FINAL REPORT

Emission Inventory Development and Projections for the Transforming Mexican Energy Sector

AQRP Project 19-023

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Executive Summary

Energy reform in Mexico initiated under the Peña-Nieto administration catalyzed transformational changes in the country's energy sector. Development of Mexico's energy sector has the potential to substantially transform the magnitude and spatial distribution of emissions from the oil and gas and power generation sectors. Although uncertainty into the future direction of Mexico's energy sector was introduced by the transition in Mexico's presidential administration as Andrés Manuel López Obrador took office on December 1, 2018, development of Mexico's hydrocarbon resources is continuing.

Emission inventories for Mexico have become essential for air quality modeling in Texas and elsewhere in the United States, including at a national scale. This project developed a bottom-up assessment of emissions for the upstream and midstream oil and gas sectors and electric power sector in Mexico for the specific purpose of supporting air quality modeling applications. Emission sources included onshore and offshore oil and gas exploration and production well sites, well flaring, natural gas compressor stations, natural gas processing plants, and electricity generating units (EGUs). Emissions estimates were developed for 2016, the base year of the EPA's national air quality modeling platform and likely the basis for future air quality modeling by the TCEQ. Future emissions assessments consider the development of Mexico's onshore conventional, shallow water, and deepwater resources.

The major oil and gas production areas (consisting primarily of vertical legacy wells) in central and southern Mexico are within the Burgos/Sabinas, Tampico-Misantla, Veracruz, and Sureste basins. Emissions at upstream onshore and offshore oil and gas well sites result from exploration (e.g., drilling, completions) and production (e.g., fugitive leaks, pneumatic controllers and pumps, liquid unloading/well venting sources) activities. In order to develop a representative oil and gas emissions inventory, emissions estimates employed one or more oil and gas activity metrics (i.e., oil production, gas production, active well count, or spud count). Because Mexico-specific oil and gas well site equipment configuration data were not readily available, emissions rates were based on representative emissions rates for specific oil and gas basins in the US (e.g., often Texas), adjusted to reflect expected minimal emissions controls in Mexico, and applied with oil and gas activity data specific to Mexican oil and gas resources. A separate analysis was performed to generate emissions estimates representative of well site flaring of natural gas in Mexico during 2016.

A criteria pollutant emission inventory was developed for the Mexican electric power sector operational during 2016. The inventory is at the spatial scale of the individual thermally-fueled (e.g., coal, coke, diesel, natural gas, oil) EGUs and employed emissions factors (kg/GWh) and annual generation estimates (GWh) obtained from publicly accessible databases provided by the key institutions for Mexico's electricity sector. Publicly available Mexican government databases were also critical in support of emissions estimation for the 11 major natural gas processing plants and 22 central compressor stations active along Mexico's national natural gas pipeline network.

This work also provided a detailed illustration of onshore and offshore areas where future development of Mexico's oil and gas resources is likely to occur based on the hydrocarbon bid rounds that occurred under the Peña-Nieto administration. Stages within bid rounds are characterized by location (shallow water, deepwater, onshore conventional, onshore unconventional), type of activity (exploration and/or extraction) as well as the contract type (license or production sharing). For the purposes of this project, a speculative assessment of emissions that could accompany ongoing development of the awarded contractual areas (onshore, shallow water, deepwater) was conducted.

1. Introduction

Understanding the influences of transboundary air pollution between the United States and its neighbors, Canada and Mexico, on domestic air quality is required for effective air quality planning and management. Emissions inventories for these countries have become essential components of air quality modeling in U.S. border states and at a national scale. Within Texas, characterizing emission sources along its border and within Mexico has been recognized as particularly important.

Mexico's energy sector has been undergoing transformational changes (IEA, 2017; Vietor and Sheldahl-Thomason, 2017). Its long history of oil production has been central to its economy. Although the country continues to be an exporter of crude oil; it is an importer of refined petroleum products, coal, and natural gas, despite its natural resources. Changes in monthly oil and natural gas production between 2000 through May 2019 (CNIH, 2019) are shown in Figure 1 and Figure 2, respectively. Declining oil production revenue and insufficient resources for exploration and downstream investment have plagued Mexico, while energy demand is increasing. Mexico's electricity demand has been increasing on average by 2.9% per year since 2000 (IEA, 2018).

Energy reform was part of a structural and institutional reform package known as *Pacto Por Mexico* initiated under President Enrique Peña-Nieto. The reform required ratification of amendments to the Mexican Constitution that were adopted in December 2013. Secondary legislation was signed into law in August 2014. A primary motivation was to encourage domestic and foreign investment and productivity growth in the oil, gas and power sectors ending the state-owned monopolies of Petróleos Mexicanos (Pemex) and the Comisión Federal de Electricidad (CFE). Mexico initiated bid rounds (*Rondas Mexico*) in 2015 to attract new investment for exploration and extraction of its onshore and offshore hydrocarbon (SENER, 2017; IEA, 2017). A transition in Mexico's presidential administration introduced uncertainty into the future direction of Mexico's energy sector. The contracts awarded under the bid rounds to date are continuing under the new administration.

Development of Mexico's energy sector may substantially transform the magnitude and spatial distribution of emissions from the oil and gas and power generation sectors. As in the United States, where profound changes in the energy sector have influenced emission inventories, it will be important to understand the existing status of the inventories for these sectors in Mexico, to track their evolution in the future, and to incorporate emissions estimates for Mexico into U.S. inventories used for air quality modeling. Shah et al. (2018) found that Mexico upstream oil and gas sources were not well represented in the U.S. Environmental Protections Agency's (EPA's) bottom-up inventory for its 2011v6.3 modeling platform in comparisons with natural gas flaring estimates derived using nighttime data collected by the Visible Infrared Imaging Radiometer Suite (VIIRS) (Elvidge et al., 2015).

Figure 1. Monthly onshore and offshore oil (1000 Barrels or MBBL) production in Mexico between January 2000 and May 2019. Source: CNIH (2019).

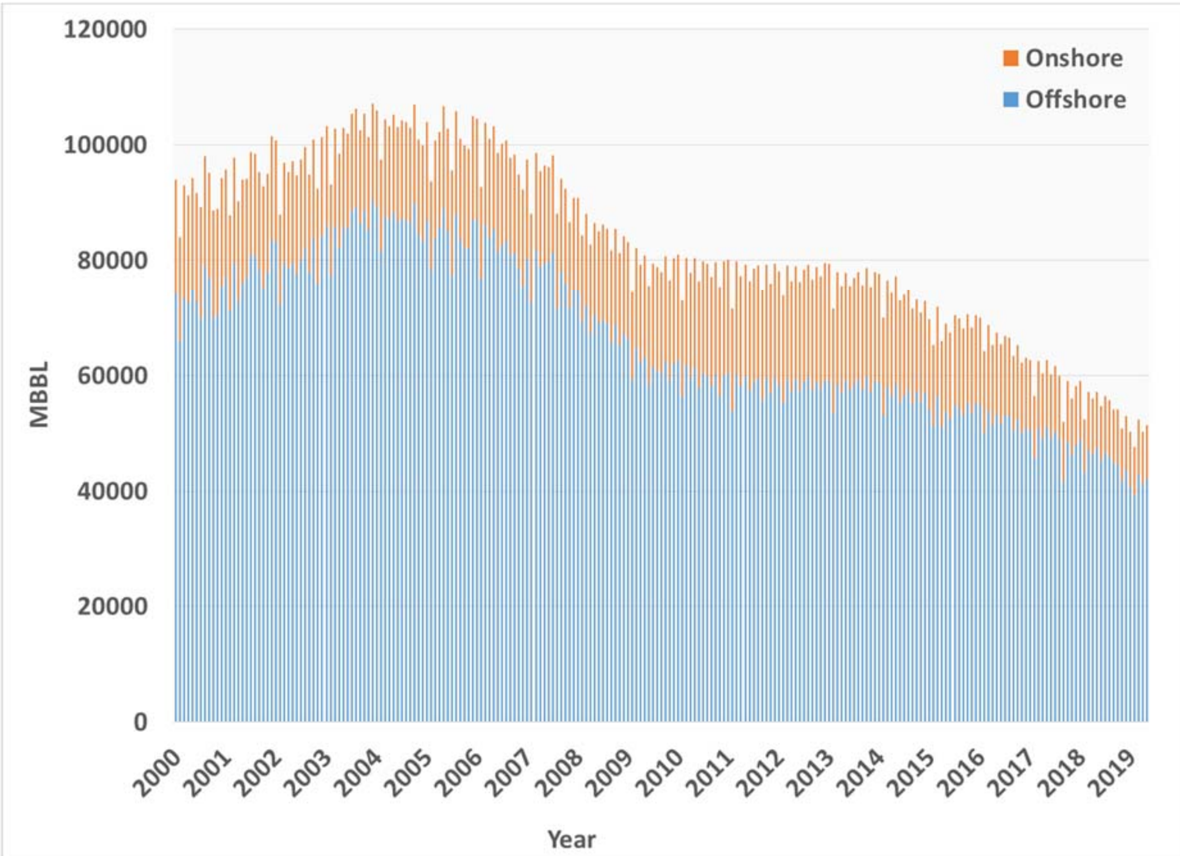
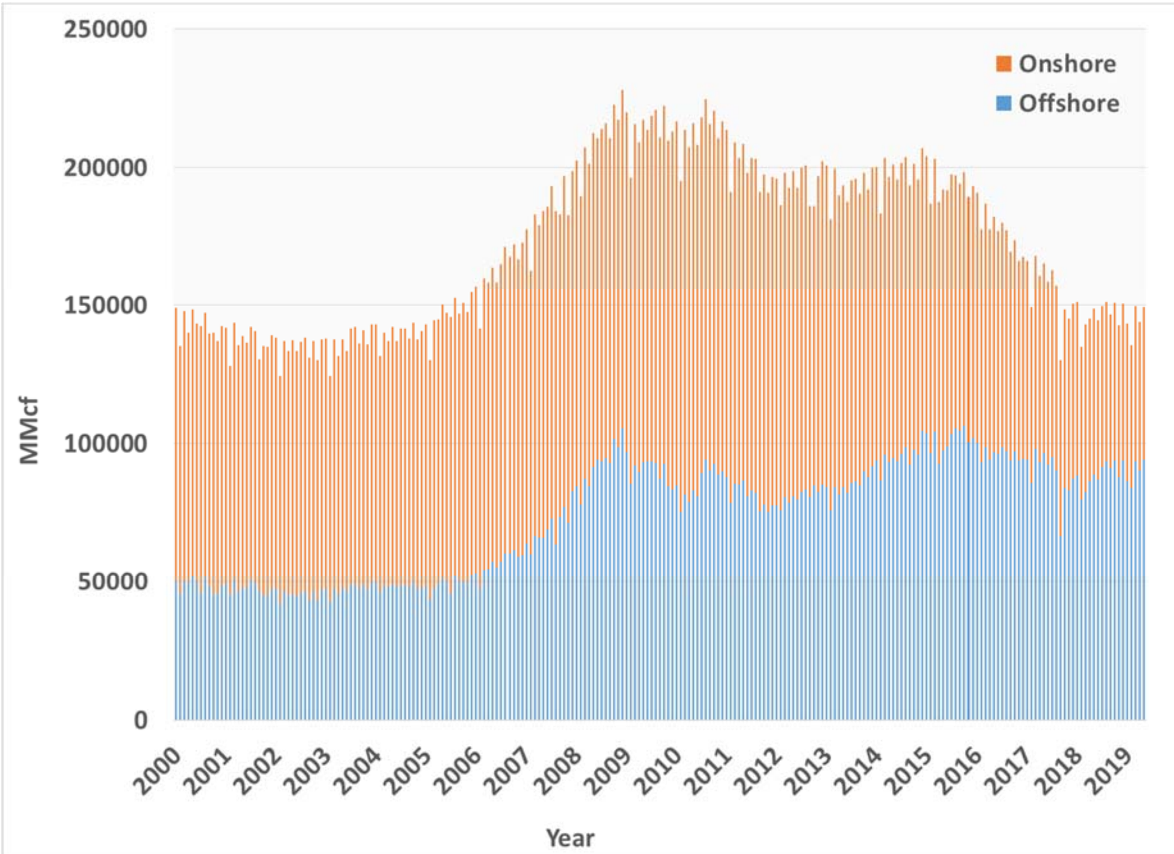


Figure 2. Monthly onshore and offshore natural gas (Million cubic feet or MMcf) production in Mexico between January 2000 and May 2019. Source: CNIH (2019).



2. Objectives

The objectives of this project were to develop a bottom-up assessment of emissions for the upstream and midstream oil and gas sectors and electric power sector in Mexico and to conduct a speculative assessment of emissions that could accompany ongoing development of contractual areas awarded under upstream sector bid rounds to date. Emission sources included onshore and offshore oil and gas exploration and production well sites, natural gas compressor stations, natural gas processing plants, and electricity generating units (EGUs). Emissions estimates were developed for 2016, the base year of the EPA's national air quality modeling platform and likely the basis for future air quality modeling by the TCEQ. Future emissions assessments consider development of Mexico's onshore conventional, shallow water, and deepwater resources. This project addressed the TCEQ's research priority to develop significant improvements in emissions inventories for Mexico, Central America, and the Caribbean, including both terrestrial and offshore emissions.

3. Data Resources

In order to provide an initial orientation to the multiple data sources used in our analyses, a brief description of the primary datasets is provided below. Further information (such as specific data fields and descriptions, implementation, quality assurance) are contained in the appropriate subsequent sections of this report.

CNIH (El Centro Nacional de Información de Hidrocarburos): Mexico's National Hydrocarbons Information Center (CNIH) of the National Hydrocarbons Commission (CNH) is responsible for the collection, administration and publication of information obtained from the exploration and extraction of hydrocarbons (https://www.gob.mx/cnh/articulos/centro-nacional-de-informacion-de-hidrocarburos-cnih-64831). CNIH was the primary source of oil and gas activity and well site descriptive data used to estimate emissions associated with upstream oil and gas activities. CNIH also provided the locations of compressor stations via the geographic information layers publicly available from the CNIH data portal (https://mapa.hidrocarburos.gob.mx).

NACEI (North American Cooperation on Energy Information; https://www.nacei.org): The NACEI online database provides descriptive parameters that included latitude and longitude coordinates for North American gas processing plants and power plants with a capacity of at least 100 MW (NACEI, 2017).

EPA (2018a): The US EPA 2014 National Emission Inventory version 2 (2014 NEIv2) is the source of US upstream wellsite emissions that was used as a basis to develop surrogate emission rates for Mexico upstream well sites.

EPA (2017): The EPA NEI O&G Tool (EPA Oil and Gas Tool, 2014 NEI Version 2.1 – Production Activities Module, 2017) is the source of upstream wellsite oil and gas activity that was used as a basis to develop surrogate emission rates for Mexico upstream well sites.

BOEM (2017): Offshore emissions from Mexican oil/gas platforms were developed from an analysis of platform and non-platform US offshore oil and gas emissions under the jurisdiction of the Bureau of Ocean Energy Management (BOEM) for calendar year 2014 as reported in Wilson et al. (2017).

Shah et al. (2018): Oil and gas well flaring emissions were based on a Mexican emissions inventory for calendar year 2012 (Shah et al., 2018) that employed data obtained from the Visible Infrared Imaging Radiometer Suite (VIIRS) (https://www.ngdc.noaa.gov/eog/viirs/download_global_flare.html).

PRODESEN (2017): Mexico's Ministry of Energy (SENER) has overarching responsibility for the coordination of the electricity sector in Mexico, including issuing the annual planning document, the National Electricity System Development Program or PRODESEN regarding generation, transmission, and distribution of electricity. Each annual report includes existing electricity generation and capacity at the facility level for both thermal and renewable resources. PRODESEN (2017) was a primary dataset for electricity generation used in support of emissions estimation for the 2016 calendar year.

COPAR (2015): The energy reform process unbundled and restructured Mexico's Federal Electricity Commission (CFE) into a state productive enterprise. Among its many responsibilities, CFE periodically publishes Costos y Parametros de Referencia or COPAR reports that are used by the Mexican government to establish the relative differences in projected costs of electricity generation by fuel and technology but also contain publicly available information on facility-specific emissions. Our team obtained the COPAR (2015) report from a web repository maintained by the Mexican Office for Economic Affairs (http://www.cofemersimir.gob.mx/portales/resumen/45107). Based on an analysis and integration of the publicly available information contained in PRODESEN (2017) and COPAR (2015), facility-specific COPAR emissions factors were an essential dataset used in support of emissions estimation for the electricity generation sector.

INEM (2008): Stack exit release parameters for electricity generation and gas processing plants were based on the 2008 Mexico National Emissions Inventory (Inventario Nacional de Emisiones de México or INEM) (ERG, 2014) point source emissions inventory as provided in the data file entitled "Mexico_2008INEM_Point_Revised_coord_14jan2015_v0" retrieved from EPA's 2011 Version 6.3 Platform (ftp://newftp.epa.gov/air/emismod/2011/v3platform/2011emissions/2011ek_cb6v2_v6_11g_inputs_oth.zip/). Combined with facility-specific gas processing volume information provided by Pemex's "Statistical Yearbook" (PEMEX, 2016), INEM (2008) was a primary source of emissions estimation data for natural gas processing plants.

4. Upstream Oil and Natural Gas Sector

4.1 Exploration and Production Activity at Oil and Gas Well Sites

Mexico's National Hydrocarbons Information Center (CNIH) of the National Hydrocarbons Commission (CNH) is responsible for the collection, administration and publication of information obtained from the exploration and extraction of hydrocarbons (https://www.gob.mx/cnh/articulos/centro-nacional-de-informacion-de-hidrocarburos-cnih-64831). CNIH was the primary source of oil and gas activity and well descriptive data used to estimate emissions associated with upstream oil and gas activities. Monthly well-specific production volumes were exported from the publicly available CNIH "Oil and Gas Statistics Interactive Dashboard" (https://sih.hidrocarburos.gob.mx/) for all individual onshore and offshore wells active during 2016. Additional relevant well-level parameters were: name, basin/field, location coordinates, type, years of production, and status.

According to CNIH, 10,458 individual well locations had non-zero oil and/or gas production during 2016. The monthly oil production volumes ranged from a minimum of 62,218 MBBL (thousand barrels) during November to a maximum of 70,044 MBBL for January. Natural gas volumes varied from November's 166,290 MMCF (million cubic feet) to January's 191,105 MMCF. The CNIH annual 2016 production volumes for oil and natural gas were 788,738 MBBL and 2,127,142 MMCF, respectively.

Figure 3 shows a mapping of individual well sites segregated by basin. A summary of annual production volumes segregated by basin and onshore/offshore designation is shown in Table 1. The numbers of active well sites among basins ranged from only 26 wells for Sabinas to 4740 wells for Tampico-Misantla. Substantial variations in basin-level production volumes occurred between basins. For example, basin-level oil production ranged from a minimum of zero for the Burgos and Sabinas natural gas basins to a maximum of 749,036 MBBL for the Sureste basin. This latter basin dominates oil production comprising 95% of Mexico-wide production. The contributions to 2016 natural gas production were greatest in the Sureste (75%) and Burgos (15%) basins.

Figure 4 and Figure 5 maps the 2016 oil and gas production, respectively. The data are aggregated to a 4km horizontal grid spacing to reduce overlap in regions of high density (i.e., regions of nearly co-located well sites); the location symbols are sized proportionally to production volumes. As quantified in Table 1, the majority of gas and (especially) oil production is found offshore within the Sureste basin with contributions comprising 79% and 54% for oil and gas, respectively. Overall, the total onshore and offshore oil production was 163,598 MBBL and 625,141 MBBL, respectively; onshore and offshore gas production was 971,696 MMCF and 1,155,446 MMCF, respectively.

Figure 3. Locations of active 2016 oil and gas wells segregated by basin.

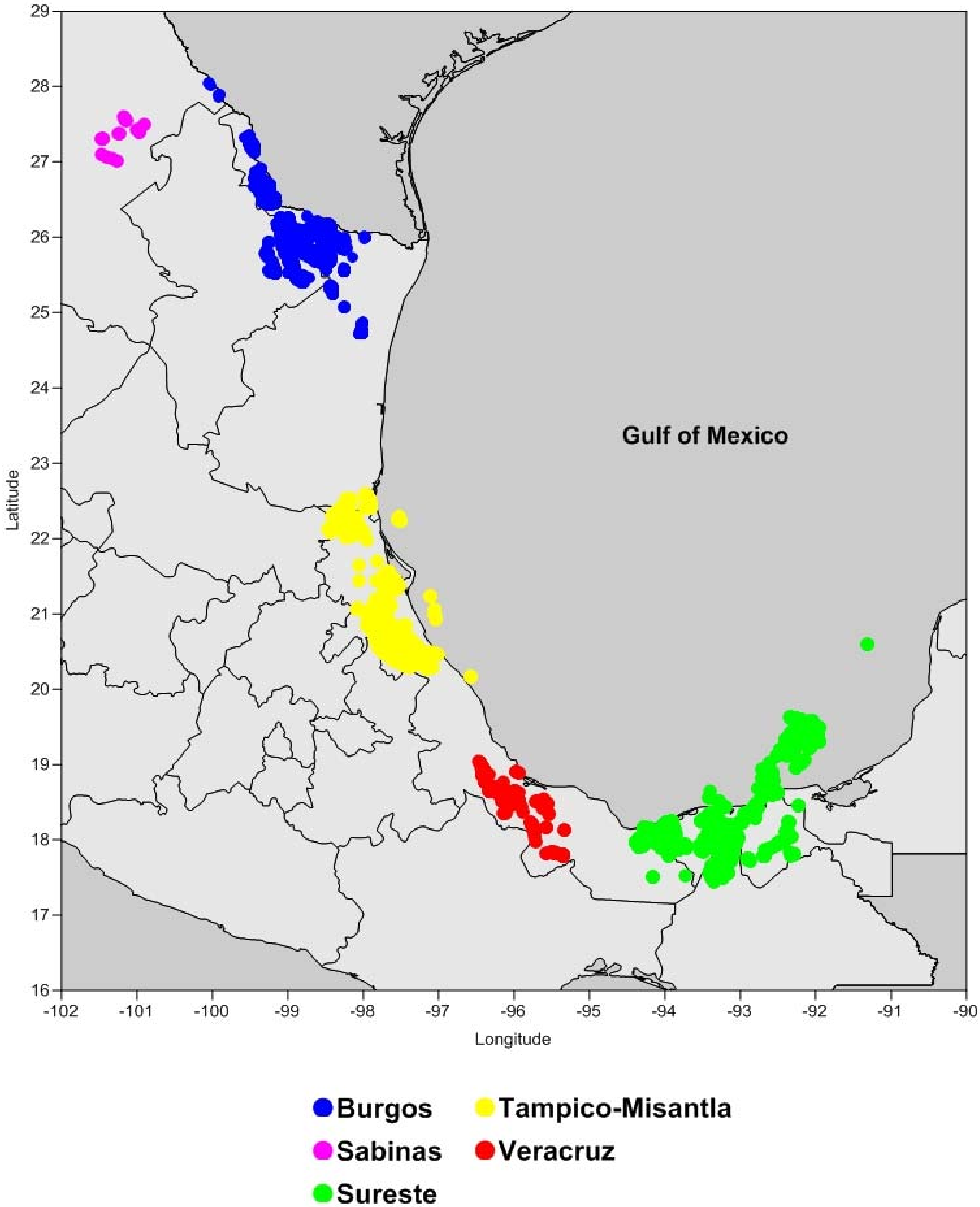


Table 1. Summary of oil and gas production during 2016 segregated by basin and onshore/offshore designation.

Basin	**Onshore or Offshore**	**Numbers of wells**	**Oil (MBBL)**	**Oil (% of Total)**	**Gas (MMCF)**	**Gas (% of Total)**
Burgos	Onshore	3273	0	0.0%	315126	14.8%
Sabinas	Onshore	26	0	0.0%	6577	0.3%
Sureste	Offshore	617	622543	78.9%	1139956	53.6%
	Onshore	1534	126472	16.0%	459314	21.6%
Tampico-Misantla	Offshore	32	2598	0.3%	15490	0.7%
	Onshore	4708	31716	4.0%	72546	3.4%
Veracruz	Onshore	268	5409	0.7%	118133	5.6%
All	Offshore	649	625141	79.3%	1155446	54.3%
	Onshore	9809	163598	20.7%	971696	45.7%
	Total	**10458**	**788738**	**100.0%**	**2127142**	**100.0%**

Figure 4. Annual 2016 oil production (individual wells aggregated to 4km x 4km grid cells). Location symbols are proportionally sized by production (MBBL).

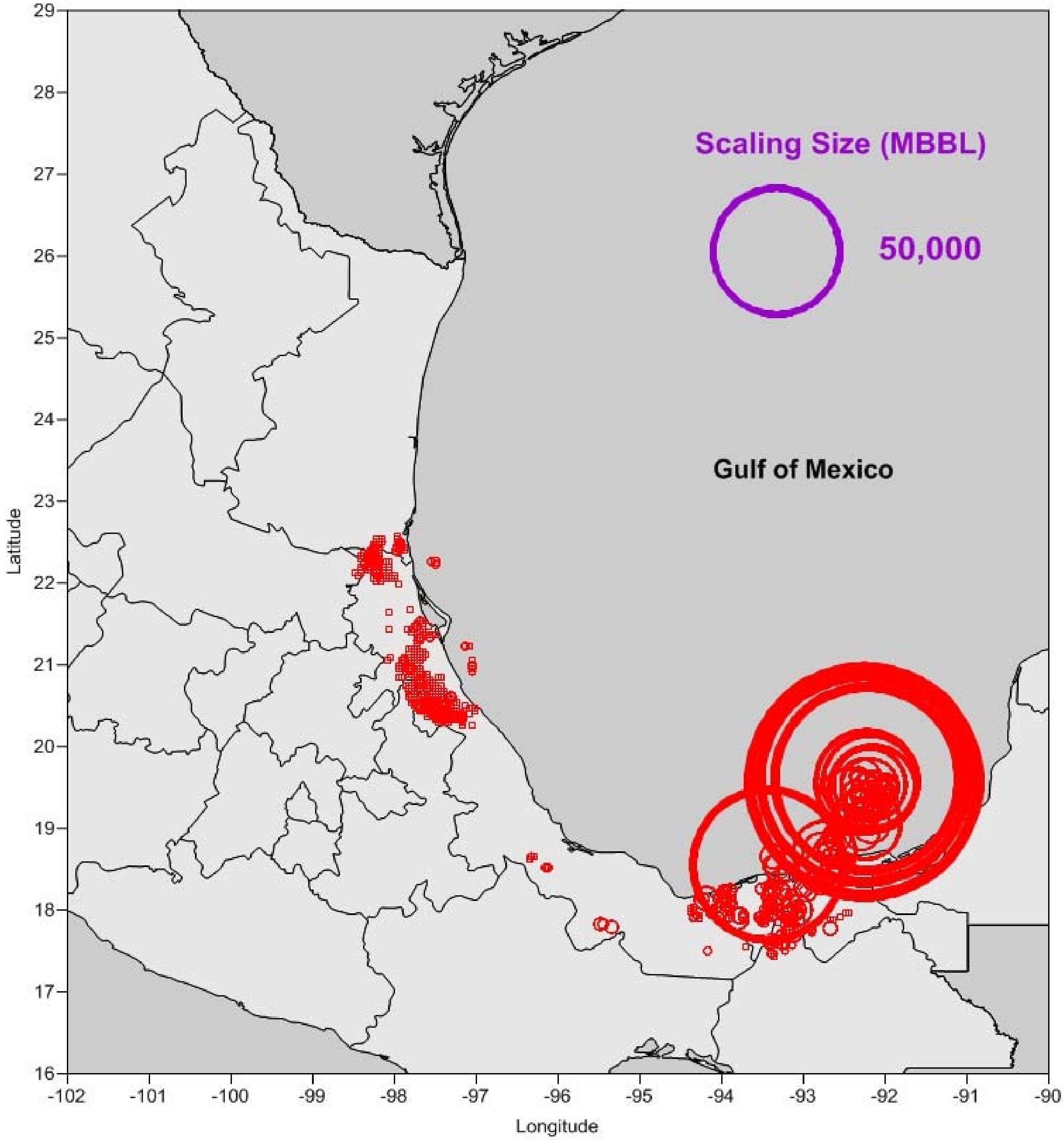
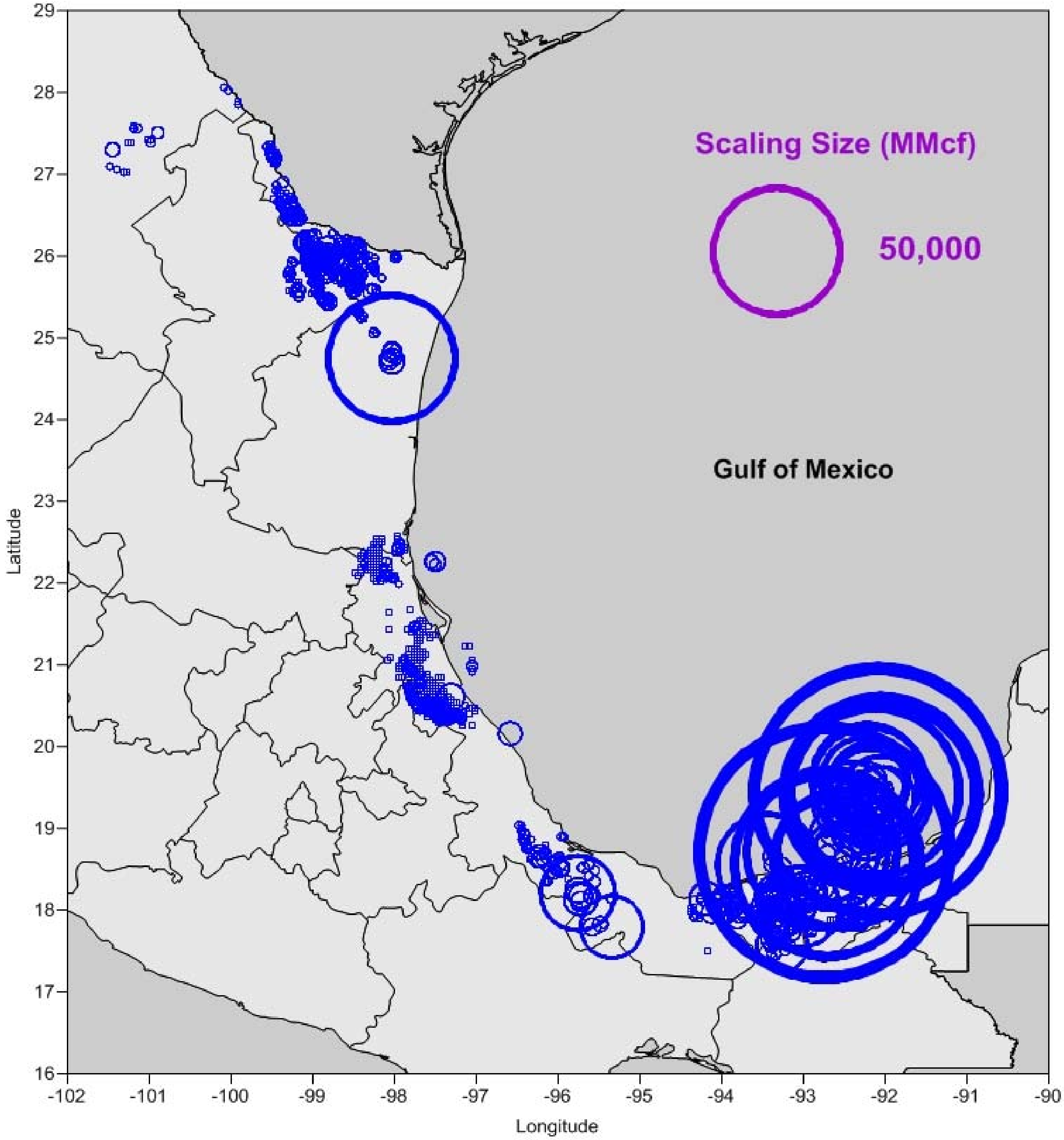


Figure 5. Annual 2016 natural gas production (individual wells aggregated to 4km by 4km grid cells). Location symbols are proportionally sized by production (MMcf).



4.2 Emission Rate Activity Factors at Oil and Gas Well Sites

Emissions at upstream oil and gas well sites result from exploration activities (e.g., drilling, hydraulic fracturing, and completion) and production activities (e.g., fugitive leaks, pneumatic controllers and pumps, wellhead engines such as compressor engine and artificial lift engines, oil and condensate tanks, and liquid unloading/well venting sources). To develop an oil and gas well site emission inventory, representative emissions for each emission source are typically estimated per oil and gas activity metric (i.e., oil production, gas production, active well count, or spud count) unless more detailed field or well specific emissions data are available from regulatory reporting programs. Representative emission rates for each source are multiplied by the associated oil and gas activity metric to estimate emissions from all of the well sites in a given area (typically a single oil and gas play or basin).

In the United States, representative emission rates are typically developed based on data collected about oil and gas operations through operator reporting under state or federal regulatory programs (e.g., Greenhouse Gas Reporting Program Subpart W -Petroleum and Natural Gas Systems: https://www.epa.gov/ghgreporting/subpart-w-petroleum-and-natural-gas-systems) or surveys of oil and gas operators (e.g., ERG, 2015), or permit data submitted as part of regulatory permitting. In the case that no representative well site equipment configuration data are available to develop area-specific emission rates for a given source category, emissions from that source category are typically estimated based on representative emission rates from another area(s).

4.2.1 Onshore oil and gas activities

No criteria air pollutant emission inventory has been developed for Mexico upstream oil and gas well sites. As described in Section 4.1, Mexico-specific oil and gas activity data are available from CNIH. Mexico-specific oil and gas well site equipment configuration data are not readily available to estimate representative emission rates for oil and gas well sites. As such, estimated representative emission rates for well sites in Mexico were based on representative emission rates for specific oil and gas basins in Texas (adjusted to reflect expected minimal emission controls in Mexico) and applied with oil and gas activity data for Mexico to develop a well site criteria air pollutant emission inventory for Mexico. In the future, this inventory should be refined by updating emission rates based on Mexico-specific oil and gas well site equipment configurations.

Table 2 shows oil and gas activity metrics that are associated with each source classification code (SCC) used in this study for the purposes of estimating onshore well site emissions.

Table 2. Oil and gas activity metrics by emission source classification code (SCC).

SCC	Source	Well Type	Oil and Gas Activity Metric (annual basis)
2310000220	Drill Rigs	All	Spuds
2310000660	Hydraulic Fracturing Engines	All	Spuds
2310020600	Compressor Engines	All	Gas Production
2310021010	Storage Tanks: Condensate	Gas	Condensate Production
2310021030	Tank Truck/Railcar Loading: Condensate	Gas	Condensate Production
2310021100	Gas Well Heaters	Gas	Active Well Count
2310021101	Natural Gas Fired 2Cycle Lean Burn Compressor Engines < 50 HP	Gas	Gas Production
2310021102	Natural Gas Fired 2Cycle Lean Burn Compressor Engines 50 To 499 HP	Gas	Gas Production
2310021103	Natural Gas Fired 2Cycle Lean Burn Compressor Engines 500+ HP	Gas	Gas Production
2310021201	Natural Gas Fired 4Cycle Lean Burn Compressor Engines <50 HP	Gas	Gas Production
2310021202	Natural Gas Fired 4Cycle Lean Burn Compressor Engines 50 To 499 HP	Gas	Gas Production
2310021203	Natural Gas Fired 4Cycle Lean Burn Compressor Engines 500+ HP	Gas	Gas Production
2310021251	Lateral Compressors 4 Cycle Lean Burn	Gas	Gas Production
2310021300	Gas Well Pneumatic Devices	Gas	Active Well Count
2310021301	Natural Gas Fired 4Cycle Rich Burn Compressor Engines <50 HP	Gas	Gas Production
2310021302	Natural Gas Fired 4Cycle Rich Burn Compressor Engines 50 To 499 HP	Gas	Gas Production
2310021303	Natural Gas Fired 4Cycle Rich Burn Compressor Engines 500+ HP	Gas	Gas Production
2310021351	Lateral Compressors 4 Cycle Rich Burn	Gas	Gas Production
2310021400	Gas Well Dehydrators	Gas	Gas Production
2310021401	Nat Gas Fired 4Cycle Rich Burn Compressor Engines <50 HP w/NSCR	Gas	Gas Production
2310021402	Nat Gas Fired 4Cycle Rich Burn Compressor Engines 50 To 499 HP w/NSCR	Gas	Gas Production
2310021403	Nat Gas Fired 4Cycle Rich Burn Compressor Engines 500+ HP w/NSCR	Gas	Gas Production
2310021501	Fugitives: Connectors	Gas	Active Well Count
2310021502	Fugitives: Flanges	Gas	Active Well Count
2310021503	Fugitives: Open Ended Lines	Gas	Active Well Count
2310021504	Fugitives: Pumps	Gas	Active Well Count
2310021505	Fugitives: Valves	Gas	Active Well Count

SCC	Source	Well Type	Oil and Gas Activity Metric (annual basis)
2310021506	Fugitives: Other	Gas	Active Well Count
2310021600	Gas Well Venting	Gas	Gas Production
2310021603	Gas Well Venting - Blowdowns	Gas	Gas Production
2310121100	Mud Degassing	Gas	Spuds
2310121401	Gas Well Pneumatic Pumps	Gas	Active Well Count
2310121700	Gas Well Completion: All Processes	Gas	Spuds
2310021509	Fugitives: All Processes	Gas	Active Well Count
2310000330	Artificial Lift	Oil	Active Well Count
2310010100	Oil Well Heaters	Oil	Active Well Count
2310010200	Oil Well Tanks - Flashing & Standing/Working/Breathing	Oil	Oil Production
2310010300	Oil Well Pneumatic Devices	Oil	Active Well Count
2310011000	Total: All Processes	Oil	Total Well Counts
2310011020	Storage Tanks: Crude Oil	Oil	Oil Production
2310011100	Heater Treater	Oil	Active Well Count
2310011201	Tank Truck/Railcar Loading: Crude Oil	Oil	Oil Production
2310011450	Wellhead	Oil	Associated Gas Production
2310011501	Fugitives: Connectors	Oil	Active Well Count
2310011502	Fugitives: Flanges	Oil	Active Well Count
2310011503	Fugitives: Open Ended Lines	Oil	Active Well Count
2310011504	Fugitives: Pumps	Oil	Active Well Count
2310011505	Fugitives: Valves	Oil	Active Well Count
2310011506	Fugitives: Other	Oil	Active Well Count
2310111100	Mud Degassing	Oil	Spuds
2310111401	Oil Well Pneumatic Pumps	Oil	Active Well Count
2310111700	Oil Well Completion: All Processes	Oil	Spuds
2310011500	Fugitives: All Processes	Oil	Active Well Count

The Western Gulf Basin in Texas and Mexico's northern basins (Burgos and Sabinas) share a common border. Sabinas and Burgos basin wells are primarily legacy vertical wells producing natural gas, with no condensate production. Emissions rates from the Burgos and Sabinas basins were assumed to be equivalent to Western Gulf Basin gas well emission rates, adjusted to remove Texas specific control estimates and condensate related emission sources. Western Gulf Basin emission rates were estimated based on emissions from the US EPA 2014 National Emission Inventory, version 2 (2014 NEIv2; EPA 2018a) normalized by oil and gas production obtained from EPA NEI O&G Tool (EPA Oil and Gas Tool, 2014 NEI Version 2.1 – Production Activities Module, 2017). Texas specific control estimates were obtained from several reference reports and information provided directly by TCEQ staff as indicated in Table 3. Table 3 shows percent changes from controlled to uncontrolled emission rates for applicable source categories and Table 4 shows Burgos and Sabinas Basin emission rates.

The major oil and gas production areas in central and southern Mexico are the Sureste, Tampico-Misantla, and Veracruz basins. Upstream well sites in Sureste, Tampico-Misantla, and Veracruz basins are primarily legacy vertical wells producing both oil and natural gas. Emission rates from upstream well sites in these basins were estimated based on Palo Duro Basin, located in northern Texas, emission rates. The Palo Duro Basin was chosen because it is also a legacy production area that consists primarily of vertical wells producing both oil and natural gas. Similar to Burgos and Sabinas, emission rate estimates were based on the 2014 NEIv2 and EPA NEI O&G Tool (v2.1). Similar to Burgos and Sabinas emission rates, Texas-specific controls for the Palo Duro Basin were removed. Table 5 shows percent changes from controlled to uncontrolled emission rates for applicable source categories and Table 6 shows Sureste, Tampico-Misantla, and Veracruz basin emission rates.

Table 3. Basis of Sabinas and Burgos basin uncontrolled emission rate adjustments and percent change from controlled to uncontrolled emission rates.

SCC	Source	Controlled Assumption Basis	Uncontrolled Assumption Basis	Percent Change from Controlled to Uncontrolled Emission Rates					
				NO_x	VOC	CO	SO_2	PM_{10}	$PM_{2.5}$
2310021100	Gas Well Heaters	AP-42, Chapter 1.4 flue gas recirculation controlled (ERG, 2013)	AP-42, Chapter 1.4 pre-NSPS uncontrolled	72%	-	-	-	-	-
2310021300	Gas Well Pneumatic Devices	Mix of low, intermittent and high bleed devices (TCEQ, 2019)	Mix of intermittent and high bleed devices (TCEQ, 2019)	-	17%	-	-	-	-
2310021400	Gas Well Dehydrators	13% of dehydrators controlled by flares (ERG, 2010)	No flaring controls	-	115%	-	-	-	-
2310000220	Drill Rigs	TX fleet controlled scenario average (ERG, 2015)	TX fleet uncontrolled scenario average (ERG, 2015)	163%	375%	433%	3233%	887%	888%
2310000660	Hydraulic Fracturing Engines	TX fleet average (ERG, 2014)	MOVES base emission rates (EPA, 2018b)	68%	299%	390%	3233%	481%	481%
2310121700	Gas Well Completion: All Processes	Flaring and green completion controls (ERG, 2014)	No flaring or green completion controls	100%	1317%	-100%	-100%	-	-

SCC	Source		Controlled Assumption Basis	Uncontrolled Assumption Basis	Percent Change from Controlled to Uncontrolled Emission Rates					
					NO_x	VOC	CO	SO_2	PM_{10}	$PM_{2.5}$
2310021101	Natural Gas-Fired Compressor Engines	2Cycle Lean Burn < 50 HP	TCEQ controlled emission factor for attainment areas (TCEQ, 2019)	AP-42, Chapter 3.2 uncontrolled emission rates	161%	-	-	-	-	-
2310021102		2Cycle Lean Burn 50 To 499 HP			61%	-	-	-	-	-
2310021103		2Cycle Lean Burn 500+ HP			61%	-	-	-	-	-
2310021201		4Cycle Lean Burn <50 HP			791%	-	-	-	-	-
2310021202		4Cycle Lean Burn 50 To 499 HP			791%	-	-	-	-	-
2310021203		4Cycle Lean Burn 500+ HP			791%	-	-	9%	-	-
2310021301		4Cycle Rich Burn <50 HP			-	115%	1123%	-	-	-
2310021302		4Cycle Rich Burn 50 To 499 HP			-	-	75%	3%	3%	3%
2310021402		4Cycle Rich Burn 50 To 499 HP w/NSCR			529%	479%	59%	1%	1%	1%
2310021403		4Cycle Rich Burn 500+ HP w/NSCR			529%	479%	59%	1%	1%	1%

Table 4. Sabinas and Burgos basin emission rates.

SCC	Source		Uncontrolled Emissions per Oil and Gas Activity Metric					
			NO_x	VOC	CO	SO_2	PM_{10}	$PM_{2.5}$
(lb/MMSCF)								
2310021100	Gas Well Heaters		2,303	129	2,025	-	184	184
2310021400	Gas Well Dehydrators		80	2,266	282	3	34	34
2310021600	Gas Well Venting		-	2,541	-	-	-	-
2310021101	Natural Gas-Fired Compressor Engines	2CycleLeanBurn<50HP	229	18	59	0	4	4
2310021102		2CycleLeanBurn50-499HP	8,187	745	1,075	2	130	130
2310021103		2CycleLeanBurn500+HP	0	0	0	-	0	0
2310021201		4CycleLeanBurn<50HP	5	-	0	-	-	-
2310021202		4CycleLeanBurn50-499HP	40	1	2	-	-	-
2310021203		4CycleLeanBurn500+HP	19,459	806	2,730	4	17	17
2310021301		4CycleRichBurn<50HP	506	5	495	0	2	2
2310021302		4CycleRichBurn50-499HP	36,266	618	28,547	6	97	97
2310021401		4CycleRichBurn<50HPw/NSCR	-	-	-	-	-	-
2310021402		4CycleRichBurn50-499HPw/NSCR	625	21	173	0	8	8
2310021403		4CycleRichBurn500+HPw/NSCR	105,128	1,690	16,494	4	57	57
(lb/active well count)								
2310021501	Fugitives	Connectors	-	62	-	-	-	
2310021502		Flanges	-	26	-	-	-	
2310021503		Open Ended Lines	-	28	-	-	-	
2310021504		Pumps	-	43	-	-	-	
2310021505		Valves	-	239	-	-	-	
2310021506		Other	-	360	-	-	-	
2310021300	Gas Well Pneumatic Devices		-	1,109	-	-	-	-
2310121401	Gas Well Pneumatic Pumps		-	510	-	-	-	-
(lb/spud)								
2310000220	Drill Rigs		15,587	2,619	9,637	1,982	1,808	1,754
2310000660	Hydraulic Fracturing Engines		14,672	2,317	9,170	1,353	1,834	1,834
2310121700	Gas Well Completion: All Processes		-	45,866	-	-	-	-

Table 5. Basis of Sureste, Tampico-Misantla, and Veracruz basin uncontrolled emission rate adjustments and percent change from controlled to uncontrolled emission rates for onshore oil and gas production well sites.

Source [a]	Well Type	Basis		Percent Change from Controlled to Uncontrolled Surrogate					
		Controlled Assumption	Uncontrolled Assumption	NOx	VOC	CO	SO_2	PM_{10}	$PM_{2.5}$
Heaters	Gas	AP-42, Chapter 1.4 flue gas recirculation controlled (ERG, 2013)	AP-42, Chapter 1.4 pre-NSPS uncontrolled	72%	-	-	-	-	-
Heater Treater	Oil	AP-42, Chapter 1.4 flue gas recirucIation controlled (ERG, 2013)	AP-42, Chapter 1.4 pre-NSPS uncontrolled	72%	-	-	-	-	-
Oil Well Pneumatic Devices	Oil	Mix of low, intermittent and high bleed devices (TCEQ, 2019)	Mix of intermittent and high bleed devices (TCEQ, 2019)	-	1%	-	-	-	-
Dehydrators	Gas	13% of dehydrators controlled by flares (ERG, 2010)	No flaring controls	-	15%	-	-	-	-
Drill Rigs	All	TX fleet controlled scenario average (ERG, 2015)	TX fleet uncontrolled scenario average (ERG, 2015)	163%	375%	433%	3233 %	887%	888%
Hydraulic Fracturing Engines	All	TX fleet average (ERG, 2014)	MOVES base emission rates (EPA, 2018b)	68%	299%	390%	3233 %	481%	481%

Source [a]		Well Type	Basis		Percent Change from Controlled to Uncontrolled Surrogate					
			Controlled Assumption	Uncontrolled Assumption	NOx	VOC	CO	SO_2	PM_{10}	$PM_{2.5}$
Natural Gas-Fired Compressor Engines	2Cycle Lean Burn < 50 HP	Gas	TCEQ controlled emission factor for attainment areas (TCEQ, 2019)	AP-42, Chapter 3.2 uncontrolled emission rates	161%	-	-	-	-	-
	2Cycle Lean Burn 50 To 499 HP				61%	-	-	-	-	-
	4Cycle Lean Burn 500+ HP				791%	-	-	9%	-	-
	4Cycle Rich Burn <50 HP				-	-	1123 %	-	-	-
	4Cycle Rich Burn 50 To 499 HP				-	-	75%	3%	3%	3%
	4Cycle Rich Burn 500+ HP w/NSCR				529%	479%	59%	1%	1%	1%

[a] no adjustments for gas well pneumatic devices because Palo Duro Basin emission inventory does not include any low bleed devices (TCEQ, 2019). No adjustments for completions based on assumption of no control for completions in the Palo Duro Basin (ERG, 2014). No adjustments for condensate tanks based on assumption of no control for completions in the Palo Duro Basin (TCEQ, 2019).

Table 6. Sureste, Tampico-Misantla, and Veracruz basin emission rates for onshore oil and gas production well sites.

SCC	Source		Well Type	Emission Factor (lb/surrogate)					
				NO_x	VOC	CO	SO_2	PM_{10}	$PM_{2.5}$
(lb/bbl)									
2310021010	Storage Tanks: Condensate		Gas	-	0.02	-	-	-	-
2310011020	Storage Tanks: Crude Oil		Oil	-	7.65	-	-	-	-
2310011201	Tank Truck/Railcar Loading: Crude Oil		Oil	<0.01	0.11	<0.01	-	-	-
(lb/MMSCF)									
2310021400	Dehydrators		Gas	0.03	0.89	0.11	<0.01	0.11	0.11
2310021600	Well Venting		Gas	-	7.97	-	-	-	-
2310021101	Natural Gas-Fired Compressor Engines	2Cycle Lean Burn < 50 HP	Gas	0.08	<0.01	0.02	-	<0.01	<0.01
2310021102		2Cycle Lean Burn 50 To 499 HP	Gas	3.39	0.31	0.44	-	0.05	0.05
2310021203		4Cycle Lean Burn 500+ HP	Gas	9.82	0.41	1.36	<0.01	<0.01	<0.01
2310021301		4Cycle Rich Burn <50 HP	Gas	0.18	-	0.16	-	-	-
2310021302		4Cycle Rich Burn 50 To 499 HP	Gas	13.49	0.23	10.66	<0.01	0.04	0.04
2310021403		4Cycle Rich Burn 500+ HP w/NSCR	Gas	38.99	0.63	6.10	<0.01	0.02	0.02
2310020600		Compressor Engines	All	0.03	<0.01	<0.01	-	<0.01	<0.01
(100 lb/active well count)									
2310021300	Pneumatic Devices		Gas	-	1.27	-	-	-	-
2310121401	Pneumatic Pumps		Gas	-	2.83	-	-	-	-
2310021100	Gas Well Heaters		Gas	0.73	0.04	0.62	-	0.06	0.06
2310021501	Fugitives	Connectors	Gas	-	0.34	-	-	-	-
2310021502		Flanges	Gas	-	0.14	-	-	-	-
2310021503		Open Ended Lines	Gas	-	0.16	-	-	-	-
2310021504		Pumps	Gas	-	0.24	-	-	-	-
2310021505		Valves	Gas	-	1.67	-	-	-	-
2310021506		Other	Gas	-	2.00	-	-	-	-
2310010300	Pneumatic Devices		Oil	-	39.29	-	-	-	-

SCC	Source		Well Type	Emission Factor (lb/surrogate)					
				NO_x	VOC	CO	SO_2	PM_{10}	$PM_{2.5}$
2310111401	Pneumatic Pumps		Oil	-	8.80	-	-	-	-
2310000330	Artificial Lift		Oil	22.83	0.31	35.30	<0.01	0.19	0.19
2310011100	Heater Treater		Oil	0.90	0.05	0.76	<0.01	0.07	0.07
2310011501	Fugitives	Connectors	Oil	-	4.36	-	-	-	-
2310011502		Flanges	Oil	-	1.01	-	-	-	-
2310011503		Open Ended Lines	Oil	-	1.64	-	-	-	-
2310011504		Pumps	Oil	-	6.07	-	-	-	-
2310011505		Valves	Oil	-	15.56	-	-	-	-
2310011506		Other	Oil	-	22.96	-	-	-	-
2310011000	Total: All Processes		All	0.02	0.06	0.09	0.18	-	-
(1000 lb/spud)									
2310121700	Completion		Gas	-	-	-	<0.01	-	-
2310111700	Completion		Oil	0.09	45.00	0.41	0.75	-	-
2310111100	Mud Degassing		Oil	-	25.77	-	-	-	-
2310000220	Drill Rigs		All	23.75	4.08	18.89	1.96	4.92	4.77
2310000660	Hydraulic Fracturing Engines		All	1.37	0.22	0.86	0.16	0.17	0.17

4.2.2 Offshore oil and gas activities

Emissions from offshore oil and gas platforms result from exploration activities (e.g., drilling,) and production activities (e.g., fugitive leaks, engines, turbines, boilers, and flares). 2016 equipment configurations, process emission rates, and other inputs necessary to estimate Mexico specific emissions from offshore oil and gas platforms were not readily available. Therefore, US offshore emission inventory estimates were normalized by offshore oil and gas activity, then combined with Mexico offshore oil and gas activity to estimate Mexico offshore oil and gas emissions in this analysis.

In the US, offshore oil and gas emissions under the jurisdiction of the Bureau of Ocean Energy Management (BOEM) were estimated for platform and non-platform emission sources for calendar year 2014 in Wilson et al. (2017), hereafter referred to as the BOEM 2014 inventory. The BOEM 2014 inventory includes emissions from offshore platforms in the Gulf of Mexico. BOEM 2014 inventory platform emission estimates were developed based on platform operator emissions submissions, if available. If operator submitted emissions were not available, emissions per oil and gas activity metric based on representative equipment and process configurations were used to estimate emissions. Platform emissions in the BOEM 2014 inventory include the following emission sources:

- Amine Units
- Boiler, heaters, and burners
- Diesel and gasoline engines
- Drilling equipment
- Combustion flares
- Fugitive Sources
- Glycol dehydrators
- Loading operations
- Losses from flashing
- Mud degassing
- Natural gas engines
- Turbines
- Pneumatic pumps
- Pressure and level controllers
- Storage tanks
- Cold vents
- Minor sources (e.g., wellhead protectors and living quarters)

The BOEM 2014 inventory also includes non-platform emissions (from mobile vessels). Non-platform emissions are available by area and lease block, but are not cross-referenced to specific lease numbers. Extrapolations of US non-platform emissions from BOEM 2014 inventory were not used to develop Mexico non-platform emissions because non-platform emissions are dependent on spatial domain and travel patterns away from platforms which are not expected to be consistent for US and Mexico; additionally, it was not feasible to isolate non-platform emissions associated with offshore activity applicable to Mexico, i.e., shallow water platforms. Non-platform emissions in the BOEM 2014 inventory include:

- Oil and Gas Production Sources

- Drilling rigs
- Pipelaying operations.
- Support helicopters.
- Support vessels.
- Survey vessels.
- Non-Oil and Gas Production Sources
- Biogenic and geogenic sources.
- Commercial fishing vessels.
- Commercial marine vessels (including cruise ships and lightering services).
- LOOP.
- Military vessels (U.S. Coast Guard/U.S. Navy).
- Recreational fishing vessels.

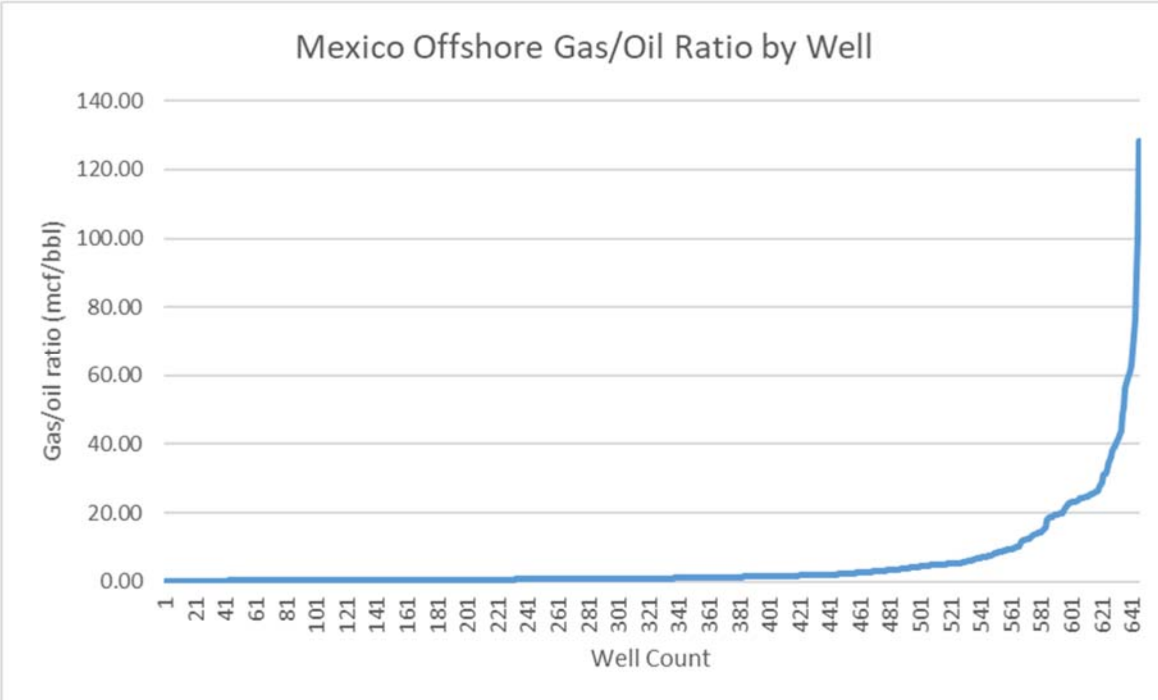
Recent year criteria air pollutant emissions have not been developed for Mexico offshore oil and gas sources. Mexico specific offshore oil and gas activity data is available from the CNIH.

In the absence of Mexico specific information about offshore platform emissions and equipment and process configurations, we have estimated representative emission rates for shallow oil and gas platforms in the US and applied those estimates to Mexico offshore oil and gas activity data to develop an offshore oil and gas emission inventory for Mexico. Representative US-based platform emission rates for each emissions source category were multiplied by the associated Mexico oil and gas activity metric to estimate Mexico offshore oil and gas emissions. Emission controls were assumed to be similar for the US and Mexico.

In the future, this inventory should be refined by adding non-platform emissions and by updating platform emissions based on Mexico specific offshore platform equipment and process configurations and emission rates.

2016 Mexico offshore oil and gas activity is located primarily in the Cuencas Del Sureste Basin with a small number of platforms in the Tampico-Misantla Basin. All offshore activity in Mexico in base year 2016 occurred in shallow water, less than 500 feet deep. In 2016, most offshore wells in Mexico produced both oil and gas; only 4 of 650 wells (all located in the Tampico-Misantla Basin) produced gas, but not oil. Figure 6 shows the 2016 gas/oil ratio (GOR) for Cuencas Del Sureste Basin off shore oil and gas wells.

Figure 6. Mexico gas/oil ratio for wells with oil production during 2016.



Emissions per unit of production factors were developed and relied upon exclusively to estimate Mexico offshore emissions because 2016 Mexico platform counts were not readily available (only well counts were available).

Emissions per unit of production were developed based on (1) detailed BOEM 2014 inventory database emissions by lease number and source category from Wilson et al. (2017) and (2) BOEM offshore oil and gas production estimates (https://www.data.boem.gov/Main/Production.aspx). Because 2016 offshore oil and gas production in Mexico was limited to shallow water, only US offshore leases in water less than 500 feet deep were included in the analysis. For wells with both oil and gas production, the analysis only considered Mexico offshore oil and gas production GOR range from 0 to 130 mcf/bbl. For dry gas wells, only wells with gas, but no oil production were considered. *Lease number* is the key that was used to associate data in the BOEM 2014 inventory database and the BOEM production database. Estimated emission rates are based on 427 leases with both oil and gas production and 53 leases with dry gas production. 311 lease numbers were dropped (159 with oil and gas production, 12 with dry gas production, and 140 with no oil and gas production) from the production database because an associated match was not found in the BOEM 2014 inventory database. 249 lease numbers were dropped, 53 which did not have any criteria pollutant emissions from the emission database because an associated match was not found in the BOEM production database.

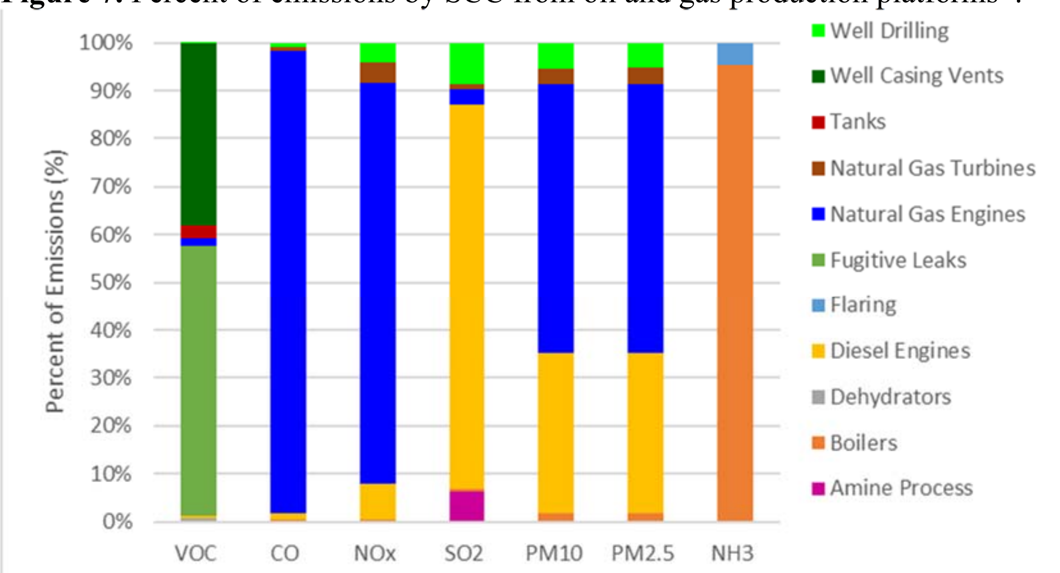
Estimates of total platform emissions per unit of production summed across all categories are presented in Table 7. Figure 7 and Figure 8 show the estimated distribution of offshore oil and gas emissions by source category.

Table 7. Emissions per unit of production from oil and gas platforms*.

Applicability	VOC	CO	NO_x	SO_2	PM_{10}	$PM_{2.5}$	NH_3	Units
Cuencas Del Sureste and Tampico Misantla (Oil and gas production)	825	902	738	5.56	10.2	10.2	0.123	lb/Mbbl/yr
Tampico-Misantla (Dry gas production only)	32.4	40.7	30.9	0.353	0.218	0.217	0.008	lb/MMcf/yr

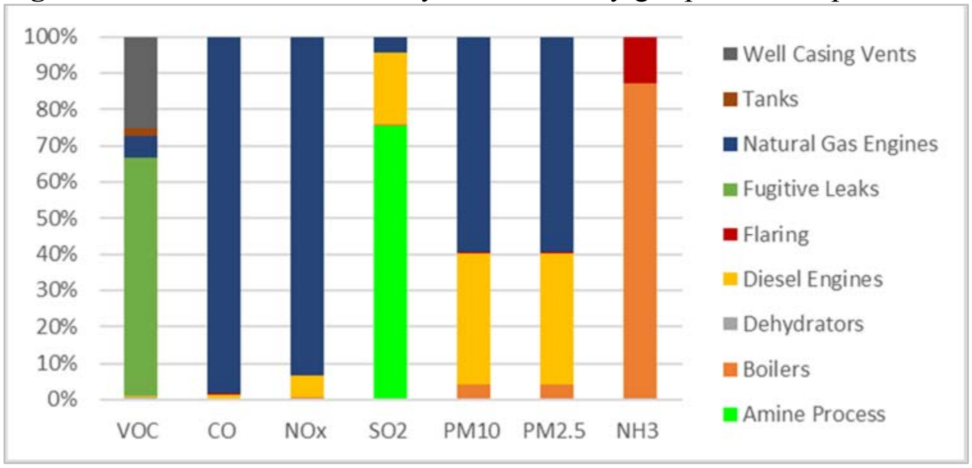
*Estimates do not include non-platform sources.

Figure 7. Percent of emissions by SCC from oil and gas production platforms*.



*not classified and well completions not shown because contributions <1% for all pollutants for these categories

Figure 8. Percent of emissions by SCC from dry gas production platforms*.

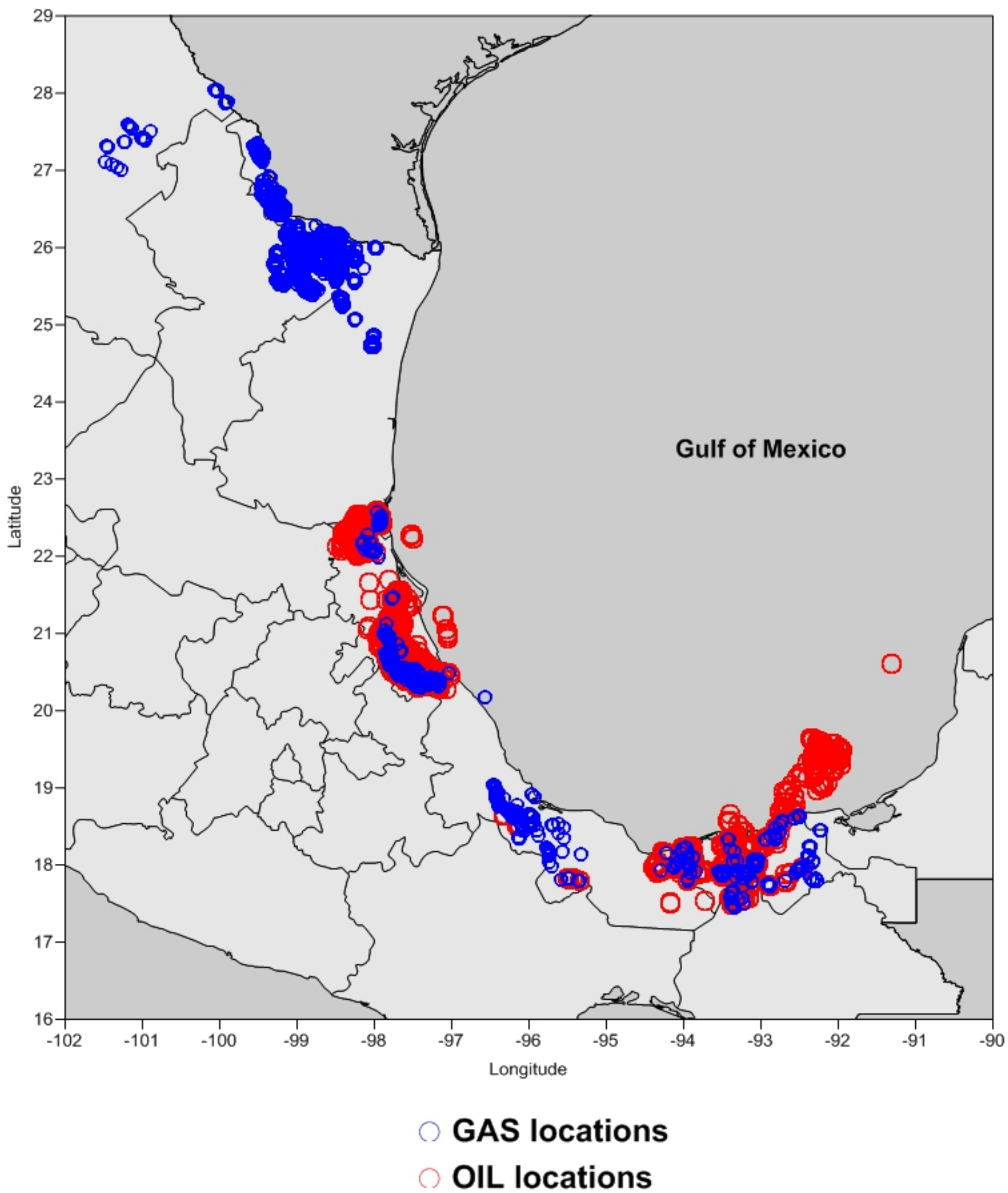


*not classified and well completions not shown because contributions <1% for all pollutants for these categories

4.3 Emission Estimates at Oil and Gas Well Sites

Emissions were calculated for a monthly temporal resolution at the spatial scale of individual well sites (e.g., point sources). The emission rates provided in Section 4.2 required that each well be characterized by basin, onshore or offshore, and oil or gas designation. As previously discussed, all but 4 of the 650 offshore wells (i.e., platforms) had non-zero oil production and were designated as oil wells. Per US EIA guidance (https://www.eia.gov/petroleum/wells/pdf/full_report.pdf), onshore wells were designated as either oil or natural gas based on a gas-oil ratio (GOR) of 6,000 cubic feet (cf) of natural gas to 1 barrel (b) of oil (cf/b) using the total annual production values for 2016. If the GOR was equal to or less than 6,000 cf/b then the well was classified as an oil well; if the GOR was greater than 6,000 cf/b, the well was classified as a natural gas well. Figure 9 shows a mapping of the oil/gas designations used for the purposes of emissions estimation.

Figure 9. Oil and gas designations for 2016 well sites.

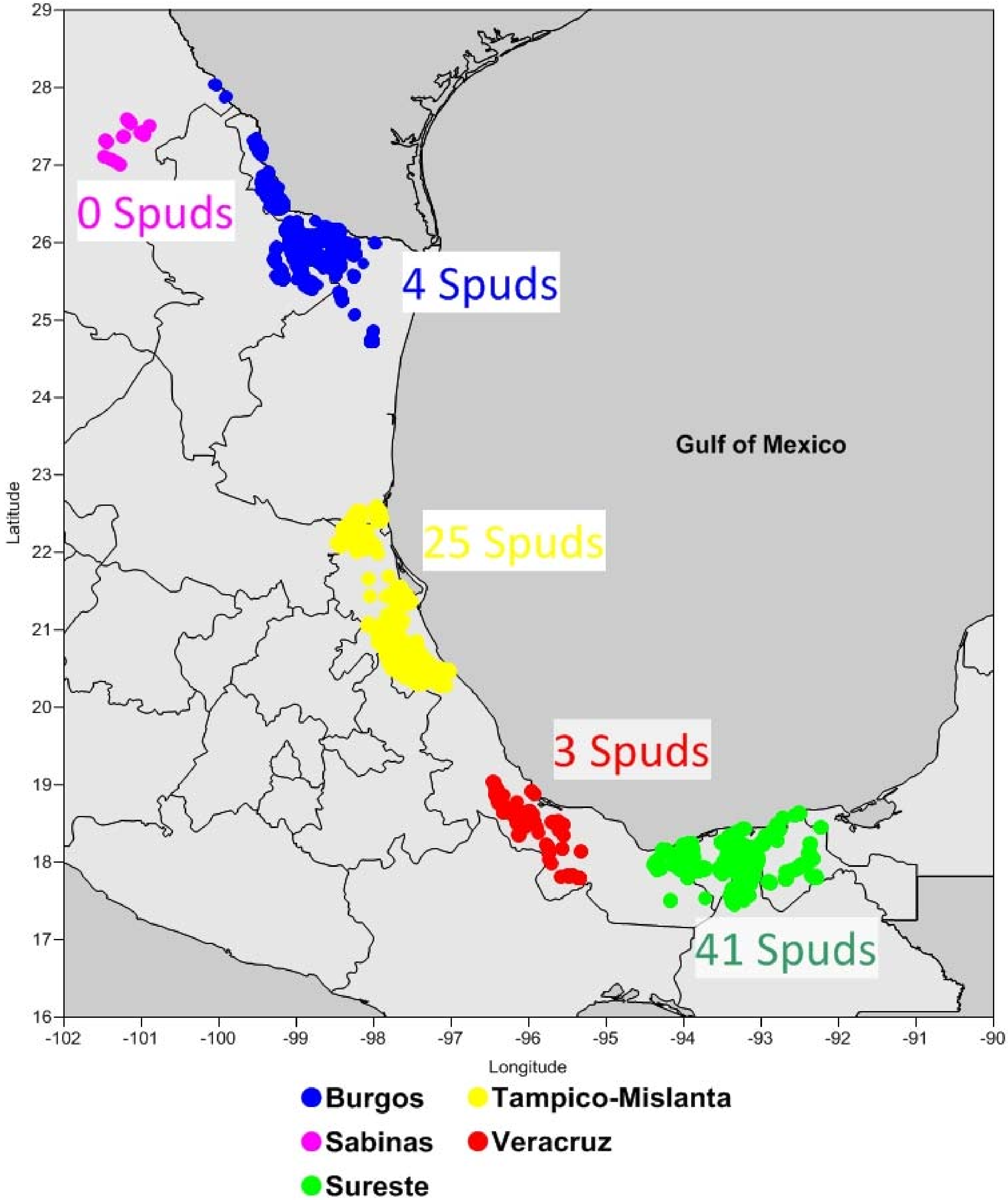


The emissions estimate calculations for offshore wells only required oil and/or gas monthly production volumes combined with the emission rate factors shown in Table 7. These platform-specific emissions were then distributed among production activities at each location using the SCC percentages visually displayed in Figure 7 and Figure 8.

With respect to emissions estimation for onshore wells, the oil and gas activity metrics are gas production, oil production, numbers of active wells, and numbers of onshore spuds (ref. Table 2). For SCCs with production-based emission rates, the monthly production volumes (oil and/or gas) were directly multiplied by the appropriate emissions factor to estimate emissions at each well site. For SCCs that assign annual emissions based on non-zero production activity (i.e., an active well), the emission rates were converted to a monthly temporal resolution with the assumption of an equal daily distribution throughout the year. Emissions for this latter category were then assigned to any month that had non-zero production activity.

As shown in Table 2, each spudding event is associated with a set amount of emissions. According to CNIH, a total of 73 new wells were drilled ("perforated") by various operators during 2016 (CNIH, 2019). The numbers of spudding events reported by basin are presented visually in Figure 10. For the purposes of emissions estimation, the spudding duration is assumed to span the entire year (i.e., annualized) and the basin-specific spudding emissions are spatially allocated equally across all active well locations. This methodology is intended to capture a generalized representation of the overall temporal and spatial distributions of emissions associated with spudding activities during 2016.

Figure 10. Numbers of onshore 2016 spudding events by basin.



Upstream oil and gas emissions results

Table 8 shows the estimated annual 2016 upstream oil and gas emissions (tons), and as a percentage of total emissions in Table 9; all results are aggregated by basin and onshore/offshore designation. The percentages of emissions aggregated by basin and onshore/offshore designation are shown graphically in Figure 11. Geographic maps that illustrate the spatial distribution of emissions across the individual well site locations are shown in Figures 12 through 17.

Mexico-wide emissions ranged from a minimum of 38.6 tons for NH_3 to a maximum of 844,385 tons for VOC. Among basins, Sabinas had relatively low emissions in contrast to the large emissions totals for Sureste that had 83% of total emissions (based on NO_x) from offshore platforms. As shown graphically in Figure 11, emissions of all pollutants except VOC are dominated by Sureste offshore sources. More detailed emissions totals aggregated by SCC are provided in Appendix 1. The relatively high percentage contributions to total VOC emissions from onshore sources compared to other pollutants is primarily driven by large emissions associated with crude oil storage tanks.

Table 8. Annual estimated emissions (tons) of NO_x, CO, SO_2, VOC, $PM_{2.5}$, PM_{10}, and NH_3 from upstream oil and gas activities during 2016 aggregated by basin and onshore/offshore designation.

Basin	**Onshore or Offshore**	**Gas (MMCF)**	**Oil (MBBL)**	**NO_x (tons)**	**CO (tons)**	**SO_2 (tons)**	**VOC (tons)**	**$PM_{2.5}$ (tons)**	**PM_{10} (tons)**	**NH_3* (tons)**
Burgos	Onshore	315126	0	27291.8	8212.4	3.8	5183.9	91.4	91.5	
Sabinas	Onshore	6577	0	568.3	170.6	0.1	50.2	1.8	1.8	
Sureste	Offshore	1140159	622983	229827.8	280863.1	1732.1	256733.4	3164.4	3168.3	38.4
	Onshore	459111	126032	10118.8	4694.2	31.5	429286.6	144.5	147.5	
Tampico-Misantla	Offshore	15490	2598	1044.6	1284.8	8.2	1161.0	13.8	13.8	0.2
	Onshore	72546	31716	5080.5	6307.1	44.8	130793.8	108.3	110.1	
Veracruz	Onshore	118133	5409	3838.7	1187.8	4.2	21176.3	21.4	21.6	
All	Offshore	1155649	625581	230872.4	282147.9	1740.3	257894.4	3178.2	3182.2	38.6
	Onshore	971493	163158	46898.2	20572.1	84.3	586490.9	367.3	372.4	0.0
	Total	**2127142**	**788738**	**277770.6**	**302720.1**	**1824.6**	**844385.3**	**3545.5**	**3554.6**	**38.6**

*NH_3 not estimated for onshore wells.

Table 9. Results shown in the previous Table 8 but as a percentage of total emissions.

Basin	Onshore or Offshore	Gas (MMCF)	Oil (MMBBL)	NO_x (tons)	CO (tons)	SO_2 (tons)	VOC (tons)	$PM_{2.5}$ (tons)	PM_{10} (tons)	NH_3* (tons)
Burgos	Onshore	14.8%	0.0%	9.8%	2.7%	0.2%	0.6%	2.6%	2.6%	
Sabinas	Onshore	0.3%	0.0%	0.2%	0.1%	0.0%	0.0%	0.0%	0.0%	
Sureste	Offshore	53.6%	79.0%	82.7%	92.8%	94.9%	30.4%	89.3%	89.1%	99.5%
	Onshore	21.6%	16.0%	3.6%	1.6%	1.7%	50.8%	4.1%	4.1%	
Tampico-Misantla	Offshore	0.7%	0.3%	0.4%	0.4%	0.4%	0.1%	0.4%	0.4%	0.5%
	Onshore	3.4%	4.0%	1.8%	2.1%	2.5%	15.5%	3.1%	3.1%	
Veracruz	Onshore	5.6%	0.7%	1.4%	0.4%	0.2%	2.5%	0.6%	0.6%	
All	Offshore	54.3%	79.3%	83.1%	93.2%	95.4%	30.5%	89.6%	89.5%	100.0%
	Onshore	45.7%	20.7%	16.9%	6.8%	4.6%	69.5%	10.4%	10.5%	0.0%
	Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

*NH_3 not estimated for onshore wells.

Figure 11. Percentage of total emissions aggregated by basin and onshore/offshore designation as a graphical bar chart.

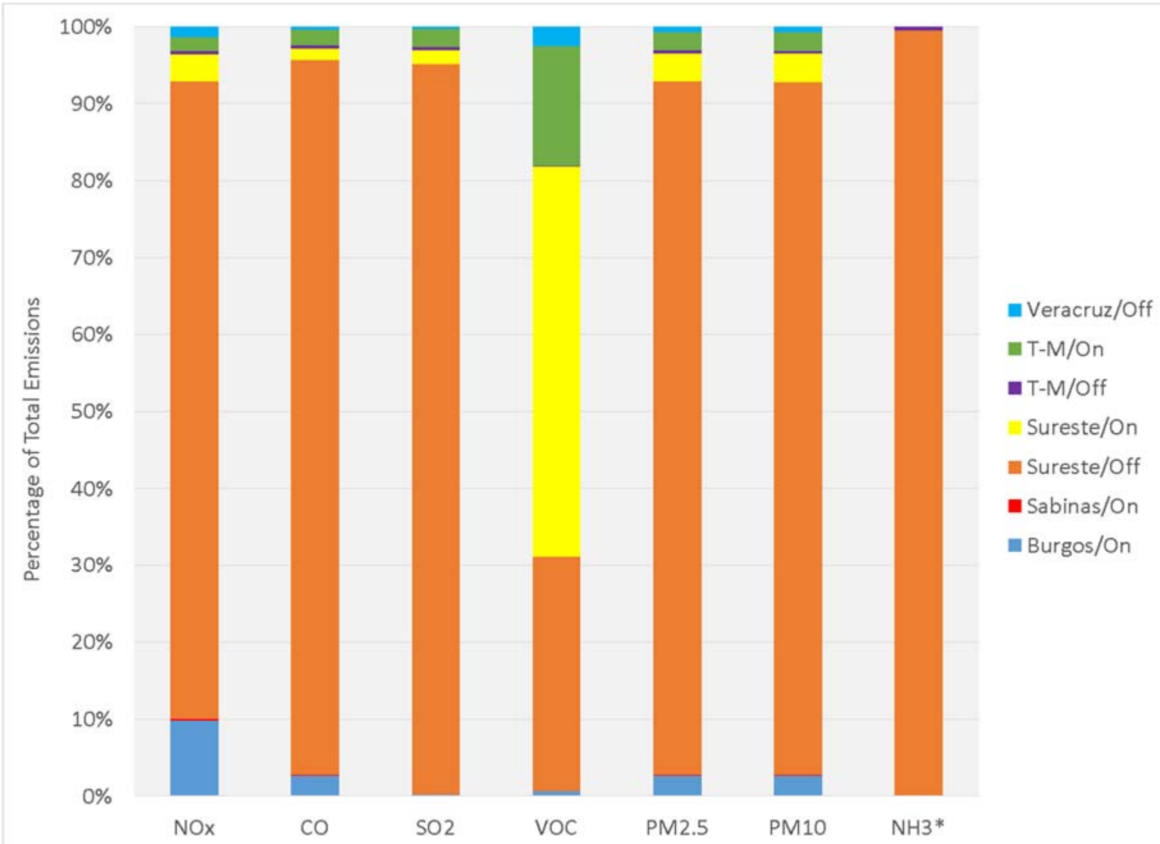


Figure 12. Annual 2016 NO_x emissions (individual wells aggregated to 4km by 4km grid cells). Location symbols are proportionally sized by emissions.

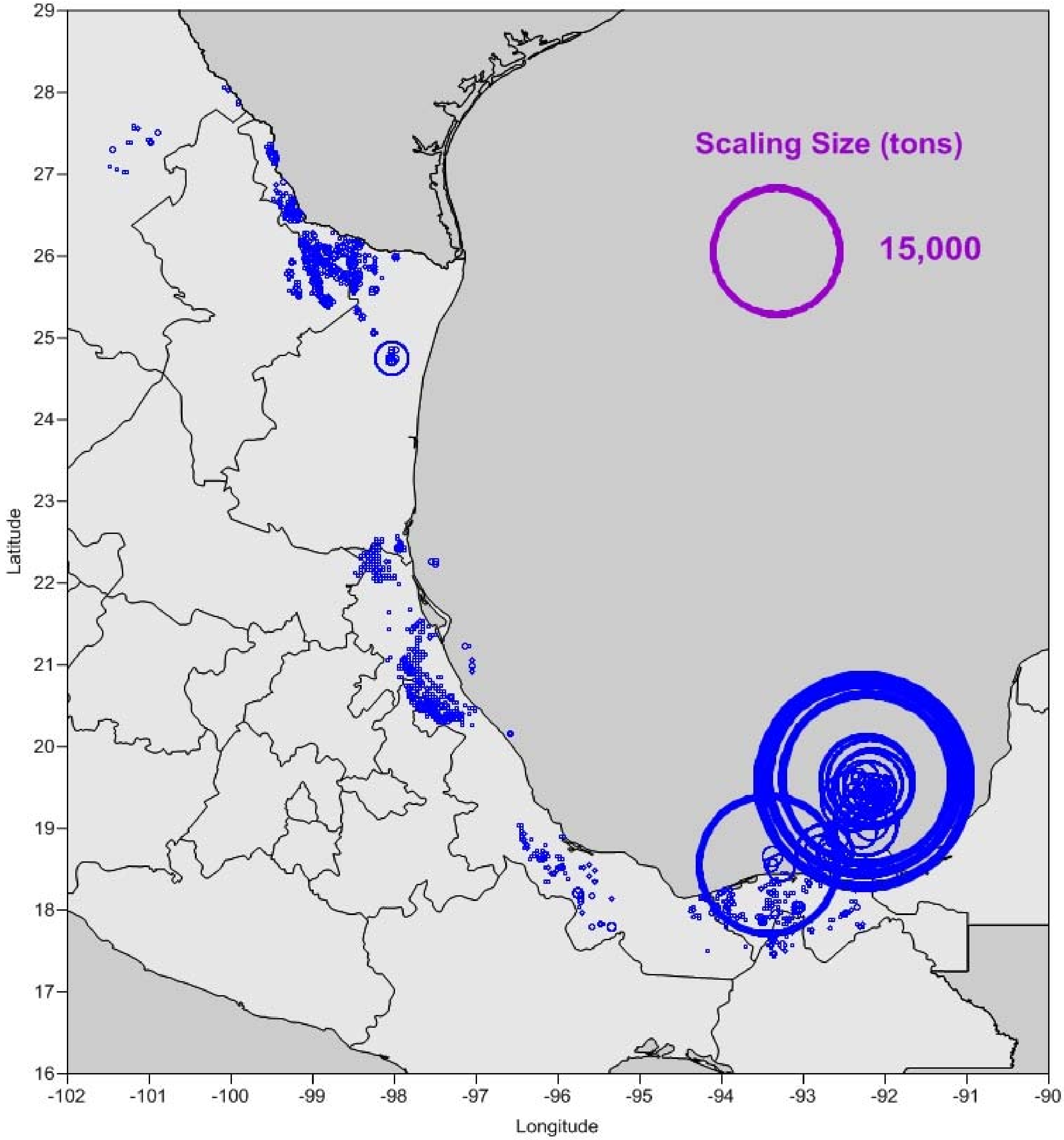


Figure 13. Annual 2016 VOC emissions (individual wells aggregated to 4km by 4km grid cells). Location symbols are proportionally sized by emissions.

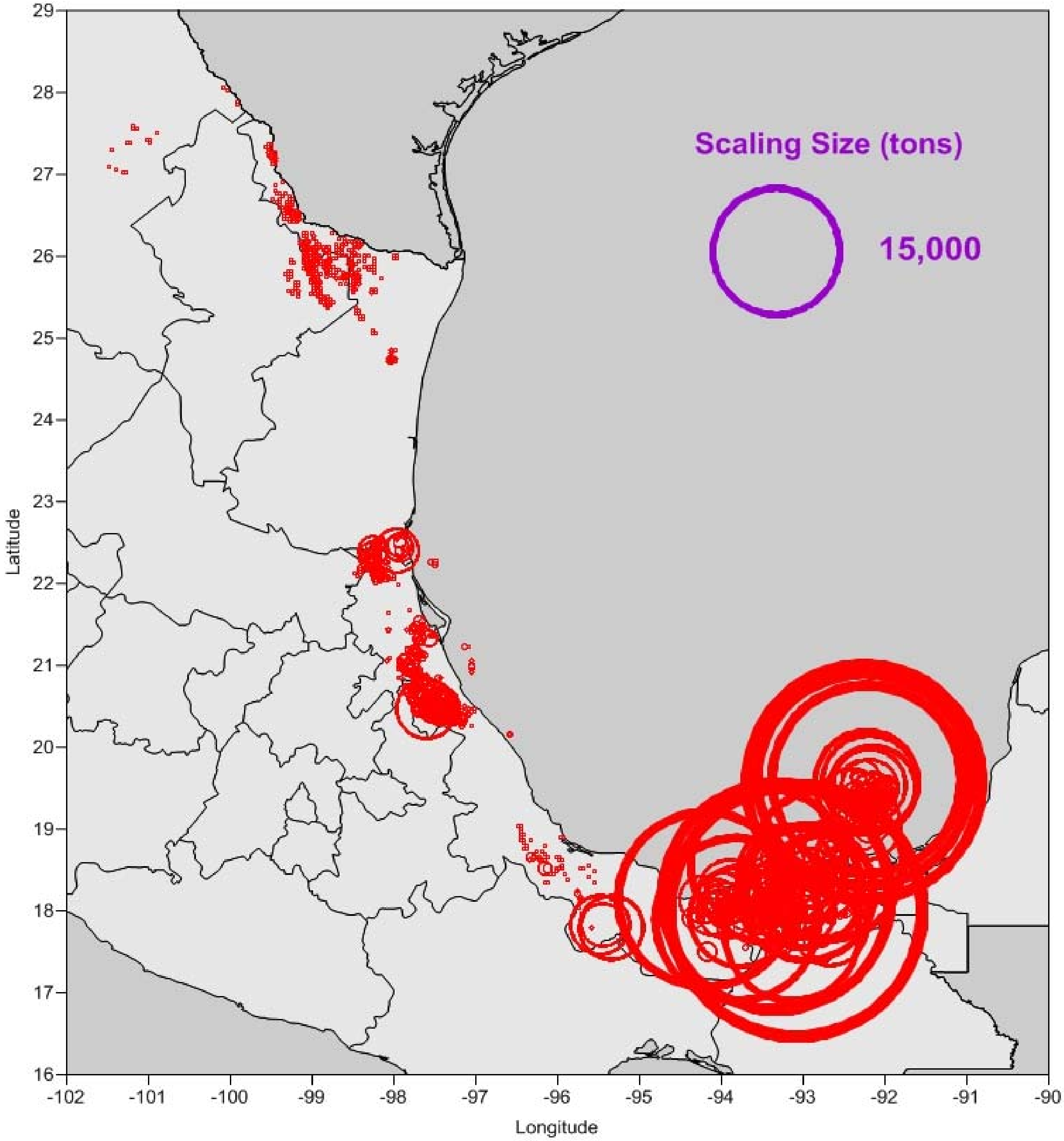


Figure 14. Annual 2016 CO emissions (individual wells aggregated to 4km by 4km grid cells). Location symbols are proportionally sized by emissions.

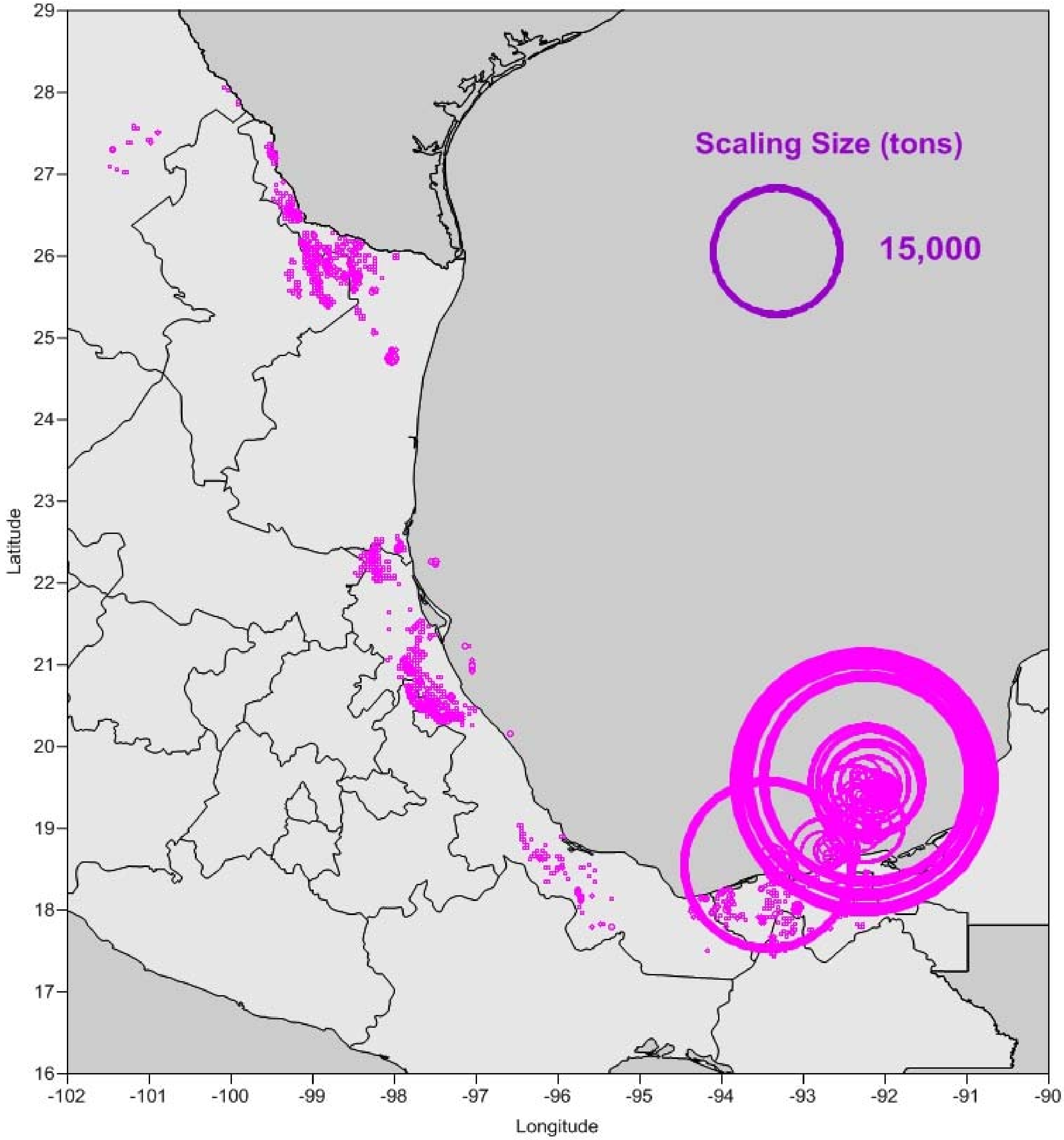


Figure 15. Annual 2016 SO_2 emissions (individual wells aggregated to 4km by 4km grid cells). Location symbols are proportionally sized by emissions.

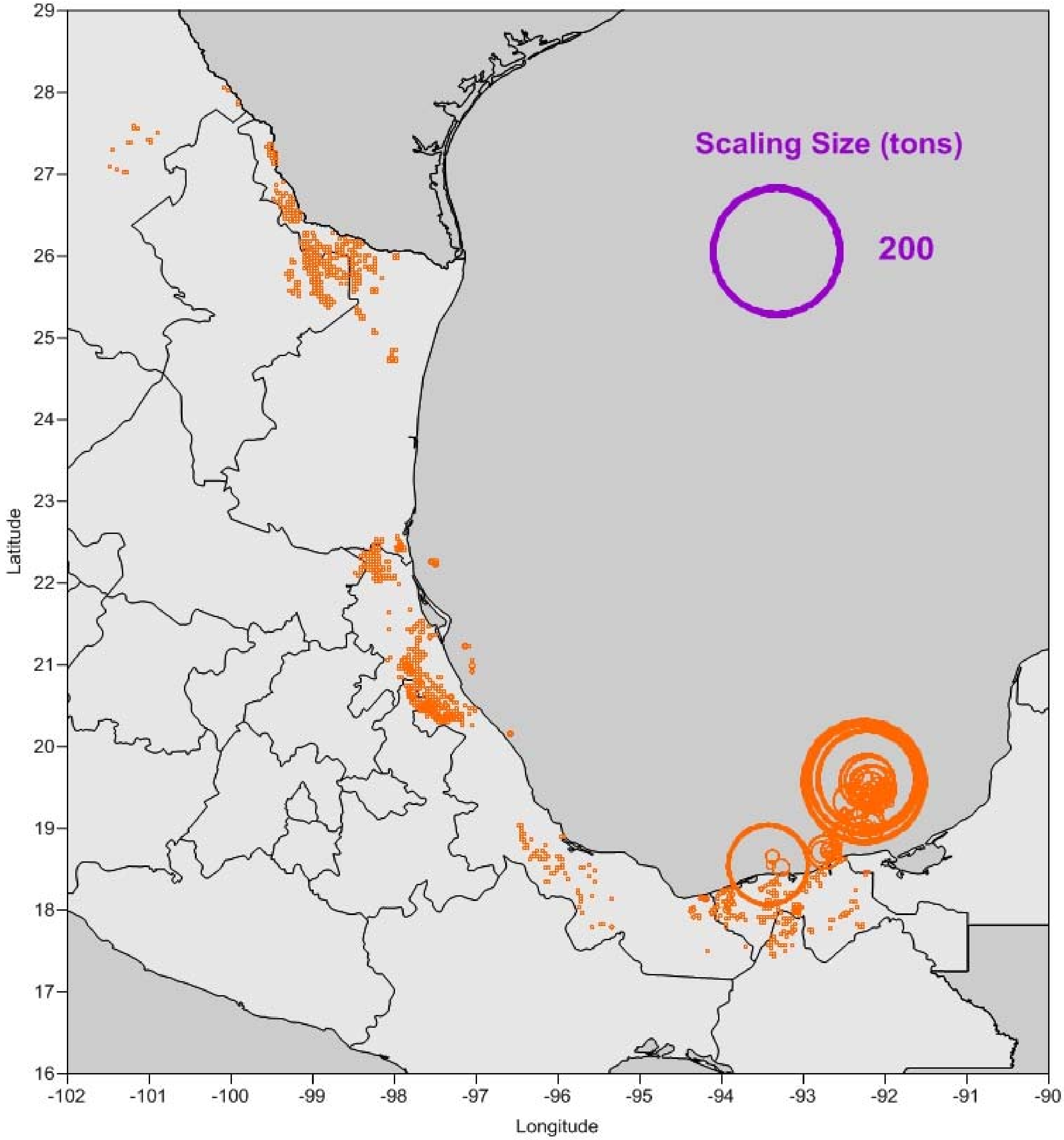


Figure 16. Annual 2016 $PM_{2.5}$ emissions (individual wells aggregated to 4km by 4km grid cells). Location symbols are proportionally sized by emissions.

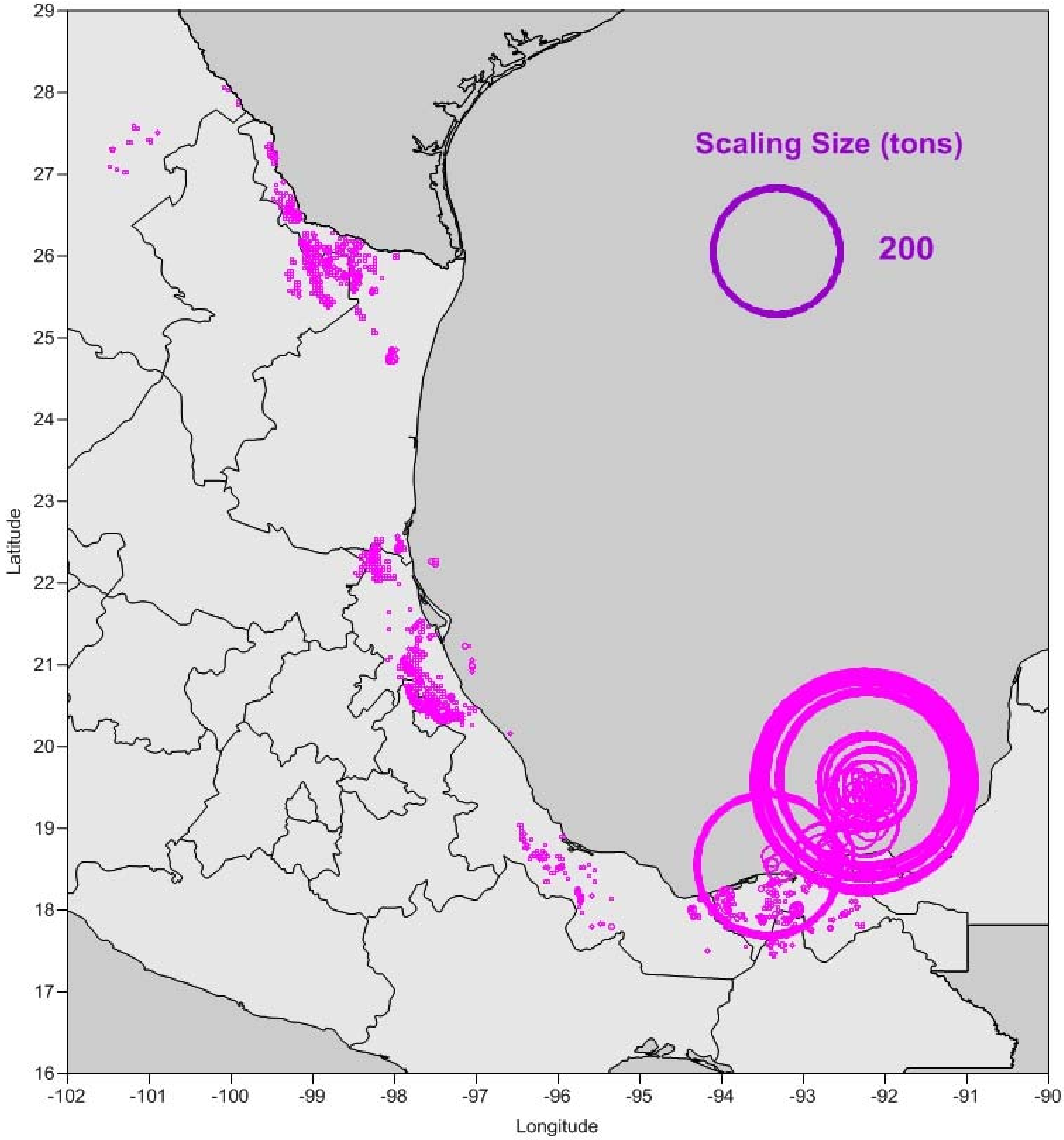
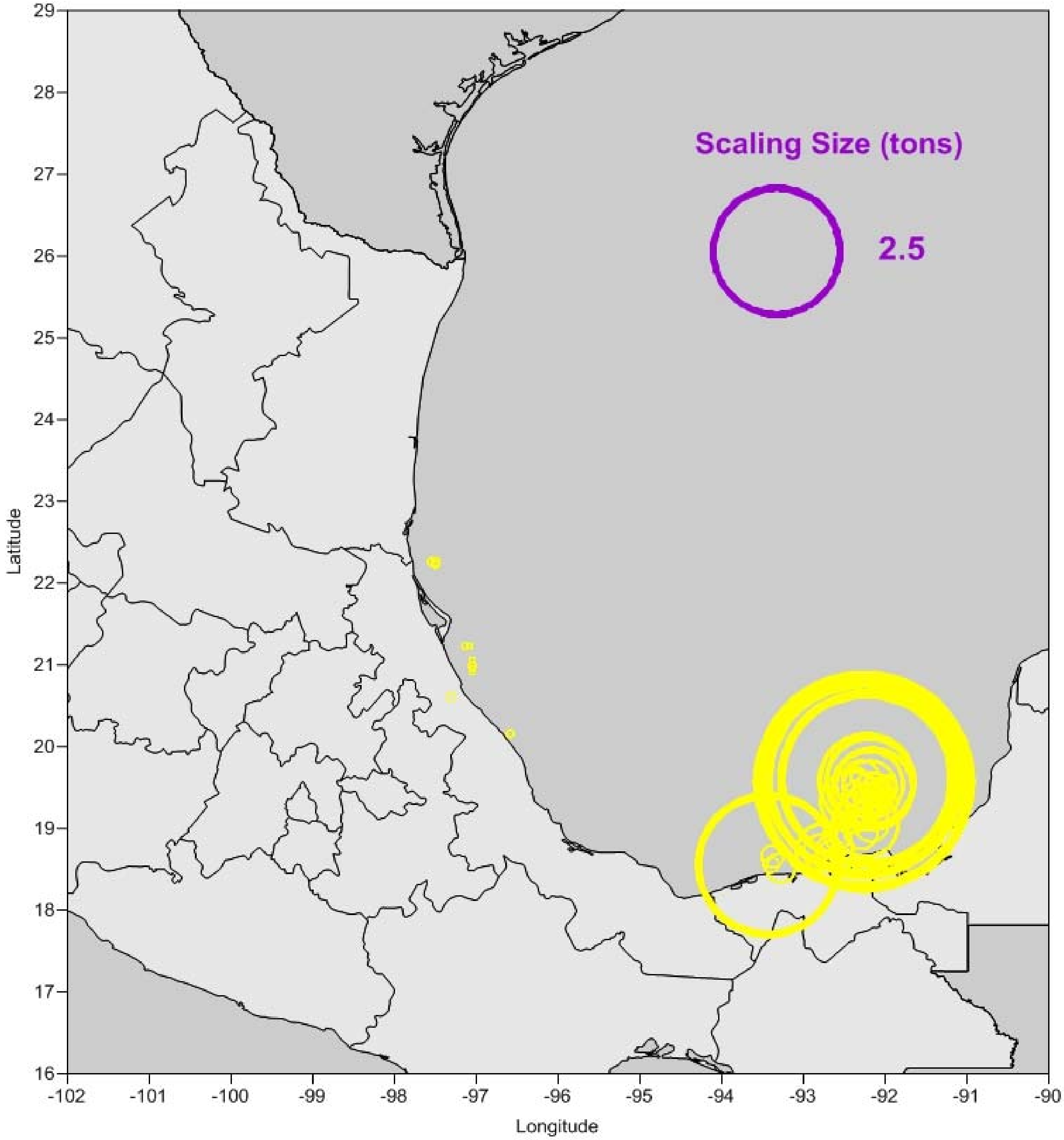


Figure 17. Annual 2016 NH_3 emissions (individual wells aggregated to 4km by 4km grid cells). Location symbols are proportionally sized by emissions.



Upstream oil and gas well/platform stack release parameters

The emissions release parameters for oil and gas wells were assigned to represent low-level and non-buoyant emissions source types as summarized in Table 10. Section 7.0 of this report provides an overview of the point source datasets delivered in AFS (AIRS Facility System) format.

Table 10. Stack release parameters assigned to upstream oil and gas well and platform sources.

Parameter	Value
Stack height	2.0 meters for onshore wells, 25.0 meters for offshore wells (representative of overwater platforms)
Stack exit diameter	0.001 meters
Stack gas exit temperature	293 Kelvin
Stack gas exit velocity	0.001 meters per second (m/s)

4.3 Well Site Flaring

Regulatory emission control requirements that would result in substantial flaring at Mexico upstream well sites are not required at this time; however, we suspect that flaring controls may be used at upstream well sites as a safety measure to control sources such as casinghead gas. In addition to the above emission rates, the Mexico oil and gas emission inventory developed herein includes circa-2012 screening level flaring emission estimates from Shah et al. (2018; Table 11). The Shah et al. (2018) estimates of Mexico oil and gas well site flaring emissions were developed by applying reference emission factors to upstream oil and gas flaring volumes. Upstream oil and gas flaring volume estimates were obtained from the Visible Infrared Imaging Radiometer Suite (VIIRS) (https://www.ngdc.noaa.gov/eog/viirs/download_global_flare.html). Screening level emission factors for upstream oil and gas flares are based on AP-42 (US EPA, 2018) and EPA NEI O&G Tool (EPA Oil and Gas Tool, 2014 NEI Version 2.1 – Production Activities Module, 2017).

Table 11. Emission estimates for upstream O&G flares in Mexico during 2012.

Pollutant	Emissions (tpy)
VOC	23,005
NO_x	6,579
CO	30,073
SO_2	72,666

In order to generate emission estimates representative of natural gas flaring for 2016, projection factors were calculated as the basin-specific annual gas production for 2016 relative to 2012. For the Sureste Basin, which accounts for close to 100% of offshore oil and gas production, both onshore and offshore factors were developed. The resulting projection factors (ref. Table 12) were multiplied by the 2012 emissions to estimate emissions for 2016. A spatial mapping across the 135 individual flaring locations for VOC is provided in Figure 18. Because the 2012 emissions estimation methodology assumed a linear relationship among pollutants, the relative spatial distributions of NO_x, CO, and SO_2 for 2016 are identical to that shown for VOC.

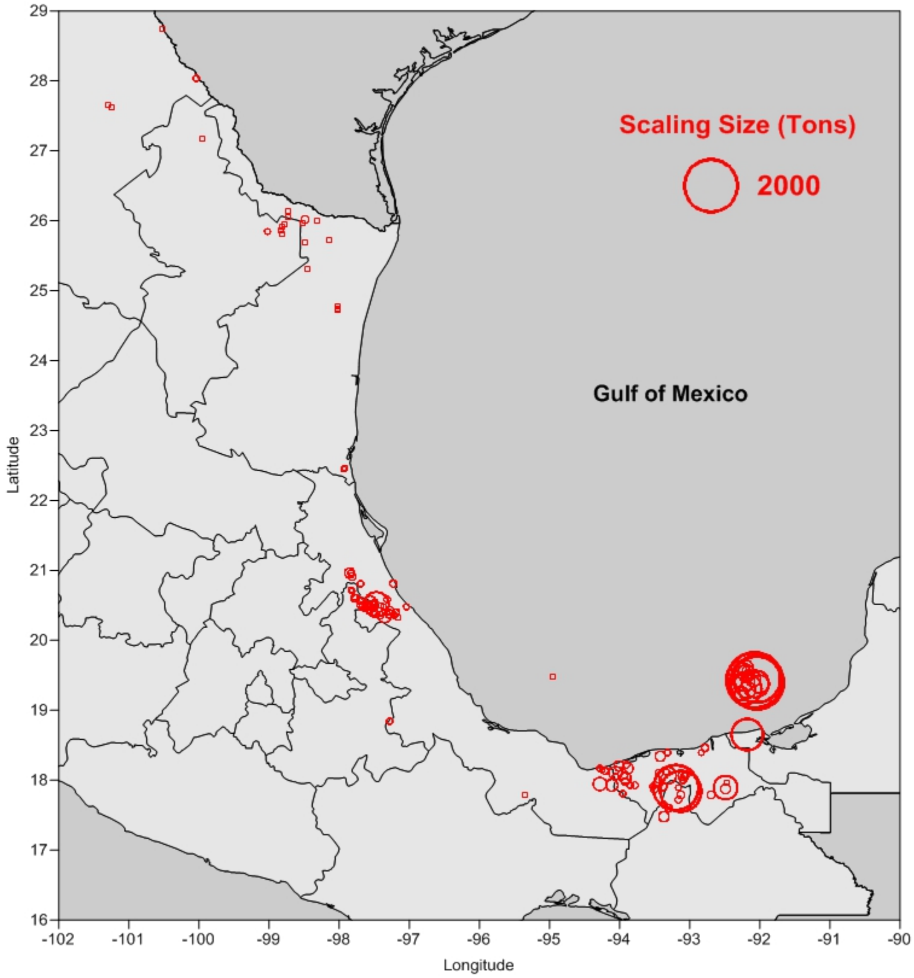
Table 12. Emission projection factors (total gas production for 2016 relative to 2012) and annual flare emissions for 2016.

Basin	Projection Factor	2016 VOC (tons)	2016 NO_x (tons)	2016 CO (tons)	2016 SO_2 (tons)
Burgos	0.718	184.6	52.9	241.4	583.2
Sabinas	0.262	5.4	1.5	7.0	16.9
Sureste (offshore)	1.201	12890.3	3696.3	16850.6	40716.8
Sureste (onshore)	0.761	6403.5	1836.2	8370.8	20226.7
Tampico-Misantla	0.983	3466.2	993.9	4531.1	10948.7
Veracruz	0.537	28.7	8.2	37.6	90.8
Total	--	22978.8	6589.1	30038.5	72583.1

Upstream well flaring stack release parameters

The stack exit release parameters for flares were identical to those provided by Shah et al. (2018). Section 7.0 of this report provides an overview of the point source emissions datasets delivered in AFS format.

Figure 18. Locations of active flaring assumed for 2016; the location symbols are sized by annual VOC emissions (tons).

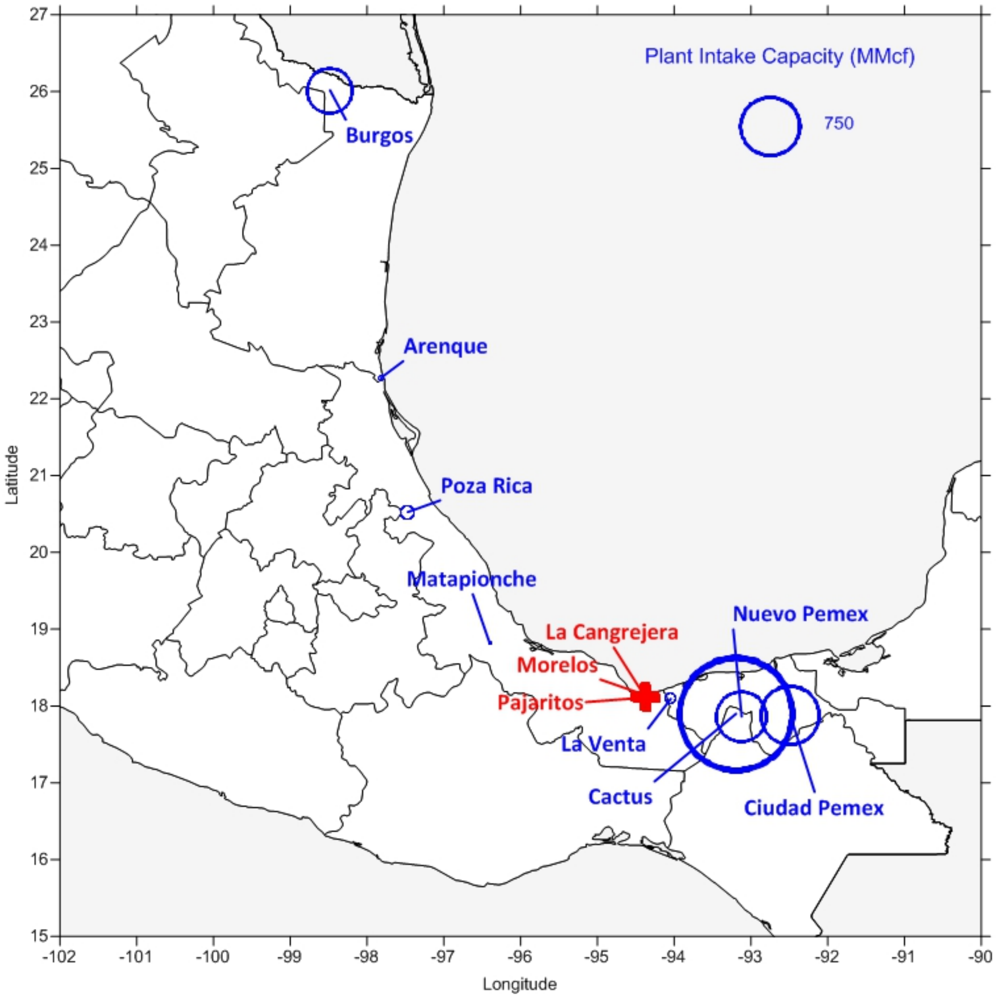


5. Midstream Oil and Natural Gas Sector

5.1 Natural Gas Processing Plants

Gas processing plants treat raw natural gas by separating impurities, various non-methane organic compounds (NMOCs), and fluids to produce pipeline quality dry natural gas. Figure 19 shows the eleven gas processing plants that were active during 2016 according to Pemex's "Statistical Yearbook" (PEMEX, 2016, pg 12, pg 47). Locations for eight of the eleven plants included as point sources in the 2008 Mexico National Emissions Inventory (*Inventario Nacional de Emisiones de México* or INEM) (ERG, 2014) are sized by their total natural gas intake for 2016. Three of the eleven plants were not identified in the 2008 INEM. The locational coordinates are based on those provided by NACEI (2017).

Figure 19. Locations of the eight INEM (sized in blue by 2016 natural gas intake) and three co-located non-INEM (plotted using co-located "+" symbols in red) natural gas processing plants.



Individual emissions data records (e.g., by facility, SCC and pollutant) for the eight INEM gas processing plants were identified by facility name and extracted from the 2008 INEM point source dataset. Their locations were evaluated for reasonableness by comparing with latitude/longitude coordinates reported by NACEI. The numbers of unique records in INEM among the eight facilities varied from a minimum of 28 at Arenque to a maximum of 329 for Ciudad Pemex. PEMEX (2016) reported the annual natural gas intake at each of the eight facilities for years 2008 and 2016; therefore, the relative intake values were used to generate facility-specific projection factors in order to adjust the annual 2008 emission inventory to represent 2016 production conditions.

The natural gas intake volumes and resulting emission factors are summarized in Table 13. For each facility, these factors were multiplied by the annual 2008 emissions to estimate 2016 emissions. The remaining original parameter values in each INEM point source emissions record (e.g., source and facility IDs, SCCs, stack release parameters) were maintained; only the annual emissions were updated.

Table 13. Natural gas intake volumes for 2008 and 2016 and emission projection factors (total gas production for 2016 relative to 2008) for the eight INEM gas processing plants.

Facility	2008 Gas Volume (mmcf/day)	2016 Gas Volume (mmcf/day)	Emission Factor
Arenque	26	31	1.192
Burgos	808	560	0.693
Cactus	1597	1452	0.909
Ciudad Pemex	891	738	0.828
La Venta	62	102	1.645
Matapionche	54	17	0.315
Nuevo Pemex	598	627	1.048
Poza Rica	86	145	1.686

Three additional gas processing plants (La Cangrejera, Morelos, Pajaritos) were identified as active in PEMEX (2016) but were missing in the INEM. These non-INEM facilities were assumed to be nearly co-located within the far southeastern portions of Veracruz immediately south of the Bay of Campeche (ref. Figure 19). In order to generate emission projection factors for these plants, linear regression equations were developed between the PEMEX (2016) petrochemical production associated with each of the eight INEM gas processing facilities and facility-wide emissions for NO_x, CO, VOC, $PM_{2.5}$, PM_{10}, and NH_3 (ref. Appendix 2). The regression results were used to estimate emissions at the three non-INEM plants. Due to a lack of production information and limited information on processing technologies, SO_2 emissions were not estimated.

Based on the combined petrochemical production from the three non-INEM facilities, a surrogate INEM facility (Nuevo Pemex) was selected to provide representative emissions release characteristics (i.e., distribution of emissions by pollutant and SCC in addition to stack release parameters). The emissions from the three non-INEM facilities were combined at a single co-located coordinate provided by NACEI for Pajaritos. Otherwise, the inventory emission release parameter records were identical to Nuevo Pemex.

Total annual emissions from gas processing plants are compared between 2008 and 2016 in Table 14. The emissions increases (except for SO_2) for 2016 compared to 2008 are primarily related to the absence of the La Cangrejera and Morelos facilities in the 2008 INEM.
The 2016 facility-specific emission totals for NO_x, CO, and $SO_2/10$ are shown graphically in Figure 20 and for VOC, $PM_{2.5}$, PM_{10}, and NH_3 in Figure 21.

Stack exit release parameters at gas processing plants

As noted previously, the stack release parameters for gas processing plants were based on those contained in the 2008 INEM. Section 7.0 of this report provides an overview of the AFS formatted datasets delivered for 2016 point sources.

Table 14. Annual emissions from gas processing plants for 2008 and 2016.

Pollutant	INEM 2008 (tons)	2016 (tons)	Difference (tons)	Difference (%)
CO	4816	6624	1808	38%
NH_3	151	214	63	42%
NO_X	13282	18073	4791	36%
PM_{10}	931	1166	235	25%
$PM_{2.5}$	926	1159	233	25%
SO_2	75577	66314	-9263	-12%
VOC	363	435	72	20%

Figure 20. Plant-wide annual NO_x, CO, and SO_2 emissions for 2016 gas processing plants.

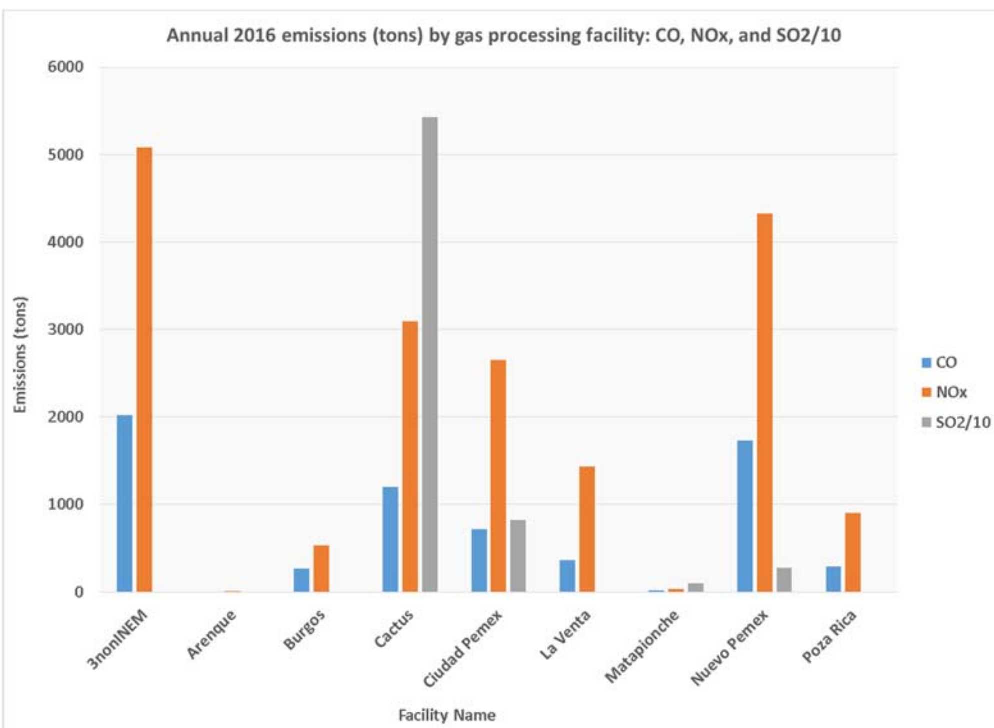
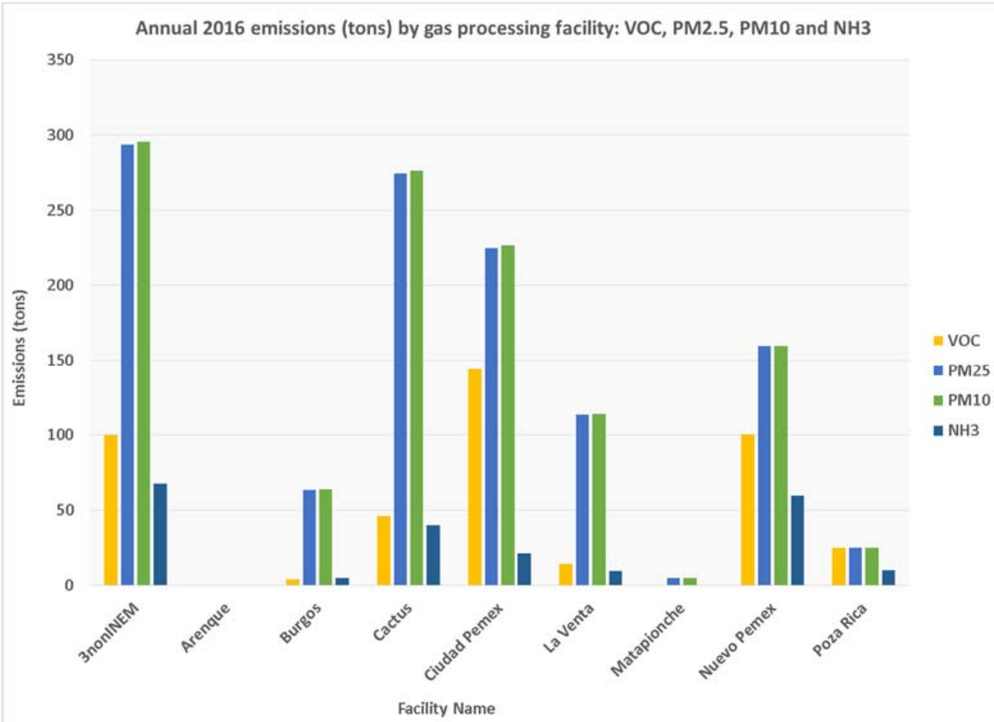


Figure 21. Plant-wide annual VOC, $PM_{2.5}$, PM_{10} and NH_3 emissions for 2016 gas processing plants.



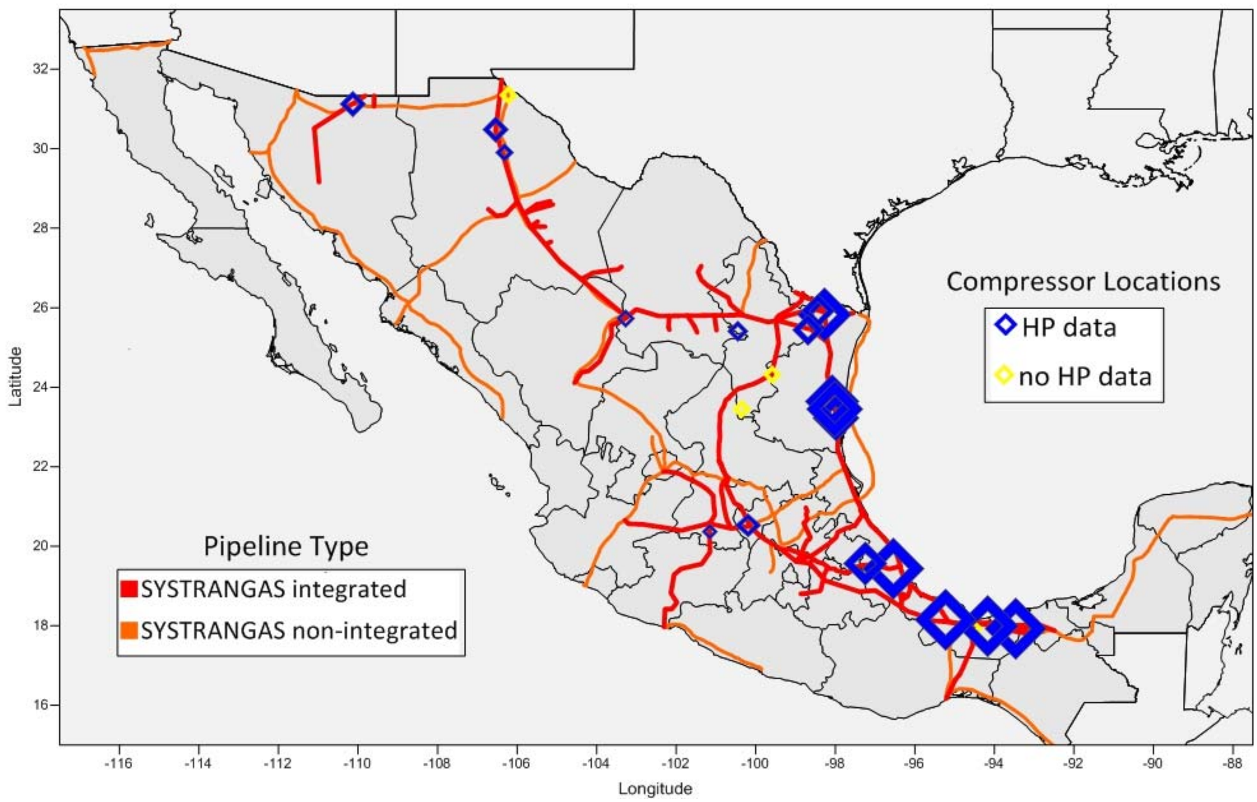
5.2 Natural Gas Compressor Stations

Compressor stations located in oil and gas fields and along gas lines compress natural gas for transport in accordance with pipeline pressure requirements. Typically, the primary source of criteria pollutant emissions at compressor stations are natural gas-fired engines and/or turbines.

Compressor stations along pipelines were not identified in the 2008 INEM for any point source, indicating that emissions were not included in the INEM. CNIH provides the locations of compressor stations via the geographic information layers publicly available from the CNIH data portal (https://mapa.hidrocarburos.gob.mx). The CNIH compressor mapping layer indicates that 22 central compressor stations are currently in operation along National Integrated Natural Transport and Storage System (SYSTRANGAS, which is under the jurisdiction of the National Center for Natural Gas Control or CENAGAS) pipelines. The locations of all compressor stations and natural gas pipeline networks that were extracted as shapefiles from the CNIH data portal are displayed in Figure 22.

An internet web search did not identify a source of annual natural gas throughputs for individual compressor stations in the SYSTRANGAS pipeline network; however, publicly available data resources (SENER, 2013; Eduardo, 2019) have reported the total installed horsepower for 18 of the 22 central compressor stations. The locations of these 18 compressors are shown in Figure 23 and sized by the installed horsepower (HP); the four remaining compressors for which no information on installed horsepower was obtained are displayed using yellow diamond symbols.

Figure 22. The locations of active compressor stations and a representation of the natural gas pipeline network obtained via the CNIH data portal (https://mapa.hidrocarburos.gob.mx). Compressors with known installed horsepower (HP) are plotted using blue diamond symbols sized by horsepower. Compressor stations with no information on installed horsepower are shown as yellow diamonds.



Typically, the primary source of criteria pollutant emissions at compressor stations are natural gas-fired engines and/or turbines. Emissions were not estimated for equipment in addition to turbines and engines located at compressor stations. Table 15 shows EPA AP-42 emission rates for both engines and turbines; however, because no information was available on the type of engine employed at each compressor station, uncontrolled 4-stroke rich bun engines were conservatively assumed for all 22 compressor stations. The horsepower values for the 22 stations ranged from a minimum of 4700 HP for a single compressor to a maximum of 55,000 HP for four compressors. For the purposes of emissions estimation, the average HP value across the 18 compressors (30, 618 HP) was assumed for the four compressors that lacked information on installed horsepower. All engines were conservatively assumed to operate 8784 hours per year at 100% load.

Table 15. AP-42 compressor station emission rates.

Pollutant	Uncontrolled 4-Stroke Rich Burn Engine (g/hp-hr)[1]	Uncontrolled Turbine (g/hp-hr)[1]
NO_x	8.02E+00	1.16E+00
CO	1.35E+01	2.98E-01
VOC	1.07E-01	7.62E-03
SO_2	2.13E-03	1.23E-02
PM_{10}	7.04E-02	2.40E-02
$PM_{2.5}$	7.04E-02	2.40E-02

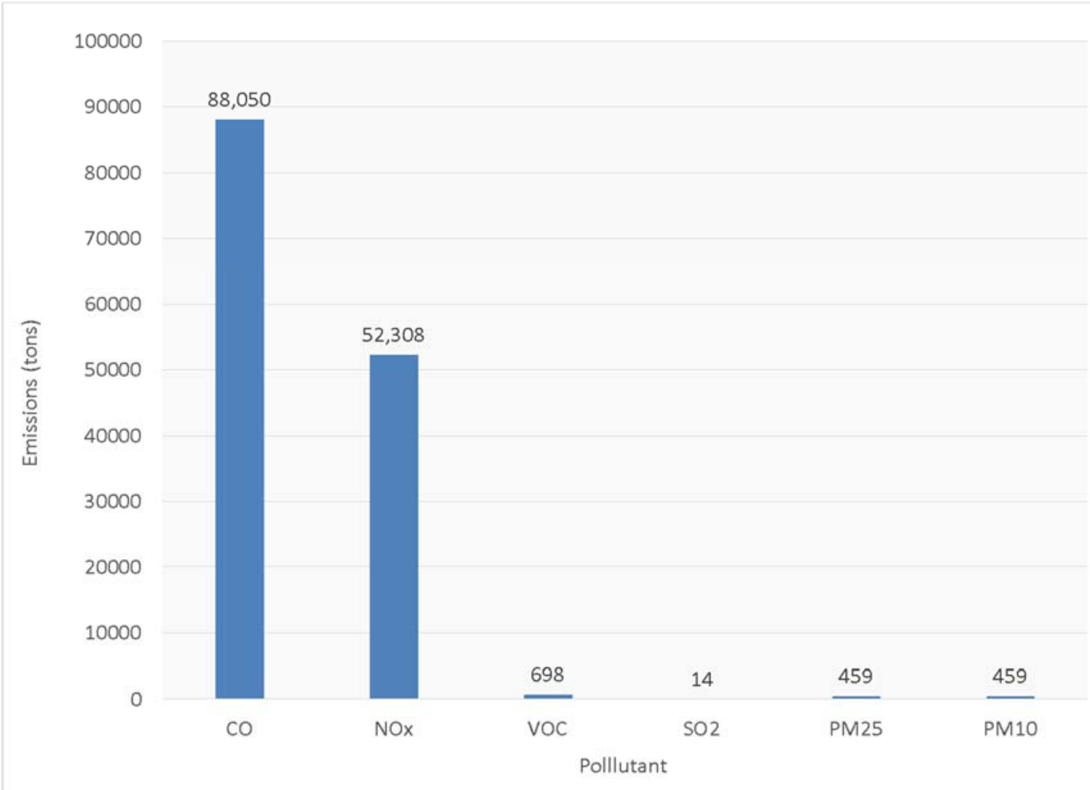
[1] AP-42 emission factors in unit of pounds per million British thermal units (lb/MMBTU) were converted to units of grams per horsepower-hour (g/hp-hr) assuming a fuel heat input of 8000 British thermal units per horsepower-hour (BTU/hp-hr).

Figure 23 presents the annual 2016 emission estimates summed across the 22 compressor stations. Emissions of CO and NO_x are dominant; emissions were not estimated for NH_3.

Stack exit release parameters for compressor stations

Stack release parameters for compressor sources were assigned as SMOKE (Sparse Matrix Operator Kerner Emissions) default values contained in the file "pstk.m3.txt" (https://www.cmascenter.org/smoke/documentation/2.3/html/ch03s04s02.html). Section 7.0 of this report provides an overview of the point source emissions datasets delivered in AFS format.

Figure 23. Estimated annual 2016 emissions (tons) associated with compressor stations.



6. Electricity Generating Units

Mexico's National Electric System (SEN) has three power grids, which have not had transmission interconnections but could in the future, the National Interconnected System (Sistema Interconectado Nacional or SIN), Baja California Interconnected System (Sistema Interconectado Baja California or BCA), and Baja California Sur Electric System (BCS). Several institutions are instrumental to Mexico's electricity sector structure and operation. The Ministry of Energy (SENER) has overarching responsibility for the coordination of the electricity sector in Mexico, including issuing the yearly planning document, the National Electricity System Development Program or PRODESEN. The energy reform process unbundled and restructured Mexico's Federal Electricity Commission (CFE) into a state productive enterprise. CFE oversees the National Center for Energy Control (CENACE), the autonomous electricity system operator, which is similar to independent system operators (ISOs) and regional transmission organizations (RTOs) in the United States.

In this work, the emissions inventory for EGUs employed emissions factors (kg/GWh) and annual generation estimates (GWh) obtained from publicly accessible databases provided by the key institutions for Mexico's electricity sector. The primary data components of the inventory development process were generation, coordinates, emissions rates, and stack release parameters described in detail below.

6.1 Generation

As a result of energy reforms, SENER has been required to issue the PRODESEN report that serves as the primary planning instrument regarding generation, transmission, and distribution of electricity in Mexico. Each annual report includes existing electricity generation and capacity at the facility level for both thermal and renewable resources. The report establishes the generation capacity outlook over a 15-year period to meet forecasted energy demand as well as providing targets aggregated by technology to comply with clean energy goals. The PRODESEN report published in 2017 included total annual electricity generation for 2016. Table 16 shows gross electricity generation across individual technologies and/or fuels. Grid-wide capacities for thermal, renewable, and other resources were 52,331 MW, 18,529 MW, and 2,651 MW, respectively.

Table 16. Grid-wide capacity (MW) and 2016 generation (GWh) aggregated by electricity technology types. Adapted from PRODESEN 2017: Tables 2.1.1 and 2.2.1.

Technology	Capacity (MW)	Percent of Total Capacity	Generation (GWh)	Percent of Total Generation
THERMAL				
Combined Cycle	27274	37.1%	160378	50.2%
Conventional	12594	17.1%	40343	12.6%
Coal	5378	7.3%	34208	10.7%
Turbogas	5052	6.9%	12600	4.0%
Internal Combustion	1453	2.0%	3140	1.0%
Fluidized Bed	580	0.8%	3826	1.2%
Total Thermal	**52331**	**71.2%**	**254496**	**79.7%**
RENEWABLE				
Hydroelectric	12589	17.1%	30909	9.7%
Wind	3735	5.1%	10463	3.3%
Geothermal	909	1.2%	6148	1.9%
Solar	145	0.2%	160	0.1%
Bioenergy	889	1.2%	1471	0.5%
Miscellaneous	262	0.4%	93	0.0%
Total Renewable	**18529**	**25.2%**	**49244**	**15.4%**
OTHER				
Nuclear	1608	2.2%	10567	3.3%
Efficient Cogeneration	1036	1.4%	5053	1.6%
Regenerative brakes	7	0.0%	4	0.0%
Total Other	2651	3.6%	15624	4.9%
TOTAL	**73510**	**100.0%**	**319364**	**100.0%**

Facility-level data fields for thermal resources were extracted from the PRODESEN electricity generation datasets and included facility name, state, generation capacity (MW) and gross generation (GWh). The primary fuel consumed at each facility had to be obtained from separate 2016 and 2017 PRODESEN datasets that were likely used by Mexico in support of electricity grid modeling simulations to predict current and future year generation. Data fields of interest were the facility unit name, fuel consumed, technology type, state, and EGU-specific generation capacity. In order to merge this latter EGU-specific dataset with the gross generation facility-level data, cross-referencing was necessary. This cross-referencing (i.e., matching or mapping) was manually performed using a record-by-record visual comparison of the facility and EGU names. Typically, one or more EGUs were identified that were likely associated with a given facility. For quality assurance purposes, results were cross-checked to verify that the total generation capacity matched between the two datasets.

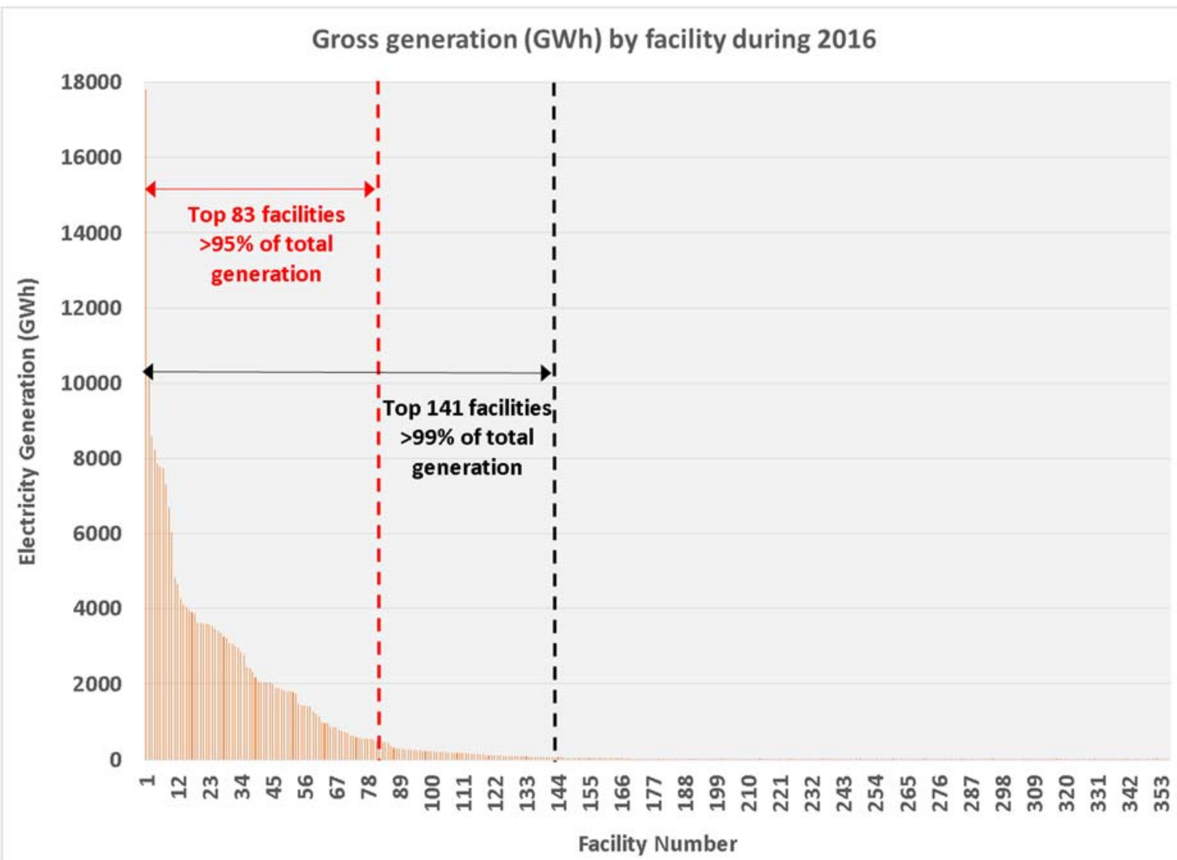
Table 17 shows the results for thermal (i.e., fossil fuel) facilities aggregated by technology and fuel. The percentage contributions to grid-wide generation from thermal resources grouped by fuel was 71.9%, 13.6%, and 12.7% for natural gas, coal, and oil, respectively. Combined cycle technology had the greatest contribution at 63.1%. For the purposes of this work, electricity generation associated with Pemex facilities (e.g., gas processing and chemical plants, refineries, oil and gas exploration and/or production) were excluded from the analysis; these Pemex sources (of which almost 60% of electricity generation originated from a single gas processing plant) accounted for only 2.8% of 2016 electricity generation.

Table 17. 2016 thermal electricity generation from non-Pemex facilities aggregated by technology and fuel. The numbers of unique facilities are also provided.

Primary Fuel	Technology	Numbers of Facilities	Generation (GWh)	Percent of Total Generation
Coal	Coal	3	34208	13.6%
Coke	Fluidized Bed	2	3826	1.5%
Diesel	Internal Combustion	92	323	0.1%
	TurboGas	21	397	0.2%
Gas	Cogeneration	20	2400	1.0%
	Combined Cycle	67	159291	63.1%
	Conventional	24	8375	3.3%
	Internal Combustion	39	793	0.3%
	TurboGas	58	10707	4.2%
Oil	Conventional	23	29952	11.9%
	Internal Combustion	6	2019	0.8%
Total	All	355	252289	100.0%

Figure 24 presents the 2016 thermal generation at the facility-level ranked in descending order of contributions. Individual contributions to total generation were strongly skewed. For example, the top 83 facilities accounted for 95% of combined electricity generation; the top 141 facilities accounted for 99% of electricity generation. The technology types among the top 83 facilities aggregated by technology and fuel were: 52 combined cycle (natural gas), 3 coal, 13 conventional and internal combustion (oil), 7 conventional (natural gas), 2 fluidized bed (coke), 5 turbogas (natural gas) and one cogeneration (natural gas).

Figure 24. 2016 thermal electricity generation (GWh) at the facility-level. Each column represents a single facility ranked in descending order of generation. Due to the vertical scaling, the contributions from a majority of the facilities are not discernable; for example, 207 facilities had generation < 50 GWh; 140 < 10 GWh.

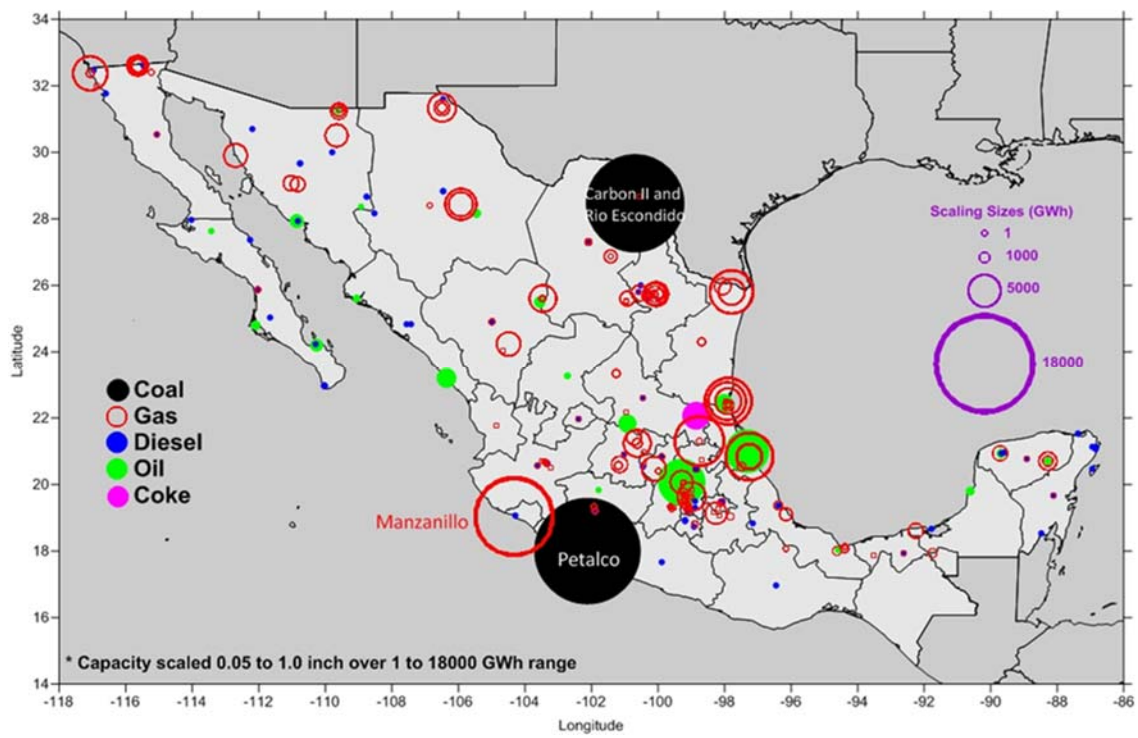


6.2 Coordinates

Latitude and longitude coordinates for EGUs were assigned based on an analysis of two distinct datasets. One dataset was the 2008 INEM; for each facility, an average latitude and longitude was determined across all unique emissions sources, which were often spatially co-located, that had a North American Industry Classification System (NAICS) identification code indicative of fuel combustion. A second dataset was provided by the North American Cooperation on Energy Information (NACEI). The NACEI online database, which originated from CFE-CENACE, had descriptive parameters including latitude and longitude coordinates for North American power plants with a capacity of at least 100 MW. The coordinate mapping results are provided in detail in Appendix 3.

Locations for all facilities, grouped by primary fuel, are shown spatially in Figure 25 along with their annual 2016 electricity generation. The Carbon II and Rio Escondido coal-fired electricity generation facilities were nearly co-located in far northeastern Coahuila (approximately 30 km from the Rio Grande). Unless otherwise noted, contributions from these two coal plants were combined for spatial mappings.

Figure 25. Locations of thermal electricity generation grouped by primary fuel type. Location symbols are sized by 2016 annual generation in GWh.



6.3 Emissions

The 2017 PRODESEN report provided generic emission factors (kg/MWh) by technology and generator capacity and/or fuel for CO_2, SO_2, NO_x, and total suspended particulate matter (TSP). Generic emissions factors for VOC, $PM_{2.5}$, PM_{10}, and NH_3 were not included. Minimal additional information on criteria pollutant emissions for the electricity sector were provided in the PRODESEN report; however, Table 4.2.3 in the report did include a footnote reference (translated into English as) “Source: Reference costs and parameters for the formulation of investment projects in the electricity sector (COPAR-CFE, 2016)". A publicly available version of the latter report was unable to be located; however, the analogous report for year 2015 entitled “COPAR 2015, GENERATION, Edition 35, CFE Federal Electricity Commission, Subdirección de Programación, Evaluation Coordination" was retrieved from a web repository maintained by the Mexican Office for Economic Affairs (http://www.cofemersimir.gob.mx/portales/resumen/45107). The primary objective of the *Costos y Parametros de Referencia* or COPAR was to establish the relative differences in projected costs of electricity generation by fuel and technology. Our interpretation was that CFE likely generates an emissions inventory for EGUs on an annual basis. However, other than the INEM, no other publicly available information was obtained regarding the development of a facility-specific annual emissions inventory for Mexico.

COPAR (2015; the COPAR report has been provided as an attachment to this report) provided facility-specific emissions factors for CO_2, CH_4, N_2O, CO, NO_x, NMVOC, SO_2, and TSP in units of kg/MWh, as well as annual electricity generation in GWh (ref. COPAR Table 7.4). The generation and emission rates varied among the facilities suggesting plant-specific data and/or assumptions rather than the application of generic conditions related to assumed technology and/or plant characteristics. The COPAR emission factors and annual net generation were inferred by our team to be representative of operational conditions during 2014.

Based on an analysis and integration of the available information contained in COPAR (2015) and PRODESEN (2017), a methodology was developed to estimate EGU emissions that primarily leveraged the facility-specific COPAR emission factors. Emission factors were first mapped to individual PRODESEN facilities. These factors were then multiplied by the 2016 annual electricity generation to estimate annual emissions at the facility level. Additional methodologies were needed to (1) account for facilities not explicitly contained in COPAR (2015), (2) estimate $PM_{2.5}$ and PM_{10} from TSP, and (3) estimate emissions of NH_3 as this latter pollutant was not addressed by either COPAR (2015) or PRODESEN (2017). The emission estimation methodology is described in Appendix 4.

Table 18 shows estimated annual 2016 emissions (tons), and as a percentage of total emissions in Table 19. The aggregated emissions from thermal EGUs in Mexico ranged from a minimum of 3,237 tons for VOC to a maximum of 859,258 tons for SO_2. Relative contributions among technology and fuel types could vary substantially among pollutants. For example, the top three contributors to total NO_x emissions were from combined cycle (44%), coal (36%) and conventional oil (7%) compared to top three contributions for SO_2 from conventional oil (60%), coal (27%) and internal oil combustion (5%). The relative contributions from a given fuel type to electricity generation versus emissions could also vary substantially. For example, oil combustion accounted for 13% of electricity generation but dominated as a source of SO_2 (64%), $PM_{2.5}$ (70%), and PM_{10} (73%). Geographic maps that illustrate the spatial distribution of emissions across the individual electricity generation facilities are shown in Figures 26 through 31.

Table 18. Annual estimated emissions (tons) of NO_x, CO, SO_2, VOC, $PM_{2.5}$, PM_{10}, and NH_3 from electricity generation during 2016 aggregated by technology and fuel.

Technology	Fuel	NO_x (tons)	CO (tons)	SO_2 (tons)	VOC (tons)	$PM_{2.5}$ (tons)	PM_{10} (tons)	NH_3 (tons)
By Technology and Fuel								
Coal	Coal	188435	3948	235116	318	922	3534	1
Fluidized Bed	Coke	3205	102	10963	12	168	171	0
Combined Cycle	Gas	229415	57471	16722	1584	4761	4761	3036
Cogeneration		2332	643	3007	69	279	279	34
Conventional		10099	2719	9533	221	932	932	144
Internal Combustion		1495	381	4	10	31	31	20
TurboGas		20344	5188	60	132	417	417	274
Internal Combustion	Diesel	2688	10	15423	1	37	37	4
TurboGas		3605	100	18482	34	44	44	43
Internal Combustion	Oil	26902	7130	32444	95	563	563	1139
Conventional		38647	5266	517504	763	17264	26560	798
By Fuel Only								
Coal		188435	3948	235116	318	922	3534	1
Coke		3205	102	10963	12	168	171	0
Gas		263686	66402	29326	2014	6419	6419	3508
Diesel		6293	109	33906	35	80	80	47
Oil		65549	12397	549947	858	17827	27123	1980
Total (all fuels)		527167	82959	859258	3237	25417	37328	5493

Table 19. Results shown in the previous Table 18 but as a percentage of total emissions.

Technology	Fuel	NO_x (tons)	CO (tons)	SO_2 (tons)	VOC (tons)	$PM_{2.5}$ (tons)	PM_{10} (tons)	NH_3 (tons)
By Technology and Fuel								
Coal	Coal	35.7%	4.8%	27.4%	9.8%	3.6%	9.5%	0.0%
Fluidized Bed	Coke	0.6%	0.1%	1.3%	0.4%	0.7%	0.5%	0.0%
Combined Cycle	Gas	43.5%	69.3%	1.9%	48.9%	18.7%	12.8%	54.9%
Cogeneration		0.4%	0.8%	0.3%	2.1%	1.1%	0.7%	0.6%
Conventional		1.9%	3.3%	1.1%	6.8%	3.7%	2.5%	2.6%
Internal Combustion		0.3%	0.5%	0.0%	0.3%	0.1%	0.1%	0.4%
TurboGas		3.9%	6.3%	0.0%	4.1%	1.6%	1.1%	5.0%
Internal Combustion	Diesel	0.5%	0.0%	1.8%	0.0%	0.1%	0.1%	0.1%

Technology	Fuel	NO_x (tons)	CO (tons)	SO_2 (tons)	VOC (tons)	$PM_{2.5}$ (tons)	PM_{10} (tons)	NH_3 (tons)
TurboGas		0.7%	0.1%	2.2%	1.0%	0.2%	0.1%	0.8%
Internal Combustion	Oil	5.1%	8.6%	3.8%	2.9%	2.2%	1.5%	20.6%
Conventional		7.3%	6.3%	60.2%	23.6%	67.9%	71.2%	15.2%
By Fuel Only								
Technology	**Electricity Generation**	**NOx (tons)**	**CO (tons)**	**SO2 (tons)**	**VOC (tons)**	**PM2.5 (tons)**	**PM10 (tons)**	**NH3 (tons)**
Coal	13.56%	35.7%	4.8%	27.4%	9.8%	3.6%	9.5%	0.0%
Coke	1.52%	0.6%	0.1%	1.3%	0.4%	0.7%	0.5%	0.0%
Gas	71.97%	50.0%	80.0%	3.4%	62.2%	25.3%	17.2%	63.4%
Diesel	0.29%	1.2%	0.1%	3.9%	1.1%	0.3%	0.2%	0.8%
Oil	12.67%	12.4%	14.9%	64.0%	26.5%	70.1%	72.7%	35.8%
Total (all fuels)	100.00%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

Figure 26. NO_x emissions (tons) from thermal electricity generation during 2016; location symbols are sized by emissions.

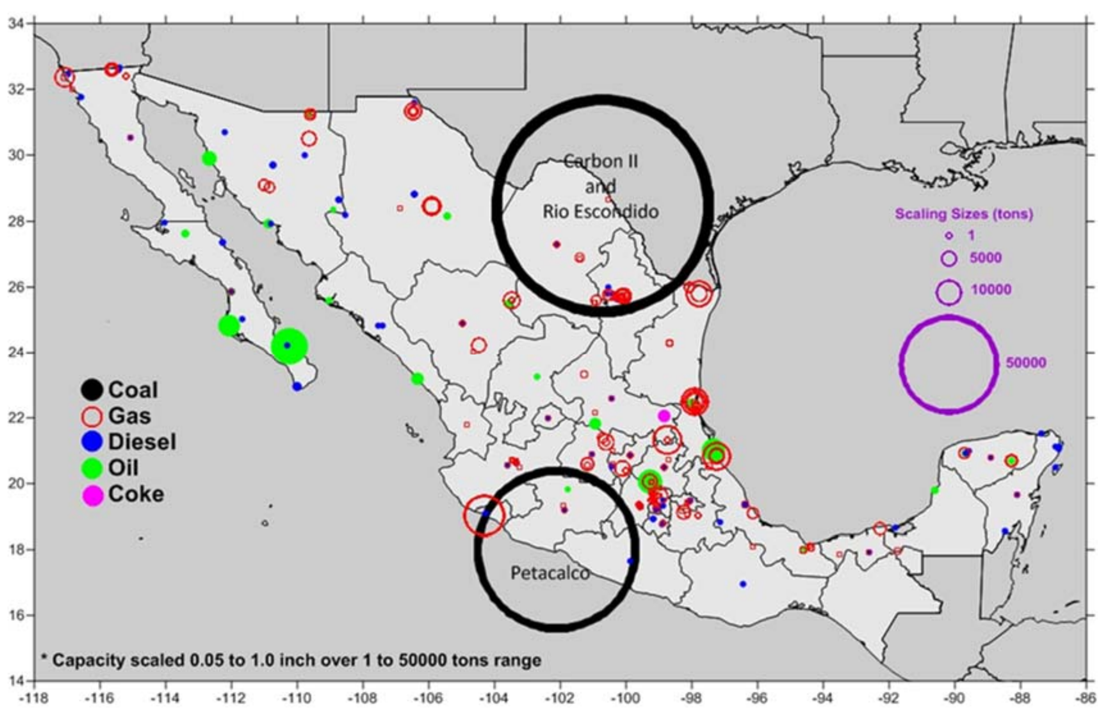


Figure 27. CO emissions (tons) from thermal electricity generation during 2016; location symbols are sized by emissions.

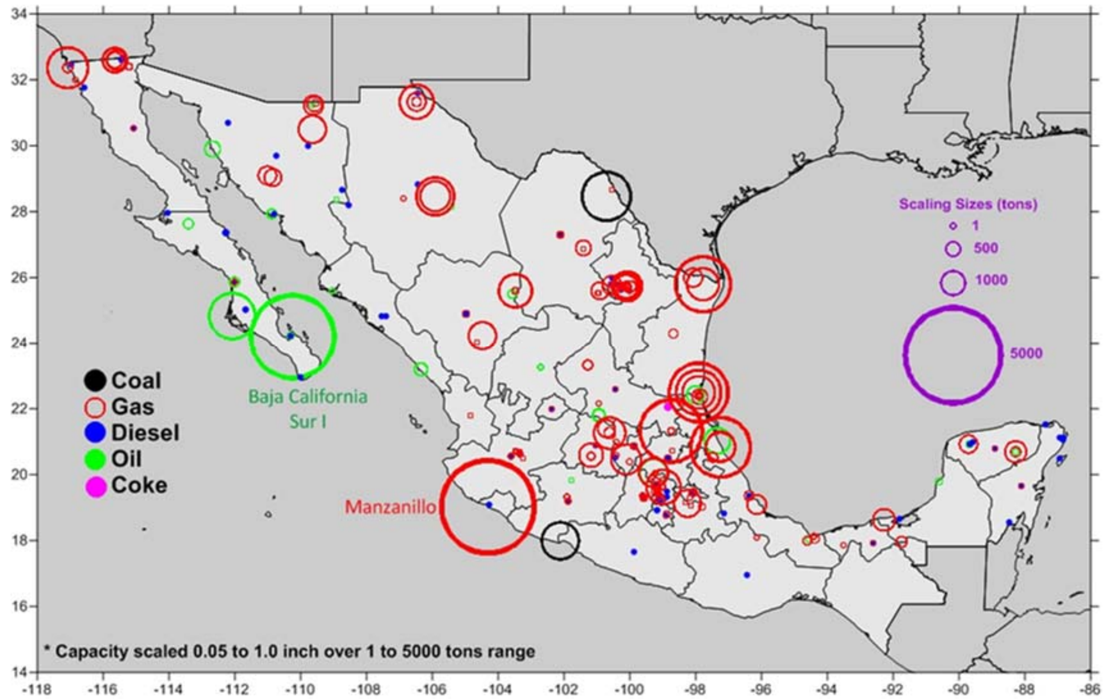


Figure 28. SO_2 emissions (tons) from thermal electricity generation during 2016; location symbols are sized by emissions.

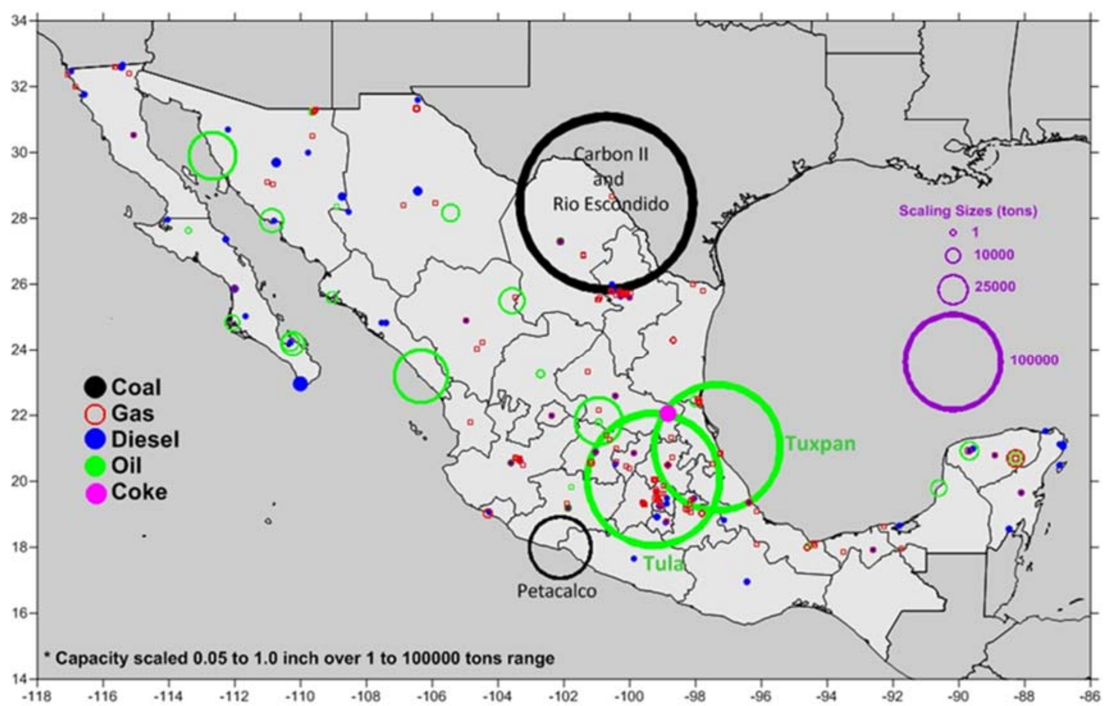


Figure 29. VOC emissions (tons) from thermal electricity generation during 2016; location symbols are sized by emissions

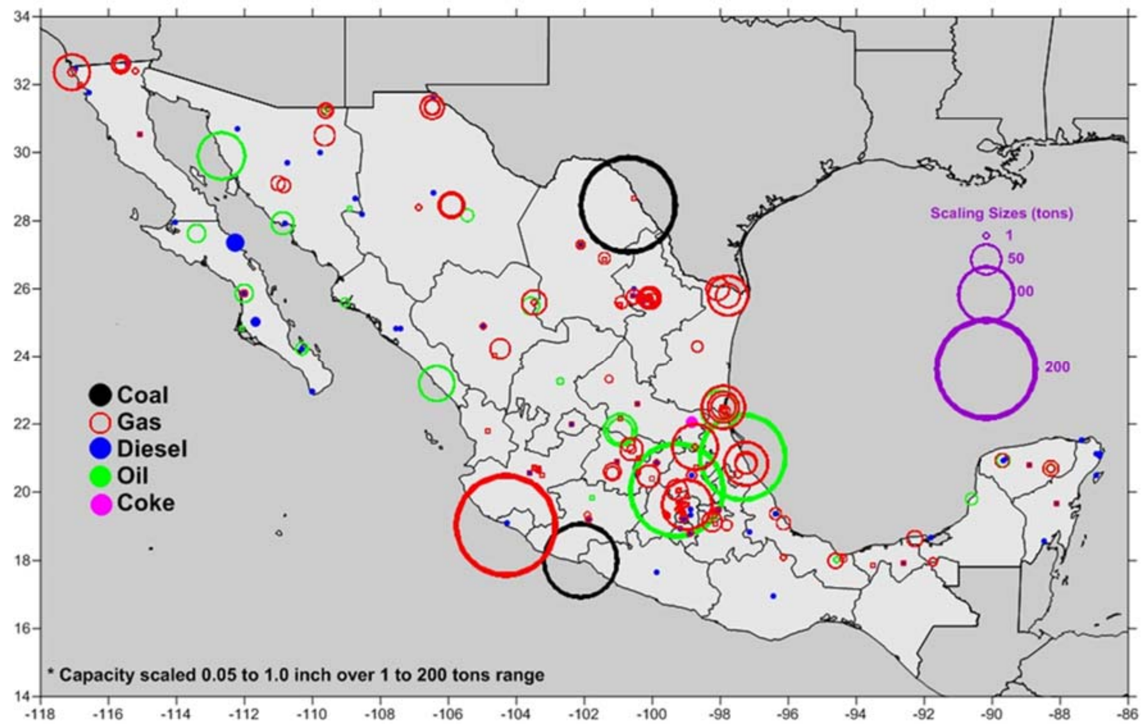


Figure 30. $PM_{2.5}$ emissions (tons) from thermal electricity generation during 2016; location symbols are by emissions.

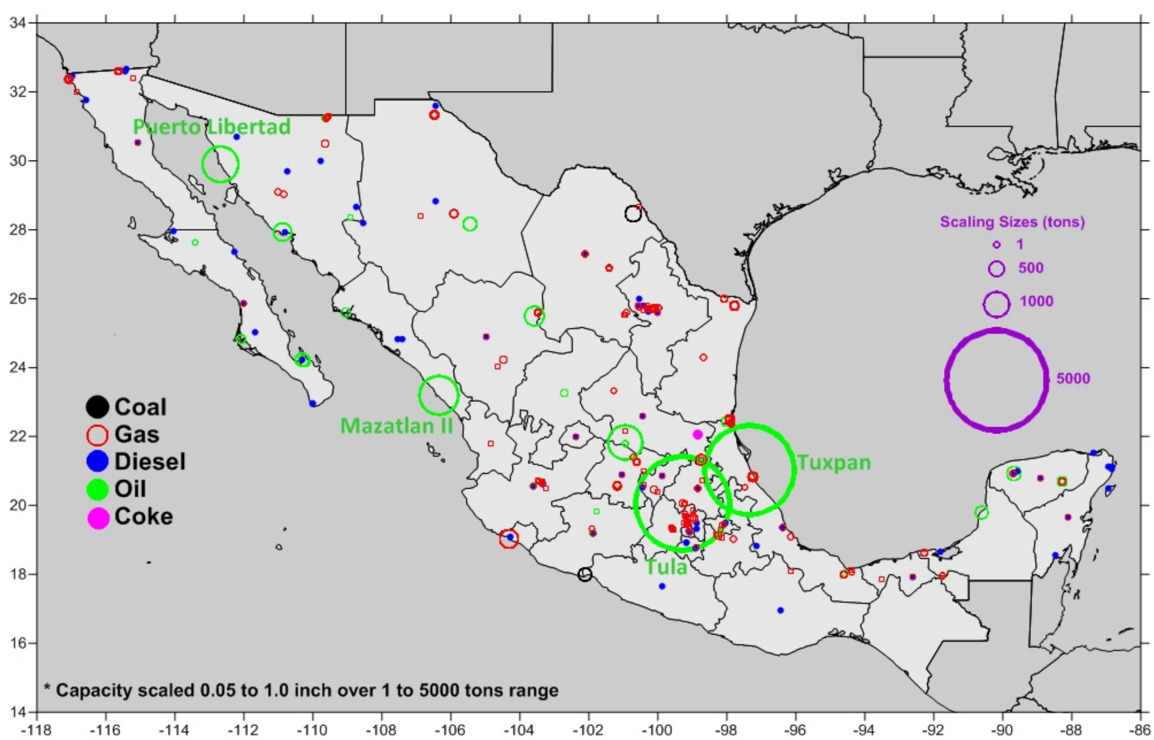
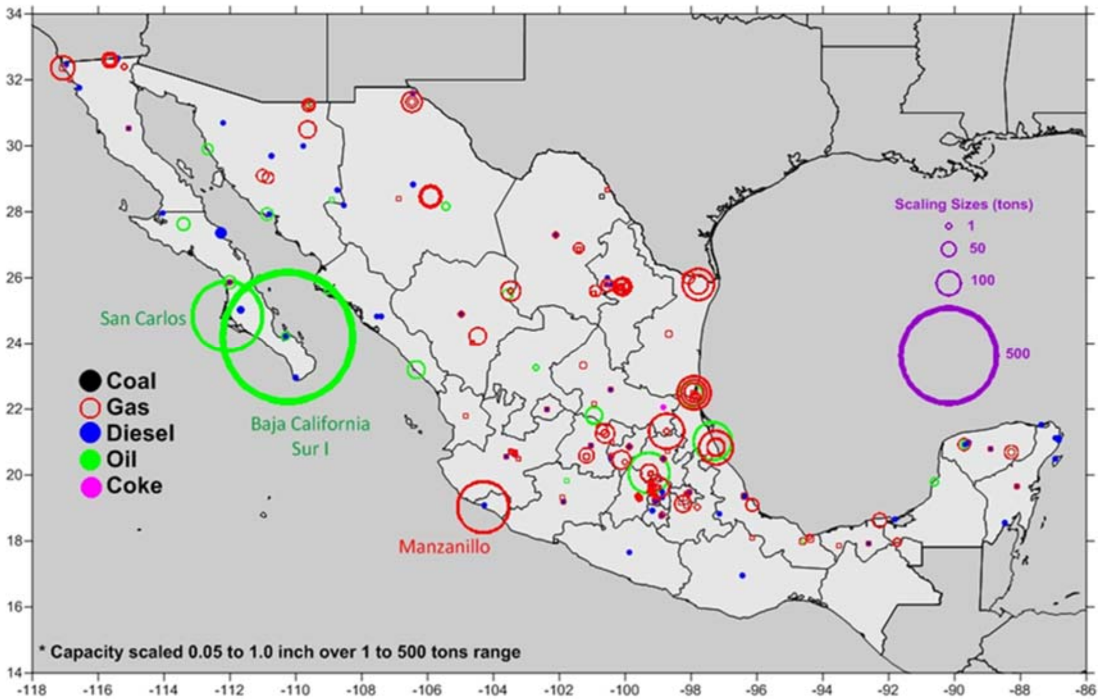


Figure 31. NH_3 emissions (tons) from thermal electricity generation during 2016; location symbols are sized by emissions.



6.4 Comparisons between the 2008 INEM and 2016 Inventory

In order to compare emissions estimates between the 2008 INEM and the 2016 inventory, INEM CO emissions were summed by facility across all fuel combustion SCCs. The primary fuel type at each facility was then assumed to be consistent with the SCC designation that had the largest CO emissions. Facility names were visually matched between INEM and PRODESEN with an absolute consistency requirement for fuel type. This methodology mapped 131 INEM facilities to 156 PRODESEN EGUs. Emissions across these facilities were summed for each dataset by pollutant and fuel type; the results are shown in Table 20. Figure 32 graphically compares total emissions by pollutant between the 2008 INEM and 2016 datasets.

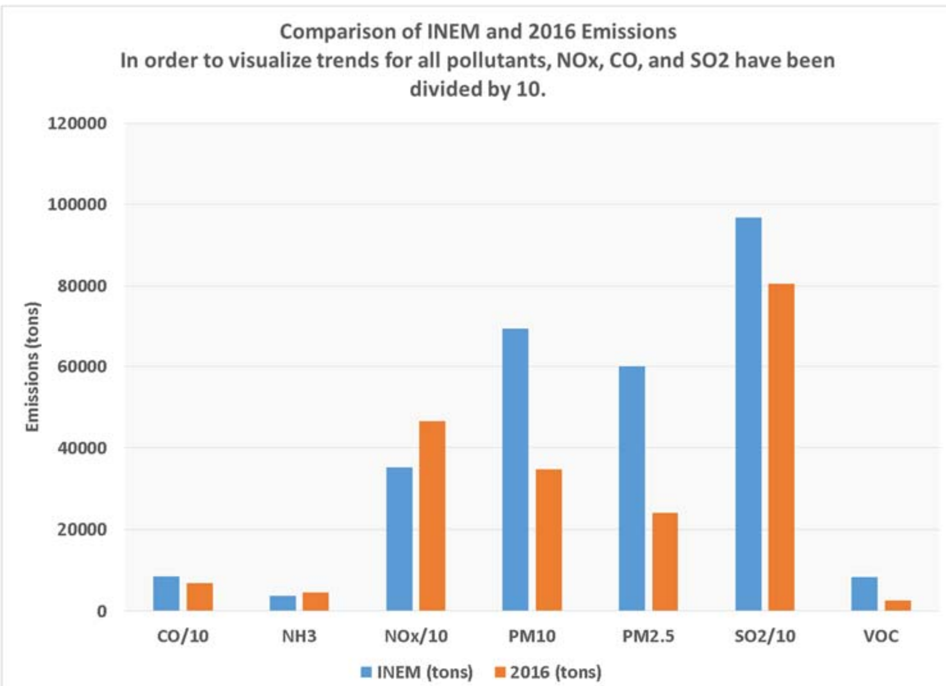
Total emissions associated with electricity generation were relatively lower in 2016 compared to the INEM with the exception of NO_x and NH_3. Combined across facilities and fuels, the percent differences were +32%, -20%, -17%, -69%, -60%, -50%, and +21%, for NO_x, CO, SO_2, VOC, $PM_{2.5}$, PM_{10}, and NH_3, respectively. Among pollutants for a given fuel type and/or within a given fuel type and pollutant, large variability was often evident between the datasets. For example, the percentage change between 2008 INEM and 2016 at gas facilities varied from -80% for VOC to +86% for NO_x.

Table 20. Comparison of 2008 INEM and 2016 emissions aggregated by pollutant and fuel.

Fuel	Pollutant	INEM (tons)	2016 (tons)	Difference (tons)	Percent Change 2016 to INEM
All fuels	**CO**	**85708**	**68177**	**-17532**	**-20%**
Coal		19465	3948	-15517	-80%
Coke		203	102	-101	-50%
Diesel		192	106	-86	-45%
Gas		60782	52089	-8693	-14%
Oil		5066	11932	6866	136%
All fuels	**NH_3**	**3841**	**4644**	**803**	**21%**
Coal		102	1	-101	-99%
Coke		1	0	0	-75%
Diesel		65	45	-20	-31%
Gas		2853	2752	-101	-4%
Oil		820	1846	1026	125%
All fuels	**NO_x**	**352967**	**465205**	**112238**	**32%**
Coal		175131	188404	13273	8%
Coke		5977	3205	-2772	-46%
Diesel		2023	5231	3208	159%
Gas		110700	205471	94772	86%
Oil		59137	62894	3757	6%
All fuels	**PM_{10}**	**69445**	**34709**	**-34736**	**-50%**
Coal		21261	3534	-17728	-83%
Coke		347	171	-176	-51%
Diesel		803	66	-737	-92%
Gas		19994	4480	-15514	-78%
Oil		27040	26458	-582	-2%
All fuels	**$PM_{2.5}$**	**60088**	**24049**	**-36040**	**-60%**
Coal		20504	922	-19582	-96%
Coke		340	168	-172	-51%
Diesel		588	66	-523	-89%
Gas		19638	4480	-15158	-77%
Oil		19018	18413	-605	-3%
All fuels	**SO_2**	**968214**	**805549**	**-162665**	**-17%**
Coal		297955	235078	-62878	-21%
Coke		23034	10963	-12071	-52%
Diesel		16124	27814	11690	72%
Gas		31116	6911	-24204	-78%
Oil		599985	524783	-75202	-13%

Fuel	Pollutant	INEM (tons)	2016 (tons)	Difference (tons)	Percent Change 2016 to INEM
All fuels	**VOC**	**8418**	**2645**	**-5773**	**-69%**
Coal		396	318	-78	-20%
Coke		19	12	-8	-40%
Diesel		34	34	1	2%
Gas		7373	1481	-5893	-80%
Oil		596	800	205	34%

Figure 32. Comparison of the 2008 and 2016 inventories by pollutant for all fuels combined. NO_x, CO, and SO_2 emission have been divided by 10.



In order to further compare the results between the 2008 and 2016 inventories, a limited number of facilities were directly compared. These facilities had relatively large contributions (within their fuel type category) to total electricity generation. Additionally, they had explicit (facility-specific) mappings to the COPAR (2015) emission rates.

Table 21 presents results for the three coal plants that have been operational since 1982 (Rio Escondido) and 1993 (Carbon II and Petacalco). With the exception of NO_x, coal-combustion emissions were substantially lower in 2016 compared to the INEM. There is large variability in trends, with much greater emissions at individual facilities, such as NO_x at Petacalco and SO_2 at Rio Escondido, offsetting considerably lower emissions in the INEM estimates for most other pollutants and locations.

In the absence of significant operational changes at a given facility, a generally consistent emissions profile would seem reasonable; however, the relative changes in facility-specific pollutant emissions between the INEM and 2016 were generally not consistent. For example, the percentage changes (2016 relative to INEM) at Carbon II for NO_x and SO_2 were -36% and -49.6%, respectively. Analogous changes at Petacalco were 569% for NO_x and -48.2% for SO_2; at Rio Escondido, -31.0% for NO_x and 341.1% for SO_2.

Although conjecture, the facility-specific differences in relative emissions changes among pollutants might be caused, in part, by changes in operational conditions (e.g., chemical characteristics of the fuel burned, modifications to emissions controls and/or technology efficiency performance). Alternatively, differences in the underlying data and methodology used in support of the 2008 INEM could be inconsistent with the publicly available information from the COPAR (2015) and PRODESEN (2017) databases.

Table 21. Comparison of 2008 INEM and 2016 emissions for coal facilities.

Facility Name	Pollutant	INEM (tons)	2016 (tons)	Difference (tons)	Percent change 2016 to INEM
Carbon II	CO	1175	1057	-118	-10%
	NH_3	4	0	-4	-96%
	NO_X	78909	50318	-28591	-36%
	PM_{10}	1841	943	-899	-49%
	$PM_{2.5}$	1818	246	-1572	-87%
	SO_2	162329	81793	-80536	-50%
	VOC	144	86	-58	-41%
Petacalco	CO	2454	1669	-784	-32%
	NH_3	96	0	-96	-100%
	NO_X	11942	79893	67952	569%
	PM_{10}	8990	1500	-7490	-83%
	$PM_{2.5}$	8465	391	-8074	-95%
	SO_2	114298	59154	-55144	-48%
	VOC	144	137	-6	-5%
Rio Escondido	CO	15837	1222	-14615	-92%
	NH_3	2	0	-2	-92%
	NO_X	84280	58193	-26087	-31%
	PM_{10}	10430	1091	-9339	-90%
	$PM_{2.5}$	10221	285	-9937	-97%
	SO_2	21328	94131	72803	341%
	VOC	108	95	-13	-12%

A similar comparison is shown in Table 22 for the Chihuahua II (combined cycle natural gas) and Tuxpan (conventional oil) facilities that have been in operation since 2001 and 1991, respectively. Similar to the results for the coal facilities, there is large variability between 2008 INEM and 2016 emissions estimates by pollutant and fuel. For example, relative increases (compared to the INEM) in CO and NO_x emissions at Chihuahua II were 28.3% and 150%, respectively. At Tuxpan, the range of absolute differences in pollutant emissions was relatively lower than those for Chihuahua II. Nonetheless, for example, 2016 CO emissions were slightly higher by 6% while NO_x was 20% lower compared to INEM.

Table 22. Comparison of 2008 INEM and 2016 emissions at the Chihuahua II and Tuxpan facilities.

Facility Name	Pollutant	INEM (tons)	2016 (tons)	Difference (tons)	Percent change 2016 to INEM
Chihuahua II (combined cycle gas)	CO	1340	1720	379	28%
	NH_3	72	91	19	26%
	NO_X	2696	6740	4044	150%
	PM_{10}	513	139	-374	-73%
	$PM_{2.5}$	509	139	-370	-73%
	SO_2	7	21	14	206%
	VOC	210	43	-167	-80%
Tuxpan (conventional oil)	CO	1023	1085	62	6%
	NH_3	155	173	18	12%
	NO_X	10684	8597	-2087	-20%
	PM_{10}	5973	6453	479	8%
	$PM_{2.5}$	3901	4194	293	8%
	SO_2	106425	126557	20131	19%
	VOC	54	162	109	202%

Overall, the comparison of results at these five individual facilities supports the hypothesis that the data assumptions and/or methodology used in support of the development of the 2008 INEM are not consistent with those obtained from more recent data resources provided by Mexican government agencies. However, given the lack of sufficient documentation among the INEM, COPAR, and PRODESEN datasets, our team was unable to assign a definitive explanation for the documented discrepancies.

6.5 Stack Release Parameters

Emissions release parameters were not provided as part of the PRODESEN dataset; therefore, the INEM was leveraged to assign stack exit release parameters for the 2016 inventory. As noted previously, 131 individual INEM facilities were specifically matched to 156 PRODESEN EGUs (one INEM facility could be associated with multiple PRODESEN EGUs). For these facilities, the INEM release parameters corresponding to the SCC record(s) with the greatest CO emissions were used directly to represent facility-wide emissions release characteristics. These 156 PRODESEN facilities comprised 85% of the total electricity generation during 2016.

For the remaining 199 PRODESEN facilities, representative generic values were developed based on the 131 INEM CO records. Visual investigation was performed to identify any obvious trends and/or patterns of variability aggregated by primary fuel type, capacity, and/or generation. Although the stack release parameters were highly variable, aggregation by fuel type captured the central tendencies in variations among the INEM facilities. An exception was the consideration of technology for natural gas combustion that grouped combined cycle facilities (commonly with capacities >100MW) separately from the other natural gas technologies.

Table 23 presents the median values of stack height, stack diameter, stack temperature, and stack exit velocity calculated across the 131 facility records grouped by combustion category. These generic stack release parameters were used to represent the emission characteristics at all remaining (unmapped) PRODESEN facilities. These 199 facilities accounted for 15% of electricity generation during 2016. As shown in Table 24, SCC categories were also assigned to be consistent with primary fuel type.

Table 23. Generic stack exit release parameters grouped by combustion category.

Fuel (Technology)	Height (m)	Diameter (m)	Temperature (K)	Velocity (m/s)
Diesel (All)	7.65	1.15	603.75	8.94
Gas (Combined Cycle)	36.6	5.44	380.87	19.01
Gas (All except Combined Cycle)	17.1	1.99	470.48	13.84
Oil (All)	53.3	3.30	431.82	20.14

Table 24. Default SCC categories assigned to the facilities (grouped by fuel) that used generic release parameters shown in Table 23.

Fuel	SCC	Level One Description	Level Two Description	Level Three Description	Level Four Description
Diesel	20100101	Internal Combustion Engines	Electric Generation	Distillate Oil (Diesel)	Turbine
Gas	20100201	Internal Combustion Engines	Electric Generation	Natural Gas	Turbine
Oil	10100401	External Combustion Boilers	Electric Generation	Residual Oil - Grade 6	Boiler, Normal Firing

7.0 AFS (AIRS Facility System) datasets

The midstream and upstream emissions results for 2016 are provided as an attachment to this report and to the AQRP permanent database archive in AFS (AIRS Facility Subsystem) data file format (ftp://amdaftp.tceq.texas.gov/DFW8H2/ei/2006basecase/point/AFS-EPS3-v3.pdf).

Individual AFS files were generated for each of the five source types (i.e., upstream oil and gas activities, upstream flaring, compressor stations, gas processing plants, EGUs). Table 25 provides a listing of the populated AFS field variables in additional to relevant comments.

Table 25. AFS fields for midstream and upstream 2016 point source datasets.

Variable	Columns	Type	Description	Comments
INFIPS	12-16	A	FIPS state&county code	First two digits are the state code; final three digits are municipio; offshore sources are assigned “99000”
INSCC	29-38	A	Source Classification Code	
INPLNT	40-49	A	Plant identification number	Alphanumeric values assigned to ensure record uniqueness; e.g., “FLARE01, FLARE02...”
INSTCK	51-60	A	Stack number	Alphanumeric values assigned to ensure record uniqueness; e.g., “FLARE01, FLARE02...”
IPEROD	77-78	A	Period of Emission	Blank = annual
IBEGDT	80-87	I	Beginning time (YYMMDDHH)	e.g., 16010100
IENDDT	89-96	I	End time (YYMMDDHH)	e.g., 16123124
XLOC	98-107	R	Latitude	Units: decimal degrees
YLOC	109-118	R	Longitude	Units: decimal degrees
STKHT	123-127	R	Stack height	Units: meters
STDIAM	129-133	R	Stack exit diameter	Units: meters
STEXTP	135-139	R	Stack gas exit temperature	Units: Kelvin
STEXVL	141-145	R	Stack gas exit velocity	Units: meters per second (m/s)
INPOL	176-180	I	Pollutant code	
CRTPOL	182-191	R	Emission of specified pollutant	Units: tons
SITE_NAME	334-358	A	Name of site	This name is provided for unique tracking to the original data source(s)

Variable	Columns	Type	Description	Comments
POLLUTANT	387-390	A	Pollutant species name	
UPDATE	434-438	A	Extract version	e.g., initially “VER1”

Six individual AFS data files (annual emissions) were created using the following nomenclature:

1. AQRP2019_MXEI_ONSHORE_WELLS_2016_AFS_VER1.txt
2. AQRP2019_MXEI_OFFSHORE_WELLS_2016_AFS_VER1.txt
3. AQRP2019_MXEI_WELL_FLARING_2016_AFS_VER1.txt
4. AQRP2019_MXEI_GAS_PROCESSING_PLANTS_2016_AFS_VER1.txt
5. AQRP2019_MXEI_COMPRESSOR_STATIONS_2016_AFS_VER1.txt
6. AQRP2019_MXEI_EGUS_2016_AFS_VER1.txt

Additionally, a single additional AFS data file (“AQRP2019_MXEI_FUTURE _PROJECTIONS_AFS_VER1.txt”) was generated to represent projected future year emissions using the methodology and assumptions as outlined in Section 9.2 of this report. Stack release parameters were based on those contained in files (1-6) above.

8.0 Chemical speciation profiles

Chemical speciation profile recommendations are provided for all unique SCCs contained in the AFS 2016 emission inventories (ref. Section 7.0). The basis for these recommendations were TCEQ’s current speciation cross reference dataset (one speciation profile code per SCC) entitled “gsref_TEMPLATE.27Jun2018” and EPA’s default speciation profiles dataset “gsref_cmaq_cb6_2014fa_nata_cb6” used by EPA in support of the 2011 National Emission Inventory Version 6.2 Platform (https://www.epa.gov/air-emissions-modeling/2011-version-62-platform). Generally, Ramboll Environ recommended TCEQ’s current cross reference results and gap-filled with EPA default profiles. The results of the profile analysis are provided as a separate dataset to this report in a Microsoft Excel file entitled “AQRP2019_MXEI_speciation_profiles.xlsx”. Specifically, the Microsoft Excel worksheet “oilgas_nonpoint_xref” includes all original unique SCC code and parameter information from the AFS 2016 datasets along with the profile results (codes and names) and any comments on the recommendations, as appropriate.

9.0 Hydrocarbon Bids Rounds and Future Emissions Assessment

9.1 Background

Mexico initiated bid rounds, *Rondas Mexico*, in 2015 as part of a plan to attract new investment for exploration and extraction of its onshore and offshore hydrocarbon resources. The CNH maintains information regarding the status of the bid rounds and awarded contracts via the portal: https://rondasmexico.gob.mx, which served as the primary resource for this project. Bid rounds completed to date were conducted over the following timeline:

Round One
1.1 Shallow water (July 15, 2015)
1.2 Shallow water (September 30, 2015)
1.3 Onshore conventional (December 15, 2015)
1.4 Deepwater (December 5, 2016)

Round Two
2.1 Shallow water (June 19, 2017)
2.2 Onshore conventional (July 12, 2017)
2.3 Onshore conventional (July 12, 2017)
2.4 Deepwater (January 31, 2018)

Round Three
3.1 Shallow water (March 28, 2018)

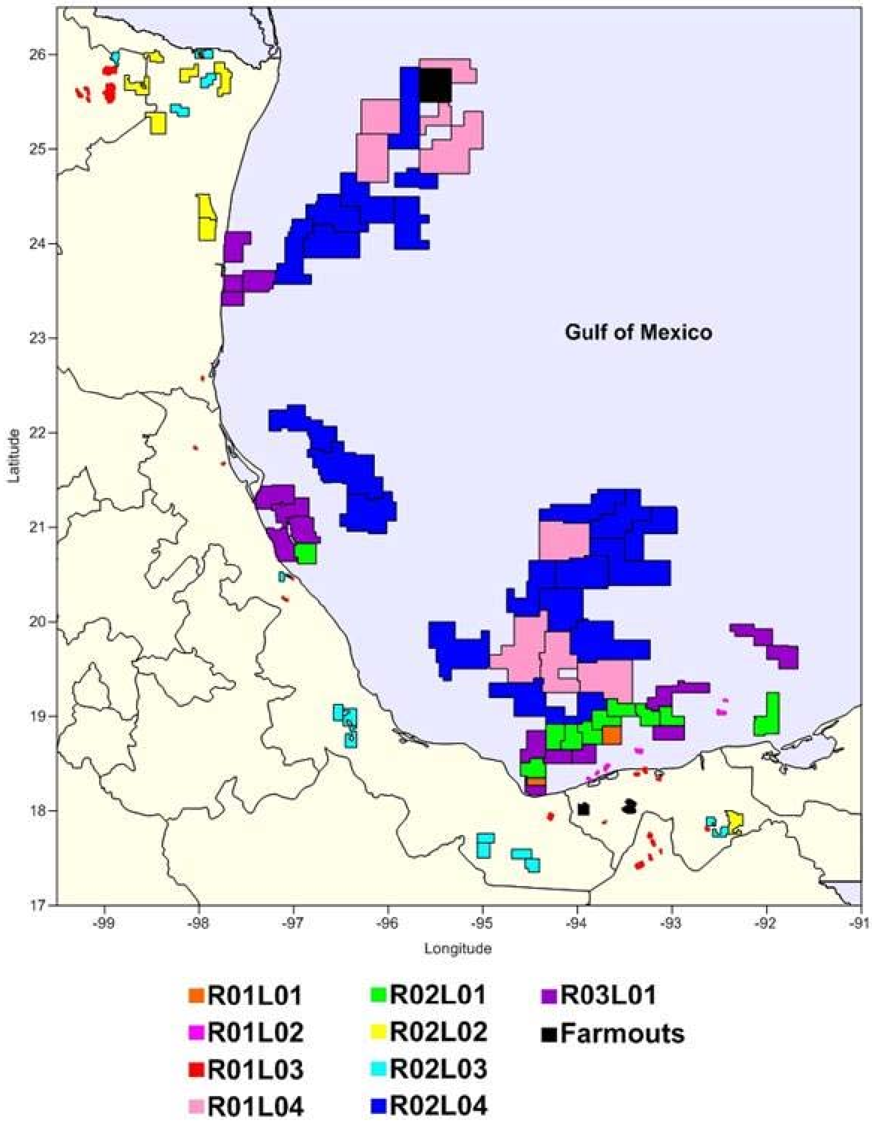
Pemex retained most of its onshore and shallow water resources as part of the initial allocation (Round Zero). Historically it lacked the investment and experience required for shale and deepwater resources, which have been largely undeveloped in Mexico. Stages within bid rounds are characterized by location (shallow water, deepwater, onshore conventional, onshore unconventional), type of activity (exploration and/or extraction) as well as the contract type (license or production sharing).

Andrés Manuel López Obrador took office on December 1, 2018 and announced the suspension of new bid rounds contingent on the review and performance of previously awarded contracts and expressed his opposition to hydraulic fracturing (Chapa, 2019; Webber, 2018). Two additional stages in Round 3 were suspended: 3.2 which was to have offered onshore conventional blocks, and 3.3, which would have offered onshore conventional blocks and, for the first time, onshore unconventional blocks. However, contracts awarded in the bid rounds above are continuing under the administration.

As of June 2019, CNH had 111 current exploration and extraction contracts: 104 from the bid rounds (with one early termination), 3 farmouts, and 5 Pemex contract migrations (https://rondasmexico.gob.mx/media/5068/cifras_relevantes_june_2019_web.pdf). Awarded blocks and farmouts are shown in Figure 33, which was created from shapefiles of tendered blocks available via the Rondas Mexico portal. Blocks that were declared void were manually tracked through each bidding process and filtered from the map such that it includes only awarded blocks.

CNH reported production from 29 contracts in April 2019, primarily from onshore awards in Rounds 1.3, 2.2, and 2.3 as well as from onshore field farmouts and Pemex contract migrations. (https://rondasmexico.gob.mx/media/5068/cifras_relevantes_june_2019_web.pdf). The Zama oilfield shallow water discovery (Round 1.1, Block 7) announced by Talos Energy (U.S.), Premier Oil (U.K.), and Sierra Oil and Gas (Mexico) in July 2017 was a notable discovery to date, as it was the first offshore exploration well drilled by the private sector in Mexico.

Figure 33. Awarded blocks color-coded by bid round. "R" indicates the round (ronda) and "L" the bidding (licitación) phase. Source: https://rondasmexico.gob.mx/eng/rounds/ with blocks declared as void manually filtered from the available shapefiles.



9.2 Future Emissions

Figure 34 shows the locations of awarded contractual areas relative to active onshore well locations in 2016. Figure 35 shows ancillary information for shallow water blocks and active shallow water locations in 2016, as well as awarded deepwater blocks. These maps provide an important perspective on where development is likely to occur in the future; however, development of the contractual areas awarded through the bid rounds is in the very early stages. Although information on 1P/2P/3P reserves or probabilistic reserve volumes is available, the reserves data do not convey either prospective production volumes or the timeline over which production will occur.

Figure 34. Locations of active 2016 oil and gas wells (red; ref. Figure 3) and awarded blocks (yellow).

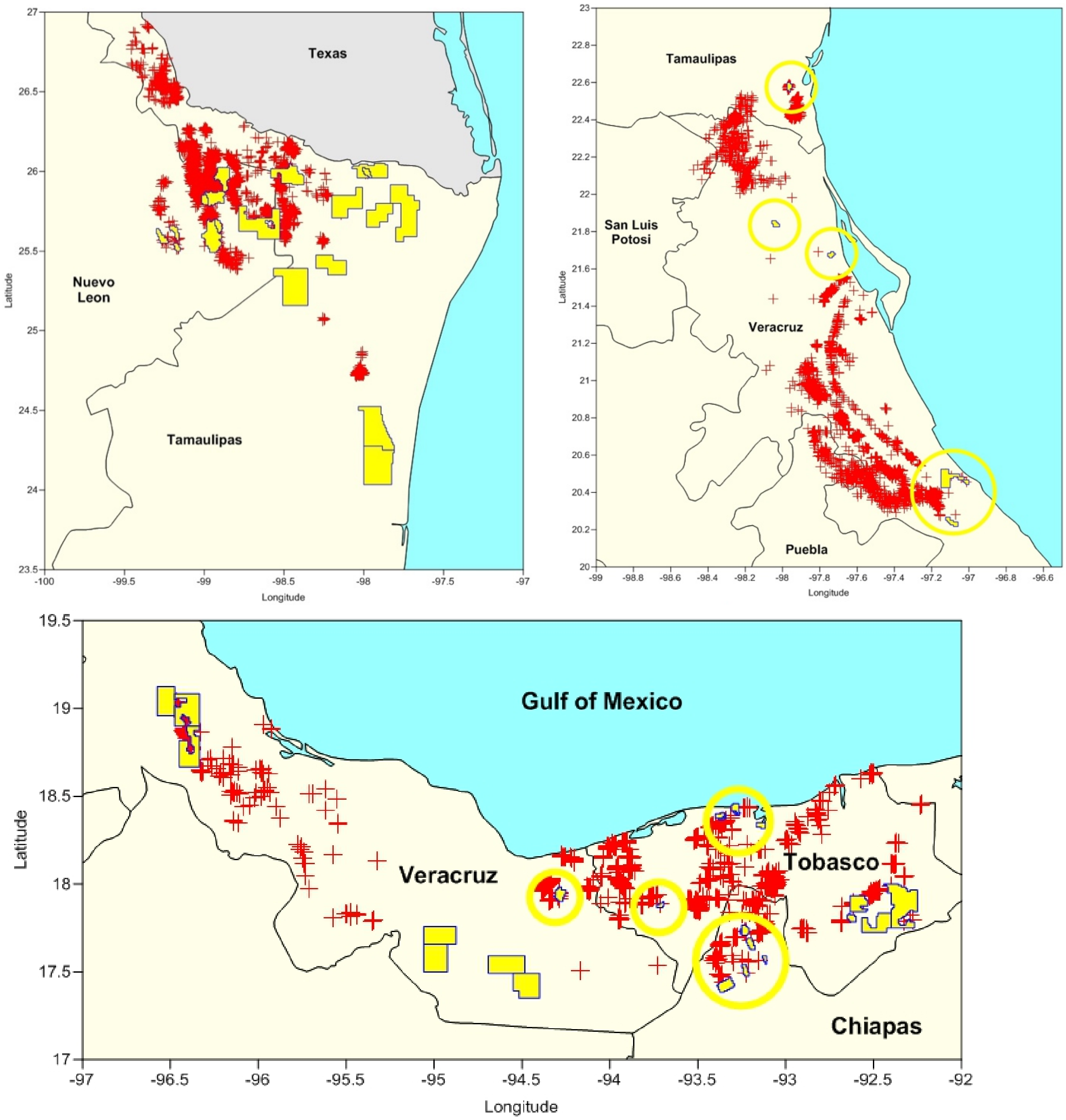
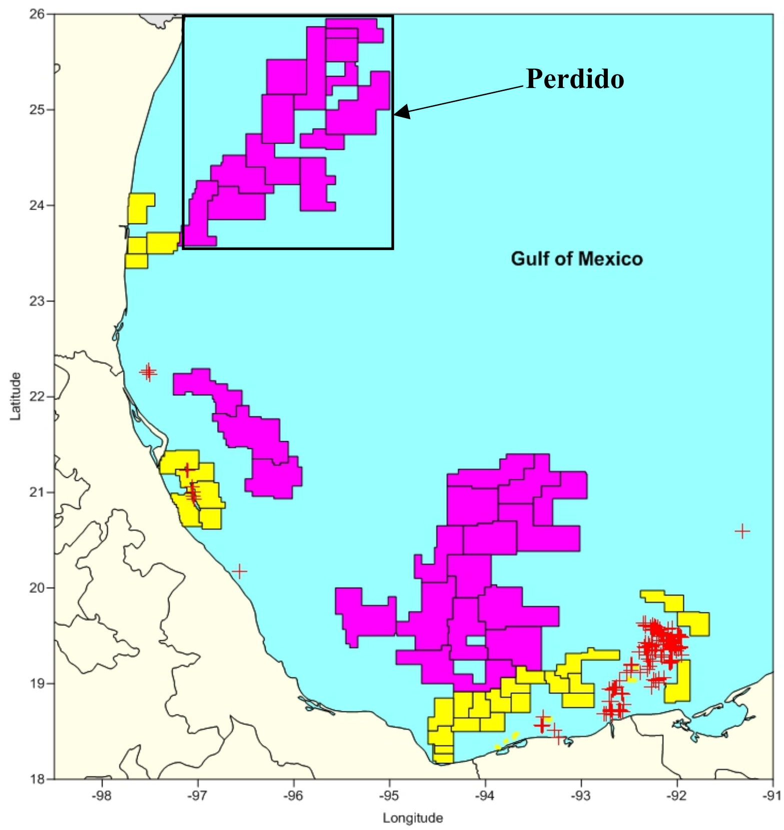


Figure 35. Active shallow water wells in 2016 (red; ref. Figure 3), awarded shallow water contractual areas (yellow), and awarded deepwater contractual areas (purple).



For the purposes of this project, a speculative assessment of emissions that could accompany ongoing development of the awarded contractual areas was conducted. The deepwater Perdido Fold Belt in the Gulf of Mexico spans the U.S.-Mexico maritime border. The northern edge of the awarded blocks in the Perdido area of Mexico, shown in Figure 36, lies along the maritime border. A single lease in the U.S. Gulf of Mexico that was active in 2014, which is the year of the most recent BOEM emissions inventory, and in close proximity to the US-Mexico border was selected to represent the potential for development of the Mexican blocks. The platform, shown in Figure 37, is identified as A-Perdido (Lease No. G17565, Block AC857) and has been active since 2010, producing 120,006,604 bbl of oil from 2010 to date (16,499,511 bbl in 2014) (https://www.data.boem.gov/Production/ProductionData/Default.aspx). Emissions sources and totals by pollutant associated with the A-Perido platform in 2014 are summarized in Appendix 5. For perspective, the 2014 oil and gas production volumes from A-Perdido represent roughly 4.5% and 3.5%, respectively, of offshore deepwater Gulf of Mexico oil and gas production during 2016 (based on estimated federal offshore production provided by BOEM, 2017; https://www.boem.gov/BOEM-Deepwater-Operation-Presentation/).

An estimate of emissions associated with future development of the Mexican Perdido blocks was made by assuming a single platform present in 50% of the blocks with annual emissions totals equivalent to those of the A-Perdido platform in 2014. The emissions assumed for the Mexican Perdido were spatially allocated across all contractual blocks in proportion to their areal size. Because historical data are not available to represent Mexican emissions associated with potential deepwater activities in the western and southern Gulf of Mexico contractual areas, the emissions totals assumed for the Mexican Perdido were also assumed and spatially distributed across the remaining (i.e., non-Perdido) Mexican deepwater contractual areas.

Emissions associated with future development for onshore sources were estimated by assuming a 20% increase in 2016 emissions by basin (ref. Table 8) and distributing emissions across all blocks within that basin. A similar approach was followed for shallow water blocks in the western Gulf of Mexico and Bay of Campeche. A summary of the emissions aggregated by basin and location for this scenario and the deepwater scenarios is provided in Table 26. A spatial mapping of NO_x emissions is shown in Figure 36.

Figure 36. Location of the A-Perdido platform in the Gulf of Mexico.

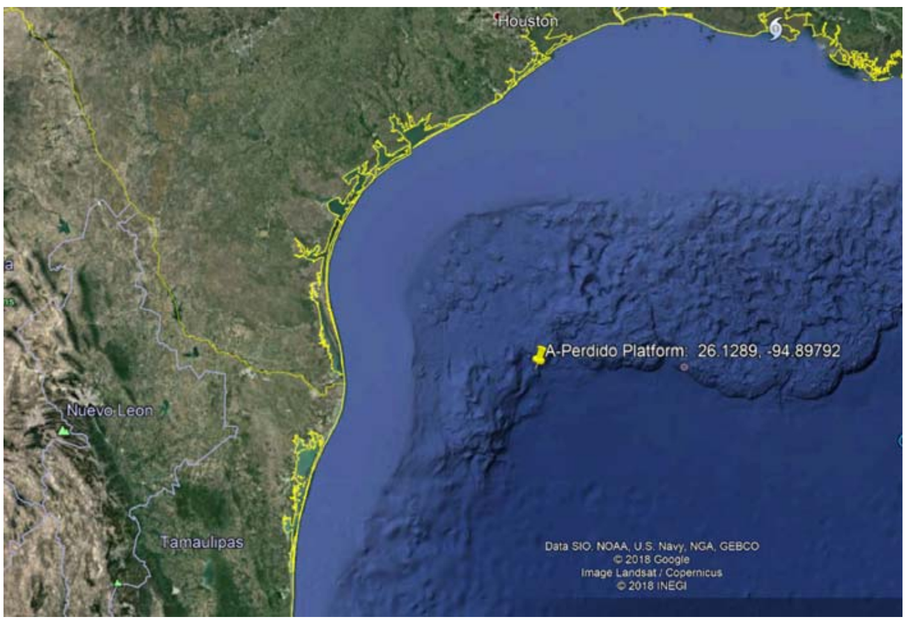
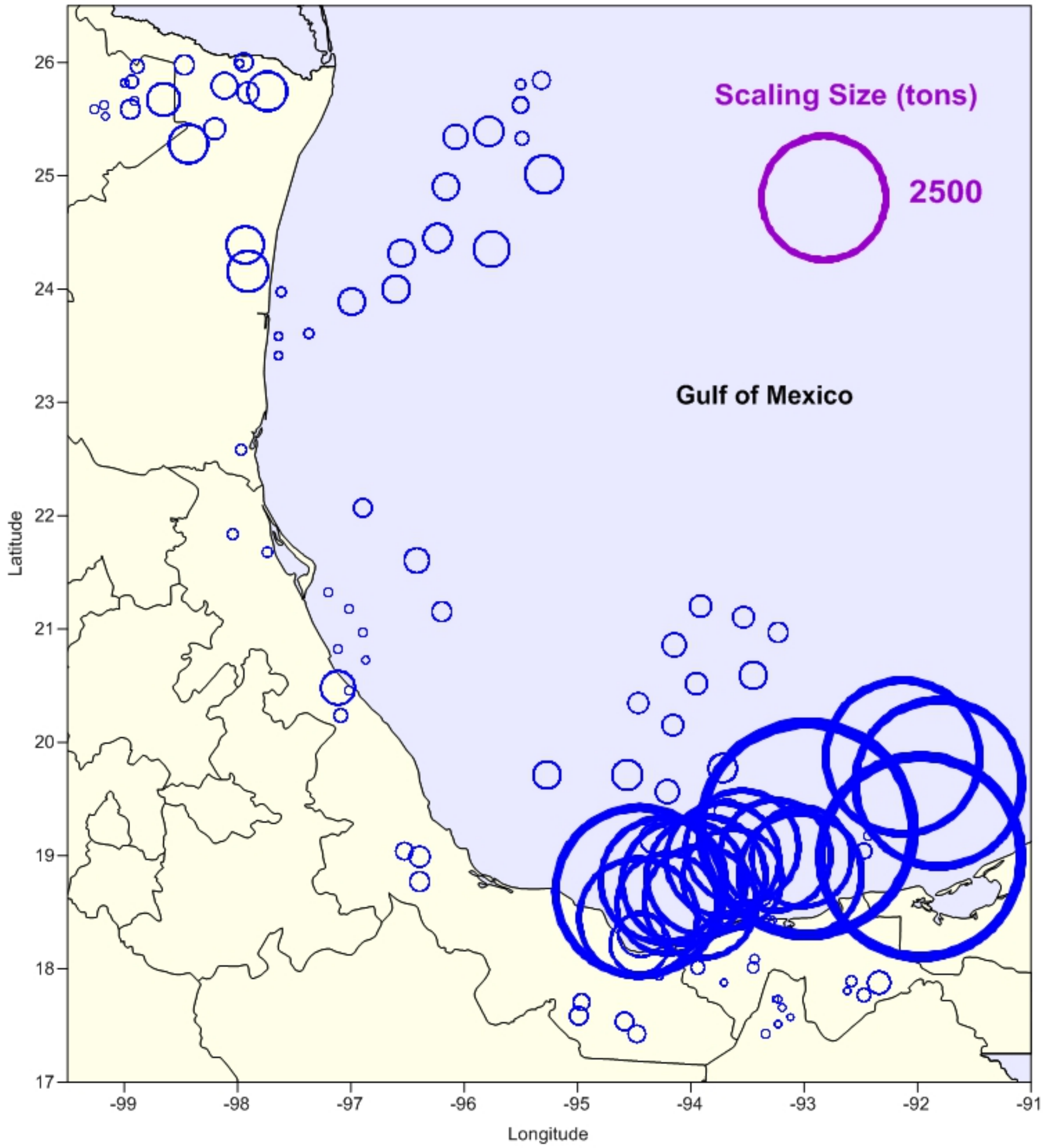


Table 26. Annual projected future year emissions (tons) of NO_x, CO, SO_2, VOC, $PM_{2.5}$, PM_{10}, and NH_3 from upstream oil and gas activities aggregated by basin and location.

Basin	Location	NO_x (tons)	CO (tons)	SO_2 (tons)	VOC (tons)	$PM_{2.5}$ (tons)	PM_{10} (tons)	NH_3 (tons)
Burgos	onshore	5458.4	1642.5	0.8	1036.8	18.3	18.3	0.0
	shallow water	208.9	257.0	1.6	232.2	2.8	2.8	0.0
Perdido	deepwater	5069.5	1457.4	91.1	268.7	94.2	94.3	2.2
Sureste	deepwater	4731.5	1360.2	85.1	250.7	87.9	88.0	2.0
	onshore	2023.8	938.8	6.3	85857.3	28.9	29.5	0.0
	shallow water	45965.6	56172.6	346.4	51346.7	632.9	633.7	7.7
Tampico-Misantla	deepwater	1013.9	291.5	18.2	53.7	18.8	18.9	0.4
	onshore	1016.1	1261.4	9.0	26158.8	21.7	22.0	0.0
	shallow water	208.9	257.0	1.6	232.2	2.8	2.8	0.0
Veracruz	onshore	767.7	237.6	0.8	4235.3	4.3	4.3	0.0
Total		**66464.2**	**63876.0**	**561.0**	**169672.3**	**912.5**	**914.4**	**12.4**

Figure 37. Projected future year NO_x emissions (tons). Emissions are plotted using the centroid coordinate of each individual contractual area.



10.0 Audits of Data Quality

Quality assurance was addressed throughout the project.

10.1 Upstream oil and gas production volumes

As described in Section 4.1, annual upstream oil and gas volumes were retrieved from CNIH for 10,458 individual well locations. In support of volume verification, Gary McGaughey compared the total annual Mexico-wide CNIH volumes to the PEMEX (2016) production volumes, which showed general agreement. Spatial mappings of the CNIH well locations were used to verify the well site designations essential to our emissions methodology, such as basin, onshore/offshore and oil/gas designations, and the general spatial variations in magnitude of natural gas and oil production volumes.

10.2 Upstream and midstream emissions calculations

The emission rates and SCC distributions for upstream oil and gas sources (ref. Section 4.2) were developed by John Grant and reviewed for reasonableness by Greg Yarwood and Tejas Shah. The well-level emissions calculations that applied the Section 4.2 emission rates in combination with emission surrogates (e.g., well counts, oil and/or gas volumes, spudding events) were performed by Gary McGaughey and evaluated for reasonableness by John Grant who applied a top-level (Mexico-wide) analysis. The spatial mappings for all pollutants were reviewed for reasonableness by the Ramboll and UT teams.

Well flaring emissions were calculated by Gary McGaughey and confirmed for reasonableness by John Grant and Tejas Shah. The calculation methodology to estimate emissions for natural gas processing plants and compressors was developed and implemented by Gary McGaughey; Yosuke Kimura reviewed these calculations and independently replicated the results for one representative gas processing plant and one representative compressor station.

The EGU emissions methodology was developed by Gary McGaughey and Elena McDonald-Buller. Reasonableness verifications included spatial mapping of the thermal electricity generation facilities by fuel, technology type, and generation capacity compared to available mappings provided by Mexican federal agencies. The relevant geographic and descriptive facility information used in support of the emissions calculations were also rigorously compared to the PRODESEN and COPAR datasets for consistency; differences were investigated and the appropriate data values were determined by subjective judgement. With respect to the thermal emissions inventory, available Mexico-wide estimates of CO_2 for 2016 reported in PRODESEN (2017) were compared to results that used COPAR (2015) emission rate factors (not reported here but using a methodology similar to that for other pollutants) to establish general consistency in the relative magnitude of emissions, aggregated by technology and fuel type. The resulting EGU emissions for all pollutants were explicitly mapped and reviewed for general reasonableness by the combined Ramboll and UT teams.

10.3 AFS files

Gary McGaughey prepared the AFS files; emission totals were confirmed by Yosuke Kimura to be consistent with those shown in the report, aggregated by source type and pollutant. The AFS latitude and longitude locations were mapped and visually evaluated for reasonableness for each source type (e.g., oil and gas wells, EGUs, etc). Specific source records were randomly chosen from the AFS file for confirmation that the appropriate stack exit release parameters were specified and that the subset of AFS data fields were populated as intended.

11.0 Conclusions and Recommendations

Energy reform in Mexico initiated under the Peña-Nieto administration catalyzed transformational changes in the country's energy sector. Development of Mexico's energy sector has the potential to substantially transform the magnitude and spatial distribution of emissions from the oil and gas and power generation sectors. Although uncertainty into the future direction of Mexico's energy sector was introduced by the transition in Mexico's presidential administration as Andrés Manuel López Obrador took office on December 1, 2018, development of Mexico's hydrocarbon resources is continuing.

Emission inventories for Mexico have become essential for air quality modeling in Texas and elsewhere in the United States, including at a national scale. This project developed a bottom-up assessment of emissions for the upstream and midstream oil and gas sectors and electric power sector in Mexico for the specific purpose of supporting air quality modeling applications. Emission sources included onshore and offshore oil and gas exploration and production well sites, natural gas compressor stations, natural gas processing plants, and electricity generating units. Emissions estimates were developed for 2016, the base year of the EPA's national air quality modeling platform and likely the basis for future air quality modeling by the TCEQ.

This work also provided a detailed illustration of onshore and offshore areas where future development of Mexico's oil and gas resources is likely to occur based on the hydrocarbon bid rounds that occurred under the Peña-Nieto administration. In addition, a speculative assessment of emissions that could accompany ongoing development was developed.

Several recommendations were outcomes of this project. Although activity data for many emission sources were available through intensive mining of national data, emission factors were, with the exception of electric generating units, drawn from U.S. resources. An on-going need for Mexico-specific data exists. Furthermore, an improved understanding of the implementation of emission controls and technological improvements in Mexico should be a future objective. More than 100 contractual areas for exploration and development of Mexico's onshore and offshore hydrocarbon resources have been awarded over the past several years. Although notable discoveries have been made, overall the development of these areas is largely in its infancy. Monitoring of the progress of these contracts should continue and inventories adjusted accordingly.

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Appendix

Appendix 1. Upstream oil and gas emissions aggregated by SCC.

Annual 2016 emissions from upstream onshore oil and gas activities aggregated by SCC and ranked in descending order of NO_x.

SCC	Generalized Description	NO_x	VOC	CO	SO_2	$PM_{2.5}$	PM_{10}
2310021403	Gas Prod: Nat Gas Fired 4Cycle Rich Burn Compressor Engines 500+ HP w/NSCR	24633.0	396.5	3861.0	0.9	13.4	13.4
2310021302	Gas Prod: Natural Gas Fired 4Cycle Rich Burn Compressor Engines 50 To 499 HP	8506.2	145.1	6703.8	1.3	22.5	22.5
2310021203	Gas Prod: Natural Gas Fired 4Cycle Lean Burn Compressor Engines 500+ HP	5075.8	210.1	708.0	0.9	4.4	4.4
2310000330	Oil/Gas Prod: Artificial Lift	4848.3	64.8	7496.1	1.2	41.2	41.2
2310021102	Gas Prod: Natural Gas Fired 2Cycle Lean Burn Compressor Engines 50 To 499 HP	1988.6	180.8	260.9	0.3	31.4	31.4
2310000220	Oil/Gas Prod: Drill Rigs	851.2	146.2	671.5	4.1	168.2	173.4
2310021100	Gas Prod: Gas Well Heaters	403.7	22.6	353.7	0.0	32.1	32.1
2310011100	Oil Prod: Heater Treater	191.6	10.5	161.0	0.3	14.6	14.6
2310021301	Gas Prod: Natural Gas Fired 4Cycle Rich Burn Compressor Engines	116.4	0.8	111.3	0.0	0.3	0.3
2310021402	Gas Prod: Nat Gas Fired 4Cycle Rich Burn Compressor Engines 50 To 499 HP w/NSCR	100.5	3.4	27.8	0.1	1.3	1.3
2310000660	Oil/Gas Prod: Hydraulic Fracturing Engines	76.7	12.1	48.0	1.7	9.7	9.7
2310021101	Gas Prod: Natural Gas Fired 2Cycle Lean Burn Compressor Engines < 50 HP	52.5	4.0	13.6	0.0	0.9	0.9
2310021400	Gas Prod: Gas Well Dehydrators	19.6	541.3	67.1	2.1	27.1	27.1
2310011201	Oil Prod: Tank Truck/Railcar Loading: Crude Oil	10.2	7729.1	46.2	0.0	0.0	0.0
2310020600	Natural Gas Compressor Engines	8.2	1.5	3.0	0.0	0.3	0.3
2310021202	Gas Prod: Natural Gas Fired 4Cycle Lean Burn Compressor Engines 50 To 499 HP	6.5	0.1	0.4	0.0	0.0	0.0
2310011000	Oil Prod: Total: All Processes	5.3	14.8	24.3	45.5	0.0	0.0
2310111700	Oil Expl: Oil Well Completion: All Processes	3.1	1553.8	14.2	25.9	0.0	0.0

SCC	Generalized Description	NO_x	VOC	CO	SO_2	$PM_{2.5}$	PM_{10}
2310021201	Gas Prod: Natural Gas Fired 4Cycle Lean Burn Compressor Engines	0.9	0.0	0.0	0.0	0.0	0.0
2310021103	Gas Prod: Natural Gas Fired 2Cycle Lean Burn Compressor Engines 500+ HP	0.0	0.0	0.1	0.0	0.0	0.0
2310011505	Oil Prod: Fugitives: Valves	0.0	3303.1	0.0	0.0	0.0	0.0
2310011504	Oil Prod: Fugitives: Pumps	0.0	1289.4	0.0	0.0	0.0	0.0
2310011503	Oil Prod: Fugitives: Open Ended Lines	0.0	349.1	0.0	0.0	0.0	0.0
2310011502	Oil Prod: Fugitives: Flanges	0.0	215.3	0.0	0.0	0.0	0.0
2310011501	Oil Prod: Fugitives: Connectors	0.0	925.0	0.0	0.0	0.0	0.0
2310111401	Oil Expl: Oil Well Pneumatic Pumps	0.0	1868.3	0.0	0.0	0.0	0.0
2310021010	Gas Prod: Storage Tanks: Condensate	0.0	186.0	0.0	0.0	0.0	0.0
2310011020	Oil Prod: Storage Tanks: Crude Oil	0.0	547027.2	0.0	0.0	0.0	0.0
2310010300	Oil/Gas Prod: Oil Well Pneumatic Devices	0.0	8342.9	0.0	0.0	0.0	0.0
2310010200	Oil/Gas Prod: Oil Well Tanks - Flashing & Standing/Working/Breathing	0.0	0.0	0.0	0.0	0.0	0.0
2310010100	Oil/Gas Prod: Oil Well Heaters	0.0	0.0	0.0	0.0	0.0	0.0
2310121100	Gas Expl: Mud Degassing	0.0	0.0	0.0	0.0	0.0	0.0
2310121401	Gas Expl: Gas Well Pneumatic Pumps	0.0	925.6	0.0	0.0	0.0	0.0
2310011450	Oil Prod: Wellhead	0.0	0.0	0.0	0.0	0.0	0.0
2310021504	Gas Prod: Fugitives: Pumps	0.0	77.8	0.0	0.0	0.0	0.0
2310021501	Gas Prod: Fugitives: Connectors	0.0	111.7	0.0	0.0	0.0	0.0
2310021351	Gas Prod: Lateral Compressors 4 Cycle Rich Burn	0.0	0.0	0.0	0.0	0.0	0.0
2310021303	Gas Prod: Natural Gas Fired 4Cycle Rich Burn Compressor Engines 500+ HP	0.0	0.0	0.0	0.0	0.0	0.0
2310021502	Gas Prod: Fugitives: Flanges	0.0	47.3	0.0	0.0	0.0	0.0
2310021503	Gas Prod: Fugitives: Open Ended Lines	0.0	51.5	0.0	0.0	0.0	0.0
2310021300	Gas Prod: Gas Well Pneumatic Devices	0.0	1788.4	0.0	0.0	0.0	0.0
2310011506	Oil Prod: Fugitives: Other	0.0	4874.3	0.0	0.0	0.0	0.0
2310121700	Gas Expl: Gas Well Completion: All Processes	0.0	91.7	0.0	0.0	0.0	0.0
2310111100	Oil Expl: Mud Degassing	0.0	889.7	0.0	0.0	0.0	0.0
2310021505	Gas Prod: Fugitives: Valves	0.0	448.2	0.0	0.0	0.0	0.0
2310021506	Gas Prod: Fugitives: Other	0.0	653.0	0.0	0.0	0.0	0.0
2310021600	Gas Prod: Gas Well Venting	0.0	1987.9	0.0	0.0	0.0	0.0

SCC	Generalized Description	NO_x	VOC	CO	SO_2	$PM_{2.5}$	PM_{10}
2310021603	Gas Prod: Gas Well Venting - Blowdowns	0.0	0.0	0.0	0.0	0.0	0.0
2310021030	Gas Prod: Tank Truck/Railcar Loading: Condensate	0.0	0.0	0.0	0.0	0.0	0.0
2310021401	Gas Prod: Nat Gas Fired 4Cycle Rich Burn Compressor Engines	0.0	0.0	0.0	0.0	0.0	0.0
2310021251	Gas Prod: Lateral Compressors 4 Cycle Lean Burn	0.0	0.0	0.0	0.0	0.0	0.0
ALL	TOTAL ONSHORE	46898.2	586490.9	20572.1	84.3	367.3	372.4

Annual 2016 emissions from upstream offshore oil and gas activities aggregated by SCC and ranked in descending order by NOx.

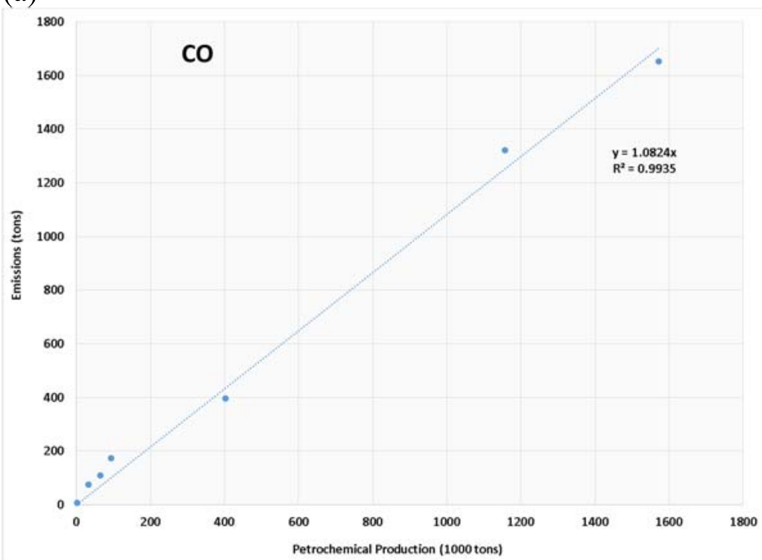
SCC	Final Generalized Desc	NO_x	VOC	CO	SO_2	$PM_{2.5}$	PM_{10}
20200253	Int Comb: Natural Gas, 4-cycle Rich Burn	170736.8	2279.2	263419.8	44.8	1308.4	1308.4
20200102	Int Comb: Distillate Oil (Diesel), Reciprocating	17209.2	1154.4	3840.4	1394.4	1063.3	1064.2
20200252	Int Comb: Natural Gas, 2-cycle Lean Burn	11138.7	693.4	2022.3	3.4	402.2	402.2
20200201	Int Comb: Natural Gas, Turbine	9725.6	64.2	2486.7	19.0	105.3	105.4
31000122	Oil Prod: Well Drilling	9510.9	239.3	2520.8	151.5	166.8	169.8
20200254	Int Comb: Natural Gas, 4-cycle Lean Burn	6406.2	931.3	4211.2	4.6	1.1	1.1
20200251	Int Comb: Natural Gas, 2-cycle Rich Burn	3697.7	230.2	671.4	1.1	73.4	73.4
20200256	Int Comb: Natural Gas, 4-cycle Clean Burn	1010.5	206.5	1503.6	1.0	0.2	0.2
10200603	Ext Comb: Natural Gas, < 10 Million BTU/hr	757.0	41.9	634.5	4.6	37.5	37.5
10200602	Ext Comb: Natural Gas, 10-100 Million BTU/hr	322.8	19.6	297.2	2.1	17.6	17.6
20200255	Int Comb: Natural Gas, 2-cycle Clean Burn	286.7	58.7	426.7	0.3	0.1	0.1
31000160	Oil Prod: Flares	50.5	3.3	100.3	0.4	1.5	1.5
10200701	Ext Comb: Process Gas, Petroleum Refinery Gas	11.2	0.6	9.4	0.1	0.6	0.6
10200601	Ext Comb: Natural Gas, > 100 Million BTU/hr	8.4	0.2	3.7	0.0	0.2	0.2
20201702	Int Comb: Gasoline, Reciprocating Engine	0.1	0.2	0.1	0.0	0.0	0.0
31000127	Oil Prod: Flanges and Connections	0.0	1443.2	0.0	0.0	0.0	0.0
31000101	Oil Prod: Well Completion	0.0	507.8	0.0	0.0	0.0	0.0
31000123	Oil Prod: Well Casing Vents	0.0	97893.5	0.0	0.0	0.0	0.0
31000224	Nat Gas Prod: Pump Seals	0.0	26487.5	0.0	0.0	0.0	0.0
40400321	Condensate Storage and Working Tanks	0.0	270.9	0.0	0.0	0.0	0.0
31088811	Nat Gas Prod: Fugitive Emissions	0.0	74842.0	0.0	0.0	0.0	0.0
31000307	Nat Gas Prod: Relief Valves	0.0	5974.5	0.0	0.0	0.0	0.0
31000305	Nat Gas Prod: Amine Process	0.0	0.0	0.0	113.0	0.0	0.0

SCC	Final Generalized Desc	NO_x	VOC	CO	SO_2	$PM_{2.5}$	PM_{10}
31000304	Nat Gas Prod: Glycol Dehydrator (See also 31000301-31000303)	0.0	1996.3	0.0	0.0	0.0	0.0
31000229	Nat Gas Prod: Gathering Lines	0.0	5.2	0.0	0.0	0.0	0.0
31000124	Oil Prod: Valves: General	0.0	32484.3	0.0	0.0	0.0	0.0
31000225	Nat Gas Prod: Compressor Seals	0.0	13.7	0.0	0.0	0.0	0.0
31000126	Oil Prod: Pump Seals	0.0	1074.8	0.0	0.0	0.0	0.0
31000207	Nat Gas Prod: Valves: Fugitive Emissions	0.0	1817.3	0.0	0.0	0.0	0.0
31000199	Oil Prod: Processing Operations: Not Classified	0.0	65.8	0.0	0.0	0.0	0.0
31000146	Oil Prod: Gathering Lines	0.0	69.7	0.0	0.0	0.0	0.0
31000132	Oil Prod: Atmospheric Wash Tank (2nd Stage of Gas-Oil Separation): Flashing Loss	0.0	2205.9	0.0	0.0	0.0	0.0
31000130	Oil Prod: Fugitives: Compressor Seals	0.0	332.0	0.0	0.0	0.0	0.0
40400322	Crude Oil Storage and Working Tanks	0.0	4193.7	0.0	0.0	0.0	0.0
31000226	Nat Gas Prod: Flanges and Connections	0.0	293.2	0.0	0.0	0.0	0.0
ALL	TOTAL OFFSHORE	230872.4	257894.4	282147.9	1740.3	3178.2	3182.2

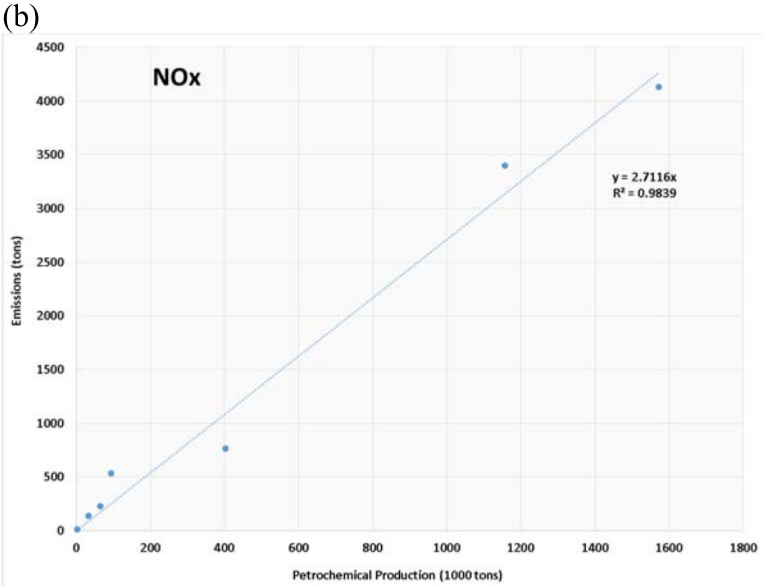
Appendix 2. Linear Regression Equations Used in the Development of Natural Gas Processing Emissions Estimates

INEM plant-wide emissions by pollutant versus combined petrochemical production in 2008 for (a) CO, (b) NO_x, (c) VOC, (d) $PM_{2.5}$, (e) PM_{10}, (f) NH_3.

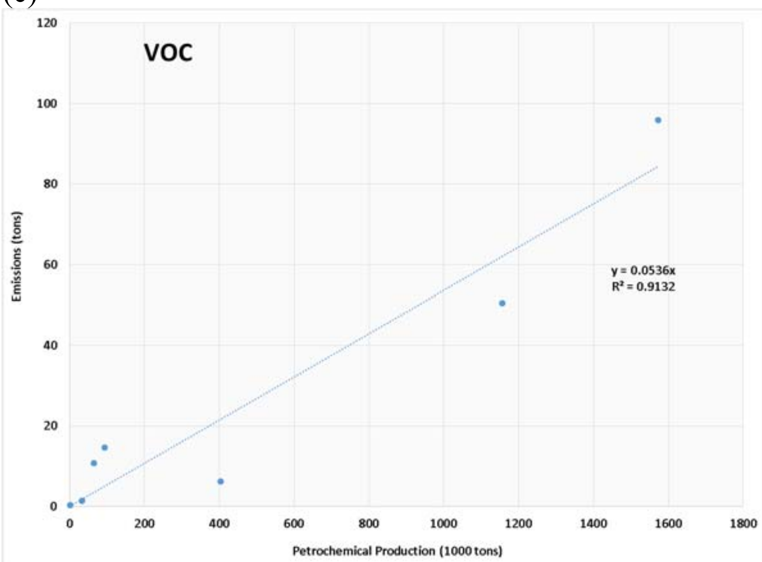
(a)



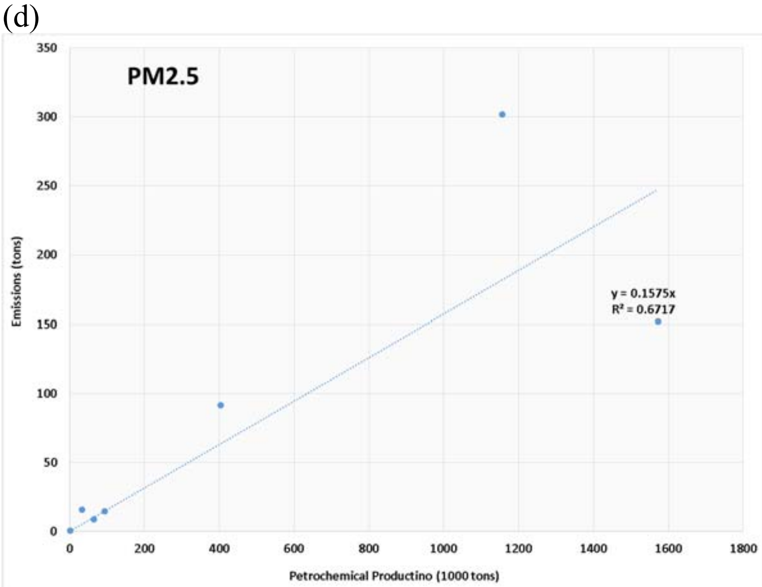
(b)



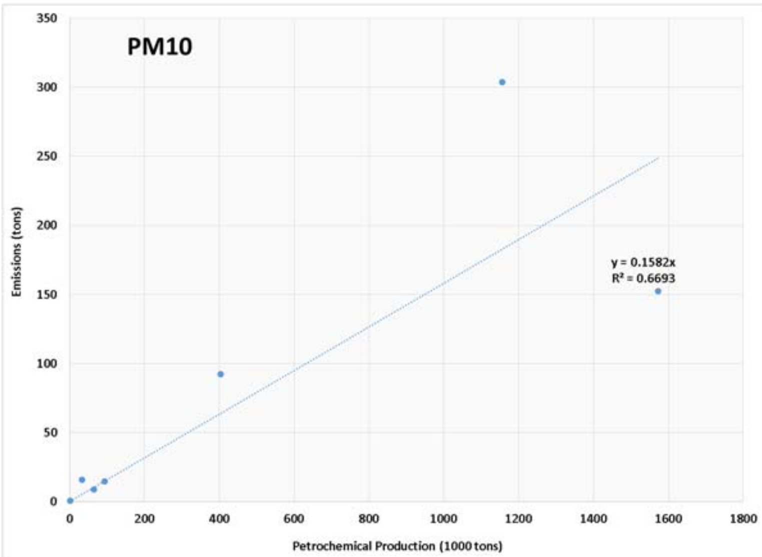
(c)


VOC
Emissions (tons)
0
20
40
60
80
100
120
y = 0.0536x
R² = 0.9132
0
200
400
600
800
1000
1200
1400
1600
1800
Petrochemical Production (1000 tons)

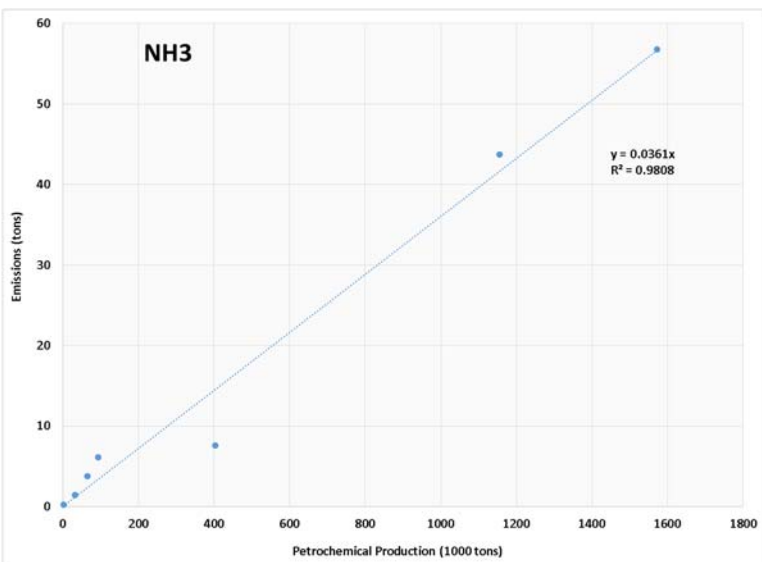
(d)


PM2.5
Emissions (tons)
0
50
100
150
200
250
300
350
y = 0.1575x
R² = 0.6717
0
200
400
600
800
1000
1200
1400
1600
1800
Petrochemical Productino (1000 tons)

(e)


PM10
y = 0.1582x
R^2 = 0.6693
Emissions (tons)
Petrochemical Production (1000 tons)
0
50
100
150
200
250
300
350
0
200
400
600
800
1000
1200
1400
1600
1800

(f)


NH3
y = 0.0361x
R^2 = 0.9808
Emissions (tons)
Petrochemical Production (1000 tons)
0
10
20
30
40
50
60
0
200
400
600
800
1000
1200
1400
1600
1800

Appendix 3. Coordinate Assignment Methodology for Electricity Generating Units

The methodology outlined below was adopted to map one or more INEM/NACEI facility records with the PRODESEN report. Although confidence was high that the vast majority of EGUs were within 5 km of their actual location (particularly for the larger facilities), additional efforts to further quality assure and refine these coordinates (such as visual verification using high resolution satellite imagery) is recommended in the future.

Coordinates assignment methodology:

1.) Based on a manual record-by-record inspection of facility names, one or more potential mappings were made between the INEM/NACEI and PRODESEN datasets. In addition to the facility names and coordinates, ancillary parameter fields useful for mapping included: state of location, primary fuel, primary technology, and capacity. With respect to follow-on manual verifications in support of quality assurance, emphasis was on the largest facilities. Overall, of the 355 PRODESEN facilities active during 2016, potential facility mappings were identified for 235 facilities and 88 facilities in the INEM and NACEI, databases, respectively.

2.) Based on the results in (1), PRODESEN mappings for 3 facilities were only available in NACEI; therefore, NACEI coordinates were used.

3.) INEM matches only were identified for 112 PRODESEN facilities; therefore, INEM coordinates were applied following confirmation of consistency in the states of location.

4.) Both NACEI and INEM coordinates were available for 85 PRODESEN facilities. The distance between the NACEI and INEM coordinates was less than 5km for the majority of facilities so NACEI coordinates were assigned. For the remaining facilities, Google Earth satellite imagery was sometimes used to identify the most likely locations, which resulted in the assignment of 13 facilities to INEM.

5.) The remaining 146 of the total 355 PRODESEN facilities were not mapped using the methodology outlined in steps (1-6) above so were assigned to the centroid of the appropriate Mexican state.

A summary of the plant matching in support of coordinate assignments is presented in the following table, aggregated by primary fuel and coordinates source as well as coordinates source only. Although only 84 of 355 facilities were assigned to NACEI coordinates, these 84 facilities contributed the vast majority (90.55%) of total electricity generation during 2016. NEI and centroid of state coordinates were applied to 125 facilities (7.52% of total generation) and 146 facilities (1.93% of total generation), respectively.

Total electricity generation from thermal (e.g., fossil-fuel) facilities during 2016 aggregated by source of coordinates. The number of unique facilities is also provided.

Primary Fuel	Source of Coordinates	Number of Facilities	Total Generation (GWh)	Percent of Generation
Grouped by primary fuel and coordinates source				
Coal	NACEI	3	34208.20	13.56%
Coke	NACEI	2	3825.74	1.52%
Diesel	State Centroid	67	256.64	0.10%
	NEI	46	462.52	0.18%
Gas	State Centroid	72	4191.66	1.66%
	NACEI	65	160660.04	63.68%
	NEI	71	16713.68	6.62%
Oil	State Centroid	7	410.47	0.16%
	NACEI	14	29761.83	11.80%
	NEI	8	1798.04	0.71%
Total	All	355	252288.82	100.00%
Grouped by coordinates source only				
All	State Centroid	146	4858.76	1.93%
	NACEI	84	228455.82	90.55%
	NEI	125	18974.24	7.52%
	Total	355	252288.82	100.00%

Appendix 4. Emission Estimation Methodology for Electricity Generating Units

In addition to the emission factors (kg/MWh) for CO_2, CH_4, N_2O, CO, NO_x, NMVOC, SO_2, and TSP, the COPAR (2015) facility-specific data records also included parameter fields for technology (combined cycle, coal, conventional, or turbogas/internal combustion) and primary fuel (coal, diesel, natural gas, oil). The COPAR and PRODESEN datasets were merged primarily based on a visual comparison of facility names with additional consideration of consistency for technology and fuel type. Of the 101 individual COPAR facilities, PRODESEN mappings were identified for 92 facilities. (The 9 unmatched COPAR facilities had minimal contributions to electricity generation for year 2014 with the exception of Preita I, which was not operational during 2016.) The table below presents a summary of the matched results aggregated by technology and fuel. Combined, these 89 COPAR (2015) facilities accounted for 57.2% of the total annual electricity generation during 2016.

Numbers of facilities (and associated annual electricity generation during 2016) that were explicitly mapped to the COPAR (2015) Table 7.5 emissions rates.

Technology	Fuel	Numbers of Facilities	COPAR Matching Facilities	Total Generation (GWh)	Generation from COPAR (GWh)	COPAR % of Total Generation
Coal	Coal	3	3	34208.20	34208.20	100.00%
Combined Cycle and Cogeneration	Gas	87	25	161691.21	70511.79	43.61%
Conventional	Gas	24	5	8375.14	4389.66	52.41%
	Oil	23	14	29951.55	29427.56	98.25%
Internal Combustion	Diesel	92	2	322.62	21.97	6.81%
	Gas	39	0	792.53	0.00	0.00%
	Oil	6	4	2018.79	1871.64	92.71%
TurboGas	Diesel	21	15	396.53	330.29	83.29%
	Gas	58	21	10706.50	3456.19	32.28%
Fluidized Bed	Coke	2	0	3825.74	0.00	0.00%
Total	All	355	89	252288.82	144217.30	57.16%

Facility-specific emissions factors were not available for 266 facilities representing 42.8% of electricity generation. In order to characterize generic emissions for these facilities, median emission rates were calculated across the COPAR facilities grouped by the technology and fuel designations. The table below presents the median emission factor results. These generic emissions factors were applied to the vast majority of remaining facilities operational during 2016 that did not have facility-specific COPAR (2015) mappings.

Generic emissions rates (kg/MWh) for electricity generation facilities not explicitly mapped to COPAR (2015) Table 7.5.

Technology	Primary Fuel	NO_x (kg/MWh)	CO (kg/MWh)	SO_2 (kg/MWh)	NMVOC (kg/MWh)	TSP (kg/MWh)
Coal	Coal	5.8560	0.1230	9.5190	0.0100	0.4770
Combined Cycle	Gas	1.3110	0.3300	0.0040	0.0090	0.0270
Conventional and Cogeneration		0.8815	0.2430	1.1365	0.0260	0.1055
Internal Combustion		1.7115	0.4365	0.0050	0.0110	0.0350
TurboGas		1.7115	0.4365	0.0050	0.0110	0.0350
Internal Combustion and TurboGas	Diesel	7.6675	0.0285	43.9875	0.0040	0.1045
Conventional	Oil	1.2140	0.1540	18.8320	0.0230	1.1960
Internal Combustion		16.1460	4.0240	14.6830	0.4190	0.2370

Of the three remaining PRODESEN facilities that were not assigned emission factors based on the aforementioned approaches, two of those facilities had fluidized bed technology that combined for 1.52% of electricity generation during 2016. For these two facilities, the generic PRODESEN (2017) SO_2 emission rate of 2.6 kg/MWh was assumed. Emissions for other pollutants were assigned as a percentage of SO_2 on a mass basis consistent with the facility-specific 2008 INEM emissions profiles. An additional facility had negligible contributions to generation and a primary fuel "exothermic chemical reaction", and as such was ignored.

With respect to particulate emissions, the PRODESEN (2017) and COPAR (2015) datasets provided emissions estimates for "particulates", which was confirmed to correspond to TSP. Emissions for $PM_{2.5}$ and PM_{10} were estimated as a percentage of TSP per the table below. Emission factors for NH_3 were not available from PRODESEN (2017) or COPAR (2015). Based on an analysis of facility-specific emissions in the INEM dataset (limited to the ~160 facilities generally matched by facility name to one or more potential PRODESEN facilities), mass ratio comparisons grouped by capacity, technology, and/or primary fuel were investigated among the various pollutants to discern any trends or patterns. The central tendency of NH_3 to CO mass ratios were consistent across a given fuel type, suggesting that NH_3 might have been assumed proportional to the amount of fuel consumed. It was unclear how and/or if other plant-specific characterizations (such as control technology) might have been considered in the estimation of NH_3 for the INEM. For the purposes of this work, a generic characterization of NH_3 emissions was assumed as median NH_3 to CO mass ratios across the individual INEM facilities grouped by fuel type. These median values shown in the second table below were applied to all electricity facilities active during 2016.

$PM_{2.5}$ and PM_{10} mass ratios of TSP aggregated by combustion category.

Combustion Category	PM_{10} Mass Fraction of TSP	$PM_{2.5}$ Mass Fraction of TSP	Notes	Reference
Gas (Combined Cycle, TurboGas, and Internal Combustion)	1.000	1.000	All particulate is assumed to be <= 1 um in size	AP-42, Section 1.4 and Table 3.3-1
Diesel (TurboGas and Internal Combustion)	1.000	1.000	All particulate is assumed to be <= 1 um in size	AP-42, Section 1.4 and Table 3.3-1
Gas (Conventional)	1.000	1.000	Because natural gas is a gaseous fuel, filterable PM emissions are typically low. Particulate matter from natural gas combustion has been estimated to be less than 1 micrometer in size and has filterable and condensable fractions. Particulate matter in natural gas combustion are usually larger molecular weight hydrocarbons that are not fully combusted.	AP-42, Chapter 1, Section 1.4
Internal Combustion (oil)	1.000	1.000	All particulate is assumed to be <= 1 um in size	AP-42, Table 3.3-1
coal	0.230	0.060	Assume dry bottom boilers burning pulverized coal; and uncontrolled PM emissions	AP-42, Table 1.1-6
Oil (Conventional)	0.800	0.520	Assume utility boiler firing residual oil	AP-42, Table 1.3-4

INEM-derived NH_3 to CO mass fractions used to estimate NH_3 emissions associated with fuel combustion.

Primary Fuel	**NH_3 to CO mass ratio**
Coal	0.0001
Coke	0.0014
Gas	0.0528
Oil	0.1597
Diesel	0.4285

Appendix 5. Emissions sources and 2014 pollutant totals (tons) associated with the US A-Perdido platform (Lease No. G17565 Block AC857).

SCC Description 1	SCC Description 2	SCC Description 3	SCC Description 4	SCC	CO	NH_3	NO_X	PM_{10}-PRI	$PM_{2.5}$-PRI	SO_2	VOC
External Combustion Boilers	Industrial	Natural Gas	10-100 Million BTU/hr	10200602	1.26	0.05	1.50	0.07	0.07	0.01	0.08
Internal Combustion Engines	Industrial	Distillate Oil (Diesel)	Reciprocating	20200102	27.27		118.64	6.55	6.54	10.94	7.18
Internal Combustion Engines	Industrial	Natural Gas	Turbine	20200201	141.03		550.37	5.95	5.95	1.15	3.61
Industrial Processes	Oil and Gas Production	Crude Oil Production	Well Casing Vents	31000123							0.42
Industrial Processes	Oil and Gas Production	Crude Oil Production	Valves: General	31000124							4.30
Industrial Processes	Oil and Gas Production	Crude Oil Production	Pump Seals	31000126							0.00
Industrial Processes	Oil and Gas Production	Crude Oil Production	Flanges and Connections	31000127							0.24
Industrial Processes	Oil and Gas Production	Crude Oil Production	Atmospheric Wash Tank (2nd Stage of Gas-Oil Separation): Flashing Loss	31000132							0.00

SCC Description 1	SCC Description 2	SCC Description 3	SCC Description 4	SCC	CO	NH_3	NO_X	PM_{10}-PRI	$PM_{2.5}$-PRI	SO_2	VOC
Industrial Processes	Oil and Gas Production	Crude Oil Production	Flares	31000160	24.76	0.24	5.43			0.05	0.48
Industrial Processes	Oil and Gas Production	Natural Gas Production	Valves: Fugitive Emissions	31000207							1.34
Industrial Processes	Oil and Gas Production	Natural Gas Production	Compressor Seals	31000225							0.01
Industrial Processes	Oil and Gas Production	Natural Gas Production	Flanges and Connections	31000226							0.21
Industrial Processes	Oil and Gas Production	Natural Gas Processing	Glycol Dehydrator (See also 31000301-31000303)	31000304							0.00
Industrial Processes	Oil and Gas Production	Fugitive Emissions	Fugitive Emissions	31088811							17.93
Chemical Evaporation	Petroleum Liquids Storage (non-Refinery)	Oil and Gas Field Storage and Working Tanks	External Floating Roof Tank, Crude Oil, working+breathing+flashing	40400322							0.00
				Grand Total	**194.32**	**0.29**	**675.93**	**12.57**	**12.56**	**12.15**	**35.82**