Center for the New Energy Economy
Project Report for WESTAR-WRAP

Analysis of EGU Emissions for Regional Haze Planning and Ozone Transport Contribution

Final Report
June 14, 2019

Project Website: http://www.wrapair2.org/EGU.aspx

Overview

The Center for the New Energy Economy (CNEE) at Colorado State University conducted an analysis of current and future emissions of nitrogen oxides (NOx) and sulfur dioxide (SO2) from fossil-fueled electricity generating units (EGUs) in 13-Western states[1] for the Western States Air Resources Council (WESTAR) and Western Regional Air Partnership (WRAP). WRAP state air quality staff and representatives of Western electric utilities actively participated in the project and helped develop the study parameters, including information needed for Western regional air quality analyses and planning under the federal Clean Air Act.

The primary purpose of this project was to develop emissions information for use in regional modeling as part of the ongoing implementation of the Regional Haze Rule, and for ozone analysis and planning.

This report describes results related to the project's two major objectives:

1) A comprehensive database of information on the fleet of fossil fuel-fired EGUs in 13-Western states (circa 2014-2018) that contains information on the plants operating characteristics and NOx and SO2 emissions; and

2) A projection of 2028 NOx and SO2 emissions based on expected plant closures, fuel switching, and emission controls under a "rules on the books" scenario.

The data developed through this project will also be used by WESTAR and WRAP to quantify how emissions from fossil fuel-fired EGUs affects ozone formation at urban and rural locations across the West.

[1] Arizona, California, Colorado, Idaho, Montana, Nevada, New Mexico, North Dakota, Oregon, South Dakota, Utah, Washington, and Wyoming

Data Review

As part of the national Acid Rain Program, EGU operators from across the country are required to submit emissions information and other data on plant operations to US EPA's Air Markets Program. This information is publicly available on the Air Markets Program Data website - https://ampd.epa.gov/ampd/ .

In order to compile and quality assure (QA) a comprehensive database of information on the fleet of fossil-fired EGUs in the 13-Western states covered by this project, the information contained in the EPA database was downloaded and circulated to project participants for review. A complete description of the data review process can be found on the project website - http://www.wrapair2.org/EGU.aspx

During this review process, state and utility participants were asked to review the Acid Rain Program Data for 2014 to 2018 and to provide any corrections. Calendar year 2014 data for EGUs will be used in the WRAP's "shakeout" modeling runs (see table below) and calendar year 2018 EGU data will be used in the baseline modeling run unless plant operating conditions dictate the use of another year.

Western Regional Modeling Plan – Spring 2019 update		
Modeling Scenario	**Timeframe**	**Objectives / Characteristics / Change from previous scenario(s)**
2014 Shakeout v1 (actual emissions)	Dec. 2018 through early April 2019	• Compare Met and Biogenics datasets • Evaluate Boundary Conditions (BCs) • Uses 2014 NEIv2 data with limited corrections by states • Modeling Performance Evaluation • Identify Modeling Needs in Plan
2014 Shakeout v2 (actual emissions)	May through July 2019	• Finalize MPE results with improved inputs • Re-run GEOS-Chem global model for BCs with natural / anthro. sensitivity • Revised emissions – all CA anthro data, OGWG inputs • Will use recommended model configuration from v1

Current/Representative Baseline (planning rather than year-specific emissions, basis of all subsequent runs)	June through August 2019	• Apply v2 GEOS-Chem global model BCs
		• Revised emissions from 2014 actual, new EGU, OGWG, and FSWG inputs
		  ○ reflective of current emission rates and "normal" operations
		  ○ "representative" annual fire emissions to smooth out variation
		• Basis of all 2028 scenarios, will use model configuration from v1 / v2
		• Best reflect current emissions profile for each source potentially impacting Class I area visibility [source(s) identified from Q/D analysis]

Dynamic Model Evaluations (02, 14, 28)	Start Summer 2019	• Use 2014 met, BCs, biogenics for all • Actual 02 and 14 emissions, OTB for 2028 • Provide modeled glide path, Regional Haze Progress for anthro emissions
2028 Emissions from Rules OTB / OTW	August through October 2019	• Model visibility impact / calculate Reasonable Progress Goal for each Class I area "if no additional controls" were adopted • 2028 OTB emissions may be same as Current/Representative Baseline rate • Add international anthro contributions from Shakeout V2 • Gridded emissions to be used for Weighted Emissions Potential analysis
2028 Source Apportionment / Sensitivity	October 2019 through early 2020	• 2 sensitivity runs: increased emissions separately for wildfire and Rx fire • PSAT/OSAT run for state/source sector groups
2028 Control Strategy Run	Jan. through March 2020	• SCC-level "potential additional" SO2, NOx, PM % decreases from each state • Model visibility impact / calculate RPG for each Class I area "if additional controls" were to be adopted

In addition to confirming the accuracy of the historical emissions information contained in EPA's database, project participants were asked to address the following:

1) Provide information on any units not covered by the Acid Rain Program (referred to here as non-CAMD units). These are units that due to age (old) or size (small) are not reported to EPA under the Acid Rain Program.
2) Identify years when units experienced overhauls or major unplanned outages, or were off-line for extended periods due to one-time events such as installation of pollution control equipment.

3) Provide information on current emission controls and emission rates for each unit, including any new controls or permit conditions that are not fully reflected in the 2014-18 data.

4) Dates for planned unit retirements.

5) Identify units that switched fuel from coal to natural gas.

The information provided in response to these questions has been incorporated in the data files described below in order to prepare the 2028 "Rules-on-the-Book" emissions inventory that will be used in the WRAP's initial 2028 modeling runs to assess reasonable progress toward achieving visibility goals at the Class 1 Areas covered by the Regional Haze Rule.

Summary of Results

Note: Each of the data files referenced below can be found along with this report on the project website. http://www.wrapair2.org/EGU.aspx

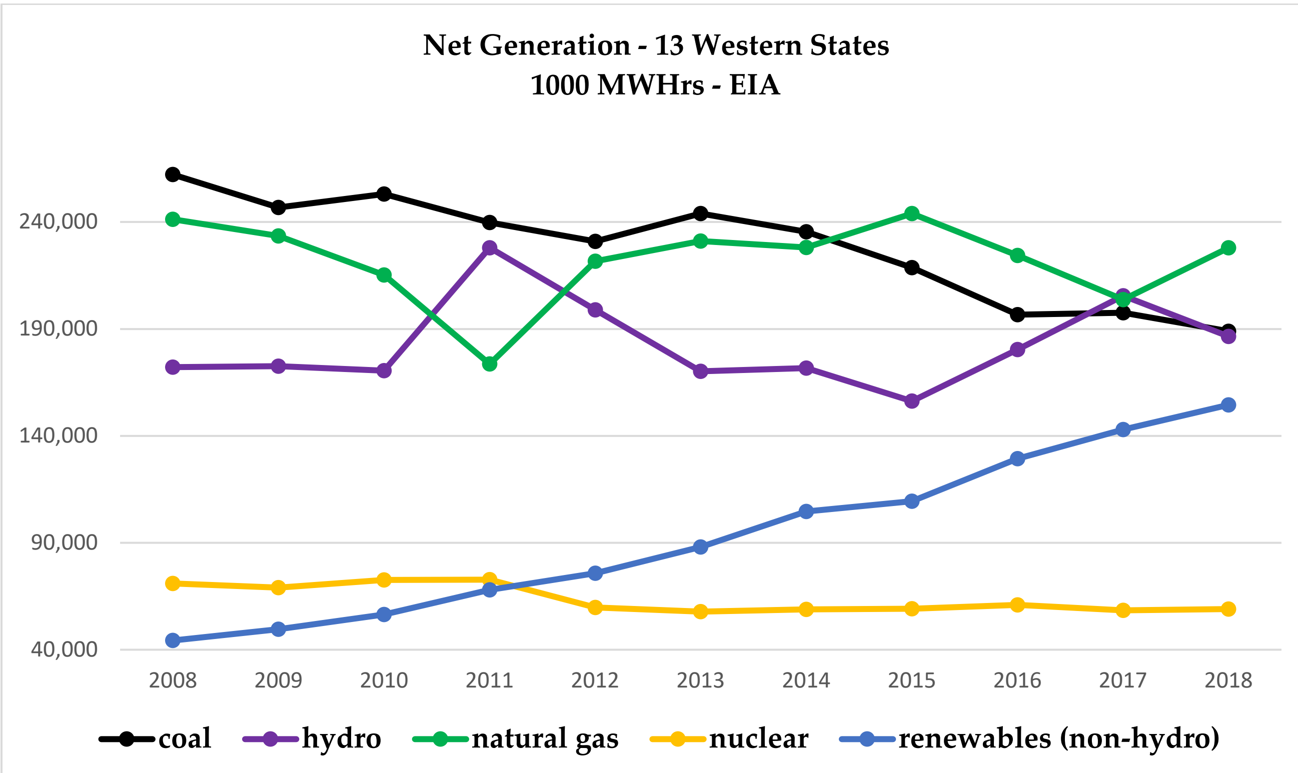


Figure 1: Electricity Generation in the Western U.S.

Power plant emissions in the West over the last ten years have been influenced by a number of factors, including changes in the generation mix. While total generation across the 13-state region has not increased significantly over the last 10 years, there has been a pronounced decrease in coal generation (-28%) and a corresponding increase in renewable generation (+349%). This trend away from coal and toward more renewables is expected to continue as more Western coal plants are scheduled to retire in the coming years. Unlike other parts of the country, the West has not seen a marked increase in natural gas generation over the last ten years.

Source: https://www.eia.gov/electricity/data/browser/ (See: Data File 1 – Net Generation)

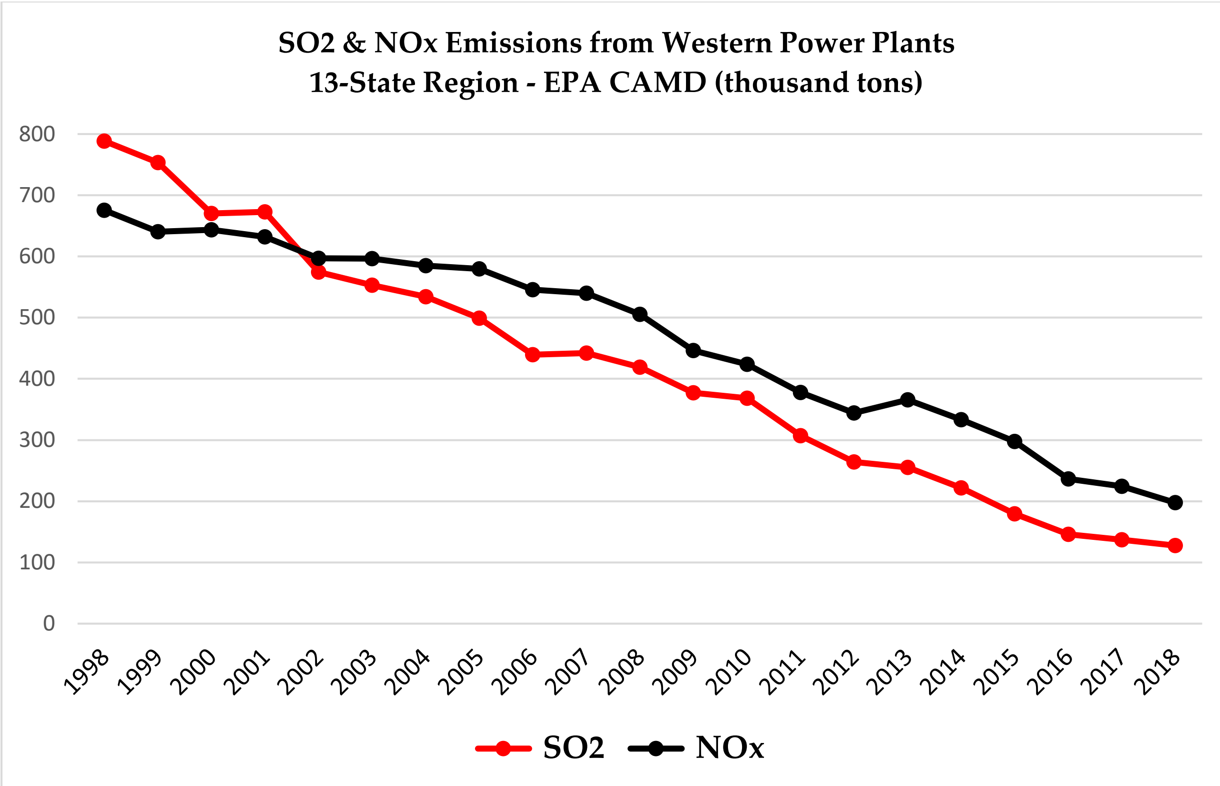


Figure 2: Western US Power Sector Emissions Trends
SO2 and NOx emissions from the Western power sector have decreased dramatically over the last 20 years. 2018 EGU emissions of SO2 were 84% below 1998 levels and NOx emissions were 71% below 1998.

Source: https://ampd.epa.gov/ampd/ (See: Data File 2 – 1998-2018 CAMD)

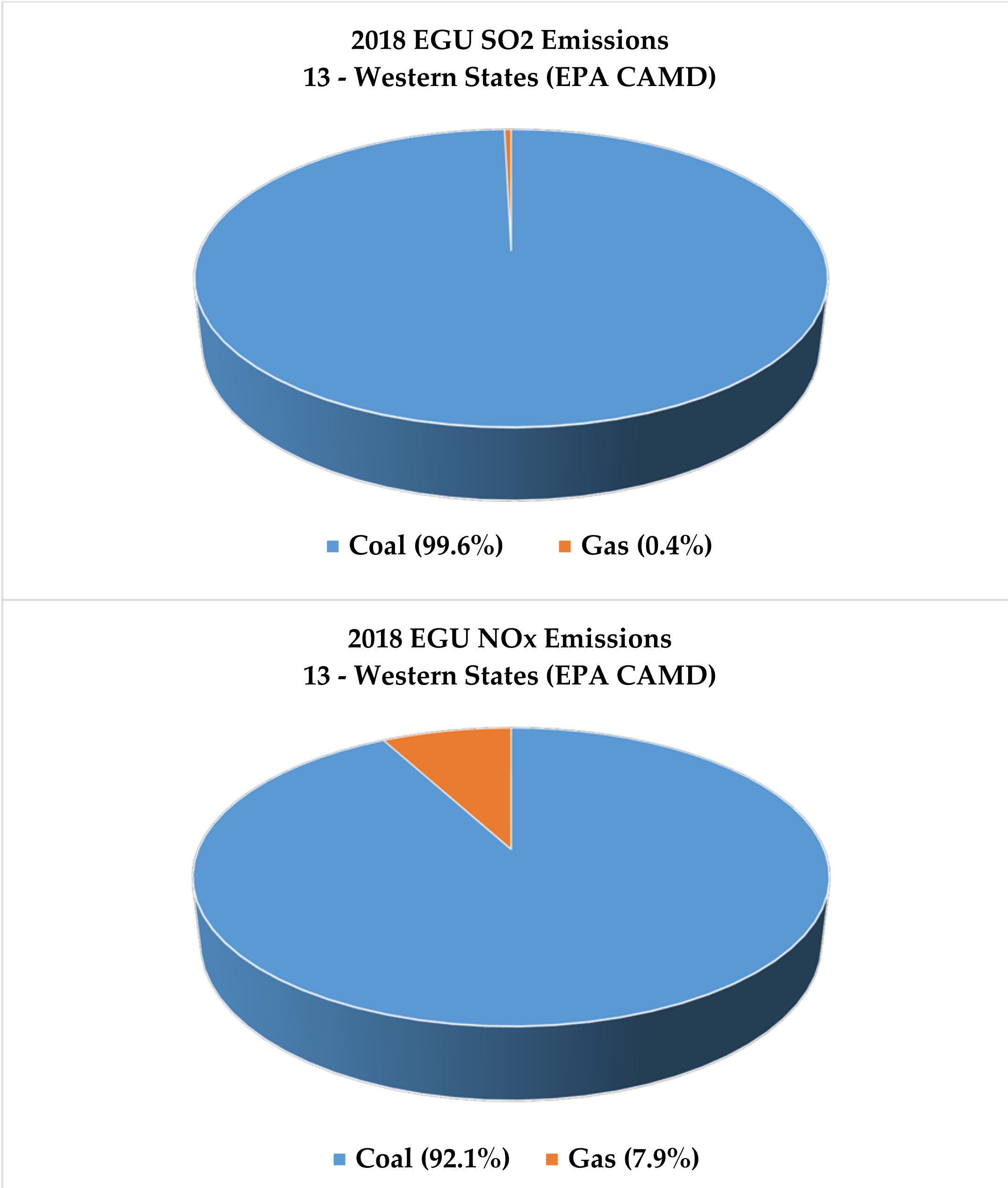


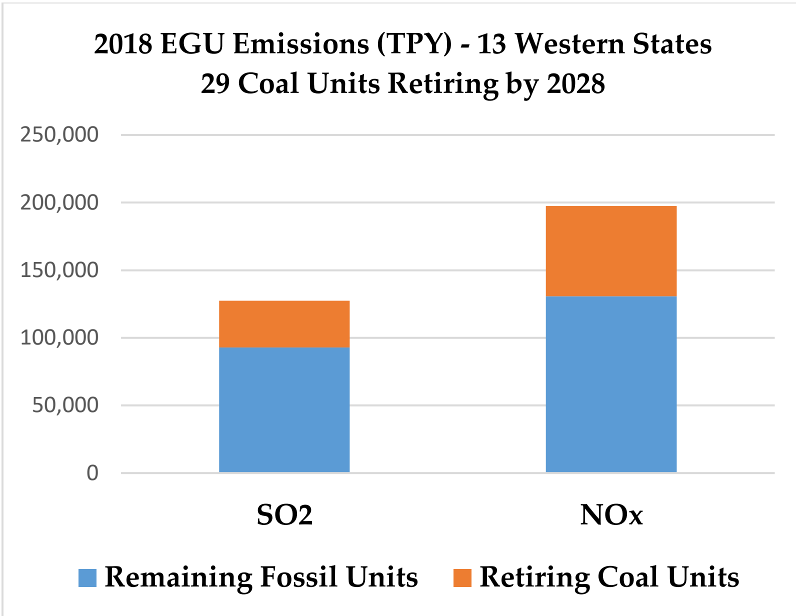
Figure 3: Coal vs. Gas Contribution to EGU Emissions Inventory
Most EGU emissions of SO_2 and NOx in the Western US in 2018 came from the 84 generating units powered by coal. Gas-fired generation contributed almost zero SO_2 and 8% of EGU NOx emissions in 2018. Most of the NOx emissions from gas-fired generation in 2018 came from the 253 units emitting 10 tons per year or more. The 271 units that emitted less than 10 tons per year contributed less than 0.5% of 2018 EGU NOx emissions in the West.

Source: https://ampd.epa.gov/ampd/ (See: Data File 3 – 2018 Charts)

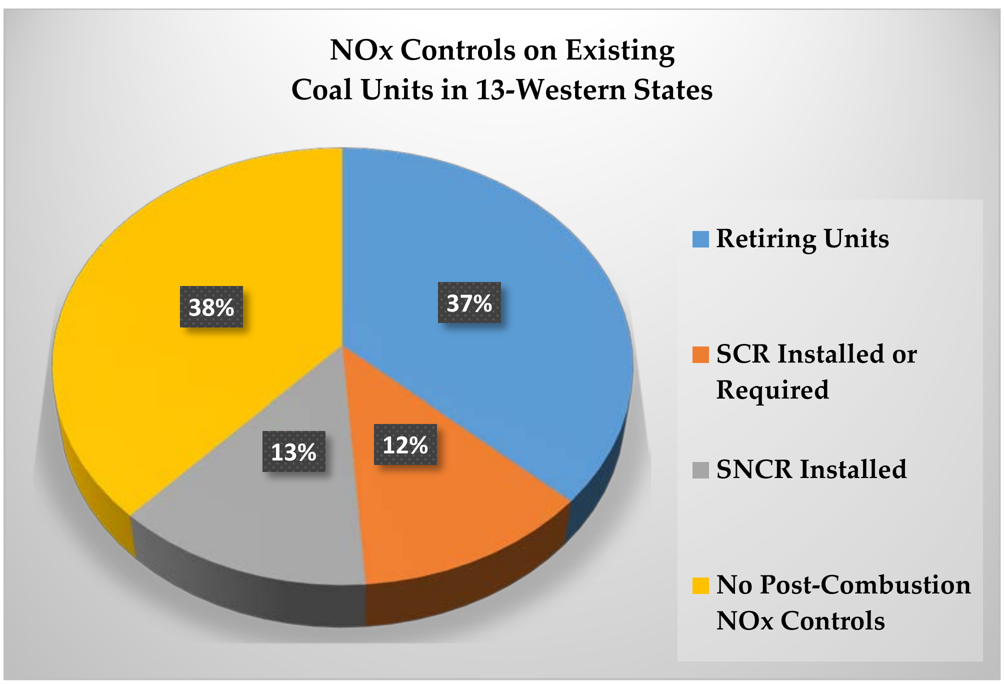
<u>Western Coal Unit Retirements by 2028</u> (See: Data File 4 – Western Coal Units)

State	Facility Name	Unit ID	Nameplate Capacity (MW)	In-Service Year	Retirement Year	notes
AZ	Cholla	1	114	1962	2025	APS IRP
AZ	Cholla	3	312	1980	2025	APS IRP
AZ	Cholla	4	414	1981	2025	PAC IRP
AZ	Navajo Generating Station	1	803	1974	2019	announced retirement
AZ	Navajo Generating Station	2	803	1975	2019	announced retirement
AZ	Navajo Generating Station	3	803	1976	2019	announced retirement
CO	Comanche (470)	1	383	1973	2022	Xcel Colorado Energy Plan
CO	Comanche (470)	2	396	1975	2025	Xcel Colorado Energy Plan
CO	Craig	C1	446	1980	2025	Legal/Regulatory
CO	Nucla	1	100	1991	2022	Legal/Regulatory
MT	Colstrip	1	358	1975	2019	Legal/Regulatory
MT	Colstrip	2	358	1976	2019	Legal/Regulatory
MT	Lewis & Clark	B1	50	1958	2020	announced retirement
ND	R M Heskett	B1	25	1954	2021	announced retirement
ND	R M Heskett	B2	75	1963	2021	announced retirement
NM	San Juan	1	369	1976	2022	PNM IRP (has SNCR)
NM	San Juan	4	555	1982	2022	PNM IRP (has SNCR)
NV	North Valmy	1	277	1981	2025	NV IRP (may retire earlier)
NV	North Valmy	2	290	1985	2025	NV IRP
OR	Boardman	1SG	642	1980	2021	Legal/Regulatory
UT	Intermountain	1SGA	820	1986	2025	announced retirement
UT	Intermountain	2SGA	820	1987	2025	announced retirement
WA	Centralia	BW21	730	1972	2021	Legal/Regulatory (12/31/2020)
WA	Centralia	BW22	730	1973	2026	Legal/Regulatory (12/31/2025)
WY	Naughton	3	384	1971	2018	Switched to gas 1/31/19
WY	Dave Johnston	BW41	134	1959	2027	PAC IRP
WY	Dave Johnston	BW42	134	1961	2027	PAC IRP
WY	Dave Johnston	BW43	255	1964	2027	PAC IRP
WY	Dave Johnston	BW44	400	1972	2027	PAC IRP

<u>Table 1:</u>
29 of the 84 coal units operating in the West in 2018 will retire by 2028. Emissions from these units are therefore zeroed out of the 2028 emissions projections produced by this project.



<u>Figure 4:</u> Emissions from coal units that will retire by 2028 comprised 27% of the SO2 and 34% of the NOx emitted in 2018 by all EGUs (coal and gas) in the 13-state Western region. (See: Data File 3 – 2018 Charts)



<u>Figure 5: NOx Controls on Existing Coal Units -</u> While the regional haze program is not technology forcing like the NSPS or NESHAP, it is helpful to understand the type of control technology currently in place at each EGU that plans to operate in 2028. Of the NOx emissions from coal units in 2018, 12% of the emissions came from units with SCRs installed or required; 13% came from units with SNCR installed; and 38% came from units not planned to retire by 2028 and which do not have post-combustion controls for NOx. The list of units in each category is shown below. (See: Data File 3 – 2018 Charts & Data File 4 – Western Coal Units)

Table 2: Coal Units by Type of NOx Controls (See: Data File 4 – Western Coal Units)

The coal units in this table are those not currently planned for retirement by 2028.

State	Facility Name	Unit ID	Nameplate Capacity (MW)	In-Service Year	notes
	SCR INSTALLED				
AZ	Coronado Generating Station	U1B	411	1979	Retire or install SCR in 2025
AZ	Coronado Generating Station	U2B	411	1980	SCR 2014
AZ	Springerville	4	458	2009	SCR
AZ	Springerville	TS3	458	2006	SCR
CO	Comanche (470)	3	857	2010	SCR
CO	Craig	C2	446	1979	SCR 2017
CO	Hayden	H1	190	1965	SCR in 2015
CO	Hayden	H2	275	1976	SCR 2016
CO	Pawnee	1	552	1981	SCR 2014
MT	Hardin	1	116	2006	SCR
NM	Four Corners	4	818	1969	SCR 2017
NM	Four Corners	5	818	1970	SCR 2017
NV	TS Power Plant	1	242	2008	SCR
SD	Big Stone	1	450	1975	SCR
WY	Dry Fork Station	1	484	2011	SCR
WY	Jim Bridger	BW73	608	1976	SCR 2015
WY	Jim Bridger	BW74	608	1979	SCR 2016
WY	Laramie River	1	570	1981	SCR 2019
WY	Wygen I	1	90	2003	SCR
WY	Wygen II	1	95	2008	SCR
WY	Wygen III	1	116	2010	SCR
	SNCR INSTALLED				
AZ	Apache Station	3	204	1979	SNCR 2017
CO	Craig	C3	474	1984	SNCR 2017
ND	Leland Olds	1	216	1966	SNCR
ND	Leland Olds	2	440	1975	SNCR
ND	Milton R Young	B1	257	1970	SNCR
ND	Milton R Young	B2	477	1977	SNCR
ND	Spiritwood Station	1	106	2014	SNCR
WY	Laramie River	2	570	1981	SNCR 2018
WY	Laramie River	3	570	1982	SNCR 2018

Table 2: Coal Units by Type of NOx Controls (cont.)

The coal units in this table are those not currently planned for retirement by 2028.

	NO POST COMBUSTION CONTROLS FOR NOX				
State	**Facility Name**	**Unit ID**	**Nameplate Capacity (MW)**	**In-Service Year**	**notes**
AZ	Springerville	1	425	1985	LNB w/ OFA
AZ	Springerville	2	425	1990	LNB w/ OFA
CO	Martin Drake	6	75	1968	ULNB/OFA - Round 1 RH SIP
CO	Martin Drake	7	132	1974	ULNB/OFA - Round 1 RH SIP
CO	Rawhide Energy Station	101	294	1984	Enhanced OFA-Rnd 1 RH SIP
CO	Ray D Nixon	1	207	1980	ULNB/OFA - Round 1 RH SIP
MT	Colstrip	3	778	1984	
MT	Colstrip	4	778	1986	
ND	Antelope Valley	B1	435	1984	
ND	Antelope Valley	B2	435	1986	
ND	Coal Creek	1	605	1979	
ND	Coal Creek	2	605	1980	
ND	Coyote	B1	450	1981	
NM	Escalante	1	257	1984	Zoloscan combustion controls
UT	Bonanza	1-Jan	500	1986	
UT	Hunter	1	525	1978	Round 1 RH FIP in Litigation
UT	Hunter	2	525	1980	Round 1 RH FIP in Litigation
UT	Hunter	3	527	1983	
UT	Huntington	1	541	1977	Round 1 RH FIP in Litigation
UT	Huntington	2	496	1974	Round 1 RH FIP in Litigation
WY	Jim Bridger	BW71	608	1974	New plantwide permit (2019)
WY	Jim Bridger	BW72	617	1975	New plantwide permit (2019)
WY	Naughton	1	192	1963	
WY	Naughton	2	256	1968	
WY	Neil Simpson II	1	90	1995	
WY	Wyodak	BW91	402	1978	Round 1 RH FIP in Litigation

<u>Description of Methodology for 2028 Emissions Projections</u>

After incorporating input from project participants on current operating characteristics of Western EGUs, including current and required controls, "Rules-on-the-Books" NOx and SO2 emissions scenarios were developed for the year 2028 using the following methodology:

1) Remove coal units that will retire by 2028 (per Table 1 above)

2) Calculate 2028 emissions from remaining coal units using the following information:
   a. Gross load (MW-hr) based on:
      i. **<u>Scenario 1</u>**: highest annual gross load over the last three years (2016-18)
      ii. **<u>Scenario 2</u>**: the average gross load over the last three years (2016-18)

   b. Heat Rate (btu/kw-hr) for each unit based on the 2016-18 three-year average.

   c. NOx and SO2 emission rates (lb/mmbtu) for each unit based on one of the following:
      i. average emission rates over the last three years (2016-18) for units with no recent changes to emission controls;
      ii. 2018 emission rates for units that recently added emission controls; or
      iii. emission rates expected in accordance with current permit conditions but not reflected in 2018 data.

   d. 2028 emissions in tons per year of NOx and SO2 were then calculated for each remaining coal unit as follows: ***Ton Per Year = ((Gross Load) x (Heat Rate) x (Emission Rate)) / 2x10^{6}***. Results for each remaining coal unit under Scenario 1 and Scenario 2 are shown in "Data File 5 – 2028 Coal Scenarios".

3) 2018 actual emissions are used to estimate 2028 emissions from the fleet of natural gas-fired EGUs. "Data File 6 – 2018 and 2028 gas units" shows the 2028 NOx and SO2 inventory for gas units across the 13-state region[2]. The 2028 inventory has: 1) retiring gas units removed, 2) new gas units added, and 3) capacity factors adjustments as noted by the operators.

4) 2017/18 actual emissions for the "non-CAMD" units (which are not included in EPA's database[3]) are used to estimate 2028 emissions from these sources with 1) retiring units removed, 2) new units added, and 3) expected changes in capacity factors as noted by the operators. (See Data File 7: non-CAMD units)

The resulting 2028 NOx and SO2 emissions for Western EGUs are shown below. (See: Data File 5 - 2028 Coal Scenarios)

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[2] CARB will provide the inventory and forecast for EGU's in CA. EPA data is used here as a placeholder for CA.

[3] The WRAP should ensure that emissions from the non-CAMD units included here are not already included in other parts of the stationary sources emissions inventory.

2028 Scenarios

As described above, two 2028 emissions scenarios have been developed for the remaining coal units. The only difference between the two scenarios is the assumption regarding capacity factors (i.e., gross load expressed as MW-hours per year). Scenario 1 calculates 2028 emissions using the highest gross load over the last three years, whereas Scenario 2 calculates 2028 emissions using average gross load over the last three years (2016-18). As shown in Figures 6 and 7, the difference in total emissions between these two scenarios is relatively small, especially compared to the overall reductions from 2008.

Since there is no specific guidance on which methodology to use for forecasting 2028 emissions from EGUs for Regional Haze planning, and because there are good arguments to be made in favor of both scenarios, WRAP members will have to engage in further discussions to determine whether Scenario 1 or Scenario 2 should be used in the 2028 Rules-on-the-Books modeling runs.

Total Scenario 2 emissions from remaining coal units are about 9.5% lower than Scenario 1, but it is important to note that no adjustments have been made to the three-year average capacity factors used to calculate Scenario 2. During the data review process for this project, plant operators identified years when units were down for extended periods due to unplanned outages or major overhauls, or for installation of pollution controls. If the WRAP elects to use Scenario 2 emissions for modeling, it may be appropriate to remove data for years when units experienced extended outages. A preliminary analysis indicates that incorporating these adjustments would shrink the difference between the two scenarios to less than 5%.

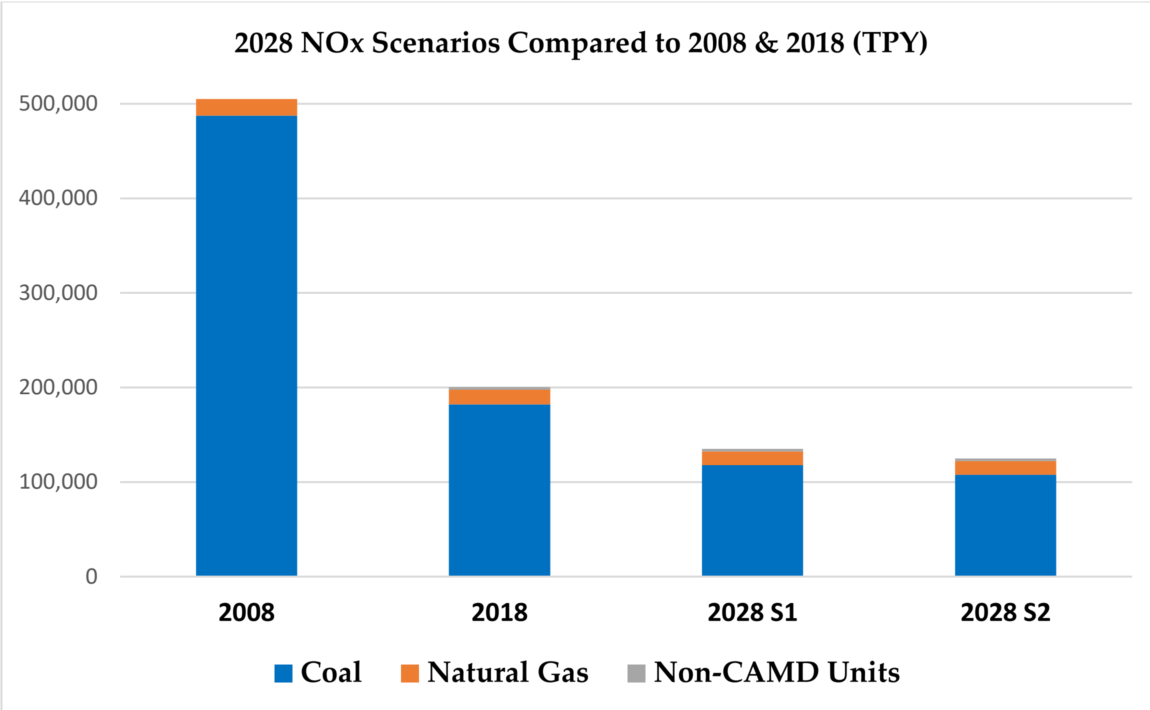


Figure 6:
2028 Scenario 1 NOx emissions are 73% below 2008 levels and 33% below 2018 levels.
2028 Scenario 2 NOx emissions are 75% below 2008 levels and 38% below 2018 levels.

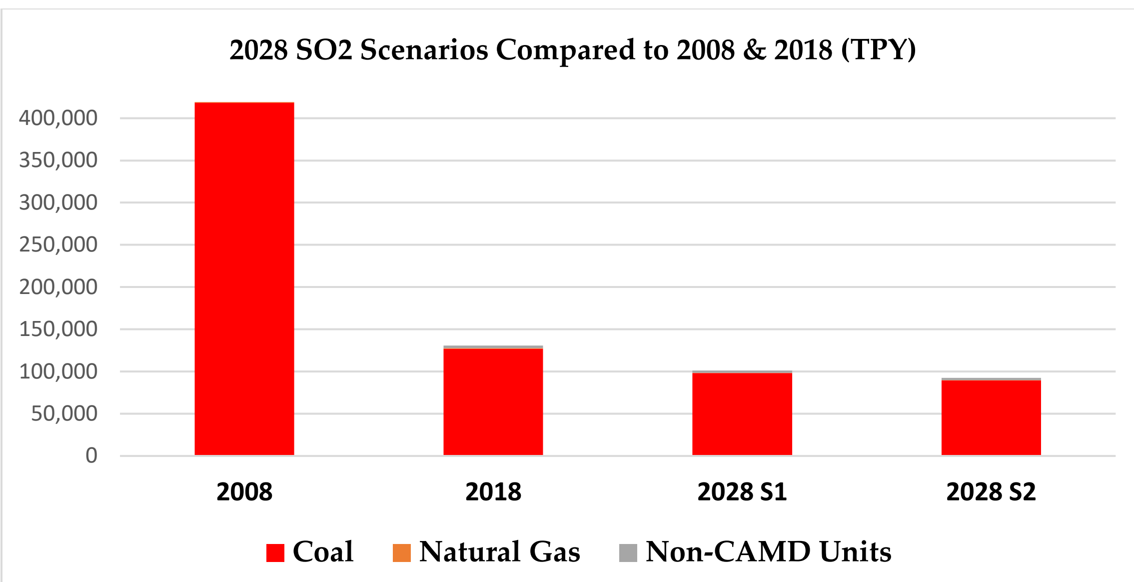
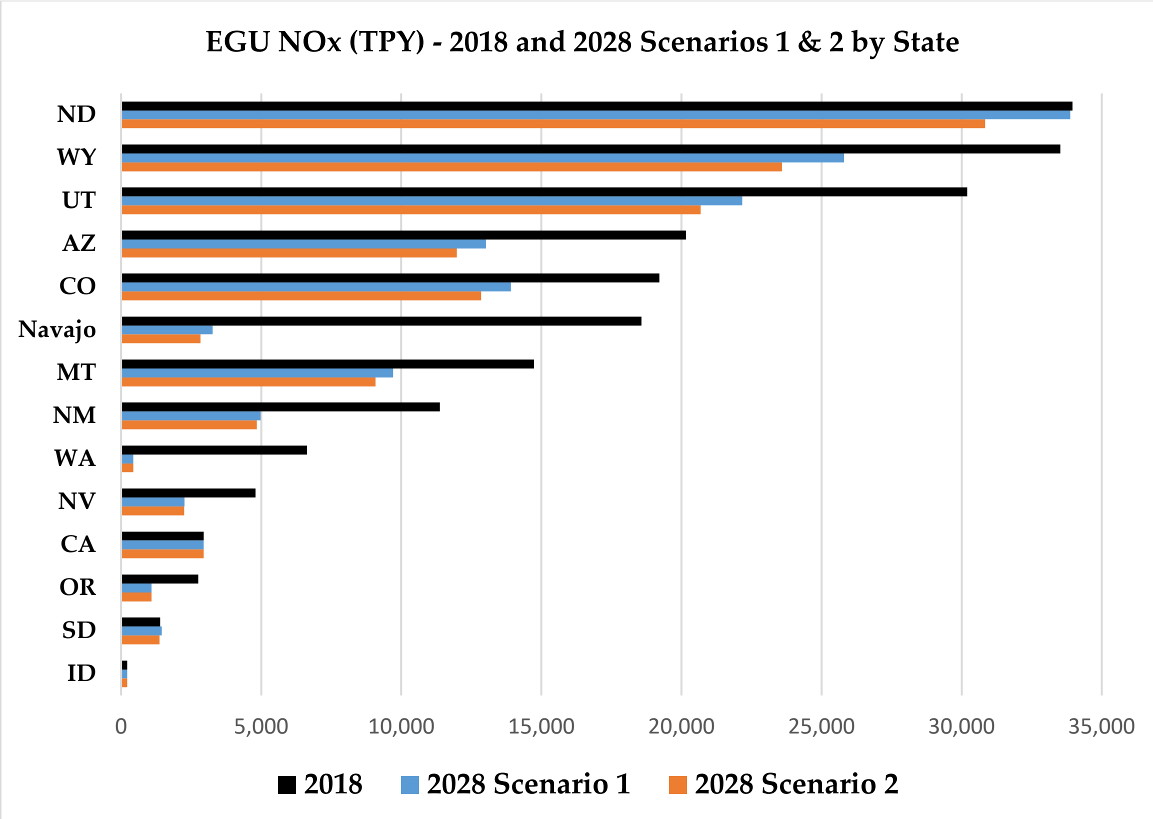


Figure 7:
2028 Scenario 1 SO2 emissions are 76% below 2008 levels and 23% below 2018 levels.
2028 Scenario 2 SO2 emissions are 78% below 2008 levels and 29% below 2018 levels.



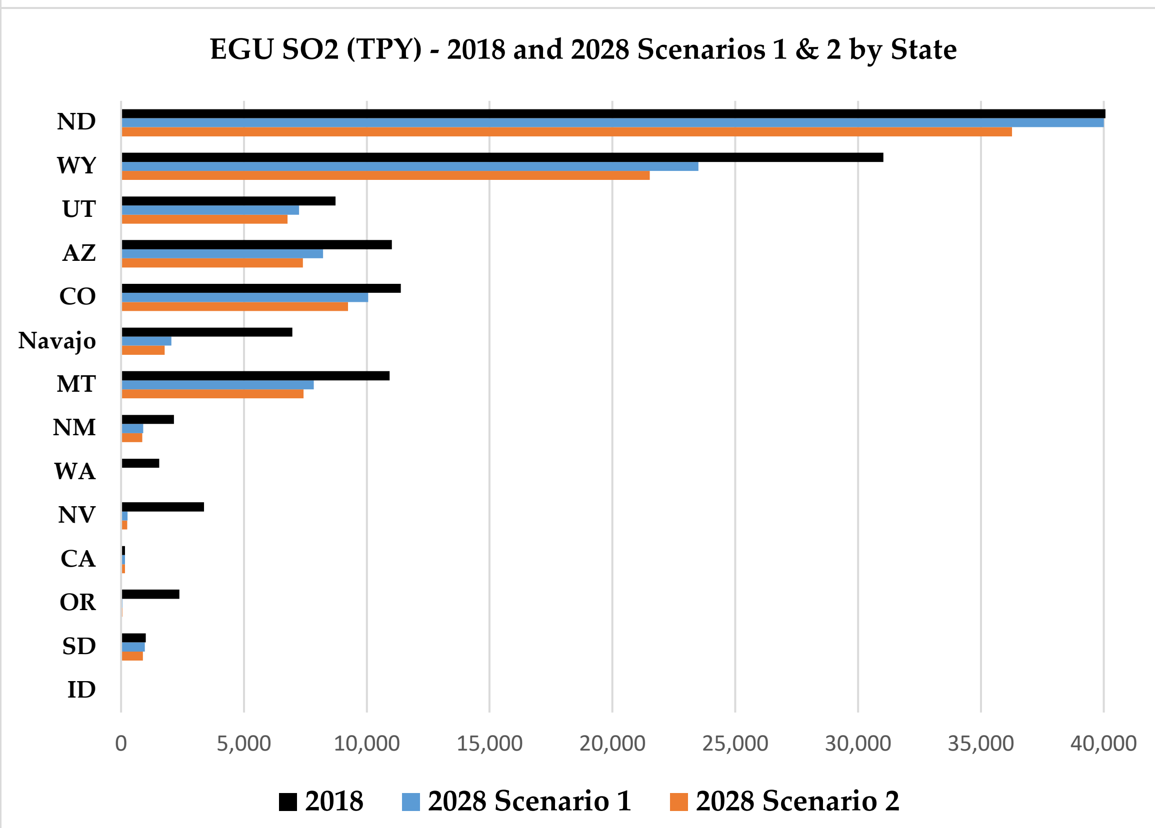


Figure 8: (See: Data File 8 – 2018 and 2028 by State)

Figure 9a: NOx Emission Rates (lb/mmbtu) and 2028 Tons Per Year (Scenario 1) for each remaining coal unit are graphed below to illustrate the range of emission profiles for those units that are not planned to retire by 2028. Table 2 above shows current NOx controls for each of these units. (See: Data File 9–scatter plots). See Table 3 below for key to numbering on this graph.

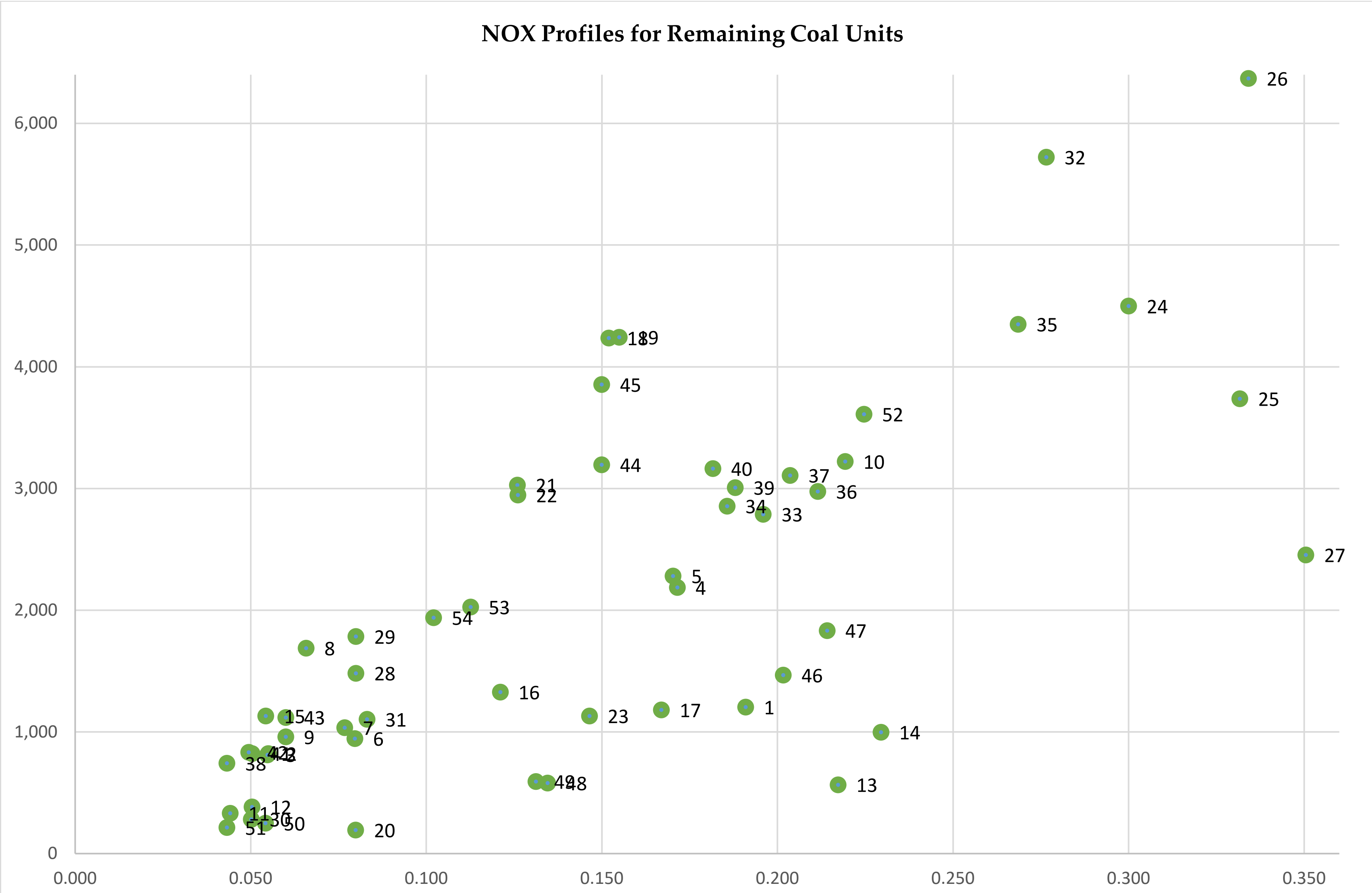


Figure 9b: SO2 Emission Rates (lb/mmbtu) and 2028 Tons Per Year (Scenario 1) for each remaining coal unit are graphed below to illustrate the range of emission profiles for those units that are not planned to retire by 2028.
(See: Data File 9–scatter plots). See Table 3 below for key to numbering on this graph.

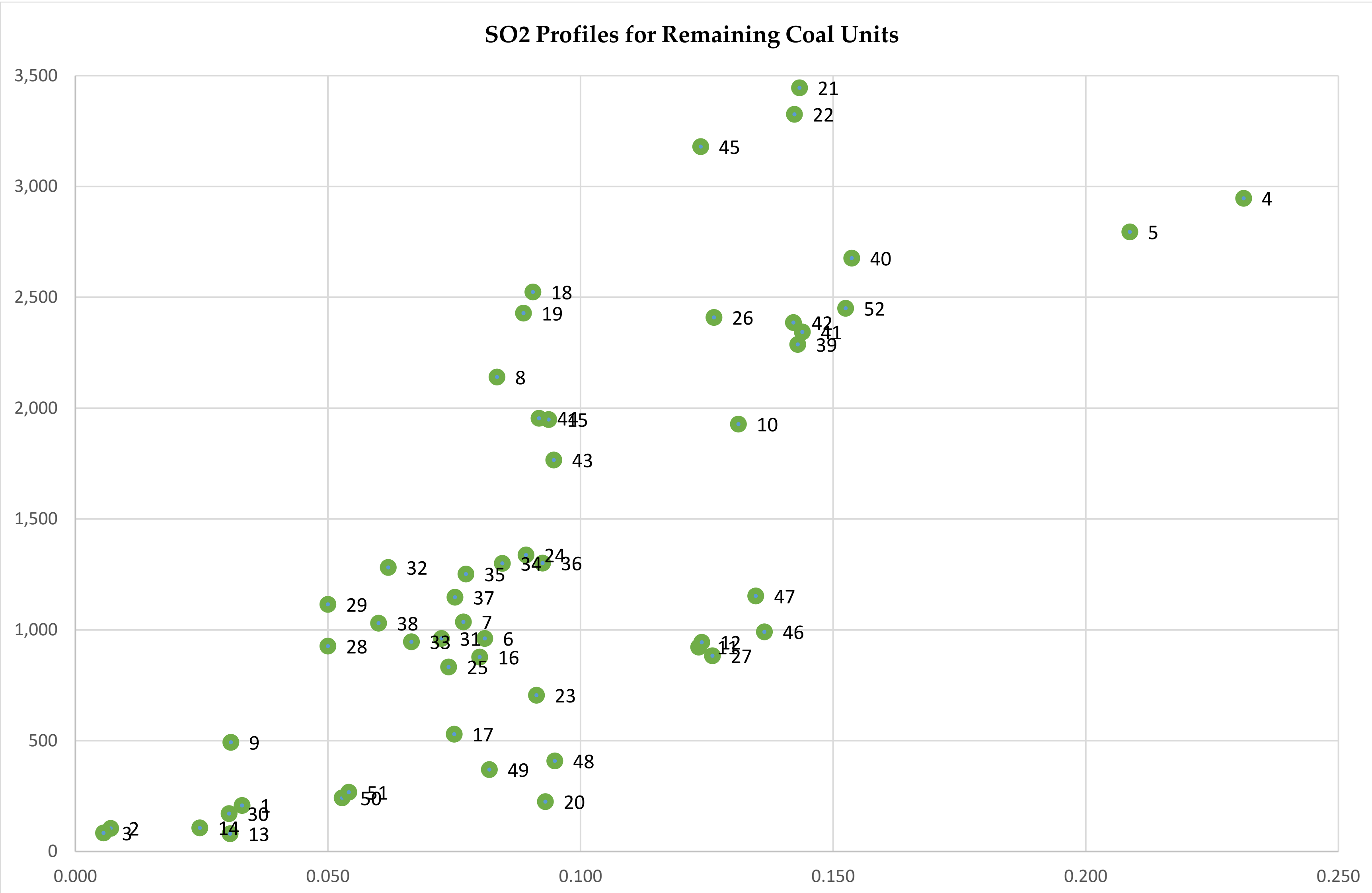
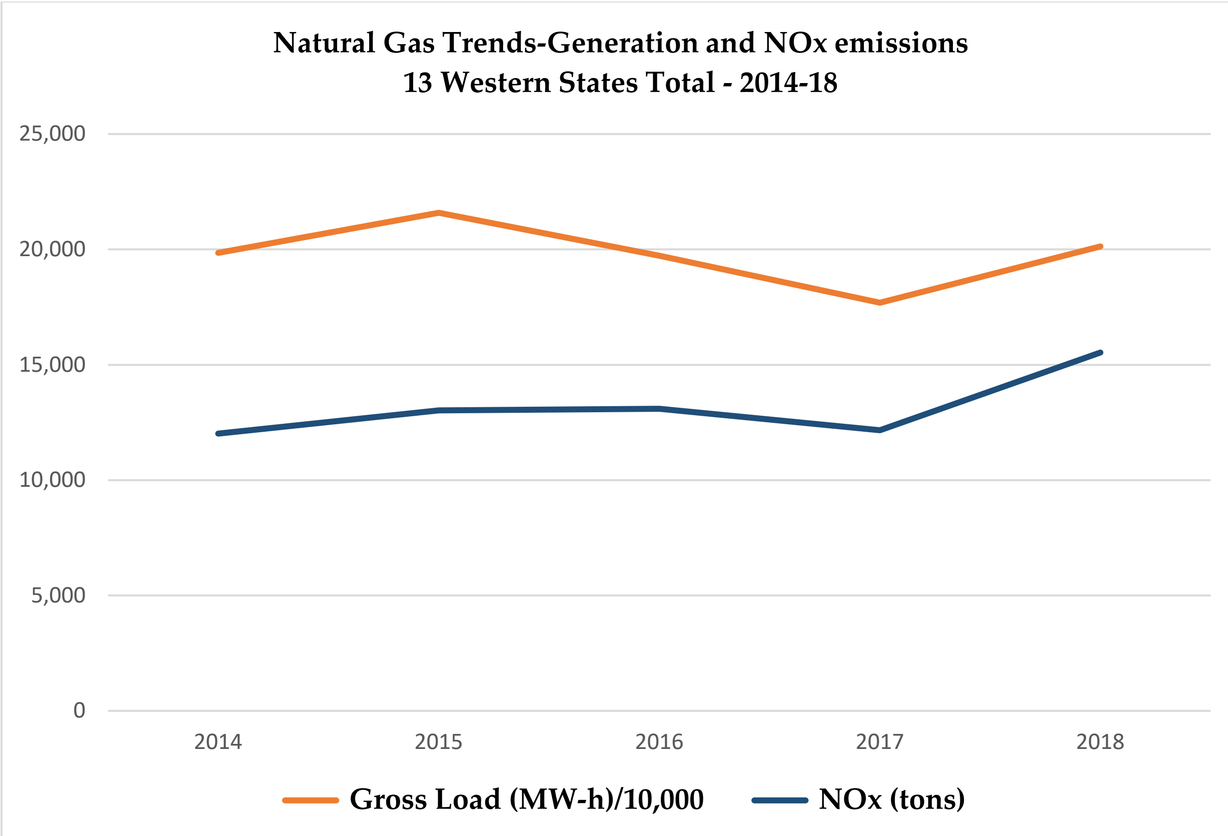


Table 3: Key to numbering of units on Figures 9a and 9b. Column 1 in the table below shows the data label number corresponding to each remaining coal unit included in the graphs.

Data Label	State	Facility Name	Unit ID	2028 NOX ER	2028 NOX Tons (Scenario 1)	2028 SO2 ER	2028 SO2 Tons (Scenario 1)
1	AZ	Apache Station	3	0.191	1,203	0.033	208
2	AZ	Coronado	U1B	0.055	821	0.007	105
3	AZ	Coronado	U2B	0.055	812	0.006	83
4	AZ	Springerville	1	0.172	2,186	0.231	2,947
5	AZ	Springerville	2	0.170	2,281	0.209	2,795
6	AZ	Springerville	4	0.080	945	0.081	961
7	AZ	Springerville	TS3	0.077	1,035	0.077	1,036
8	CO	Comanche	3	0.066	1,688	0.083	2,140
9	CO	Craig	C2	0.060	958	0.031	492
10	CO	Craig	C3	0.219	3,221	0.131	1,928
11	CO	Hayden	H1	0.044	330	0.123	922
12	CO	Hayden	H2	0.050	383	0.124	944
13	CO	Martin Drake	6	0.217	565	0.031	80
14	CO	Martin Drake	7	0.230	997	0.025	107
15	CO	Pawnee	1	0.054	1,130	0.094	1,949
16	CO	Rawhide	101	0.121	1,326	0.080	877
17	CO	Ray D Nixon	1	0.167	1,180	0.075	530
18	MT	Colstrip	3	0.152	4,236	0.091	2,524
19	MT	Colstrip	4	0.155	4,242	0.089	2,428
20	MT	Hardin	U1	0.080	193	0.093	225
21	ND	Coal Creek	1	0.126	3,028	0.143	3,445
22	ND	Coal Creek	2	0.126	2,946	0.142	3,326
23	ND	Leland Olds	1	0.147	1,131	0.091	705
24	ND	Leland Olds	2	0.300	4,498	0.089	1,338
25	ND	Milton R Young	B1	0.332	3,738	0.074	833
26	ND	Milton R Young	B2	0.334	6,369	0.126	2,409
27	NM	Escalante	1	0.351	2,454	0.126	883
28	NN	Four Corners	4	0.080	1,482	0.050	926
29	NN	Four Corners	5	0.080	1,783	0.050	1,114
30	NV	TS Power Plant	1	0.050	281	0.030	171
31	SD	Big Stone	1	0.083	1,102	0.072	961
32	UT	Bonanza	43466	0.277	5,722	0.062	1,281
33	UT	Hunter	1	0.196	2,788	0.067	946
34	UT	Hunter	2	0.186	2,855	0.085	1,299
35	UT	Hunter	3	0.269	4,349	0.077	1,252
36	UT	Huntington	1	0.212	2,975	0.093	1,301
37	UT	Huntington	2	0.204	3,108	0.075	1,147
38	WY	Dry Fork Station	1	0.043	741	0.060	1,030
39	WY	Jim Bridger	BW71	0.188	3,007	0.143	2,287
40	WY	Jim Bridger	BW72	0.182	3,163	0.154	2,677
41	WY	Jim Bridger	BW73	0.050	821	0.144	2,344
42	WY	Jim Bridger	BW74	0.050	831	0.142	2,386
43	WY	Laramie River	1	0.060	1,119	0.095	1,766

44	WY	Laramie River	2	0.150	3,194	0.092	1,955
45	WY	Laramie River	3	0.150	3,853	0.124	3,180
46	WY	Naughton	1	0.202	1,466	0.136	991
47	WY	Naughton	2	0.214	1,832	0.135	1,153
48	WY	Neil Simpson II	1	0.135	579	0.095	409
49	WY	Wygen I	1	0.131	592	0.082	370
50	WY	Wygen II	1	0.054	249	0.053	242
51	WY	Wygen III	1	0.043	213	0.054	267
52	WY	Wyodak	BW91	0.225	3,610	0.152	2,450
53	ND	Antelope Valley	B1	0.113	2,026		
54	ND	Antelope Valley	B2	0.102	1,938		
		Units not graphed as values are outside range					
	ND	Antelope Valley	B1			0.361	6,483
	ND	Antelope Valley	B2			0.345	6,554
	ND	Coyote	B1	0.456	7,852	0.863	14,878



<u>Figure 10: Source: EPA CAMD</u> (See Data File 10 – gas 2014-18)

The 2028 emissions projections developed for this project generally use 2018 actual emissions for natural gas-fired EGUs. As shown in Figure 1, natural gas generation on the Western Grid has varied over the last ten years, but there has not been an overall increase in gas generation. Given the expectation for continued deployment of renewable energy in the West and implementation of a number of new state policies related to clean and renewable energy, assuming no significant changes in natural gas emissions from 2018 levels is a reasonable assumption for this air quality planning exercise.

As shown in Figure 10, 2018 NOx emissions from natural gas-fired EGUs in the West were higher than in recent years. This is due in part to some steam units fuel-switching from coal to natural gas.