SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT

Draft Socioeconomic Impact Assessment for
Proposed Amended Rule 1135 – Emissions of Oxides of Nitrogen from Electricity Generating Facilities

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EXECUTIVE SUMMARY

A socioeconomic analysis was conducted to assess the potential impacts of Proposed Amended Rule (PAR) 1135 on the four-county region of Los Angeles, Orange, Riverside and San Bernardino. A summary of the analysis and findings is presented below.

Elements of Proposed amendments	PAR 1135 - Emissions of Oxides of Nitrogen for Electricity Generating Facilities will be the first command-and-control rule to be amended as part of the transition process of facilities from the NOx RECLAIM program to a command-and-control regulatory structure. PAR 1135 applies to RECLAIM and non-RECLAIM electricity generating facilities that own and operate electricity generating units (e.g., boilers; gas turbines with the exception of cogeneration turbines; and internal combustion engines on Santa Catalina Island) and are investor-owned electric utilities, publicly owned electric utilities, or have a generation capacity of at least 50 megawatts of electrical power. PAR 1135 will update NOx emission limits to reflect current BARCT and to provide implementation timeframes. The provisions in PAR 1135 establish NOx and ammonia (NH3) emission limits for boilers and gas turbines and NOx, ammonia, carbon monoxide, volatile organic compounds, and particulate matter for internal combustion engines located on Santa Catalina Island. Additionally, PAR 1135 establishes provisions for monitoring, reporting, recordkeeping, and establishes exemptions from specific provisions. PAR 1135 is estimated to reduce NOx emissions by 0.9 tons per day by January 1, 2027.
Affected Facilities and Industries	There are 32 electricity generating facilities subject to PAR 1135. All 32 facilities are classified under NAICS Code 221112 - Utilities (Fossil Fuel Electric Power Generation). Of these 32 affected facilities, 17 are located in Los Angeles County, six are in Orange County, six are in Riverside County, and the remaining three facilities are located in San Bernardino County. Twenty-seven facilities are currently in the NOx RECLAIM program. Twenty-nine of the 32 facilities were identified as not needing additional pollution controls, installation of new equipment, or modifications to their existing equipment in order to comply with PAR 1135. The electricity generating units at these facilities are not expected to require modifications to comply with PAR 1135 because the electricity generating units either: 1) currently meet the NOx emission limit; 2) are currently eligible for a low-use provision; 3) have NOx emission levels that are near the proposed NOx emission limit and the unit is exempt from the NOx emission limit because potential equipment modifications exceed a cost-effectiveness threshold of $50,000 per ton of NOx reduced; or 4) are scheduled by facility operators to be either shut down or repowered due to other regulatory requirements not pertaining to PAR 1135.

	Only three electricity generating facilities would be expected to have existing electric power generating units that would require potential modifications (e.g., installing new or modifying existing air pollution control systems, and repowering or replacing existing electric power generating units) in order to comply with PAR 1135.
Assumptions of Analysis	There are five diesel internal combustion engines located at a single facility that are expected to be replaced in order to comply with PAR 1135. Equipment and installation costs are expected to result in a one-time capital cost of \$3.9 million for each unit. There are three natural gas boilers operated by a municipality. The operator plans to shut down the three natural gas boilers and repower them with three natural gas turbines (one 20 megawatt (MW) unit, and two 44 MW units). One-time capital costs for the 20 MW unit consists of \$19.8 million in equipment costs and \$10.2 million in construction and development fees. Capital costs for the 44 MW units are expected to be \$35.8 million per unit in equipment costs and an additional \$17.4 million per unit in construction and development fees. Another municipality that operates four natural gas simple cycle gas turbines has scheduled for the catalyst in each of the four existing selective catalytic reduction (SCR) systems to be replaced with more efficient catalyst to comply with the updated BARCT NOx concentration limits in PAR 1135. Replacement of two 30.58 MW units are expected to result in a one-time capital cost consisting of \$439,000 per unit in equipment costs, \$1.1 million in installation costs per unit, and \$165,000 per unit for spent catalyst disposal and administrative fees. Replacement of two 47.3 MW units are expected to result in a one-time capital cost consisting of \$241,000 per unit in equipment costs, \$1.1 million in installation costs per unit, and \$165,000 per unit for spent catalyst disposal and administrative fees. Recurring costs for all four units are comprised of \$1,400 per unit in increased ammonia costs annually and an increase of \$55,000 per unit in SCR replacement costs incurred every five years. All 32 facilities will be required to have their permits modified as a result of PAR 1135. Permit fees for each piece of equipment will result in a one-time cost ranging from \$3,160 - \$23,933. A subset of six facilities may also be required to pay a one-time notification fee of \$2,637.
Compliance Costs	The entirety of the overall annual compliance cost is expected to be incurred by the utilities sector. Average annual compliance costs from 2019 - 2045 are expected to range from \$6.4 - \$8.7 million for the low (1% real interest rate) and high (4% real interest rate) cost scenarios, respectively. Based on the high cost scenario, the majority of costs of PAR 1135, \$8.2 million (94%), stem from installation of five diesel internal combustion engines and three natural gas turbines at two separate facilities. The additional costs of SCR

	replacement and permit modifications are estimated at about $360,000 and $110,000, respectively.
Jobs and Other Socioeconomic Impacts	Based on the above assumptions, the compliance cost of PAR 1135, and the application of the Regional Economic Models, Inc. (REMI) model, it is projected that 88 to 134 jobs will be forgone annually, on average, between 2019 and 2045. The projected job loss impacts represent about 0.0012% of total employment in the four-county region. The utilities sector is projected to incur all of the compliance costs and thus experience some jobs forgone. The reduction in disposable income would dampen the demand for goods and services in the local economy, resulting in a small number of jobs forgone projected in sectors such as construction (NAICS 23), retail trade (NAICS 44 - 45), wholesale (NAICS 42), and food services (NAICS 72). The remainder of the projected reduction in employment would be across all major sectors of the economy from secondary and induced impacts of PAR 1135.
Competitiveness	It is projected that the utility sector, where all of the affected facilities belong, would experience a rise in its relative cost of production of 0.062% - 0.085% in 2025 for the low and high cost scenarios, respectively. The utility sector is also expected to experience an increase in its delivered price by 0.032% - 0.044% in 2025 for the low and high cost scenarios. Delivered prices that a facility may charge for specific goods or services may increase at a greater rate than this, allowing incurred costs to be passed through to downstream industries and end-users. The remaining sectors are likely to experience increases in the relative cost of production and relative delivered price with respect to their counterparts in the rest of the U.S.
Potential NOx RTC Market Impacts	If PAR 1135 is adopted, 27 facilities are expected to receive an initial determination notification because, according to staff's evaluation, all of their permitted RECLAIM NOx source equipment will be subject to this rule once PAR 1135 is adopted. Electricity generating facilities in RECLAIM will need to begin complying with PAR 1135 while in RECLAIM and through the transition out of RECLAIM. Staff has committed to issue a final determination notification to any facilities to exit them from RECLAIM until New Source Review (NSR) issues are resolved. The 27 affected facilities currently account for 9.4% of annual NOx emissions and 19.7% of NOx RECLAIM trading credit (RTC) holdings in the NOx RECLAIM universe. The simultaneous transition of the 27 electricity generating facilities out of the NOx RECLAIM program could potentially assert upward pressure on the discrete-year NOx RTC prices. However, many facilities will likely opt to remain in RECLAIM given RECLAIM's advantageous NSR provisions. In addition, electricity generating facilities tend to be sellers of RTCs in RECLAIM.

INTRODUCTION

Control measure CMB-05 from the SCAQMD's 2016 Air Quality Management Plan (AQMP) and its adoption resolution establish a timeline to transition facilities from NOx RECLAIM to a command-and-control regulatory structure. PAR 1135 applies to RECLAIM and non-RECLAIM electricity generating facilities that own and operate electricity generating units (e.g., boilers; gas turbines with the exception of cogeneration turbines; and internal combustion engines on Santa Catalina Island) and are investor-owned electric utilities, publicly owned electric utilities, or have a generation capacity of at least 50 megawatts of electrical power. PAR 1135 will update emission limits to reflect current Best Available Retrofit Control Technology (BARCT) and to provide implementation timeframes. The provisions in PAR 1135 establish NOx and ammonia (NH3) emission limits for boilers and gas turbines and NOx, ammonia, carbon monoxide, volatile organic compounds, and particulate matter for internal combustion engines located on Santa Catalina Island. Additionally, PAR 1135 establishes provisions for monitoring, reporting, recordkeeping, and establishes exemptions from specific provisions. PAR 1135 is estimated to reduce NOx emissions by 0.9 tons per day by January 1, 2027.

LEGISLATIVE MANDATES

The socioeconomic impact assessments at SCAQMD have evolved over time to reflect the benefits and costs of regulations. The legal mandates directly related to the assessment of the proposed amended rule include the SCAQMD Governing Board resolutions and various sections of the California Health & Safety Code (H&SC).

SCAQMD Governing Board Resolutions

On March 17, 1989 the SCAQMD Governing Board adopted a resolution that calls for an economic analysis of regulatory impacts that includes the following elements:

- Affected industries
- Range of probable costs
- Cost-effectiveness of control alternatives
- Public health benefits

Health & Safety Code Requirements

The state legislature adopted legislation that reinforces and expands the Governing Board resolutions for socioeconomic impact assessments. Health and Safety Code sections 40440.8(a) and (b), which became effective on January 1, 1991, require a socioeconomic analysis be prepared for any proposed rule or rule amendment that "will significantly affect air quality or emissions limitations."

Specifically, the scope of the analysis should include:

- Type of affected industries
- Impact on employment and the regional economy
- Range of probable costs, including those to industry
- Availability and cost-effectiveness of alternatives to the rule
- Emission reduction potential
- Necessity of adopting, amending or repealing the rule in order to attain state and federal ambient air quality standards

Health and Safety Code section 40728.5, which became effective on January 1, 1992, requires the SCAQMD Governing Board to actively consider the socioeconomic impacts of regulations and make a good faith effort to minimize adverse socioeconomic impacts. It also expands socioeconomic impact assessments to include small business impacts, specifically:

- Type of industries or business affected, including small businesses
- Range of probable costs, including costs to industry or business, including small business

Finally, Health and Safety Code section 40920.6, which became effective on January 1, 1996, requires incremental cost-effectiveness be performed for a proposed rule or amendment that imposes Best Available Retrofit Control Technology or "all feasible measures" requirements relating to ozone, carbon monoxide (CO), oxides of sulfur (SOx), oxides of nitrogen (NOx), and their precursors.

Incremental cost-effectiveness is defined as the difference in costs divided by the difference in emission reductions between a control alternative and the next more stringent control alternative. The necessity analysis and the analysis of control alternatives and their incremental cost-effectiveness are presented in the Staff Report prepared for the proposed amendments.

REGULATORY HISTORY

Rule 1135 – Emissions of Oxides of Nitrogen from Electric Power Generating Boilers was adopted in 1989 and applied to electric power generating steam boiler systems, repowered units, and alternative electricity generating sources. Rule 1135 set a NOx system-wide average emission limit of 0.25 lb/MWh and a daily NOx emissions cap for each utility system. Rule 1135 established interim emissions performance levels with a 1996 final compliance date. Additionally, Rule 1135 required Emission Control Plans and continuous emissions monitoring systems. The total annualized cost of these amendments was estimated at $74.0 million with an average cost-effectiveness of $10,000 per ton of NOx reduced.

Rule 1135 was submitted to the California Air Resources Board (CARB) for review, prior to submittal to the U.S. Environmental Protection Agency (U.S. EPA), Region IX, for revision to the State Implementation Plan (SIP). In March 1990, CARB staff informed SCAQMD that the adopted rule was lacking specificity in critical areas of implementation and enforcement, and was considered incomplete for submission to U.S. EPA as a State Implementation Plan (SIP) revision.

The December 21, 1990 amendment of Rule 1135 was principally developed to resolve many of the implementation and enforceability issues. This amendment included accelerated retrofit dates for emission controls, unit-by-unit emission limits, modified compliance plan and monitoring requirements, computerized telemetering, and an amended definition of alternative resources. The total annualized cost of these amendments was estimated at $12.5 million with a cost-effectiveness of $4,000 per ton of NOx reduced.

In order to consider additional staff recommendations regarding system-wide emission rates, daily emission caps, annual emission caps, oil burning, and cogeneration, the Board continued the public hearing. The July 19, 1991 amendment addressed all of these outstanding issues, including those related to modeling and BARCT analysis. U.S. EPA approved Rule 1135 into the SIP on August 11, 1998.

Electricity Generating Facilities and RECLAIM

Throughout the RECLAIM program, there have been specific provisions for electricity generating facilities. In June 2000, RECLAIM program participants experienced a sharp and sudden increase in NOx RECLAIM trading credit (RTC) prices for both 1999 and 2000 compliance years. Based on the 2000 RECLAIM Annual Report, electricity generating facilities had an initial allocation of 2,302 tons of NOx per year. In compliance year 2000, these facilities reported NOx emissions of 6,788 tons per year, approximately 4,400 tons per year over their initial allocation. This was primarily due to an increased demand for power generation and delayed installation of controls by electricity generating facilities. The electric power generating industry purchased a large quantity of RTCs and depleted the available RTCs. This situation was compounded because few RECLAIM facilities added control equipment.

As a result, in May 2001, the Board adopted Rule 2009 – Compliance Plan for Power Producing Facilities (Rule 2009). To facilitate emission reduction projects at the facilities with the majority of the emissions in RECLAIM, Rule 2009 required installation of BARCT through compliance plans at electricity generating facilities. Diesel internal combustion engines providing power to Santa Catalina Island were not subject to Rule 2009 because the facility only generates 9 megawatts of energy and did not qualify as a Power Producing Facility in RECLAIM. Despite the increase in NOx RTC demand, emissions from electricity generating facilities fell from 26 tons per day (TPD) of NOx emissions in 1989 to less than 10 TPD of NOx emissions by 2005. Since then, with equipment replacement and increased reliance on renewable sources, NOx emissions have further decreased to less than 4 TPD.

AFFECTED INDUSTRIES

There are 32 electricity generating facilities subject to PAR 1135. All 32 facilities are classified under NAICS Code 221112 - Utilities (Fossil Fuel Electric Power Generation). Of these 32 affected facilities, 17 are located in Los Angeles County, six are in Orange County, six are in

Riverside County, and the remaining three facilities are located in San Bernardino County. Twenty-seven facilities are currently in the NOx RECLAIM program. Of the remaining five facilities, one is currently subject to SCAQMD Rules 1134 and 1135 and four are not subject to Rule 1134 or 1135 because of current applicability requirements in the rules.

Twenty-nine of the 32 facilities were identified as not needing to modify their existing equipment in order to comply with PAR 1135. The electric power generating units at these facilities are not expected to require modifications to comply with PAR 1135 because the electric power generating units either: 1) currently meet the NOx emission limit; 2) are currently eligible for a low-use provision; 3) have existing NOx emission levels that are near the proposed NOx emission limit and the unit is exempt from the NOx emission limit because potential equipment modifications exceed a cost-effectiveness threshold of $50,000 per ton of NOx reduced; or 4) are scheduled by facility operators to be either shut down or repowered due to other regulatory requirements not pertaining to PAR 1135.

Only three electricity generating facilities would be expected to have existing electric generating units that would require potential modifications (e.g., installing new or modifying existing air pollution control systems, or repowering or replacing existing electric power generating units) in order to comply with PAR 1135.

Small Businesses

SCAQMD defines a “small business” in Rule 102, for purposes of fees, as one which employs 10 or fewer persons and which earns less than $500,000 in gross annual receipts. SCAQMD also defines “small business” for the purpose of qualifying for access to services from SCAQMD’s Small Business Assistance Office as a business with an annual receipt of $5 million or less, or with 100 or fewer employees. In addition to SCAQMD's definition of a small business, the federal Clean Air Act Amendments (CAAA) of 1990 and the federal Small Business Administration (SBA) also provide definitions of a small business.

The California Health and Safety Code section 42323 classifies a business as a “small business stationary source” if it: (1) is owned or operated by a person who employs 100 or fewer individuals; (2) is a small business as defined under the federal Small Business Act (15 U.S.C. Sec. 631, et seq.); and (3) emits less than 10 tons per year of any single pollutant and less than 20 tons per year of all pollutants. The SBA definitions of small businesses vary by six-digit North American Industrial Classification System (NAICS) codes. In general terms, a small business must have no more than 500 employees for most manufacturing industries, and no more than $7 million in average annual receipts for most nonmanufacturing industries.[1] A business in the industry of fossil fuel electric power generation (NAICS 221112) with fewer than 750 employees is considered a small business by SBA.

Of the 32 affected facilities within SCAQMD’s jurisdiction, 15 are public utilities. Information on sales and employees for the 17 remaining facilities were available in the Dun and Bradstreet

[1] The latest SBA definition of small businesses by industry can be found at http://www.sba.gov/content/table-small-business-size-standards.

Enterprise Database.[2] Under SCAQMD's definition of small business, there are no small businesses affected by PAR 1135. Using the SBA definition of small business for the fossil fuel electric power generation sector, 17 of the facilities are considered small businesses. Under the CAAA definition of small business, eight of the facilities are considered small businesses.

COMPLIANCE COST

The main requirements of PAR 1135 that have cost impacts for affected facilities would include one-time costs and annual recurring costs. The one-time costs would include capital and installation of SCRs, diesel internal combustion engines, natural gas turbines, and one-time permit modifications. Annual recurring cost estimates include annual operating and maintenance costs of SCRs and additional ammonia usage.

The average annual cost of PAR 1135 is estimated to be $6.4 - $8.7 million between 2019 and 2045, for the low and high cost scenarios, respectively. The low cost scenario assumes a real interest rate of 1%, while the high cost scenario assumes a 4% real interest rate. The entirety of the overall annual compliance costs is expected to be incurred by the utility sector.

Staff has used the following sources to estimate costs of capital, installation, operating and maintenance of SCRs, diesel internal combustion engines, and natural gas turbines:

1) Catalog of CHP Technologies, U.S. EPA Combined Heat and Power Partnership, September 2017.
2) Vendor Cost Estimates.

Of the 32 facilities that are in the PAR 1135 universe, only three facilities were identified as candidates for modifying their existing equipment in order to comply with PAR 1135. Required modifications (and associated costs) to electricity generating units in order to meet the updated BARCT NOx concentration limits in PAR 1135 are detailed below.

There are five diesel internal combustion engines (each installed more than 33 years ago) located at one facility that are expected to be replaced in order to comply with PAR 1135. Based on vendor estimates, equipment and installation costs result in a one-time capital cost of $3.9 million for each unit.

There are three natural gas boilers operated by a municipality. Prior to the development of PAR 1135, the operator presented a project to their city council proposing plans to shut down the three natural gas boilers. Staff has assumed the municipality will repower them with three natural gas turbines (one 20 MW unit and two 44 MW units). Based on U.S. EPA data, one-time capital costs for the 20 MW unit consists of $19.8 million in equipment costs and an additional $10.2 million in construction and development fees. Capital cost for the 44 MW units consist of $35.8 million

[2] Dun & Bradstreet Enterprise Database, 2018.

per unit in equipment costs and an additional $17.4 million per unit in construction and development fees.

Another municipality that operates four natural gas simple cycle gas turbines has tentatively scheduled for the catalyst in each of the four existing SCR systems to be replaced with more efficient catalyst to comply with the updated BARCT NOx concentration limits in PAR 1135. Based on vendor cost estimates, replacement of two 30.6 MW units will result in one-time capital costs consisting of $439,000 per unit in equipment costs, $1.1 million per unit in installation costs, and $165,000 per unit for spent catalyst disposal and administrative fees. Replacement of two 40.6 MW units will result in one-time capital costs consisting of $241,000 per unit in equipment costs, $1.1 million per unit in installation costs, and $165,000 per unit for spent catalyst disposal and administrative fees. Recurring costs for all four units are comprised of $1,400 per unit in increased ammonia costs annually and an increase of $55,000 per unit in SCR replacement costs incurred every five years.

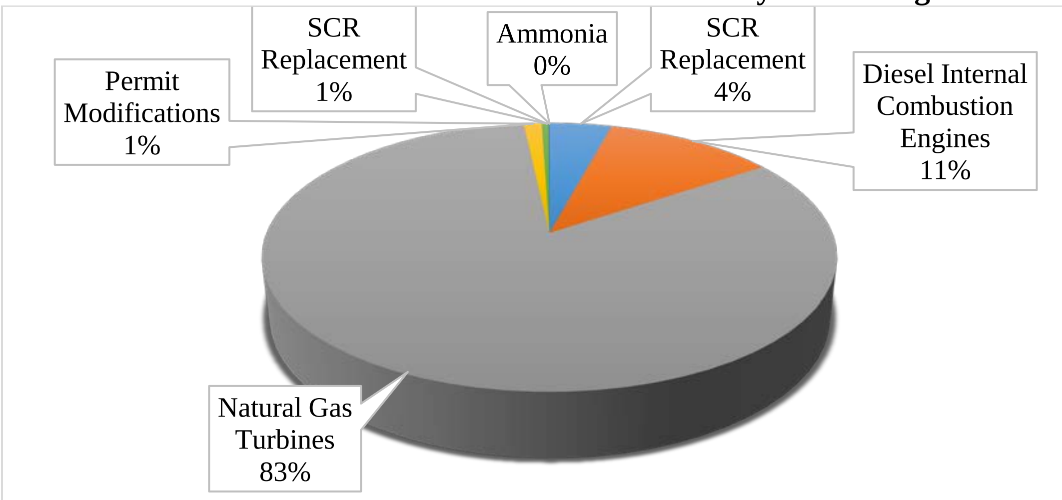
In addition, all 32 facilities will be required to have their permits modified as a result of PAR 1135. Permit fees for each piece of equipment will result in a one-time cost ranging from $3,160 - $23,933. A subset of six facilities may also be required to pay a one-time notification fee of $2,637.

Table 1 and Figure 1 present the distribution of the overall costs by selected cost categories. The majority of costs of PAR 1135 ($8.2 million annually) stem from installation of five diesel internal combustion engines and three natural gas turbines. The additional capital costs of SCR replacement and permit modifications are estimated at about $360,000 and $110,000, respectively.

Table 1:
Total and Average Annual Cost of PAR 1135 by Cost Category

	Present Worth Value (2019)		**Annual Average (2019-2045)**	
Cost Categories	**1% Discount Rate**	**4% Discount Rate**	**1% Real Interest Rate**	**4% Real Interest Rate**
One-Time Cost				
SCR Replacement (including installation)	$3,847,914	$3,608,256	$266,177	$364,418
Diesel Internal Combustion Engines (including installation)	$18,725,488	$15,717,001	$728,124	$996,859
Natural Gas Turbines (including installation)	$131,277,405	$113,458,877	$5,283,791	$7,233,932
Permit Modifications	$1,838,115	$1,645,603	$76,847	$105,210
Recurring Costs				
SCR Replacement	$1,145,113	$788,918	$40,686	$40,686
Ammonia	$122,598	$83,479	$5,030	$5,030
Total	**$156,956,633**	**$135,302,135**	**$6,400,655**	**$8,746,135**

Figure 1:
Annual Estimated Costs of the PAR 1135 Series by Cost Categories



JOBS AND OTHER SOCIOECONOMIC IMPACTS

The REMI model (PI+ v2.2) was used to assess the total socioeconomic impacts of a regulatory change (i.e., the proposed rule).[3] The model links the economic activities in the counties of Los Angeles, Orange, Riverside, and San Bernardino, and for each county, it is comprised of five interrelated blocks: (1) output and demand, (2) labor and capital, (3) population and labor force, (4) wages, prices and costs, and (5) market shares.[4]

The assessment herein is performed relative to a baseline ("business as usual") where the proposed amendments would not be implemented. The proposed amendments would create a regulatory scenario under which the affected facilities would incur an average annual compliance costs totaling \$6.4 - \$8.7 million. Direct effects of the proposed amendments have to be estimated and used as inputs to the REMI model in order for the model to assess secondary and induced impacts for all actors in the four-county economy on an annual basis and across a user-defined horizon (2019 - 2045). Direct effects of the proposed amendments include additional costs to the affected entities and additional sales, by local vendors, of equipment, devices, or services that would meet the proposed requirements.

While compliance expenditures may increase the cost of doing business for affected facilities, the purchase and installation of additional equipment combined with spending on operating and

[3] Regional Economic Modeling Inc. (REMI). Policy Insight® for the South Coast Area (70 sector model). Version 2.2, 2018.

[4] Within each county, producers are made up of 66 private non-farm industries, three government sectors, and a farm sector. Trade flows are captured between sectors as well as across the four counties and the rest of U.S. Market shares of industries are dependent upon their product prices, access to production inputs, and local infrastructure. The demographic/migration component has 160 ages/gender/race/ethnicity cohorts and captures population changes in births, deaths, and migration. (For details, please refer to REMI online documentation at http://www.remi.com/products/pi.)

maintenance, may increase sales in other sectors. Table 2 lists the industry sectors modeled in REMI that would either incur a cost or benefit from the compliance expenditures.[5]

As discussed earlier, the total average annual compliance costs for affected facilities by PAR 1135 was estimated to range from $6.4 - $8.7 million per year, depending on the real interest rate assumed (1% - 4%).

PAR 1135 is expected to result in approximately 88 - 134 jobs on average forgone annually, between 2019 and 2045, depending on the real interest rate assumed (1% - 4%). The projected job loss impacts represent about 0.0008% - 0.0012% of the total employment in the four-county region.

Table 2:
Industries Incurring *vs.* Benefitting from Compliance Costs/Spending

Source of Compliance Costs	**REMI Industries Incurring Compliance Costs (NAICS)**	**REMI Industries Benefitting from Compliance Spending (NAICS)**
SCR Replacement	Utilities (22)	*One-time Capital Cost:* Machinery Manufacturing (333), Construction (23)
Natural Gas Turbines		*One-time Capital Cost:* Machinery Manufacturing, Construction
Diesel Internal Combustion Engines		*One-time Capital Cost:* Machinery Manufacturing, Construction
Permit Modifications		*One-time Capital Cost:* Public Administration (92)
SCR Replacement (Maintenance)		*Recurring Cost:* Professional, Scientific, and Technical Services (541)
Ammonia		*Recurring Cost:* Chemical Manufacturing (325)

[5] Improved public health due to reduced air pollution emissions may also result in a positive effect on worker productivity and other economic factors; however, public health benefit assessment requires the modeling of air quality improvements. Therefore, it is conducted for AQMPs and not for individual rules or rule amendments.

As presented in Table 3, 235 additional jobs could be created in the overall economy in 2022. This is mainly due to additional purchase and spending on installation of diesel internal combustion engines, natural gas turbines, and SCR replacement provided by the industries of machinery manufacturing, construction, and professional and technical services sectors. As the cost of doing business kicks in and is maintained, the positive impact of spending subsides and jobs forgone are expected to begin. Although the utility sector would bear the entirety of the estimated total compliance costs of PAR 1135, the industry job impact is projected to be relatively small (annual average of 4 jobs foregone between 2019 and 2045). The impact to the utility sector is expected to be small due to the fact that utilities can potentially pass the additional compliance costs on to rate payers.

In earlier years of the regional simulation, the sector of machinery manufacturing (NAICS 333), construction (NAICS 23), and professional and technical services (NAICS 541) are projected to gain jobs from additional demand for equipment installation and maintenance made by the affected facilities on average. The remainder of the projected reduction in employment would be across all major sectors of the economy from secondary and induced impacts of the proposed amendments. In earlier years positive job impacts from the expenditures made by the affected facilities would more than offset the jobs forgone from the additional cost of doing business. Jobs foregone in the later years are due to additional costs of doing business by affected facilities.

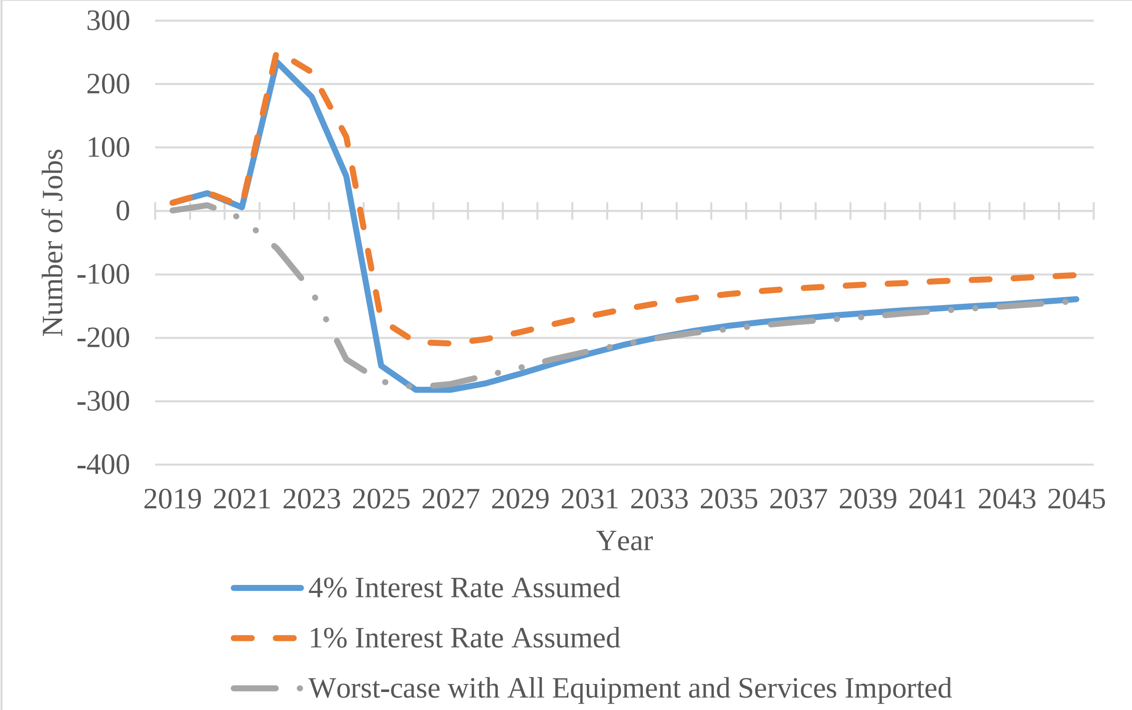
As the cost of doing business kicks in and is maintained, and positive impact of spending gradually subsides, jobs foregone across all sectors are expected to begin. The reduction in disposable income would dampen the demand for goods and services in the local economy, thus resulting in a relatively large number of jobs forgone projected in sectors such as construction (NAICS 23), professional, scientific and support services, and retail trade (NAICS 44 - 45). A smaller number of jobs foregone are expected in wholesale trade (NAICS 42), administrative and support services (NAICS 561), and food services (NAICS 722).

Table 3:
Job Impacts of PAR 1135 (High Cost Scenario)

Industries (NAICS)	2020	2022	2025	2035	2045	Average Annual Jobs (2019 - 2045)	Average Annual Baseline (2019 - 2045)	% Change from Baseline Jobs
Utilities (22)	0	-1	-6	-5	-1	-4	20,469	-0.019%
Construction (23)	7	59	-93	-32	-10	-30	469,843	-0.006%
Machinery manufacturing (333)	0	21	1	-1	-1	2	19,979	0.008%
Rest of manufacturing (31-33)	0	3	-9	-2	-3	-4	557,185	-0.001%
Total manufacturing (31-33)	0	24	-8	-3	-4	-2	577,164	0.000%
Professional, scientific, and technical services (54)	2	37	-13	-34	-32	-21	922,718	-0.002%
Retail trade (44-45)	2	16	-20	-15	-12	-11	981,761	-0.001%
Administrative and support services (561)	1	12	-13	-12	-11	-9	817,224	-0.001%
Food services and drinking places (722)	1	8	-8	-11	-10	-7	729,571	-0.001%
Wholesale trade (42)	1	7	-9	-6	-5	-5	477,451	-0.001%
State and local government (92)	6	10	-5	-15	-11	-9	907,126	-0.001%
Other industries	8	39	-61	-45	-39	-34	4,798,261	-0.001%
Total	**28**	**235**	**-244**	**-181**	**-139**	**-134**	**11,278,751**	**-0.001%**

Figure 2 presents a trend of job gain and losses over the 2019 - 2045 time frame. The increase in jobs in 2022 are due to additional spending on installation of diesel internal combustion engines and natural gas turbines. Staff has analyzed an alternative scenario (worst case) where the affected facilities would not purchase any control or service from providers within the South Coast Air Basin. This scenario would result in an average of 170 jobs forgone annually.

Figure 2:
Projected Regional Job Impact, 2019-2045



Competitiveness

The additional cost brought on by PAR 1135 would increase the cost of services rendered by the affected industries in the region. The magnitude of the impact depends on the size, diversification, and infrastructure in a local economy as well as interactions among industries. A large, diversified, and resourceful economy would absorb the impact described above with relative ease.

Changes in production/service costs would affect prices of goods produced locally. The relative delivered price of a good is based on its production cost and the transportation cost of delivering the good to where it is consumed or used. The average price of a good at the place of use reflects prices of the good produced locally and imported elsewhere.

It is projected that the utility sector, where most of the affected facilities belong, would experience a rise in its relative cost of production of 0.062% - 0.085% in 2025 for the low and high cost scenarios, respectively. The utility sector is also expected to experience an increase in its delivered price by 0.032% - 0.044% in 2025 for the low and high cost scenarios, respectively. Delivered prices that a facility may charge for specific goods or services may increase at a greater rate than predicted, allowing incurred costs to be passed through to downstream industries and end-users. The remaining sectors are likely to experience increases in the relative cost of production and relative delivered price with respect to their counterparts in the rest of the U.S.

UPDATED COST IMPACTS ASSESSMENT FOR COMPLIANCE WITH RULE 2002

Potential Impacts for NOx RECLAIM Facilities Ready to Exit

Rule 2002(f)(9) prohibits a RECLAIM facility from selling any future compliance year RECLAIM Trading Credits (RTCs) upon receipt of a final determination notification that it is ready to exit the NOx RECLAIM program. If PAR 1135 is adopted, 27 facilities are expected to receive an initial determination notification because, according to staff's evaluation, all of their permitted RECLAIM NOx source equipment will be subject to this rule once PAR 1135 is adopted. Final determination notifications will not be issued, however, until New Source Review (NSR) issues are resolved. In addition, staff is working on amendments to Rules 2001 and 2002 that will allow a facility to remain in RECLAIM to allow time for the SCAQMD to address NSR and permitting for the transition from RECLAIM to a command-and-control regulatory structure.

Among the 27 facilities, 17 were allocated NOx RTCs (no cost or fee when RTCs were allocated) at the outset of the NOx RECLAIM program (the remaining 12 facilities joined the NOx RECLAIM program after its inception in 1994 and were not issued allocations). The initial allocations for the 17 facilities amounted to approximately 4.81 tons per day (TPD). Due to past adjustments including reductions in allocations or "shaves," and more importantly, the sale of these initial allocations as infinite-year block (IYB) RTCs to other NOx RECLAIM facilities and brokers/investors, the total NOx RTCs currently held by these 27 facilities is 4.42 TPD for compliance years 2019 and later.[6] At the same time, total NOx emissions from these same facilities have declined to 1.86 TPD in 2016.

If these 27 facilities receive final determination notifications in 2018, they will not be able to sell their NOx RTCs for compliance year 2019 and onwards. For the purpose of this analysis, it is assumed that none of the 27 facilities would acquire additional NOx RTCs or sell their current NOx RTC holdings of 4.42 TPD before receiving a final determination notification. However, it is foreseeable that at least some of these NOx RTC holdings may be sold or transferred before they are frozen due to receipt of final determination notifications. In addition, staff has committed to not issuing any final determination notifications until NSR issues are resolved. Lastly, as they pertain to SCAQMD, RTCs are not property rights. It is known to all market participants that are purchasing RTCs beyond the current compliance year is accompanied by known investment risks that are embedded within the RECLAIM programs. The risk factors include, but may not be limited to, programmatic allocation shaves, potential RTC trade freezes, and the eventual sunset of either RECLAIM program.

Since there were no costs associated with the initially allocated NOx RTCs for a RECLAIM facility, the facilities would not incur financial losses as a result of complying with Rule 2002(f)(9) if their frozen future compliance year NOx RTC holdings are at or below their respective adjusted initial allocations. However, it was estimated that, out of the total 4.42 TPD of future compliance year NOx RTCs currently held by the 27 facilities, at least 1.51 TPD were acquired by some of the

[6] According to the NOx RTC holdings data as of July 31, 2018 and excluding any transactions that may have occurred after this date.

affected facilities in addition to their initial allocations, either through purchases with positive prices or transfers at no cost. If these facilities continue to stay in the NOx RECLAIM program and their NOx emissions remain between 5% above and below their 2016 levels,[7] then 0.10 TPD of these additionally acquired RTCs were estimated to be used for compliance purposes, with the remaining 1.41 TPD being potential surplus RTCs available for sale or transfer. Applying the most recent 12-month rolling average NOx RTC price for compliance year 2017 of $2,530 per ton,[8] the total value of all potential surplus RTCs would be approximately $1.3 million for the compliance year 2019. These facilities can elect to transfer or sell these RTCs prior to receiving a final determination notification. If the electricity generating facility is holding these RTCs at or after the final determination notification they will not be able to sell, use, or transfer the RTCs.

In addition, five out of the 27 facilities are estimated to have insufficient NOx RTC holdings if they were to continue to stay in the NOx RECLAIM program and their NOx emissions remain between 5% above and below their 2016 levels. By exiting the NOx RECLAIM program, these facilities would avoid the need to acquire about 0.13 - 0.18 TPD of NOx RTCs which, if also valued at $2,530 per ton, would imply potential total cost-savings approximately worth $119,000 - $162,000 for the compliance year 2019.[9]

The value of potential surplus RTCs and RTCs needed to comply varies in subsequent years due to future shaves. The current schedule calls for a 2.0 TPD shave beginning in 2020, a 2.0 TPD shave beginning in 2021, and a 4.0 TPD shave beginning in 2023. For electricity generating facilities in RECLAIM, the number of projected surplus RTCs decreases from 1.42 TPD in 2019 to 1.00 TPD in 2022. Over the same time period, the number of RTCs needed to comply increases from 0.15 TPD in 2019 to 0.37 TPD in 2022.[10] As a result, the total compliance year cost of freezing exiting facilities' RTCs decreases from $1.2 million in 2019 to $0.6 million in 2022.

The year electricity generating facilities exit RECLAIM could have a significant effect on the cumulative costs on RTCs if electricity generating facilities do not sell or transfer any RTCs prior to receiving their final determination notification. Cumulative costs of freezing RTCs range from $3.8 million in 2019 to $0.6 million in 2022.[11] Table 4 includes the total value of potential RTC sales foregone for all affected facilities with surplus RTCs exiting RECLAIM, as well as the potential total cost-savings for all facilities with insufficient RTC holdings for potential exit years 2019, 2020, 2021, and 2022.

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[7] In order to estimate the number of RTCs needed for compliance in future years, it is necessary to project the emissions levels of all electricity generating facilities. We analyze three scenarios; 1) emissions are 5% below 2016 levels; 2) emissions remain at 2016 levels; and 3) emissions are 5% above 2016 levels.

[8] 12-month rolling average of Compliance Year 2017 NOx RTCs, as calculated from July 2017 to July 2018. See Table I of "Twelve-Month and Three-Month Rolling Average Price of Compliance Years 2017 and 2018 NOx and SOx RTCs," available at: http://www.aqmd.gov/docs/default-source/reclaim/nox-rolling-average-reports/nox-and-sox-rtcs-rolling-avg-price-cy-2017-18---jul-2018.pdf

[9] Cost savings vary based on the projected emissions in compliance year 2019. The range in cost savings presented represents 5% below/above 2016 emission levels.

[10] Results are based on the assumption that NOx emissions in the years 2019, 2020, 2021, and 2022 remain at 2016 levels.

[11] Cumulative costs of freezing RTCs is calculated by summing the total compliance cost for current year and each subsequent year (up to and including 2022).

The dollar figures for the potential costs and savings for facilities exiting RECLAIM listed in Table 4 are highly sensitive to the assumed RTC price of $2,530 per ton. In general, RTC prices are highly variable, with prices typically decreasing as their expiration dates approach and during the 60 days after expiration during which they can be traded. This general trend has been repeated every year since 1994 except for compliance years 2000 and 2001 (during the California energy crisis). Prices for NOx RTCs that expired in calendar year 2017 also followed this general trend. The general declining trend of RTC prices nearing and just past expiration indicates there was an adequate supply to meet RTC demand during the final reconciliation period following the end of the compliance years. Further uncertainty has been introduced due to the Governing Board's decision to transition to a command-and-control regulatory structure.

Table 4:
Forgone Sales and Cost-savings
for Affected Facilities by Potential Year of RECLAIM Exit

	Year of RECLAIM Exit			
	2019	**2020**	**2021**	**2022**
Acquired RTCs potentially for sale if remain (TPD)	1.415	1.323	1.298	0.996
Potential RTC sales foregone if exiting	$1,306,448	$1,221,673	$1,198,323	$919,316
RTCs need for compliance if remain (TPD)	0.152	0.197	0.233	0.365
Total cost-savings by exiting	$140,528	$181,491	$215,199	$337,325
Total compliance year cost	$1,165,921	$1,040,182	$983,124	$581,991
Cumulative cost from exiting	$3,771,218	$2,605,297	$1,565,115	$581,991

Note: Results are based on the assumption that NOx emissions in the years 2019, 2020, 2021, and 2022 remain at 2016 levels. Assumes an RTC price of $2,530 per ton.

Potential NOx RTC Market Impacts

Since the SCAQMD Governing Board's March 2017 adoption of the 2016 AQMP, which includes the sunset of NOx RECLAIM, the number of NOx IYB trades has decreased significantly. The IYB price has also declined rapidly, from a 12-month rolling average of $380,057 per ton in January 2017 to $20,103 per ton in July 2018, which largely reflects the remaining years of the NOx RECLAIM program life that is expected by the market participants. However, the short-term price impact of facility exit on the discrete-year RTC market may not go hand-in-hand with the overall impact of the NOx RECLAIM program transition on the IYB market, as evidenced by the surge in discrete-year NOx RTC prices in 2017.

The analysis below will focus on the potential impacts to the discrete-year NOx RTC market due to compliance with Rule 2002. The potential exit of the 29 facilities from the NOx RECLAIM program could possibly affect the demand and supply in the NOx RTC market for compliance year 2019 and beyond, as well as the future prevailing NOx RTC prices. Therefore, the remaining NOx RECLAIM facilities may be indirectly impacted as a result.

Table 5 reports the potentially foregone market demand and supply for three different NOx emission scenarios. The first scenario assumes future NOx emissions of the 27 facilities would be 5% below their respective 2016 levels; the second scenario assumes the same emission levels as in 2016; and the third scenario assumes their future NOx emissions would be 5% above their respective 2016 levels. These scenarios are consistent with the variations of overall NOx emissions from the RECLAIM universe, which had a maximum year-over-year difference of approximately 5% during the period of 2011 - 2016.

The foregone market demand, as estimated by the shortage of a facility's future compliance year NOx RTC holdings for NOx emissions reconciliation, would be about 0.13 - 0.18 TPD. At the same time, the potential foregone market supply from *all* facilities with potential surplus RTC holdings is estimated at 2.64 - 2.78 TPD, or about 1,400% - 2,050% greater than the estimated foregone market demand. However, some of these facilities with potential surplus NOx RTCs have never sold or transferred NOx RTCs to another NOx RECLAIM facility since the NOx RECLAIM program began in 1994. Therefore, it is reasonable to assume that they will not participate in the market even if they continue to stay in the NOx RECLAIM program. When estimated by the potential surplus NOx RTC holdings from only the facilities with a historical record of NOx RTC sales and/or transfers, the foregone market supply is estimated to be lower at 2.39 - 2.57 TPD, or about 1,360% - 1,980% greater than the estimated foregone market demand.

Additionally, when compared to the 7.0 TPD of discrete-year NOx RTCs traded in calendar year 2017, the estimated net foregone market supply of 2.39 - 2.78 TPD represents 34% - 37% of that total traded volume.[12] Given the analysis above and the fact that the 27 facilities currently account for 9.4% of annual NOx emissions and 19.7% of NOx RTC holdings in the NOx RECLAIM universe, the simultaneous transition of the 27 PAR 1135 facilities out of the NOx RECLAIM program could potentially exert upward pressure on the discrete-year NOx RTC prices.

There are currently procedures in place to intervene if the NOx RTC price becomes excessively high. Rule 2002(f)(1)(H) specifies that in the event that the NOx RTC price exceeds $22,500 per ton based on the 12-month rolling average, or exceeds $35,000 per ton based on the 3-month rolling average calculated pursuant to subparagraph (f)(1)(E), the Executive Officer will report the determination to the Governing Board. If the Governing Board finds that the 12-month rolling average RTC price exceeds $22,500 per ton or the 3-month rolling average RTC price exceeds

[12] In calendar year 2017, a total of 2,556 tons of discrete year NOx RTCs were traded (2556 tons/365 days = 7.0 TPD). See page ES-2 of "Annual RECLAIM Audit Report for 2016 Compliance Year," available at http://www.aqmd.gov/docs/default-source/reclaim/reclaim-annual-report/2016-reclaim-report.pdf. Notice, however, that some of the RTCs might have been traded more than once in the same year.

$35,000 per ton, then the Non-tradable/Non-usable NOx RTCs, as specified in subparagraphs (f)(1)(B) and (f)(1)(C) valid for the period in which the RTC price is found to have exceeded the applicable threshold, shall be converted to Tradable/Usable NOx RTCs upon Governing Board concurrence.

Table 5:
Potential Impacts on NOx RTC Market Demand and Supply

		NOx Emission Scenarios for Future Compliance Years		
		5% Below 2016 NOx Emissions	***Same as 2016 NOx Emissions***	***5% Above 2016 NOx Emissions***
A	**Foregone Market Demand (TPD)**	0.129	0.153	0.176
B	**Foregone Market Supply (TPD)** *– From All Facilities with Surplus RTC Holdings*	2.777	2.707	2.637
C	**Net Foregone Market Supply (TPD)** (= *B* - *A*)	2.648	2.554	2.461
	Percent Difference: ***(Supply – Demand)/Demand*** (= *C* / *A*)	2,046%	1,673%	1,399%
D	**Foregone Market Supply (TPD)** *– From Facilities with Surplus RTC Holdings & Historical Record of RTC Sales/Transfers*	2.700	2.634	2.567
E	**Net Foregone Market Supply (TPD)** (= *D* - *A*)	2.571	2.481	2.391
	Percent Difference: ***(Supply – Demand)/Demand*** (= *E* / *A*)	1,986%	1,625%	1,359%

Note: The supply and demand of NOx RTCs are expressed in TPD and rounded to the nearest thousandth. Percent differences are rounded to the nearest integer.

It is possible some or all facilities choose not to exit RECLAIM upon receipt of their initial determination notification. The vast majority of facilities will likely opt to remain in RECLAIM following the adoption of PAR 1135. The decision to remain in RECLAIM coincides with more favorable NSR provisions and those facilities with surplus RTCs have incentive to remain in order to sell excess credits. Conversely, those facilities with insufficient RTC holdings have incentive to opt out of RECLAIM and forego acquiring the necessary RTCs to comply with RECLAIM requirements. Under this scenario, the adoption of PAR 1135 could potentially result in a net cost savings as it pertains to the RTCs currently held by RECLAIM electricity generating facilities.