the aggregated DSM programs and the disaggregated DSM options that are likely to be used in the LDSM submodule. The final list of aggregated options will be developed in keeping with the data handling capacity of the ECP submodule.

#### 2.2.1.2 Linkages with the Electricity Fuel Dispatch Submodule

During each iteration of the NEMS model, the LDSM outputs regional LDCs to the EFD submodule. The curves used in the current version of the model, reflect demand impacts associated with conservation based DSM options only. These are incorporated into the electricity demand estimates created by the NEMS demand modules. Future improvements in the model will adjust these LDCs for load management DSM options (e.g., A/C load control, cool storage etc.), and intermittent technology load shape impacts. Once completed, these changes will reflect the choices made by the ECP optimization model. In the present

[2] These present value annual costs are the sum of DSM investment costs (i.e., initial program costs) and annual utility program costs, such as utility rebates and incentives.

version, however, load management DSM options cannot be modelled directly in the NEMS demand modules.

In future versions of the model, the LDSM will supply the ECP module with the delta LDCs (i.e., curves that show how much load will be generated in each block of the system LDC) for each of the intermittent technologies that will compete within the ECP submodule. The availability and pattern of the load shapes for intermittent renewable technologies, will be provided by the NEMS Renewables module. The LDSM submodule will adjust the LDCs supplied for the EFD module, to reflect the ECP model's choices concerning the utilization of intermittent renewable technologies.

#### 2.2.1.3 Linkages with the Electricity Finance and Pricing Submodule

The final intra-module LDSM linkage is with the EFP submodule. The EFP submodule develops estimates of utility revenue requirements, financing needs, and electricity rates based on capacity expansion decisions, fuel prices, and electricity demand. The LDSM provides outputs to the EFP submodule, and requires inputs from the EFP.

<u>Outputs</u>

After DSM programs are chosen by the ECP submodule, this information is passed on to the LDSM submodule. The LDSM interprets this information, and calculates the market impacts of these DSM options. This information is expressed as a fraction of the current market for different technologies, and is passed on to the demand modules by the LDSM. Based on current estimates of the market sizes, the demand modules estimate the new mix of technologies in the market, expressed in absolute numbers. These estimates are then returned to the LDSM.

Using this data, the LDSM develops utility costs (e.g., incentives, administration costs) incurred in each NERC region and demand sector. These program costs are output to the EFP submodule to incorporate into utility expenses and capital expenditures.

<u>Inputs</u>

In order to develop estimates of rebates, the LDSM requires forecasts of customer electricity rates. These regional electricity rates are used to calculate the payback associated with each DSM option. Rebates will be set in LDSM to achieve a 2-year customer payback. This 2-year payback criterion is based on standard utility practice, along with information derived from a survey of utility DSM programs. The survey was conducted by ICF Resources as a part of this project. Its primary function was to get a picture of actual DSM programs offered by utilities, as well as the level of costs incurred and incentives offered. The survey revealed that a 2-year payback criteria is used by many utilities in their DSM planning.

<u>Linkage Example</u>

Let us assume, that in the New England EMM region the LDSM submodule is gauging the effectiveness of a DSM program offering incentives on the purchase of more efficient refrigerators. Assume further, that the program is in the residential sector, and is aimed at existing households only. The LDSM has the incremental cost of the more efficient refrigerator. The LDSM needs the electricity rates in the EMM region, in order to compute what would constitute a 2-year payback for the customer. Based on the amount of savings needed for a 2-year payback, and the incremental costs of the more efficient refrigerator, the LDSM will be able to compute the level of rebate that the utility can offer for that DSM option.

Accordingly, the LDSM makes changes in the system load shapes and the LDCs, to reflect the reduction in refrigerator load as a result of the program, provided that the program is selected by the ECP submodule. Once these changes have been made, the costs incurred in the program must be recovered in the region's revenue requirement. Thus the costs of the program to the utilities of that region must be passed on to the EFP submodule, which then includes them as expenses in the appropriate category of the revenue requirements of the region.

### 2.2.2 Inter-Module Data Linkages

The LDSM Submodule already has linkages with the NEMS demand modules. Soon it will also be linked with the NEMS Renewable Module. The LDSM has been designed to transfer and adjust electricity demand forecasts prior to the capacity expansion and dispatch decisions, within the EMM. The following paragraphs give more details about these functions.

There are three linkages of the LDSM with the NEMS demand modules. First, the LDSM transforms Census Division electricity demand projections from the demand submodules into EMM regional demand estimates. These estimates are then translated into system load shapes for use by the Electricity Capacity Planning (ECP) and Electricity Fuel Dispatch (EFD) submodules of the EMM module. Second, the demand submodules transfer and share information on technology characteristics (electricity usage and costs) and market size with the LDSM submodule. As electric technologies and usage patterns change over time, the demand modules transfer data conforming to these changes, to the LDSM submodule. The LDSM is designed to directly access the technology characteristics database for each demand module. Third, after the EMM submodules choose economic DSM programs, the LDSM submodule translates program information into participation levels for the NEMS demand modules. The demand models transfer and share information about technology characteristics and market size with the LDSM. The LDSM accesses a technology characteristics database in each demand module.

The linkage between the LDSM submodule and the NEMS Renewable Module is not complete. Once completed, the LDSM submodule will translate the daily and seasonal pattern of generation associated with non-dispatchable, intermittent renewable technologies into the generation curve representations (GCR) compatible with the ECP LDCs. These will reflect the maximum availability of the technologies as prescribed by the Renewables Model.

Table 2 lists the linkages between the LDSM and the other modules. Examination of this Table and Figure 1 shows that the LDSM interacts closely with these other modules during NEMS model runs. The following discussion highlights these inter-module linkages in greater detail.

**Table 2** Inter-Module Linkages

| NEMS Module | Inputs to LDSM from Module | Outputs from LDSM to Module |
|---|---|---|
| **Demand Modules (Residential, Commercial, Industrial, Transportation)** | • UECs and current stock data, by equipment type<br>• Equipment investment and operating costs<br>● Electric demand by region and end-use | • Participation Shares by Equipment and Efficiency Levels |
| **Renewable** | • Hourly and Seasonal Generation patterns, assuming maximum possible utilization of renewable technologies | |

### 2.2.2.1 Linkages with the NEMS Demand Modules

The LDSM Submodule is ready to be fully linked with the demand modules in NEMS. This complete linkage is necessary because the development of total system load shapes for the ECP and the EFD, and DSM programs for the ECP depends on detailed data on the level and characteristics of regional electricity demand. Since the linkage categories are similar between the LDSM and the three demand modules, this section presents all of these linkages in total.[3] In addition, the following discussion is divided into the inputs and outputs to the LDSM submodule.

Inputs

The inputs to the LDSM submodule from the demand modules include:

- UECs and current stock data, by equipment type
- Equipment investment and operating costs
- Electric demand by region and end-use

In each yearly iteration of NEMS, the NEMS demand modules develop regional (9 Census division levels) electricity demand for each of the end-uses. The LDSM first translates the Census Division estimates into EMM regional electricity demand. Next, the LDSM develops total EMM region system load shapes from the end-use demand estimates. Section 4.2 discusses this load shape development process.

In order to support the other major demand-related function of LDSM, i.e., the development of DSM programs, the LDSM submodule requires inputs on the end-use technologies. The LDSM and the NEMS demand modules share the same basic data on technology cost and performance. This is important, since DSM activities promote energy efficient technologies that are already commercially available, or are likely to be available. Hence, these technologies must form a part of the technology stock for that particular year,

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[3] It has not been determined how the process based approach in the industrial module will be linked to a technology based approach that the LDSM follows. Linkages will be specified when information is available about usage patterns, efficiencies, and baseline assumptions.

in the demand submodules. The role of DSM is to bring about faster penetration of already existing technologies. If the same data base is not used by the demand submodules and the LDSM, there will be a divergence with respect to the technology assumptions that are being made by the demand submodules, and those being made by the LDSM. In keeping with these requirements, a joint data base has been developed by the LDSM and demand submodules.

The promotion of certain energy efficient technologies through DSM is based on two key attributes of the technologies, namely: (1) the incremental demand and load impact and (2) the incremental cost to achieve greater efficiency or load control.

Outputs

The outputs from the LDSM submodule to the NEMS demand modules are associated with the results of the DSM selection process conducted in the ECP submodule of the EMM. The ECP chooses "economic" DSM programs for future years. The LDSM translates size and characteristics of the DSM programs selected for the next year, into Census division equipment participation levels for input into the NEMS demand modules. These participation levels are expressed as fractions of available market. They indicate both, what technology gained participants and what technology lost participants. This function is performed over time, since a DSM program that has been selected will be implemented over a period of years. The LDSM also has the capability of outputting to the demand modules specific portions of the end-use equipment markets that will implement the DSM option. In other words, if a DSM program is being implemented over a period of five years, and has a potential market of 100,000 customers, the LDSM submodule allocates potential customers to the program over the five year period, such that the total number of customers is 100,000.

#### 2.2.2.2 Linkages with the NEMS Renewable Module

The other set of inter-module linkage is with the NEMS Renewable module. This feature has not yet been coded into the submodule. Once this has been done, the LDSM will have the capability of translating hourly and seasonal generation from non-dispatchable, intermittent renewable technologies into load shape impacts (in LDC form) for input to the ECP. These hourly and seasonal generation patterns will be input from the NEMS Renewable Module. If an intermittent technology is chosen by the ECP submodule, these load shape impacts are used in the LDSM to develop adjusted system LDCs for input into the EFD submodule of EMM.

An Example

Suppose, that in the year 1994, in an EMM region in California, as a result of legislation or technological innovation, a large amount of solar capacity comes on stream. In the NEMS framework, the ECP submodule will be able to choose this as a new supply option. If this is the case, the choice is transmitted to the LDSM which must adjust the LDC of the region to accommodate this change. In order to adjust the LDC, the LDSM will use the typical load shape from a solar generating facility, that provides additional capacity especially in the day-time summer hours, and to a lesser extent in the winter day-time hours.

# 3. MODEL OVERVIEW AND RATIONALE

## 3.1 PHILOSOPHICAL AND THEORETICAL APPROACH

Increasingly stringent regulations, and a greater emphasis on the preservation of the environment, have in recent years, made it increasingly difficult for utilities to add to their generating capacity. On the other hand, the excess capacity that had been built into the system in the sixties and early seventies, has been gradually eroded as a result of increases in demand. Consequently, state and local governments, as well as utilities have sought ways to reduce the need for new generation sources, by modifying the ways in which electricity is used in the country. Most state commissions now require that utilities review all possible options, including DSM, in their plans to meet consumer demand. It is therefore logical, that the NEMS framework include a system for modeling DSM activities as an alternative to supply side options.

Traditionally, several supply options are competed against each other when planning new generating capacity. However, DSM measures focus on individual end-uses or appliances, while generating capacity must be planned on the basis of aggregated demand and supply estimates. In order to allow DSM measures to compete against supply options, therefore, both demand and supply-side options must be expressed in terms that are comparable. The LDSM submodule follows such an approach.

The LDSM develops system load shapes for the thirteen EMM regions. These are used by the ECP submodule for capacity planning. Selected DSM programs are represented as changes in load duration curves, and competed against supply side options.

The LDSM has a database of DSM options in the residential and commercial sectors. The industrial DSM option database will be added when the industrial demand module is ready with the information needed. The residential and commercial sector, option database contains individual DSM options that map a "baseline" technology to a "DSM" technology. The baseline technology consumes more energy or else is characterized by a less economical pattern of energy usage over a 24 hour period, than the DSM technology. The energy savings resulting from the replacement of one unit of "baseline" technology with one unit of DSM technology are represented as delta load duration curves. Each curve consists of a predetermined number of load blocks characterized by different avoided costs.

The cost of energy saving is then compared against the LDC block specific avoided costs of electricity production for that region. These avoided costs are obtained from the ECP submodule of the EMM. Using this criterion in the form of the Total Resource Cost (TRC) test, all DSM options are pre-screened inside the LDSM submodule. Only those options that pass the test are developed further. Hence it is assumed that only those DSM measures whose cost of energy savings compares favorably with the avoided cost of electricity production, would be promoted by a utility.

For each successful DSM option, the DSM technology must then be "penetrated" into the market depending on the existing market share of the base and DSM technologies in the years over which the DSM program is offered. The market shares for the different technologies are obtained from the respective demand modules (residential, commercial or, in the future, the industrial sector).

These options are then aggregated into DSM programs. The energy savings accruing from these programs and the associated program costs on a regional level, are then passed on to the ECP submodule for competing against supply side options. The DSM programs finally chosen as a result of this competition in the ECP submodule are then transferred back to the LDSDM submodule where they are disaggregated into individual DSM options. Once this is done, the resulting changes in stock are computed, aggregated to the appropriate census division level, and passed on to the respective demand modules. In this manner, the LDSM submodule uses DSM measure information at the level of individual appliances, and combines it with aggregated demand and avoided cost information, in order to produce DSM programs that can be competed against supply side options. The final choice of DSM programs is made by the ECP submodule, and is then translated into changes in stock, which are executed by the demand modules.

### 3.2 FUNDAMENTAL ASSUMPTIONS

There are several implicit assumptions about DSM activities that have been made in the model design. The database of technologies used by the LDSM submodule for the residential and commercial sectors, assumes that these technologies are available throughout the U.S at costs that are comparable. The industrial sector data is, in fact, not being used at present since the industrial demand module data is not available. Commercial sector technology data is, however, region specific. Future versions of the model may also include region specific data for the residential and industrial sectors, but that would require further efforts to obtain the necessary data. Such enhancements would be useful, since DSM options have been chosen based on these choices of technologies. Furthermore, the model makes inherent assumptions about the commercial availability of energy efficient appliances in the future. The dates when these appliances will become available, their estimated capital and maintenance costs, as well as efficiencies are assumed inside the joint technology database. These assumptions can, however, be changed in future runs of the model, as more information becomes available.

Secondly, the model chooses the TRC (Total Resource Cost) test for the pre-screening of DSM options. A precise description of the test is presented later in the text. The general concept of the test is that only the options with sufficiently high ratios of economic benefits to costs are accepted. The annual benefits are calculated as the sum of the products of energy savings times the avoided costs of meeting the demand. The costs include the incremental costs of purchasing of the appliances and the administrative costs of implementing the option. Both the benefits and the costs are appropriately discounted and summed over the entire technical life of the affected equipment. It is assumed that this test is the preferred test criterion used by utilities across the country in assessing the financial viability of their DSM programs, and that only financially viable DSM programs are promoted by utilities. As a possible exception to this rule, in the future, the model may have the provision for hardwiring some DSM programs as "must run" programs mandated by state governments and utility commissions.

Another assumption relates to the aggregation and disaggregation of individual DSM options, into DSM programs. When the ECP submodule chooses a fraction of a DSM program, it is assumed that the same fraction of each DSM option has been chosen, and the penetration of individual options is handled accordingly.

### 3.3 ALTERNATIVE APPROACHES AND REASONS FOR SELECTION

The modeling approach used in the LDSM, represents an advancement in the modeling of DSM as a utility resource option. Although DSM analyses have been incorporated into previous models and modeling approaches, no other model has the same breadth of treatment of load shape impacts, DSM screening, ability to link directly with customer demand models, and national scope in one modeling framework. At the same time, however, during the development of the LDSM submodule, the best approaches and methodologies used in other models have been incorporated.

The LDSM has been designed to approximate the actual DSM planning environment. In this context, three overall energy and electricity policy models were examined, and three electric utility system planning and DSM screening models were examined. These models are described in greater detail below.

The LDSM submodule uses relevant characteristics from both existing screening and utility planning models and from regional and national level DSM models. However, the integration requirements with respect to NEMS make it impossible to include existing models within the NEMS framework. As a result, the LDSM is essentially a new model that draws on the best features of the existing models, with capabilities beyond those of existing models.

### 3.3.1 Energy Policy Models

There are existing policy models that attempt to model DSM within a national, or regional-level electric utility planning context. These models include DOE's FOSSIL2, Policy Assessment Corporation's ENERGY 2020, and EPA's Electric and Gas Utility Modeling System (EGUMS). The first two models are very similar — both of these models are systems dynamics models, and share the same heritage (i.e., FOSSIL2). Although these models are useful for policy analysis, the level of detail on DSM planning is minimal. Customer choice is modeled through supply curves. Load shapes are not used. In addition, the systems dynamics basis for these models would make it difficult to transfer the approach to the NEMS intertemporal modeling framework.

FOSSIL2

FOSSIL2, the integrating analysis tool used for the National Energy Strategy, is a dynamic simulation model which forecasts long term (30 to 40 years) behavior of the U.S. energy system. The model is an equilibrium energy market model in which energy markets "clear" over time as a result of feedback among prices, demand, and production capacity. FOSSIL2 uses a systems dynamics methodology. FOSSIL2 addresses demand-side management considerations explicitly as end-use "conservation" technologies. These technologies are represented in "supply" curves that plot cumulative savings against capital costs expressed in ($/MMBTU - dollars per million Btu) for each end use and fuel type. The technologies are arrayed in a least-cost order on the curve and the cheapest measures are implemented first.

Although FOSSIL2 is an excellent model for overall policy modeling, its coverage of DSM measures and load shape representation is not very detailed. In particular, vintage and technology detail is not extensive, and DSM measures are not directly competed against supply-side options.

ENERGY 2020

ENERGY 2020 is very similar in structure to FOSSIL2. They are both based on a systems dynamics framework. ENERGY 2020 forms an integrated planning framework that simulates the interactions within the energy sector under various external and policy conditions. The ENERGY 2020 framework can be automatically calibrated, using generally available data, and modified to represent any particular energy source, utility company, or geographical area. The Policy Assessment Corporation has extended the basic systems dynamics structure of FOSSIL2, and has developed extensive detail on utility financing and DSM measures.

Although ENERGY 2020 is a flexible framework and can conduct detailed analyses, its systems dynamics structure cannot be integrated into the mainframe, yearly iteration form of the NEMS.

ELECTRIC AND GAS UTILITY MODELING SYSTEM (EGUMS)

The last model, EGUMS, is similar in concept to NEMS. EGUMS has been developed for the U.S. EPA by RCG/Haigler-Bailly. It is a multi-region modeling system that simulates utility decision-making under alternative policy scenarios. EGUMS forecasts demand, DSM, and capacity planning in sequence for the complete planning horizon in one pass, and iterates through these steps until convergence. The DSM portion of EGUMS evaluates numerous energy conservation measures (ECMs) for cost-effectiveness, selects cost-effective ECMs, projects ECM market penetration, and develops adjustments to system load shapes. DSM options are examined in the capacity expansion model through these adjustments to system load shapes. Due to this structure, the model does not have demand feedback between years in response to yearly changes and trends in avoided costs and electricity rates.

Nevertheless, the model does have several unique capabilities that LDSM incorporates. In particular, EGUMS does directly link detailed EPRI end-use forecasting models with the DSM portion of their model. Changes in electricity demand forecasts affects DSM potential and cost-effectiveness. The LDSM has a similar linkage with the detailed NEMS demand modules. The DSM screening and market penetration calculations for both models are also similar, and use a payback acceptance framework. The payback acceptance framework relates maximum potential market penetration to the underlying customer economics, measured by simple payback. The shorter the payback period, the larger the maximum penetration.

### 3.3.2 Utility System Planning and DSM Screening Models

Specialized DSM and utility planning models exist in the electric utility sector. In general, these models are designed to do specific utility analysis, and are not able conduct the full set of linkages and functions required of LDSM. These models can be categorized as DSM screening models (e.g., EPRI's DSManager or Synergic Resources Corporation's COMPASS models) or large-scale planning models which have substantial DSM planning capabilities (e.g., EPRI's EGEAS). DSM screening models determine DSM option cost-effectiveness. Utilities use these models to design programs or as a pre-screen before examining DSM options in systems planning models. Utility system planning models conduct detailed optimization of future utility operation. Typically, only supply-side options are considered in these models, but several models, e.g., EGEAS, have the ability to directly compare DSM options with supply-side options. These models are discussed below.

<u>DSMANAGER</u>

DSManager has been developed for the Electric Power Research Institute by Electric Power Software to conduct detailed assessments of DSM options. DSManager is a microcomputer-based model. DSManager calculates the impact of DSM alternatives on utilities and their customers. The model tracks both the physical changes, such as the level of power demand, and the dollar flows. DSManager produces a quantitative estimate of the costs and benefits for each of the affected parties using simplified and flexible models of the electric system and its customers. DSManager is in wide use by electric utilities to screen and select DSM alternatives.

DSManager is a microcomputer-based model that cannot be easily integrated into the NEMS framework. However, the DSM screening portion of the LDSM follows all the basic analytical steps conducted by DSManager.

<u>COMPASS</u>

The Comprehensive Market Planning and Analysis System (COMPASS) developed by the Synergic Resources Corporation is very similar in design to DSManager. COMPASS is also implemented on microcomputers. Both models are used by electric utilities to assess the potential for DSM options in their service territories, and to screen these options on cost-effectiveness. COMPASS differs from DSManager primarily in its inclusion of market potential and market penetration algorithms.

As was the case with DSManager, COMPASS also cannot be easily integrated into NEMS framework. Nevertheless, the LDSM does include similar approaches to the market potential and penetration algorithms included in COMPASS.

EGEAS

The Electric Generation Expansion Analysis System (EGEAS) is a modular generation expansion package that enables utility planners to evaluate the caliber of least cost strategies, the influence of independent power producers on utility expansion, and alternatives regarding avoided costs and/or life extension scenarios. EGEAS is not an integrating model. The model enumerates the type, size, and installation date for each selected demand- and supply-side alternative. All of these parameters have to set up prior to operation. NEMS requires a more flexible structure. The strength of EGEAS is its extensive modeling flexibility and its ability to compete DSM and supply-side alternatives. Nevertheless, the size of this model and its non-integration capabilities limits its possible application within NEMS and the LDSM.

# 4. MODEL STRUCTURE

As was discussed in Section 1.2, Model Summary, the LDSM Submodule has several functions and purposes. To summarize what has been said earlier, the three primary functions of the submodule are to (a) develop regional system load duration curves from demand estimates for the ECP and EFD modules, (b) screen potential DSM options for analysis by the EMM Capacity Planning module, and (c) supply the demand modules with feedback from the ECP concerning the shifts in end-use technology resulting from the optimal choice of DSM options. In addition to these three functions, the LDSM also translates the 9 Census division electricity demand estimates into the 13 NERC regions and subregions that the EMM requires.

The LDSM submodule is designed to simulate the DSM planning efforts at electric utilities. Furthermore, the LDSM will provide the bridge between demand forecasting and utility resource planning. For each yearly iteration, the demand models will provide the integrating module with the total electricity demand by region for the current year, along with demand by end-use, building type and technology type. This information identifies the size of the potential market for utility-sponsored DSM programs. Naturally occurring customer-driven energy efficiency changes are modeled by the demand models and serve as input into the DSM market penetration estimation procedure. Central to the question of naturally occurring efficiencies versus DSM induced efficiencies, is the issue of free riders, i.e., what proportion of DSM customers would have shifted to more efficient technologies even in the absence of DSM programs. Later sections touch upon this issue in more detail, since assumptions about free ridership play a big role in the cost effectiveness of a DSM program.

The Integrating Module also obtains forecasts of future electricity demand from the demand modules by end-use, building type and technology type. These forecasts are used by LDSM in developing system load shapes for the ECP submodule and for projecting DSM market penetration. The development and screening of DSM programs is conducted by LDSM. Actual choice of DSM programs as part of future utility resource plans is made by the ECP submodule.

Figure 2 displays the sequence of tasks that LDSM conducts during each yearly iteration of the NEMS model. These tasks include:

- Mapping of Census Region Demand Estimates into EMM Regions
- Development of System Load Shapes
- Development of Intermittent Technology Load Shape Adjustments (not ready yet)
- Screening of DSM Options
- Computations of the DSM load impact curves and program lifetime costs
- Computation of sectoral peak loads necessary for the ECP module calculations
- Disaggregation of Selected DSM Programs
- Computation of the annual expenditures of utilities on DSM programs

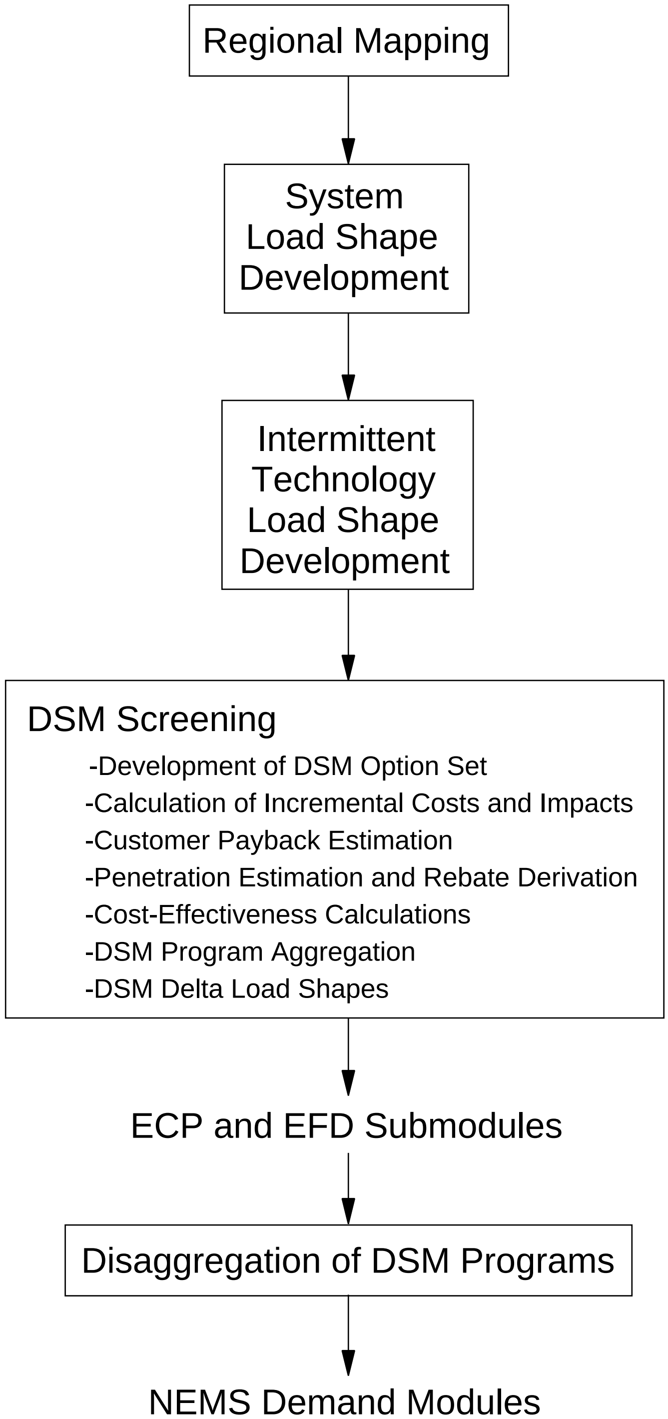



**Figure 2:** LDSM Tasks.

This chapter summarizes the approaches to accomplish these tasks within the LDSM. The sections that follow discuss each of these tasks in order.

## 4.1 MAPPING OF DEMAND ESTIMATES INTO EMM REGIONS

One of the functions of the LDSM submodule is to provide the interface for demand data between the NEMS demand modules and the EMM module. This component conducts two tasks. The first task is the translation of the sectoral demand estimates that are produced by 9 Census divisions within the NEMS demand modules into the 13 EMM Regions. Finally, the LDSM will need to translate any DSM programs impacts back into the Census Divisions in the form of percentages of available market that has to be subjected to the technology shifts.

## 4.2 DEVELOPMENT OF SYSTEM LOAD SHAPES

This section describes the methodology used to construct electric utility load curves in the LDSM. The end result of these calculations is the seasonal and annual load duration curves for each of the 13 EMM regions. The overall methodology can be described as consisting of two steps:

- Step 1: Forecasting regional chronological hourly loads for each hour of the year
- Step 2: Sorting Hourly loads to produce load duration curve representations for ECP and EFD.

Both of these steps are divisible into smaller sub-parts, and these are described in detail below.

### 4.2.1 Forecasting Regional Chronological Hourly Loads

The LDSM submodule has developed 8760 hourly system load curves to reflect different appliance usage patterns (e.g., space heating demands may be higher at certain hours, while at other times the water heating load may dominate the LDC). Investments in different utility demand side management programs, will similarly yield different results at different times of the day, and at different times of the year. The impact of energy efficiency improvement type DSM options is already incorporated in the analysis, through appliance stock adjustments, accomplished by the demand forecasting modules. In the future, the LDSM submodule will also adjust the hourly system load curves to account for impact from load management type of DSM options. In addition, once enhancements to the model are complete, the LDSM will make adjustments to reflect the generation of intermittent technologies by subtracting the hourly generation of such technologies from the forecast system loads[4]. In constructing and modifying these curves, the LDSM uses a combination of load shape data from various sources and historical load shape data collected by the North American Electric Reliability Council (NERC).

Many utilities use such chronological hourly load shapes to predict their customers' demand patterns. The hourly system load curves are developed by these utilities, from the bottom up. To do this the utilities must have information about the technologies and usage patterns of their customers. At a national level, however, the building of such load shapes can present significant data problems. At present, the end-use load shape data readily available for this effort, are not of sufficient quality to allow for the construction of system

[4] This approach will allow the EFD module to ignore the generation of intermittent technologies in its simulation of dispatch (since this generation will already be netted out of the demand it dispatches to). An alternative to this adjustment is to allow the EFD to dispatch intermittent technologies. However the approach used by the EFD (i.e. representing electric demand using a load duration curve rather than a chronological load curve) cannot adequately represent the generation of such technologies.

load shapes from the ground up. In other words, when the load shapes for each end-use are summed together, the resulting system load curve does not closely replicate the actual curve. This may be because the end-use load curves do not conform to the actual usage pattern in the region. Efforts are underway, which will make better quality data available in coming years. One example is the new Central Electric End-use Data (CEED), run by the Electric Power Research Institute (EPRI), whose purpose is to collect, catalogue and disseminate such information. The LDSM will take advantage of such information as it becomes available.

There are two different approaches used within the LDSM model for the forecasting of hourly loads, namely, the Basic Approach and the Delta Approach. In the Basic Approach (that is the more intuitive one), hourly loads for each individual end-use are calculated and then summed to yield the system hourly loads. In the current version of the code, this approach is used for the development of the DSM Program Load Impact Curves and the demand sector load curves (which are necessary for finding the sectoral peak loads that are required by the EFP model).

In the Delta Approach, the starting point is a historical hourly load curve of the system (or other aggregate of end-use loads) observed in a chosen base year. This curve is then modified using the end-use load shapes in case the contribution of the end-uses has changed since the base year.

There are plans to implement the Basic Approach for the system load curves computations. However, that will require additional efforts to improve the load shape database utilized by LDSM.

Once enhancements have been completed, the LDSM will have three generic types of hourly load shapes. The current version has only the first type of the three described below. The list of these end-uses is given in Table 3. As shown, the table lists the technologies and services that use electricity in the two customer sectors, namely, residential and commercial. (The industrial sector is represented in LDSM as a single aggregate because the Industrial Demand module does not provide data at the end-use level.) The second type of end-use, to be included in future enhancements to the model, represents the impacts of the individual load management type of DSM options. The third type of "generic load shapes" are the generation patterns of the intermittent technologies. These will also feature in future versions of the submodule. The LDSM submodule will receive inputs for these technologies from the NEMS Renewables Module, and subtract the appropriate level of generation from the system load forecast for inputting to the EFD submodule.

#### 4.2.1.1 Basic Approach

The basic algorithm can be thought of as an end-use building block approach. The system demand is divided into a set of components called end-uses. The hourly loads for each end-use are forecast. Next the hourly loads of each end-use is summed to yield the forecast of system load at the customers' meter (i.e., hourly system sales). The final step is to simulate transmission and distribution losses. The regional hourly loads are calculated as the sum of hourly system sales and transmission and distribution losses.

Each of these sub-steps is described below.

##### 4.2.1.1.1 Computing End-Use Hourly Loads

In calculating the hourly loads for an end-use, the LDSM requires two major inputs:

- annual sales forecast
- typical load shapes that allocate end-use annual load to each hour in a year

The annual sales forecast is determined endogenously in NEMS. The annual sales forecast for each of the base end-uses is passed to the LDSM from the NEMS demand models. The typical load shapes for each end-use are an exogenous input to LDSM. Typical load shapes are input by month and by day-type (peak day, week day, and week end).[5]

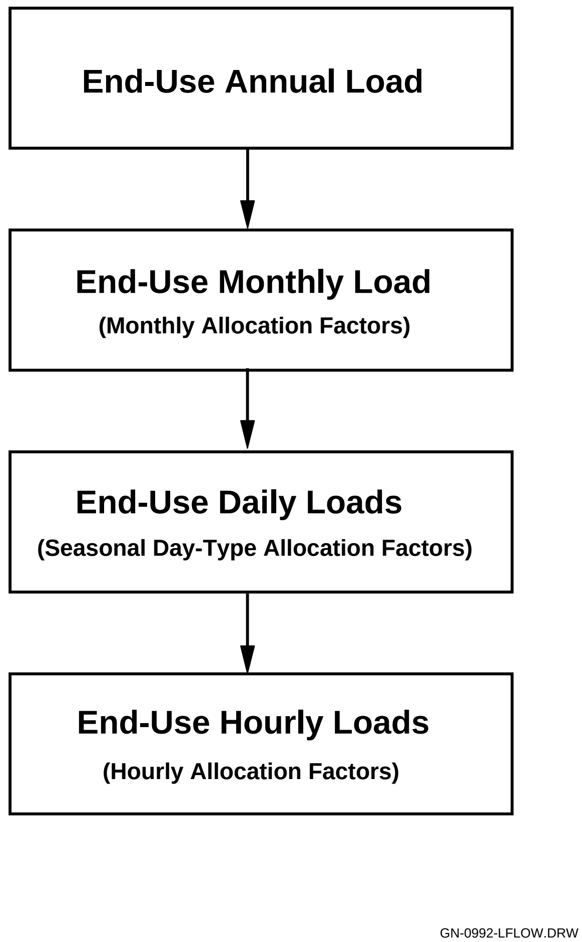



**Figure 3:** Steps in the Computation of End-Use Hourly Loads

The first stage in the development of end-use hourly loads is to prepare, for each end-use, a normalized hourly load profile. This is a one time procedure for the entire NEMS analysis, and so it was put into the LDSM submodule's pre-processor, LSRDBMGR. Computing end-use normalized, hourly load profiles from the end-use inputs is a three step process. Figure 3 gives a flowchart of the three steps. All three steps utilize data that are supplied on a standardized load shape representation (LSR) file. Each LSR file

---

[5] This definition of seasons and day-types may vary depending on the format of the typical load shapes input to the model. Each day represents a period of 24 hours. As the data base for load shapes improves over time, more detailed day-types can be defined.

contains a complete set of data describing a single end-use. The LSRs in the current version of the LDSM come from the RELOAD database.

The first step is to divide the annual sales forecast into a set of monthly sales forecasts. This is accomplished based on a set of exogenous input monthly allocation factors. The monthly allocation factors are a set of weights assigned to each month. These weights inform the LDSM submodule of the relative energy usage from month to month. For example, the input data could assign January the weight of 1.0, and if February uses 20 percent more energy then its weight would be 1.2. Similarly, if September's usage was 15 percent less, its weight would be 0.85. In this way the inputs can define the relative energy usage from month to month. Another way of assigning weights is to define the annual energy usage as 100 percent. Then each month's weight is given by its percentage contribution to the annual load. Thus, if 20 percent of the annual load is used during January, its weight could be 20 and then if September is responsible for only 5 percent of annual energy usage its weight would be 5. This technique is valid as long as the sum of the monthly weights is 100. Regardless of the technique by which the user assigns these monthly allocation factors, LDSM will use them to allocate annual load to monthly load.

The second step of the conversion is to allocate monthly loads to daily loads. This is done in a similar construct as that by which annual load is assigned to monthly load allocations. It is accomplished with a set of day-type allocation factors which specify the relative energy use for each day type. All days within a month assigned to a given day-type are assumed to have the same load.

The third and final step in the conversion is to divide each day's load into a set of hourly loads for that day. This is done in the same manner as annual load is allocated to monthly load. The only difference is that the hourly allocation factors (sets of these factors are referred to as 24-hour load shapes in the data input file) are provided based upon season and day-type. Thus, instead of providing a set of allocation factors for each day of the forecast year, or only one set that applies for every day in the year, the user can provide a 24-hour load shape for each combination of season and day-type in the forecast year. Therefore, when dividing the daily load into hourly load, the relative energy usage ratios are selected based upon the day-type the day is assigned to and the season to which the month the day falls into is assigned.

It is the complete set of hourly loads that describes the load shape of the end-use. Thus, these computational techniques must be applied to each hour within each day within each month in the forecast year as they are defined in the calendar file. The exact computations performed during each of these three steps is discussed below.

#### 4.2.1.1.1.1 Allocation of Annual Load to Monthly Load

Allocation of annual load to monthly loads is accomplished in a two step process described below. Since the monthly allocation factors supplied in the LSR files may not be normalized, first, the normalization factor is computed. Second, this normalization factor is applied to each monthly allocation factor. This yields the percentage of annual load assigned to each month.

The normalization factor is computed by summing the monthly allocation factors for each month. Therefore,

$$DMNF = \sum_{m=1}^{NM} DMAF_m$$

Where:

| | | |
|---|---|---|
| DMNF | = | the normalization factor for monthly allocation |
| NM | = | the number of months in the forecast year |
| $DMAF_m$ | = | the monthly allocation factor for month m (input) |

Next this normalization factor is used to normalize the monthly allocation factors. Therefore,

$$DNMAF_m = \frac{DMAF_m}{DMNF}$$

Where:

| | | |
|---|---|---|
| $DNMAF_m$ | = | the normalized monthly allocation factor for month m |
| $DMAF_m$ | = | the monthly allocation factor for month m |
| DMNF | = | the normalization factor for monthly allocation |

#### 4.2.1.1.1.2 Allocation of Monthly Load to Daily Load

Allocation of monthly load to daily load is accomplished by performing a weighted normalization on the daily allocation factors. The daily allocation factor set (an allocation factor for each day-type) is selected based upon the season to which the month is assigned. A daily load amount is computed for each day-type. This daily load is the load for every day in the month of that day-type. The allocation factors represent relative energy usage on a typical day of each day-type. The weighted normalization is performed using the number of days assigned to each day-type as weights.

There is a set of daily load allocation factors input for each season of the year. These are computed from the LSRs. Each seasonal set includes an allocation factor for each day-type in that season. The different months are allocated to different seasons, and the corresponding seasonal set is used to allocate the daily load to the different day types in the month. Thus, the set of daily allocation factors used, vary by season though the computations will be performed for each month. Hence, more than one month may use the same set of allocation factors, if they are assigned to the same season.

The weighted normalization of daily allocation factors is accomplished in three computations. First, the weighted daily allocation factors are computed as follows:

$$DWDAF_{mt} = (ND_{mt} * DDAF_{mt})$$

Where:

| | | |
|---|---|---|
| $DWDAF_{mt}$ | = | the weighted daily allocation factor for day-type t in month m |
| $ND_{mt}$ | = | the number of days in month m that are assigned to day-type t |
| $DDAF_{mt}$ | = | the daily allocation factor for day-type t in month m (input) |

Then the normalization factor is computed as the sum of these weighted allocation factors. Therefore,

$$DDNF_m = \sum_{t=1}^{NDT} DWDAF_{mt}$$

Where:

| | | |
|---|---|---|
| $DDNF_m$ | = | the normalization factor for daily allocation in month m |
| NDT | = | the number of day-types |
| $DWDAF_{mt}$ | = | the weighted daily allocation factor for day-type t in month m |

Finally, the normalized allocation factor (percent of monthly allocation) for each day-type is computed by dividing each daily allocation factor by the normalization factor. Therefore,

$$DNDAF_{mt} = \frac{DDAF_{mt}}{DDNF_m}$$

Where:

| | | |
|---|---|---|
| $DNDAF_{mt}$ | = | the normalized daily allocation factor for day-type t in month m |
| $DDAF_{mt}$ | = | the weighted daily allocation factor for day-type t in month m |
| $DDNF_m$ | = | the normalization factor for daily allocation in month m |

The last step is to combine these normalized daily allocation factors with the monthly allocation factors. This is accomplished by multiplying the daily normalized allocation factors times the monthly normalized allocation factors.

$$DDTL_{mt} = DNDAF_{mt} * DNMAF_m$$

Where:

| | | |
|---|---|---|
| $DDTL_{mt}$ | = | fraction of the annual load allocated to each day assigned to day-type t in month m |
| $DNDAF_{mt}$ | = | the normalized daily allocation factor for day-type t in month m |
| $DNMAF_m$ | = | the normalized monthly allocation factor for month m |

#### 4.2.1.1.1.3 Allocation of Daily Load to Hourly Load

Allocation of daily load to hourly loads is accomplished by normalizing the hourly allocation factors (each set of hourly allocation factors is referred to as a 24-hour load shape) and combining the result with the daily allocation of load. This can be broken down into a three step process. First, the normalization factor is computed. Next, this normalization factor is applied to each hourly allocation factor. This yields the percentage of daily load assigned to each hour. Finally, these hourly allocation percentages are multiplied into fractions of total annual load allocated to each day, thus yielding fractions of annual load allocated to each hour of the year.

A set of hourly load allocation factors (24-hour load shapes) is supplied on an LSR file. There is one set input for each combination of season and day-type, and each set includes 24 hourly allocation factors.

The set that is used for each day is the one for the day-type to which the day is assigned and the season to which the month the day falls into is assigned. Note that although the equations presented in this section refer to information that varies by month and day-type, the actual information input by the user varies by season and day-type, respectively.

The normalization factor is computed by summing the hourly allocation factors for each hour of the day. Therefore,

$$DHNF_{mt} = \sum_{h=1}^{24} DHAF_{mth}$$

Where:

| | | |
|---|---|---|
| $DHNF_{mt}$ | = | the normalization factor for hourly allocation for day type t in month m |
| $DHAF_{mth}$ | = | the hourly allocation factor for hour h of day type t in month m |

Next this normalization factor is used to normalize the hourly allocation factors. Therefore,

$$DNHAF_{mth} = \frac{DHAF_{mth}}{DHNF_{mt}}$$

Where:

| | | |
|---|---|---|
| $DNHAF_{mth}$ | = | the normalized hourly allocation factor for hour h of day type t in month m |
| $DHAF_{mth}$ | = | the hourly allocation factor for hour h of day type t in month m |
| $DHNF_{mt}$ | = | the normalization factor for hourly allocation for day type t in month m |

Finally, each normalized hourly allocation factor is multiplied into a fraction of annual load, allocated to a given day, yielding a fraction of annual load allocated to each hour. Thus,

$$DHL_{mdh} = DNHAF_{mth} * DDTL_{mt}$$

Where:

| | | |
|---|---|---|
| $DHL_{mdh}$ | = | fraction of annual load allocated to hour h of day d in month m |
| $DNHAF_{mth}$ | = | the normalized hourly allocation factor for hour h of day type t in month m |
| $DDTL_{mt}$ | = | fraction of the annual load allocated to each day assigned to day-type t in month m |

Finally the normalized hourly load profile is given as:

$\{DHL_{mdh}$ such that m=1,2,...NM; d=1,2,...$ND_m$; h=1,2,...24$\}$

Where:

| | | |
|---|---|---|
| $DHL_{mdh}$ | = | fraction of annual load allocated to hour h of day d in month m |
| NM | = | the number of months in the forecast year |
| $ND_m$ | = | the number of days in month m of the forecast year |

Such a set of values is developed from the LSR files by the LSRDBMGR preprocessor for each end-use, and stored on the direct access file. Each record on the file defines hourly distribution of annual load for one end-use. To speed up computations, the LDSM model refers to the values on each record using the hour-in-the-year index as explained below.

$$\text{DistLo} = DHL_{mdh}$$

Where:

| | | |
|---|---|---|
| DistLo(H) | = | fraction of annual load allocated to hour H of a year |
| $DHL_{mdh}$ | = | fraction of annual load allocated to hour h of day d in month m |

#### 4.2.1.1.2 Combining End-Use Load Shapes

The second sub-step of the methodology is to combine the end-use hourly load shapes into one system load shape for the forecast year. The combination of end-use hourly loads is accomplished by an hour-by-hour summation over the forecast year. This procedure is conducted for each EMM region as follows:

$$\text{SYLOAD}(H) = \sum_{e=1}^{\text{NUSES}} \text{DistLo}_e(H) * \text{load1}_e$$

Where:

| | | |
|---|---|---|
| SYLOAD(H) | = | system load in hour H |
| $load1_e$ | = | annual load forecast for end-use e (1 stands for base type approach) |

#### 4.2.1.1.3 Simulating Transmission and Distribution Losses

The system load shape calculated above is the sum of hourly sales for each end-use. Thus, it is the hourly sales for the system. The EFD and ECP require hourly generation requirements, not hourly sales. The final step is to increase the hourly system load requirements by the fraction of generation lost on transmission and distribution.

In LDSM, this is accomplished by multiplying the hourly load values in the EMM region system load curves by the exogenously defined transmission and distribution loss factor. Since the values are supplied on the input by EMM region and then are applied to the EMM regional loads, no mapping of the multipliers from Census to EMM regions is required.

A transmission and distribution loss factor represents an average of an EMM region's percentage of energy lost during transmission and distribution. The values of those factors are quite stable at a regional level because they reflect the efficiency of a transmission and distribution network as a whole. Unless considerable changes in voltages ond distances of transmission take place they do not change significantly. Therefore, those factors are modelled in LDSM as fixed for the entire planning horizon.

#### 4.2.1.2 Modification to the Basic Methodology

The LDSM end-use load shape data base will evolve over several years. Initially, “off the shelf” information will be used. (Currently, EPRI's RELOAD database is used as the main source of load shape information). Over time, the data base will improve as more information becomes available (from such sources as load research, simulation, and borrowing from other utilities). This process includes adding more end-uses to the data base as well as improving the load shape data for existing end-uses. In the first phase of model development, however, the data available is not sufficiently detailed to allow using the bottoms up Basic Approach entirely. If the basic approach is used, the results obtained, especially in short term forecasts, may be significantly different from recent history. To avoid this, certain modifications have been made to the basic approach, so as to obtain reliable forecasts using the current data base.

The purpose of this section is to describe and demonstrate an alternative formulation of system load shape forecasting which allows the LDSM to take advantage of the initial system data base, yet still produce reasonable forecasts. The approach will be referred to as the delta approach.

The essence of what is referred to here as the delta approach is to introduce a new end-use into the data base. This end-use is the current utility system load for which actual load data is available. Load shape information for this “end-use” will be historical system hourly loads. The resulting hourly load forecast of this formulation is a shape which in the early forecast years is very similar to current observed shapes. Over time the shape will change in response to changes in end-use mix.

The delta approach is represented by the following formula:

$$SYLOAD(H) = DistLo_s(H) * SystemLoad + \sum_{e=1}^{NUSES} DistLo_e(H) * load2_e$$

Where:

| | | |
|---|---|---|
| $SYLOAD(H)$ | = | system load in hour H |
| $load2_e$ | = | difference between the end-use's e annual energy consumption in the current year and the base year ("delta" approach -- positive or negative value) |
| SystemLoad | = | base year total system load |
| $DistLo_e(H)$ | = | hourly load shapes for end-uses |
| $DistLo_S(H)$ | = | historical hourly load shapes for the system |
| NUSES | = | number of end-uses |

While:

$$load2_e = load1_e - BaseYrLd(e,RNB)$$

Where:

| | | |
|---|---|---|
| $BaseYrLd(e,RNB)$ | = | base year load for end-use I in EMM region RNB |
| $load1_e$ | = | current year load for end-use I |

| | | |
|---|---|---|
| $load2_e$ | = | difference between the end-use's e annual energy consumption in the current year and the base year ("delta" approach -- positive or negative value) |

### 4.2.2 Development of Load Duration Curves for the ECP and EFD Modules

Load Duration Curves (LDCs), are used by both the ECP and the EFD Modules. An LDC consists of a discrete number of blocks. The height of each block gives the forecasted load, and the width represents the number of hours with that specified load. Summing the widths of all blocks in the LDC gives the total number of hours in the year. However, due to the differing needs of the ECP and EFD modules, the LDCs created for each of these modules, differ. The sections below describe the specific steps used to develop the LDCs.

#### 4.2.2.1 Load Duration Curves for the ECP Module

Demand for electricity is input to the ECP module by means of approximated LDCs, specified for each of the 13 EMM regions. Both the number of blocks, and the assignment of hours to blocks is specified as input data to the program.

The assignment of hours to blocks is completed in two steps. In each step, a different sorting criteria is followed. In the first step, the 8760 hours that make up a year are assigned to a number of "segments" defined by month, day-type, and time of day, and then, hours within each segment are arranged in descending order of load. In the second step, each segment is divided into a number of "blocks". Each block has a specified percentage of the hours assigned to that segment. Two types of blocks are allowed: "regular" blocks, and "peak" blocks. The height of a regular block is equal to the average load of hours assigned to that block, while the height of a peak block is equal to the highest hourly load for hours assigned to that block.

The width of each block is equal to the number of hours in the block. The area of a regular block represents the energy demand during the hours assigned to it. The area of a peak block slightly overestimates the actual load during the hours assigned to the block. However, for narrow peak blocks, the error in approximation is not very significant. The advantage of this approach is a precise representation of the peak load.

#### 4.2.2.2 Load Duration Curves for the EFD module

LDCs for use by the EFD module, have been created for each season and for each of the 13 EMM regions. The steps involved in their creation are listed below.

All the hours in a year are sorted into a predefined number of seasons and hourly segments in each of the seasons. The hourly segments are defined by month, day-type and time of day. Hours in each of the segments are sorted in descending order of load. Each of the segments is divided into a number of vertical strips of approximately equal width, assuring that the total number of strips in each season is equal to the number specified by input data. If the number of strips is sufficiently large, we can assume without significant error, that all strips have the same width.

Next, for each season, load coordinates corresponding to the midpoints of the vertical strips are read from the load curves. These coordinates are then supplemented with the highest and the lowest load value observed in a season, and sorted in descending order. The peak value is associated with a zero time coordinate and the smallest load value is associated with a time coordinate equal to the length of that season. All other values are associated with time coordinates of the midpoints of the vertical strips. The LDCs are supplied to the EFD module as sets of load and time coordinates for each of the seasons. Thus, LDCs are generated based on chronological hourly load curves forecasted for each of the EMM regions.

## 4.3 LOAD SHAPE IMPACTS OF INTERMITTENT TECHNOLOGIES

The LDSM will adjust the hourly load curves that represent the sums of the end-use hourly demands for the generation of intermittent technologies. Thus, the resulting LDCs will already incorporate the generation of these technologies for the EFD. For the ECP to evaluate these technologies, it requires the impact by LDC segment of these technologies. In other words, the LDSM will develop a LDC for each intermittent technology to represent the maximum possible generation in each segment.

## 4.4 DSM SCREENING

The purpose of this component is to simulate utility DSM planning processes. The design of DSM programs and the evaluation of program cost-effectiveness is a specific and separate electric utility task. Within a utility, forecasting personnel develop estimates of market size and composition and system planning personnel develop future resource plans. The LDSM maintains this separate structure.

The DSM Option Screening component simulates the DSM planning process by conducting the following tasks:

- Development of set of potential DSM options
- Calculation of incremental costs and impacts associated with DSM options,
- Calculation of simple customer payback
- Estimation of market penetration and rebate levels
- Calculation of DSM option cost-effectiveness, and
- Aggregation of cost-effective DSM options into DSM program categories.

The output of this component is a set of DSM programs that are characterized by total utility cost and load shape impact in LDC format. These outputs for each aggregated DSM option are used in the ECP submodule to select future resources. The following sections describe the steps that are performed in the DSM option screening component of the LDSM.

### 4.4.1 Development of DSM Option Set

The first task in the DSM Option Screening component of LDSM is to identify and specify potential DSM options for each EMM region and for future time periods. The set of options applicable in any particular year are determined jointly by characteristics of standard and efficient electric technologies shared with the demand models, the LDSM and the set of DSM options specified. This set of DSM options has provisions for further adjustments or enhancements. The initial set of DSM options are included in Appendix A. This set can be adjusted and modified to reflect alternative DSM scenarios.

A DSM option is the most disaggregated unit of a DSM program. An option maps a baseline level technology or service characteristic to a more efficient DSM technology or service level. At a minimum, the following set of information is used to define a DSM option:

- Customer sector
- End-use

- Baseline technology
- Efficient technology
- First year option is available
- Ramp-up Period
- Administration costs
- Market: new, existing, or retrofit
- Target Maximum Participation Level, if load management program.

The LDSM options database uses the same technologies used in the demand models. For example, a central air conditioner rebate program that promotes early replacement of existing air conditioners uses the existing stock as the base technology and a high efficiency unit as the DSM technology.

The difference between the first year that the technology is available, and the last year that the technology is available, defines the window of opportunity over which DSM programs can offer options relating to that technology.

The set of DSM options includes energy efficiency, load management, and fuel switching programs. In this version of the model only energy efficiency DSM options are included. In addition, because of its direct linkage with the technologies used by the demand modules, the option set is designed to accommodate technological advances and the underlying efficiency improvements over time. This is the case, since over time, the older technologies no longer exist in the database, and the newer technologies introduced have higher efficiencies.

#### 4.4.2 Incremental Impacts

The first task in the DSM Option Screening component is the development of the incremental cost and load impacts for each DSM option. These incremental impacts are derived from the base and DSM technologies defined in the end-use technology database. These impacts are used to calculate customer payback, derive rebate levels, and technology penetration levels. In addition, the calculation of incremental impact and delta load duration curves is conducted differently for energy efficiency than for load management programs. The procedures for these two program categories is discussed below.

Energy Efficiency Programs

Incremental energy impacts associated with an energy efficiency DSM option is determined on a per unit basis. These energy impacts are referred to as usage indices (UIs). For example, residential impact are measured as a change in unit energy consumption (UEC), measured in kWh/yr., in moving from base technology 1 to efficient technology 2. Commercial impacts are measured in terms of electric usage indices (EUI), in Kwh/unit of service demand/yr. This incremental energy impact is calculated as follows:

$$EI_{dir} = UI_{1dr} - UI_{2dr}$$

Where:

| | | |
|---|---|---|
| $EI_{dir}$ | = | incremental energy change for option d in region r |
| $UI_{1dr}$ | = | usage index for base technology 1 in region r associated with option d |
| $UI_{2dr}$ | = | usage index for efficient technology 2 in region r associated with option d |

Incremental costs (IC) for energy efficiency options are derived by comparing the equipment and maintenance costs associated with the base and DSM technology in the database. If the DSM option is focused on replacing existing equipment, the full costs of the DSM technology are used as the incremental costs. If the DSM option is focused on influencing normal replacement decisions, then the incremental cost is the difference in costs between the base and DSM technologies. Incremental costs have two components, one based on capital costs and the other on maintenance costs per unit (e.g., per refrigerator, or per square foot). Maintenance costs include any ongoing labor or expenditures required to keep equipment operating. The cost of electricity consumed to operate the equipment is not included. Mathematically:

$$ICC_{dr} = TCC_{1r} - TCC_{2r}$$

$$ICO_{dr} = TCO_{1r} - TCO_{2r}$$

Where:

| | | |
|---|---|---|
| $ICC_{dr}$ | = | is incremental customer capital costs for DSM option d in region r |
| $ICO_{dr}$ | = | is incremental customer maintenance costs for DSM option d in region r |
| $TCC_{jr}$ | = | is technology capital cost for technology j in each region r |
| $TCO_{jr}$ | = | is technology maintenance cost for technology j in each region r |

The incremental demand and energy impacts for energy efficiency options is captured through the use of "delta" load shapes. Delta load shapes represent the difference in electricity consumption by time of day, between use of the base technology and the DSM technology. In this version of the LDSM, load shapes for base and DSM technologies are based on default end-use load shapes and represent unit shapes that can be scaled according to total impact. Though several alternative load shape sources exist, the EPRI RELOAD library, of load shapes forms the basis of the LDSM load shapes. The height and peak impact of each load shape will be derived by scaling the default load shape to the total electricity consumption associated with yearly market penetration. This database is still in development, and future versions of the LDSM may use other data for load shapes. Figure 4 graphically displays the development of delta load shapes for each DSM option.

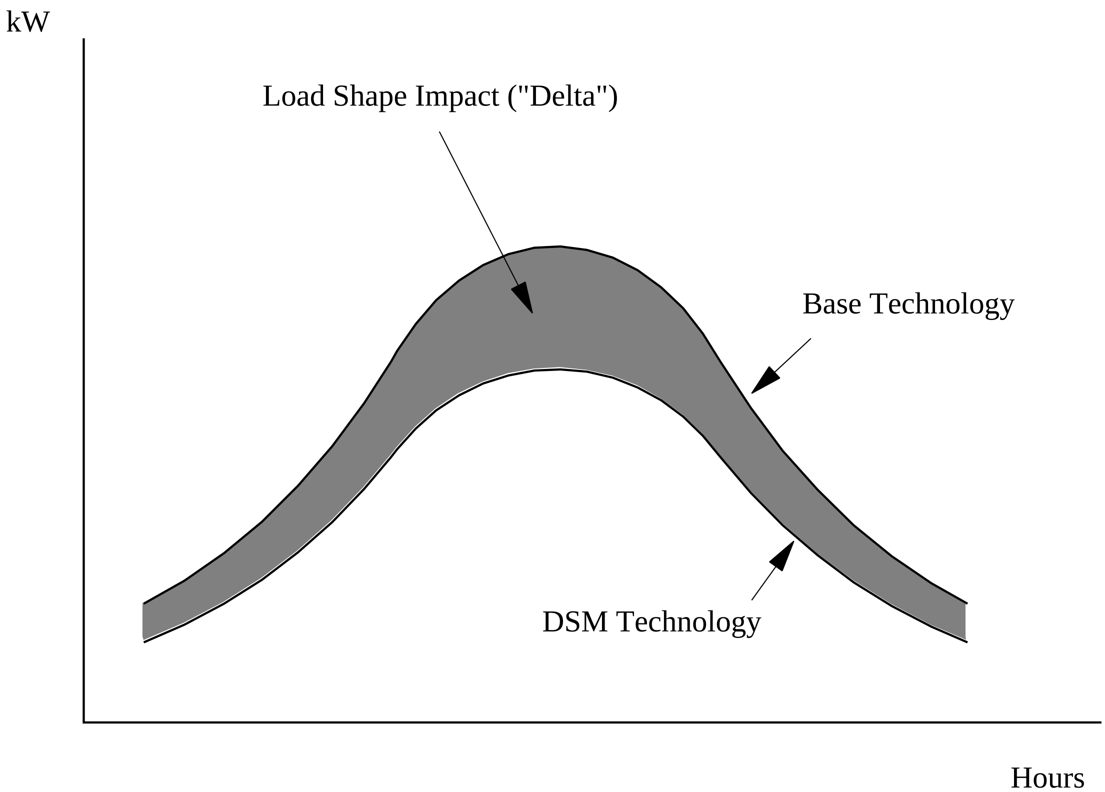



**Figure 4:** Development of Delta Load Shapes.

Delta LDCs are developed for each DSM option, in a fashion similar to system load duration curves. Thus a delta load duration curve, denoted by $LDC_{dlry}$, is defined in megawatt equivalents for DSM option d, load segment l, region r, and year z. For example, the value of $LDC_{dlry}$ for efficient central air conditioners for summer daytime may be 100 megawatts for region r in year y.

Load Management Options

Load management options are DSM options that result in load shifts from peak to non-peak hours. There is no resulting reduction in electricity consumption, in fact, there may be some increase in consumption in some cases. Examples of load management options include commercial cool storage options or baseboard heating in the residential sector. The present version of the LDSM, does not contain any load management type DSM options. However, future versions can be equipped to handle such options. This section describes the particular characteristics of load management type DSM options and suggests a methodology for dealing with them.

The incremental impacts associated with load management programs are based on the kilowatt (kW) reductions in peak load or shifts associated with each program. Load Management DSM programs are either specified by the kW reductions (and increases, where applicable) in specific time periods, or by hourly load shape impact data. Load shape impact data may be appropriate where the pattern of impact is complicated by factors such as rebound or bounce back.[6] The participation levels associated with load management programs will also be specified in the input data on DSM options.

Since implementation of load management options is generally based on utility economics, not customer economics, incremental customer cost is not as relevant for these programs. However, some customer costs would have to be measured even in these cases, for example the costs of control switches and central controllers.

Delta load shapes and delta LDCs for specific single installations of load management programs will either be specified in data inputs or will be derived from specified kW reductions in specific periods.

Regional delta LDCs in megawatts will be based on the following equation:

$$LD_{yrpl} = LM_{rpl} * DP_n * ELDC_{yrel}$$

Where:

| | | |
|---|---|---|
| $LD_{yrpl}$ | = | Changes in load segment l in year y by load shape management program p in region r (fraction) |
| $LM_{rpl}$ | = | Percentage changes in load segment l by implementation of load management program p, in region r |
| $DP_p$ | = | Participation level associated with load management program p (fraction) |
| $ELDC_{yrel}$ | = | End-use load in megawatts, for load segment l region r end-use e year y |

The size of $ELDC_{yrel}$ will be derived from end-use load shapes and market potential derived in Section 4.2.1.1.3

### 4.4.3 Payback Estimation

[6] As used here, "rebound" or "bounce back" refers to the rapid increase in electricity demand that occurs immediately after a load control period.

The first step in determining customer acceptance of DSM options and technologies is to calculate simple payback associated with DSM options without any financial incentives from utilities. Simple payback is derived using the following formula:

$$PB_{ydr} = \frac{ICC_{dr}}{(SV_{yrd} * ER_{yr}) - ICO_{dr}}$$

Where:

$PB_{ydr}$ = payback period in years for DSM option d starting in year y in region r.
$SV_{yrd}$ = megawatt-hours of savings for option d in region r for program starting in year y
$ER_{yr}$ = electricity rates per-megawatt-hour equivalent in region r for year y
$ICC_{dr}$ = is incremental customer capital costs for DSM option d in region r
$ICO_{dr}$ = is incremental customer maintenance costs for DSM option d in region r

Electricity rates for year y are input from the EFP submodule.

### 4.4.4 Penetration Estimation and Rebate Derivation

Development of projections of market penetration and customer participation in utility energy efficiency DSM programs requires detailed information on market characteristics, customer response to DSM programs, and forecasts of future penetration of efficient DSM technologies. In addition, market penetration is related to the level of incentives (e.g., financial rebates) offered by utilities. The LDSM simulates the penetration estimation function for each forecasted future year. This portion of the screening task will (a) develop estimates of maximum market penetration achievable for DSM technologies and the annual participation levels expected, and (b) derive rebate levels.

To estimate the maximum penetration of the market by the DSM option, a payback acceptance curve approach is used. This approach has been used by A.D. Little (1990), and has been incorporated into DSM Screening models such as Synergic Resources Corp.'s COMPASS and EPA's EGUMS model. As is shown in Figure 5, this approach derives projections of cumulative market penetration from the calculated payback of a DSM option, and differs by customer sector. For example, review of this figure indicates that a commercial DSM option with a 4 year payback would achieve approximately 10 percent of the commercial market. Through variations in financial incentives and rebates, market penetration can be varied.

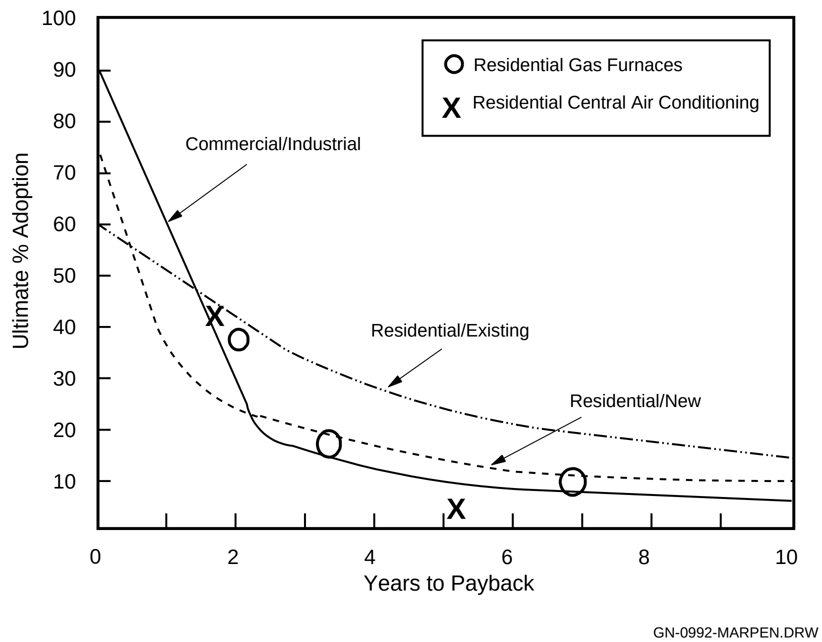



**Figure 5:** Payback Acceptance Approach

During operation, LDSM will follow a four step process. First, LDSM will calculate the rebate level for each DSM option that is necessary to achieve a two (2) year payback. If a DSM option already has less than a two year payback, a rebate is not calculated for the option. The choice of a two year payback level was based on general utility practice. This rebate derivation will be achieved with the following equation:

$$\frac{ICC_{dr} - RB_{dr}}{(LD_{yrd} * ER_{yr}) - ICO_{dr}} = 2$$

$0 \leq RB_{dr} \leq ICC_{dr}$

Where:

| | | |
|---|---|---|
| $ICC_{dr}$ | = | is incremental customer capital costs for DSM option d in region r |
| $ICO_{dr}$ | = | is incremental customer maintenance costs for DSM option d in region r |
| $RB_{dr}$ | = | Rebate level necessary to achieve a 2 year payback in region r for option d |
| $SV_{yrd}$ | = | megawatt-hours of savings for option d in region r for program starting in year y |
| $ER_{yr}$ | = | electricity rates per-megawatt-hour equivalent in region r for year y |

Second, the maximum market penetration of the DSM technology ("TO" technology), $MP_{ydr}$, associated with option d in region r that begins in every year y is simply read from the payback acceptance curve.

Third, yearly cumulative participation for each option is calculated as a linear function from current market penetration to maximum market penetration, expressed as a percentage of the available market. Current market penetration of efficient technologies will be derived from the stock data supplied by the demand modules by technology region and year. The LDSM may also be equipped with an option to override the use of this payback acceptance curve approach and provide rebate and participation levels directly, input by the user. The participation arithmetic will be conducted with the following set of equations. Total potential market size $TM_{dry}$ for a DSM option d[7] in region r for program starting in year y is calculated by:

$$TM_{ydr} = (CM_{y1dr} + CM_{y2dr}) * MP_{ydr} - CM_{y2dr}$$

where:

| | | |
|---|---|---|
| $TM_{dry}$ | = | total potential market size for DSM option d[8] region r year y |
| $MP_{ydr}$ | = | maximum market penetration of the DSM technology ("TO" technology), associated with option d region r year y |
| $CM_{y2dr}$ | = | current market size for region r for efficient technology 2 associated with option d in year y |
| $CM_{y1dr}$ | = | current market size for region r for base technology 1 associated with option d in year y |

Annual maximum participation level $AP_{ydr}$ in region r for option d for year y will be calculated with the following equations:

during the ramp-up period:

$$AP_{ydr} = TM_{ydr} * \frac{(y - y_0 + 1)}{RU_d}$$

---

7〉 The definition of d will determine what category of technologies are applicable.

8〉 The definition of d will determine what category of technologies are applicable.

beyond the ramp-up period:

$AP_{ydr} = TM_{ydr}$

where:

| | | |
|---|---|---|
| $AP_{ydr}$ | = | annual maximum participation level in region r for option d for year y |
| $TM_{dry}$ | = | total potential market size for DSM option d[9] region r year y |
| $RU_d$ | = | ramp-up period for option d |
| $y_0$ | = | the first year of implementation of the DSM option d |

In the fourth step, the total maximum possible incremental savings $TS_{ydr}$ associated with option d in region r for year y would then be calculated by

$$TS_{ydr} = (UI_{y2dr} - UI_{y1dr}) * AP_{ydr}$$

where:

| | | |
|---|---|---|
| $TS_{ydr}$ | = | total maximum possible incremental savings associated with option d in region r for year y |
| $AP_{ydr}$ | = | annual maximum participation level in region r for option d for year y |
| $UI_{y1dr}$ | = | usage index for base technology 1 in region r associated with option d in year y |
| $UI_{y2dr}$ | = | usage index for efficient technology 2 in region r associated with option d in year y |

#### 4.4.4.1 The Free-Ridership Issue and Penetration

In the calculations of program effectiveness, it is important that we include in our consideration the "free riders" issue. Free riders are those customers who would have adopted the program recommended efficiency measures, even in the absence of the DSM program, but who now participate in the program, and, hence, are entitled to the financial incentives of the program. Due to this; energy savings or the load reductions achieved by these customers as a result of DSM programs, do not contribute to net savings, although costs of providing the service to them is a part of program costs.

A study by Marjorie McRae et al, on free riders in the residential sector, conducted a detailed analysis of ten utility DSM programs. The results showed that the net impacts of these residential programs, ranged between 25 to 33% of the utilities' expected values (i.e., 67 to 75% of the participants were free riders). Though the applicability of these numbers to all DSM programs may be questionable, they do indicate that utilities tend to overestimate the impact of their DSM programs. The reason for this is that most utilities do not perform a detailed analysis to estimate the number of free riders in their programs; they do not assume that efficiency improvements may be occurring naturally, and hence by offering DSM programs the utility may be paying for efficiency improvements which may have happened even otherwise.

The current version of the model deals with this problem assuming that the rebates will be paid to all the customers that apply the efficient (TO) technology. In practice it is known that only a fraction of

[9] The definition of d will determine what category of technologies are applicable.

*potential* free riders will ever apply for rebates. The design and marketing of DSM programs plays a very important role in how many potential free riders may claim rebates. The approach followed in this version of the model lays down the maximum limit of free ridership in any program. This is possible, since the restart file gives us information on appliance stocks in the absence of DSM. Thus, the LDSM module uses this information to compute the maximum number of free riders. In the computation of costs of DSM programs by the ECP module, the maximum number of free riders plays an important role. As the number of free riders increase, the program costs go up dramatically, and the program becomes uncompetitive. In this fashion, the present version of the LDSM is able to factor in the role played by naturally occurring efficiency improvements (i.e., the appliance mix in the absence of DSM).

Future versions of the LDSM could further refine this process by analysing the percentage of free riders for different types of programs and marketing practices, and factor these into the utility's cost computations.

#### 4.4.4.2 The Targetable Market and Cost Calculations

The demand module of NEMS provide the LDSM submodule with forecasts of the expected stock changes over the coming years. The categories into which the stock is divisible are:

(1) Retiring Stock: This includes stock that is expected to naturally retire over the next year. This segment would be a part of the market for "replacement" type DSM programs. The costs incurred in such programs are therefore the incremental cost of the more efficient appliance over the baseline appliance that would have been purchased in the absence of the program.

(2) New Construction or New Stock: This includes those appliances that are meant for the new customers that are likely to join the grid over the next year as a result of new construction. DSM programs targeted at this segment incur costs that are the incremental costs of the more efficient appliance over the cost of the appliance that was to be bought in the absence of the program.

(3) Existing Stock: This is a forecast of the stock that is continuing from the last year, and is not expected to retire over the next year. DSM programs targeted at this market segment are inducing early retirement. The LDSM submodule does not keep track of the remaining useful life of existing appliances that are removed from the stock as a result of DSM programs. Thus, in the calculation of costs in this category, the salvage value of the existing equipment and the incremental cost of the new equipment would have to be included in the cost computations. Where salvage value data is not available, the salvage value is presumed to be zero. DSM options that apply to this part of the stock, have not been implemented in the current version. They may be included in the next version of the code.

#### 4.4.4.3 Information Flows Between the LDSM and Demand Modules

Communication between the LDSM and the Demand Modules follows two paths:

1) Through the RESTART files created by the Residential and Commercial Modules during the pre-LDSM NEMS runs
2) Through the COMMON blocks defined in the designated INCLUDE files in the LDSM code

**Table 5: Information Flow Between LDSM and Demand Modules.**

| SPECIFICATION OF DATA ITEM | RESTART FILE OR INCLUDE FILE NAME | Direction Of Transfer | |
|---|---|---|---|
| | | DEMAND FORECASTING MODELS | LDSM |
| Market shares of end-use technologies in the entire time horizon if no DSM practices are available | RESIDENTIAL RESTART FILE, COMMERCIAL RESTART FILE | FROM | TO |
| End-use technology data | DSMRETDB, DSMCMTDB | FROM | TO |
| End-use demand, for each of the EMM regions, for the current year | DSMTFRES, DSMTFCOM | FROM | TO |
| Technological shifts due to DSM application, for each of the EMM regions, for the current year, expressed in terms of number of appliances for Residential and amount of service demand for Commercial sector (for the first run year - 0) | DSMTFRES, DSMTFCOM | FROM | TO |
| Level of DSM Utilization determined as optimal by the ECP module, expressed as percentages of the maximum possible technological shifts resulting from each of the DSM Options listed in the DSM option data base, for the next run year, for each of the EMM regions | DSMTFRES, DSMTFCOM | TO | FROM |

Based on the tasks outlined in the main flow chart of the model (shown as Figure 1 in Appendix B) Table 5 showing data transfers between the Demand Modules and LDSM submodule has been constructed. The exchange of information between the Demand Modules has the following four objectives:

1) The LDSM reads the technology stock information from the RESTART files to forecast LDSM Program impacts and costs for the entire ECP time horizon (this data is always updated according to the foresight assumptions, in the current run, for each of the sectors of electricity demand)

2) The LDSM imports the end-use technology data to calculate incremental DSM option costs and the annual energy savings resulting from technological shifts

3) The LDSM supplies the Demand Modules with information about the optimal level of DSM penetration, as determined by the ECP model, so that the Demand Modules, in the next run year, can incorporate these changes into their new appliance stock assessment. Thus the demand modules adjust their forecast to incorporate the impacts of DSM.

4) The LDSM imports the actual number of appliances (amount of service demand) that are being shifted from the demand modules, to allow for precise calculation of DSM costs. These costs are then passed on to the EFP module.

### 4.4.5 Cost-Effectiveness Calculations

The primary screening function of the LDSM DSM screening component is to select DSM options based on overall cost-effectiveness. Benefits and costs for each potential DSM option will be calculated. Options which have benefit/cost ratios greater than 1 will pass the screen. The benefit and costs will be based on the California Total Resource Cost (TRC) test. This test compares the total cost (customer direct costs, which include equipment and maintenance costs, plus utility program costs) of an option to the utility benefits of reduced demand and energy (system avoided capital and energy costs). This test is the primary cost-effectiveness test required by state regulatory commissions. The general form of this test is given below. The test must be performed for each of the 13 EMM regions being modeled.

$$TRC = \frac{\text{PV of Avoided System Costs}}{\text{PV of DSM Options Costs}}$$

This can be further expanded in the following form:

$$TRC_{rd} = \frac{\sum_{y=1}^{N} \frac{\left( MA_{ryl} \right) \, x \, \left( LD_{yrdl} \right)}{(1 + i)^{y}}}{\left( ICC_{dr} \right) + \sum_{y=1}^{N} \frac{YPC_{yrd}}{(1 + i)^{y}}}$$

Where:

| | | |
|---|---|---|
| $TRC_{rd}$ | = | Total Resource Costs for region r and option d |
| $MA_{ryl}$ | = | Marginal electricity costs in region r, year y and conforming to the l segment of the load duration curve |
| $LD_{yrdl}$ | = | Changes in the load segment l in year y, due to the DSM option d, in region r |
| $ICC_{dr}$ | = | incremental customer capital costs for DSM option d in region r |
| $YPC_{yrd}$ | = | Yearly option costs for program d, in year y, in region r |
| i | = | Discount rate used in the calculations |
| N | = | Lifetime of appliance in years |

The present value (PV) of DSM option costs will be derived by calculating the present value of total incremental customer costs and program costs in each future year associated with program participation. The PV of system avoided costs will be calculated by multiplying regional system avoided costs by load duration curve segment ($LD_{yrdl}$) times the total load shape impact of the DSM option.

### 4.4.6 DSM Program Aggregation

The final task in the DSM Screening component of the LDSM submodule is the development of aggregate DSM programs. Aggregation of economic DSM options is necessary because of the computational limitations of the ECP submodule. It was decided that the maximum number of DSM programs that are to compete within the ECP optimization scheme should not exceed 30 per region. (The current DSM database assumes 11 DSM programs.) This will keep the size of the optiomization problem and the computational times of the ECP module within the acceptable limits. The DSM programs are defined by customer end-use and (in the future) load management category. This aggregation is accomplished by summing together all costs and LDC impacts for each DSM option within each program. The tables in Appendix A contain a list of DSM programs and aggregation that will be modeled in the LDSM submodule.

## 4.5 DSM PROGRAM DISAGGREGATION

The final component of the LDSM submodule is the disaggregation of the DSM programs chosen by the ECP submodule for utility investment. The ECP submodule may choose full or less than full implementation of DSM programs. Within LDSM, the scale chosen by ECP is used as the basis for determining the participation levels in percentage terms. For example, if the ECP chooses 50 megawatts of a potential 100 megawatts aggregated DSM option, then all of the individual options within the aggregated option will be scaled down by 50%. In addition, the DSM programs chosen by ECP are based on EMM regions. The LDSM submodule translates these DSM program decisions to the census division level that is used by the Demand Modules of NEMS.

# APPENDIX A
## DSM OPTION AGGREGATION

Appendix A contains a list of the DSM options and programs in the LDSM. The attached tables A1, A2, and A3 contain the DSM options and programs for the residential and commercial sectors, that have been implemented in this version of the LDSM. The options planned for the industrial sector are shown in Table A4. These options are slated for implementation in future versions of the LDSM, and are not included in this version of the model. Table A4 also indicates in the left column, the aggregated DSM programs for the industrial sector, that will be input to the ECP submodule in future versions of the model, if they pass the economic screening test. Both the residential and commercial sectors have 88 options each.

**Table A1: Residential DSM Programs in the Current Version of the LDSM[1〉]**

| Program Code | Residential Program Description |
|---|---|
| FREF&AC | Residential Program "From" EFs & CACs to Heat Pumps |
| RSCTOHP | Residential Space Conditioning "To" Heat Pumps |
| RAC&CAC | Residential Cooling with RACs and CACs |
| RESWTHT | Residential Water Heating Program |
| REF&FRE | Residential Refrigerator and Freezer Program |
| RESLIGH | Residential Lighting Program |
| RESOTHR | Residential Other Appliances Program |

**Table A2: Commercial DSM Programs in the Current Version of the LDSM[2〉]**

| Program Code | Commercial Program Description |
|---|---|
| CMFRCAC | Commercial Program mapping "From" CACs |
| COMTOHP | Commercial Space Heating Program mapping "To" Heat Pumps |

1〉 The lighting DSM programs do not have corresponding options in the current version. These options will be added to our DSM option database in the near future. However, an enhanced algorithm to calculate those options will have to be developed, because the data available from the demand module does not contain all the necessary information. We will have to make some assumptions about the number of replacements and additions to the stock each year, hourly utilization of different technologies, etc.

2〉 The only data on the other appliances technology group available from the demand module is the total consumption of electricity by census divisions and building types. Unless more precise data becomes available, the inclusion of the other appliance DSM options may be difficult to accomplish.

| | |
|---|---|
| CMLIGHT | Commercial Lighting Program |
| CMOTHER | Commercial Other Appliances Program |

**Table A3: Residential DSM Options in the Current Version of the LDSM**

| Option Code | Program Code | Region[1] | Residential Option Description |
|---|---|---|---|
| R101S | FREF&AC | N | Install 13.1 HP (if CAC exists) |
| R102S | FREF&AC | S | Install 15.1 SEER HP (if CAC exists) |
| R103S | FREF&AC | N | Install HP (if CAC exists) |
| R104S | FREF&AC | S | Install HP (if CAC exists) |
| R105S | FREF&AC | N | Install HP (if CAC exists) |
| R106S | FREF&AC | S | Install HP (if CAC exists) |
| R107S | FREF&AC | S | Install HP (if CAC exists) |
| R201A | RSCTOHP | N | Improve HP to 13 SEER |
| R203A | RSCTOHP | S | Improve HP to 13 SEER |
| R205A | RSCTOHP | N | Improve HP to 13 SEER |
| R206A | RSCTOHP | S | Improve HP to 13.3 SEER |
| R207A | RSCTOHP | S | Improve HP to 13.3 SEER |
| R208A | RSCTOHP | N | Improve HP to 15.14 SEER |
| R210A | RSCTOHP | S | Improve HP to 15.14 SEER |
| R212A | RSCTOHP | N | Improve HP to 15.14 SEER |
| R213M | RSCTOHP | N | Improve HP to 13.3 SEER |
| R215M | RSCTOHP | S | Improve HP to 13.3 SEER |
| R217M | RSCTOHP | S | Improve HP to 13.3 SEER |
| R218M | RSCTOHP | N | Improve HP to 15.1 SEER |
| R220M | RSCTOHP | S | Retrofit HP to 15.1 SEER |
| R222S | RSCTOHP | N | Improve HP to 9.5 HSPF, 13.3 SEER |
| R223S | RSCTOHP | S | Improve HP to 9.5 HSPF, 13.3 SEER |
| R224S | RSCTOHP | N | Improve HP to 9.5 HSPF, 13.3 SEER |
| R225S | RSCTOHP | S | Improve HP to 9.5 HSPF, 13.3 SEER |
| R226S | RSCTOHP | S | Improve HP to 9.93 HSPF, 15.1 SEER |
| R227S | RSCTOHP | S | Improve HP to 9.93 HSPF, 15.1 SEER |
| R301A | RAC&CAC | N | Improve CAC to 10.5 SEER |

| Option Code | Program Code | Region[1] | Residential Option Description |
|---|---|---|---|
| R303A | RAC&CAC | N | Improve CAC to 10.5 SEER |
| R304A | RAC&CAC | N | Improve CAC to 13.3 SEER |
| R306A | RAC&CAC | S | Improve CAC to 13.3 SEER |
| R307A | RAC&CAC | N | Improve CAC to 13.3 SEER |
| R308A | RAC&CAC | S | Improve CAC to 13.3 SEER |
| R309A | RAC&CAC | S | Improve CAC to 15.1 SEER |
| R310A | RAC&CAC | S | Improve CAC to 15.1 SEER |
| R313M | RAC&CAC | N | Improve CAC to 10.5 SEER |
| R315M | RAC&CAC | S | Improve CAC to 10.5 SEER |
| R316M | RAC&CAC | N | Improve CAC to 10.5 SEER |
| R317M | RAC&CAC | S | Improve CAC to 10.5 SEER |
| R318M | RAC&CAC | N | Improve CAC to 13.1 SEER |
| R319M | RAC&CAC | N | Improve CAC to 13.1 SEER |
| R321M | RAC&CAC | S | Improve CAC to 13.3 SEER |
| R322M | RAC&CAC | S | Improve CAC to 13.3 SEER |
| R323M | RAC&CAC | S | Improve CAC to 15.1 SEER |
| R333M | RAC&CAC | S | Improve CAC to 15.1 SEER |
| R339S | RAC&CAC | S | Improve CAC to 13.3 SEER |
| R340S | RAC&CAC | N | Improve CAC to 13.3 SEER |
| R341S | RAC&CAC | S | Improve CAC to 13.3 SEER |
| R342S | RAC&CAC | S | Improve CAC to 14.87 SEER |
| R343S | RAC&CAC | N | Improve CAC to 14.87 SEER |
| R344S | RAC&CAC | S | Improve CAC to 14.87 SEER |
| R401A | RAC&CAC | S | Improve RAC to 10.83 SEER |
| R402A | RAC&CAC | S | Improve RAC to 10.83 SEER |
| R404A | RAC&CAC | N | Improve RAC to 9.42 SEER |
| R405M | RAC&CAC | S | Improve RAC beyond 10.83 |
| R406M | RAC&CAC | N | Improve RAC to 10.8 SEER |
| R407M | RAC&CAC | N | Improve RAC to 9.42 SEER |
| R408M | RAC&CAC | S | Improve RAC to 9.42 SEER |

| Option Code | Program Code | Region[1] | Residential Option Description |
|---|---|---|---|
| R409S | RAC&CAC | N | Improve RAC to 10.42 EER |
| R410S | RAC&CAC | S | Improve RAC to 10.42 EER |
| R411S | RAC&CAC | N | Improve RAC to 9.42 EER |
| R412S | RAC&CAC | S | Improve RAC to 9.42 EER |
| R413S | RAC&CAC | N | Improve RAC to 9.88 EER |
| R414S | RAC&CAC | S | Improve RAC to 9.88 EER |
| R702S | REF&FRE | A | Efficient Refrigerator (>1995) |
| R703S | REF&FRE | A | Efficient Refrigerator (>2000) |
| R802S | REF&FRE | A | Efficient Freezer (>1995) |
| R803S | REF&FRE | A | Efficient Freezer (>2000) |
| R702S | REF&FRE | A | Efficient Regrigerator (>1995) |
| R703S | REF&FRE | A | Efficient Regrigerator (>2000) |
| R801S | REF&FRE | A | 1990 Standards Freezer |
| R802S | REF&FRE | A | Efficient Freezer (>1995) |
| R803S | REF&FRE | A | Efficient Freezer (>2000) |
| R702S | REF&FRE | A | Efficient Regrigerator (>1995) |
| R703S | REF&FRE | A | Efficient Regrigerator (>2000) |
| R802S | REF&FRE | A | Efficient Freezer (>1995) |
| R803S | REF&FRE | A | Efficient Freezer (>2000) |
| R702S | REF&FRE | A | Efficient Regrigerator (>1995) |
| R703S | REF&FRE | A | Efficient Regrigerator (>2000) |
| R802S | REF&FRE | A | Efficient Freezer (>1995) |
| R803S | REF&FRE | A | Efficient Freezer (>2000) |
| R702S | REF&FRE | A | Efficient Regrigerator (>1995) |
| R703S | REF&FRE | A | Efficient Regrigerator (>2000) |
| R802S | REF&FRE | A | Efficient Freezer (>1995) |
| R803S | REF&FRE | A | Efficient Freezer (>2000) |
| R702S | REF&FRE | A | Efficient Regrigerator (>1995) |
| R703S | REF&FRE | A | Efficient Regrigerator (>2000) |
| R802S | REF&FRE | A | Efficient Freezer (>1995) |

| Option Code | Program Code | Region[1] | Residential Option Description |
|---|---|---|---|
| R803S | REF&FRE | A | Efficient Freezer (>2000) |

**Table A3: Commercial DSM Options in the Current version of the LDSM[3]**

| Option Code[2] | Program Code | Commercial Options Description |
|---|---|---|
| CA102 | CMLIGHT | EFFICIENT LIGHTING (T8 W/ ELEC BALL.) |
| CA102N | CMLIGHT | EFFICIENT LIGHTING (T8 W/ ELEC BALL.) |
| CA201 | CMFRCAC | HIGH EFFICIENCY CHILLER |
| CA201N | CMFRCAC | HIGH EFFICIENCY CHILLER |
| CA202 | CMFRCAC | HIGH EFFICIENCY CAC |
| CA202N | CMFRCAC | HIGH EFFICIENCY CAC |
| CA301 | COMTOHP | HI EFF AIR TO AIR HEAT PUMP |
| CA301N | COMTOHP | HI EFF AIR TO AIR HEAT PUMP |
| CB102 | CMLIGHT | EFFICIENT LIGHTING (T8 W/ ELEC BALL.) |
| CB102N | CMLIGHT | EFFICIENT LIGHTING (T8 W/ ELEC BALL.) |
| CB201 | CMFRCAC | HIGH EFFICIENCY CHILLER |
| CB201N | CMFRCAC | HIGH EFFICIENCY CHILLER |
| CB202 | CMFRCAC | HIGH EFFICIENCY CAC |
| CB202N | CMFRCAC | HIGH EFFICIENCY CAC |
| CB301 | COMTOHP | HI EFF AIR TO AIR HEAT PUMP |
| CB301N | COMTOHP | HI EFF AIR TO AIR HEAT PUMP |
| CC102 | CMLIGHT | EFFICIENT LIGHTING (T8 W/ ELEC BALL.) |
| CC102N | CMLIGHT | EFFICIENT LIGHTING (T8 W/ ELEC BALL.) |
| CC201 | CMFRCAC | HIGH EFFICIENCY CHILLER |
| CC201N | CMFRCAC | HIGH EFFICIENCY CHILLER |
| CC202 | CMFRCAC | HIGH EFFICIENCY CAC |
| CC202N | CMFRCAC | HIGH EFFICIENCY CAC |
| CC301 | COMTOHP | HI EFF AIR TO AIR HEAT PUMP |
| CC301N | COMTOHP | HI EFF AIR TO AIR HEAT PUMP |

[3] All commercial sector DSM options are available in all EMM regions.

| Option Code[2] | Program Code | Commercial Options Description |
|---|---|---|
| CD102 | CMLIGHT | EFFICIENT LIGHTING (T8 W/ ELEC BALL.) |
| CD102N | CMLIGHT | EFFICIENT LIGHTING (T8 W/ ELEC BALL.) |
| CD201 | CMFRCAC | HIGH EFFICIENCY CHILLER |
| CD201N | CMFRCAC | HIGH EFFICIENCY CHILLER |
| CD202 | CMFRCAC | HIGH EFFICIENCY CAC |
| CD202N | CMFRCAC | HIGH EFFICIENCY CAC |
| CD301 | COMTOHP | HI EFF AIR TO AIR HEAT PUMP |
| CD301N | COMTOHP | HI EFF AIR TO AIR HEAT PUMP |
| CE102 | CMLIGHT | EFFICIENT LIGHTING (T8 W/ ELEC BALL.) |
| CE102N | CMLIGHT | EFFICIENT LIGHTING (T8 W/ ELEC BALL.) |
| CE201 | CMFRCAC | HIGH EFFICIENCY CHILLER |
| CE201N | CMFRCAC | HIGH EFFICIENCY CHILLER |
| CE202 | CMFRCAC | HIGH EFFICIENCY CAC |
| CE202N | CMFRCAC | HIGH EFFICIENCY CAC |
| CE301 | COMTOHP | HI EFF AIR TO AIR HEAT PUMP |
| CE301N | COMTOHP | HI EFF AIR TO AIR HEAT PUMP |
| CF102 | CMLIGHT | EFFICIENT LIGHTING (T8 W/ ELEC BALL.) |
| CF102N | CMLIGHT | EFFICIENT LIGHTING (T8 W/ ELEC BALL.) |
| CF201 | CMFRCAC | HIGH EFFICIENCY CHILLER |
| CF201N | CMFRCAC | HIGH EFFICIENCY CHILLER |
| CF202 | CMFRCAC | HIGH EFFICIENCY CAC |
| CF202N | CMFRCAC | HIGH EFFICIENCY CAC |
| CF301 | COMTOHP | HI EFF AIR TO AIR HEAT PUMP |
| CF301N | COMTOHP | HI EFF AIR TO AIR HEAT PUMP |
| CG102 | CMLIGHT | EFFICIENT LIGHTING (T8 W/ ELEC BALL.) |
| CG102N | CMLIGHT | EFFICIENT LIGHTING (T8 W/ ELEC BALL.) |
| CG201 | CMFRCAC | HIGH EFFICIENCY CHILLER |
| CG201N | CMFRCAC | HIGH EFFICIENCY CHILLER |
| CG202 | CMFRCAC | HIGH EFFICIENCY CAC |
| CG202N | CMFRCAC | HIGH EFFICIENCY CAC |

| Option Code[2] | Program Code | Commercial Options Description |
|---|---|---|
| CG301 | COMTOHP | HI EFF AIR TO AIR HEAT PUMP |
| CG301N | COMTOHP | HI EFF AIR TO AIR HEAT PUMP |
| CH102 | CMLIGHT | EFFICIENT LIGHTING (T8 W/ ELEC BALL.) |
| CH102N | CMLIGHT | EFFICIENT LIGHTING (T8 W/ ELEC BALL.) |
| CH201 | CMFRCAC | HIGH EFFICIENCY CHILLER |
| CH201N | CMFRCAC | HIGH EFFICIENCY CHILLER |
| CH202 | CMFRCAC | HIGH EFFICIENCY CAC |
| CH202N | CMFRCAC | HIGH EFFICIENCY CAC |
| CH301 | COMTOHP | HI EFF AIR TO AIR HEAT PUMP |
| CH301N | COMTOHP | HI EFF AIR TO AIR HEAT PUMP |
| CI102 | CMLIGHT | EFFICIENT LIGHTING (T8 W/ ELEC BALL.) |
| CI102N | CMLIGHT | EFFICIENT LIGHTING (T8 W/ ELEC BALL.) |
| CI201 | CMFRCAC | HIGH EFFICIENCY CHILLER |
| CI201N | CMFRCAC | HIGH EFFICIENCY CHILLER |
| CI202 | CMFRCAC | HIGH EFFICIENCY CAC |
| CI202N | CMFRCAC | HIGH EFFICIENCY CAC |
| CI301 | COMTOHP | HI EFF AIR TO AIR HEAT PUMP |
| CI301N | COMTOHP | HI EFF AIR TO AIR HEAT PUMP |
| CJ102 | CMLIGHT | EFFICIENT LIGHTING (T8 W/ ELEC BALL.) |
| CJ102N | CMLIGHT | EFFICIENT LIGHTING (T8 W/ ELEC BALL.) |
| CJ201 | CMFRCAC | HIGH EFFICIENCY CHILLER |
| CJ201N | CMFRCAC | HIGH EFFICIENCY CHILLER |
| CJ202 | CMFRCAC | HIGH EFFICIENCY CAC |
| CJ202N | CMFRCAC | HIGH EFFICIENCY CAC |
| CJ301 | COMTOHP | HI EFF AIR TO AIR HEAT PUMP |
| CJ301N | COMTOHP | HI EFF AIR TO AIR HEAT PUMP |
| CK102 | CMFRCAC | EFFICIENT LIGHTING (T8 W/ ELEC BALL.) |
| CK102N | CMFRCAC | EFFICIENT LIGHTING (T8 W/ ELEC BALL.) |
| CK201 | CMFRCAC | HIGH EFFICIENCY CHILLER |
| CK201N | CMFRCAC | HIGH EFFICIENCY CHILLER |

| **Option Code**[2] | **Program Code** | **Commercial Options Description** |
|---|---|---|
| CK202 | CMFRCAC | HIGH EFFICIENCY CAC |
| CK202N | CMFRCAC | HIGH EFFICIENCY CAC |
| CK301 | COMTOHP | HI EFF AIR TO AIR HEAT PUMP |
| CK301N | COMTOHP | HI EFF AIR TO AIR HEAT PUMP |

**Table A4: Industrial DSM Options Planned for Future Versions of the LDSM**

| **Aggregated DSM Programs** | **Detailed DSM Options** |
|---|---|
| Motor Drives | • Installation of high efficiency standard motors<br>• Installation of motors with adjustable speed drives<br>• Proper sizing of motors in industrial establishments<br>• Informational program for proper sizing and maintenance of motors |
| HVAC Related Programs | • Informational and technical assistance program for existing HVAC systems<br>• Installation of energy efficient HVAC measures in new and existing buildings<br>• Installation of energy efficient electric fans<br>• Installation of energy efficient air conditioner units<br>• Installation of heat recovery systems<br>• Installation of water source heat pump systems |
| Lighting | • Comprehensive lighting program for new industrial construction<br>• Comprehensive lighting improvement programs for existing industrial buildings |
| Load Management | • Installation of load control devices on HVAC and process control equipment<br>• Installation of energy management systems in industrial establishments<br>• Promotion of interruptible service to industrial customers<br>• Installation of radio activated direct line control devices<br>• Promotion of time-of-use rates among industrial customers<br>• Installation of thermal cool storage systems |

# APPENDIX B

Appendix B contains the model abstract and a detailed discussion of the algorithms within the LDSM. The appendix is divided into different sections.

## 1.0 Model Abstract

### 1.1 Model Background and Functions to be Performed

The LDSM code was developed according to the standards of the VS Fortran compiler. Most of the data that the LDSM uses, comes from other modules of the NEMS. The in-house data developed for the LDSM submodule consists of the LSR database, and the DSM options database. The LSR database used in this version of the model is based on EPRI's RELOAD database, while the options database was developed using ICF Resources Inc. DSM experience, and a survey of actual options offered by utilities in different parts of the U.S. The sources surveyed included data from the Bonneville Power Administration, Lawrence Berkeley Laboratories, ICF's analysis for the EPA, the EGUMS model documentation, and Integrated Resource Planning (IRP) reports from state commissions. More information about the input data is presented in Appendix D.

As shown in Figure B-1, the LDSM model requires some preprocessing of the input data, that mainly translates sequentially organized data into direct access file organization. Direct access files allow for relatively fast access to the extensive data sets, thus avoiding putting all the data into the computer's memory.

As mentioned previously, the LDSM submodule is designed as a link between the demand modules of the National Energy Modelling System (NEMS) and the Electric Capacity Planning (ECP), Electricity and Fuel Dispatch, and Electricity Financial and Pricing submodules of the Electricity Marketing Module (EMM). (The EMM itself is a part of the NEMS). In order to perform this function, the LDSM must interact with each of these modules and submodules (the major interactions with the rest of the NEMS system, as well as data flow are presented in Figure B-1).

## 1.2 An Overview of Tasks of the LDSM Submodule

The major tasks and the general flow of data within the LDSM model are presented in Figure B-2.

figure b-2

The entire set of computations within the LDSM code can be divided into two major segments that are run at different stages of the NEMS run:

- LDSM-1 -- This is run after the Demand modules' run and before the ECP module's run
- LDSM-2 -- This is run after the ECP module's run

The LDSM-1 performs five major tasks:

1) Develops the Load Duration Curves for the ECP model
2) Develops the Load Duration Curves for the EFD model
3) Develops a set of DSM Programs that are to compete with generation options within the ECP model
4) Supplies the EFP model with the estimates of the sectoral peak loads and electricity sales

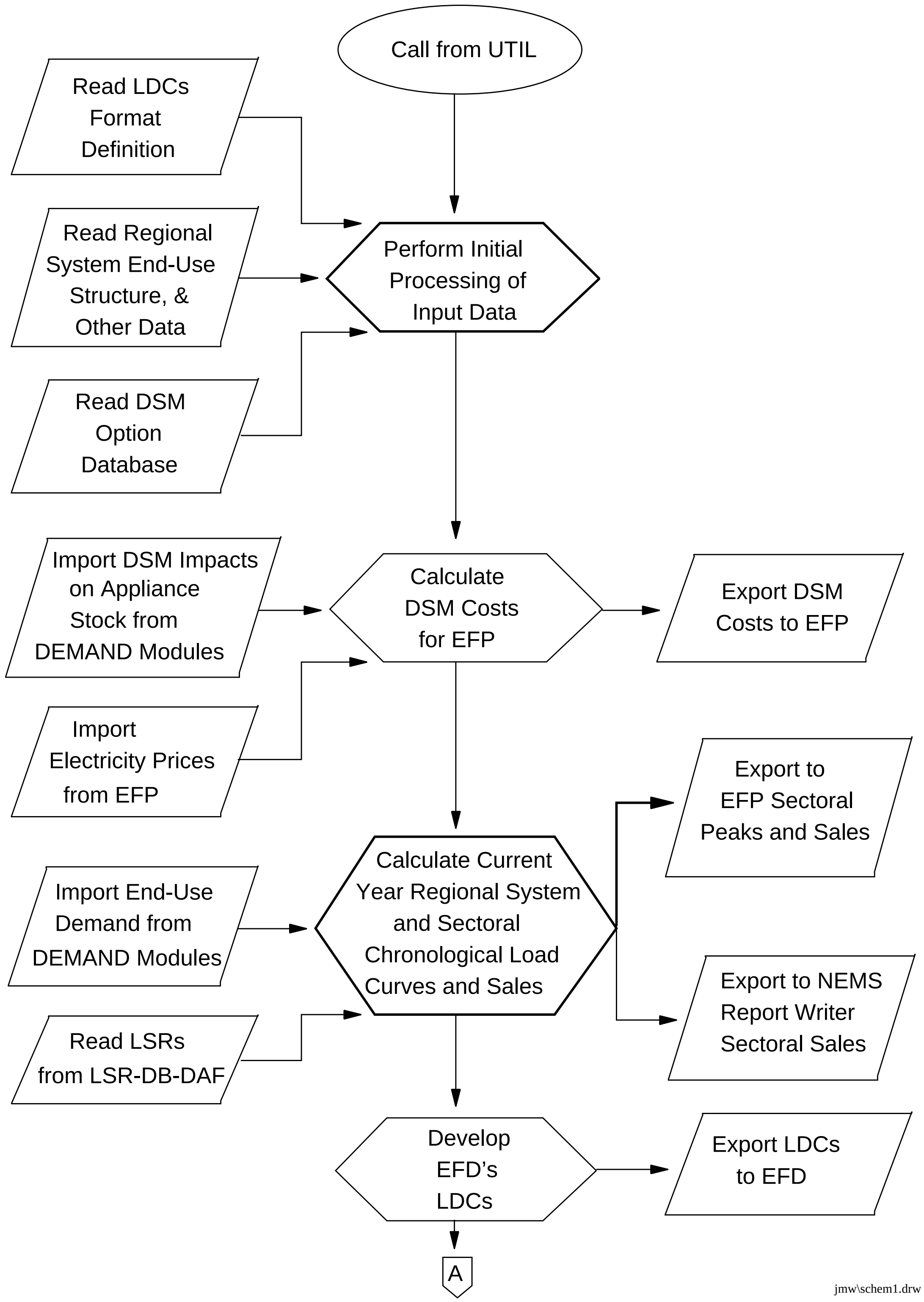
5) Supplies the EFP model with the estimates of the current year expenditures on DSM programs

The flow of computations in the LDSM-1 can be divided into a number of following steps:

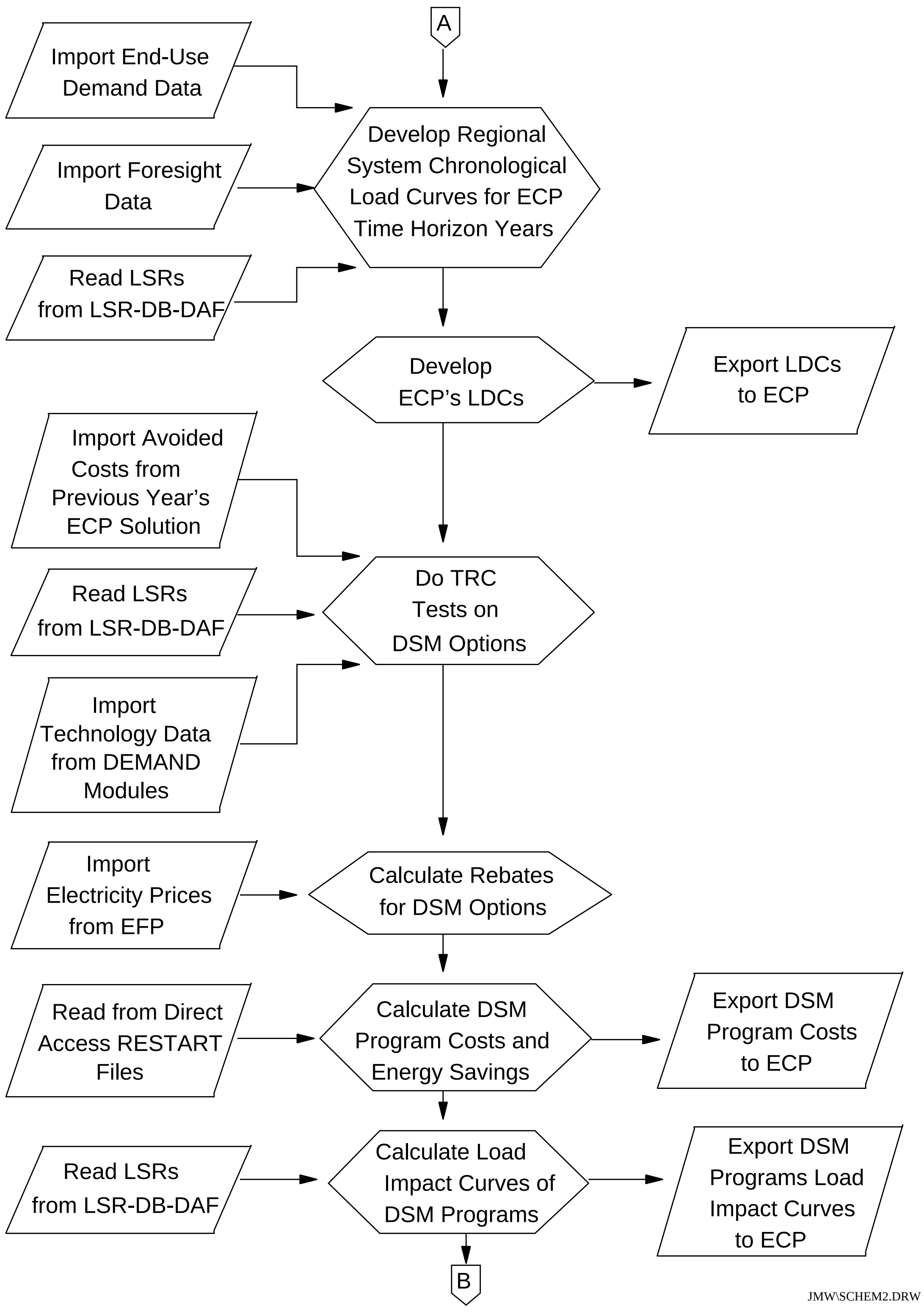
1) Development of regional system chronological load curves for the current year (Subroutines DSMFOR, DSMARE, DSMACM, DSMAIN, DSMATR, DSMDLT, DSMHLM)
2) Calculation of current year sectoral load peaks required by the EFP model (Subroutine DSMEFP)
3) Calculation of current year costs of DSM programs (Subroutine DSMEFP2)
4) Development of Load Duration Curves for the EFD module (in the future at this step the system curves will first be adjusted for renewable technology generation) (Subroutine DSMEFD)
5) Development of Load Duration Curves for the ECP model, for the first year of its time horizon (Subroutine DSMLCP)
6) Prescreening of the DSM Options listed in the database using the most recent assessment of the electric supply avoided costs, utilizing the Total Resource Cost test (Subroutines DSMTRCR, DSMTRCC)
7) Calculation of rebates necessary to achieve the predefined pay-back period (Subroutines DSMTRCR, DSMTRCC)
8) Aggregation of the options that passed the TRC test into a number of DSM programs, and calculation of the costs and the annual changes in the end-use demand caused by the programs, for the entire ECP time horizon (Subroutine DSMPCIM)
9) Calculation of chronological system load curves for the future years of the ECP time horizon (Subroutine DSMECP1)
10) Calculation of the ECP LDCs for the future years within the ECP time horizon (Subroutine DSMLCP)
11) Calculation of Load Impact Curves (delta load curves) for DSM programs for all future years within the ECP time horizon (Subroutine DSMPRGL)

The LDSM-2 part performs one major task -- disaggregates to option level, the DSM programs chosen for the next year's implementation in the current optimal ECP solution (Subroutine DSMECP2). The LDSM-2 supplies the Demand Modules with the percentages of the maximum possible technological shifts resulting from each of the DSM options.

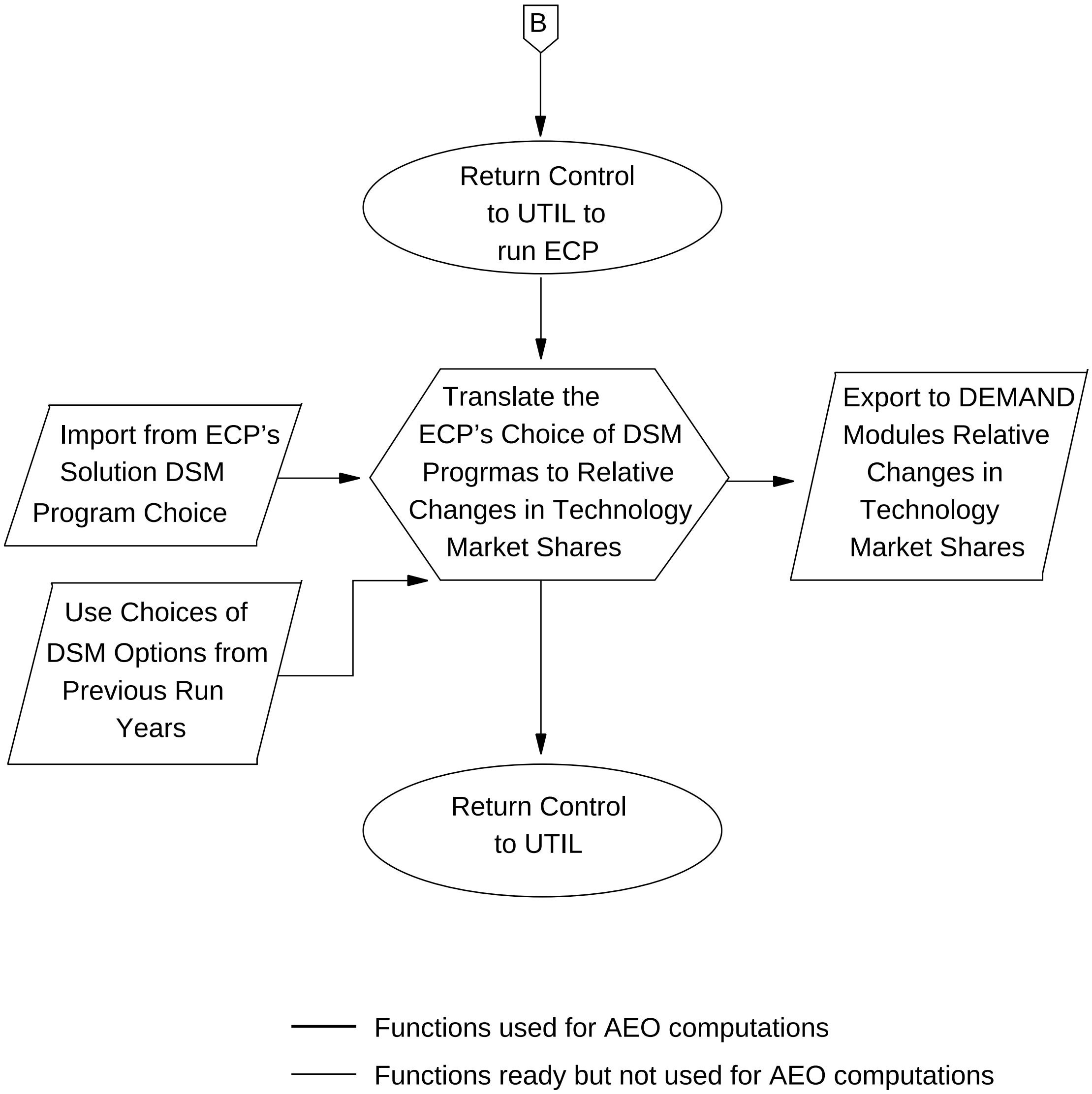
**FIGURE B-3**
**PAGE 1 OF 3**
**SCHEMATIC DIAGRAM OF LDSM COMPUTATIONAL FLOW**



# FIGURE B-3
## PAGE 2 OF 3
## SCHEMATIC DIAGRAM OF LDSM COMPUTATIONAL FLOW



## FIGURE B-3
### PAGE 3 OF 3
### SCHEMATIC DIAGRAM OF LDSM COMPUTATIONAL FLOW

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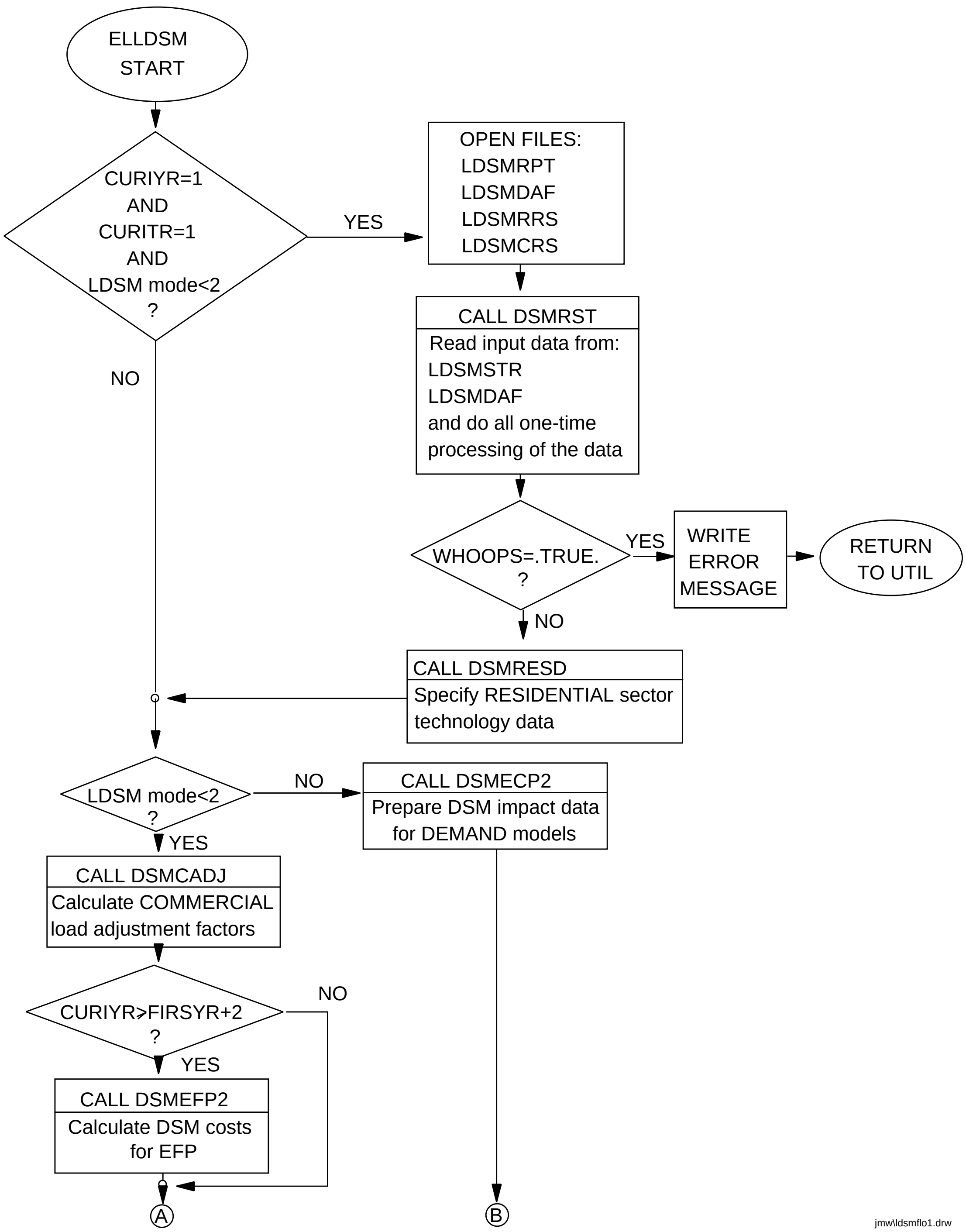
# FIGURE B-4
## PAGE 1 OF 2
## LDSM MAIN SUBROUTINE FLOWCHART



# FIGURE B-4
## PAGE 2 OF 2
## LDSM MAIN SUBROUTINE FLOWCHART

## LDSM Main Subroutine Flowchart (continued)

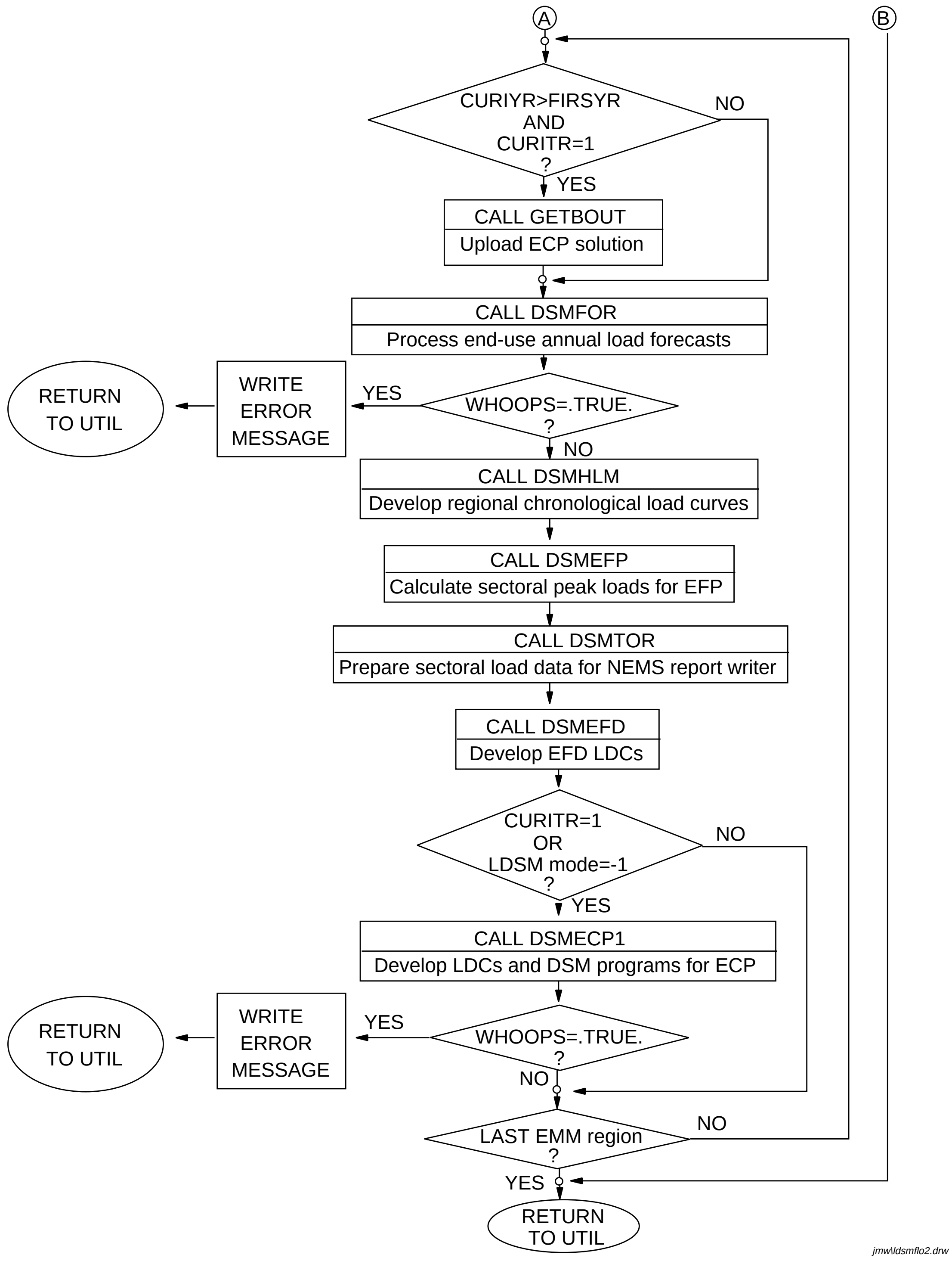


figure b-5

figure b-6

A schematic flow chart of computations in the LDSM code, is presented in Figure B-3. A more computer code oriented, precise presentation of the flow of computations in the main LDSM routine ELLDSM is presented in Figure B-4. Figures B-5 through B-10 present the general structure of the subroutine calls within the model. Table B1 contains a list of all the LDSM subroutines with a brief description of their functions.

figure b-7

figure b-8

figure b-6

figure b-10

The next section of appendix B describes the major steps in the LDSM's computations. In the description we begin from the formulae that yield the final program outputs and then elaborate how the more particular data items required for these computations, are derived in the code.

**Table B1: List of Subroutines in the LDSM Source Code**

| Subroutine Name | Brief Description |
|---|---|
| ELLDSM | Main routine of the code |
| DSMSTR | Reads input data and performs all one-time processing |
| DSMRESD | Supplies residential sector technology data |
| DSMCADJ | Calculates commercial load adjustment factors |
| DSMEFP2 | Calculates DSM costs for EFP |
| DSMFOR | Calculates annual end-use load forecasts |
| DSMHLM | Develops system chronological load curves |
| DSMEFP | Calculates sectoral load peaks for EFP |
| DSMEFD | Develops EFD LDCs |
| DSMQSR | Sorts REAL matrices |
| DSMTOR | Prepares sectoral data for NEMS report writer |
| DSMECP1 | Develops LDCs and DSM programs for ECP |
| DSMECP2 | Calculates DSM impacts for the Demand models |
| DSMSKP | Skips comment lines on input |
| DSMQSI | Sorts INTEGER matrices |
| DSMARE | Imports end-use demand data from the Residential Model |
| DSMACM | Imports end-use demand data from Commercial Model |
| DSMATR | Imports end-use demand data from Industrial Model |
| DSMDLT | Calculates the "delta approach" end-use demands |
| DSMNVAL | Maps CENSUS division data to EMM region data |
| DSMNWS | Adds up end-use hourly load |
| DSMPRGD | Initially defines the DSM programs |
| DSMPCIM | Calculates costs and load impacts of DSM programs |
| DSMPRGL | Develops chronological load impact curves of DSM programs |
| DSMTRCR | Performs TRC tests on residential DSM options |
| DSMTRCC | Performs TRC tests on commercial DSM options |

| Subroutine Name | Brief Description |
|---|---|
| DSMLCP | Develops EFP format LDCs from chronological curves |
| DSMREBR | Calculates rebates for residential DSM options |
| DSMREBC | Calculates rebates for commercial DSM options |
| DSMCVAL | Maps EMM region data to CENSUS division data |

## 2.0 Details of the LDSM's Algorithms

This part of appendix B consists of sections 2.1 through 2.5, each describing a specific algorithm of the LDSM submodule. While describing the equations, an attempt has been made to keep variable names similar to the names used in the actual code. (The indices put into parentheses represent actual indices of the variables in the code, while the indices presented as subscripts do not exist as explicit indices of the code variables, rather, they are implied by the Do-loops used in the code). Section 2.1 describes the methodology used for developing load duration curves for the EFP and EFD modules of the NEMS. Sub-section 2.1.3 describes the methodology used in the development of chronological hourly load curves for the EMM regions. Section 2.2 deals with the development of coincident and non-coincident peak loads for different sectors. These peaks are then supplied to the EFP module for the calculation of prices for electricity. Section 2.3 has sub-sections 2.3.1 through 2.3.4. This section describes how the DSM programs are created and characterized such that they can compete against supply-side options within the ECP model. After competing, the chosen DSM programs must then be implemented. Section 2.4 describes how the selected DSM programs, impact the market penetration of technologies, and change the technological mix. The final section, 2.5, describes how DSM costs for the current year run of the model are computed. These costs are needed by the EFP module of NEMS.

Formula presentation conventions

In the presentation of the formulae, we decided to use the variables from the source code. Because it was unpractical to quote long lists of all variable indices (as they were used in the code) we chose to present only those indices that were relevant for the formula. Quite often, to improve clarity of the formula presentation, we decided to add some non-existent in the code indices. The indices that existed in the source code were displayed in the parentheses following the variables. The indices added to the variables for better clarity of presentation were displayed as subscripts.

### 2.1 Development of Load Duration Curves for the ECP and EFD Modules

Load Duration Curves (LDCs), are used by both the ECP and the EFD Modules. The LDCs used by both the modules are represented in an approximated form of a discrete number of blocks. The height of each block gives the forecasted load, and the width represents the number of hours with that specified load. Summing the widths of all blocks in the LDC gives the total number of hours in the period it applies to. Due to the differing needs of the ECP and EFD modules, the LDCs for the ECP are created on annual basis, while the EFD requires seasonal curves. The sections below describe the specific steps used to develop the LDCs.

### 2.1.1 Load Duration Curves for the ECP Module

Demand for electricity is input to the ECP module by means of approximated LDCs, specified for each of the 13 EMM regions. Both the number of blocks, and the assignment of hours to blocks is specified as input data to the program.

The assignment of hours to blocks is completed in two steps. In the first step, the 8760 hours that make up a year are assigned to a number of "segments" defined by month, day-type, and time of day and then sorted in descending order in each of the segments. In the second step, each segment is divided into a number of "blocks". Each block includes a specified percentage of the hours assigned to a segment. Two types of blocks are allowed: "regular" blocks, and "peak" blocks. The height of a regular block is equal to the average load of hours assigned to that block, while the height of a peak block is equal to the highest hourly load for hours assigned to that block.

The width of each block is equal to the number of hours in the block. The area of a regular block represents the energy demand during the hours assigned to it. The area of a peak block slightly overestimates the actual load during the hours assigned to the block. However, for narrow peak blocks, the error in approximation is not very significant. The advantage of this approach is a precise representation of the peak load.

Currently the LDCs used by ECP are represented by 11 blocks that are defined as shown in the table below. In the current LDC definitions all blocks pertain to all days in a week so the day-types are not specified in the table.

**Table 1. Example Definition of the LDC for the ECP model**

| LDC BLOCK | MONTHS | HOURS | %% OF A TIME SEGMENT | PEAK/NON-PEAK TYPE |
|---|---|---|---|---|
| 1 | JUNE JULY AUG SEPT | 8-18 | 5 | P |
| 2 | JUNE JULY AUG SEPT | 8-18 | 95 | N |
| 3 | JUNE JULY AUG SEPT | 6-7 19-24 | 100 | N |
| 4 | JUNE JULY AUG SEPT | 1-5 | 100 | N |
| 5 | DEC JAN FEB MARCH | 9-16 | 100 | N |
| 6 | DEC JAN FEB MARCH | 6-8 17-24 | 5 | P |
| 7 | DEC JAN FEB MARCH | 6-8 17-24 | 95 | N |
| 8 | DEC JAN FEB MARCH | 1-5 | 100 | N |
| 9 | APR MAY OCT NOV | 8-17 | 100 | N |
| 10 | APR MAY OCT NOV | 6-7 18-24 | 100 | N |
| 11 | APR MAY OCT NOV | 1-5 | 100 | N |

This function is accomplished in subroutine DSMLCP of the code.

### 2.1.2 Load Duration Curves for the EFD module

LDCs for use by the EFD module are created following the same procedure as described for the ECP curves. This time however, a number of LDCs are created, one for each of a number of seasons in a year. In the following table a current definition of the LDCs is presented, where in each of the six seasons an LDC is defined with 18 load blocks. All blocks apply to all days in a week, so the day-types are not specified in the table.

**Table 2. Example Definition of the LDC for the EFD model**

| SEASON | LDC BLOCK | MONTHS | HOURS | %% OF A TIME SEGMENT | PEAK/NON-PEAK TYPE |
|---|---|---|---|---|---|
| 1 | 1 | JAN FEB | 9-16 | 1 | P |
| 1 | 2 | JAN FEB | 9-16 | 3 | N |
| 1 | 3 | JAN FEB | 9-16 | 9 | N |
| 1 | 4 | JAN FEB | 9-16 | 29 | N |
| 1 | 5 | JAN FEB | 9-16 | 29 | N |
| 1 | 6 | JAN FEB | 9-16 | 29 | N |
| 1 | 7 | JAN FEB | 6-8 17-24 | 1 | P |
| 1 | 8 | JAN FEB | 6-8 17-24 | 3 | N |
| 1 | 9 | JAN FEB | 6-8 17-24 | 9 | N |
| 1 | 10 | JAN FEB | 6-8 17-24 | 29 | N |
| 1 | 11 | JAN FEB | 6-8 17-24 | 29 | N |
| 1 | 12 | JAN FEB | 6-8 17-24 | 29 | N |
| 1 | 13 | JAN FEB | 1-5 | 1 | P |
| 1 | 14 | JAN FEB | 1-5 | 3 | N |
| 1 | 15 | JAN FEB | 1-5 | 9 | N |
| 1 | 16 | JAN FEB | 1-5 | 29 | N |
| 1 | 17 | JAN FEB | 1-5 | 29 | N |
| 1 | 18 | JAN FEB | 1-5 | 29 | N |
| 2 | 1 | DEC MARCH | 9-16 | 1 | P |
| 2 | 2 | DEC MARCH | 9-16 | 3 | N |
| 2 | 3 | DEC MARCH | 9-16 | 9 | N |
| 2 | 4 | DEC MARCH | 9-16 | 29 | N |
| 2 | 5 | DEC MARCH | 9-16 | 29 | N |
| 2 | 6 | DEC MARCH | 9-16 | 29 | N |
| 2 | 7 | DEC MARCH | 6-8 17-24 | 1 | P |
| 2 | 8 | DEC MARCH | 6-8 17-24 | 3 | N |
| 2 | 9 | DEC MARCH | 6-8 17-24 | 9 | N |
| 2 | 10 | DEC MARCH | 6-8 17-24 | 29 | N |
| 2 | 11 | DEC MARCH | 6-8 17-24 | 29 | N |

| SEASON | LDC BLOCK | MONTHS | HOURS | %% OF A TIME SEGMENT | PEAK/NON-PEAK TYPE |
|---|---|---|---|---|---|
| 2 | 12 | DEC MARCH | 6-8 17-24 | 29 | N |
| 2 | 13 | DEC MARCH | 1-5 | 1 | P |
| 2 | 14 | DEC MARCH | 1-5 | 3 | N |
| 2 | 15 | DEC MARCH | 1-5 | 9 | N |
| 2 | 16 | DEC MARCH | 1-5 | 29 | N |
| 2 | 17 | DEC MARCH | 1-5 | 29 | N |
| 2 | 18 | DEC MARCH | 1-5 | 29 | N |
| 3 | 1 | APR MAY | 8-17 | 1 | P |
| 3 | 2 | APR MAY | 8-17 | 3 | N |
| 3 | 3 | APR MAY | 8-17 | 9 | N |
| 3 | 4 | APR MAY | 8-17 | 29 | N |
| 3 | 5 | APR MAY | 8-17 | 29 | N |
| 3 | 6 | APR MAY | 8-17 | 29 | N |
| 3 | 7 | APR MAY | 6-7 18-24 | 1 | P |
| 3 | 8 | APR MAY | 6-7 18-24 | 3 | N |
| 3 | 9 | APR MAY | 6-7 18-24 | 9 | N |
| 3 | 10 | APR MAY | 6-7 18-24 | 29 | N |
| 3 | 11 | APR MAY | 6-7 18-24 | 29 | N |
| 3 | 12 | APR MAY | 6-7 18-24 | 29 | N |
| 3 | 13 | APR MAY | 1-5 | 1 | P |
| 3 | 14 | APR MAY | 1-5 | 3 | N |
| 3 | 15 | APR MAY | 1-5 | 9 | N |
| 3 | 16 | APR MAY | 1-5 | 29 | N |
| 3 | 17 | APR MAY | 1-5 | 29 | N |
| 3 | 18 | APR MAY | 1-5 | 29 | N |
| 4 | 1 | JUNE SEPT | 8-18 | 1 | P |
| 4 | 2 | JUNE SEPT | 8-18 | 3 | N |
| 4 | 3 | JUNE SEPT | 8-18 | 9 | N |
| 4 | 4 | JUNE SEPT | 8-18 | 29 | N |
| 4 | 5 | JUNE SEPT | 8-18 | 29 | N |

| SEASON | LDC BLOCK | MONTHS | HOURS | %% OF A TIME SEGMENT | PEAK/NON-PEAK TYPE |
|---|---|---|---|---|---|
| 4 | 6 | JUNE SEPT | 8-18 | 29 | N |
| 4 | 7 | JUNE SEPT | 6-7 19-24 | 1 | P |
| 4 | 8 | JUNE SEPT | 6-7 19-24 | 3 | N |
| 4 | 9 | JUNE SEPT | 6-7 19-24 | 9 | N |
| 4 | 10 | JUNE SEPT | 6-7 19-24 | 29 | N |
| 4 | 11 | JUNE SEPT | 6-7 19-24 | 29 | N |
| 4 | 12 | JUNE SEPT | 6-7 19-24 | 29 | N |
| 4 | 13 | JUNE SEPT | 1-5 | 1 | P |
| 4 | 14 | JUNE SEPT | 1-5 | 3 | N |
| 4 | 15 | JUNE SEPT | 1-5 | 9 | N |
| 4 | 16 | JUNE SEPT | 1-5 | 29 | N |
| 4 | 17 | JUNE SEPT | 1-5 | 29 | N |
| 4 | 18 | JUNE SEPT | 1-5 | 29 | N |
| 5 | 1 | JULY AUG | 8-18 | 1 | P |
| 5 | 2 | JULY AUG | 8-18 | 3 | N |
| 5 | 3 | JULY AUG | 8-18 | 9 | N |
| 5 | 4 | JULY AUG | 8-18 | 29 | N |
| 5 | 5 | JULY AUG | 8-18 | 29 | N |
| 5 | 6 | JULY AUG | 8-18 | 29 | N |
| 5 | 7 | JULY AUG | 6-7 19-24 | 1 | P |
| 5 | 8 | JULY AUG | 6-7 19-24 | 3 | N |
| 5 | 9 | JULY AUG | 6-7 19-24 | 9 | N |
| 5 | 10 | JULY AUG | 6-7 19-24 | 29 | N |
| 5 | 11 | JULY AUG | 6-7 19-24 | 29 | N |
| 5 | 12 | JULY AUG | 6-7 19-24 | 29 | N |
| 5 | 13 | JULY AUG | 1-5 | 1 | P |
| 5 | 14 | JULY AUG | 1-5 | 3 | N |
| 5 | 15 | JULY AUG | 1-5 | 9 | N |
| 5 | 16 | JULY AUG | 1-5 | 29 | N |
| 5 | 17 | JULY AUG | 1-5 | 29 | N |

| SEASON | LDC BLOCK | MONTHS | HOURS | %% OF A TIME SEGMENT | PEAK/NON-PEAK TYPE |
|---|---|---|---|---|---|
| 5 | 18 | JULY AUG | 1-5 | 29 | N |
| 6 | 1 | OCT NOV | 8-17 | 1 | P |
| 6 | 2 | OCT NOV | 8-17 | 3 | N |
| 6 | 3 | OCT NOV | 8-17 | 9 | N |
| 6 | 4 | OCT NOV | 8-17 | 29 | N |
| 6 | 5 | OCT NOV | 8-17 | 29 | N |
| 6 | 6 | OCT NOV | 8-17 | 29 | N |
| 6 | 7 | OCT NOV | 6-7 18-24 | 1 | P |
| 6 | 8 | OCT NOV | 6-7 18-24 | 3 | N |
| 6 | 9 | OCT NOV | 6-7 18-24 | 9 | N |
| 6 | 10 | OCT NOV | 6-7 18-24 | 29 | N |
| 6 | 11 | OCT NOV | 6-7 18-24 | 29 | N |
| 6 | 12 | OCT NOV | 6-7 18-24 | 29 | N |
| 6 | 13 | OCT NOV | 1-5 | 1 | P |
| 6 | 14 | OCT NOV | 1-5 | 3 | N |
| 6 | 15 | OCT NOV | 1-5 | 9 | N |
| 6 | 16 | OCT NOV | 1-5 | 29 | N |
| 6 | 17 | OCT NOV | 1-5 | 29 | N |
| 6 | 18 | OCT NOV | 1-5 | 29 | N |

LDCs are generated based on chronological hourly load curves forecasted for each of the EMM regions. A procedure for developing those curves is presented in the next chapter.

### 2.1.3 Development of Chronological Hourly Load Curves for Regional Systems

The methodology used for the development of chronological hourly load curves makes two basic assumptions. The first is that future hourly load curves may be appropriately forecast by modifying historical load curves, to accommodate projected changes in the mix of end-use consumption. The second assumption is that it is possible to define a set of end-uses such that the distribution of annual electric load for each end-use remains relatively unchanged during the entire planning horizon.

All the load data used for the development of the forecasted system load curves is supplied to the LDSM module in a standardized format called Load Shape Representations (LSRs).

Historical LSRs for regional systems have been developed using 8760 hours of historical observations of load. To avoid averaging load data from several years, one representative year based on "typical" weather and economical conditions was chosen for the development of LSRs.

To improve the performance of the LDSM model during NEMS runs, LSRs representing load data are initially processed by the LDSM preprocessor (LSRDBMGR), Figure B-1. This extracts necessary information from the LSRs and stores it in a binary format on the direct access file -- Direct Access File Load Shape Representation Data Base (DAF-LSR-DB). Each record contains information extracted from one LSR. The first record stores information about the number of records in the database and information extracted from a calendar file, which is common for all the load shapes (a calendar file defines how to represent load data as day-type specific LSRs.)

The approach used in the LDSM allows for greater flexibility in the representation of load data. Days with similar load characteristics are aggregated into groups called day-types. All the days assigned to a given day-type are represented by the same daily load profile. This approach has two advantages over creating a separate load profile for each day in the year. First, a smaller number of daily load profiles lowers computational times. Second, the daily profiles developed from load observations from several days, allow us to eliminate some random variations in an hourly load. The way of grouping days into day-types is input to the preprocessor on a standard PC-HELM calendar file. Currently, following the organization of the hourly load data on the RELOAD data-base, the LSRs input to the LDSM are defined with 36 day-types -- week-days, week-ends and peak-days for each of the 12 months.

Each of the records on the DAF-LSR-DB stores values representing fractions of total annual energy demand assigned to each hour of each day-type. These percentages are directly used during LDSM computations without any additional processing.

In the LDSM, forecasting of chronological load curves for regions in the model is accomplished in the following steps. First, the current "NEMS year" demand for electricity, by each of the end-uses, is obtained from the demand forecasting modules of NEMS. If load curves are developed for the years after the current "NEMS year", the data are scaled up or down according to the "foresight" of demand in each of the sectors. Because the demand modules of NEMS work with census divisions, this demand has to be mapped to EMM regions. The following formula is used in the computations.

$$load = \sum_{k=1}^{nCENSUSreg} \{demand(CURIYR,k) * XQELxx(k,K1) / XQELxx(k,CURIYR) * MapCtoN(RNB,k,se$$

where:

| | |
|---|---|
| K1 = | year for which a chronological load curve is being developed |
| CURIYR = | current "NEMS year" |
| nCENSUSreg = | number of census divisions |
| RNB = | index of a current EMM region |
| k = | index of a census division = 1..nCENSUSreg |
| sector = | index of a demand sector |
| load = | annual electric load for a current end-use in a current EMM region in year K1 |
| demand(CURIYR,k) = | demand forecast imported from a demand module |
| XQELxx(k,K1) = | "foresighted" demand for an entire sector, that the end-use belongs to |
| MapCtoN(RNB,k,sector) = | fraction of census division k value that contributes to EMM region RNB value |

In the next step we calculate the differences between the current year and the base year demand for each of the end-uses. If the base year demand is input as zero values, the first year data is used as the base year data.

Next, the chronological hourly load curves are developed, according to the following formula.

$$SYLOAD(H) = DistLo_S(H) * SystemLoad + \sum_{I=1}^{NumSec} \{ \sum_{j=1}^{NEUSES(I)} [DistLo_{I,j}(H) * load2_{I,j}] \}$$

where:

| | |
|---|---|
| H = | hours in a year |
| I=1..NumSec = | index of sector |
| j=1..NEUSES(I) = | index of end-use within a sector |
| NEUSES(I) = | number of end-uses in a sector |
| SYLOAD(H) = | system load in hour H |
| $DistLo_S(H)$ = | historical hourly load shape for the system |
| $DistLo_{I,j}(H)$ = | hourly load shape |
| SystemLoad = | base year total system load |
| $load2_{I,j}$ = | difference between end-use's annual energy consumption in the current year and the base year (positive or negative value) |

The following subroutines handle the processing described in this subsection in the LDSM code: DSMHLM, DSMFOR, DSMARE, DSMACM, DSMAIN, DSMATR, DSMDLT, and DSMNWS.

## 2.2 Computations of Coincident and Non-Coincident Peak Loads for Different Sectors as Needed by the EFP Model

To find the peak loads for different sectors, chronological load curves for the sectors are necessary. Given that information about historical load shapes for the sectors is not available, these curves have to be developed by simple addition of hourly loads for all the end-uses belonging to each of the sectors. This is done using the following formula.

$$SectorLoad(SECTOR,H) = \sum_{j=1}^{NEUSES(SECTOR)} \{DistLo_j(H) * load1_j\}$$

where:

| | |
|---|---|
| H = | hours in a year |
| SECTOR = | sector index |
| j=1..NEUSES(SECTOR) = | index of an end-use within a sector |
| NEUSES(SECTOR) = | number of end-uses in a sector |
| $DistLo_j(H)$ = | hourly load shape |
| $load1_j$ = | end-use's annual energy consumption |
| SectorLoad(SECTOR,H) = | hourly load for a sector |

When the curves are ready, the non-coincident peaks are read as the maximum values on the curve and the coincident peaks as the load values at the hour of system peak. The above processing takes place in DSMNWS and DSMEFP subroutines.

## 2.3 Generation of a Choice of Competitive DSM Programs

The second major function of the LDSM model is the generation of DSM programs that can successfully compete with supply-side options during the creation of an optimal plan for the electric power system.

Given the complicated nature of the technical and economic mechanisms that govern the cost-effectiveness of the electric power system, a reasonable choice of competitive DSM options can be made only by optimizing the entire system over a long time horizon. However, the computational capabilities of the capacity planning model are constrained both by the available computer memory and limits on computation time. It is impossible to represent all the available DSM options as separate optimization variables given these constraints. Instead, the model uses a limited number of aggregated DSM programs each consisting of a number of DSM options of a similar nature, that, based on some prior simplified tests, have a good chance of being competitive. The procedure of preparation of the DSM programs within the LDSM model is presented below.

### 2.3.1 Definition of the DSM programs

In the current version of the model there are two groups of DSM programs; one applies to the residential sector and the other to the commercial sector. These two groups of programs are prepared in a slightly different way, given the differences in data structure of end-use technologies in each of the sectors.

The LDSM prepares sets of DSM programs, for each of the EMM regions and each of the years in the ECP planning horizon. This function is handled by the following two subroutines in the code: DSMPROG, and DSMPCIM. Each of the programs is represented by:

1) Total program cost, equal to the sum of program costs incurred during all years of the ECP planning horizon, discounted to the beginning of the planning horizon.

2) A matrix of load impact values, specified for each of the load blocks and each of the years in the planning horizon, assuming that the program is implemented at the maximum range

DSM programs consist of DSM options, which are defined in the DSM option database input to the model. One of the entries in the database defines in which DSM program a given option may be included. The choice of options that will finally be incorporated into the programs in different regions and different years of the time horizon depends on a number of tests performed by the model.

DSM programs are defined in the code for every region and year of the time horizon. The testing of options for each of the programs is completed in the following order:

1) The program checks if an option is available in the next year to the one in which the demand module is currently operating. (The assumption being used here is that the capacity planning model can at the earliest affect appliance stock in the year following the one in which the DSM program is begun).

2) The program checks if an option is available for the current region.

3) The program checks if the RESTART file contains information about all the technologies affected by an option (for commercial sector this applies only to FROM technologies).

4) The program performs a Total Resource Cost (TRC) test.

5) The program performs a Payback Period test.

### 2.3.2 The Total Resource Cost Test

The Total Resource Cost (TRC) test determines if a following condition is met:

OptionBenefits/OptionCost > PROFTH

while: OptionBenefits >= 0
OptionCost > 0

where:

| | |
|---|---|
| OptionBenefits = | total option benefits discounted to the beginning of implementation of the option; per single appliance for residential sector, and per unit of service demand for commercial sector |
| OptionCost = | total option costs discounted to the beginning of implementation of the option; per single appliance for residential sector, and per unit of service demand for residential sector |
| PROFTH = | profitability threshold, an input to the program |

Option benefits are calculated as described below. Given considerable amount of time required for computations of load impact curves for options, a simplifying assumption was made, and the load impact curve of an option, did not change with time.

$$\text{OptionBenefits} = \sum_{y=1}^{EqL} \{ \sum_{M=1}^{ECPnumBl} \{\text{EnSavings}(M) * \text{EPAVOID}(M,y) * \text{pvfa}\} + \text{EnSavings}(1) * \text{EPRMRGN}(y) * \text{pvfa}\}$$

where:

| | |
|---|---|
| EqL = | the shortest technical life of all the types of appliances affected by an option |
| ECPnumBl = | number of blocks in ECP's LDC |
| y=1..EqL = | index of a year in the technical life of an appliance |
| M=1..ECPnumBl = | index of a block in the ECP LDC |
| OptionBenefits = | total option benefits |
| EnSavings(H) = | energy savings per single appliance/unit of service demand expressed as the heights of blocks in the Load Impact Curve |
| EPAVOID(H,y) = | avoided costs of electricity discounted to the beginning of the planning horizon (for the years beyond the ECP planning horizon, the last year value, appropriately discounted, is used) |
| EPRMRGN(y) = | avoided costs of the reserve margin discounted to the beginning of the planning horizon (for the years beyond the ECP planning horizon, the last year value, appropriately discounted, is used) |

pvfa = present value adjustment factor that recalculates the avoided costs so they are present valued to the beginning of implementation of the DSM option, rather than to the beginning of the ECP planning horizon

Avoided costs of electricity depend on time-of-day and time-in-a-year. Because of this, the load impact of an option has to be explicitly specified for each of the blocks in the LDC. This is done by means of a Load Impact Curve (LIC). In the LIC the blocks are defined exactly the same way as in the current system LDC. The blocks in an LIC are not sorted by descending order of load (so an LIC is a slightly different notion than an LDC.)

LICs are based on chronological curves of the load impacts of options. These curves are calculated as follows:

For the Residential Sector:

$$\mathrm{OIMPACT}(H) = \sum_{K=1}^{ntech_{ff}} \{\mathrm{DistLo}_K(H) * \sum_{L=1}^{tdn_{ff}} \mathrm{UEC}_{K,L}\} - \sum_{K=1}^{ntech_{tt}} \{\mathrm{DistLo}_K(H) * \sum_{L=1}^{tdn_{tt}} \mathrm{UEC}_{K,L}\}$$

For the Commercial Sector:

$$\mathrm{OIMPACT}(H) = \sum_{K=1}^{ntech_{f}} \{\mathrm{DistLo}_K(H) * uecc_K\} - \sum_{K=1}^{ntech_{t}} \{\mathrm{DistLo}_K(H) * uecc_K\}$$

where:

ff = index depicting technologies being replaced ("FROM" technologies)
tt = index depicting replacing technologies ("TO" technologies)
K=1..ntech = index of a consecutive DSM option database technology affected by the option
L=1..tdn = index of a demand module technology corresponding to a DSM option data base technology (applies to residential sector only, where technologies are defined differently in the demand forecasting module than in the DSM option database)
H = hour in a year
$UEC_{K,L}$ = unitary energy consumptions for residential sector technologies
$uecc_K$ = unitary energy consumptions for commercial sector technologies
$DistLo_K(H)$ = hourly load shape
OIMPACT(H) = chronological load impact curve for an option

Option costs consist of two major elements: option incremental costs, and DSM program administrative and operational costs. These costs are calculated per unit of energy saved. For the commercial sector, incremental operational and maintenance costs are also included in the data base.

For the Residential Sector:

$$\mathrm{OptionCost}_R = \mathrm{IncrOptionCost} + \sum_{y=1}^{EqL} \{\mathrm{AnnualEnSavings} * \mathrm{DSMROptionCost(opti)}\}$$

where:

EqL = the shortest technical life of all the types of appliances affected by an option
y=1..EqL = index of a year in the technical life of an appliance
opti = index of a current option
R = depicts residential sector

$OptionCost_R$ = total option costs in residential sector
IncrOptionCost = incremental option cost per one appliance/unit of service demand
AnnualEnSavings = annual energy savings per one appliance/one unit of service demand
DSMROptionCost(opti) = cost of implementation of an option per one unit of energy saved during the entire life of an appliance in residential sector

Calculation of cost elements and annual energy savings is done as shown below. For the commercial module's database, capital costs are specified per unit of actually satisfied service demand, and operational and maintenance costs are specified per unit of service demand that can be theoretically satisfied. As a result, the latter must be divided by the capacity factor for that technology:

$$OptionCost_C = IncrOptionCost + \sum_{y=1}^{EqL} \{AnnualEnSavings * DSMCOptionCost(opti) + OMcost * pvfc\}$$

where:

EqL = the shortest technical life of all the types of appliances affected by an option
y=1..EqL = index of a year in the technical life of an appliance
opti = index of a current DSM option
C = depicts commercial sector
$OptionCost_C$ = total option costs in commercial sector
IncrOptionCost = incremental option cost per one appliance/unit of service demand
AnnualEnSavings = annual energy savings per one appliance/one unit of service demand
DSMCOptionCost(opti) = cost of implementation of an option per one unit of energy saved during the entire life of an appliance in commercial sector
OMcost = annual incremental operational and maintenance costs for commercial sector technologies
pvfc = factor that present-values costs to the beginning of implementation of an option

Calculation of cost elements and annual energy savings is done as shown below. For the commercial module's database, capital costs are specified per unit of actually satisfied service demand, and operational and maintenance costs are specified per unit of service demand that can be theoretically satisfied. As a result, the latter must be divided by the capacity factor for that technology:

For Residential Sector Options:

$$IncrOptionCost_R = \sum_{K=1}^{ntech_{tt}} \{ \sum_{L=1}^{tdnt_{tt}} [Cost_{K,L}] \} - \sum_{K=1}^{ntech_{ff}} \{ \sum_{L=1}^{tdn_{ff}} [Cost_{K,L}] \}$$

$$AnnualEnSavings_R = \sum_{K=1}^{ntech_{ff}} \{ \sum_{L=1}^{tdn_{ff}} [UEC_{K,L}] \} - \sum_{K=1}^{ntech_{tt}} \{ \sum_{L=1}^{tdn_{tt}} [UEC_{K,L}] \}$$

For Commercial Sector Options:

$$IncrOptionCost_C = \sum_{K=1}^{ntech_{tt}} \{TechCost_{K,1}\} - \sum_{K=1}^{ntech_{ff}} \{TechCost_{K,1}\}$$

$$OMCost = \sum_{K=1}^{ntech_{tt}} \{TechCost_{K,2} \ / \ capfac_K\} - \sum_{K=1}^{ntech_{ff}} \{TechCost_{K,2} \ / \ capfac_K\}$$

$$AnnualEnSavings_C = \sum_{K=1}^{ntech_{ff}} \{uecc_K\} - \sum_{K=1}^{ntech_{tt}} \{uecc_K\}$$

where:

R = depicts residential sector
C = depicts commercial sector
ff = index depicting technologies being replaced, ("FROM" technologies)
tt = index depicting replacing technologies ("TO" technologies)
K=1..ntech = index of a consecutive DSM option data base technology affected by the option
L=1..tdn = index of a demand module technology corresponding to the DSM option data base technology
ntech = number of DSM option database technologies affected by an option
tdn = number of a demand module technologies affected by an option
IncrOptionCost = incremental option cost per one appliance/unit of service demand
$Cost_{K,L}$ = cost of purchase of one appliance
$TechCost_{K,1}$ = cost of purchase of equipment per one unit of service demand
$TechCost_{K,2}$ = annual operational and maintenance cost for equipment per one unit of service demand
OMcost = annual incremental operational and maintenance costs for commercial sector technologies
$capfac_K$ = capacity factor for the technology K
AnnualEnSavings = annual energy savings per one appliance/one unit of service demand
$UEC_{K,L}$ = unitary energy consumption for residential technologies
$uecc_K$ = unitary energy consumptions for commercial technologies

The residential sector unit energy consumptions for each technology, are supplied by the restart file. The commercial sector unit energy consumptions (per unit of actual service demand satisfied in a year) are calculated as the reciprocals of technology efficiencies that are imported from the commercial sector technology database. The capacity factors are also imported from the same database. An intermediate step of translating data from census divisions to NERC regions has to be done, since the demand module works at the census division level, while the LDSM works at the level of NERC regions.

uecc=1.0/teff

while:

$$teff = \sum_{k=1}^{nCENSUSreg} \{TechEff(k) * MapCtoN(RBN,k,sector)$$

$$capfac = \sum_{k=1}^{nCENSUSreg} \{CapacityFactor(k) * MapCtoN(RNB,k,sector)$$

where:

nCENSUSreg = number of census divisions
RNB = index of a current EMM region
k = index of a census division = 1..nCENSUSreg
sector = index of a demand sector
teff = efficiency of a technology in a current NERC region
capfac = capacity factor of a technology in a current EMM region
TechEff(k) = efficiency of a technology in census division k, as imported from the demand module database
CapacityFactor(k) = capacity factor of a technology in census division k, as imported from the demand module database
MapCtoN(RNB,k,sector) = fraction of census division K value that contributes to EMM region RNB value

An option may fail the TRC test due to some supplementary checks performed by the program. An option fails if:

1) AnnualEnSavings < 0
2) OptionBenefits < 0

The TRC computations are handled in the DSMTRCR, and DSMTRCC subroutines of the LDSM code.

### 2.3.3 Computations of Rebates and the Payback Period Test

Rebates are calculated as the difference between an incremental option cost and savings due to implementation of an option in a predefined number of years.

For the Residential Sector:

$$REBATE_R = IncrOptionCost_R - PAYBACK * (AnnualEnSavings_R * EPRICE_T(RNB))$$

For the Commercial Sector:

$$REBATE_C = IncrOptionCost_C - PAYBACK * (AnnualEnSavings_C * EPRICE_T(RNB) - OMcost)$$

where:

R = depicts residential sector
C = depicts commercial sector
RNB = index of a current EMM region
T = index of a tariff appropriate for a given sector
REBATE = rebate per one appliance/unit of service demand (dependently on sector)
PAYBACK = payback period
IncrOptionCost = incremental option cost per one appliance/unit of service demand
AnnualEnSavings = annual energy savings per one appliance/one unit of service demand
OMcost = annual incremental operational and maintenance costs for commercial sector technologies
$EPRICE_T(RNB)$ = price for electricity imported from the EFP module

Given the above definition of a rebate, when it becomes negative it means that the consumer investment will be repaid by energy savings in less than the assumed payback period. Such an attractive option would not require DSM for acceptability, and normal market mechanisms would be sufficient for its penetration, and hence such options should be excluded from further analysis by the LDSM. Hence, an option fails the Payback Period Test if:

REBATE < 0

### 2.3.4 Computations of DSM Program Load Impact

After deciding upon which DSM options are to be aggregated under which DSM program, the load impacts of the programs are calculated. The load impact of a program is dependent upon the EMM region, the start year, and the year of its implementation. The load impacts, specified for each of the blocks of the ECP LDC, are represented by Load Impact Curves. These functions are handled in the DSMPCIP and DSMPRGL subroutines of the LDSM code.

The LICs are developed based on chronological curves that represent hourly load savings due to implementation of the programs. The following formula shows how these curves are created:

$$PIMPACT(H) = \sum_{P=1}^{NTECHAFFP(P)} \{DistLo_j(H) * DeltaEnergy(j,SYRix,K11,P)\}$$

where:

| | |
|---|---|
| H = | hours in a year |
| P = | index of a DSM program |
| j=1..NTECHAFFP(P) = | index of a technology affected by the DSM program |
| K11 = | index of a consecutive year of implementation of the DSM program |
| SYRix = | index of a start year of a DSM program |
| NTECHAFFP(P) = | number of technologies affected by the DSM program |
| PIMPACT(H) = | hourly load impact of the program |
| $DistLo_P(H)$ = | hourly load shape |
| DeltaEnergy(j,SYRix,K11,P) = | change in energy demand by technology j, in year K11, due to DSM program P if it is started in year SYRix |

The list of technologies affected by a given DSM program is determined during the testing of DSM options. The change in energy demand for each of the technologies is calculated as follows:

For the Residential Sector:

$$DeltaEnergy(j,SYRix,PYRix,P) = +/- \sum_{x=1}^{PYRix} \{NumbAppl_{SYRix,x,D}\} * UEC(YRR,j)$$

For the Commercial Sector:

$$DeltaEnergy(L,SYRix,PYRix,P) = +/- \sum_{x=1}^{PYRix} \{ServDem_{SYRix,x,D}\} * uecc_L$$

where:

j = index of a technology
D = index of a DSM option affecting the technology
SYRix = index of a start year of a DSM program
PYRix = index of a current year of implementation of a DSM program
x = index of a year between the beginning and current year of implementation of a program
P = index of a DSM program
YRR = index of a RESTART file planning horizon year that corresponds to PYRix
DeltaEnergy(j,SYRix,PYRix,P) = change in energy demand by technology j, in program year PYRix, due to DSM program P if it is started in year SYRix; positive value for "FROM" technologies, negative for "TO" technologies
$NumbAppl_{SYRix,x,D}$ = number of appliances replaced by DSM option D, in the x-th year of its implementation, if it is started in year SYRix
$ServDem_{SYRix,x,D}$ = amount of service demand that is subjected to replacements of equipment due to the DSM option J, in the x-th year of its implementation, if it the option is started in year SYRix
UEC(YRR,j) = unitary energy consumption in year YRR, technology j, in residential sector
$uecc_j$ = unitary energy consumption for technology j in commercial sector

The number of appliances (residential sector) or the amount of service demand (commercial sector) that can be affected by a program in a given year results from an assessment of possible market penetrations of the options. Computation of the maximum possible market penetration of a DSM option is based on the idea of the program acceptance curve. The curve gives the percentage of an entire market for a given type of technology that will be served by a "TO" technology. This percentage depends on the length of an option's payback period. The next parameter that influences market penetration of the program is the ramp-up period. The model assumes a linear ramp-up period. At the end of this period, an option can be implemented to the full extent prescribed by the acceptance curve.

The current market size for each of the options is calculated in the program in a simplified fashion, as a sum of markets served by the "TO" and the "FROM" technologies before an option is implemented. If there are more than one "TO" and/or "FROM" technologies the numbers applying to the minimum size technologies are used. Given that, the computations of the maximum extent to which an option can be implemented are performed as follows:

For the Residential Sector:

$$NumbAppl_{SYRix,PYRix,D} = ((MMKSF + MMKST) * RMS - MMKST) * (1.0 - Rshift(RNB,opti))$$

For the Commercial Sector:

$$ServDem_{SYRix,PYRix,D} = ((MMKSF + MMKST) * RMS - MMKST) * (1.0 - Cshift(RNB,opti))$$

where:

D = index of a DSM option
SYRix = index of a start year of a DSM program
PYRix = index of a current year of a DSM program implementation
RNB = index of a current EMM region

opti = index of a current DSM option

$NumbAppl_{SYRix,PYRix,D}$ = number of appliances replaced by DSM option D, in year PYRix of its implementation, if it is started in year SYRix (if the value is negative it is replaced by 0)

$ServDem_{SYRix,PYRix,D}$ = amount of service demand that is subjected to replacements of equipment due to the DSM option J, in PYRix year of its implementation, if the option is started in year SYRix (if the value is negative it is replaced by 0)

MMKSF = minimum market size among the "FROM" technologies

MMKST = minimum market size among the "TO" technologies

RMS = resulting market size served by the "TO" technology after implementation of an option, expressed as a fraction

Rshift(RNB,opti) = fraction of the available market that is already committed to technology shifts due to decisions made in previous years, for residential sector

Cshift(RNB,opti) = fraction of the available market that is already committed to technology shifts due to decisions made in previous years, for commercial sector

One important assumption of the LDSM module is, that ECP decisions concerning the implementation of some DSM programs in the next year will not be reconsidered in the subsequent runs of the model. These decisions are assumed to hold true for the rest of the NEMS planning horizon. In other words all the decisions made by ECP about implementation of the DSM programs for the second year of its current planning horizon are final and cause an increase of penetration of the market by an option, dictated by the ramp-up profile. This means that in each year, some fraction of the market available for an option, may already be committed to it and hence may not be subject to a current year decision. Fractions of the market, already committed by previous decisions, are calculated as follows:

$$Rshift(RNB,opti) = \sum_{YY=FIRSYR+1}^{CURIYR-1} \{RopChoice(YY,RNB,opti) * ppramp\}$$

while:

IF (Y-YY) <= DSMROptionRamp(opti) THEN
  ppramp= 1.0 / DSMROptionRamp(opti) * (Y-YY)
ELSE
  ppramp= 1.0

where:

ppramp = ramp-up slope

DSMROptionRamp(opti) length of ramp-up period

RNB = index of a current EMM region

opti = index of a current DSM option

YY = index of a year when the decision was made

FIRSYR = first year of the NEMS planning horizon

CURIYR = current "NEMS year"

Y = index of a year of NEMS planning horizon for which the fraction is calculated

Rshift(RNB,opti) = fraction of the available market that is already committed to technology shifts due to decisions made in previous years, for residential sector

RopChoice(YY,RNB,opti) = number between 0 and 1 that specifies extent of implementation of an option opti in year YY in region RNB

The value of CopChoice is calculated in a similar way but with values that apply to the commercial sector.

### 2.3.5 Computations of the Costs of the Programs

LDSM calculates the total costs (actualized to the beginning of the ECP planning horizon) for each of the programs and for each of the possible start years, incurred during all the years of running the programs within the ECP planning horizon. The following formulae show the computations for an example of a residential sector DSM program. For the commercial sector, the algorithm of computations is the same, except that the units used to calculate the amount of technological switches are units of Service Demand rather than number of appliances.

$$DSMPRCST(SYRix,RNB,P) = \sum_{opti=1}^{nopt} \{ \sum_{PYR=SYR}^{ECPLastYearIndex} \{CurrNA_{opti},PYR + CurrFR_{opti},PYR) * (REBATE + OneYearEnSav_{opti} * DSMRoptionCost(opti)) * df\}\}$$

where:

| | |
|---|---|
| SYRix = | index of a start year of a DSM program |
| RNB = | index of a current EMM region |
| P = | DSM program index |
| opti = | index of a current DSM option |
| nopt = | number of DSM options in a program |
| PYR = | DSM program year index on the scale of the NEMS time horizon |
| SYR = | DSM program start year index on the scale of the NEMS time horizon |
| CurrNA = | maximum number of appliances that may be shifted from "FROM" to "TO" technologies resulting from the DSM program |
| CurrFR = | maximum number of free-rider appliance shifts that will accompany the DSM program induced shifts |
| REBATE = | rebate per one appliance |
| $OneYearEnSav_{opti}$ = | annual energy savings due to a shift of one appliance from the "FROM" to the "TO" technology |
| DSMRoptionCost(opti)= | unitary DSM option administrative costs (per 1 kWh of saved energy) |
| DSMPRCST(SYRix,RNB,P) = | total discounted cost of DSM program P in region RNB if started in year SYRix |
| df = | discount factor |
| ECPLastYearIndex = | index of the last year of the ECP time horizon |

while:

$CurrNA_{opti,PYR}$ = ((MMKSF + MMKST) * RMS - MMKST) * (1.0 - Rshift(RNB,opti))*(1.0/DSMROptinRamp(opti))*(PYR-SYR+1)

$CurrFR_{opti,PYR}$ = MMKST * (1.0 - Rshift(RNB,opti))*(1.0/DSMROptionRamp(opti))*(PYR-SYR+1)

where:

| | |
|---|---|
| PYR = | DSM program year index on the scale of the NEMS time horizon |
| SYR = | DSM program start year index on the scale of the NEMS time horizon |
| opti = | index of a current DSM option |
| RNB = | index of a current EMM region |

MMKSF = minimum market size among the "FROM" technologies
MMKST = minimum market size among the "TO" technologies
RMS = resulting market size served by the "TO" technology after implementation of an option, expressed as a fraction
Rshift(RNB,opti) = fraction of the available market that is already committed to technology shifts due to decisions made in previous years, for residential sector
DSMROptionRamp(opti) length of ramp-up period
CurrNA = maximum number of appliances that may be shifted from "FROM" to "TO" technologies resulting from the DSM program
CurrFR = maximum number of free-rider appliance shifts that will accompany the DSM program induced shifts

## 2.4 Computation of the Impact of DSM Programs on the Market Penetration of End-Use Technologies

ECP decisions about DSM program choice have to be passed to the demand forecasting modules so that the electric appliance stock record and the load forecast could be adjusted to reflect the implied technology shifts. Every year, the LDSM passes to the demand forecasting modules, cumulative market penetrations by DSM option. These penetrations result from decisions made between the beginning of the planning horizon and the current year, and are expressed as fractions of the market available for each of the options in any given year. Because the demand modules require data by census division, the results of the DSM program choice have to be translated into the numbers applicable to census divisions. Subroutine DSMECP2 of the LDSM code handles this part of the computations. The penetrations are calculated as follows:

$$DSMrFracOptionMarket_{k,D} = \sum_{RNB=1}^{nNERCreg} \{[RopChoice(CURIYR,RNB,D) + Rshift(RNB,D)] * MapNtoC(RNB,k,sector)$$

while:

RopChoice(CURIYR,RNB,D) = DSMPRCHOICE(RNB,P) * (1.0-Rshift(RNB,D))

where:

k = index of a CENSUS division
D = index of an option
RNB = index of a EMM region
CURIYR = index of a current "NEMS year"
sector = index of a demand sector
nNERCreg = number of EMM regions that are used in computations
Rshift(RNB,opti) = fraction of the available market that is already committed to technology shifts due to decisions made in previous years, for residential sector
Rshift(RNB,D) = fraction of the available market that is already committed to technology shifts due to decisions made in previous years
RopChoice(CURIYR,RNB,D)= number between 0 and 1 that specifies extent of implementation of an option n in the year next to year CURIYR in region RNB

DSMPROCHOICE(RNB,RNB,P) = number between 0 and 1 that represents the extent of implementation of DSM program P in region RNB, in the CURIYR+1 year, supplied by the ECP module

$DSMrFracOptionMarket_{k,D}$ = fraction of a market available for an option D in census division k, that has been decided to be subjected to the option in the next computational year

MapNtoC(RNB,k,sector) = fraction of EMM region RNB value, that contributes to a census division k value

## 2.5 Computations of "Current" Year DSM Costs for the EFP Module

For each year and iteration, the demand forecasting modules calculate current year utilization of "TO" technologies that includes both free riders and the shifts resulting from DSMoptions, and pass them to the LDSM module. These computations are handled by DSMEFP2, DSMREBR, and DSMREBC subroutines in the code. Computations within the demand forecasting modules should be conducted as follows:

For the Residential Sector:

DSMrNumUnitChange(D) = ((MMKSF + MMKST) * RMS) * DSMrFracOptionMarket(D)

For the Commercial Sector:

DSMcServDemChange(D) = ((MMKSF + MMKST) * RMS) * DSMcFracOptionMarket(D)

where:

D = index of a DSM option

DSMrNumUnitChange(D) = number of appliances of a DSM option, "TO" technology, replaced, in the current year ("free riders" + DSM option real participants)

DSMcServDemChange(D) = amount of service demand that is subjected to replacements of equipment with the "TO" technology of a DSM option D in the current year

MMKSF = minimum market size among the "FROM" technologies

MMKST = minimum market size among the "TO" technologies

RMS = resulting market size served by the "TO" technology given full implementation of an option, expressed as a fraction

DSMrFracOptionMarket(D) = fraction of a market available for an option D, that has been decided to be subjected to the option in the current year

Data supplied by the Demand modules is utilized for the computation of current expenditures on DSM programs as follows:

For the Residential Sector:

$$\mathrm{DSMAnnualCost(RNB,RES)} = \sum_{k=1}^{\mathrm{nCENSUSreg}} \{(\mathrm{DSMrNumUnitChange(D)} * [\mathrm{REBATE} + \mathrm{DSMROptionCost}$$
$$\mathrm{AnnualEnSavings)} * \mathrm{MapCtoN(RNB,k,RES)}]$$

For the Commercial Sector:

$$DSMAnnualCost(RNB,COM) = \sum_{k=1}^{nCENSUSreg} \{(DSMcServDemChange(D) * [REBATE + DSMCOptionCos$$
$$AnnualEnSavings) * MapCtoN(RNB,k,COM)]$$

where:

| | |
|---|---|
| RNB = | index of a EMM region |
| RES = | index of the residential sector |
| COM = | index of the commercial sector |
| k = | index of a CENSUS division |
| nCENSUSreg = | number of CENSUS divisions |
| D = | index of a DSM option |
| MapCtoN(RNB,k,sector) = | fraction of census division I value that contributes to an EMM region value |
| REBATE = | rebate per one appliance/unit of service demand (dependently on sector) |
| AnnualEnSavings = | annual energy savings per one appliance/unit of service demand |
| DSMROptionCost(D) = or DSMCOptionCost(D) | cost of implementation of an option per one unit of saved energy |
| DSMAnnualCost(RNB,RES) = | current year expenditures on DSM programs in residential sector |
| DSMAnnualCost(RNB,COM) = | current year expenditures on DSM programs in commercial sector |
| DSMrNumUnitChange(D) = | number of appliances of a DSM option, "TO" technology, replaced, in the current year ("free riders" + DSM option real participants) |
| DSMcServDemChange(D) = | amount of service demand that is subjected to replacements of equipment with the "TO" technology of a DSM option D in the current year |

Values for the variables REBATE and AnnualEnSavings are calculated in the same way as described in section 2.3.3., using the most recent estimates of the current year UECs and electricity prices.

# APPENDIX C

## Detailed Specification of Variables Used Within the LDSM Submodule

Appendix C gives the detailed list of (1) variables used in the LDSM submodule documentation, (2) variables that have been imported from the other modules of NEMS. These variables are listed in six different tables, numbered 1 through 6. Each table is preceded by a brief description of the variables included in the table that follows. All the source code variables that are not included in the following tables, can be found in the source code listing that is enclosed in the second volume of this document where each of them is well defined in the common statements. The Volume 2. presents also a table that lists for each of the source code variables the exact listing of source code lines where it appears.

### 1.0 Specification of the Variables Used in the LDSM Documentation

The following table presents all the variables plus all the indices used within the text of the LDSM Documentation. For each of the variables/indices we quote a corresponding source code variable/index, as well as we specify the units. All the names are presented in alphabetical order.

**Table 1. Specification of the variables and indices used in the documentation**

| Variable or index name used in the documentation | Description | Variable name in the source code | Units |
|---|---|---|---|
| AnnualEnSavings | annual energy savings per one appliance/one unit of service demand | AnnualEnSavings | GWh/appl or GWH/uSD [4] |
| AP | option annual maximum participation | CurrNA,CurrSD | # appl/a or uSD/a [5] |
| BaseYrLd | end-use base year load | BaseYrLd | GWh |
| C | index depicting Commercial sector | COM | - |
| CapacityFactor | technology capacity factor (imported from the demand module database) | CapacityFactor | 1 [6] |

[4] GWh = Giga Watt*hour
appl = appliance
uSD = unit of Service Demand

[5] a = annum

[6] 1 - for variables with no physical units (e.g. energy efficiency of an appliance -- Btu/Btu=1)

| Variable or index name used in the documentation | Description | Variable name in the source code | Units |
|---|---|---|---|
| capfac | technology capacity factor in EMM region | capfac | 1 |
| $CM_1$ | current market size for base technology | MMKSF | # appl/a uSD/a |
| $CM_2$ | current market size for efficient technology 2 | MMKST | # appl/a uSD/a |
| COM | index of the commercial sector | COM | - |
| Cost | cost of purchase of one appliance | Cost | $/appl |
| Cshift | fraction of the available market that is already committed to technology shifts due to decisions made in previous years, for commercial sector | Cshift | 1 |
| CURIYR | current year index | CURIYR | - |
| CurrFR | maximum number of free-rider appliance shifts that will accompany the DSM program induced shifts | CurrFR | # appl/a uSD |
| CurrNA | maximum number of appliances that may be shifted from FROM to TO technologies resulting from the DSM program | CurrNA | # appl/a |
| D | index for a DSM option | opti | - |
| d | index for a DSM option | opti | - |
| DDAF | weighted daily allocation factor | DayTypRatio | 1 |
| DDNF | normalization factor for daily allocation | TOTMON | 1 |
| DDTL | fraction of the annual load allocated to a day | ENDFAC | 1 |

| Variable or index name used in the documentation | Description | Variable name in the source code | Units |
|---|---|---|---|
| DeltaEnergy | change in technology energy demand; positive value for FROM technologies, negative for TO technologies | DeltaEnergy | GWh |
| demand | demand forecast imported from a demand module | demand | TTBtu/a or BLua or MMBtu/a [7] |
| df | discount factor | df | 1 |
| DHAF | hourly allocation factor | HourLoad | 1 |
| DHL | fraction of annual load allocated to an hour | DistLo | 1 |
| DHNF | normalization factor for hourly allocation | TOTAL | 1 |
| DistLo | hourly load shape | DistLo | 1 |
| DMAF | monthly allocation factor for month m | MonAlloFact | 1 |
| DMNF | normalization factor for monthly allocation | TOTAL | 1 |
| DNDAF | normalized daily allocation factor | - | 1 |
| DNHAF | normalized hourly allocation factor | HourLoad | 1 |
| DNMAF | normalized monthly allocation factor | - | 1 |
| DP | Participation level associated with load management program (fraction) | not ready | 1 |
| DSMAnnualCost | current year expenditures on DSM programs | DSMAnnualCost | $mln |

[7] TTBtu = Trillion British Thermal Units
MMBtu = Million British Thermal Units
BLua = Billion Lumen*years

| Variable or index name used in the documentation | Description | Variable name in the source code | Units |
|---|---|---|---|
| DSMCOptionCost | cost of implementation of an option per one unit of saved energy | DSMCOptionCost | $mln/GWh |
| DSMcServDemChange | amount of service demand shifted due to a DSM option implementation | DSMcServDemChange | uSD |
| DSMPRCST | total discounted cost of DSM program | DSMPRCST | $mln |
| DSMPROCHOICE | number between 0 and 1 that represents the extent of implementation of a DSM program | DSMPROCHOICE | 1 |
| DSMrFracOptionMarket | fraction of a market available for an option, that has been decided to be subjected to the option in the current year | DSMrFracOptionMarket | 1 |
| DSMrNumUnitChange | number of appliances shifted due to an option implementation in the current year (free riders + DSM option real participants) | DSMrNumUnitChange | # appl |
| DSMROptionCost | cost of implementation of an option per one unit of saved energy | DSMROptionCost | $mln/GWh |
| DSMRoptionCost | unitary DSM option administrative costs (per 1 kWh of saved energy) | DSMRoptionCost | $/kWh |
| DSMROptionRamp | length of ramp-up period | DSMROptionRamp | a |
| DWDAF | weighted daily allocation factor for a day-type | - | 1 |
| e | index for an end-use | J | - |
| ECPLastYearIndex | index of the last year of the ECP time horizon | ECPLastYearIndex | - |
| ECPnumBl | number of blocks in ECP's LDC | ECPnumBl | 1 |

| Variable or index name used in the documentation | Description | Variable name in the source code | Units |
|---|---|---|---|
| EI | incremental energy change for an option | OneYearEnSav | GWh |
| ELDC | End-use load in megawatts | LoadForec | MW |
| EnSavings | energy savings per single appliance/unit of service demand expressed as the heights of blocks in the Load Impact Curve | EnSavings | GW |
| EPAVOID | avoided costs of electricity discounted to the beginning of the planning horizon (for the years beyond the ECP planning horizon, the last year value, appropriately discounted, is used) | EPAVOID | $mln/GW |
| EPRICE | price for electricity imported from the EFP module | EPRICE | $/kWh |
| EPRMRGN | avoided costs of the reserve margin discounted to the beginning of the planning horizon (for the years beyond the ECP planning horizon, the last year value, appropriately discounted, is used) | EPRMRGN | $mln/GW |
| EqL | shortest technical life of all the types of appliances affected by an option | EqL | a |
| ER | electricity rates per-megawatt-hour equivalent | EPRICE | $/MWh |
| ff | index depicting technologies being replaced, ( FROM technologies) | - | - |
| FIRSYR | first year of the NEMS planning horizon | FIRSYR | - |

| Variable or index name used in the documentation | Description | Variable name in the source code | Units |
|---|---|---|---|
| h | index for an hour in a day | M | - |
| H | index for an hour in a year | M | - |
| i | Discount rate used in the calculations | DISCFA | 1 |
| ICC | incremental customer capital costs for a DSM option | IncrOptionCost | $ |
| ICO | incremental customer maintenance costs for a DSM option | OMcost | $ |
| IncrOptionCost | incremental option cost per one appliance/unit of service demand | IncrOptionCost | $/appl or $/uSD |
| I | index of sector | SECTOR | - |
| j | index for a technology | L | - |
| k | index for a CENSUS division | k | - |
| K | index for a DSM technology | K | - |
| K1 | year for which a chronological load curve is being developed | K1 | - |
| K11 | index of a consecutive year of implementation of the DSM program | K11 | - |
| l | index for a load segment | ECPnumBl | - |
| L | index for a Demand Module technology | L | - |
| LD | Changes in the load segment due to a DSM option | EnSavings | MW |
| LM | Percentage changes in a load segment due to implementation of a load management program | - | 1 |
| load | annual electric load for an end-use | load | GWh |

| Variable or index name used in the documentation | Description | Variable name in the source code | Units |
|---|---|---|---|
| load1 | annual load forecast for an end-use (1 stands for base type approach) | load1 | GWh |
| load2 | difference between an end-use's annual energy consumption in the current year and the base year (delta approach -- positive or negative value) | load2 | GWh |
| L | index of a demand module technology corresponding to the DSM option data base technology | L | - |
| m | index for a month | m | - |
| M | index for a block in LDC | M | - |
| MapCtoN | fraction of a census division value that contributes to an EMM region value | MapCtoN | 1 |
| MapNtoC | fraction of an EMM region value, that contributes to a census division value | MapNtoC | 1 |
| MA | Marginal electricity costs | EPRMRGN | $/kWh |
| MMKSF | minimum market size among the FROM technologies | MMKSF | # appl or uSD |
| MMKST | minimum market size among the TO technologies | MMKST | # appl or uSD |
| MP | maximum market penetration of a DSM technology (TO technology) | MMKST | 1 |
| M | index of a block in the ECP LDC | M | - |
| N | Lifetime of an appliance in years | EquipLife | a |

| Variable or index name used in the documentation | Description | Variable name in the source code | Units |
|---|---|---|---|
| n | index for a load management program | - | - |
| nCENSUSreg | number of census divisions | nCENSUSreg | 1 |
| ND | number of days in a month of the forecast year | NODAYS | 1 |
| NDT | number of day-types | NODAYT | 1 |
| NEUSES | number of end-uses in a sector | NEUSES | 1 |
| NM | number of months in the forecast year | NMONTH | 1 |
| nNERCreg | number of EMM regions that are used in computations | nNERCreg | 1 |
| nopt | number of DSM options in a program | nopt | 1 |
| ntech | number of DSM option database technologies affected by an option | ntech | 1 |
| NTECHAFFP | number of technologies affected by the DSM program | NTECHAFFP | 1 |
| NumbAppl | number of appliances replaced by a DSM option | NumbAppl | 1 |
| NumSec | number of the demand sectors | NumSec | 1 |
| NUSES | number of end-uses | NUSES | 1 |
| OIMPACT | chronological load impact curve for an option | SYLOAD | GW |
| OMcost | annual incremental operational and maintenance costs for commercial sector technologies | OMcost | $mln/a |

| Variable or index name used in the documentation | Description | Variable name in the source code | Units |
|---|---|---|---|
| OneYearEnSav | annual energy savings due to a shift of one appliance from the FROM to the TO technology | OneYearEnSav | GWh |
| opti | index of a current DSM option | opti | - |
| OptionBenefits | total option benefits discounted to the beginning of implementation of the option; per single appliance for residential sector, and per unit of service demand for commercial sector | OptionBenefits | $mln |
| OptionCost | total option costs discounted to the beginning of implementation of the option; per single appliance for residential sector, and per unit of service demand for residential sector | OptionCost | $mln |
| P | index for a DSM program | I | - |
| PAYBACK | payback period | PAYBACK | a |
| PB | payback period in years for a DSM option | PAYBACK | a |
| PIMPACT | hourly load impact of the program | SYLOAD | GW |
| ppramp | ramp-up slope | ppramp | 1 |
| PROFTH | profitability threshold, an input to the program | PROFTH | 1 |

| Variable or index name used in the documentation | Description | Variable name in the source code | Units |
|---|---|---|---|
| pvfa | present value adjustment factor that recalculates the avoided costs so they are present valued to the beginning of implementation of the DSM option, rather than to the beginning of the ECP planning horizon | pvfa | 1 |
| pvfc | factor that present-values costs to the beginning of implementation of an option | pvfc | 1 |
| PYR | DSM program year index on the scale of the NEMS time horizon | PYR | - |
| PYRix | index of a current year of implementation of a DSM program | PYRix | - |
| r | index for a region | RNB | - |
| R | index depicting Residential sector | RES | - |
| RB | Rebate level necessary to achieve a 2 year payback | REBATE | $ |
| REBATE | rebate per one appliance/unit of service demand (dependently on sector) | REBATE | $/appl |
| RES | index of the residential sector | RES | - |
| RMS | resulting market size served by the TO technology after implementation of an option, expressed as a fraction | RMS | 1 |
| RNB | index for an EMM region | RNB | - |

| Variable or index name used in the documentation | Description | Variable name in the source code | Units |
|---|---|---|---|
| RopChoice | number between 0 and 1 that specifies extent of implementation of an option | RopChoice | 1 |
| Rshift | fraction of the available market that is already committed to technology shifts due to decisions made in previous years | Rshift | 1 |
| RU | ramp-up period for an option | pramp | a |
| S | index depicting System | S | - |
| SECTOR | index of a demand sector | SECTOR | - |
| sector | index of a demand sector | sector | - |
| SectorLoad | hourly load for a sector | SectorLoad | GW |
| ServDem | amount of service demand that is subjected to replacements of equipment due to a DSM option | ServDem | uSD |
| SV | megawatt-hours of savings for an option | AnnualEnSavings | MWh |
| SYLOAD | hourly system load | SYLOAD | GW |
| SYR | DSM program start year index on the scale of the NEMS time horizon | SYR | - |
| SYRix | index of a start year of a DSM program | SYRix | - |
| SystemLoad | base year total system load | SystemLoad | GWh |
| T | index of a tariff appropriate for a given sector | - | - |
| t | index for a daytype | t | - |
| TCC | technology capital cost | Cost,TechCost | $ |

| Variable or index name used in the documentation | Description | Variable name in the source code | Units |
|---|---|---|---|
| tdn | number of a demand module technologies affected by an option | tdn | - |
| TechCost | cost of purchase of equipment per one unit of service demand | TechCost | $/uSD |
| TechCost | annual operational and maintenance cost for equipment per one unit of service demand | TechCost | $/uSD/a |
| TechEff | efficiency of a technology imported from the demand module database | TechEff | 1 |
| teff | efficiency of a technology in a current EMM region | teff | 1 |
| TM | total potential market size for a DSM option | ToNumbAppl | # of appl |
| TRC | Total Resource Costs for an option | TRC | $ |
| TS | total maximum possible incremental savings associated with an option | OneYearEnSav | MWh |
| tt | index depicting replacing technologies (TO technologies) | tt | - |
| uecc | unitary energy consumption for a technology in the commercial sector | uecc | uSD/a |
| UEC | unitary energy for a technology in the residential sector | UEC | GWh/a |
| $UI_1$ | usage index for a base technology 1 | UEC,uecc | MWh/a |
| $UI_2$ | usage index for an efficient technology 2 | UEC,uecc | MWh/a |

| Variable or index name used in the documentation | Description | Variable name in the source code | Units |
|---|---|---|---|
| x | index of a year between the beginning and current year of implementation of a program | x | - |
| XQELxx | foresighted demand for the entire sector that the end-use belongs to | XQELRE,XQELCM, XQLIN,XQLTR | TTBtu |
| y | index of year in a technical life of an appliance | y | - |
| Y | index for a year in the NEMS planing horizon | Y | - |
| y0 | first year of implementation of a DSM option | SYR | - |
| YPC | yearly option costs | DSMROptionCost, DSMCoptonCost | $ |
| YRR | index of a RESTART file planning horizon year that corresponds to PYRix | YRR | - |
| YY | index of a year when the decision was made | YY | - |

## 2.0 Source Code Variable Indices

The LDSM model code has been written in such a way that all the dimensions of the model can be redefined by simply changing PARAMETER statements specified in the designated INCLUDE file: DSMDIMEN. Below we present a table that specifies all the major indices used throughout the LDSM model. Obviously, in the code, these indices are referred to by using varying variable names. However, in the dimensioning statements they are defined by the parameter names given below. In the table below, the values of the dimensioning parameters are also specified, as they appear in the current version of the code. The indices in the table are listed in alphabetical order.

**Table 2. Variable Indices**

| INDEX | Index Description | Current Value |
|---|---|---|
| COM | COMMERCIAL SECTOR INDEX | 2 |
| ELCOOLX | INDEX FOR ELECTRICITY IN RESIDENTIAL COOLING DEMAND TABLE | 1 |

| | | |
|---|---|---|
| ELDRYEX | INDEX FOR ELECTRICITY IN RESIDENTIAL DRYERS DEMAND TABLE | 2 |
| ELHEATX | INDEX FOR ELECTRICITY IN RESIDENTIAL HEATING DEMAND TABLE | 2 |
| ELINDEX | INDEX FOR ELECTRICITY IN COMMERCIAL DEMAND SUBMODULE | 1 |
| ELLDVHX | INDEX FOR ELECTRICITY IN TRANSPORTATION MODULE, LIGHT DUTY ELECTR. VEHICLES DEMAND TABLE | 6 |
| ELRAILX | INDEX FOR ELECTRICITY IN TRANSPORTATION MODULE, RAILWAYS DEMAND TABLE | 1 |
| ELSECHX | INDEX FOR ELECTRICITY IN RESIDENTIAL SECONDARY HEATING DEMAND TABLE | 2 |
| ELSTOVX | INDEX FOR ELECTRICITY IN RESIDENTIAL STOVES DEMAND TABLE | 3 |
| ELWHEAX | INDEX FOR ELECTRICITY IN RESIDENTIAL WATER HEATING DEMAND TABLE | 2 |
| IND | INDUSTRIAL SECTOR INDEX | 3 |
| MAXBLOCK | MAXIMUM NUMBER OF BLOCKS IN ALL EFD LDCs (MAXEFDS*MAXEFDB) | 300 |
| MAXCBT | MAXIMUM NUMBER OF COMMERCIAL BUILDING TYPES USED IN LDSM | 11 |
| MAXCDSMO | MAXIMUM NUMBER OF COMMERCIAL DSM OPTIONS IN OPTION DATA BASE | 88 |
| MAXCOP | MAXIMUM NUMBER OF DSM OPTIONS THAT MAY BE CHOSEN BY ECP FOR COMMERCIAL SECTOR (in all regions) | 1500 |
| MAXCRG | MAXIMUM NUMBER OF CENSUS DIVISIONS | 9 |
| MAXCTECH | MAXIMUM NUMBER OF COMMERCIAL TECHNOLOGIES TO BE AFFECTED BY DSM | 10 |
| MAXDAY | MAXIMUM NUMBER OF DAYS IN A CALENDAR FILE MONTH | 3 |
| MAXDECT | MAXIMUM NUMBER OF DECISION TYPES USED IN DSM OPTIONS | 3 |

| | | |
|---|---|---|
| MAXDMT | MAXIMUM NUMBER OF DEMAND MODULE TECHNOLOGIES AFFECTED BY ONE DSM OPTION | 8 |
| MAXDSMP | MAXIMUM NUMBER OF DSM PROGRAMS FOR ONE REGION AND ONE SECTOR | 12 |
| MAXDTP | MAXIMUM NUMBER OF DAY-TYPES | 3 |
| MAXECPB | MAXIMUM NUMBER OF BLOCKS IN ONE SEGMENT OF ECP LDC DEF. | 3 |
| MAXECPS | MAXIMUM NUMBER OF SEGMENTS IN ECP LDC DEFINITION | 9 |
| MAXECTB | MAXIMUM TOTAL NUMBER OF BLOCKS IN ECP LDC = MAXECPS*MAXECPB | MAXECPB* MAXECPS |
| MAXEFDB | MAXIMUM NUMBER OF BLOCKS IN ONE SEASON LDC FOR EFD | 30 |
| MAXEFDS | MAXIMUM NUMBER OF SEASONS USED BY EFD MODULE | 6 |
| MAXEU | MAXIMUM NUMBER OF END-USES | 120 |
| MAXFRT | MAXIMUM NUMBER OF FROM TECHNOLOGIES AFFECTED BY ONE DSM OPTION | 2 |
| MAXHOUR | MAXIMUM NUMBER OF HOURS IN A YEAR +1 = MAXMON*MAXDAY*24+1 | MAXMON* MAXDAY *24+1 |
| MAXITV | MAXIMUM NUMBER OF HOURLY INTERVALS PER SEGMNET IN ECP/EFD LDC DEF. | 2 |
| MAXMON | MAXIMUM NUMBER OF MONTHS | 12 |
| MAXNLST | MAXIMUM NUMBER OF LISTS OF REGIONS TO DEFINE DSM OPTIONS | 3 |
| MAXNRG | MAXIMUM NUMBER OF EMM REGIONS | 13 |
| MAXNTPO | MAXIMUM NUMBER OF DEMAND MODULE TECHNOLOGIES PER OPTION (TO+FROM) | 8 |
| MAXOPR | MAXIMUM NUMBER OF DSM OPTIONS PER DSM PROGRAM | 100 |

| | | |
|---|---|---|
| MAXPCPH | MAXIMUM NUMBER OF COINCIDENT PEAK HOURS USED FOR PEAK LOAD COMPUTATIONS | 20 |
| MAXRBT | MAXIMUM NUMBER OF RESIDENTIAL BUILDING TYPES USED IN LDSM | 3 |
| MAXRDSMO | MAXIMUM NUMBER OF RESIDENTIAL DSM OPTIONS IN OPTION DATA BASE | 88 |
| MAXRDT | MAXIMUM NUMBER OF DECISION TYPES FOR RESIDENTIAL SECTOR USED IN LDSM | 2 |
| MAXREC | MAXIMUM NUMBER OF RECORDS ON DAF-LSR-DB | 1600 |
| MAXREU | MAXIMUM NUMBER OF RESIDENTIAL SECTOR END-USES | 10 |
| MAXRHOUR | MAXIMUM NUMBER OF HOURS IN A REAL YEAR | 8784 |
| MAXRLST | MAXIMUM NUMBER OF REGIONS+1 ON EACH OF THE REGIONS LISTED | 14 |
| MAXRRST | MAXIMUM NUMBER OF RECORDS ON RESTART FILE FOR ONE SECTOR | 4520 |
| MAXRTECH | MAXIMUM NUMBER OF RESIDENTIAL TECHNOLOGIES TO BE AFFECTED BY DSM | 37 |
| MAXSEA | MAXIMUM NUMBER OF SEASONS | 12 |
| MAXSEC | NUMBER OF SECTORS | 4 |
| MAXTAF | MAXIMUM NUMBER OF TECHNOLOGIES AFFECTED BY ONE DSM PROGRAM | 100 |
| MAXTOT | MAXIMUM NUMBER OF TO TECHNOLOGIES AFFECTED BY ONE DSM OPTION | 2 |
| MSEGEFD | MAXIMUM NUMBER OF SEGMENTS PER SEASON IN EFD LDC | 3 |
| NCRRD | NUMBER OF CENSUS DIV. USED IN RESIDENTIAL DEMAND SUBMODULE | 9 |
| NCRTR | NUMBER OF CENSUS DIVISIONS USED IN TRANSPORTATION SECTOR DEMAND MODULE | 9 |
| NEFCOO | NUMBER OF ENERGY FORMS USED FOR RESIDENTIAL COOLING | 3 |

| | | |
|---|---|---|
| NEFDRY | NUMBER OF ENERGY FORMS USED FOR RESIDENTIAL DRYERS | 2 |
| NEFELDV | NUMBER OF ENERGY FORMS USED FOR ELECTRIC LIGHT DUTY VEHICLES | 9 |
| NEFHTR | NUMBER OF ENERGY FORMS USED FOR RESIDENTIAL HEATING | 7 |
| NEFRAIL | NUMBER OF ENERGY FORMS USED FOR RAILROADS | 3 |
| NEFSHT | NUMBER OF ENERGY FORMS USED FOR RESIDENTIAL SECONDARY HEATING | 7 |
| NEFSTO | NUMBER OF ENERGY FORMS USED FOR RESIDENTIAL STOVES | 3 |
| NEFWHR | NUMBER OF ENERGY FORMS USED FOR RESIDENTIAL HEATING | 4 |
| NUMCTCE | NUMBER OF ELEMENTS IN COMMERCIAL TECHNOLOGY CODE | 3 |
| NYRESTC | NUMBER OF YEARS ON COMMERCIAL RESTART FILE | 26 |
| NYRESTR | NUMBER OF YEARS ON RESIDENTIAL RESTART FILE | 25 |
| NYRRD | NUMBER OF YEARS USED IN RESIDENTIAL DEMAND SUBMODULE | 26 |
| NYRTR | NUMBER OF YEARS USED IN TRANSPORTATION SECTOR DEM. MODULE | 26 |
| RES | RESIDENTIAL SECTOR INDEX | 1 |
| TNSEEFD | MAXIMUM TOTAL NUMBER OF SEGMENTS IN ALL SEASONS IN EFD LDC | 18 |
| TRA | TRANSPORTATION SECTOR INDEX | 4 |

## 3.0 Input Variables From Other EMM Submodules

### 3.1 Data imported to LDSM from the Electric Financial and Pricing Module

**Table 3.1 Data Accessed through the Common Blocks of the EFP Module**

| VARIABLE NAME | COMMON BLOCK NAME | VARIABLE SPECIFIC. | UNITS | IND.1 | IND.2 | IND.3 |
|---|---|---|---|---|---|---|

| | | | | | | |
|---|---|---|---|---|---|---|
| EPRICE | CA | Electricity Price | $/kWh | sector index (1 - Resid. 2 - Commer. 3 - Indust. 4 - Transp 5 - Total) | system function (4 - total) | 13 NERC regions |

NERC regions are assumed to be in the following order:
1 = ECAR
2 = ERCOT
3 = MAAC
4 = MAIN
5 = MAPP
6 = NY
7 = NE
8 = FL
9 = STV
10 = SPP
11 = NWP
12 = RA
13 = CNV

## 3.2 Data imported to LDSM from the Electric Capacity Planning Module

**Table 3.2 Data uploaded from the ECP solution**

| VARIABLE NAME | COMMON BLOCK NAME | VARIABLE SPECIFIC. | UNITS | IND.1 | IND.2 |
|---|---|---|---|---|---|
| EPAVOID | BILDOUT | Electric Supply Avoided Costs | mln$/GW | Blocks of the ECP LDC | Years in the ECP time horizon |
| DSMPRCHOICE | DSMTFECP | Choice of DSM programs made by ECP | 1 | EMM regions | DSM programs |

## 3.3 Data Imported to LDSM from the UTIL module

**Table 3.3 Data accessed in the common blocks of UTIL module**

| VARIABLE NAME | COMMON BLOCK NAME | VARIABLE SPECIFIC. | UNITS | IND.1 | IND.2 |
|---|---|---|---|---|---|
| XQELRE | MXQBLK | Foresight of Residential Sector Demand | Trill. Btus | Census Div. | Years 1990-2015 |
| XQELCM | MXQBLK | Foresight of Commercial Sector Demand | Trill. Btus | Census Div. | Years 1990-2015 |
| XQELIN | MXQBLK | Foresight of Industrial Sector Demand | Trill. Btus | Census Div. | Years 1990-2015 |

| | | | | | |
|---|---|---|---|---|---|
| XQELTR | MXQBLK | Foresight of Transportation Sector Demand | Trill. Btus | Census Div. | Years 1990-2015 |

## 4.0 Input Variables From Other NEMS Models

### 4.1 Data imported to LDSM from the Residential Demand Forecasting Model

LDSM imports data from the Residential Demand Forecasting Model by three different means:

1) Reading the RESTART file, developed by the Residential Forecasting Model in the run with the LDSM being switched off (translated into the direct access file format by the RSTGEN program)

2) Direct accessing Residential Demand Forecasting Model common blocks

3) Utilizing copies of some parts of the Residential Demand Forecasting Model code (copied into the LDSM code) that contain hardwired data items

Data items imported in the above ways are specified below.

**Table 4.1.1 Data items supplied by the residential RESTART file**

| VARIABLE NAME | VARIABLE SPECIFICATION | UNITS | INDEX | INDEX 2 | INDEX 3 | INDEX 4 |
|---|---|---|---|---|---|---|
| HTRADD | HEATING ADDITIONS | # OF APPL. | YEARS 1991-2015 | 12 EQ. TYPES (*) | 3 BUILD. TYPES | 9 CENSUS DIV. |
| HRP | HEATING REPLACEMENTS | # OF APPL. | YEARS 1991-2015 | 12 EQ. TYPES (*) | 3 BUILD. TYPES | 9 CENSUS DIV. |
| HNUEC | HEATING UEC'S | thousand Btu/a | YEARS 1991-2015 | 11 EQ. TYPES (*) | 3 BUILD. TYPES | 9 CENSUS DIV. |
| NHTRSHR | HEATING MKT. SHARE | 1 | YEARS 1990-2015 | 29 EQ. TECH. (**) | 3 BUILD.TYPES | 9 CENSUS DIV. |
| HEFF | HEATING EFFICIENCY | 1 | 29 EQ. TECH. (**) | | | |
| HCN | HEATING CONSUMPTION | thousand Btu/a | YEARS 1990-2015 | 9 CENSUS DIV. | | |
| CLADD | COOLING ADDITIONS | # OF APPL. | YEARS 1991-2015 | 3 EQ. TYPES (***) | 3 BUILD. TYPES | 9 CENSUS DIV. |
| CRP | COOLING REPLACEMENTS | # OF APPL. | YEARS 1991-2015 | 3 EQ. TYPES (***) | 3 BUILD. TYPES | 9 CENSUS DIV. |
| CNUEC | COOLING UEC'S | thousand Btu/a | YEARS 1991-2015 | 3 EQ TYPES (***) | 3 BUILD.TYPES | 9 CENSUS DIV. |
| NRACSHR | RAC MKT. SHARE | 1 | YEARS 1990-2015 | 3 BUILD. TYPES | 9 CENSUS DIV. | |

| | | | | | | |
|---|---|---|---|---|---|---|
| NCACSHR | CAC MKT. SHARE | 1 | YEARS 1990-2015 | 3 BUILD. TYPES | 9 CENSUS DIV. | |
| CEFF | COOLING EFFICIENCIES | 1 | 9 EQ. TECH. (-) | | | |
| COOLCN | COOLING CONSUMPTION | thousand Btu/a | YEARS 1990-2015 | 9 CENSUS DIV. | | |
| H2OADD | WATER HEAT. ADDITIONS | # OF APPL. | YEARS 1991-2015 | 4 EQ. TYPES (+) | 3 BUILD. TYPES | 9 CENSUS DIV. |
| WRP | WATER HEAT. REPLACEM. | # OF APPL. | YEARS 1991-2015 | 4 EQ. TYPES (+) | 3 BUILD. TYPES | 9 CENSUS DIV. |
| WNUEC | WATER HEAT. UEC'S | thousand Btu/a | YEARS 1991-2015 | 4 EQ. TYPES (+) | 3 BUILD. TYPES | 9 CENSUS DIV. |
| NH2OSHR | WATER H. MKT. SHARE | 1 | YEARS 1990-2015 | 9 EQ. TECHN. (++) | 3 BUILD. TYPES | 9 CENSUS DIV. |
| WEFF | WATER H. EFFICIENCIES | 1 | 9 EQ. TECH. (++) | | | |
| WCN | WATER H. CONSUMPTION | thousand Btu/a | YEARS 1990-2015 | 9 CENSUS DIV. | | |
| REFADD | REFRIGERATORS ADDIT. | # OF APPL. | YEARS 1991 -2015 | 3 BUILD. TYPES | 9 CENSUS DIV. | |
| RRP | REFRIGERATORS REPL. | # OF APPL. | YEARS 1991-2015 | 3 BUILD. TYPES | 9 CENSUS DIV. | |
| RNUEC | REFRIGERATORS UEC'S | thousand Btu/a | YEARS 1991-2015 | 3 BUILD. TYPES | 9 CENSUS DIV. | |
| NREFSHR | REFRIG. MKT. SHARE | 1 | YEARS 1990-2015 | 5 EQ. TECHN. (+++) | 3 BUILD. TYPES | 9 CENSUS DIV. |
| REFF | REFRIGER. EFFICIENCY | 1 | 5 EQ. TECH. (+++) | | | |
| REFCON | REFRIG. CONSUMPTION | thousand Btu/a | YEARS 1990-2015 | 9 CENSUS DIV. | | |
| FRZADD | FREEZERS ADDITIONS | # OF APPL. | YEARS 1991-2015 | 3 BUILD. TYPES | 9 CENSUS DIV. | |
| FRP | FREEZERS REPLACEM. | # OF APPL. | YEARS 1991-2015 | 3 BUILD. TYPES | 9 CENSUS DIV. | |

| | | | | | | |
|---|---|---|---|---|---|---|
| FNUEC | FREEZERS UEC'S | thousand Btu/a | YEARS 1991-2015 | 3 BUILD. TYPES | 9 CENSUS DIV. | |
| NFRZSHR | FREEZERS MKT. SHARE | 1 | YEARS 1990-2015 | 3 EQ. TECHN. (@) | 3 BUILD. TYPES | 9 CENSUS DIV. |
| FEFF | FREEZERS EFFICIENCY | 1 | 3 EQ. TECH. (@) | | | |
| FRZCON | FREEZERS CONSUMPTION | thousand Btu/a | YEARS 1990-2015 | 9 CENSUS DIV. | | |

It is assumed that the definition of CENSUS divisions is exactly the same as in the rest of the NEMS system.

3 building types are:

1 = Single family homes
2 = Multi family homes
3 = Mobile homes

(*) 12 heating equipment types are:
1 = Electric Furnace
2 = Heat Pump
3 = Electric Other
4 = Gas Furnace
5 = Gas Radiator
6 = Gas Other
7 = Kerosene Furnace
8 = LPG Furnace
9 = LPG Other
10 = Oil Furnace
11 = Oil Other
12 = Wood Stoves

(**) 29 heating equipment technologies are:
1 = Electric Furnace
2 = Heat Pump
3 = Heat Pump
4 = Heat Pump
5 = Electric Other
6 = Gas Furnace
7 = Gas Furnace
8 = Gas Furnace
9 = Gas Radiator
10 = Gas Radiator
11 = Gas Radiator
12 = Gas Other
13 = Gas Other
14 = Gas Other

15 = Kerosene Furnace
16 = Kerosene Furnace
17 = Kerosene Furnace
18 = LPG Furnace
19 = LPG Furnace
20 = LPG Furnace
21 = LPG Other
22 = LPG Other
23 = LPG Other
24 = Oil Furnace
25 = Oil Furnace
26 = Oil Furnace
27 = Oil Other
28 = Oil Other
29 = Oil Other

(***) 3 cooling equipment types are:
1 = RAC
2 = CAC
3 = HP (for cooling)

(-) 9 cooling equipment technologies are:
1 = RAC
2 = RAC
3 = RAC
4 = CAC
5 = CAC
6 = CAC
7 = HP (for cooling)
8 = HP (for cooling)
9 = HP (for cooling)

(+) 4 water heating equipment types are:
1 = Natural Gas
2 = Electric
3 = Fuel Oil
4 = Liq Pet Gas

(++) 9 water heating equipment technologies are:
1 = Natural Gas
2 = Natural Gas
3 = Natural Gas
4 = Electric
5 = Electric
6 = Fuel Oil
7 = Fuel Oil
8 = Liq Pet Gas
9 = Liq Pet Gas

(+++) 5 refrigeration equipment technologies are:

1 = Refrigerator 1
2 = Refrigerator 2
3 = Refrigerator 3
4 = Refrigerator 4
5 = Refrigerator 5

(@) 3 freezer equipment technologies are:
1 Freezer 1
2 Freezer 2
3 Freezer 3

**Table 4.1.2 Data Directly Accessed in the Common Blocks of the Residential Demand Model**

| VARIABLE NAME | COMMON BLOCK NAME | VARIABLE SPECIFICATION | INDEX 1 | INDEX 2 | INDEX 3 | INDEX 4 |
|---|---|---|---|---|---|---|
| HTRCON | HTCN | HEATING DEMAND | MMBtu/a | YEARS 1990-2015 | FUEL TYPE ELEC. = 7 | 9 CENSUS DIV. |
| COOLCN | CLCN | COOLING DEMAND | MMBtu/a | YEARS 1990-2015 | FUEL TYPE ELEC.= 3 | 9 CENSUS DIV. |
| H2OCON | HWCN | W. HEATING DEM. | MMBtu/a | YEARS 1990-2015 | FUEL TYPE ELEC.= 4 | 9 CENSUS DIV. |
| REFCON | RFCN | REFRIGERAT. DEMAND | MMBtu/a | YEARS 1990-2015 | 9 CENSUS DIV. | |
| FRZCON | FZCN | FREEZERS DEMAND | MMBtu/a | YEARS 1990-2015 | 9 CENSUS DIV. | |
| LTCON | LTC | LIGHTING DEMAND | MMBtu/a | YEARS 1990-2015 | 9 CENSUS DIV. | |
| APCON | APC | APPLIANCES DEMAND | MMBtu/a | YEARS 1990-2015 | 9 CENSUS DIV. | |
| CKCON | CKCN | STOVES DEMAND | MMBtu/a | YEARS 1990-2015 | FUEL TYPE ELEC.= 3 | 9 CENSUS DIV. |
| DRYCON | DRYCN | DRYERS DEMAND | MMBtu/a | YEARS 1990-2015 | FUEL TYPE ELEC.= 2 | 9 CENSUS DIV. |
| SHTCON | SHC | SUPPL. HEAT. DEMAND | MMBtu/a | YEARS 1990-2015 | FUEL TYPE ELEC.= 7 | 9 CENSUS DIV. |
| DSMrNumUnitChange | DSMTFRES | POST-dsm NO. OF APPLIANCES IN THE "TO" TECHS. | # OF APPL. | INDEX ON THE LIST OF DSM OPTIONS CHOSEN IN THE PREVIOUS YEAR | | |

It is assumed that the definition of census divisions is exactly the same as in the rest of the NEMS system.

**Table 4.1.3 Residential Data Hardwired in the Code**

| VARIABLE NAME | VARIABLE SPECIFICATION | UNITS | INDEX 1 | INDEX 2 |
|---|---|---|---|---|
| EquipLife | Lifetime of equipment | a | Technology group | Technology type |

| | | | | |
|---|---|---|---|---|
| Cost | Cost of purchase of equipment | $/ITEM | Technology group | Technology type |

Technology groups are:
1 = Heating
2 = Cooling
3 = Water Heating
4 = Refrigerators
5 = Freezers

Technology types are:

In heating:
1 = Electric Furnace
2 = Heat Pump 1
3 = Heat Pump 2
4 = Heat Pump 3

In cooling:
1 = RAC 1
2 = RAC 2
3 = RAC 3
4 = CAC 1
5 = CAC 2
6 = CAC 3
7 = Heat Pump 1
8 = Heat Pump 2
9 = Heat Pump 3

In water heating:
4 = Water Heater 1
5 = Water Heater 2

In refrigerators:
1 = Refrigerator 1
2 = Refrigerator 2
3 = Refrigerator 3
4 = Refrigerator 4
5 = Refrigerator 5

In freezers:
1 = Freezer 1
2 = Freezer 2
3 = Freezer 3

### 4.2 Data imported to the LDSM from the Commercial Demand Forecasting Module

LDSM imports data from the Commercial Demand Forecasting Module in two ways:

1) Reading the RESTART file, developed by the Commercial Forecasting Model in the run with the LDSM being switched off (translated into the direct access file format by the RSTGEN program)
2) Direct accessing Commercial Demand Forecasting Module common blocks

**Table 4.2.1 Data Read from the Commercial Binary RESTART File**

| VARIABLE NAME | VARIABLE SPECIFICATION | UNITS | IND.1 | IND.2 | IND.3 | IND.4 | IND.5 | IND.6 |
|---|---|---|---|---|---|---|---|---|
| CMnumLiveElecEquip | Total count of live elec. equip. types | | 9 CENSUS DIV. | 11 Build. types | 6 Services | YEARS 1990-2015 | | |
| CMLiveElecEquipID | Technology and vintage subscripts from the KTECH technology characterization table, uniquely identifying equip. type | | 9 CENSUS DIV. | 11 Build. types | 6 Services | 30 max. number of equip. types | techn. vintage | YEARS 1990-2015 |
| CMLiveElecEquipSD | Absolute amount of service demand | Trill. Btu/a or Billion Lumen Years | 9 CENSUS DIV. | 11 Build. types | 6 Services | 30 max. number of equip. types | Dec. type: 1 New 2 Repl. 3 Retr. | YEARS 1990-2015 |
| SECELC | Electric demand from the entire sector | Trill. Btu/a | 9 CENSUS DIV. | YEARS 1990-2015 | | | | |

It is assumed that the definition of CENSUS divisions is exactly the same as in the rest of the NEMS system.

11 building types are:

1 = small offices
2 = large offices
3 = restaurants
4 = retail
5 = groceries
6 = warehouses
7 = schools
8 = colleges
9 = health service
10 = lodging
11 = miscellaneous

6 services are:

1 = space heating
2 = space cooling
3 = water heating
4 = ventilation
5 = cooking
6 = lighting

**Table 4.2.2 Data Directly Accessed in the Common Blocks of the Commercial Demand Module**

| VARIABLE NAME | COMMON BLOCK NAME | VARIABLE SPECIFIC. | UNITS | IND.1 | IND.2 | IND.3 | IND.4 | IND.5 |
|---|---|---|---|---|---|---|---|---|
| TechEff | KDAT | Equipment efficiency | 1 | 9 CENS.DIV. | 6 serv. | techn. index | vint. index | |
| TechCost | KDAT | Unit installed capital cost per unit of actual capacity<br><br>Annual O&M cost per unit of theoretical capacity | $/(thousand Btu of S.D./h) or $/(billion Lu*a/h)<br><br>$/(thousand Btu of S.D./h)/a or $/(billion Lu*a/h)/a | techn. index | vint. index | 1=cap. 2=OM | | |
| TechLife | KDAT | Average life expectancy of equipment | a | techn. index | vint. index | | | |
| CapacityFactor | KDAT | Capacity factor of equipment | 1 | 9 CENS.DIV. | 11 build. types | 6 serv. | | |
| EndUseConsump | COMPARM | End-use electricity consumption | Trillion Btu/a | Fuel index elec.=1 | 6 serv. | 11 build. types | 9 CENS. DIV. | YEAR 1990-2015 |
| DSMcServDemChange | DSMTFCOM | Post-DSM amount of service demand being satisfied by the "TO" technologies | Trill. Btu/a or Billion Lumen Years/a | Index on the list of DSM options chosen in the previous year | | | | |

## 4.3 Data imported to LDSM from the Industrial Forecasting Module

Currently the entire industrial sector demand is represented as one end-use. However, LDSM is capable to represent the sector more precisely as soon as appropriate data becomes available from the Industrial Demand Forecasting Module.

## Table 4.3 Data accessed in the common blocks of the Industrial Demand Forecasting Module

| VARIABLE NAME | COMMON BLOCK | VARIABLE SPECIFICATION | UNITS | IND.1 | IND.2 |
|---|---|---|---|---|---|
| QELIN | QBLK | Total industrial electric demand | Trillion Btu/a | 9 CENSUS DIVISIONS | YEARS 1990-2015 |

## 4.4 Data imported to LDSM from the Transportation Forecasting Module

## Table 4.4 Data Accessed in the Common Blocks of the Transportation Demand Module

| **VARIABLE NAME** | **COMMON BLOCK NAME** | **VARIABLE SPECIFICATION** | **UNITS** | **DIR.1** | **IND.2** | **IND.3** |
|---|---|---|---|---|---|---|
| TRQLDV | TRANREP | Light Duty Vehicles Energy Use | Trillion Btu/a | Fuel index elec.=6 | 9 CENSUS DIVISIONS | YEARS 1990-2015 |
| TRQRAILR | TRANREP | Rail Road Energy Use | Trillion Btu/a | Fuel index elec.=1 | | |

# 5.0 Variables from External Sources

## Table 5 Input Variables from External Soruces

| **Variable Name** | **Description** | **Ind.1** | **Ind.2** | **Units** | **Data Source** | **Common Block** | **Input File Name** |
|---|---|---|---|---|---|---|---|
| DISTLO | HOURLY LOAD SHAPE | hours in a year | | 1 | RELOAD database | none | LDSMDAF |
| MONTYP | SEASON ASSIGNMENT OF MONTH | month | | - | RELOAD database | DSMCLn | LDSMSTR |
| JDAYTP | DAY-TYPE ASSIGNMENT FOR EACH DAY | day | month | - | RELOAD database | DSMCLn | LDSMSTR |
| WEIGHT | WEIGHTS INDICATING NUMBER OF DAYS REPRESENTED BY EACH DAY IN CALENDAR | day | month | 1 | RELOAD database | DSMCLn | LDSMSTR |
| NODAYS | NUMBER OF DAYS IN EACH MONTH | month | | 1 | RELOAD database | DSMCLn | LDSMSTR |
| NODAYT | NUMBER OF DAY-TYPES | | | 1 | RELOAD database | DSMCLn | LDSMSTR |
| NMONTH | NUMBER OF MONTHS | | | 1 | RELOAD database | DSMCLn | LDSMSTR |
| NOSEA | NUMBER OF SEASONS | | | 1 | RELOAD database | DSMCLn | LDSMSTR |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| IDAYTQ | NUMBER OF REAL DAYS WHICH ARE REPRESENTED BY DAYTYPE IN A MONTH | day | month | 1 | RELOAD database | DSMCLn | LDSMSTR |
| MONAME | MONTH NAMES | month | | - | RELOAD database | DSMCLc | LDSMSTR |
| SENAME | SEASON NAMES | seasone | | - | RELOAD database | DSMCLc | LDSMSTR |
| DTNAME | DAY-TYPE NAMES | day-type | | - | RELOAD database | DSMCLc | LDSMSTR |
| RprogCode | list of codes identifying Residential DSM programs | DSM program | | - | | DSMOPc | LDSMSTR |
| CprogCode | list of codes identifying Commercial DSM programs | DSM program | | - | | DSMOPc | LDSMSTR |
| RtechNumb | number of residential technologies that may be affected by DSM | | | 1 | | DSMOPi | LDSMSTR |
| CtechNumb | number of commercial technologies that may be affected by DSM | | | 1 | | DSMOPi | LDSMSTR |
| Rtechcode | list of residential technology codes | technol. | | - | | DSMOPc | LDSMSTR |
| CtechCode | list of commercial technology 3-element codes | technol. | elem. of code | 1 | | DSMOPc | LDSMSTR |
| RtechDMtn | number of DEMAND MODULE technologies represented by one LDSM technology | technol. | | - | | DSMOPi | LDSMSTR |
| RtechDMG | list of technology group indicies | technol. | dem. mod. tech. | - | | DSMOPi | LDSMSTR |
| RtechDMT | list of technology indicies within techn. groups | technol. | dem. mod. tech. | - | | DSMOPi | LDSMSTR |
| RRlistN | number of region groups used during residential DSM option definition | | | 1 | | DSMOPi | LDSMSTR |
| CRlistN | number of region groups used during commercial DSM option definition | | | 1 | | DSMOPi | LDSMSTR |
| RRlistID | list identifiers for residential sector | list | | - | | DSMOPc | LDSMSTR |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| CRlistID | list identifiers for commercial sector | list | | - | | DSMOPc | LDSMSTR |
| RdecTYPn | number of decision types in residential sector | | | 1 | | DSMOPi | LDSMSTR |
| CdecTYPn | number of decision types in commercial sector | | | 1 | | DSMOPi | LDSMSTR |
| RdecTYPid | decision type identifiers in residential sector | dec. type | | - | | DSMOPc | LDSMSTR |
| CdecTYPid | decision type identifiers in commercial sector | dec. type | | - | | DSMOPi | LDSMSTR |
| RbuildTn | number of building types in residential sector | | | 1 | | DSMOPi | LDSMSTR |
| CbuildTn | number of building types in commercial sector | | | 1 | | DSMOPi | LDSMSTR |
| RbuildTid | building types identifiers in residential sector | build. type | | - | | DSMOPc | LDSMSTR |
| CbuildTid | building types identifiers in commercial sector | build. type | | - | | DSMOPi | LDSMSTR |
| DSMROptionNumb | Number of DSM options available for residential sector | | | 1 | | DSMOPi | LDSMSTR |
| DSMROptionCode | vector of residential sector DSMOption code names | option | | - | | DSMOPc | LDSMSTR |
| DSMROptionRegion | # of list of regions to which the option applies | option | | 1 | | DSMOPi | LDSMSTR |
| DSMROptionBuildT | # of building type to which the option applies | option | | 1 | | DSMOPi | LDSMSTR |
| DSMROptionDecType | # of decision type to which the option applies | option | | 1 | | DSMOPi | LDSMSTR |
| DSMROptionFromTnum | number of FROM technologies affected by option | option | | 1 | | DSMOPi | LDSMSTR |
| DSMROptionFromTech | indices of FROM technologies | option | technol. | - | | DSMOPi | LDSMSTR |
| DSMROptionToTnum | number of TO technologies affected by option | option | | 1 | | DSMOPi | LDSMSTR |
| DSMROptionToTech | indices of TO technologies | option | technol. | - | | DSMOPi | LDSMSTR |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| DSMROptionCost | Marketing/administrative costs of option /kWh saved | option | | $/kWh | El.Utility Survey | DSMOPr | LDSMSTR |
| DSMROptionFyr | first year when the option is available index | option | | - | | DSMOPi | LDSMSTR |
| DSMROptionRamp | number of ramp-up years for the option | option | | 1 | | DSMOPi | LDSMSTR |
| NRPROG | number of residential DSM programs | | | 1 | | DSMOPi | LDSMSTR |
| DSMCOptionNumb | Number of DSM options available for commercial sector | | | 1 | | DSMOPi | LDSMSTR |
| DSMCOptionCode | vector of commercial sector DSM option code names | option | | - | | DSMOPc | LDSMSTR |
| DSMCOptionBuildT | building type to which the option applies | option | | - | | DSMOPi | LDSMSTR |
| DSMCOptionDecType | decision type to which the option applies | option | | - | | DSMOPi | LDSMSTR |
| DSMCOptionFromTnum | number of FROM technologies affected by option | option | | 1 | | DSMOPi | LDSMSTR |
| DSMCOptionFromTech | FROM technology KTECH codes for option | option | elem. of code | - | | DSMOPi | LDSMSTR |
| DSMCOptionToTnum | number of TO technologies affected by option | option | | 1 | | DSMOPi | LDSMSTR |
| DSMCOptionToTech | TO technology KTECH codes for the option | option | elem. of code | - | | DSMOPi | LDSMSTR |
| DSMCOptionCost | Marketing/administrative costs of the option | option | | $/kWh | El.Utility Survey | DSMOPr | LDSMSTR |
| DSMCOptionFyr | first year when the option is available | option | | - | | DSMOPi | LDSMSTR |
| DSMCOptionRamp | number of ramp-up years of the option | option | | 1 | | DSMOPi | LDSMSTR |
| NCPROG | number of commercial DSM programs | | | 1 | | DSMOPi | LDSMSTR |
| PAYBACK | DSM option pay-back period | | | a [8] | El.Utility Survey | DSMOPi | LDSMSTR |

[8] a = annum

## 6.0 Output Variables Calculated Within Submodule

### Table 6 Output Variables Calculated Within Submodule

| Variable Name | Description | Indicies | Units | Subroutine | Output To |
|---|---|---|---|---|---|
| DSMNPROG | number of DSM programs to be considered | | 1 | DSMRST | ECP |
| DSMPRCST | DSM program costs | program start year, EMM region, DSM program | $mln | DSMPCIM | ECP |
| DSMPRLIM | DSM program load impact dimentions: program start year, program year, region, LDC block, program # | program start year, program year, EMM region, LDC block, DSM program | GW | DSMPRGL | ECP |
| ECPLDCBH | ECP LDC block heights | year of ECP time horizon, EMM region, LDC block | GW | DSMLCP | ECP |
| ECPLDCBS | ECP LDC block segment assignement | year of ECP time horizon, EMM region, LDC block | - | DSMLCP | ECP |
| ECPLDCBW | ECP LDC block widths | year of ECP time horizon, EMM region, LDC block | a | DSMRST | ECP |
| ECPnumSg | Number of segments in LDC for ECP module | | 1 | DSMRST | ECP |
| ECPsgDblock | %% of hours allocated to blocks in each segment | ECP segment, block in the segment | 1 | DSMRST | ECP |
| ECPsgDbltyp | type peak/non-peak of a block | ECP segment, block in the segment | - | DSMRST | ECP |
| ECPsgDnB | Number of blocks in each of segments of ECP LDC | ECP segment | | DSMRST | ECP |
| DSMrOptionsNumber | number of DSM options chosen for each of CENSUS div. | CENSUS div. | 1 | DSMECP2 | RES. DEM. |
| DSMrOptionIndex | list of indices of DSM options chosen by ECP | DSM option | - | DSMECP2 | RES. DEM. |
| DSMrFracOptionMarket | optimal fraction of the maximum tech. shift | DSM option | 1 | DSMECP2 | RES. DEM. |
| DSMcOptionsNumber | number of chosen DSM options | CENSUS div. | 1 | DSMECP2 | COMM. DEM. |
| DSMcOptionIndex | list of indices of chosen DSM options | DSM option | - | DSMECP2 | COMM. DEM. |

| | | | | | |
|---|---|---|---|---|---|
| EFDLDCYC | load coordinates of EFD LDC data points | EMM region, EFD seasone, EFD LDC block | GW | DSMEFD | EFD |
| EFDLDCPR | EFD LDC data point ranks in segments | EMM region, EFD seasone, EFD LDC block | - | DSMEFD | EFD |
| EFDLDCSA | EFD LDC data point segment assignement | EMM region, EFD seasone, EFD LDC block | - | DSMEFD | EFD |
| EFDLDCBW | EFD LDC block widths | EFD seasone | h | DSMEFD | EFD |
| EFDnS | number of EFD seasons | | 1 | DSMRST | EFD |
| EFDnumBl | number of blocks in EFD LDCs | EFD seasone | 1 | DSMRST | EFD |
| EFDnumSeg | number of segments in EFD LDCs | EFD seasone | 1 | DSMRST | EFD |
| DSMcFracOptionMarket | optimal fraction of the maximum tech. shift | DSM option | 1 | DSMECP2 | COMM. DEM. |
| SecLoad | current year sectoral load | sector,year | GWh | DSMEFP | EFP |
| SecAnnulPeak | Coincident/Noncoincident sectoral annual peak | year,sector, conicident/non-conicident | GW | DSMEFP | EFP |
| SecAnnPeaAvPCP | Avereges of sectorial loads from top NpeakH system peak hours | year,sector | GW | DSMEFP | EFP |
| NpeakH | number of hours used for calculation of SecAnnPeakAvPCP values | | 1 | DSMEFP | EFP |
| DSMAnnualCost | Annual DSM costs by sector | year,sector | $mln | DSMEFP2 | EFP |

# APPENDIX D

## Quality of Data and Estimation

Most of the data processed by LDSM is imported from the other modules of the NEMS system. The only direct inputs to the LDSM include:

- End-use Load Shape Representations
- Historical System Load Shape Representations for the EMM regions
- Transmission and Distribution Loss Factors for the EMM regions
- DSM Option Database
- Payback Acceptance Curves

### End-Use Load Shape Representations

The majority of the end-use Load Shape Representations (LSRs) utilized by ULDSM were derived from the EPRI RELOAD database. This database provides a library of residential, commercial and industrial load shapes that were developed based on metered data collected by various electric utilities, as well as from engineering simulations.

The base part of the residential and commercial portion of the RELOAD library contains the load shape data assembled in the Customer Response portion of the EPRI's DSM project and documented in EPRI document EM5676, V.1. The data was supplied by Bonneville Power Administration (BPA), Tennessee Valley Authority (TVA) and Consumer's Power Company (CPCo). The library was later supplemented with data that originated from Southern California Edison and Pacific Gas and Electric. The industrial load shape data included in the RELOAD database originated from Batelle-Columbus and was gathered for the EPRI DSM Customer Response Project on industrial reference load shapes and DSM impacts.

Because the RELOAD data base did not provide the transportation end-use LSRs, the LSRs for the two electric end-uses modelled in the sector (electric vehicles and electric trains) were developed based on the information available at ICF Resources Inc.

### Historical System Load Shape Representations for the EMM Regions

The historical regional system LSRs were developed from available 1990 EIA load data. The LSRs used by LDSM represent regional system load patterns with 36 distinct 24-hour load profiles -- one for each of the three day-types (week-day, week-end, and peak-day) for each of the 12 months in a year. The LSRs were developed from historical data using the HELM-PC software package.

### Transmission and Distribution Loss Factors for the EMM regions

The transmission and distribution loss factors currently utilized by ULDSM are based on 1990 electric sales and electric generation data available from EIA.

## DSM Option Database

Several data sources were used to derive the DSM Option Database. These sources are documented below.

From and To Technologies

The DSM Option database was developed to identify the set of DSM programs which are being offered or potentially could be offered by electric utilities, i.e., the "from" and "to" technologies in LDSM. This set was developed to be consistent with the equipment choices available from the Demand Modules. The sources for the DSM programs was an extensive review of existing government and private utility reports and databases on DSM options. The primary sources for these programs were Electric Power Research Institute documents, the DSM database developed to support the Electric and Gas Utility Modeling System (EGUMS) for the U.S. EPA, and electric utility Integrated Resource Planning (IRP) reports. The key IRP reports were those filed by New England Electric System, New York State Electric and Gas, PacifiCorp, Duke Power, Kentucky Power, Cincinnati Gas and Electric, and Pacific Gas and Electric. In addition, technology reports from the Bonneville Power Administration, the Northwest Power Planning Council, and Lawrence Berkeley Lab were used to further define possible DSM programs.

Load Shape Choice

Each of the "From" and "TO" technologies that defined the DSM options was assigned a load shape. These load shapes were chosen from the RELOAD database and were selected based on the building type and the technology characteristics.

Administrative Costs

Administrative costs were derived from the EGUMS DSM database. The U.S. EPA reviewed utility DSM reports and plans, and reports produced by the American Council for an Energy Efficient Economy (ACEEE) to derive levelized costs associated with specific residential, commercial, and industrial program types. However, there is not a single, quality source of information of utility administrative costs at the end-use or customer sector level. Further work will be conducted to enhance the quality of the administrative cost data. Possible data sources include Form EIA-861, and the DEEP project being managed by Lawrence Berkeley Lab for DOE.

Ramp-Up Periods

Each DSM program is assumed to follow a set market penetration pattern. The duration of time before the program achieves maximum market acceptance is termed the ramp-up period. The length of time assumed for the LDSM database was derived from review of ACEEE, EPRI, and utility IRP plans.

## Payback Acceptance Curves

Payback acceptance curves associate the economic attractiveness of a DSM option (measured in terms of simple payback) to maximum market acceptance. A variety of sources were examined for possible acceptance curves. These sources include EPRI, A.D. Little papers, and the acceptance curves used in Synergic Resources Corporation's COMPASS model. For the current version of the model we used the curves published by Synergic Resources Corporation.

# REFERENCES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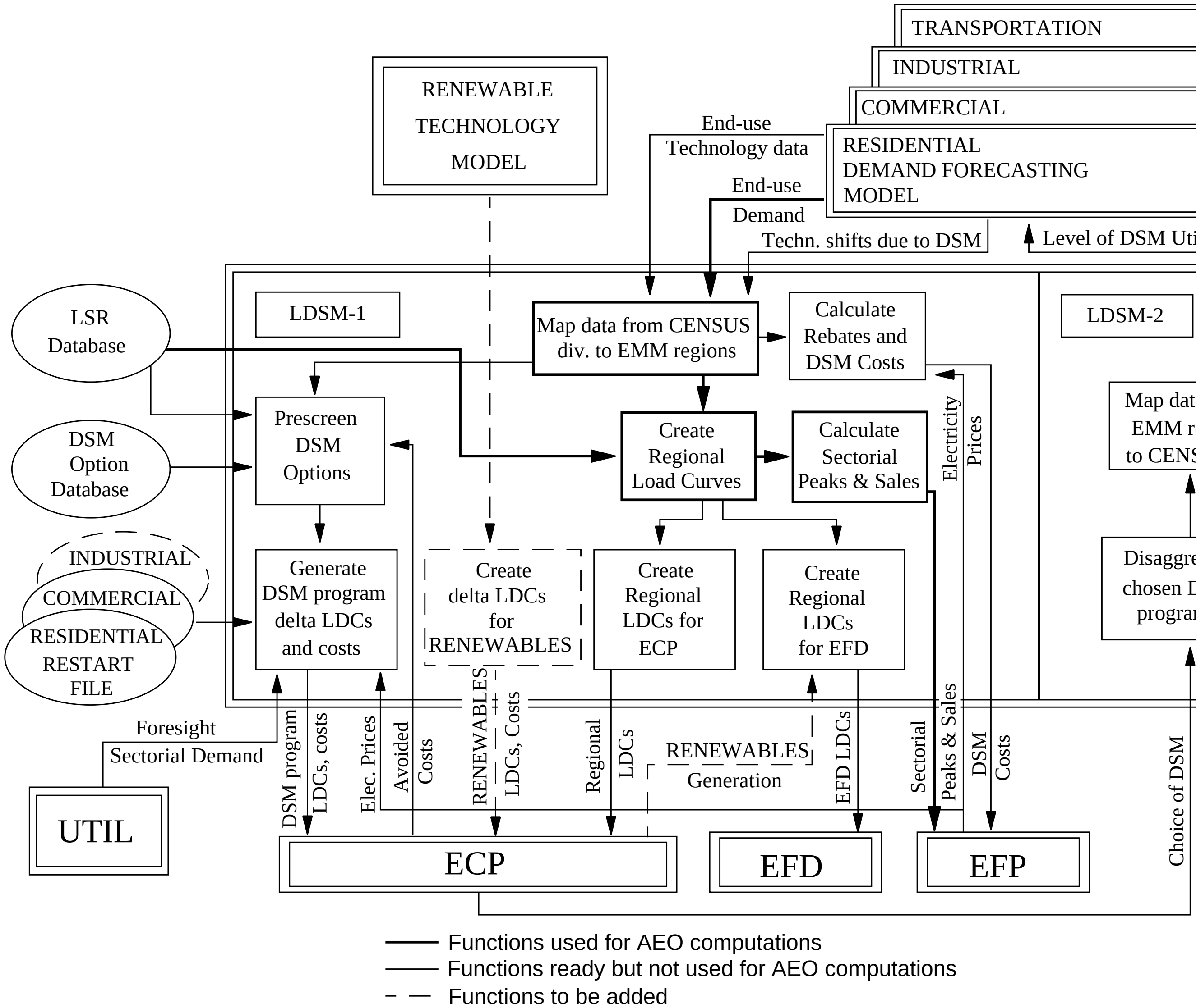
## FIGURE B-1
## LDSM AND ITS EXTERNAL DATA COMMUNICATION

1/ Dashed lines depict linkages that are not yet supported by the current version of the LDSM code.

## FIGURE B-2 LDSM INFORMATION FLOWS



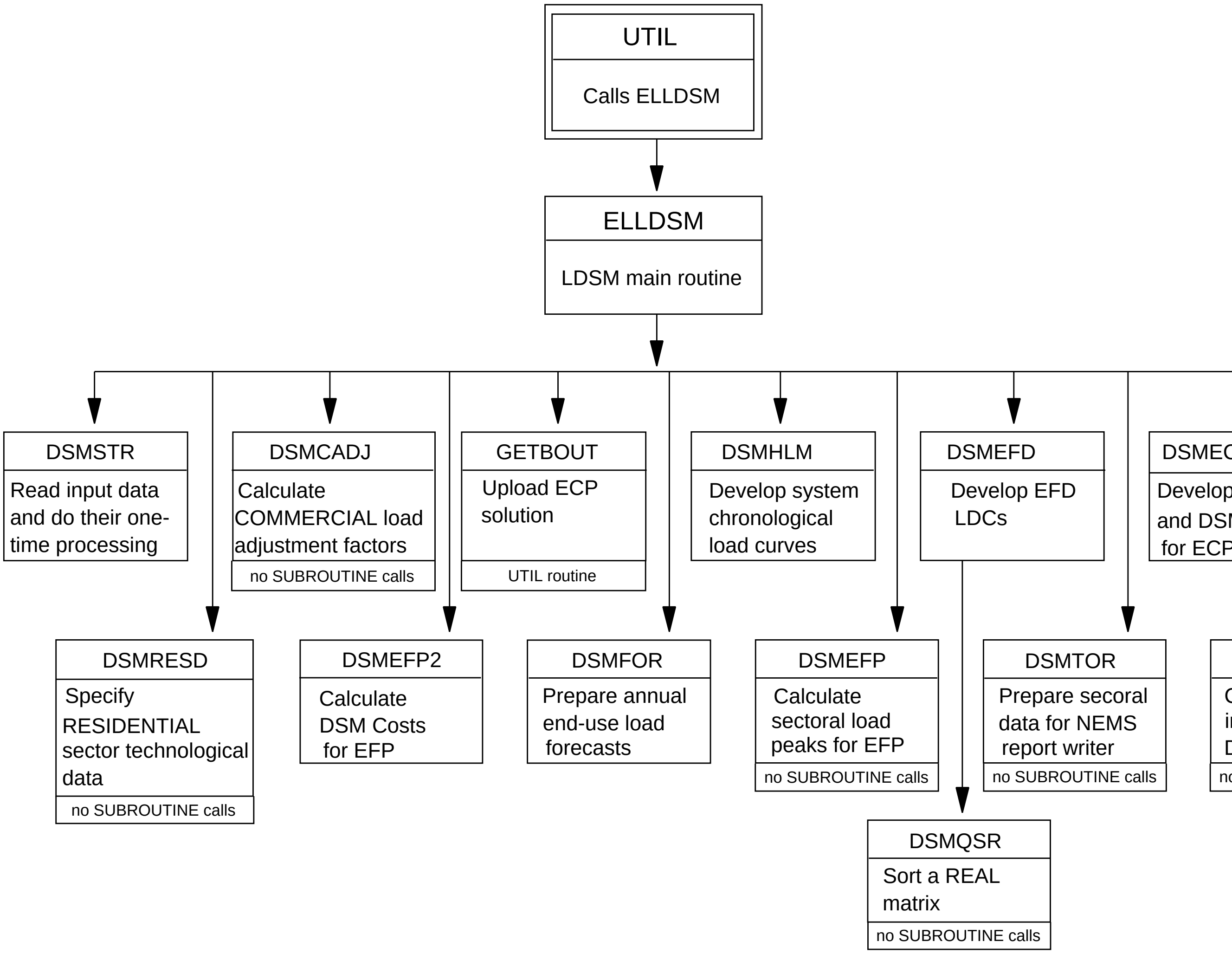



Figure B-4: Flowchart of ELLDSM SUBROUTINE and FUNCTION calls

**FIGURE B-6**
**FLOWCHART OF DSMSTR SUBROUTINE AND FUNCTION CALLS**

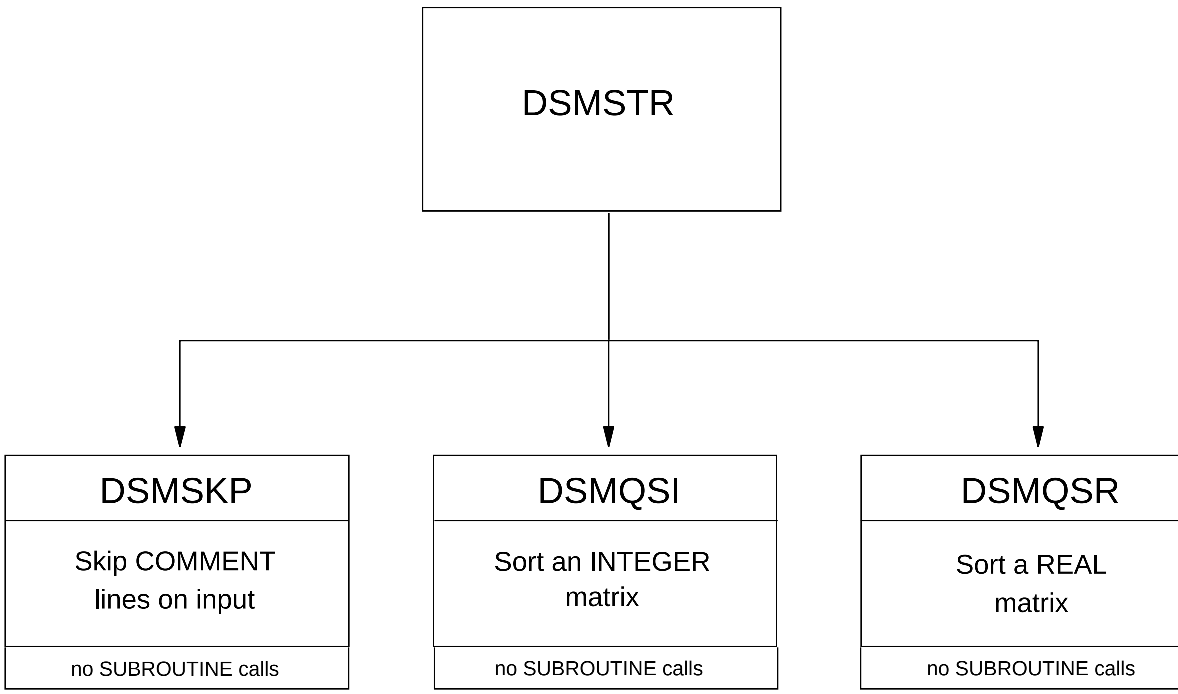


**FIGURE B-7**
**FLOWCHART OF DSMFOR SUBROUTINE AND FUNCTION CALLS**

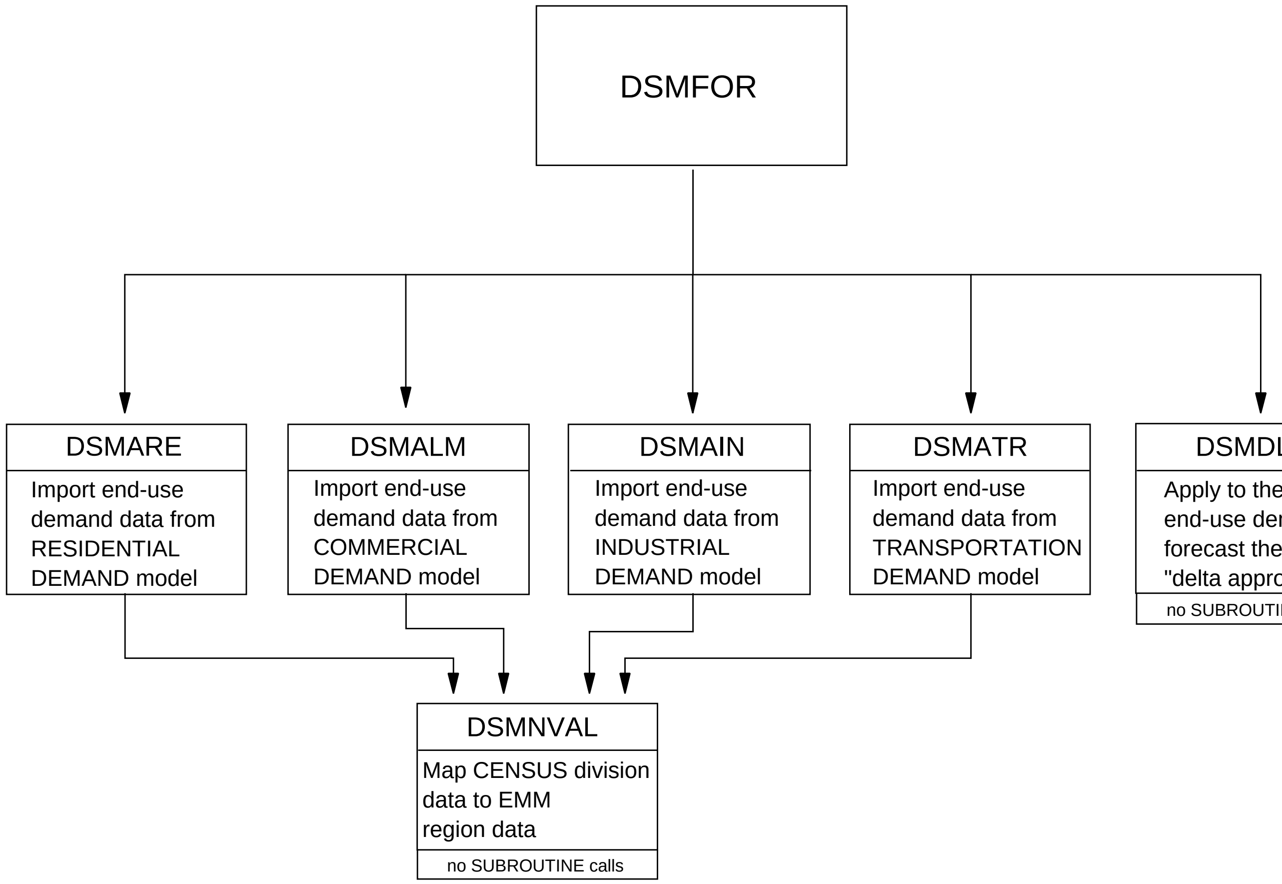


**FIGURE B-8**
**FLOWCHART OF DSMHLM SUBROUTINE AND FUNCTION CALLS**

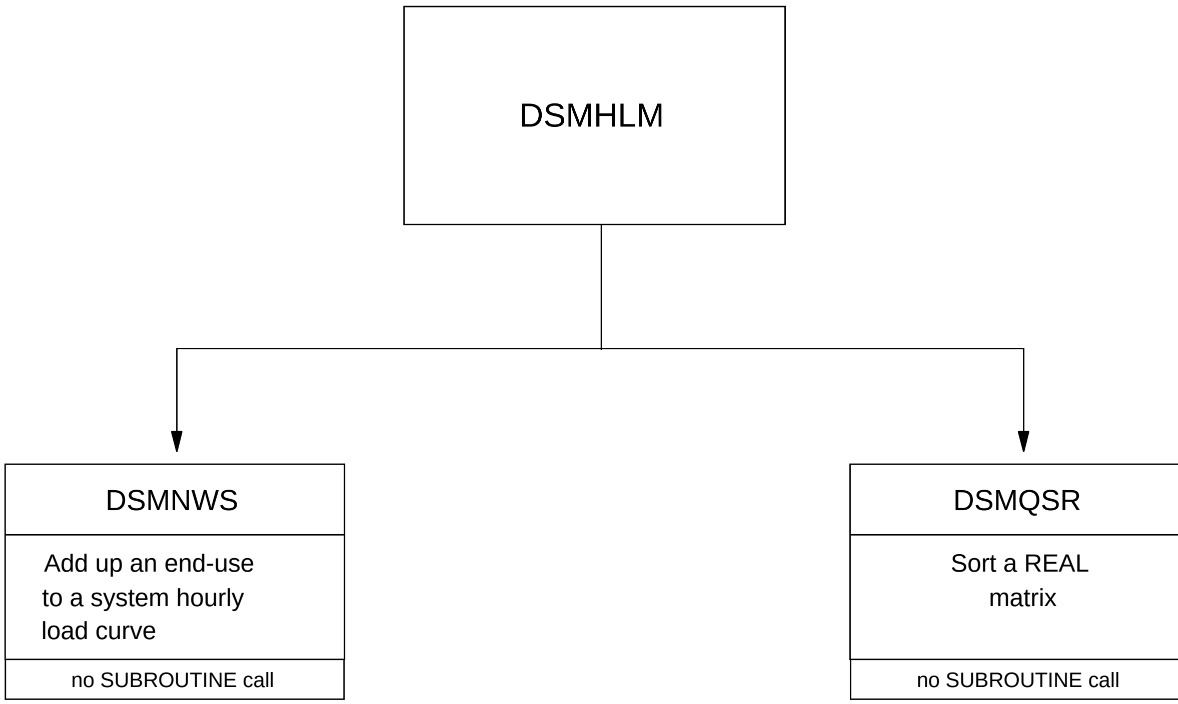
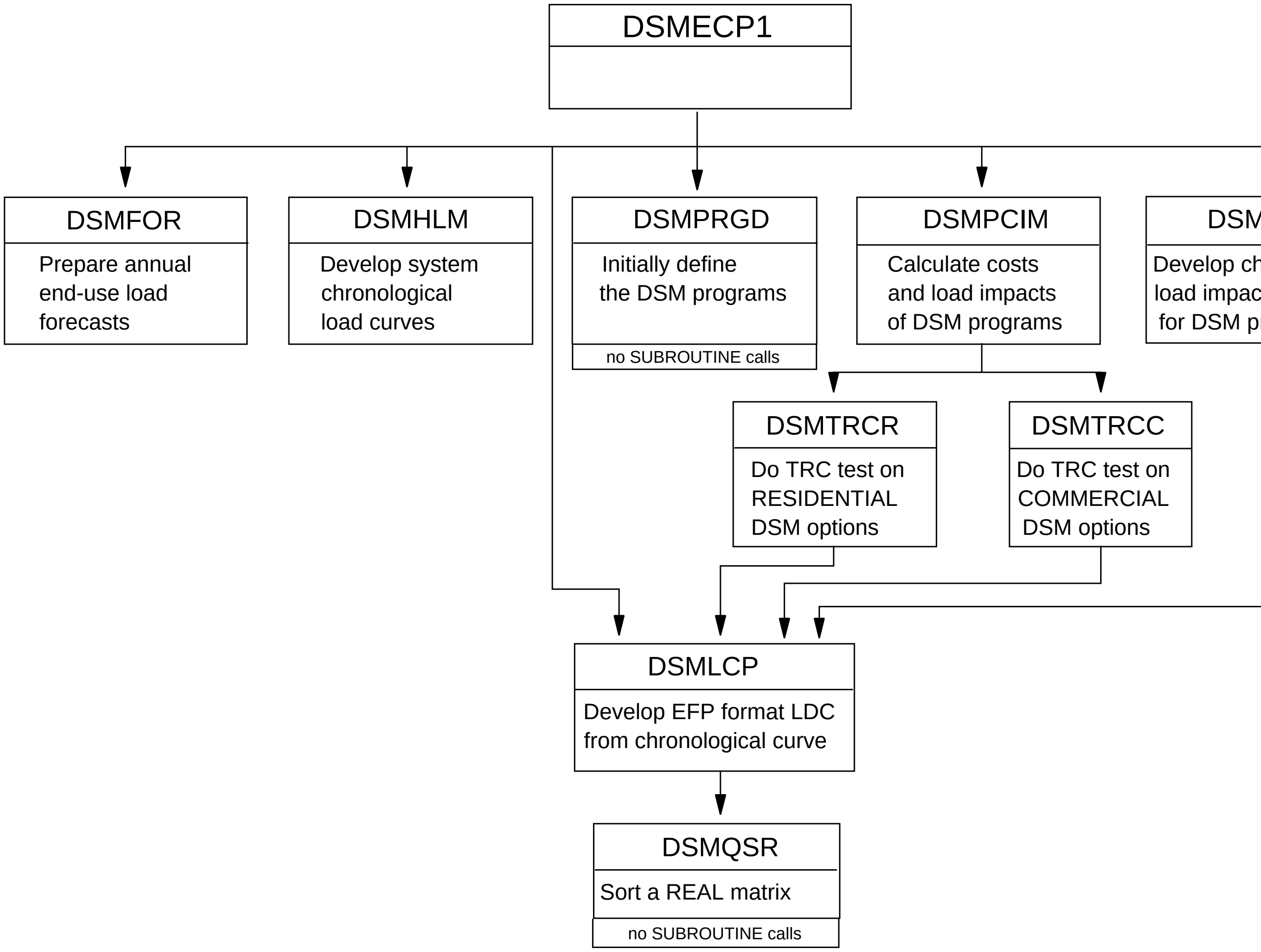
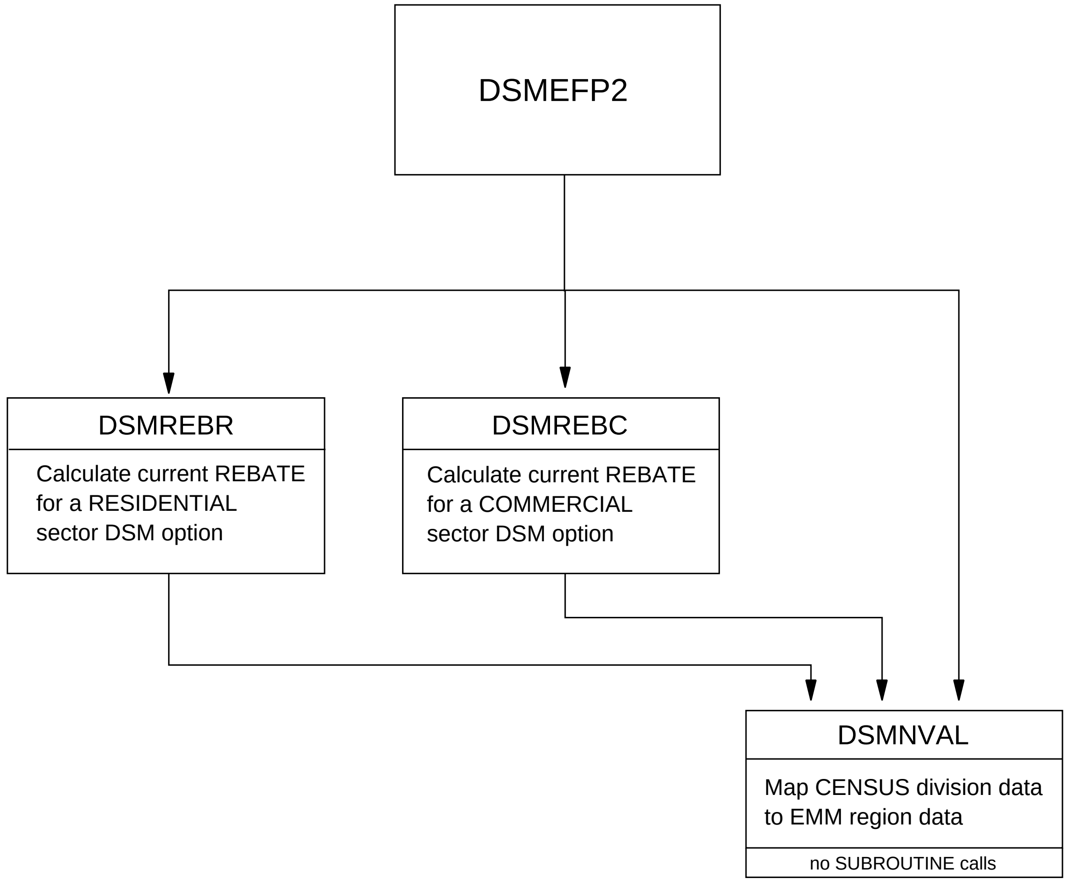


**FIGURE B-9**
**FLOWCHART OF DSMECP1 SUBROUTINE AND FUNCTION CALLS**



## FIGURE B-10
## FLOWCHART OF DSMEFP2 SUBROUTINE AND FUNCTION CALLS



1. N - This refers to ECAR, MAAC, MAIN, MAPP, NY, NE, and NWP EMM regions
   S - This refers to ERCOT, FL, STV, SPP, RA, and CNV EMM regions
   A - This refers to all EMM regions

2. DSM options with "N" at the end of the name apply to "NEW" stock purchases, while all other DSM options apply to "EXIST