3. Power System Operation Assumptions

This chapter describes the assumptions pertaining to the North American electric power system as represented in the EPA 2023 Reference Case.

3.1 Model Regions

EPA 2023 Reference Case models the power sector in the contiguous United States, and 10 Canadian provinces (with Newfoundland and Labrador represented as two regions on the electricity network even though politically they constitute a single province[13]) as an integrated network.[14]

There are 67 IPM model regions covering the contiguous United States.[15] The IPM model regions are largely consistent with the regional configuration presented in the NERC Long-Term Reliability Assessments.[16] IPM model regions reflect the administrative structure of regional transmission organizations (RTOs) and independent system operators (ISOs). Further disaggregation allows a more accurate characterization of the operation of the United States power markets by providing the ability to represent transmission bottlenecks across RTOs and ISOs, as well as key transmission limits within them. Other items of note in the IPM regional definition include:

- The NERC assessment regions of MISO, PJM, and SPP cover the areas of the corresponding RTOs and are designed to better represent transmission limits and dispatch in each area. In IPM, model regions are designed to represent planning areas within each RTO and/or areas with internal transmission limits. Accordingly, MISO area is disaggregated into 14 IPM regions. PJM assessment area is disaggregated into 9 IPM regions, and SPP is disaggregated into 5 IPM regions.

- New York is disaggregated into 8 IPM regions, to better represent flows around New York City and Long Island, and to better represent flows across New York State from Canada and other United States regions. The NERC assessment region SERC is divided into Kentucky, TVA, AECI, the Southeast, and the Carolinas. New England is disaggregated into CT, ME, and rest of New England regions. ERCOT is also disaggregated into 3 IPM regions. IPM retains the NERC assessment areas within the overall WECC regions, and further disaggregates these areas using sub-regions from the WECC Power Supply Assessment. In total, WECC is disaggregated into 16 IPM regions.

Figure 3-1 contains a map showing the EPA 2023 Reference Case model regions.

Table 3-1 defines the abbreviated region names appearing on the map and gives a crosswalk between the IPM model regions, the NERC assessment regions, and regions used in the Energy Information Administration's (EIA's) National Energy Model System (NEMS) that is the basis for EIA's Annual Energy Outlook (AEO) reports.

[13] This results in a total of 11 Canadian model regions being represented in EPA 2023 Reference Case.

[14] Because United States and the Canadian power markets are being modeled in an integrated manner, IPM can model the transfer of power in between the two countries endogenously. This transfer of power is limited by the available transmission capacity in between the two countries. Hence, it is possible for the model to build capacity in one country to meet demand in the other country when economic and is operationally feasible.

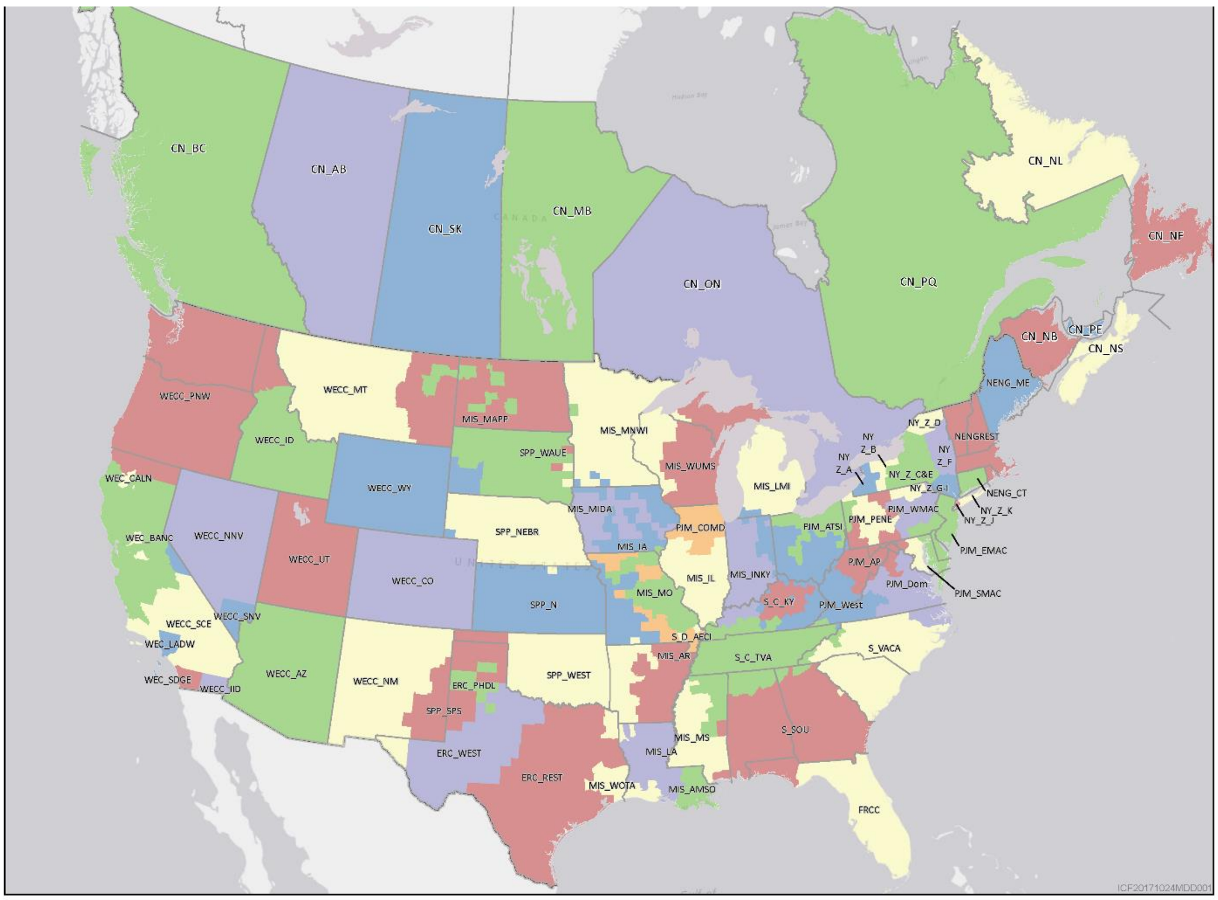
[15] The 67 U.S. IPM model regions include 64 power market regions and 3 power switching regions.

[16] IPM regions also generally conform to the boundaries of the National Energy Modeling System (NEMS) model to provide for a more accurate translation of demand projections taken from the Annual Energy Outlook (AEO).

3.2 Electric Load Modeling

Net energy for load and net internal demand are inputs to IPM that together are used to represent the grid demand for electricity. Net energy for load is the projected annual electricity grid demand, prior to accounting for intra-regional transmission and distribution losses. Net internal demand (peak demand) is the maximum hourly demand within a given year after removing interruptible demand. Table 3-2 shows the electricity demand assumptions (expressed as net energy for load) used in EPA 2023 Reference Case. It is based on the net energy for load in the AEO 2023 Reference Case.[17] Also added is the incremental demand from USEPA OTAQ's on the book rules as of end of December 2023 that are not captured in the AEO 2023 demand projections. Incremental demand was calculated by running OMEGA and MOVES models to calculate total energy consumption for all Zero Emission Vehicles (ZEVs) by EPA's OTAQ (see Attachment 3-1).

Figure 3-1 EPA 2023 Reference Case Model Regions



[17] The electricity demand in EPA 2023 Reference Case for the U.S. lower 48 states and the District of Columbia is obtained for each IPM model region by disaggregating the Total Net Energy for Load projected for the corresponding NEMS Electric Market Module region as reported in the Electricity and Renewable Fuel Tables 54.1-54.25 at https://www.eia.gov/outlooks/aeo/tables_ref.php.

For purposes of documentation, Table 3-2 and Table 3-3 present the net energy for load on a national- and regional-level, respectively. EPA 2023 Reference Case models net energy for load in each of the 67 U.S. IPM regions in the following steps:

- The net energy for load in each of the 25 NEMS electricity regions is taken from the AEO 2023 Reference Case.
- NERC balancing areas are assigned to both IPM regions and NEMS regions to determine the share of the NEMS net energy for load in each NEMS region that falls into each IPM region. These shares are calculated in the following steps.
  - Map the NERC Balancing Authorities/ Planning Areas in the United States to the 67 IPM regions.
  - Map the Balancing Authorities/ Planning Areas in the United States to the 25 NEMS regions.
  - Using the 2016 hourly load data from FERC Form 714, ISOs, and RTOs, calculate the proportional share of the load in the 25 NEMS regions that share geography with the 67 IPM regions.
  - Using the calculated load shares for each NEMS region that falls into each IPM region, calculate the total net energy for load for each IPM region from the NEMS regional load in the AEO 2023 Reference Case.

Table 3-1 Mapping of NERC Regions and NEMS Regions with the EPA 2023 Reference Case Model Regions

NERC Assessment Region	AEO 2021 NEMS Region	Model Region	Model Region Description
ERCOT	TRE (1)	ERC_REST	ERCOT_Rest
	TRE (1)	ERC_GWAY	ERCOT_Tenaska Gateway Generating Station
	TRE (1)	ERC_FRNT	ERCOT_Tenaska Frontier Generating Station
	TRE (1)	ERC_WEST	ERCOT_West
	TRE (1)	ERC_PHDL	ERCOT_Panhandle
FRCC	FRCC (2)	FRCC	FRCC
MAPP	MISW (3), SPPN (19)	MIS_MAPP	MISO_MT, SD, ND
MISO	MISC (4)	MIS_IL	MISO_Illinois
	MISC (4)	MIS_INKY	MISO_Indiana (including parts of Kentucky)
	MISW (3)	MIS_IA	MISO_Iowa
	MISW (3)	MIS_MIDA	MISO_Iowa-MidAmerican
	MISE (5)	MIS_LMI	MISO_Lower Michigan
	MISC (4)	MIS_MO	MISO_Missouri
	MISW (3)	MIS_WUMS	MISO_Wisconsin- Upper Michigan (WUMS)
	MISW (3)	MIS_MNWI	MISO_Minnesota and Western Wisconsin
	MISS (6)	MIS_WOTA	MISO_WOTAB (including Western)
	MISS (6)	MIS_AMSO	MISO_Amite South (including DSG)
	MISS (6)	MIS_AR	MISO_Arkansas
	MISS (6)	MIS_MS	MISO_Mississippi
	MISS (6)	MIS_LA	MISO_Louisiana
ISO-NE	ISNE (7)	NENG_CT	ISONE_Connecticut
	ISNE (7)	NENGREST	ISONE_MA, VT, NH, RI (Rest of ISO New England)
	ISNE (7)	NENG_ME	ISONE_Maine
NYISO	NYUP (9)	NY_Z_C&E	NY_Zone C&E
	NYUP (9)	NY_Z_F	NY_Zone F (Capital)
	NYUP (9)	NY_Z_G-I	NY_Zone G-I (Downstate NY)
	NYCW (8)	NY_Z_J	NY_Zone J (NYC)
	NYCW (8)	NY_Z_K	NY_Zone K (LI)
	NYUP (9)	NY_Z_A	NY_Zone A (West)

NERC Assessment Region	AEO 2021 NEMS Region	Model Region	Model Region Description
	NYUP (9)	NY_Z_B	NY_Zone B (Genesee)
	NYUP (9)	NY_Z_D	NY_Zone D (North)
PJM	PJME (10)	PJM_WMAC	PJM_Western MAAC
	PJME (10)	PJM_EMAC	PJM_EMAAC
	PJME (10)	PJM_SMAC	PJM_SWMAAC
	PJMW (11)	PJM_West	PJM West
	PJMW (11)	PJM_AP	PJM_AP
	PJMC (12)	PJM_COMD	PJM_ComEd
	PJMW (11)	PJM_ATSI	PJM_ATSI
	PJMD (13)	PJM_Dom	PJM_Dominion
	PJME (10)	PJM_PENE	PJM_PENELEC
SERC-E	SRCA (14)	S_VACA	SERC_VACAR
SERC-N	SRCE (16)	S_C_KY	SERC_Central_Kentucky
	MISC (4), SPPS (17)	S_D_AECI	SERC_Delta_AECI
	SRCE (16)	S_C_TVA	SERC_Central_TVA
SERC-SE	SRSE (15)	S_SOU	SERC_Southeastern
SPP	SPPN (19)	SPP_NEBR	SPP Nebraska
	SPPC (18)	SPP_N	SPP North- (Kansas, Missouri)
	SPPS (17)	SPP_KIAM	SPP_Kiamichi Energy Facility
	SPPS (17)	SPP_WEST	SPP West (Oklahoma, Arkansas, Louisiana)
	SPPS (17)	SPP_SPS	SPP SPS (Texas Panhandle)
	SPPN (19)	SPP_WAUE	SPP_WAUE
California/Mexico (CA/MX)	CANO (21)	WEC_CALN	WECC_Northern California (not including BANC)
	CASO (22)	WEC_LADW	WECC_LADWP
	CASO (22)	WEC_SDGE	WECC_San Diego Gas and Electric
	CASO (22)	WECC_SCE	WECC_Southern California Edison
Northwest Power Pool (NWPP)	NWPP (23)	WECC_MT	WECC_Montana
	CANO (21)	WEC_BANC	WECC_BANC
	BASN (25)	WECC_ID	WECC_Idaho
	BASN (25)	WECC_NNV	WECC_Northern Nevada
	BASN (25), SRSG (20)	WECC_SNV	WECC_Southern Nevada
	BASN (25)	WECC_UT	WECC_Utah
	NWPP (23)	WECC_PNW	WECC_Pacific Northwest
Rocky Mountain Reserve Group (RMRG)	RMRG (24)	WECC_CO	WECC_Colorado
	BASN (25), RMRG (24)	WECC_WY	WECC_Wyoming
Southwest Reserve Sharing Group (SRSG)	SRSG (20)	WECC_AZ	WECC_Arizona
	SRSG (20)	WECC_NM	WECC_New Mexico
	SRSG (20)	WECC_IID	WECC_Imperial Irrigation District (IID)
Canada		CN_AB	Canada_Alberta
		CN_BC	Canada_British Columbia
		CN_MB	Canada_Manitoba
		CN_NB	Canada_New Brunswick
		CN_NF	Canada_New Foundland
		CN_NL	Canada_Labrador
		CN_PE	Canada_Prince Edward island
		CN_NS	Canada_Nova Scotia
		CN_ON	Canada_Ontario
		CN_PQ	Canada_Quebec
		CN_SK	Canada_Saskatchewan

Table 3-2 Electric Load Assumptions in the EPA 2023 Reference Case

Year	Net Energy for Load (Billions-of kWh)
2028	4,459
2030	4,597
2035	4,939
2040	5,254
2045	5,576
2050	5,928
2055	6,274

Table 3-3 Regional Electric Load Assumptions in the EPA 2023 Reference Case

IPM Region	Net Energy for Load (Billions of kWh)						
	2028	2030	2035	2040	2045	2050	2055
ERC_FRNT	0	0	0	0	0	0	0
ERC_GWAY	0	0	0	0	0	0	0
ERC_PHDL	0	0	0	0	0	0	0
ERC_REST	399	411	438	466	494	529	563
ERC_WEST	35	35	38	40	43	46	49
FRCC	267	276	296	314	336	359	383
MIS_AMSO	37	37	40	42	44	47	50
MIS_AR	43	44	46	49	52	55	59
MIS_IA	23	23	25	26	27	28	29
MIS_IL	52	53	55	58	60	63	66
MIS_INKY	101	103	108	113	118	124	129
MIS_LA	56	57	60	64	68	72	77
MIS_LMI	106	109	117	123	128	135	140
MIS_MAPP	9	9	10	10	11	11	12
MIS_MIDA	29	29	31	32	34	35	37
MIS_MNWI	96	99	106	112	118	123	129
MIS_MO	42	43	46	48	50	53	55
MIS_MS	26	27	29	30	32	35	37
MIS_WOTA	38	39	41	43	46	49	52
MIS_WUMS	70	72	76	80	84	88	92
NENG_CT	34	35	39	41	44	47	49
NENG_ME	12	13	14	15	16	17	18
NENGREST	90	94	105	114	122	130	137
NY_Z_A	16	17	19	20	22	23	24
NY_Z_B	10	11	12	13	14	15	15
NY_Z_C&E	24	25	28	30	32	34	36
NY_Z_D	4	4	5	5	5	6	6
NY_Z_F	13	13	15	16	17	18	19
NY_Z_G-I	20	21	23	25	27	28	30
NY_Z_J	55	56	60	64	67	71	75
NY_Z_K	25	26	29	31	32	34	36
PJM_AP	51	52	56	58	61	65	68
PJM_ATSI	72	74	79	83	87	92	96
PJM_COMD	101	104	111	116	121	126	131
PJM_Dom	116	121	129	137	145	154	164
PJM_EMAC	154	161	179	193	206	219	230
PJM_PENE	18	19	20	21	22	24	25
PJM_SMAC	69	72	77	81	85	91	95
PJM_West	210	214	224	234	245	257	269
PJM_WMAC	59	60	63	66	70	75	79
S_C_KY	35	35	37	39	41	43	45
S_C_TVA	172	175	184	192	201	211	221
S_D_AECI	18	19	19	20	21	22	23
S_SOU	256	263	278	293	311	330	349

IPM Region	Net Energy for Load (Billions of kWh)						
	2028	2030	2035	2040	2045	2050	2055
S_VACA	237	244	259	274	293	312	332
SPP_KIAM	0	0	0	0	0	0	0
SPP_N	80	82	87	91	96	101	106
SPP_NEBR	32	33	35	37	39	41	42
SPP_SPS	37	37	39	42	44	47	50
SPP_WAUE	26	27	28	29	30	32	33
SPP_WEST	110	113	120	128	136	145	155
WEC_BANC	17	17	19	21	22	24	25
WEC_CALN	131	137	154	168	181	193	205
WEC_LADW	37	40	48	53	57	61	64
WEC_SDGE	24	25	28	31	33	35	37
WECC_AZ	105	109	119	128	138	149	162
WECC_CO	74	77	87	95	103	111	119
WECC_ID	26	27	29	31	34	37	40
WECC_IID	5	5	5	6	7	7	8
WECC_MT	14	14	15	16	18	19	21
WECC_NM	25	26	28	31	34	37	40
WECC_NNV	15	15	17	18	19	21	23
WECC_PNW	190	196	213	231	248	266	284
WECC_SCE	119	125	140	153	164	175	186
WECC_SNV	29	30	33	35	38	41	44
WECC_UT	41	42	46	50	54	58	63
WECC_WY	25	25	27	29	31	34	37

3.2.1 Distributed Solar Photovoltaics

Distributed solar photovoltaic (DPV) generation constitutes a significant and growing source of new electricity generation in the United States. As a result, DPV generation has become increasingly pertinent from an integrated resource planning perspective because it has the potential to significantly impact the shapes of the residual load curves that are available for the grid-connected generation sources to meet. The DPV implementation in EPA 2023 Reference Case seeks to reflect this impact on the load shape by directly representing the magnitude and timing of the electricity demand projected to be satisfied by distributed solar PV as part of the total net energy for load.

Electricity Demand Assumptions: Electricity demand assumptions are represented by the total net energy for load from the AEO 2023 Reference Case. To account for DPV generation, the AEO 2023 Reference Case projections of end-use solar photovoltaic generation are added to AEO 2023 Reference Case projections of net energy for load.

Unit-Level Data Assumptions: Non-dispatchable DPV model plants at the IPM region and state level are implemented in IPM to capture the impact of the DPV generation on the shapes of the residual load curves available for the grid-connected generation sources to meet. Their generation patterns are governed by assumed DPV generation profiles provided by NREL.

The capacity and capacity factors of DPV model plants are calculated as follows. First, the AEO 2023 Reference Case end-use solar photovoltaic generation and capacity data that are available at the NEMS region level are apportioned to IPM region level, using the methodology for mapping the electricity demand projections from NEMS regions to IPM regions. Then, the IPM region-level data are further apportioned to the state level, using state shares of regional energy sales as reported by the 2020 EIA Form 861. The data are next used to derive IPM region and state-level capacity factor data. Finally, the resulting IPM region and state-level capacity data are hardwired to the DPV model plants, while the capacity factor data are implemented by appropriately scaling the NREL's IPM region and state-level DPV hourly generation profiles. For this analysis, NREL's DPV hourly generation profiles for the highest resource class in each of the IPM region and state categories were scaled by multiplying the hourly generation values with the ratio between the AEO 2023 Reference Case capacity factor and the capacity factor underlying the NREL's hourly generation profiles.

3.2.2 Demand Elasticity

EPA 2023 Reference Case has the capability to endogenously adjust electricity demand based on changes to the price of power. However, this capability is exercised only for sensitivity analyses where different price elasticities of demand are specified for purposes of comparative analysis. The default assumption is that the electricity demand shown in Table 3-2, which was derived from EIA modeling that already considered price elasticity of demand, is static as IPM solves for least-cost electricity supply. The approach maintains a consistent expectation of future load between the EPA Platform and the corresponding EIA Annual Energy Outlook reference case (e.g., between EPA 2023 Reference Case and the AEO 2023 Reference Case).

3.2.3 Net Internal Demand (Peak Demand)

EPA 2023 Reference Case has separate regional winter, spring, summer, and fall peak demand values, as derived from each region's seasonal load duration curve (found in Table 2-2). Peak projections for the 2028-2032 period were estimated based on NERC ES&D 2022 load factors[18], and the estimated energy demand projections are shown in Table 3-3. For post 2032 years when NERC ES&D 2022 load factors were not available, the NERC ES&D 2022 load factors for 2032 were projected forward using growth factors embedded in the AEO 2023 Reference Case load factor projections.

Table 3-4 illustrates the national sum of each region's seasonal peak demand, and Table 3-26 presents each region's seasonal peak demand. Because each region's seasonal peak demand need not occur at the same time, the national peak demand is defined as non-coincidental (i.e., national peak demand is a summation of each region's peak demand at whatever point in time that region's peak occurs across the given time period).

Table 3-4 National Non-Coincidental Net Internal Demand in the EPA 2023 Reference Case

Year	Peak Demand (GW)			
	Winter	Spring	Summer	Fall
2028	720	615	808	662
2030	742	636	830	683
2035	799	691	890	739
2040	854	739	955	790
2045	915	789	1,028	845
2050	983	843	1,110	906
2055	1,038	890	1,173	956

Notes:
This data is an aggregation of the model-region-specific peak demand loads.

[18] Load factors can be calculated at the NERC assessment region level based on the NERC ES&D 2022 projections of net energy for load and net internal demand. All IPM regions that map to a particular NERC assessment region are assigned the same load factors. In instances where sub regional level load factor details could be estimated in selected ISO/RTO zones, those load factors were assigned to the associated IPM region.

3.2.4 Regional Load Shapes

EPA 2023 Reference Case uses the year 2018 as the "normal weather year"[19] for all IPM regions. The 2018 chronological hourly load data were assembled by aggregating individual utility load curves taken from Federal Energy Regulatory Commission Form 714 data and individual ISOs and RTOs.

3.3 Transmission

The contiguous United States and Canada can be represented by several power markets that are interconnected by a transmission grid. This section details the assumptions about the transfer capabilities and costs used to represent this transmission grid in the EPA 2023 Reference Case.

3.3.1 Inter-regional Transmission Capability

Table 3-27[20] shows the firm and non-firm Total Transfer Capabilities (TTCs) between model regions. TTC is a metric that represents the capability of the power system to import or export power reliably from one region to another. The purpose of TTC analysis is to identify the sub-markets created by commercially significant constraints. Firm TTCs, also called Capacity TTCs, specify the maximum power that can be transferred reliably, even after the contingency loss of a single transmission system element such as a transmission line or a transformer (a condition referred to as N-1, or "N minus one"). Firm TTCs provide a high level of reliability and are used for capacity transfers. Non-firm TTCs, also called Energy TTCs, represent the maximum power that can be transferred reliably when all facilities are under normal operation (a condition referred to as N-0, or "N minus zero"). Non-firm TTCs specify the sum of the maximum firm transfer capability between sub-regions and incremental curtailable non-firm transfer capability. Non-firm TTCs are used for energy transfers since they provide a lower level of reliability than Firm TTCs, and transactions using Non-firm TTCs can be curtailed under emergency or contingency conditions.

The amount of energy and capacity transferred on a given transmission link is modeled on a seasonal basis for all run years in the EPA 2023 Reference Case. All the modeled transmission links have the same TTCs for all seasons. The maximum values for firm and non-firm TTCs, wherever available, were obtained from public sources, such as market reports and regional transmission plans, listed below.

i) Generic Transmission Constraint Definitions posted to MIS Secure as of May 1, 2022,
ii) ISO New England, 2020 Economic Study: Draft Scope of Work and High-Level Assumptions for Production Simulations - Part II of III, June 17, 2020,
iii) ISO New England, Forward Capacity Auction 17 Transmission Transfer Capabilities & Capacity Zone Development, April 28, 2022,
iv) IESO, Annual Planning Outlook, Transfer Capabilities Across Major Interfaces and Interties, December 2021,
v) Manitoba Hydro, Transmission Interface Capability Report, May 19, 2022,
vi) New York State Reliability Council, LLC, New York Control Area Installed Capacity Requirement for the Period May 2023 to April 2024, Appendices, December 9, 2022,
vii) PJM Real Time transfer limits,
viii) PJM 2022 RTEP Base Assumptions,

[19] The term "normal weather year" refers to a representative year whose weather is closest to the long-term (e.g., 30 year) average weather. The selection of a "normal weather year" can be made, for example, by comparing the cumulative annual heating degree days (HDDs) and cooling degree days (CDDs) in a candidate year to the long-term average. For any individual day, heating degree days indicate how far the average temperature fell below 65 degrees F; cooling degree days indicate how far the temperature averaged above 65 degrees F. Cumulative annual heating and cooling degree days are the sum of all the HDDs and CDDs, respectively, in a given year.

[20] In the column headers in Table 3-27, the term "Energy TTC (MW)" is equivalent to non-firm TTCs and the term "Capacity TTC (MW)" is equivalent to firm TTCs.

ix) PJM, 2024/2025 RPM Base Residual Auction Planning Period Parameters,
x) WECC 2022 Western Assessment of Resource Adequacy Report and associated Topology Maps
xi) WECC 2016 Power Supply Assessment,
xii) AESO Information Document ATC and Transfer Path Management ID #2011-001R,
xiii) Nova Scotia Power Transmission System Operating Limits 2022,
xiv) Atlantic Energy Gateway Transmission Modeling Study Report.

Where public sources were not available, the maximum values for firm and non-firm TTCs are based on ICF's expert view. ICF analyzes the operation of the grid under normal and contingency conditions, using industry-standard methods, and calculates the transfer capabilities between regions. To calculate the transfer capabilities, ICF uses standard power flow data developed by the market operators, transmission providers, or utilities, as appropriate.

Furthermore, each transmission link between model regions shown in Table 3-27 represents a one-directional flow of power on that link. Due to the physical nature of electron flow across the grid, the maximum amount of power flow possible from region A to region B may be more or less than the maximum amount of flow of power possible from region B to region A.

3.3.2 Joint Transmission Capacity and Energy Limits

Table 3-5 shows the annual joint limits to the transmission capabilities between model regions, which are identical for the firm (capacity) and non-firm (energy) transfers. The joint limits were obtained from public sources where available or based on ICF's expert view. A joint limit represents the maximum simultaneous firm or non-firm power transfer capability of a group of interfaces. It restricts the amount of firm or non-firm transfers between one model region (or group of model regions) and a different group of model regions. For example, the New England market is connected to the New York market by four transmission links:

- NENG_CT to NY_Z_G-I: 600 MW
- NENGREST to NY_Z_F: 800 MW
- NENGREST to NY_Z_D: 0 MW
- NENG_CT to NY_Z_K: 734 MW

Without any simultaneous transfer limits, the total transfer capability from New England to New York would be 2,134 MW. However, current system conditions and reliability requirements limit the total simultaneous transfers from New England to New York to 1,730 MW, as shown in Table 3-5. IPM uses joint limits to ensure that this and similar reliability limits are not violated. Therefore, each individual link can be utilized to its limit as long as the total flow on all links does not exceed the joint limit.

Table 3-5 Annual Joint Capacity and Energy Limits to Transmission Capabilities between Model Regions in the EPA 2023 Reference Case

Region Connections	Transmission Path	Capacity TTC (MW)	Energy TTC (MW)
NY_Zone G-I (Downstate NY) & NY_Zone J (NYC) to NY_Zone K (LI)	NY_Z_G-I to NY_Z_K NY_Z_J to NY_Z_K	1,613	
NY_Zone K(LI) to NY_Zones G-I (Downstate NY) & NY_Zone J (NYC)	NY_Z_K to NY_Z_G-I NY_Z_K to NY_Z_J	135	
ISO NE to NYISO	NENG_CT to NY_Z_G-I NENGREST to NY_Z_F NENG_CT to NY_Z_K NENGREST to NY_Z_D	1,730	
NYISO to ISO NE	NY_Z_G-I to NENG_CT NY_Z_F to NENGREST NY_Z_K to NENG_CT NY_Z_D to NENGREST	1,730	
PJM West & PJM_PENELEC & PJM_AP to PJM_ATSI	PJM_West to PJM_ATSI	9,925	

<table>
<tr><th>Region Connections</th><th>Transmission Path</th><th>Capacity TTC (MW)</th><th>Energy TTC (MW)</th></tr>
<tr><td></td><td>PJM_PENE to PJM_ATSI
PJM_AP to PJM_ATSI</td><td colspan="2"></td></tr>
<tr><td>PJM_ATSI to PJM West & PJM_PENELEC & PJM_AP</td><td>PJM_ATSI to PJM_West
PJM_ATSI to PJM_PENE
PJM_ATSI to PJM_AP</td><td colspan="2">9,925</td></tr>
<tr><td>PJM_West & PJM_Dominion to SERC VACAR</td><td>PJM_West to S_VACA
PJM_Dom to S_VACA</td><td>2,208</td><td>3,424</td></tr>
<tr><td>SERC VACAR to PJM_West & PJM_Dominion</td><td>S_VACA to PJM_West
S_VACA to PJM_Dom</td><td>2,208</td><td>3,424</td></tr>
<tr><td>MIS_MAPP & SPP_WAUE to MIS_MNWI</td><td>MIS_MAPP to MIS_MNWI
SPP_WAUE to MIS_MNWI</td><td>3,000</td><td>5,000</td></tr>
<tr><td>MIS_MNWI to MIS_MAPP & SPP_WAUE</td><td>MIS_MNWI to MIS_MAPP
MIS_MNWI to SPP_WAUE</td><td>3,000</td><td>5,000</td></tr>
<tr><td>SERC_Central_TVA & SERC_Central_Kentucky to PJM West</td><td>S_C_TVA to PJM_West
S_C_KY to PJM_West</td><td>3,000</td><td>4,500</td></tr>
<tr><td>PJM West to SERC_Central_TVA & SERC_Central_Kentucky</td><td>PJM_West to S_C_TVA
PJM_West to S_C_KY</td><td>3,000</td><td>4,500</td></tr>
<tr><td>MIS_INKY to PJM_COMD & PJM_West</td><td>MIS_INKY to PJM_COMD
MIS_INKY to PJM_West</td><td>4,586</td><td>6,509</td></tr>
<tr><td>PJM_COMD & PJM_West to MIS_ INKY</td><td>PJM_COMD to MIS_INKY
PJM_West to MIS_INKY</td><td>5,998</td><td>8,242</td></tr>
<tr><td>NY_Z_C&E & NY_Z_A to PJM_PENELEC</td><td>NY_Z_C&E to PJM_PENE
NY_Z_A to PJM_PENE</td><td colspan="2">1,050</td></tr>
<tr><td>PJM_PENELEC to NY_Z_C&E & NY_Z_A</td><td>PJM_PENE to NY_Z_C&E
PJM_PENE to NY_Z_A</td><td colspan="2">1,365</td></tr>
<tr><td>PJM_SMAC & PJM_WMAC to PJM_EMAC</td><td>PJM_SMAC to PJM_EMAC
PJM_WMAC to PJM_EMAC</td><td colspan="2">8,594</td></tr>
<tr><td>PJM_AP, PJM_DOM, PJM_EMAC, PJM_WMAC to PJM_SMAC</td><td>PJM_AP to PJM_SMAC
PJM_DOM to PJM_SMAC
PJM_EMAC to PJM_SMAC
PJM_WMAC to PJM_SMAC</td><td colspan="2">7,947</td></tr>
<tr><td>PJM_AP, PJM_ATSI & PJM_DOM to PJM_PENELEC, PJM_SMAC & PJM_WMAC</td><td>PJM_AP to PJM_PENE
PJM_AP to PJM_SMAC
PJM_AP to PJM_WMAC
PJM_ATSI to PJM_PENE
PJM_DOM to PJM_SMAC</td><td colspan="2">5,965</td></tr>
<tr><td>NY_Z_C&E, NY_Z_F & NENG_CT to NY_Z_G-I</td><td>NY_Z_C&E to NY_Z_G-I
NY_Z_F to NY_Z_G-I
NENG_CT to NY_Z_G-I</td><td colspan="2">5,250</td></tr>
<tr><td>NY_Z_A to NY_Z_B & PJM_PENELEC</td><td>NY_Z_A to NY_Z_B
NY_Z_A to PJM_PENE</td><td colspan="2">2,650</td></tr>
<tr><td>CN_AB to CN_BC & WECC_MT</td><td>CN_AB to WECC_MT
CN_AB to CN_BC</td><td colspan="2">1,000</td></tr>
<tr><td>CN_BC & WECC_MT to CN_AB</td><td>WECC_MT to CN_AB
CN_BC to CN_AB</td><td colspan="2">1,110</td></tr>
</table>

3.3.3 Transmission Link Wheeling Charge

The transmission link wheeling charge is the cost of transferring electric power from one region to another. The EPA 2023 Reference Case has no wheeling charges within individual IPM regions and no charges between IPM regions that fall within the same RTO. The wheeling charges, expressed in 2022 mills/kWh, are shown in Table 3-27 in the column labeled "Transmission Tariff."

3.3.4 Transmission Losses

The EPA 2023 Reference Case assumes a 2.8 percent inter-regional transmission loss of energy transferred in the Western interconnection and a 2.4 percent inter-regional transmission loss of energy transferred in Eastern Interconnection and ERCOT. These factors are based on average loss factors calculated from standard power flow data developed by the transmission providers.

3.3.5 New Transmission Builds

EPA 2023 Reference Case includes new endogenous transmission build options starting in 2030.[21] An important dynamic driving this change is the increased deployment of new renewable generation capacity that is at a significant distance from the load centers driving its deployment. Consequently, the inability to deploy additional transmission capacity endogenously may be unduly limiting the economic potential of new renewable capacity. More generally, enabling transmission capacity expansion allows IPM to co-optimize generation and transmission builds and solve for the optimal mix of generation and transmission additions to meet capacity and energy needs.

For these transmission build options, representative costs were derived from NREL's Jobs and Economic Development Impact (JEDI) model. Inputs to the JEDI model included the likely voltage rating, a representative length of line between each region, and the type of terrain expected to be traversed. The approach included:

- Determination of likely voltage rating. The cost of transmission lines varies with voltage rating. Higher voltage ratings typically have higher costs per unit length. To minimize maintenance, inventory, and other costs, it is likely that a new transmission line in an area will be rated at a voltage similar to transmission lines already existing in the area. Further, it is likely that an interregional line would be rated at or close to the highest voltage rating of the area's backbone transmission system due to economies of scale. ICF reviewed the backbone transmission system in each of the model regions to determine the likely voltage rating that would be used for new transmission lines. For example, the backbone transmission system in the Northeast (New York and the New England states) is rated 345 kV. While the systems also have underlying 230 kV and lower voltage transmission lines, it is likely that new inter-regional transmission lines would be rated 345 kV. In most of the southeastern U.S. states the backbone voltage is 500 kV; therefore, we assume that a line between Florida and Southern Company, for example, would likely be rated 500 kV.

- Estimation of representative line lengths. The cost of transmission lines also varies with the length of line. The length of a particular line will depend on several factors, including the location of existing interconnecting substations, existing rights-of-way, area of need within the zone, and other factors. The length cannot be determined in advance without knowing the specific application. For this analysis EPA made a simplifying assumption that lines would be built between the geographic centers of the regions. In instances where the transmission line lengths that are calculated using the centroid approach are longer than a typical maximum for the assumed line voltage, the typical maximum[22] length was used to estimate the unit cost of the line.

- Assessment of terrain. Transmission line costs also vary with terrain. For example, a line traversing a mountainous region would have a higher capital cost than a line in a flat, rural area. Terrain classifications in the JEDI model include "Desert/Remote", "Mountainous", and "Flat With Access". The model also allows for specification of population densities, including "In Town", "Near Town", and "Rural". Terrain classifications and population densities were assigned that best represented the area that lines between the regions would likely traverse. For example, the terrain traversed by a line between New York City and Long Island was classified as Flat With

[21] New transmission options in EPA 2023 Reference Case are built simultaneously in both directions as transmission lines when built can allow bidirectional flows.

[22] The typical maximum line lengths by voltage class were estimated based on a review of projects that were under construction or complete in 2015-2018 EIA Form 411 datasets. The EIA Form 411 data was supplemented with information from the year 2016 EEI report Transmission Projects: At a Glance that describes major high voltage projects proposed by investor-owned utilities.

Access and the population density was specified as In Town, while a line between Nebraska and the Oklahoma-Missouri area was classified as Flat With Access and Rural.

Together, this information was used to determine the total cost of a new transmission line between each pair of contiguous IPM regions. ICF then calculated a unit cost in $/kW for each transmission link using estimates of the power (MW) ratings for each transmission line. The bidirectional unit costs for new transmission lines are shown in Table 3-27.

3.4 International Imports

The United States electric power system is connected with the transmission grids in Canada and Mexico and the three countries actively trade in electricity. The Canadian power market is endogenously modeled in EPA 2023 Reference Case, but Mexico is not. International electric trading between the United States and Mexico is represented by an assumption of net imports based on information from AEO 2023 Reference Case. Table 3-6 summarizes the assumptions on net imports into the United States from Mexico.

Table 3-6 International Electricity Imports (billions kWh) in the EPA 2023 Reference Case

	2028	2030	2035	2040	2045	2050	2055
Net Imports from Mexico	3.05	3.05	3.05	2.77	2.77	2.77	2.77

Note 1: Source: AEO 2023 Reference Case

Note 2: Imports & exports transactions from Canada are endogenously modeled in IPM.

3.5 Capacity, Generation, and Dispatch

While the capacity of existing units is an exogenous input into IPM, the dispatch of those units is an endogenous decision. The capacity of existing generating units included in EPA 2023 Reference Case can be found in the National Electrical Energy Data System (NEEDS), a database which provides IPM with information on all currently operating and planned-committed electric generating units. NEEDS is discussed in Chapter 4.

A unit’s generation over a time period is defined by its dispatch pattern. IPM determines the optimal economic dispatch profile given the operating and physical constraints imposed on the unit. In EPA 2023 Reference Case, unit-specific operational and physical constraints are represented through availability, capacity factor, and turndown constraints.

3.5.1 Availability

Power plant availability is the percentage of time that a generating unit is available to provide electricity to the grid. Availability takes into account both scheduled maintenance and forced outages; it is formally defined as the ratio of a unit’s available hours adjusted for the derating of capacity (due to partial outages) to the total number of hours in a year when the unit was in an active state. For most types of units in IPM, availability parameters are used to specify an upper bound on generation to meet demand. Table 3-7 summarizes the availability assumptions used in EPA 2023 Reference Case, which are based on data from NERC Generating Availability Data System (GADS) 2017-2021 and AEO 2023 Reference Case. NERC GADS summarizes the availability data by plant type and size class. Unit-level availability assignments in EPA 2023 Reference Case are made based on the unit’s plant type and size as presented in NEEDS. Table 3-33 shows the availability assumptions for all generating units in EPA 2023 Reference Case.

Table 3-7 Availability Assumptions in the EPA 2023 Reference Case

Plant Type	Annual Availability (%)
Biomass	83
Coal Steam	67 - 83
Combined Cycle	84
Combustion Turbine	86 - 93
Energy Storage	96
Fossil Waste	90
Fuel Cell	87
Geothermal	87
Hydro	75 - 82
IGCC	79 - 83
Landfill Gas	90
Municipal Solid Waste	90
Non-Fossil Waste	90
Nuclear	70 - 99
O/G Steam	62 - 85
Offshore Wind	95
Onshore Wind	95
Pumped Storage	81
Solar PV	90
Solar Thermal	90

Notes:

Ranges in unit level availability are based on varying plant sizes.

In the EPA 2023 Reference Case, separate seasonal (winter, spring, summer, and fall) availabilities are defined. For the fossil and nuclear unit types shown in Table 3-33, seasonal availabilities differ only in that no planned maintenance is assumed to be conducted during the on-peak – summer (June, July, and August) months for summer peaking regions and on-peak – winter (December, January, and February) months for winter peaking regions. Characterizing the availability of hydro, solar, and wind technologies is more complicated due to the seasonal and locational variations of the resources. The procedures used to represent seasonal variations in hydro are presented in Section 3.5.2 and of wind and solar in Section 4.4.5.

3.5.2 Capacity Factor

For non-dispatchable technologies - such as run-of-river hydro, wind, and solar - IPM uses generation profiles, not availabilities, to define the upper bound on the generation obtainable from the unit. The capacity factors that result from the implementation of generation profiles are the percentage of the maximum possible power generated by the unit. The seasonal capacity factor assumptions for hydro facilities contained in Table 3-8 were derived from EIA Form 923 data for the 2013-2022 period. A discussion of capacity factors and generation profiles for wind and solar technologies is contained in Section 4.4.5 and Table 4-18, Table 4-19, Table 4-35, Table 4-44, and Table 4-45.

Table 3-8 Seasonal Hydro Capacity Factors (%) in the EPA 2023 Reference Case

Model Region	Winter Capacity Factor	Spring Capacity Factor	Summer Capacity Factor	Fall Capacity Factor	Annual Capacity Factor
ERC_REST	13%	13%	13%	10%	12%
FRCC	65%	70%	51%	49%	58%
MIS_AR	46%	55%	56%	40%	51%
MIS_IA	41%	49%	47%	41%	45%
MIS_IL	58%	64%	62%	58%	60%
MIS_INKY	47%	37%	59%	58%	52%
MIS_LA	60%	65%	65%	58%	62%
MIS_LMI	64%	70%	58%	50%	60%
MIS_MAPP	60%	67%	69%	59%	65%
MIS_MIDA	32%	32%	31%	32%	32%
MIS_MNWI	57%	57%	61%	59%	59%

Model Region	Winter Capacity Factor	Spring Capacity Factor	Summer Capacity Factor	Fall Capacity Factor	Annual Capacity Factor
MIS_MO	47%	49%	51%	37%	47%
MIS_WOTA	31%	33%	32%	22%	31%
MIS_WUMS	64%	64%	63%	65%	64%
NENG_CT	43%	52%	33%	33%	39%
NENG_ME	58%	63%	45%	44%	51%
NENGREST	41%	49%	31%	30%	36%
NY_Z_A	75%	73%	72%	73%	73%
NY_Z_B	45%	44%	44%	44%	44%
NY_Z_C&E	51%	50%	51%	51%	51%
NY_Z_D	88%	75%	75%	75%	79%
NY_Z_F	52%	51%	50%	49%	51%
NY_Z_G-I	29%	29%	29%	29%	29%
PJM_AP	50%	54%	42%	39%	46%
PJM_ATSI	22%	21%	24%	25%	23%
PJM_COMD	43%	47%	48%	40%	45%
PJM_Dom	27%	27%	20%	18%	22%
PJM_EMAC	44%	58%	29%	25%	37%
PJM_PENE	50%	59%	44%	33%	46%
PJM_West	35%	36%	32%	29%	33%
PJM_WMAC	45%	56%	39%	34%	43%
S_C_KY	33%	31%	29%	26%	30%
S_C_TVA	55%	45%	42%	42%	46%
S_D_AECI	16%	30%	26%	9%	21%
S_SOU	32%	29%	23%	21%	26%
S_VACA	32%	30%	23%	24%	27%
SPP_N	19%	20%	20%	15%	19%
SPP_NEBR	38%	41%	41%	36%	39%
SPP_WAUE	41%	45%	45%	40%	43%
SPP_WEST	28%	33%	35%	22%	31%
WEC_BANC	17%	24%	26%	15%	21%
WEC_CALN	20%	31%	35%	18%	28%
WEC_LADW	10%	16%	17%	8%	14%
WEC_SDGE	16%	23%	27%	14%	22%
WECC_AZ	25%	29%	29%	22%	27%
WECC_CO	20%	21%	21%	9%	19%
WECC_ID	35%	46%	44%	30%	40%
WECC_IID	25%	37%	46%	24%	36%
WECC_MT	36%	45%	45%	34%	41%
WECC_NM	17%	21%	22%	15%	19%
WECC_NNV	38%	56%	56%	41%	49%
WECC_PNW	45%	46%	42%	33%	42%
WECC_SCE	19%	31%	39%	18%	29%
WECC_SNV	17%	28%	24%	18%	22%
WECC_UT	32%	39%	39%	28%	35%
WECC_WY	24%	33%	46%	23%	34%

Note: Annual capacity factor is provided for information purposes only. It is not used for modeling purposes.

Capacity factor limits are used to define the upper bound on generation obtainable from nuclear units because nuclear units will typically dispatch to their availability, and consequently, capacity factor and availability limits are equivalent. The capacity factors (and, consequently, the availabilities) of existing nuclear units in EPA 2023 Reference Case vary from region to region and over time. Further discussion of the nuclear capacity factor assumptions in EPA 2023 Reference Case is contained in Section 4.6.

In the EPA 2023 Reference Case, minimum capacity factor requirements of 10% are applied to existing coal steam units, and 2% are applied to existing oil/gas steam units and coal-to-gas retrofits in regions without capacity markets in EPA 2023 Reference Case. NYISO, ISONE, PJM, and MISO are assumed to have capacity markets. Additionally, oil/gas steam units are assigned minimum capacity factors under certain conditions. These minimum capacity factor constraints reflect stakeholder comments that if left unconstrained, IPM does not project as much operation from oil/gas steam units as has occurred historically. This dynamic is often the result of local transmission constraints, unit-specific grid reliability requirements, or other drivers that are not captured in EPA's modeling. EPA examined its modeling treatment of these units and introduced minimum capacity factor constraints to better reflect the real-world behavior of these units. The approach is designed to balance the continued operation of these units in the near-term with allowing economic forces to influence decision-making over the modeling time horizon. As a result, the minimum capacity factor limitations are relaxed over time (and are terminated even earlier if the capacity in question reaches 60 years of age). Historical operational data indicate that oil/gas steam units with high-capacity factors have maintained a high level of generation over many years. To reflect persistent operation of these units, minimum capacity factors for higher capacity factor units are phased out more slowly than those constraints for lower capacity factor units. The steps in assigning these capacity constraints are as follows:

i) Calculate an annual capacity factor for each oil/gas steam unit over a ten-year baseline (2013-2022).
ii) Identify the minimum capacity factor over this baseline period for each unit.
iii) Terminate the constraints in the earlier of (a) the run-year in which the unit reaches 60 years of age or (b) based on the assigned minimum capacity factor and the model year indicated in the following schedule:
    - For model year 2028, remove minimum constraint from units with capacity factor < 10%
    - For model year 2030, remove minimum constraint from units with capacity factor < 15%
    - No constraints beyond 2030

3.5.3 Turndown

Turndown assumptions in EPA 2023 Reference Case are used to prevent coal and oil/gas steam units from operating as peaking units, which would be inconsistent with their operational capabilities and assigned costs. The turndown constraints in EPA 2023 Reference Case require coal steam and oil/gas steam units to dispatch no less than a fixed percentage of the unit capacity in the 23 base and mid-load segments of the load duration curve in order to dispatch 100% of the unit in the peak load segments of the LDC. Oil/gas steam units are required to dispatch no less than 25% of the unit capacity in the 23 base- and mid-load segments of the LDC in order to dispatch 100% of the unit capacity in the peak load segment of the LDC. Operating under the fixed percentage of base- and mid-load segments does not preclude the unit from operating during peak hours. It merely reduces the share of peak hours in which it can operate. The unit level turndown percentages for coal units were estimated based on a review of hourly Air Markets Program Data (AMPD) data and are shown in Table 3-28.

3.6 Reserve Margins

A reserve margin is a measure of the system's generating capability above the amount required to meet the net internal demand (peak load) requirement. It is defined as the difference between total dependable capacity and annual system peak load divided by annual system peak load. The reserve margin capacity contribution for variable renewable units is described in Section 4.4.5; the reserve margin capacity contribution for other units is the capacity in the NEEDS for existing units or the capacity built by IPM for new units. In practice, each NERC region has a reserve margin requirement, or comparable reliability standard, which is designed to encourage electric suppliers in the region to build beyond their peak requirements to ensure the reliability of the electric generation system within the region.

In IPM, reserve margins represent the reliability standards in effect in each NERC region. Individual reserve margins for each NERC region are derived from reliability standards in NERC's electric reliability reports. The IPM regional reserve margins are imposed throughout the entire time horizon. EPA 2023 Reference Case reserve margin assumptions are shown in Table 3-9.

Table 3-9 Planning Reserve Margins in the EPA 2023 Reference Case

Model Region	Reserve Margin
CN_AB	10.6% - 11.2%
CN_BC	10.6% - 11.2%
CN_MB	12.0%
CN_NB	20.0%
CN_NF	20.0%
CN_NL	20.0%
CN_NS	20.0%
CN_ON	13.3% - 14.8%
CN_PE	15.0%
CN_PQ	11.3%
CN_SK	15.0%
ERC_FRNT	15.0%
ERC_GWAY	15.0%
ERC_PHDL	13.8%
ERC_REST	13.8%
ERC_WEST	13.8%
FRCC	18.6%
MIS_AR	18.6%
MIS_ MS	18.6%
MIS_IA	18.6%
MIS_IL	18.6%
MIS_INKY	18.6%
MIS_LA	18.6%
MIS_LMI	16.1% - 16.9%
MIS_MAPP	16.1% - 16.9%
MIS_MIDA	16.1% - 16.9%
MIS_MNWI	16.1% - 16.9%
MIS_MO	16.1% - 16.9%
MIS_AMSO	18.6%
MIS_WOTA	16.1% - 16.9%
MIS_WUMS	16.1% - 16.9%
NENG_CT	16.1% - 16.9%
NENG_ME	16.1% - 16.9%
NENGREST	16.1% - 16.9%
NY_Z_A	15.0%
NY_Z_B	15.0%
NY_Z_C&E	15.0%
NY_Z_D	15.0%
NY_Z_F	15.0%
NY_Z_G-I	15.0%
NY_Z_J	15.0%
NY_Z_K	15.0%
PJM_AP	14.7%
PJM_ATSI	14.7%
PJM_COMD	14.7%
PJM_Dom	14.7%
PJM_EMAC	14.7%
PJM_PENE	14.7%
PJM_SMAC	14.7%
PJM_West	14.7%
PJM_WMAC	14.7%
S_C_KY	15.0%
S_C_TVA	15.0%
S_D_AECI	15.0%
S_SOU	15.0%
S_VACA	15.0%
SPP_KIAM	15.0%
SPP_N	16.0%
SPP_NEBR	16.0%
SPP_SPS	16.0%
SPP_WAUE	16.0%
SPP_WEST	16.0%
WEC_BANC	12.4% - 14.0%
WEC_CALN	12.4% - 14.0%
WEC_LADW	16.9% - 18.1%
WEC_SDGE	16.9% - 18.1%
WECC_AZ	16.9% - 18.1%
WECC_CO	16.9% - 18.1%
WECC_ID	16.9% - 18.1%
WECC_IID	16.9% - 18.1%
WECC_MT	12.4% - 14.0%
WECC_NM	11.2% - 12.3%
WECC_NNV	12.4% - 14.0%
WECC_PNW	16.9% - 18.1%
WECC_SCE	16.9% - 18.1%
WECC_SNV	12.4% - 14%
WECC_UT	12.4% - 14%
WECC_WY	12.4% - 14%

3.7 Operating Reserves

EPA 2023 Reference Case models operating reserve requirements in IPM to ensure that an appropriate mix of supply resources will be included that is consistent with maintaining reliability standards, especially in later years as new capacity deploys more rapidly. Operating reserves are typically deployed in order of the response speed, from fast to slow. In general, the categories of reserves include:[23]

- Frequency-Responsive Reserves. This is the fastest response. It has traditionally been provided through the automatic action of synchronous generators that react to slow down and arrest frequency deviations as a result of the inertia of the machines or their governor action (also

[23] Denholm, Paul, Yinong Sun, and Trieu Mai. 2019. An Introduction to Grid Services: Concepts, Technical Requirements, and Provision from Wind. Golden, CO: National Renewable Energy Laboratory. NREL/TP-6A20-72578. https://www.nrel.gov/docs/fy19osti/72578.pdf.

referred to as primary frequency response or PFR). As a result of the increase in renewable integration and loss of generators that provide inertial response, other products are emerging to provide frequency response on a very fast (sub-minute) timescale.

- Regulating Reserves. This is the rapid response by generators to balance supply and demand to maintain system frequency. The regulation reserve can address the random fluctuations in the load that create imbalances in supply and demand.

- Contingency Reserves. These reserves are deployed to cover the unplanned loss of power plants or transmission lines. Contingency reserves generally include spinning, non-spinning, and supplemental reserves. Spinning reserves respond quickly and are supplemented or replaced with non-spinning and supplemental reserves that are usually less costly.

- Ramping Reserves. This is used to address slower variations or events that occur over a longer period, such as variable generation forecast errors. Ramping reserves, also known as load-following or flexibility reserves, are an emerging product that is becoming more important with the increasing penetration of variable generation sources such as wind and solar.

The operating reserve products currently procured in United States electricity markets include regulating reserves, contingency reserves, and ramping reserves. FERC Order No. 842 requires that new generation resources that participate in the electricity markets provide some form of frequency-responsive reserve to support the reliability of the grid, but the Order does not mandate explicit compensation for the product. EPA's implementation of operating reserve requirements is consistent with the products offered in the electricity markets. The operating reserves modeled explicitly in EPA 2023 Reference Case are regulating reserves, contingency reserves, and ramping reserves. The plant types that can provide these reserves are listed in Table 3-12. Based on current regulations, new generation resources that are built in the EPA 2023 Reference Case are assumed to have the capability to provide frequency-responsive reserves. It is reasonable to expect that sufficient frequency-responsive reserves will be available to support grid reliability in IPM analyses, even if the requirement is not modeled explicitly.

3.7.1 Operating Reserve Requirements

Operating reserve requirements typically depend on the load and load forecast error. As variable renewable generation increase, it is likely that the operating reserve requirements will increase due to the variability of the renewable resources.[24,25] Table 3-10 shows operating reserve assumptions, which are based on the National Renewable Energy Laboratory (NREL) report, Operating Reserves in Long-term Planning Models.[26] The long-term requirements include components that depend on the penetration of wind and solar resources to address the expected increase in variability as more variable resources enter the market.

Table 3-10 Operating Reserve Requirement Assumptions by Type in the EPA 2023 Reference Case

Product	Operating Reserve Load Requirement	Operating Reserve Requirement for Wind	Operating Reserve Requirement for Solar	Operating Reserve Timescale
Spinning	3% of load	-	-	10 minutes
Regulation	1% of load	0.5% of wind capacity	0.3% of solar PV capacity	5 minutes
Flexibility	-	10% of wind capacity	4% of solar PV capacity	60 minutes

The operating reserve requirements, when modeled in IPM, have a significant impact on model size. To counter this effect, EPA made two simplifying assumptions. First, the spinning reserve, regulation, and

[24] Western Wind and Solar Integration Study (WWSIS) Phase 1, National Renewable Energy Laboratory (GE Energy), May 2010

[25] Analysis of Wind Generation Impact on ERCOT Ancillary Services Requirements, Electric Reliability Council of Texas (GE Energy), March 2008

[26] Cole, W. et al., Operating Reserves in Long-term Planning Models (NREL), June 2018

flexibility requirements are combined into a single product. Second, these constraints may be implemented only in the later years when renewable penetration and operating reserve requirements are highest; this representation of operating reserve requirements can be activated or deactivated by run year for any scenario analyzed using IPM. The operating reserve requirements in the EPA 2023 Reference Case, when modeled, are applied to the 17 regional groups summarized in Table 3-11.

Table 3-11 Operating Reserve Regions in the EPA 2023 Reference Case

Operating Reserve Region	EPA 2023 Reference Case Model Region
ERCOT	ERC_PHDL, ERC_REST, and ERC_WEST
FRCC	FRCC
ISO-NE	NENG_CT, NENGREST and NENG_ME
MISO East	MIS_WUMS, MIS_MIDA, MIS_IA, MIS_IL, MIS_LMI, MIS_INKY and MIS_MO
MISO South	MIS_MS, MIS_AR, MIS_AMSO, MIS_WOTA and MIS_LA
MISO West	MIS_MAPP and MIS_MNWI
NYISO	NY_Z_A, NY_Z_B, NY_Z_C&E, NY_Z_D, NY_Z_F, NY_Z_G-I, NY_Z_J and NY_Z_K
PJM East	PJM_PENE, PJM_EMAC, PJM_WMAC and PJM_SMAC
PJM West	PJM_West, PJM_AP, PJM_COMD, PJM_Dom and PJM_ATSI
SERC-E	S_VACA
SERC-N	S_C_TVA and S_C_KY
SERC-SE	S_SOU
SPP	SPP_WAUE, SPP_SPS, SPP_WEST, SPP_NEBR, SPP_N and S_D_AECI
WECC-CAMX	WEC_SDGE, WECC_SCE, WEC_CALN and WEC_LADW
WECC-NWPP	WECC_MT, WECC_ID, WECC_PNW, WECC_NNV, WECC_UT, WECC_SNV and WEC_BANC

3.7.2 Generation Characteristics

The ability of a generator to provide operating reserves varies with the technology type. The more flexible a unit (i.e., faster ramp rate), the higher its operating reserve capability. Table 3-12 shows the assumed operating reserve capabilities for different generation technologies and are based on the NREL's report, Operating Reserves in Long-term Planning Models. For example, gas combustion turbines and combined cycles have faster ramp rates than coal plants; therefore, gas plants can provide more operating reserves per unit capacity than coal plants. EPA also assumed that capacity meeting energy needs cannot provide operating reserves at the same time. For example, if 75% of a generator's capacity is serving the energy market, only 25% will be available to be offered into the operating reserve market. Table 3-12 summarizes the ramp rates of power plant technologies. Since EPA 2023 Reference Case is incorporating a single composite operating reserves product, the maximum operating reserve contributions are based on the 10-minute spinning reserve requirement.

Table 3-12 Operating Reserve Contribution Assumptions by Technology in the EPA 2023 Reference Case

Technology	Assumed Ramp Rate (%/minute)	Maximum Operating Reserve Contribution (%)
Combustion Turbine	8	80
Combined Cycle	5	50
Coal Steam	4	40
Geothermal	4	40
CSP with Storage	10	100
Biomass	4	40
Oil/Gas Steam	4	40
Hydro	100	100
Energy Storage	100	100

Generation resources that are not fast starting cannot provide operating reserves unless they are already operating. To provide operating reserves, the plant must also be dispatching into the energy market.

3.8 Power Plant Lifetimes

EPA 2023 Reference Case does not include any pre-specified assumptions about power plant lifetimes (i.e., the duration of service allowed) except for nuclear units. All conventional fossil units (coal, oil/gas steam, combustion turbines, and combined cycle), and biomass units can be retired during a model run if their retention is deemed uneconomic.

Nuclear Retirement: The EPA 2023 Reference Case does not assume that commercial nuclear reactors will be retired upon license expiration. EPA 2023 Reference Case incorporates life extension costs to enable these operating life extensions. (See Sections 4.2.8 and 4.6). For unit specific retirement years, see NEEDS.

3.9 Heat Rates

Heat rates, expressed in British thermal units (Btus) per kilowatt-hour (kWh), are a measure of an electric generating unit's (EGU's) efficiency. As in previous versions of NEEDS, with the exception of deploying the heat rate improvement option described below, heat rates of existing EGUs remain constant over time. This assumption reflects two offsetting factors:

i) Plant efficiencies tend to degrade over time, and
ii) Increased maintenance and component replacement costs act to maintain, or improve, an EGU's generating efficiency.

The heat rates for the model plants in EPA 2023 Reference Case are based on values from the AEO 2020 Reference Case and are informed by fuel use and net generation data reported on Form EIA-923. These values were screened and adjusted using a procedure developed by EPA (as described below) to ensure that the heat rates used in EPA 2023 Reference Case are within the engineering capabilities of the various EGU types.

The result of an earlier EPA engineering analysis, the upper and lower heat rate limits shown in Table 3-13 were applied to coal steam, oil/gas steam, combined cycle, combustion turbine, and internal combustion engines. If the reported heat rate for such a unit was below the applicable lower limit or above the upper limit, the upper or lower limit was substituted for the reported value.

Table 3-13 Lower and Upper Limits Applied to Heat Rate Data in the EPA 2023 Reference Case

Plant Type	Heat Rate (Btu/kWh)	
	Lower Limit	Upper Limit
Coal Steam	8,300	14,500
Oil/Gas Steam	8,300	14,500
Combined Cycle - Natural Gas	5,500	15,000
Combined Cycle - Oil	6,000	15,000
Combustion Turbine - Natural Gas - 80 MW and above	8,700	18,700
Combustion Turbine - Natural Gas < 80 MW	8,700	36,800
Combustion Turbine - Oil and Oil/Gas - 80 MW and above	6,000	25,000
Combustion Turbine - Oil and Oil/Gas < 80 MW	6,000	36,800
IC Engine - Natural Gas	8,700	18,000
IC Engine - Oil and Oil/Gas - 5 MW and above	8,700	20,500
IC Engine - Oil and Oil/Gas < 5 MW	8,700	42,000

3.10 Existing Legislations and Regulations Affecting Power Sector

This section describes the existing federal, regional, and state SO_2, NO_x, mercury, HCl, and CO_2 emissions regulations and legislations that are represented in EPA 2023 Reference Case. EPA 2023 Reference Case also includes three non-air federal rules affecting EGUs: Cooling Water Intakes (316(b)) Rule, Coal Combustion Residuals from Electric Utilities (CCR), and the Effluent Limitations and Guidelines Rule. The first four subsections discuss national and regional regulations. The next five subsections describe state-level environmental regulations, a variety of legal settlements, emission assumptions for potential units, renewable portfolio standards, and Canadian regulations for CO_2 and renewables.

3.10.1 Inflation Reduction Act

The Inflation Reduction Act (IRA) contains a number of tax credit provisions that affect power sector operations. The Clean Electricity Investment and Production Tax Credits (provisions 48E and 45Y of the IRA) are described in more detail in Section 4.5. The credit for Carbon Capture and Sequestration (provision 45Q) is described in Section 3.12. The impacts of the Zero-Emission Nuclear Power Production Credit (provision 45U) are reflected through modifying nuclear retirement limits, as described in Section 4.6.1. The Credit for the Production of Clean Hydrogen (provision 45V) is reflected through the inclusion of an exogenously delivered price of hydrogen fuel, see Section 9.5. The Advanced Manufacturing Production Tax Credit (45X) was reflected through adjustments to the short-term capital cost added for renewable technologies, see Section 4.4.3.

3.10.2 SO_2 Regulations

Unit-level Regulatory SO_2 Emission Rates and Coal Assignments: Before discussing the national and regional regulations affecting SO_2, it is important to note that unit-level SO_2 permit rates, including SO_2 regulations arising out of State Implementation Plan (SIP) requirements, which are not only state-specific but also county-specific, are captured at model set-up in the coal choices given to coal-fired existing units in EPA 2023 Reference Case. Since SO_2 emissions are dependent on the sulfur content of the fuel used, the SO_2 permit rates are used in IPM to define fuel capabilities.

For instance, a unit with a SO_2 permit rate of 3.0 lbs/MMBtu would be provided only with those combinations of fuel choices and SO_2 emission control options that would allow the unit to achieve an out-of-stack rate of 3.0 lbs/MMBtu or less. If the unit finds it economical, it may elect to burn a fuel that would achieve a lower SO_2 rate than its specified permit limit. In EPA 2023 Reference Case, there are six different sulfur grades of bituminous coal, four different grades of subbituminous coal, four different grades of lignite, and one sulfur grade of residual fuel oil. There are two different SO_2 scrubber options and one DSI option for coal units. Further discussion of fuel types and sulfur content is contained in Chapter 7. Further discussion of SO_2 control technologies is contained in Chapter 5.

National and Regional SO_2 Regulations: The national program affecting SO_2 emissions in EPA 2023 Reference Case is the Acid Rain Program established under Title IV of the Clean Air Act Amendments (CAAA) of 1990, which set a goal of reducing annual SO_2 emissions by 10 million tons below 1980 levels. The program, which became operational in 2000, affects all SO_2 emitting electric generating units greater than 25 MW. The program provides trading and banking of allowances over time across all affected electric generation sources.

The annual SO_2 caps over the modeling time horizon in EPA 2023 Reference Case reflect the provisions in Title IV. For allowance trading programs like the Acid Rain Program that allow banking of unused allowances over time, we usually estimate an allowance bank that is assumed to be available by the first year of the modeling horizon (which is 2028 in EPA 2023 Reference Case). However, the Acid Rain Program has demonstrated a substantial oversupply of allowances that continues to grow over time, and we anticipate projecting that the program's emission caps will not bind the model's determination of SO_2 emissions regardless of any level of initial allowance bank assumed. Therefore, EPA 2023 Reference Case does not assume any Title IV SO_2 allowance bank amount for the year of 2028 (notwithstanding that a large allowance bank will exist in that year in practice), because such an assumption would have no material impact on projections given the nonbinding nature of that program. Calculating the available 2028 allowances involved deducting allowance surrenders due to NSR settlements and state regulations from the 2028 SO_2 cap of 8.95 million tons. The surrenders totaled 977 thousand tons in allowances, leaving 7.973 million of 2021 allowances remaining. Specifics of the allowance surrender requirements under state regulations and NSR settlements can be found in Table 3-29 and Table 3-30.

EPA 2023 Reference Case also includes a representation of the Western Regional Air Partnership (WRAP) Program, a regional initiative involving New Mexico, Utah, and Wyoming directed toward addressing visibility issues in the Grand Canyon and affecting SO_2 emissions starting in 2018. The WRAP specifications for SO_2 are presented in Table 3-23.

3.10.3 NO_x Regulations

Much like SO_2 regulations, existing NO_x regulations are represented in EPA 2023 Reference Case through a combination of system level NO_x programs and generation unit-level NO_x limits. In EPA 2023 Reference Case, Good Neighbor Plan (GNP[27]) the NO_x SIP Call trading program, Cross State Air Pollution Rule (CSAPR), the CSAPR Update, and the Revised CSAPR Update Rule are represented. Table 3-23 shows the specification for the entire modeling time horizon.

By assigning unit-specific NO_x rates based on 2019 data, EPA 2023 Reference Case is implicitly representing Title IV unit-specific rate limits and Clean Air Act Reasonably Available Control Technology (RACT) requirements for controlling NO_x emissions from electric generating units in ozone non-attainment areas or in the Ozone Transport Region (OTR).[28] Unlike SO_2 emission rates, NO_x rates are calculated off historical data and reflect the fuel mix for that particular year at the unit. NEEDS represents up to four scenario NO_x rates based on historical data to capture seasonal and existing control variability. These rates are constant and do not change independently of the fuel mix assumed in the model. If the unit undertakes a post-combustion control retrofit, a coal-to-gas retrofit, a natural gas cofiring retrofit, then these rates would change in the model projections.

<u>NO_x Emission Rates</u>

Future emission projections for NO_x are a product of a unit's utilization (heat input) and emission rate (lbs/MMBtu). A unit's NO_x emission rate can vary significantly depending on the NO_x reduction requirements to which it is subject. For example, a unit may have a post-combustion control installed (i.e., SCR or SNCR), but only operate it during the time of the year in which it is subject to NO_x reduction requirements (e.g., the unit only operates its post-combustion control during the ozone season). Therefore, its ozone-season NO_x emission rate would be lower than its non-ozone-season NO_x emission rate. Because the same individual unit can have such a large variation in its emission rate, the model needs a suite of emission rate modes from which it can select the value most appropriate to the conditions in any given model scenario. The different emission rates reflect the different operational conditions a unit may experience regarding upgrades to its combustion controls and the operation of its existing post-combustion controls. Four modes of operation are developed for each unit, with each mode carrying a potentially different NO_x emission rate for that unit under those operational conditions.

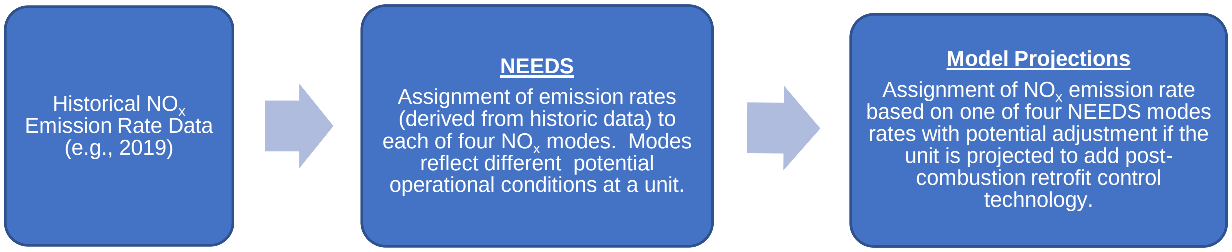
The emission rates assigned to each mode are derived from historical data (where available) and presented in NEEDS. When the model is run, IPM selects one of these four modes through a decision process depicted in Figure 3-3 below. The four modes address whether units upgrade combustion controls and/or operate *existing* post-combustion controls; the modes themselves do not address what happens to the unit's NO_x rate if it is projected to add a *new* post-combustion NO_x control. If a unit is projected to add a new post-combustion control, then after the model selects the appropriate input mode,

[27] https://www.epa.gov/Cross-State-Air-Pollution/good-neighbor-plan-2015-ozone-naaqs

[28] The OTR consists of the following states: Maine, New Hampshire, Vermont, Massachusetts, Rhode Island, Connecticut, New York, New Jersey, Pennsylvania, Delaware, Maryland, District of Columbia, and northern Virginia.

it adjusts that mode's emission rate downwards to reflect the retrofit of SCR or SNCR; the adjusted rate will reflect the greater percentage removal from the mode's emission rate or an emission rate floor. The full process for determining the NO_x rate of units in EPA 2023 Reference Case model projections is summarized in Figure 3-2.

Figure 3-2 Modeling Process for Obtaining Projected NO_x Emission Rates



NO_x Emission Rates in NEEDS Database

The NO_x rates were derived, wherever possible, directly from actual monitored NO_x emission rate data reported to EPA under the Acid Rain and Cross-State Air Pollution Rule in 2019.[29] The emission rates themselves reflect the impact of applicable NO_x regulations.[30] For coal-fired units, NO_x rates were used in combination with empirical assessments of NO_x combustion control performance to prepare a set of four possible starting NO_x rates to assign to a unit, depending on the specific NO_x reduction requirements affecting that unit in a model run.

The reason for having a framework of four potential NO_x rate modes applicable to each unit in NEEDS is to enable the model to select from a range of NO_x rates possible at a unit, given its configuration of NO_x combustion controls and its assumed operation of existing post-combustion controls. There are up to four basic operating states for a given unit that significantly impacts its NO_x rate, and thus there are four NO_x rate modes.

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:
    - If a unit has operated its post-combustion control year-round during the most recent of 2019, 2017, 2016, 2015, 2014, 2011, 2009, or 2007 years then mode 1 = mode 2, which reflects that the control will likely continue to operate year-round (and thus a "not run" emission rate option is not needed as justified by historical data).
    - If a unit has not operated its post-combustion control during the most recent of 2019, 2017, 2016, 2015, 2014, 2011, 2009, or 2007 years, mode 1 will be based on this data

[29] By assigning unit-specific NO_x rates based on 2019 data, EPA 2023 Reference Case is implicitly representing Title IV unit-specific rate limits and Clean Air Act Reasonably Available Control Technology (RACT) requirements for controlling NO_x emissions from electric generating units in ozone non-attainment areas or in the Ozone Transport Region (OTR). Unlike SO_2 emission rates, NO_x emission rates are assumed not to vary with coal type but are dependent on the combustion properties of the generating unit. Under the EPA 2023 Reference Case, the NO_x emission rate of a unit can only change if the unit is retrofitted with NO_x post-combustion control equipment or if it is assumed to install state-of-the-art NO_x combustion controls. In instances where a coal steam unit converts to natural gas, the NO_x rate is assumed to reduce by 50%. When a coal unit cofires with natural gas, its NO_x rate is capped at 0.15 lbs/MMBtu.

[30] Because 2019 NO_x rates reflect CSAPR, we no longer apply any incremental CSAPR related NO_x rate adjustments exogenously for CSAPR affected units in EPA 2023 Reference Case.

and mode 2 will be calculated using the method described under Question 3 in Attachment 3-2.

    - If a unit has <u>operated its post-combustion control seasonally</u> 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.

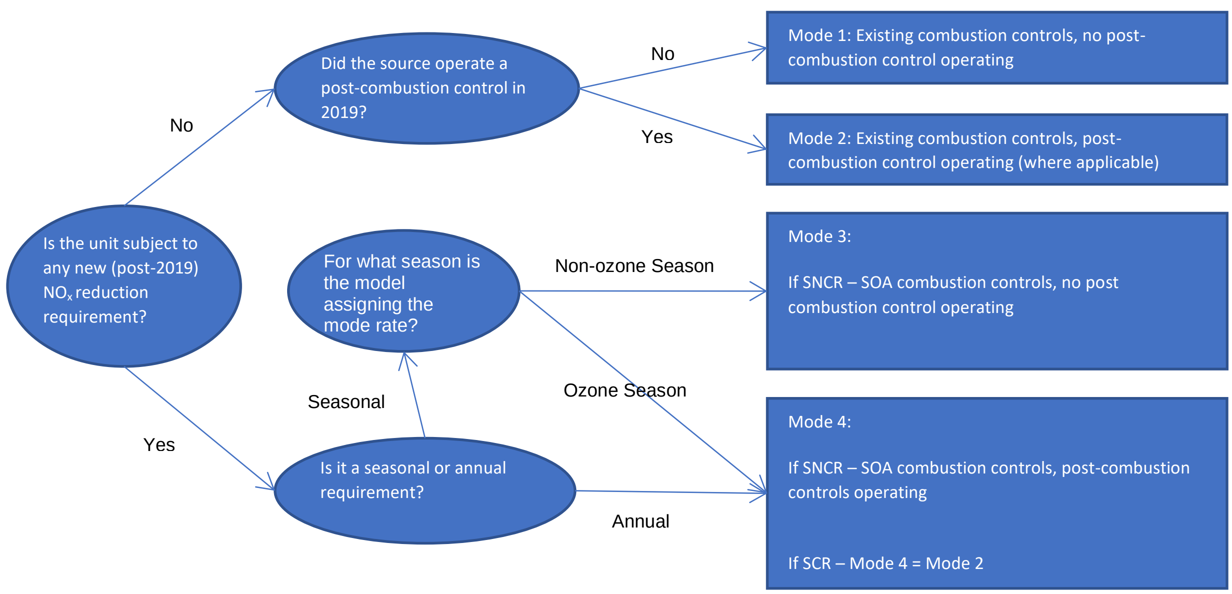
- For a unit without an existing post-combustion control, mode 1 = mode 2, which reflects the unit's historic NO_x rates from a recent year.

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.

Emission rates derived for each unit operating under each of these four modes are presented in NEEDS. Note that not every unit has a different emission rate for each mode, because certain units cannot in practice change their NO_x rates to conform to all potential operational states described above.

Figure 3-3 How One of the Four NO_x Modes Is Ultimately Selected for a Unit



<u>State-of-the-art combustion controls (SOA combustion controls)</u>

The definition of state-of-the-art varies depending on the unit type and configuration, indicating the incremental combustion controls that are required to achieve a state-of-the-art combustion control configuration for each unit. For instance, if a wall-fired, dry bottom boiler (highlighted below) currently has LNB but no overfire air (OFA), the state-of-the-art rate calculated for such a unit would assume a NO_x emission rate reflective of overfire air being added at the unit. As described in the attachment of this chapter, the state-of-the-art combustion controls reflected in the modes are only assigned to a unit if it is subject to a *new* (post-2019) NO_x reduction requirement (i.e., a NO_x reduction requirement that did not apply to the unit during its 2019 operation that forms the historic basis for deriving NO_x rates for units in EPA 2023 Reference Case). Existing reduction requirements as of 2019, under which units have already made combustion control decisions, would not trigger the assignment of the state-of-the-art modes that reflect additional combustion controls.

Table 3-14 State-of-the-Art Combustion Control Configurations by Boiler Type in the EPA 2023 Reference Case

Boiler Type	Existing NO_x Combustion Control	Incremental Combustion Control Necessary to Achieve State-of-the-Art
Tangential Firing	Does not Include LNC1 and LNC2	LNC3
	Includes LNC1, but not LNC2	Conversion from LNC1 TO LNC3
	Includes LNC2, but not LNC3	Conversion from LNC2 TO LNC3
	Includes LNC1 and LNC2 or LNC3	-
Wall Firing, Dry Bottom	Does not Include LNB and OFA	LNB + OFA
	Includes LNB, but not OFA	OFA
	Includes OFA, but not LNB	LNB
	Includes both LNB and OFA	-

Note:
LNB = Low NOx Burner Technology, LNC1 = Low NOx coal-and air nozzles with close-coupled overfire air, LNC2 = Low NOx Coal-and-Air Nozzles with Separated Overfire Air, LNC3 = Low NOx Coal-and-Air Nozzles with Close-Coupled and Separated Overfire Air, OFA = Overfire Air.

The emission rates for each generating unit under each mode are included in the NEEDS database, described in Chapter 4. Attachment 3-2 gives further information on the procedures employed to derive the four NO_x mode rates.

Because of the complexity of the fleet and the completeness/incompleteness of historic data, there are instances where the derivation of a unit's modeled NO_x emission rate is more detailed than the description provided above. For a more complete step-by-step description of the decision rules used to develop the NO_x rates, see Attachment 3-2.

3.10.4 Multi-Pollutant Environmental Regulations

<u>GNP</u>

On March 15, 2023, EPA finalized the Good Neighbor Plan (GNP) for the 2015 ozone National Ambient Air Quality Standards (NAAQS). Starting in 2023, 22 states will be subject to ozone season NO_x budgets consistent with Table 3-15. The programs' assurance provisions, which restrict the maximum amount of exceedance of an individual state's emissions budget each year through the use of banked or traded allowances to 21% of the state's budget, are also implemented. The starting allowance bank in 2023 is 22,319 tons, which is equal to the number of banked allowances at the start of the GNP after old CSAPR Update / RCU allowances were converted. This is equal to the sum of the states' 10.5% variability limits. In run year 2030, coal facilities greater than 100 MW lacking SCR controls and certain oil/gas steam facilities greater than 100 MW that lack existing SCR controls located in these states must meet daily emission rate limits, effectively forcing affected units to install new SCR controls, find other means of compliance, or retire. Additionally, within the GNP footprint, EPA models NO_x emissions rates at affected facilities that reflect operating and optimized existing controls.

Table 3-15 Ozone-Season NO_x Emission Caps (Tons) for Fossil Units greater than 25MW in the EPA 2023 Reference Case

State	2028	2030 onwards
Alabama	7,546	5,578
Arkansas	4,877	4,334
Illinois	5,511	4,901
Indiana	10,446	7,631
Kentucky	9,513	9,291
Louisiana	3,592	3,592
Maryland	717	717
Michigan	7,256	6,886
Minnesota	3,515	2,012
Mississippi	1,848	1,848
Missouri	8,868	8,191
Nevada	1,271	989
New Jersey	930	930
New York	4,033	4,033
Ohio	8,391	7,742
Oklahoma	4,649	4,649
Pennsylvania	8,646	5,827
Texas	27,112	26,174
Utah	3,150	3,150
Virginia	2,871	2,361
West Virginia	11,710	11,710
Wisconsin	4,123	4,123
Regional Cap	116,178	104,685

CSAPR, CSAPR Update, and RCU

EPA 2023 Reference Case includes the ozone-season NO_x limits reflecting the Cross-State Air Pollution Rule (CSAPR) Rule, CSAPR Update Rule, and the Revised CSAPR Update Rule federal regulatory measures to address transport under the 1997and 2008 National Ambient Air Quality Standards (NAAQS) for ozone. For states in which the Good Neighbor Plan is the most recently promulgated ozone-season program, then the GNP limitations replace those from these prior programs for modeling purposes (and these prior program limitations are shown for informational purposes only here).

The state budgets for Ozone Season NO_x for the CSAPR Update Rule (that were not further adjusted in the Revised CSAPR Update Rule) are shown in Table 3-16. Additionally, Georgia was modeled as a separate region, with Georgia units unable to trade allowances with units in other states and received its CSAPR Phase 2 budget and assurance level, as shown in Table 3-16. This is because Georgia, unlike the other states covered by the CSAPR Update Rule, did not significantly contribute to a downwind nonattainment or maintenance receptor for the 2008 NAAQS. Further, Georgia did not have a remanded Ozone Season NO_x budget related to a D.C. Circuit Court decision on the original Cross-State Air Pollution Rule.

The programs' assurance provisions, which restrict the maximum amount of exceedance of an individual state's emissions budget each year through the use of banked or traded allowances to 21% of the state's budget, are also implemented. This is equal to one-and-a-half times the sum of the states' 21% variability limits. For more information on CSAPR, go to https://www.epa.gov/csapr. For more information on the CSAPR Update, go to https://www.epa.gov/airmarkets/final-cross-state-air-pollution-rule-update.

Table 3-16 G1 and G2 CSAPR Update State Budgets, Variability Limits, and Assurance Levels for Ozone-Season NO_x (Tons) – 2021 through 2054

State	Budget	Variability Limit	Assurance Level
Alabama	13,211	2,774	15,985
Arkansas	9,210	1,934	11,144
Iowa	11,272	2,367	13,639
Kansas	8,027	1,686	9,713
Missouri	15,780	3,314	19,094
Mississippi	6,315	1,326	7,641
Oklahoma	11,641	2,445	14,086
Tennessee	7,736	1,625	9,361
Texas	52,301	10,983	63,284
Wisconsin	7,915	1,662	9,577
Georgia Budget, Variability Limit, and Assurance Level for Ozone-Season NO_x			
Georgia	24,041	5,049	29,090

On March 15, 2021, EPA finalized the Revised Cross-State Air Pollution Rule Update for the 2008 ozone National Ambient Air Quality Standards (NAAQS) to address the D.C. Circuit's remand of the CSAPR Update Rule. Starting in 2021, 12 of the 22 states covered in the CSAPR Update Rule will revise ozone season NO_x budgets consistent with Table 3-17. The programs' assurance provisions, which restrict the maximum amount of exceedance of an individual state's emissions budget each year through the use of banked or traded allowances to 21% of the state's budget, are also implemented. The starting allowance bank in 2023 is 22,488 tons, which is equal to the number of banked allowances at the start of the Revised CSAPR Update program after old CSAPR Update allowances were converted. This is equal to the sum of the states' 21% variability limits.

Table 3-17 Revised CSAPR Update State Budgets, Variability Limits, and Assurance Levels for Ozone-Season NO_x for G3 states (tons)

State	Budget (tons)	Variability Limit (tons)	Assurance Level (tons)
2021			
Illinois	9,102	1,911	11,013
Indiana	13,051	2,741	15,792
Kentucky	15,300	3,213	18,513
Louisiana	14,818	3,112	17,930
Maryland	1,499	315	1,814
Michigan	12,727	2,673	15,400
New Jersey	1,253	263	1,516
New York	3,416	717	4,133
Ohio	9,690	2,035	11,725
Pennsylvania	8,379	1,760	10,139
Virginia	4,516	948	5,464
West Virginia	13,334	2,800	16,134
2022			
Illinois	9,102	1,911	11,013
Indiana	12,582	2,642	15,224
Kentucky	14,051	2,951	17,002
Louisiana	14,818	3,112	17,930
Maryland	1,266	266	1,532
Michigan	12,290	2,581	14,871
New Jersey	1,253	263	1,516
New York	3,416	717	4,133
Ohio	9,773	2,052	11,825
Pennsylvania	8,373	1,758	10,131
Virginia	3,897	818	4,715

State	Budget (tons)	Variability Limit (tons)	Assurance Level (tons)
West Virginia	12,884	2,706	15,590
2023			
Illinois	8,179	1,718	9,897
Indiana	12,553	2,636	15,189
Kentucky	14,051	2,951	17,002
Louisiana	14,818	3,112	17,930
Maryland	1,266	266	1,532
Michigan	9,975	2,095	12,070
New Jersey	1,253	263	1,516
New York	3,421	718	4,139
Ohio	9,773	2,052	11,825
Pennsylvania	8,373	1,758	10,131
Virginia	3,980	836	4,816
West Virginia	12,884	2,706	15,590
2024 -2059			
Illinois	8,059	1,692	9,751
Indiana	9,564	2,008	11,572
Kentucky	14,051	2,951	17,002
Louisiana	14,818	3,112	17,930
Maryland	1,348	283	1,631
Michigan	9,786	2,055	11,841
New Jersey	1,253	263	1,516
New York	3,403	715	4,118
Ohio	9,773	2,052	11,825
Pennsylvania	8,373	1,758	10,131
Virginia	3,663	769	4,432
West Virginia	12,884	2,706	15,590

MATS

Finalized in 2011, the Mercury and Air Toxics Rule (MATS) establishes National Emissions Standards for Hazardous Air Pollutants (NESHAPS) for the “electric utility steam generating unit” source category, which includes those units that combust coal or oil for the purpose of generating electricity for sale and distribution through the electric grid to the public. EPA 2023 Reference Case applies the input-based (lbs/MMBtu) MATS control requirements for mercury and hydrogen chloride to covered units.

EPA 2023 Reference Case assumes that all active coal-fired generating units with a capacity greater than 25 MW have complied with the MATS filterable PM requirements through the operation of either electrostatic precipitator (ESP) or fabric filter (FF) particulate controls. No additional PM controls beyond those in NEEDS are modeled in EPA 2023 Reference Case.

EPA 2023 Reference Case does not model the alternative SO_2 standard offered under MATS for units to demonstrate compliance with the rule’s HCl control requirements. Coal steam units with access to lignite in the modeling are required to meet the “existing coal-fired unit low Btu virgin coal” standard. For more information on MATS, go to http://www.epa.gov/mats/.

Regional Haze

The Clean Air Act establishes a national goal for returning visibility to natural conditions through the “prevention of any future, and the remedying of any existing impairment of visibility in Class I areas [156 national parks and wilderness areas], where impairment results from manmade air pollution.” On July 1, 1999, EPA established a comprehensive visibility protection program with the issuance of the regional haze rule (64 FR 35714). The rule implements the requirements of section 169B of the CAAA and requires states to submit State Implementation Plans (SIPs) establishing goals and long-term strategies for reducing emissions of air pollutants (including SO_2 and NO_x) that cause or contribute to visibility impairment. The requirement to submit a regional haze SIP applies to all 50 states, the District of Columbia, and the Virgin Islands. Among the components of a long-term strategy is the requirement for states to establish emission limits for visibility-impairing pollutants emitted by certain source types (including EGUs) that were placed in operation between 1962 and 1977. These emission limits are to reflect Best Available Retrofit Technology (BART). States may perform individual point source BART determinations, or meet the requirements of the rule with an approved BART alternative. An alternative regional SO_2 cap for EGUs under Section 309 of the regional haze rule is available to certain western states whose emission sources affect Class 1 areas on the Colorado Plateau.

Since 2010, EPA has approved regional haze State Implementation Plans (SIPs) or, in a few cases, put in place regional haze Federal Implementation Plans for several states. The BART limits approved in these plans (as of January 2021) that will be in place for EGUs are represented in EPA 2023 Reference Case as follows.

- Source-specific NO_x or SO_2 BART emission limits, minimum SO_2 removal efficiency requirements for FGDs, limits on sulfur content in fuel oil, constraints on fuel type (e.g., natural gas only or prohibition of certain fuels such as petroleum coke), or commitments to retire units are applied to the relevant EGUs.
- EGUs in states that rely on CSAPR trading programs to satisfy BART must meet the requirements of CSAPR.
- EGUs in states that rely on state power plant rules to satisfy BART must meet the emission limits imposed by those state rules.
- For the three western states (New Mexico, Wyoming, and Utah) with approved Section 309 SIPs for SO_2 BART, emission constraints were not applied as current and projected emissions are well under the regional SO_2 cap.

Table 3-34 lists the NO_x and SO_2 limits applied to specific EGUs, and other implementations applied in IPM. For more information on the Regional Haze Rule, go to https://www.epa.gov/visibility.

On June 28, 2021, EPA filed a status update with the United States Court of Appeals for the District of Columbia Circuit noting that “the agency is convening a proceeding for reconsideration” of the August 2020 rule known as the “Texas Regional Haze BART and Interstate Visibility Transport FIP.” Any changes from the that effort will be incorporated into EPA modeling when finalized.

3.10.5 CO_2 Regulations

The Regional Greenhouse Gas Initiative (RGGI) is a CO_2 cap and trade program affecting fossil fired electric power plants 25 MW or larger in Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Rhode Island, Vermont, and Virginia. Table 3-23 shows the specifications for RGGI that are implemented in EPA 2023 Reference Case. If/when other states join RGGI and finalize/implement regulations, EPA will adjust its representation accordingly.

As part of California’s Assembly Bill 32 (AB32), the Global Warming Solutions Act, a multi-sector GHG cap-and-trade program was established that establishes long-term economy-wide emission targets, starting in 2013 for electric utilities and large industrial facilities, with distributors of transportation, natural gas, and other fuels joining the capped sectors in 2015. In addition to in-state sources, the cap-and-trade program also covers the emissions associated with qualifying, out-of-state EGUs that sell power into California. Due to the inherent complexity in modeling a multi-sector cap-and-trade program where the participation of out-of-state EGUs is determined based on endogenous behavior (i.e., IPM determines whether qualifying out-of-state EGUs are projected to sell power into California), EPA has developed a simplified methodology to model California's economy-wide cap-and-trade program as follows.

- Adopt the AB32 cap-and-trade allowance price from EIA's AEO2023 Reference Case, which fully represents the non-power sectors. All qualifying fossil-fired EGUs in California are subject to this price signal, which is applied through the end of the modeled time horizon since the underlying legislation requires those emission levels to be maintained.
- Assume the marginal CO_2 emission rate for each IPM region that exports power to California to be 0.428 MT/MWh.
- For each IPM region that exports power to California, convert the $/ton CO_2 allowance price projection into a mills/kWh transmission wheeling charge using the marginal emission rate from the previous step. The additional wheeling charge for qualifying out-of-state EGUs is equal to the allowance price imposed on affected in-state EGUs. Applying the charge to the transmission link ensures that power imported into California from out-of-state EGUs must account for the cost of CO_2 emissions represented by its generation, such that the model may clear the California market in a manner consistent with AB32 policy treatment of CO_2 emissions.

Federal CO_2 standards for existing sources are not modeled, given ongoing litigation and regulatory review.[31] For new fossil fuel-fired sources, EPA 2023 Reference Case continues to include the Standards of Performance for Greenhouse Gas Emissions from New, Modified, and Reconstructed Stationary Sources: Electric Generating Units (New Source Rule).[32] Although this rule is also being reviewed,[33] the standards of performance are legally in effect until such review is completed and/or revised. In addition, state level CO_2 standards were implemented in Colorado (HB21-1266), Massachusetts (Massachusetts Senate Bill 9), North Carolina (North Carolina House Bill 951), Oregon (Oregon House Bill 2021), and Washington (Washington state SB5126).

[31] EPA Memorandum: "Status of Affordable Clean Energy Rule and Clean Power Plan," February 12, 2021. Available at https://www.epa.gov/sites/default/files/2021-02/documents/ace_letter_021121.doc_signed.pdf.

[32] 80 FR 64510

[33] 82 FR 16330

3.10.6 Non-Air Regulations Impacting EGUs

Cooling Water Intakes (316(b)) Rule

Section 316(b) of the Clean Water Act requires that National Pollutant Discharge Elimination System (NPDES) permits for facilities with cooling water intake structures ensure that the location, design, construction, and capacity of the structures reflect the best technology available to minimize harmful impacts on the environment. Under a 1995 consent decree with environmental organizations, EPA divided section 316(b) rulemaking into three phases. All new facilities except offshore oil and gas exploration facilities were addressed in Phase I in December 2001; all new offshore oil and gas exploration facilities were later addressed in June 2006 as part of Phase III. This final rule also removes a portion of the Phase I rule to comply with court rulings. Existing large electric-generating facilities were addressed in Phase II in February 2004. Existing small electric-generating and all manufacturing facilities were addressed in Phase III (June 2006). However, Phase II and the existing facility portion of Phase III were remanded to EPA for reconsideration because of legal proceedings. This final rule combines these remands into one rule and provides a holistic approach to protecting aquatic life impacted by cooling water intakes. The rule covers roughly 1,065 existing facilities that are designed to withdraw at least 2 million gallons per day of cooling water. EPA estimates that 544 power plants are affected by this rule.

The final regulation has three components for affected facilities: 1) reduce fish impingement through a technology option that meets best technology available requirements, 2) conduct site-specific studies to help determine whether additional controls are necessary to reduce entrainment, and 3) meet entrainment standards for new units at existing facilities when additional capacity is added. EPA 2023 Reference Case includes the cost of complying with this rule. The cost assumptions and analysis for 316(b) can be found in Chapter 8.7 of the Rule's Technical Development Document for the Final Section 316(b) Existing Facilities Rule at https://www.epa.gov/sites/production/files/2015-04/documents/cooling-water_phase-4_tdd_2014.pdf.

For more information on 316(b), go to https://www.epa.gov/cooling-water-intakes.

Combustion Residuals from Electric Utilities (CCR)

In December of 2014, EPA finalized national regulations to provide a comprehensive set of requirements for the safe disposal of coal combustion residuals (CCRs), commonly known as coal ash, from coal-fired power plants. The final rule is the culmination of extensive study on the effects of coal ash on the environment and public health. The rule establishes technical requirements for CCR landfills and surface impoundments under Subtitle D of the Resource Conservation and Recovery Act.

EPA 2023 Reference Case includes cost of complying with this rule's requirements by taking the estimated plant-level compliance cost identified for the CCR final rule and apportioning them into unit-level cost[34]. Three categories of unit-level cost were quantified: capital cost, fixed operating and maintenance cost (FOM), and variable operating and maintenance (VOM) cost. The method for apportioning these costs to the unit-level for inclusion in EPA Platform is discussed in the Addendum to the RIA for EPA's 2015 Coal Combustion Residuals (CCR) Final Rule. The initial plant-level cost estimates are discussed in the Rule's Regulatory Impact Analysis.

In September of 2017, EPA granted petitions to reconsider some provisions of the rule. In granting the petitions, EPA determined that it was appropriate, and in the public's interest to reconsider specific provisions of the final CCR rule based in part on the authority provided through the Water Infrastructure for Improvements to the Nation (WIIN) Act. At time of this modeling update, EPA had not committed to changing any part of the rule or agreeing with the merits of the petition – the Agency is simply granting

[34] CCR related cost adders were not applied to units with CCR-based retirement dates no later than 12/31/2028.

petitions to reconsider specific provisions. Should EPA decide to revise specific provisions of the final CCR rule, it will go through notice and comment period, and the rules corresponding model specification would be subsequently changed in future base case platforms.

On July 29, 2020, the U.S. Environmental Protection Agency (EPA) finalized several changes to the regulations for this rule to implement the court's vacatur of certain closure requirements. In response to court rulings, this final rule specified that all unlined surface impoundments are required to retrofit or close, not just those that have detected groundwater contamination above regulatory levels. The rule also changed the classification of compacted-soil lined or "clay-lined" surface impoundments from "lined" to "unlined," which means that formerly defined clay-lined surface impoundments are no longer considered lined surface impoundments and need to be retrofitted or closed. These changes, and corresponding requirements and cost, are reflected in this version of IPM using the same methodology described in the Addendum for the RIA for EPA's 2015 CCR Rule mentioned above.

For more information on CCR, go to http://www.epa.gov/coalash/coal-ash-rule.

Effluent Limitation and Guidelines (ELG)

In September 2015, the EPA finalized a rule revising the regulations for the Steam Electric Power Generating category (40 CFR Part 423).[35] The rule established federal limits on the levels of toxic metals in wastewater that can be discharged from power plants. The rule established or updated standards for wastewater streams from flue gas desulfurization, fly ash, bottom ash, flue gas mercury control, and gasification of fuels.

On October 13, 2020 – EPA published a reconsideration rule that revised the requirements for flue gas desulfurization (FGD) wastewater and bottom ash (BA) transport water; revised the voluntary incentives program for FGD wastewater; added subcategories; and established new compliance dates. These changes, and corresponding requirements and costs, are reflected in EPA 2023 Reference Case. EPA reflects this rule in this base case by apportioning the estimated total capital, and FOM costs to likely affected units based on controls and capacity. The cost adders are reflected in the model inputs and were applied starting in 2025, by which point the requirements were expected to be fully implemented.

On July 26, 2021, EPA announced it was initiating a supplemental rulemaking to strengthen certain discharge limits in the Steam Electric Power Generating category. EPA undertook a science-based review of the 2020 Steam Electric Reconsideration Rule under Executive Order 13990, finding that opportunities for improvement exist. EPA intends to issue a proposed rule for public comment in the fall of 2022. The current rule will continue to be implemented (and reflected in IPM) and any additional or updated requirements from this supplemental rulemaking will be incorporated when final.

For more information on ELG, go to https://www.epa.gov/eg/effluent-guidelines-plan.

3.10.7 State-Specific Environmental Regulations

EPA 2023 Reference Case represents enacted laws and regulations in states affecting emissions from the electricity sector. Table 3-29 summarizes the provisions of state laws and regulations that are represented in EPA 2023 Reference Case.

[35] https://www.epa.gov/eg/steam-electric-power-generating-effluent-guidelines-2015-final-rule

3.10.8 New Source Review (NSR) Settlements

New Source Review (NSR) settlements refer to legal agreements with companies resulting from the permitting process under the CAAA, which requires industry to undergo an EPA pre-construction review of proposed environmental controls either on new facilities or as modifications to existing facilities where there would result in a “significant increase” in a regulated pollutant. A summary of the units affected and how the settlements were modeled can be found in Table 3-30.

State settlements and citizen settlements are also represented in EPA 2023 Reference Case. These are summarized in Table 3-31 and Table 3-32 respectively.

3.10.9 Emission Assumptions for Potential (New) Units

There are no location-specific variations in the emission and removal rate capabilities of potential new units. In IPM, potential new units are modeled as additional capacity and generation that may come online in each model region. Across all model regions, the emission and removal rate capabilities of potential new units are the same, and they reflect applicable federal emission limitations on new sources. The specific assumptions regarding the emission and removal rates of potential new units in EPA 2023 Reference Case are presented in Table 3-24. (Note: Nuclear, wind, solar, and fuel cell technologies are not included in Table 3-24 because they do not emit any of the listed pollutants.) For additional details on the modeling of potential new units, see Chapter 4.

3.10.10 Renewable Portfolio Standards and Clean Energy Standards

Renewable Portfolio Standards (RPS) generally refer to various state-level policies that require renewable generation to meet a specified share of generation or sales. In the EPA 2023 Reference Case, the state RPS requirements are represented at a state level based on existing requirements. Table 3-18 and Table 3-19 show the state-level RPS and solar carve-out requirements.

Table 3-18 Renewable Portfolio Standards in the EPA 2023 Reference Case

State	2028	2030	2035	2040	2045	2050	2055
Arizona	8.6%	8.6%	8.6%	8.6%	8.6%	8.6%	8.6%
California	52.0%	57.3%	70.7%	84.0%	97.3%	100.0%	100.0%
Colorado	20.9%	20.9%	20.9%	20.9%	20.9%	20.9%	20.9%
Connecticut	40.0%	44.0%	44.0%	44.0%	44.0%	44.0%	44.0%
District of Columbia	73.0%	87.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Delaware	26.5%	28.0%	40.0%	40.0%	40.0%	40.0%	40.0%
Iowa	0.6%	0.6%	0.6%	0.6%	0.5%	0.5%	0.5%
Illinois	32.5%	40.0%	45.0%	50.0%	50.0%	50.0%	50.0%
Massachusetts	36.0%	40.0%	45.0%	50.0%	55.0%	60.0%	60.0%
Maryland	47.5%	50.0%	50.0%	50.0%	50.0%	50.0%	50.0%
Maine	71.0%	80.0%	85.0%	90.0%	95.0%	100.0%	100.0%
Michigan	35.0%	35.0%	35.0%	35.0%	35.0%	35.0%	35.0%
Minnesota	34.0%	40.0%	55.0%	55.0%	55.0%	55.0%	55.0%
Missouri	10.5%	10.5%	10.5%	10.5%	10.5%	10.5%	10.5%
North Carolina	11.6%	11.6%	11.6%	11.6%	11.6%	11.6%	11.6%
New Hampshire	23.0%	23.0%	23.0%	23.0%	23.0%	23.0%	23.0%
New Jersey	46.5%	52.5%	52.5%	52.5%	52.5%	52.5%	52.5%
New Mexico	41.6%	45.2%	57.2%	69.2%	70.7%	72.3%	72.3%
Nevada	34.8%	41.4%	41.4%	41.4%	41.4%	41.4%	41.4%
New York	61.2%	70.0%	70.0%	70.0%	70.0%	70.0%	70.0%
Ohio	7.6%	7.6%	7.6%	7.6%	7.6%	7.6%	7.6%
Oregon	18.6%	23.7%	31.1%	35.5%	39.9%	39.9%	39.9%
Pennsylvania	8.0%	8.0%	8.0%	8.0%	8.0%	8.0%	8.0%
Rhode Island	55.5%	72.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Texas	6.5%	6.3%	6.0%	5.7%	5.4%	5.1%	5.1%
Virginia	26.1%	30.8%	44.5%	60.2%	76.0%	78.4%	78.4%
Vermont	67.0%	71.0%	75.0%	75.0%	75.0%	75.0%	75.0%

State	2028	2030	2035	2040	2045	2050	2055
Washington	12.2%	12.2%	12.2%	12.2%	12.2%	12.2%	12.2%
Wisconsin	9.6%	9.6%	9.6%	9.6%	9.6%	9.6%	9.6%

Notes:
The Renewable Portfolio Standard percentages are applied to modeled electricity sale projections.
North Carolina standards are adjusted to account for swine waste and poultry waste set-asides.

Table 3-19 State RPS Solar Carve-outs in the EPA 2023 Reference Case

State	2028	2030	2035	2040	2045	2050	2055
District of Columbia	4.50%	5.00%	7.00%	9.50%	10.00%	10.00%	10.00%
Delaware	4.25%	5.00%	10.00%	10.00%	10.00%	10.00%	10.00%
Illinois	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%
Maryland	14.50%	14.50%	14.50%	14.50%	14.50%	14.50%	14.50%
Minnesota	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%
Missouri	0.21%	0.21%	0.21%	0.21%	0.21%	0.21%	0.21%
North Carolina	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%
New Hampshire	0.70%	0.70%	0.70%	0.70%	0.70%	0.70%	0.70%
New Jersey	3.74%	2.21%	1.10%	1.10%	1.10%	1.10%	1.10%
Oregon	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%
Pennsylvania	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%

Clean Energy Standards require a certain percentage of electricity sales be met through zero carbon resources, such as renewables, nuclear, and hydropower. These requirements are summarized in Table 3-20. In addition, multiple U.S. states have adopted offshore wind energy policies, which are summarized in Table 3-21. Thermal generation limits are imposed in states where RPS or CES standards exceed 50% of sales to ensure that the states do not generate excess thermal power to satisfy exports. Table 3-22 summarizes the limits imposed in EPA 2023 Reference Case. These limits are not provided in affected PJM and New England states, as these states can meet their RPS requirements within PJM or ISONE.

Table 3-20 Clean Energy Standards in the EPA 2023 Reference Case

State	2028	2030	2035	2040	2045	2050	2055
California	-	-	-	-	-	100%	100%
Colorado	-	-	-	-	-	51%	51%
Connecticut	-	40%	70%	100%	100%	100%	100%
Illinois	-	-	-	-	-	100%	100%
Massachusetts	48%	60%	65%	70%	75%	80%	80%
Minnesota	-	75%	90%	100%	100%	100%	100%
Nevada	-	-	-	-	-	100%	100%
New Mexico	-	-	-	-	70%	90%	90%
New York	-	-	-	100%	100%	100%	100%
Oregon	-	-	-	100%	100%	100%	100%
Washington	-	100%	100%	100%	100%	100%	100%

Table 3-21 Offshore Wind Mandates in the EPA 2023 Reference Case

State	Bill/Act	Mandate Specifications	Implementation Year
Maryland	Senate Bill 516	400 MW, 800 MW, and 1,200 MW of offshore wind capacity by 2026, 2028 and 2030 respectively	2030
Maryland	Maryland Offshore Wind Energy Act of 2013	368 MW of offshore wind capacity (248 MW of US Wind, Inc. and 120 MW of Skipjack Offshore Energy, LLC projects)	2023
New Jersey	Executive Order No. 92	7,500 MW of offshore wind capacity by 2035	2035
Connecticut	House Bill 7156	2,000 MW of offshore wind capacity by 2030	2030

State	Bill/Act	Mandate Specifications	Implementation Year
Massachusetts	2016 Bill 4568	An Act to Promote Energy Diversity, legislation allows for the procurement of approximately 1,600MW of offshore wind	
		800MW Vineyard Wind	2024
		800MW South Coast Wind aka Mayflower Wind	2025
	Massachusetts Energy Diversity Act	4,000 MW of offshore wind capacity by 2027	2028
New York	Climate Leadership and Community Protection Act	9,000 MW of offshore wind capacity by 2035	2035
Virginia	Virginia Clean Economy Act	Development by Dominion Energy Virginia of qualified offshore wind projects having an aggregate rated capacity of not less than 5,200 megawatts by December 31, 2032 (Senate Bill 1441, legp604.exe (virginia.gov)	2035
Maine	Final Report of the Ocean Energy Task Force, 2009	Goal of 5,000 MW of offshore wind capacity by 2030	Not implemented
California		3,500 MW by 2030 and 25,000 MW by 2045	2030

Table 3-22 Fossil Generation Limits (GWh) in the EPA 2023 Reference Case

State	2028	2030	2035	2040	2045	2050	2055
California	158,266	150,564	135,237	102,949	75,365	73,943	89,090
Colorado	-	-	-	-	-	51,354	54,187
Illinois	-	-	-	91,212	94,870	11,251	11,710
New Mexico	-	-	14,248	11,682	11,995	6,309	6,747
Nevada	-	-	-	-	-	5,874	6,514
New York	69,195	58,109	63,363	14,244	15,195	15,925	16,652
Oregon	-	-	-	7,530	8,258	8,982	9,698
Virginia	-	-	-	66,893	44,218	42,019	44,149
Washington	-	10,676	11,704	12,796	14,035	15,264	16,481

3.11 Emissions Trading and Banking

Several environmental air regulations included in EPA 2023 Reference Case involve regional trading and banking of emission allowances. This includes the Regional Greenhouse Gas Initiative (RGGI) for CO_2; and the West Region Air Partnership's (WRAP) program regulating SO_2 (adopted in response to the federal Regional Haze Rule).

Table 3-23 summarizes the key parameters of these trading and banking programs as incorporated in EPA 2023 Reference Case. EPA 2023 Reference Case does not include any explicit assumptions on the allocation of emission allowances among model plants under any of the programs.

3.11.1 Intertemporal Allowance Price Calculation

Under a perfectly competitive cap-and-trade program that allows banking (with a single, fixed future cap, and full banking allowed), the allowance price always increases by the discount rate between periods if affected sources have allowances banked between those two periods. This is a standard economic result for cap-and-trade programs and is consistent with producing a least-cost solution.

EPA 2023 Reference Case uses the same discount rate assumption that governs all intertemporal economic decision-making in the model. The approach assumes that allowance trading is a standard activity engaged in by generation asset owners and that their intertemporal investment decisions as related to allowance trading will not fundamentally differ from other investment decisions. For more information on how this discount rate was calculated, see Section 10.4.

Table 3-23 Trading and Banking Rules in the EPA 2023 Reference Case

	WRAP- SO_2	RGGI - CO_2
Coverage	All fossil units > 25 MW[1]	All fossil units > 25 MW[2]
Timing	Annual	Annual
Size of Initial Bank (MTons)	The bank starting in 2018 is assumed to be zero	2028: 68,000
Total Allowances (MTons)	2018 - 2059: 89.6	2028: 94,183 2029: 90,528 2030 - 2059: 86,873

Notes:
[1] New Mexico, Utah, and Wyoming.
[2] Connecticut, Delaware, Maine, New Hampshire, New York, Vermont, Rhode Island, Massachusetts, Maryland, Virginia, and New Jersey.

Table 3-24 Emission and Removal Rate Assumptions for Potential (New) Units in the EPA 2023 Reference Case

	Controls, Removal, and Emissions Rates	Ultra-Supercritical Pulverized Coal	Ultra-Supercritical Pulverized Coal with 36% CCS	Ultra-Supercritical Pulverized Coal with 90% CCS	Advanced Combined Cycle	Advanced Combined Cycle with CCS	Advanced Combustion Turbine	Biomass	Geothermal	Landfill Gas
SO_2	Removal / Emissions Rate	98% with a floor of 0.06 lbs/MMBtu	98% with a floor of 0.06 lbs/MMBtu	98% with a floor of 0.06 lbs/MMBtu	None	None	None	0.08 lbs/MMBtu	None	None
NO_x	Emission Rate	0.05 lbs/MMBtu	0.05 lbs/MMBtu	0.05 lbs/MMBtu	0.011 lbs/MMBtu	0.011 lbs/MMBtu	0.011 lbs/MMBtu	0.02 lbs/MMBtu	None	0.09 lbs/MMBtu
Hg	Removal / Emissions Rate	90%	90%	90%	Natural Gas: 0.00014 lbs/MMBtu Oil: 0.48 lbs/MMBtu	Natural Gas: 0.00014 lbs/MMBtu Oil: 0.48 lbs/MMBtu	Natural Gas: 0.00014 lbs/MMBtu Oil: 0.48 lbs/MMBtu	0.57 lbs/MMBtu	3.7	None
CO_2	Removal / Emissions Rate	202.8 - 219.3 lbs/MMBtu	36%	90%	Natural Gas: 117.08 lbs/MMBtu Oil: 161.39 lbs/MMBtu	90%	Natural Gas: 117.08 lbs/MMBtu Oil: 161.39 lbs/MMBtu	None	None	None
HCL	Removal / Emissions Rate	99% with a floor of 0.001 lbs/MMBtu	99% with a floor of 0.001 lbs/MMBtu	99% with a floor of 0.001 lbs/MMBtu						

Table 3-25 Recalculated NO_x Emission Rates for SCR Equipped Units Sharing Common Stacks with Non-SCR Units in the EPA 2023 Reference Case

Plant Name	UniqueID_Final	Capacity (MW)	NOx Post-Comb Control	SCR Online Year	Mode 1 NO_x Rate (lbs/MMBtu)	Mode 2 NO_x Rate (lbs/MMBtu)	Mode 3 NO_x Rate (lbs/MMBtu)	Mode 4 NO_x Rate (lbs/MMBtu)
Ghent	1356_B_2	495			0.305	0.305	0.305	0.305
Ghent	1356_B_3	485	SCR	2004	0.075	0.075	0.075	0.075
Cooper	1384_B_1	116			0.273	0.273	0.199	0.199
Cooper	1384_B_2	225	SCR	2012	0.075	0.075	0.075	0.075
Clifty Creek	983_B_4	196	SCR	2003	0.075	0.075	0.075	0.075
Clifty Creek	983_B_5	196	SCR	2002	0.075	0.075	0.075	0.075
Clifty Creek	983_B_6	196			0.667	0.3	0.667	0.3

3.12 45Q – Credit for Carbon Dioxide Sequestration

Inflation Reduction Act of 2022, Section 45Q – which amended a Credit for Carbon Dioxide Sequestration originally passed in 2008 (hereafter referred to as the 45Q tax credit) is implemented in EPA 2023 Reference Case.

The updated 45Q tax credit offers increased monetary incentives through a tax credit for the capture and geologic storage of CO_2 that electric power plants and other industrial sources in the United States would otherwise emit. The essential features of the tax credit are as follows:

- $60 per metric ton in 2022 for CO_2 captured and injected into existing oil wells for enhanced oil recovery (EOR). The credit is adjusted for inflation post-2026.
- $85 per metric ton in 2022 for CO_2 captured and sequestrated in geologic formation (non-EOR). The credit is adjusted for inflation post-2026.
- The difference in the amounts of credit between EOR and non-EOR is designed to recognize that the EOR-captured CO_2 can be used to produce oil that may not otherwise be recovered, while the non-EOR-stored CO_2 does not bring additional revenue.
- Credits are available to plants that start construction or begin a retrofit before January 1, 2033 and are assumed to be applied for the first 12 years of operation. Due to an assumed construction lead time of 5 plus years for CCS retrofits, CCS retrofits in 2030 and 2035 run years are assumed to qualify for the tax credit.

The 45Q tax credit is implemented by applying its value through an adjustment to the step prices in the CO_2 storage cost curves. The process involves converting the credit amounts into 2022 real dollars, calculating weighted average tax credits by run year, and applying the weighted average tax credits to the individual step prices in the CO_2 storage cost curves.

List of tables and attachments that are uploaded directly to the web:

Table 3-26 Regional Net Internal Demand in EPA 2023 Reference Case

Table 3-27 Annual Transmission Capabilities of U.S. Model Regions in EPA 2023 Reference Case

Table 3-28 Turndown Assumptions for Coal Steam Units in EPA 2023 Reference Case

Table 3-29 State Power Sector Regulations included in EPA 2023 Reference Case

Table 3-30 New Source Review (NSR) Settlements in EPA 2023 Reference Case

Table 3-31 State Settlements in EPA 2023 Reference Case

Table 3-32 Citizen Settlements in EPA 2023 Reference Case

Table 3-33 Availability Assumptions in EPA 2023 Reference Case

Table 3-34 BART Regulations included in EPA 2023 Reference Case

Attachment 3-1 Incremental Demand Accounting for the On-the-books EPA OTAQ GHG Rules

Attachment 3-2 NO_x Rate Development in EPA 2023 Reference Case