ENERGY 2020 Documentation

Volume 8

Input Data and Assumptions

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Input Data and Assumptions

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Per peer reviewers: Provide data (parameters) which would describe each technology. For example, DPL, DCTC, DFTC, PEPL, PFTC, PCTC, MMSM0, etc.

1. Introduction

This document provides a summary of the data inputs and assumptions as well as sources of data used as input to ENERGY 2020. The data sources and model assumptions reported consist of those used for Environment and Climate Change Canada's version of ENERGY 2020. This document is in a development phase, and some sectors' data inputs are not incorporated yet.

1.1. Data Requirements and General Sources

ENERGY 2020 simulates the North American system of energy consumption and supply. Data are required for each of the regions simulated in the model - Canada (by province and territory); U.S. (state-level data aggregated to EIA's census divisions for demand data; EIA's Electricity Market Module regions for electric supply); and Mexico (total national).

ENERGY 2020 requires both historical data and projections to calibrate and generate forward-looking projections. Historical data are input for the period 1985 through the last year for which detailed sector and end-use data are available. Projections through 2050 are input for economic drivers as well as any specific sectors for which exogenous projections are to be calibrated.

As a multi-sector analytical tool, ENERGY 2020 requires data and assumptions covering a broad range of economic sectors and their interactions. In most cases, the necessary data – both historical and projected – are available from public sources. Data specific to Canada are typically populated by Environment and Climate Change Canada from a variety of data sources with a large portion of data obtained from Statistic Canada. Data specific to the U.S. are populated from U.S. federal sources, primarily from the U.S. Department of Energy. Mexico's data are obtained from public sources where available - largely from Mexico's Secretariat of Energy (SENER): http://sie.energia.gob.mx/bdiController.do?action=temas&fromCuadros=true.

Input data are required in seven areas:[1]

1. Economic and demographic
2. Fuel prices
3. Demand sector data (energy usage and technology characteristics)
4. Financial

[1] "Data" here refers to both historical data and assumptions and projections of future inputs.

5. Emissions and air regulations
6. Electricity sector
7. Oil, gas, coal, steam, oil refinery, and biofuel production

Data within each of these areas are required for each region simulated in the model – Canada (by province and territory), U.S. (by state or EIA census divisions), and Mexico (national-level). ENERGY 2020 requires both historical data and projections to calibrate and generate forward-looking projections. Historical data are input for the period 1985 through the last year for which detailed sector and end-use data are available. Projections through 2050 are input for economic drivers as well as any specific sectors for which exogenous projections are to be calibrated.

1.1.1. Input Data Location

Canada input data that are updated annually are housed in Access databases (named vData.accdb, vData_OilRefinery.accdb, and vData_Electricity_CN.accdb) and populated by Environment and Climate Change Canada staff.

The U.S. specific input data are input to the model mostly through text files in the model's Superset subdirectory (for EIA-related data that comes in at the state level) or as text files in the 2020Model subdirectory (for regional level U.S. data) The exception is for U.S. electric generating unit data. The electric unit data is input to the model through an Access database, vData_Electricity_US.accdb (obtained from the U.S. Department of Energy's EIA database).

Model assumptions of input data that are not updated are typically built into the source code files named as *Data.src and housed inside the model's Engine subdirectory. These files include RData.src, CData.src, IData.src, TData.src, and SData.src (for residential, commercial, industrial, transportation, and supply respectively).

1.2. Organization of the Document

This input data and assumptions document is organized by type of data and cover the topics listed below. The appendix contains tables of default data assumptions that are hard-coded into the model files and not updated annually. These data represent default values some of which are overwritten in text files housed in 2020Model.

- Section 1. Introduction
- Section 2. Economic, Demographic, and Temperature
- Section 3. Fuel Prices
- Section 4. Demand Sector Data (Energy Usage and Technology Characteristics)
- Section 5. Financial Data

- Section 6. Emissions and Air Regulations
- Section 7. Electricity Supply
- Section 8. Oil, Gas, Refinery, Biofuel and Other Supply

2. Economic and Demographic

2.1. Economic Drivers

Economic growth projections are an important factor in forecasting energy demand and supply. The drivers for energy demand vary by nation. Canada economic drivers are selected by Environment and Climate Change Canada; U.S. drivers are chosen to align with the U.S. EIA's economic drivers used to produce the U.S. projections reported in the *Annual Energy Outlook*. The driver for passenger transportation was modified to be population rather than personal income. Historical values for these U.S. economic drivers are obtained from the Macroeconomic Activity Module (MAM) of EIA's NEMS model used to produce the AEO report. Projections into the future are based on growth rates from the AEO. Mexico's economic drivers are chosen based on the availability of publicly available data. Table 1 compares the economic drivers of Canada, U.S., and Mexico for each economic category within the residential, commercial, industrial, and transportation sectors.

Table 1. Economic Drivers for Canada, U.S., and Mexico Energy Demand

Sector	Canada	U.S.	Mexico
Residential			
Single Family	Floor Space	Households	Population
Multi Family	Floor Space	Households	Population
Other Residential	Floor Space	Households	Population
Commercial			
Wholesale Trade	Floor Space	Gross Output	Services Gross Output
Retail Trade	Floor Space	Gross Output	Services Gross Output
Warehousing and Storage	Floor Space	GRP	Services Gross Output
Info. and Cultural Industries	Floor Space	Gross Output	Services Gross Output
Offices	Floor Space	Gross Output	Services Gross Output
Educational Services	Floor Space	Gross Output	Services Gross Output
Health Care & Social Assist.	Floor Space	Gross Output	Services Gross Output
Arts, Accom., Food, Other	Floor Space	Gross Output	Services Gross Output
Natural Gas Distribution	NG Demand	Gross Output	Industry Gross Output
Oil Pipelines	National Oil Production	Gross Output	Industry Gross Output
Natural Gas Pipelines	NG Demand Local Gas Prod. (BC, AB)	Gross Output	Industry Gross Output
Street Lighting	GRP	GRP	GRP
Industrial			
Food & Tobacco	Gross Output	Gross Output	Gross Output

Sector	Canada	U.S.	Mexico
Textiles	Gross Output	Gross Output	Textiles & Clothing GO
Apparel	Gross Output	Gross Output	Textiles & Clothing GO
Lumber	Gross Output	Gross Output	Other Mfg. GO
Furniture	Gross Output	Gross Output	Other Mfg. GO
Pulp and Paper Mills	Gross Output	Gross Output	Other Mfg. GO
Converted Paper	Gross Output	Gross Output	Other Mfg. GO
Printing	Gross Output	Gross Output	Other Mfg. GO
Petrochemicals	Gross Output	Gross Output	Chemicals Gross Output
Industrial Gas	Gross Output	Gross Output	Chemicals Gross Output
Other Chemicals	Gross Output	GRP	Chemicals Gross Output
Fertilizer	Gross Output	Gross Output	Chemicals Gross Output
Petroleum Products	National RPP Production	Gross Output	Other Mfg. GO
Rubber	Gross Output	Gross Output	Other Mfg. GO
Leather	Gross Output	Gross Output	Other Mfg. GO
Cement	Gross Output	GRP	Other Mfg. GO
Glass	Gross Output	Gross Output	Other Mfg. GO
Lime & Gypsum	Gross Output	Gross Output	Other Mfg. GO
Other Non-Metallic	Gross Output	Gross Output	Other Mfg. GO
Iron & Steel	Gross Output	GRP	Other Mfg. GO
Aluminum	Gross Output	GRP	Other Mfg. GO
Other Nonferrous Metal	Gross Output	Gross Output	Other Mfg. GO
Fabricated Metals	Gross Output	Gross Output	Other Mfg. GO
Machines	Gross Output	Gross Output	Mach.&Trans. Equip. GO
Computers	Gross Output	Gross Output	Other Mfg. GO
Electric Equipment	Gross Output	Gross Output	Other Mfg. GO
Transport Equipment	Gross Output	Gross Output	Mach.&Trans. Equip. GO
Other Manufacturing	Gross Output	Gross Output	Other Mfg. GO
Iron Ore Mining	Gross Output	Gross Output	Industry Gross Output
Other Metal Mining	Gross Output	Gross Output	Industry Gross Output
Non-Metal Mining	Gross Output	Gross Output	Industry Gross Output
Light Oil Mining	Local Oil Production	Local Oil Production	N/A
Heavy Oil Mining	Local Oil Production	N/A	N/A
Frontier Oil Mining	Local Oil Production	N/A	N/A
Primary Oil Sands	Local Oil Production	N/A	N/A
SAGD Oil Sands	Local Oil Production	N/A	N/A
CSS Oil Sands	Local Oil Production	N/A	N/A
Oil Sands Mining	Local Oil Production	N/A	N/A
Oil Sands Upgraders	Local Oil Production	N/A	N/A
Conventional Gas Production	Local NG Production	Local NG Production	Industry Gross Output
Sweet Gas Processing	Local NG Production	N/A	N/A
Unconventional Gas Production	Local NG Production	N/A	N/A
Sour Gas Processing	Local NG Production	N/A	N/A

Sector	Canada	U.S.	Mexico
LNG Production	Local LNG Production	Local LNG Production	Industry Gross Output
Coal Mining	Gross Output	GRP	Industry Gross Output
Construction	Gross Output	Gross Output	Industry Gross Output
Forestry	Gross Output	Gross Output	Agriculture Gross Output
On Farm Fuel Use	Gross Output	Gross Output	Agriculture Gross Output
Crop Production	Gross Output	Gross Output	N/A
Animal Production	Gross Output	Gross Output	N/A
Transportation			
Passenger	Population	Personal Income	Personal Income
Freight	GRP	GRP	GRP
Air Passenger	Personal Income	Personal Income	Personal Income
Air Freight	GRP	GRP	GRP
Foreign Passenger	GRP	GRP	GRP
Foreign Freight	GRP	GRP	GRP
Residential Off-Road	GRP	GRP	GRP
Commercial Off-Road	GRP	GRP	GRP
Miscellaneous Sectors (not used)			
Miscellaneous	N/A	N/A	N/A
Electric Resale	N/A	N/A	N/A
Miscellaneous Sectors (used to hold Energy Demands from Suppliers)			
Utility Electric Generation	Electric Utility Gen.	Electric Utility Gen.	Electric Utility Gen.
Biofuel Production	Biofuel Production	Biofuel Production	N/A
Steam Generation	Steam Generation	Steam Generation	N/A
Miscellaneous Sectors (used for Emissions Accounting Only)			
Solid Waste	Total Households	Gross Output	N/A
Wastewater	Total Households	Gross Output	N/A
Incineration	Total Households	Gross Output	N/A
Land Use	Land Acres	Gross Output	N/A
Road Dust	Freight Miles	Gross Output	N/A
Agriculture Open Sources	Farm Gross Output	Gross Output	N/A
Forest Fires	Land Acres	Gross Output	N/A
Biogenics	Land Acres	Gross Output	N/A

2.2. Macroeconomic Input Data Requirements

The macroeconomic input data required to be updated annually consist of the variables listed in Table 2 that are used as drivers of energy demand. These data are required for the historical and forecast period.

Table 2. Economic Input Data Requirements

Economic Input Data Requirements	Variable Name
Inflation and exchange rates • Inflation Index ($/$) • Exchange Rate ($Canada/$US)	 XInfla(Year) XExchg(Year)
Demographic • Population (Millions) • Households (Number) • Personal Income (Real$/Year)	 XPopT(Area,Year) XHHS(ECC,Area,Year) XRPI(Area,Year)
Economic Activity • Floor Space per Unit (Sq. Units/Bldg) • Gross Output (Real M$/Year) • Regional Gross Product (Real M$/Year)	 FSUnit(ECC,Area,Year) XGO(ECC,Area,Year) XGRP(Area,Year)
Physical life of production capacity (Yrs)	PCPL(ECC,Area,Year)

Table 3 lists the data sources used to obtain the U.S. and Canada macroeconomic data, and Table 4 identifies the data sources used to obtain macroeconomic data for Mexico.

Table 3. Economic Input Data Sources

Canada Data Source	U.S. Data Source
Canada economic indicators are from Statistics Canada, obtained from Environment and Climate Change Canada's TIM macroeconomic model.	U.S. economic indicators are from Macroeconomic Activity Module (MAM) of the National Energy Modeling System (NEMS), U.S. DOE, Energy Information Administration. MAM/NEMS uses forecast from Global Insight as input.

Two sources were used to obtain Mexico macroeconomic input data consisting of Mexico population, gross output, personal income, and GDP. The sources used for this data are listed in Table 4.

Table 4. Economic Input Data Sources for Mexico

Data Sources for Mexico Economic Drivers	
Economic Indicator	**Source**
Population	International Monetary Fund (Oct 2015), World Economic Outlook Database. www.imf.org/external/pubs/ft/weo/2015/02/weodata/weoselgr.aspx
GDP	
Gross Output	World Bank (2016). www.data.worldbank.org/country/mexico#cp_wdi
Personal Income (GNI)	

2.3. Other Macroeconomic Assumptions

Other model assumptions are input to ENERGY 2020 related to economic characteristics, such as production capacity. These assumptions are input to the model through MData.src and include the following:

- Production Capacity Characteristics
  - Economic Capacity Utilization Fraction
  - Physical Life of Production Capacity
- Other Miscellaneous
  - Municipal Waste Decay Time
  - Inflation Rate Smooth Time
  - Inflation Rate Base Year

2.4. Temperature

Heating and cooling degree days (DegreeDay)

a. NOAA degree days by state and month in vData_Superset.accdb, https://www7.ncdc.noaa.gov/CDO/CDODivisionalSelect.jsp
b. EIA degree days by census division and month.
   Source: U.S. Energy Information Administration, *February 2019 Monthly Energy Review*:
   - Table_1.9_Heating_Degree-Days_by_Census_Division.xlsx
   - Table_1.10_Cooling_Degree-Days_by_Census_Division.xlsx
c. The U.S. degree days have a base temperature of 65°F (equivalent to 18°C). Canada degree days have a base temperature of 18°C.

The temperature data exists in three places one of which provides an alternative source for the data:

a) vData.accdb – has annual heating and cooling degree days for Canada for 1985-2014. The Access table is vDDay while the values are stored in vCDD and vHDD of VBInput.

b) vData_Superset – has monthly heating and cooling degree days for 50 US states for 1985-2013. The January 2014 values are also in the database. The Access table is vDegreeDay while the values are stored in DegreeDay in Superset.

c) Observed_CAN_US_1981-2012_HDDCDD_allBase18_Raw.dta – has monthly heating and cooling degree days for Canada and for US regions for 1981-2012. The values are stored in vCDD and vHDD of VBInput. This data is not currently used and thus the procedures below (2, 7, and 8) have been grayed out.

3. Fuel Prices

Energy price data is a key component to the ENERGY 2020 forecast and is generally updated annually when new historical data is available. Energy prices can play a significant role in end user decisions on equipment, capital and operating decisions. Fuel costs can be critical in determining the costs of electric dispatch, as well as input costs of some industrial processes and home heating. ENERGY2020 calculates future electric prices based in part on these fuel costs.

Energy prices are largely determined by international markets, although domestic demand, such as electric sector demand for natural gas can influence prices. As a result, fuel prices are treated by the model as an exogenous input. The wholesale price of oil, natural gas, and coal are exogenous inputs from the World Oil Price, Henry Hub Price of Natural Gas, and Minemouth Price of Coal.

Historic retail energy price data for the US are taken from the U.S. DOE State Energy Data System (SEDS). The future values for US retail prices are assumed to grow at the same rate as reported in the *AEO* Reference Case scenario.

Final delivered prices can be read in directly or 'built-up' within the model by using a base delivered prices with separate tax inputs applied on top. The U.S. retail price is read in directly, and the Canada historic fuel price is input as a base delivered price with fuel taxes split out. Canada's retail energy price data source is Statistics Canada.

Electricity Price
Electricity prices are calculated endogenously by the model based on generation costs and dispatch. While, the model estimates retail electricity prices, actual consumer prices may differ as a result of political, regulatory or market influences. The model can be calibrated to actual prices, within reasonable parameters, for the historic period.

Wholesale Fuel Price
Price of energy in wholesale markets by fuel type in constant dollars per mmbtu is provided by Environment and Climate Change Canada (as vENPN). The current model version applies the same wholesale prices to all areas in the model. Historical and forecast values are input to the model for use as an exogenous price forecast. This price generally reflects the sale price of a fuel by producers for the relevant market. For example, the oil wholesale price will generally be the price of oil globally.

Delivered Fuel Price
The consumer price of energy by fuel type in constant dollars per mmbtu for Canadian areas is provided by Environment and Climate Change Canada. This value is the 'base' price (vFPBase), meaning that is has been stripped of all relevant taxes. Delivered fuel prices for U.S. areas are updated annually by state using data from the EIA State Energy Data System's fuel price outputs.

Sales Tax
Percentage of tax paid per unit of fuel sold is provided for Canadian areas by ECCC (vFPSM). Data for the last historical year is held constant for the forecast. Taxes for U.S. area are assumed to be 7%.

Fuel Tax (Excise Tax)
Nominal dollar of tax paid per mmbtu of fuel sold is provided for Canadian areas by ECCC (vFPTax). Data for the last historical year are held constant. Excise taxes for U.S. areas are assumed to be already included in their respective delivered price input.

Table 5. Energy Prices and Taxes Input Data Requirements

Input Data Requirements	Variable	Description
Wholesale Fuel Price ($/mmBtu)	XENPN(Fuel,Nation,Year)	The wholesale price paid to producers.
Delivered Fuel Price ($/mmBtu)	XFP(Prices,Area,Year)	Price paid for fuel by consumers.
Taxes • Energy Sales Tax ($/$) • Fuel Tax ($/mmBtu)	FPSM(Prices,Area,Year) FPTax(Prices,Area,Year)	Sales tax is the percentage of tax paid per unit of fuel sold. Fuel tax is nominal dollar of tax paid per mmbtu of fuel sold.

4. Demand Sector Input Data (Residential, Commercial, Industrial, Transportation)

Primary inputs to the demand module consist of economic drivers (some of which come from an exogenously input macroeconomic forecast and others calculated in the supply module), delivered and wholesale fuel prices from the supply modules, technology characteristics (for processes and devices), such as physical lifetimes and costs), and inputs from the demand calibration. Table 6 lists exogenous inputs to the demand module.

Table 6. Exogenous Inputs Required for Demand Module

Description	Variable Name and Definition
Historical energy demand (TBtu/Yr)	
- End-use	XDmd(Enduse,Tech,EC,Area,Year)
- Cogeneration	XCgDmd(Tech,EC,Area,Year)
- Feedstock	XFsDmd(Tech,EC,Area,Year)
- Steam generation	XStDmd(FuelEP,Area,Year)
Prices (Historical and Future)	
- Wholesale Fuel Price ($/mmBtu)	XENPN(Fuel,Nation,Year)
- Delivered Fuel Price ($/mmBtu)	XFP(Prices,Area,Year)
Emissions coefficients (Tonnes/TBtu)	
- Energy-related	POCX(Enduse,FuelEP,EC,Poll,Area)
- Cogeneration	CgPOCX(FuelEP,EC,Poll,Area,Year)
- Feedstock	FsPOCX(Fuel,Tech,EC,Poll,Area,Year)
Device characteristics (in one initialization year)	
- Historical Physical Life of Equipment (Yrs)	XDPL(Enduse,Tech,EC,Area,Year)
- Device Capital Cost ($/mmBtu/Yr)	XDCC(Enduse,Tech,EC,Area,Year)
- Historical Device Efficiency (Btu/Btu)	XDEE(Enduse,Tech,EC,Area,Year)
- Maximum Device Efficiency (Btu/Btu)	DEM(Enduse,Tech,EC,Area)
- Device Efficiency Standards (Btu/Btu)	DEStd(Enduse,Tech,EC,Area,Year)
Process characteristics (in one initialization year)	
- Process Energy Capital Cost ($/($/Yr))	XPCC(Enduse,Tech,EC,Area,Year)
- Maximum Process Efficiency ($/mmBtu)	PEM(Enduse,EC,Area)
- Process Efficiency Standards ($/Btu)	PESTD(Enduse,Tech,EC,Area,Year)

Input data assumptions that are not updated annually are listed in tables in **Appendix 1** by sector.

ENERGY 2020 Industrial End-Use Definitions

The industrial end-uses in ENERGY 2020 consist of the following categories:

- Process Heat
- Motors
- Other Substitutables

- Miscellaneous
- Off-Road
- Steam Production

Definitions for each of these end-use categories are as follows.

Process Heat: Process heat is the thermal energy used in an industrial process. Process heating is common during the manufacture of most industrial products, including those made out of metal, plastic, rubber, concrete, glass, and ceramics. Common industrial process heating systems fall in one of the following categories:

- Fuel-based process heating systems
- Electric-based process heating systems
- Steam-based process heating systems
- Other process heating systems, including heat recovery, heat exchange systems, and fluid heating systems. Source: http://www1.eere.energy.gov/manufacturing/tech_deployment/pdfs/process_heating_sourcebook2.pdf

Motors: Electric motors used to power production processes and heating, cooling and ventilation systems.

Other Substitutables: End-uses which are able to substitute other fuels for electricity, such as dryers can use electricity but also natural gas.

Miscellaneous: Anything that is not included in the categories of Process Heat, Motors, or Other Substitutables.

Off-Road: Industrial off-road vehicles, such as tractors and fork lifts.

Excess Steam: The proportion of steam production for sale and does not include what may be produced and consumed on-site.

Technology Characteristics Input Data Requirements

Device Technology Characteristics

- Historical Device Efficiency
- Historical Device Capital Cost
- Historical Device Efficiency Standards
- Device Initialization Year
- Device Saturation

Process Technology Characteristics

- Historical Process Efficiency
- Historical Process Capital Cost
- Historical Process Efficiency Standards

Model Input Assumptions

Device Technology Assumptions

- Maximum Device Efficiency
- Device Capital Cost Limit
- Device Operating Cost Fraction
- Device Physical Life of Equipment
- Retrofit Market Share Variance Factor

Process Technology Assumptions

- Space Heat Initial Efficiency Differences
- Ratio of Maximum to Average Process Efficiency
- Market Share Variance Factor
- Retrofit Market Share Variance Factor
- Retrofit Process Capital Cost Multiplier
- Temperature Sensitive Fraction of Load

4.1. Technology Characteristics (Devices/Equipment)

This section provides a summary of the primary input assumptions of efficiency, cost and lifetimes of residential and commercial technologies (devices) represented in ENERGY 2020 (January 2017 Spruce version). The residential and commercial technologies consist of space heat, air conditioning, water heating, lighting, refrigeration, other substitutables, and other non-substitutables by type of fuel used (natural gas, electricity, oil, LPG, and biomass). The specific model input variables summarized in this document (with variable names in parentheses) are: historical device efficiency (XDEE), historical efficiency standard (DESTD), capital cost (XDCC), operation and maintenance cost (DOCF), and device lifespan (DPL).

4.1.1. How ENERGY 2020 Uses Efficiency and Capital Cost Input Data by Technology

Combining historical efficiency and capital cost data together with fuel prices, O&M costs, device lifetimes, and the maximum efficiency available, ENERGY 2020 creates a set of efficiency and capital cost curves. These curves represent historical consumer choices of efficiencies and capital costs relative to fuel prices and allow the model to project future efficiency and cost choices given future fuel prices. The relationship is defined to reflect consumer preferences in the absence of any efficiency standards, therefore, historical data are occasionally adjusted to estimate what levels would have been without standards. Efficiency in ENERGY 2020 further represents a marginal rather than an average efficiency, that is, it represents the efficiency of new devices selected in a specified year rather than the average efficiency of all existing devices in that year.

4.1.2. Residential and Commercial Technology Input Data – Summary Tables

Table 7 summarizes the input assumptions for each residential technology represented in the model having historical demand, and Table 2 summarizes the input assumptions for the commercial technologies. The base year of this input data is the year 2000. The historical data summarized includes marginal device efficiency (XDEE), maximum device efficiency (DEM), historical efficiency standards (DESTD), capital costs (XDCC), operation and maintenance costs (DOCF), and device lifetimes (DPL). Whereas the data shown in these tables are representative of the values in the model, the specific values are those for Ontario in the 2017 Spruce version of the model (values may vary slightly by province and sector).

Table 7. Residential Sector Technology Input Assumptions (Base Year 2000)

Residential Enduse	Residential Technology	Device Efficiency (Btu/Btu)	Maximum Device Efficiency (Btu/Btu)	Historical Efficiency Standard (Btu/Btu)	Capital Cost (2013$US/ MMBtu/yr)	Operation and Maintenance Cost (Percent of Capital)	Device Lifespan (Years)
Space Heat	Natural Gas	0.56	0.97	0.80	$46.08	2.4%	23
	Electric	0.98	1.00	-	$51.50	1.8%	23
	Oil	0.56	0.97	0.80	$74.30	2.4%	23
	LPG	0.80	0.97	0.80	$39.84	2.4%	23
	Biomass	0.55	0.65	0.55	$57.00	1.3%	23
	Geothermal	3.00	4.00	-	$169.97	1.2%	23
	Heat Pump	2.30	3.00	-	$36.47	1.8%	
Air Conditioning	Electric	1.85	3.50	2.65	$493.51	1.5%	15
	Geothermal	3.00	4.00	-	-	-	15
	Heat Pump	2.65	3.00	-	-	1.5%	15
Water Heating	Natural Gas	0.43	0.97	0.62	$80.07	0.0%	13
	Electric	0.63	1.00	0.90	$133.95	0.0%	13
	Oil	0.41	0.97	0.59	$120.09	0.0%	13
	LPG	0.55	0.97	0.55	$88.40	0.0%	13
	Biomass	0.20	0.65	-	$57.00	0.0%	13
Lighting	Electric	0.65	0.95	-	$9.93	0.0%	6
Refrigeration	Electric	0.40	0.98	0.42	$319.18	0.0%	19
Other Substitutables	Electric	0.65	1.30	-	$215.11	0.0%	13
	Natural Gas	0.65	0.97	-	$281.21	0.0%	13
Other Non-Substitutables	Electric	0.65	0.98	-	$65.50	0.0%	10

Table 8. Commercial Sector Technology Input Assumptions (Base Year 2000)

Commercial Enduse	Commercial Technology	Device Efficiency (Btu/Btu)	Maximum Device Efficiency (Btu/Btu)	Historical Efficiency Standard (Btu/Btu)	Capital Cost (2013$US/ MMBtu/yr)	Operation and Maintenance Cost (Percent of Capital Cost)	Device Lifespan (Years)
Space Heat	Natural Gas	0.76	0.97	N/A	$74.13	2.2%	18
	Electric	0.98	1.00	N/A	$190.65	3.0%	18
	Oil	0.79	0.97	N/A	$156.15	2.0%	18
	LPG	0.60	0.97	N/A	$86.44	2.2%	18
	Steam	0.97	0.99	N/A	$13.60	3.0%	18
	Geothermal	3.00	4.00	N/A	$10,108	1.4%	18
	Heat Pump	2.30	3.00	N/A	$1,265	3.0%	18
Air Conditioning	Electric	2.80	3.50	N/A	$579.09	1.0%	18
	Natural Gas	0.76	2.00	N/A	$683.71	1.7%	18
	Geothermal	3.00	4.00	N/A	$10,108	1.4%	18
	Heat Pump	2.65	3.00	N/A	$1,265	3.0%	18
Water Heating	Natural Gas	0.76	0.97	N/A	$202.15	0.0%	8
	Electric	0.98	0.99	N/A	$307.96	0.0%	8
	Oil	0.78	0.97	N/A	$392.25	0.0%	8
	LPG	0.60	0.97	N/A	$202.15	0.0%	8
Lighting	Electric	0.65	0.95	0.715	$12.57	0.0%	7
Refrigeration	Electric	0.30	0.98	N/A	$404.65	0.0%	15
Other Substitutables	Electric	0.65	1.30	N/A	$74.74	0.0%	10
Other Non-Substitutables	Electric	0.65	0.98	N/A	$83.05	0.0%	7

The methodology used to estimate each of these input values for residential inputs and commercial inputs. Several different sources are used to develop this data and/or provide a sanity check for the input values consisting of the following:

- Annual Energy Outlook (AEO) 2015
- Assumptions reports of the AEO 2015
- Inputs to National Energy Modeling System (NEMS) reference forecast
- 2011, Navigant Consulting report conducted for the EIA
- 1980 Annual Report to Congress (ARC80), where more recent data is unavailable
- DoE's Buildings Energy Data Book

- Regulatory text from the U.S. government to set and check efficiency standard assumptions

Data Adjustments

These sources provide a reasonable set of data used to estimate model input data. However, some adjustments are required. ENERGY 2020 projects marginal efficiencies by technology on an annual basis and in the absence of standards. However, the data sources typically report a single year for average efficiency rather than marginal efficiency and include the impacts of historical efficiency standards. The average efficiency for the most recent year available along with capital costs for the same year, where possible, are converted to marginal and input to the model for one selected initialization year. In that initialization year, the model uses the data to calculate the parameters of the efficiency and cost curves.

The initialization year (currently year 2000) is selected to be the most recent historical year that allows a long enough time for the model to fully populate capital and machinery stocks - enough time to get a close to a lifetime of marginal efficiency into the average efficiency. In the initialization year, the calculated marginal efficiency (DEE) equals the exogenously input efficiency (XDEE). During calibration, ENERGY 2020 executes through the historical years, calculating annual efficiencies based on the curve parameters and fuel prices, along with adjustments based on the historical data.

Further adjustments are made to the historical marginal efficiencies to account for historical efficiency standards. This adjustment is made based on an assumption that a consumer choice efficiency is roughly 30% below any existing standards. Future work could be performed to test the impact of alternative assumptions to the consumer choice efficiency being 30% below standards.

The list below summarizes the steps taken to translate available technology data into model inputs and are described in further detail in Sections 2 and 3 of this document.

Steps Followed to Translate Available Technology Data into ENERGY 2020 Inputs:

1. Obtain historical data – reliable annual data is generally difficult to obtain so single representative year is often selected.
2. Estimate marginal inputs from averages where required
3. Estimate efficiencies in absence of standards – current assumption is that consumer-choice efficiency is 30% below any historical efficiency standard.
4. Select initialization year. This year would ideally be representative of the year where input data is available but also allow the model several years to fully populate capital and machinery stocks before the forecast. The current initialization year is 2000.

5. Estimate input data value in initialization year if needed (when available data is for different year).
6. Execute the model to initialize the efficiency and cost curves in the initial year. Curves are developed based on input prices, costs, and efficiencies in the initial year.

4.1.3. Residential and Commercial Technology Data Sources

This section details the data sources that were used to both develop residential and commercial sector efficiency inputs and for comparison to review the subsequent outputs to the model.

Annual Energy Outlook

The Annual Energy Outlook (AEO) is a comprehensive energy forecast produced annually by the U.S. Energy Information Administration (EIA). Specific to the residential sector, this outlook includes levels of stock efficiency for a variety of devices and enduses. This data typically includes two historical years and a 25 year or longer forecast. Some of this historical data has been directly read into the model as an input for efficiency. Since the data is for stock values, sometimes an adjustment is made to produce an estimate for a marginal value required to roughly achieve the listed stock average. The forecast efficiencies are frequently used as a check against the efficiencies in the ENERGY 2020 reference case.

http://www.eia.gov/forecasts/aeo/er/index.cfm

The National Energy Modeling System

The National Energy Modeling System (NEMS) is a detailed energy model that that EIA develops and executes to produce the AEO. NEMS source code is available for public review and use via the EIA website. This source code contains inputs and assumptions to NEMS similar to what is required for ENERGY 2020. Specifically, for residential the rsmpq.txt source code file contains capital cost data for devices used in NEMS. The data in this text file was converted to a format to fit the type of devices in ENERGY 2020 by averaging across relevant NEMS devices. This average capital cost data was then converted from installed dollars per unit to installed dollars per amount of energy used per year to match ENERGY 2020 specifications.

http://www.eia.gov/forecasts/aeo/info_nems_archive.cfm

Residential Energy Consumption Survey

The 2009 Residential Energy Consumption Survey is the latest data collection survey performed by the EIA to collect data on annual consumption by household by region in the US. Data related to total energy consumption by a specific enduse and fuel type was combined with number of households to produce and estimate of annual consumption per household per device type. This data was used with the NEMS capital cost data to convert capital costs into a format usable by ENERGY 2020

http://www.eia.gov/consumption/residential/data/2009/

AEO Residential Assumptions Report

The EIA produces a series of assumptions reports with the AEO to show some of the underlying assumptions used to produce their forecast. Specific to residential, the assumptions report includes average cost and efficiency data for a couple of select devices. This data was used to check the model outputs when available.

http://www.eia.gov/forecasts/aeo/assumptions/pdf/residential.pdf

Navigant Consulting Reference Case Residential and Commercial Building Technologies Report for the U.S. Energy Information Administration

In 2011, Navigant Consulting produced a report for the EIA researching efficiency and cost characteristics of variety of residential and commercial devices. Referred to in this document as the 'Navigant report', this document contains researched characteristics for the existing installed base of devices, and a forecast of these characteristics for range of years in the future dependent on the level of desired efficiency by the consumer. Depending on the specific device, these characteristics can include capacity, energy efficiency, unit and installed costs, annual maintenance costs, and expected device lifespan. Data for the installed base is used as an input to ENERGY 2020 for several devices. Capital and maintenance costs and forecast are used as a check for the costs being output by the model.

https://www.eia.gov/analysis/studies/buildings/equipcosts/

Buildings Energy Data Book

Produced by the U.S. Department of Energy, the Buildings Energy Data Book is a database containing summary statistics of the energy characteristics of building as a whole and several specific devices historically. This data is used to check model inputs and results where relevant.

http://buildingsdatabook.eren.doe.gov/

U.S. Efficiency Standard Regulations

Regulatory text from the U.S. government is used to set and check efficiency standard assumptions historically for any relevant devices.

http://www.ecfr.gov/cgi-bin/text-idx?SID=80dfa785ea350ebeee184bb0ae03e7f0&mc=true&node=se10.3.430_132&rgn=div8

1980 Annual Report to Congress

Energy statistics and assumptions about characteristics from 1980 Annual Report to Congress (ARC80) are used by the model when specific or more recent data is unavailable.

Expert Opinion and Modeler's Assumptions

Input and analysis from other reports or experts in the field are used as inputs and checks to the model when available. If specific data is unavailable an assumption by the modeler is sometimes used to produce inputs designed around efficiency and cost assumptions relative to other similar devices.

4.2. Transportation Technology Characteristics Assumptions

Efficiency and capital cost assumptions for light duty vehicles in 2012 are listed in the table below.

Assumptions Used for Light Duty Vehicle Characteristics			
2012	E2020 Efficiency (l/100km equiv)	AEO Efficiency (l/100km equiv)	AEO New Vehicle Price (2013 US$)
Gasoline	8.437	6.708	$ 25,100
Diesel	7.172	5.333	$ 27,200
Electric	-	1.713	$ 36,300
Natural Gas	-	7.538	$ 37,400
Propane	-	7.259	$ 36,900
Plug-In Hybrid	-	3.148	$ 40,700

The following table shows the model assumptions used for the cost of new generation by plant type. The source of this data is primarily from Annual Energy Outlook 2015.

Levelized Cost of New Base Load Generation in 2030			
	Levelized Cost (CN$2010/MWh)	**Variable Cost (CN$2010/MWh)**	**Fixed Cost (CN$2010/MWh)**
Gas/Oil Peaking	$57.73	$46.32	$11.40
Gas/Oil Comb Cycle	$52.01	$34.05	$17.86
Gas/Oil Steam	$184.79	$154.69	$30.10
Coal	$85.62	$31.60	$54.02
Advanced Coal	$104.24	$33.14	$71.10
Nuclear	$107.30	$4.41	$93.22
Base Hydro	$132.21	$0.00	$132.21
Peak Hydro	$79.33	$0.00	$79.33
CHP/Other	$142.13	$41.55	$100.58
Biomass	$143.77	$35.41	$108.36
Landfill Gas/Waste	$267.47	$8.67	$129.51
Wind	$161.67	$0.00	$145.11
Solar	$394.72	$0.00	$394.72
Pumped Hydro	$113.40	$0.00	$113.40
Small Hydro	$179.70	$0.00	$179.70
Wave	$734.93	$0.00	$119.85
Geothermal	$734.93	$0.00	$119.85
Coal with CCS	$153.19	$31.53	$96.12
Biogas	$0.00	$0.00	$0.00

5. Financial Data

These are financial assumptions in the residential, commercial, industrial, and demand sectors.

- Historical and Projected Income Tax Rate
- Return on Investment
- Account Percentage of Device Life Taxed
- Device Investment Tax Credit
- Device Risk Premium
- Device Book Life
- Process Investment Tax Credit
- Retrofit ‘Hassle Cost’ Multiplier
- Cogeneration Investment Tax Credit
- Cogeneration Risk Premium
- Cogeneration Tax Life
- Cogeneration Book Life

6. Emissions and Air Regulations

- Emissions coefficients and inventories
- Process emissions inputs
- GHG Process Emissions Coefficients
- CAC Process Emissions Inventories

6.1. Input Data Requirements and Assumptions

Input Data Requirements

- GHG Emissions Coefficients
- Energy Emissions Coefficients
- Cogeneration Emissions Coefficients
- Feedstock Emissions Coefficients
- CAC Emissions Inventories
- Energy Emissions Inventories
- Cogeneration Emissions Inventories
- Feedstock Emissions Inventories

Model Assumptions

- Emissions Coefficients Conversions
- Emission Reduction Cost Curve Parameters
- Normalized Reduction Cost
- Reduction Variance Factor
- Reduction Operation and Maintenance Costs
- Reduction Physical Lifetime
- Voluntary Reduction Response Time
- Pollution Cost Adjustment Time

Emissions resulting from energy consumption by the demand sector and supply sector are tracked by source of emissions and type of pollutant. The sources of emissions come from both energy-related (combustion and non-combustion) and non-energy related sources.

6.2. Sources and Types of Pollutants

The four sources of emissions tracked in ENERGY 2020 are categorized by method by which the pollutant is created and are listed below.

- Energy emissions: Emissions from combustion of fuels.
- Process emissions: Emissions from economic activity.

- Feedstock emissions: Emissions from non-combusted fuels used as raw material input to processes.
- Fugitive emissions: Emissions from leaks of gases into the air (venting, flaring, and other fugitives).

Nineteen types of pollutants are represented in the model, including seven greenhouse gases (GH), eleven criteria air contaminants (CAC), and one other category consisting of water usage as shown in Table 9.

Table 9. Pollutants Represented in ENERGY 2020

Pollutants Represented in ENERGY 2020	
Greenhouse Gases	
Nitrous Oxide (N2O)	Perfluorocarbon (PFC)
Carbon Dioxide (CO2)	Hydrofluorocarbon (HFC)
Methane (CH4)	Nitrogen Trifluoride (NF3)
Sulphur-Hexafluoride (SF6)	
Criteria Air Contaminants	
Sulphur Oxides (SOX)	Particulate Matter 10 (PM10)
Nitrogen Oxides (NOX)	Black Carbon (BC)
Particulate Matter Total (PMT)	Mercury (Hg)
Volatile Org Comp. (VOC)	Ammonia (NH3)
Carbon Monoxide (COX)	Ozone (O3)
Particulate Matter 2.5 (PM25)	
Other	
Water Use (H2O)	

6.3. Calculating Emissions

Emissions coefficients are used to project emissions into the future for each type of pollutant. The definition of the emission coefficients vary based on the source of emissions. For emissions caused by combustion of fuels, the coefficients are defined as unit of emissions produced per unit of energy combusted. For other sources of emissions, coefficients are defined as the unit of emissions produced per unit of economic activity (for process emissions), per unit of raw fuel use (for feedstock emissions), or per unit of gas leakage (for fugitive emissions). Total emissions are calculated by multiplying the respective emissions coefficients times the amount of energy consumed for energy-related emissions, the amount of economic activity for process emissions, the of raw fuel used as feedstock for feedstock emissions, and the amount of gas leaked for fugitive emissions.

Emissions coefficients for each type of pollutant (by area, economic category, enduse, technology, and fuel if relevant) are needed in order to project future emissions. For GHG emissions coefficients, these coefficients known energy-related engineering calculations. In this case, historical coefficients are directly input to the model, and total emissions are a simple calculation of energy use multiplied by the emissions coefficient. However, the CAC coefficients contain more complexity and are not so easily obtained. As a result, an implied coefficient is calculated based on historical inventories of CAC emissions. The coefficient is calculated from the inventory using several different methods. See section below on calculating emissions coefficients for a summary of the various methods used.

6.4. Emissions Reduction Mechanisms

Several mechanisms are in place to simulate the energy suppliers and consumers taking specific measures designed to directly mitigate emissions in response to price signals, such as increased prices due to carbon taxes or cap-and-trade systems.

The types of emissions-reducing mechanisms in place consist of offsets and reduction curves, implementing generic energy efficiency improvements, and improving work practices in the oil and gas industry. Electric utilities additionally will respond to increased emissions prices and/or targets by switching to lower-emitting fuel sources of generation, such as natural gas and renewables.

6.4.1. Offsets and Reduction Curves

Given an increased carbon price, three mechanisms are in place to reduce emissions based on reduction cost curves: 1) offset reductions from agriculture, forestry, and waste; 2) carbon capture and storage sequestering (CCS); and 3) improvements to industrial processes.

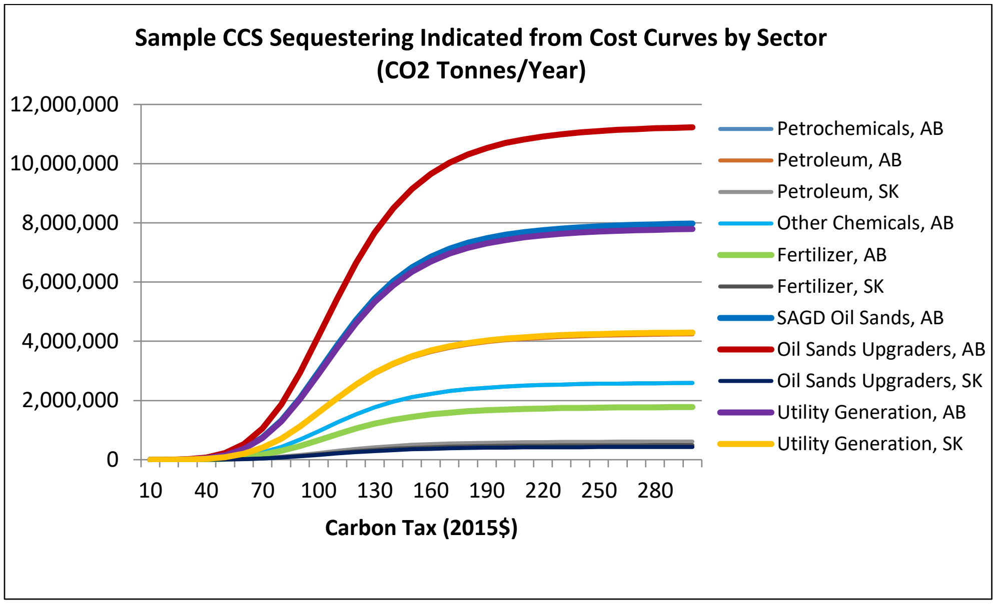
Offsets from Agriculture, Forestry, and Waste

There are currently seven types of offsets represented in ENERGY 2020. Each of the offsets is mapped to an economic category (ECC) in ENERGY 2020 and to a Pollutant. The offset mapping is listed below.

Offset		ECC		Pollutant
Landfill Gas Capture Solid Waste (LFG)	→	Solid Waste	→	CH4
Anaerobic Wastewater Treatment (WWT)	→	Wastewater	→	CH4
Aerobic Composting Solid Waste (AC)	→	Solid Waste	→	CH4
Nitrous Oxide Agriculture (NERA)	→	Crop production	→	N2O
Anaerobic Decomposition Agriculture (AD)	→	Animal production	→	CH4
Wood Biomass Agriculture (WB)	→	Crop production	→	CH4
Forestry	→	Forestry	→	CO2

Carbon capture and storage (CCS) sequestering

The amount of carbon capture and storage sequestering implemented is determined based on a carbon cost curve whose parameters are model inputs. CCS is represented in the Chemical, Oil Sands, and Electric Utility sectors within Alberta and Saskatchewan. An exogenous amount of sequestering also could be input to the model to indicate government developed CCS. The exogenous level of sequestering serves as the minimum amount of sequestering developed. A sample of the reduction cost curves represented in the model by type of gas and industry is shown in the figure below. Curve parameters are input through the policy file named *GHG_CCSCurves.txp* and stored in the 2020Model subdirectory.



Improvements to Industrial Processes: Industrial processes emission non-CO2 reduction cost curves are represented in the model. The figure below illustrates the fraction of emissions reduced at various levels of carbon taxes by economic sector.

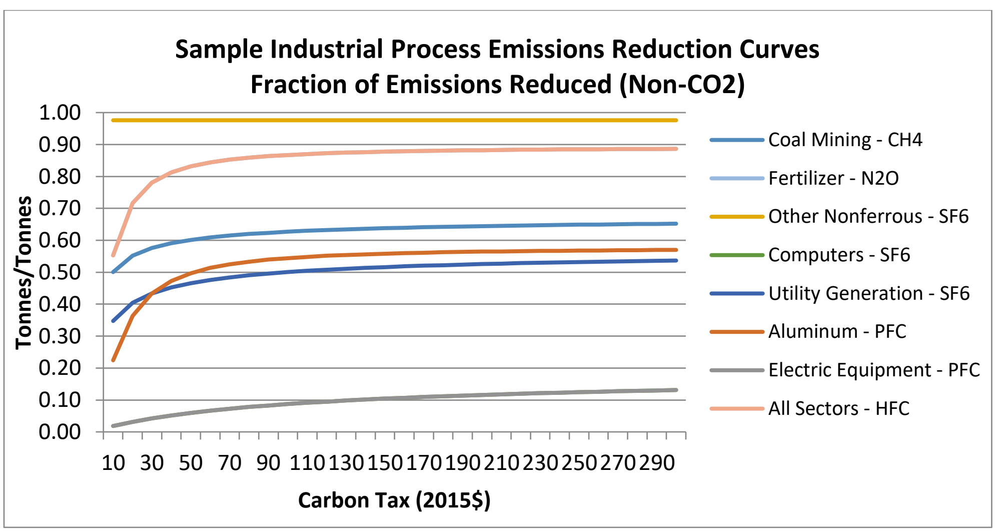


Table 10 identifies which pollutants are reduced by the emissions-reduction curves initiated by carbon prices. These curves are able to be set as active or non-active with the use of a model switch.

Table 10. Industries and Pollutants Impacted by Offsets and Reduction Cost Curves

	Industrial Sector	Industrial Processes	CCS	Agriculture, Forestry, Waste Offsets
1	Food & Tobacco	HFC	-	-
2	Textiles	HFC	-	-
3	Apparel	HFC	-	-
4	Lumber	HFC	-	-
5	Furniture	HFC	-	-
6	Pulp and Paper Mills	HFC	-	-
7	Converted Paper	HFC	-	-
8	Printing	HFC	-	-
9	Petrochemicals	HFC	CO2	-
10	Industrial Gas	HFC	-	-
11	Other Chemicals	HFC	CO2	-
12	Fertilizer	N2O, HFC	CO2	-
13	Petroleum Products	HFC	CO2	-
14	Rubber	HFC	-	-
15	Leather	HFC	-	-
16	Cement	HFC	-	-
17	Glass	HFC	-	-
18	Lime & Gypsum	HFC	-	-
19	Other Non-Metallic	HFC	-	-
20	Iron & Steel	HFC	-	-
21	Aluminum	PFC, HFC	-	-
22	Other Nonferrous Metal	SF6, HFC	-	-
23	Fabricated Metals	HFC	-	-
24	Machines	HFC	-	-
25	Computers	SF6, HFC	-	-
26	Electric Equipment	PFC, HFC	-	-
27	Transport Equipment	HFC	-	-
28	Other Manufacturing	HFC	-	-
29	Iron Ore Mining	HFC	-	-
30	Other Metal Mining	HFC	-	-
31	Non-Metal Mining	HFC	-	-
32	Light Oil Mining	HFC	-	-
33	Heavy Oil Mining	HFC	-	-
34	Frontier Oil Mining	HFC	-	-
35	Primary Oil Sands	HFC	-	-
36	SAGD Oil Sands	HFC	CO2	-
37	CSS Oil Sands	HFC	-	-
38	Oil Sands Mining	HFC	-	-
39	Oil Sands Upgraders	HFC	CO2	-
40	Sweet Gas production	HFC	-	-
41	Sweet Gas Processing	HFC	-	-
42	Sour Gas production	HFC	-	-
43	Sour Gas Processing	HFC	-	-
44	LNG production	HFC	-	-
45	Coal Mining	CH4, HFC	-	-

	Industrial Sector	Industrial Processes	CCS	Agriculture, Forestry, Waste Offsets
46	Construction	HFC	-	-
47	Forestry	HFC	-	CO2
48	On Farm Fuel Use	HFC	-	-
49	Crop production	HFC	-	N2O, CH4
50	Animal production	HFC	-	CH4
51	Utility Generation	SF6, HFC	CO2	-
52	Solid Waste	-	-	CH4
53	Waste Water	-	-	CH4

6.4.2. Data Sources for Offsets, Efficiency and Fugitive Reduction Curves

Carbon Capture and Storage (CCS)
Alberta Carbon Capture and Storage Development Council. (2009). Accelerating Carbon Capture and Storage Implementation in Alberta Final Report. Edmonton, Alberta. Available from: http://www.canadiancleanpowercoalition.com/pdf/GS26%20-%20CCS_Implementation.pdf

Natural Gas Processing – Formation CO2
McCollum, D.L. and J. M. Ogden (2006). Techno-Economic Models for Carbon Dioxide Compression, Transport, and Storage & Correlations for Estimating Carbon Dioxide Density and Viscosity. Institute of Transportation Studies, University of California, Davis. Davis, CA. Available from: https://escholarship.org/uc/item/1zg00532

Oil Sands Energy Efficiency
Suncor Energy and Jacobs Consultancy (2012). A Greenhouse Gas Reduction Roadmap for Oil Sands. Prepared for CCEMC. Available from: http://eralberta.ca/wp-content/uploads/2017/05/GHG-Reduction-Roadmap-Final-Report-Alberta-Oil-Sands-Energy-Efficiency-and-GHG-Mitigation-Roadmap.pdf

Refineries Energy Efficiency
California Air Resources Board (2013). Energy Efficiency and Co-Benefits Assessment of Large Industrial Sources Refinery Sector Public Report. Available from: https://www.arb.ca.gov/cc/energyaudits/eeareports/refinery.pdf

Upstream Oil and Gas Sector
Stantec Consulting and Marbek Resource Consultants Ltd. (2009). Energy Efficiency Potential in Canada's Upstream Oil and Gas Sector. Prepared for NRCan. Ottawa, Ontario.

Forestry
Environment Canada (2012). GHG Mitigation Potential of the Land Use, Land Use Change and Forestry (LULUCF) Sector in Canada.

Landfill gas
Conestoga-Rovers & Associates (2012). Identification of potential additional greenhouse gas emissions reductions from Canadian municipal solid waste landfills. Prepared for Environment Canada. Mississauga, Ontario.

Wastewater/ Agriculture/Waste
ICF Marbek (2012). Canadian Offset Supply Estimates. Calgary, Alberta.

Non-CO2 Emissions Reduction Cost Curve
Global Mitigation of Non-CO2 Greenhouse Gases: 2010 – 2030 (September 2013) (EPA Report 430R13011)

6.4.3. Generic Energy Efficiency Improvements

Code is in place which allows the industrial sectors to activate improvements to device and process efficiency curves. Additionally, generic device and process efficiency improvements are introduced to the model across the residential, commercial, and industrial sectors. The level of improvements is exogenously set.

6.4.4. Oil and Gas Industry Work Practices

Emission-reduction measures within the oil and gas industry ("work practices") are incorporated into the model based on increases to carbon prices and include reductions from the following five areas:

- Venting emissions reductions
- Flaring emission reductions of CO2 from Reduced Emission Completion (REC) programs which capture gas from hydraulic fracturing
- Sequestering of formation CO2 - natural gas processing industry sequestering of formation CO2.
- Fugitive emission reductions from pneumatic device improvements
- Fugitive emission reductions from Leak Detection and Repair (LDAR) programs
- Other fugitive emission reductions CH4 – sets a minimum level based on an overall 45% target

A summary of the industries and pollutants impacted by the oil and gas work practices is listed in Table 11.

Table 11. Pollutants Reduced by Oil and Gas Industry Work Practices

ENERGY 2020 Sectors Impacted by Oil and Gas Industry Work Practices						
Industrial Sector	Venting	RECs Flaring	Formation CO2 Sequestering	Pneumatic Devices Fugitives	LDAR Fugitives	Other Fugitives
Light Oil Mining	CH_4 (+CO_2, VOC)			CH_4		CH_4
Heavy Oil Mining	CH_4 (+CO_2, VOC)			CH_4		CH_4
Frontier Oil Mining				CH_4		CH_4
Primary Oil Sands	CH_4 (+CO_2, VOC)					CH_4
SAGD Oil Sands						CH_4
CSS Oil Sands						CH_4
Oil Sands Mining						CH_4
Oil Sands Upgraders						CH_4
Sweet Gas production		CO_2			CO_2, CH_4, VOC	CH_4
Sweet Gas Processing			CO_2	CH_4		CH_4
Sour Gas production		CO_2			CO_2, CH_4, VOC	CH_4
Sour Gas Processing			CO_2			CH_4

6.5. Calculating Emissions Coefficients

6.5.1. Energy-related CAC emissions from demand sector

For the demand sector energy-related CAC emissions, an emissions coefficient is first calculated from the known historical CAC emissions (emissions divided by energy consumed). There are sectors in which historical CAC emissions for a particular fuel exist; however, no historical fuel demand exist. In those instances, the historical emissions are categorized as process emissions. Cogeneration coefficient is set equal to the energy coefficient due to a lack of specific data. The feedstock coefficient, which sets values for non-combustions emissions, is currently set to zero to avoid double-counting issues since its historical inventories are also found in the process inputs. The code described above can be found in the following 2020Model files: CAC_Industrial.txt, CAC_Commercial.txt, CAC_Residential.txt, CAC_Transportation.txt.

6.5.2. Process Emissions CACs

Several sectors that produce CAC emissions aren't modeled in detail by ENERGY 2020 and have no input fuel demands. These sectors are given energy and process emissions coefficients in CAC_Macroeconomy.txt based on their historical inventories and corresponding economic driver in order to account for their expected emissions in the model forecast. Some sectors, such as Forest Fires, have a constant value set for the driver so the model assumes that we will generally have the same amount of emissions from these sources in the future as we have had historically.

6.5.3. Electric Utility CACs

Generating electric utility coefficients is more complex compared to the demand sectors since ENERGY 2020 simulates electric generation, fuel consumption, and emissions at the unit level. Since there are two separate sources of data for Utility Generation emissions, sector-wide inventories across each area (XEnFPol) and NPRI data containing unit-level emissions (vUnPol), the CAC_ElectricGeneration.txt file contains code developed to both. Units are initialized with the same energy and process coefficient across a given area by dividing the sum of all unit fuel usage (UnDmd) in a given area by the corresponding inventory (XEnFPol). The inventory is re-calculated using the new coefficient (UnPOCX) and any differences between the calculated and historical inventories are placed into process.

If a unit contains data from NPRI then the coefficients are adjusted using the NPRI data. Other units not included in the NPRI data have their emissions coefficients recalculated in order to match the sector-wide inventory. In practice, the NPRI data and sector-wide inventories often do not agree completely so it is difficult to match both inputs at once. As a compromise, the code is designed to iterate between adjusting based on the NPRI data and the sector-wide inventories ten times in order balance between the two data sources and create the most reasonable estimate possible.

6.6. Emissions-Related Input Data

Input data differs by the type of the pollutant (GHG vs. CAC) and the method by which the pollutant is created (Combustion, Process, etc.). ENERGY 2020 reads in emissions-related coefficients and inventories as input data through the Access database, vData.accdb. The following lists the emissions-related variables that are in the Access database along with a short description of each:

- vPOCX: Energy emissions coefficients (GHG)
- vFsPOCX: Feedstock emissions coefficients (GHG)
- vEUPOCX: Electric Utility energy emissions coefficients (GHG)
- vTrEnFPOCX: Transportation energy emissions coefficients (GHG)
- vTrFsPOCX: Transportation feedstock emissions coefficients (GHG)
- vEnFPol: Energy emissions inventories (CAC)
- vMEPol: Process emissions inventories
- vOREnFPol: Off-road emissions inventories (CAC)
- vTrEnFPol: Transportation energy emissions (CAC)

- vTrMEPol: Transportation process emissions
- vFlPol: Flaring emissions inventories
- vFuPol: Fugitive emissions inventories
- vVnPol: Venting emissions inventories
- vUnPol: NPRI utility emissions inventories
- vNPRICode: NPRI data unit identification data

6.6.1. Emission Factors

Table 1 provides a rough estimate of carbon dioxide equivalent emissions emitted per unit of energy consumed by fossil fuel type for combustion and industrial processes for the 2017 Reference Case. These numbers are estimates based on latest available data based on Intergovernmental Panel on Climate Change (IPCC) methodology. Specific emission factors can vary slightly by year, sector, and province.

Table 1: Mass of CO_2 eq Emissions Emitted per Quantity of Energy for Various Fuels

Fuel	CO2 eq. Emitted [grams per mega joule (g/MJ)]
Aviation Gasoline	74.25
Biodiesel	7.31
Biomass	5.47
Coal	90.79
Coke	110.10
Coke Oven Gas	36.25
Diesel	74.23
Ethanol	2.31
Gasoline	68.71
Heavy Fuel Oil	75.22
Jet Fuel	69.38
Kerosene	68.15
Landfill Gases/Waste	35.10
Light Fuel Oil	71.17
LPG	44.60
Lubricants	36.34
Naphtha Specialties	17.77
Natural Gas	46.80
Natural Gas Raw	57.20
Other Non-Energy Products	36.41
Petrochemical Feedstocks	14.22
Petroleum Coke	84.58
Still Gas	51.49

7. Electricity Supply

Electric Units

- Characteristics
- Historical Data

Aggregated Electric Sector Data

- Electric loads
- GHG Emissions Coefficients
- Electric Sales
- Electric Exports

Electricity Supply Assumptions

- Electric Construction Assumptions
- Financial Assumptions
- Transmission
- Generating Load
- Dispatch Assumptions
- CAC Emission Reductions

The electric supply segment of ENERGY 2020 simulates the electric system through the use of individual generation units. Each unit is required to be assigned characteristics, such as location, nation, plant type, and historical data, such as capacity and generation, to function in the model.

In addition, aggregate-level input data is required by the model for the unit-level simulation to dispatch properly. Examples include peak loads by electric node and details about the electric transmission network.

7.1. Electric Generating Units

7.1.1. Electric Generating Characteristics

Characteristics for Canadian units are regularly updated by ECCC using the input Canadian electric unit database (vData_ElectricUnits_CN.accdb). Each unit is automatically assigned a unit code (UnCode) based on the value of the Unit column in the vUnArea table.

US unit data is maintained and regularly updated by SSI using the input US electric unit database (vData_ElectricUnits_US.accdb). US units are aggregated by plant type and US area based on EIA data.

Table 12. Electric Generating Unit Characteristics

Generating Unit Characteristic	Variable Name	Description
Area	vUnArea(Unit)	Location of unit
Nation	vUnNation(Unit)	Country of unit
Name	vUnName(Unit)	Name of generating unit
Owner	vUnOwner(Unit)	Owner of generating unit
Generating Company	vUnGenCo(Unit)	Model generating company (GenCo) of the unit. The model has the capability to simulate specific generating companies if input data is available. The current version assigns a single company to each model area.
Node	vUnNode(Unit)	Electric node where unit is located.
Plant Type	vUnPlant(Unit)	Plant type assigned from list of ENERGY 2020 plant types.
Online Date	vUnOnline(Unit)	First year of operation.
Retirement Data	vUnRetire(Unit)	Last year of operation.
Industrial Cogeneration Switch	vUnCogen(Unit)	Switch indicating if unit is industrial cogeneration. '0' is used if the unit is solely for electric generation. '1' is used if the unit is cogeneration.
Economic Sector	vUnSector(Unit)	Assignment of economic sector if unit is industrial cogeneration unit. Non-cogeneration units are generally assigned the 'UtilityGen' sector.
Facility	vUnFacility(Unit).	Facility name if the unit is part of a facility. Used for emissions policies that enact regulation at the facility level.
Primary Fuel Type	vUnF1(Unit)	The primary fuel used by the unit.
Emissions Indicator	vUnEmit(Unit)	Switch indicating if unit produces emissions ('0' no emissions; '1' unit emits).
'Must Run' Status	vUnMustRun(Unit)	Switch to indicate the unit must always be dispatched if generation is needed regardless of market price. '1' signifies that the unit is must run.

7.1.2. Electric Generating Unit Historical Data

Historical data for Canadian units are regularly updated by ECCC using the input Canadian electric unit database (vData_ElectricUnits_CN.accdb). Forecast values can optionally be read in for use by the model to match projections of future operation at each unit.

Table 13. Electric Generating Unit Historical Input Data Requirements

Unit Data	Variable	Description
Capacity	vUnGC	Generating capacity in megawatts of each unit for each year
Generation	vUnEGA.	Total annual generation in gigawatt hours for each unit.

Unit Data	Variable	Description
Energy Demand	vUnDmd	Annual gigajoules of energy consumption of each unit for each fuel type.
Heat Rate	vUnHrt	Annual ratio of Btu input per kilowatt hour output for each unit
Fuel Fraction	vUnFlFr	Annual ratio of amount of fuel type consumed over total fuel consumption.
Energy Availability Factor	vUnEAF	Availability factor for each unit by model month and year.
Outage Rate	vUnOR	Outage rate of each unit by year '1' reflects that the unit was offline the entire year.
Capital Cost	vUnGCCC	Overnight capital costs for each unit in fixed dollars per kW of constructed capacity.
CAC Emissions Inventory	vUnPol	Annual tonnes or kilograms of emissions by fuel type per unit by pollutant.
Emissions Reduction O&M Cost	vUnROCF	Cost factor of operating emissions reduction devices per unit.
Sequestration Fraction	vUnSqFr	Percentage of sequestered emissions of total emissions per unit.

7.2. Aggregated Electric Sector Input Data

The required inputs below are required to simulate the electric generation system as a whole. This data primarily influences the flow of electricity across electric nodes during the electric unit dispatch.

GHG Emissions Coefficients

GHG emissions coefficients for Canadian electric units by pollutant type, fuel consumed, plant type, and area are provided by ECCC. US GHG coefficients are provided by SSI based on available data.

Electric Sales

Total gigawatt hour sales for Canadian areas by model month are provided by ECCC through the Electric fuel type in the input demand variables. This value is converted from annual to months using the input peak load data. US sales by state uses data from the EIA's Form EIA-826, converted to fit the model's months and areas.

Electric Exports

Gigawatt hours exported to other Canadian areas (vAreaSales) and the US (vExpSales) are provided for Canadian areas by ECCC.

Electric Imports

Gigawatt hours imported from other Canadian areas (vAreaPurchases) and the US (vExpPurchases) are provided for Canadian areas by ECCC.

7.2.1. Transmission Network Assumptions

Electric transmission between nodes is simulated by assigning characteristics of the transmissions lines that send power back and forth between nodes. These characteristics can be different depending on the direction of the flow, where one node can be defined to send more power to another node than it can receive in return.

Characteristics of flows between Canadian nodes and between Canada and the US are maintained by ECCC based on historical data and forecast assumptions. Flow characteristics between US nodes are maintained by SSI.

Maximum Loading on Transmission Lines

Maximum amount of load from an origin node to a destination node by time period, month, and year (LLMax). This value reflects the maximum that the model can endogenously dispatch from one node to the other.

Minimum Loading on Transmission Lines

Minimum load from an origin node to a destination node by time period, month, and year (LLMin). This ensures that the model must endogenously dispatch at least the specified amount from one node to the other.

Exogenous Loading on Transmission Lines

Exogenous load from an origin node to a destination node by time period, month, and year (HDXLoad). This ensures that the model must dispatch the specified amount from one node to the other.

Transmission Wheeling Charge

Transmission charge from an origin node to a destination node by year (XLLVC) in dollars per megawatt hour transmitted.

Electric Loads

Electric load data is used by the model as an input for electric generation calibration and dispatch.

Monthly Peak Loads

Input for the peak load in megawatts for Canadian areas in each model month is updated by ECCC. US areas use monthly peak load data by state from the EIA's Form EIA-411 data converted by SSI to fit the model's months and areas.

Monthly Minimum Loads

The model is able to read in minimum loads if specific historical data is available. Currently, the minimum load for each area in the model is assumed at 55% of the average load for each model month based on research into historical minimum loads in Massachusetts by Jeff Amlin.

7.2.2. Construction Assumptions

Assumptions related to the model's endogenous capacity planning and construction sections.

- Desired Reserve Margin
- Maximum Fraction of Capacity Built Endogenously
- Base Build Fraction
- Construction Delay
- Maximum Potential Capacity
- Build Decision Cost of Power Limit
- Fraction of New Oil and Gas Plant Capacity Assigned to Combined Cycle Plants
- Maximum Project Size
- Minimum Project Size
- Price Differential Fraction
- Green Power Cost Curve Parameters
- Green Power Market Share Non-Price Factor
- Green Power Market Share Variance Factor
- Renewable Plant Building Curve Parameters
- Renewable Market Share Variance Factor
- Renewable Market Share Non-Price Factor

Desired Reserve Margin

The default reserve margin for each electric node for construction planning is assumed to be 15% higher than the anticipated peak load.

Maximum Fraction of Capacity Built Endogenously

The maximum fraction of capacity that can be endogenously built by the model is set to 15%

Base Build Fraction

The percentage of base power that can be built endogenously is set to 2%

Construction Delay

Number of years for total initiated capacity to come online by plant type is set using values from the EIA's Annual Energy Outlook documentation.

Maximum Potential Capacity

This variable (XGCPot) determines the availability of each plant type per model area for endogenous construction. For example, an inland state would have zero potential for building ocean based generation units. The potential for new capacity by plant type is set for each model area using a variety of sources, including ECCC for Canadian areas and NREL renewable potential data for US areas.

Build Decision Cost of Power Limit

For a unit to be endogenously constructed using based on forecasted prices, the decision price must be greater than the long run marginal cost by a certain amount. This is assumed to be 10%.

Fraction of New Oil and Gas Plant Capacity Assigned to Combined Cycle Plants

New endogenously built gas plant capacity is assumed to be split 80% into combined cycle plants and 20% into turbine plants for Canadian areas that build natural gas units in the forecast.

Maximum Project Size

The maximum amount of capacity built by plant type for each area. The default value is that there is no maximum. Selected areas have an upper limit set based on expert feedback on the types of likely projects.

Minimum Project Size

A minimum amount of new capacity per unit for each plant type is set using assumptions about general project size. For example, nuclear unit has a much higher minimum project size than a gas unit given known differences in the scope required of each.

Price Differential Fraction

The price differential fraction is assumed to be 35%.

Renewable Plant Building Curve Parameters

When renewable power capacity is desired for construction (such as when simulating a renewable portfolio standard), the model determines the type of renewable constructed using a cost curve.

Renewable Market Share Variance Factor

The variance factor for the curve is assumed to be -10 for Canadian areas and -5 for US areas.

Renewable Market Share Non-Price Factor

The default non-price factor for all areas is the same across all renewable plant types. This value can be adjusted in policies to favor one plant type over another based on expert knowledge.

7.2.3. Financial Assumptions

Assumptions regarding pricing and risk related factors for capacity construction.

- Capacity Credit
- Common Stock Risk Premium
- Generation Capacity Development Time
- Generation Capacity Book Life
- Generation Capacity Tax Life
- Income Tax Rate
- Smoothing Time
- Weighted Cost of Capital
- Transmission Assumptions
- Transmission and Distribution Loss Factors
- Transmission Line Efficiency
- Load Assumptions
- Minimum Hours of Operation of Baseload and Intermediate Plants
- Dispatch Assumptions
- Fraction of Fixed Costs in Block
- Fraction of Variable Costs in Block
- Dispatch Price for Emergency Power
- CAC Emission Reductions
- Capital Charge Rate for Reductions
- Reduction Cost Multiplier
- Reduction Construction Time
- Reduction Capital Lifetime
- Reduction Operating Cost Factor

- Reduction Curve Parameters
- Reduction Cost Normal
- Reduction Variance Factor

Capacity Credit

Wind generation is assumed a 15% capacity credit

Generation Capacity Development Time

New capacity is constrained by development time for renewable/alternative plant types. This is currently set to 10 years.

Generation Capacity Book Life

The book life for each plant used to calculate the capital charge rate is 30 years.

Generation Capacity Tax Life

Tax life is assumed to be 80% of the book life.

Income Tax Rate

A total tax rate of 34% is used for the capital charge rate based on US state and federal data.

Smoothing Time

Prices are smoothed over two years when forecasting capacity planning.

Weighted Cost of Capital

The default weighted cost of capital for the capital charge rate is assumed to be 3.5%.

Transmission Line Efficiency

The default transmission efficiency used by the model is 93%

Minimum Hours of Operation of Baseload and Intermediate Plants

When calculating forecast load shapes, base load plants in the forecast are assumed to operate at least 4000 hours a year. Intermediate plants are assumed to operate at least 1000 hours per year.

Dispatch Assumptions

Assumptions used for the dispatch portion of the model code.

Fraction of Variable Costs in Block

All plant types assumed bid 100% of variable costs in each block except for Nuclear (25%) and Coal (50%)

Dispatch Price for Emergency Power

The default price for emergency power is $250 per megawatt hour.

CAC Emission Reductions

Assumptions related to building CAC reduction devices in response to reduction policies in the model.

Capital Charge Rate for Reductions

The capital charge rate for emission reduction devices is assumed to be 12%

Reduction Construction Time

The construction time for new reduction devices is currently 1 year.

Reduction Capital Lifetime

Reduction devices are assumed to have a capital lifetime of 30 years.

Reduction Operating Cost Factor

The operating cost reduction factor relative to the permit price varies by pollutant and fuel type. SOX reductions are assumed to have a factor of .35, NOX a factor of .13, and other CAC pollutants a factor 0.22. Values are based on estimates from Dave Sawyer.

Reduction Curve Parameters

Emissions reductions are based on emission reduction curve parameters. Values for NOX and SOX reductions are provided by Seton Seibert. Other emission reduction curves use assumptions developed by SSI.

8. Oil and Gas, Refinery, Biofuel and Other Supply

- Production
  - Oil Production
  - Natural Gas Production
  - Coal Production
  - Refined Petroleum Product Production
  - Liquefied Natural Gas Production
- Imports and Exports
  - Coal
  - Oil and Natural Gas
  - Refined Petroleum Product Imports
- Steam Generation Fuel Demands

8.1. Oil and Gas Sector Key Input Data and Sources

The section below lists key input data required for input to the oil and gas production module, the input variable name, the source of the data, and the file containing the data in ENERGY 2020.

Oil and Gas Production Input Data

- Production Unit Characteristics
  - Area
  - Nation
  - Name
  - Economic Sector
  - Production Process
  - Initial Year
  - Gas Transmission Node
  - Fuel Type Produced
- Production and Reserves
  - Oil Production
  - Natural Gas Production
  - Historical Proven Reserves
  - Historical Proven Developed Reserves
- Financial Data
  - Income Tax Rate
  - Historical Oil and Gas Price
- Natural Gas Transmission Characteristics
  - Historical Level of Natural Gas in Storage
  - Natural Gas Transmission Flow
  - Natural Gas Transmission Capacity

Oil and Gas Production Input Assumptions

- Supply Elasticities
- Production Costs
- Oil Import Price Elasticity
- Oil Supply Elasticity
- Oil Production Cost
    - Oil Production Unit Full Cost
    - Oil Production Unit Full Cost for New Production
    - Oil Production Unit Full Cost for Existing Production
    - Oil Production Year for Existing Plants
- Supply Cost Search Parameters
    - ROI Target for Supply Cost Search
    - Maximum Price for Supply Cost Search
    - Minimum Price for Supply Cost Search
    - Price Adder for Supply Cost Search
- Financial Assumptions
    - Return on Investment
    - Development Depreciation Rate
    - Discovery Depreciation Rate
    - Sustaining Depreciation Rate
    - Abandonment Cost Fraction
    - Operation and Maintenance Costs
    - Weighted Cost of Capital
    - Exogenous Development Capital Costs
    - Exogenous Discovery Capital Costs
    - Exogenous Sustaining Capital Costs
    - Gross Royalty Rate Price Parameters
    - Maximum Gross Revenue Royalty Rate
    - Minimum Gross Revenue Royalty Rate
    - Net Revenue Rate Price Parameters
    - Maximum Net Revenue Royalty Rate
    - Minimum Net Revenue Royalty Rate
    - Operating Working Capital Days Payment
- Endogenous Discovery Rate Parameters
    - Discovery Rate Maximum Multiplier from ROI
    - Discovery Rate Minimum Multiplier from ROI
    - Discovery Rate Variance Factor for ROI
- Endogenous Production Parameters
    - Production Rate Maximum Multiplier from ROI
    - Production Rate Minimum Multiplier from ROI
    - Production Rate Variance Factor for ROI

- Gas Supply Elasticity to Change Prices
- Gas Production Unit Full Cost

Dispatch Availability

- LNG Gas Available for Dispatch
- Production Gas Available for Dispatch
- Storage Gas Available for Dispatch

Gas Storage

- Fraction of Gas Storage which is Filled
- Unit Non-Fuel Variable Cost from Storage
- Exogenous Storage Capacity

Natural Gas

- Natural Gas Load Shape Factor
- Natural Gas Transmission Efficiency
- Exogenous LNG Imports Capacity
- Exogenous LNG Exports Capacity
- Natural Gas Transmission Variable Cost
- Historical Natural Gas Variable Cost from LNG
- Historical Natural Gas Variable Cost from Production
- World Natural Gas Price Differential

Table 14. Oil and Gas Supply Sector Input Data Variables, Location, Sources

Input Data - Variable Name, Input File Name, and Description	Source
Natural gas input data (SpOGResData.txt) • XPdPN(GNode,ProcOG,Year) Natural Gas Production (TBtu/Yr)	AEO 2012, Figure 108
Financial input data (SpOGFinData.txt) • OGAbCFr(OGUnit,Year) OG Abandonment Cost Fraction ($/($/Yr)) • OGITxRate(OGUnit,Year) OG Initial Tax Rate ($/$) • XDevCap(OGUnit,Year) Exogenous Development Capital Costs ($/mmBtu) • XDisCap(OGUnit,Year) Exogenous Discovery Capital Costs ($/mmBtu) • XSusCap(OGUnit,Year) Exogenous Sustaining Capital Costs ($/mmBtu) • XOGOMCosts(OGUnit,Year) OG O&M Costs ($/mmBtu)	2014 CERI Report, Table 3.1 and Table 3.8 and Energy Briefing Note (Nov. 2010), Figure 6
Oil and gas play parameters (SpOGFinData.txt) • OGArea(OGUnit) 'Area' • OGECC(OGUnit) 'Economic Sector' • OGFuel(OGUnit) 'Fuel Type' • OGInitYear(OGUnit) 'Initial Year of Project (Year)' • OGNation(OGUnit) 'Nation' • OGNode(OGUnit) 'Natural Gas Transmission Node' • OGProcess(OGUnit) 'Production Process'	Various sources
Oil Production Costs (OilProdCost.txt) • OPUC(Process,Nation,Year) 'Oil Production Unit Full Cost ($/mmBtu)'	Expert opinion

Input Data - Variable Name, Input File Name, and Description	Source
Price/Cost Variables (vData.accdb) • XENPN(Fuel,Nation,Year) 'Wholesale Energy Prices (1985 US$/mmBtu)' • XFP(Prices,Area,Year) 'Delivered Fuel Price ($/mmBtu)'	Values from Environment and Climate Change Canada sources

The following tables list the input variables and example inputs for each.

Table 15. Input Data and Assumptions Required for Each Play with Sample Values

Variable (by OGUnit)	Descriptor	Sample Values (2015)
xPd	Historical Production (TBtu/Yr)	xPd=11.60 (NL_Hebron_0001)
xPdRate	Historical Production Rate (TBtu/Yr/TBtu)	xPdRate=0.80
xDevCap	Exogenous Development Capital Costs ($/mmBtu)	xDevCap=22.90, SAGD
XOGOMCosts	OG Operating & Maintenance Costs ($/mmBtu)	xOGOMCosts=1.48, SAGD
xRsDev	Historical Developed Resources (TBtu/Yr)	xRsDev=83,347 (BC Light Oil)
xSusCap	Exogenous Sustaining Capital Costs ($/mmBtu)	1.15, SAGD
ByFrac	Byproducts Production Fraction (Btu/Btu)	ByFrac=0.0
DevDpRate	Development Depreciation Rate ($/$)	0.0105, Oil 0.2800, Gas
DevDMB0	Development Costs Depletion Multiplier Coeff. ($/$)	DevDMB0 = 0 (CN, MX) DevDMB0 = -0.25, US
DevLCMB0	Development Costs Learning Curve Multiplier Coeff. ($/$)	DevLCMB0 = 0.0
DevMaxM	Development Rate Maximum Multiplier from ROI (Btu/Btu)	DevMaxM = 2.00
DevMinM	Development Rate Minimum Multiplier from ROI (Btu/Btu)	DevMinM = 0.00
DevVar	Development Rate Variance (Btu/Btu)	DevVar = 1.00
DevVF	Development Rate Variance Factor for ROI (Btu/Btu)	DevVF = -10.00
DilFrac	Diluent Fraction (Btu/Btu)	DilFrac = 0.30 (Bitumen units)
FkFrac	Feedstock Fraction (Btu/Btu)	FkFrac = 1.00 (Upgraders only) FkFrac = 0.0 (other plays)
GRRMax	Maximum Gross Revenue Royalty Rate ($/$)	GRRMax = 0.09
GRRMin	Minimum Gross Revenue Royalty Rate ($/$)	GRRMin = 0.01
GRRPr	Gross Revenue Royalty Rate Slope to Price ($/$)	GRRPr = 0
NRRMax	Maximum Net Revenue Royalty Rate ($/$)	NRRMax = 0.4
NRRMin	Minimum Net Revenue Royalty Rate ($/$)	NRRMin = 0.25
OGFPAdd	Price Adder for Supply Cost Search ($/mmBtu)	OGFPAdd = 1/5.8 (oil) OGFPAdd = 0.05 (gas)
OGFPDChg	OG Price Delivery Charge ($/mmBtu)	OGFPDChg = 0
OGFPMax	Maximum Price for Supply Cost Search ($/mmBtu)	OGFPMax = 200/5.8 (oil) OGFPMax = 50 (gas)
OGFPMin	Initial Price for Supply Cost Search ($/mmBtu)	OGFPMin = 0.0 (oil) OGFPMin = 0.0 (gas)
OGITxRate	OG Initial Tax Rate ($/$)	OGITxRate = 0.12*0.5 (oil) OGITxRate = 0.12*1.0 (gas)
OGROIN	Return on Investment Normal ($/Yr/$)	OGROIN = 0.0842 (SAGD, CSS) OGROIN = 0.1087 (Upgraders)

Variable (by OGUnit)	Descriptor	Sample Values (2015)
OpDMB0	Operating Costs Depletion Multiplier Coefficient ($/$)	OpDMB0 = 0.0
OpLCMB0	Operating Costs Learning Curve Multiplier Coefficient ($/$)	OpLCMB0 = 0.0
OWCDays	Operating Working Capital Days Payment (Days)	OWCDays = 45
PdC0OG	Learning Curve Initial Cumulative Production (TBtu)	PdC0OG = 1.0
PdMax	Maximum Production Rate (TBtu/TBtu)	PdMax = 1e12
PdMaxM	Production Rate Maximum Multiplier from ROI (Btu/Btu)	PdMaxM = 1.00
PdMinM	Production Rate Minimum Multiplier from ROI (Btu/Btu)	PdMinM = 0.00
PdVar	Production Rate Variance (Btu/Btu)	PdVar = 1.00
PdVF	Production Rate Variance Factor for ROI (Btu/Btu)	PdVF = -10.00
ROITarget	ROI Target for Supply Cost Search ($/$)	ROITarget = 0.10 (oil) ROITarget = 0.15 (gas)
RsD0OG	Learning Curve Initial Developed Resources (TBtu)	RsD0OG = 1.0
RyLevFactor	Royalty Levelization Factor ($/$)	RyLevFactor = 1.00
SusDpRate	Sustaining Depreciation Rate ($/$)	SusDpRate = 1.00

8.2. Input Data Requirements and Key Variables of Oil Refinery Sector

Oil Refining Input Assumptions

- Crude Oil Price Relative to World Oil Price
- Maximum Yield, Minimum Yield
- Refining Unit Capacity

Historical input data required for the oil refinery includes demand, production, imports, exports, intra-country flows, crude oil processed, oil refinery production capacity. These data are obtained from Environment and Climate Change Canada via the Access database named, vData_OilRefinery.accdb. The input data and variables are listed in Table 16.

Table 16. Historical Oil Refinery Input Data

Historical Input Data Requirement	Variable Definition
RPP production (TBtu/Yr)	
- By refinery and fuel	XRfProd(RfUnit,Fuel,Year)
- By nation and fuel	XRPPProdNation(Fuel,Nation,Year)
- By area and fuel	XRPPProdArea(Fuel,Area,Year)
RPP Imports (TBtu/Yr)	
- within North America by fuel	XRPPImportsNation(Fuel,Nation,Year)
- within North America total	XRPPImportsROW(Fuel,Area,Year)
- to Rest of World	XRPPImports(Nation,Year)
RPP Exports (TBtu/Yr)	
- within North America by fuel	XRPPExportsNation(Fuel,Nation,Year)
- within North America total	XRPPExports(Nation,Year)
- from Rest of World	XRPPExportsROW(Fuel,Area,Year)

Intra-country flows (TBtu/Yr) - Imports - Exports	 XRPPImportsArea(Fuel,Area,Year) XRPPExportsArea(Fuel,Area,Year)
Crude Oil Refined (TBtu/Yr)	XRPPCrude(Crude,Area,Year)
RPP supply adjustments (TBtu/Yr) - by fuel and area - by nation	 XRPPAdjustArea(Fuel,Area,Year) XRPPAdjustments(Nation,Year)
RPP Demands (TBtu/Yr)	XRPPDemandArea(Fuel,Area,Year)
Refining unit production capacity (TBtu/Yr)	XRfCap(RfUnit,Year)

Assumptions regarding prices, costs, transportation limits, and oil refinery yields are required for input to the oil refinery sector and are listed in Table 17. These assumptions are input to the model through a text file stored in the 2020Model subdirectory (RefiningData.txt).

Table 17. Input Data Assumptions Required for Oil Refinery Sector

Input Variable Name	Input Assumption Requirements Description
Oil Refining Prices and Costs	
OilPrRatio(Crude,Nation,Year)	Crude Oil Price Relative to World Oil Price ($/$)
RfVCProd(RfUnit,Fuel,Crude,Year)	Variable Cost of Processing Crude Oil ($/mmBtu)
Oil Refinery Transportation	
RfPathEff(GNode,GNodeX,RfMode,Year)	RPP Transmission Efficiency (Btu/Btu)
RfPathVC(GNode,GNodeX,RfMode,Year)	Variable Cost of Transporting RPP ($/mmBtu)
RfTrMax(GNode,GNodeX,RfMode,Year)	RPP Transmission Capacity (TBtu/Year)
RPP Refining Yields	
RfMaxYield(RfUnit,Fuel,Crude,Year)	Maximum RPP Yield per Crude Oil (Btu/Btu)
RfMinYield(RfUnit,Fuel,Crude,Year)	Minimum RPP Yield per Crude Oil (Btu/Btu)

8.3. Biofuel Supply Input Data

Data Requirements

- Production Energy Efficiency
- Market Share Non-Price Factor
- Biofuel Feedstock Price
- Biofuel Production Capital Cost
- Biofuel Production O&M Costs

Biofuels Supply Input Assumptions

- Ethanol Production Characteristics
- Biofuel Production Characteristics

Ethanol

- Ethanol Production Capital Costs
- Ethanol Production O&M Costs
- Ethanol Producer Consumption Fraction
- Ethanol Production Physical Lifetime
- Ethanol Pollution Coefficient

Biofuel

- Capacity Utilization Factor for Planning
- Production Energy Usage Fraction
- Physical Lifetime
- Pollution Coefficient
- Market Share Variance Factor
- Biofuel Yield from Feedstock
- Biofuel Production O&M Cost Factor
- Biofuel Cogeneration
- Capital Cost
- Capacity Utilization Factor
- Demands Fuel/Tech Split
- Operation Cost Fraction
- Equipment Lifetime

Table 18, Table 19, Table 20, and
Table 21 list the input data and assumptions, and sources, where relevant, for input requirements of the biofuel supply sector covering general assumptions and those related to financial inputs, cogeneration and feedstocks.

Table 18. Biofuel Sector General Input Data Assumptions and Sources

Description	Variable Name (Set Dimensions)	Value	Source
Biofuel Production Capacity Utilization Factor for Planning (mmBtu/mmBtu)	**BfCUFP** Biofuel,Tech, Feedstock,Area,Year	Value = 0.80	Per Jeff Amlin
Biofuel Production Capacity Utilization Factor Maximum (mmBtu/mmBtu)	**BfCUFMax** Biofuel,Area	Future = 0.90 Historical = 1	Per Jeff Amlin
Biofuel Production Energy Efficiency (Btu/Btu)	**BfEff** Biofuel,Tech, Feedstock,Area,Year	.035 to.033 from 2009 to 2013	ECCC spreadsheet: "Biofuel_Module_Parameters_Rob_05Jan2015.xlsx"
Biofuel Market Share Non-Price Factor (mmBtu/mmBtu)	**BfMSM0** Biofuel,Tech, Feedstock,Area,Year	Electric=-2.4 Gas=0.0 Oil=-3.25	Draft estimates which will be revised and ultimately calibrated once historical data are available.

Description	Variable Name (Set Dimensions)	Value	Source
Biofuel Production as a Fraction of National Demands (Btu/Btu)	**BfProdFrac** Biofuel,Area,Nation		Input based on historical Biofuels production.
Biofuel Production Physical Lifetime (Years)	**BfPL** Year	10 years	Set equal to Industrial Heat lifetime for a preliminary value.
Biofuels to Prices Map (1=Map)	**BfPricesMap** Biofuel,Prices	Equal to 1, based on set selections	We do not have Biodiesel prices; Temporarily using Diesel
Biofuel Pollution Coefficient (Tonnes/TBtu)	**BfPOCX** FuelEP,Poll,Area, Year	Value = 0.0	Preliminary values based on Industrial POCX, EC: Chemicals, Enduse: Heat.
Biofuel Market Share Variance Factor (mmBtu/mmBtu)	**BfVF**; Biofuel,Tech, Feedstock,Area,Year	Value = -2.5	Set same as Industiral XMVF for a preliminary value
Map between Tech and Prices	**TechPricesMap** Tech,Prices	Equal to 1, based on set selections	No specific Biodiesel prices; Temporarily using Diesel

Table 19. Biofuel Sector Input Data Assumptions - Financials

Description	Variable Name	Value	Source
Biofuel Production Capital Cost, Real $/mmBtu	**BfCC** Biofuel,Tech, Feedstock,Area,Year	Value = 0.9661 $CN/Litre Ethanol in 2013	"Biofuel_Module_Parameters _Rob_05Jan2015.xlsx" *With adjustments based on judgment.
Biofuel Production Capital Charge Rate, $/$	**BfCCR** Biofuel,Feedstock, Area	Value = 0.08	Reduced from standard value due to low interest rates per Jeff Amlin.
Biofuel Delivery Charge, Real $/mmBtu	**BfDChg** Prices,Area,Year	Value = 0.0	
Biofuel Production O&M Cost Factor, Real $/$/Yr	**BfOF** Biofuel,Tech, Feedstock,Area,Year	Value = 0.05	Standard value
Biofuel Production Subsidy, $/mmBtu	**BfSubsidy**; Nation,Year	Value = 0.0	
Biofuel Production O&M Costs (Real $/mmBtu)	**BfUOMC** Biofuel,Tech, Feedstock,Area,Year	Value = 0.13 $CN/litre ethanol in 2013	ECCC spreadsheet: "Biofuel_Module_Parameters _Rob_05Jan2015.xlsx"

Table 20. Biofuel Supply Sector Input Data Assumptions - Cogeneration

Description	Variable Name (Set Dimensions)	Value	Source
Cogeneration Capital Cost; $/mmBtu/Yr	**CgCC** Tech,Area,Year	CgCC=ICgCC	From Industrial Database CgCC for Other Chemicals
Cogeneration Capacity Utilization Factor, Btu/Btu	**CgCUF** Tech,Area	Value = 0.894	Same as Industrial database CgCUFP for Other Chemicals
Cogeneration Demands Fuel/Tech Split, Btu/Btu	**CgFrac** Fuel,Tech,Area, Year	CgFrac=ICgFrac	From Industrial database, using CgFrac from Other Chemicals
Cogeneration Market Share; Btu/Btu	**CgMSF** Tech,Area,Year	Value = 0.0	Per J. Amlin
Cogeneration Operation Cost Fraction; $/Yr/$	**CgOF** Tech,Area	Value = 0.05	Standard value
Cogeneration Equipment Lifetime (Years)	**CgPL** Tech,Area.	Value = 25	Industrial Cogeneration physical lifetime for a preliminary value.

Table 21. Biofuel Supply Sector Input Assumptions - Feedstocks

Description	Variable Name	Value	Source
Biofuel Feedstock Price, $/Tonne	**BfFsPrice** Feedstock,Area, Year	Value = 259.02 for 2011; similar prices in other years	ECCC spreadsheet: Biofuel_Module_Parameters_v2.1.xlsx
Biofuels Feedstock Yield, Btu/Tonne	**BfFsYield** Biofuel,Tech, Feedstock,Area, Year	Value = 4978846.621 for 2008	Based on %efficiency from a theoretical maximum of 427 Litres per metric tonne of Corn Stover. Source: http://www.ethanolproducer.com/articles/9658/survey-cellulosic-ethanol-will-be-cost-competitive-by-2016; file Biofuel_Module_Parameters_v2.1.xlsx

Table 22. Oil, Gas, Coal, and Refinery Production, Imports, and Exports

Variable	Description
Production	Energy production data by fuel type, area, and year.
Coal Production	Coal production in tBtu per year for Canadian areas is provided by ECCC (vCProd). US Coal production data is extracted annually from the EIA Annual Energy Outlook and uses future years as an exogenous forecast. US

Variable	Description
	production is currently entirely contained in the model's 'Mountain' region to avoid issues mapping the EIA's coal sub-regions into the appropriate model area.
Oil Production	Oil production for Canadian areas by sector is provided by ECCC (vOAProd) by petajoule produced per historical and forecast year. National production data from EIA's Annual Energy Outlook is used for the US.
Natural Gas Production	Natural gas production for Canadian areas by sector is provided by ECCC (vGAProd) by petajoule produced per historical and forecast year. National production data from EIA's Annual Energy Outlook is used for the US.
Refined Petroleum Product Production	Refined petroleum product production for Canadian areas is provided by ECCC (vRPPAProd) by terajoule produced per historical and forecast year. National production data from EIA's Annual Energy Outlook is used for the US.
Liquefied Natural Gas Production	Liquefied natural gas production for Canadian areas by terajoules produced per historical and forecast year is provided by ECCC (vLNGAProd).
Imports	Imports of produced energy from other nations
Coal Imports	Coal imports in tBtu per historical year for Canadian areas is provided by ECCC (vCImports). US Coal import data is extracted annually from the EIA Annual Energy Outlook and uses future years as an exogenous forecast.
Oil and Natural Gas Imports	National oil and natural gas imports by terajoule per historical and forecast year for Canada is provided by ECCC (vImports). US oil and gas historical and forecast data for imports is extracted annually from the EIA's Annual Energy Outlook.
Refined Petroleum Product Imports	National refined petroleum product imports by terajoule per historical and forecast year for Canada is provided by ECCC (vRPPImports). US refined petroleum product historical and forecast data for imports is extracted annually from the EIA's Annual Energy Outlook.
Exports	Exports of produced energy to other nations
Coal Exports	Coal exports in tBtu per historical year for Canadian areas is provided by ECCC (vCExports).
Oil and Natural Gas Exports	National oil and natural gas exports by terajoule per historical and forecast year for Canada is provided by ECCC (vExports). US oil and gas historical and forecast data for exports is extracted annually from the EIA's Annual Energy Outlook.
Refined Petroleum Product Exports	National refined petroleum product imports by terajoule per historical and forecast year for Canada is provided by ECCC (vRPPExports). US refined petroleum product historical and forecast data for exports is extracted annually from the EIA's Annual Energy Outlook.

Variable	Description
Steam Generation Fuel Demands	Fuel consumption for generating steam for sale is provided by ECCC (vStDmd) for Canadian area by fuel type in terajoules of fuel consumed per historical year.

8.4. Supply Assumptions - Conversion Factors

The section below details assumptions used for the supply segment in ENERGY 2020. The supply segment includes various global assumptions, such as unit conversion factors, used in all parts of the model structure.

Table 23. Conversion Factors used in Supply Sector

Variable	Definition
Energy Conversions	Conversion ratios are read into the model to convert various fuel types into thermal units (btu) for use in the model if needed.
Various Fuels to Btu	Conversions for non-electric fuel types into btu from their common input units are read into the model. Examples include converting cubic feet of gas and barrels of oil into btu. Engineering values researched by Jeff Amlin is the source for the conversion data.
Electric Conversions	A conversion of 3412 btu per kilowatt hour is used for electricity.
Time Conversions	Conversions for the various time units used by the model.
Days per Month	The number of days per type of month in the model. The current version contains two 'months', Summer and Winter. Summer is assigned 183 days and Winter is assigned 182.
Hours per Month	The total number of hours in a month is the number of days in a month multiplied by 24.
Pollution Conversion Factor to eCO2	Conversion factors for various greenhouse gases from tonnes to CO2 equivalent values. Conversions were updated by ECCC in 2015.
Energy Requirement Growth Rate	A default growth rate of fuel used per economic segment is used for an equation during the model's supply calibration initialization. Values are based on historical State Energy Data System demands.

8.5. Steam Generation Assumptions

The Steam Generation economic sector is contained within the supply segment. This sector consumes energy to produce steam for sale to other economic sectors that have steam demands.

Capital Cost of Steam Capacity: Steam capital costs are assumed to be $30 per mmbtu output per year based on data found for a Swedish steam production unit.

Capital Charge Rate of Steam Capacity: The steam capital charge rate is assumed to be 12%

O&M Cost of Steam Production: Steam capital costs are assumed to be $2.50 per mmbtu based on data found for a Swedish steam production unit.

8.6. Other Supply-Related Assumptions

Sequestering eCO2 Reduction Operating Cost Factor: The percentage operating cost of capital cost of sequestering emissions. Updated by ECCC in 2014 to use the assumption of 4% for gas production sectors and 8% for all other sectors.

Daily Use Factor for Gas: Load shape data for natural gas usage by month, load time period, and class. Values developed by Jeff Amlin using NEGC (New England Governor's Council) gas data.

Electric Load Shape: Load shape assumptions for electric demand by month, load time period for the miscellaneous and electric resale sectors. Values developed using New England Power Pool (NEPOOL) data from 1995.

Interregional Coal Export Market Shares: The fraction of the North American market for coal which is satisfied by production from each area. Last updated using CANSIM data in 2007.

Coal Producer Consumption Fraction: Historical assumptions regarding the amount of coal consumption by coal producers for each Canadian area. Last updated using CANSIM data in 2005.

Appendix 1: Input Assumptions Hard-Coded Data Values

Residential Module Hard-Coded Data

Residential Sector Input Assumptions	Value
DEPM(Enduse,Tech,EC,Area,Year) 'Device Energy Price Multiplier ($/$)'	1
EEImpact(Enduse,Tech,EC,Area,Year) 'Energy Efficiency Impact (Btu/Btu)'	0
EESat(Enduse,Tech,EC,Area,Year) 'Energy Efficiency Saturation (Btu/Btu)'	0
EEUCosts(Enduse,Tech,EC,Area,Year) 'Energy Efficiency Unit Costs ($/mmBtu)'	0.0
XEE(Enduse,Tech,EC,Area,Year) 'Exogenous Energy Efficiency (TBtu)'	0.0
XDR(Enduse,EC,Month,Area,Year) 'Exogenous Demand Response (MW)'	0
AdmFr(Enduse,Area) 'Administrative Costs Fraction ($/$)'	0.0
BAT(tv) 'Short Term Utilization Adjustment Time (YR)'	1
BE(tv) 'Budget Elasticity Factor ($/$)' Source: Demand81, regression based on oil price shocks, GAB	
BMM(Enduse,Tech,EC,Area,Year) 'Budget Multiplier Adjustment (Btu/Btu)'	1
CgAT(tv) 'Cogeneration Implementation Time (Years)' From the FOSSIL79 work, modified by JSA and GAB 11/27/90	1.0
CgCC(Tech,EC,Area,Year) 'Cogeneration Capital Cost ($/mmBtu/Yr)'	0 CgCC(Solar)=20
CgHRtM(Tech,EC,Area,Year) 'Cogeneration Thermal Efficiency (Btu/KWh)' This is an engineering value (10,500) "Energy Efficiency and the Pulp and Paper Industry" by Lars J. Nilsson, Eric D. Larson, Kenneth Gilbreath, and Ashok Gupta, 100 pp., ACEEE 1996, IE962 http://www.aceee.org/pubs/ie962.htm Biomass use mid-range quote from ACEEE article of 63 kwh/MBtu (15873=1000000/63) Solar fuel usage is only the electricity needed to monitor, control, or back-up the system, therefore we assume a very low heat rate. Jeff Amlin 5/20/13	10500 – Default; 15873 – Biomass; 8550 – Oil, LPG, Gas 1 – Solar
CgIVTC(Year) 'Cogen. Investment Tax Credit ($/$)' The federal investment tax credit was ended in 1986. DRI, Table 7. The proper years are selected and CgIVTC is given a value of seven percent.* 3. P. Cross 6/13/94	0 0.097—Year 1985
CgLoad(Tech) 'Cogeneration Demand Load to ECD'	1 0—Electric
CgMSMM(Tech,EC,Area,Year) 'Cogeneration Market Share Mult. Policy ($/$)'	1
CgRisk(Tech) 'Cogeneration Risk Premium (DLESS)'	0.05
CgSCM(Tech) 'Cogeneration Shared Cost Mult. ($/$)'	0.30 1.00—Solar
CgPL(Tech,EC,Area) 'Cogeneration Equipment Lifetime (Years)'	15
CgPotMult(Tech,EC,Area,Year) 'Cogeneration Potential Multiplier (Btu/Btu)'	1
CgResI(Tech,Area) 'Cogeneration Resource Base (mmBtu)	0
CgResI(Tech,Area) 'Cogeneration Resource Base (mmBtu)'	0
CgTL(Tech,EC,Area) 'Cogeneration Tax Life (Years)' Standard accounting practice specifies the tax life to be approximately 80 percent of the physical lifetime.	12
CgBL(Tech,EC,Area) 'Cogen. Equip. Book Value Lifetime (Years)' This is the book value plant life time of cogenerator from George Backus developed data.	15
CgCUFP(Tech,EC,Area) 'Cogeneration CUF for Planning (Btu/Btu)'	0

Residential Sector Input Assumptions	Value
	0.30—Solar
CgOF(Tech,EC,Area) 'Cogeneration Operation Cost Fraction ($/Yr/$)'	0 0.10—Solar
CgPOCS(FuelEP,EC,Poll,Area,Year) 'Cogeneration Pollution Standards' This is a policy value. An arbitrarily high value is used to represent no pollution standards.	1E12
XCgVF(Tech,EC) 'Cogen. Variance Factor ($/$)' This is the standard variance factor for the industrial sector based on EIA AEO modeling circa ARC 80. J. Amlin 09/21/09	-2.5
CHRM(EC,Area,Year) 'Cooling to Heating Ratio Multplier'	1
CROIN(Enduse,Tech,EC,Area,Year) 'Conservation Return on Investment ($/Yr/$)'	0

XDCC(Enduse,Tech,EC,Area,Year) 'Device Capital Cost ($/mmBtu/Yr)'
The sources of this data are as follows:
Space heat - ARC 80, maximum flue efficiency or COP.
Water heating - ARC 80 different in Vermont.
Cooking - ARC 80
Drying - ARC 80
Refrigeration - ARC 80
Lighting - 1992 Policy Act as interpeted by G. Backus
Electric A/C - ARC 80
Gas air conditioners from AGA, May 26, 1989 (EA-1989-S), Energy Analysis "An Analysis of the Economies of Gas Engines-Driven Chillers".
Miscellaneous - ARC 80
Also check EPRI EA-433 V2, p.3-64.
ARC 80 used for all values
(Gas,Oil,Solar,Electric XDCC (EPRI EA-433 V2, p.3-64))
Use Gas cooking costs for oil cooking costs.
(Heat 18.18 24.67 59.00 6.48)

All values are initialized to -99 (not specified). Values are read in by enduse and technology for the initial year (Zero) and converted to 1985$ from 1975$. The costs are divided by the 90 percent capacity factor used in the ARC80 table.

	Elec	*Gas*	*Coal*	*Oil*	*Bio*	*Solar*	*LPG*	*Stm*	*Geo*	*HPump*
Space Heating	*17.70*	*23.13*	*19*	*36.0*	*17.23*	*132*	*23.13*	*36.0*	*60.0*	*40.0*
Water Heating	*8.50*	*18.05*	*19*	*23.5*	*17.23*	*82*	*18.5*	*23.5*	*30.0*	*20.0*
Other Subs	*65.02*	*85*	*19*	*85.0*	*17.23*	*0*	*85.0*	*85.0*	*0*	*0*
Refrigerators	*96.48*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*
Lighting	*3.00*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*
Air Conditioning	*24.17*	*34.12*	*0*	*0*	*0*	*0*	*34.12*	*0*	*10.0*	*10.0*
Other Non-Subs	*19.80*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*

DCCLimit(Enduse,Tech,EC,Area,Year) 'Device Capital Cost Limit Multiplier ($/$)'	10
DCCP(Enduse,Tech,EC,Area,Year) 'Capital Cost of Rebated Device ($/mmBtu/Yr)'	0
DCCU(Enduse,Tech,EC,Area,Year) 'Device Capital Cost Increment ($/mmBtu/Yr)'	0
DCMM(Enduse,Tech,EC,Area,Year) 'Capital Cost Maximum Mult. ($/$)'	1
DEEP(Enduse,Tech,EC,Area,Year) 'Device Efficiency Policy Variable (Btu/Btu)'	0
DEEAM(Enduse,Tech,EC,Area,Year) 'Average Device Efficiency Multiplier (Fraction)'	1
XDEER(Enduse,Tech,EC,Area,Year) 'Exogenous Policy Participation Response (Btu/Btu)'	0
DEM(Enduse,Tech,EC,Area) 'Maximum Device Efficiency (Btu/Btu)'	

Residential Sector Input Assumptions	**Value**
The source of the data is as follows: For space heat - ARC 80, maximum flue efficiency or COP. For water heating - LBL, J. Amlin - adjusted by R. Allen. For cooking - LBL, AHAM, EPRI, J. Amlin For drying - J. Amlin For refrigeration - ?? get REEPS standard data ?? For lighting - 1992 Policy Act as interpeted by G. Backus For electric A/C - For gas air conditioners from AGA, May 26, 1989 (EA-1989-S), Energy Analysis "An Analysis of the Economies of Gas Engines-Driven Chillers". For miscellaneous - J. Amlin by definition	

	Elec	*Gas*	*Coal*	*Oil*	*Biomass*	*Solar*	*LPG*	*Steam*	*Geoth*	*HPump*
Primary Heat	*1.00*	*0.97*	*0.97*	*0.97*	*0.65*	*10.00*	*0.97*	*0.99*	*4.00*	*4.50*
Water Heating	*0.99*	*0.97*	*0.97*	*0.97*	*0.65*	*10.00*	*0.97*	*0.99*	*4.00*	*4.50*
Other Subs	*1.30*	*0.97*	*0.97*	*0.97*	*0.65*	*1.00*	*0.97*	*0.99*	*0.00*	*0.00*
Refrigerators	*0.98*	*0.00*	*0.00*	*0.00*	*0.00*	*0.00*	*0.00*	*0.00*	*0.00*	*0.00*
Lighting	*0.95*	*0.00*	*0.00*	*0.00*	*0.00*	*0.00*	*0.00*	*0.00*	*0.00*	*0.00*
Air Conditioning	*3.50*	*2.00*	*0.00*	*0.00*	*0.00*	*10.00*	*2.00*	*0.00*	*4.00*	*4.50*
Other Non-Subs	*0.98*	*0.00*	*0.00*	*0.00*	*0.00*	*0.00*	*0.00*	*0.00*	*0.00*	*0.00*

RPEMM(Enduse,Tech,EC,Area,Year) 'Retrofit Max. Device Eff. Multiplier (Btu/Btu)'	1
RDEMM(Enduse,Tech,EC,Area,Year) 'Retrofit Max. Device Eff. Multiplier (Btu/Btu)'	1
XDEMM(Enduse,Tech,EC,Area,Year) 'Max. Device Eff. Multiplier (Btu/Btu)'	1
DESTD(Enduse,Tech,EC,Area,Year) 'Device Eff. Standards (Btu/Btu)' The standards are from different sources as follows: Hot Water - Attachment 1-a from Stu Slote dated 4/22/93 A/C - M. Jourabchi's interpretation of the standards. 1990-1992 Refrigerator - M. Jourabchi's interpretation of the standards a 15% Improvement over 1988 1993+ Refrigerator - Efficiency Standards from Memo from Jeff Forward 5/26/93. Reflects newer standards plus effects of the government's Golden Carrot program. The long term value revised per Stu 6/17/93 Wood Stoves - Field Performance of Advanced Technology Woodstoves in Glens Falls, New York. 1988-1989. Vol 1. 6/2/93 via Stu Slote Gas, Oil, LPG Space Heating - Attachment 1-a from Stu Slote dated 4/22/93, revised per Stu 6/17. All values are initialized to 0. The standards are as follows: Gas hot water from 1990 to the final year, the value is 0.62. Oil hot water from 1990 to the final year, the value is 0.59. Electric hot water from 1990 to the final year, the value is 0.90. LPG hot water from 1990 to the final year, the value is 0.55. Electric air conditioning for 1990, the value is 2.6. Electric air conditioning for 1991, the value is 2.61. Electric air conditioning for 1992 to the final year, the value is 2.65. Electric refrigeration for 1990 to 1992, the value is 0.30 times 1.15. Electric refrigeration for 1993, the value is 0.40. Electric refrigeration from 1994 to the final year, the value is 0.42.	0—Initialized 0.62—Gas HW 0.59—Oil HW 0.90—Electric HW 0.55—LPG HW 2.60—Elec AC 1990 2.61—Elec EC 1991 2.65—Elec AC 0.345—Refrig Elec, 1990-1992 0.400—Refrig Elec 1993 0.420—Refrig Elec 0.55—Heat Biomass 0.80—Heat Gas, Oil, LPG

Residential Sector Input Assumptions	**Value**
Biomass space heating from 1993 to the final year, the value is 0.55. Gas space heating from 1993 to the final year, the value is 0.80. Oil space heating from 1993 to the final year, the value is 0.80. LPG space heating from 1993 to the final year, the value is 0.80.	
DESTDP(Enduse,Tech,EC,Area,Year) 'Device Eff. Standards Policy (Btu/Btu)'	0
DIVTC(Tech,Area,Year) 'Device Investment Tax Credit ($/$)' The federal investment tax credit was ended in 1986. DRI, Table 7.	0
DPIVTC(Year) 'Device Policy Investment Tax Credit ($/$)'	0
DOCF(Enduse,Tech,EC,Area,Year) 'Device Operating Cost Fraction ($/Yr/$) Device Operating Costs are computed by dividing O&M costs by capital costs for the base year ($1985/mmBtu). The data is from ARC 80, pp. 288-289 and for gas air conditioners AGA, May 26, 1989 (EA-1989-S), Energy Analysis "An Analysis of the Economies of Gas Engines-Driven Chillers". The new heating and hot water data is from: Attachment 1-a from Stu Slote dated 4/22/93	

	Elec	*Gas*	*Coal*	*Oil*	*Biomass*	*Solar*	*LPG*	*Stm*	*Geoth*	*HPump*
Heat	*0.018*	*0.024*	*0.011*	*0.02*	*0.013*	*0.012*	*0.024*	*0.03*	*0.012*	*0.018*
HW	*0.00*	*0.00*	*0.00*	*0.00*	*0.00*	*0.01*	*0.00*	*0.00*	*0.01*	*0.00*
Other Sub	*0.00*	*0.00*	*0.00*	*0.00*	*0.00*	*0.00*	*0.00*	*0.00*	*0.00*	*0.00*
Refrig	*0.00*	*0.00*	*0.00*	*0.00*	*0.00*	*0.00*	*0.00*	*0.00*	*0.00*	*0.00*
Lighting	*0.00*	*0.00*	*0.00*	*0.00*	*0.00*	*0.00*	*0.00*	*0.00*	*0.00*	*0.00*
AC	*0.02*	*0.02*	*0.00*	*0.00*	*0.00*	*0.00*	*0.02*	*0.00*	*0.00*	*0.02*
Oth N Sub	*0.00*	*0.00*	*0.00*	*0.00*	*0.00*	*0.00*	*0.00*	*0.00*	*0.00*	*0.00*

TAXPCT(Area,Year) 'Standard accounting percent of device life that is taxed.'	0.80
XDPL(Enduse,Tech,EC,Area,Year) 'Physical Life of Equipment (Years)' The values of this variable are from DOE Std. Research, Rudermann, ARC 80 The values are read in for the initial year (Zero) and then the other years are set equal to it. Then the device physical lifetime is set equal to the minimum value of the device physical lifetime (DPL) that was read in and the physical life of production capacity (PCPL).	23—Heat 13—Hot Water 13—Substitutables 19—Refrigeration 6—Light 15—Air Cond. 10—Other Non-Substitutable
DRISK(Enduse,Tech) 'Device Risk Premium ($/$)'	0
XLSF(Enduse,EC,Hour,Day,Month,Area) 'Load Shape Factor (MW/MW)' The source is the NEPOOL electric load shapes, NEPOOL July 1995. The data is read in directly. The average is normalized so that the sum over all seasons is equal to 1.0. The average load values (XLSF) are mutiplied times the hours per season (ND) and summed across all seasons. This value (SSum) is used to adjust XLSF. 3. J. Amlin 6/13/94	

Space Heating	*Peak*	*Ave*	*Min*
Summer	*0*	*0*	*0*
Winter	*5.911*	*2.255*	*1.860*

Water Heating	*Peak*	*Ave*	*Min*
Summer	*0.488*	*0.936*	*0.603*
Winter	*0.467*	*1.064*	*1.034*

Other Substitutable	*Peak*	*Ave*	*Min*
Summer	*0.901*	*0.897*	*0.265*
Winter	*2.252*	*1.075*	*0.166*

Residential Sector Input Assumptions	**Value**
Refrigerator *Peak* *Ave* *Min* *Summer* *1.178* *1.139* *0.895* *Winter* *0.995* *0.899* *0.715* *Lighting* *Peak* *Ave* *Min* *Summer* *0.414* *0.728* *0.358* *Winter* *3.459* *1.172* *0.358* *Air Conditioning* *Peak* *Ave* *Min* *Summer* *4.000* *2.000* *1.000* *Winter* *0* *0* *0* *Other NonSubstitutable* *Peak* *Ave* *Min* *Summer* *0.914* *0.893* *0.465* *Winter* *2.128* *1.142* *0.484*	
XCgLSF(Tech,EC,Hour,Day,Month,Area) 'Cogeneration Load Shape (MW/MW)' Placeholder values for Cogeneration Shapes	Same as Refrigeration XLSF
XCgLSFSold(EC,Hour,Day,Month,Area) 'Cogeneration Sold to Grid Load Shape (MW/MW)' Placeholder values for Cogeneration Shapes	Same as Refrigeration XLSF
XDUF(Enduse,EC,Day,Month,AREA) 'Natural Gas Daily Use Factor (Therm/Therm)' Gas Daily Use Factors assumed the same as Electric Load Shapes	Per XLSF summed over Peak/Avg/Min
MSMM(Enduse,Tech,EC,Area,Year) 'Non-Price Market Share Factor Multiplier ($/$)'	1
XMVF(Enduse,Tech,EC,Area,Year) 'Market Share Variance Factor ($/$)' The value is from Demand81. P. Cross 10/23/95	-2.3
XPCC(Enduse,Tech,EC,Area,Year) 'Process Capital Cost ($/Driver/Yr)' The data was developed from the US I/O Tables by REMI in $1987 Energy Office. J. Amlin 7/15/94	1.930—in 1987$ and adjusted by inflation
PCCMM(Enduse,Tech,EC,Area,Year) 'Process Capital Cost Maximum Mult. ($/$)'	1
PCCP(Enduse,Tech,EC,Area,Year) 'Capital Cost of "rebated" Process ($/($/Yr))'	0
PCCU(Enduse,Tech,EC,Area,Year) 'Process Capital Cost Increment ($/($/Yr))'	0
PDIF(Enduse,Tech,EC,Area) 'Difference between the initial heating process efficiency for each Technology (Btu/Btu)' The values were developed by M.Jourabchi, MEOER. -P. Cross 10/23/95.	1.64—Elec, Heat Pump 1.0—Gas, Coal, Biomass, Solar, LPG, Steam, Geothermal 1.06—Oil
XPEE(Enduse,Tech,EC,Area,Year) 'Historical Process Efficiency ($/Btu)' The default value of this variable is -99.	-99
XPEER(Enduse,Tech,EC,Area,Year) 'Exogenous Policy Particpation Response (Btu/Btu)'	0
XPEMM(Enduse,Tech,EC,Area,Year) 'Pro. Eff. Max. Multi ($/Btu/($/Btu))'	1
PEMX(Enduse,Tech,EC,Area) 'Ratio of Maximum to Average Process Efficiency' The values of this variable are from Demand81.	1 2.5—AC and Heat
PESTD(Enduse,Tech,EC,Area,Year) 'Process Efficiency Standards ($/Btu)'	0
PESTDP(Enduse,Tech,EC,Area,Year) 'Process Efficiency Standards Policy ($/Btu)'	0
PIVTC(Year) 'Process Investment Tax Credit ($/$)'	0
POCAM(FuelEP,EC,Poll,Area,Year) 'Average Pollution Coefficients Multiplier (Fraction)'	1
PPIVTC(Year) 'Process Policy Investment Tax Credit ($/$)'	0
POCS(Enduse,FuelEP,EC,Poll,Area,Year) 'Pollution Standards (Tonnes/TBtu)' This policy variable has an aribrarily high value used to represent no pollution standards.	1E12

Residential Sector Input Assumptions	**Value**
ROIN(EC,Area) 'Return on Investment ($/Yr/$)' The values of this variable are from Demand81.	0.071
RDCCM(Enduse,Tech,EC,Area,Year) 'Retrofit Device Capital Cost Multiplier ($/$)'	1.5
RDVF(EC,Area) 'Device Retrofit Market Share Variance Factor (DLESS)'	-2.3
RPVF(EC,Area) 'Process Retrofit Market Share Variance Factor (DLESS)'	-2.3
RHCM(EC,Area,Year) 'Retrofit Hassle-Cost Multiplier ($/$)'	0.20
RPCCM(Enduse,Tech,EC,Area,Year) 'Retrofit Process Capital Cost Multiplier ($/$)'	1.5
RPMSLimit(EC,Area,Year) 'Process Retrofit Market Share Limit (1/Yr)'	0.01
TSLoad(Enduse,EC,Area) 'Temperature Sensitive Fraction of Load (Btu/Btu)' 75% of heating and cooling load is temperature sensitive - Nathalie Trudeau 12/21/07	0 0.75—Heat and AC
TxRt(EC,Area,Year) 'Income Tax Rate on Energy Consumer ($/$)' The data is from DRI, Tables 7 & 10, -. J. Amlin 7/15/94	

Year	*TxRt*	*Yr*	*TxRt*	*Yr*	*TxRt*
1985	*0.121*	*1995*	*0.128*	*2005*	*0.131*
1986	*0.127*	*1996*	*0.128*	*2006*	*0.131*
1987	*0.119*	*1997*	*0.128*	*2007*	*0.132*
1988	*0.119*	*1998*	*0.129*	*2008*	*0.132*
1989	*0.123*	*1999*	*0.129*	*2009*	*0.133*
1990	*0.126*	*2000*	*0.130*	*2010*	*0.133*
1991	*0.126*	*2001*	*0.130*	*2011+*	*0.134*
1992	*0.127*	*2002*	*0.130*		
1993	*0.127*	*2003*	*0.130*		
1994	*0.127*	*2004*	*0.131*		

XRM(FuelEP,EC,Poll,Area,Year) 'Exogenous Average Pollution Coefficient Reduction Multiplier (Tonnes/Tonnes)'	1

Commercial Demand Module Hardcoded Data

These data are hardcoded in the commercial demand module (file CData.src). These data are subject to periodic review and update.

Commercial Sector Input Assumptions	Value
DEPM(Enduse,Tech,EC,Area,Year) 'Device Energy Price Multiplier ($/$)'	1
EEImpact(Enduse,Tech,EC,Area,Year) 'Energy Efficiency Impact (Btu/Btu)'	0
EESat(Enduse,Tech,EC,Area,Year) 'Energy Efficiency Saturation (Btu/Btu)'	0
EEUCosts(Enduse,Tech,EC,Area,Year) 'Energy Efficiency Unit Costs ($/mmBtu)'	0
XEE(Enduse,Tech,EC,Area,Year) 'Exogenous Energy Efficiency (TBtu)'	0
XDR(Enduse,EC,Month,Area,Year) 'Exogenous Demand Response (MW)'	0
PEPM(Enduse,Tech,EC,Area,Year) 'Process Energy Price Multiplier ($/$)'	1
ADMFR(Enduse,Area) 'Administrative Costs Fraction ($/$)' There are no administrative costs in the base case.	0
BAT(tv) 'Short Term Utilization Adjustment Time (YR)' Source: Demand81, regression based on oil price shocks, GAB	1
BE(tv) 'Budget Elasticity Factor ($/$)' Source: Demand81, regression based on oil price shocks, GAB	0
BMM(Enduse,Tech,EC,Area,Year) 'Budget Multiplier Adjustment (Btu/Btu)'	1
CgAT(tv) 'Cogeneration Implementation Time (Years)'	1
CgCC(Tech,EC,Area,Year) 'Cogeneration Capital Cost ($/mmBtu/Yr)' These values are for Textiles from ARC 80. - J. Amlin 8/13/02	9.20, converted from 1975$ to 1985$
CgHRtM(Tech,EC,Area,Year) 'Cogeneration Thermal Efficiency (Btu/KWh)' This is an engineering value (10,500) "Energy Efficiency and the Pulp and Paper Industry" by Lars J. Nilsson, Eric D. Larson, Kenneth Gilbreath, and Ashok Gupta, 100 pp., ACEEE 1996, IE962 http://www.aceee.org/pubs/ie962.htm Biomass use mid-range quote from ACEEE article of 63 kwh/MBtu (15873=1000000/63) Solar fuel usage is only the electricity needed to monitor, control, or back-up the system, therefore we assume a very low heat rate. Jeff Amlin 5/20/13	10500 – Default; 15873 – Biomass; 8550 – Oil, LPG, Gas 1 – Solar
CgIVTC(Year) 'Cogen. Investment Tax Credit ($/$)' The federal investment tax credit was ended in 1986. DRI, Table 7. The proper years are selected and CgIVTC is given a value of seven percent.* 3. P. Cross 6/13/94	0 0.097—Year 1985
CgLoad(Tech) 'Cogeneration Demand Load to ECD'	1 0—Electric
CgMSMM(Tech,EC,Area,Year) 'Cogeneration Market Share Mult. Policy ($/$)'	1
CgRisk(Tech) 'Cogeneration Risk Premium (DLESS)'	0.05
CgSCM(Tech) 'Cogeneration Shared Cost Mult. ($/$)'	0.30 1.00—Solar
CgPL(Tech,EC,Area) 'Cogeneration Equipment Lifetime (Years)'	15
CgPotMult(Tech,EC,Area,Year) 'Cogeneration Potential Multiplier (Btu/Btu)'	1
CgResI(Tech,Area) 'Cogeneration Resource Base (mmBtu)	0
CgResI(Tech,Area) 'Cogeneration Resource Base (mmBtu)'	0
CgTL(Tech,EC,Area) 'Cogeneration Tax Life (Years)' Standard accounting practice specifies the tax life to be approximately 80 percent of the physical lifetime.	12
CgBL(Tech,EC,Area) 'Cogen. Equip. Book Value Lifetime (Years)'	15

Commercial Sector Input Assumptions	**Value**
This is the book value plant life time of cogenerator from George Backus developed data.	
CgCUFP(Tech,EC,Area) 'Cogeneration CUF for Planning (Btu/Btu)'	0.366—Health 0.427—All other EC
CgOF(Tech,EC,Area) 'Cogeneration Operation Cost Fraction ($/Yr/$)'	0.05
CgPOCS(FuelEP,EC,Poll,Area,Year) 'Cogeneration Pollution Standards' This is a policy value. An arbitrarily high value is used to represent no pollution standards.	1E12
XCgVF(Tech,EC) 'Cogen. Variance Factor ($/$)' This [-2.5] is the standard variance factor for the industrial sector based on EIA AEO modeling circa ARC 80. J. Amlin 09/21/09 Jeff? - this variable should have a value - 08/25/10	0
CHRM(EC,Area,Year) 'Cooling to Heating Ratio Multplier'	1
CROIN(Enduse,Tech,EC,Area,Year) 'Conservation Return on Investment ($/Yr/$)'	0

XDCC(Enduse,Tech,EC,Area,Year) 'Device Capital Cost ($/mmBtu/Yr)'
The sources of this data are as follows:
* Space heat - ARC 80, maximum flue efficiency or COP.
* Water heating - ARC 80 pp. 288-289
* Cooking - ARC 80 pp. 288-289
* Drying - ARC 80 pp. 288-289
* Refrigeration - ARC 80 pp. 288-289
* Lighting - 1992 Policy Act as interpeted by G. Backus
* Electric A/C - ARC 80 pp. 288-289
* Gas air conditioners from AGA, May 26, 1989 (EA-1989-S), Energy
* Analysis "An Analysis of the Economies of Gas Engines-Driven Chillers".
* Miscellaneous - ARC 80
* ARC 80 used for all values
* ARC 80 for Res + Com coal + biomass and Industrial
* other Res + Com XDCC from EPRI EA-433 V2, p.3-64

It is read in by enduse and technology for the 1985 into a scratch
* variable CapCost. All the ECs and Areas are set the same.

P. Cross 10/24/95.

	Elec	*Gas*	*Coal*	*Oil*	*Bio*	*Solar*	*LPG*	*Stm*	*Geo*	*HPump*
Space Heating	*9.00*	*22.90*	*19.0*	*42.22*	*25.52*	*138.90*	*22.90*	*42.22*	*60.0*	*40.0*
Water Heating	*9.00*	*22.90*	*19.0*	*42.22*	*0*	*138.90*	*22.90*	*42.22*	*30.0*	*20.0*
Other Subs	*19.08*	*11.34*	*19.0*	*11.34*	*0*	*0*	*11.34*	*11.34*	*0*	*0*
Refrigerators	*107.20*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*
Lighting	*3.33*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*
Air Conditioning	*35.56*	*34.12*	*0*	*34.12*	*0*	*0*	*34.12*	*0*	*10.0*	*10.0*
Other Non-Subs	*22.00*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*

DCCLimit(Enduse,Tech,EC,Area,Year) 'Device Capital Cost Limit Multiplier ($/$)'	10
DCCP(Enduse,Tech,EC,Area,Year) 'Capital Cost of Rebated Device ($/mmBtu/Yr)'	0
DCCU(Enduse,Tech,EC,Area,Year) 'Device Capital Cost Increment ($/mmBtu/Yr)'	0

Commercial Sector Input Assumptions	**Value**
DCMM(Enduse,Tech,EC,Area,Year) 'Capital Cost Maximum Mult. ($/$)'	1
DEEP(Enduse,Tech,EC,Area,Year) 'Device Efficiency Policy Variable (Btu/Btu)'	0
DEEAM(Enduse,Tech,EC,Area,Year) 'Average Device Efficiency Multiplier (Fraction)'	1
XDEER(Enduse,Tech,EC,Area,Year) 'Exogenous Policy Participation Response (Btu/Btu)'	0

DEM(Enduse,Tech,EC,Area) 'Maximum Device Efficiency (Btu/Btu)'
The source of the data is as follows:
For space heat - ARC 80, maximum flue efficiency or COP.
For water heating - LBL, J. Amlin - adjusted by R. Allen.
For cooking - LBL, AHAM, EPRI, J. Amlin
For drying - J. Amlin
For refrigeration - ?? get REEPS standard data ??
For lighting - 1992 Policy Act as interpeted by G. Backus
For electric A/C -
For gas air conditioners from AGA, May 26, 1989 (EA-1989-S), Energy Analysis "An Analysis of the Economies of Gas Engines-Driven Chillers".
For miscellaneous - J. Amlin by definition
The values are read in directly.
P. Cross 10/23/95.

	Elec	*Gas*	*Coal*	*Oil*	*Bio*	*Solar*	*LPG*	*Stm*	*Geo*	*HPump*
Space Heating	*1.00*	*0.97*	*0.97*	*0.97*	*0.65*	*10.0*	*0.97*	*0.99*	*4.00*	*4.50*
Water Heating	*0.99*	*0.97*	*0.97*	*0.97*	*0.65*	*10.0*	*0.97*	*0.99*	*4.00*	*4.50*
Other Subs	*1.30*	*0.97*	*0.97*	*0.97*	*0.65*	*0*	*0.97*	*0.99*	*0*	*0*
Refrigerators	*0.98*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*
Lighting	*0.95*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*
Air Conditioning	*3.50*	*2.00*	*0*	*2.00*	*0*	*10.0*	*2.00*	*0*	*4.00*	*4.50*
Other Non-Subs	*0.98*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*

RPEMM(Enduse,Tech,EC,Area,Year) 'Retrofit Max. Device Eff. Multiplier (Btu/Btu)',	1
RDEMM(Enduse,Tech,EC,Area,Year) 'Retrofit Max. Device Eff. Multiplier (Btu/Btu)'	1
XDEMM(Enduse,Tech,EC,Area,Year) 'Max. Device Eff. Multiplier (Btu/Btu)'	1
DESTD(Enduse,Tech,EC,Area,Year) 'Device Eff. Standards (Btu/Btu)'	0.715—Electric Light, 2000-2008 0.7475—Electric Light, 2009-Final
DESTDP(Enduse,Tech,EC,Area,Year) 'Device Eff. Standards Policy (Btu/Btu)'	0
DIVTC(Tech,Area,Year) 'Device Investment Tax Credit ($/$)'	0
DPIVTC(Year) 'Device Policy Investment Tax Credit ($/$)'	0

DOCF(Enduse,Tech,EC,Area,Year) 'Device Operating Cost Fraction ($/Yr/$)'
Device Operating Costs are computed by dividing O&M costs by capital costs for the base year ($1985/mmBtu). The data is from ARC 80, pp. 288-289 and for gas air conditioners AGA, May 26, 1989 (EA-1989-S), Energy Analysis "An Analysis of the Economies of Gas Engines-Driven Chillers". The new heating and hot water data is from: Attachment 1-a from Stu Slote dated 4/22/93 The values are read in directly. 4. P. Cross 6/14/94

	Elec	*Gas*	*Coal*	*Oil*	*Bio*	*Solar*	*LPG*	*Stm*	*Geo*	*HPump*
Space Heating	*0.030*	*0.022*	*0.010*	*0.020*	*0.013*	*0.013*	*0.014*	*0.030*	*0.014*	*0.030*
Water Heating	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0.010*	*0*

Commercial Sector Input Assumptions							Value			
Other Subs	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*
Refrigerators	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*
Lighting	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*
Air Conditioning	*0.010*	*0.017*	*0*	*0*	*0*	*0*	*0*	*0.017*	*0*	*0*
Other Non-Subs	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*

FSPOCS(Fuel,EC,Poll,Area,Year) 'Feedstock Pollution Standards (Tonnes/TBtu)'	1E12
TAXPCT(Area,Year) 'Standard accounting percent of device life that is taxed.'	0.80
XDPL(Enduse,Tech,EC,Area,Year) 'Physical Life of Equipment (Years)' The values of this variable are from DOE Std. Research, Rudermann, ARC 80 The values are read in for the initial year (Zero) and then the other years are set equal to it. Then the device physical lifetime is set equal to the minimum value of the device physical lifetime (DPL) that was read in and the physical life of production capacity (PCPL). * 3. J. Amlin 7/15/94	18—Heat 8—Hot Water 10—Substitutables 15—Refrigeration 7—Light 18—Air Conditioning 7—Non-Substitables
DRISK(Enduse,Tech) 'Device Risk Premium ($/$)'	0
XDST(Enduse,EC,Area,Year) 'Device Saturation (Btu/Btu)'	1

XLSF(Enduse,EC,Hour,Day,Month,Area) 'Load Shape Factor (MW/MW)'
The source is the NEPOOL electric load shapes, NEPOOL July 1995. The data is read in directly. The average is normalized so that the sum over all seasons is equal to 1.0. The average load values (XLSF) are mutiplied times the hours per season (ND) and summed across all seasons. This value (SSum) is used to adjust XLSF. 3. J. Amlin 6/13/94

XLSF	*Peak*	*Ave*	*Min*
Summer	*1.634*	*1.020*	*0.489*
Winter	*1.522*	*0.980*	*0.502*

SSum(EU)=sum(H,M)(XLSF(EU,EC,H,Average,M,Area)*Hours(M))/8760
XLSF(Average)=XLSF/SSum

XCgLSF(Tech,EC,Hour,Day,Month,Area) 'Cogeneration Load Shape (MW/MW)' Placeholder values for Cogeneration Shapes	Same as Refrigeration XLSF
XCgLSFSold(EC,Hour,Day,Month,Area) 'Cogeneration Sold to Grid Load Shape (MW/MW)' Placeholder values for Cogeneration Shapes	Same as Refrigeration XLSF
XDUF(Enduse,EC,Day,Month,AREA) 'Natural Gas Daily Use Factor (Therm/Therm)' Gas Daily Use Factors assumed the same as Electric Load Shapes	Per XLSF summed over Peak/Avg/Min
XMVF(Enduse,Tech,EC,Area,Year) 'Market Share Variance Factor ($/$)'	-2.3
XPCC(Enduse,Tech,EC,Area,Year) 'Process Capital Cost ($/($/Yr))' The data was developed from the US I/O Tables by REMI. Data is in $1987. The historical process capital cost is used to initialize the model. It is defined as the current dollar of capital stock (housing) per Base dollar of income. This needs to be checked since we are now using commercial floorspace instead of gross output. These numbers are from the NEB version of the model. JSA 02/21/09	0.4058—Wholesale 0.3451—Retail 0.3446—Warehouse 0.5680—Information 0.0596—Offices 0.1804—Health 0.3300—Other Comm. 0.7223—NGDistribution 0.3713—Oil Pipeline

Commercial Sector Input Assumptions	**Value**
	0.3713—Gas Pipeline 0.3446—Street Lighting
PCCMM(Enduse,Tech,EC,Area,Year) 'Process Capital Cost Maximum Mult. ($/$)'	1
PCCP(Enduse,Tech,EC,Area,Year) 'Capital Cost of "rebated" Process ($/($/Yr))'	0
PCCU(Enduse,Tech,EC,Area,Year) 'Process Capital Cost Increment ($/($/Yr))'	0
PDIF(Enduse,Tech,EC,Area) 'Difference between the initial heating process efficiency for each fuel (Btu/Btu)'	1
XPEE(Enduse,Tech,EC,Area,Year) 'Historical Process Efficiency ($/Btu)'	-99
XPEER(Enduse,Tech,EC,Area,Year) 'Exogenous Policy Particpation Response (Btu/Btu)'	0
XPEMM(Enduse,Tech,EC,Area,Year) 'Pro. Eff. Max. Multi ($/Btu/($/Btu))'	1
PEMX(Enduse,Tech,EC,Area) 'Ratio of Maximum to Average Process Efficiency' The values of this variable are from Demand81.	1.0 2.5—AC, Heat
PESTD(Enduse,Tech,EC,Area,Year) 'Process Efficiency Standards ($/Btu)'	0
PESTDP(Enduse,Tech,EC,Area,Year) 'Process Efficiency Standards Policy ($/Btu)'	0
PIVTC(Year) 'Process Investment Tax Credit ($/$)'	0
POCAM(FuelEP,EC,Poll,Area,Year) 'Average Pollution Coefficients Multiplier (Fraction)'	1
PPIVTC(Year) 'Process Policy Investment Tax Credit ($/$)'	0
POCS(Enduse,FuelEP,EC,Poll,Area,Year) 'Pollution Standards (Tonnes/TBtu)' A policy value. An aribrarily high value is used to represent no pollution standards.	1E12
ROIN(EC,Area) 'Return on Investment ($/Yr/$)'	0.066
RDCCM(Enduse,Tech,EC,Area,Year) 'Retrofit Device Capital Cost Multiplier ($/$)'	1.5
RDVF(EC,Area) 'Device Retrofit Market Share Variance Factor (DLESS)' The value is from Demand81. -P. Cross 10/23/95.	-2.3
RPVF(EC,Area) 'Process Retrofit Market Share Variance Factor (DLESS)' The value is from Demand81. -P. Cross 10/23/95.	-2.3
RHCM(EC,Area,Year) 'Retrofit Hassle-Cost Multiplier ($/$)'	0.20
RPCCM(Enduse,Tech,EC,Area,Year) 'Retrofit Process Capital Cost Multiplier ($/$)'	1.5
RPMSLimit(EC,Area,Year) 'Process Retrofit Market Share Limit (1/Yr)'	0.95
TSLoad(Enduse,EC,Area) 'Temperature Sensitive Fraction of Load (Btu/Btu)'	0.0 1.0—Heat 0.3—Air Conditioning
TxRt(EC,Area,Year) 'Income Tax Rate on Energy Consumer ($/$)' The data is from DRI, Tables 7 & 10, -P. Cross 7/25/94	0.485—1985 to 1986 0.38—1987 0.34—1988-1992 0.35—1993-Final
XRM(FuelEP,EC,Poll,Area,Year) 'Exogenous Average Pollution Coefficient Reduction Multiplier (Tonnes/Tonnes)'	1

Industrial Demand Module Hardcoded Data

These data are hardcoded in the industrial demand module (file IData.src). These data are subject to periodic review and update.

Industrial Sector Model Assumptions	Value
DEPM(Enduse,Tech,EC,Area,Year) 'Device Energy Price Multiplier ($/$)'	1
EEImpact(Enduse,Tech,EC,Area,Year) 'Energy Efficiency Impact (Btu/Btu)'	0
EESat(Enduse,Tech,EC,Area,Year) 'Energy Efficiency Saturation (Btu/Btu)'	0
EEUCosts(Enduse,Tech,EC,Area,Year) 'Energy Efficiency Unit Costs ($/mmBtu)',	0
XEE(Enduse,Tech,EC,Area,Year) 'Exogenous Energy Efficiency (TBtu)'	0
XDR(Enduse,EC,Month,Area,Year) 'Exogenous Demand Response (MW)'	0
PEPM(Enduse,Tech,EC,Area,Year) 'Process Energy Price Multiplier ($/$)'	1
ADMFR(Enduse,Area) 'Administrative Costs Fraction ($/$)'	0
BAT(tv) 'Short Term Utilization Adjustment Time (YR)'	1
BE(tv) 'Budget Elasticity Factor ($/$)'	0
BMM(Enduse,Tech,EC,Area,Year) 'Budget Multiplier Adjustment (Btu/Btu)'	1
CgAT(tv) 'Cogeneration Implementation Time (Years)' From the FOSSIL79 work, modified by JSA and GAB 11/27/90	1
CgCC(Tech,EC,Area,Year) 'Cogeneration Capital Cost ($/mmBtu/Yr)' This data is from ARC 80. The data is read in directly for the ecs specified. Adjusted from 1975$ to 1985$.	9.20—Textiles 4.18—Pulp & Paper, Converted Paper, Iron & Steel, Other NonFerrous 3.35—Petrochemicals, Industiral Gas, Other Chemicals, Fertilizer
CgHRtM(Tech,EC,Area,Year) 'Cogeneration Thermal Efficiency (Btu/KWh)' This is an engineering value (10,500) "Energy Efficiency and the Pulp and Paper Industry" by Lars J. Nilsson, Eric D. Larson, Kenneth Gilbreath, and Ashok Gupta, 100 pp., ACEEE 1996, IE962 http://www.aceee.org/pubs/ie962.htm Biomass use mid-range quote from ACEEE article of 63 kwh/MBtu (15873=1000000/63) Solar fuel usage is only the electricity needed to monitor, control, or back-up the system, therefore we assume a very low heat rate. Jeff Amlin 5/20/13	10500 – Default; 15873 – Biomass; 8550 – Oil, LPG, Gas 1 – Solar
CgIVTC(Year) 'Cogen. Investment Tax Credit ($/$)' The federal investment tax credit was ended in 1986. DRI, Table 7.	0 0.097—1985 Only
CgLoad(Tech) 'Cogeneration Demand Load to ECD'	1 0—Electric
CgMSMM(Tech,EC,Area,Year) 'Cogeneration Market Share Mult. Policy ($/$)'	1
CgRisk(Tech) 'Cogeneration Risk Premium (DLESS)'	0.05
CgSCM(Tech) 'Cogeneration Shared Cost Mult. ($/$)'	0.30
CgPL(Tech,EC,Area) 'Cogeneration Equipment Lifetime (Years)'	25
CgPotMult(Tech,EC,Area,Year) 'Cogeneration Potential Multiplier (Btu/Btu)'	1
CgResI(Tech,Area) 'Cogeneration Resource Base (mmBtu)'	0
CgTL(Tech,EC,Area) 'Cogeneration Tax Life (Years)' Standard accounting practice specifies the tax life to be approximately 80 percent of the physical lifetime.	20
CgBL(Tech,EC,Area) 'Cogen. Equip. Book Value Lifetime (Years)'	20

Industrial Sector Model Assumptions	**Value**
This is the book value plant life time of cogenerator from George Backus developed data.	
CgCUFP(Tech,EC,Area) 'Cogeneration CUF for Planning (Btu/Btu)'	0.691—Food&Tobacco, Textiles, Aparrell 0.627—Lumber, Furniture, Pulp&Paper, Converted Paper 0.894—Printing, Chemicals (4 EC), Petroleum Products, Rubber, Leather, Cement, Glass, Lime, Other NonMeta, Iron, Aluminum, NonFerrous, Fab Metals, Machines, Computers, Elec Equip, Trans Equip, Other Mfg 0.560—Iron Mining, Other Metal Mining, NonMetal Mining, Light Oil Mining, Heavy Oil Mning, Frontier Ol, Primary OS, SAGD OS, CSS OS, OS Mining, OS Upgraders, Sweet Gas Prod, Sweet Gas Proc, Sour Gas Prod, Sour Gas Proc, LNG Prod, Coal Mining, Construction 0.538—Forestry, On Farm Fuel, Crop Prod, Animal Prod
CgOF(Tech,EC,Area) 'Cogeneration Operation Cost Fraction ($/Yr/$)'	0.05
CgPOCS(FuelEP,EC,Poll,Area,Year) 'Cogeneration Pollution Standards' This is a policy value. An arbitrarily high value is used to represent no pollution standards.	1E12
XCgVF(Tech,EC) 'Cogen. Variance Factor ($/$)' This is the standard variance factor for the industrial sector based on EIA AEO modeling circa ARC 80. J. Amlin 09/21/09	0 -2.5—Primary Oil Sands, SAGD Oil Sands, CSS Oil Sands, Oil Sands Mining, Oil Sands Upgraders
CHRM(EC,Area,Year) 'Cooling to Heating Ratio Multplier'	0
CIM(Enduse,CEnduse,Tech,EC,Area) 'Cross-Impact Multiplier (Btu/Btu)'	0
CROIN(Enduse,Tech,EC,Area,Year) 'Conservation Return on Investment ($/Yr/$)'	0
XDCC(Enduse,Tech,EC,Area,Year) 'Device Capital Cost ($/(MBTU/YR))' This data is from the following sources: * All capital costs are from ARC 80, pp. 288-289 - industrial or * commerical unless otherwise noted. $75/MBtu * Motors from ?? * The data not from ARC 80 is multiplied by .9 the capacity factor * so that all the capacity costs can be divided by 0.9.	3.18—Gas 3.56—Oil 7.61—Coal 5.98—Biomass 9.37—Electric 88.9—Solar 3.18—LPG

Industrial Sector Model Assumptions	**Value**
* Direct Heat is from an EPRI report which has the same costs for * electric and gas. * Direct heat is an open flame * Indirect heat is a boiler. - P. Cross 10/25/95. Revise to use indirect heating efficiencies and let the process efficiencies pick up the differences between industries - Jeff Amlin 9/15/16	3.56—Steam 19.8—Electric Other NonSubs 1.985—Electric Motors 1.895—Offroad
DCCLimit(Enduse,Tech,EC,Area,Year) 'Device Capital Cost Limit Multiplier ($/$)'	10
DCCP(Enduse,Tech,EC,Area,Year) 'Capital Cost of Rebated Device ($/mmBtu/Yr)'	0
DCCU(Enduse,Tech,EC,Area,Year) 'Device Capital Cost Increment ($/mmBtu/Yr)'	0
DCMM(Enduse,Tech,EC,Area,Year) 'Capital Cost Maximum Mult. ($/$)'	1
DEEP(Enduse,Tech,EC,Area,Year) 'Device Efficiency Policy Variable (Btu/Btu)'	0
DEEAM(Enduse,Tech,EC,Area,Year) 'Average Device Efficiency Multiplier (Fraction)'	1
XDEER(Enduse,Tech,EC,Area,Year) 'Exogenous Policy Participation Response (Btu/Btu)'	0
DEM(Enduse,Tech,EC,Area) 'Maximum Device Efficiency (Btu/Btu)' This data is from ARC80. Electric efficiencies from G. Backus 2/10/02 Revise to use indirect heating efficiencies and let the process efficiencies pick up the differences between industries - Jeff Amlin 9/15/16	0.97—Gas, Oil, Coal, LPG 0.80—Biomass 2.50—Electric Heat, Substitutables, Offroad, Steam 0.98—Electric Motors, Non-Substitutables 10.0—Solar 0.99—Steam
RPEMM(Enduse,Tech,EC,Area,Year) 'Retrofit Max. Device Eff. Multiplier (Btu/Btu)'	1
RDEMM(Enduse,Tech,EC,Area,Year) 'Retrofit Max. Device Eff. Multiplier (Btu/Btu)'	1
XDEMM(Enduse,Tech,EC,Area,Year) 'Max. Device Eff. Multiplier (Btu/Btu)'	1
DESTD(Enduse,Tech,EC,Area,Year) 'Device Eff. Standards (Btu/Btu)'	0 0.7475—Electric Motors from 1993-Final
DESTDP(Enduse,Tech,EC,Area,Year) 'Device Eff. Standards Policy (Btu/Btu)'	0
DIVTC(Tech,Area,Year) 'Device Investment Tax Credit ($/$)'	0
DPIVTC(Year) 'Device Policy Investment Tax Credit ($/$)'	0
DOCF(Enduse,Tech,EC,Area,Year) 'Device Operating Cost Fraction ($/Yr/$)' Source: Device Operating Costs are computed by dividing O&M costs by capital costs for the base year ($1975/MBTU). Source: ARC 80, pp. 288-289. 2. It is read in for primary heat, Tech and EC. 3. P. Cross 10/25/95.	0 For Heat, Other Substitutables, Offroad: 0.045—Gas, LPG, Electric, Solar 0.047—Oil 0.072—Coal 0.098—Biomass 0.030—Steam
TAXPCT(Area,Year) 'Standard accounting percent of device life that is taxed.' Standard accounting practices.	0.80
XDPL(Enduse,Tech,EC,Area,Year) 'Physical Life of Equipment (Years)'	10—Heat

Industrial Sector Model Assumptions	**Value**
	10—Other Subtstitables 10—Offroad 17—Electric Substitutables, Motors, Non-Substitutables, Offroad
DRISK(Enduse,Tech) 'Device Risk Premium ($/$)'	0
XDST(Enduse,EC,Area,Year) 'Device Saturation (Btu/Btu)'	1
FSPOCS(Fuel,EC,Poll,Area,Year) 'Feedstock Pollution Standards (Tonnes/TBtu)' This is a policy value. An arbitrarily high value is used to represent no pollution standards.	1E12

XLSF(Enduse,EC,Hour,Day,Month,Area) 'Load Shape Factor (MW/MW)'
1. The source is the NEPOOL electric load shapes, NEPOOL July 1995.
2. The data is read in directly. The average is normalized
* so that the sum over all seasons is equal to 1.0. The average load
* values (XLSF) are mutiplied times the hours per season (ND) and summed
* across all seasons. This value (SSum) is used to adjust XLSF.
3. J. Amlin 6/13/94

XLSF	*Peak*	*Ave*	*Min*
Summer	*1.100*	*1.020*	*0.800*
Winter	*1.100*	*0.980*	*0.800*

XCgLSF(Tech,EC,Hour,Day,Month,Area) 'Cogeneration Load Shape (MW/MW)'	Set equal to XLSF
XCgLSFSold(EC,Hour,Day,Month,Area) 'Cogeneration Sold to Grid Load Shape (MW/MW)'	Set equal to XLSF
XDUF(Enduse,EC,Day,Month,AREA) 'Natural Gas Daily Use Factor (Therm/Therm)'	Per XLSF summed over Peak/Avg/Min
MSMM(Enduse,Tech,EC,Area,Year) 'Non-Price Market Share Factor Multiplier ($/$)'	1
XMVF(Enduse,Tech,EC,Area,Year) 'Market Share Variance Factor ($/$)'	-2.5

XPCC(Enduse,Tech,EC,Area,Year) 'Process Capital Cost ($/($/Yr))'

Food & Tobacco	*0.5446*
Textiles	*0.3074*
Apparel	*0.3595*
Lumber	*0.3403*
Furniture	*0.3313*
Pulp and Paper	*0.4328*
Converted Paper	*0.4328*
Printing	*0.4145*
Petrochemicals	*0.5373*
Industrial Gas	*0.5373*
Other Basic Chem	*0.5373*
Fertilizers	*0.5373*
Petroleum Products	*0.6255*
Rubber	*0.3548*
Leather	*0.3492*
Cement	*0.3756*
Glass	*0.3756*
Lime & Gypsum	*0.3756*
Other Non-Metallic	*0.3756*
Iron & Steel	*0.2257*
Aluminum	*0.2257*
Other Nonferrous	*0.2257*
Fabricated Metals	*0.3052*
Machines	*0.3243*
Computers	*0.3243*
Electric Equipment	*0.3569*
Transport Equipment	*0.3209*
Other Manufacturing	*0.4407*
Iron Ore Mining	*0.6775*
Other Metal Mining	*0.6775*
Non-metal Mining	*0.6775*
Light Oil Mining	*0.6775*
Heavy Oil Mining	*0.6775*
Frontier Oil Mining	*0.6775*
Primary Oil Sands	*0.6775*
SAGD Oil Sands	*0.6775*
CSS Oil Sands	*0.6775*
Oil Sands Mining	*0.6775*
Oil Sands Upgraders	*0.6775*
Sweet Gas Production	*0.6775*
Sweet Gas Processing	*0.6775*
Sour Gas Production	*0.6775*
Sour Gas Processing	*0.6775*
LNG Production	*0.6775*
Coal Mining	*0.6775*
Construction	*0.3410*
Forestry	*0.2108*
On Farm Fuel Use	*0.2108*
Crop Production	*0.2108*
Animal Production	*0.2108*

PCCMM(Enduse,Tech,EC,Area,Year) 'Process Capital Cost Maximum Mult. ($/$)'	1
PCCP(Enduse,Tech,EC,Area,Year) 'Capital Cost of "rebated" Process ($/($/Yr))'	0
PCCU(Enduse,Tech,EC,Area,Year) 'Process Capital Cost Increment ($/($/Yr))'	0
PDIF(Enduse,Tech,EC,Area) 'Difference between the initial heating process efficiency for each fuel (Btu/Btu)'	1 3.3333—Iron and Steel Electric Heat
XPEE(Enduse,Tech,EC,Area,Year) 'Historical Process Efficiency ($/Btu)'	-99
XPEER(Enduse,Tech,EC,Area,Year) 'Exogenous Policy Particpation Response (Btu/Btu)'	0
XPEMM(Enduse,Tech,EC,Area,Year) 'Pro. Eff. Max. Multi ($/Btu/($/Btu))'	1
PEMX(Enduse,Tech,EC,Area) 'Ratio of Maximum to Average Process Efficiency' The values of this variable are from Demand81.	2.5
PESTD(Enduse,Tech,EC,Area,Year) 'Process Efficiency Standards ($/Btu)'	0
PESTDP(Enduse,Tech,EC,Area,Year) 'Process Efficiency Standards Policy ($/Btu)'	0
PIVTC(Year) 'Process Investment Tax Credit ($/$)'	0
POCAM(FuelEP,EC,Poll,Area,Year) 'Average Pollution Coefficients Multiplier (Fraction)'	1
PPIVTC(Year) 'Process Policy Investment Tax Credit ($/$)'	0
POCS(FuelEP,EC,Poll,Area,Year) 'Pollution Standards (Tonnes/TBtu)' This is a policy value. An arbitrarily high value is used to represent no pollution standards.	1E12
ROIN(EC,Area) 'Return on Investment ($/Yr/$)' The values of this variable are from Demand81.	0.066
RDCCM(Enduse,Tech,EC,Area,Year) 'Retrofit Device Capital Cost Multiplier ($/$)'	1.5
RDVF(EC,Area) 'Device Retrofit Market Share Variance Factor (DLESS)'	-2.5
RPVF(EC,Area) 'Process Retrofit Market Share Variance Factor (DLESS)'	-2.5
RHCM(EC,Area,Year) 'Retrofit Hassle-Cost Multiplier ($/$)'	0.20
RPCCM(Enduse,Tech,EC,Area,Year) 'Retrofit Process Capital Cost Multiplier ($/$)'	1.5
RPMSLimit(EC,Area,Year) 'Process Retrofit Market Share Limit (1/Yr)'	0.95
TSLoad(Enduse,EC,Area) 'Temperature Sensitive Fraction of Load (Btu/Btu)'	0
TxRt(EC,Area,Year) 'Income Tax Rate on Energy Consumer ($/$)' The data is from DRI, Tables 7 & 10	0.35—1993 to final 0.34—1988 to 1992 0.38—1987 0.495—1985 to 1986
XPOLUTE(Enduse,FuelEP,EC,Poll,Area,Year) 'Exogenous Pollution Adjustment (Tonnes/Yr)'	0
XRM(FuelEP,EC,Poll,Area,Year) 'Exogenous Average Pollution Coefficient Reduction Multiplier (Tonnes/Tonnes)'	1

Transportation Demand Module Hardcoded Data

These data are hardcoded in the transportation demand module (file TData.src). These data are subject to periodic review and update.

Transportation Variable/Model Assumption	Value
DEPM(Enduse,Tech,EC,Area,Year) 'Device Energy Price Multiplier ($/$)'	1
EEImpact(Enduse,Tech,EC,Area,Year) 'Energy Efficiency Impact (Btu/Btu)'	0
EEUCosts(Enduse,Tech,EC,Area,Year) 'Energy Efficiency Unit Costs ($/mmBtu)'	0
XEE(Enduse,Tech,EC,Area,Year) 'Exogenous Energy Efficiency (TBtu)'	0
XDR(Enduse,EC,Month,Area,Year) 'Exogenous Demand Response (MW)'	0
PCXFM(Fuel,Tech,Poll,Area,Year) 'Pollution Coefficient Fuel Mulitplier (Tonnes/Tonnes)' This multiplier allows alternative fuels (ethanol, biodiesel) to have a different emission factor from the primary fuel(gasoline, diesel). The value is the fraction of the "technology emission factor" (POCX) which is applied to this fuel. For now, I will assume that the technology emission factor is based on the primary fuel and will specify a lower value for ethanol and biodiesel. This variable should be specified for each pollutant and technology (which has a non-one value for DMFrac).	1 0—Ethanol CO2 for Gasoline Vehices 0.05—Biodiesel CO2 for Diesel Vehices
PEPM(Enduse,Tech,EC,Area,Year) 'Process Energy Price Multiplier ($/$)'	1
ADMFR(Enduse,Area) 'Administrative Costs Fraction ($/$)'	0
BAT(tv) 'Short Term Utilization Adjustment Time (YR)'	1
BE 'Budget Elasticity Factor ($/$)'	0
BMM(Enduse,Tech,EC,Area,Year) 'Budget Multiplier Adjustment (Btu/Btu)'	1
CgAT(tv) 'Cogeneration Implementation Time (Years)'	1
CgCC(Tech,EC,Area,Year) 'Cogeneration Capital Cost ($/mmBtu/Yr)' This data is from ARC 80. – G.Backus	0
CgHRtM(Tech,EC,Area,Year) 'Cogeneration Thermal Efficiency (Btu/KWh)'	10500
CgIVTC(Year) 'Cogen. Investment Tax Credit ($/$)' The federal investment tax credit was ended in 1986. DRI, Table 7.	0 0.097—For 1985
CgLoad(Tech) 'Cogeneration Demand Load to ECD'	0
CgMSMM(Tech,EC,Area,Year) 'Cogeneration Market Share Mult. Policy ($/$)'	1
CgRisk(Tech) 'Cogeneration Risk Premium (DLESS)'	0.05
CgSCM(Tech) 'Cogeneration Shared Cost Mult. ($/$)'	0.30
CgPL(Tech,EC,Area) 'Cogeneration Equipment Lifetime (Years)'	25
CgPotMult(Tech,EC,Area,Year) 'Cogeneration Potential Multiplier (Btu/Btu)'	1
CgResI(Tech,Area) 'Cogeneration Resource Base (mmBtu)'	0
CgTL(Tech,EC,Area) 'Cogeneration Tax Life (Years)' Standard accounting practice specifies the tax life to be approximately 80 percent of the physical lifetime.	20
CgBL(Tech,EC,Area) 'Cogen. Equip. Book Value Lifetime (Years)' This is the book value plant life time of cogenerator from George Backus developed data.	20
CgCUFP(Tech,EC,Area) 'Cogeneration CUF for Planning (Btu/Btu)'	0.50
CgOF(Tech,EC,Area) 'Cogeneration Operation Cost Fraction ($/Yr/$)'	0.05
CgPOCS(FuelEP,EC,Poll,Area,Year) 'Cogeneration Pollution Standards'	1E12
XCgVF(Tech,EC) 'Cogen. Variance Factor ($/$)' This is the standard variance factor for the industrial sector based on EIA AEO modeling circa ARC 80. J. Amlin 09/21/09	-2.5

Transportation Variable/Model Assumption	**Value**
CHRM(EC,Area,Year) 'Cooling to Heating Ratio Multplier'	0
CROIN(Enduse,Tech,EC,Area,Year) 'Conservation Return on Investment ($/Yr/$)'	0
DCCLimit(Enduse,Tech,EC,Area,Year) 'Device Capital Cost Limit Multiplier ($/$)'	10
DCCP(Enduse,Tech,EC,Area,Year) 'Capital Cost of Rebated Device ($/mmBtu/Yr)'	0
DCCU(Enduse,Tech,EC,Area,Year) 'Device Capital Cost Increment ($/mmBtu/Yr)'	0
DCMM(Enduse,Tech,EC,Area,Year) 'Capital Cost Maximum Mult. ($/$)'	1
DEEP(Enduse,Tech,EC,Area,Year) 'Device Efficiency Policy Variable (Btu/Btu)'	0
DEEAM(Enduse,Tech,EC,Area,Year) 'Average Device Efficiency Multiplier (Fraction)'	1
XDEER(Enduse,Tech,EC,Area,Year) 'Exogenous Policy Participation Response (Btu/Btu)'	0
RPEMM(Enduse,Tech,EC,Area,Year) 'Retrofit Max. Device Eff. Multiplier (Btu/Btu)'	1
RDEMM(Enduse,Tech,EC,Area,Year) 'Retrofit Max. Device Eff. Multiplier (Btu/Btu)'	1
XDEMM(Enduse,Tech,EC,Area,Year) 'Max. Device Eff. Multiplier (Btu/Btu)'	1
DESTD(Enduse,Tech,EC,Area,Year) 'Device Eff. Standards (Btu/Btu)'	0
DESTDP(Enduse,Tech,EC,Area,Year) 'Device Eff. Standards Policy (Btu/Btu)'	0
DIVTC(Tech,Area,Year) 'Device Investment Tax Credit ($/$)'	0
DPIVTC(Year) 'Device Policy Investment Tax Credit ($/$)'	0
DPConv(Enduse,Tech,EC,Area,Year) 'Device Process Conversion (Vehicle Mile/Passenger Mile)'	1

DOCF(Enduse,Tech,EC,Area,Year) 'Device Operating Cost Fraction ($/Yr/$)'
Device Operating Costs are computed by dividing O&M costs by capital costs for the base year ($1975/MBTU)

	Passenger	*Freight*	*AirPass*	*AirFr*	*ForAirPas*	*ForAirFr*	*Res OfR*	*Com OfR*
LDVGasoline	*0.255*	*0.183*	*0*	*0*	*0*	*0*	*0.545*	*0.545*
LDVDiesel	*0.255*	*0.183*	*0*	*0*	*0*	*0*	*0.545*	*0.545*
LDVPropane	*0.255*	*0.183*	*0*	*0*	*0*	*0*	*0*	*0*
LDVNaturalGas	*0.255*	*0.183*	*0*	*0*	*0*	*0*	*0*	*0*
LDVElectric	*0.208*	*0.183*	*0*	*0*	*0*	*0*	*0*	*0*
LDVEthanol	*0.255*	*0.183*	*0*	*0*	*0*	*0*	*0*	*0*
LDVHybrid	*0.255*	*0.183*	*0*	*0*	*0*	*0*	*0*	*0*
LDVFuelCell	*0.255*	*0.183*	*0*	*0*	*0*	*0*	*0*	*0*
LDTGasoline	*0.183*	*0.545*	*0*	*0*	*0*	*0*	*0.545*	*0.545*
LDTDiesel	*0.255*	*0.545*	*0*	*0*	*0*	*0*	*0.545*	*0.545*
LDTPropane	*0.255*	*0.545*	*0*	*0*	*0*	*0*	*0*	*0*
LDTNaturalGas	*0.255*	*0.545*	*0*	*0*	*0*	*0*	*0*	*0*
LDTElectric	*0.255*	*0.545*	*0*	*0*	*0*	*0*	*0*	*0*
LDTEthanol	*0.255*	*0.545*	*0*	*0*	*0*	*0*	*0*	*0*
LDTHybrid	*0.255*	*0.545*	*0*	*0*	*0*	*0*	*0*	*0*
LDTFuelCell	*0.255*	*0.545*	*0*	*0*	*0*	*0*	*0*	*0*
Motorcycle	*0.255*	*0*	*0*	*0*	*0*	*0*	*0*	*0*

Transportation Variable/Model Assumption					**Value**			
BusGasoline	*0.057*	*0.057*	*0*	*0*	*0*	*0*	*0*	*0*
BusDiesel	*0.057*	*0.057*	*0*	*0*	*0*	*0*	*0*	*0*
BusPropane	*0.057*	*0*	*0*	*0*	*0*	*0*	*0*	*0*
Bus Natural Gas	*0.057*	*0*	*0*	*0*	*0*	*0*	*0*	*0*
BusElectric	*0.057*	*0*	*0*	*0*	*0*	*0*	*0*	*0*
TrainDiesel	*0.057*	*0*	*0*	*0*	*0*	*0*	*0*	*0*
TrainElectric	*0.057*	*0*	*0*	*0*	*0*	*0*	*0*	*0*
Plane Jet Fuel	*0.08*	*0*	*0.08*	*0*	*0.08*	*0*	*0*	*0*
Plane Gasoline	*0.08*	*0*	*0.08*	*0*	*0.08*	*0*	*0*	*0*
HDV2BGasoline	*0.183*	*0.545*	*0*	*0*	*0*	*0*	*0.545*	*0.545*
HDV3Gasoline	*0.183*	*0.545*	*0*	*0*	*0*	*0*	*0.545*	*0.545*
HDV4Gasoline	*0.183*	*0.545*	*0*	*0*	*0*	*0*	*0.545*	*0.545*
HDV5Gasoline	*0.183*	*0.545*	*0*	*0*	*0*	*0*	*0.545*	*0.545*
HDV6Gasoline	*0.183*	*0.545*	*0*	*0*	*0*	*0*	*0.545*	*0.545*
HDV7Gasoline	*0.183*	*0.545*	*0*	*0*	*0*	*0*	*0.545*	*0.545*
HDV8AGasoline	*0.183*	*0.545*	*0*	*0*	*0*	*0*	*0.545*	*0.545*
HDV8BGasoline	*0.183*	*0.545*	*0*	*0*	*0*	*0*	*0.545*	*0.545*
HDV2BDiesel	*0.183*	*0.545*	*0*	*0*	*0*	*0*	*0.545*	*0.545*
HDV3Diesel	*0.183*	*0.545*	*0*	*0*	*0*	*0*	*0.545*	*0.545*
HDV4Diesel	*0.183*	*0.545*	*0*	*0*	*0*	*0*	*0.545*	*0.545*
HDV5Diesel	*0.183*	*0.545*	*0*	*0*	*0*	*0*	*0.545*	*0.545*
HDV6Diesel	*0.183*	*0.545*	*0*	*0*	*0*	*0*	*0.545*	*0.545*
HDV7Diesel	*0.183*	*0.545*	*0*	*0*	*0*	*0*	*0.545*	*0.545*
HDV8ADiesel	*0.183*	*0.545*	*0*	*0*	*0*	*0*	*0.545*	*0.545*
HDV8BDiesel	*0.183*	*0.545*	*0*	*0*	*0*	*0*	*0.545*	*0.545*
MarineLight	*0.462*	*0.388*	*0*	*0*	*0*	*0*	*0.388*	*0.388*
MarineHeavy	*0.462*	*0.388*	*0*	*0*	*0*	*0*	*0.388*	*0.388*
Off-Road	*0.462*	*0.388*	*0*	*0*	*0*	*0*	*0.388*	*0.388*

The transportation O&M factor is too high. We need to research a new value.
For passenger vehicles we have this from KG Duleep, ICF’s auto guru. His thoughts: Normal O&M non-fuel costs are 3 to 5 cents a mile depending on vehicle size. An average car does about 12,500 miles/year so cost would be ~ $500 which is about 2 percent of ave. first cost (~$25,000). Normal replacement parts add about $2500 over the life of the car, which is about $165/year, so about 2.7% would be good. (This does not include registration fees, taxes, or insurance which we assume should be left out.)
Note from Jeff Amlin - registration fees, taxes, or insurance should be included in the final number.

0.027—Passenger
0.057—Freight, Residential Offroad, Commercial Offroad

0.057—Bus Gasoline, Bus Diesel, Bus NG, Bus Propane, Bus Electric, Train Diesel, Train Electric
0.080—Plane Jet Fuel, Plane Gasoline
0.057—Marine Light, Marine Heavy

TAXPCT(Area,Year) 'Standard accounting percent of device life that is taxed.'	0.80

Transportation Variable/Model Assumption	Value
Standard accounting practices.	
XDPL(Enduse,Tech,EC,Area,Year) 'Physical Life of Equipment (Years)' This is data from ARC 80. All enduses, tech, and ecs are given a value of 15 years and residential highway type of use is 7 years. From Nathalie Trudeau of Environment Canada (05/17/2007)	12 7—Passenger default for Buses, Planes, etc. 13—Small Cars (LDVGasoline-LDVFuelCell, Motorcycle) 9—Light Trucks (LDTGasoline-LDTFuelCell) 12—Freight default (Trains, etc) 9—Freight Light Trucks (HDV2BGasoline-HDV2BDiesel) 11—Freight Medium Trucks (HDV3Gasoline-HDV6Diesel) 13—Freight Heavy Trucks (HDV7Gasoline-HDV8BDiesel)
DRISK(Enduse,Tech) 'Device Risk Premium ($/$)'	0
XDST(Enduse,EC,Area,Year) 'Device Saturation (Btu/Btu)'	1
FsPOCS(Fuel,Tech,Poll,Area,Year) 'Feedstock Pollution Standards (Tonnes/TBtu)'	1E12
XLSF(Enduse,EC,Hour,Day,Month,Area) 'Load Shape Factor (MW/MW)' Assume off-peak charging of electric vehicles - Jeff Amlin 5/10/16	

XLSF	*Peak*	*Ave*	*Min*
Summer	*0.0*	*1.000*	*1.500*
Winter	*0.0*	*1.000*	*1.500*

XCgLSF(Tech,EC,Hour,Day,Month,Area) 'Cogeneration Load Shape (MW/MW)'	Set equal to XLSF
XCgLSFSold(EC,Hour,Day,Month,Area) 'Cogeneration Sold to Grid Load Shape (MW/MW)'	Set equal to XLSF
XDUF(Enduse,EC,Day,Month,AREA) 'Natural Gas Daily Use Factor (Therm/Therm)'	Per XLSF summed over Peak/Avg/Min
MSMM(Enduse,Tech,EC,Area,Year) 'Non-Price Market Share Factor Multiplier ($/$)'	1
XMVF(Enduse,Tech,EC,Area,Year) 'Market Share Variance Factor ($/$)'	-2.5
XPCC(Enduse,Tech,EC,Area,Year) 'Process Capital Cost ($/($/Yr))' The historical process capital cost is used to initialize the model. It is defined as the current dollar of capital stock (housing) per unit of the Driver. P. Cross 7/19/94.	

	Passenger	*Freight*	*AirPass*	*AirFr*	*ForAirPas*	*ForAirFr*	*Res OfR*	*Com OfR*
LightGasoline	*1.93*	*0.345*	*0*	*0*	*0*	*0*	*0.562*	*0.562*
LightDiesel	*1.93*	*0.345*	*0*	*0*	*0*	*0*	*0.562*	*0.562*
LightPropane	*1.93*	*0.345*	*0*	*0*	*0*	*0*	*0*	*0*
LightCNG	*1.93*	*0.345*	*0*	*0*	*0*	*0*	*0*	*0*
LightElectric	*1.93*	*0.345*	*0*	*0*	*0*	*0*	*0*	*0*

Transportation Variable/Model Assumption					**Value**			
LightEthanol	*1.93*	*0.345*	*0*	*0*	*0*	*0*	*0*	*0*
LightHybridGasoline	*1.93*	*0.345*	*0*	*0*	*0*	*0*	*0*	*0*
LightFuelCellGasoline	*1.93*	*0.345*	*0*	*0*	*0*	*0*	*0*	*0*
MediumGasoline	*1.93*	*0.562*	*0*	*0*	*0*	*0*	*0.562*	*0.562*
MediumDiesel	*1.93*	*0.562*	*0*	*0*	*0*	*0*	*0.562*	*0.562*
MediumPropane	*1.93*	*0.562*	*0*	*0*	*0*	*0*	*0*	*0*
MediumCNG	*1.93*	*0.562*	*0*	*0*	*0*	*0*	*0*	*0*
MediumEthanol	*1.93*	*0.562*	*0*	*0*	*0*	*0*	*0*	*0*
MediumHybridGasoline	*1.93*	*0.562*	*0*	*0*	*0*	*0*	*0*	*0*
MediumFuelCellGasoline	*1.93*	*0.562*	*0*	*0*	*0*	*0*	*0*	*0*
Motorcycle	*1.93*	*0*	*0*	*0*	*0*	*0*	*0*	*0*
BusGasoline	*0.345*	*0*	*0*	*0*	*0*	*0*	*0*	*0*
BusDiesel	*0.345*	*0*	*0*	*0*	*0*	*0*	*0*	*0*
BusPropane	*0.345*	*0*	*0*	*0*	*0*	*0*	*0*	*0*
BusCNG	*0.345*	*0*	*0*	*0*	*0*	*0*	*0*	*0*
BusElectric	*1.93*	*0.345*	*0*	*0*	*0*	*0*	*0.345*	*0.345*
TrainDiesel	*0.345*	*0.562*	*0*	*0*	*0*	*0*	*0.562*	*0.562*
TrainElectric	*1.93*	*0.345*	*0*	*0*	*0*	*0*	*0.345*	*0.345*
Plane	*0.345*	*0*	*0.345*	*0*	*0.345*	*0*	*0*	*0*
Plane	*0.345*	*0*	*0.345*	*0*	*0.345*	*0*	*0*	*0*
HeavyGasoline	*0.345*	*0.562*	*0*	*0*	*0*	*0*	*0.562*	*0.562*
HeavyGasoline	*0.345*	*0.562*	*0*	*0*	*0*	*0*	*0.562*	*0.562*
HeavyGasoline	*0.345*	*0.562*	*0*	*0*	*0*	*0*	*0.562*	*0.562*
HeavyGasoline	*0.345*	*0.562*	*0*	*0*	*0*	*0*	*0.562*	*0.562*
HeavyGasoline	*0.345*	*0.562*	*0*	*0*	*0*	*0*	*0.562*	*0.562*
HeavyGasoline	*0.345*	*0.562*	*0*	*0*	*0*	*0*	*0.562*	*0.562*
HeavyGasoline	*0.345*	*0.562*	*0*	*0*	*0*	*0*	*0.562*	*0.562*
HeavyGasoline	*0.345*	*0.562*	*0*	*0*	*0*	*0*	*0.562*	*0.562*
HeavyDiesel	*0.345*	*0.562*	*0*	*0*	*0*	*0*	*0.562*	*0.562*
HeavyDiesel	*0.345*	*0.562*	*0*	*0*	*0*	*0*	*0.562*	*0.562*
HeavyDiesel	*0.345*	*0.562*	*0*	*0*	*0*	*0*	*0.562*	*0.562*
HeavyDiesel	*0.345*	*0.562*	*0*	*0*	*0*	*0*	*0.562*	*0.562*
HeavyDiesel	*0.345*	*0.562*	*0*	*0*	*0*	*0*	*0.562*	*0.562*
HeavyDiesel	*0.345*	*0.562*	*0*	*0*	*0*	*0*	*0.562*	*0.562*
HeavyDiesel	*0.345*	*0.562*	*0*	*0*	*0*	*0*	*0.562*	*0.562*
HeavyDiesel	*0.345*	*0.562*	*0*	*0*	*0*	*0*	*0.562*	*0.562*
MarineDiesel	*0.345*	*0.562*	*0*	*0*	*0*	*0*	*0.562*	*0.562*
MarineHFO	*0.345*	*0.562*	*0*	*0*	*0*	*0*	*0.562*	*0.562*
LightGasoline	*1.93*	*0.345*	*0*	*0*	*0*	*0*	*0.562*	*0.562*
LightDiesel	*1.93*	*0.345*	*0*	*0*	*0*	*0*	*0.562*	*0.562*

PCCMM(Enduse,Tech,EC,Area,Year) 'Process Capital Cost Maximum Mult. ($/$)'	1
PCCP(Enduse,Tech,EC,Area,Year) 'Capital Cost of "rebated" Process ($/($/Yr))'	0

Transportation Variable/Model Assumption	Value
PCCU(Enduse,Tech,EC,Area,Year) 'Process Capital Cost Increment ($/($/Yr))'	0
PDIF(Enduse,Tech,EC,Area) 'Difference between the initial heating process efficiency for each fuel (Btu/Btu)'	1
XPEE(Enduse,Tech,EC,Area,Year) 'Historical Process Efficiency ($/Btu)'	-99
XPEER(Enduse,Tech,EC,Area,Year) 'Exogenous Policy Particpation Response (Btu/Btu)'	0
XPEMM(Enduse,Tech,EC,Area,Year) 'Pro. Eff. Max. Multi ($/Btu/($/Btu))'	1
PEMX(Enduse,Tech,EC,Area) 'Ratio of Maximum to Average Process Efficiency' The concept of maximum process efficiency for transportation needs further investigation. Jeff Amlin 5/27/10	1
PESTD(Enduse,Tech,EC,Area,Year) 'Process Efficiency Standards ($/Btu)'	0
PESTDP(Enduse,Tech,EC,Area,Year) 'Process Efficiency Standards Policy ($/Btu)'	0
PIVTC(Year) 'Process Investment Tax Credit ($/$)'	0
POCAM(FuelEP,Tech,Poll,Area,Year) 'Average Pollution Coefficients Multiplier (Fraction)'	1
PPIVTC(Year) 'Process Policy Investment Tax Credit ($/$)'	0
POCS(Enduse,FuelEP,Tech,Poll,Area,Year) 'Pollution Standards (Tonnes/TBtu)' An aribrarily high value is used to represent no pollution standards.	1E12
ROIN(EC,Area) 'Return on Investment ($/Yr/$)'	0.066
RDCCM(Enduse,Tech,EC,Area,Year) 'Retrofit Device Capital Cost Multiplier ($/$)'	1.5
RDVF(EC,Area) 'Device Retrofit Market Share Variance Factor (DLESS)'	-2.5
RPVF(EC,Area) 'Process Retrofit Market Share Variance Factor (DLESS)'	-2.5
RHCM(EC,Area,Year) 'Retrofit Hassle-Cost Multiplier ($/$)'	0.20
RPCCM(Enduse,Tech,EC,Area,Year) 'Retrofit Process Capital Cost Multiplier ($/$)'	1.5
RPMSLimit(EC,Area,Year) 'Process Retrofit Market Share Limit (1/Yr)'	0.95
TSLoad(Enduse,EC,Area) 'Temperature Sensitive Fraction of Load (Btu/Btu)'	0
TxRt(EC,Area,Year) 'Income Tax Rate on Energy Consumer ($/$)' The data is from DRI, Tables 7 & 10. -- P. Cross 7/25/94.	0.35—1993 to final 0.34—1988 to 1992 0.38—1987 0.495—1985 to 1986
XRM(Tech,EC,Poll,Area,Year) 'Exogenous Average Pollution Coefficient Reduction Multiplier (Tonnes/Tonnes)'	1

Appendix 2: Emission Reduction Curves

Venting Emission Reduction Curve Coefficients ($/Tonne)	
Light Oil Mining	**Heavy Oil Mining & Primary Oil Sands**
$A_0 = 1.85601$	$A_0 = 1.87465$
$B_0 = -0.78771$	$B_0 = -0.60289$
$C_0 = 0.92446$	$C_0 = 0.93798$

Venting Reduction Capital Cost Curve Coefficients ($/$)	
Light Oil Mining	**Heavy Oil Mining & Primary Oil Sands**
$A(cc)_0 = 3.17029$	$A(cc)_0 = 8.56275$
$B(cc)_0 = -0.53467$	$B(cc)_0 = -0.66629$
$C(cc)_0 = 1591.937$	$C(cc)_0 = 1317.020$

The fraction of methane (CH4) captured from venting reductions is assumed to be equal to 0.50. The emission factors assumed for venting reductions for CO2 and VOC and are listed in the table below in tonnes per tonnes of methane for the light oil mining, heavy oil mining, and primary oil sands industries. Additionally, flaring venting emissions reduces methane (CH4), but increases CO2 only and the coefficients are listed below.

Venting Reduction Emission Factors (Tonnes/Tonne CH4)			Emission Factors for Flared CH4 (Tonnes/Tonnes)
Industry Impacted	**CO2**	**VOC**	**CO2**
Light Oil Mining	0.1887	0.0573	2.4014
Heavy Oil Mining, Primary Oil Sands	0.4057	0.0528	1.5041

The coefficients depend on the assumed gas speciation profiles as listed below.

		Light Oil	**Heavy Oil**
Venting Gas Component Concentrations		100%	100%
CO2		7.79%	2.89%
CH4		40.16%	72.29%
C2H6		14.70%	6.78%
VOC:		34.80%	12.89%
C3H8	Propane	13.86%	4.94%
C4H10	Butane	12.64%	3.00%
C5H12	Pentane	5.35%	1.54%
C6H14	Hexane	2.15%	0.67%
C7H16	Heptane	0.20%	0.89%
C8H18	Octane	0.20%	0.59%
C9H20	Nonane	0.20%	0.67%
C10H22	Decane	0.20%	0.59%
NOX		2.80%	5.16%

NOTE: TABLE BELOW THAT HAS EXAMPLE FILES FITS BETTER IN ASSUMPTIONS BOOK

Calibration Variable	Calibration Variable Description	Initial Projection Methodology	Examples of Files that Revise Calibration Variables (2017 Reference Case)
MMSM0	Marginal Market Share Multiplier (Non-Price Factor)	YMMSMM=16	AdjustMarketShare.txt AdjustMarketShare_MX.txt AdjustGasPipeline-NT.txt AdjustPetroleum.txt AdjustPEIFood_Res.txt AdjustNBOil.txt AdjustDemands_NS.txt
CERSM	Capital Energy Requirement Multiplier (Lifestyle Multiplier)	YCERSM=3	AdjustOtherNonferrous.txt AdjustPetroleum.txt AdjustNBOil.txt
CUF	Capacity Utilization Factor	YCUF=1	AdjustPetroleum.txt StockAdjustment.txt
DEMM	Max. Device Efficiency Mult.	YDEMM=3	DeviceEfficiencyMultiplierForecast .txt
PEMM	Max. Process Efficiency Mult.	YPEMM=3	AdjustVehicleTravel.txt
FsPEE	Feedstock Process Efficiency	YFsPEE=3	None
CgCUF	Cogen. Capacity Utilization Factor	YCgCUF=3	None
CgMSM0	Cogeneration Marginal Market Share Multiplier (Non-Price Factor)	YCgMSM=3	CogenMarketShare.txt

Adjustments Made to Projections of Calibration Variables

This section provides tables describing several modifications made to calibration variables that overwrite the initial values assigned during model execution. This list is not inclusive and is meant to illustrate the types of modifications made during the forecast review and development process. Table 24 provides examples of modifications to the initial method of projecting the non-price factor (MMSM0) impacting marginal fuel market shares. Table 25 illustrates modifications made impacting projections of the demand equation calibration variables - capacity utilization factor (CUF) and capital energy requirement multiplier (CERSM).

Table 24. Examples of Adjustment Files impacting the Marginal Fuel Market Shares

Example Adjustment Files of Calibration Variables (MMSM0)

AdjustMarketShare.txt • Residential space heat in ON, SK, MB, NL, PE, and NU: Recalculates MMSM0 to set future marginal fuel market share (MMSF) equal to the average market share (AMSF) in the last historical year • Residential coal space heat in SK: Sets MMSM0=-5.0 (increasing market resistance) • Commercial space heat across Canada and Industrial Gas Space heat in ON and AB; Pulp and paper industry space heat in NB; Other manufacturing in AB: Recalculates MMSM0 to set future marginal market share (MMSF) equal to average in the last historical year (AMSF) • Iron ore mining, coal space heat in QC: Set MMSM0 equal to value for Oil. • Lumber gas in MB: MMSM0=-5; Lumber electric in MB: MMSM0=-10 • Passenger transportation in Canada: MMSM0 equals MMSM0 in last historical year **AdjustMarketShare_MX.txt** • Sets Mexico value for MMSM0 such that future marginal market shares equal the average market share in the last historical year. **AdjustGasPipeline-NT.txt** • Assigns Natural Gas Pipelines (NGPipeline) in Northwest Territories starting in 2017 equal to Alberta's values because this industry does not start until after 2017 (after the calibration period). **AdjustPetroleum.txt** • Adjusts non-price factors for space heat and steam in Canada's Petroleum industry (oil refineries) as well as sets the variance factor equal to zero. **AdjustPEIFood_Res.txt** • Increases the use of natural gas in the Food and Tobacco industry in PEI by setting MMSM0=0 (no resistance). • Shifts residential space heating from oil to electricity in PEI by adjusting MMSM0. **AdjustNBOil.txt** Assign calibration variables for NB oil to 2012 values.

Table 25. Adjustment Files Impacting Energy Demand Calibration Variables (CERSM, CUF)

Files that Overwrite Calculated Values of Calibration Variables
CERSM
AdjustOtherNonferrous.txt Sets CERSM values for Other Nonferrous oil and electricity in NL equal to QC. **AdjustPetroleum.txt** Shuts down NS Petroleum industry (oil refineries) by setting CERSM = 0 starting in 2015. Adjusts AB and NL Petroleum industries (oil refineries) to be more energy intensive by increasing CERSM starting in 2016. **AdjustNBOil.txt**

Assigns calibration variables for NB oil to 2012 values.
CUF
StockAdjustment.txt Adjusts the value of CUF if very low or very high. Values are very low when capital stock does not retire fast enough to match the drop in energy demands, such as with coal where demands drop to nearly zero and capital stock does not retire fast enough due to lifetime assumptions. To adjust for this, the StockAdjustment.txt file retires excess capital stock in the first year of the forecast. If CUF is very high, we adjust for this by adding capital stock in the first year of the forecast such that the CUF equals 1.0 The projection method is not modified. CUF will be equal to 1.0 in the long run forecast either by the capital stock adjustment or trending back to 1.0. **AdjustPetroleum.txt** Sets future CUF for Canada Petroleum industry equal to the last historical year.

9. U.S. Specific Demand Sector Input Data (2020Model)

These data are input to the model through text files in \2020Model.

Filename	Variable Description	Source
EconomicDrivers_CA.txt	XPopT(Area,Year) 'Population (Millions)' XHHS(ECC,Area,Year) 'Households (Households)' XRPI(Area,Year) 'REMI Total Personal Income (Real M$/Yr)'	
CogenHeatRates.txt	CgHRtM(Tech,EC,Area,Year) 'Marginal Cogeneration Heat Rate (Btu/KWh)'	NRTEE Study
ProcessCapitalCosts.txt	XPCC(Enduse,Tech,EC,Area,Year) 'Process Capital Cost ($/Driver/Yr)'	Res - US Census Data Ind – REMI I/O Table Oil Sands - CERI Report, Table 3.1 Gas Mining - Energy Briefing Note (Nov. 2010), Figure 6.
DeviceEfficiencies andCaptialCosts.txt	XDCC(Enduse,Tech,EC,Area,Year) 'Device Capital Cost ($/mmBtu/Yr)' XDEE(Enduse,Tech,EC,Area,Year) 'Historical Device Efficiency (Btu/Btu)'	AEO Stock Efficiency Tables NEMS input files 'rsmeqp.txt' and 'ktek.xml'
SequesteringPenalty.txt	SqPenalty(Tech,EC,Poll,Area,Year) 'Sequestering Energy Penalty (TBtu/Tonne)'	Replacing Natural Gas in Alberta's Oil Sands: Trade-Offs Associated with Alternative Fossil Fuels", by Jennifer M. McKellar, Joule A. Bergerson, and Heather L. MacLean, from Energy & Fuels 2010 24 (3), 1687-1695
ResDemand_CA.txt	XDmd(Enduse,Tech,EC,Area,Year) 'Energy Demands (TBtu/Yr)'	Volume 2: Electric Demand by Utility Planning Area California Energy Commission. CEC-200-2013-004-V1-CMF
ResGas_CA.txt	XDmd(Enduse,Tech,EC,Area,Year) 'Energy Demands (TBtu/Yr)'	
ComDemand_CA.txt	XDmd(Enduse,Tech,EC,Area,Year) 'Energy Demands (TBtu/Yr)'	Volume 2: Electric Demand by Utility Planning Area California Energy Commission. CEC-200-2013-004-V1-CMF
ComGas_CA.txt	XDmd(Enduse,Tech,EC,Area,Year) 'Energy Demands (TBtu/Yr)'	
IndDemand_CA.txt	XDmd(Enduse,Tech,EC,Area,Year) 'Energy Demands (TBtu/Yr)'	Volume 2: Electric Demand by Utility Planning Area California Energy Commission. CEC-200-2013-004-V1-CMF
IndFuelEP_CA.txt	XDmd(Enduse,Tech,EC,Area,Year) 'Energy Demands (TBtu/Yr)' XCgDmd(Tech,EC,Area,Year) 'Exogenous Cogeneration (TBtu/Yr)'	
TransDemand_CA.txt	XDmd(Enduse,Tech,EC,Area,Year) 'Energy Demands (TBtu/Yr)'	California Emissions - Transport Demand Estimation v160118.xlsx

	DmFrac(Enduse,Fuel,Tech,EC,Area,Year) 'Energy Demands Fuel/Tech Split (Btu/Btu)'	California GHG Inventory 2013 - Coded v160120.xlsx
GHG_Macroeconomy_US.txt	MEPOCX(ECC,Poll,Area,Year) 'Process Pollution Coefficient (Tonnes/$B-output)'	US GHG Inventory 1990-2007 Table Summary.xls
GHG_Macroeconomy_CA.txt	MEPOCX(ECC,Poll,Area,Year) 'Process Pollution Coefficient (Tonnes/$B-output)'	California Emissions All Fuels v160108.xlsx
GHG_Residential_CA.txt	POCX(Enduse,FuelEP,EC,Poll,Area,Year) 'Pollution Coefficient (Tonnes/TBtu)'	CH4 Coefficient Examinations.xlsx
GHG_Transportation_CA.txt	POCX(Enduse,FuelEP,Tech,EC,Poll,Area,Year) 'Marginal Pollution Coefficients (Tonnes/TBtu)' TrMEPX(Tech,EC,Poll,Area,Year) 'Non-Energy Pollution Coefficient (Tonnes/Vehicle Miles)'	California Emissions All Fuels v160108.xlsx ARB California GHG Inventory
CAC_ReductionCurves_2009.txt	PCostN(FuelEP,EC,Poll,Area) 'Pollution Reduction Cost Normal ($/Tonne)' PVF(FuelEP,EC,Poll,Area) 'Pollution Reduction Variance Factor (($/Tonne)/($/Tonne))'	
CAC_ReductionCurves_2011.txt	PCostN(FuelEP,EC,Poll,Area) 'Pollution Reduction Cost Normal ($/Tonne)' PVF(FuelEP,EC,Poll,Area) 'Pollution Reduction Variance Factor (($/Tonne)/($/Tonne))'	

10. U.S. Specific Supply Sector Input Data (2020Model)

These data are input to the model through text files in \2020Model.

Filename	Variable Description	Source
WholesalePrices-AEO.txt	XENPN(Fuel,Nation,Year) 'Wholesale Energy Prices (1985 US$/mmBtu)'	Natural gas – AEO, Jan 2014 MER 9.10; Coal - AER 2012 table 7.9 Oil – EIA for WTI price Ethanol price = Oil
CoalSupply_Data.txt	XCExpMSF(Area,Year)'Interregional Coal Export Market Shares - Ref. Case (TBtu/TBtu)' XCAProd(Area,Year) 'Coal Production - Reference Case (TBtu/Yr)' CPConFr(Area,Year) 'Coal Producer Consumption Fraction (Btu/Btu)'	CN - CANSIM 128-0002 and 128-0009 US - AEO 2014ER
DeliveredPrices_US.txt	FPTax(Prices,Area,Year) 'Fuel Tax ($/mmBtu)'	US - Estimated based on available online data
DeliveredPrices_US.txt	FPSM(Prices,Area,Year) 'Energy Sales Tax ($/$)'	US - Estimated based on available online data
OilProdCost.txt	OPUC(Process,Nation,Year) 'Oil Production Unit Full Cost ($/mmBtu)'	Estimates from Nick Macaluso updated July 2010
SpOGResData.txt	XPdPN(GNode,ProcOG,Year) 'Natural Gas Production (TBtu/Yr)'	AEO 2012, Figure 108 Data
SpOGFinData.txt	OGAbCFr(OGUnit,Year) 'OG Abandonment Cost Fraction ($/($/Yr))' OGITxRate(OGUnit,Year) 'OG Initial Tax Rate ($/$)' XDevCap(OGUnit,Year) 'Exogenous Development Capital Costs ($/mmBtu)' XDisCap(OGUnit,Year) 'Exogenous Discovery Capital Costs ($/mmBtu)' XSusCap(OGUnit,Year) 'Exogenous Sustaining Capital Costs ($/mmBtu)' XOGOMCosts(OGUnit,Year) 'OG O and M Costs ($/mmBtu)'	2014 CERI Report, Table 3.1 and Table 3.8 Energy Briefing Note (Nov. 2010), Figure 6.
SpGTrData.txt	XGLvStorage(GNode,Month,Year) 'Historical Level of Natural Gas in Storage (TBtu)' GTrMax(GNode,GNodeX,Month,Year) 'Natural Gas Transmission Capacity (TBtu/Month)' XGCapLNGImports(GNode,Month,Year) 'Exogenous LNG Imports Capacity (TBtu/Yr)' XGCapLNGExports(GNode,Month,Year) 'Exogenous LNG Exports Capacity (TBtu/Yr)' XGVCLNG(GNode,Month,Year) 'Historical Natural Gas Variable Cost from LNG ($/mmBtu)'	Form EIA-191M, "Monthly Underground Gas Storage Report" and Form EIA-191A, "Annual Underground Gas Storage Report" AEO “Natural Gas Pipeline Capacity & Utilization” FERC “North American LNG Import/Export Terminals” Various recorded LNG export proposals

SpBiofuel_Data.txt	BfFsYield(Biofuel,Tech,Feedstock,Area,Year) 'Biofuel Yield From Feedstock (Btu/Tonne)'	Estimated based on available online data
ElectricLossFactors.txt	TDEF(Fuel,Area,Year) 'T&D Efficiency (MW/MW)'	California – CEC-200-2013-004-V1-CMF report
PlantCharacteristics.txt	GCCCN(Plant,Area,Year) 'Overnight Construction Costs ($/KW)' HRTM(Plant,Node,GenCo,Year) 'Marginal Heat Rate (Btu/KWh)' UFOMC(Plant,Area,Year) 'Unit Fixed O&M Costs ($/KW)' UOMC(Plant,Area,Year) 'Unit O&M Costs ($/MWh)' CD(Plant,Year) 'Construction Delay (Years)' NuclearFuelCost(Area,Year) 'Nuclear Fuel Costs ($/MWh)' UOR(Plant,GenCo,Year) 'Unscheduled Outage Rate (MW/MW)'	AEO 2014 Various other sources per plant type Ontario Power Generation Annual Report 2013, overview page and page 86. Union Electric's "Generation Technologies for Integrated Resource Planning", Janauary, 1995 Clean Power Plan Technical Documentation, 2015
GHG_Energy-US.txt	POCX(Enduse,FuelEP,EC,Poll,Area,Year) 'Marginal Pollution Coefficients (Tonnes/TBtu)' CgPOCX(FuelEP,EC,Poll,Area,Year) 'Cogeneration Pollution Coefficient (Tonnes/TBtu)'	
ElectricTransmission_US.txt	LLMax(Node,NodeX,TimeP,Month,Year) 'Maximum Loading on Transmission Lines (MW)'	
ElectricTransmission_CA.txt	LLMax(Node,NodeX,TimeP,Month,Year) 'Maximum Loading on Transmission Lines (MW)' HDXLoad(Node,NodeX,TimeP,Month,Year) 'Exogenous Loading on Transmission Lines (MW)' XLLVC(Node,NodeX,Year) 'Transmission rate ($/MWh)'	
GHG_ElectricGeneration_CA.txt	MEPOCX(ECC,Poll,Area,Year) 'Process Pollution Coefficient (Tonnes/$B-output)' UnMECX(Unit,Poll,Year) 'Process Pollution Coefficient (Tonnes/GWh)'	California Emissions All Fuels v160108.xlsx

California-Specific Input Data

Default U.S. energy data are obtained from SEDS and AEO forecast. For the state of California, the SEDS/AEO data are overwritten by California-specific data from the California Energy Commission and the California Air Resources Board.

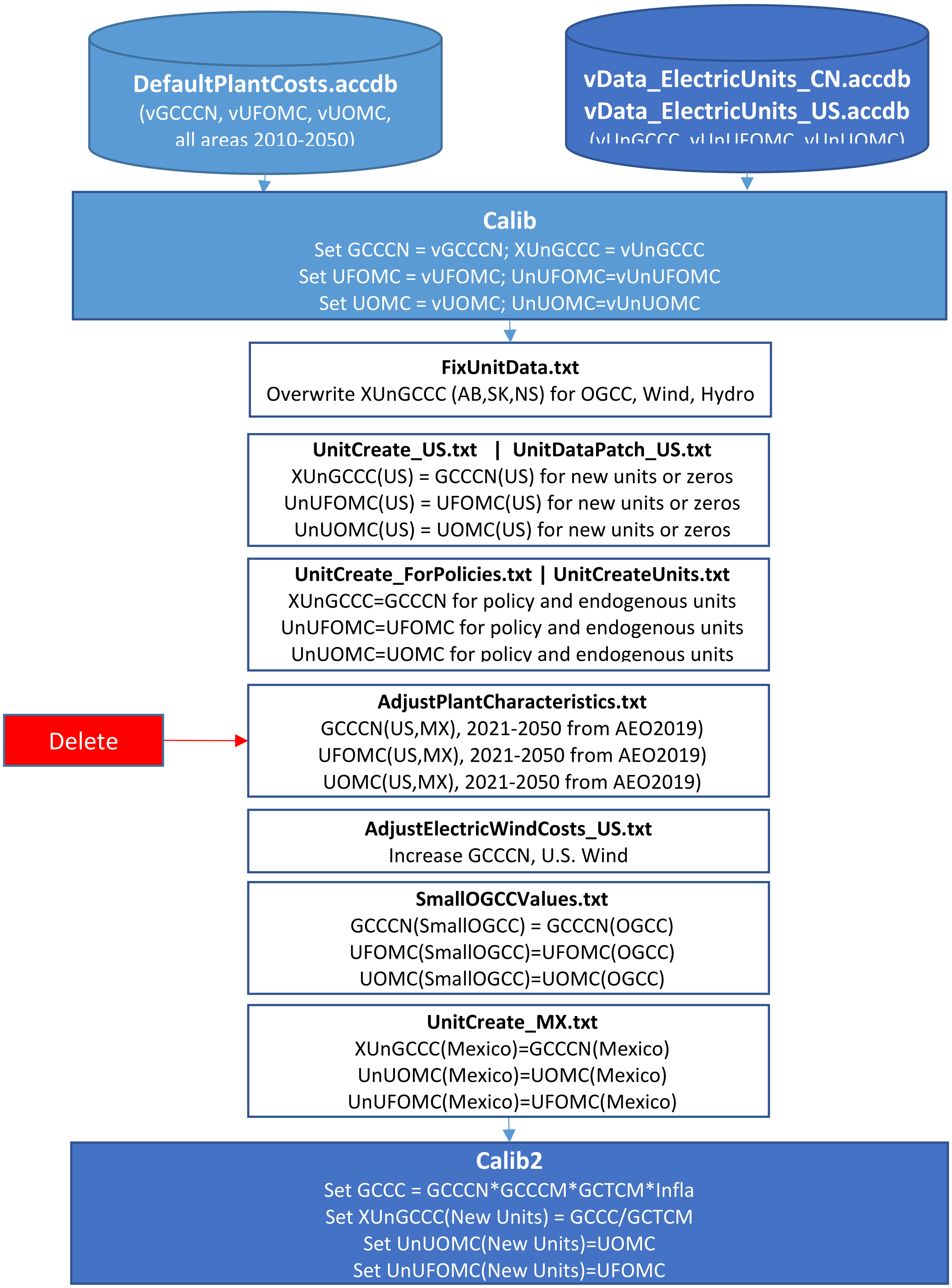
The following data were updated in August 2017 (model's last historical year 2015):

1. ***Load data (Peak loads and losses)***: California historical peak load from 1990-2015, source: "California Energy Demand 2016 Update - Mid Demand Case", Dec 2016,
    - Form 1.4: Net Peak Demand (total end use load plus losses minus self-generation).
    - Model input file: PeakLoads_CA.txt
2. ***Energy Consumption (Electricity):*** Historical electricity demands and forecast from 1990-2027
    a. *Electricity demands. Source1*: "California Energy Demand Updated Forecast, 2017-2027". December 2016 | CEC-200-2016-016-SD, Mid Demand Case, Form 1.1: Total Electricity Consumption by Sector. ("TN215506_20170123T111112_FINAL_CEDU2016_STATEWIDE_Mid_Demand_Case.xls")
    - *Note* – the Form 1.1 includes cogeneration
    - *Residential end-use splits (electricity and gas); Commercial end-use splits by building type (electricity) - Source2:* "Attachment_12-References_for_Energy_End-Use_Electricity_Demand_and_GHG_Emissions_Calculations.pdf"
    - Residential electricity - ResDemand_CA.txt (electricity demand broken out by end use).
    - Passenger Transportation (LDVElectric) – Form 1.1 (TransDemand_CA.txt)
    - *California energy demand by economic category and fuel*: Residential and Commercial extracted and estimated using fuel use numbers from the emissions inventory; Detailed industrial demand data is updated –"Industrial& MiningForecastbyNAICSGroup.xls"; Transportation fuel forecast: CEC's "IEPR Transportation.xls"
3. ***Energy Consumption (Natural gas):*** California electricity forecast from 1990-2027 from CEC ("Chap7Gastables-RF2-09.xls")
4. ***Emissions Coefficients*** – Standardized emission factors for electricity and gas
    a. Source: "Attachment_12-References_for_Energy_End-Use_Electricity_Demand_and_GHG_Emissions_Calculations.pdf"
    b. *Emissions Inventory from California ARB*

5. ***Electricity Sales by Sector*** - Form 1.1b: Electricity Sales by Sector (consumption minus self-generation)
    a. Form 1.2: Net Energy for Load (consumption plus losses minus self-generation)
    b. Form 1.7a: Private Supply by Sector
6. ***Economic forecast assumptions:*** "California Energy Demand 2016 Update - Mid Demand Case" ("TN215506_20170123T111112_FINAL_CEDU2016_STATEWIDE_Mid_Demand_Case.xls")
    a. Form 2.2: Economic and Demographic Assumptions (population, personal income, manufacturing output)
    b. Form 2.2: from 2015 Update (People per household). People per household were used to estimate number of households (Population/ppl/household).
7. ***Electric utility generation and cogeneration by plant type from California Energy Commission (CEC):*** "ELECTRICITY_GEN_1997-2008 v2.xls"
8. ***Electric utility new plant characteristics (costs, heat rate, etc.):*** E3 Data for 33% RPS Analysis – "GenerationCosts.doc"; Loss Factor - "Chap1Stateforms-RF2-09 v2.xls"

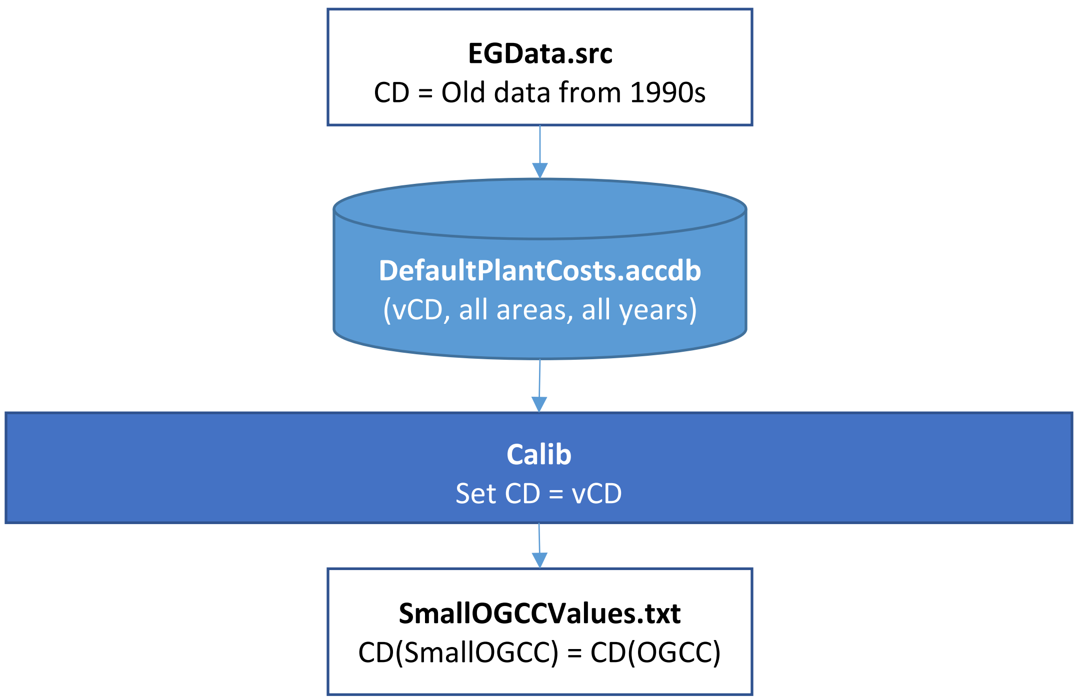
11. Electric Utility Capital Costs Flow of Inputs and Adjustments

Capital Cost Inputs: vGCCCN, vUnGCCC; vUFOMC, vUnUFOMC; vUOMC, vUnUOMC.



Input Data Flow Chart – Construction Delay

Construction Delay (CD) Inputs: vCD



Heat Rate Inputs: vHRTM, vUnHrt

1. AdjustPlantCharacteristics.txt
2. Electric_NG_EPS.txp
    a. Reduce heat rate of small OGCC units
3. ElectricEnergyMgmt.txp
    a. Decrease HRTM; Decrease UnHrt
4. SmallOGCCValues.txt

    a. Assign value of HRTM for SmallOGCCs
5. FixUnitData.txt
    a. Set maximum UnHrt for AB and SK OGCC units
    b. UnHrt=xmax(UnHrt,370*1e6/POCXGHG)
6. UnitConstruction_US.txt
    a. HRTM(OGCT,Future)=9800
7. UnitCreate_ForPolicies.txt, UnitCreate_MX.txt, UnitCreate_US.txt, UnitCreateUnits.txt
    a. UnHrt=HRTM
8. UnitDataPatch_US.txt
    a. Do If UnHRt lt MinHeatRateThreshold
    b. UnHRt=HRTM
    c. Else UnHRt gt MaxHeatRateThreshold
    d. UnHRt=MaxHeatRateThreshold
9. UnitDataExtension_CA.txt: Set California, Geothermal units: UnHrt=3412
10. UnitGeneration_MX.txt
    a. UnHRt=UnHRt*HeatRateAdjust
    b. Select FuelEP(NaturalGas,Coal,HFO)
    c. HeatRateAdjust=XEUD/XEUDEstimate
    d. XUnDmd=xmax(XUnEGA*UnHRt/1e6*xUnFlFr,0)
11. UnitScaleGenerationFuel_US.txt
    a. Adjust US heat rates after 2000: UnHrt=UnHrt*EGFAMult
    b. Adjust US heat rates before 2000: UnHrt(U,Y)=UnHrt(U,2001)
    c. Assign future values of heat rate: UnHrt(U,Y)=UnHrt(U,Last)
12. UnitDataExtension_US.txt
    a. Assign UnHrt pre-2011 and post-2016
13. ECapacityExpansion
14. UnHRt=HRTM (for new units)