SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT

Draft Socioeconomic Impact Assessment For
Proposed Rule 1109.1 – Emissions of Oxides of Nitrogen from Petroleum Refineries and Related Operations
Proposed Rule 429.1 – Startup and Shutdown Provisions at Petroleum Refineries and Related Operations
Proposed Amended Rule 1304 – Exemptions
Proposed Amended Rule 2005 – New Source Review for RECLAIM

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EXECUTIVE SUMMARY

A socioeconomic analysis has been conducted to assess the impacts of Proposed Rule 1109.1, Proposed Rule 429.1, and Proposed Amended Rules 1304 and 2005. The same level of analysis has also been performed on the California Environmental Quality Act (CEQA) alternatives. A summary of the analysis and findings are presented below.

Key Elements of the Proposed Amendments	Proposed Rule 1109.1 – Emissions of Oxides of Nitrogen from Petroleum Refineries and Related Operations (PR 1109.1) will facilitate the transition of petroleum refineries and facilities with related operations to petroleum refineries to a command-and-control regulatory structure and partially implement Control Measure CMB-05 of the 2016 Air Quality Management Plan (AQMP). PR 1109.1 applies to oxides of nitrogen (NOx) emitting combustion equipment at facilities, including asphalt plants, biofuel plants, hydrogen production plants, petroleum refineries, facilities that operate petroleum coke calciners, sulfuric acid plants, and sulfur recovery plants. The proposed rule will establish NOx and Carbon Monoxide (CO) emission limits to reflect the Best Available Retrofit Control Technologies (BARCT) for most combustion equipment categories at these facilities. Additionally, PR 1109.1 establishes provisions for monitoring, recordkeeping, and reporting and provides alternative implementation and compliance approaches including an Implementation Plan (I-Plan), BARCT Equivalent Compliance Plan (B-Plan), and BARCT Equivalent Mass Cap Plan (B-Cap), which provides flexibility and opportunities for facilities to reduce cost impacts. Proposed Rule 429.1 - Startup and Shutdown Provisions at Petroleum Refineries and Related Operations (PR 429.1) exempts units from PR 1109.1 NOx and CO emission limits and applicable rolling average provisions during startup, shutdown, and catalyst maintenance events. PR 429.1 also establishes requirements during startup and shutdown pursuant to U.S. EPA policies to regulate startup, shutdown, and malfunction. PR 429.1 limits the duration of startup and shutdown events and the frequency of scheduled startups. Additionally, PR 429.1 establishes best management practices for startup and shutdown events and notification and recordkeeping requirements. The provisions in PR 429.1 are not expected to impose additional costs to facilities, nor are they expected to result in additional emission reductions. As such, no adverse socioeconomic impacts are anticipated. Proposed amendments for Rule 1304 – Exemptions (Rule 1304) and Rule 2005 – New Source Review for RECLAIM (Rule 2005) are necessary to implement a narrow Best Available Control Technology (BACT) exemption. The exemption will allow for emission

	increases associated with air pollution control equipment installed for regulatory compliance with a Best Available Retrofit Control Technology (BARCT) rule required to transition the RECLAIM program for NOx to a command-and-control regulatory structure. The provisions in Rule 1304 and Rule 2005 are not expected to impose additional costs to facilities, nor are they expected to result in additional emission reductions. As such, no adverse socioeconomic impacts are anticipated.
Affected Facilities and Industries	PR 1109.1 will affect 16 facilities, including nine petroleum refineries, three small refineries, and four facilities with related operations. The three small refineries consist of two asphalt refineries and one biodiesel refinery, and the four facilities with related operations include three hydrogen plants and one sulfuric acid plant. Eleven of the 16 facilities are classified under NAICS 324 – Petroleum and Coal Products Manufacturing, four facilities are classified under NAICS 3251 – Basic Chemical Manufacturing, and the remaining facility is classified as NAICS 3259 – Other Chemical Product and Preparation Manufacturing. All 16 affected facilities are located in Los Angeles County. PR 1109.1 applies to nearly all combustion equipment at petroleum refineries and related facilities. Based on South Coast AQMD's permit database and facility surveys, staff has identified 292 units that will be subject to the PR 1109.1, with six major classes of equipment: process heaters & boilers (including steam methane (SMR) heater), gas turbines, fluid catalytic cracking units (FCCU), sulfur recovery unit/tail gas (SRU/TG) incinerators, vapor incinerators, and coke calciners. Across the 16 affected facilities there are 224 process heaters & boilers, 19 SRU/TG incinerators, 13 vapor incinerators, 12 gas turbines, 5 FCCUs, and 1 coke calciner.
Assumptions for the Analysis	PR 1109.1 is expected to result in approximately 7 to 8 tons per day (tpd) of NOx emission reductions from the installation and operation of control technology in order to comply with the lower NOx limits of PR 1109.1. For the sake of this analysis, however, a NOx emission reduction of 7.83 tpd was assumed. The 7.83 tpd emission reduction estimate represents staff's assumption regarding the units that would qualify to meet the Table 2 conditional limits with all other units meeting the Table 1 emission limits. The 7 – 8 tpd emission reduction range represents the range of emission reductions the rule will achieve considering the flexibility in the compliance options, the potential eligibility of the conditional limits for units not identified by staff, and the added emission reduction from the ten percent environmental benefit under the B-Cap approach. Compliance with the NOx limits in the proposed rule may overlap with projects currently taking place to comply with the 2015 NOx

	RECLAIM shave. This is due to 2017 emissions being used as baseline for the BARCT analysis in this proposed project, and those emissions could have since been reduced if a RECLAIM shave project has taken place since 2017. The proposed project is expected to achieve NOx emission reductions for every class and category of equipment and staff anticipates that 74 units will be retrofitted with new Selective Catalytic Reduction (SCR) Systems, 15 existing SCRs will be upgraded (SCR upgrade), and 76 units will be retrofitted with Ultra Low-NOx Burner (ULNB) technology. An assumed implementation schedule was developed which would comply with the emission reduction targets and schedule outlined in Table 4 of the proposed rule. The actual implementation of control equipment is uncertain and will likely differ from the schedule described here as affected facilities have been given flexibility in regards to which units will be required to meet the percent reductions specified in their approved implementation plan (I-Plan) to meet proposed BARCT emission limits. The analysis assumes that all capital costs (equipment and installation) are incurred in the year prior to implementation. Additionally, all recurring costs (O&M) and emission reductions begin in the implementation year assumed. The annualization factor used for capital costs is based on a real interest rate of 1% or 4% and a 25-year equipment life was assumed for all control equipment. All dollar figures are presented in 2018 dollars.
Cost Impacts	South Coast AQMD solicited direct input from affected facilities on the expected total installed costs and operating and maintenance (O&M) costs of all potential pollution control equipment necessary to implement BARCT. In 2018, South Coast AQMD staff received cost estimates from affected facilities that included 49 total installed cost (TIC) estimates that were obtained from 7 refineries for SCR retrofit and upgrade projects on heaters and boilers > 40 MMBtu/h. In 2021 affected facilities provided additional or revised cost estimates that included a total of 108 TIC estimates. Subsequently, Norton Engineering Consultants, Inc. provided an independent review of the facility provided cost data. Norton's conclusion was that the costs provided by the facilities are not unreasonable, considering the potential complexity. Staff assumed all SCR and ULNB costs received from facilities included capital, engineering, construction, tax, and shipping. In

addition, all cost was assumed to include increased labor costs associated with Senate Bill (SB) 54 which requires refineries to use unionized construction labor. TIC provided were in different years and staff conservatively escalated all costs at 4% annual inflation rate to the 2018 dollar year.

In addition, staff modified the U.S. EPA SCR cost spreadsheet using actual TIC estimates provided by the facilities to reflect the actual TIC of SCR installations in the refinery sector. Cost assumptions were discussed extensively at multiple working group meetings and staff consulted with U.S. EPA Air Economics Group regarding staff's proposed methodology for revision of the SCR cost spreadsheet. Staff's revised methodology was approved and endorsed to reflect the change for the refinery sector. For ULNB TCI, staff used facility-submitted costs to fit a cost curve based on heat input (MMBtu/hr).

For the purpose of this analysis, facility-submitted costs are used when available. When facility submitted costs for a unit are unavailable, cost estimates generated from the SCR and ULNB cost curves based on the specific unit's heat input (MMBtu/hr) were used.

The table below includes the net present value of capital, O&M, and total costs by equipment category based on a 4% discount rate. Total discounted costs are estimated to be $2.36 billion.

Total Discounted Costs by Equipment Category (4% Discount Rate)

Equipment Category	Capital (2018$ Millions)	O&M (2018$ Millions)	Total (2018$ Millions)
Boiler	$182.8	$28.7	$211.5
Coke Calciner	$39.1	$6.4	$45.5
FCCU	$61.5	$3.6	$65.2
Gas Turbine	$49.1	$5.3	$54.5
Heater	$1,649.2	$231.5	$1,880.6
SMR Heater	$63.2	$7.1	$70.3
SRU/TG	$26.7	$0.3	$26.9
Vapor Incinerator	$9.0	$0.2	$9.2
Total	**$2,080.5**	**$283.1**	**$2,363.6**

The table below includes the annual average of capital, O&M, and total costs by equipment category assuming capital costs are annualized using a 4% real interest rate. It is expected that average annual equipment costs will be $133.88 million on average.

Average Annual Cost by Equipment Category (4% real interest rate)

Equipment Category	Capital (2018$ Millions)	O&M (2018$ Millions)	Total (2018$ Millions)
Boiler	$9.81	$1.51	$11.32
Coke Calciner	$1.96	$0.32	$2.27
FCCU	$3.47	$0.19	$3.66
Gas Turbine	$2.38	$0.28	$2.66
Heater	$95.40	$13.05	$108.45
SMR Heater	$3.06	$0.34	$3.40
SRU/TG	$1.58	$0.02	$1.60
Vapor Incinerator	$0.52	$0.01	$0.53
Total	**$118.18**	**$15.70**	**$133.88**

Facilities installing new pollution control equipment will also incur additional administrative costs, such as compliance plan submission and permitting fees. Twelve facilities are expected to submit compliance plans. Plan submission fees are one-time costs billed at an hourly rate of $211.24 per hour and it is assumed that review of each compliance plan will require 120 hours of staff time. Affected facilities are also expected to incur one-time permitting costs due to permit processing for SCR applications ($6,104.08 per unit), change of condition to heater/boiler equipment permits ($8,308.45 per unit), processing fee for new burner heater/boiler equipment permits ($9,685.81 per unit), and Title V permit revisions ($2,853.99 per unit). Additionally, facilities installing new SCRs will incur annual permitting costs of $1,975.52 per unit per year.

Due to the large emission reductions projected from implementation of PR 1109.1, it is expected that affected facilities will incur a cost savings from reduced emission fees. Estimated cost savings were calculated using the estimated annual NOx emission reductions and assuming costs of $836.23 per ton of NOx for those facilities emitting more than 75 tons per year and $349.55 per ton of NOx for those facilities emitting more than 4 tons but less than 25 tons per year. Facilities' total cost savings due to NOx emission reductions are expected to reach $2.38 million per year upon full implementation.

Total discounted costs are expected to range from $2.336 billion to $2.920 billion based on 1% and 4% discount rates, respectively, and the average annual total costs of PR 1109.1 is expected to range from $98.10 million to $132.45 million per year based on the 4% and 1% real interest rate, respectively.

Total Compliance Costs

Cost Category	NPV (2018$ Millions)		Average Annual (2022 - 2057) (2018$ Millions)	
	1%	4%	1%	4%
Capital Costs	$2,494.02	$2,080.54	$83.83	$118.18
O&M Costs	$469.96	$283.11	$15.70	$15.70
Administrative Costs	$6.69	$4.96	$0.22	$0.22
Emissions Fees	-$50.63	-$32.36	-$1.66	-$1.66
Total	**$2,920.03**	**$2,336.24**	**$98.10**	**$132.45**

Job Impacts

Direct effects of the proposed project are used as inputs to the REMI model in order for the model to assess secondary and induced impacts for all the industries in the four-county economy on an annual basis and across a user-defined horizon: 2022 (first year assumed for the facilities to incur compliance costs due to BARCT implementation) to 2057 (last year cost associated with equipment installation are incurred). Direct effects of the proposed amendments include: (1) additional costs (net of emissions fee savings) to the 16 facilities that would install control equipment, (2) additional sales by local vendors of equipment, devices, or services that would meet the proposed requirements, and (3) increased fuel costs to all industries and consumers in the region.

Whereas all the compliance expenditures that are incurred by the affected facilities would increase their cost of doing business, the purchase of additional control equipment such as SCR, ULNB, and equipment installation would increase the spending and sales of businesses in various sectors, some of which may be located in the South Coast AQMD region.

The impact analysis assumes that facilities will pass on a percentage of their compliance costs onto consumers and local industries through an increase in the regional price of gasoline. Based on the report included in Appendix A, "The Impact of Proposed Rule 1109.1 on Fuel Prices and Demand in South Coast AQMD Region", it is assumed that 30% of total annual O&M costs, net of cost savings due to reduced emission fees, is passed on to consumers and industries through increased gasoline prices. The average annual increase in the price of gasoline is estimated to be 0.0035 cents per gallon. For added context, if 100% of all costs (capital and O&M) were passed on to consumers, it is projected that gasoline prices will increase by 0.99 cents per gallon (a 0.26% increase) on average, with a maximum expected increase of 1.42 cents per gallon (a 0.40% increase).

	Gas prices are expected to slowly increase as control equipment is installed over time. A maximum percentage increase of 0.014% is reached in 2033 upon full implementation of the rule. After 2033, price increases are expected to steadily decline as O&M costs remain constant and gas price projections steadily rise. When the compliance cost is annualized using a 4% real interest rate, it is projected that an annual average of 213 net jobs could be created annually from 2022 to 2057. The projected job impact becomes slightly more positive when the compliance cost annualized at a 1% interest rate is used. In earlier years of the implementation, the positive job impacts from the compliance expenditures made by affected facilities would more than offset the jobs forgone from the additional cost of doing business. From 2022-2032, it is projected that an average of 1,837 jobs would be added annually. In 2032, when most of the spending is expected to occur, about 4,435 additional jobs are projected in the regional economy. The positive job impact would trickle down to the sectors of construction, miscellaneous professional services, retail & wholesale trade, food services, and real estate. However, as affected facilities continue to incur the amortized capital expenditures and annual O&M costs, reductions in job growth would set in, resulting in jobs forgone in later years. Despite incurring the majority of the total compliance cost, the petroleum and coal products manufacturing industry (NAICS 324) is projected to experience only minor impacts in terms of jobs forgone (14 on average). This is due to the fact that the industry is capital-intensive. As such, less labor would be required to produce the same amount of products or services.
Impact of CEQA Alternatives	Four alternatives to the proposed project were developed for the CEQA analysis associated with this proposal, Alternative A - No Project, Alternative B - More Stringent, Alternative C - Less Stringent, and Alternative D - Limited Start-Up, Shutdown, Malfunction. This section provides a description of each alternative as well as an assessment of the possible socioeconomic impacts resulting from these alternatives. Alternatives A and D have identical NPV of compliance costs, job impacts, and cost-effectiveness to the proposed project given the modeling assumptions employed. Alternative B has a higher NPV of compliance costs given the expedited implementation schedule for small heaters and boilers, resulting in more of the compliance costs to occur in earlier periods. Alternative C has a lower NPV of compliance costs due to the assumption of an extended implementation schedule for all units, thus allowing for compliance

	costs to occur in later periods.
Public Health Benefits	The South Coast Air Basin is one of only two "extreme" non-attainment areas in the nation that have not reached the federal 8-hour ozone standard. In addition, the South Coast Air Basin remains a non-attainment area for the federal PM2.5 standards. According to recent estimates by the California Air Resources Board, elevated ambient PM2.5 levels result in approximately 4,100 premature deaths annually in the South Coast Air Basin. The reductions in ozone and PM2.5 associated with the proposed rule have the potential to reduce the mortality and morbidity incidences associated with NOx emissions. Public health benefits resulting from compliance with PR 1109.1 are calculated using an incidence per ton (IPT) methodology, developed by the U.S. Environmental Protection Agency. The IPT methodology is an approximation based on the assumption that the relationship between emissions and adverse health outcomes is linear. The public health benefits analysis presented is based on the proposed project which assumes 74 new SCRs, 15 SCR upgrades, and 76 ULNBs will be installed as a result of 1109.1. PR 1109.1 is projected to result in a reduction in NOx emissions of 7 to 8 tpd upon full implementation; however, for the sake of the health benefit analysis, 7 tpd was conservatively assumed. The increased use of ammonia associated with the SCR controls creates the potential for ammonia slip. It is expected that the installation of 74 new SCRs will result in a 0.63 tpd increase in ammonia emissions. Ammonia is also a precursor to PM2.5. Using IPT methodology, decreases in NOx emissions will result in positive health benefits (reductions in mortality and morbidity resulting from decreased ambient PM2.5 concentrations), while concurrent increases in NH3 will result in increases in mortality and morbidity. Projected reductions of NOx are much larger than the expected increase in NH3, resulting in a net benefit to the South Coast Air Basin. Emissions changes are expected to cumulatively result in approximately 370 premature mortalities avoided from long-term and short-term PM2.5 exposure. Additionally, it is expected that PR 1109.1 will result in approximately 6,200 fewer asthma attacks and nearly 21,400 fewer work loss days over the course of the time period from 2023-2037. The discounted total monetized public health benefits over the 15-year time period is projected to be \$3.49 billion using a 1% discount rate and \$2.63 billion using a 4% discount rate. Total discounted public health benefits were calculated over a shorter time period (2022-2037 for health benefits vs 2022-2057 for compliance costs), therefore the NPV for monetized health benefits

	cannot be directly compared to the NPV of compliance costs, but even so, monetized health benefits exceed total costs.

INTRODUCTION

Proposed Rule 1109.1

Proposed Rule 1109.1 – Emissions of Oxides of Nitrogen from Petroleum Refineries and Related Operations (PR 1109.1) will facilitate the transition of petroleum refineries and facilities with related operations to petroleum refineries from the current RECLAIM program to a command-and-control regulatory structure and partially implement Control Measure CMB-05 of the 2016 Air Quality Management Plan (AQMP). PR 1109.1 applies to oxides of nitrogen (NOx) emitting combustion equipment at facilities, including asphalt plants, biofuel plants, hydrogen production plants, petroleum refineries, and facilities that operate petroleum coke calciners, sulfuric acid plants, and sulfur recovery plants. The proposed rule will establish NOx and carbon monoxide (CO) emission limits to reflect BARCT for combustion equipment categories at these facilities. Additionally, PR 1109.1 establishes provisions for monitoring, recordkeeping, and reporting and provides alternative implementation and compliance approaches including an Implementation Plan (I-Plan), BARCT Equivalent Compliance Plan (B-Plan), and BARCT Equivalent Mass Cap Plan (B-Cap) which provides flexibility and opportunities for facilities to reduce cost impacts while achieving equivalent emission reductions.

Proposed Rule 429.1

Proposed Rule 429.1 - Startup and Shutdown Provisions at Petroleum Refineries and Related Operations (PR 429.1) exempts units from PR 1109.1 NOx and CO emission limits and applicable rolling average provisions during startup, shutdown, and catalyst maintenance events. PR 429.1 also establishes requirements during startup and shutdown pursuant to U.S. EPA policies to regulate startup, shutdown, and malfunction. PR 429.1 limits the duration of startup and shutdown events and the frequency of scheduled startups. Additionally, PR 429.1 establishes best management practices for startup and shutdown events and notification and recordkeeping requirements. The provisions in PR 429.1 are not expected to impose additional costs to facilities, nor are they expected to result in additional emission reductions. As such, no adverse socioeconomic impacts are anticipated.

Proposed Amended Rules 1304 and 2005

Proposed amendments for Rule 1304 – Exemptions (Rule 1304) and Rule 2005 – New Source Review for RECLAIM (Rule 2005) are necessary to implement a narrow Best Available Control Technology (BACT) exemption. The exemption will allow for emission increases associated with air pollution control equipment installed for regulatory compliance with a Best Available Retrofit Control Technology (BARCT) rule required to transition the RECLAIM program for NOx to a command-and-control regulatory structure. Rule 1304 and Rule 2005 are not expected to impose additional costs to facilities, nor are they expected to result in additional emission reductions. As such, no adverse socioeconomic impacts are anticipated.

REGULATORY HISTORY

Rule 1109

On November 1, 1985, South Coast AQMD adopted Rule 1109 – Emissions of Oxides of Nitrogen from Boilers and Process Heaters in Petroleum Refineries. The rule was subsequently amended on August 5, 1988. Rule 1109 was applicable to all boilers and process heaters in petroleum refineries and established a NOx refinery-wide emission limit of 0.14 lb/MMBtu (approximately 120 ppm NOx corrected to three percent oxygen) for the units operated on gaseous fuel, 0.308 lb/MMBtu (approximately 250 ppm NOx corrected to three percent oxygen) for the units operated on liquid fuel, and the weighted average of these limits for the units operated concurrently on both liquid and gaseous fuels when the units are firing at the maximum rated capacity.

RECLAIM

The South Coast AQMD Governing Board adopted the Regional Clean Air Incentives Market (RECLAIM) program in October 1993. The purpose of RECLAIM was to reduce NOx and Sulfur Oxides (SOx) emissions through a market-based approach for facilities with NOx or SOx emissions greater or equal to four tons per year. The program replaced a series of existing and future command-and-control rules and was designed to provide facilities with the compliance flexibility. RECLAIM was designed to achieve emission reductions in aggregate equivalent to what would occur under a command-and-control regulatory approach. Regulation XX – RECLAIM includes a series of rules that specify the applicability and procedures for determining NOx and SOx facility emissions allocations, program requirements, as well as monitoring, reporting, and recordkeeping requirements for RECLAIM facilities. When RECLAIM was adopted, all petroleum refineries and facilities with operations related to petroleum facilities (related facilities) transitioned to this market-based program.[1]

Pursuant to Health & Safety Code §40440, South Coast AQMD is required to periodically assess the advancement in control technologies that are representative of BARCT to ensure that RECLAIM facilities achieve the same emission reductions that would have occurred under a command-and-control approach and that RECLAIM sources contribute to the efforts in the Basin to achieve the federal National Ambient Air Quality Standards (NAAQS). Over the course of RECLAIM, there have been two BARCT reassessment for NOx in 2005 and 2015.

In 2005, Regulation XX was amended to achieve additional NOx reductions pursuant to the 2003 AQMP Control Measure CMB-10. The NOx RTC shave target for the 2005 amendments was 7.7 tons per day (tpd) from 2007 to 2011. The actual NOx emission reductions between the timeframe

[1] A socioeconomic analysis of RECLAIM was conducted at the time of its adoption. The cost of RECLAIM was estimated to be $80.8 million annually, on average, compared with the $138.7 million cost of the corresponding command-and-control system (which included rules and control measures in the 1991 AQMP that were subsumed by RECLAIM). RECLAIM was predicted to result in an average of 866 jobs forgone annually, compared with 2,013 jobs forgone under the command-and-control system. Based on the five occupational categories from the lowest-paid to the highest-paid, RECLAIM was projected to result in increased employment opportunities for nearly every category relative to the command-and-control system.

of 2006 and 2012 was 4 tpd. Of these 4 tpd, 2.6 tpd (or 65%) originated from facility shutdowns, while 1.4 tpd (or 35%) came from either emission controls, process changes, and/or from decreases in production levels. The proposed amendments also addressed requirements for demonstrating BARCT equivalency in accordance with H&SC §40440. In addition, trading restrictions for electricity generating producing facilities were removed.

On December 4, 2015, Regulation XX was again amended to reduce NOx allocations for the largest NOx emitters by 12 tpd. Refineries and related industries represented approximately 7.9 tpd (66%) of the 12 tpd. The intent of the BARCT reassessments was to ensure the RECLAIM program achieved the BARCT in aggregate. Additionally, it was estimated that the refinery sector would incur average annual costs of $51.3 million from 2018-2035 as a result of the shave. However, recent evaluation of the units at petroleum refineries and related industries indicate 88% of the equipment at those facilities are not operating at levels representative of BARCT. And as of August 2021, only nine permits have been submitted from petroleum refineries and related industries for large NOx reduction projects, compared to the 91 SCR projects assumed to be needed to achieve the 2015 NOx shave.

On January 5, 2018, the Governing Board adopted amendments to Rule 2001 – Applicability and Rule 2002 – Allocations for Oxides of Nitrogen (NOx) and Oxides of Sulfur (SOx). Amendments to Rule 2001 ended the addition of any facilities into RECLAIM, and Rule 2002 included provisions to establish the overall process to transition facilities from the RECLAIM program to a command-and-control regulatory structure. Before a facility can be transitioned out of RECLAIM, the facility must either have all equipment at BARCT or be subject to a rule that establishes BARCT requirements for their equipment. As a result, it is expected that as applicable source-specific or industry-specific BARCT rules are adopted or amended, staff can initiate the transition process for facilities subject to those rules.

LEGISLATIVE MANDATES

The legal mandates directly related to the assessment of the proposed rule include South Coast AQMD Governing Board resolutions and various sections of the California Health & Safety Code.

South Coast AQMD Governing Board Resolutions

On March 17, 1989 the South Coast AQMD 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 and Safety Code Requirements

The state legislature adopted legislation which reinforces and expands the Governing Board resolutions for socioeconomic impact assessments. California Health and Safety Code section

40440.8, which became effective on January 1, 1991, requires a socioeconomic impact assessment be performed for any proposed rule, rule amendment, or rule repeal which "will significantly affect air quality or emissions limitations."

Specifically, the scope of the socioeconomic impact assessment should include the following:

- 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; and
- 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 South Coast AQMD 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 it includes the following:

- Type of industries or business affected, including small businesses; and
- 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 which imposes Best Available Retrofit Control Technology or "all feasible measures" requirements relating to ozone, CO, SOx, NOx, and their precursors.

AFFECTED FACILITIES

PR 1109.1 will affect 16 facilities, including nine petroleum refineries, three small refineries, and four facilities with related operations. The three small refineries consist of two asphalt refineries and one biodiesel refinery, and the four facilities with related operations include three hydrogen plants and one sulfuric acid plant. Eleven of the 16 facilities are classified under NAICS 324 – Petroleum and Coal Products Manufacturing, four facilities are classified under NAICS 3251 – Basic Chemical Manufacturing, and the remaining facility is classified as NAICS 3259 – Other Chemical Product and Preparation Manufacturing. All 16 affected facilities are located in Los Angeles County.

PR 1109.1 applies to nearly all combustion equipment at petroleum refineries and related facilities. Based on South Coast AQMD's permit database and facility surveys, staff has identified 292 units that will be subject to the PR 1109.1, with six major classes of equipment: process heaters & boilers (including steam methane (SMR) heater), gas turbines, fluid catalytic cracking units (FCCU), sulfur recovery unit/tail gas (SRU/TG) incinerators, vapor incinerators, and coke calciners. Across the 16 affected facilities there are 224 process heaters & boilers, 19 SRU/TG incinerators, 13 vapor incinerators, 12 gas turbines, 5 FCCUs, and 1 coke calciner.

Small Business

The South Coast AQMD 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. The South Coast AQMD also defines "small business" for the purpose of qualifying for access to services from the South Coast AQMD's Small Business Assistance Office (SBAO) as a business with an annual receipt of $5 million or less, or with 100 or fewer employees. In addition to the South Coast AQMD's definitions of a small business, the federal Small Business Administration (SBA) and the federal 1990 Clean Air Act Amendments (1990 CAAA) also provide definitions of a small business.

The 1990 CAAA classifies a business as a "small business stationary source" if it: (1) employs 100 or fewer employees, (2) does not emit more than 10 tons per year of either VOC or NOx, and (3) is a small business as defined by SBA. The SBA definitions of small businesses vary by six-digit NAICS codes. In general terms, a small business must have no more than 500 employees for most manufacturing and mining industries.[2] More specifically, the petroleum refineries sector (NAICS 324110) has 1,500 employees as the threshold below which a business is considered small. Additionally, the industrial gas manufacturing sector (NAICS 325120) has a small business threshold of 1,000 employees.

Publicly available data on the number of employees by facility exists for all 16 affected facilities. Additionally, 2021 Dun and Bradstreet data on revenue is available for all affected facilities. Based on this data, there are no affected facilities that meet the South Coast AQMD's definitions of a small business (both Rule 102 and SBAO). Based on SBA's definition of a small business, two small refinery facilities would be classified as a small business. Under the 1990 CAAA definition, there are no facilities meeting the criterion to be considered a small business.[3]

METHODOLOGY OF SOCIOECONOMIC IMPACT ASSESSMENT

PR 1109.1 is expected to result in approximately 7 to 8 tpd of NOx emission reductions from the installation and operation of control technology in order to comply with the lower NOx limits of PR 1109.1. For the sake of this analysis, however, a NOx emission reduction of 7.83 tpd was assumed.[4] The 7.83 tpd emission reduction estimate represents staff's assumption regarding the units that would qualify to meet the Table 2 conditional limits with all other units meeting the Table 1 emission limits. The 7 – 8 tpd emission reduction range represents the range of emission reductions the rule will achieve considering the flexibility in the compliance options, the potential eligibility of the conditional limits for units not identified by staff, and the added emission reduction from the ten percent environmental benefit under the B-Cap approach.

[2] https://www.sba.gov/sites/default/files/files/Size_Standards_Table.pdf

[3] Based on facility-level data on NOx and VOC emissions for calendar years 2018, 2019, and 2020.

[4] The 7.83 tpd projection does not include emission reductions from 67 small heaters and 5 small boilers (less than 40 MMBtu) expected to be retrofitted with emerging technology.

Compliance with the NOx limits in the proposed rule may overlap with projects currently taking place to comply with the 2015 NOx RECLAIM shave. This is due to 2017 emissions being used as baseline for the BARCT analysis in this proposed project, and those emissions could have since been reduced if a RECLAIM shave project has taken place since 2017.

The proposed project is expected to achieve NOx emission reductions for every class and category of equipment and staff anticipates that 74 units will be retrofitted with new Selective Catalytic Reduction (SCR) Systems, 15 existing SCRs will be upgraded (SCR upgrade), and 76 units will be retrofitted with Ultra Low-NOx Burner (ULNB) technology. Table 1 below presents the estimated number of new or upgraded pollution control equipment by equipment category.

Table 1: Estimated Number of NOx Control Devices by Equipment/Source Category

Equipment Category	Number of Affected Facilities	Estimated Number of Control Devices
Process Heaters	7	60 SCR
		49 ULNB
		6 SCR upgrade
Boilers	7	9 SCR
		10 ULNB
		2 SCR upgrade
FCCUs	2	2 SCR
Coke Calciner	1	1 SCR
Gas Turbines	2	5 SCR upgrade
SRU/TG	6	9 ULNB
SMR Heaters	4	2 SCR
		2 SCR upgrade
Vapor Incinerators	4	8 ULNB

Based on the control devices listed in Table 1, an assumed implementation schedule was developed which would comply with the emission reduction targets and schedule outlined in Table 4 of the proposed rule. The actual implementation of control equipment is uncertain and will likely differ from the schedule described here as affected facilities have been given flexibility in regards to which units will be required to meet the percent reductions specified in their approved implementation plan (I-Plan) to meet proposed BARCT emission limits. Table 2 below summarizes the assumed implementation schedule by equipment category.

This analysis assumes that all capital costs (equipment and installation) are incurred in the year prior to implementation. Additionally, all recurring costs (O&M) and emission reductions begin in the implementation year shown in Table 8. Table 3 below provides the projected emission reductions by year and equipment category.

South Coast AQMD received direct input from affected facilities on the expected total installed costs and operating and maintenance (O&M) costs of all potential pollution control equipment necessary to implement BARCT. In 2018 South Coast AQMD received cost estimates from affected facilities that included 49 total installed cost (TIC) estimates that were obtained from 7 refineries for SCR retrofit and upgrade projects on heaters and boilers > 40 MMBtu/h. In 2021, affected facilities provided additional or revised cost estimates that included a total of 108 additional or revised TIC estimates. Revised cost estimates for all but two units received in 2021 were 1.05 to 2.4 times greater than initial estimates. Subsequently, Norton Engineering Consultants, Inc. provided an independent review of the facility cost data to determine whether the costs submitted were reasonable, realistic, and justified for NOx control equipment installations. The independent review ultimately determined that the facility costs submitted "do not appear unreasonable."[5]

Staff assumed all SCR and ULNB costs received from facilities included capital, engineering, construction, tax, and shipping. In addition, all cost was assumed to include increased labor costs associated with Senate Bill (SB) 54 which requires refineries to use unionized construction labor. TIC provided were in different years and staff conservatively escalated all costs at 4% annual inflation rate to the 2018 dollar year.

In addition, staff modified the U.S. EPA SCR cost spreadsheet using actual TIC estimates provided by the facilities to reflect the actual TIC of SCR installations in the refinery sector. Staff consulted with U.S. EPA Air Economics Group regarding staff's proposed methodology for revision of the SCR cost spreadsheet. Staff's revised methodology was approved and endorsed to reflect the change for the refinery sector. For ULNB TCI, staff used facility-submitted costs to fit a cost curve based on heat input (MMBtu/hr).

For the purpose of this analysis, facility-submitted costs are used when available. When facility submitted costs for a unit are unavailable, cost estimates generated from the SCR and ULNB cost curves based on the specific unit's heat input (MMBtu/hr) were used.

[5] http://www.aqmd.gov/docs/default-source/rule-book/Proposed-Rules/1109.1/norton-report-rev-2-barct-cost-review.pdf?sfvrsn=6

Table 2: Assumed Installation Schedule by Equipment Category

Year	Boilers	FCCU	Coke Calciner	Gas Turbines	Process Heaters	SRU/TG	SMR Heaters	Vapor Incinerators
2023 (Shave Projects)	4 ULNB + 3 SCR + 1 SCR upgrade	1 SCR	-	3 SCR upgrade	8 ULNB + 8 SCR + 1 SCR upgrade	-	2 SCR	-
2024	-	-	-	-	5 ULNB + 7 SCR	1 ULNB	-	2 ULNB
2025	1 ULNB + 1 SCR	-	1 SCR	-	1 ULNB + 2 SCR + 1 SCR upgrade	-	1 SCR upgrade	-
2026	1 ULNB + 1 SCR	-	-	1 SCR upgrade	9 ULNB + 10 SCR	-	-	-
2027	1 ULNB + 1 SCR	-	-	-	4 ULNB + 7 SCR + 2 SCR upgrade	-	-	-
2028	1 ULNB + 1 SCR	-	-	1 SCR upgrade	6 ULNB + 7 SCR	3 ULNB	-	3 ULNB
2029	1 ULNB + 1 SCR	-	-	-	4 ULNB + 5 SCR + 1 SCR upgrade	-	-	-
2030	-	1 SCR	-	-	7 ULNB SCR + 6 SCR	-	-	-
2031	1 ULNB + 1 SCR	-	-	-	2 ULNB + 3 SCR	1 ULNB	1 SCR upgrade	2 ULNB
2032	1 SCR upgrade	-	-	-	1 ULNB + 2 SCR + 1 SCR upgrade	1 ULNB	-	1 LNB
2033	-	-	-	-	2 ULNB + 3 SCR	3 ULNB	-	-
Total	**10 ULNB + 9 SCR + 2 SCR upgrade**	**2 SCR**	**1 SCR**	**5 SCR upgrade**	**49 ULNB + 60 SCR + 6 SCR upgrade**	**9 ULNB**	**2 SCR + 2 SCR upgrade**	**8 ULNB**

Table 3: Projected NOx Emission Reductions Based on Assumed Installation Schedule by Equipment Category by Year (in tpd)

Year	Boilers	Coke Calciner	FCCU	Gas Turbines	Heaters	SMR Heaters	SRU/TG	Vapor Incinerators	Total
2023 (Shave Projects)	1.25	-	0.13	0.24	0.51	0.54	-	-	**2.68**
2024	-	-	-	-	0.60	-	-	0.01	**0.61**
2025	0.07	0.66	-	-	0.08	0.07	-	-	**0.89**
2026	0.10	-	-	0.11	0.67	-	-	-	**0.89**
2027	0.35	-	-	-	0.38	-	-	-	**0.72**
2028	0.02	-	-	0.11	0.30	-	0.06	0.01	**0.50**
2029	0.28	-	-	-	0.30	-	-	-	**0.58**
2030	-	-	0.22	-	0.24	-	-	-	**0.46**
2031	0.09	-	-	-	0.18	0.02	0.01	0.01	**0.29**
2032	0.04	-	-	-	0.05	-	0.01	-	**0.10**
2033	-	-	-	-	0.09	-	0.02	-	**0.11**
Total	**2.19**	**0.66**	**0.35**	**0.46**	**3.42**	**0.63**	**0.09**	**0.02**	**7.83**

COMPLIANCE COST BY EQUIPMENT CATEGORY

Fluid Catalytic Cracking Units (FCCU)

An FCCU converts heavy gas oils from the distillation process into more valuable gasoline and lighter products. Currently there are five refineries that operate five FCCUs in the South Coast Air Basin. The five units cumulatively emit a total of 0.83 tpd of NOx. For more information on FCCUs, including a detailed process description, assessment of available control technologies, and BARCT cost-effectiveness analysis, please see Appendix D of the most recent PR 1109.1 Staff Report.

There is one FCCU unit that is currently operating at the proposed BARCT limit. It is assumed that two FCCU units currently without NOx controls will install new SCRs, and two units with NOx controls will perform SCR upgrades.

The total compliance cost of the proposed amendments for refinery FCCUs includes one-time capital costs and recurring O&M costs. The one-time cost includes the capital cost of SCRs and their installations. The total installed cost of the 2 SCRs are estimated at $19.5 and $58.5 million, respectively. It is assumed that 20% of one-time capital costs are attributed to equipment costs and the remaining 80% to installation. The annual O&M costs for the 2 SCR units include utility costs (electricity) and ammonia costs. The annual O&M cost for each SCR unit is estimated at $0.14 million. It is assumed that 30% of annual operating costs are attributed to utility costs and the remaining 70% to ammonia.

Assuming a 25-year life for equipment and installation, and a discount rate of 4%, the net present value (NPV) of all capital costs is estimated at $61.53 million. The NPV of all annual operating and maintenance costs is estimated to be $3.62 million. Table 4 presents detailed costs by refinery.

Table 4: FCCUs – Net Present Value of All Equipment, Installation, and Annual Operating Costs (Millions of 2018 Dollars)

Refinery	Equipment Cost	Installation Cost	Total O&M	Electricity/Water	Ammonia/Caustic	Catalyst	Other Maintenance
7	$3.750	$15.000	$2.058	$0.617	$0.823	$0.412	$0.206
9	$8.555	$34.220	$1.564	$0.469	$0.626	$0.313	$0.156
Total	**$12.305**	**$49.220**	**$3.622**	**$1.087**	**$1.449**	**$0.724**	**$0.362**

Process Heaters and Boilers

Refinery process heaters and boilers are used extensively throughout various processes in refinery operations such as distillation, hydrotreating, fluid catalytic cracking, alkylation, reforming, and delayed coking. The refinery heaters and boilers primarily burn refinery gas which is generated at the refinery. Most of these boilers and heaters use natural gas as back-up or supplemental fuel.

Process Heaters

Process heaters are direct-fired heaters designed to supply the heat necessary to raise the temperature of feedstock to the distillation or reaction levels. There are 185 heaters currently in operation at affected facilities within the South Coast Air Basin. These units cumulatively emitted 5.03 tpd of NOx in 2017.

For the purpose of the analysis, controlling NOx emissions from process heaters is assumed to be accomplished through SCR upgrades, the installation of SCR, and/or installation of ULNB. It is assumed that seven refineries would install 15 SCR units only, while three refineries will perform four SCR upgrades only. It is also assumed that three refineries will install three ULNBs only. Additionally, it is assumed that seven refineries will install 45 SCR + ULNBs and two refineries will install a newULNB and perform an upgrade to an existing SCR. In total, there will be 60 new SCRs installed, six SCR upgrades performed, and 49 new ULNBs installed to existing process heaters.

The estimated TIC of new SCR installations range from $12.4 million to $70.0 million. It is assumed that 20% of one-time capital costs are attributed to equipment costs and the remaining 80% to installation. Annual O&M costs resulting from SCR installations are estimated to range from $0.09 million to $1.0 million per year. Annual operating costs were distributed among electricity (30%), ammonia (40%), catalyst (20%), and other annual maintenance (10%).

The estimated TIC of SCR upgrades range from $22.2 million to $40.5 million. It is assumed that 20% of one-time capital costs are attributed to equipment costs and the remaining 80% to installation. Annual O&M costs resulting from SCR upgrades are estimated to range from $0.12 million to $0.26 million per year. Annual operating costs were distributed among electricity (30%), ammonia (40%), catalyst (20%), and other annual maintenance (10%).

The TIC of ULNB installations is estimated to range from $12.7 million to $27.4 million. It is assumed that 20% of one-time capital costs are attributed to equipment costs and the remaining 80% to installation. The recurring O&M cost for each unit is estimated to be $0.1 million annually. The annual O&M costs are distributed among electricity (50%) and other annual maintenance (50%).

The TIC of SCR + ULNB installations is estimated to range from $8.3 million to $44.3 million. It is assumed that 20% of one-time capital costs are attributed to equipment costs and the remaining 80% to installation. Annual O&M costs are estimated to range from $0.09 million to $0.24 million per year. Annual operating costs were distributed among electricity (30%), ammonia (40%), catalyst (20%), and other annual maintenance (10%).

The TIC of the SCR upgrade + ULNB installations is estimated at $22.2 million. It is assumed that 20% of one-time capital costs are attributed to equipment costs and the remaining 80% to installation. Annual O&M costs are estimated to be $0.21 million per year. Annual operating costs were distributed among electricity (30%), ammonia (40%), catalyst (20%), and other annual maintenance (10%).

In addition, 64 heaters with a size less than 40 MMbtu have been identified as potential candidates for further emission reductions beyond the year 2033 with the expected future introduction of new emission control technology. These small heaters emitted 0.50 tpd of NOx based on 2017 emissions data.

The TIC of the emerging technology for small heaters is estimated to range from $0.59 million to $22.4 million. It is assumed that 20% of one-time capital costs are attributed to equipment costs and the remaining 80% to installation. Annual O&M costs are estimated to range from $0.069 million to $0.109 million per year. Annual operating costs were distributed among electricity (30%), ammonia (40%), catalyst (20%), and other annual maintenance (10%).

Assuming a 25-year life for equipment and installation, and a discount rate of 4%, the NPV is of all capital costs is estimated at $1.65 billion. The NPV of all annual operating and maintenance costs is estimated to be $231.5 million. Table 5 presents detailed costs by refinery.

Table 5: Process Heaters – Net Present Value of All Equipment, Installation, and Annual Operating Costs (Millions of 2018 Dollars)

Refinery	Equipment Cost	Installation Cost	Total O&M	Electricity/Water	Ammonia/Caustic	Catalyst	Other Maintenance
1	$77.74	$310.94	$43.79	$13.14	$17.52	$8.76	$4.38
4	$58.75	$235.01	$24.33	$7.30	$9.73	$4.87	$2.43
5	$49.46	$197.85	$62.39	$18.72	$24.95	$12.48	$6.24
6	$27.58	$110.33	$26.02	$7.81	$10.41	$5.20	$2.60
7	$54.73	$218.92	$38.57	$11.57	$15.43	$7.71	$3.86
8	$18.95	$75.82	$12.39	$3.72	$4.96	$2.48	$1.24
9	$34.54	$138.15	$17.90	$5.37	$7.16	$3.58	$1.79
10	$2.65	$10.61	$2.50	$0.75	$1.00	$0.50	$0.25
11	$2.97	$11.87	$1.78	$0.53	$0.71	$0.36	$0.18
16	$2.46	$9.83	$1.80	$0.54	$0.72	$0.36	$0.18
Total	**$329.83**	**$1,319.32**	**$231.47**	**$69.44**	**$92.59**	**$46.29**	**$23.15**

Boilers

Boilers are combustion sources used to generate the steam necessary for plant operations. There are currently 28 boilers in operation potentially affected by PR 1109.1. In 2017, these 28 boilers emitted 2.55 tpd of NOx.

It is assumed that controlling NOx emissions from boilers will be accomplished by installing nine new SCR + ULNB at five refineries, one ULNB + SCR upgrade at one refinery, and one SCR upgrade at one refinery.

The TIC for the nine SCR + ULNB installations is estimated to range from $9.0 million to $39.1 million. It is assumed that 20% of one-time capital costs are attributed to equipment costs and the remaining 80% to installation. Annual O&M costs are estimated to range from $0.10 million to $0.21 million per year. Annual operating costs were distributed among electricity (30%), ammonia (40%), catalyst (20%), and other annual maintenance (10%).

The TIC for the ULNB + SCR upgrade is estimated to be $14.0 million. It is assumed that 20% of one-time capital costs are attributed to equipment costs and the remaining 80% to installation. Annual O&M costs are estimated to be $0.20 million per year. Annual operating costs were assumed to be distributed among electricity (30%), ammonia (40%), catalyst (20%), and other annual maintenance (10%).

The TIC for the SCR upgrade is estimated to be $18.1 million. It is assumed that 20% of one-time capital costs are attributed to equipment costs and the remaining 80% to installation. Annual O&M costs are estimated to be $0.24 million per year. Annual operating costs were assumed to be distributed among electricity (30%), ammonia (40%), catalyst (20%), and other annual maintenance (10%).

In addition, an additional 5 boilers with a size less than 40 MMbtu have been identified as potential candidates for further emission reductions with the expected introduction of new emission control technology. The rule states that achieving 5 ppm is not required until the operator cumulatively replaces 50% or more of the burners starting from the date of rule adoption. These small boilers emitted 0.50 tpd of NOx based on 2017 emissions data.

The TIC for the emerging control technology for small boilers is estimated to be $6.38 million. It is assumed that 20% of one-time capital costs are attributed to equipment costs and the remaining 80% to installation. Annual O&M costs are estimated to be $0.068 million per year. Annual operating costs were assumed to be distributed among electricity (30%), ammonia (40%), catalyst (20%), and other annual maintenance (10%).

Assuming a 25-year life for equipment and installation, and a discount rate of 4%, the NPV is of all capital costs is estimated at $182.8 million. The NPV of all annual operating and maintenance costs is estimated to be $28.72 million. Table 6 presents detailed costs by refinery.

Table 6: Boilers – Net Present Value of All Equipment, Installation, and Annual Operating Costs (Millions of 2018 Dollars)

Refinery	Equipment Cost	Installation Cost	Total O&M	Electricity/Water	Ammonia/Caustic	Catalyst	Other Maintenance
3	$2.68	$10.73	$1.60	$0.48	$0.64	$0.32	$0.16
4	$12.38	$49.52	$5.19	$1.56	$2.08	$1.04	$0.52
5	$2.44	$9.76	$2.55	$0.77	$1.02	$0.51	$0.26
6	$4.54	$18.15	$6.22	$1.87	$2.49	$1.24	$0.62
7	$8.03	$32.13	$7.17	$2.15	$2.87	$1.43	$0.72
8	$2.69	$10.77	$3.06	$0.92	$1.23	$0.61	$0.31
10	$1.64	$6.54	$1.25	$0.37	$0.50	$0.25	$0.12
16	$2.16	$8.65	$1.68	$0.50	$0.67	$0.34	$0.17
Total	**$36.56**	**$146.25**	**$28.72**	**$8.62**	**$11.49**	**$5.74**	**$2.87**

Steam Methane Reduction (SMR) Heaters

Steam methane reformers are specialized process heaters used in hydrogen production. Hydrogen is primarily used in the refining industry to reduce or remove contaminants such as nitrogen, metals, sulfur, olefins and aromatic content in fuels. There are currently 11 SMR heaters potentially affected by PR 1109.1. These 11 units emitted NOx at a rate of 1.02 tpd in 2017.

It is assumed that controlling NOx emissions from SMR heaters will be accomplished through the installation of SCR and SCR upgrades. In total, two new SCR installations are expected at two refineries and two SCR upgrades are expected at two refineries.

The TIC for the new SCR installations is estimated to range from $17.0 million to $32.0 million. It is assumed that 20% of one-time capital costs are attributed to equipment costs and the remaining 80% to installation. Annual O&M costs are estimated to be $0.20 million per year. Annual operating costs were distributed among electricity (30%), ammonia (40%), catalyst (20%), and other annual maintenance (10%).

The TIC for the SCR upgrades is expected to range from $8.4 million to $11.4 million. It is assumed that 20% of one-time capital costs are attributed to equipment costs and the remaining 80% to installation. Annual O&M costs are estimated to range from $0.03 million to $0.06 million per year. Annual operating costs were distributed among electricity (30%), ammonia (40%), catalyst (20%), and other annual maintenance (10%).

Assuming a 25-year life for equipment and installation, and a discount rate of 4%, the NPV is of all capital costs is estimated at $63.18 million. The NPV of all annual operating and maintenance costs is estimated to be $7.13 million. Table 7 presents detailed costs by refinery.

Table 7: SMR Heaters – Net Present Value of All Equipment, Installation, and Annual Operating Costs (Millions of 2018 Dollars)

Refinery	Equipment Cost	Installation Cost	Total O&M	Electricity/Water	Ammonia/Caustic	Catalyst	Other Maintenance
1	$2.032	$8.127	$0.783	$0.235	$0.313	$0.157	$0.078
6	$6.154	$24.615	$3.004	$0.901	$1.202	$0.601	$0.300
7	$1.180	$4.721	$0.274	$0.082	$0.110	$0.055	$0.027
8	$3.269	$13.077	$3.064	$0.919	$1.226	$0.613	$0.306
Total	**$12.635**	**$50.541**	**$7.126**	**$2.138**	**$2.851**	**$1.425**	**$0.713**

Gas Turbines

Gas turbines are used in refineries to produce both electricity and steam. There are a total of twelve gas turbines currently in operation at the refineries in the South Coast Air Basin. Currently, there are two gas turbines operating with natural gas achieving 2 ppmv NOx limit in practice. The total NOx emissions from the twelve gas turbines account for 1.45 tpd of NOx emissions.

All gas turbines operating with refinery gas have existing SCRs. For the purpose of the analysis, a total of five gas turbines across two refineries are assumed to complete SCR upgrades.

The estimated TIC of SCR upgrades ranges from $8.6 million to $12.3 million. It is assumed that 20% of the TIC is attributable to equipment costs with the remaining 80% resulting from installation. The estimated annual O&M cost ranges from $0.03 million to $0.15 million. It is assumed that 30% of the annual O&M costs is attributable to utility costs, 40% to ammonia, 20% to catalyst, and 10% to other periodic maintenance.

Assuming a 25-year life for equipment and installation, and a discount rate of 4%, the NPV is of all capital costs is estimated at $49.1 million. The NPV of all annual operating and maintenance costs is estimated to be $5.33 million. Table 8 presents detailed costs by refinery.

Table 8: Gas Turbines – Net Present Value of All Equipment, Installation, and Annual Operating Costs (Millions of 2018 Dollars)

Refinery	Equipment Cost	Installation Cost	Total O&M	Electricity/Water	Ammonia/Caustic	Catalyst	Other Maintenance
4	$2.837	$11.347	$3.932	$1.180	$1.573	$0.786	$0.393
5	$6.990	$27.960	$1.397	$0.419	$0.559	$0.279	$0.140
Total	**$9.827**	**$39.307**	**$5.329**	**$1.599**	**$2.132**	**$1.066**	**$0.533**

Sulfur Recovery Units and Tail Gas Units (SRU/TGUs)

Refinery SRU/TGUs, including their incinerators, are classified as major sources of both NOx and SOx emissions. Because sulfur is a naturally occurring and undesirable component of crude oil, refineries employ a sulfur recovery system to maximize sulfur removal.

There are 19 SRU/TGs currently operating in the South Coast AQMD emitting a cumulative total of 0.42 tpd of NOx. It is estimated that a total of nine Low-NOx burners will be installed across six facilities as a result of 1109.1 implementation.

The TIC of the nine ULNBs is estimated to range from $2.6 million to $6.1 million. It is assumed that 20% of the capital cost is attributable equipment acquisition cost with the remaining 80% resulting from installation. The recurring O&M cost for each unit is estimated to range from $2,000 to $4,000 annually. The annual O&M costs are distributed among electricity (50%) and other annual maintenance (50%).

Assuming a 25-year life for equipment and installation, and a discount rate of 4%, the NPV is of all capital costs is estimated at $26.6 million. The NPV of all annual operating and maintenance costs is estimated to be $0.281 million. Table 9 presents detailed costs by refinery.

Table 9: SRU/TG – Net Present Value of All Equipment, Installation, and Annual Operating Costs (Millions of 2018 Dollars)

Refinery	Equipment Cost	Installation Cost	Total O&M	Electricity/Water	Other Maintenance
1	$0.40	$1.58	$0.02	$0.01	$0.01
3	$0.80	$3.19	$0.04	$0.02	$0.02
5	$2.80	$11.19	$0.15	$0.07	$0.07
6	$0.43	$1.70	$0.02	$0.01	$0.01
9	$0.55	$2.20	$0.03	$0.01	$0.01
10	$0.36	$1.46	$0.02	$0.01	$0.01
Total	**$5.33**	**$21.32**	**$0.28**	**$0.14**	**$0.14**

Coke Calciner

Petroleum coke is the heaviest portion of crude oil which cannot be recovered in the normal oil refining process. Instead, it is processed in a delayed coker unit to generate a carbonaceous solid referred to as “green coke,” a commodity. To improve the quality of the product, it is sent to a calciner to make calcined petroleum coke.

There is currently only one coke calciner in operation in the South Coast Air Basin. This unit currently emits NOx at a rate of 0.71 tpd.

This analysis assumes that the coke calciner will be retrofitted with SCR. Cost estimates for SCR systems provided by vendors range from $5 million to $8 million per unit. One-time installation costs are estimated to be 4.5 times of the equipment cost based on the recommendation by NEC in the 2015 BARCT assessment. The TIC is assumed to be $44.0 million with an assumed equipment cost of $8 million and installation costs of $36 million.

Staff estimated the annual O&M cost to be $458,000, based on the annual operating costs reported in the survey for a SCR installed on a gas turbine.[6] Annual operating costs were distributed among electricity (30%), ammonia (40%), catalyst (20%), and other annual maintenance (10%).

Assuming a 25-year life for equipment and installation, and a discount rate of 4%, the NPV is of all capital costs is estimated at $39.1 million. The NPV of all annual operating and maintenance costs is estimated to be $6.36 million.

Vapor Incinerators

Vapor Incinerators are one of the most proven methods to control VOCs emissions released form industrial sources by means of thermal destruction. The term “incineration” refers to an ultimate disposal method which is a thermal treatment of waste materials (solid, liquid, or gas) through a combustion process in the presence of oxygen.

There is currently a total of 13 vapor incinerators, afterburners, and thermal oxidizers in operation in the South Coast Air Basin. The total NOx emissions from the 13 vapor incinerators located in the South Coast AQMD is 0.08 tpd.

This analysis assumes that eight vapor incinerators across four facilities will be retrofitted with ULNBs. The TIC for the eight ULNBs is estimated to range from $0.3 million to $4.9 million per unit. One-time capital costs are distributed between equipment (20%) and installation (80%) costs. Recurring O&M costs are estimated to be $2,000 annually per unit. O&M costs are distributed between electricity (50%)and other periodic maintenance (50%).

Assuming a 25-year life for equipment and installation, and a discount rate of 4%, the NPV is of all capital costs is estimated at $8.97 million. The NPV of all annual operating and maintenance costs is estimated to be $0.197 million. Table 10 presents the detailed costs by refinery.

[6] Gas turbines were chosen as a reference point because the flue gas flow rate is similar to that of the calciner. Staff also included the additional cost required to fuel the duct burner that will heat the flue gas to the appropriate temperature for the low-temperature catalysts.

Table 10: Vapor Incinerators – Net Present Value of All Equipment, Installation, and Annual Operating Costs (Millions of 2018 Dollars)

Refinery	Equipment Cost	Installation Cost	Total O&M	Electricity/Water	Other Maintenance
5	$0.29	$1.16	$0.06	$0.03	$0.03
6	$0.17	$0.67	$0.02	$0.01	$0.01
10	$0.86	$3.44	$0.07	$0.04	$0.04
11	$0.48	$1.90	$0.04	$0.02	$0.02
Total	**$1.80**	**$7.18**	**$0.20**	**$0.10**	**$0.10**

Tables 11below summarizes the estimated total equipment costs expected to result from PR 1109.1. Table 11 includes the total discounted cost (NPV) and average annual cost capital, O&M, and total costs by equipment category assuming a 4% real interest rate. It is expected that discounted total costs will be $2.36 billion and average annual total costs will be $133.88 million.

Table 11: Summary of Costs by Equipment Category (in Millions of 2018 Dollars)

Equipment Category	NPV			Average Annual		
	Capital	O&M	Total	Capital	O&M	Total
Boiler	$182.81	$28.72	$211.54	$9.81	$1.51	$11.32
Coke Calciner	$39.12	$6.36	$45.48	$1.96	$0.32	$2.27
FCCU	$61.52	$3.62	$65.15	$3.47	$0.19	$3.66
Gas Turbine	$49.13	$5.33	$54.46	$2.38	$0.28	$2.66
Heater	$1,649.15	$231.47	$1,880.62	$95.40	$13.05	$108.45
SMR Heater	$63.18	$7.13	$70.30	$3.06	$0.34	$3.40
SRU/TG	$26.65	$0.28	$26.93	$1.58	$0.02	$1.60
Vapor Incinerator	$8.97	$0.20	$9.17	$0.52	$0.01	$0.53
Total	**$2,080.54**	**$283.11**	**$2,363.64**	**$118.18**	**$15.70**	**$133.88**

Administrative Costs

Permitting and Plan Fees

Facilities installing new pollution control equipment will also incur additional administrative costs, such as compliance plan submission and permitting fees. Twelve facilities are expected to submit compliance plans. Plan submission fees are one-time costs billed at an hourly rate of $211.24 per hour and it is assumed that review of each compliance plan will require 120 hours of staff time. Affected facilities are also expected to incur one-time permitting costs due to permit processing for SCR applications ($6,104.08 per unit), change of condition to heater/boiler equipment permits

($8,308.45 per unit), processing fee for new burner heater/boiler equipment permits ($9,685.81 per unit), and Title V permit revisions ($2,853.99 per unit). Additionally, facilities installing new SCRs will incur annual permitting costs of $1,975.52 per unit per year. Table 12 below includes a breakdown of plan submission and permitting costs, including the number of expected projects, the year cost is incurred, and NPV (in millions of dollars).

Table 12: Plan Submission and Permitting Fees (Millions of Dollars)

Action	2022		2023		2025		2028		Total
	# of Projects	NPV	# of Projects	NPV	# of Projects	NPV	# of Projects	NPV	
Plan Submittal Fee	12	$0.29	-	-	-	-	-	-	$0.29
Permit Processing Fee for SCR Applications	-	-	45	$0.25	27	$0.14	17	$0.08	$0.47
Change of Condition to Heater/Boiler Equipment Permits	-	-	45	$0.35	27	$0.19	17	$0.11	$0.64
Permit Processing Fee for New Burners Heater/Boiler Equipment Permits	-	-	38	$0.34	23	$0.19	15	$0.11	$0.64
Title V Permit Revision for All Potential Applications	-	-	83	$0.22	49	$0.12	33	$0.07	$0.41
Annual Permit Fees	-	-	-	-	-	-	-	-	$2.50
Total		**$0.29**		**$1.16**		**$0.64**		**$0.37**	**$4.67**

Potential Cost Savings Due to Reduced Emissions

Due to the large emission reductions projected from implementation of PR 1109.1, it is expected that affected facilities will incur a cost savings from reduced emission fees. Estimated cost savings were calculated using the estimated annual NOx emission reductions and assuming costs of $836.23 per ton of NOx for those facilities emitting more than 75 tons per year (Refineries 1-9) and $349.55 per ton of NOx for those facilities emitting more than 4 tons but less than 25 tons per year (Refineries 10 & 11).[7,8] Facilities' total cost savings due to NOx emission reductions are expected to reach $2.38 million per year upon full implementation.[9] See Table 13 and 14 below for a breakdown of projected NOx emissions and estimated cost savings by refinery.

[7] Emissions reductions from small boilers and heaters (less than 40 MMBtu) are not included in this calculation.
[8] Fee levels are found in Table III of Rule 301 (http://www.aqmd.gov/docs/default-source/rule-book/reg-iii/rule-301.pdf?sfvrsn=91). Current fee levels are $946.76 for facilities emitting more than 75 tons per year and $395.75 for facilities emitting between 4 and 25 tons per year. These fee levels have been deflated to 2018 dollars using the August 8, 2021 updates to the Marshall and Swift Cost Index.
[9] South Coast AQMD fees may be raised in future years to account for the decrease in revenue, however It is uncertain whether emission fees will be raised or some other fees.

Table 13: Projected NOx Emission Reductions by Refinery by Year (tpd)

Refinery	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033 – 2047*
1	0.06	0.06	0.13	0.31	0.32	0.44	0.44	0.61	0.63	0.64	0.65
2	0.00	0.00	0.66	0.66	0.66	0.66	0.66	0.66	0.66	0.66	0.66
3	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.09	0.09	0.10
4	0.00	0.15	0.17	0.51	0.86	1.03	1.42	1.49	1.49	1.52	1.54
5	0.24	0.45	0.45	0.62	0.76	0.92	0.99	0.99	0.99	1.02	1.08
6	1.53	1.53	1.53	1.58	1.70	1.71	1.71	1.71	1.71	1.72	1.72
7	0.39	0.39	0.46	0.56	0.65	0.65	0.65	0.65	0.80	0.80	0.80
8	0.46	0.64	0.68	0.73	0.73	0.73	0.83	0.83	0.83	0.83	0.83
9	0.00	0.07	0.09	0.09	0.11	0.11	0.15	0.37	0.39	0.40	0.42
10	0.00	0.00	0.00	0.00	0.00	0.02	0.02	0.02	0.03	0.03	0.03
11	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.01
Total	**2.68**	**3.29**	**4.18**	**5.07**	**5.79**	**6.29**	**6.87**	**7.33**	**7.62**	**7.72**	**7.83**

*Emission reductions occur at the level reported in each year of the time horizon (2033, 2034,…, 2047)

Table 14: Projected Cost Savings Due to Reduced NOx Emissions by Refinery by Year (Millions of 2018 dollars)

Refinery	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033 - 2047*
1	$0.019	$0.019	$0.041	$0.096	$0.098	$0.135	$0.135	$0.186	$0.193	$0.196	$0.199
2	$0.000	$0.000	$0.201	$0.201	$0.201	$0.201	$0.201	$0.201	$0.201	$0.201	$0.201
3	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.026	$0.026	$0.030
4	$0.000	$0.045	$0.053	$0.155	$0.263	$0.316	$0.434	$0.456	$0.456	$0.465	$0.470
5	$0.073	$0.138	$0.138	$0.189	$0.231	$0.281	$0.301	$0.301	$0.301	$0.312	$0.330
6	$0.466	$0.466	$0.466	$0.482	$0.518	$0.523	$0.523	$0.523	$0.523	$0.525	$0.525
7	$0.119	$0.119	$0.140	$0.171	$0.200	$0.200	$0.200	$0.200	$0.245	$0.245	$0.245
8	$0.141	$0.195	$0.207	$0.224	$0.224	$0.224	$0.252	$0.252	$0.252	$0.252	$0.252
9	$0.000	$0.023	$0.029	$0.029	$0.033	$0.033	$0.045	$0.112	$0.118	$0.123	$0.128
10	$0.000	$0.000	$0.000	$0.000	$0.000	$0.003	$0.003	$0.003	$0.004	$0.004	$0.004
11	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.001	$0.001	$0.001
Total	**$0.818**	**$1.005**	**$1.275**	**$1.547**	**$1.768**	**$1.916**	**$2.094**	**$2.233**	**$2.320**	**$2.351**	**$2.385**

*Cost savings are incurred at the level reported in each year of the time horizon (2033, 2034,…, 2047)

Total Compliance Costs

Total compliance costs in Table 15 below include costs form equipment acquisition and installation, annual O&M costs associated with equipment use, administrative costs, such as permitting and plan fees, and potential cost savings from reduced emissions fees paid. Table 15 includes the total discounted cost (NPV) and average annual cost by cost category for both a 1% and 4% real interest rate. Total discounted costs are expected to range from $2.336 billion to $2.920 billion based on 1% and 4% discount rates, respectively, and the average annual total costs of PR 1109.1 is expected to range from $98.10 million to $132.45 million per year.

Table 15: Total Compliance Costs (in Millions of 2018 Dollars)

Cost Category	NPV		Average Annual (2022 - 2057)	
	1%	4%	1%	4%
Capital Costs	$2,494.02	$2,080.54	$83.83	$118.18
O&M Costs	$469.96	$283.11	$15.70	$15.70
Administrative Costs	$6.69	$4.96	$0.22	$0.22
Emissions Fees	-$50.63	-$32.36	-$1.66	-$1.66
Total	**$2,920.03**	**$2,336.24**	**$98.10**	**$132.45**

MACROECONOMIC IMPACTS ON THE REGIONAL ECONOMY

The Regional Economic Model (REMI, PI+ v2.5.0) was used to assess the total socioeconomic impacts of the anticipated policy change (i.e., the proposed rule).[10][11] 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.[12]

It should be noted that the REMI model is not designed to assess impacts on individual operations. The model was used to assess the impacts of the proposed project on various industries that make up the local economy. Cost impacts on individual operations were assessed outside of the REMI model and used as inputs into the REMI model.

Impact of Proposed Amendments

The assessment herein is performed relative to a baseline ("business as usual") where the proposed amendments would not be implemented. It is assumed that the 16 facilities would finance the

[10] Regional Economic Modeling Inc. (REMI). Policy Insight® for the South Coast Area (160-sector model). Version 2.5.0, 2021.

[11] REMI v2.5.0 has been updated based on The U.S. Economic Outlook for 2021-2023 from the University of Michigan's Research Seminar in Quantitative Economics (RSQE) release on May 21, 2021, The Long-Term Economic Projections from CBO (supplementing CBO's March 2021 report The 2021 Long-Term Budget Outlook), and updated BEA data for 2020 (revised on May 27, 2021).

[12] Within each county, producers are made up of 156 private non-farm industries and sectors, 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.)

capital and installation costs of control equipment, or more specifically, these one-time costs are assumed to be amortized and incurred over the equipment life. The proposed project is assumed to induce full BARCT installation at the 16 affected facilities, which would create a policy scenario under which the affected facilities would incur an average annual compliance cost of approximately $133.88 million when costs are annualized using a 4% real interest rate, or $99.53 million when evaluated using a 1% real interest rate from year 2022 onwards when all controls are assumed to have been installed.

Direct effects of the proposed project are used as inputs to the REMI model in order for the model to assess secondary and induced impacts for all the industries in the four-county economy on an annual basis and across a user-defined horizon: 2022 (first year when the affected facilities are assumed to incur compliance costs due to BARCT implementation) to 2057 (last year cost associated with equipment installation are incurred). Direct effects of the proposed amendments include (1) additional costs (net of cost savings due to lower emissions fees) to the 16 facilities that would install control equipment, (2) additional sales by local vendors of equipment, devices, or services that would meet the proposed requirements, and (3) increased fuel costs to all industries and consumers in the region.

Whereas all the compliance expenditures that are incurred by the affected facilities would increase their cost of doing business, the purchase of additional control equipment such as SCR, ULNB, and equipment installation would increase the spending and sales of businesses in various sectors, some of which may be located in the South Coast AQMD region. Table 16 lists the industry sectors modeled in REMI that would either incur cost or benefit from the compliance expenditures.

Table 16: Industries Incurring *vs.* Benefitting from Compliance Costs/Spending

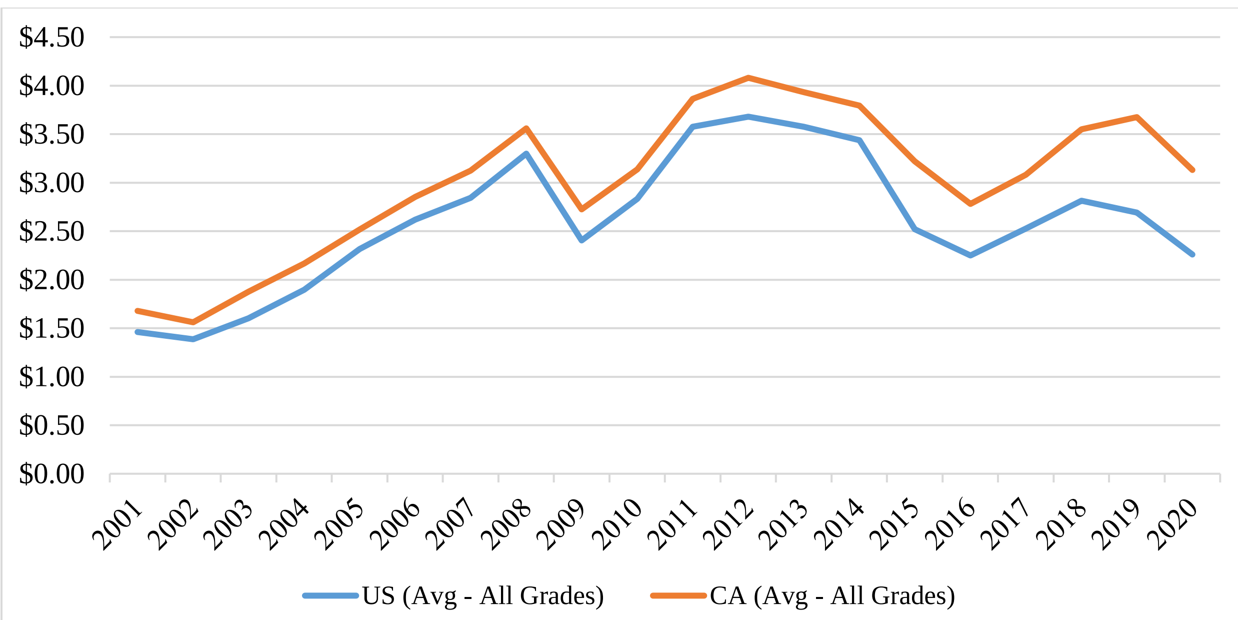
Source of Compliance Costs	REMI Industries Incurring Compliance Costs	REMI Industries Benefitting from Compliance Spending
Installation of SCR and ULNB technology	Petroleum and Coal Products Manufacturing (NAICS 324), Basic Chemical Manufacturing (NAICS 3251)	*One-time-Capital:* Industrial Machinery Manufacturing (NAICS 3332)
Installation of SCR and ULNB technology	Petroleum and Coal Products Manufacturing (NAICS 324), Basic Chemical Manufacturing (NAICS 3251)	*One-time-Capital:* Construction (NAICS 23)
Permitting and Plan Submission Fees	Petroleum and Coal Products Manufacturing (NAICS 324), Basic Chemical Manufacturing (NAICS 3251)	*One-time-Capital:* State and Local Government (NAICS 92)
Operating and Maintenance Costs: Other Maintenance	Petroleum and Coal Products Manufacturing (NAICS 324), Basic Chemical Manufacturing (NAICS 3251)	*Recurring:* Other Professional, Scientific, and Technical Services (NAICS 5419)
Operating and Maintenance Costs: Electricity, Water	Petroleum and Coal Products Manufacturing (NAICS 324), Basic Chemical Manufacturing (NAICS 3251)	*Recurring:* Electric Power Generation, Transmission, and Distribution (NAICS 2211)
Operating and Maintenance Costs: Ammonia, Caustic	Petroleum and Coal Products Manufacturing (NAICS 324), Basic Chemical Manufacturing (NAICS 3251)	*Recurring:* Basic Chemical Manufacturing (NAICS 3251)
Operating and Maintenance Costs: Cost Savings Due to Reduced Emissions Fees	State and Local Government (NAICS 92)	*Recurring:* Petroleum and Coal Products Manufacturing (NAICS 324), Basic Chemical Manufacturing (NAICS 3251)
Operating and Maintenance Costs: Annual Permit Fees	Petroleum and Coal Products Manufacturing (NAICS 324), Basic Chemical Manufacturing (NAICS 3251)	*Recurring:* State and Local Government (NAICS 92)

Impacts on Regional Fuel Prices

The impact analysis assumes that facilities will pass on a percentage of their compliance costs onto consumers and local industries through an increase in the regional price of gasoline. Based on the report included in Appendix A, "The Impact of Proposed Rule 1109.1 on Fuel Prices and Demand in South Coast AQMD Region," it is assumed that 30% of total annual O&M costs, including the cost savings due to reduced emission fees, is passed on to consumers and industries through increased gasoline prices.

REMI requires that modeled changes in fuel prices be inputted as a percentage change. To calculate the percentage increase in fuel price we first calculate the per gallon cost of compliance by dividing total annual passed through O&M costs (or 30% of total annual O&M costs) by total annual refinery distillation capacity.[13] The average annual increase in the price of gasoline is estimated to be .0035 cents per gallon. Then the calculated per gallon cost is divided by future projected gasoline price. The future gasoline price is based on the U.S. Energy Information Administration (EIA) motor gasoline price projections for 2021-2050.[14,15] Based on recent historical annual gasoline price data (2015-2020) from EIA (see Figure 1) it is assumed that future average gasoline prices in California are 29% higher than the projected average US price.[16] See Figure 2 below for the annual projected gasoline price for the U.S. and California from 2021-2050.

Figure 1: Historical Annual Average Per Gallon Gasoline Price for U.S. and California



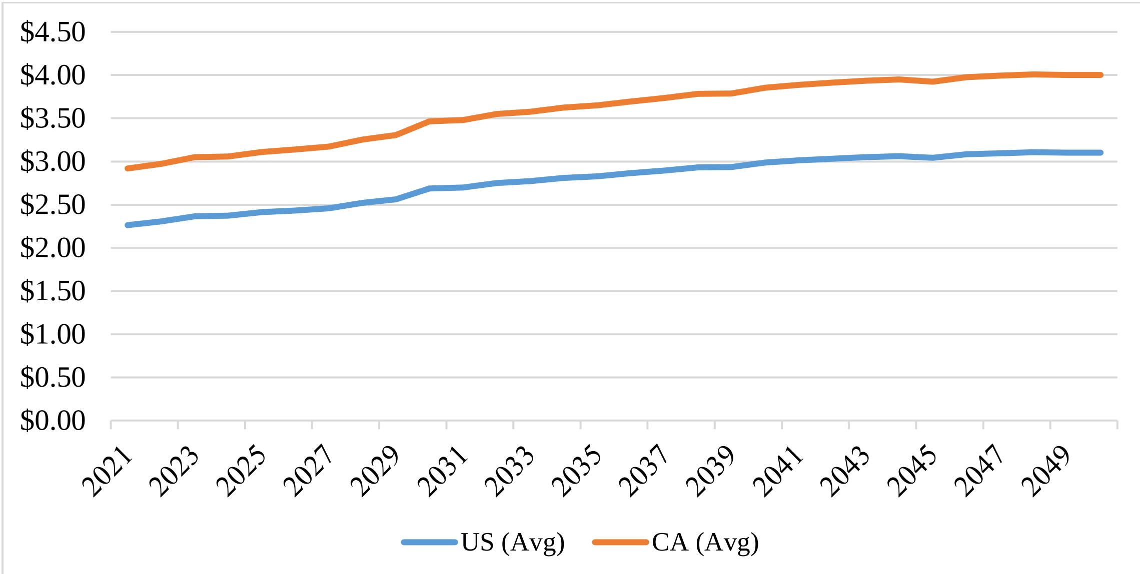
[13] Estimates of 2019 annual distillation capacity by refinery (in bbl/day) can be found in Table 1 of Appendix A. It is assumed that 42 gallons of petroleum products are produced per bbl. In addition, an average refinery capacity factor of 0.873 is assumed based on the 20-year average for PADD 5 reported by the EIA.

[14] https://www.eia.gov/outlooks/aeo/data/browser/#/?id=12-AEO2021&cases=ref2021~aeo2020ref&sourcekey=0

[15] EIA gasoline price projections were provided in 2020 dollars. The August 2021 update to the Marshall and Swift Cost Index was used to convert future prices to 2018 dollars.

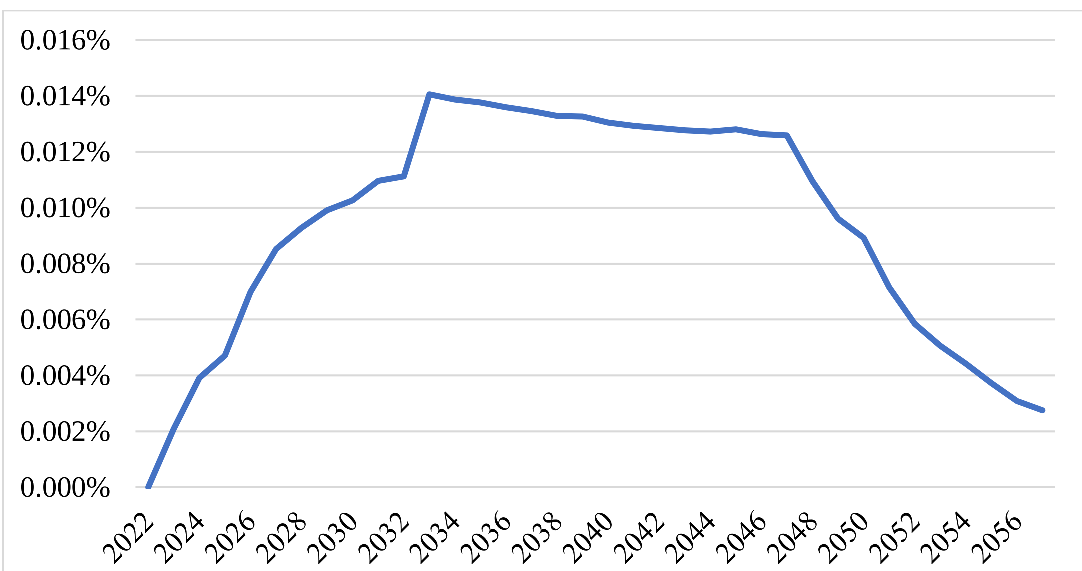
[16] 2015-2020 historical annual average 'all grade' price data for the US and California can be found here: https://www.eia.gov/dnav/pet/pet_pri_gnd_dcus_nus_w.htm

Figure 2: U.S. and California Projected Per Gallon Gasoline Price 2021-2050 (in 2018 dollars)



The estimated annual percentage increase in gasoline price is shown below in Figure 3. Gas prices are expected to slowly increase as control equipment is installed over time. A maximum percentage increase of 0.014% is reached in 2033 upon full implementation of the rule. After 2033, price increases are expected to steadily decline as O&M costs remain constant and gas price projections steadily rise. In later years, impacts to fuel prices decline dramatically due to expected lower annual O&M costs.

Figure 3: Estimated Percentage Increase in Gasoline Prices Resulting from PR 1109.1 Implementation



Regional Job Impacts

When the compliance cost is annualized using a 4% real interest rate, it is projected that an annual average of 213 net jobs could be created annually from 2022 to 2057. The projected job impact is more positive (342 jobs created annually) when the compliance cost annualized at a 1% interest rate is used.

In earlier years of the implementation, the positive job impacts from the compliance expenditures made by affected facilities would more than offset the jobs forgone from the additional cost of doing business (Table 17). From 2022-2032, it is projected that an average of 1,837 jobs would be added annually. In 2032, when most of the spending is expected to occur, about 4,435 additional jobs are projected in the regional economy. The positive job impact would trickle down to the sectors of construction, miscellaneous professional services, retail & wholesale trade, food services, and real estate. However, as affected facilities continue to incur the amortized capital expenditures and annual O&M costs, reductions in job growth would set in, resulting in jobs forgone in later years.

Despite incurring the majority of the total compliance cost, the petroleum and coal products manufacturing industry (NAICS 324) is projected to experience only minor impacts in terms of jobs forgone (14 on average). This is due to the fact that the industry is capital-intensive. As such, less labor would be required to produce the same amount of products or services.

In earlier years, positive job impacts are projected in the sectors of architectural and structural metals manufacturing (NAICS 3323) and industrial machinery manufacturing (NAICS 3332), due to purchase of various types of control equipment (including SCR and ULNB) by the affected facilities (as presented in Table 17). Likewise, the construction sector is projected to gain many jobs during the early years of the time horizon, due to the installation of control equipment. In addition, the sector of other professional, scientific, and technical services (NAICS 5419) is projected to also gain jobs across the entire planning horizon. Operating and maintenance expenditures would benefit the industries of basic chemical manufacturing (NAICS 3251) for additional sales of ammonia and electricity generation, transmission, and distribution (NAICS 2211) for electricity.

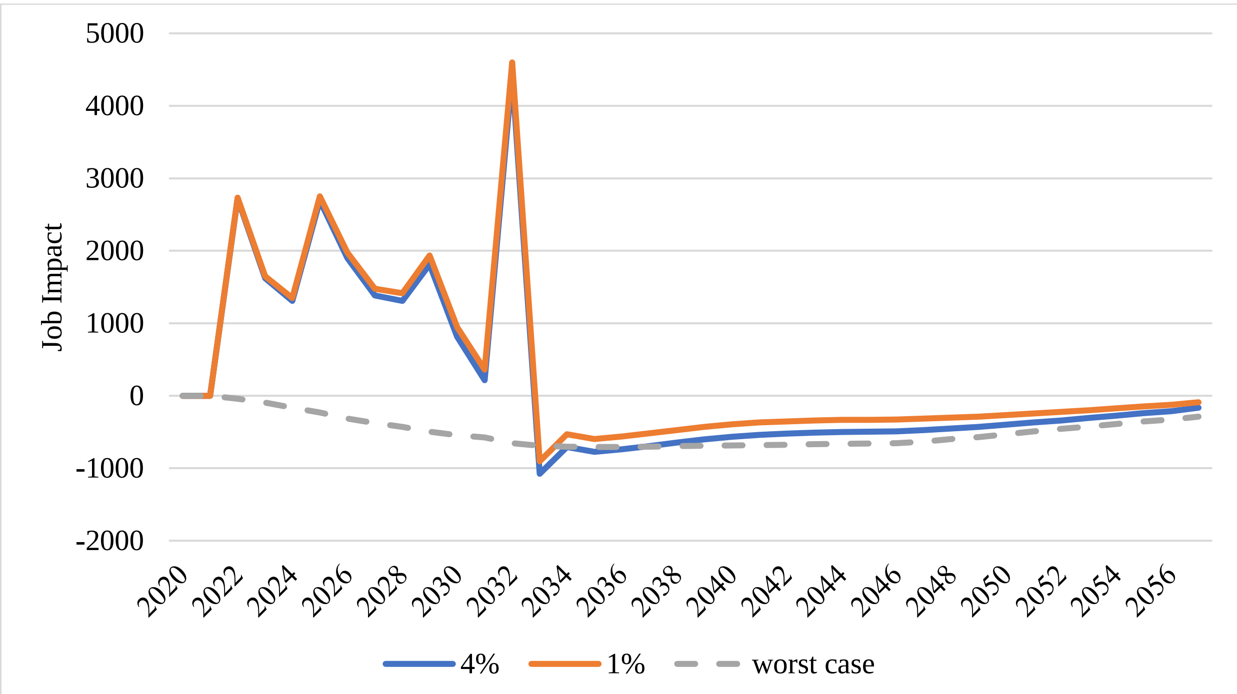
The projected reduction in disposable income from the overall jobs forgone in the later years would dampen the demand for goods and services in the local economy, thus contributing to jobs forgone in sectors such as the rest of manufacturing, retail trade, wholesale, and accommodation and food services. As presented in Table 17, many major sectors of the regional economy would experience negative, albeit minor, job impacts in later years from the secondary and induced effects of BARCT implementation.

Table 17: Projected Job Impacts of Full BARCT Implementation for Select Industries by Year

Industry	2022	2027	2032	2037	2047	2057	Average Annual (2022-2057)	Baseline Average Annual (2022-2057)	% Change from Baseline
Construction (23)	1,429	897	2,669	-189	-55	5	283	572,266	0.049%
Other professional, scientific, and technical services (5419)	9	11	26	10	10	1	9	76,008	0.012%
Offices of health practitioners (6211-6213)	62	21	104	-6	-2	0	7	392,074	0.002%
Industrial machinery manufacturing (3332)	27	17	40	0	0	0	6	1,238	0.501%
Architectural and structural metals manufacturing (3323)	23	14	40	-3	-1	0	5	18,759	0.024%
Architectural, engineering, and related services (5413)	36	17	53	-10	-5	-1	3	105,440	0.003%
Retail trade (44-45)	173	56	203	-46	-34	-8	1	926,446	0.000%
Basic chemical manufacturing (3251)	0	1	1	0	0	0	0	2,204	0.006%
Waste management and remediation services (562)	4	1	5	-3	-2	-1	-1	26,845	-0.004%
Food services and drinking places (722)	73	42	123	-22	-33	-17	-2	729,552	0.000%
Real estate (531)	70	18	95	-18	-17	-12	-2	615,022	0.000%
Oil and gas extraction (211)	0	-2	-5	-6	-5	-1	-4	1,863	-0.206%
Management, scientific, and technical consulting services (5416)	17	4	20	-13	-10	-4	-5	195,135	-0.003%
Warehousing and storage (493)	11	-2	4	-12	-7	-1	-6	101,407	-0.005%
Wholesale trade (42)	62	15	67	-33	-23	-7	-9	421,576	-0.002%
Transit and ground passenger transportation (485)	22	6	33	-26	-25	-12	-13	349,167	-0.004%
Petroleum and coal products manufacturing (324)	0	-7	-15	-21	-18	-6	-14	4,527	-0.307%
State and Local Government (92)	85	95	136	-86	-94	-36	-23	1,016,786	-0.002%
All Industries	**2,720**	**1,384**	**4,435**	**-695**	**-473**	**-166**	**213**	**11,889,543**	**0.002%**

Figure 4 presents a projected time series of job impacts over the 2020-2057 time horizon. Based on Abt Associate's 2014 recommendation to enhance socioeconomic analysis by conducting scenario analysis on major assumptions, staff has analyzed an alternative scenario (worst case) where the affected facilities would not purchase any control equipment or services from providers within the Basin. This is a hypothetical scenario in order to test the sensitivity of the previously discussed scenarios where the analyses rely on REMI's embedded assumptions about how the capital and O&M spending would be distributed inside and outside the region. In reality, utilities expenditures are paid to local utilities producers. Moreover, construction jobs related to control installation are likely to increase hiring from the local labor force. This worst-case scenario would result in an annual average of approximately 516 jobs forgone. The 516 jobs forgone represents less than 0.005% of total jobs in the region.

Figure 4: Projected Regional Job Impact, 2020-2057



Competitiveness

For an analysis of the expected impacts of PR 1109.1 on regional fuel prices, please see the Impacts of Regional Fuel Prices section of this document. Estimated impacts are based on the assumption that 30% of annual O&M costs are passed on to consumers. For added context, if 100% of all costs (capital and O&M) were passed on to consumers, it is projected that gasoline prices will increase by 0.99 cents per gallon (or a 0.26% increase) on average, with a maximum expected increase of 1.42 cents per gallon (or a 0.40% increase).

Job Impacts by Occupation and Income Group

REMI provides a breakdown job impacts by occupation type. See Table 18 below for the projected job impacts by year for each major occupation category. All job impacts across the region are accounted for in Table 18. Construction and extraction occupations are projected to experience the largest growth in employment as a result of PR 1109.1. This occupation category includes trade workers, helpers, extraction workers and supervisors. Installation, maintenance and repair occupations are also expected to experience relatively strong employment growth. This category includes electrical and electronic equipment mechanics, installers & repairers, as well as vehicle and mobile equipment mechanics, installers & repairers. Legal workers, educators, protective workers (fire, police), and life & physical scientists are all projected to experience minor negative job impacts.

Table 18: Job Impacts by Occupation, 2022-2057

Occupation	2022	2027	2032	2037	2047	2057	Annual Average (2022-2057)	Baseline Annual Average (2022-2057)	% Change from Baseline
Management, business, and financial operations occupations	295	143	480	-84	-56	-21	17	1,521,282	0.001%
Computer, mathematical, architecture, and engineering occupations	84	35	120	-35	-26	-11	-3	585,436	-0.001%
Life, physical, and social science occupations	10	5	15	-6	-5	-2	-1	86,290	-0.001%
Community and social service occupations	14	9	23	-6	-7	-3	-1	192,777	0.000%
Legal occupations	14	5	18	-8	-5	-2	-1	120,057	-0.001%
Educational instruction and library occupations	46	41	73	-34	-38	-17	-8	553,075	-0.001%
Arts, design, entertainment, sports, and media occupations	20	4	27	-6	-3	-3	0	374,024	0.000%
Healthcare occupations	128	57	218	-20	-21	-11	10	1,304,086	0.001%
Protective service occupations	25	14	35	-18	-16	-6	-5	260,916	-0.002%
Food preparation and serving related occupations	84	46	139	-26	-35	-18	-2	847,583	0.000%
Building and grounds cleaning and maintenance, personal care and service occupations	108	38	167	-29	-24	-9	1	863,635	0.000%
Sales and related, office and administrative support occupations	489	200	685	-130	-86	-28	21	2,511,233	0.001%
Farming, fishing, and forestry occupations	1	1	2	-1	0	0	0	24,040	0.000%

Construction and extraction occupations	896	562	1,678	-127	-42	1	173	447,963	0.039%
Installation, maintenance, and repair occupations	199	107	340	-46	-28	-9	21	538,948	0.004%
Production occupations	120	47	158	-35	-20	-6	4	445,549	0.001%
Transportation and material moving occupations	186	69	258	-86	-62	-20	-13	1,167,112	-0.001%
Military	0	0	0	0	0	0	0	45539	0.000%
All Occupations	**2720**	**1384**	**4435**	**-695**	**-473**	**-166**	**213**	**11889543**	**0.002%**

REMI also groups occupations into five categories according to income quintiles. Group 1 has the lowest-paid occupations while Group 5 has the highest-paid occupations. Table 19 below shows the job impact as a percentage of the baseline jobs under the proposed amendments for each occupational wage group.

A positive figure indicates that the proposed amendments create more jobs and a negative figure means the opposite. In earlier years of the implementation of these amendments, the positive job impacts from the compliance expenditures made by affected facilities would more than offset the jobs proportionally forgone from the additional cost of doing business. However, as affected facilities continue to incur the amortized capital expenditures, reductions in job growth would set in, resulting in jobs forgone in later years.

As shown in Table 18, from 2022 through 2032, the full installation of BARCT controls is projected to result in more jobs created with respect to the baseline for all occupational groups. In later years, however, proportionately fewer jobs would be foregone for lower paid than higher paid jobs.

Table 19: Job Impact of the Proposed Amendments by Occupational Wage Group by Year

Occupational Income Group	% Impact from Baseline					
	2022	2027	2032	2037	2047	2057
Group 1 (1st 20%)	0.013%	0.005%	0.018%	-0.003%	-0.003%	-0.001%
Group 2 (2nd 20%)	0.020%	0.008%	0.029%	-0.006%	-0.004%	-0.001%
Group 3 (3rd 20%)	0.049%	0.027%	0.084%	-0.009%	-0.005%	-0.001%
Group 4 (4th 20%)	0.023%	0.012%	0.037%	-0.007%	-0.005%	-0.002%
Group 5 (5th 20%)	0.017%	0.008%	0.026%	-0.005%	-0.004%	-0.001%

Incremental Cost Effectiveness

Please refer to the most recent version of the Staff Report.

CEQA ALTERNATIVES

Four alternatives to the proposed amendments were developed for the CEQA analysis associated with this proposal, Alternative A - No Project, Alternative B - More Stringent, Alternative C - Less Stringent, and Alternative D - Limited Start-Up, Shutdown, Malfunction. This section provides a description of each alternative as well as an assessment of the possible socioeconomic impacts resulting from these alternatives.

Alternative A – No Project

CEQA requires the specific alternative of "No Project" to be evaluated. A "No Project" Alternative consists of what would occur if the proposed project was not approved; in this case, not adopting the proposed rule. Alternative A is the "No Project" approach such that petroleum refineries and facilities related to petroleum refineries would remain under the NOx RECLAIM program and not be subject to a command-and-control rule. Since the transition of RECLAIM facilities into a command and control approach was the directive under control measure CMB-05 in the 2016 AQMP, the "No Project" alternative would hinder the full implementation of the control measure, not achieve the anticipated emission reductions in a timely manner, or satisfy the objectives of the proposed project.

However, remaining subject to the RECLAIM program under Alternative A would not eliminate the state law in Assembly Bill 617 that requires air districts "in nonattainment for one or more air pollutants to adopt an expedited schedule for the implementation of best available retrofit control technology, as specified." The bill applies to each industrial source that, as of January 1, 2017, was subject to a specified market-based compliance mechanism (e.g., RECLAIM or GHG Cap and Trade) and gives highest priority to those permitted units that have not modified emissions-related permit conditions for the greatest period of time. Thus, facilities would still need to be evaluated under a BARCT analysis and, depending on the outcome of that analysis, would need to take action to comply. However, the BARCT analysis under Alternative A and the proposed project is expected to be the same with the same determinations and NOx emission limits. The major difference is that under the RECLAIM program, facilities could potentially opt to use RECLAIM trading credits (RTCs) to meet allocation goals and not install physical control technology. Facilities under Alternative A could also be subject to a different implementation period to demonstrate compliance with the BARCT NOx emission limit. Other elements in the rule such as averaging times, exemptions, recordkeeping, reporting, and monitoring may also be different under the RECLAIM program.

The costs associated with complying with BARCT under RECLAIM are speculative, given the uncertainty surrounding the use of RTCs to meet compliance targets. As a result, for the purpose of this socioeconomic analysis, staff has assumed that costs for Alternative A would be identical to the costs associated with the proposed project given that the BARCT requirements would be the same under the 'No Project' scenario. This is a conservative approach because RECLAIM facilities would be expected to comply using RTCs if that is more cost-effective.

Alternative B - More Stringent Proposed Project

Under the proposed project, there is a set of requirements for some equipment categories, such as small boilers and heaters, that would not need to meet a lower NOx limit at this time due to the determination that is not cost effective under the BARCT analysis or the technology required to meet the lower limit is considered "emerging". The proposed project, however, does require the equipment to meet the lower NOx limit at a future date. In the case of the small boilers less than 40 MMBTU/hour, achieving 5 ppm is not required until the operator cumulatively replaces 50% or more of the burners starting from the date of rule adoption. For small heaters less than 40 MMBTU/hour, achieving 9 ppm with emerging technology is not required until ten years after rule adoption. Alternative B would propose shortening those deadlines so that small boilers would need to meet 5 ppm in six months of 25% or more of the burners being replaced and small heaters would need to meet the 9 ppm within five years of rule adoption (see Table 20 below).

The overall benefits from Alternative B compared to the proposed project will be the same except the benefits will be achieved sooner under Alternative B. All other elements, limits, and deadlines would be the same under Alternative B as is in the proposed project. For the purpose of this socioeconomic analysis, it is assumed that all small heaters are installed and begin operation in 2026 and all small boilers are installed and in operation beginning in 2025.

Table 20: Alternative B Accelerating Future Lower NOx Limit

Equipment Category	No. of Units in Category	Future NOx Limit (ppm)	Alternative B Implementation Date	2017 NOx Emissions (tpd)	NOx Emission Reduction (tpd)
Heaters < 40 MMBtu/hr	67	9	Within 5 years of rule adoption	0.50	0.36
Boilers < 40 MMBtu/hr	5	5	Within 6 months of 25% or more of burners cumulatively being replaced	0.013	0.009

Alternative C – Less Stringent Proposed Project

Under Alternative C, the implementation period could be extended to provide more time for each facility's individual projects to take place to achieve the proposed lower NOx limit. Under the proposed project, operators with six or more units complying with Table 1 (of the proposed rule), Table 2 (of the proposed rule), a B-Plan, or a B-CAP in PR 1109.1 have the option to either: a) submit permit applications by July 1, 2023 and achieve the NOx and CO emission limits in Table 1 of PR 1109.1 no later than 36 months after a Permit to Construct is issued, or b) submit an I-Plan to achieve NOx and CO limits under a two- or three-phase timeline. The development of the I-

Plan options in Table 6 of PR 1109.1 is a culmination of input from the refineries regarding timeframes and percent reductions; under Alternative C, the time frames could be extended, and percentage reduction targets could be reduced in each phase as presented in Table 21. Both Alternative C and the proposed project would still require the combustion units to meet the proposed NOx emission concentration limit. While the overall quantity of anticipated NOx emission reductions would not be expected to change under Alternative C when compared to the proposed project, more time would be provided for the NO emission reductions to occur, and thus incremental benefit to the environment, are achieved would be delayed.

Table 21: Alternative C (Less Stringent) Implementation Schedule

		Phase I	Phase II	Phase III
I-Plan Option 1	**Percent Reduction Targets**	**70 → 35**	**100 → 50**	**N/A → 100**
	Permit Application Submittal Date	July 1, 2023	January 1, 2027	N/A → January 1, 2031
I-Plan Option 2	**Percent Reduction Targets**	**60 → 30**	**80 → 60**	**100**
	Permit Application Submittal Date	July 1, 2023	January 1, 2025	January 1, 2028
I-Plan Option 3	**Percent Reduction Targets**	**50 → 25**	**100 → 50**	**N/A → 100**
	Permit Application Submittal Date	January 1, 2025	January 1, 2029	N/A → January 1, 2033
I-Plan Option 4	**Percent Reduction Targets**	**50-60 → 30**	**80 → 60**	**100**
	Permit Application Submittal Date	N/A (need to comply by July 1, 2024	January 1, 2025	January 1, 2028
I-Plan Option 5	**Percent Reduction Targets**	**50 → 25**	**70→ 50**	**100**
	Permit Application Submittal Date	July 1, 2022	July 1, 2024	January 1, 2028

Alternative C is less stringent than the proposed project because of an extended implementation schedule of proposed control equipment. Again, NOx limits and the actions to be taken to achieve those limits are expected to be the same under Alternative C as they are for the proposed project. For this analysis, it is assumed that the implementation dates are pushed back by a maximum of two years for all equipment affected in the proposed project.

Alternative D – Limited Start-up, Shutdown, and Malfunction

The proposed project would allow emissions occurring during start-ups, shutdowns, and malfunctions (SSM), pursuant to the definitions in the PR 429.1, to not be considered when determining compliance with the NOx emission limits in PR 1109.1. The proposed project limits the duration of the SSM event as well as limits the severity (e.g., peak NOx concentration in terms of ppm) of the event. While difficult to predict when these SSM events could occur and how impactful they could be, examination of past patterns and researching the duration periods that have been previously required either in the permit conditions or consent decrees helped develop the SSM allowances for the proposed project. Alternative D would reduce the duration of these SSM allowances when compared to the proposed project as outlined in Table 22. This could require facilities to be more diligent in their start-up or shutdown procedures to ensure quick turnarounds and less emission spiking. More attention to maintenance and upkeep of equipment would be needed to reduce the number of malfunction and subsequent equipment downtimes. If additional measures are not taken to reduce the event duration or severity of the peak emissions, under Alternative D, the temporary spike in emissions would need to be incorporated when demonstrating compliance with the NOx limits.

Table 22: SSM Allowances in Proposed Project and Alternative D

Unit	Proposed Project SSM Not to Exceed (hours)	Alternative D SSM Not to Exceed (hours)
Boilers and Process Heaters without NOx Post-Combustion Control Equipment, Gas Turbines, Flares, Vapor Incinerators without NOx Post-Combustion Control Equipment or Castable Refractory	2	2
Boilers and Process Heaters with NOx Post-Combustion Control Equipment, Steam Methane Reformer Heaters, Sulfuric Acid Furnaces	48	24
Steam Methane Reformer with Gas Turbine	60	30
FCCUs, Petroleum Coke Calciner, or SRU/TG Incinerators	120	60

NOx limits and the actions to be taken to achieve those limits are expected to be the same under Alternative D as they are for the proposed project. For the sake of this analysis, it is assumed that there is no change in costs, emission reductions and/or implementation schedule from the proposed project.

Table 23 presents a comparison of the alternatives in terms of annual average cost, NPV (of compliance costs), jobs impacts, and a discounted cash flow (DCF) cost-effectiveness estimate based on a 4% discount and real interest rate. Alternatives A and D have identical NPV, job impacts, and cost-effectiveness to the proposed project given the assumptions made above. Alternative B has a higher NPV given the expedited implementation schedule for small heaters and boilers, resulting in more of the compliance costs to occur in earlier periods. Additionally, job impacts for Alternative B are slightly less positive due to the more stringent implementation timeline. Alternative C has a lower NPV due to the assumption of an extended implementation schedule for all units, thus allowing for compliance costs to occur in later periods.

Table 23: Average Annual Costs, NPV and Job Impacts by CEQA Alternative

Alternatives	Average Annual Cost (4%) (Millions of 2018$)	NPV (4%) (Millions of 2018$)	Average Annual Job Impacts (2022-2057)	DCF Cost-Effectiveness ($/ton)
Proposed Project	$132.45	$2,336.24	213	$32,698
Alternative A - No Project	$132.45	$2,336.24	213	$32,698
Alternative B - More Stringent	$132.45	$2,465.01	199	$34,570
Alternative C - Less Stringent	$132.45	$2,076.91	225	$29,068
Alternative D - Limited Start-up, Shutdown, and Malfunction	$132.45	$2,336.24	213	$32,698

PUBLIC HEALTH BENEFITS

The South Coast Air Basin is one of only two "extreme" non-attainment areas in the nation that have not reached the federal 8-hour ozone standard. Ground-level ozone, or smog, forms when volatile organic compounds (VOC) photochemically react with nitrogen oxides (NOx) in the presence of sunlight. Ozone exposure can cause immediate, adverse effects on the respiratory system and result in various symptoms such as coughing, throat irritation, chest pain, and shortness of breath. It can also inflame the lining of the lungs, and for asthma patients, it may increase the number and severity of attacks. Long-term impacts of frequent exposure to ozone may lead to permanent lung damage and increase the risk of premature death.

In addition, the South Coast Air Basin remains a serious non-attainment area for the federal PM2.5 standards. Exposure to high levels of PM2.5 have been shown to cause and aggravate cardiopulmonary illnesses, including heart attacks, irregular heartbeat, aggravated asthma, decreased lung function, and increased respiratory symptoms, such as irritation of the airways, coughing or difficult breathing. These outcomes result in increased absences from school and work, hospitalization, and other medical expenses. Exposure to PM2.5 is associated with premature deaths. According to past estimates by the California Air Resources Board, elevated ambient PM2.5 levels result in approximately 4,100 premature deaths annually in the South Coast Air Basin.

Oxides of nitrogen (NOx) is a precursor to both PM2.5 and ozone. Therefore, the reductions in ozone and PM2.5 associated with the proposed rule have the potential to reduce the mortality and morbidity incidences associated with NOx emissions. Public health benefits resulting from compliance with PR 1109.1 are calculated using an incidence per ton (IPT) methodology, developed by the U.S. Environmental Protection Agency.[17,18,19] The IPT methodology is an approximation based on the assumption that the relationship between emissions and adverse health outcomes is linear. Furthermore, the IPT methodology relies on the following assumptions, (1) changes in health incidence are proportional to ambient PM2.5 concentrations; (2) changes in primary pollutant concentrations (PM2.5) are proportional to changes in directly emitted PM2.5; and (3) changes in secondary pollutant concentrations (nitrate PM2.5) are also proportional to changes in precursor emissions (NOx). This final assumption can vary for individual actions due to the complex chemical reactions that occur to create regional pollutants. However, as PR 1109.1 is part of a larger emission reduction strategy, a simplifying assumption is that the health benefits for every ton of NOx reduction in that strategy yields equal benefits.

The public health benefits analysis presented here is based on the proposed project which assumes 74 new SCRs, 15 SCR upgrades, and 76 ULNBs will be installed as a result of PR 1109.1. PR 1109.1 is projected to result in a reduction in NOx emissions of 7 to 8 tpd upon full implementation, however, for the sake of the health benefit analysis, 7 tpd was assumed. The increased use of ammonia associated with the SCR controls creates the potential for ammonia slip. South Coast AQMD staff expects that the installation of 74 new SCRs will result in 0.63 tpd of increased ammonia emissions[20]. Ammonia is also a precursor to PM2.5.

It should be noted that ozone formation violates many of the assumptions underlying the IPT methodology and, as a result, the potential benefits resulting from reductions in ambient ozone concentrations are not quantified in this analysis.

Incidence Per Ton Methodology

Because of the assumed linear relationship between emissions and health outcomes, estimates of reductions in health endpoints resulting from PR 1109.1 can be found by multiplying expected changes in emissions by an IPT factor for each health endpoint.[21] The IPT factors for each health endpoint were calculated using estimated control strategy emissions reductions, air quality modeling in the U.S. EPA's Community Multiscale Air Modeling System (CMAQ), and public health benefits estimation using the U.S. EPA's Environmental Benefits Mapping and Analysis Program – Community Edition (BenMAP-CE) from the 2016 Air Quality Management Plan (AQMP). Total emissions reductions in years 2023 and 2031 resulting from 2016 AQMP control strategies are shown in Table 24 below, while the corresponding reductions in modeled health outcomes in 2023 and 2031 are shown in Table 25 below.

[17] https://www.ncbi.nlm.nih.gov/pmc/articles/PMC2770129/
[18] https://pubmed.ncbi.nlm.nih.gov/23022875/
[19] https://www.epa.gov/sites/default/files/2018-02/documents/sourceapportionmentbpttsd_2018.pdf
[20] The analysis does not include ammonia slip from the 17 SCR upgrades expected given that SCR upgrades are not projected to result in an increase in ammonia slip above pre-project levels.
[21] https://ww2.arb.ca.gov/sites/default/files/2019-08/Estimating%20the%20Health%20Benefits%20Associated%20with%20Reductions%20in%20PM%20and%20NOX%20Emissions%20-%20Detailed%20Description.pdf

NOx contributes to ambient concentrations of PM2.5 through the formation of nitrate PM2.5. For the sake of calculating contribution to ambient PM2.5 concentrations, it was assumed that each ton of NOx emitted is equivalent to 0.03 tons of directly emitted PM2.5.[22,23]

Regional-specific IPT factors for directly emitted PM2.5 and NOx were calculated using the modeled emission reductions and corresponding health outcomes shown in Tables 24 and 25. A regional-specific IPT factor for directly emitted PM2.5 is calculated by dividing the estimated reduction in incidence of a given health endpoint by the total PM2.5 emission reductions in the years 2023 and 2031.[24] Linear interpolation is then used to generate IPT factors for the remaining years (2024-2030). IPT factors for those years beyond 2031 are simply set equal to the calculated 2031 IPT factor. Regional-specific IPT factors for NOx are calculated similarly after netting out the impacts from directly emitted PM2.5.[25]

As part of the 2015 RECLAIM NOx Shave, South Coast AQMD staff conducted a series of regional simulations to determine the impacts of reducing NOx by the proposed RTC shave while increasing the potential for creating ammonia slip due to increased use of ammonia needed for the operation of SCR controls. Based on the regional air quality modeling simulations run, this analysis assumes that one ton of ammonia is equivalent to 7.36 tons of NOx.[26]

Table 24: 2016 AQMP Projected Emission Reductions by Pollutant (tpd)

	2023	2031
NOx	124	128
PM2.5	0.22	3.4

Note: Projected emission reductions are average of summer planning period (May 1 to September 30).

[22] U.S. EPA's February 2018 Technical Support Document, "Estimating the Benefit per Ton of Reducing PM2.5 Precursors from 17 Sectors," estimates the average monetary public health benefits of NOx emissions across all industries is roughly 3% of direct PM emissions (https://www.epa.gov/sites/production/files/2018-02/documents/sourceapportionmentbpttsd_2018.pdf).

[23] The ratio of NOx to PM2.5 could potentially be higher than the 0.03 assumed here. Previous work done on the 2007 AQMP suggested that each ton of NOx emitted is equivalent to 0.1 tons of directly emitted PM2.5 in regards to annual PM2.5 concentrations. A higher NOx to PM2.5 ratio would lead to an increase in IPT factors for NOx and corresponding decrease in IPT factors for directly emitted PM2.5. Given that NOx emission reductions from PR 1109.1 are projected to be significantly greater than directly emitted PM2.5, the 0.03 ratio is used in an attempt to provide a conservative estimate of potential public health benefits.

[24] Reductions in health incidence were estimated for 2023 and 2031 in the 2016 AQMP.

[25] IPT factors also increase over time reflecting the projected increases in population by age class underpinning health effects modeling.

[26] In the analysis, NOx emissions were reduced at RECLAIM facilities by a total of 14 tpd while increasing ammonia slip emissions from the same facilities by 1.63 tpd. The simulations were run for the 2021 draft baseline emissions inventory to estimate the impact when full implementation of the RECLAIM shave was expected to be achieved. The effect of decreasing 14 tpd of NOx resulted in a decrease of annual PM2.5 of approximately 0.7 µg/m3 and the increase in ammonia slip caused a concurrent increase in annual PM2.5 of approximately 0.6 µg/m3. (http://www.aqmd.gov/docs/default-source/Agendas/Governing-Board/2015/2015-dec4-030.pdf)

Table 25: 2016 AQMP Modeled Reductions in Incidence Due to PM2.5 Exposure

	2023	2031	Average Annual
Premature Deaths Avoided, All Cause			
Long-Term PM2.5 Exposure	1,394	2,716	1,512
Short-Term PM2.5 Exposure[1]	100	194	108
Reduced Morbidity Incidence			
Long-Term PM2.5 Exposure			
Acute Bronchitis	1,039	1,890	1,087
Short-Term PM2.5 Exposure			
Acute Myocardial Infarction, Nonfatal	33	71	38
Asthma Exacerbation (Wheeze, Cough, Shortness of Breath)	23,321	42,780	24,495
Asthma, New Onset (Wheeze)	2,956	5,577	3,151
HA, All Cardiovascular (less Myocardial Infarctions)	164	337	183
HA, All Respiratory (less Asthma)[2]	136	290	155
HA, Ischemic Stroke	79	171	91
HA and ED Visits, Asthma	142	260	149
Lower Respiratory Symptoms	12,268	22,387	12,850
Upper Respiratory Symptoms	24,342	44,720	25,587
Minor Restricted Activity Days[3]	528,869	961,248	552,809
Work Loss Days[3]	91,689	166,826	95,892

* Each health effect represents the point estimate of a statistical distribution of potential outcomes. Please see Appendix 3-B of the 2016 AQMP Final Socioeconomic Report where the 95-percent confidence intervals are reported. Health effects for other years during the period 2017 to 2031 were based on interpolated, as opposed to modeled, air quality changes. The study population of each C-R function utilized can be found in Appendix 3-B of the 2016 AQMP Final Socioeconomic Report.

[1] Premature deaths avoided due to short-term exposure to PM2.5 are likely to partially overlap with those due to long-term PM2.5 exposure. Therefore, the total premature deaths associated with PM2.5 will be lower than simply summing across mortality effects from both short-term and long-term exposure (Industrial Economics and Thurston 2016a; Kunzli et al. 2001).

[2] This is the pooled estimate of two health endpoints: HA, Chronic Lung Disease (less Asthma) (18-64 years old) and HA, All Respiratory (65 or older).

[3] Expressed in person-days. Minor Restricted Activity Days (MRAD) refer to days when some normal activities are avoided due to illness.

These estimated IPT factors were then used to generate estimates of the impacts on health incidence resulting from expected emission reductions resulting from PR 1109.1 compliance.

Table 26 below shows projected changes in NOx and NH3 emissions in tpd for the years 2023 to 2037. PR 1109.1 is expected to result in approximately 31,300 cumulative tons of NOx reductions and an increase of cumulative 2,700 tons of NH3 emissions over the course over the time period from 2023 to 2037.

Table 26: Projected Annual Changes in NOx and NH3 Emissions from 2023 to 2037 (tpd)

	2023	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033 – 2037***
NOx Decrease	2.40	2.94	3.74	4.53	5.18	5.62	6.14	6.55	6.81	6.90	7.00
NH3 Increase	0.20	0.24	0.30	0.37	0.44	0.48	0.52	0.57	0.60	0.61	0.63

*Emission changes occur at the level reported in each year of the time horizon (2033, 2034,…, 2037)

Using IPT methodology, decreases in NOx emissions will result in positive health benefits (reductions in mortality and morbidity resulting from decreased ambient PM2.5 concentrations), while concurrent increases in NH3 will result in increases in mortality and morbidity due to increased ambient PM2.5 concentrations. Projected reductions of NOx are much larger than the expected increase in NH3, resulting in a net benefit to the South Coast Air Basin. Table 27 shows the corresponding net reductions in health incidence resulting from the emission changes in Table 26 and derived using the estimated IPT factors. Emissions changes are expected to cumulatively result in approximately 370 premature mortalities avoided from long-term and short-term PM2.5 exposure. Additionally, it is expected that PR 1109.1 will result in approximately 6,200 fewer asthma attacks and nearly 21,400 fewer work loss days over the course of the time period from 2023-2037.[27]

[27] Given that the assumed equipment life of SCR and LNB is 25 years, PR 1109.1 is expected to yield public health benefits well beyond the 2023-2037 time horizon analyzed here. A shorter time horizon was chosen given the uncertainty regarding the value of IPT factors beyond the year 2031.

Table 27: Estimated Net Reductions in Incidence Resulting from Projected Changes in NOx and NH3 Emissions

Endpoint	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033 - 2037*
Premature Deaths Avoided, All Cause											
Long-Term PM2.5 Exposure	10	13	16	19	21	23	25	26	27	27	27
Short-Term PM2.5 Exposure	1	1	1	1	2	2	2	2	2	2	2
Reduced Morbidity Incidence											
Long-Term PM2.5 Exposure											
Acute Bronchitis	7	9	12	14	15	17	18	18	19	19	19
Short-Term PM2.5 Exposure											
Acute Myocardial Infarction, Nonfatal	0	0	0	0	1	1	1	1	1	1	1
Asthma Exacerbation (Wheeze, Cough, Shortness of Breath)	164	213	269	317	348	376	407	414	428	423	425
Asthma, New Onset (Wheeze)	21	27	34	41	45	49	53	54	56	55	55
HA, All Cardiovascular (less Myocardial Infarctions)	1	2	2	2	3	3	3	3	3	3	3
HA, All Respiratory (less Asthma)	1	1	2	2	2	2	3	3	3	3	3
HA, Ischemic Stroke	1	1	1	1	1	1	2	2	2	2	2
HA and ED Visits, Asthma	1	1	2	2	2	2	2	3	3	3	3
Lower Respiratory Symptoms	86	112	141	166	183	197	213	217	224	221	223
Upper Respiratory Symptoms	171	222	281	331	364	393	425	433	448	442	445
Minor Restricted Activity Days	3709	4817	6090	7162	7863	8478	9158	9320	9620	9495	9559
Work Loss Days	643	835	1056	1242	1364	1471	1589	1617	1669	1648	1659

*Health incidence reductions occur at the level reported in each year of the time horizon (2033, 2034,…, 2037)

Valuation of Public Health Benefits

Monetary valuations of all estimated reductions in adverse health outcomes were calculated. The 2016 AQMP calculated the total monetary valuation for each health endpoint by multiplying the number of reduced outcomes for each endpoint by an estimate of the economic value of reducing the associated health risk for each endpoint. For reductions in premature mortalities, an estimate of the value of a statistical life (VSL) was used which came from aggregating reduced health risks. To generate value estimates for morbidities such as hospital admissions or emergency room visits, a cost-of-illness (COI) methodology was typically used. A detailed description of VSL and COI estimates can be found in Chapter 3 of the 2016 AQMP Final Socioeconomic Report. A summary of all monetary values and their associated reference(s) can be found in Appendix 3B of the 2016 AQMP Final Socioeconomic Report.

Staff estimated benefits per ton (BPT) factors for each health endpoint analyzed in the 2016 AQMP. BPT factors are calculated by dividing monetized public health benefits by modelled emission reductions from the AQMP. For example, a NOx BPT factor is calculated by dividing the estimated monetized health benefits of a given health endpoint by the total NOx emission reductions in the years 2023 and 2031. Linear interpolation was used to generate BPT factors for the intermittent years (2024-2030). BPT factors for those years beyond 2031 are simply set equal to the calculated 2031 BPT factor. BPT factors for PM2.5 are calculated similarly.[28] Table 28 below shows annual monetized health benefits over the entire compliance period (2023-2037). For the years 2023 – 2037, estimated discounted total monetized public health benefits is $3.49 billion using a 1% discount rate and $2.63 billion using a 4% discount rate. All dollar figures are in of 2018 dollars.[29,30]

Total discounted public health benefits were calculated over a shorter time period (2022-2037 for health benefits vs 2022-2057 for compliance costs), therefore the NPV for monetized health benefits can’t be directly compared to the NPV of compliance costs, but even so, monetized health benefits exceed total costs.

Table 28: Projected Annual Monetized Health Benefits Resulting from Projected Emission Changes (Millions of 2018 Dollars)

	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033-2037*
Monetized Health Benefits	$101.5	$134.8	$174.1	$209.2	$234.5	$258.0	$284.4	$295.2	$310.6	$306.6	$308.7

*Benefits a incurred at the level reported in each year of the time horizon (2033, 2034,…, 2037)

[28] BPT factors increase over time reflecting the projected increases in population by age class and increases in VSL due to projected increases in future incomes.
[29] 2015 dollar figures presented in the 2016 AQMP Final Socioeconomic Report have been adjusted to 2018 dollars using a price inflator of 4.64% based on the October 2020 Marshall & Swift price index (average, all industries).
[30] To avoid double-counting, total monetized public health benefits do not include monetized benefits from reduced mortalities due to short-term PM2.5 exposure.

Uncertainty in Public Health Benefits Estimation

The IPT methodology employed in this analysis is a proven reduced-form tool to estimate public health benefits and currently utilized by CARB and the U.S. EPA. However, the linearity assumption underpinning the IPT and BPT methodologies employed here is necessarily an approximation, and does not account for complex chemistry, precursor pollutant interactions, and finer-scale geographical effects in the same way that detailed modeling can, as in the 2016 AQMP (using CMAQ and BenMAP). In addition, the relative contribution of NOx to PM2.5 concentrations is subject to uncertainty and may vary by location. Actual changes in PM2.5 concentrations may be higher or lower than what is projected in this analysis. The approximations shown here are consistent with the detailed and holistic 2016 AQMP analysis to the extent that the proposed rule is included as a part of that overall strategy.

APPENDIX A: THE IMPACT OF PROPOSED RULE 1109.1 ON FUEL PRICES AND DEMAND IN THE SOUTH COAST AQMD REGION

The Impact of PR 1109.1 on Fuel Prices and Demand in the South Coast AQMD Region

Erich J. Muehlegger, Ph.D.

July 30, 2021

1 Executive Summary

This report estimates the impacts of South Coast Air Quality Management District's ("South Coast AQMD") Proposed Rule ("PR") 1109.1 on the prices of and demand for refined products in the South Coast AQMD region. Central to this exercise is an evaluation of the pass-through of costs by refineries in the Los Angeles area. That is, when refinery costs rise, are refineries able to commensurately increase the prices of refined products? Or, does competition from refineries outside of Los Angeles limit local refiners' ability to raise prices? This report first discusses the economic concept of pass-through and how it relates to the specific details of the refined product markets in the South Coast AQMD region. It provides two sources of evidence that speak to the appropriate pass-through rate for the compliance costs associated with PR 1109.1. Finally, it translates the pass-through estimates into impacts on prices and demand for refined fuels.

The main conclusions of the report are four-fold.

- First, under normal conditions, the market for refined products in Southern California is largely served by local refineries, reflective of the unique requirements of refined fuels in the South Coast AQMD region and the lack of pipeline delivery infrastructure into the region.

- Second, refineries from outside the region (and outside the United States) play an important role in the market by: (1) competing with Los Angeles refineries in markets served by both (e.g., Phoenix), and (2) delivering product to Los Angeles at times when prices rise (e.g., after the Torrance refinery fire.) This competition tends to moderate prices and limit the ability of Los Angeles refiners to pass-through production costs into spot prices. A quantitative examination of the pass-through of credit prices is consistent with a moderate pass-through rate.

- Third, scaling annual operational costs of compliance on a per-gallon basis, average costs across the five major refineries in Los Angeles County are roughly 0.2 cents per gallon. Including annualized capital costs associated with PR 1109.1, the per-gallon costs average 2.5 cents per gallon.

- If the costs are fully-passed onto retail price, the per-gallon cost increase would imply a retail price increase of less than one percent, even with the inclusion of annualized capital costs. But, using a pass-through estimate (30%) that reflects the competition faced by refineries in the South Coast AQMD region, the impact on retail prices would be more modest, totalling less than one cent per gallon, even if annualized capital costs are included. As the price effects are small, the effect on overall fuel consumption would be negligible.

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2 Statement of Qualifications

My name is Erich J. Muehlegger. I am an Associate Professor of Economics at University of California, Davis and a research associate of the National Bureau of Economic Research. Prior to my employment at University of California, Davis, I was an Assistant Professor and Associate Professor of Public Policy at Harvard Kennedy School and received my Ph.D. in Economics from Massachusetts Institute of Technology in 2005. The statements expressed herein are mine alone, and do not reflect the views of the institutions with whom I am or have been affiliated.

In my research, I have specialized in the impact of regulation and taxes on the decisions of firms and consumers in energy markets. My dissertation examined the price impact of "boutique gasoline blends" in the late 1990's including California's blend of reformulated gasoline. Since receiving my doctorate, I have authored or co-authored seventeen peer-reviewed papers, many of which examine how regulations, taxes or input costs are passed-through by firms onto customers in energy markets. These papers have been published in top Economics journals, including *Journal of Political Economy*, *Review of Economics and Statistics*, *American Economic Journal: Economic Policy*, and *Journal of Public Economics*. My CV is attached as Appendix B.

3 Introduction

South Coast Air Quality Management District ("South Coast AQMD") staff is developing a new rule, the goal of which is to reduce NOx emissions associated with refinery operations in the South Coast AQMD region (Los Angeles, Orange, Riverside, and San Bernardino counties). The rule is known as Proposed Rule 1109.1-Emissions of Oxides of Nitrogen from Petroleum Refineries and Related Operations ("PR 1109.1"). The proposed rule would affect nine petroleum refineries, three small refineries, and four related operations, such as hydrogen production and sulfuric acid manufacturing, all located within Los Angeles County.

Under PR 1109.1, petroleum refineries and related operations will be required to install pollution control equipment to reduce their NOx emissions. Staff projects 284 pieces of equipment are potentially subject to PR 1109.1 and a subset of these units will require the installation or upgrade of control equipment including Selective Catalytic Reduction System (SCR) and/or Low-NOx Burner technology. PR 1109.1 has the potential for significant emission reductions, in the range of 7 – 9 tons per day.

This report has been commissioned by the South Coast AQMD to evaluate the impacts of PR 1109.1 on the prices and demand for refined products in the region. Central to this exercise is an evaluation of the pass-through of costs by refineries in the Los Angeles area. That is, when refinery costs rise, are refineries able to commensurately increase the prices of refined products? Or, does competition from refineries outside Los Angeles limit local refiners' ability to raise prices? To assess the impacts of PR 1109.1, I first discuss the economic concept of pass-through and how it relates to the specific details of the refined product markets in the South Coast AQMD region. I then provide two sources of evidence that speak to the appropriate pass-through rate for the compliance costs associated with PR 1109.1. Finally, I translate the pass-through estimates into impacts on prices and demand for refined fuels.

4 The Economics of Pass-through

Pass-through is defined as the amount by which a firm raises its price in response to changes in its underlying costs. Pass-through has fundamental implications for firm profitability as well as consumer welfare. Put simply, if a firm cannot pass-through cost increases, by raising the price at which it sells its goods to customers when its costs rise, the amount of profit it earns per unit sold declines. In these cases, the firm bears the burden of rising costs. But, if the firm can pass-through cost increases onto consumers by raising its prices, the firm can preserve its profit margin. In this case, consumers bear the burden of the cost increase in the form of higher prices.

Pass-through also plays a central role in policy analysis because a firm's costs arise from the taxes and regulations it faces, as well as the cost of inputs used for production. As regulations, fees, taxes or other imposed costs change, a firm may pass-through those costs onto consumer just as it might pass-through the costs of inputs to production. Understanding how much of these costs are passed-through to consumers speaks directly to whether consumers or producers bear the burden of the regulation, fee, tax or other cost change.

Before turning to the details of the refined product market in the South Coast AQMD region, I first discuss two broad ideas relevant to pass-through analysis and relevant to this report: (1) the factors that determine the degree of pass-through in a market, and (2) the distinction between different types of costs the implications for pass-through.

4.1 Pass-through is determined by competitive forces.

The ability of a firm to pass-through its costs is determined by competitive forces in the marketplace. If a firm does not face any pressure from competitors (or customers), it will happily pass-through any cost increase into higher prices at which it sells its goods. But, in practice, a firm faces competitive pressure from two sources that limit its ability to pass-through costs onto consumers.

The first source of competitive pressure comes, naturally, from other firms in the marketplace. If a firm (or set of firms) attempts to raise its price, other firms in the marketplace have incentive to undercut the higher price and increase their sales at the expense of the firm that raised price. This price competition is driven by the desire to maximize profits and is commonplace. In almost all industries, firms compete with and face competition from other firms in the marketplace all the time. Yet, some firms face more price competition than others. In particular, in industries or in markets where a large number of firms compete (or could easily compete if they so chose), the competitive pressure from is greater and further limits the firm from passing-through costs.[1] In contrast, if a firm faces few competitors or operates in a location that is costly for other firms to serve, it might be able to pass-through a higher proportion of a cost increase.

The second source of competitive pressure comes from the customers themselves. Customers decide whether to purchase a good and how much of a good to purchase based on the price they have to pay. For some goods, customers might have relatively little desire to curtail their consumption, even as prices rise. This might be the case for necessities, goods that have few substitutes, goods

[1] Although for purposes of exposition, I focus on the case where costs are rising, a similar intuition can apply to settings where costs fall. Where competition is high and a firm competes with many rivals, a firm might modestly lower its price if it's costs fall because it can steal customers from many of its competitors while increasing its profits per unit.

that consumers rely upon or goods for which customers have a very strong preference. But, for other goods, consumers might readily shift away from the good or curtail the amount they consume in response to higher prices. In economics, we use the demand elasticity as a measure of how responsive customer demand is to the price of a good. Mathematically, the demand elasticity is the percent change in demand caused by a one percent increase in the price of the good. The demand elasticity of the good can be thought of as the amount of "competitive pressure" that customers themselves exert upon firms. For inelastic goods, like necessities, customers continue to consume the good even if prices rise. All else equal, this lack of response by consumers enables a firm to pass-through a higher fraction of cost increases. But, if consumers readily reduce consumption in response to higher prices (i.e., demand is relatively elastic), a firm will not find it in its interest to raise prices as costs rise, since higher prices might drive away many of its customers.

It is important to note that the two sources of competitive pressure are unrelated. For some goods and in some markets, a firm might face little pressure from other firms, but might sell a good from which consumers readily switch away. And in other markets, a firm might sell a "necessity," but face price competition from many other firms in the marketplace. In both of these cases, the firm might have relatively little ability to pass-through input costs, taxes or regulatory costs.

4.2 Firms pass-through variable, not fixed costs

Economics distinguishes between two types of costs: variable and fixed costs. The former are costs that vary with the quantity produced by the firm. Typically, we think of most input costs, as well as taxes and fees that increase with production (like emissions fees), to be part of variable costs. Fixed costs, on the other hand, do not vary with the quantity produced by the firm and include most capital investments. Regardless of the amount a firm chooses to produce, the firm is responsible for the payments on any purchased capital or other fixed costs.

The distinction between variable and fixed costs is an important one for pass-through, because when the firm sets prices to maximize profits, those prices depend *on the variable costs the firm faces, not on the fixed costs.* To illustrate the intuition behind this insight, consider the example of a profit-maximizing gas station. When the gas station sets its price, that price balances two competing forces. As the gas station sets a higher price, it earns more on every gallon that it sells measured as the difference between the retail price and the firm's variable costs. But, as the firm sets a higher price, it also sells less gas, as the high price is unattractive to potential customers. Profit maximization balances these two considerations, raising price up until the point at which the loss of sales more than offsets any benefit to the firm from raising the profit margin on each unit sold.

Building on the example, suppose that the wholesale price of gasoline (i.e., the price at which the station purchases gasoline from a supplier) rises, increasing the gas station's variable costs. If the gas station does not change its prices, its profits will fall, since the wholesale price of gasoline has increased and it earn less profit on every gallon that it sells. But, if the gas station raises its price in response to the cost increase, it will recoup some of its lost profits, even if it sells slightly fewer gallons at the higher price. Because variable costs affect the incremental profit that a firm earns when it sells additional units of the good, a firm has the incentive to adjust its prices (and hence, amount it sells) in response to a variable cost change. Pass-through is a measure of this response, the amount by which prices change in response to a change in *variable costs*.[2]

In contrast, a firm's fixed costs do not affect the profit-maximizing prices it would set. Returning again the hypothetical example of a gasoline station above, suppose that the gas station faces a rent increase, rather than an increase in the wholesale price of gasoline. From the gas station's perspective, rent is a fixed cost. The station has to pay the rent to operate in any capacity, but the rent is a fixed amount that doesn't change if the firm sells more (or fewer) gallons of gasoline, unless the firm chooses to cease operations completely. While the rent increase does lower the firm's total profits, it does not affect the amount a firm earns for each incremental gallon that it sells (i.e., the difference between the retail price the station sets and the wholesale price the station pays to a supplier.) Consequently, the firm has no incentive to adjust its prices in response to the rent increase – if the firm was setting the profit-maximizing price before the rent increase, it would want to set the same price afterwards, because the underlying amount that it earns when it sells each gallon has not changed. Thus, although the fixed costs affect firm profits, fixed costs do not affect the profit maximizing prices that a firm would choose to set, and hence, are not passed-through to retail prices as are variable costs.

Many factors change a firm's variable costs. Naturally, a firm's input costs are an important consideration – in the setting of refined fuels, if the cost of crude oil rises, the cost to produce each unit of refined products rises commensurately. Regulatory policy can also affect a firm's variable costs. If, for example, the government levies per-unit taxes on a firm or charges emissions fees that depend on the amount that the firm produces, the taxes or fees change the amount of profit that the firm earns for each unit that it sells and can be thought of analogously to a change in input costs. Or, alternatively, if government regulation requires firms to add additional equipment or change their operations in a way that increases the cost to produce each unit of output, the firm will pass-through these costs in the same way it might pass-through the costs of rising input prices.

5 Features of the Refined Product Market in the South Coast AQMD region

I now describe the salient features of the refined product market in the South Coast AQMD region focusing on those particularly relevant to the pass-through analysis for PR 1109.1.

As a starting point, consider the demand for refined products and the extent to which consumer might influence the rate of pass-through. Refined petroleum products (such as gasoline, diesel fuel, kerosene and other petroleum products) tend to be relative inelastic goods with respect to price. For most uses, there are relatively few substitutes and it is difficult to substantially reduce consumption. As an example, consider gasoline, the vast majority of which is used for light-duty-transportation. Although drivers have options available to reduce gasoline consumption (e.g., in the short-run, individuals can carpool, take alternative forms of transportation or reduce

[2]Economists further distinguish *marginal* costs from variable costs, where a firm's marginal cost is the incremental cost of the last unit of the good produced. Although, technically, pass-through measures the degree to which a firm adjusts prices in response to marginal costs, in this setting, regulatory costs shift both marginal and inframarginal variable costs.

discretionary trips; in the longer-run, individuals shift towards higher mileage vehicles), a driver's gasoline consumption is largely driven by factors that are hard or costly to change, like where they live, what car they drive, and where they work. A long empirical literature in economics estimates the demand elasticity for gasoline and finds strong and consistent evidence with this intuition. Levin et al. (2017) and Li et al. (2014), to cite two recent examples, both estimate demand of gasoline to be inelastic, with elasticity estimates of -0.36 and -0.27, respectively. Translating the demand elasticities into a specific example, the estimates imply that a 10 percent increase in gasoline prices lowers overall demand for gasoline by a scant 3 percent.

Turning to the competitive pressure from the supply-side, refined products in Southern California come from several sources. The majority of refined products are produced locally. Although PR 1109.1 is expected to impact 16 facilities, this report focuses on the subset of the facilities that product the majority of gasoline and diesel in the Los Angeles area. This subset includes the Los Angeles area refineries of Chevron El Segundo, PBF Energy Torrance, Marathon Petroleum Carson, Marathon Petroleum Wilmington, Phillips 66 Carson, Phillips 66 Wilmington, and Valero Wilmington.[3] Collectively, these refineries have the capacity to process roughly one million barrels of oil per day and represent the vast majority of the refining capacity in the South Coast AQMD region.

Table 1 lists the refineries in Los Angeles, their distillation capacities and whether they produce gasoline or diesel fuel for California markets. For completeness, the table also lists two specialized small refineries in the Los Angeles area that produce asphalt that are also expected to be impacted by PR 1109.1. Figure 1a maps the location of the seven refineries in the Los Angeles metro area, along with the location of the ports of Long Beach and Los Angeles that can offload deliveries of refined petroleum products.

Table 1: Los Angeles Petroleum Refineries

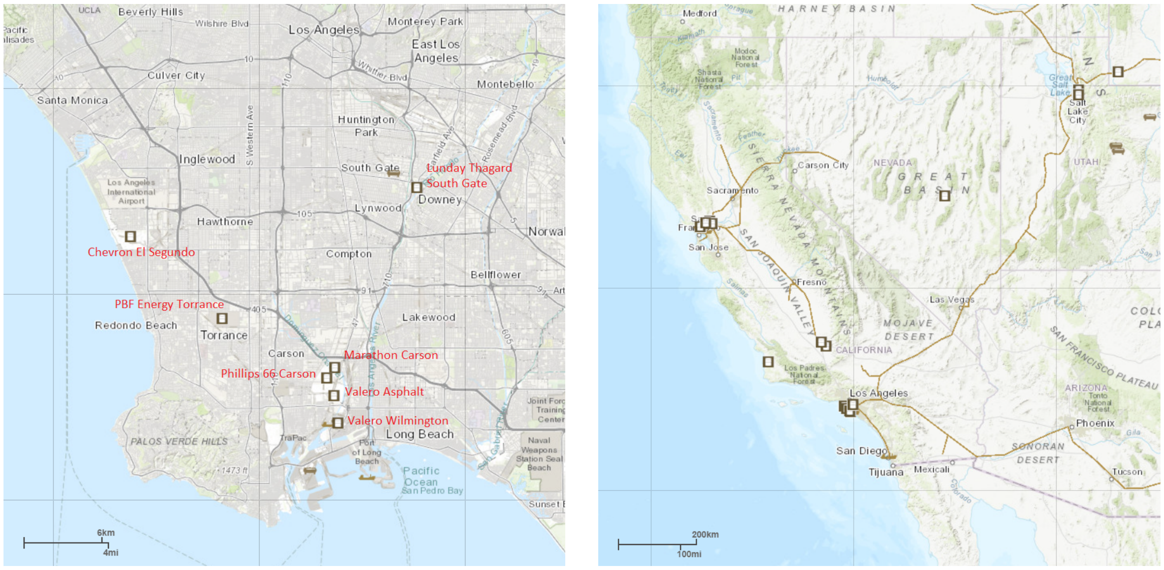
Refinery	Distillation Capacity in 2020 (bbls/day)	CARB gasoline	CARB diesel
Marathon, Carson/Wilmington	363,000	Yes	Yes
Chevron, El Segundo	269,000	Yes	Yes
PBF Energy, Torrance	160,000	Yes	Yes
Phillips 66, Carson/Wilmington	139,000	Yes	Yes
Valero, Wilmington	85,000	Yes	Yes
Lunday Thagard, South Gate	9,500	No	No
Valero, Wilmington (Asphalt)	8,500	No	No

CARB refers to the California Air Resources Board. Source: California Energy Commission, Energy Almanac. https://www.energy.ca.gov/data-reports/energy-almanac/californias-petroleum-market/californias-oil-refineries

[3] In the subsequent tables, figures and discussion, the adjoining Marathon Petroleum refineries in Carson and Wilmington are aggregated together, consistent with refinery reporting by the California Energy Commission. Similarly, the linked Phillips 66 refineries in Carson and Wilmington are also aggregated.

Figure 1: Refining, Product Pipelines and Petroleum Ports

(a) Los Angeles Metro Area (b) California and Neighboring States



Source: Energy Information Administration, U.S. Energy Mapping System, https://www.eia.gov/state/maps.php. Refinery names added. Product pipeline maps are not publicly available at the geographic resolution of panel (a).

Supplementing local production of refined fuels, firms from outside Southern California ship refined product to the ports of Los Angeles and Long Beach. Barge shipments transport product from Northern California and tanker shipments move refined product to Southern California from other parts of the U.S. and the world, albeit with a several week delay.[4] But, relative to U.S. markets east of the Rocky Mountains that are relatively well-connected to Gulf Coast refineries by low-cost refined product pipelines, California (and the West Coast) is more isolated – no pipelines exist that deliver refined product to California.

California is further isolated by the fuel content requirements that dictate the chemical composition and properties of transportation fuels. California's fuel content regulations are more stringent than those required by the federal government.[5] As a result, fuel meeting California's requirements is more costly to produce and, hence, relatively few refineries outside of California regularly produce reformulated blendstock ("RBOB") that meets the more stringent California reformulated gasoline ("RFG") requirements. These unique features of the California market for refined fuels are widely recognized by industry participants, academics and policymakers.[6]

As a result of both the transportation constraints and the special requirements of California's transportation fuels, refined product shipments from outside the region are typically modest in volume. Relative to the local refining capacity in Los Angeles, that can process over one million barrels of oil per day, gasoline and distillate imports (including blendstock) from abroad into the

[4]Rail shipments of refined products are relatively low, although rail does deliver significant amounts of ethanol from the midwest to wholesale terminals in California for terminal blending into RBOB.

[5]California's reformulated gasoline Phase 3 standards (see Title 13, California Code of Regulations, sections 2250-2273.5) place more stringent limits on vapor pressure and require fuel meets other specifications supplementary to the federal reformulated gasoline requirements.(see Title 40, Code of Federal Regulations, section 1090.220)

[6]See, e.g., Factors Affecting Petroleum Markets at https://www.energy.ca.gov/data-reports/energy-almanac/californias-petroleum-market

ports of Los Angeles, Long Beach and El Segundo averaged 21 thousand and 7 thousand barrels per day, respectively.[7] Although data on barge and tanker shipments from other parts of the U.S. are not available at the same level of geography, shipments to Los Angeles from other parts of the U.S. are similarly modest. Gasoline shipments from Northern to Southern California averaged, roughly 30 thousand barrels per day between 2015 - 2019.[8] Shipments from outside of the West Coast are smaller still. Aggregate gasoline and diesel shipments by barge or tanker from the Gulf Coast to the West Coast (PADD 5) collectively averaged approximately 6 thousand barrels per day over 2001 - 2020.[9]

Despite typically modest shipments into Los Angeles, competition from refineries outside the region play two important roles. First, refineries from outside the region compete with Los Angeles refineries to produce RBOB serve other the broader region. As mapped in Figure 1b, pipelines connect Los Angeles to San Diego, Phoenix and Las Vegas. Refined product delivered to Phoenix competes with refined product delivered on a west-bound pipeline from Texas, connecting through Tucson. And, similarly, refined product delivered to Las Vegas competes with product delivered by pipeline from Salt Lake City and other Rocky Mountain refineries. Second, most of Southern California's demand for refined products is served by the refineries in the Los Angeles area. But, when the prices of refined products rise in Los Angeles relative to other markets, refineries from outside the region increase shipments into the region, limiting the amount by which prices can rise.

6 Empirical Evidence on the Pass-through

This report assesses the potential impact of the PR 1109.1 under full implementaiton on prices and demand for refined products. Central to this exercise is specifying the appropriate pass-through rate for a change in variable costs arising from the costs of complying with the proposed rule. Yet, since the proposed rule has yet to be implemented, I use two separate approaches to benchmark the appropriate rate of pass-through. First, I compare the characteristics of the refined product market in California to the settings of previous studies that have estimated pass-through rates for refined products and examine the response of imports and competitive pressure from outside the region in response to supply shortfalls. Second, I directly estimate the pass-through for comparable costs arising from the RECLAIM program. As I discuss below, both of these approaches point towards a moderate pass-through rate, on the order of roughly 30%.

6.1 Benchmarking relative to previous studies suggests refineries can partially pass-through costs.

A first approach to determining the relevant pass-through rate for the compliance costs associated with PR 1109.1 relates the characteristics of the refined product market in the South Coast AQMD region to settings examined in previous work. Although previous studies don't focus specifically on refined products in the South Coast AQMD region, a comparison of the characteristics of the refined product market in the South Coast AQMD region to the settings used in previous studies provides one way to evaluate the relevant pass-through rate for PR 1109.1.

[7] Company Level Imports, Energy Information Administration, 2001 - 2020, summarized by author.

[8] Petroleum Watch, California Energy Commission, March 2021. https://www.energy.ca.gov/sites/default/files/2021-03/2021-03\%20Petroleum\%20Watch.pdf

[9] Movements by Tanker and Barge between PAD Districts, Energy Information Administration, 2001 - 2020, summarized by author.

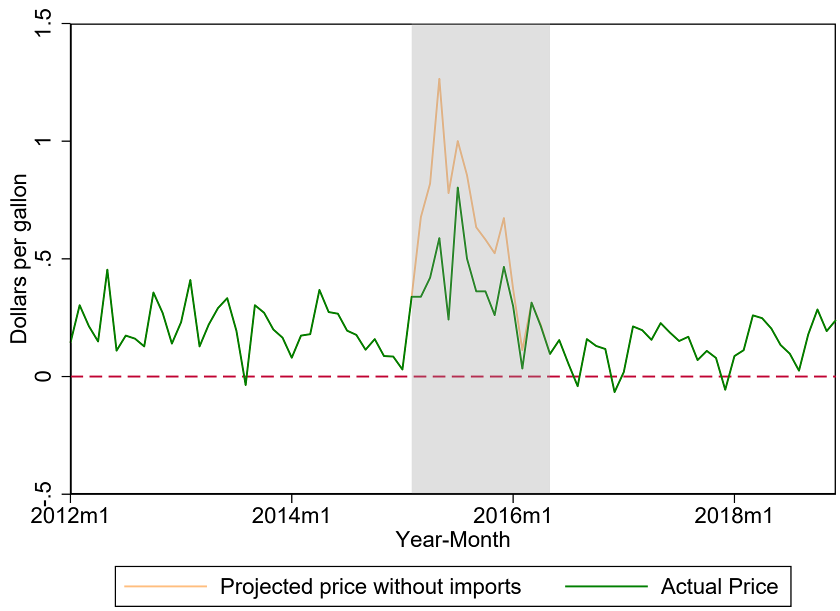
An important distinction highlighted in previous studies is that the ability of firms to pass-through cost, tax or regulatory changes depends on whether costs change for all (or virtually all) of the refiners selling into a market, or whether costs change for only a subset of refiners that supply a market. In the case of the former, changes to variable costs that affect all the firms serving a market are almost fully passed-through to consumers (see e.g., Marion and Muehlegger (2011)). This category of cost changes includes rising or falling world crude oil prices and state and federal taxes that are levied on all transportation fuel sold in an area, regardless of where the refined products were made. In both cases, all firms face higher costs, yet the demand for refined products is relatively inelastic and relatively few substitutes exist. Hence, the pass-through rate for a change in costs that affects all of the firms is unlikely to be tempered by consumers (due to relatively inelastic demand) nor by competition from other firms (as all firms are affected by world crude prices or fuel taxes). In such cases, firms pass-through the vast majority (if not all) of cost or tax changes onto consumers.

In contrast, if costs change for a subset of refiners serving a market, Muehlegger and Sweeney (2017) finds evidence of much lower pass-through rates. Moreover, as the number of firms affected by the cost change declines, so does the ability of the firm to pass-through cost changes. A firm has virtually no ability to pass-through cost changes that affect themselves alone, while pass-through for costs that affect the subset of firms that serve a market varies between 20 and 40 percent depending on the size of the market and the ability of firms outside the region to ship product into the market. Again, the intuition behind this result is relatively straightforward. Although the demand is still inelastic for the good, if costs only change for a few firms in the market, those firms still have to compete with the other firms for whom costs have not changed. The importance of the former group relative to the latter group dictates whether pass-through rates are very low or pass-through rates are closer to the full pass-through benchmark for world crude oil price changes or state fuel taxes.

Applying these ideas to the market for refined products in Southern California, several implications can be drawn. As discussed above, most of the refined product produced in Southern California is refined locally. Collectively, the five refineries in Los Angeles that produce refined product have the capacity to process roughly one million barrels of oil per day, the grand majority of which is processed into high margin products like gasoline and distillate. In comparison, other sources of supply (e.g., imports into the ports of Long Beach or Los Angeles, or shipments from other U.S. refineries) are a smaller fraction of the overall market. Yet, even these sources, small though they are, may provide competitive pressure on the refineries in Southern California, suggesting that partial pass-through, similar to the estimates for regional cost changes identified in Muehlegger and Sweeney (2017), is plausible.

As evidence of the competitive pressure created by the refineries outside the Los Angeles area, I examine the response of firms outside of Los Angeles to the fire at the ExxonMobil Torrance refinery (now owned by PBF Energy) in February 2015. The explosion and fire disabled the refinery's fluid catalytic cracking unit and required extensive, unexpected repairs to the refinery, lasting until May 2016. The sixteen-month refinery outage caused a substantial shortfall of almost one-sixth of the refinery capacity in Southern California and had a dramatic impact on market for gasoline. To be clear, the unexpected nature of the Torrance refinery fire partially contributed to the impact. Faced with a planned refinery maintenance or other expected change in production (such as a change that might be induced by PR 1109.1), refiners both inside and outside of Los Angeles would adjust production and inventories in advance and, in so doing, would smooth the impacts. Regardless, the Torrance refinery fire provides an excellent example of how refineries outside of Los Angeles adjust to serve the market in the South Coast AQMD region.

Figure 2: LA RBOB vs. Gulf Coast Gasoline Spot Differential, 2012 - 2018

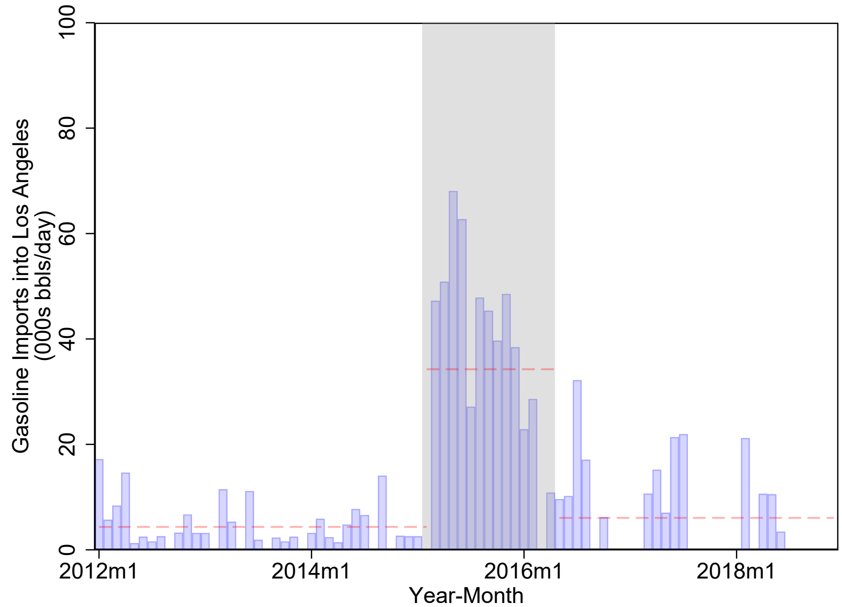


Notes: Grey region corresponds to the window during which the Torrance refinery was shutdown following the Feb. 2015 fire.
Source: EIA Spot Prices for Crude Oil and Petroleum Products, http://www.eia.gov/dnav/pet/pet_pri_spt_s1_m.htm,

Figure 2 plots (in green) the average price differential between the spot price for RBOB sold in Los Angeles and the spot price for conventional gasoline sold in the Gulf Coast. The window during which the Torrance refinery was under repairs is highlighted in grey. As the green line illustrates, the spot price in Los Angeles is regularly above the spot price for conventional in the Gulf Coast – if the spot prices were exactly equal, they would track the dotted red line plotted at zero on the y-axis. During the three years preceding the outage, the spot price for RBOB in Los Angeles was 20 cents per gallon higher than the spot price for conventional gasoline in the Gulf Coast. This premium reflects the more stringent environmental requirements required to meet RBOB specifications and the higher cost of refining in California relative to the Gulf Coast. During the outage window, this premium increases - averaging roughly 35 cents per gallon for the sixteen-months prior to the restart of the Torrance refinery in May 2016. After the refinery returned to operation, the RBOB spot premium declined, averaging 13 cents per gallon from June 2016 - December 2018.

On the one hand, the fifteen cent increase in the spot prices differential during the outage reflects the scarcity of gasoline supply in the West Coast and the relatively few numbers of refineries that produce gasoline that meets RBOB specifications. Yet, the outage led to a supply-side response from refineries outside of the region as well. Figure 3 plots total international deliveries of finished gasoline and blendstocks to either the port of Los Angeles or the port of Long Beach, over a similar time frame. As the figure illustrates, the shortage caused by the unexpected outage of the Torrance

Figure 3: Gasoline Imports into Los Angeles, 2012 - 2018



Notes: Grey region corresponds to the window during which the Torrance refinery was shutdown following the Feb. 2015 fire.
Source: EIA Company level imports, https://www.eia.gov/petroleum/imports/companylevel/

refinery (and the rising price premium of the RBOB spot price) stimulated production from outside the region. During the window of the Torrance refinery outage, foreign refineries began to produce gasoline meeting RBOB requirements.[10] Prior to the outage, international gasoline imports into the ports of Los Angeles and Long Beach averaged roughly seven thousand barrels per day (plotted as the left-most dotted line in Figure 3). But, shortly after the Torrance refinery fire, and contemporaneous with the increase in RBOB spot prices, international imports increased more than five-fold, replacing a substantial fraction of the lost gasoline production from the Torrance refinery.[11] Although we only observe what actually happened to spot prices for RBOB in Los Angeles, the yellow line in Figure 2 projects what might have happened if imports had not increased and the inelastic demand for gasoline had driven up the price, based on estimates of the gasoline price elasticity from Levin et al. (2017).[12] Absent the imports, customers would have had to curtail demand in response to the refinery outage. The yellow line represents how much prices would have had to increase, based on a demand elasticity of -0.36, to meet the refined product

[10]In principle, other domestic refineries might also have produced and supplied RBOB to Los Angeles, but publicly available data only tracks domestic shipments between PADDs and does not delineate shipments by destination to the same degree as the import data.

[11]Although figure 3 does not delineate between gasoline imports meeting and not meeting RBOB requirements, the data from the EIA does identify three broad classes of gasoline imports: (1) conventional gasoline or blendstock, (2) reformulated gasoline or blendstock and (3) gasoline blending components that are not designated as either meeting conventional gasoline or reformulated gasoline specifications. Roughly one-quarter of the imports were classified as each of the first two categories, whereas half of the imports during the outage window were classified simply as blending components.

[12]Levin et al. (2017) estimates gasoline demand elasticity based on daily price and purchase data for 243 U.S. cities. By comparing how purchases change as prices rise and fall, the paper estimates price elasticities of demand for gasoline between -0.27 and -0.36, depending on the specification.

shortage purely through a reduction in customer demand. The difference between what actually happened (the green line) and the projection of what might have happened absent imports (the yellow line) highlights the important role that imports (and foreign refineries) play in moderating spot prices in the California market.

6.2 Direct estimates for comparable policies are consistent with moderate rates of pass-through.

The preceding section suggests that moderate rates of pass-through (comparable to the 20 - 40 percent pass-through rates found in previous studies for changes in costs affecting a group of refineries that typically serve a local market) might be appropriate given the role that international refineries play as potential suppliers to the market for refined fuels in the South Coast AQMD region. Although international refineries do not typically ship substantial volumes of refined product to Los Angeles, they do form a set of competitors that can and do serve the market and act to temper price increases, such as those caused by the Torrance refinery fire in 2015.

To support this assessment, I directly estimate the pass-through rate for a policy comparable in scope to PR 1109.1, the RECLAIM program. RECLAIM is a local emissions trading program administered by South Coast AQMD that required firms to obtain and use tradeable emissions credits when emitting criteria pollutants, namely NOx and SOx. Although different in many ways than PR 1109.1, RECLAIM provides a suitable comparison because of the local scope of the program. Like PR 1109.1, RECLAIM applies to refineries only under the jurisdiction of the South Coast AQMD, raising costs for those firms relative to competitors from outside the region.

Policymakers often use tradeable credits (or permits) to reduce pollution from industrial facilities in a cost-effective manner. A credit trading program like RECLAIM has two key features. First, the number of credits creates a hard cap on the total amount of pollution that can be emitted. This provides a way for a jurisdiction to tighten the cap over time, gradually reducing pollution from industrial facilities. Second, the credits are tradeable, such that firms can buy or sell pollution rights amongst themselves in response to their needs. Tradability allows firms that cannot easily reduce pollution to purchase credits from firms that can reduce pollution at low cost or from facilities that shutdown. This ensures that pollution can be reduced in a cost-effective manner.

The price of the tradeable credits is determined by the interaction of supply and demand. If the number of credits is high relative to emissions, the equilibrium price will be low, as many potentially sellers may be willing to offer credits to potential buyers. But, if demand for emission credits rises or firms anticipate that supply will be more binding in the future, the equilibrium price of credits will rise.

Importantly, as the price of credits rises and falls, the variable costs of the firms rise and fall commensurately, since firms emitting pollution could choose to sell credits at the market price, rather than pollute. In economics, this is referred to as an "opportunity cost." There are examples of opportunity costs in economics from education (in which students pay the "opportunity cost" of not working while in school) to lost time associated with taking a slower method of transportation. In this setting, the "opportunity cost" reflects the amount of money the firm could have earned if it had chosen to sell the credit rather than use the credit to emit pollution. This cost doesn't depend on the actual price a firm paid for the credit – even if credits were purchased earlier at lower prices (or received for free), the market price of credits reflects the effective cost of the firm faces when it chooses to use a credit rather than sell it. The use of the market price as reflective of the oppotunity costs faced by a firm using pollution credits has been used in other papers to understand pass-through, notably Fabra and Reguant (2014) and Hintermann (2016), which examine how the price of tradable credits impact the cost of electricity generators and wholesale electricity prices.

To estimate the pass-through of RECLAIM credit prices, I use regression analysis to examine the degree to which the retail price of gasoline in Los Angeles changes in response to changes in emissions credit costs, measured on a comparable per-gallon basis. Regression analysis is an analytical technique that estimates the relationship between a set of explanatory variables and an outcome of interest. It provides a means to isolate the quantitative relationship between particular factors and the outcome, *holding the other explanatory variables fixed.* It is commonly used by businesses, policy-makers, governments, analysts and social scientists to understand quantitative relationships in many settings.

Here, regression analysis provides a means to estimate the pass-through rate of the cost of credits onto gasoline prices in the Los Angeles area, distinct from other changes that might affect the overall demand or supply of fuels in California.[13] To do so, the regression explains the per-gallon tax-inclusive retail price of gasoline in Los Angeles using two explanatory variables: changes in the per-gallon tax-inclusive retail price of gasoline in San Francisco and changes in the per-gallon average price of RECLAIM credits necessary to produce refined products.[14] The regression model estimates, on average, how much gasoline prices in Los Angeles change in months when the gasoline price in San Francisco changes or the opportunity cost of pollution (as measured by average credit price) changes.

I include the former explanatory variable to control for changes that affect the overall market for fuels in California. These include state-wide legislative or regulatory changes, like the Low Carbon Fuel Standard or changes to state fuel excise taxes, as well as shocks that impact fuel prices throughout California, like unexpected refinery outages. As presented in the Appendix, the regression model estimates a coefficient of roughly one for gasoline prices in San Francisco, suggesting that, on average, the retail gasoline prices in Los Angeles and San Francisco tend to move in unison. For every cent per gallon increase in retail prices in San Francisco, the retail price in Los Angeles also rises by roughly one cent per gallon as well. To be clear, this doesn't imply that there aren't other factors that might only affect northern or southern California. Other local regulatory changes, taxes, or fees might cause prices in the two locations to diverge. But, the coefficient does suggest that prices in northern and southern California do tend to move in unison, on average.

I include the latter variable to capture the changes in the cost to produce gasoline (and other products) at refineries in South Coast AQMD. As credit prices rise, the effective cost to produce gasoline at refineries in South Coast AQMD rises, relative to refineries outside the region. Likewise, if credit prices fall, the cost to produce gasoline also falls. If firms are able to pass-through credit costs into retail prices, the price of gasoline in Los Angeles should move in a similar direction as credit prices (controlling for changes in the overall fuel market in California). How much the price of gasoline changes as permit prices change provides an estimate of the pass-through rate.

[13] Although the scope of this report extends to refined products other than just gasoline, publicly-available data limitations preclude a similar analysis for other refined products.

[14] Further details of the data, regression model and results are provided in Technical Appendix A.

In contrast to the relatively tight relationship between the price of gasoline is Los Angeles and San Francisco, the regression model estimates a coefficient of roughly 0.30 for changes in the average RECLAIM NOx credit prices. Put in layman's terms, for a one cent-per-gallon increase in the cost of NOx credits, prices for retail gasoline rise by roughly 0.3 cents per gallon. Taken in concert with the qualitative argument in the previous section, the quantitative evidence is consistent with the conclusion that refineries in the Los Angeles area have the ability to partially pass-through cost changes into both spot and retail prices. All else equal, the competitive pressure on Los Angeles refineries prevents the refiners from fully passing-through the cost change onto credit prices. Although firms can and do increase prices in response to local conditions and/or cost changes, the competitive pressure from refineries outside the region limit their ability to do so fully. Based on the qualitative and quantitative evidence, I conclude that a pass-through rate of roughly 30% is appropriate as a benchmark for PR 1109.1.

7 Impact of the PR 1109.1 on Prices and Demand

With the pass-through estimate from the preceding section, I turn to estimating the impact of PR 1109.1 on retail prices and demand for fuels. As discussed in section 4, the pass-through rate reflects the amount by which a change in the variable costs of production are incorporated into the retail price of a good. By multiplying the pass-through rate and the anticipated compliance costs of the proposed rule, I reach an estimate of the impact of the proposed rule on retail prices.

I use estimates of the variable (O&M) and capital costs associated with PR 1109.1 under full implementation, as provided by the South Coast AQMD. The annual variable costs and the anticipated capital costs for the major refineries in Los Angeles are provided in columns 2 and 3 of Table 2.[15] Annual variable compliance costs vary across refineries, from a high of $8.6 million to $2.8 million. Capital costs exhibit similar variation, from $1.46 billion to $232 million. Based on these total capital costs, column 4 reports the annualized capital costs, using a 25-year investment lifetime and a discount rate (9.08%) based on the average cost of capital for the five parent companies that own the major refineries in Los Angeles.[16] In columns 5 and 6, I scale the annual variable costs (column 2) and the annualized fixed costs (column 4) into cents per gallon (cpg), based on the distillation capacity of each refinery and a capacity factor equal to the mean capacity factor (87.3%) of refineries on the West Coast (PADD 5) over 2000 - 2019, both as reported by the Energy Information Administration.

As argued in section 4.2, any pass-through estimate should focus on changes to the variable costs of production. Although the annual anticipated increase in operational costs as a result of PR 1109.1 is on the order of several million dollars a year per facility, when measured on a per-gallon basis, the increase in operational costs amounts to a fraction of a penny per gallon. Across all five refineries, the per-gallon increase in O&M costs, are roughly 0.2 cents per gallon of refined product.[17] Multiplying the average increase in per-gallon variable costs as a result of PR 1109.1 by the estimated rate of pass-through from the previous section, I estimate the proposed rule would have negligible effects on the price of refined fuels in the South Coast AQMD region.

[15] Refinery names are omitted for purposes of anonymity.

[16] The discount rate of 9.08% was chosen to be reflective of the average cost of capital faced by Los Angeles refiners. South Coast AQMD Socioeconomic Impact Assessments typically use a 4% real interest rate when annualizing capital costs. The use of the lower discount rate would lower annualized costs.

[17] As a point of reference, a refinery that processes, on average, 100 thousand barrels of oil per day, can produce roughly 1.5 billion gallons of refined product over the course of a year.

Table 2: Estimated Costs of PR 1109.1

	Estimated Costs ($mil)			Estimated Costs (cpg)	
		Capital Costs			Capital Costs
Refinery	O&M	Total	Annualized	O&M	Annualized
Refinery A	8.6	1,469	136.5	0.18	2.80
Refinery B	6.0	415	38.6	0.17	1.07
Refinery C	3.7	521	48.4	0.20	2.60
Refinery D	3.4	484	45.0	0.30	3.95
Refinery E	2.8	232	21.6	0.14	1.07
Average - All Refineries				0.20	2.30

Notes: Estimated O&M costs and total capital costs based on South Coast AQMD staff estimates. Annualization of fixed costs based on a 25-year lifetime and a weighted average cost of capital of 9.08%. Per gallon costs are calculated based on 2019 refinery distillation capacity and an average refinery capacity factor of 87.3%.

The anticipated capital investments associated with full-implementation of PR 1109.1 are fixed costs and would not naturally be considered in a pass-through calculation. But, as an upper-bound on the potential impacts of PR 1109.1, I calculate the change in per-gallon costs inclusive of annualized capital costs. The average increase in costs, inclusive of annualized fixed costs, is 2.50 cents per gallon. Applying a pass-through rate of 30%, prices for refined products would rise by less than a cent per gallon. The modest price increases imply little potential impact on fuel consumption.[18]

8 Discussion of Additional Considerations

The analysis above considers the impacts of PR 1109.1 using evidence from the current market for refined products in the South Coast AQMD region. Yet, the investments required under the proposed rule would be made gradually over time, during which the market for refined products might change in meaningful ways. This section discusses two potential ways in which the settings used above might differ from the setting that would exist after the proposed rule goes into effect, with particular emphasis on how those changes might affect the conclusions above. But, to be clear, none of the differences described below substantively change the fundamental conclusions of the analysis above.

8.1 Anticipation by market participants would further moderate price effects.

The empirical analysis in section 6 examines two events, changes in RECLAIM credit prices and the response to the Torrance refinery fire, to understand the extent to which refineries in Los Angeles might be able to pass-through the impact of a cost change. Yet, these events differ from the PR 1109.1 in a meaningful way. The Torrance refinery fire was unexpected as are changes in the prices of emissions credits under the RECLAIM program. In contrast, the investments required under the PR 1109.1 will occur gradually and are likely to be well-anticipated by market participants.

[18] A large academic and policy literature finds consistent evidence that the demand for transportation fuels is relatively inelastic with respect to price. See, e.g., Levin et al. (2017), and Li et al. (2014) as two recent studies, which estimate gasoline price elasticities of -0.36 and -0.27, respectively.

If competitors can benefit from adjusting their production in response to the proposed rule, anticipating the market changes allow them to respond in a more fluid fashion. A firm that anticipates the changes to the market can increase production of RBOB (or other fuels) in advance, schedule deliveries and manage operations in the way that incorporates the upcoming changes in a flexible manner. All else equal, this would tend to further limit the ability of regulated refineries to pass-through cost changes associated with the 1109.1 program.

As a specific illustration of this point, it is instructive to consider the response of the market to the Torrance refinery fire in February 2015. Immediately after the refinery fire, prices rose substantially and inventories were drawn down. But, after several weeks, foreign refineries adjusted their production, began to produce products like RBOB, and began to deliver the product to ports in Los Angeles. This lag, between the event and the response by firm in the market, reflects the time required by firms to adjust in response to unexpected market conditions and is one of the reasons why unexpected events (like a refinery fire) might have a large impact on prices. Yet, if the outage has been scheduled and anticipated by the other firms in the industry, it's reasonable to expect that the other firms, would adjust production in advance, so at so provide a more seamless transition.

8.2 Electrification of the vehicle fleet would further limit impacts.

Finally, it is instructive to consider how the market for refined fuels might change more broadly over the next several decades. We are on the cusp of a potential transformative shift in the transportation sector, away from a century-long reliance on fossil fuels in transportation towards electrification of the vehicle fleet. Yet, we are still early on this path. Even in California, where electric vehicle adoption has outpaced adoption in other states, the fleet of vehicles still runs almost entirely on gasoline. In 2020, the share of electric vehicles as a fraction of all vehicles on the road was roughly 2.2% in California and 2.6% in the Los Angeles Metropolitan Statistical Area.[19] But, as battery costs fall, the expectation by policymakers and industry participants is that a larger and larger share of the vehicle fleet will shift towards vehicles with electric powertrains.

This shift will have two impacts on the conclusions of this report. First and foremost, the gradual shift away from refined petroleum products for transportation will lower demand, gradually relaxing production constraints and leading to lower prices for transportation fuels. All else equal, this would tend to reduce the prices for refined products in Southern California. But, second, electrification of the vehicle fleet would tend to make the demand for gasoline more elastic (i.e., responsive to prices). Currently, the vast majority of multi-car households are still completely reliant on gasoline, and thus, have relatively little ability to substitute away from gasoline in response to higher prices. But, in a future world in which two-car households have one electric vehicle and one gasoline powered vehicle, households can more easily reduce gasoline consumption by shifting miles towards the household's electric vehicle. This would tend to make the demand for gasoline more elastic and consequently, reduce the ability of firms to pass-through cost increases.

[19]Source: California Energy Commission, Zero Emission Vehicle and Infrastructure Statistics, https://www.energy.ca.gov/data-reports/energy-insights/zero-emission-vehicle-and-charger-statistics.

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Appendix A Technical Appendix

The goal of the regression analysis is to examine the pass-through of RECLAIM credit prices onto the retail prices of gasoline in the South Coast AQMD region, controlling for other factors that affect overall gasoline prices in California (such as the Low Carbon Fuel Standard, changes in state gasoline taxes or refinery outages that affect prices throughout the state.) By necessity, this exercise involves some abstraction away from the complex details of the RECLAIM program. Here, the empirical exercise estimates how retail prices for gasoline in Los Angeles change as RECLAIM tradable credits ("RTCs") increase or decrease in value. If firms pass-through the RTC price into the price at which they sell gasoline, we would expect a positive relationship between the two price series.

A.1 Regression Data

The data for the regression analysis come from two publicly-available sources. I use price publicly-available data for Los Angeles and San Francisco from the Energy Information Administration, which reports the monthly average tax-inclusive retail price (reported in cents per gallon) in a select set of major cities. For RTC prices, I use publicly-reported data on transactions provided by South Coast AQMD. The RECLAIM transaction data provides information on the total price, quantity and expiration date of all credits included as part of each arms-length transaction. Based on conversations with South Coast AQMD officials, I calculate average monthly RTC prices for 2000 - present, focusing specifically on Infinite Year Block ("IYB") transactions.[20] For each transaction, I calculate the per-pound NOx price that would rationalize the total price of the transaction given the quantity and expiration dates of all credits included as part of the transaction, discounted by the average cost of capital of the five refiners in Los Angeles. In months with more than one transaction, I calculate the quantity-weighted average per-pound price weighing across all transactions in that month. I further translate the monthly average RTC price into a monthly average price-per-gallon by dividing the per-gallon prices by average NOx emissions per gallon of refined product for the five major refineries in the Los Angeles area over 2000-2019, as provided by the South Coast AQMD.

A.2 Specification

To calculate the pass-through of the RTC prices through to retail prices of Los Angeles, I first-difference the retail prices and average infinite-year block RTC prices and regress the first-differenced retail price in Los Angeles against the first-differenced retail price in San Francisco and the first-differenced average price in RTC prices.

$$\Delta P_t^{LA} = \alpha + \beta \Delta P_t^{SF} + \gamma \Delta P_t^{RTC} + \varepsilon_t \tag{1}$$

where ΔP_t^{LA} and ΔP_t^{SF} correspond to the first-differenced retail gasoline prices in Los Angeles and San Francisco, respectively, in cents per gallon. ΔP_t^{RTC} is the first-differenced average price of infinite-year block RTC transactions.

[20] As described above, since the RTC price reflects the "opportunity cost" of emitting pollution, the analysis uses transactions involving one of the refineries in Los Angeles, as well as transactions between non-refining firms.

A.3 Results

Table 3 presents the results from the regression model. The specification in column 1 regresses the change in the average monthly retail price in Los Angeles on the change in the average monthly retail price in San Francisco and the change in the average NOx permit price, as described above. The coefficient on the retail price in San Francisco indicates that, all else equal, the two retail price series move in unison. The coefficient on the change in the average NOx permit price is estimated at 0.28, consistent with a pass-through rate of roughly 30%.

Table 3: Regression Results

	(1)	(2)
Retail Price in SF	1.02***	1.01***
	(0.030)	(0.042)
Brent Crude Price		0.042
		(0.041)
NOX Permit Price	0.28	0.46
	(1.04)	(1.10)
Observations	219	219
R-Squared	0.92	0.92

Notes: Standard errors are in parentheses. *, **, and *** denote significance at 10%, 5% and 1% significance level.

In parentheses, I report the standard errors of the point estimates. The standard error of the coefficient of the NOx permit price is substantially higher than the standard error on the coefficient of the retail price in San Francisco. This reflects the fact that there is less variation in the NOx permit price, and consequently, the coefficient is estimated with less precision. The magnitude of the standard error, relative to the point estimate, implies less statistical confidence in the coefficient on permit prices. Yet, the point estimate is generally consistent with the pass-through rates estimated (with greater statistical precision) in similar settings.[21]

In column 2, I report the point estimates of a specification that includes the change in the Brent crude spot price, in addition to the other two variables described above. Notably, the coefficient on the Brent crude spot price is estimated to be quite close to zero – after controlling for the retail price in San Francisco, the addition of the Brent crude spot price does help to explain the retail price in Los Angeles. In column 2, the original coefficients are largely unchanged. The estimate of pass-through is modestly higher, at 45%, but given the amount by which the proposed rule is anticipated to increase variable costs, still implies effects on prices of less than a penny per gallon, even if annualized capital costs are included.

[21] See, e.g., Muehlegger and Sweeney (2017).

Appendix B Curriculum Vitae

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2014-present DEPARTMENT OF ECONOMICS, UC – DAVIS
Associate Professor (2016-present), Assistant Professor (2014-2016)
Graduate Program Chair (2016-2020)
Institute for Transportation Studies, Faculty Affiliate (2015-present)
Transportation, Technology and Policy Graduate Group, Affiliate (2015-present)
Davis Energy Economics Program, Faculty Affiliate (2014-present)

2005-2014 HARVARD KENNEDY SCHOOL, HARVARD UNIVERSITY.
Assistant Professor (2005-2010)
Associate Professor, untenured (2010-2014)
Harvard Environmental Economics Program, Faculty Fellow (2005-2014)
Regulatory Policy Program, Faculty Chair (2006-2009)
Harvard University Center for the Environment, Faculty Associate (2007-2014)
Harvard Lab for Economic Applications and Policy, member (2009-2014)

Spring 2010 DEPARTMENT OF ECONOMICS, COLUMBIA UNIVERSITY
Visiting Scholar

PROFESSIONAL APPOINTMENTS

2010-present NATIONAL BUREAU OF ECONOMIC RESEARCH, EEE
Research Associate (2016 – present)
Faculty Research Fellow (2010 – 2016)

2015-present JOURNAL OF ENVIRONMENTAL ECONOMICS AND MANAGEMENT,
Member of the Editorial Board

2018-present NATIONAL TAX JOURNAL,
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EDUCATION

Primary Fields: Energy, Environment, Public Finance, Industrial Organization

2000-2005 MIT, CAMBRIDGE, MA. Ph.D., Economics.

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RESEARCH PUBLICATIONS

1. "Pass-Through of Own and Rival Cost Shocks: Evidence from the U.S. Fracking Boom" (with Richard Sweeney), forthcoming, ***Review of Economics and Statistics***

2. "Air Pollution and Criminal Activity: Microgeographic Evidence from Chicago" (with Evan Herrnstadt, Anthony Heyes and Soodeh Saberian), forthcoming, ***American Economic Journal: Applied Economics***

3. "Who Bears the Economic Burdens of Environmental Regulations?" (with Don Fullerton) ***Review of Environmental Economics and Policy****, 13:1, p.62-82, Winter 2019.*

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6. "Consumer Learning and Hybrid Vehicle Adoption" (with Garth Heutel) ***Environmental and Resource Economics***, 62:1, p.125-161, September 2015.

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8. "Gasoline Taxes and Consumer Behavior" (with Shanjun Li and Joshua Linn) ***American Economic Journal: Economic Policy***, 6: 4, p. 302-342, November 2014

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10. "Consumer Response to Cigarette Excise Tax Changes" (with Lesley Chiou), ***National Tax Journal***, 67: 3, p. 621-650, September 2014.

11. "Heuristic Strategies, Firm Behavior and Industry Information" (with Cynthia Lin) ***Journal of Economic Behavior and Organization***, 86: 1, p. 10-23, February 2013.

12. "Tax Incidence and Supply Conditions" (with Justin Marion), ***Journal of Public Economics***, 95, p. 1202-1212. October 2011.

13. "Giving Green to Get Green: Incentives and Consumer Adoption of Hybrid Vehicle Technology." (with Kelly Gallagher), ***Journal of Environmental Economics and Management***, 61, p. 1-15. January 2011.

14. "Do Americans Consume Too Little Natural Gas? An Empirical Test of Marginal Cost Pricing" (with Lucas Davis), ***Rand Journal of Economics***, 41, p. 791-810. Winter 2010.

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17. "Measuring Illegal Activity and the Effects of Regulatory Innovation: Tax Evasion and the Dyeing of Untaxed Diesel" (with Justin Marion). ***Journal of Political Economy***,116:4, p. 633-666, August 2008.

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18. "Infinite Ergodic Index Z^d Actions in Infinite Measure" (with B. Narasimhan, A. Raich, C. Silva, M.Touloumtzis, and W. Zhao). ***Colloquium Mathematicum***, vol. 82, No. 2 (1999), 167-190.

19. "Lightly Mixing on Dense Algebras" with (A. Raich, C. Silva and W. Zhao). ***Real Analysis Exchange***, Vol. 23, No. 1, (1998), 259-266.

BOOK CHAPTERS AND OTHER PUBLICATIONS

20. "Land Use Regulation and Commuting Patterns" (with Daniel Shoag) ***Procedia Engineering*** *107*, p. 488-493, 2015.

*21. "*Cell Phones and Motor Vehicle Fatalities" (with Daniel Shoag), ***Procedia Engineering*** *78*, p. 173-177, September 2014.

22. Commentary on Dealing with Expropriations: General Guidelines for Oil Contracts, "The Natural Resources Trap: Private Investment without Public Commitment" MIT Press, 2011.

RECENT WORKING PAPERS

"Air Pollution as a Cause of Violent Crime" (with Evan Herrnstadt, Anthony Heyes and Soodeh Saberian)

"Correcting Estimates of Electric Vehicle Emissions Abatement: Implications for Climate Policy" (with David Rapson) ***revisions requested Journal of the Association of Environmental and Resource Economists***

"Subsidizing Low and Middle-Income Adoption of Electric Vehicles: Quasi-Experimental Evidence from California" (with David Rapson) ***revisions requested Journal of Public Economics***

"Future paths of electric vehicle adoption in the United States: Predictable determinants, obstacles and opportunities" (with James Archsmith and David Rapson)

OLDER WORKING PAPERS

"Gasoline Price Spikes and Regional Gasoline Content Regulations: A Structural Approach."

"Market Effects of Regulatory Heterogeneity: A Study of Regional Gasoline Content."

"Endogenous Facility Reliability: Evidence from Oil Refinery Fires"

FELLOWSHIPS AND GRANTS

2019	Principal Investigator, *Institute for Transportation Studies, SB1 2019-2020 Research Grant* "Do electricity prices affect EV adoption?" (with David Rapson and James Bushnell) $61,159
2018	Principal Investigator, *Institute for Transportation Studies, SB1 2018-19 Research Grant* "How much pollution abatement do EV subsidies buy us?" (with David Rapson) $75,710

2017 Principal Investigator, *Institute for Transportation Studies, SB1 2017-18 Research Grant* “Estimating the Effects of the Enhanced Fleet Modernization Project - Plus Up" and the Elasticity of Demand for Electric Vehicles” (with David Rapson) $79,986

2017 Principal Investigator, *National Center for Sustainable Transportation and California Department of Transportation* “Understanding the distributional impacts of vehicle policy: Who buys new and used alternative vehicles?” (with David Rapson) $99,101

2017 Principal Investigator, *National Center for Sustainable Transportation and US Department of Transportation* “Seed Grant: EV Incentive Pass-through and Dealer Margins” (with David Rapson) $31,400

2017 Principal Investigator, *Institute for Transportation Studies – Public Transportation Account Project* “Environmental Justice and Barriers to Low-Income EV Adoption” (with David Rapson) $39,824

2015 Principal Investigator, *New England University Transportation Center Research Grant*, “The Local Effects of the American Recovery and Reinvestment Act on Economic Activity and Traffic Safety” (with Daniel Shoag) $85,565

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2013 Taubman Center for State and Local Government Research Grant ($15,000)

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2011 Principal Investigator, *Energy Technology and Innovation Project*, “Cell Phones and Vehicle Safety.” $32,822

2010 Principal Investigator, *Energy Technology and Innovation Project*, “Gasoline Taxes and Consumer Behavior.” $59,243

2007 Principal Investigator, *Mossavar-Rahmani Center for Business and Government and Energy Technology Innovation Project*, “Incentives for Hybrid Vehicles.” $28,635

2006 KSG Dean's Research Fund $5,000

2002 Fellowship, MIT Center for Energy and Environmental Policy Research.

2000-2003 National Science Foundation Graduate Research Fellowship

TEACHING AWARDS AND EXPERIENCE

2017 Tom Mayer Distinguished Teaching Award, UC Davis

2013 Dean's Award for Teaching, Harvard Kennedy School
2012 Dean's Award for Teaching, Harvard Kennedy School
2008 Dean's Award for Teaching, Harvard Kennedy School
2007 Dean's Award for Teaching, Harvard Kennedy School
2006 Dean's Award for Teaching, Harvard Kennedy School

UC-Davis:

ECN221C: Graduate Industrial Organization (2014-present)
ECN121B: Strategy, Competition and Regulation (2014-present)
ECN145: Transportation Economics (2015 - present)

Harvard Kennedy School:

Executive Education: Modules on Empirical Methods and Environmental Policy

BGP200: Strategy, Competition and Regulation (2008-2013)
API105: Markets and Market Failure with Cases (2008)
API201: Quantitative Analysis and Empirical Methods (2005 - 2008, 2011-2013)

OTHER EXPERIENCE

2003-2005 Teaching Assistant, MIT Department of Economics

2001-2002 Research Assistant, Professor Paul Joskow.

1997-2011 CompassLexecon, Cambridge, MA
Analyst (1997-1998), Senior Analyst (1998-2000), Consultant (2000-2005), Academic Affiliate (2005-2011)

ACADEMIC PRESENTATIONS (SINCE 2005)

2021 Michigan State, Boston University, NBER EPEE, AERE Annual Conference

2019	USC, UCSB, TE3 conference, Empirical Methods in Energy Economics summer meeting
2018	ETH Zurich, Connecticut, Occasional Environmental Economics Conference (UCSB), Environmental Taxation Workshop (Maryland)
2017	UCLA, LSU, UC Berkeley Energy Camp, NBER Hydrocarbon Infrastructure meeting, Empirical Methods in Energy Economics summer meeting, AERE annual conference
2016	AERE annual conference, UC Berkeley Energy Camp, Arizona
2015	UC Irvine, UC Davis, Michigan
2014	UC Davis, UC Berkeley
2013	University of Colorado, Harvard, University of Illinois – Urbana Champaign, ETH Zurich, University of Lugano.
2012	Yale, UC Santa Barbara, ASSA meetings, Cornell.
2011	ASSA meetings, Stanford, Northwestern, UC Davis, Maryland AREC, UC Berkeley Energy Camp
2010	Columbia, Duke, International Industrial Organization Conference.
2009	Yale, Columbia Business School, Harvard, Columbia.
2008	American Economics Association Meetings, Boston University, International Industrial Organization Conference, Harvard (2), MIT, Brandeis, NBER Summer Institute – Economics of Taxation, NBER Summer Institute – Environmental and Energy Economics.
2007	Federal Reserve, Tufts, International Industrial Organization Conference, UC Berkeley, Yale.
2006	Harvard, International Industrial Organization Conference, Yale SOM, Federal Trade Commission, UC Berkeley.
2005	Harvard, Cornell, USC, UC Irvine, Northeastern, Department of Justice, Federal Trade Commission.

OTHER INVITED PRESENTATIONS

Academic Panel Lead – Climate Lab Roundtable on Green Tax Credits, June 2021.

Commentor – GAO Methodology: Effects of Mergers and Market Concentration on Wholesale Gasoline Prices. 2008, 2009

Lead Speaker, U.S. / Taiwan Dialogue on Hybrid Vehicles. Sponsored by the U.S. State Department. 2009.

PROFESSIONAL SERVICE

Referee for *American Economic Review, American Economic Review Insights, Quarterly Journal of Economics, Journal of Political Economy, Review of Economic Studies, Proceedings of the National Academy of Science, Review of Economics and Statistics, Journal of European Economics Association, AER Insights, AEJ: Microeconomics, AEJ: Economic Policy, AEJ: Applied Economics, Journal of Public Economics, RAND Journal of Economics, Journal of Environmental Economics and Management, Journal of Applied Econometrics, International Journal of Industrial Organization, Journal of the Association of Environmmental and Resource Economics, Journal of Industrial Organization, Journal of Industrial Economics, Review of Industrial Organization, Health Economics, National Tax Journal, Games and Economic Behavior, Scandinavian Journal of Economics, Southern Economic Journal, BE Journals in Economic Analysis and Policy, Energy Journal, Energy Economics, Journal of Policy Analysis and Management, Journal of Urban Economics, Environment and Resource Economics, Public Finance Review, Environmental Research Letters, International Tax and Public Finance, Energy Policy, Scandinavian Journal of Economics, Public Budgeting and Finance, Contemporary Economics and Policy, Science Advances*

American Economic Review Excellence in Refereeing Award, 2010.

Ad-hoc reviewer for *National Science Foundation, Canadian Social Science and Humanities Research Council, Alfred P. Sloan Foundation, NBER pre-doctoral fellowship committee.*

Conference committee member: *2016 AERE, 2017 AERE, 2018 AERE, 2018 NASMES, 2018 NTA Annual Meeting, 2018 EMEE, 2019 EMEE, 2019 AERE, 2019 NTA Annual Meeting, 2020 AERE, 2021 AERE*

Session Chair: *2006 IIOC, 2012 ASSA*, 2016 *AERE.*

Conference co-organizer: Making Social Science Transparent conference, UC Davis, April 2016

Discussant: 2011 NBER EEE, ASSA Meetings (2017, 2015(x3), 2014 (x2), 2013, 2011), 2010 NBER Winter IO, IIOC (2010, 2008, 2007, 2006), 2007 Harvard Conference on Oil and Populism. 2016 SOCCAM Meeting

COMMITTEE SERVICE

Department Service:
Graduate Program Chair (2016 – 2020)
Mental Health Committee (2020 – present)

Levine Family Seminar Series (2014)
Teaching Evaluation Committee (2014, 2015)
Industrial Organization Seminar Organizer (2015, 2016)
Environmental and Energy Economics Seminar co-organizer (2018)

Division Service:
Institute for Social Sciences Executive Committee (2015, 2016)
Graduate Studies Support Committee (2018-2020, member) (2020-2021, chair)

University Service:
Graduate Affairs Committee for Energy Graduate Group (2016 – present)
Department Representative to the Academic Senate (2017 - present)

Other Service:
Academic Affairs committee member, Energy Graduate Group (2017 - 2019)

Previous Committee Service:
HKS Faculty Research Seminar Coordinator (2011, 2012)

PhD Admissions Committee (2009 - 2013)
Junior Analytics Search Committee (2006 - 2008).
MPP Admissions Committee (2005).

Joseph Crump Fellowship Committee (2008 - 2012)
Harvard University Center for the Environment Fellowship Committee (2008)
Student Internship Fund Committee (2005, 2007)

ADVISING

Oral exam committee member:

2014-2015: Khaled Kheiravar, Jiwon Lee, Ariel Pihl, Irwin Rojas (ARE)
2015-2016: James Archsmith (chair), Yuan Chen (ARE)
2016-2017: Guozhen Li (TTP), Hanjiro Ambrose (TTP), Natalie Popovich (ARE), Tongxin Xu (TTP)
2017-2018: Kelsey Fortune, Jack Gregory (ARE)
2018-2019: Ethan Krohn, Nick Bowden (EGG), Armando Rangel (ARE), Xiaotong Su
2019-2020: Megan Song (ARE), Yijing Wang (ARE)
2020-2021: Shotaro Nakamura, Qian Wang (ARE), Sarah Smith (ARE), Sonia Wang (ARE)

PhD Dissertations - Kate Emans (2008, Amherst College)
Jonathan Borck (2008, Analysis Group)
Hunt Allcott (2009, NYU)
David Molin (2009, CompassLexecon)
Matthew Ranson (2012, Abt Associates)
Richard Sweeney (2015, Boston College)

Evan Herrnstadt (2015, HUCE post-doc)
Samuel Stolper (2016, Michigan SNRE)
James Archsmith (2017, Maryland AREC)
Natalie Popovich (2019 ARE, Berkeley National Labs)
Khaled Kheiravar (2019, California Air Resources Board)
Tongxin Xu (TTP, 2019, Xmotors)
Ethan Krohn (2020, U.S. Census Bureau)
Nick Bowden (EGG, 2020, Ameren Corporation)
Jack Gregory (ARE)
Kelsey Fortune
Xiaotong Su
Armando Rangel (ARE)
Reid Taylor
Kepler Illich
Jiyeon Cheon (ARE)
Qian Wang (ARE)
Pedro Orozco (ARE)

Master's Theses - Alemayehu Kuma Awas (2006, MPA-ID)
Jonathan Phillips (2007, MPP)
Issac Wohl (2007, MPP)
Erik Wurster (2007, MPP)
David Grasso (2009, MPP)
Bruce Haupt (2009, MPP)
Claudia Sanchez (2009, MPP)
Sierra Peterson (2009, MPP)
Daniel Vetter (2011, MBA/MPP)

Undergrad Theses - Michael Libert (2009, Economics)