NEEDS v.6 User Guide, May 2019

The National Electric Energy Data System (NEEDS) is the database of existing and planned-committed units which are modeled in the EPA Initial Run v.6. Units that are currently operational in the electric industry are termed as “existing” units. Units that are not currently operating but are firmly anticipated to be operational in the future, and have either broken ground (initiated construction) or secured financing are termed “planned-committed”.

It is important to note that the NEEDS database only describes the configuration of the fleet for the model’s first projection year; NEEDS may not include representation of retrofits or retirements that may be expected to occur (e.g., pursuant to a finalized enforcement action, as described in the next paragraph) by a date subsequent to the first projection year. One advantage of this approach is that the model retains the flexibility to select the least-cost response of affected units to those future-year requirements, instead of requiring the analyst to presuppose a particular response (as would be necessary for representation in NEEDS). For example, some enforcement actions allow affected facilities to select from different combinations of retrofits and retirements across multiple units by specified deadlines occurring in the future modeling horizon. Under this modeling approach, the NEEDS database would show the “starting point” conditions of the affected units (i.e., their expected configuration as of the end of 2020) and the model would be given a separate constraint describing subsequent operating requirements affecting those units (i.e., an enforcement action’s terms requiring retrofits or retirements by a future year such as 2025).

The modeling constraints affecting future unit behavior that are imposed as run specifications include federal and state environmental regulations, enforcement action settlements and consent decrees, and energy efficiency and renewable portfolio standards. The specific constraints included in the IPM v.6 platform are described in section 3.9 of the IPM Documentation available at https://www.epa.gov/airmarkets/clean-air-markets-power-sector-modeling. These constraints, as inputs to the model, also appear in the RPT Replacement Files (Excel file) in the “Environmental Measures” workbook for any given IPM analysis; the constraints included for EPA’s Initial Run Using IPM v.6 are reported on this worksheet in the model input/output files posted on EPA’s power sector modeling website, https://www.epa.gov/airmarkets/clean-air-markets-power-sector-modeling

Starting in the May 2019 version of NEEDS v6, a new worksheet "New Capacity Hardwired" was added to NEEDS. Units listed on this worksheet are new units that have either come online or have come to be considered "firm" (ground broken and/or firm financial commitments have been made) since the IPM v6 Platform was released in May 2018. This new capacity has been "hardwired" into the May 2019 Reference Case, meaning the model is forced to build a specific amount and type of capacity in specific locations corresponding to the units on this worksheet, in the appropriate run years. However, in files that are developed by post-processing IPM outputs (i.e. parsed and flat files), this capacity will not be listed by specific plant names, but instead will be represented as generic new capacity.

NEEDS is maintained in spreadsheet format. Below is a guide to the fields found in NEEDS.

Field Name	Column	Definition	Key to Recurring Column Values
Plant Name	A	The plant's name.	———
UniqueID_Final	B	The unique identifier assigned to a boiler or generator within a plant. It consists of the Plant ID (or ORIS Code), an indication of whether the unit is a boiler ("B"), generator ("G"), or committed unit ("C"), and the Unit ID. For example, for the Unique ID "113_B_1", "113" is the Plant ID, "B" indicates that this unit is a boiler, and "1" indicates that the ID of the boiler is 1.	———
ORIS Plant Code	C	A unique identifier assigned to each power plant in NEEDS. While the ORIS code is unique for each plant, all generating units within a plant will typically have the same ORIS code. For committed units (i.e., those not currently operating, but firmly anticipated to be operational in the future), the entry in this field might be a dummy ORIS code assigned as a placeholder unique ID to the committed plant. (Note: ORIS originally referred to the Office of Regulatory Information Systems in the Department of Energy (DOE) Energy Information Administration (EIA) which was responsible for assigning unique identification codes to utility power plants.)	———
Boiler/Generator/Committed Unit	D	An indicator of whether the unit is a boiler, generator, or committed unit. Committed units are those with a future expected in-service date (see “On Line Year”)	B = Boiler G = Generator C = Committed Unit
Unit ID	E	The identifier assigned to each unit (boiler and/or generator) in a given plant.	———
CAMD Database UnitID	F	Unit-level identifier assigned by EPA's Clean Air Markets Division (CAMD) business system. Unlike other identification codes (e.g., ORIS codes), which are subject to change, once assigned to a unit, the CAMD Database Unit ID does not change. Used primarily for internal tracking purposes at EPA.	———
PlantType	G	The type of electric generating unit, usually defined by the "prime mover" and/or fuels burned. "Prime mover" refers to the machine (e.g., engine, turbine, water wheel) that drives an electric generator or the device that converts energy to electricity directly (e.g., photovoltaic solar and fuel cell(s)).	Biomass Coal Steam Combined Cycle Combustion Turbine Fossil Waste Fuel Cell Geothermal Hydro IGCC Landfill Gas Municipal Solid Waste Non-Fossil Waste Nuclear O/G Steam Pumped Storage Solar Tires Wind
Combustion Turbine/IC Engine	H	Clarifies the engine type for units with “Combustion Turbine” plant type. An Internal Combustion (IC) Engine is a reciprocating engine which uses pistons to extract energy from a fluid to perform work. A Combustion Turbine is a stand-alone turbine combusting fuel to drive a generator (a combined cycle less the Heat Recovery Steam Generator (HRSG)).	Combustion Turbine IC Engine
Region Name	I	The region, used in the EPA Initial Run v.6 using the Integrated Planning Model (IPM), where the generating unit is located. IPM regions are defined to enable IPM to accurately represent the operation and structure of U.S. and Canada electric power system. IPM regions are generally subdivisions of the 8 North American Electric Reliability Council (NERC) regions and aggregations of the electricity grid's contiguous control areas.	See Appendix or Figure 3-1 and Table 3-1 of the IPM Documentation for a map and description of the IPM regions

State Name	J	These five fields identify the geographic location of the unit. The State Code is the FIPS State Code, and the County Code is the FIPS County Code. New units have blanks in these columns, while committed units have zeros for county codes. Federal information processing standards (FIPS) codes are a standardized set of numeric or alphabetic codes issued by the National Institute of Standards and Technology (NIST) to ensure uniform identification of geographic entities through all federal government agencies.	———
State Code	K		———
County	L		———
County Code	M		———
FIPS5	N		———
Capacity (MW)	O	The net summer dependable capacity (in megawatts) of the unit available for generation for sale to the grid. Net summer dependable capacity is the maximum capacity that the unit can sustain over the summer peak demand period reduced by the capacity required for station services or auxiliary equipment.	———
Heat Rate (Btu/kWh)	P	The net heat input (in Btu) required to generate 1 kilowatt hour of electricity. It is a measure of a generating unit's efficiency. See Section 3.8 in the Documentation for EPA's Power Sector Modeling Platform 6 using IPM for more details.	———
On Line Year	Q	The year in which the unit is commissioned.	———
Retirement Year	R	The year in which the unit is to be decommissioned. ("9999" indicates that the unit has not been retired.)	———
Firing	S	This field, which applies only to boilers, indicates the burner type and configuration (e.g., cell, cyclone, FBC (fluidized bed combustion), stoker/SPR, tangential, or vertical). A blank appears in instances where the firing characteristics of a boiler are unknown or the unit is a not a boiler.	**Cell:** boilers that combine 2-3 standard burners into a compact, vertical assembly installed on the furnace wall; multiple cells utilized within a furnace. **Cyclone:** A special type of burner for coals with low fusion point ashes. Combustion occurs within the horizontal burner generating high temps which turn the ash into molten slag. The term "wet bottom" furnace often accompanies the cyclone burner. **FBC:** "fluidized bed combustion" where solid fuels are suspended on upward-blowing jets of air, resulting in a turbulent mixing of gas and solids and a tumbling action which provides especially effective chemical reactions and heat transfer during the combustion process. **Stoker/SPR:** stoker boilers where lump coal is fed continuously onto a moving grate or chain which moves the coal into the combustion zone in which air is drawn through the grate and ignition takes place. The carbon gradually burns off, leaving ash which drops off at the end into a receptacle, from which it is removed for disposal. **Tangential (also referred to as "corner firing"):** burners located along furnace corners in multiples of 4. Burner angle is off-set working conjunction with the opposing corner burner to create a vertical, circular swirling combustion zone within the furnace. **Turbo (wall fired burner):** Burner design for pet coke and low volatile bituminous coals (Riley trademark name: "Turbo Furnace"). Hour glass shaped furnace with rectangular shaped burners angled downwards. **Vertical:** standard furnace (assume wall fired) **Wall:** standard burner / furnace design used today. Circular burners located on the front and rear furnace walls at multiple elevations.
Bottom	T	This field, which applies only to boilers, indicates whether the bottom of the combustion chamber is "wet" (i.e., ash is removed from the furnace in a molten state) or "dry" (i.e., the boiler has a furnace bottom temperature below the ash melting point and the bottom ash is removed as a solid). A blank appears in instances where the bottom characteristics of a boiler were not known or the unit was not a boiler.	Dry Wet
Cogen?	U	This field indicates whether a unit is a cogenerator. A unit is considered a cogenerator if it produces electricity and another form of useful thermal energy (such as heat or steam), used for industrial, commercial, heating, or cooling purposes.	Y (Yes) N (No)
Modeled Fuels	V	The fuels that can be combusted or used by the unit.	Biomass Bituminous Distillate Fuel Oil Fossil Waste Geothermal Hydro Landfill Gas Lignite MSW Natural Gas Non-Fossil Waste Nuclear Fuel Petroleum Coke Pumped Storage Residual Fuel Oil Solar Subbituminous Tires Waste Coal Wind

Wet/DryScrubber	W	This field indicates if a unit has an SO2 scrubber, and, if so, whether it is a wet or dry scrubber. Also known as flue gas desulfurization (FGD) systems, SO2 scrubbers use chemical and physical absorption to remove SO2 from the flue gas. Wet scrubbers use a liquid sorbent to remove SO2 and the flue gas leaving the absorber is moisture saturated. With dry scrubbers the flue gas leaving the absorber is not saturated. For circulating fluidized bed units (as shown in the "Firing" field), this field indicates whether reagent injection is used for SO2 control. Reagent injection involves adding finely crushed limestone to the fluidized bed. During combustion, the limestone is reduced to lime, the sulfur in the fuel is oxidized to form SO2, and, in the presence of excess oxygen, the SO2 reacts with the lime particles to form calcium sulfate, which can be removed with the bottom ash or collected with the fly ash by a downstream particulate matter (PM) control device.	Dry Scrubber Wet Scrubber Reagent Injection
Scrubber_Online_Year	X	The first year of operation of an existing or committed SO_2 scrubber	———
Scrubber Efficiency	Y	The removal efficiency of the SO_2 scrubber.	———
NOx Comb Control	Z	This field indicates the NO_X combustion controls employed by a generating unit. Combustion controls reduce NO_X emissions during the combustion process generally by regulating flame characteristics such as temperature and fuel-air mixing.	**AA** Advanced Overfire Air **BF** Biased Firing (alternate burners) **BOOS** Burners-Out-Of-Service **CM** Combustion Modification/Fuel Reburning **CO** Combustion Optimization **DLNB** Dry Low NOx Burners **FR** Flue Gas Recirculation **FU** Fuel Reburning **H2O** Water Injection **LA** Low Excess Air **LN** Low NOx Burner **LNB** Low NOx Burner Technology (Dry Bottom only) **LNBO** Low NOx Burner Technology w/ Overfire Air **LNC1** Low NOx Burner Technology w/ Closed-coupled OFA **LNC2** Low NOx Burner Technology w/ Separated OFA **LNC3** Low NOx Burner Technology w/ Closed-coupled/Separated OFA **LNCB** Low NOx Cell Burner **LNF** Low NOx Furnace **MR** Methane Reburn **N2** Nitrogen **NDI** Nitrogen Diluent Injection **NGR** Natural Gas Reburn **NH3** Ammonia Injection **OFA** Overfire Air O**ther** Other **ROFA** Rotating Overfire Air **SC** Slagging **SOFA** Stationary Overfire Air **STC** Staged Combustion **STM** Steam Injection
NOx Post-Comb Control	AA	This column indicates the post-combustion NO_X emission controls at a generating unit. There are two NO_X post-combustion control options: Selective Catalytic Reduction (SCR) or Selective Non-Catalytic Reduction (SNCR). Post-combustion controls operate downstream of the combustion process and remove NOx emissions from the flue gas.	**SCR** Selective Catalytic Reduction **SNCR** Selective Noncatalytic Reduction
SCR_Online_Year	AB	The first year of operation of an existing or committed SCR	———
SNCR_Online_Year	AC	The first year of operation of an existing or committed SNCR	———
PM Control	AD	This field indicates the presence of particulate matter (PM) controls	**B** Baghouse **C** Cyclone **ESPH** Hot side electrostatic precipitator **ESPC** Cold side electrostatic precipitator **WS** Wet PM Scrubber
FlueGasConditioning_Flag	AE	Indicates if the unit has flue gas conditioning	———
Mercury_Controls	AF	Dedicated Mercury emission controls in existence at a generating unit	ACI (Activated Carbon Injection)
ACI_Online_Year	AG	The first year of operation of an existing or committed ACI	———
Mercury_Controls Efficiency	AH	The removal efficiency of the mercury control device.	———
SO2 Permit Rate (lbs/mmBtu)	AI	The SO_2 emission rate (in lb/mmBtu) limit that applies to the unit due to federal, state or local emission regulations.	———

Mode 1 NOx Rate (lbs/mmBtu)	AJ	The 4 NOx rates in NEEDS allow modeling of any conceivable scenario involving NOX controls. Mode 1 and Mode 2 reflect a unit's emission rates with its existing configuration of combustion and post-combustion (i.e., SCR or SNCR) controls. • For a unit with an existing post-combustion control, mode 1 reflects the existing post-combustion control not operating and mode 2 the existing post-combustion control operating. However: o If a unit has operated its post-combustion control year round during 2017, 2016, 2015, 2014, 2011, 2009, and 2007 years then mode 1 = mode 2, which reflects that the control will likely continue to operate year round. o If a unit has not operated its post-combustion control during 2017, 2016, 2015, 2014, 2011, 2009, and 2007 years, mode 1 will be based on historic data and mode 2 will be calculated using the method described under Question 3 in Attachment 3 1. o If a unit has operated its post-combustion control seasonally in recent years (i.e., either only in the summer or winter, but not both), mode 1 will be based on historic data from when the control was not operating, and mode 2 will be based on historic data from when the SCR was operating. • For a unit without an existing post-combustion control, mode 1 = mode 2 which reflects the unit's historic NOx rates from a recent year. See Section 3.9.2 of the Documentation for EPA Initial Run v.5.13 for more information on NOx Rates in NEEDS.	—
Mode 2 NOx Rate (lbs/mmBtu)	AK		—
Mode 3 NOx Rate (lbs/mmBtu)	AL	The 4 NOx rates in NEEDS allow modeling of any conceivable scenario involving NOX controls. Mode 3 and Mode 4 emission rates parallel modes 1 and 2 emission rates, but are modified to reflect installation of state-of-the-art combustion controls on a unit if it does not already have them. • For units that already have state-of-the-art combustion controls: Mode 3 = mode 1 and mode 4 = mode 2. See Section 3.9.2 of the Documentation for EPA Initial Run v.5.13 for more information on NOx Rates in NEEDS.	—
Mode 4 NOx Rate (lbs/mmBtu)	AM		—
Hg EMF for BIT	AN	Mercury Emission Modification Factor (EMF) when the unit combusts bituminous coal. "Mercury EMF" is defined as the percentage of fuel mercury left after accounting for the mercury removal obtained by the SO2, NOx, and particulate controls.	—
Hg EMF for SUB	AO	Mercury Emission Modification Factor (EMF) when the unit combusts subbituminous coal.	—
Hg EMF for LIG	AP	Mercury Emission Modification Factor (EMF) when the unit combusts lignite coal.	—
HCL Removal	AQ	Indicates the HCl removal efficiency based upon the exisng HCL controls such as SO2 scrubber and DSI.	—
DSI Unit	AR	Flag indicating if the unit has dry sorbent injection (DSI)	—
DSI Online Year	AS	The first year of operation of an existing or committed dry sobent injection (DSI) equipment	—
CCS	AT	Flag indicating if the unit has carbon capture and sequestration (CCS)	—
CCS Removal	AU	The CO2 removal efficiency of the CCS control	—
C2G	AV	Flag Indicating if this unit has been/will be converted from coal to gas	—
C2G Online Year	AW	The first year of operation of an existing or committed coal-to-gas (C2G) conversion	—
BART Affected Unit	AX	Flag indicating if the unit is subject to Best Available Retrofit Technology (BART) requirements	—