California PATHWAYS Model Framework and Methods

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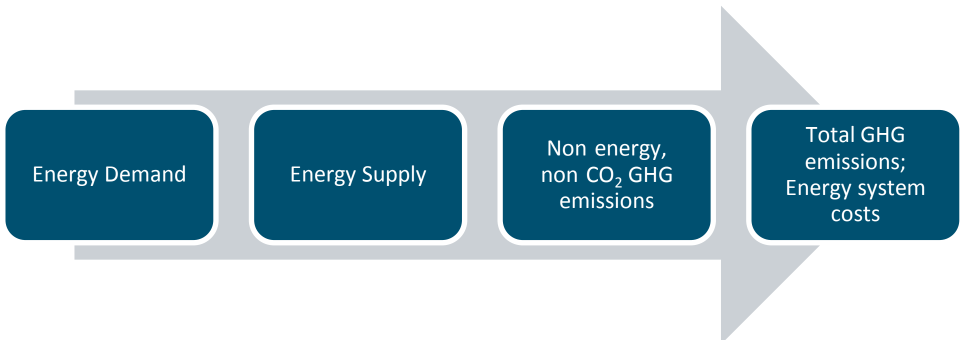
1 Model Overview

PATHWAYS is a long-horizon energy model developed by Energy and Environmental Economics, Inc. (E3) that can be used to assess the cost and greenhouse gas emissions impacts of California's energy demand and supply choices. The model can contextualize the impacts of different individual energy choices on energy supply systems (electricity grid, gas pipeline) and energy demand sectors (residential, commercial, industrial) as well as examine the combined impact of disparate strategies designed to achieve deep de-carbonization targets. This document provides an overview of the California PATHWAYS modeling framework and methodology. Data input sources and scenario assumptions are documented in a separate appendix to the California Air Resources Board 2030 Proposed Scoping Plan.

This methodology report is structured around the key elements of the PATHWAYS model as illustrated in Figure 1. Section 2 describes energy demand sectors and sources of energy demand data, Section 3 describes energy supply infrastructure and fuel types and Section 4 discusses non-energy, non-CO2 greenhouse gas emissions. This section describes the basic modeling framework utilized in PATHWAYS to synthesize energy demand and energy supply options to calculate greenhouse gas (GHG) emissions and energy system costs for each scenario.

Figure 1. Basic model framework



1. **Energy Demand:** projection of energy demand for ten final energy types. Projected using an activity-based approach, with a stock roll-over accounting of the stock of energy end-use technologies in most sectors.

2. **Energy Supply:** informed by energy demand projections. Final energy supply can be provided by either fossil fuel primary energy types (oil, natural gas, coal) or by decarbonized sources and processes (renewable electricity generation, biomass conversion processes, carbon capture and sequestration). The energy supply module projects costs and GHG emissions of all energy types.

3. **Non-energy, non-CO_2 GHG emissions:** Examples of non-energy GHG emissions include methane and N_2O emissions from agriculture and waste, refrigerant F-gases, and emissions from cement production.

4. **Summary Outputs:** Calculation of total GHG emissions and energy-system costs (end-use stocks as well as energy costs). These summary

outputs are used to compare economic and environmental impacts of scenarios.

PATHWAYS projects energy demand in eight demand sectors shown in Table 1.

Table 1 PATHWAYS Demand Sectors

Sector	
Residential	Petroleum Refining
Commercial	Agriculture
Industrial	Water-Energy and Transportation, Communication, and Utilities (TCU)
Transportation	Oil & Gas Extraction

For those sectors that can be represented at the stock level – residential, commercial, and transportation – PATHWAYS models a stock roll-over of technologies by vintage for individual subsector (i.e. air conditioners, light duty vehicles, etc.). For all other sectors, PATHWAYS utilizes a regression approach to project energy demand out to 2050. These two approaches are utilized to project ten final energy supply types (Table 2).

Table 2 PATHWAYS Final Energy Types

Final Energy	
Electricity	Gasoline
Pipeline Gas	Liquid Petroleum Gas (LPG)
Compressed Pipeline Gas	Refinery and Process Gas
Liquefied Pipeline Gas	Coke

Final Energy	
Diesel	Waste Heat

These final energy types can be supplied by a variety of different resources. For example, pipeline gas can be supplied with natural gas, biogas, hydrogen, and/or synthetic natural gas (produced through power-to-gas processes). These supply composition choices affect the cost and emissions profile of each final energy type. Likewise, gasoline can be supplied with fossil gasoline or renewable gasoline; diesel can be supplied with fossil gasoline or renewable diesel; electricity can be supplied with natural gas, coal, hydroelectric power, renewable power, etc.

2 Final Energy Demand Projections

2.1 Stock roll-over methodology

The basic stock roll-over methodology is used both in the development of the demand unit projections as well as the supply unit stock analysis. For example, PATHWAYS uses a stock roll-over function to project square feet of indoor space and uses a stock roll-over function to estimate the stock efficiency of air conditioners used to cool that indoor space. The basic mechanics of stock roll-over are used throughout the model in estimating basic energy service demands, calculating current and future baseline stock efficiencies, and calculating the impacts of mitigation measures. The stock roll-over modeling approach necessitates inputs concerning the initial composition of equipment (vintage, fuel type, historical efficiencies, etc.) as well as estimates of the useful lives of each type of equipment.

Stock roll-over functions are determined by technology useful lives, scenario-defined sales penetration rates, and the shapes of those sales penetrations (S-curves that might more closely mirror market adoption; and linear adoptions that may more accurately reflect policy instruments). Given that the model is designed to provide information on the technologies necessary to reach long-term carbon goals, these adoption rate input assumptions are not forecasts: they are not dynamically adjusted to reflect consumer preference, energy costs, payback periods, etc. which might inform technological adoption rates in practice. PATHWAYS models a stock roll-over at the technology level for a limited set of subsectors in which homogeneous supply units could be determined (i.e. residential water heating).

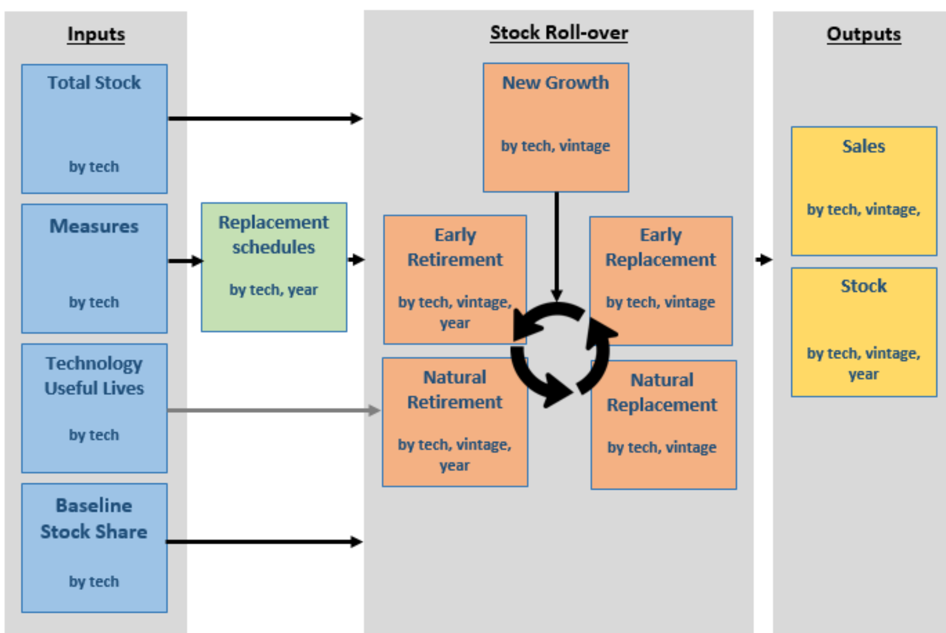
The Residential, Commercial, and Transportation modules include stock roll-over functionality that governs changes in technology stocks and sales over time. The stock-roll-over mechanism determines the technology composition of stock and sales for equipment; it does not impact the total (aggregate) stock trajectory. For example, we use this stock roll-over process to determine the composition of both the existing (pre-2010) and future (2011-2050) stock of residential buildings and equipment. For buildings, changes in stock composition include both housing type (single family, multi-family, mobile-home) and vintage. Different housing types have different energy service demands and average floor areas. Across housing types, building shell efficiency improves over time with increasing vintage, while increases in floor area increase energy service demand for some energy end uses. End use equipment efficiency generally improves with vintage.

The Transportation Module includes a stock roll-over mechanism that governs changes in on-road (LDV, MDV, and HDV) vehicle stock composition, fuel economy, fuel switching opportunities, and vehicle costs over time. The mechanism tracks vehicle vintage — the year in which a vehicle was purchased — by vehicle sub-category. The total stock trajectory is an input to the roll-over logic. Other key inputs include the useful economic life of equipment, user-defined measures, and baseline stock shares.

Baseline stock shares specify: 1) the initial technology stock composition; and 2) the technology composition of new growth absent any user-input measures. In the Baseline, the baseline stock shares determine market shares throughout the analysis timeframe. In other scenarios, the stock roll-over mechanism adjusts market shares and, thereby, technology composition of equipment stock based on user-defined measures.

Figure 2 shows the key components of the stock roll-over logic and the relations among them.

Figure 2: Overview of Stock Roll-over Mechanism



PATHWAYS derives adjusted market shares from user-defined measures. By aggregating market share impacts across measures, PATHWAYS calculates aggregate replacement schedules that capture market share deviations from the

Baseline scenario. These schedules drive the stock roll-over calculations and outputs.

PATHWAYS captures natural decay of equipment over time using a Poisson distribution, with a mean (λ_t) equal to the expected useful life of the building or equipment. The equipment natural retirement ratio, $B_{v,y,t}$, of vintage *v* in year *y* for technology *t* is given by the following formula:

Equation 1

$$\beta_{v,y,t} = e^{-\lambda_t} \frac{{\lambda_t}^{y-v+1}}{(y-v+1)!}$$

We use the Poisson distribution as an approximation to the survival functions in the NEMS Residential Demand Module, which are based on a Weibull distribution fitted to the linear survival functions historically used in NEMS.[1] The Poisson distribution has a right-skewed density function, which becomes more bell-shaped around λ_t at higher values of λ_t (i.e. longer expected lifetimes). Survival functions, both in PATHWAYS and NEMS, are a significant source of uncertainty. This uncertainty plays a smaller role in analyses with long timeframes relative to equipment useful lives.

Tracking equipment vintages is central to the stock roll-over-over logic. PATHWAYS estimates the initial technology composition of stock by vintage by applying the baseline stock shares and using the survival function to determine

[1] For more on the approach used in NEMS, see U.S. Energy Information Administration, "Residential Demand Module of the National Energy Modeling System: Model Documentation 2013," November 2013, http://www.eia.gov/forecasts/aeo/nems/documentation/residential/pdf/m067(2013).pdf.

the percentage of stock from each historical vintage that would not retire prior to the initial analysis year. The initial analysis year varies by equipment type based on useful lives, but it is typically between 1950 and 1986.

The roll-over mechanism steps through each analysis year and dynamically calculates five key variables by technology and vintage:

- **Natural retirement**: Natural decay of equipment by vintage and technology, consistent with the Poisson survival function. If two technologies have the same useful life and there are no applicable early replacement measures, the same percentage of a given vintage of these technologies will retire each year.
- **Early retirement**: Early equipment retirement due to user-defined early replacement measures. For all remaining technologies purchased before the user-defined cutoff year, PATHWAYS retires a portion of equipment equal to the user-defined annual replacement ratio, by vintage.
- **Natural replacement**: Sales to replace naturally retired equipment. In the absence of user-defined natural replacement measures, PATHWAYS replaces each naturally retired equipment with equipment of the same technology. In the presence of user-defined natural replacement measures, replacement schedules determine deviations of replacement technology composition from retirement technology composition. In the event that the total stock decreases relative to the prior year, natural replacement sales are reduced pro rata across technologies.
- **Early replacement**: Sales due to user-defined early replacement measures. Generally, all user-defined early replacement technologies replace all early-retired technologies. If total stock decreases relative to

the prior year, PATHWAYS reduces natural replacements before early replacements. If the total stock decreases by more than would be commensurate with natural retirement, early replacement sales are reduced pro rata.

- **New growth**: Sales due to new adoption, i.e. equipment purchased for a reason other than replacing retired equipment. Any increase in total stock relative to the prior year constitutes new growth. Absent user-defined measures, baseline sales shares determine technology composition of new growth. In the presence of user-defined natural replacement measures, replacement schedules determine deviations of new growth technology composition from these baseline stock shares.

After calculating these five variable for each year, vintage, and technology, PATHWAYS calculates total sales by the following formula:

Equation 2

$$Sales_{v,t} = Natural\ Replacement_{v,t} + Early\ Replacement_{v,t} + New\ Growth_{v,t}$$

Equation 3 presents the calculation of total stock by year, vintage, and technology:

Equation 3

$$Stock_{y,v,t} = Stock_{y-1,v,t} - Natural\ Retirement_{y,v,t} - Early\ Retirement_{y,v,t} + Sales_{y,v,t}$$

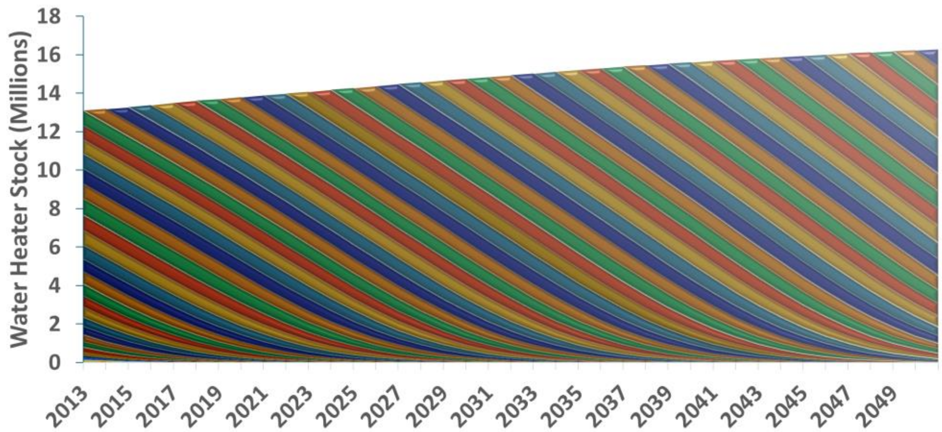
Note that year and vintage are equivalent for the sales variable.

A simple example facilitates understanding of how the stock roll-over process drives changes in stock composition and vintage. Consider a region that has 200 homes in 1999, half of which (100) are single family and half of which are multi-family. All homes have an expected 50-year lifetime. Assume all of the single family homes were built in 1950, and all multi-family homes were built in 1960. At the end of 1999, the natural decay ratios for the single and multi-family homes will be 0.056 and 0.021, respectively,[2] indicating that 6 single family homes (=100 * 0.056) and 2 multi-family homes (=100 * 0.021) will be retiring at year's end. Assume, for illustration, that all eight of these homes will be replaced with single family homes and that there is no growth in the housing stock. This means that, in year 2000, there will be 102 single family homes (= 100 – 6 + 8) and 98 multi-family homes (= 100 – 2 + 0). In 2000, single family homes account for 51% of the housing stock, an increase from 50% in 1999. All eight homes that are replaced in 2000 will have a 2000 vintage, and will have higher building shell efficiency than previous vintages.

We use the same stock roll-over process for end use equipment, illustrated in Figure 3 for residential water heaters with 16-year expected useful lifetime. Each wedge in the figure represents an equipment vintage, and each wedge narrows and eventually declines to zero as the entire vintage is retired. For instance, the 2013 vintage completely turns over by the early 2046. In this instance, the total stock trajectory is governed by the number of households over time.

[2] With an expected useful life of 50 years, the replacement coefficients for 50-year (i.e., built in 1950) and 40-year (built in 1960) homes are $e^{-50}\frac{50^{50}}{50!} = 0.056$ and $e^{-50}\frac{50^{40}}{40!} = 0.021$, respectively.

Figure 3. Illustration of stock roll-over process for residential water heaters (each stripe represents a different vintage year)



2.2 Residential

PATHWAYS' Residential Module is used to project residential final energy consumption, CO_2 emissions, and end-use equipment costs by census region and year for the 12 end uses shown in Table 3. The first 11 end uses are represented at a technology level, while the "Other" subsector is represented on an aggregate basis.[3]

Table 3. Residential end uses and model identifiers

Subsector	Model Identifier
Water Heating	RES_WH

[3] "Other" includes ceiling fans, coffee machines, dehumidifiers, DVD players, external power supplies, furnace fans, home audio equipment, microwaves, personal computers, rechargeable devices, security systems, set-top boxes, spas, televisions, and video game consoles.

Subsector	Model Identifier
Space Heating	RES_SH
Central Air Conditioning	RES_CA
Room Air Conditioning	RES_RA
Lighting	RES_LT
Clothes Washing	RES_CW
Clothes Drying	RES_CD
Dishwashing	RES_DW
Cooking	RES_CK
Refrigeration	RES_RF
Freezer	RES_FR
Other	RES_OT

Changes in final energy consumption, CO_2 emissions, and end use equipment costs in the Residential Module are driven by changes to the stock of buildings and energy end use equipment, which grow, roll-over (retire), and are replaced over time. Stock growth and replacement — new stock — provides an opportunity for efficiency improvements in buildings and equipment, and for fuel switching through changes in equipment. Users reduce residential CO_2 emissions in PATHWAYS by implementing measures that change the building and equipment stock over time.

2.2.1 FINAL ENERGY CONSUMPTION

PATHWAYS calculates residential final energy consumption (R.FEC) of different final energy types in each year as the product of two terms: (1) housing type-specific unit energy service demand (e.g., dishwasher cycles per year per single-family home in 2025) scaled by an activity driver (e.g., number of single-family homes in 2025); and (2) end use equipment efficiency that is weighted by the market share for a given vintage of a given type of equipment (e.g., the share of 2020 vintage LED lights in total residential light bulbs in 2025).

Equation 4

$$R.FEC_{ey} = \sum_{j}\sum_{k}\sum_{m}\sum_{v} ACT_{jy} \times ESD_{jky} \times \frac{MKS_{kmvey}}{EFF_{kmvey}}$$

New Subscripts

e	final energy type	electricity, pipeline gas, liquefied petroleum gas (LPG), fuel oil
y	year	model year (2010 to 2050)
j	home type	single family home, multi-family home, mobile home
k	end use	12 end uses in Table 3
m	equipment type	based on equipment types specific to the end uses in Table 3
v	vintage	equipment vintage (1950 to year y)

New Variables

$R.FEC_{ey}$	is residential final energy consumption of final energy type e in year y
ACT_{jy}	is an activity driver for home type j in year y
ESD_{jky}	is adjusted unit energy service demand per unit of activity for home type j for end use k in year y
MKS_{kmvey}	is the market share for vintage v of equipment type m consuming final energy type e for end use k in year y
EFF_{kmvey}	is the energy efficiency of vintage v of equipment type m consuming final energy type e for end use k in year y

Table 4 shows the equipment units, efficiency units, and final energy types associated with 11 of the 12 residential end uses (excluding “other”).

Table 4. Residential Subsector Inputs

End use	Equipment units	Efficiency units	Final Energy Types
Water Heating	Water heater	BTU_{-out}/BTU_{-in}	Pipeline gas, electricity, fuel oil, LPG
Space Heating	Furnace, radiator, heat pump	BTU_{-out}/BTU_{-in}	Pipeline gas, electricity, fuel oil, LPG
Central Air Conditioning	Central air conditioner, heat pump	BTU_{-out}/BTU_{-in}	Electricity
Room Air Conditioning	Room air conditioner	BTU_{-out}/BTU_{-in}	Electricity
Lighting	Lamp or Bulb	Kilolumens/kilowatt	Electricity
Clothes Washing	Clothes Washer	BTU_{-out}/BTU_{-in}, normalized water use factor	Electricity
Clothes Drying	Clothes Dryer	BTU_{-out}/BTU_{-in}	Pipeline gas, electricity
Dishwashing	Dishwasher	$BTU_{-out}/BTU_{-in;}$ Normalized Water Use Factor	Electricity
Cooking	Range (oven and stovetop)	BTU_{-out}/BTU_{-in}	Pipeline gas, electricity, fuel oil, LPG
Refrigeration	Refrigerator	BTU_{-out}/BTU_{-in}	Electricity
Freezer	Freezer	BTU_{-out}/BTU_{-in}	Electricity

2.2.1.1 Activity Drivers

The Residential Sector Module's two activity drivers are households and floor area, segmented by housing unit type, and housing unit vintage. Projections of households are based on population projections out to 2050 from the California Department of Finance estimates[4] and a linear regression that projects persons

[4] http://www.dof.ca.gov/Forecasting/Demographics/Projections/

per household using data and estimates from 1990 to 2022, also from the California Department of Finance.

Equation 5

$$HPP_y = 0.3558 - 0.000475p$$

New Variables

HPP_y	is the number households per person in year y
P	p is year number, measured in annual increments from a base year (1990 = 1)

PATHWAYS uses total population and households per person to estimate the total number of households (THH) by census region and year.

Equation 6

$$THH_y = POP_y \times HPP_y$$

New Variables

THH_y	is the total number of households in year y
POP_y	is the projected population in year y

PATHWAYS projects future housing units by type and year using the stock roll-over approach described in Section 2.1, which allows for changes in housing type, floor area, and vintage over time. Housing units that are being renovated or retired are then replaced with a new vintage and type of home. New vintage housing units of different types are also added as the number of households in each region grows.

Equation 7

$$THH_{jy+1} = \sum_{v}^{y} THH_{vjy} \times (1 - \beta_{vy}) + (THH_{vjy} \times \beta_{vy} + NHH_{y+1}) \times \theta_{jy}$$

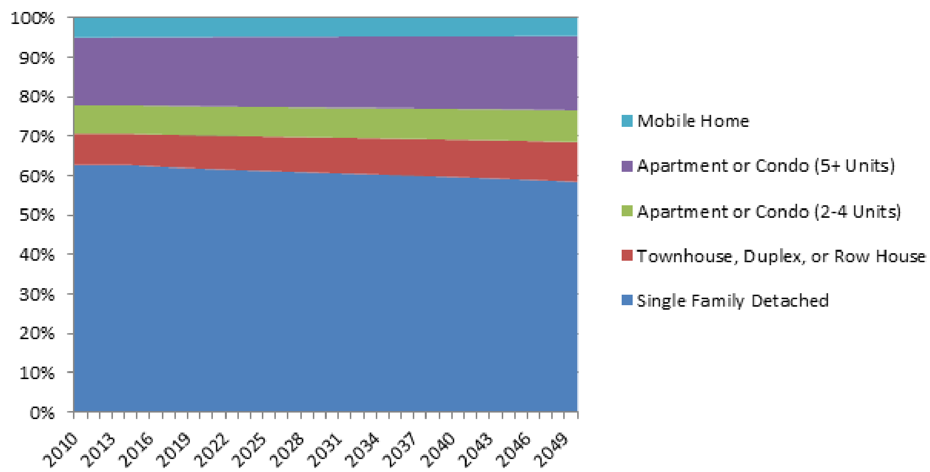
New Variables

THH_{jy+1}	is the number of housing units of type j in year y+1
THH_{vjy}	is the number of housing units of vintage v and type j in year y
NHH_{y}	is the number of new households in year y+1
θ_{jy}	is the share of housing unit type j in total housing units in year y

The replacement coefficients (β) are based on an expected 50-year lifetime for homes, where “lifetime” is more precisely defined as the time before retirement or renovation. To overcome the lack of data on housing vintages by type, we generate distributions of historical vintages of the existing (2010) housing stock by applying the stock roll-over retrospectively. The share coefficients (θ) are based on those found in California's 2009 Residential Appliance Saturation Survey (RASS 2009)[5]. This stock roll-over process leads to relatively small changes in the structure of the national housing stock over time, as shown in Figure 4.

[5] Documentation from http://www.energy.ca.gov/appliances/rass/; data from https://websafe.kemainc.com/RASS2009/Default.aspx

Figure 4. Baseline housing stock by type and vintage over time



PATHWAYS projects total residential floor area by housing type using housing type-, and vintage-specific average floor areas (square feet per home) from RASS 2009.

Equation 8

$$RFA_{jy+1} = ARF_{jy+1} \times THH_{jy+1}$$

New Variables

RFA_{jy+1}	is the total residential floor area for housing type j in year y
ARF_{jy+1}	is the average residential floor area per housing type j in year y

2.2.1.2 Unit Energy Service Demand

In the residential sector, unit energy service demand is the demand for energy services (e.g., lumens, wash cycles, space heating) for each of the 12 end uses in Table 3 normalized by either household or floor area. Service demands vary across census regions (e.g., warmer regions need less heating) and housing unit types (e.g., multi-family units need less heat per square foot than single family homes).

2.2.1.2.1 Unit Energy Service Demand Adjustments

To arrive at a final unit energy service demand term, we account for end-use specific special cases. Space heating and cooling demand are dependent on changing climate conditions. Using RASS 2009, cooling demand in kWh/household is input separately for each housing type for each California climate zone. Similarly, annual heating in therms/household is input for each housing type for each utility service territory. Heating and cooling service demand are then moderated by the thermal performance of building shells. Shell performance multipliers (ratios to reference performance) for various potential shell improvements are based on those used in the AEO's NEMS model, where they are calculated using thermal simulation models. Building shells are tracked as stock technologies and can be influenced through building shell stock measures.

2.2.1.3 Equipment Measures, Adoption, and Market Shares

PATHWAYS reduces residential CO_2 emissions relative to a reference case through measures that change the composition of new building and equipment. Users implement residential measures in PATHWAYS by calibrating equipment-specific adoption curves. Adoption of new equipment leads to changes in market share for a given vintage and type of equipment over time.

In PATHWAYS, turnover of existing stock and new stock growth drive sales of new residential end use equipment. In the reference case, sales penetration for a given type of equipment — its share of new sales — is based on RASS 2009. Users change reference case sales penetrations by choosing the level and approximate timing of saturation for a given type of equipment (e.g., new sales of high efficiency heat pump water heaters saturate at 30% of total new water heater sales in 2030). PATHWAYS allows the user to choose between linear and S-shaped adoption curves. In the main report, sales penetrations (SPN) for most end uses are based on aggregated S-shaped curves

Equation 9

$$SPN_{kmvey} = \frac{SAT_{kme}}{1 + \propto^{x}}$$

where x is a scaling coefficient that shifts the curve over time based on a user defined measure start year and time-to-rapid-growth (TRG) period (in years)

Equation 10

$$x = \frac{MSY_{kme} + TRG_{kme} - y}{TRG_{kme}}$$

and TRG is calculated as

Equation 11

$$TRG_{kme} = \frac{ASY_{kme} - MSY_{kme}}{2}$$

New Variables

SPN_{kmvey}	is the sales penetration of vintage v of equipment type m for end use k using final energy type e in year y
SAT_{kme}	is the saturation level of equipment type m for end use k using final energy type e in a specified year
α	is a generic shape coefficient, which changes the shape of the S-curve
MSY_{kme}	is measure start year for equipment type m for end use k using final energy type e in a specified year
TRG_{kme}	is the time-to-rapid-growth for adoption of equipment type m for end use k using final energy type e in a specified year
ASY_{kme}	is the approximate saturation year for adoption of equipment type m for end use k using final energy type e

Market shares for an equipment vintage in a given year are the initial stock of that vintage, determined by the adoption curve, minus the stock that has turned over and been replaced, divided by the total stock of equipment in that year (e.g., the share of 2020 vintage LEDs in the total stock of lighting equipment in 2025).

Equation 12

$$MKS_{kmvey+1} = \frac{EQP_{vkme} - \sum_{v}^{y} EQP_{vkme} \times \left(1 - \beta_{vy}\right)}{EQP_{ky+1}}$$

New Variables

$MKS_{kmvey+1}$	is the market share of vintage v of equipment type m for end use k using final energy type e in year y+1
EQP_{vkme}	is the stock of equipment adopted of equipment type m for end use k using final energy type e that has vintage v
EQP_{ky}	is the total stock of equipment for end use k in year y+1

If total sales of new equipment exceed sales of user-determined measures (i.e., if the share of measures in new sales is less than 100% in any year), adoption of residual equipment is assumed to match that in the reference case. In cases where adoption may be over-constrained, PATHWAYS normalizes adoption saturation so that the total share of user-determined measures in new sales never exceeds 100% in any year.

2.2.2 CO_2 EMISSIONS

We calculate total CO_2 emissions from the residential sector in each year as the sum product of final energy consumption and a CO_2 emission factor by fuel type.

Equation 13

$$R.CO2_y = \sum_e R.FEC_{ey} \times CEF_e$$

Variables

$R.CO2_y$	is residential CO_2 emissions in year y
CEF_e	CEF_e is a CO_2 emission factor for energy type e, which is time invariant

All CO_2 emission factors for primary energy are based on higher heating value (HHV)-based emission factors used in AEO 2013. CO_2 emission factors for energy carriers are described in the Energy Supply section. In cases where electricity sector CO_2 emissions are reported separately from residential sector emissions, the R.FEC term in the above equation is zeroed out.

2.2.3 ENERGY SYSTEM COSTS

Energy system costs are defined in PATHWAYS as the incremental capital and energy cost of measures. The incremental cost of measures is measured relative to a reference technology, which is based on the equipment that was adopted in the Reference Case.

2.2.3.1 Capital Costs

PATHWAYS calculates end use capital (equipment and building efficiency) costs by vintage on an annualized ($/yr) basis, where annual residential equipment costs (R.AQC) are the total residential equipment cost (R.TQC) multiplied by a capital recovery factor (CRF).

Equation 14

$$R.AQC_{kmv} = R.TQC_{kmv} \times CRF$$

Equation 15

$$CRF = \frac{r}{[1-(1+r)^{-EUL_m}]}$$

Variables

R.AQC$_{kmv}$	is the annual residential equipment cost for vintage v of equipment type m in end use k
R.TQC$_{kmv}$	is the total residential equipment cost for vintage v of equipment type m in end use k
r	is a time, housing type, region, and equipment invariant discount rate
EUL$_m$	is the expected useful life of equipment type m

PATHWAYS uses a discount rate of 10%, reflecting the historical average of real credit card interest rates.[6] This discount rate is not intended to be a hurdle rate, and is not used to forecast technology adoption. Rather, it is meant to be a broad reflection of the opportunity cost of capital to households.

Consistent with our stock roll-over approach to adoption and changes in the equipment stock, we differentiate between the cost of equipment that is replaced at the end of its expected useful life ("natural replacement"), and equipment that is replaced before the end of its useful life ("early replacement").

[6] This roughly reflects the historical average of real credit card interest rates. From, 1974 to 2011, the CPI-adjusted annual average rate was 11.4%. Real rates are calculated as $r^R = \frac{(1+r^N)}{(1+i)} - 1$, where i is a rate of consumer inflation based on the CPI.

The incremental cost of equipment that is naturally replaced is the annual cost of that equipment minus the annual cost of equipment used in the reference case.

Equation 16

$$R.IQC_{kmv} = R.AQC_{kmv} - R.AQC'_{kmv}$$

New Variables

$R.IQC_{kmv}$	is the incremental annual residential equipment cost in end use k
$R.AQC_{kmv}$	is the annual residential equipment cost for equipment type m that consumes final energy type e in end use k for a given scenario examined in this report
$R.AQC'_{kmv}$	is the annual residential equipment cost for equipment type m that consumes final energy type e in end use k for the reference case

For equipment, early replacement measures are assessed the full technology cost and do not include any salvage value.

PATHWAYS calculates total incremental residential end use equipment costs in year y as the sum of annual incremental costs across vintages, equipment types, and end uses.

Equation 17

$$R.IQC_y = \sum_k \sum_m \sum_v^y R.IQC_{kmv}$$

New Variables

R.IQC$_y$	is the total incremental cost of residential end use equipment in year y

2.2.3.2 *Energy Costs*

Annual residential energy costs (R.AEC) in PATHWAYS are calculated by multiplying final energy consumption (R.FEC) by final energy type in each year by a unit energy price (P) in that year.

Equation 18

$$R.AEC_{ey} = R.FEC_{ey} \times P_{ey}$$

New Variables

R.AEC$_{ey}$	is the total annual residential energy cost for final energy type e in year y
P$_{ey}$	Is the unit price of final energy type e in year y

Electricity and fuel prices are calculated in the supply side modules, described in the Energy Supply section. Incremental annual residential energy costs are calculated relative to the reference case.

Equation 19

$$R.IEC_{ey} = R.AEC_{ey} - R.AEC'_{ey}$$

New Variables

$R.IEC_{ey}$	is the total incremental annual residential energy cost for final energy type e in year y
$R.AEC'_{ey}$	is the total annual residential energy cost for final energy type e in year y in the reference case

2.3 Commercial

PATHWAYS' Commercial Module is used to project commercial sector final energy consumption, CO_2 emissions, and end-use equipment costs by year for the eight end uses shown in Table 5 and the seven fuels shown in

Table 6. The first seven end uses are represented at a technology level, while the "Other" subsector is represented on an aggregate basis.

Table 5. Commercial end uses and model identifiers

Subsector	Model Identifier
Air Conditioning	AC
Cooking	CK
Lighting	LT
Refrigeration	RF
Space Heating	SH
Ventilation	VT
Water Heating	WH
Other	OT

Table 6. Fuels used in the commercial sector

Fuel
Electricity
Pipeline Gas
Fuel Oil
Liquefied Petroleum Gas (LPG)
Kerosene
Wood
Waste Heat

Changes in final energy consumption, CO_2 emissions, and end use equipment costs in the Commercial Module are driven by changes to the stock of buildings and energy end use equipment, which grow, roll-over (retire), and are replaced over time. Stock growth and replacement — new stock — provides an opportunity for efficiency improvements in buildings and equipment, and for fuel switching through changes in equipment. Users reduce commercial CO_2 emissions in PATHWAYS by implementing measures that change the equipment stock over time. Users can also implement Demand Change Measures that directly alter the demand for services met by equipment. For example, water efficiency efforts translate into reduced water heating loads and office illumination levels are trending downwards due to increasing use of computer monitors rather than paper for work tasks.

2.3.1 FINAL ENERGY CONSUMPTION

PATHWAYS calculates commercial final energy consumption (C.FEC) of different final energy types in each year as the product of two main terms: (1) service-territory-specific unit energy service demand (e.g., water heating demand in PG&E's territory in 2025) and (2) end use equipment efficiency that is weighted by the market share for a given vintage of a given type of equipment in a territory (e.g., the share of 2020 vintage high efficiency heat pump water heaters in total commercial water heating equipment in PG&E's territory in 2025).

Table 7 shows the equipment units, efficiency units, and final energy types associated with commercial end uses, excluding “other”.

Table 7. Commercial Subsector Inputs

End use	Equipment units	Efficiency units	Final Energy Types
Air Conditioning	Air conditioner	BTU_{-Out}/BTU_{-in}	Electricity
Cooking	Range	BTU_{-Out}/BTU_{-in}	Pipeline gas, electricity
Lighting	Lamp or Bulb	Kilolumens/kilowatt	Electricity
Refrigeration	Refrigerator	BTU_{-Out}/BTU_{-in}	Electricity
Space Heating	Furnace, radiator, heat pump	BTU_{-Out}/BTU_{-in}	Pipeline gas, electricity, waste heat
Ventilation	Ventilation system	BTU_{-Out}/BTU_{-in}	Electricity
Water Heating	Water heater	BTU_{-Out}/BTU_{-in}	Pipeline gas, electricity

2.3.1.1 Activity Drivers

The Commercial Module’s main activity driver is commercial floor area, segmented by utility service territory. Total commercial building floor area estimates per utility service territory from 1990 to 2024 are provided by the CEC's California Energy Demand 2014-2024 Final Forecast Mid-Case.[7] Floor areas for

[7] http://www.energy.ca.gov/2013_energypolicy/documents/demand-forecast/mid_case/

the remaining years up to 2050 are projected for each service territory using linear regression.

2.3.1.2 Unit Energy Service Demand

In the commercial sector, unit energy service demand is the demand for energy services (e.g., lumens, space heating, space cooling) for each of the 8 end uses, normalized by floor area. The service demand is derived from Unit Energy Consumption measured at the end use level for each service territory as reported in CEUS (2006). This source doesn't include numbers for all service territories, so SCE values are used for LADWP and Other, based on geographic proximity. To arrive at a unit energy service demand term, we multiply the unit energy demand (i.e. the measured energy consumption) by the aggregate efficiency of the stock (i.e. the fraction of energy that delivers the service) for a given calibration year, typically 2009.

Equation 20: Unit Energy Service calculation

$$UES_{eik} = \left(UED_{eiky} \times \sum_{m} \sum_{v} \frac{MKS_{ikmvey}}{EFF_{kmvey}} \right)_{y=2009}$$

New Subscripts

e	final energy type	electricity, pipeline gas, liquefied petroleum gas (LPG), fuel oil
y	year	in the model year (2010 to 2050)
i	utility territory	Geographic territory for LADWP, PG&E, SDG&E, SCE, SMUD, and Other
k	end use	8 end uses in Table 5
m	equipment type	based on equipment types specific to the end uses in Table 5
v	vintage	equipment vintage (1950 to year y)

New Variables

$\mathbf{UES_{eik}}$	is the unit energy service requirement (service demand per square foot) for energy type e in territory i for end use k (evaluated in the year 2009)
$\mathbf{UED_{ieky}}$	is the measured energy demand per square foot for energy type e in territory i for end use k in year y
$\mathbf{MKS_{ikmvey}}$	is the market share for vintage v of equipment type m consuming final energy type e for end use k in territory i in year y
$\mathbf{EFF_{kmvey}}$	is the energy efficiency of vintage v of equipment type m consuming final energy type e for end use k in year y

Note that this unit energy service demand is calculated using a bottom-up end use intensity metric. To ensure that the bottom-up calculations match the top down measured commercial energy consumption, the UES is calibrated against top down commercial measured energy consumption data, C.MEC[8].

Equation 21: Adjusted service demand

$$ESD_{eik} = UES_{eik} \times \left(\frac{\sum_k \sum_i UES_{eik} \times ACT_{iy}}{C.MEC_{ey}} \right)_{y=2009}$$

New Variables

ESD_{eik}	is the adjusted energy service demand per sqft for energy type e in territory i for end use k
$C.MEC_{ey}$	is the measured total commercial energy demand for energy type e in year y
ACT_{iy}	is an activity driver, i.e. floor space, for service territory i in year y

[8] In this case we use the total commercial gas usage from the 2014 IEPR, split by end use shares of usage according to CEUS, 2006.

Equation 22: Commercial final energy

$$C.FEC_{ey} = \sum_i \sum_k \sum_m \sum_v ACT_{iy} \times ESD_{iek} \times DCF_{key} \times \frac{MKS_{ikmvey}}{EFF_{kmvey}}$$

New Variables

$C.FEC_{ey}$	is commercial final energy consumption of final energy type e in year y
DCF_{key}	Is the demand change factor (default is 1, or no change) introduced by demand change measures for energy type e within end use k in year y

2.3.1.3 Equipment Measures, Adoption, and market Shares

PATHWAYS reduces commercial CO_2 emissions relative to a reference case through measures that change the composition of equipment in the stock. Users implement commercial measures in PATHWAYS by calibrating equipment-specific adoption curves. Adoption of new equipment leads to changes in market share for a given vintage and type of equipment over time.

In PATHWAYS, turnover of existing stock and new stock growth drive sales of new commercial end use equipment. In the Reference scenario, retiring stock of a given type of equipment is replaced by the same type. In other words, its share of new sales maintains its historical penetration. Users change reference case sales penetrations by choosing the level and approximate timing of saturation for a given type of equipment (e.g., new sales of high efficiency heat pump water heaters saturate at 30% of total new water heater sales in 2030). PATHWAYS allows the user to choose between linear and S-shaped adoption curves. In general, sales penetrations (SPN) for most end uses are based on aggregated S-shaped curves.

Equation 23

$$SPN_{kmvey} = \frac{SAT_{kme}}{1 + \propto^{x}}$$

Equation 23 defines the SPN, where x is a scaling coefficient that shifts the curve over time based on a user defined measure start year and time-to-rapid-growth period (in years). Equation 24 defines the scaling coefficient x, where TRG is calculated in Equation 25.

Equation 24

$$x = \frac{MSY_{kme} + TRG_{kme} - y}{TRG_{kme}}$$

Equation 25

$$TRG_{kme} = \frac{ASY_{kme} - MSY_{kme}}{2}$$

New Variables

SPN_{kmvey}	is the sales penetration of vintage v of equipment type m for end use k using final energy type e in year y
SAT_{kme}	is the saturation level of equipment type m for end use k using final energy type e in a specified year
α	is a generic shape coefficient, which changes the shape of the S-curve
MSY_{kme}	is measure start year for equipment type m for end use k using final energy type e in a specified year
TRG_{kme}	is the time-to-rapid-growth for adoption of equipment type m for end use k using final energy type e in a specified year
ASY_{kme}	is the approximate saturation year for adoption of equipment type m for end use k using final energy type e

Market shares for an equipment vintage in a given year are the initial stock of that vintage, determined by the adoption curve, minus the stock that has turned over and been replaced, divided by the total stock of equipment in that year (e.g., the share of 2020 vintage LEDs in the total stock of lighting equipment in 2025).

Equation 26

$$MKS_{kmvey+1} = \frac{EQP_{vkme} - \sum_{v}^{y} EQP_{vkme} \times \left(1 - \beta_{vy}\right)}{EQP_{ky+1}}$$

New Variables

$MKS_{kmvey+1}$	is the market share of vintage v of equipment type m for end use k using final energy type e in year y+1
EQP_{vkme}	is the stock of equipment adopted of equipment type m for end use k using final energy type e that has vintage v
EQP_{ky}	is the total stock of equipment for end use k in year y+1

If total sales of new equipment exceed sales of user-determined measures (i.e., if the share of measures in new sales is less than 100% in any year), adoption of residual equipment is assumed to match that in the reference case. In cases where adoption may be over-constrained, PATHWAYS normalizes adoption saturation so that the total share of user-determined measures in new sales never exceeds 100% in any year.

Given the large number of potential measures, equipment adoption in PATHWAYS is generally not done by utility service territory. Instead, equipment is allocated through equipment ownership, which is determined by building stock in each service territory.

2.3.2 CO_2 EMISSIONS

PATHWAYS calculates total CO_2 emissions from the commercial sector in each year as the sum product of final energy consumption and a CO_2 emission factor by energy type.

Equation 27

$$C.CO2_y = \sum_e C.FEC_{ey} \times CEF_e$$

Variables

$C.CO2_y$	is commercial CO_2 emissions in year y
CEF_e	CEF_e is a CO_2 emission factor for energy type e, which is time invariant

All CO_2 emission factors for primary energy are based on higher heating value (HHV)-based emission factors used in AEO 2013. CO_2 emission factors for energy carriers are described in a separate section. In cases where electricity sector CO_2 emissions are reported separately from commercial sector emissions, the C.FEC term in the above equation is zeroed out.

2.3.3 ENERGY SYSTEM COSTS

Energy system costs are defined in PATHWAYS as the incremental capital and energy cost of measures. The incremental cost of equipment is measured relative to a reference technology, which is based on the equipment that was adopted in the Reference Case.

2.3.3.1 Capital Costs

PATHWAYS calculates end use capital (equipment and building efficiency) costs by vintage on an annualized ($/yr) basis, where annual commercial equipment costs (C.AQC) are the total commercial equipment cost (C.TQC) multiplied by a capital recovery factor (CRF).

Equation 28

$$C.AQC_{kmv} = C.TQC_{kmv} \times CRF$$

Equation 29

$$CRF = \frac{r}{[1 - (1 + r)^{-EUL_m}]}$$

Variables

$C.AQC_{kmv}$	is the annual commercial equipment cost for vintage v of equipment type m in end use k
$C.TQC_{kmv}$	is the total commercial equipment cost for vintage v of equipment type m in end use k
r	is a time, building type, region, and equipment invariant discount rate
EUL_m	is the expected useful life of equipment type m

PATHWAYS uses a discount rate of 10%, roughly approximating an average pretax return on investment. This discount rate is not intended to be a hurdle rate, and is not used to forecast technology adoption. Rather, it is meant to be a broad reflection of the opportunity cost of capital to firms.

Consistent with the stock roll-over approach to adoption and changes in the equipment stock, PATHWAYS differentiate between the cost of equipment that is replaced at the end of its expected useful life ("natural replacement"), and equipment that is replaced before the end of its useful life ("early replacement"). The incremental cost of equipment that is naturally replaced is the annual cost of that equipment minus the annual cost of equipment used in the Reference scenario.

Equation 30

$$C.IQC_{kmv} = C.AQC_{kmv} - C.AQC'_{kmv}$$

New Variables

C.IQC$_{kmv}$	is the incremental annual commercial equipment cost in end use k
C.AQC$_{kmv}$	is the annual commercial equipment cost for equipment type m that consumes final energy type e in end use k for a given scenario examined in this report
C.AQC'$_{kmv}$	is the annual commercial equipment cost for equipment type m that consumes final energy type e in end use k for the reference case

PATHWAYS calculates total incremental commercial end use equipment costs in year y as the sum of annual incremental costs across vintages, equipment types, and end uses.

Equation 31

$$C.IQC_{y} = \sum_{k}\sum_{m}\sum_{v}^{y} C.IQC_{kmv}$$

New Variables

C.IQC$_{y}$	is the total incremental cost of commercial end use equipment in year y

2.3.3.2 Demand Change Measure costs

For demand change measures, energy efficiency costs are the product of measure-specific reductions in energy service demand and the measure-specific levelized cost of implementation (LC).

Equation 32: Annualized demand change measure costs

$$C.FMC_y = \sum_e \sum_r \sum_k MEI_{krey} \times LC_r$$

New Variables

$C.FMC_y$	Demand change measure costs
MEI_{kmey}	Measure energy impact for measure r with final energy type e for end use k in year y
LC_r	Input levelized costs for measure r

2.3.3.3 Energy Costs

Annual commercial energy costs (C.AEC) in PATHWAYS are calculated by multiplying final energy consumption (C.FEC) by final energy type in each year by a unit energy price (P) in that year and adding the annual demand change measure costs.

Equation 33

$$C.AEC_{ey} = C.FEC_{ey} \times P_{ey} + C.FMC_y$$

New Variables

$C.AEC_{ey}$	is the total annual commercial energy cost for final energy type e in year y
P_{ey}	Is the unit price of final energy type e in year y

Electricity and fuel prices are calculated in the supply side modules, described elsewhere. Incremental annual commercial energy costs are calculated relative to the designated reference scenario.

Equation 34

$$C.IEC_{ey} = C.AEC_{ey} - C.AEC'_{ey}$$

New Variables

$C.IEC_{ey}$	is the total incremental annual commercial energy cost for final energy type e in year y
$C.AEC'_{ey}$	is the total annual commercial energy cost for final energy type e in year y in the reference case

2.4 Transportation

PATHWAYS' Transportation Module is used to project final transportation energy consumption, CO_2 emissions, and end-use equipment costs for the 9 transportation sectors consuming the 7 fuels listed in Table 8 and Table 9, respectively. Table 8 also indicates whether each subsector is modeled using calibrated *stock* turnover, where fuel usage is calculated as the sum of fuels used by the changing vehicle stock providing forecast Vehicle Miles Traveled (VMT), or using California forecasts of *fuel* demand (extended to 2050 using regression where required), with individually specified measures directly altering the trajectory of fuel demand over time. Note that biofuels can be blended into each of the these fuel categories, so biodiesel and renewable diesel can be included in the diesel fuel category, for example. Likewise, ethanol is included in the gasoline fuel category and biogas can appear in the LNG and the CNG categories.

Table 10Table 10 details the fuels used by each vehicle type (for stock subsectors) or subsector.

Table 8. Transportation subsectors

Subsector	Model type
Light duty vehicles (LDV)	Stock
Medium duty vehicles (MDV)	Stock
Heavy duty vehicles (HDV)	Stock
Buses (BU)	Stock
Aviation (AV)	Fuel
Passenger Rail (PR)	Fuel
Freight Rail (FR)	Fuel
Ocean Going (OG)	Fuel
Harbor Craft (HC)	Fuel

Table 9. Transportation fuels

Fuels
Electricity
Gasoline
Diesel
Liquefied Pipeline Gas (LNG)
Compressed Pipeline Gas (CNG)
Hydrogen
Kerosene-Jet Fuel

Note that biofuels can be blended into each of the these fuel categories, so biodiesel and renewable diesel can be included in the diesel fuel category, for example. Likewise, ethanol is included in the gasoline fuel category and biogas can appear in the LNG and the CNG categories.

Table 10. Fuel Use by Vehicle Type

Vehicle Type	Name	Fuel(s)
Light duty auto	Reference Gasoline LDV	Gasoline

Vehicle Type	Name	Fuel(s)
Light duty auto	SP Gasoline LDV	Gasoline
Light duty auto	PHEV25	Electricity, Gasoline
Light duty auto	SP PHEV25	Electricity, Gasoline
Light duty auto	BEV	Electricity
Light duty auto	Hydrogen Fuel Cell	Hydrogen
Light duty truck	Reference Gasoline LDV	Gasoline
Light duty truck	SP Gasoline LDV	Gasoline
Light duty truck	PHEV25	Electricity, Gasoline
Light duty truck	SP PHEV25	Electricity, Gasoline
Light duty truck	BEV	Electricity
Light duty truck	Hydrogen Fuel Cell	Hydrogen
Motorcycle	Reference Gasoline LDV	Gasoline
Medium duty	Reference MDV-Gasoline	Gasoline
Medium duty	SP MDV Gasoline	Gasoline
Medium duty	Reference MDV-Diesel	Diesel
Medium duty	SP MDV Diesel	Diesel
Medium duty	SP MDV CNG	Compressed Pipeline Gas (CNG)
Medium duty	SP MDV Battery Electric	Electricity
Medium duty	SP MDV Hydrogen FC	Hydrogen
Heavy Duty	Reference Diesel HDV	Diesel
Heavy Duty	SP HDV Diesel	Diesel
Heavy Duty	Reference CNG HDV	Compressed Pipeline Gas (CNG)
Heavy Duty	SP HDV CNG	Compressed Pipeline Gas (CNG)
Heavy Duty	SP HDV Battery Electric	Electricity
Heavy Duty	SP HDV Hydrogen FCV	Hydrogen
Bus	Gasoline Bus	Gasoline
Bus	Diesel Bus	Diesel
Bus	CNG Bus	Compressed Pipeline Gas (CNG)
Bus	BEV Bus	Electricity
Aviation	N/A	Kerosene (Jet Fuel)
Ocean Going	N/A	Diesel, Electricity (In port)
Harbor Craft	N/A	Diesel, Electricity
Passenger Rail	N/A	Electricity, Diesel

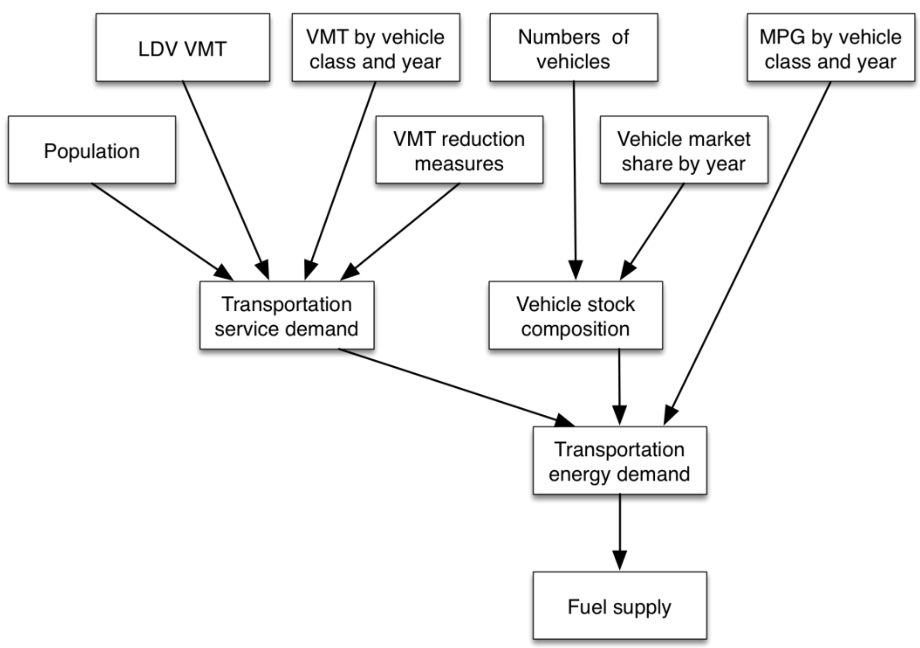
Vehicle Type	Name	Fuel(s)
Freight Rail	N/A	Electricity, Diesel

2.4.1 MODEL SUMMARY

Based on the character of best available data, the Transportation Module uses a mixture of stock accounting (for on-road vehicles) and regression-extended state forecasts of fuel consumption (for off-road vehicles).

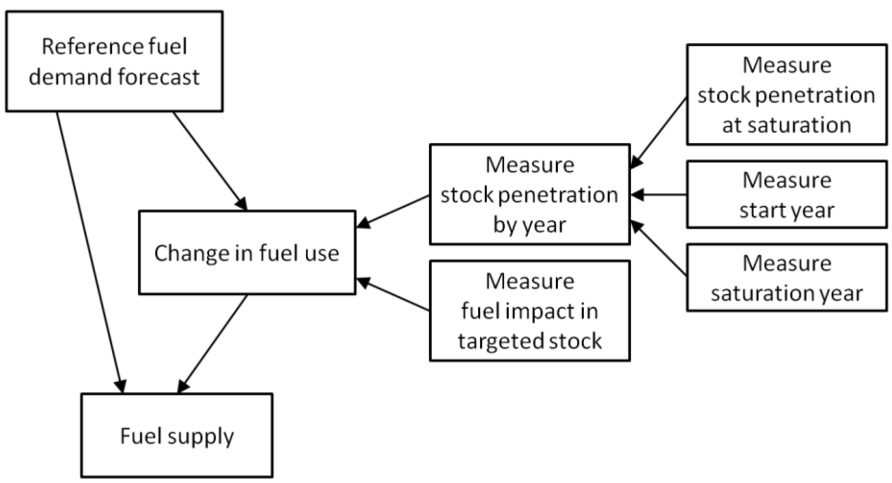
For stock sub-sectors, (i.e. LDVs, MDVs, HDVs, and Buses), transportation service demand (i.e. VMT) and total vehicle counts are based on linear extrapolation out to 2050 of CARB EMFAC 2014 data. The drivers of transportation fuel demand in stock sectors are illustrated in Figure 5 using LDVs as an example.

Figure 5. Drivers of transportation fuel use for stock modeled sub-sectors, using light duty vehicles for illustration.



For fuel-only sectors, i.e. passenger rail, freight rail, harbor craft, oceangoing vehicles, and aviation, reference fuel consumption is based on a linear fit of forecasts from the CARB VISION off-road model. The drivers of fuel demand in fuel-only sub-sectors are illustrated in Figure 6.

Figure 6: Drivers of transportation fuel use for fuel modeled sub-sectors.



2.4.2 MEASURES

Measures specify the timing and magnitude of deviations from the reference case caused by mitigation efforts over time. The stock modeled sub-sectors of the Transportation Module capture changing market share, roll-over (retirement), and replacement of vehicles over time. Stock growth and replacement — new stock — provides an opportunity for vehicle efficiency improvements and fuel switching. Users reduce transportation CO_2 emissions in PATHWAYS by implementing measures that reduce VMT or change the characteristics of the deployed vehicle stock over time.

The fuel-only sub-sectors of the Transportation Module use CA forecasts of fuel demand, extrapolated to 2050 using linear regression. For these sub-sectors, users implement aggregate energy efficiency and fuel switching measures that lead directly to percentage changes in the amount and type of fuels consumed by the vehicles in a particular subsector. These measures directly modify the reference forecast of transportation fuel demand. In the fuel-only subsectors, rates of measure roll outs are constrained to reflect expected stock lifetimes.

There are three types of measures that impact different drivers of emissions in the Transportation Module.

1. **Service demand change measures** reduce VMT for specific stock modeled vehicle types. Measures of this type are used to model actions that reduce driving, for example, Smart Growth and transit oriented development can reduce VMT in cars.
2. **Stock measures** change the relative portion of each vehicle type (i.e. plug-in hybrids (PHEVs), fuel cell vehicles (FCVs), battery electric vehicles (BEVs), more efficient internal combustion vehicles (ICEs), etc.) sold from one year to the next. Measures of this type are used to model the timing and magnitude of market adoption of new technologies and vehicle types, like PHEVs and BEVs and market declines of older vehicle technologies, like conventional ICEs.
3. **Aggregate measures** directly reduce demand for specific fuels in fuel-based sub-sectors. Measures of this type are used to model the fuel impacts of market adoption of vehicle technologies, (e.g. electric light rail, fuel switching, powering ships with electricity while in port, and operational changes, flying fewer but larger planes or slow steaming in

shipping). Typically the percentage change in fuels specified in aggregate measures are based on side calculations using the best available information on potential savings.

2.4.3 TRANSPORTATION STOCK ACCOUNTING FOR ON-ROAD VEHICLES

2.4.3.1 Stock Final Energy Consumption

PATHWAYS calculates transportation stock final energy consumption (T.SEC) of different final energy types in each year as the product of two main terms: (1) district-, vehicle-type-, and vintage-specific VMT and (2) vehicle fuel economy that is weighted by the market share for a given vintage of a given type of equipment in a district (e.g., the share of 2020 vintage battery electric vehicles in the total number of vehicles in the SCAQMD district in 2025).

Equation 35

$$T.SEC_{ey} = \sum_{i}\sum_{k}\sum_{m}\sum_{v} ACT_{imy} \times ESD_{mvy} \times \frac{MKS_{imvey}}{EFF_{mvey}}$$

New Subscripts

e	final fuel type	electricity, gasoline, diesel, liquefied pipeline gas (LNG), compressed pipeline gas (CNG), hydrogen
y	year	model year (2010 to 2050)
i	air quality district	SJVAPCD, SCAQMD, Other
k	vehicle category	LDV, MDV, HDV, Buses
m	vehicle sub-category	vehicle sub-categories (i.e. auto, truck, motorcycle in LDV)
v	vintage	vehicle vintage (1950 to year y)

New Variables

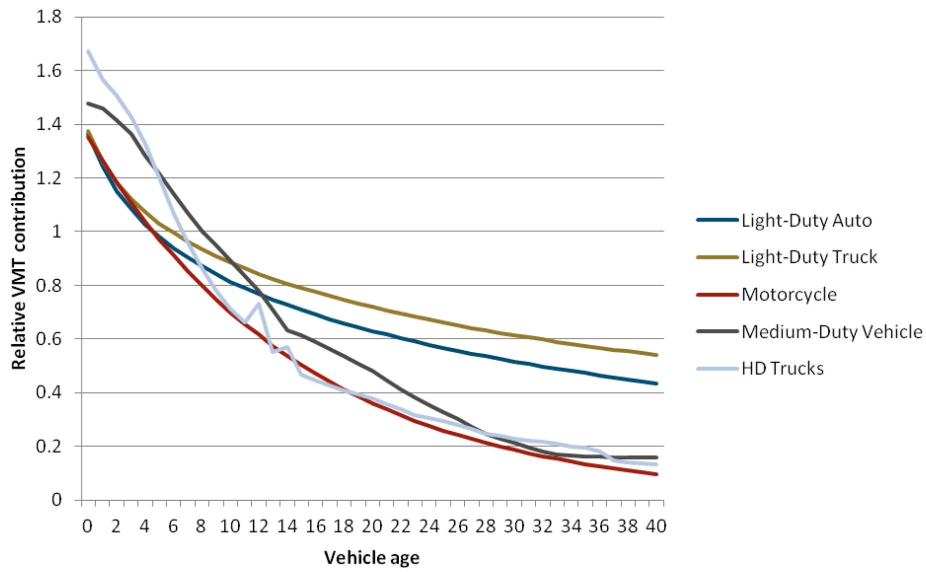
$T.SEC_{ey}$	is transportation stock final energy consumption of final fuel type e in year y
ACT_{imvy}	is VMT per vehicle sub-category m per vintage v per air quality district i in year y
ESD_{iky}	is vehicle fuel economy per vehicle sub-category m per vintage v in year y
MKS_{imvey}	is the market share for vintage v of vehicle sub-category m consuming fuel type e in air quality district i in year y
EFF_{mvey}	is the energy efficiency of vintage v of vehicle sub-category m consuming final fuel type e in year y

2.4.3.2 Service Demand

The Transportation Sector Module's units of service demand are Vehicle Miles Traveled (VMT), segmented by air quality district, vehicle sub-type, and vehicle age.[9] The default VMT trajectories are based on the CARB Vision model.[10]

Figure 7 illustrates the impact vehicle age has on VMT by vehicle sub-type - the basic relationship is that the older a vehicle is, the less it is assumed to be driven.

Figure 7: Relative VMT contribution from vehicles of different ages for different vehicle sub-types



2.4.3.3 Vehicle Counts

Total vehicle counts by air quality district and vehicle sub-category are based on the CARB EMFAC 2014 forecast, with a linear extrapolation from 2035 to 2050. We project future vehicle types using the stock roll-over approach described in Sections 2.1, which defaults to replacing retiring vehicles with new vehicles of the same fuel type, but allows for changes in vehicle fuel type, fuel economy, costs, and vintage over time.

Equation 36: total vehicle counts

$$TV_{ijy+1} = \sum_{v}^{y} TV_{vijy} \times (1 - \beta_{vy}) + (TV_{vijy} \times \beta_{vy} + NV_{ijy+1}) \times \theta_{ijy}$$

New Variables

TV_{ijy+1}	is the number of vehicles of type j in air quality district i in year y+1
TV_{vijy}	is the number of vehicles of vintage v and type j in air quality district i in year y
NV_{ijy}	is the number of new vehicles of type j in air quality district i in year y+1
θ_{ijy}	is the share of vehicle type j in total vehicles in year y

The replacement coefficients (β) are based on an expected lifetimes for vehicles, where "lifetime" is more precisely defined as the mean time before retirement, or λ in the Poisson distribution used to determine retirement fractions.

2.4.3.4 Vehicle Measures, Adoption, and Market Shares

PATHWAYS reduces stock transportation CO_2 emissions relative to a reference case through measures that change the composition of new vehicles. Users implement transportation stock measures in PATHWAYS by selecting vehicle-specific adoption curves. Adoption of new vehicles leads to changes in market share for a given vintage and type of vehicle over time.

In PATHWAYS, turnover of existing stock and new stock growth drive sales of new vehicles. In the reference case, sales penetration for a given type of vehicle — its share of new sales — is based on the reference case. Users change reference case sales penetrations by choosing the level and approximate timing of saturation for a given type of vehicle (e.g., new sales of battery electric autos saturate at 30% of total new auto sales in 2030). PATHWAYS allows the user to choose between linear and S-shaped adoption curves. In the main scenarios, sales penetrations (SPN) for most vehicle types are based on aggregated S-shaped curves

Equation 37

$$SPN_{mvey} = \frac{SAT_{me}}{1 + \propto^{x}}$$

where x is a scaling coefficient that shifts the curve over time based on a user defined measure start year and time-to-rapid-growth (TRG) period (in years).

Equation 38

$$x = \frac{MSY_{me} + TRG_{me} - y}{TRG_{me}}$$

and TRG is calculated as

Equation 39

$$TRG_{me} = \frac{ASY_{me} - MSY_{me}}{2}$$

New Variables

SPN_{mvey}	is the sales penetration of vintage v of vehicle type m using final energy type e in year y
SAT_{me}	is the saturation level of vehicle type m using final energy type e
α	is a generic shape coefficient, which changes the shape of the S-curve
MSY_{me}	is the measure start year for vehicle type m using final energy type e in a specified year
TRG_{me}	is the time-to-rapid-growth for adoption of vehicle type m using final energy type e in a specified year
ASY_{me}	is the approximate saturation year for adoption of vehicle type m using final energy type e

Market shares for a vehicle of a specific vintage in a given year are the initial stock of that vintage (determined by the adoption curve) minus the stock that has turned over and been replaced, divided by the total stock of vehicles in that year (e.g., the share of 2020 vintage battery electric autos in the total stock of autos in 2025).

Equation 40

$$MKS_{mvey+1} = \frac{EQP_{vme} - \sum_{v}^{y} EQP_{vme} \times \left(1 - \beta_{vy}\right)}{EQP_{y+1}}$$

New Variables

MKS_{mvey+1}	is the market share of vintage v of vehicle type m using final energy type e in year y+1
EQP_{vme}	is the stock of vehicles adopted of vehicle type m using final energy type e with vintage v
EQP_{y+1}	is the total stock of vehicles in year y+1

If total sales of new vehicles exceed sales of user-determined measures (i.e., if the share of measures in new sales is less than 100% in any year), adoption of residual vehicles is assumed to match that in the reference case. In cases where adoption may be over-constrained, PATHWAYS normalizes adoption saturation so that the total share of user-determined measures in new sales never exceeds 100% in any year.

Given the large number of potential measures, vehicle adoption in PATHWAYS is generally not done by air quality district. Instead, vehicles are regionalized through equipment ownership, which is determined separately for each district. This assumption is consistent with state-wide policies, and is important for understanding the district-level results.

2.4.4 TRANSPORTATION FUEL-ONLY SUB-SECTOR ACCOUNTING

The Transportation Module includes fuel-only accounting of energy use for off-road vehicles (aviation, passenger rail, freight rail, oceangoing vessels, harbor craft) where fuel use forecasts provide the best available data. For these subsectors, the default fuel consumption data is pulled from the CARB VISION model, with a linear extrapolation to 2050 performed via regression models.

2.4.4.1 Fuel-only Measures

In fuel-only sub-sectors, scenarios alter reference trajectories for transportation fuel consumption using measures that directly alter transportation fuel consumption. Within each sub-sector, fuel-only measures consist of several attributes, which are detailed in Table 11.

Table 11: Attributes of fuel-only "aggregate" measures

Attribute	Description
Impacted Stock	The fraction of stock impacted by the measure in the saturation year
Replacement Fuel	The fuel used after the measure
Impacted Fuel	The fuel impacted by the measure
EE Improvement	The fraction of reference scenario fuel use eliminated within the impacted stock
Start Year	The year when the first impacts of the measure are first achieved
Saturation Year	The year when the measure impacts reach their full potential
Levelized Cost	The cost of the measure levelized across energy saved in $/Demand Unit

Between the start year and the saturation year, measure impacts follow a linear ramp until they save the full EE Improvement for the full impacted stock. If the impacted fuel and replacement fuels are the same, then the aggregate measure changes the consumption of that single fuel, as would be expected for either service demand (VMT) or vehicle efficiency (VMT/fuel) changes.

Equation 41: Fraction of stock impacted

$$FSI_{jmey} = max\left(min\left(\frac{y_{sat} - y}{y_{sat} - y_{start}}, 1\right), 0\right) \times SF_{jme}$$

New Variables

FSI_{jmey}	fraction of stock impacted per measure m per vehicle type j per fuel type e in year y
y_{sat}	saturation year
y_{start}	measure start year
SF_{jme}	"stock fraction" by measure m per vehicle type j per fuel type e in the saturation year
ECI_{jme}	fractional energy change in impacted stock (aka EE Improvement) per measure m per vehicle type j per fuel type e

Note that the saturation calculation is forced by the *max* and *min* functions to fall within limits of 0 and 1, representing the period prior to implementation and the period after complete saturation, respectively.

2.4.4.1.1 Energy Efficiency and Fuel Switching

Before the fuel energy change associated with efficiency can be calculated, fuel switching must be accounted for. The fuel energy impacted, FEI, is the energy consumption impacted by a given measure and is subtracted from the impacted fuel and added to the replacement fuel. Thus it has no impact when the impacted and replacement fuels are the same.

Equation 42: Fuel switched

$$FEI_{jmey} = \sum_{i} FSI_{jmey} \times REF_{ijey} \times EF_{jme}$$

New Variables

FEI_{jmey}	fuel energy impacted per measure m per vehicle type j per fuel type e in year y
REF_{ijey}	Reference energy consumption per vehicle type j per fuel type e per service territory i in year y
EF_{jme}	"energy fraction" altered per measure m per vehicle type j per fuel type e in the saturation year

The "fuel energy replaced" (**FER**) is the "fuel energy impacted" (**FEI**) adjusted for any efficiency change described by the measure.

Equation 43: Replaced fuel energy

$$FER_{jmey} = \sum_{i} FEI_{jmey} \times (1 - EEI_{jme})$$

New Variables

FER_{mefy}	replaced fuel energy per measure m per vehicle type j per fuel type e in year y
EEI_{mef}	energy efficiency improvement per measure m per fuel type e per vehicle type j

Equation 44: Fuel-only transportation energy

$$T.FEC_{ey} = \sum_{j}\left(\sum_{i} REF_{ijey} + \sum_{m} -FEI_{jmey} + FER_{jmey}\right)$$

New Variables

$T.FEC_{ey}$	Fuel-only energy consumption for fuel type e in year y

2.4.5 CO_2 EMISSIONS

We calculate total CO_2 emissions from the transportation sector in each year as the sum product of final energy consumption (itself the sum of final stock energy consumption from on-road vehicles and final fuel energy consumption from off-road vehicles) and a CO_2 emission factor.

Equation 45: Transportation CO_2 emissions

$$T.CO2_{y} = \sum_{e}\left((T.SEC_{ey} + T.FEC_{ey}) \times CEF_{ey}\right)$$

Variables

$T.CO2_y$	is transportation CO_2 emissions in year y
$T.SEC_{ey}$	is the final stock energy (i.e. on-road) for energy type e in year y
$T.FEC_{ey}$	is the final fuel-only energy (i.e. off-road) for energy type e in year y
CEF_{ey}	CEF_{ey} is a CO_2 emission factor for energy type e, which can vary by year for energy carriers, like pipeline gas.

All CO_2 emission factors for primary energy are based on higher heating value (HHV)-based emission factors used in AEO 2013. CO_2 emission factors for energy carriers are calculated and described in the Energy Supply sections.

2.4.6 ENERGY SYSTEM COSTS

Energy system costs are defined in PATHWAYS as the incremental capital and energy cost of measures. The incremental cost of measures is measured relative to a reference technology, which is based on vehicles that were adopted (stock), measure implementation costs (fuels only), and fuels consumed in the reference case.

2.4.6.1 Capital Costs

PATHWAYS calculates end use capital (vehicle efficiency) costs by vintage on an annualized ($/yr) basis, where annual transportation vehicle costs (T.AQC) are the total transportation vehicle cost (T.TQC) multiplied by a capital recovery factor (CRF) plus the annualized costs of non-stock measures (T.AMC).

Equation 46: Annual vehicle costs

$$T.AQC_{mv} = T.TQC_{mv} \times CRF$$

Equation 47: Capital recovery factor

$$CRF = \frac{r}{[1-(1+r)^{-EUL_m}]}$$

Variables

$T.AQC_{mv}$	is the annual vehicle cost for vintage v of vehicle type m
$T.TQC_{mv}$	is the total vehicle cost for vintage v of vehicle type m
r	is a time, vehicle type, district invariant discount rate
EUL_m	is the expected useful life of vehicle type m

PATHWAYS uses a discount rate of 10%, approximating the historical average of real credit card interest rates.[11] This discount rate is not intended to be a hurdle rate, and is not used to forecast technology adoption. Rather, it is meant to be a broad reflection of the opportunity cost of capital to vehicle owners.

Consistent with our stock roll-over approach to adoption and changes in the vehicle stock, we differentiate between the cost of vehicles that are replaced at the end of their expected useful life ("natural replacement"), and vehicles that are replaced before the end of their useful life ("early replacement"). The incremental cost of vehicles that are naturally replaced is the annual cost of the vehicles minus the annual cost of vehicles used in the reference case.

[11] From, 1974 to 2011, the CPI-adjusted annual average rate was 11.4%. Real rates are calculated as $r^R = \frac{(1+r^N)}{(1+i)} - 1$, where i is a rate of consumer inflation based on the CPI. Nominal credit card interest rates are from Board of Governors of the Federal Reserve System, "Report to the Congress on the Profitability of Credit Card Operations of Depository Institutions," June 2012, http://www.federalreserve.gov/publications/other-reports/credit-card-profitability-2012-recent-trends-in-credit-card-pricing.htm. Historical CPI data are from Bureau of Labor Statistics, "CPI Detailed Report Tables," June 2014, http://www.bls.gov/cpi/cpid1406.pdf.

Equation 48: Incremental equipment costs

$$T.IQC_{mv} = T.AQC_{mv} - T.AQC'_{mv}$$

New Variables

$T.IQC_{mv}$	is the incremental annual transportation vehicle equipment cost for vehicle type m
$T.AQC_{mv}$	is the annual cost for vehicle type m that consumes final energy type e for a given scenario examined in this report
$T.AQC'_{mv}$	is the annual vehicle cost for vehicle type m that consumes final energy type e for the reference case

For vehicles, early replacement measures are assessed the full technology cost and do not include any salvage value. We calculate total incremental transportation vehicle costs in year y as the sum of annual incremental costs across vintages and vehicle types.

Equation 49: Total incremental cost of vehicles

$$T.IQC_y = T.AMC_y + \sum_m \sum_v^y T.IQC_{mv}$$

New Variables

$T.IQC_y$	is the total incremental cost of vehicles in year y
$T.AMC_y$	is the annual measure implementation cost for non-stock measures

2.4.6.2 Fuel-Only Measure Costs

For fuel-only (i.e., non-fuel switching) measures, energy efficiency costs are the product of measure-specific reductions in final energy and the measure-specific levelized cost of implementation (LC).

Equation 50: Annualized fuel-only measure costs

$$T.FMC_y = \sum_e \sum_m \left(\sum_j FEI_{jmey} \times LC_m \right)$$

New Variables

T.FMC$_y$	Fuel-only aggregate measure costs in year y
LEC$_m$	Input levelized costs for measure m

2.4.6.3 Energy Costs

Annual transportation energy costs (T.AEC) in PATHWAYS are calculated by multiplying final energy consumption for each final energy type in each year ($T.SEC_{ey}$+$T.FEC_{ey}$) by a unit energy price (P) in that year.

Equation 51: Annual energy costs

$$T.AEC_{ey} = (T.SEC_{ey} + T.FEC_{ey}) \times P_{ey}$$

New Variables

T.AEC$_{ey}$	is the total annual transportation energy cost for final energy type e in year y
P$_{ey}$	Is the unit price of final energy type e in year y

Electricity prices are calculated through the Electricity Sector Module, described in the Electricity section. Non-electricity (e.g., pipeline gas) prices are calculated in supply side fuels module and received by the Transportation module as inputs. Incremental annual transportation energy costs are calculated relative to the designated reference scenario.

Equation 52: Incremental energy costs

$$T.IEC_{ey} = T.AEC_{ey} - T.AEC'_{ey}$$

New Variables

$T.IEC_{ey}$	is the total incremental annual transportation energy cost for final energy type e in year y
$T.AEC'_{ey}$	is the total annual transportation energy cost for final energy type e in year y in the reference case

2.4.6.4 Total Annual Costs

Total annual transportation costs are the sum of levelized incremental equipment costs (on-road), levelized measure costs (off-road), and incremental fuel costs.

Equation 53. Total annual costs

$$T.AIC_y = T.IQC_y + T.FMC_y + \sum_e T.IEC_{ey}$$

New Variables

$T.AIC_y$	is the transportation annual incremental costs for a scenario in year y

2.4.7 VEHICLE CLASS MAPPING BETWEEN EMFAC AND PATHWAYS

Table 12 below shows the mapping of EMFAC to PATHWAYS vehicle classes. LDVs include Light-Duty Autos (LDA), Light-Duty Trucks (LDT), and Motorcycles (MCY).

Table 12: Vehicle class mapping between EMFAC and PATHWAYS

EMFAC Vehicle & Technology type	PATHWAYS Vehicle Class
LDA - DSL	LDA
LDA - GAS	LDA
LDT1 - DSL	LDT
LDT1 - GAS	LDT
LDT2 - DSL	LDT
LDT2 - GAS	LDT
LHD1 - DSL	MDV
LHD1 - GAS	MDV
LHD2 - DSL	MDV
LHD2 - GAS	MDV
MCY - GAS	MCY
MDV - DSL	LDT
MDV - GAS	LDT
T6 Ag - DSL	MDV
T6 CAIRP heavy - DSL	MDV
T6 CAIRP small - DSL	MDV
T6 instate construction heavy - DSL	MDV
T6 instate construction small - DSL	MDV
T6 instate heavy - DSL	MDV
T6 instate small - DSL	MDV
T6 OOS heavy - DSL	MDV
T6 OOS small - DSL	MDV
T6 Public - DSL	MDV
T6 utility - DSL	MDV
T6TS - GAS	MDV
T7 Ag - DSL	HDV
T7 CAIRP - DSL	HDV
T7 CAIRP construction - DSL	HDV
T7 NNOOS - DSL	HDV

T7 NOOS - DSL	HDV
T7 other port - DSL	HDV
T7 POAK - DSL	HDV
T7 POLA - DSL	HDV
T7 Public - DSL	HDV
T7 Single - DSL	HDV
T7 single construction - DSL	HDV
T7 SWCV - DSL	HDV
T7 tractor - DSL	HDV
T7 tractor construction - DSL	HDV
T7 utility - DSL	HDV
T7IS - GAS	HDV
PTO - DSL	HDV
SBUS - DSL	BUS
SBUS - GAS	BUS
UBUS - DSL	BUS
UBUS - GAS	BUS
Motor Coach - DSL	BUS
OBUS - GAS	BUS
All Other Buses - DSL	BUS

2.5 Industry & Other

PATHWAYS' Industrial Module (IND) is used to project industrial manufacturing final energy consumption, CO2 emissions, and measure implementation costs for the 26 sectors, 7 End-uses, and 5 fuels listed in Table 13, Table 14, and

Table 15. Energy accounting in the Industrial Module is performed through fuel use projections for each end use in each subsector, with emissions calculated based on the fuels consumed. Note that non-manufacturing industrial activities, like oil and gas exploration, oil refining, agriculture, and TCU each have their own modules and are documented separately.

Table 13. Industrial subsectors

Subsectors	
Apparel & Leather	Mining
Cement	Nonmetallic Mineral
Chemical Manufacturing	Paper
Computer and Electronic	Plastics and Rubber
Construction	Primary Metal
Electrical Equipment & Appliance	Printing
Fabricated Metal	Publishing
Food & Beverage	Pulp & Paperboard Mills
Food Processing	Semiconductor
Furniture	Textile Mills
Glass	Textile Product Mills
Logging & Wood	Transportation Equipment
Machinery	Miscellaneous

Table 14: Industrial End-Uses

Industrial End Uses
Conventional Boiler Use
Lighting
HVAC
Machine Drive
Process Heating
Process Cooling & Refrigeration
Other

Table 15. Industrial fuels

Fuels
Electricity
Pipeline Gas
Waste Heat
Diesel
Gasoline

The Industrial Module does not use a detailed stock roll-over mechanism through which users implement measures. Instead, users implement energy efficiency and fuel switching measures that directly lead to percentage changes in the amount and type of energy consumed by specific end uses, spanning all relevant subsectors. Measure penetrations used in scenarios are intended to be exogenously constrained by a high-level understanding of constraints on the depth or speed of deployment.

This section describes methods for calculating final energy consumption (Section 2.5.1), CO_2 emissions (Section 2.5.2), and energy system costs (Section 2.5.3) in the Industrial Module.

2.5.1 FINAL ENERGY CONSUMPTION

Industrial electricity and natural gas use in PATHWAYS is based on linear extrapolation of the CEC industrial energy use forecasts (2012-2024) made in support of the CALEB 2010 report[12]. CALEB forecasts for these fuels are available for each of the industrial sub-sectors found in PATHWAYS. Industrial diesel

[12] http://uc-ciee.org/downloads/CALEB.Can.pdf

consumption in PATHWAYS is then calibrated to match the ARB emissions inventory in 2014. To complete baseline forecasts, linear regression is used to extend electricity, natural gas, and diesel consumption volumes out to 2050. Emissions inventory records show minimal gasoline usage in manufacturing categories, so baseline gasoline usage is set to zero. Next, subsector fuel use is allocated across end uses using percentages drawn from the CPUC Navigant Potential Study, 2013[13]. Finally, natural gas and waste heat modifiers from the industrial calculations of the CHP supply module, i.e. waste heat production based on installed CHP capacity and thermal supply parameters in CA according to the DOE and ICF[14], are added to industrial energy use (note: net CHP natural gas use can be negative), split across sub-sectors and end uses proportional to their heating natural gas usage. In the official list of fuels, natural gas is designated as pipeline gas to reflect the possibility that low carbon synthetic and bio-derived gases could be blended with natural gas in the future.

[13] http://www.cpuc.ca.gov/General.aspx?id=2013

[14] http://www.eea-inc.com/chpdata/States/CA.html

Equation 54: Reference energy forecast for industrial energy consumption

$$REF_{jefy} = \left((FC.D_{jy} + FC.E_{fy} + FC.NG_{fy}) \times ES_{jef} + CHP_{jefy}\right)$$

New Subscripts

f	fuel type	electricity, pipeline gas, waste heat, diesel, gasoline
y	year	Year of energy use
J	subsector	26 subsectors in Table 13
e	end use	7 end uses in Table 14

New Variables

$FC.D_{jy}$	Forecast of diesel usage for subsector j and year y; fuel type f is implied
$FC.E_{jfy}$	Forecast of electricity usage for subsector j and year y; fuel type f is implied
$FC.NG_{jfy}$	Forecast of natural gas usage for subsector j and year y; fuel type f is implied
ES_{jef}	Energy share breakdown by subsector j, end use e, and fuel type f
CHP_{jefy}	CHP waste heat and fuel use for subsector j, end use e, fuel type f, in year y
REF_{jefy}	Reference industrial energy forecast for subsector j, end use e, fuel type f, in year

2.5.1.1 Energy impacted by measures

Equation 55: Fraction of "impacted fuel" energy altered by measures

$$FIF_{mefy} = max\left(min\left(\frac{y_{sat} - y}{y_{sat} - y_{start}}, 1\right), 0\right) \times SF_{mef}$$

New Variables

FIF_{mefy}	fraction of "impacted fuel" altered per measure m, end use e, and fuel type f in year y
y_{sat}	saturation year
y_{start}	measure start year
SF_{mef}	"stock fraction" altered per measure m, end use e, and fuel type f in the saturation year

Note that the impacted fuel calculation is forced by the *max* and *min* functions to fall within limits of 0 and 1, representing the period prior to implementation and the period after complete saturation, respectively.

2.5.1.2 Energy Efficiency and Fuel Switching

Before the fuel energy change associated with efficiency can be calculated, fuel switching must be accounted for. The fuel energy impacted, FEI, is the energy consumption impacted by a given measure and is subtracted from the impacted fuel type and added to the replacement fuel type. Thus it has no impact when the impacted and replacement fuels are the same.

Equation 56: Fuel energy switched away from impacted fuel

$$FEI_{mefy} = \sum_{j} REF_{jefy} \times FIF_{mefy} \times EF_{mef}$$

New Variables

FEI_{mefy}	impacted fuel energy switched per measure m, end use e, and fuel type f in year y
EF_{mef}	"energy fraction" altered per measure m, end use e, and fuel type f in the saturation year

The "fuel energy replaced" (FER) is the "fuel energy impacted" (FEI) adjusted for any efficiency change described by the measure.

Equation 57: Replaced fuel energy

$$FER_{mefy} = \sum_{i} FEI_{mefy} \times (1 - EEI_{mef})$$

New Variables

FER_{mefy}	replaced fuel energy per measure m, end use e, and replacement fuel f in year y
EEI_{mef}	energy efficiency improvement per measure m, end use e, and replacement fuel f

Equation 58: Final industrial energy

$$I.FEC_{fy} = \sum_{e} \left(\sum_{j} REF_{jefy} + \sum_{m} -FEI_{mefy} + FER_{mefy} \right)$$

New Variables

$I.FEC_{fy}$	industrial final energy consumption of fuel type f in year y

2.5.2 CO_2 EMISSIONS

CO2 emissions from the industrial sector are composed of the final energy demand multiplied by the delivered fuel emissions rates. Emission rates vary over time and are determined in the fuels modules of the model because the content of pipeline gas, delivered electricity, and liquid fuels can be reduced through investments in decarbonizing supply side energy.

Equation 59

$$I.CO2_y = \sum_e I.FEC_{fy} \times CEF_{fy}$$

New Variables

$I.CO2_y$	total industrial CO_2 emissions in year y
CEF_{fy}	net CO_2 emission factor for fuel type f in year y

Gross and net CO_2 emissions factors are only different for biomass, where the net CO_2 emission factor is assumed to be zero.

2.5.3 ENERGY SYSTEM COSTS

Energy system costs are defined in PATHWAYS as the incremental capital and energy cost of measures. We apply costs on a levelized ($ per energy) basis to the impacted energy across both energy efficiency and fuel switching.

Equation 60: efficiency and fuel switching costs

$$EEC_y = \sum_m \sum_e \sum_f FEI_{mefy} \times LEC_m$$

New Variables

EEC_y	annualized energy efficiency measure costs in year y
LEC_m	levelized energy efficiency or fuel switching costs for measure m

2.5.4 REFINING

The Refining (REF) module captures energy used in the refining of oil into fuels and other products. Refining Coke, Process Gas, and LPG usage data, spanning 2000 to 2011, come from the CARB GHG Emissions Inventory. Pipeline Gas usage data comes from CEC's 2010 CALEB and spans 2012 to 2024. All of these fuels are allocated to gas utility service territories proportional to refinery electricity demand (broken out by electric service territory). Electricity usage data comes from the CEC's 2009 Energy Demand Forecast, and span 1990 to 2020. Fuels are extrapolated out to 2050 using linear regression and then split across end uses using energy share data from the 2013 CPUC Navigant Potential Study. End uses include Conventional Boiler Use, Lighting, HVAC, Machine Drive, Process Heating, Process Cooling & Refrigeration, and Other. Process heating is the biggest energy end use in refining by an order of magnitude and is met primarily by Process Gas and Pipeline Gas. Waste Heat and Pipeline Gas usage from REF-sited CHP (calculated in the CHP module) are added in to complete the reference case energy usage for REF with Electricity, Pipeline Gas, Coke, Process Gas, LPG, and Waste Heat as fuels.

REF Measures directly reduce energy by an amount based on a stock impact fraction multiplied by end use improvement ratio, ramped in a linear fashion from 0-100% between the measure start and saturation years. With selections for impacted and replacement fuel categories, measure inputs allow fuel switching as well as within-fuel efficiency.

REF Demand Change Measures reduce demand for all refining activity based on a demand change fraction. Year by year reductions are calculated along a linear ramp from zero in 2015 to the year in which the demand change reaches 100% of its potential, typically set to 2050.

2.5.5 OIL AND GAS

The Oil and Gas Extraction (OGE) module captures energy used in the extraction of oil and gas, which is dominated by Pipeline Gas. Pipeline Gas inputs are from CEC's 2010 CALEB model[15] and span 2012 to 2024. Electricity inputs are from the CEC's 2009 2010-2020 Energy Demand Forecast, and span 1990 to 2020. Both fuels are extrapolated out to 2050 using linear regression. Waste Heat and Pipeline Gas usage from OGE-sited CHP (calculated in the CHP module) are added in to complete the reference case energy usage for OGE with Electricity, Pipeline Gas, and Waste Heat fuels.

OGE Measures directly reduce energy by an amount based on a stock impact fraction multiplied by end use improvement ratio, ramped in a linear fashion from 0-100% between the measure start and saturation years. With selections for impacted and replacement fuel categories, measure inputs allow fuel switching as well as within-fuel efficiency.

OGE Demand Change Measures reduce demand for all oil and gas extraction activity based on a demand change fraction. Year by year reductions are calculated along a linear ramp from zero in 2015 to the year in which the demand change reaches 100% of its potential. An important question for the future of OGE is

[15] California Energy Balance Update and Decomposition Analysis for the Industry and Building Sectors http://uc-ciee.org/downloads/CALEB.Can.pdf

whether in-state reductions in oil and gas will lead to decreases in in-state extraction.

2.5.6 TRANSPORTATION COMMUNCIATIONS AND UTILITIES

Transportation Communications and Utilities (TCU) energy supports public infrastructure, like street lighting and waste treatment facilities. Street lighting is so prominent that the TCU sub-categories are "Street lighting" and "TCU Unspecified". Although dominated by Electricity, fuels also include Pipeline Gas, with inputs for both ranging from 1990 to 2024 from the IEPR 2014 Demand Forecast, Mid-Case. These are extrapolated out to 2050 using linear regression. Waste Heat and Pipeline Gas usage from TCU-sited CHP (calculated in the CHP module) are added in to complete the reference case energy usage for TCU with Electricity, Pipeline Gas, and Waste Heat fuels.

TCU measures directly reduce energy by an amount based on a stock impact fraction multiplied by end use improvement ratio, ramped in a linear fashion from 0-100% between the measure start and saturation years. With selections for impacted and replacement fuel categories, measure inputs allow fuel switching as well as within-fuel efficiency. Because TCU energy usage is generally miscellaneous, the most obvious and dominant efficiency measure is the LED conversion of streetlights.

TCU Demand Change Measures reduce demand for street lighting (where they might represent de-lamping) and all other TCU activity based on separate demand change fractions. Year by year reductions are calculated along a linear ramp from zero in 2015 to the year in which the demand change reaches 100% of its potential, typically set to 2050.

2.5.7 AGRICULTURE

The agricultural module (AGR) tracks the energy use of physical infrastructure of agriculture, like buildings and pumps. Farm vehicles, like tractors, are tracked in the Transportation (TRA) module and livestock, waste, and soil emissions are tracked in the Non-CO_2 module (NON). Agricultural Electricity and Pipeline Gas consumption input data come from the IEPR 2014 Demand Forecast, Mid-Case for years spanning 1990 to 2024. Gasoline usage come from the CARB GHG Emissions Inventory for years 2000-2011 and Diesel usage comes from EIA data on Adjusted Sales of Distillate Fuel Oil by End Use for years 1984-2011. All fuels are extrapolated out to 2050 using linear regression. Waste Heat and Pipeline Gas usage from AGR-sited CHP (calculated in the CHP module) are added in, proportional to Pipeline Gas usage, to complete the reference case energy usage for AGR with Electricity, Pipeline Gas, Diesel, Gasoline, and Waste Heat fuels. These fuels are allocated across end uses HVAC, Lighting, Motors, Refrigeration, Water Heating and Cooling, Process, and Miscellaneous according the percentage breakdowns in the CPUC Navigant Potential Study from 2013.[16] The Miscellaneous category is essentially diesel used for pumping and is the largest energy use category.

AGR measures apply to individual end uses and directly reduce energy by an amount based on a stock impact fraction multiplied by an end use improvement ratio, ramped in a linear fashion from 0-100% between the measure start and

[16] http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M088/K661/88661468.PDF

saturation years. With selections for impacted and replacement fuel categories, measure inputs allow fuel switching as well as within-fuel efficiency.

AGR Demand Change Measures reduce demand for all agricultural activity based on a final demand change fractions. Year by year reductions are calculated along a linear ramp from zero in 2015 to the year, typically set to 2050, in which the demand change reaches its final potential.

2.6 Water-Related Energy Demand

PATHWAYS' Water-Energy Module (Water Module) aims to capture the energy demand associated with the procurement, treatment, conveyance and wastewater-treatment of water in the state of California. While a small portion of the overall energy demand in California, (less than .1% of total energy demand or 75.83 GWh in 2011 by our methodology), water-related energy is included in the model in an effort to capture the entirety of the state's energy needs.

The forecasting of this energy demand begins with a forecast of the state's water demand, which comes from the California Water Plan.[17] The California Water Plan projects water demand for each of California's 10 hydrologic regions by demand sector (agriculture, industry, commercial and residential) from 2010 until 2050. For reference, we provide the 10 hydrologic regions and their respective water demand allocations in 2010 in Figure 8.

[17] State of California, Natural Resources Agency, Department of Water Resources. "The Strategic Plan." California Water Plan: Update 2013 1 (2013): 26 Feb. 2015. http://www.water.ca.gov/waterplan/cwpu2013/final/

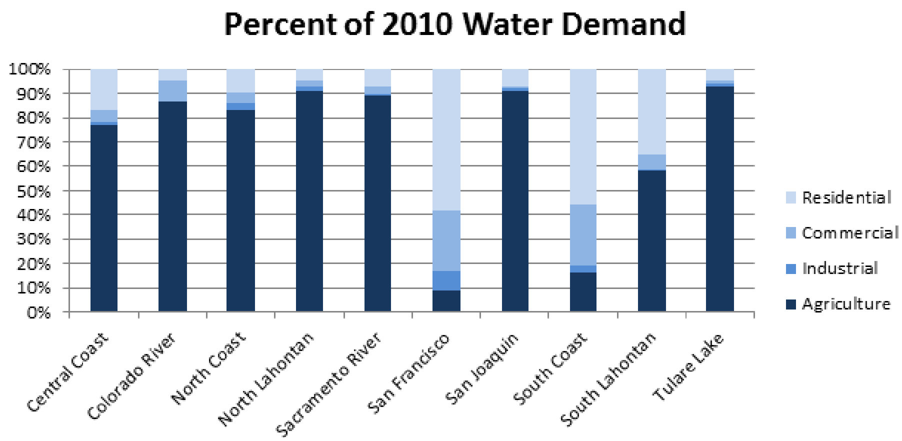


Figure 8. Ten California Hydrologic Regions

With yearly projections of water demand, PATHWAYS allows the user to define incremental water supply portfolios and calculates the electricity demand associated with meeting the state's water demand in each year given the energy intensity of supply, conveyance, and treatment. The energy intensity and supply portfolio options are described further in the following sections.

For industrial, commercial and residential demand, energy demand is broken into four components: supply, treatment, conveyance and wastewater treatment. As the energy intensities of treatment, conveyance and wastewater components do not vary significantly by sector, they are applied uniformly to the 3 sectors as follows:

Table 16. Energy Intensity of Water Supply by Component

Component	Energy Intensity (kWh/Acre Foot)
Treatment	100

Conveyance	300
Wastewater Treatment	100[18]

For the supply component, we note that energy intensity varies significantly depending on the method of supply. Thus, this component is indexed by supply method. Four supply proxies were chosen as the predominant means of meeting water demand over the projected period of time: desalination, reclaiming (recycling) water, conservation and pumping groundwater. Their respective energy intensities are shown below.

Table 17. Energy Intensity of Water Supply Options

Supply Proxy	Energy Intensity (kWh/Acre Foot)
Desalination	2500
Reclaimed Water	1000
Conservation	0
Groundwater	600

2.6.1 REFERENCE WATER-RELATED ENERGY DEMAND FORECAST

The State Water Plan features several different projection scenarios for water demand, with variation associated with population growth as well as changes in urban and agricultural density. To be conservative, the Water Module utilizes the water demand projections of the Current Trend Population-Current Trend Density scenario (CTP-CTD), which, as the name implies, sustains today's trends

[18] This value will be adjusted to 500 kWh/Acre-Foot in future versions of the model in an attempt to further improve the model's accuracy.

through 2050. Some figures are included below for comparative reference between this scenario and others:

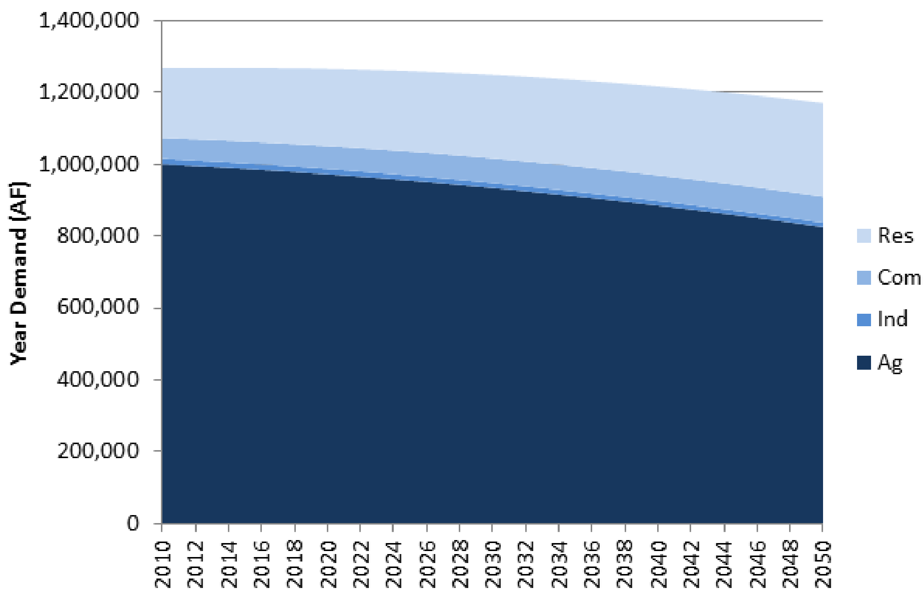
Table 18. State Water Plan Scenarios and Indicators

Scenario[19]	2050 Population (millions)	2050 Urban Footprint (million acres)	2050 Irrigated Crop Area (million acres) [3]
CTP-CTD	51.0	6.7	8.9
High Population	69.4	7.6	8.6
Low Population	43.9	6.2	9.0
High Density	51.0	6.3	9.0
Low Density	51.0	7.1	8.7

The CTP-CTD scenario then uses its assumption about population growth and development to project yearly demand in each demand sector in each hydrologic region. Based on historical data, these projections show a lot of fluctuation (for example, years 2023 and 2024 correspond to the droughts of 1976 and 1977). Given the breadth of scope of the California PATHWAYS project and the smaller role that the Water Module plays in it, the year-to-year detail of these projections was replaced with a smoothed quadratic regression, resulting in the following projection of demand by sector from 2010 to 2050.

[19] Unless explicitly stated, assume current trends for population and density are used; e.g. High Population uses higher than current population trends and current density trends.

Figure 9: Yearly demand (AF) by demand sector, 2010-2050



Note that this projection shows a decrease over time in water demand for agriculture-related use. This is a characteristic of the California Water Plan, which anticipates a decrease in irrigated crop area (as has been observed over the last 10 years) and, thus, a reduction in demand for agricultural water.

2.6.2 WATER SOURCE ENERGY INTENSITIES

The various energy intensities used in the Water Module come from 2 different sources and represent our best attempt at generalizing figures that are highly variable on a case by case basis. For example, the energy intensity of distributing water can vary by a factor of 50, depending on the terrain the water crosses and the method by which it is transmitted. Using the Embedded Energy in Water

Studies,[20] the energy intensities for supply (desalination, reclaimed water, groundwater), treatment, conveyance and wastewater treatment are calculated. The GEI study provides summary data on the variation in energy intensity observed across the state of California. Given the bounds on these figures, we chose mid-range energy intensities for each component of energy demand. For industrial, commercial and residential demand, energy demand is broken into four components: supply, treatment, conveyance and wastewater treatment. As the energy intensities of treatment, conveyance and wastewater components do not vary significantly by sector, they are applied uniformly across the non-agricultural sectors as follows (see Table 19). Energy intensities vary significantly depending on the method of supply, so four supply proxies were chosen as the predominant means of meeting water demand over the projected period of time: desalination, reclaiming (recycling) water, conservation and pumping groundwater. Their respective energy intensities are listed below.

[20] GEI Consultants, and Navigant Consulting. Embedded Energy in Water Studies Study 2: Water Agency and Function Component Study and Embedded Energy- Water Load Profiles. California Public Utilities Commission Energy Division, 5 Aug. 2011. Web. 26 Feb. 2015. <ftp://ftp.cpuc.ca.gov/gopher-data/energy%20efficiency/Water%20Studies%202/Study%202%20-%20FINAL.pdf>.

Table 19. Energy intensities by component for non-agricultural water demands in PATHWAYS

Component		Observed Lower Bound (kWh/AF)	Observed Upper Bound (kWh/AF)	Mid range Intensity (kWh/AF)
Supply	Desalination	2,281	4,497	**2,500**
	Reclaimed Water	349	1,111	**1,000**
	Groundwater	295	953	**600**
Treatment		14	234	**100**
Conveyance		15	837	**300**
Wastewater Treatment		1	1,476	**100**

Because agriculture has unique needs pertaining to water compared to the other three sectors (such as lower standards for treatment and no wastewater), energy intensity was not broken into these components but rather one energy intensity factor was applied to the entire water demand associated with the sector. This figure (500 kWh/AF) was informed by the User Manual for the Pacific Institute Water to Air Models[21], who used the same figure to represent the energy intensity of supply and conveyance for agriculture-related water demand.

[21] Wolff, Gary, Sanjay Gaur, and Maggie Winslow. User Manual for the Pacific Institute Water to Air Models. Rep. no. 1. Pacific Institute for Studies in Development, Environment, and Security, Oct. 2004. Web. 26 Feb. 2015. <http://pacinst.org/wp-content/uploads/sites/21/2013/02/water_to_air_manual3.pdf>.

2.6.3 WATER SUPPLY PORTFOLIOS

PATHWAYS relies on historical data to characterize the energy intensity associated with water demand in 2010 and allows the user to specify portfolio compositions for meeting incremental water demands by sector from 2010 to 2050. Note that Conservation is treated as a zero-energy intensity supply source, rather than a demand modifier, so the water demand in PATHWAYS will not account for reductions related to conservation not already included in the California Water Plan. Supply portfolios are interpolated between user-defined portfolios at specific years. The portfolio options are listed below.

Table 20. "Today's portfolio": Current water portfolio by sector

Supply Proxy	Agriculture	Industrial	Commercial	Residential
Desalination	0%	0%	0%	0%
Reclaimed Water	0%	40%	40%	40%
Conservation	0%	10%	10%	10%
Groundwater	100%	50%	50%	50%

Table 21. "High Groundwater & Reclaimed" Portfolio

Supply Proxy	Agriculture	Industrial	Commercial	Residential
Desalination	0%	10%	10%	10%
Reclaimed Water	0%	40%	40%	40%
Conservation	0%	10%	10%	10%
Groundwater	100%	40%	40%	40%

Table 22. "High Reclaimed" Portfolio

Supply Proxy	Agriculture	Industrial	Commercial	Residential
Desalination	0%	20%	20%	20%
Reclaimed Water	0%	40%	40%	40%

Conservation	0%	20%	20%	20%
Groundwater	100%	20%	20%	20%

Table 23. Mixed, Low Groundwater" Portfolio

Supply Proxy	Agriculture	Industrial	Commercial	Residential
Desalination	0%	25%	25%	25%
Reclaimed Water	0%	40%	40%	40%
Conservation	0%	25%	25%	25%
Groundwater	100%	10%	10%	10%

Table 24. Mixed, No Groundwater

Supply Proxy	Agriculture	Industrial	Commercial	Residential
Desalination	0%	25%	25%	25%
Reclaimed Water	0%	45%	45%	45%
Conservation	0%	30%	30%	30%
Groundwater	100%	0%	0%	0%

Table 25. Mixed, Low Conservation

Supply Proxy	Agriculture	Industrial	Commercial	Residential
Desalination	0%	0%	25%	25%
Reclaimed Water	0%	0%	55%	55%
Conservation	0%	0%	10%	10%
Groundwater	100%	100%	10%	10%

2.6.4 WATER-RELATED MEASURES

Some measures defined in the energy sectors in PATHWAYS have implications for water demand – for example, urban water efficiency programs can be implemented as demand change measures in the Commercial and Residential sectors under water heating measures. These reduce both water demand and energy demand. The Water Module in PATHWAYS does not interact dynamically with these types of demand change measures, so the user must specify parallel measures in the Water Module to reflect water demand-related impacts. This can be achieved through the supply portfolio composition, specifically by increasing the contribution of Conservation as a water supply source.

2.6.5 INTEGRATION OF WATER-RELATED LOADS IN PATHWAYS

Water-related loads are incorporated into the electricity module using two different approaches. Desalination loads, which may be used in the electricity module to help balance renewables, are allocated into weekly electricity demand based on seasonal trends in the demand for water in the sectors that are supplied by desalination (commercial, industrial, and residential in the scenarios investigated in PATHWAYS). Industrial water demand is assumed to be flat over the course of the year. For residential and commercial demand, the Metropolitan Water District of Southern California's data on monthly water sales for all member agencies for 2012 were used as representative distributions of water demand over the 12 months of the year. The resulting weekly desalination loads are then included in the electricity sector as flexible loads with a user-defined load factor and modeled using the same approach applied to grid electrolysis and power-to-gas. The default load factor for desalination plants is 79%, which allows the resource to follow the seasonal variation in demand, but not provide significant flexibility to the grid.

All other electricity demands related to water (non-desalination supply, treatment, conveyance, and wastewater treatment) are included in the TCU sector (transportation, communications, and utilities) annual electricity demand and are shaped throughout the year using the load shaping module described in the Electricity Sector documentation.

3 Energy Supply

The final energy demand projections described above are used to project energy supply stocks and final delivered energy prices and emissions. This makes the PATHWAYS supply and demand dynamic and allows PATHWAYS to determine inflection points for emissions reductions and costs for each final energy type (i.e. electricity, pipeline gas, etc.) as well as opportunities for emissions reduction using a variety of different decarbonization strategies. PATHWAYS models twelve distinct final energy types listed in Table 26 that can be broadly categorized as electricity, pipeline gas, liquid fuels, and other. For each final energy type, PATHWAYS models different primary energy sources and conversion processes. Additionally, PATHWAYS models delivery costs for some final energy types. The methodology for calculating the costs and emissions of these supply choices is described in this section.

Table 26. Final energy types

Energy Type	Energy Type Category
Electricity	Electricity
Pipeline Gas	Pipeline Gas
Liquefied Pipeline Gas (LNG)	
Compressed Pipeline Gas (CNG)	
Gasoline	Liquid Fuels
Diesel	
Kerosene-Jet Fuel	
Hydrogen	
Refinery and Process Gas	Other
Coke	
LPG	
Waste Heat	

3.1 Electricity

The electricity module simulates the planning, operations, cost, and emissions of electricity generation throughout the state of California. This module interacts with each of the energy demand modules so that the electricity system responds in each year to the electricity demands calculated for each subsector. Both planning and operations of the electricity system rely not only on the total electric energy demand, but also on the peak power demand experienced by the system, so the module includes functionality to approximate the load shape from the annual electric energy demand. Interactions between the load shaping, generation planning, system operations, and revenue requirement modules are summarized in Figure 10. The subsector energy demand calculated within each sector demand module first feeds into a Load Shaping module to build an hourly load shape for each year in the simulation. This load shape drives procurement to meet both an RPS constraint and a generation capacity reliability constraint in the Planning Module. System operations are then modeled based on the resources that are procured in the Planning Module and the annual load shapes, and finally the results of the operational simulation and the capital expenditures from the Planning Module are fed into simplified revenue requirement and cost allocation calculations. The outputs of the Electricity Module include: generation by resource type and fuel type, electricity sector emissions, statewide average electricity rates, and average electricity rates by sector. Each sub-module is described in this section.

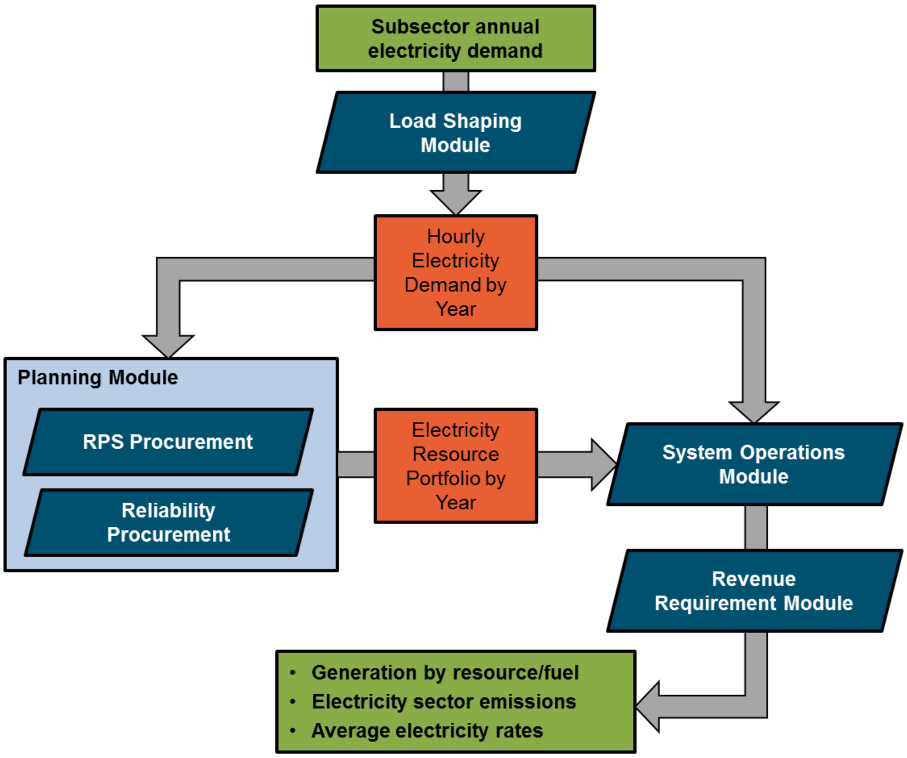


Figure 10. Summary of electricity module

3.1.1 LOAD SHAPING

Single year hourly load shapes were derived for 18 sectors/subsectors based on available hourly load and weather data. For each subsector, shapes were obtained from publicly available data sources, including DEER 2008, DEER 2011, CEUS, BeOpt, and PG&E Static and Dynamic load shapes. For each temperature-sensitive subsector, corresponding temperature data was obtained from each of the 16 climate zones.

3.1.1.1 Load Shaping Methodology

The load shaping module first requires normalization of each input load shape from its corresponding weather year to the simulation year. This process occurs in two steps. First, the load shape is approximated as a linear combination of the hourly temperature in each climate zone, the hourly temperature in each climate zone squared, and a constant. This regression is performed separately for weekdays and weekends/holidays to differentiate between behavioral modes on these days.

Equation 61.

$$\boldsymbol{x_i \approx \sum_{k\in CZ}\left[a_{ik}w_{ik}^2 + b_{ik}w_{ik}\right] + c_{ik}}$$

where x_i is the input load shape, w_{ik} is the hourly temperature in climate zone k in the weather year associated with the input load shape, and a_{ik}, b_{ik}, and c_{ik} are constants. Next, the hourly temperature data for the simulation year in PATHWAYS is used to transform the input load shapes into the same weather year. This process also occurs separately for weekdays and weekends/holidays.

Equation 62.

$$\boldsymbol{y_i \approx \sum_{k\in CZ}\left[a_{ik}W_k^2 + b_{ik}W_k\right] + c_{ik}}$$

where W_k is the hourly temperature in climate zone k in the PATHWAYS simulation weather year. Each set of weekday and weekend/holiday shapes are then combined into a single yearlong hourly shape to match the weekend/holiday schedule of the PATHWAYS simulation year. This results in 61 load shapes that reflect the same weather conditions and weekend/holiday schedules as the PATHWAYS simulation year.

The next step is to combine the load shapes to best reflect both the total historical hourly load and the annual electricity demand by subsector. The model achieves this by normalizing each load shape so that it sums to 1 over the year and selecting scaling factors that represent the annual electricity demand associated with each shape. These scaling factors are selected to ensure that the total electricity demand associated with the load shapes in each subsector sums to the electricity demand in that subsector in a selected historical year. An optimization routine is also used to minimize the deviation between the sum of the energy-weighted hourly load shapes and the actual hourly demand in the same historical year, based on data from the CAISO's OASIS database.

The optimization routine includes two additional sets of variables to allow for more accurate calibration to the historical year. The first set of variables addresses limitations in the availability of aggregate load shapes by subsector. Because some of the load shapes being used represent a single household or a single building, aggregation of these shapes may result in more variable load shapes than are seen at the system level. To account for this, the model shifts each load shape by one hour in each direction and includes these shifted load shapes in the optimization in addition to the original load shape. The model then selects scaling factors for each of the three versions of each shape to automatically smooth the shapes if this improves the fit to hourly historical data.

In addition to the load shape smoothing variables, a set of constants are also included in the model for each subsector. This allows the model to translate load shapes up and down (in addition to the scaling) to best approximate the hourly historical load. The scaling factors and constants solved for in the optimization routine are then used to construct a single shape for each subsector. These shapes are input into PATHWAYS and are scaled in each year according to the subsector electricity demand to form the system-wide hourly load shape. Example load shapes derived using this process are shown in Figure 11. At left, the average daily load shape for weekdays in September corresponding to historical 2010 demand is shown. For illustration, the load shape at right reflects the impacts of reducing all lighting demands by 50% from the 2010 historical demand.

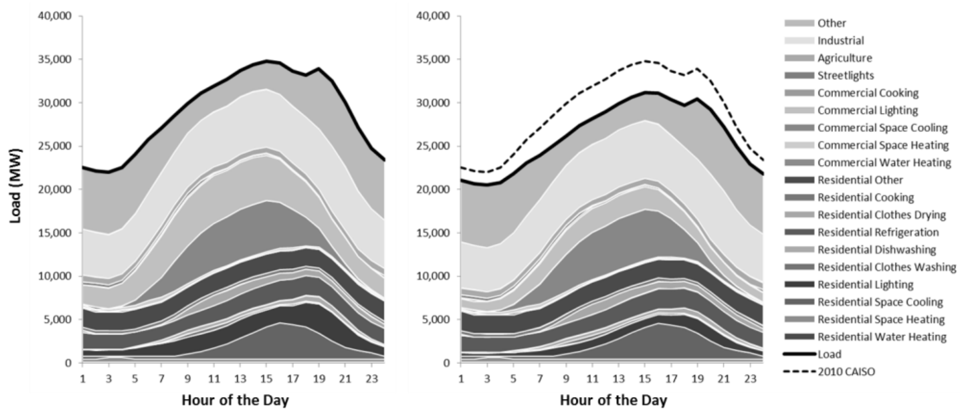


Figure 11. Example load shaping: impact of 50% reduction in lighting demand in average California load shape for weekdays in September 2010.

Some subsectors in PATHWAYS do not have available representative load shapes. The load shaping module combines these subsectors into an “undefined” subsector and models their contribution to the demand in the optimization routine as a linear combination of all of the available load shapes and a constant. After the optimization routine has solved, the difference between the historical hourly demand and the aggregated hourly shape of all defined subsectors is normalized to sum to 1 and this shape is used to represent any subsectors in PATHWAYS that lack specific load shape information.

3.1.2 GENERATION PLANNING

The aggregate load shape is used to inform generation planning, which occurs in three stages: user-specified resources, renewable policy compliance, and reliability requirement compliance. These are described below.

1. **Specified Resources.** For systems in which resource plans are available, the user may specify the capacity (in MW) of, or annual energy (in GWh) from, each generating resource in each year in the "Time-Dependent Generator Attributes" table. Vintages must also be supplied for this fleet of *specified resources* so that they can be retired at the end of their useful life. Early retirement can be imposed by reducing the total installed capacity of a resource type in future years. The model will retire resources according to age (oldest retired first) to meet the yearly capacities specified by the user. In addition, the model will replace generators at the end of their useful life with new resources (with updated cost and performance parameters) of the same type to maintain the user specified capacity in each year. If the resource capacities are not known after a specific year then the user can specify the capacity to be "NaN" and the model will retire resources without replacement at the end of their useful lifetimes.

2. **Renewable Energy Compliance.** In the second stage of generation planning, the model simulates renewable resource procurement to meet a user-specified renewable portfolio standard (RPS). In each year, the renewable net short is calculated as the difference between the RPS times the total retail sales and the total sum of the renewable generation available from specified resources and resources built in prior years. This renewable net short is then supplied with additional renewable build according to user-defined settings. The user can define resource composition rules in each year or a subset of years (eg. If the user specifies 50% wind and 50% solar in 2030 and 80% solar and 20% wind in 2050, the model will fill the net short in 2030 with 50% wind and 50% solar and will linearly interpolate between this composition and 80% solar, 20% wind by 2050 for filling the net short in all years between 2030 and 2050).

   Once the renewable build and composition is determined for each year, PATHWAYS selects resources from the same database that is used by the RPS Calculator to meet the specified procurement strategies in a least-cost way. For example, if the model calls for 1,000 GWh of solar resources to be procured in a given year, PATHWAYS will select solar resources on a least-cost basis to meet the energy target of 1,000 GWh/yr. The costs of these resources then feed into the renewable generation fixed cost component of the revenue requirement calculation. The database also includes transmission costs for each project, which feed into the transmission fixed cost component of the revenue requirement calculation.

3. **Reliability procurement.** The final stage in generation planning is to ensure adequate reliable generating capacity to meet demand. In each year, the model performs a load-resource analysis to compare the reliable capacity to the peak electricity demand. The reliable capacity of the renewable resources is approximated by the total renewable generation level in the hour with the highest net load in the year, where the net load equals the total load minus the renewable generation. The reliable capacity of dispatchable resources is equal to the installed capacity. When the total reliable capacity does not exceed the peak demand times a user-specified planning reserve margin, the model builds additional dispatchable resources with a user-specified composition in each year.[22] The default planning reserve margin is equal to 15% of peak demand. The final resource stack determined for each year by the electricity planning module feeds into both the system operations and the revenue requirement calculations. These calculations are described in the following sections.

3.1.3 SYSTEM OPERATIONS

System operations are modeled in PATHWAYS using a loading order of resources with similar types of operational constraints and a set of heuristics designed to approximate these constraints. The system operations loading order is summarized in Figure 12. The model first simulates renewable and must-run

[22] While peak demand and renewable ELCC's are approximated in this model for the purposes of approximating contributions to economy-wide cost and carbon emissions, the fidelity of the PATHWAYS model is not adequate to inform quantitative electricity-system planning studies, so these parameters should not be examined for use in more detailed planning or operational studies.

generation; then approximates flexible load shapes; dispatches energy-limited resources, like hydropower; dispatches energy storage resources; simulates dispatchable thermal resources with a stack model; and finally calculates any imbalances (unserved energy or renewable curtailment). The outputs of the Operational Module include: generation by resource, annual operating cost, renewable curtailment, and exports of electricity.

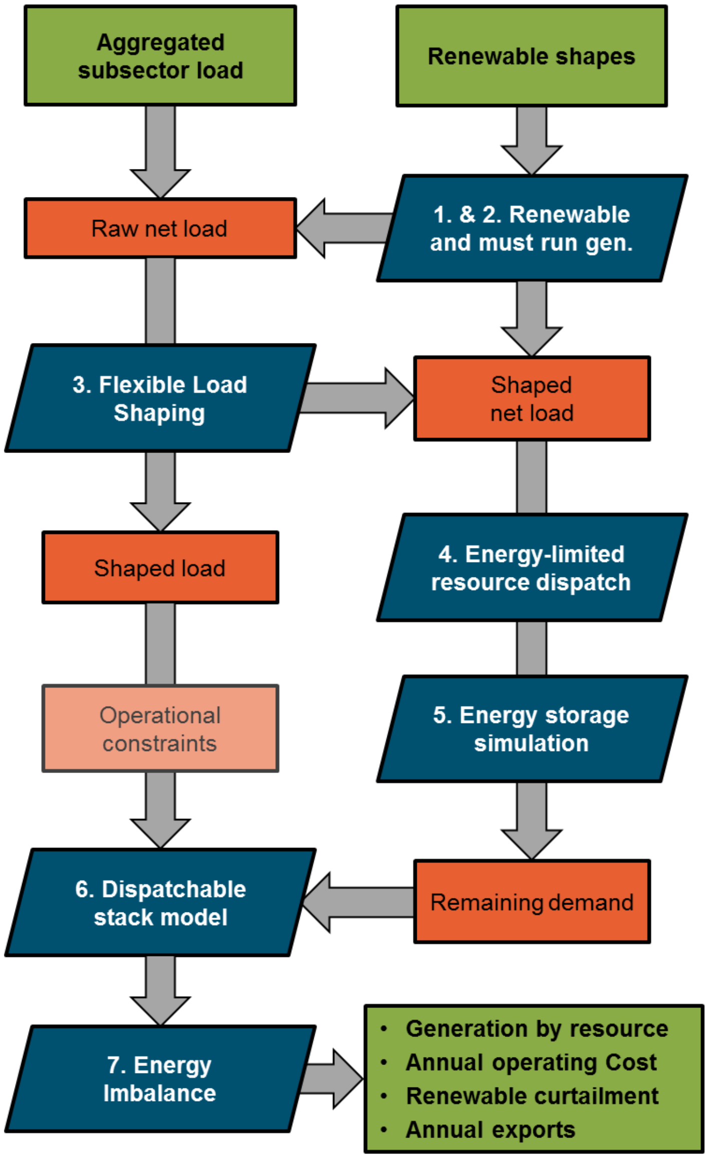


Figure 12. Summary of Electricity System Operations logic

Consistent with this modeling framework, generation resources must each be classified into one of the following operational modes: must-run; variable renewable; energy-limited; and dispatchable. These classifications are listed for the resource types in this analysis in Table 27.

Table 27. Operational modes by resource type

Technology	Operational Mode
Nuclear	Must-run
CHP	Must-run
Coal	Dispatchable
Combined Cycle Gas (CCGT)	Dispatchable
CCGT with CCS	Dispatchable
Steam Turbine	Dispatchable
Combustion Turbine	Dispatchable
Conventional Hydro	Energy-Limited
Geothermal	Must-run
Biomass	Energy-Limited
Biogas	Energy-Limited
Small Hydro	Must-run
Wind	Variable Renewable
Centralized PV	Variable Renewable
Distributed PV	Variable Renewable
CSP	Variable Renewable
CSP with Storage	Variable Renewable

3.1.3.1 Must run resources

Must run resources are modeled with constant output equal to their installed capacity times their availability after considering outages in each year or with constant output that sums to the input annual energy, depending on user specifications. These resources run regardless of the conditions on the system and are therefore scheduled first.

3.1.3.2 Variable renewable resources

Variable renewable resources include any resource that has energy availability that changes over time and has no upward dispatchability. This includes all wind and solar resources. For each of these resources, a resource shape is selected, which characterizes the maximum available power output in each hour. These shapes are scaled in each year to match the total annual energy generation determined by the renewable procurement calculation. These resources can either be constrained to never generate in excess of these scaled renewable shapes (curtailable) or constrained to generate at levels that always exactly match the scaled renewable shapes (non-curtailable). The curtailment is affected by both the load and the ability of other resources on the system to balance the renewable resources. Renewable curtailment is therefore approximated as a *system imbalance* after all other resources have been modeled. The curtailability assumptions for variable renewable resources are summarized in Table 28.

Table 28. Operating assumptions for renewable resources

Technology	Able to Curtail?
Geothermal	No
Biomass	No
Biogas	No
Small Hydro	No
Wind	Yes
Centralized PV	Yes

Technology	Able to Curtail?
Distributed PV	No
CSP	Yes
CSP with Storage	No[23]

3.1.3.3 Flexible Loads

Flexible loads are modeled at the subsector level. For each demand subsector, the user specifies what fraction of the load is flexible and the number of hours that the load can be shifted. The model approximates each flexible load shape as the weighted sum of a 100% rigid load shape component and a 100% flexible load shape component, which in the most extreme case can move in direct opposition to the hourly rigid load shape over the course of each week:

Equation 63.

$$L_t = (1 - x)\hat{L}_t + xF_t$$

where $\hat{L}_t$ is the subsector load shape with no flexibility, F_t is a perfectly flexible load shape, and x is a coefficient between 0 and 1. Most flexible loads are not, however, perfectly flexible. When an energy service can only be shifted by a limited amount of time, the portion of the load that acts as perfectly flexible in Equation 26 must account for this limitation. In PATHWAYS, this is accomplished with the following approximation. For each subsector, the load shape is shifted

[23] CSP with Storage resources must generate according to the hourly shape in each hour, but the hourly shape utilizes the energy storage module logic to approximate the dispatchability of these resources.

over various time durations. For each shift duration, the resulting load shape is approximated by a linear combination of the original load shape and an inverted load shape (the average load minus the original load shape):

Equation 64

$$\hat{L}_{t-s} \approx a\hat{L}_t + b\left[\bar{L} - \hat{L}_t\right]$$

where s is the time shift and $\bar{L}$ is the average of $\hat{L}_t$ over the time scale of interest (one week for most loads, but one year for loads that can provide seasonal flexibility). The coefficients a and b can be found for each subsector as functions of s using least squares fits to the load shape data. In PATHWAYS, a load that can shift by s hours provides $\frac{b(s)}{a(s)+b(s)}$ of load that can act in complete opposition to the original load shape. This portion of the partially flexible load is therefore conservatively modeled as completely flexible. PATHWAYS stores $\frac{b(s)}{a(s)+b(s)}$ for each subsector and various values of s and uses these functions to approximate x in Equation 63:

Equation 65.

$$x = f \times \frac{b(s)}{a(s) + b(s)}$$

where f is the portion of the subsector load that can be shifted s hours. Both f and s are inputs that must be provided by the user for each subsector in each case. The flexible portion of the load in the model is dynamically shaped to flatten the net load (load net of must-run resources and variable renewables) on a weekly basis or on an annual basis in each year. The flexible load dispatch therefore changes both with demand measures and renewable supply measures.

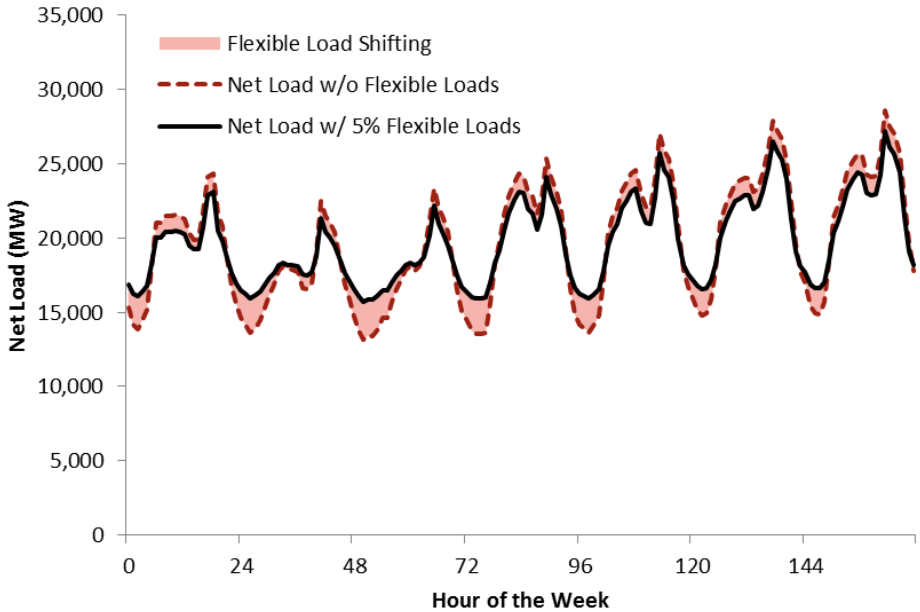


Figure 13. Example of flexible load shifting – 5% of the gross load assumed to be 100% flexible within the week.

The effects of introducing flexible loads on the total net load is shown in Figure 13 for an example week in which 5% of the gross load is approximated as 100% flexible within the week.

In addition to subsector-level flexible loads, flexible fuel production (electrolysis to produce hydrogen, power to gas, compression of pipeline gas, and liquification of pipeline gas) and desalination is modeled in PATHWAYS. These loads are modeled as *negative* energy-limited resources (described in section 1.1.3.5), with seasonal energy constraints. Produced fuels (hydrogen, compressed pipeline gas, and liquid pipeline gas) are assumed to be storable over several weeks so seasonal allocation of energy demand to produce these fuels is driven by seasonal imbalances between the load and the availability of renewables. Seasonal demand for desalination is instead driven by seasonal non-agricultural water demands, which are calculated in the Water Module. The flexibility is also limited by the extent to which the facilities have been oversized to accommodate low load factors. The user inputs the assumed load factor for each fuel production load and for desalination plants to tune the amount of flexibility provided by the new loads. The default load factors are listed in Table 29.

Table 29. Default load factors for potentially flexible desalination and fuel production loads

Load	Default Load Factor
Desalination	0.79
Grid Electrolysis	0.25
Power to Gas	0.25
Compressed Natural Gas	1.0 (inflexible)
Liquefied Natural Gas	1.0 (inflexible)

3.1.3.4 Electric Vehicle Charging

Electric vehicle charging is a special class of flexible loads. Because additional data are available on driving demand patterns, PATHWAYS is able to constrain flexible electric vehicle charging more strictly according to behavior and ability to dispatch load. In order to design these constraints, data on vehicle trips from the

2009 National Household Travel Survey were used to simulate the driving and charging patterns of a fleet of 10,000 electric vehicles (this fleet size was determined to be adequately large to capture appropriate levels of charging shape diversity for an hourly resolution simulation), each with a 30 kWh battery and 0.311 kWh/mi efficiency (96.5 mile range). Vehicle days were selected regardless of geography or vehicle type, reflecting the modeling philosophy that adoption of new technologies should not necessarily alter the magnitude or quality of delivered energy services to achieve carbon goals. Each vehicle was randomly selected from the database and charging patterns were derived over the course of the day based on two rules:

1. As soon as the vehicle is parked at a location with a charging station, the vehicle charges at a fixed power (3.3kW) until either the battery is full or the car is unplugged in order to make its next trip. Simulations were performed in which chargers were assumed to be available only at home and in which chargers were assumed to be available both at home and at work, providing two distinct charging shapes.

2. The charge state of the battery at midnight at the end of the day is equal to the charge state at midnight at the beginning of the day to ensure that the charging behavior on the simulated day does not impact the ability of the car to provide the needed services on the next day.

3. If the vehicle does not have enough charge in its battery to complete a trip on the simulated day, it is discarded and flagged as an unlikely candidate for electric vehicle adoption. The percent of vehicle-days found to be ineligible for electric vehicle adoption was found to depend

on the availability of workplace chargers and whether the day was a weekday or weekend/holiday. The driving demand could be met for 93% of selected vehicle-weekdays without running out of charge if charging was only available at home, while demand could be met for 95.3% of vehicle-weekdays if workplace charging was also available. Weekend driving demands were more challenging to meet given the assumed vehicle charging parameters. Driving demand could be met for 80.7% of selected vehicle-weekends if charging was only available at home and 86.2% if charging was also available at work.

This simulation provided an "Immediate" charging shape, in which vehicles are charged as soon as possible to prepare for the next trip. In order to bound the flexibility of the EV charging loads, this simulation was repeated by altering the first rule so that vehicles were instead charged immediately before the next trip so as to simulate the maximum potential to delay the charging load ("Just-in-time" charging). The charging rate was also fixed at 6.6kW for this simulation. These simulations provided 8 EV charging shapes:

Table 30. Simulated electric vehicle charging shapes

Shape No.	Day Type	Charger Locations	Charging Strategy
1	Weekday	At-home only	Immediate
2	Weekday	At-home only	Just-in-time
3	Weekday	At-home and workplace	Immediate
4	Weekday	At-home and workplace	Just-in-time

Shape No.	Day Type	Charger Locations	Charging Strategy
5	Weekend	At-home only	Immediate
6	Weekend	At-home only	Just-in-time
7	Weekend	At-home and workplace	Immediate
8	Weekend	At-home and workplace	Just-in-time

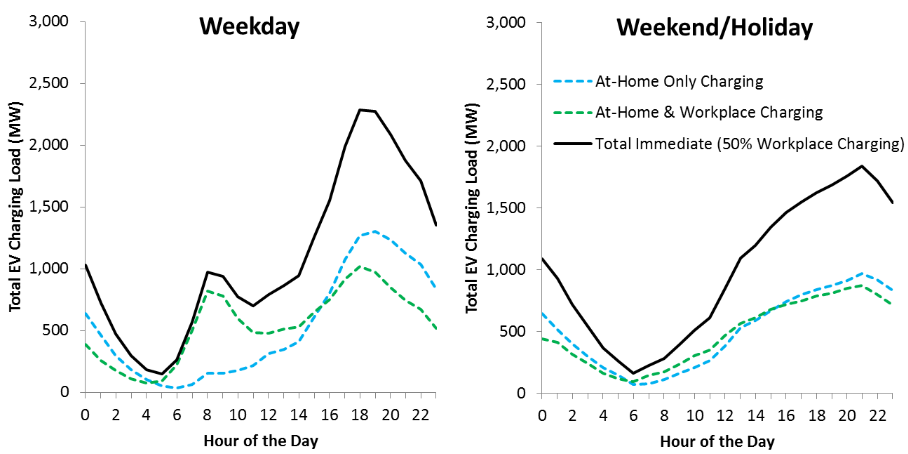


Figure 14. Weekday and Weekend/Holiday EV Charging shapes broken out by charger availability for a case with 50% workplace charger availability

In PATHWAYS, these shapes are combined for each case to build a single annual Immediate charging shape and a single annual Just-in-time charging shape based on the simulation calendar year and the user-defined availability of workplace charging for each case. For example, if 50% of EV drivers are able to charge their vehicle at work, then the Immediate charging shape is equal to 0.5 times the "At-home and Workplace” charging shape plus 0.5 times the “At-home only” charging shape. This example is illustrated in Figure 14.

To simulate electric vehicle charging flexibility, PATHWAYS uses the Immediate and Just-in-time charging shapes to bound the cumulative energy demand for electric vehicle charging in each hour. The Just-in-Time charging shape provides a lower bound for the cumulative charging energy (ie. if the vehicle fleet as a whole is not charged at the level required by the Just-in-Time charging shape, then some vehicles will not be adequately charged in time for their next trip). Similarly, the Immediate charging shape provides an upper bound on the cumulative energy demand for charging (ie. if the cumulative energy delivered to vehicles exceeds that associated with the Immediate charging shape, then the model is attempting to deliver energy to a vehicle that is not yet plugged in). In PATHWAYS these bounds are translated into constraints that make use of the energy storage logic (described in Section 3.1.3.6) to simulate delayed (or stored) electric vehicle charging over time. The portion of the electric vehicle load that is treated in this manner is equal to the portion of the light duty vehicle subsector demand that the user specifies as flexible. The remaining vehicle electricity demand uses the Immediate charging shape derived for the case.

3.1.3.5 Energy-limited resources

Energy-limited resources include any resource that must adhere to a specified energy budget over a weekly time horizon. Some energy-limited resources, like conventional hydropower, have energy budgets that change over time to account for seasonal fluctuations in resource availability and other constraints. Other energy-limited resources, like biomass and biogas, use a dynamic weekly energy budget that distributes resource use between weeks according to the relative electricity imbalance (between load and must-run plus renewable resources) across the weeks. For renewable energy-limited resources, the energy budget ensures that energy from the resources is being delivered for RPS compliance and the energy-limited dispatch also allows the resource to contribute to balancing the system. In addition to the weekly energy budgets, these resources are constrained by weekly minimum and maximum power output levels as well. The dispatch for these resources is approximated using the following heuristic. The method is illustrated in Figure 15 and Figure 16.

1. A normalized hourly demand shape is calculated from the load net of all must-run and variable renewable resources. This net load shape is first translated on a weekly basis so that it averages to zero in each week.

Equation 66

$$n_t = \hat{n}_t - \bar{n}$$

2. The zero-averaged demand shape is then scaled so that the minimum to maximum demand over the course of each week is equal to the minimum to maximum power output of the energy-limited resource.

Equation 67

$$N_t = (P_{max} - P_{min}) \times n_t$$

3. The scaled demand shape is then translated so that the total weekly demand sums to the energy budget of the energy-limited resource.

Equation 68

$$M_t = N_t + \frac{E}{168\text{hrs/wk}}$$

4. The transformed demand shape calculated in Step 3 will necessarily violate either the minimum or maximum power level constraints for the energy-limited resource in some hours, so two additional steps are required to meet the remaining constraints. In the first of these steps, the transformed demand shape is forced to equal the binding power constraint in hours when it would otherwise violate the constraint.

Equation 69

$$L_t = \begin{cases} P_{min} & \text{if } M_t < P_{min} \\ M_t & \text{if } P_{min} \leq M_t \leq P_{max} \\ P_{max} & \text{if } M_t > P_{max} \end{cases}$$

5. The *truncation* adjustment in Step 4 impacts the summed weekly energy of the transformed demand shape, so a final step is required to re-impose the energy budget constraint. In the weeks in which the transformed demand shape exceeds the energy budget, the model defines a downward capability signal equal to the difference between the transformed demand shape and the minimum power level. A portion of this signal is then subtracted from the transformed demand shape so that the weekly energy is equal to the energy budget. In the weeks in which the transformed demand shape does not meet the energy budget, the model defines an upward capability signal equal to the difference between the maximum power level and the transformed demand shape. A portion of this signal is then added to the

transformed demand shape so that the weekly energy is equal to the energy budget. This energy adjustment is summarized by:

Equation 70

$$P_t = \begin{cases} L_t + (E - \Sigma L_t)\dfrac{L_t - P_{min}}{\sum(L_t - P_{min})} & \text{if } \Sigma L_t \geq E \\ L_t + (E - \Sigma L_t)\dfrac{P_{max} - L_t}{\sum(P_{max} - L_t)} & \text{if } \Sigma L_t < E \end{cases}$$

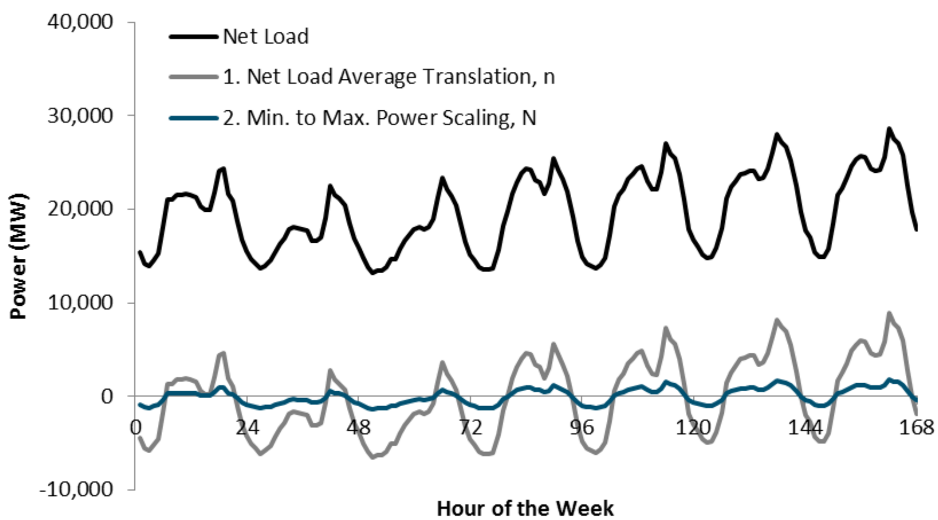


Figure 15. Energy-limited resource dispatch Steps 1 & 2 - Normalization and scaling of the net load shape

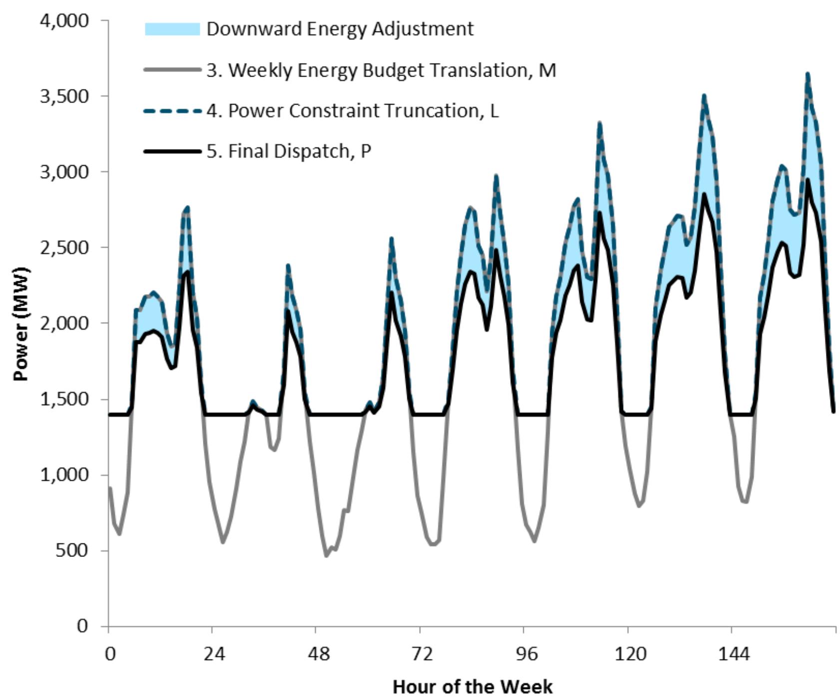


Figure 16. Energy-limited resource dispatch Steps 3 - 5 – Translation, truncation, and energy budget adjustment

3.1.3.6 Energy storage

Energy storage resources in PATHWAYS are aggregated into a single equivalent system-wide energy storage device with a maximum charging capacity, maximum discharging capacity, maximum stored energy capacity, and roundtrip efficiency. The simplified energy storage device is described schematically in Figure 17. The key variables are the charging level, C_t, the discharging level, D_t, and the stored energy, S_t, in each hour.

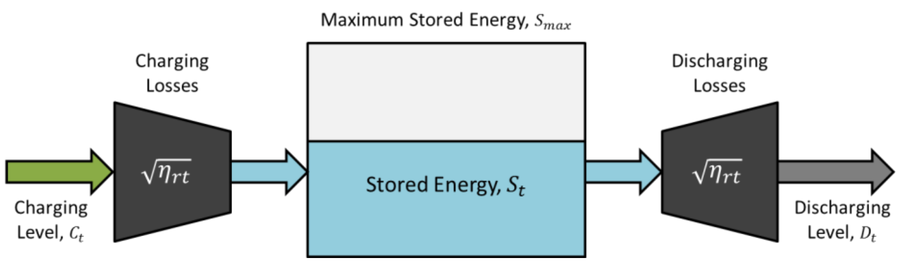


Figure 17. Energy storage model

The storage system acts by storing any renewable energy in excess of the load in each hour (subject to constraints on maximum charging and maximum stored energy) and discharging any stored energy in hours in which the load exceeds the generation from must-run, variable renewable, and energy-limited resources. In PATHWAYS, this functionality is modeled using the following equations in each time step:

Equation 71

$$C_t = \begin{cases} \min\left(\left\{G_t - L_t, C_{max}, \dfrac{S_{max} - S_{t-1}}{\sqrt{\eta_{rt}}}\right\}\right) & \text{if } G_t > L_t \\ 0 & \text{if } G_t \leq L_t \end{cases}$$

$$D_t = \begin{cases} 0 & \text{if } G_t > L_t \\ \min\left(\left\{L_t - G_t, D_{max}, \frac{S_{t-1}}{\sqrt{\eta_{rt}}}\right\}\right) & \text{if } G_t \leq L_t \end{cases}$$

$$S_t = S_{t-1} + \sqrt{\eta_{rt}} C_t - \frac{D_t}{\sqrt{\eta_{rt}}}$$

where G_t is the total generation from must-run, variable renewable, and energy-limited resources, L_t is the load, C_{max} is the maximum charging level, and D_{max}

is the maximum discharging level. This heuristic storage dispatch algorithm is intended to alleviate short- and long-term energy imbalances, but it is not intended to represent optimal storage dispatch in an electricity market. The stored energy level begins at 0MWh in the first hour of the first year of the simulation so that energy can only be stored once a storage facility has been built and excess renewables have been used to charge the system. The operating parameters for the equivalent system-wide energy storage device in each year are calculated from the operating parameters of each storage device that is online in that year. The maximum charging level, maximum discharging level, and maximum stored energy are each calculated as the sum of the respective resource-specific parameters across the full set of resources. The round-trip efficiency is calculated using the following approximation. Consider a storage system that spends half of its time discharging and discharges at its maximum discharge level. For this system, the total discharged energy over a period of length T will equal:

Equation 72

$$\int_0^T D_i(t)\,dt = \frac{D_i^{max} \times T}{2}$$

For this system, the total losses can be described by:

Equation 73

$$Losses_i = \int_0^T \left[\frac{D_i(t)}{\eta_i} - D_i(t)\right] dt = \frac{(1-\eta_i) D_i^{max} \times T}{2\eta_i}$$

where η_i is the round-trip losses of storage device i. If the system has several storage devices operating in this way, the total losses are equal to:

Equation 74

$$Losses = \frac{T}{2}\sum_i \frac{1-\eta_i}{\eta_i} D_i^{max} = \frac{T}{2}\left(\sum_i \frac{D_i^{max}}{\eta_i} - D_{max}\right)$$

where D_{max} is the aggregated maximum discharge capacity. The total discharged energy is equal to:

Equation 75

$$Energy = \sum_i \frac{D_i^{max} \times T}{2} = \frac{T}{2} D_{max}$$

The system-wide roundtrip efficiency is therefore approximated by:

Equation 76

$$\frac{Energy}{Energy+Losses} = \frac{D_{max}}{D_{max}+\sum_i \frac{D_i^{max}}{\eta_i} - D_{max}} = \frac{D_{max}}{\sum_i \frac{D_i^{max}}{\eta_i}}$$

The energy storage operational parameters used in this analysis are summarized in Table 31.

Table 31. Energy storage technology operational parameters

Technology	Year 1	Roundtrip Efficiency in Year 1	Year 2	Roundtrip Efficiency in Year 2

Pumped Hydro	2010	70.5%	2020	80%
Batteries	2010	75%	2020	80%
Flow Batteries	2010	75%	2020	80%

3.1.3.7 Dispatchable resources

Dispatchable resources are used to provide the remaining electricity demand after must-run, variable renewable, energy-limited, and storage resources have been used. Dispatch of these resources, which include thermal resources and imports, is approximated using a stack model with heuristics to approximate operational constraints that maintain system reliability. In the stack model, resources are ordered by total operational cost on a $/MWh basis. The operational cost includes: fuel costs equal to the fuel price times the heat rate; carbon costs equal to the price of carbon times the fuel carbon intensity times the heat rate; and input variable operations and maintenance costs. Resources are dispatched in stack order until the remaining load is met. In addition, a minimum generation rule is included to approximate constraints related to voltage, inertia, and transmission flows, which is described below.

- **Frequency Response Requirement** – Frequency response requirements can be met with either conventional dispatchable resource or energy storage. If the frequency response requirement is selected to be met with conventional resources, the user can specify which resources are eligible to meet that requirement and the total quantity (in MW) required. The thermal dispatch is then performed in two steps: first, the resources that can contribute to meeting the constraint are dispatched in order of cost to meet the constraint in each hour, taking into account the assumption that every 1 MW of conventional resource online in a given hour can provide 0.08 MW of frequency response; next, the remaining resources (including any unused resources that could have contributed to meeting the frequency response requirement) are dispatched in order of cost to meet any remaining load.

If the user elects to meet the frequency response requirement with energy storage resources, the model constrains the dispatch of energy storage resources such that they always maintain sufficient capacity (in MW) to dispatch in the event that they are needed for frequency control.

3.1.3.8 Imports/Exports

Imports are simulated in PATHWAYS by a collection of resources intended to reflect the historical emissions of imported electricity and any predicted changes in the composition of imports going forward, including the expiration of coal contracts. The user specifies the operating mode for each class of imports to best match historical operations. The default assumptions are listed in Table 32 below.

Table 32. Operational modes of each class of imports

Import Classification	Operational Mode	Emissions Intensity (tCO2/MMBtu)	Availability Assumptions
Specified Coal	Must Run	0.0942	2,875MW, rolls off with coal contract expiration by 2030
Specified BPA	Energy-Limited	0.0427	2,609 MW max, 8,000 GWh/yr, assumed to stay constant going forward
Specified Gas	Dispatchable	0.0529	1,245 MW, capacity adjusts in future years so that total import capacity equals an import limit of 12,620MW
Unspecified	Dispatchable	0.0427	4,809 MW, assumed to stay constant going forward
Unspecified Non-emitting	Energy-Limited	0	1,082MW, represents Hoover and Palo Verde, assumed to stay constant going forward

The model also allows the user to specify a maximum level of exports out of California. The default assumption, based largely on historical exports to the Pacific Northwest, is that California can export up to 1,500 MW (net of imports) in any hour. In its aggregate emissions accounting, PATHWAYS assumes that the emissions associated with any exported power (which are based on the full composition of resources generating in export hours) is exported to neighboring states (ie. not included in California's emissions total). This represents a departure from the current inventory rules, which count all emissions from generators located within the state as well as all emissions from imported electricity. A separate electricity GHG output was also created in the PATHWAYS model to report electricity sector emissions including emissions associated with exported power, to reflect consistency with this aspect of CARB's GHG accounting rules.

3.1.3.9 System imbalances

Once the dispatch has been calculated for each type of resource, the model calculates any remaining energy imbalances. The planning module is designed to ensure that any negative imbalance (potential unserved energy) may be met with conventional demand response resources (the available capacity of which is defined by the user for each case). Demand response dispatch events are tracked and the costs associated with dispatching these resources are added to the operational costs in the revenue requirement (rather than tracking specific demand response program costs). The system might also encounter potential overgeneration conditions, in which the generation exceeds demand. These conditions might arise due to a combination of factors, including low load, high must run generation, high variable renewable generation, and minimum generation operating constraints. Overgeneration conditions are first mitigated with exports to neighboring regions, based on the user-specified maximum export level. For accounting purposes, the exported power emissions rate is approximated as the generation-weighted average emissions rate of all resources generating in each hour. If excess generation remains after accounting for exports then overgeneration is avoided by curtailing renewable resources. Both the delivered renewable energy and the percent of renewable generation that is curtailed in each year are outputs of the model. The model does not procure additional renewable resources to meet RPS targets if renewable curtailment results in less delivered RPS energy than is required for compliance. This renewable overbuild must be decided by the user.

The system operations module outputs include:

- Total annual generation from each technology and fuel type
- Total annual electric sector emissions
- Total electric sector fuel, variable O&M, and carbon costs
- Expected annual delivered renewable energy and percent of renewable generation curtailed

3.1.4 REVENUE REQUIREMENT

The revenue requirement calculation includes the annual fixed costs associated with generation, transmission, and distribution infrastructure as well as the annual variable costs that are calculated in the System Operations Module. The methodology for calculating fixed costs in each year is described below.

3.1.4.1 Generation

Fixed costs for each generator are calculated in each year depending on the vintage of the generator and the user-specified capital cost and fixed O&M cost inputs by vintage for the generator technology. Throughout the financial lifetime of each generator, the annual fixed costs are equal to the vintaged capital cost times a levelization factor plus the vintage fixed O&M costs, plus taxes and insurance. For eligible resources, taxes are net of production tax credits and/or investment tax credits. If the plant's useful lifetime is longer than its financing lifetime, then no levelized capital costs are applied to the years between the end of the financing lifetime and the retirement of the plant (only fixed O&M and variable costs are applied in these years). This methodology is also used to cost energy storage infrastructure and combined heat and power infrastructure. Generator cost assumptions were informed by the E3 report, "Cost and Performance Review of Generation Technologies: Recommendations for WECC 10- and 20-Year Study Process," Prepared for the Western Electric Coordinating Council, Oct. 9, 2012.[24] Cost and financing assumptions for energy storage technologies are summarized in Table 33 below.

Table 33. Capital cost inputs for energy storage technologies

Technology	Capital Cost (2012$/MW)	Financing Lifetime (yrs)	Useful Life (yrs)
Pumped Hydro	2.23M	30	30
Batteries	4.3M	15	15
Flow Batteries	4.3M	15	15

3.1.4.2 Transmission System

Transmission costs are broken into two components: sustaining transmission costs and RPS-driven transmission costs. Sustaining transmission costs include all costs associated with existing transmission infrastructure, incremental transmission build to accommodate load growth, and reliability-related upgrades. These costs are broken into "growth-related" costs, which are driven over time by the annual transmission system peak demand and "non-growth-related"

[24] https://www.nwcouncil.org/media/6867814/E3_GenCapCostReport_finaldraft.pdf

which can escalate at a user-input rate to reflect increasing costs of maintenance and upgrades. The default sustaining transmission cost assumptions are listed in Table 34.

Table 34. Transmission system cost assumptions

Assumption	Default Value	Notes
Reference Year	2012	
Reference Year Transmission (Tx) Costs	$3.125B/yr	Source: 2012 IOU Revenue Requirements, scaled up by load to rest of state
Growth-Driven Portion of Sustaining Tx Costs	100%	
Escalation Rate for Non-Growth Driven Portion of Sustaining Tx Costs	-	Not used under default settings

RPS-driven costs are approximated from the resource-specific levelized transmission cost adders (in $/MWh) for resources selected from the RPS Calculator database. In each year, the levelized transmission cost adders for the procured renewable resources are multiplied by the procured renewable energy by resource and added to the sustaining transmission annual costs to represent the full costs of the transmission system. Transmission costs associated with renewables built prior to 2012 are not modeled explicitly and are rolled into the sustaining transmission cost component.

3.1.4.3 Distribution System

Distribution costs are broken into sustaining distribution costs and distributed generation-driven costs. Sustaining distribution costs are driven by the growth in the distribution peak with a 5-yr lag incorporated to better fit historical distribution components of the IOU revenue requirements. In each year the growth rate of the sustaining distribution cost is approximated by:

Equation 77

$$c_y^{Dx} = \left[c_{y-1}^{Dx}\right]^{r_{y-5}+k}$$

where r_{y-5} is the growth rate of the distribution system peak in year $y-5$, k is a constant equal to 1.021 (based on historical data), and c_{2012}^{Dx} is the total distribution component of the IOUs' revenue requirements in 2012, scaled up to the rest of the state by load ($12.218B). Distributed generation costs are approximated as a fixed input $/MWh times the total rooftop solar generation in each year.

3.1.5 COST ALLOCATION

PATHWAYS also allocates electricity costs to each sector based on an embedded cost framework designed to accommodate new phenomena in the electricity sector like flexible loads, energy storage, and fuel production loads. In this framework, the average electricity rate in each sector (residential, commercial, industrial, transportation, and fuel production) depends on the sector's contribution to the need for: conventional generation investments and fixed O&M costs; fuel and variable O&M costs for conventional generation; renewable resource procurement; transmission investments; distribution system upgrade costs; distributed generation-related costs; and other costs, like program costs and fees. The methods for calculation of these contributions are summarized in Table 35.

Table 35. Electricity cost allocation methodology

Cost Component	Methodology for Allocation by Sector	Notes
Conventional Generation Fixed Costs	Percent contribution of the sector-wide load shape to the peak demand for conventional generation times the total conventional generation fixed costs	
Conventional Generation Fuel and Variable O&M Costs	Product of hourly average variable costs ($/MWh) and hourly demand	
Renewable Generation Costs	Percent contribution of the sector-wide annual energy demand to the total annual energy demand times the total renewable generation cost	Costs include renewable-driven transmission costs and energy storage costs for balancing
Transmission Costs	Percent contribution of the sector-wide load shape to the peak demand on the transmission system (net of distribution and sub-transmission level generation) times the total annual sustaining transmission costs	Excludes renewable-driven transmission costs
Distribution Costs	Percent contribution of the sector-wide load shape to the peak demand on the distribution system times the total annual sustaining distribution costs	Excludes distributed generation-driven transmission costs
Distributed Generation Interconnection Costs	Percent of distributed PV installed capacity by sector times the total distributed generation-related distribution costs	
Other (programs and fees)	Percent contribution of sector-wide annual energy demand to total annual energy demand	

The resulting cost allocation is shown for the Reference Case in Figure 18, juxtaposed against the 2013 historical allocation of electricity costs in the IOUs.

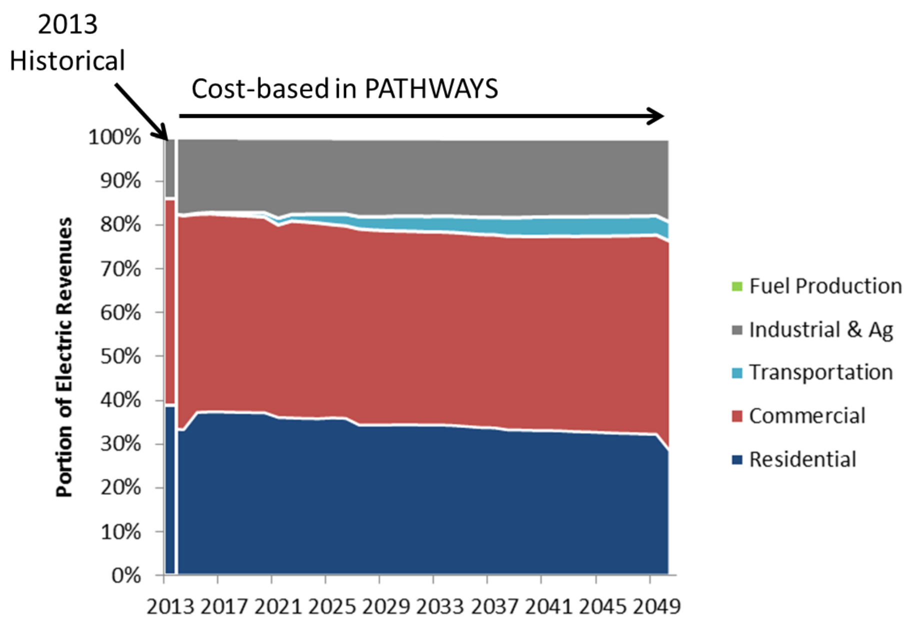


Figure 18. Cost allocation results for the Reference Case, shown against the 2013 average cost allocation across the IOUs

The allocated electricity system costs by sector are then divided by the sector-specific electricity demand (gross demand, as electricity system costs include the costs of behind-the-meter CHP and rooftop PV resources) to produce an average electricity rate by sector. These average rates flow through each sector module to calculate sector-wide energy costs.

3.1.6 EMISSIONS

The electricity module also calculates an average emissions rate for electricity generation based on the emissions rates specified for each generating technology, the energy generated by each technology in each year, and the carbon capture fraction of each technology (if CCS is employed). The average emissions rate, E, for electricity is therefore:

Equation 78

$$E = \frac{\sum_{k,t} P_{k,t} \times e_k \times \left(1 - f_k^{CC}\right)}{Total\ Sales}$$

where $P_{k,t}$ is the power output in hour t (within the year of interest), e_k is the emissions rate, which is equal to the carbon intensity of the fuel times the heat rate, and f_k^{CC} is the carbon capture fraction for technology k. This emissions rate is applied to the electricity demand associated with each sector to determine the contribution of electricity emissions to each sector's total emissions.

3.1.6.1 CHP emissions accounting

One exception to this approach is the emissions accounting for combined heat and power (CHP) resources. The electricity sector models gross electric generation from CHP resources (both the power used onsite and the power exported to the grid) because PATHWAYS tracks gross electricity demand by sector. For emissions accounting, the average heat rate of existing CHP facilities is tuned to match the total historical CHP emissions in 2012 (including all inventoried emissions allocated to the electricity sector as well as the commercial and industrial sectors). In PATHWAYS, the total emissions obtained using this gross heat rate must then be allocated to the electricity sector based on total electricity generation and to the sectors in which CHP resources are providing heating services. The portion allocated to electricity, f_{elec}, is determined based on the power-to-heat ratio, r_{p2h}, of the CHP resources by technology type, according to:

Equation 79

$$f_{elec} = \frac{r_{p2h}}{1 + r_{p2h}}$$

The assumed power-to-heat ratios (based on EIA Form 923) are listed in Table 36.

Table 36. CHP technology power to heat ratios (EIA Form 923)

CHP Technology	Power to Heat Ratio (Btu Electric/Btu Thermal)
Existing CHP	1.23
Phosphoric Acid Fuel Cell (PAFC) - 200 kW	1.17
PAFC – 400 kW	1.17
Molten Carbonate Fuel Cell (MCFC) - 300 kW	2.13
MCFC – 1,500 kW	2.15
Gas Turbine – 3,000 kW	0.68
Gas Turbine – 10 MW	0.73
Gas Turbine – 40 MW	1.07

CHP Technology	Power to Heat Ratio (Btu Electric/Btu Thermal)
Microturbine – 65 kW	0.54
Microturbine (multi-unit) – 250 kW	0.71
Reciprocating Engine (rich burn) – 100 kW	0.56
Reciprocating Engine (clean burn) – 800 kW	0.79
Reciprocating Engine (clean burn) – 3,000 kW	0.97
Reciprocating Engine (clean burn) – 5,000 kW	1.12

3.1.6.2 Exports emissions accounting

PATHWAYS also allows limited exports of electricity out of California to meet demands elsewhere in the Western Interconnect when California would otherwise curtail renewable energy. The default assumption is that up to 1,500 net MW can be exported out of California, based largely on historical exports to the Pacific Northwest.[25] In hours in which California exports power, PATHWAYS does not reduce the greenhouse emissions attributed to California, consistent with current ARB Emission Inventory accounting protocol.

[25] Note that historically California has not net exported under any conditions because as power is sent from California to the Pacific Northwest, it is also being imported from the Southwest into California. The assumption of net exports out of California represents a significant departure from historical flows across the Western Interconnect and requires more detailed study.

3.2 Pipeline gas

The term pipeline gas is used here and throughout the PATHWAYS model to acknowledge the potential of the pipeline to deliver products other than traditional natural gas. PATHWAYS models multiple decarbonization strategies for the pipeline including biomass conversion processes, hydrogen, and synthetic methane from power-to-gas processes. Below is a description of the commodity products included in the pipeline in our decarbonization scenarios as well as a discussion of the approach to modeling delivery charges for traditional as well as compressed and liquefied pipeline gas.

PATHWAYS models the California pipeline system's delivery of pipeline gas as well as compressed pipeline gas, and liquefied pipeline gas for transportation uses. We model these together in order to assess the capital cost implications of changing pipeline throughput volumes. Delivery costs of pipeline gas are a function of capital investments at the transmission and distribution-levels and delivery rates can be broadly separated into core (usually residential and small commercial) and non-core (large commercial, industrial, and electricity generation) categories. Core service traditionally provides reliable bundled services of transportation and sales compared to non-core customers with sufficient volumes to justify transportation-only service.

To model the potential implications of large changes in gas throughput on delivery costs, we use a simple revenue requirement model for each California IOU. This model includes total revenue requirements by core and non-core customer designations, an estimate of the real escalation of costs (to account for increasing prices of commodities, labor, engineering, etc.) of delivery services, an estimate of the remaining capital asset life of utility assets, and the percent of the delivery rate related to capital investments. These last two model inputs influence the rate at which the rate base depreciates, which will affect the delivery rates under scenarios where there is a rapid decline in pipeline throughput that outpaces capital depreciation. We assume that 50% of the revenue requirement of a gas utility is related to throughput growth and that capital assets have an average 30-year remaining financial life. This means that the revenue requirement at most could decline 1.7% per year and that any decline in throughput exceeding this rate would result in escalating delivery charges for remaining customers. This is a result of utilities being forced to recover revenue from a declining amount of throughput, increasing rates for remaining customers and potentially encouraging fuel switching, thus accelerating the process. These costs will have to be recovered and so need to continue to be represented even in scenarios where there are rapid declines in pipeline throughput.

3.3 Natural Gas

3.3.1 COMPRESSED PIPELINE GAS

We model the costs of compression facilities at $.87/Gallons of Gasoline Equivalent (GGE) based on an average of cost ranges reported by Argonne National Laboratory （Argonne National Laboratory，2010）. Additionally, we model the electricity use of compressing facilities at 1 kWh per GGE based on the same report. These inputs affect the emissions associated with compressed pipeline gas relative to pipeline gas.

3.3.2 LIQUEFIED PIPELINE GAS

We model the non-energy costs of liquefaction facilities at $.434/Gallons of Gasoline Equivalent (GGE) based on an analysis by the Gas Technology Institute （Gas Technology Institute，2004）. Additionally, we model the electricity use of liquefaction facilities using electric drive technologies at $3.34 kWh per GGE based on the same report. These inputs affect the emissions associated with liquefied pipeline gas relative to pipeline gas.

3.4 Liquid Fossil Fuels

Liquid fuels are primarily fuels used for transportation and include diesel, gasoline, jet-fuel, and hydrogen as well as LPG. We model biofuel processes for both diesel fuel as well as gasoline that are described in Section 3.7. Jet-fuel and LPG are only supplied as conventional fossil fuels. The sections below discuss conventional fossil price projections as well as liquid hydrogen delivery.

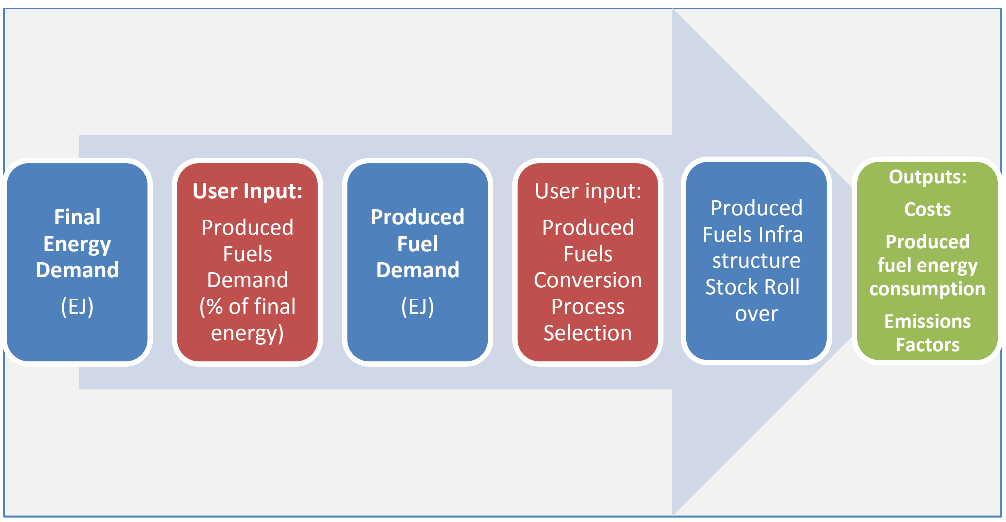
3.5 Refinery and Process Gas; Coke

We do not model any costs associated with refinery and process gas. We do model the costs of coke from the 2013 AEO Reference Case scenario.

3.6 Synthetically produced fuels

PATHWAYS’ Produced Fuel Module calculates the energy demand, cost, and emissions associated with hydrogen and synthetic methane. Demand for these fuels is combined with user-selected conversion processes to drive demand for produced fuels production facilities. PATHWAYS uses vintage-specific cost and conversion efficiency inputs to calculate stock-average production cost and efficiency values, drawing on a stock roll-over mechanism. These average cost and efficiency values are then used, along with final demand for produced fuels, to calculate the energy demand (GJ of energy input), cost ($/GJ), and emissions intensity (kgCO_2/GJ) of produced fuels.

Figure 19. Produced Fuels Module Framework



3.6.1 CONVERSION PROCESSES FOR PRODUCED FUELS

In PATHWAYS, hydrogen can be produced through three conversion pathways: (1) electrolysis, which uses electricity as an energy source and water as a source of hydrogen; (2) steam reforming, which uses natural gas as an energy and hydrogen source; (3) steam reforming with carbon capture and storage, which captures the CO_2 emitted from natural gas in the reforming process. The share of hydrogen demand met by each of these pathways is user defined. Synthetic methane is only produced through methanation, a process that converts hydrogen produced through electrolysis and CO2 into methane. Table 37 shows the assumed cost and efficiency parameters for these four conversion processes.

Table 37. Conversion process inputs

Produced fuel type (t)	Conversion process (c)	Input energy (i)	Conversion efficiency (CE)	Levelized annual capital costs (PF.ACC)	Levelized non energy operating Costs (PF.OCC)	CO_2 capture ratio (CC)
Hydrogen	Electrolysis	Electricity	65%-78% (LHV)	$0.65-1.53/kg-year	$0.05/kg	N/A
Hydrogen	Reformation	Natural Gas	62%-71% (LHV)	$0.54-0.68/kg-year	$0.17/kg	N/A
Hydrogen	Reformation w/CCS	Natural Gas	62%-71% (LHV)	$0.47-0.59/kg-year	$0.17/kg	0.9
Synthetic Methane	Methanat-ion	Electricity	52%-63% (HHV)	$7.6-18.5/MMBTU-year	$6.5/MMBTU	N/A

3.6.2 DEMAND FOR PRODUCED FUELS

Final demand for produced fuels (PFD, in GJ/yr) is determined both directly by final demand sectors (e.g., hydrogen demand in the transportation sector), and indirectly through demand for energy carriers that contain produced fuels (e.g., residential demand for pipeline gas that contains hydrogen and synthetic methane). The shares of produced fuels in a given final energy carrier during a given timeframe are user-determined; users input shares in a start and end year and PATHWAYS linearly interpolates annual shares between these points.[26] Each produced fuel is tracked in PATHWAYS by conversion process.

[26] When produced fuels are used as final energy carriers, SF is set to 100%. Before the user-specified start year, SF is set to zero.

Equation 80

$$PFD_{tcy} = \sum_{e} FEC_{ey} \times SF_{tey} \times PF_{tcy}$$

$$SF_{tey} = SF_{tey_0} + \frac{SF_{tey_T} - SF_{tey_0}}{y_T - y_0} \times (y - y_0)$$

New Subscripts

t	produced fuel type	hydrogen, synthetic methane
c	conversion process	electrolysis, reforming, reforming w/ CCS, methanation
E	final energy carrier	pipeline gas, hydrogen, electricity
Y	year	is the model year (2014 to 2050)
y_0	start year	user input value, between 2014 and 2049
y_T	end year	user input value, between 2015 and 2050

New Variables

PFD_{tcy}	Final demand for produced fuel type t and conversion process type c in year y
FEC_{ey}	Final energy consumption of final energy carrier e in year y
SF_{tey}	Share of fuel type t in final energy carrier e (e.g., share of synthetic methane in pipeline gas) in year y
PF_{tcy}	Share of fuel type t from conversion process c (e.g., share of hydrogen produced through electrolysis) in year y

3.6.3 STOCK ROLL-OVER MECHANICS FOR PRODUCED FUELS

The Produced Fuels Module includes a stock roll-over mechanism that governs changes in the composition of produced fuels' infrastructure over time, including costs and efficiency of production. The mechanism tracks production facility vintages — the year in which a facility was constructed — by census region. At the end of each year, PATHWAYS retires or rebuilds some amount of a given production facility for conversion type c in a given region ($S.RET_y$), by multiplying the initial stock of each vintage (S_{vy}) by a replacement coefficient (β_{vy}).

Equation 81

$$S.RET_{tcvy} = S.EXT_{tcvy} \times \beta_{vy}$$

New Variables

$S.RET_{ctvy}$	is the amount of existing production facilities of vintage v of conversion process c to produce fuel type t retired or replaced in year y
β_{vy}	is a replacement coefficient for vintage v in year y

The replacement coefficients are generated by a survival function that uses Poisson distribution, with a mean (λ) equal to the expected useful life of the facility.

Equation 82

$$\beta_{vy} = e^{-\lambda} \frac{\lambda^{y-v+1}}{(y-v+1)!}$$

Growth in final demand for produced fuel is used to project the growth of production facility stock (maximum EJ of production capacity per year), using an assumed capacity factor.

Equation 83

$$S.GRW_{tcy} = \frac{PFD_{tcy} - PFD_{tcy-1}}{CF_{tc}}$$

New Variables

$S.GRW_{tcy}$	Growth in stock of production facilities producing fuel type t with conversion process c in year y
CF_{tc}	Capacity factor of production facilities producing fuel type t with conversion process c

At the beginning of the following year (y+1), PATHWAYS replaces retired stock and adds new stock to account for growth in produced fuels. The vintage of these new stock additions is then indexed to year y+1.

Equation 84

$$S.NEW_{tcy+1} = \sum_{v} S.RET_{tcvy} + S.GRW_{tcy}$$

New Variables

$S.NEW_{tcy+1}$	New stock of production facilities producing fuel type t with conversion process c in year y+1

3.6.4 ENERGY CONSUMPTION OF PRODUCED FUELS

Because produced fuels are derived from other energy carriers, the Produced Fuels Module receives its energy input from energy supply modules (e.g., the Electricity Module). These energy supply modules must provide the energy both to meet final demand for produced fuels and to cover the energy lost in conversion processes. The calculated consumption of produced fuel energy inputs is used in other energy supply modules, like the Electricity Module. These energy supply modules must meet the demand from final energy modules as well as this energy demand from produced fuels processes. The equation used to calculate the energy demand from produced fuels processes is shown below.

Equation 85 Produced fuel energy consumption

$$PF.EC_{ity} = \sum_{c} \sum_{v} PFD_{cy} * CE_{vce} * \frac{S.EXT_{vcy}}{S.EXT_{cy}} * P_{iy} * PF_{ctv}$$

New Subscripts

i	energy input	electricity, natural gas

New Variables

$PF.EC_{ity}$	is the energy consumption of input energy type i for produced fuel type t in year y
CE_{tcv}	Conversion efficiency of vintage v production facilities producing fuel type t with conversion process c
$S.EXT_{tcvy}$	Existing stock of vintage v production facilities producing fuel type t with conversion process c in year y
$S.EXT_{tcy}$	Existing stock of production facilities producing fuel type t with conversion process c in year y

3.6.5 TOTAL COST OF PRODUCED FUELS

Total produced fuel costs (PF.T, $ per GJ of fuel produced) are composed of the fixed capital costs (PF.C), energy costs (PF.E), and non-energy operating costs (PF.O) of production facilities.

Equation 86

$$PF.T_{ty} = PF.C_{ty} + PF.E_{ty} + PF.O_{ty}$$

New Variables

$PF.T_{ty}$	Total cost ($/GJ) of produced fuel type t in year y
$PF.C_{ty}$	Capital cost ($/GJ) of produced fuel type t in year y
$PF.E_{ty}$	Energy cost ($/GJ) of produced fuel type t in year y
$PF.O_{ty}$	Operating cost ($/GJ) of produced fuel type t in year y

Annualized capital costs for produced fuels (PF.C) are indexed by vintage, as shown in Equation 87.

Equation 87

$$PF.C_{ty} = \sum_{c}\sum_{v}\frac{PF.ACC_{tcv} \times S.EXT_{tcvy}}{PFD_{tcy}}$$

New Variables

$PF.ACC_{tcv}$	Annualized unit capital cost of vintage v production facilities producing fuel type t with conversion process c

Energy costs for produced fuels (PF.E) are determined by the cost of energy inputs divided by vintage-weighted conversion efficiency.

Equation 88

$$\boldsymbol{PF.E_{ty} = \sum_{c}\sum_{i}\frac{P_{iy} \times PF.EC_{ity}}{PFD_{tcy}}}$$

New Variables

P_{iy}	Price of input energy i in year y

Non-energy operating costs for produced fuels (PF.O) are based on vintage-specific operating costs.

Equation 89

$$PF.O_{ty} = \sum_{c}\sum_{v}\frac{PF.AOC_{tcv} \times S.EXT_{tcvy} \times CF_{tc}}{PFD_{tcy}}$$

New Variables

$PF.AOC_{tcv}$	Annual non-energy operating cost for vintage v production facilities producing fuel type t with conversion process c

3.6.6 EMISSIONS FACTORS FOR PRODUCED FUELS

The emissions factor for produced fuels is a function of the total emissions associated with the input energy to the produced fuels divided by the total fuel production.

Equation 90

$$CEF_{ty} = \sum_{c}\sum_{i}\frac{PTD_{tciy} \times CEF_{iy} \times CC_{c}}{PFD_{tcy}}$$

New Variables

CEF_{ty}	CO_2 emissions factor of produced fuel type t in year y
PTD_{tciy}	Total energy demand for fuel type t produced with fuel type c and energy input i in year y
CEF_{iy}	CO_2 emissions factor for input energy i in year y
CC_c	is the CO_2 emissions capture ratio of conversion process c

3.7 Biomass and Biofuels

The biomass and biofuel assumptions in version 2.4 of the PATHWAYS model are based on biofuel inputs from scenarios developed in the California Air Resources Board Biofuel Supply Module (BFSM). The BFSM uses the PATHWAYS transportation energy demand by scenario as an input in order to calculate the reduction in carbon intensity of transportation fuels based on the requirements and definitions of the Low Carbon Fuel Standard (LCFS). The BFSM then calculates the type and quantity of transportation biofuels that would be cost-effective for consumers relative to fossil fuel prices for gasoline, diesel, and compressed natural gas, given a set of assumptions about the Renewable Fuel Standard, LCFS prices, carbon prices and the cost of delivered biofuels. For more information about the biofuel assumptions used in the scenarios, see ARB's Technical Documentation of the Biofuel Supply Module.[27]

The BFSM provides the PATHWAYS model with estimated annual cost-effective transportation biofuel quantities by type, based on transportation fuel demand and LCFS credit prices consistent with each scenario's input assumptions. PATHWAYS uses these quantities of final biofuel supply as inputs. The BFSM uses lower heating value accounting; PATHWAYS converts all values to be consistent with higher heating value accounting.

3.7.1 DELIVERED COST OF BIOFUELS

The BFSM provides PATHWAYS with selected biomass quantities by feedstock type and price, as well as conversion costs, transportation costs and process efficiency assumptions. The final costs of delivered biofuels for ethanol, renewable gasoline, biodiesel, renewable diesel and biogas are calculated in PATHWAYS.

The quantities of biofuels in each scenario, as calculated in the BFSM, are based on a supply curve approach which compares the subsidized biofuel cost (including LCFS credits, carbon prices, federal subsidies and other potential policy levers) to the cost of the fossil fuel alternative. While these subsidies play a role in determining the mix and quantities of biofuels selected in each scenario in the BFSM, they are not included in the delivered fuel costs calculated in PATHWAYS

[27] Biofuel Supply Module Technical Documentation available as part of the materials from the September 14, 2016 CARB Public Workshop on the Transportation Sector to Inform Development of the 2030 Target Scoping Plan Update, available here: **www.arb.ca.gov/cc/scopingplan/meetings/meetings.htm**

as they generally represent transfers within the state. The PATHWAYS delivered biofuel costs are meant to represent the total cost to produce and deliver biofuels to California. As a result, biofuel costs in PATHWAYS and the BFSM will be different.

In order to calculate the delivered cost of biofuels, PATHWAYS first determines the marginal selected resource by biofuel type (e.g., biomethane, renewable gasoline, renewable diesel, biodiesel and ethanol) by creating a supply curve from the selected feedstocks, as determined by the BFSM model. Biofuel costs for each biofuel type are priced at the all-in cost of this marginal resource for each scenario, which includes feedstock costs, transportation costs, conversion costs, and delivery costs.

3.7.2 EMISSIONS INTENSITY OF BIOFUELS

The emissions intensity of delivered bioenergy in PATHWAYS is assumed to be zero, and emissions associated with producing fuels and feedstocks outside of California are not considered, consistent with the ARB Emission Inventory accounting protocols.

In contrast, the BFSM applies the LCFS lifecycle emissions accounting framework, which takes into account all GHG emissions (or savings) associated with the production, transportation, and use of a given fuel, whether they occur in-state or out-of-state. For example, avoided greenhouse gas emissions from methane that would have otherwise been released from manure had the biogas not been captured for use as a fuel, are credited to transportation fuels under the LCFS lifecycle emissions accounting framework. Under the ARB emissions inventory accounting, these avoided methane emissions are reflected in the "non-energy, non-CO2" sector in PATHWAYS rather than as part of biofuels carbon accounting in the transportation fuels sector.

This difference in GHG accounting between the PATHWAYS model and the BFSM is not a problem from an analytical perspective, since the differences reflect how greenhouse gas emissions are allocated between fuels and sectors. However, it is important to keep in mind this distinction in GHG accounting when comparing results across models. For example, while the BFSM may calculate a scenario that has a 20% reduction in the carbon intensity of fuels using the LCFS lifecycle emissions accounting framework, the PATHWAYS model, using the ARB emission inventory framework, will typically show fewer carbon reductions coming from biofuels for the same total quantity of biofuels.

4 Non-Energy, Non-CO_2 Greenhouse Gases

PATHWAYS' Non-Energy/Non-CO_2 Module, called the NON module for the rest of this document, is used to project emissions from sources not related to energy conversion, e.g. chemically created CO_2 from cement manufacturing, and sources of non-CO_2 greenhouse gases, such as methane. Regardless of gas, all emissions are tracked using 100-year global warming potential CO_2 equivalent (CO_2eq) units, according to conversion and reporting guidelines for CARB's emissions inventory, which follows IPCC conventions.

NON categories are listed in Table 38, along with their tracked emissions and the method used to forecast their baseline emissions. Different categories in the NON module employ different forecasting techniques. Methane, N_2O, and CO_2 emissions are based on the 2016 ARB Inventory[28] for years 2000-2014, and then are held constant in the baseline forecast after 2014. F-gas forecasts are based on an external model of fugitive emissions developed by CARB which projects the total F-gas emissions trajectory to 2030, along with subsector disaggregation based on the proportions found in the CALGAPS model.[29]

[28] **https://www.arb.ca.gov/cc/inventory/data/data.htm**, Accessed in June 2016.

[29] Greenblatt, Jeffery B. 2015. "Modeling California Policy Impacts on Greenhouse Gas Emissions." Energy Policy 78 (March): 158–72. doi:10.1016/j.enpol.2014.12.024.

Table 38. NON Module emission categories and their primary emissions

Category	Emissions	Forecast method
Cement	CO_2 chemically released during production	Constant
Waste	Biogenic methane from landfills and waste water	Constant
Petroleum Refining	Fugitive methane	Constant
Oil Extraction Fugitive Emissions	Fugitive methane	Constant
Electricity Gen. Fugitive and Process Emissions	Fugitive methane and CO_2	Constant
Pipeline Fugitive Emissions	Fugitive methane	Constant
Agriculture: Enteric	Biogenic livestock methane from digestion	Constant
Agriculture: Soil Emissions	N_2O from fertilized soils	Constant
Agriculture: Manure	Methane from decaying manure	Constant
Agriculture: Other	Biomass burning CO_2 and rice methane	Constant
Fgas: RES	Fugitive refrigerants: CFCs, HCFCs, and HFCs	CARB forecast[a]
Fgas: COM	Fugitive refrigerants: CFCs, HCFCs, and HFCs	CARB forecast[a]
Fgas: IND	Fugitive refrigerants: CFCs, HCFCs, and HFCs	CARB forecast[a]
Fgas: LDV	Fugitive refrigerants: CFCs, HCFCs, and HFCs	CARB forecast[b]
Fgas: HDV	Fugitive refrigerants: CFCs, HCFCs, and HFCs	CARB forecast[b]
Fgas: Other trans	Fugitive refrigerants: CFCs, HCFCs, and HFCs	CARB forecast[b]
Fgas: Electricity	Primarily fugitive SF_6 from electrical equipment	CARB forecast[a]
Land: Fire	primarily CO_2, but not well quantified	Not included
Land: Use change	primarily CO_2, but not well quantified	Not included

[a] Emissions from 2010-2014 are based on the CARB inventory. Emissions from 2015-2030 are extrapolated from 2014 based on a linear trend between 2014-2030 using the CARB forecast for 2030 total F-gas emissions. Emissions after 2030 are extrapolated using the CALGAPS projected growth relative to 2030.

[b] Emissions from 2010-2014 are based on the CARB inventory for total transportation F-gas emissions, with subsector disaggregation based on CALGAPS. Emissions from 2015-2030 are extrapolated from 2014 based on a linear trend between 2014-2030 using the CARB forecast for

2030 total F-gas emissions. Emissions after 2030 are extrapolated using the CALGAPS projected growth relative to 2030.

Table 39 details how NON Module categories are mapped to CARB inventory categories for the methane, N_2O, and CO_2 emissions, using the IPCC disaggregation of the CARB inventory. The F-gas categories are based on the Scoping Plan category disaggregation of emissions in the CARB inventory, with transportation subsector disaggregation based on CALGAPS.

Table 39. Mapping of PATHWAYS non-energy GHG categories to IPCC categories

Category	California Emission Inventory Category IPCC level
Agriculture: Enteric	IPCC Level 1: Agriculture, etc. & IPCC Level 3 - 3A1 - Enteric Fermentation
Agriculture: Manure	IPCC Level 1: Agriculture, etc. & IPCC Level 3: 3A2 - Manure Management
Agriculture: Soil	IPCC Level 1: Agriculture, etc. & IPCC Level 3: 3C2 - Liming, 3C4 - Direct N2O Emissions, 3C5 - Indirect N2O Emissions
Agriculture: Other	IPCC Level 1: Agriculture, etc. & IPCC Level 3: 3C1 - Emissions from Biomass Burning, 3C7 - Rice Cultivations
Cement	IPCC Level 1: Industrial & IPCC Level 3: 2A1 - Cement Production
Waste	IPCC Level 1: Waste
Petroleum Refining	IPCC Level 1: Energy and IPCC Level II Fugitive and Sector: Petroleum Refining
Oil & Gas Extraction	IPCC Level 1: Energy and IPCC Level II Fugitive and Sector: Oil Extraction
Electricity Fugitive Emissions	IPCC Level 1: Energy and IPCC Level 2: 1B - Fugitive and all 'Sector and Activity Details' related to electricity generation including CHP
Pipeline Fugitive Emissions	IPCC Level 1: Energy and IPCC Level II Fugitive and Sector: Pipelines Natural Gas

The rest of this section describes methods for forecasting reference CO_2eq emissions for F-gases and defining and implementing mitigation measures in the NON Module.

4.1.1 FORECASTS FOR F-GASES

Baseline emissions trajectories for F-gas categories are built from a combination of CARB inventory trajectories and those used in the CALGAPS model. The key observation is that F-gases leak out of equipment to become fugitive emissions during their normal operating lives. These emissions happen at different rates for different types of equipment, with the leakiest connections belonging to commercial refrigeration and car air conditioning (AC) units and the biggest charges of gas belonging to commercial refrigeration. There are also emissions associated with final disposal at the end of equipment life, especially refrigerators and AC units. Given charge sizes and leakage factors, combined operational and end of life total emissions (in volume of gas) can be calculated each year for the whole stock of each equipment type. Determining the composition, and therefore the average GWP, of the leaking gases is the other half of the calculation.

The gases used vary by type and vintage of equipment, so the CARB F-gas model tracks the number of each vintage of equipment in use over time, with assumptions about lifetimes determining the retirement rate of older equipment. The effective GWP of F-gases in use (and therefore leaked) is the weighted average of the GWP of all the individual pieces of equipment, and therefore changes from year to year.

Policy drivers are the primary reason the compositions have changed. Until the early 1990s, when the Montreal Protocol took hold, the F-gases used as refrigerants were CFCs, some of the most potent ozone depleting substances. Gradually CFCs have been replaced with HCFCs and HFCs, which do not significantly deplete ozone, but are very potent greenhouse gases. Now, the potent greenhouse gases are starting to be replaced by gases with lower GWP. The Reference forecast is based on estimated F-gas deployment from carrying out existing state and federal regulations prior to the 2016 Kigali Amendment to the Montreal Protocol, which will reduce the U.S. production and consumption of HFCs starting in 2019.

4.1.2 LAND USE/LAND CHANGE

Land: Use and **Land: Fire** categories of NON Module emissions are not included in the current California emission inventory data, and as a result a not currently modeled in PATHWAYS.

4.2 Mitigation measures

NON Module emission measures consist of several attributes, which are detailed in Table 40.

Table 40: Attributes of NON Module emission measures

Attribute	Description
Category	The category of emissions the measure applies to
Impact	The fraction of emissions the measure eliminates by the saturation year and after
Start Year	The first year of measure impact
Saturation Year	The year the measure reaches its full potential
Levelized Cost	The levelized cost of the measure implementation in $/TCO2eq

Between the start year and the saturation year, measure impacts follow a linear ramp, achieving the full impact fraction by the saturation year.

Equation 91: The fraction of emission reduced per year

$$FEI_{jmy} = max\left(min\left(\frac{y_{sat} - y}{y_{sat} - y_{start}}, 1\right), 0\right) \times ECI_{jm}$$

New Variables

FEI_{jmy}	fraction of emissions impacted per measure m per emission category j in year y
y_{sat}	saturation year
y_{start}	measure start year
ECI_{jm}	fractional emission change (aka Impact) per measure m per emission category j

Note that the saturation calculation is forced by the *max* and *min* functions to fall within limits of 0 and 1, representing the period prior to implementation and the period after complete saturation, respectively.

4.3 Emissions Calculations

Equation 92: Emissions change

$$EC_{jmy} = FEI_{jmy} \times RE_{jy}$$

New Variables

EC_{jmy}	emission change per measure m per emission category j in year y
RE_{jmey}	reference case emissions for category j in year y

Measure costs are already expressed in levelized \$/TCO_2eq, so mitigation cost calculations are a simple multiplication.

Equation 93: Costs

$$N.AMC_y = \sum_j \sum_m EC_{jmy} \times LC_m$$

New Variables

N.AMC$_{ey}$	annualized measure costs in year y
LC$_m$	levelized costs for measure m

Because emissions in TCO_2eq are tracked directly in the NON Module, sector total emissions are simply calculated as the sum across all categories of emission after mitigation measures have been applied.

Equation 94: Final emissions

$$N.CO2_y = \sum_j \sum_m (RE_{jy} - EC_{jmy})$$

New Variables

N.CO2$_y$	NON Module total emissions (TCO_2eq) in year y