DECLARATION OF YOLANDA ANDERSEN

I, Yolanda Andersen, declare as follows:

1. I am the Director of Member Services at the Sierra Club. I have had this position for more than 24 years.
2. In that role, I manage all aspects of the Sierra Club's customer service functions related to members, including maintaining an accurate list of members and managing the organization's member databases.
3. The Sierra Club is a non-profit membership organization incorporated under the laws of the State of California.
4. Sierra Club's mission is to explore, enjoy and protect the wild places of the Earth; to practice and promote the responsible use of the Earth's resources and ecosystems; to educate and enlist humanity to protect and restore the quality of the natural and human environment; and to use all lawful means to carry out these objectives.
5. The Sierra Club's Natural Gas Reform campaign is focused on reducing the amount and impacts of natural gas extraction, including preventing the export of unconventional natural gas without a full analysis of the environmental and public interest effects of such export.

6. When an individual becomes a member of the Sierra Club, his or her current residential address is recorded in our membership database. The database entry reflecting the member's residential address is verified or updated as needed.
7. The Sierra Club currently has 632,604 members in the United States, and 2,954 members in Louisiana. These members have a strong interest in protecting human health and the environment from the effects of natural gas extraction and export.

I declare under penalty of perjury under the laws of the United States of America that the foregoing is true and correct. Executed in San Francisco, California on April 14, 2014.

Yolanda Andersen

Yolanda Andersen

SIERRA CLUB
FOUNDED 1892

April 8, 2013

Secretary Steven Chu
U.S. Department of Energy
1000 Independence Ave SW
Washington, DC, 20585
The.Secretary@doe.gov

cc:

Gregory Woods, General Counsel
Office of the General Counsel
U.S. Department of Energy
1000 Independence Ave SW
Washington, DC, 20585

Re: Petition for Rulemaking Regarding Natural Gas Export Policy

Dear Secretary Chu:

Pursuant to 5 U.S.C. § 553(e), the Sierra Club, Catskill Citizens for Safe Energy, Center for Biological Diversity, Delaware Riverkeeper Network, Earthworks, Environment America, Friends of the Earth, Lower Susquehanna Riverkeeper, and Rogue Riverkeeper hereby petition the Department of Energy (DOE) to promulgate new regulations or guidance defining the process by which it will consider applications to export liquefied natural gas (LNG). The current guidelines are nearly thirty years old, and were designed to implement the Reagan Administration's energy policy on natural gas *imports*. They are very ill-suited to manage the serious questions raised by large-scale LNG exports, and urgently need to be revised in a fair and open public process. Although DOE asserts that it has expanded its considerations beyond those articulated by the import guidelines, its process remains unclear and poorly equipped to manage the serious energy policy questions now before it. We therefore petition it to open a public notice and comment process by which DOE will seek comments upon its outdated policy guidelines and proposals to revise them. LNG exports pose pressing public questions; DOE owes the public a policy discussion which recognizes the seriousness of these matters and responds to them with care.

I. Petitioning Parties

The following parties join this petition:

The Sierra Club is the nation's oldest and largest grassroots environmental organization, with more than 2 million members and supporters. Sierra Club's Beyond Natural Gas Campaign is focused on reducing natural gas demand, and on controlling the dangerous environmental impacts of gas production. As part of this work, the Sierra Club is a movant-intervenor in the majority of the LNG export dockets at DOE's Office of Fossil Energy ("DOE/FE").

Catskill Citizens for Safe Energy is an all-volunteer, grassroots organization that has been working to protect the public from dangerous hydraulic fracturing since 2008. Its website, catskillcitizens.org, is a reliable source of information about every aspect of shale gas extraction. Its Newsroom contains thousands of articles on the subject, and scores of scientific reports can be found in the Learn More section of its site. Catskill Citizens has been at the forefront of efforts to encourage the U.S. to develop a responsible energy export policy.

The Center for Biological Diversity is a non-profit corporation with offices throughout the United States and tens of thousands of members. The Center works to secure a future for all species, great and small, hovering on the brink of extinction. It does so through science, law and creative media, with a focus on protecting the lands, waters and climate that species need to survive.

Earthworks is a nonprofit organization dedicated to protecting communities and the environment from the impacts of irresponsible mineral and energy development while seeking sustainable solutions. Earthworks stands for clean water, healthy communities and corporate accountability. It works for solutions that protect both the Earth's resources as well as our communities.

Environment America is a federation of state-based, citizen-funded environmental advocacy organizations. It defends our environment with independent research, tough-minded advocacy and spirited grassroots action. Environment America, with hundreds of thousands of supporters from all walks of life, works to win tangible results for our environment.

Friends of the Earth, U.S. is a national, non-profit environmental advocacy organization founded in 1969 and incorporated in the District of Columbia, with its headquarters in Washington, D.C. and an office in Berkeley, California. Friends of the Earth's mission is to defend the environment and champion a healthy and just world. To this end, Friends of the Earth promotes policies and actions that address the climate change crisis and minimize the negative impacts of environmental pollution. Friends of the Earth has more than

150,000 members and activists in all 50 states. Friends of the Earth is a part of Friends of the Earth International, a federation of grassroots groups working in 76 countries on today's most urgent environmental and energy issues.

Lower Susquehanna Riverkeeper works on behalf of a friends, neighbors, outdoorsmen, recreationalists, and families who want safe drinking water, sustainable use of natural resources, and the ability to fish and swim in the Susquehanna River and her tributaries. Its program focuses on identifying sources of pollution and enforcing environmental laws. It actively educates the public on current issues, work with decision-makers to emphasize the economic and social benefits of protecting our watershed, and when necessary enforces laws protecting communities and natural resources of the basin.

Rogue Riverkeeper works to protect and restore water quality and fish populations in the Rogue River Basin of southern Oregon and adjacent coastal watersheds.

Please address correspondence in this matter to:

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II. Relief Requested

The LNG export applications now before DOE would significantly alter American energy policy if granted even in substantial part. The United States has never exported substantial quantities of natural gas beyond North America, and continental exports have always been relatively limited. The licenses before DOE would, on the other hand, give the U.S. the potential to be one of the largest gas exporters in the world. Such a shift would lead to structural changes in the national and international gas market and have important implications for climate change, manufacturing and economic policy, and issues of international trade and national security. Unfortunately, the 1984 import guidelines which now structure this consideration are not up to the task of shaping this critical analysis.

Yet those guidelines apparently continue to guide DOE's approach on LNG issues. As DOE has explained, its processes "have evolved from policy guidelines published in 1984 …, as supplemented and refined by subsequent agency adjudications."[1] To be sure, some of these "refine[ments]" – such as analysis of "environmental considerations" and "U.S. energy security" – do, indeed, bear usefully on export in ways that the 1984 guidelines do not. But they

[1] Letter from Deputy Secretary of Energy Daniel Poneman to Senator Ron Wyden. (Dec. 11, 2012) at 1-2.

have been presented simply as a list of non-exclusive factors, of questionable significance, in letters and testimony to Congress, rather than as new guidelines or regulations. Meanwhile, DOE/FE, in its only license decision to date, *Sabine Pass*, has affirmed that the import guidelines "*will be applied* to natural gas export applications."[2]

The result is that DOE's decisionmaking on export still appears to be rooted in the 1980s, and a policy document designed to speed *imports*. DOE has not solicited public comments on the appropriateness of that policy, how it should be applied in export cases, or how best to amend it in light of the very different problems posed by export.

Instead, DOE is apparently planning to move forward with a series of individual export authorization proceedings. Because these are adjudicatory processes, they do not invite broad public participation and do not provide a clear venue to announce new agency-wide policy decisions. On the other hand, DOE has shown encouraging signs that it seeks some broader public participation by commissioning programmatic economic studies on some LNG issues, and inviting public comment on those studies. That process, though far from perfect, indicates that DOE is aware that the individual cases before it implicate larger public concerns, and warrant full analysis.

DOE must follow this recognition to its proper conclusion and initiate a full public notice and comment process to update its decisionmaking guidelines on these crucial matters. The policy should also articulate how DOE will monitor any approved export terminals to ensure that they continue to be in the public interest. That rulemaking process must be fully informed by the economic and environmental and public health studies which the Natural Gas Act and the National Environmental Policy Act (NEPA) require.

III. The Existing Guidelines Are Insufficient to Address the Questions Now Before DOE and Must Be Revised

DOE is now considering whether to permit all or a portion of a proposed 28.30 billion cubic feet per day ("bcf/d") of natural gas export – the equivalent of 10,329.5 bcf per year.[3] Permitting the full volume would mark an approximately ten-fold expansion of *all* U.S. gas exports (both pipeline and LNG) and expand LNG exports specifically by a factor of about 370.[4] Indeed, the total volume proposed for export is approaching half of total marketed gas production in 2012.[5] This substantial new source of gas demand would certainly increase gas prices with important

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[2] DOE/FE, *Opinion and Order Conditionally Granting Long-Term Authorization to Export from Sabine Pass LNG Terminal to Non-Free Trade Agreement Nations*, Order No. 2961 (May 20, 2011) (emphasis added).
[3] *See* DOE/FE, *Applications Received by DOE/FE to Export Domestically Produced LNG from the Lower 48 States* (Mar. 7, 2013), available at:
http://fossil.energy.gov/programs/gasregulation/reports/summary_lng_applications.pdf.
[4] Exports in 2012 were 1,619 bcf/year, with only 28 bcf of that as LNG. *See* EIA, U.S Natural Gas Exports by Country, available at: http://www.eia.gov/dnav/ng/ng_move_expc_s1_a.htm.
[5] Total marketed gas production in 2012 was 25,304 bcf.

implications for U.S. manufacturing and energy utilities. And because roughly two-thirds (and possibly much more) of gas for export would come from new unconventional gas production,[6] export is also linked to intensifying environmental and public health impacts from the domestic gas boom. In short, LNG export, of any significant volume, implicates core questions of energy and environmental policy for the nation as a whole.

To be sure, the scope and magnitude of these potential impacts will vary by the amount of LNG export which DOE permits, and how DOE conditions those exports. But even smaller amounts of export would still greatly expand domestic gas demand and production, and would link the U.S. to international gas markets in novel ways. And, after all, the proper scope of export is the open question here which demands a policy response: How *will* DOE structure its decisionmaking around these potentially enormously consequential projects? Unfortunately, that question remains very much unanswered.

A. The Import Guidelines Were Created to Enhance Natural Gas Imports and Provide Little Guidance on Export

The Natural Gas Act provides that DOE may only permit LNG exports which are "not inconsistent with the public interest."[7] But, as Deputy Secretary Poneman has said, the Act's text "does not prescribe what factors should go into the public interest analysis."[8] DOE has instead developed its own process through a series of delegation orders and policy guidelines, culminating in the 1984 import guidelines.

Those guidelines are the product of their time and are focused on streamlining gas *imports* at market-responsive prices in order to reduce consumer rates. Before their issuance, DOE operated under a delegation order which required license applicants to affirmatively demonstrate the "[n]ational need for the natural gas to be imported or exported,"[9] and had denied several import applications that failed to make that demonstration.[10] This stance differed from the view of the Reagan Administration, whose position was that "imported gas should be regulated by the market, with the government's role limited to foreign and trade policy, broad economic considerations and national security concerns."[11] Accordingly, DOE began a public process to draft new guidelines to "reflect our market-oriented position."[12] The

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[6] *See* EIA, *Effects of Increased Natural Gas Exports on Domestic Energy Markets* (2012) at 6, available at http://www.eia.gov/analysis/requests/fe/pdf/fe_lng.pdf.
[7] 15 U.S.C. § 717b(a).
[8] Poneman-Wyden Letter, *supra* n.1, at 1.
[9] DOE Delegation Order No. 0204-54, 44 Fed. Reg. 56,735 (Oct. 2, 1979).
[10] *See, e.g.¸Tenneco Atlantic Pipeline Company*, Opinion and Order, 1 ERA ¶ 70,103 (Dec. 18, 1978); *El Paso Eastern Company*, Opinion and Order, 1 ERA ¶ 70,104 (Dec. 21, 1978).
[11] *See* 48 Fed. Reg. 34,501, 34,501 (July 29, 1983)
[12] *Id.*

final guidelines therefore take this view, and were designed to conform with the market orientation of "the President's 1983 National Energy Policy Plan."[13]

DOE's goal at the time was chiefly to deregulate a price control system which had resulted in gas price increases in some parts of the country, and replace this system with one that made allowed more direct negotiations on price between buyers and sellers, making import more sustainable.[14] Prior to the 1984 guidelines, this system of price controls, including regulatorily-approved long-term contracts, locked American buyers into a system in which they were paying above market rates for gas.[15] In earlier years, import prices from Canada (the largest supplier) had been negotiated on a "cost-of-service basis," but later negotiations between the two governments resulted in a series of agreements which supported government-determined pricing.[16] But by the fall of 1982, the Canadian imports were entering the market "at a price that began to be uncompetitive in most U.S. markets" and other imported gas supplies were encountering the same problems, driving up consumer prices.[17] Market participants, accordingly, argued that the price control system was not working and "a more flexible approach to pricing was needed" that would be driven by "direct buyer-seller negotiations."[18]

The U.S. policy goal, in response to this problem, was to limit government interventions while maintaining enough oversight to ensure "a supply of natural gas supplemental to domestic production available on a competitive, market-responsive basis, while avoiding undue dependence on unreliable sources of supply."[19] In accordance with these goals, DOE established a three part-regulatory inquiry. It would inquire, first, into "[t]he competitiveness of the import," meaning that the license applicants had to show that the imported gas would be governed by contracts allowing it to compete in the U.S market.[20] Next, DOE would consider the "[n]eed for the natural gas," a question also focused on the "marketability" of the gas in the domestic market compared to U.S. gas.[21] Third, DOE would look to the "[s]ecurity of supply," meaning that importers would have to demonstrate the "historical reliability of the supplier to provide a dependable source of gas to the United States and other countries."[22]

These three primary factors, in short, are intended to allow imported gas to flow into the United States at market prices as long as there is room in the market for it and the source of supply is dependable enough to ward off supply shocks. The hope was that allowing such unrestricted import pricing systems would lower gas prices and avoid "severe economic consequences for

[13] 49 Fed. Reg. 6,684, 6,685 (Feb. 22, 1984).
[14] *Id.* at 6,687.
[15] *Id.* at 6,684,
[16] *Id.* at 6,686.
[17] *Id.*
[18] *Id.* at 6,686-87.
[19] *Id.* at 6,687.
[20] *Id.* at 6,688.
[21] *Id.*
[22] *Id.*

the American gas consumer" by avoiding dependence on long-term expensive gas imports if the market would not accept them.[23]

Because of this focus on speeding gas to American consumers, the 1984 import guidelines understandably say almost nothing about gas *export*. The delegation order based upon them, accordingly, says only that DOE shall regulate exports "based on a consideration of the domestic need for the gas to be exported and such other matters as the Administrator finds in the circumstances of a particular case to be appropriate."[24] No further guidance is available.

B. The 1984 Guidelines Are Ill-Suited to Today's Issues

The world has changed a great deal since the 1984 guidelines. The import price control issues they were designed to solve are no longer pressing, or particularly relevant. Instead, DOE must wrestle with the proper role of LNG exports in the context of a very different U.S. economy, at a time of increasingly severe climate change, and where gas is increasingly produced using potentially hazardous technologies, including hydraulic fracturing ("fracking"). These shifts, as well as the inherent differences between gas imports and gas exports, underline why a fresh policy approach is so urgently needed.

Perhaps the most obvious shift in context since 1984 is that DOE is now dealing with large-scale gas exports for the first time. As a result, the issue which animates the 1984 guidelines -- harm to U.S. consumers from overly-expensive imported gas caused by extensive domestic price controls and poorly-drawn contracts--- is simply not present here. Instead, export economics debates center on the likely impact of linking U.S. gas supplies to the hungry world market. The potential arbitrage opportunity available to exporters to send domestic gas abroad at much higher prices, and the increased demand that such exports would create both raise significant questions about price impacts on U.S. consumers – but not because of the regulatory issues germane in 1984.[25] No one is concerned that DOE will set export price contracts at a level which would harm U.S. citizens. Instead, the question is whether the market price increases that exports will necessarily create, if permitted, are in the public interest. Thus, while DOE, in 1984, was seeking to create a market-responsive source of additional supply, free of unnecessary regulatory constraints to lower consumer prices, the question is now how new demands will alter the picture for U.S. consumers if exports compete against U.S. needs without further oversight– a competition which will necessarily raise gas prices.

In addition to this fundamental structural shift, both the source, and the effect, of increased gas consumption raise questions which were not germane in 1984. Most exported gas would be sourced from unconventional gas plays (shales, tight sands, and the like), and would be

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[23] *Id.* at 6,684.
[24] DOE Delegation Order No. 0204-111 (Feb. 22, 1984).
[25] *See generally* EIA, *Effects of Increased Natural Gas Exports on Domestic Energy Markets* (investigating these questions).

extracted with the fracking process.[26] Imported gas, obviously, does not implicate U.S. production impacts and, in any event, those unconventional plays were not available in the 1980s. Now, though, unconventional production is expanding throughout the country, raising major environmental concerns and fomenting a vigorous ongoing public debate over its wisdom and appropriate limits upon production. As a result, the environmental impacts of such production were not germane to the DOE's considerations in the way they are now.

Similarly, the effect of deepening dependence on fossil fuels in the context of global climate change was far less developed in the 1980s. Although the greenhouse effect was known, the full scope and danger of climate change was less apparent, and had not yet been recognized by the government, as it has now.[27] Because the government has now recognized that global warming is a pressing threat to public health and welfare, there is a real question whether LNG exports are in the public interest if they expand use of fossil fuels or increase greenhouse gas emissions. DOE was not considering that pressing global crisis in 1984, but that question is central today.

This list of differences could go on for pages. The point, though, is simply that the world has changed: DOE simply faces a different set of problems now than it did decades ago, and it needs the tools to address them. Although consumer protection remains central to DOE's charge, the policy model developed in 1984 to avoid unnecessarily high import prices has very little to do with the questions export raises. To address them, DOE must revisit its guidelines to ensure that they speak to the problems at hand.

C. DOE Must Address New Questions on Export Which the 1984 Guidelines Do Not Cover

The absence of any formal export policy, or clear guidelines, is a pressing problem in light of the scope and importance of the issues raised by the LNG export proposals. These issues span much of the American economy and bear importantly on critical energy and environmental policy questions. The import guidelines are silent on these matters but the vigorous public debate on export demonstrates the great public importance of approaching them with great care.

The questions at stake, in brief, include (but are definitely not limited to) the following:

<u>Impacts on Domestic Consumers</u>. Essentially all parties to this debate concede that LNG exports will raise domestic gas prices, although they differ about the magnitude and scope of these increases, and so differ on their importance. It is clear that LNG exports elevate energy prices while depressing labor income in the rest of the economy, meaning, as a DOE-

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[26] *See id.*

[27] *See* 74 Fed. Reg. 66,496 (Dec. 15, 2009) (recognizing that greenhouse gas emissions cause climate change, which endangers public health and welfare).

commissioned macroeconomic study puts it, that "[h]ouseholds with incomes solely from wages or transfers will not share" in export revenues.[28]

This price increase must be of central concern, given the Natural Gas Act's core purpose of "protect[ing] consumers against exploitation at the hands of natural gas companies."[29] In light of this charge, we are, to say the least, extremely skeptical that DOE can properly allow export-linked consumer price increases which will harm ordinary American wage earners while benefitting a narrow segment of the oil and gas industry. Certainly, the 1984 guidelines provide no support for this proposition: Although they favor market pricing, they do so as an alternative to a rigid price control system that had locked in above-market prices for gas companies. It would be inappropriate to uncritically assume that this market focus is still appropriate in the context of large-scale export, which would significantly raise consumer prices.

Export proponents, of course, maintain that *other* consumer benefits counter-balance these price increases (which they maintain will be minimal), but even if that contention is supportable when these proponents will reap profits at the expense of the general public, this debate is really the point. Exports, in any significant quantity, raise domestic prices, transferring wealth from wage earners to natural gas companies. If countervailing considerations nonetheless can balance these price increases – a point which we doubt in light of the Act's consumer-protection purpose – DOE needs to explain how, and any such considerations need to be carefully weighed and documented. The 1984 import guidelines, structured simply to increase supply (and hence to lower prices) do not provide a framework to consider these matters. If DOE believes that market price increases can be balanced by other factors, it must articulate that view in a proper public proposal and seek comments from the many Americans that position would affect.

Impacts on Domestic Industry. The same price increases felt by ordinary ratepayers are felt even more acutely by energy-intensive industries and by public gas utilities. Unsurprisingly, both groups have raised serious concerns about DOE's process. In their view, LNG export above a certain quantity could significantly impede a domestic manufacturing renaissance (and even do net harm to the U.S. trade balance as fewer of these manufactured goods are exported). That view is supported by an extensive analysis appended to recent Dow Chemical comments on the DOE-commissioned macroeconomic study.[30] In short, the possibility of diverting significant amounts of natural gas overseas – where gas prices are much higher – raises

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[28] NERA Economic Consulting, *Macroeconomic Impacts of LNG Exports from the United States* (2012) at 8,
[29] *See, e.g. Michigan Gas Co. v. FERC*, 115 F.3d 1266, 1272 (6th Cir. 1997) (citing *FPC v. Hope Natural Gas Co.*, 320 U.S. 591, 612 (1944)).
[30] Charles River Associates, *U.S. Manufacturing and LNG Exports: Economic Contributions to the U.S. Economy and Impacts on U.S. Natural Gas Prices* (2013), available at: http://www.fossil.energy.gov/programs/gasregulation/authorizations/export_study/reply_comments/Peter_A_Molinaro02_25_13.pdf.

economy-wide competitiveness questions that simply were not contemplated by the 1984 guidelines.

These questions are so substantial, in fact, that a serious debate continues even as to the net effect of LNG exports on U.S. GDP. Although the study DOE commissioned finds a net positive trend, an independent study in the record finds that the negative impacts on consumers and industry are enough to depress GDP as a whole.[31] These economists therefore caution that "policy makers need to be very careful in approving U.S. gas exports."[32] Again, the 1984 guidelines offer no guidance on how DOE should weigh these competing models, or the relative importance of the domestic manufacturing sector and the natural gas export sector, or whether harm to some domestic actors can still be in the "public interest."

<u>Environmental and Public Health Implications</u>. Large-scale LNG exports implicate at least four distinct sets of environmental and public health questions. First, and most obviously, LNG export requires a large, new, industrial infrastructure; this network of terminals, liquefaction plants, pipelines, and compressors requires careful environmental review. Second, exporting gas stimulates increased gas production – and most of that production will come from unconventional gas sources. According to the expert Shale Gas Production Subcommittee of DOE's Secretary of Energy Advisory Board, a combination of absent and inadequate regulation means that that production comes with "a real risk of serious environmental consequences."[33] The likelihood that export will exacerbate these impacts warrant careful analysis and management. Third, LNG export shifts the domestic gas market for electrical utilities, meaning that they are more likely to use coal, rather than gas, in their power plants.[34] As a result, LNG exports likely increase CO_2 emissions from U.S. power generation according to the EIA. Fourth, LNG itself is a carbon-intensive fuel,[35] with life-cycle emissions significantly greater than that of natural gas. At a minimum, the net climate and environmental impact of using this fuel is concerning. Assessing it requires a careful look at how importing nations are likely to use the fuel in their larger energy mixes. As we have noted, the pressing climate crisis (which was not clearly in view in 1984) thus raises significant questions about whether increased trade in this fossil fuel puts the public at risk.

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[31] Dr. Wallace Tyner, Purdue University, *Comparison of Analysis of Natural Gas Export Impacts from Studies Done by NERA Economic Consultants and Purdue University* (2013) at 5, available at http://www.fossil.energy.gov/programs/gasregulation/authorizations/export_study/30_Wallace_Tyner01_14_13.pdf.

[32] *Id.*

[33] Shale Gas Production Subcommittee of DOE's Secretary of Energy Advisory Board, *Second Ninety-Day Report* (2011) at 10, available at: http://www.shalegas.energy.gov/resources/111811_final_report.pdf.

[34] *See, e.g.*, *Effects of Increased Natural Gas Exports on Domestic Energy Markets* at 18-19.

[35] See Paulina Jaramillo, W. Michael Griffin, H. Scott Matthews, Comparative Life-Cycle Air Emissions of Coal, Domestic Natural Gas, LNG, and SNG for Electricity Generation, 41 Environ. Sci. Technol. 6,290 (2007), available at: http://www.ce.cmu.edu/~gdrg/readings/2007/09/13/Jaramillo_ComparativeLCACoalNG.pdf.

Importantly, the Supreme Court has repeatedly instructed that this sort of broad look at environmental considerations is required by the public interest test.[36] EPA has also urged that DOE (and FERC, which usually prepares NEPA documents for both agencies) consider the full scope of possible impacts.[37] The import guidelines, however, fail to recognize the importance and scope of these environmental obligations and DOE has, thus far, largely limited its consideration of environmental impacts in its export decisionmaking. In the recent *Sabine Pass* orders, it went so far as to assert (albeit in dicta) that many such impacts simply could not and would not be considered.[38]

This disconnect is striking and deeply problematic. The environmental and energy issues inherent in LNG export are near the center of the policy debate, but DOE's current practice, and the old import guidelines, appear to discourage it from answering them. These questions include: Is it in the public interest to double-down on unconventional gas production or to become a major supplier of fossil fuels to the world market? What conditions, if any, should apply to any such exports to mitigate environmental impacts? How do export authorizations interact with larger U.S. environmental and energy policy? And how should DOE weigh these considerations in its larger public interest analysis? Unfortunately, the 1984 import guidelines, crafted to conform with a decades-old energy plan, do not provide meaningful guidance on these matters. That is not too surprising: Imports of pipeline natural gas in the 1980s simply raise very different (and arguably less pressing) domestic environmental questions than the wholesale export of domestically produced gas as LNG during a time of worsening climate change.

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Along with these and other substantive questions, the old guidelines also fail to address important process questions. The import guidelines established a new rebuttable presumption in favor of import applicants.[39] Although the D.C. Circuit allowed this departure from past practice, it did not hold that DOE must take this approach, and emphasized that the presumption must be flexible—simply a starting point for analysis.[40] Although the presumption is intended to be flexible, applicants have relied on it in practice to urge that protests of export applications must carry a very high burden of proof – in essence that they

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[36] *See Udall v. Federal Power Comm'n*, 387 U.S. 428, 450 (1967); *NAACP v. Federal Power Comm'n*, 425 U.S. 662, 670 n.4 & 6 (1976).
[37] *See* EPA, *Scoping Comments – The Jordan Cove Energy Project LP*, FERC Dkts. PF12-7 and PF12-17 (Oct. 29, 2012); EPA, *Scoping Comments – Cove Point Liquefaction Project*, FERC Dkt. PF12-16-000 (Nov. 15, 2012) ; EPA, *Scoping Comments – The Oregon LNG Export Project and Washington Expansion Project*, FERC Dkts. PF12-18 and PF12-20.
[38] *See* Opinion and Order, *Granting Long-Term Authorization to Export Liquefied Natural Gas from Sabine Pass LNG Terminal to Non-Free Trade Agreement Nations*, Order No. 2961-A (Aug. 7, 2012) at 27-28.
[39] *See, e.g.*, 49 Fed. Reg. at 6,688-89. More specifically, the guidelines establish a series of presumptions in favor of import within each of the three considerations they set out.
[40] *Panhandle Producers and Royalty Owners Ass'n v. Economic Regulatory Admin.*, 822 F.2d 1105, 1111 (D. C. Cir. 1987).

must not only rebut an initial presumption, but carry the case entirely. This approach is, at a minimum, in tension with the Natural Gas Act's mandate to *DOE* to protect the public interest. Because DOE has an independent obligation to protect the public, it has an independent duty to carefully weigh export applications on a full record – even if a given proceeding lacks an assiduous protestor. This obligation attaches with particular force here because of the exceptional public policy importance of LNG export. As such, this is also an appropriate time to reconsider the scope, application, and extent of any presumption-based approach in LNG proceedings. As DOE expands its consideration of substantive issues, it should also clarify how it will weigh the evidence before it, and what sorts of evidence it will require.

Export, in short, raises important, and difficult, questions which DOE must address if it is to credibly determine whether exports are in the public interest, and, if so, in what volume, and with what conditions. And how DOE weighs these sometimes-competing considerations – its policy orientation – will greatly influence the final outcome. Without conceding that all of these orientations are permitted by the Natural Gas Act, a few examples are illustrative: For instance, if DOE to focus simply on "protect[ing] consumers against exploitation at the hands of natural gas companies,"[41] it might well disfavor any exports raising natural gas prices (perhaps above a certain amount). Or if DOE instead focused more on allowing the gas market to set prices, it might decide to permit all or most LNG terminals and assume that the market price (whatever it is) will be efficient and in the public interest. Or if DOE focused more on the effect of exports on domestic industry and employment it might seek to limit or phase in export to avoid price and supply shocks. Or if DOE was chiefly concerned with ensuring that export did not cause serious environmental harms, it might work to coordinate exports with the Shale Gas Production Subcommittee's recommended regulatory safeguards, or limit or bar export entirely until improved safeguards were in place. Or if DOE were actuated by climate change concerns, it might focus instead of limiting fossil fuel export and extraction as rapidly as possible. Or, of course, DOE might balance these concerns to come up with a limited export policy that attempts to serve multiple interests. The point is simply that DOE's choices are ultimately based (implicitly or explicitly) in policy judgments. The question now is whether the judgments DOE is making under the outdated guidelines properly respond to the complex issues raised by LNG export and appropriately serve the purposes of the Natural Gas Act.

Right now, those judgments remain opaque, as do the underlying criteria which DOE must use to make them. The 1984 import guidelines shed very little light because they are not well-matched to the large questions now before DOE. Before DOE moves forward with its decisions, it should therefore take the time to carefully enunciate a more modern set of policy judgments, and test those with public notice and comment. That sort of transparent process is necessary to get these important decisions right.

D. DOE's Practices to Date Demonstrate Why New Guidelines Are Needed

[41] *See, e.g. Michigan Gas Co. v. FERC*, 115 F.3d at 1272.

To its credit, DOE has sometimes recognized that case-by-case adjudication based on the import guidelines is not sufficient. But its efforts to address the larger questions have, so far, been halting, at best. DOE officials have offered public statements indicating that the agency will look beyond the guidelines, but the only order DOE has issued on this wave of LNG export applications shows almost none of that promised broad thinking. Such orders generally provide a poor venue to enunciate and explore policy changes. And while DOE has, to its credit, requested broad public comments on an economic study it commissioned, this process's outcomes are unclear, and do not appear tethered to any particular policy proposal. These processes, in short, do not substitute for a public policymaking process.

i. Informal checklists of possible considerations are not sufficient policy statements

DOE officials have acknowledged that LNG export raises policy questions beyond the import guidelines. Those statements are welcome, but they are vague. Rather than expressing a coherent policy view, they simply list a changing collection of other factors to consider, without explaining their relative importance. This approach offers the public little guidance on DOE's decisionmaking process.

The first such list of which we are aware comes from 2011 testimony from Deputy Assistant Secretary Christopher Smith. He told a Senate Committee that "a wide range of criteria" would be considered, "including":

- Domestic need for the natural gas proposed for export
- Adequacy of domestic natural gas supply
- U.S. energy security
- Impact on the U.S. economy (GDP), consumers, and industry
- Jobs creation
- U.S. balance of trade
- International considerations
- Environmental considerations
- Consistency with DOE's long-standing policy of promoting competition in the marketplace through free negotiation of trade arrangements
- Other issues raised by commenters and/or intervenors deemed relevant to the proceeding.[42]

In December 2012, Deputy Secretary Poneman offered a similar list in response to a request from Senator Wyden for further details on DOE's decisionmaking process.[43] His list, notably, adds impacts "impact on domestic natural gas prices" as a consideration, and drops

[42] Statement of Deputy Assistant Secretary Christopher Smith Before the Committee on Energy and Natural Resources, United States Senate, *The Department of Energy's Role in Liquefied Natural Gas Export Applications* (Nov. 8, 2011) at 4.
[43] Poneman-Wyden Letter, *supra* n.1, at 1.

"consistency" with DOE's market policies – suggesting something of a departure from the import guidelines' focus on market pricing.[44]

Then in March of this year, Deputy Assistant Secretary Smith offered yet another revised list to a House Subcommittee, this time omitting any reference to the "U.S. balance of trade" or to impacts on "industry."[45]

These changing and unspecified lists are unsatisfactory. While we appreciate the DOE's efforts to broadly engage these issues, the lists offer no guidance on how DOE will weigh the many issues before it. Nor does DOE explain how it will gather and assess evidence on these issues, or even which particular points are of importance (there are, for instance, many international and environmental "considerations" which DOE might focus upon). And because the issues DOE chooses to highlight vary from time to time, it is not even clear which concerns enter into the analysis in the first place.

For this reason, the consideration lists do not substitute for a full policy statement. They do not provide meaningful guidance to applicants or to potential protestors on which arguments and information will be most useful to DOE. Nor, critically, do they provide a forum for the public, as a whole, to weigh in on this vital public policy question. They identify issues, without resolving them. In practice, as we next discuss, this has meant that DOE has fallen back on the inapposite import guidelines.

ii. DOE's LNG Export Decisions Further Demonstrate the Need for Clear Policy Guidance

DOE has ruled on only one of the LNG export applications now before it. That ruling, *Sabine Pass*,[46] is driven by the policies of the import guidelines, despite the broader analysis which DOE's public issue lists seem to suggest. At a time when a policy review is obviously warranted, it follows decades-old policy guidance. But even that order evinces some discomfort with continued exports, noting, for the first time, that "the cumulative impact of these export authorizations could pose a threat to the public interest."[47] DOE should act on this concern by revisiting its export policies to ensure that they provide sufficient guidance to meet this potential threat.

The limits of *Sabine Pass*, and its earlier orders, underline why DOE needs to take a hard look at its activities. Again, the import guidelines established only one definite criterion for export: "a consideration of the domestic need for the gas to be exported," leaving all other issues to DOE's

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44 *See id.*

45 Statement of Deputy Assistant Secretary Christopher Smith Before the Oversight and Government Reform Committee, United States House of Representatives, *The Department of Energy's Program Regulating Liquefied Natural Gas Export Applications* (Mar. 19, 2013) at 3.

46 *Sabine Pass,* Order 2961, *supra* n.2.

47 *Id.* at 33.

discretion.[48] Although the delegation order which implemented the guidelines has been rescinded for more than a decade,[49] DOE nonetheless indicated that it would "continue[ ] to focus" on this consideration, along with "DOE's policy of promoting competition in the marketplace" and the security of domestic energy supplies.[50]

DOE focused accordingly. It granted an export license on the primary basis that the studies submitted by the applicant "indicate that the existing and future supply of domestic natural gas is sufficient to simultaneously support the proposed LNG export volumes as well as domestic natural gas demand" over the period of the authorization.[51] Applying a particularly heavy presumption in favor of the applicant, DOE did not investigate this matter itself. Instead, it relied on the fact that two protestors in that docket had not submitted "a rebuttal study" as sufficient to support its decision.[52] And though DOE noted that those protestors had also "alleged a variety of negative consequences," it did not find that they outweighed the applicant's claims of other economic benefits from its project.[53] Finally, as noted above, when DOE did finally (in a subsequent order) consider environmental impacts, it essentially declined to consider any impacts outside of the terminal site itself.[54]

The result is that the *Sabine Pass* orders furthered a potential LNG export boom without considering almost any of the pressing public policy questions inherent in that boom. DOE did not look far beyond the strictures of the import guidelines and the (now defunct) delegation order that accompanied them. It conducted no independent studies. Instead, it relied only on those few members of the public who happened to protest the application. Because the protestors did not contest this particular license with detailed rebuttal studies, DOE felt it was appropriate to begin a seismic shift in the gas markets without any broader process. Nor did it articulate a coherent vision for export policy, or even really acknowledge that the export boom poses qualitatively different challenges than the pipeline imports which it usually considers.[55]

[48] 49 Fed. Reg. at 6,690.

[49] *See* Redelegation Order No. 00-002.04 (Jan. 8, 2002) (rescinding earlier delegation order).

[50] *Sabine Pass*, Order 2961, at 28-29.

[51] *Id.* at 31.

[52] *See id.*

[53] *Id.*

[54] *See Sabine Pass*, Order 2961-A, *supra* n. 31, at 28-29.

[55] DOE's two earlier opinions considering relatively substantial LNG exports are likewise unilluminating. Those opinions both address potential LNG exports from Alaska, and were issued more than a decade ago. Given their circumstances, they of course do not give serious attention to the implications of the nationwide shift towards gas export that is now before DOE. Nor do they seriously consider issues related to gas extraction, or to climate change – both acutely pressing in today's carbon-constrained world. Both opinions are instead driven by the same consideration of immediate domestic need that the import guidelines impose. *See generally* DOE/FE, *Phillips Alaska, Opinion and Order Extending Authorization to Export Liquefied Natural Gas from Alaska*, Order No. 1473 (Apr. 2, 1999); DOE/FE, *Yukon Pacific, Order Granting Authorization to Export Liquefied Natural Gas from Alaska*, Order No. 350 (Nov. 16, 1989).

Thus, despite DOE's public statements, its actual decisions to date have been notably limited by the constraints of the import guidelines. The domestic supply question for a given quantity of export at a particular terminal remains the agency's focus. Other issues, no matter how practically important they are, receive short shrift. And the core pro-market program of the 1980s continues to guide DOE policy, regardless of the large, new questions which export poses.

These failings demonstrate why simply working out DOE's position in further individual proceedings is not likely to be successful. Those proceedings are inherently limited to their participants and the particular issues around particular terminals (even if considered cumulatively with others). As adjudicatory proceedings, they afford no obvious opportunity for DOE to publicly announce, and seek comment upon, a shift in policy. Nor are they are open to many important interests or for general public comment. Although DOE could, in principle, nonetheless enunciate a shift in policy through an order in such a proceeding, it is, at bottom, an awkward setting, one that discourages full discussion and durable settlement of these large issues.

While we, of course, encourage DOE to think broadly in its individual cases, *Sabine Pass* provides little ground for optimism. Rather than continuing to *de facto* follow the 1984 policy (perhaps with a few additional considerations), DOE would do much better to pull back and offer a coherent policy structure for notice and comment.

iii. DOE's Economic Studies Also Show Why a Broader Process is Important

DOE has sought public comment on one aspect of its decisionmaking, an economic study which it commissioned, but that process is limited, with unclear outcomes. Although it might usefully inform new policy guidelines, it does not substitute for them.

To DOE's credit, after *Sabine Pass* it recognized that the growing demand for LNG export required additional analysis. It therefore commissioned a two-part economic study looking at the economic impacts of large-scale export; EIA conducted the first part of that study and a private contractor, NERA, conducted the second.[56] As DOE explained, "[t]he purpose to the LNG Export Study was to evaluate the cumulative economic impact of the *Sabine Pass* authorization any future requests for authority to export LNG."[57]

DOE sought public comment on the study, but limited comments to the economic issues in the study, explaining that it might "disregard" other comments.[58] It also made clear that, though it intended to place the study and comments upon it in the record for individual LNG proceedings, it was "not establishing a new proceeding or docket" for the study itself.[59] DOE

[56] *See* 77 Fed. Reg. 73,627, 73,268 (Dec. 11, 2012).
[57] *Id.*
[58] *Id.* at 73,629.
[59] *Id.*

indicated that it would address the study and comments on a "case-by-case basis" within the LNG export process, rather than, for instance, part of a larger policy rulemaking.[60] Despite these constraints, more than 180,000 people commented on the study, indicating the exceptional breadth and intensity of public interest in DOE's decisionmaking process.[61]

The trouble is that this process, despite the vociferous comment period, does not provide DOE, the public, or applicants, with any indication of how DOE proposes to *use* the information it has received. Nor does it unambiguously give the public the chance to comment upon DOE's policy choices, or seek review of those choices in court. To be sure, DOE's actions in individual cases will ultimately indicate a policy direction based on the study, but, at that point, it will be too late. If DOE proposes a new policy, there will be no room for public notice and comment upon it because it will appear within a narrow adjudicatory decision which is not subject to public review. Or, if DOE continues to follow the 1984 guidelines, the public will have no opportunity to comment upon DOE's continuing application of those outdated principles in this context, and to new data. Further, because the vast majority of the commenters are not parties to those cases, most of the public will have no ability to seek review of DOE's decisions or ensure that their comments are heeded. In essence, DOE is skipping critical steps. Rather than using the economic study, and comments thereon, to inform policy, offer that policy for comment, and then apply it to individual cases, it is simply rushing ahead to individual "case-by-case" decisions, in the absence of any policy review.

This is a mistake. The economic study itself does not clearly indicate a direction for DOE to take. It shows that exports will generally harm wage earners and benefit gas exporters. But whether DOE chooses to favor one group or another (or strike some sort of balance) as a matter of policy remains unclear. And the study, of course, does not touch on many other areas relevant to the public interest, including environmental impacts. The study, in other words, may influence policy, but it does not set policy.

iv. New Policy Guidelines Are Needed

In sum, neither DOE's public statements, nor its sole modern LNG export decision, nor its limited comment period on economic aspects of LNG exports suffice. DOE's progress for making export decisions is fragmented, opaque, and unduly governed by policy judgments that were never intended to address today's situation. DOE would do well to move forward by revisiting its policy, before case-by-case export decisions create a *de facto* policy which may or may not be in the public interest.

E. Further Guidance Is Also Needed on DOE's Public Interest Monitoring Process

[60] *Id.*

[61] Sierra Club and many of the other petitioning groups, for instance, submitted extensive comments raising concerns with the study.

In the *Sabine Pass* process, DOE also articulated a "continuing duty to protect the public interest."[62] It indicated that changes in gas supply or demand could alter whether Sabine Pass's exports were in the public interest by, for instance, restricting supply in response to environmental concerns, or by increasing demand in the power sector.[63] DOE indicated that it would "monitor these conditions" to ensure that exports "do not subsequently lead to a reduction in the supply of natural gas needed to meet essential domestic needs."[64] It suggested that it might take appropriate action to rescind or modify export approvals, with notice and a hearing (if need be), in those circumstances.[65] This ongoing monitoring duty, too, requires clarification through a new policy process.

There are several problems with the monitoring conditions DOE has set out (though they are far better than nothing). Plainly, they are rooted, like the rest of the decision, in the 1984 import guidelines, which were designed to protect gas supply. As a result, they only obliquely touch on other possible reasons to restrict or modify exports. Such reasons might include concerns over the environmental and social impacts of large-scale gas exports and the production needed to support them, unforeseen harms to the industrial sector, or a need to curtail fossil fuel use in light of the urgent global climate crisis, which continues to intensify. Other reasons might also apply. The point here is that both the substance and structure of DOE's continuing public interest monitoring duty turns on DOE's policy judgments about the public interest. Accordingly, as DOE revisits those guidelines, it should also explain how any modified policy affects its monitoring and enforcement criteria.

IV. Petition for Relief

We are not the only voice calling for a more coherent policy process on LNG export. Senator Wyden has asked DOE to explain "how DOE will establish the actual decision-making criteria to be used in making the required export determinations … and the manner in which these criteria will be promulgated."[66] Groups as disparate as the Natural Resources Defense Council[67] and Dow Chemical[68] have made essentially the same request. The public deserves clarity, and that begins with a clear export policy.

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[62] *Sabine Pass*, Order No. 2961, *supra n. 2*, at 31-32.
[63] *Id.*
[64] *Id.* at 32.
[65] *Id.* at 33.
[66] Letter from Senator Ron Wyden to Secretary Steven Chu (Oct. 23, 2012). DOE, unfortunately, answered this letter only by reiterating its checklist of issues, without providing more substance.
[67] Kathleen Kennedy, NRDC, *Initial Comments on the NERA Study* (2013), available at http://www.fossil.energy.gov/programs/gasregulation/authorizations/export_study/kennedy_em01_24_13.pdf.
[68] Peter Molinaro, Dow Chemical, *Reply Comments on the NERA Study* (2013), http://www.fossil.energy.gov/programs/gasregulation/authorizations/export_study/reply_comments/Peter_A_Molinaro02_25_13.pdf.

DOE should pursue this policy-making process on the basis of full information. It has several channels in which to gather this information. Two are particularly important (though this list is not exclusive):

The economic studies DOE has commissioned (in addition to further work to correct deficiencies in that work noted by many commenters) provide one useful set of data once that work has been completed. DOE should open a formal docket, independent of any particular terminal, in which to consider them, and to respond to the many comments it received.

The National Environmental Policy Act (NEPA), provides another critical channel. As we have explained at length in protests and comments filed with DOE, NEPA requires an Environmental Impact Statement (EIS) for every major Federal action which could significantly affect "the quality of the human environment."[69] NEPA's "purpose is not to generate paperwork--even excellent paperwork--but to foster excellent action."[70] This means that "[t]he NEPA process is intended to help public officials make decisions that are based on an understanding of environmental consequences, and take actions that protect, restore, and enhance the environment."[71] NEPA is often used to make programmatic decisions of this sort,[72] and would be enormously helpful to DOE and to the public here. DOE should therefore prepare (or work with FERC to prepare) a programmatic EIS, fully considering the environmental and public health impacts of possible levels of LNG export. This document would essentially parallel the programmatic economic study which DOE is already conducting, and would be a necessary complement to it. Indeed, the EIS could directly test alternative approaches to LNG export policy for their likely environmental impacts.

These processes would provide DOE with much of the information it needs to make a coherent, well-supported decision on LNG export, as the Natural Gas Act requires, beginning by proposing modern policy guidelines. That process would be public, fair, and comprehensive. Through it, DOE could propose different emphases for U.S. policy, considering, for instance, whether the simple market need analysis of the 1984 guidelines is appropriate, or whether a broader analysis is more likely to serve the public – including, for instance, the factors that we, and DOE officials, have cited as important. The policy should also set forth the ways in which DOE will weigh evidence before it, and how it will manage the cumulative impacts of the many applications it is now considering. And it should explain how DOE will monitor any exports to ensure consistency with the public interest in the future.

In view of the potential importance of LNG exports, for both good and ill, and the extremely lively public debate surrounding the issue, this petition makes a modest request: DOE should look before it leaps. As DOE has already recognized, at least in part, these extraordinary requests require careful process. DOE has worked to include the public in its policy-making

[69] 42 U.S.C. § 4332(C).
[70] 40 C.F.R. § 1500.1(c).
[71] *Id.*
[72] *See* 40 C.F.R. § 1502.14(b)-(c).

even in less unusual times: The 1984 import guidelines themselves were developed through a public notice and comment process and a DOE-sponsored conference.[73] No less care is warranted here.

We therefore petition DOE to do the following:

(1) Grant no more licenses for LNG export to non-Free Trade Agreement nations until it has completed a final revision of its policy guidelines, focusing on LNG export.
(2) Conduct an Administrative Procedure Act compliant notice-and-comment process, including public hearings as warranted, to develop a new set of gas export policy guidelines which specifically and carefully articulate DOE's policy orientation on export, and the factors which it will primarily consider in individual export dockets.
(3) Support the development of these guidelines with a thorough, careful, economic study and with a full programmatic Environmental Impact Statement.

V. Conclusion

LNG export is a major national policy decision, and it deserves a commensurately careful process. For the foregoing reasons, a key part of that process is a careful, public review of the dated policy guidelines which now influence the process.

Thank you for considering this petition. In view of the importance of the issues, we request a written response within 45 days of your receipt of this document.

Sincerely,

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[73] *See*48 Fed. Reg. 34,501 (July 29, 1983) (requesting comments on proposed import/export policy and announcing a public conference).

Using GPCM® to Model LNG Exports from the US Gulf Coast

Robert Brooks, Ph.D., President, RBAC, Inc.

March 2, 2012

As the gas industry rolled into the 21st century, natural gas production was beginning to decline and the outlook for production looked rather bleak. A small upsurge due to the advent of coal-bed methane development had begun to play out and it looked like the future lay in LNG imports. Billions of dollars were spent in designing and getting permitted dozens of new LNG import terminals. Ten new terminals and two offshore receiving stations were actually built. As it turned out, the companies that lagged behind and didn't actually build these expensive terminals were the winners, because the industry as a whole did not predict an upstream revolution which was quietly occurring at the same time. A breakthrough in horizontal drilling combined with hydro-fracturing and advanced 3D imaging finally made it possible to economically develop the enormous gas and oil resources long known to exist in vast shale formations throughout much of North America.

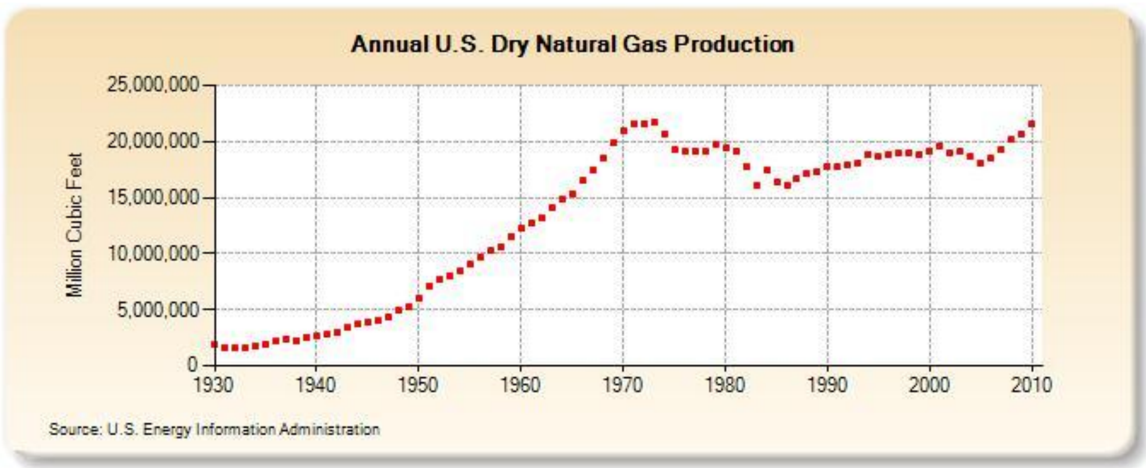


Figure 1: US Dry Natural Gas Production 1930-2010

A drilling boom began which completely turned the US production graph around. (See Figure 1.) All of a sudden there was more gas than could be easily absorbed in a recession-bound market. Natural gas prices began to erode, moving from the $6/mmbtu range to under $4/mmbtu (Figure 2), and the new challenge became "what are we going to do with all this gas?"

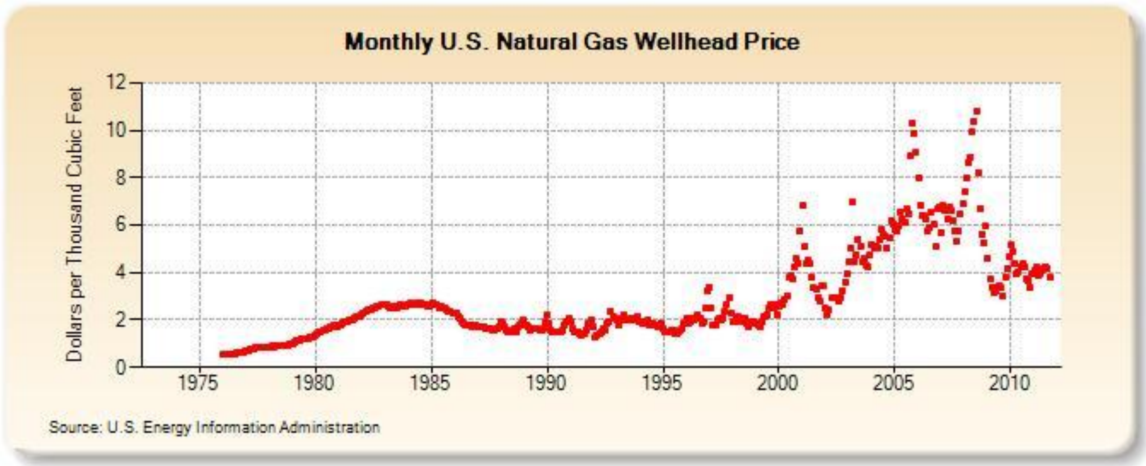


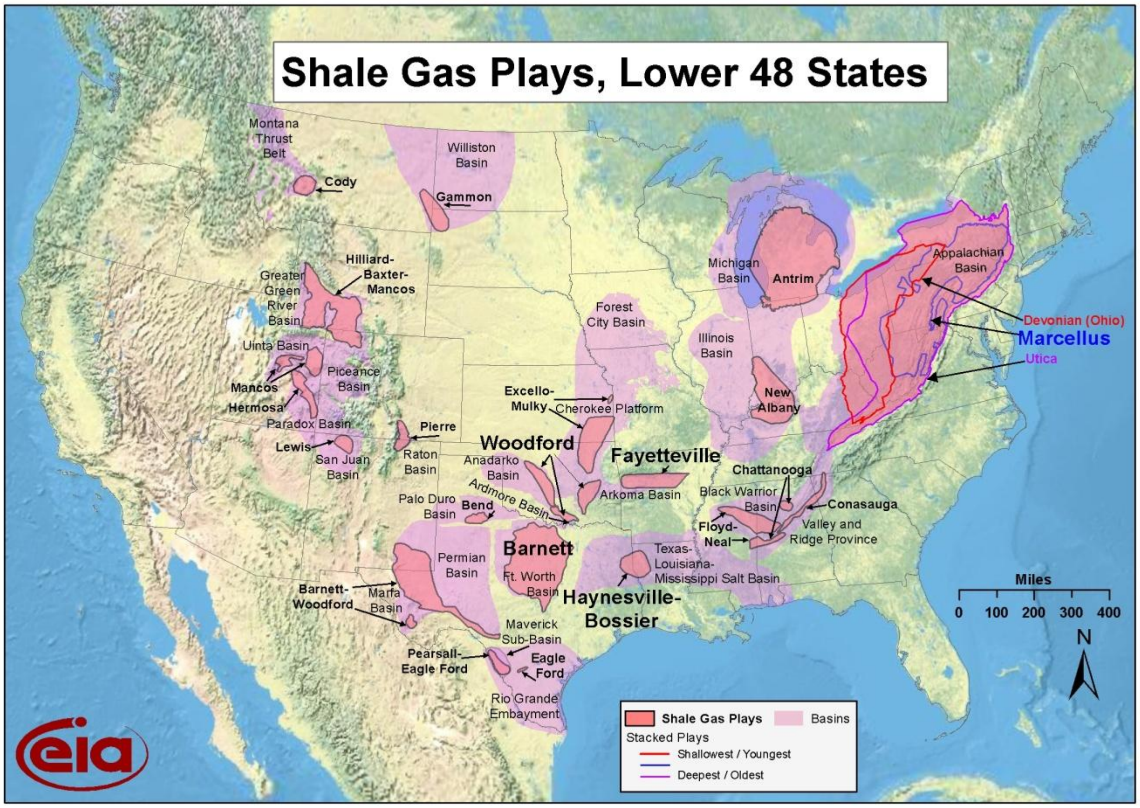
Figure 2: Monthly Natural Gas Wellhead Prices 1975-2010

Five answers have been put forward: redirect drilling from dry gas plays to plays having higher concentrations of more profitable natural gas liquids, replace coal with natural gas in electricity generation; build new fleets of natural gas powered trucks, buses, and cars; convert the gas into liquids for use in transportation; and, most recently, liquefy the gas and export it to other countries willing to pay much higher prices, notably Japan, China, Korea, and India.

As of year-end 2011 redirection to wetter gas plays has not solved the problem because the wetter gas plays have proven to be even more prolific gas producers than the dry gas plays drilled earlier. Replacing coal with gas in electricity production has been occurring but is a slow process which will take decades to unfold. Similarly, the natural gas vehicle market is growing, but from such a small base that it will take a very long time to have an impact on gas price, if ever. Gas-to-liquids is a mature technology, but is expensive, and its future in North America is still quite uncertain.

Up until very recently, the idea of liquefying excess North American natural gas and exporting it to overseas markets did not appear to be likely of success. That was before late 2011 when Cheniere Energy, owner of the Sabine Pass LNG terminal in Louisiana, announced the completion of agreements with UK-based BG Group and Spain's Gas Natural Fenosa to export LNG to Europe and Latin America and with GAIL (India) Limited for similar exports to India. Each of these agreements is for 3.5 million tons of LNG per year. In January 2012, Cheniere and Korea Gas Corporation (KOGAS) announced a similar agreement for another 3.5 million tons per year. 14 million tons per year of LNG would require almost 2 billion cubic feet per day (bcf/day) of production.

Much or most of the gas to be liquefied into LNG would be produced out of the nearby Haynesville-Bossier Shale play of northern Louisiana and east Texas. Following upon these deals, Cheniere announced plans to convert its planned Corpus Christi LNG import terminal into a second liquefaction and export terminal, this one located near the prolific Eagle Ford Shale wet gas play in South Texas.



Source: Energy Information Administration based on data from various published studies.
Updated: March 10, 2010

Figure 3: Shale Gas Plays in the United States

Some concern has been expressed by end-users of natural gas that these export projects would increase natural gas prices in the United States. Cheniere estimated that exports of 2 bcf/day could raise gas prices by as much as 10%. DOE's Energy Information Administration was requested by Congress to make its own projection. DOE assumed a much more extreme range of exports between 6 and 12 bcf/day with two different ramp-up rates (1 bcf/day per year and 3 bcf/day per year). In their 6 bcf/day scenario with 2 year ramp-up, the so-called "low, rapid" scenario, EIA projected an average price increase at the Henry Hub in Southern Louisiana of $0.60 per million btu (mmbtu) over the period 2016-2035.

Using its WGM model with the assumption of a 6 bcf/day export volume, consultant Deloitte MarketPoint LLC projected an average increase of only $0.22 mmbtu at the Henry Hub in Southern Louisiana over the same time period as EIA. Deloitte attributed the tiny magnitude of this price impact to the ability of the North American gas market to quickly and efficiently adjust to the prospect of an export market.

Using the GPCM model RBAC has produced its own analysis to address this question. Starting with RBAC's GPCM 11Q3 Base Case released in October 2011, which assumed Gulf LNG exports of 0.7 bcf/day, we have created five new scenarios: 1) no LNG exports from the US lower-48 states, 2) 1 bcf/day, 3) 2 bcf/day, 4) 4 bcf/day, and 5) 6 bcf per day. Each of the

LNG scenarios took 3 years to ramp up to maximum by 2018 and continued at that level through 2035.

The following figures show the results from these scenarios and the impact of various volumes of LNG exports on prices at Henry Hub.

Figure 4 shows Henry Hub price forecasts for the five scenarios. Prices are expected to be in the sub-$4 range from 2012-2015 for all scenarios, varying from that point depending on the volume of LNG exports in each.

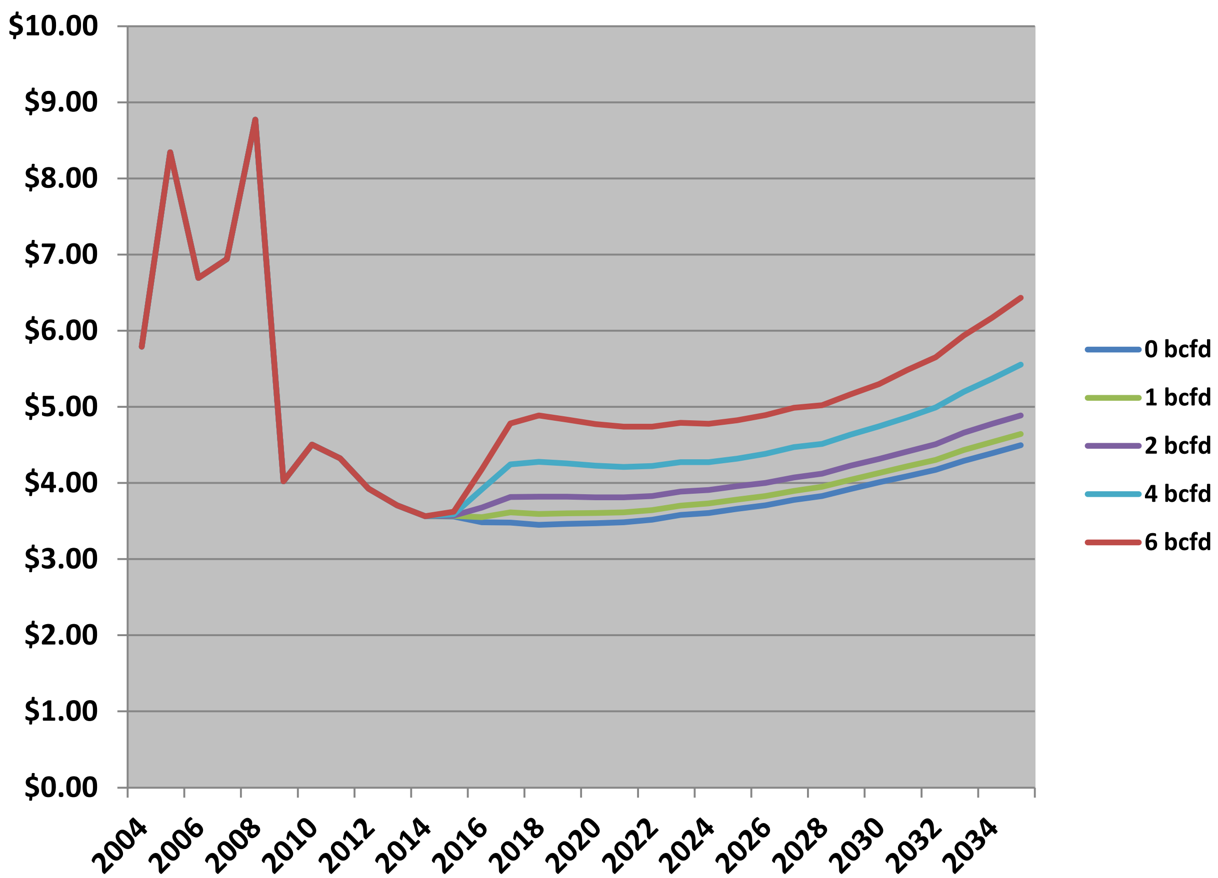


Figure 4: Annual Average Henry Hub Gas Price Forecast: 0, 1, 2, 4, and 6 bcf/day exports

Figure 5 shows the price difference between the no-LNG and the 1, 2, 4, and 6 bcf/day scenarios.

Figure 6 shows the average price impact over the 20 year 2016-2035 time period of each of the LNG export scenarios versus a zero-LNG export scenario.

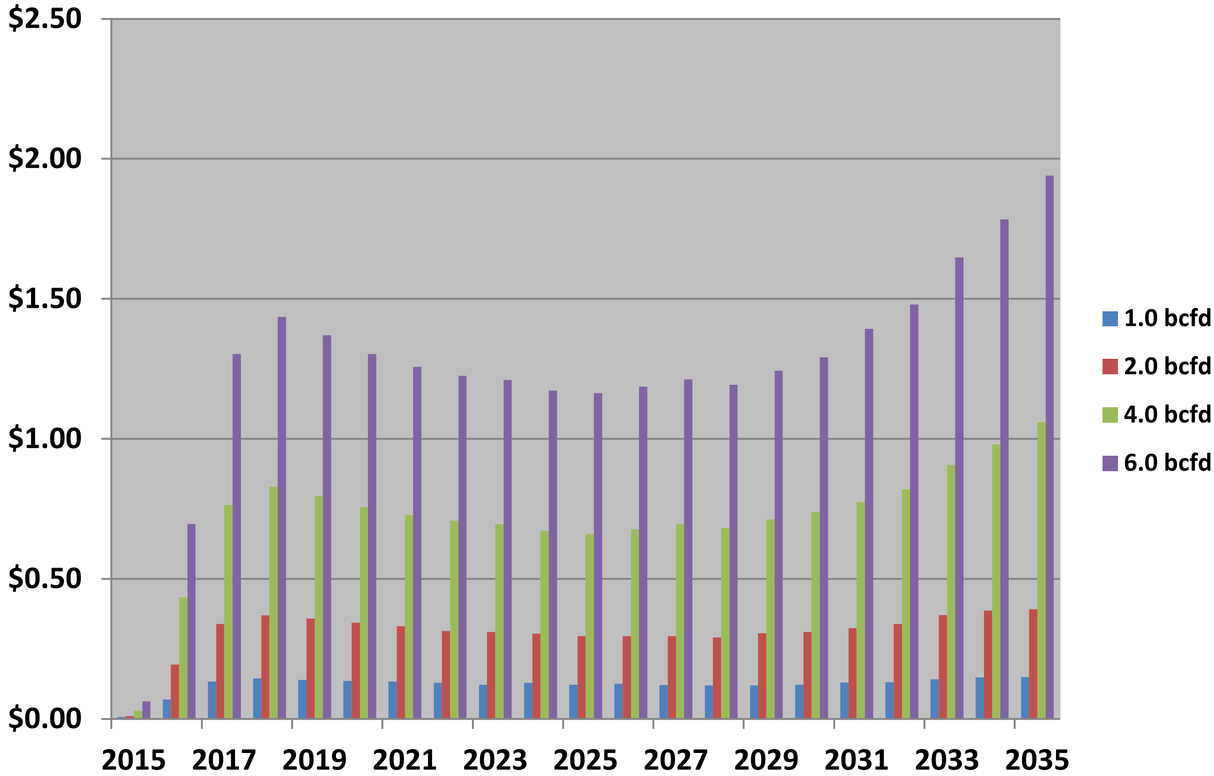


Figure 5: Price Impact at Henry Hub Due to Various Levels of Gulf Coast LNG Exports

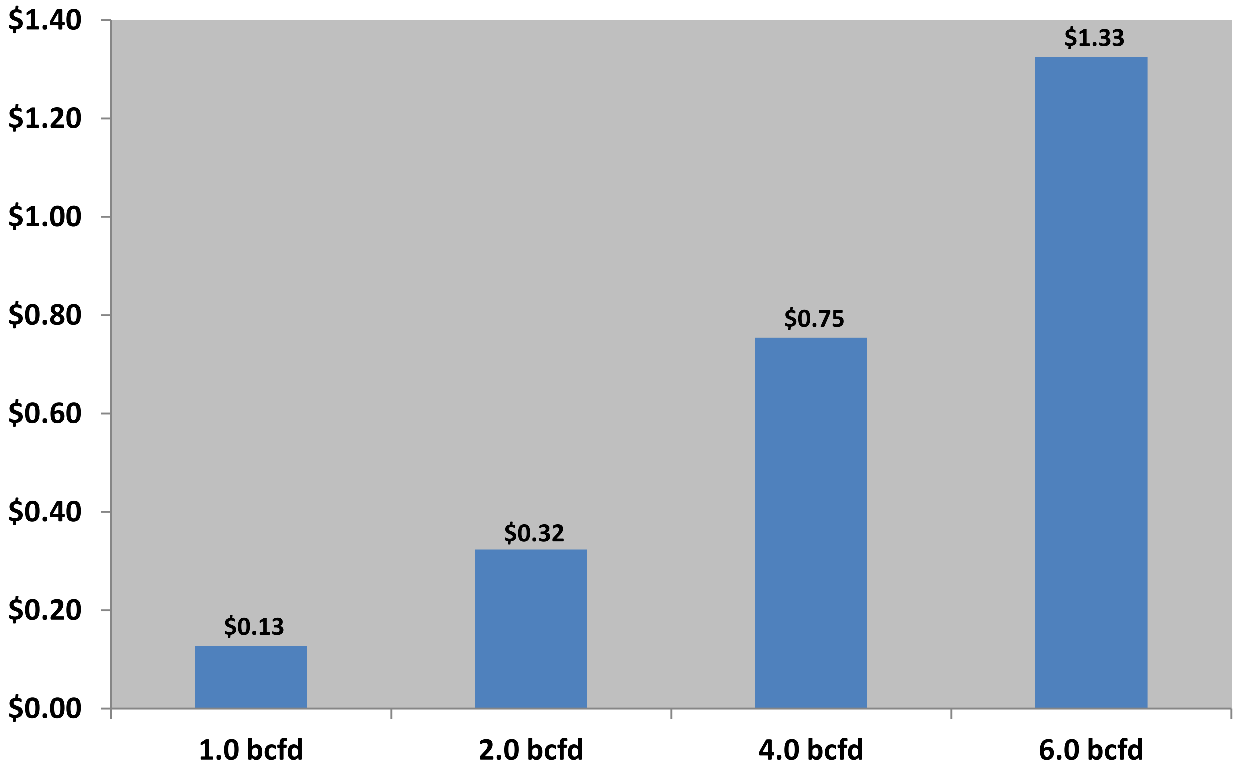


Figure 6: Average Price Impact at Henry Hub 2016-2035 of Different Gulf LNG Export Levels

The price impact of this level of LNG exports predicted using RBAC's GPCM model is about the same as Cheniere for the 2 bcf/day scenario ($0.32), but much greater for the more extreme 6 bcf/day scenario than that estimated by EIA ($0.60) or Deloitte ($0.22). It averages about $1.33 per mmbtu over the forecast horizon, a 30% increase at Henry Hub. RBAC's 6 bcf/day scenario does not forecast that the industry will respond with speed and efficiency with an insignificant gas-price increase as does the Deloitte model. The flexibility of the industry to respond to this large and sudden increase in demand comes at a price.

The following figure shows the effect of this extreme level of LNG exports and resulting higher prices on domestic gas deliveries.

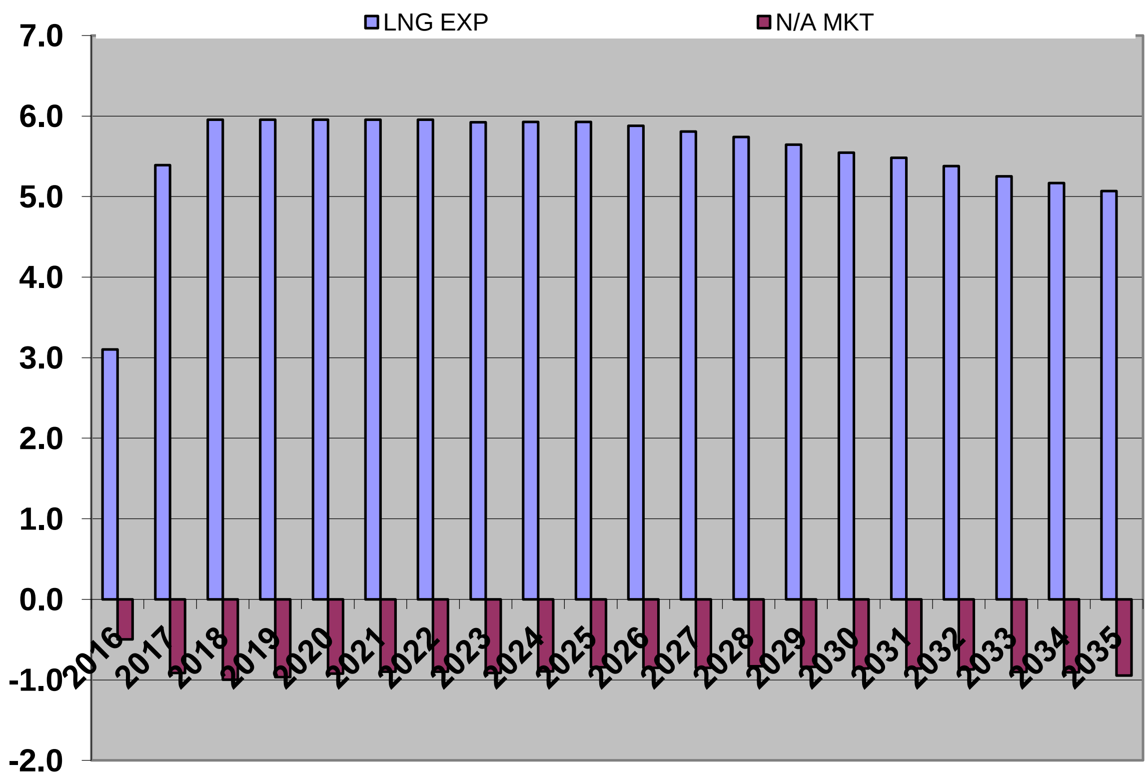


Figure 7: Impact of LNG Exports on Deliveries to the North American Market

First note that the scenario as designed ran into difficulty exporting 6 BCF/day after 2025. The amount available for export slowly fell to about 5 BCF/day by 2035. The 6 bcf/day scenario assumes 3 bcf/day from Louisiana and 3 bcf/day from Texas. In the longer run, it is more difficult to supply 3 bcf/day for LNG exports from Texas due to competition with Mexico. On average the LNG exports were about 5.5 BCF/day in this scenario.

The addition of 5.5 BCF/day LNG export demand raises prices enough to reduce deliveries to the domestic North American market by almost 0.8 BCF/day. Most of this reduction is felt by the industrial market, the most price sensitive sector in the US. Thus the net additional production required by the new LNG export market is about 4.7 BCF/day.

Perhaps one reason why EIA's price response is less than RBAC's is that EIA assumes an increase in production of only 3.8 bcf/day will be required to supply 6 bcf/day in exports. This surprising result comes about because EIA's result shows a 2.1 bcf/day decrease in gas available to consumers in the US. Their demand model is much more price-sensitive than RBAC's.

Figure 8 shows where the additional supply will originate in the 6 bcf/day RBAC scenario. About 10% of the required new supply comes from coal-bed methane and a small uptick in LNG imports. The latter is due to the fact that the Mexican market is dependent on imports from the US as well as LNG. With less pipeline gas available to Mexico from South Texas, more local gas must be produced and more LNG imported.

One surprise is that conventional sources will initially provide about 50% of the incremental supply needed for the net increase in demand with shale providing about 40%. However, as shale becomes the predominant source of production, it also takes over as the primary source of incremental supply for exports, reaching more than 60% by year 2035. This may be more a result of the fact that GPCM models physical gas flows. How gas is contracted could be quite different.

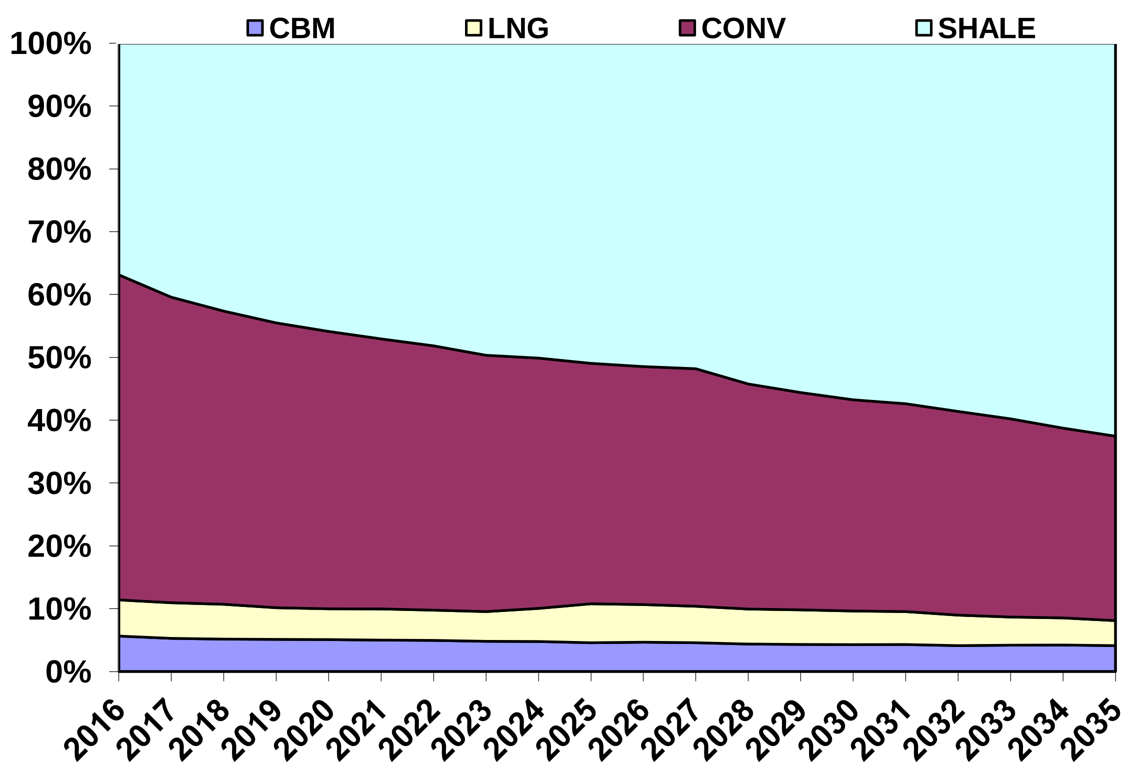


Figure 8: Share of New Supply Required in 6 bcf/day LNG Exports Scenario

Sensitivity of Results to Supply Assumptions

A sixth scenario was run to test the sensitivity of these results to the base case assumption of supply responsiveness to changes in demand. By raising price sensitivity of supply for prices higher than about $4/mmbtu, production capacity grows faster than in the original 6 bcf/day LNG exports scenario. By 2035 capacity is about 4 BCF/day (3%) higher for the same price.

Figure 9 shows the effect of this higher production sensitivity case on Henry Hub price.

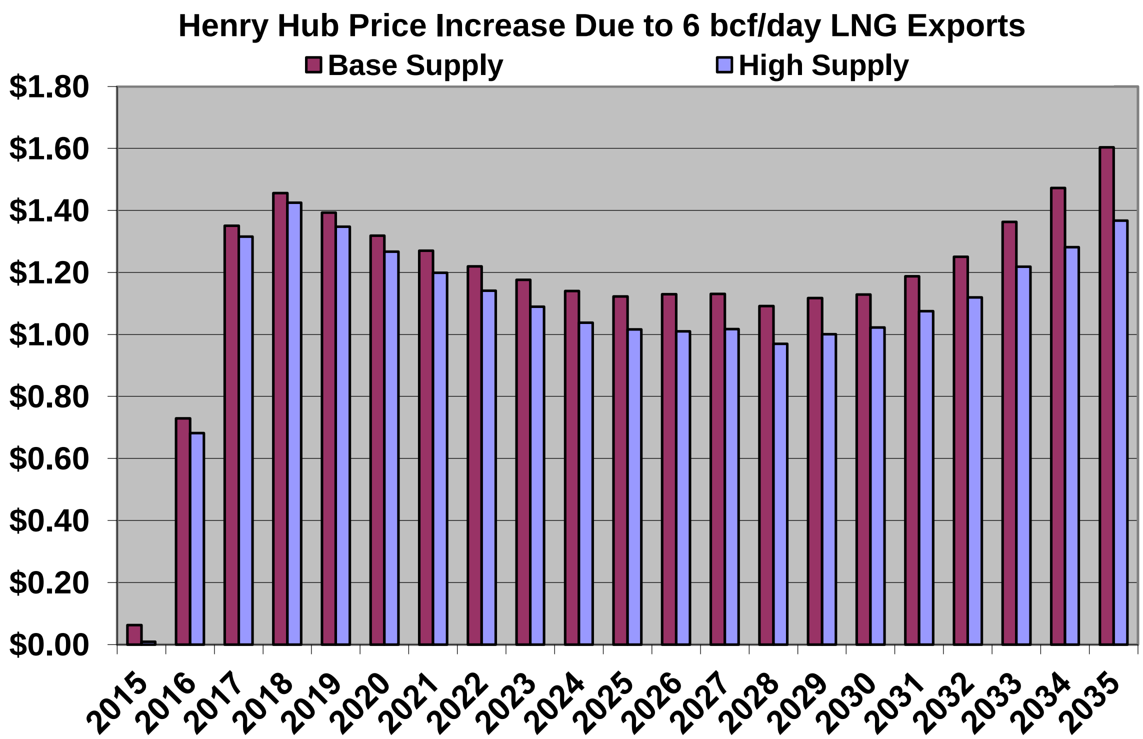


Figure 9: Sensitivity of Henry Hub Price Effect to Supply Capacity Growth

The price effect of LNG exports is reduced by about $0.05 in 2016 growing to almost $0.25 by 2035. The average price effect in the sensitivity case is $1.13, about $0.10 less than the original 6 bcf/day exports case. These results suggest that both EIA and Deloitte models may substantially underestimate the price effect of 6 bcf/day LNG exports of the magnitude reported in their studies. The adjustments which the industry makes to meet the challenge of this large new demand are not likely to be made so quickly and with so little impact on price.

Deloitte MarketPoint.
Analysis of Economic Impact of LNG Exports from the United States

Contents

Executive summary

Deloitte MarketPoint LLC (“DMP”) has been engaged by Excelerate Energy L.P. ("Excelerate") to provide an independent and objective assessment of the potential economic impacts of LNG exports from the United States. We analyzed the impact of exports from Excelerate’s Lavaca Bay terminal, located along the Gulf coast of Texas, by itself and also in combination with varying levels of LNG exports from other locations.

A fundamental question regarding LNG exports is: Are there sufficient domestic natural gas supplies for both domestic consumption and LNG exports. That is, does the U.S. need the gas for its own consumption or does the U.S. possess sufficiently abundant gas resources to supply both domestic consumption and exports? A more difficult question is: How much will U.S. natural gas prices increase as a result of LNG exports? To understand the possible answers to these questions, one must consider the full gamut of natural gas supply and demand in the U.S. and the rest of the world and how they are dynamically connected.

In our view, simple comparisons of total available domestic resources to projected future consumption are insufficient to adequately analyze the economic impact of LNG exports. The real issue is not one of volume, but of price impact. In a free market economy, price is one of the best measures of scarcity, and if price is not significantly affected, then scarcity and shortage of supply typically do not occur. In this report, we demonstrate that the magnitude of domestic price increase that results from exports of natural gas in the form of LNG is projected to be quite small.

However, other projections, including those developed by the DOE’s Energy Information Administration (EIA), estimate substantially larger price impacts from LNG exports than derived from our analysis. We shall compare different projections and provide our assessment as to why the projections differ. A key determinant to the estimated price impact is the supply response to increased demand including LNG exports. To a large degree, North American gas producers’ ability to increase productive capacity in anticipation of LNG export volumes will determine the price impact. After all, there is widespread agreement of the vast size of the North American natural gas resource base among the various studies and yet estimated price impacts vary widely. If one assumes that producers will fail to keep pace with demand growth, including LNG exports, then the price impact of LNG exports, especially in early years of operations, will be far greater than if they anticipate demand and make supplies available as they are needed. Hence, a proper model of market supply-demand dynamics is required to more accurately project price impacts.

DMP applied its integrated North American and World Gas Model (WGM or Model) to analyze the price and quantity impacts of LNG exports on the U.S. gas market.[1] The WGM projects

[1] This report was prepared for Excelerate Energy L.P. ("Client") and should not be disclosed to, used or relied upon by any other person or entity. Deloitte Marketpoint LLC shall not be responsible for any loss sustained by any such use or reliance. Please note that the analysis set forth in this report is based on the application of economic logic and specific

monthly prices and quantities over a 30 year time horizon based on demonstrated economic theories. It includes disaggregated representations of North America, Europe, and other major global markets. The WGM solves for prices and quantities simultaneously across multiple markets and across multiple time points. Unlike many other models which compute prices and quantities assuming all parties work together to achieve a single global objective, WGM applies fundamental economic theories to represent self-interested decisions made by each market "agent" along each stage of the supply chain. It rigorously adheres to accepted microeconomic theory to solve for supply and demand using an "agent based" approach. More information about WGM is included in the Appendix.

Vital to this analysis, the WGM represents fundamental natural gas producer decisions regarding when and how much reserves to develop given the producer's resource endowments and anticipated forward prices. This supply-demand dynamic is particularly important in analyzing the impact of demand changes (e.g., LNG exports) because without it, the answer will likely greatly overestimate the price impact. Indeed, producers will anticipate the export volumes and make production decisions accordingly. LNG exporters might back up their multi-billion dollar projects with long-term supply contracts, but even if they do not, producers will anticipate future prices and demand growth in their production decisions. Missing this supply-demand dynamic is tantamount to assuming the market will be surprised and unprepared for the volume of exports and have to ration fixed supplies to meet the required volumes. Static models assume a fixed supply volume (i.e., productive capacity) during each time period and therefore are prone to over-estimate the price impact of a demand change. Typically, users have to override this assumption by manually adjusting supply to meet demand. If insufficient supply volumes are added to meet the incremental demand, prices could shoot up until enough supply volumes are added to eventually catch up with demand.

Instead of a static approach, the WGM uses sophisticated depletable resource modeling to represent producer decisions. The model uses a "rational expectations" approach, which assumes that today's drilling decisions affect tomorrow's price and tomorrow's price affects today's drilling decisions. It captures the market dynamics between suppliers and consumers.

It is well documented that shale gas production has grown tremendously over the past several years. According to the EIA, shale gas production climbed to over 35% of the total U.S. production in January of 2012[2]. By comparison, shale gas production was only about 5% of the total U.S. production in 2006, when improvements in shale gas production technologies (e.g., hydraulic fracturing combined with horizontal drilling) were starting to significantly reduce production costs. However, there is considerable debate as to how long this trend will continue and how much will be produced out of each shale gas basin. Rather than simply extrapolating past trends, WGM projects production based resource volumes and costs, future gas demand, particularly for power generation, and competition among various sources in each market area. It computes incremental sources to meet a change in demand and the resulting impact on price.

assumptions and the results are not intended to be predictions of events or future outcomes.

Notwithstanding the foregoing, Client may submit this report to the U.S. Department of Energy and the Federal Energy Regulatory Commission in support of Client's liquefied natural gas "(LNG") export application.

[2] Computed from the EIA's Natural Gas Weekly Update for week ending June 27, 2012.

Based on our existing model and assumptions, which we will call the "Reference Case", we developed five cases with different LNG export volumes to assess the impact of LNG exports. The five LNG export scenarios and their assumed export volumes by location are shown in Figure 1. Other Gulf in the figure refers to all other Gulf of Mexico terminals in Texas and Louisiana besides Lavaca Bay.

All cases are identical except for the assumed volume of LNG exports. The 1.33 Bcfd case assumed only exports from Lavaca Bay so that we could isolate the impact of the terminal. In the other LNG export cases, we assumed the Lavaca Bay terminal plus volumes from other locations so that the total exports volume equaled 3, 6, 9, and 12 Bcfd. The export volumes were assumed to be constant for twenty years from 2018 through 2037.

We represented LNG exports in the model as demands at various model locations generally corresponding to the locations of proposed export terminals (e.g., Gulf Texas, Gulf Louisiana, and Cove Point) that have applied for a DOE export license. The cases are not intended as forecasts of which export terminals will be built, but rather to test the potential impact given alternative levels of LNG exports. Furthermore, the export volumes are assumed to be constant over the entire 20 year period. Since our existing model already represented these import LNG terminals, we only had to represent exports by adding demands near each of the terminals. Comparing results of the five LNG export cases to the Reference Case, we projected how much the various levels of LNG exports could increase domestic prices and affect production and flows.

Given the model's assumptions and economic logic, the WGM projects prices and volumes for over 200 market hubs and represents every state in the United States. We can examine the impact at each location and also compute a volume-weighted average U.S. "citygate" price by weighting price impact by state using the state's demand. Impact on the U.S. prices increase along with the volume of exports.

As shown in Figure 2, the WGM's projected

Figure 1: LNG export scenarios

	Export Case				
Terminal	**1.33 Bcfd**	**3 Bcfd**	**6 Bcfd**	**9 Bcfd**	**12 Bcfd**
Lavaca Bay	1.33	1.33	1.33	1.33	1.33
Other Gulf		1.67	4.67	6.67	9.67
Cove Point (MD)				1.0	1.0
Total	1.33	3.0	6.0	9.0	12.0

Figure 2: Potential Impact of LNG export on U.S. prices (Average 2018-37)

Export Case	Average US Citygate	Henry Hub	New York
1.33 Bcfd	0.4%	0.4%	0.3%
3 Bcfd	1.0%	1.7%	0.9%
6 Bcfd	2.2%	4.0%	1.9%
9 Bcfd	3.2%	5.5%	3.2%
12 Bcfd	4.3%	7.7%	4.1%

impact on average U.S. citygate prices for the assumed years of operation (2018 to 2037) ranged from well under 1% in the 1.33 Bcfd (Lavaca Bay only) case to 4.3% in the 12 Bcfd case. However, the impacts vary significantly by location. Figure 2 shows the percentage change relative to the Reference Case to the projected average U.S. citygate price and at the Henry Hub and New York prices under various LNG export volumes.

As Figure 2 shows, the price impact is highly dependent on location. The impact on the price at Henry Hub, the world's most widely used benchmark for natural gas prices, is significantly higher than the national average. The reason is that the Henry Hub, located in Louisiana, is in close proximity to the prospective export terminals, which are primarily located in the U.S. Gulf of Mexico region. Since there are several cases analyzed, we will primarily describe results of the 6 Bcfd export case since it is the middle case. The impacts are roughly proportional to the export volumes. In the 6 Bcfd export case, the impact on the Henry Hub price is an increase of 4.0% over the Reference Case. Generally, the price impact in markets diminishes with distance away from export terminals as other supply basins besides those used to feed LNG exports are used to supply those markets. Distant market areas, such as New York and Chicago, experience only about half the price impact as at the Henry Hub. Focusing solely on the Henry Hub or regional prices around the export terminals will greatly overstate the total estimated impact on the U.S. consumers.

The results show that if exports can be anticipated, and clearly they can with the public application process and long lead time required to construct a LNG liquefaction plant, then producers, midstream players, and consumers can act to mitigate the price impact. Producers will bring more supplies online, flows will be adjusted, and consumers will react to price change resulting from LNG exports.

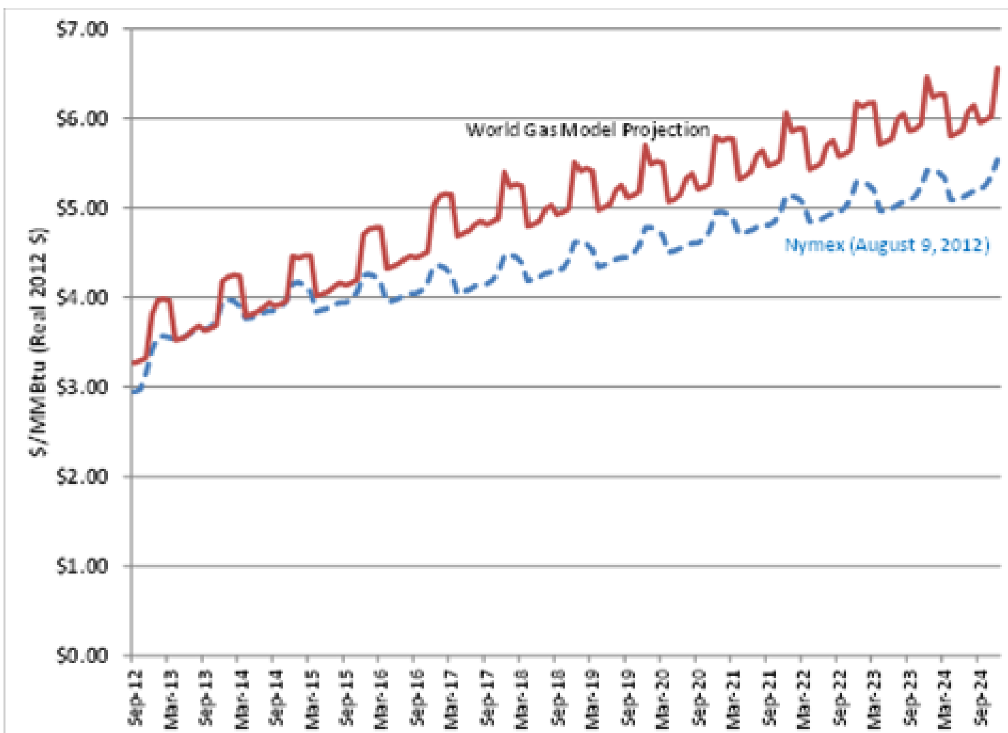
According to our projections, 12 Bcfd of LNG exports are projected to increase the average U.S. citygate gas price by 4.3% and Henry Hub price by 7.7% on average over a twenty year period (2018-37). This indicates that the projected level of exports is not likely to induce scarcity on domestic markets. The domestic resource base is expected to be large enough to absorb the incremental volumes required by LNG exports without a significant increase to future production costs. If the U.S. natural gas industry can make the supplies available by the time LNG export terminals are ready for operation, then the price impact will likely reflect the minimal change in production cost. As the industry has shown in the past several years, it is capable of responding to market signals and developing supplies as needed. Furthermore, the North American energy market is highly interconnected so any change in prices due to LNG exports from the U.S. will cause the entire market to re-equilibrate, including gas fuel burn for power generation and net imports from Canada and Mexico. Hence, the entire North American energy market would be expected to in effect work in tandem to mitigate the price impact of LNG exports from the U.S.

Overview of Deloitte MarketPoint Reference Case

The WGM Reference Case assumes a "business as usual" scenario including no LNG exports from the United States. U.S. gas demand growth rates for all sectors except for electricity were based on EIA's recently released Annual Energy Outlook (AEO) 2012 projection, which shows a significantly higher US gas demand than in the previous year's projection. Our gas demand for power generation is based on projections from DMP's electricity model, which is integrated with our WGM. (There is no intended advocacy or prediction of these events one way or the other. Rather, we use these assumptions as a frame of reference. The impact of LNG exports could easily be tested against other scenarios, but the overall conclusion would be rather similar.)

In the WGM Reference Case, natural gas prices are projected to rebound from current levels and continue to strengthen over the next two decades, although nominal prices do not return to the peak levels of the mid-to-late 2000s until after 2020. In real terms (i.e., constant 2012 dollars), benchmark U.S. Henry Hub spot prices are projected by the WGM to increase from currently depressed levels to $5.34 per MMBtu in 2020, before rising to $6.88 per MMBtu in

Figure 3: Projected Henry Hub prices from the WGM compared to Nymex futures prices



2030 in the Reference Case scenario.

The WGM Reference Case projection of Henry Hub prices is compared to the Nymex futures prices in Figure 3. (The Nymex prices, which are the dollars of the day, were deflated by 2.0%[3] per year to compare to our projections, which are in real 2012 dollars.) Our Henry Hub price projection is similar to the Nymex prices in the near-term but rises above it in the longer term. Bear in mind that our Reference Case by design assumes no LNG exports whereas there is possible there is some expectation of LNG exports from the U.S. built into the Nymex prices. Under similar assumptions, the difference between our price projection and Nymex likely would be even higher. Hence, our Reference Case would represent a fairly high price projection even without LNG exports.

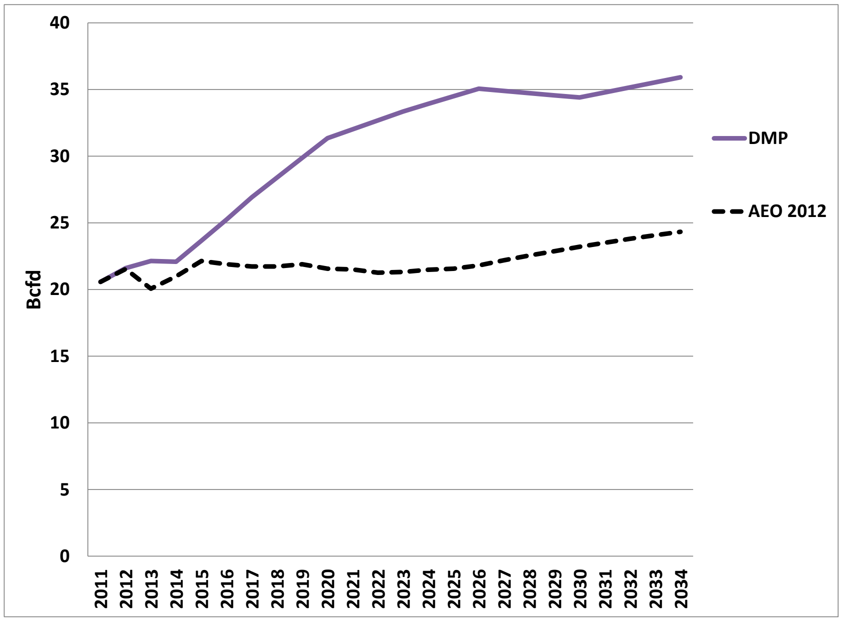
One possible reason why our price projection in the longer term is higher than market expectation, as reflected by the Nymex futures prices, is because of our projected rapid increase in gas demand for power generation. Based on our electricity model projections, we forecast natural gas consumption for electricity generation to drive North American natural gas demand higher during the next two decades.

As shown in Figure 4, the DMP projected gas demand for U.S. power generation gas is far greater than the demand predicted by EIA's AEO 2012, which forecasts fairly flat demand for power generation. In the U.S., the power sector, which accounts for nearly all of the projected future growth, is projected to increase by about 50% (approximately 11 Bcfd) over the next decade. Our integrated electricity model projects that natural gas will become the fuel of choice for power generation due to a variety of reasons, including: tightening application of existing environmental regulations for mercury, NOx, and SOx; expectations of ample domestic gas supply at competitive gas prices; coal plant retirements; and the need to back up intermittent renewable sources such as wind and solar to ensure reliability. Like the EIA's AEO 2012 forecast, our Reference Case projection does not assume any new carbon legislation.

Our electricity model, fully integrated with our gas (WGM) and coal models, contains a detailed representation of the North American electricity system including environmental emissions for key pollutants (CO2, SOx, NOx, and mercury). The integrated structure of these models is shown in Figure 5. The electricity model projects electric generation capacity addition, dispatch and fuel burn based on competition among different types of power generators given a number of factors, including plant capacities, fuel prices, heat rates, variable costs, and environmental emissions costs. The model integration of North American natural gas with the rest of the world and the North American electricity market captures the global linkages and also the inter-commodity linkages. Integrating gas and electricity is vitally important because U.S. natural gas demand growth is expected to be driven almost entirely by the electricity sector, which is predicted to grow at substantial rates.

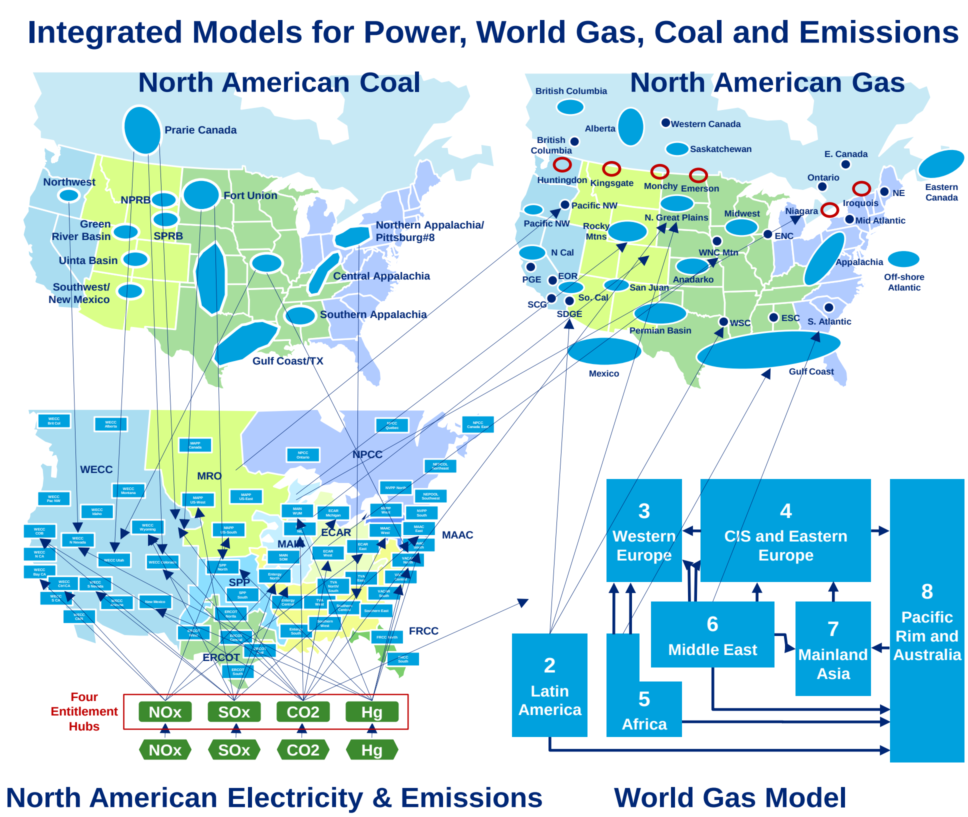
[3] Approximately the average consumer price index over the past 5 years according to the Bureau of Labor Statistics.

Figure 4: Comparison of projections of the U.S. gas demand for power generation



Furthermore, the electricity sector is projected to be far more responsive to natural gas price than any other sector. We model demand elasticity in the electricity sector directly rather than through elasticity estimates.

Figure 5: DMP North American Representation



Hence, the WGM projections include the impact of increased natural gas demand for electricity generation, which vies with LNG exports for domestic supplies. From the demand perspective, this is a conservative case in that the WGM would project a larger impact of LNG export than if we had assumed a lower US gas demand, which would likely make more supply available for LNG export and tend to lessen the price impact. Higher gas demand would tend to increase the projected prices impacts of LNG export. However, the real issue is not the absolute price of exported gas, but rather the price impact resulting from the LNG exports. The absolute price of natural gas will be determined by a number of supply and demand factors in addition to the volume of LNG exports.

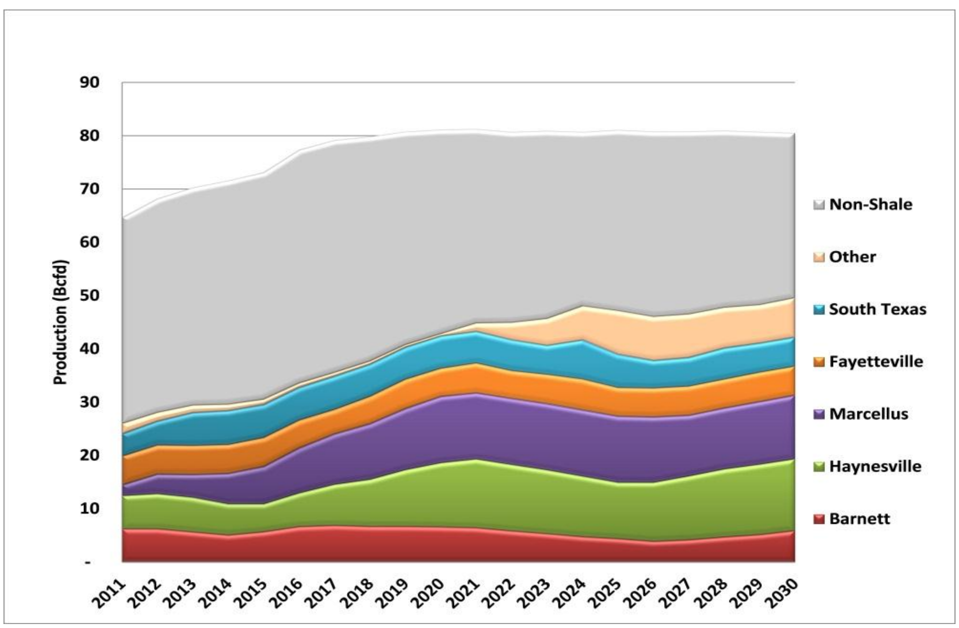
Buffering the price impact of LNG exports is the large domestic resource base, particularly shale gas which we project to be an increasingly important component of domestic supply. As shown in Figure 6, the Reference Case projects shale gas production, particularly in the Marcellus Shale in Appalachia and the Haynesville Shale in Texas and Louisiana, to grow and eventually become the largest component of domestic gas supply. Increasing U.S. shale gas output bolsters total domestic gas production, which grows from about 66 Bcfd in 2011 to almost 79 Bcfd in 2018 before tapering off.

The growth in production from a large domestic resource base is a crucial point and consistent with fundamental economics. Many upstream gas industry observers today believe that there is a very large quantity of gas available to be produced in the shale regions of North America at a more or less constant price. They believe, de facto, that natural gas supply is highly "elastic," i.e., the supply curve is very flat.

A flattening supply curve is consistent with the resource pyramid diagram that the United States Geological Survey and others have postulated. At the top of the pyramid are high quality gas supplies which are low cost but also are fairly scarce. As you move down the pyramid, the costs increase but the supplies are more plentiful. This is another interpretation of our supply curve which has relatively small amounts of low cost supplies but as the cost increases, the supplies become more abundant.

Gas production in Canada is projected to decline over the next several years, reducing exports to the U.S. and continuing the recent slide in

Figure 6: U.S. gas production by type



production out of the Western Canadian Sedimentary Basin. However, Canadian production is projected to ramp up in the later part of this decade with increased production out of the Horn River and Montney shale gas plays in Western Canada. Further into the future, the Mackenzie Delta pipeline may begin making available supplies from Northern Canada. Increased Canadian production makes more gas available for export to the U.S.

Rather than basing our production projections solely on the physical decline rates of producing fields, the WGM considers economic displacement as new, lower cost supplies force their way into the market. The North American natural gas system is highly integrated so Canadian supplies can easily access U.S. markets when economic.

Increasing production from major shale gas plays, many of which are not located in traditional gas-producing areas, has already started to transform historical basis relationships (the difference in prices between two markets) and the trend is projected to continue during the next two decades. Varying rates of regional gas demand growth, the advent of new natural gas infrastructure, and evolving gas flows may also contribute to changes in regional basis, although to a lesser degree.

Most notably, gas prices in the Eastern U.S., historically the highest priced region in North America, could be dampened by incremental shale gas production within the region. Eastern bases to Henry Hub are projected to sink under the weight of surging gas production from the Marcellus Shale. Indeed, the flattening of Eastern bases is already becoming evident. The Marcellus Shale is projected to dominate the Mid-Atlantic natural gas market, including New York, New Jersey, and Pennsylvania, meeting most of the regional demand and pushing gas through to New England and even to South Atlantic markets. Gas production from Marcellus Shale will help shield the Mid-Atlantic region from supply and demand changes in the Gulf region. Pipelines built to transport gas supplies from distant producing regions — such as the Rockies and the Gulf Coast — to Northeastern U.S. gas markets may face stiff competition. The result could be displacement of volumes from the Gulf which would depress prices in the Gulf region. Combined with the growing shale production out of Haynesville and Eagle Ford, the Gulf region is projected to continue to have plentiful production and remain one of the lowest cost regions in North America.

Understanding the dynamic nature of the natural gas market is paramount to understanding the impact of LNG exports. If LNG is exported from any particular location, the entire North American natural gas system will potentially reorient production, affecting basis differentials and flows. Basis differentials are not fixed and invariant to LNG exports or any other supply and demand changes. On the contrary, LNG exports will likely alter basis differentials, which lead to redirection of gas flows to highest value markets from each source given available capacity.

Potential impact of LNG exports

Impact on natural gas prices

We analyzed five LNG export cases within this report: one case with Lavaca Bay only (1.33 Bcfd) and four other cases with varying levels of total U.S. LNG export volumes (3 Bcfd, 6 Bcfd, 9 Bcfd and 12 Bcfd exports). Each case was run with the DMP's Integrated North American Power and Gas Models in order to capture the dynamic interactions across commodities.

For ease of reporting, we will focus on the results with 6 Bcfd of LNG exports, our middle case, without any implication that it is more likely than any other case. Given the model's assumptions, the WGM projects 6 Bcfd of LNG exports will result in a weighted-average price impact of $0.15/MMBtu on the average U.S. citygate price from 2018 to 2037. The $0.15/MMBtu increase represents a 2.2% increase in the projected average U.S. citygate gas price of $6.96/MMBtu over this time period. The projected increase in Henry Hub gas price is $0.26/MMBtu during this period. It is important to note the variation in price impact by location. The impact at the Henry Hub will be much greater than the impact in other markets more distant from export terminals.

For all five export cases considered, the projected natural gas price impacts at the Henry Hub, New York, and average US citygate from 2018 through 2037 are shown in Figure 7.

To put the impact in perspective, Figure 8 shows the price impact of the midpoint 6 Bcfd case compared to projected Reference Case U.S. average citygate prices over a twenty year period. The height of the bars represents the projected price with LNG exports.

The small incremental price impact may not appear intuitive or expected to those familiar with market traded fluctuations in natural gas prices. For example, even a 1 Bcfd increase in demand due to sudden weather changes can cause near term traded gas prices to surge because in the short term, both supply and demand are highly inelastic (i.e., fixed quantities). However, in the long-term, producers can develop more reserves in anticipation of demand growth, e.g. due to LNG exports. Indeed, LNG export projects will likely be linked in the origination market to long-term supply contracts, as well as long-term contracts with LNG buyers. There will be ample notice and

Figure 7: Price impact by scenario for 2018-37 ($/MMBtu)

Export Case	Average US Citygate	Henry Hub	New York
1.33 Bcfd	$ 0.03	$ 0.03	$ 0.02
3 Bcfd	$ 0.07	$ 0.11	$ 0.06
6 Bcfd	$ 0.15	$ 0.26	$ 0.14
9 Bcfd	$ 0.22	$ 0.36	$ 0.23
12 Bcfd	$ 0.30	$ 0.50	$ 0.29

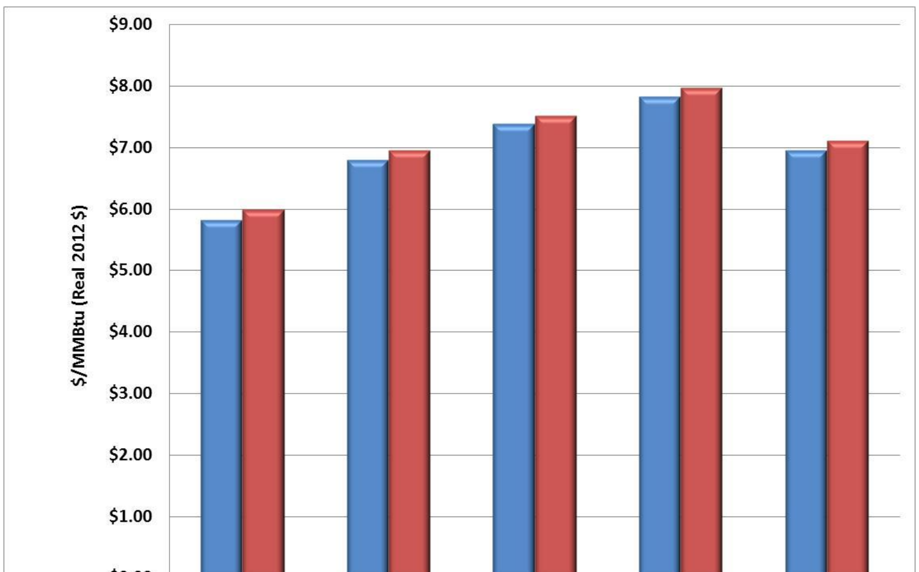
time in advance of the LNG exports for suppliers to be able to develop supplies so that they are available by the time export terminals come into operation. Therefore, under our long-term equilibrium modeling assumptions, long-term changes to demand may be anticipated and incorporated into supply decisions. The built-in market expectations allows for projected prices to come into equilibrium smoothly over time. Hence, our projected price impact primarily reflects the estimated change in the production cost of the marginal gas producing field with the assumed export volumes.

As previously stated, the model projected price impact varies by location as shown in Figure 9.

As previously described, the price impact diminishes with distance from export terminals. For all cases the impact is greatest at Henry Hub, situated near most export terminals. For the midpoint case of 6 Bcfd, the impact at the Houston Ship Channel is nearly as much as Henry Hub, at $0.26/MMBtu on average from 2018 to 2037. As distance from export terminals increases (i.e., distance to downstream markets such as Chicago, California and New York) the price impact is generally only about $0.12 to $0.14/MMBtu on average from 2018 to 2037.

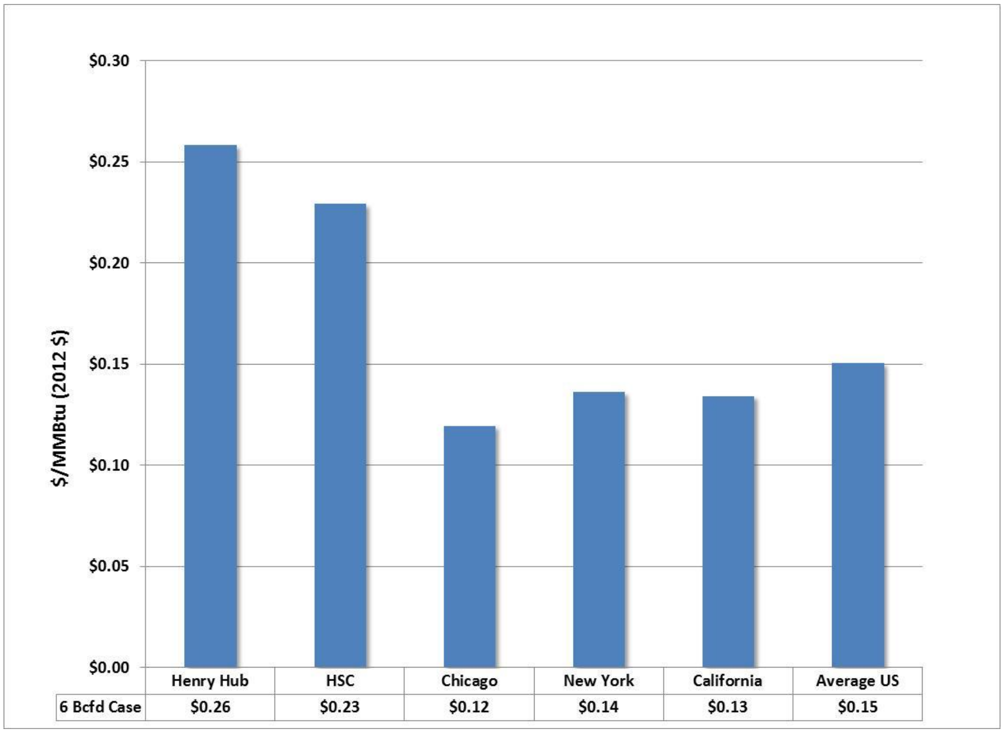
Similarly, Figures 8 and 9 corresponding to the other export cases (1.33, 3.0, 9.0 and 12.0 Bcfd) are shown in the Appendix.

Figure 8: Projected Impact of LNG exports on average U.S. Citygate gas prices (Real 2012 $)



	2018-2022	2023-2027	2028-2032	2033-2037	2018-2037
Reference Case	$5.83	$6.80	$7.38	$7.83	$6.96
6 Bcfd Case	$5.99	$6.96	$7.51	$7.97	$7.11

Figure 9: Price impact varies by location in 6 Bcfd export case (average 2018-37)



Impact on electricity prices

The projected impact on electricity prices is even smaller than the projected impact on gas prices. DMP's integrated power and gas model allows us to estimate incremental impact on electricity prices resulting from LNG export assumptions, as natural gas is also a fuel used for generating electricity. Since our integrated model represents the geographic linkages between the electricity and natural gas systems, we can compute the potential impact of LNG exports in local markets (local to LNG exports) where the impact would be the largest.

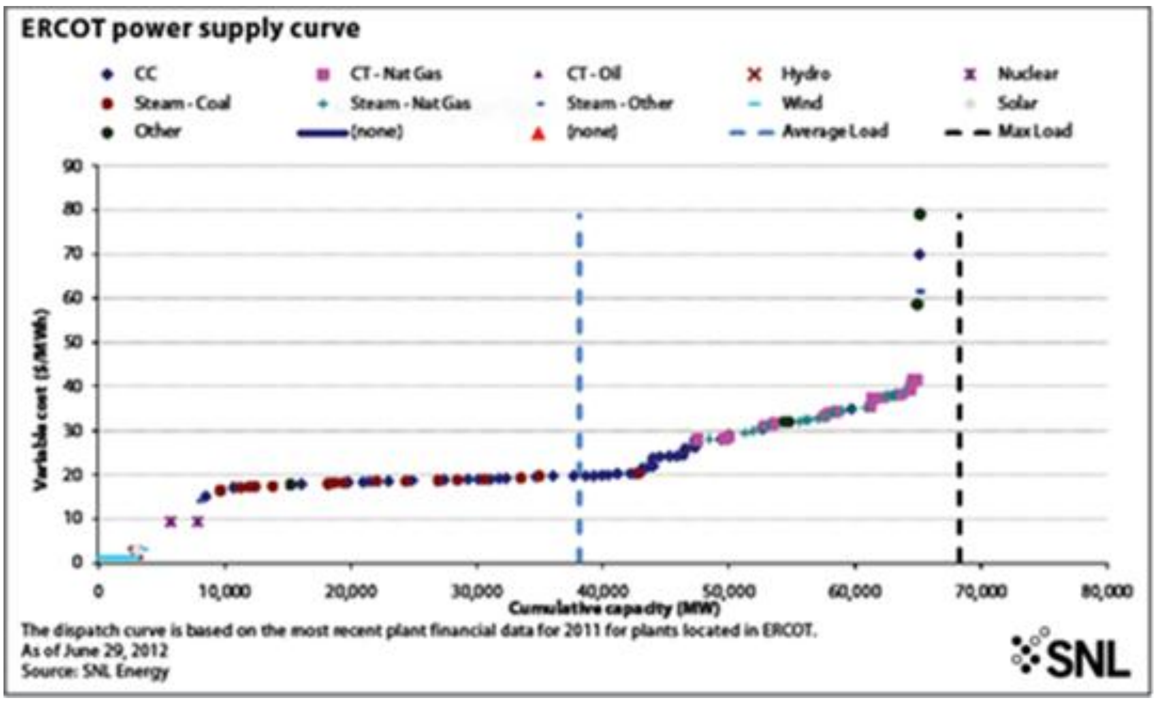
A similar comparison for electricity shows that the projected average (2018-2037) electricity prices increase by 0.8% in ERCOT (the Electric Reliability Council of Texas), under the 6 Bcfd export case. The impact on electricity prices is much less than the 4.0% Henry Hub gas price impact. For power markets in other regions, the electricity price impact is much lower, because the gas price impact is much lower.

A key reason why the price impact for electricity is less than that of gas is that electricity prices will only be directly affected by an increase in gas prices when gas-fired generation is the marginal source of power generation. That is, gas price only affects power price if it changes the marginal unit (i.e., the last unit in the generation stack needed to service the final amount of electricity load). When gas-fired generation is lower cost than the marginal source, then a small increase in gas price will only impact electricity price if it is sufficient to drive gas-fired generation to be the marginal source of generation. If gas-fired generation is already more expensive than the marginal source of generation, then an increase in gas price will not impact electricity price, since gas-fired generation is not being utilized because there is sufficient capacity from units with lower generation costs.

If gas-fired generation is the marginal source, then electricity price will increase with gas price, but only up to the point that some other source can displace it as marginal source. Every power region has numerous competing power generation plants burning different fuel types, which will mitigate the price impact of an increase in any one fuel type. Moreover, within DPM's integrated power and gas model, fuel switching among coal, nuclear, gas, hydro, wind and oil units is directly represented as part of the modeling.

Figure 10 shows the power supply curve for ERCOT. The curve plots the variable cost of generation and capacity by fuel type. Depending on where the demand curve intersects the supply curve, a generating unit with a particular fuel type will set the electricity price. During extremely low demand periods, hydro, nuclear or coal plants will likely set the price. An increase in gas price during these periods would not impact electricity price in this region because gas-fired plants are typically not utilized. Since the marginal source sets the price, a change in gas price under these conditions would not affect power prices.

Figure 10: Power supply curve for ERCOT region

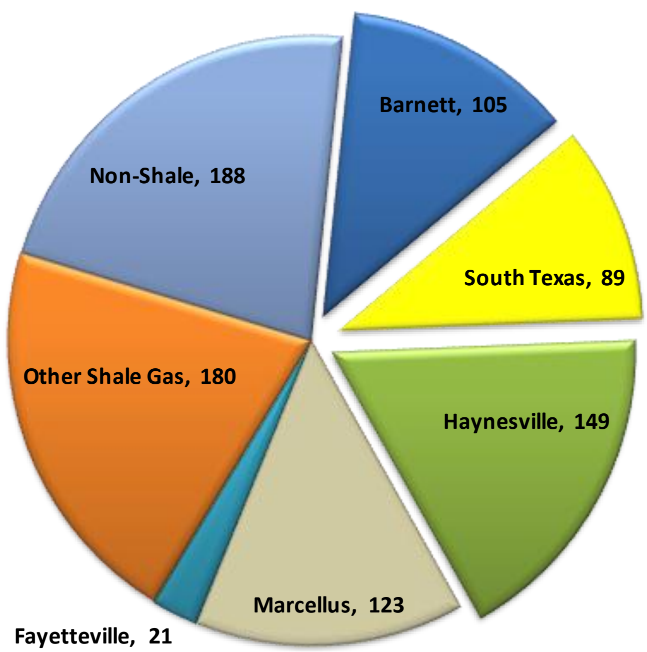


Incremental production impact in Texas from Lavaca Bay export

All of the gas used as feedstock for 1.33 Bcfd of LNG exports from Lavaca Bay is projected to come from Texas production. About one-third of the gas is incremental supplies from Texas production with the remaining two-thirds coming from Texas gas that would have otherwise been exported out of the state but instead is diverted to the terminal. The diverted volumes stimulate production in other supply basins outside Texas. Figure 11 shows the projected increase in production volume on average from 2018-2037.

The shale gas basins that are entirely or at least partially located in Texas are separated to highlight the impact on the State. One might expect South Texas, which includes Eagle Ford shales, to have a larger incremental impact. However, the region is rich in liquids and is projected to grow strongly even without boost from LNG exports. The incremental supplies indicate the marginal regions which would be stimulated with incremental demand.

Figure 11: Average incremental production with Lavaca Bay export, 2018-37 (MMcfd)

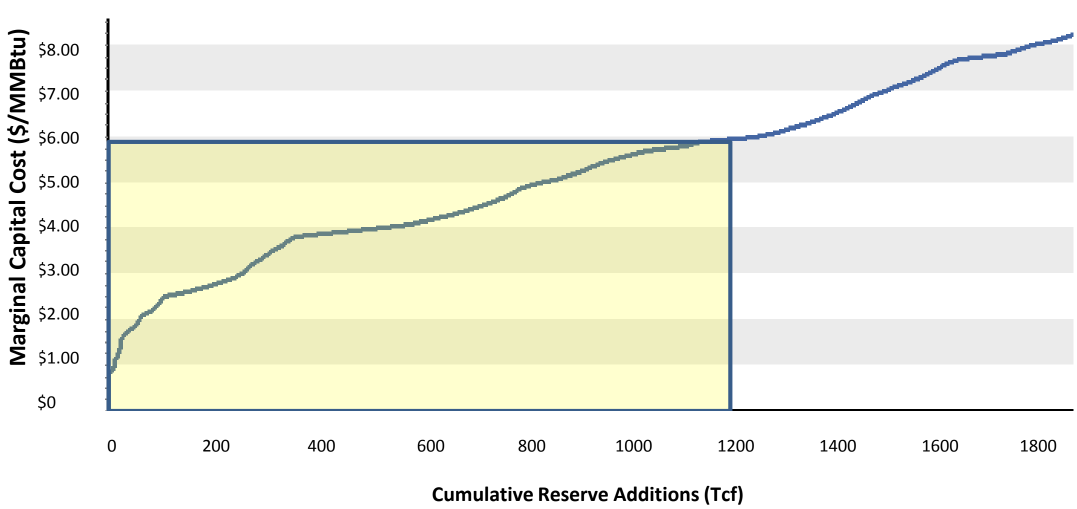


Large domestic supply buffers impact

Figure 12 shows the aggregate U.S. supply curve, including all types of gas formations. It plots the volumes of reserve additions available at different all-in marginal capital costs, including financing, return on equity, and taxes. The marginal capital cost is equivalent to the wellhead price necessary to induce a level of investment required to bring the estimated volumes on line. The model includes over one hundred different supply nodes representing the geographic and geologic diversity of domestic supply basins. The supply data is based on publically available documents and discussions with sources such as the United States Geological Survey, National Petroleum Council, Potential Gas Committee, and the DOE's Energy Information Administration.

The area of the supply curve that matters most for the next couple decades is the section below \$6/MMBtu of capital cost because wellhead prices are projected to fall under this level during most of the time horizon considered. These are the volumes that are projected to get produced over the next couple decades. The Reference Case estimates about 1,200 Tcf available at wellhead prices below \$6/MMBtu in current dollars. To put the LNG export volumes into perspective, it will accelerate depletion of the domestic resource base, estimated to include about 1,200 Tcf at prices below \$6/MMBtu in all-in capital cost, by 2.2 Tcf per year (equivalent to 6 Bcfd). Alternatively, the 2.2 Tcf represents an increase in demand of about 8% to the projected demand of 26 Tcf by the time exports are assumed to commence in 2016. The point is not to downplay the export volume, but to show the big picture. The magnitude of total LNG exports is substantial on its own, but not very significant relative to the entire U.S. resource base or total U.S. demand.

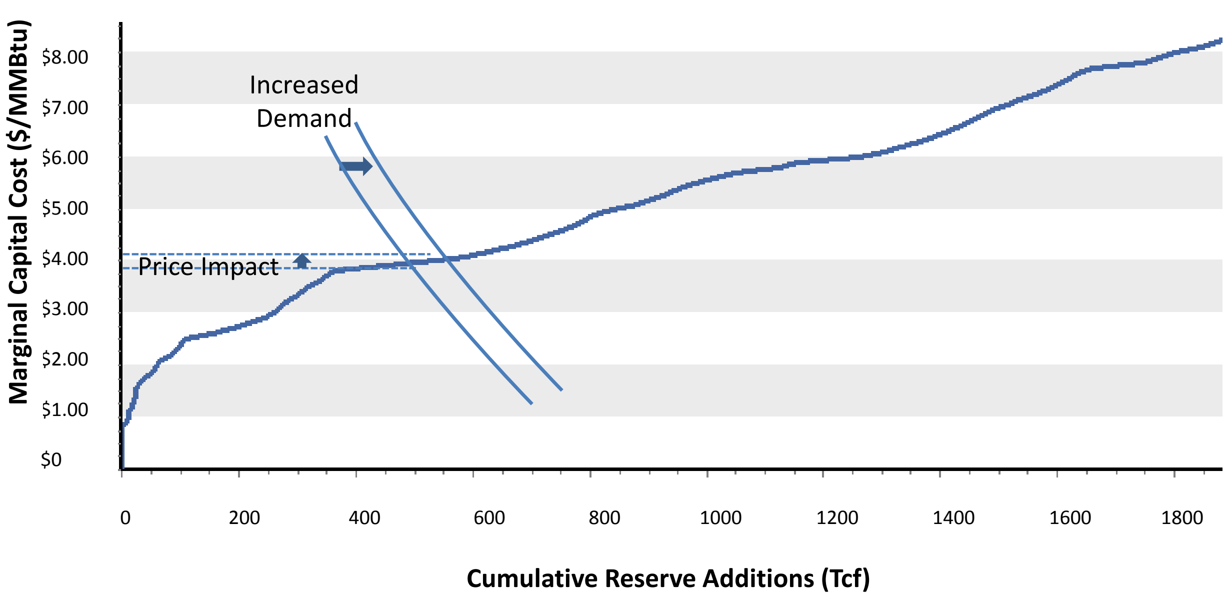
Figure 12: Aggregate U.S. natural gas supply curve (2012 $)



With regards to the potential impact of LNG exports, the absolute price is not the driving factor but rather the shape of the aggregate supply curve which determines the price impact. Figure 13 depicts how demand increase affects price. Incremental demand pushes out the demand curve, causing it to intersect the supply curve at a higher point. Since the supply curve is fairly flat in the area of demand, the price impact is fairly small. The massive shale gas resources have flattened the U.S. supply curve. It is the shape of the aggregate supply curve that really matters. Hence, leftward and rightward movements in the demand curve (where such leftward and rightward movements would be volumes of LNG export) cut through the supply curve at pretty much the same price. Flat, elastic supply means that the price of domestic natural gas is increasingly and continually determined by supply issues (e.g., production cost). Given that there is a significant quantity of domestic gas available at modest production costs, the export of 6 Bcfd of LNG would not increase the price of domestic gas very much because it would not increase the production cost of domestic gas very much.

The projected sources of incremental volumes used to meet the assumed export volumes come from multiple sources, including domestic resources (both shale gas and non-shale gas), import volumes, and demand elasticity. Figure 14 shows the sources of incremental volumes in the 6 Bcfd LNG export case on average from 2018 to 2037, the assumed years of LNG exports. (The source fractions are similar for other LNG export cases so we only show the 6 Bcfd case.) The bulk of the incremental volumes come from shale gas production. Including non-shale gas production, the domestic production contributes 63% of the total incremental volume. Net pipeline imports, comprised mostly of imports from Canada, contribute another 18%. Higher U.S. prices induce greater Canadian production, primarily from Horn River and Montney shale gas resources, making gas available for export to the U.S. The net exports to Mexico declines slightly as higher cost of U.S. supplies will likely prompt more Mexican production and would reduce the need for U.S. exports to Mexico. Higher gas prices are also projected to trigger demand elasticity so less gas is consumed, representing about 19% of the incremental volume. Most of the reduction in gas consumption comes from the power sector as higher gas prices incentivize greater utilization of generators burning other types of fuels.

Figure 13: Impact of higher demand on price (illustrative)

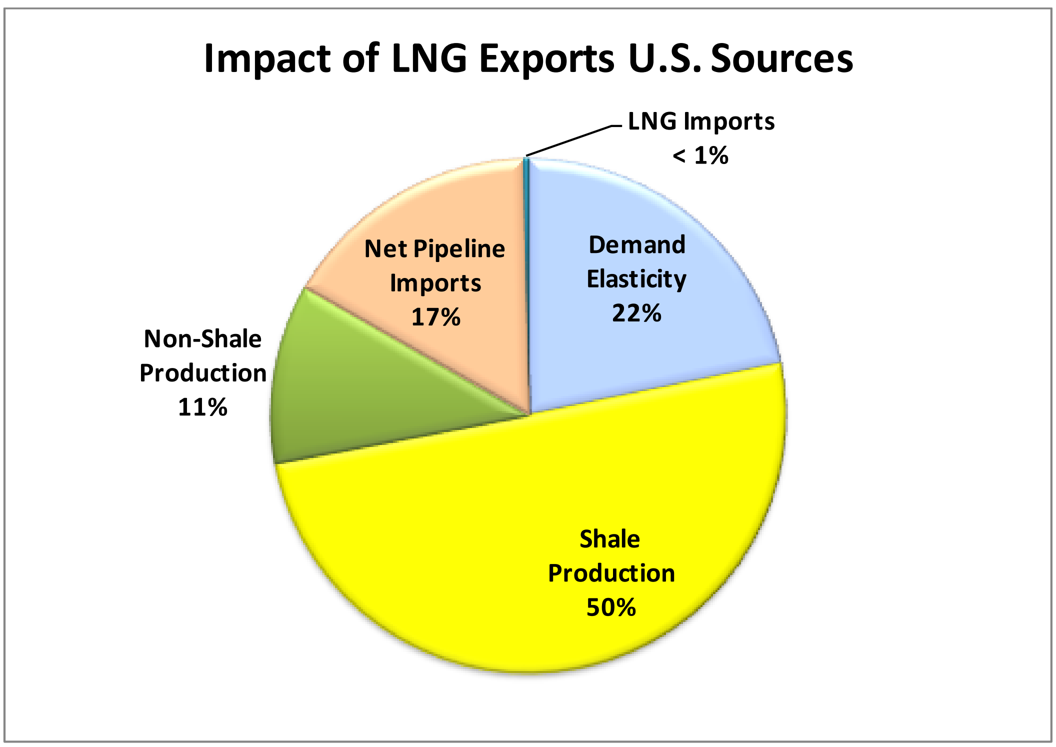


Finally, there is an insignificant increment, less than 1%, coming from LNG imports. Having both LNG imports and exports is not necessarily contradictory since there is variation in price by terminal (e.g., Everett terminal near Boston will likely see higher prices than will Gulf terminals) and by time (e.g., LNG cargos will seek to arbitrage seasonal price).

These results underscore the fact that the North American natural gas market is highly integrated and the entire market works to mitigate price impacts of demand changes.

During moderate or moderately high demand periods, coal or gas could be the marginal fuel type. If it is gas on the margin, price can rise only up to the cost of the next marginal fuel type (e.g., coal plant). If gas remains on margin, then it will be a simple calculation to see electricity price impact. At the projected Henry Hub gas price impact of $0.26/MMBtu, a typical gas plant with a heat rate of 8,000 would cost an additional $2.08/MWh (=$0.26/MMBtu x 8000 Btu/MWh x 1 MMBtu/1000 Btu). We believe that is the most that the gas price increase could elevate electricity price. Power load fluctuates greatly during a day, typically peaking during mid-afternoon and falling during the night. That implies that the marginal fuel type will also vary and gas will be at the margin only part of the time.

Figure 14: Projected sources of incremental volume in the 6 Bcfd Export Case (Average 2018-37)



Comparison of results to other studies

A number of studies, including others submitted to the DOE in association with LNG export applications, have estimated impacts of LNG exports from the U.S. The EIA also performed a study[4] at the request of the DOE. The various studies used different models and assumptions, but a comparison of their results might shed some light on the key factors and range of possible outcomes.

Figure 15 compares projections of estimated Henry Hub price impact from 2015 to 2035 with 6 Bcfd of LNG exports. The price impact ranges from 4% to 11%, with this study being on the low end and the ICF International being on the high end. The first observation is that, although the percentage differences are large on a relative basis, the range of estimated impacts is not so large. These studies consistently show that the price impact will not be that large relative to the change in demand. Bear in mind that 6 Bcfd is a fairly large incremental demand. In fact, it exceeds the combined gas demands in New York (3.3 Bcfd) and Pennsylvania (2.4 Bcfd) in 2011. These studies indicate that adding a sizeable incremental gas load on the U.S. energy system might result in a gas price increase of 11% or less.

Although we have limited data relating to specific assumptions and detailed output from the other studies, we can infer why the impacts differ so much. By most accounts, the resource base in the United States is plentiful, perhaps sufficient to last some 100 years at current production levels. All of the studies listed, including our own, had estimated natural gas resource volumes, including proved reserves and undiscovered gas of all types, of over 2,000 Tcf. Why then would the LNG export impacts vary as much as they do?

An important distinction between our analysis and the other studies is the representation of market dynamics, particularly for supply response to demand changes. That is, how do the studies represent how producers will respond to demand changes? The World Gas Model has a dynamic supply representation in which producers are assumed to anticipate demand and price changes. Producers do more than just respond to price that they see, but

Figure 15: Comparison of projected price impact from 2015-35 at the Henry Hub with 6 Bcfd of LNG exports

Study	Price without Exports ($/MMBtu)	Price with Exports ($/MMBtu)	Average Price Increase (%)
EIA	$ 5.28	$ 5.78	9%
Navigant (2010)	$ 4.75	$ 5.10	7%
Navigant (2012)	$ 5.67	$ 6.01	6%
ICF International	$ 5.81	$ 6.45	11%
Deloitte MarketPoint	$ 6.11	$ 6.37	4%

Source: Brookings Institute for all estimates besides Deloitte MarketPoint's

[4] "Effect of Increased Natural Gas Exports on Domestic Energy Markets," Howard Gruenspecht, EIA, January 2012.

rather anticipate events. Accordingly, prices will rise to induce producers to develop supplies in time to meet future demand.

Other models, primarily based on linear programming (LP)[5] or similar approaches, use static representation of supply in that supply does not anticipate price or demand growth. These static supply models require the user to input estimates of productive capacities in each future time period. The Brookings Institution completed a study assessing the impact of LNG exports and analyzing different economic approaches.[6] . As the Brookings study states:

"… static supply model, which, unlike dynamic supply models, does not fully take account of the effect that higher prices have on spurring additional production."

Since the supply volumes available in each time period is an input into LP models, the user must input how supply will respond to demand. In the case of LNG exports, the user must input how much supplies will increase and how quickly given the export volumes. Hence, the price impact is largely determined by how the user changes these inputs.

The purpose of this discussion is not to assert which approach is best, but rather to understand the differences so that the projections can be understood in their proper context. Assuming little or no price anticipation will tend to elevate the projected price impact while assuming price anticipation will tend to mitigate the projected price impact. Depending on the issue being analyzed, one approach may be more appropriate than the other. In the case of LNG export terminals, our belief is that the assumption of dynamic supply demand balance is appropriate. Given the long lead time, expected to be at least five years, required to permit, site, and construct an LNG export terminal, producers will have both ample time and plenty of notice to prepare for the export volumes. It would be a different matter if exports were to begin with little advanced notice.

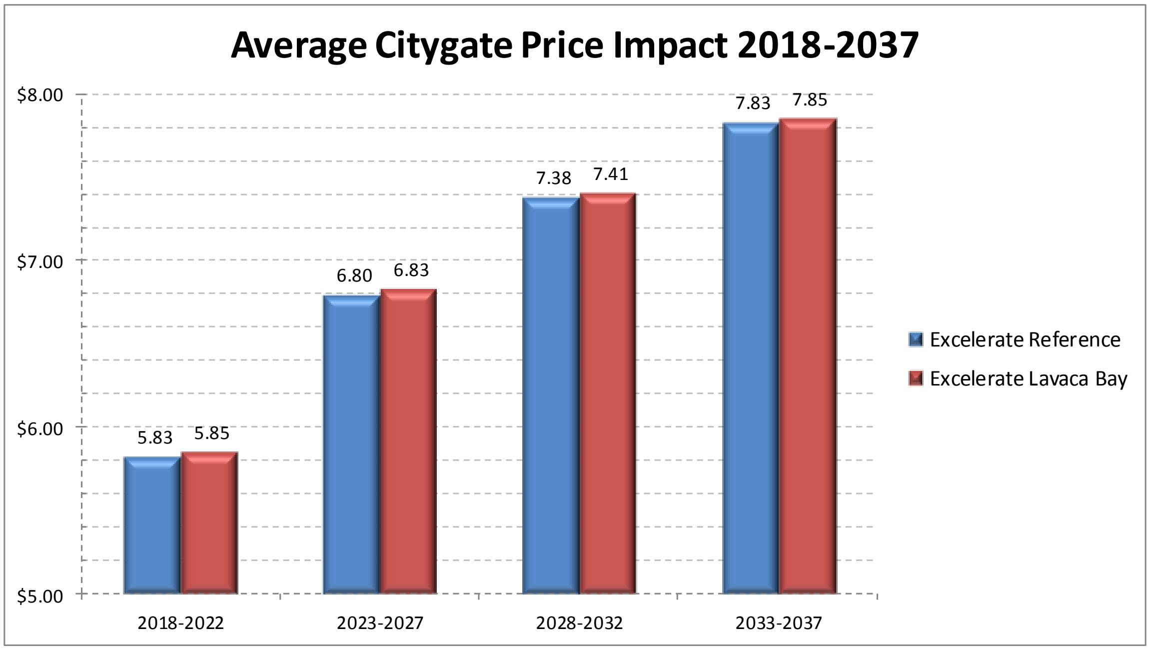
The importance of timing is evident in EIA's projections. The projected price impact is highly dependent on how quickly export volumes are assumed to ramp up. Furthermore, in all cases, the impacts are the greatest in the early years of exports. The impacts dissipate over time as supplies are assumed to eventually catch up with the demand growth.

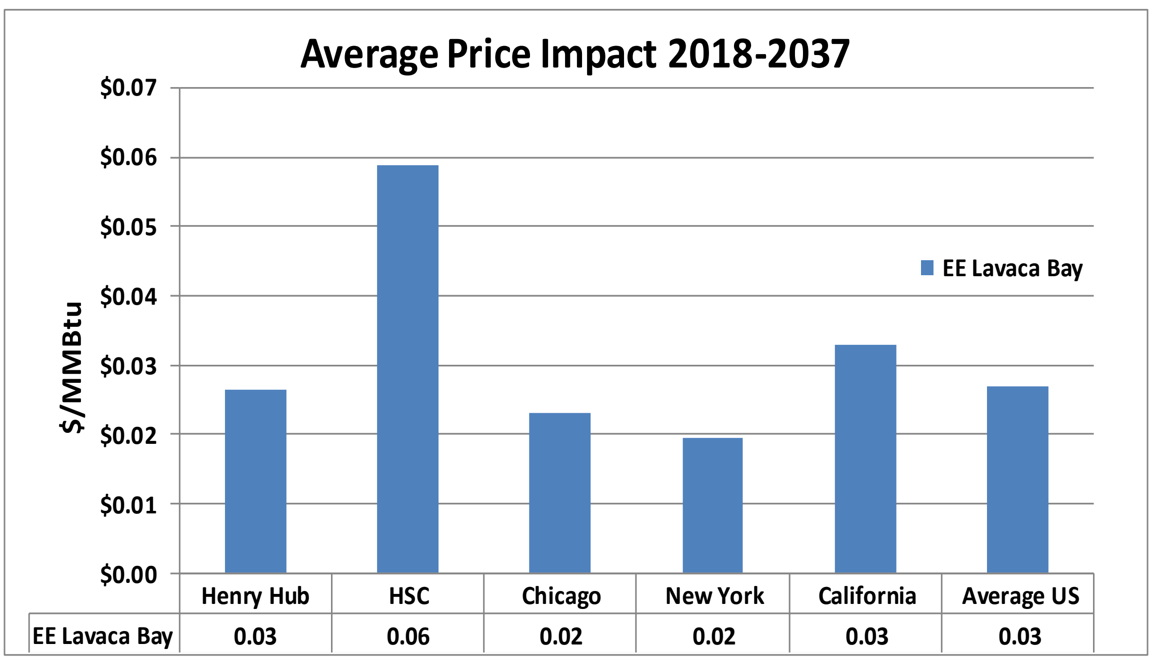
Natural gas producers are highly sophisticated companies with analytical teams monitoring and forecasting market conditions. Producers, well aware of the potential LNG export projects, are looking forward to the opportunity to supply these projects.

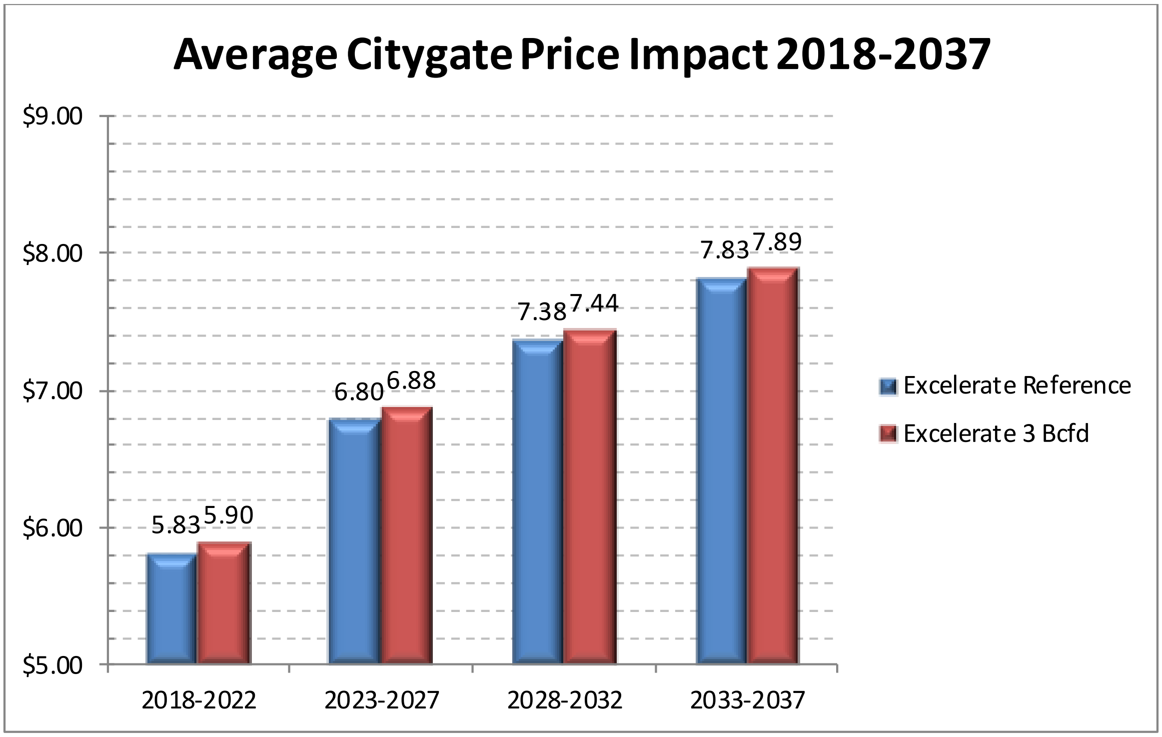
[5] Linear programming ("LP") is a mathematical technique for solving a global objective function subject to a series of linear constraints

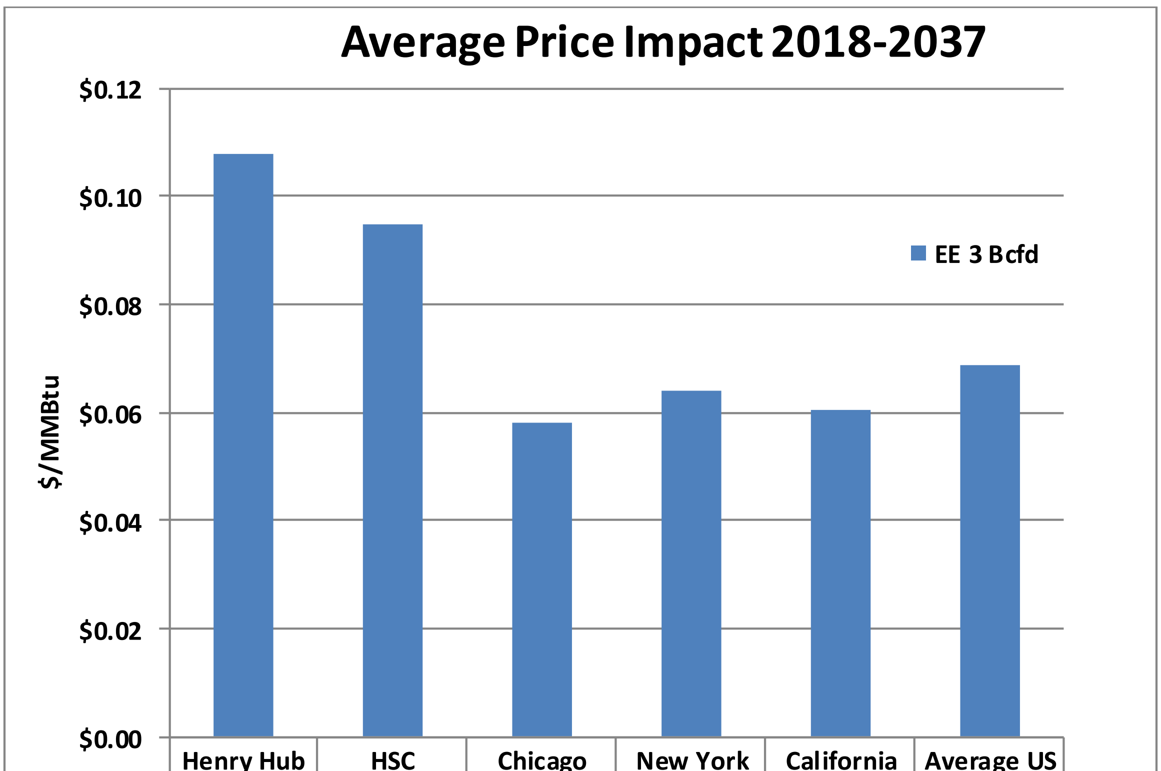
[6] "Liquid Markets: Assessing the Case for U.S. Exports of Liquefied Natural Gas," Brookings Institution (2012).

Appendix A: Price Impact Charts for other Export Cases

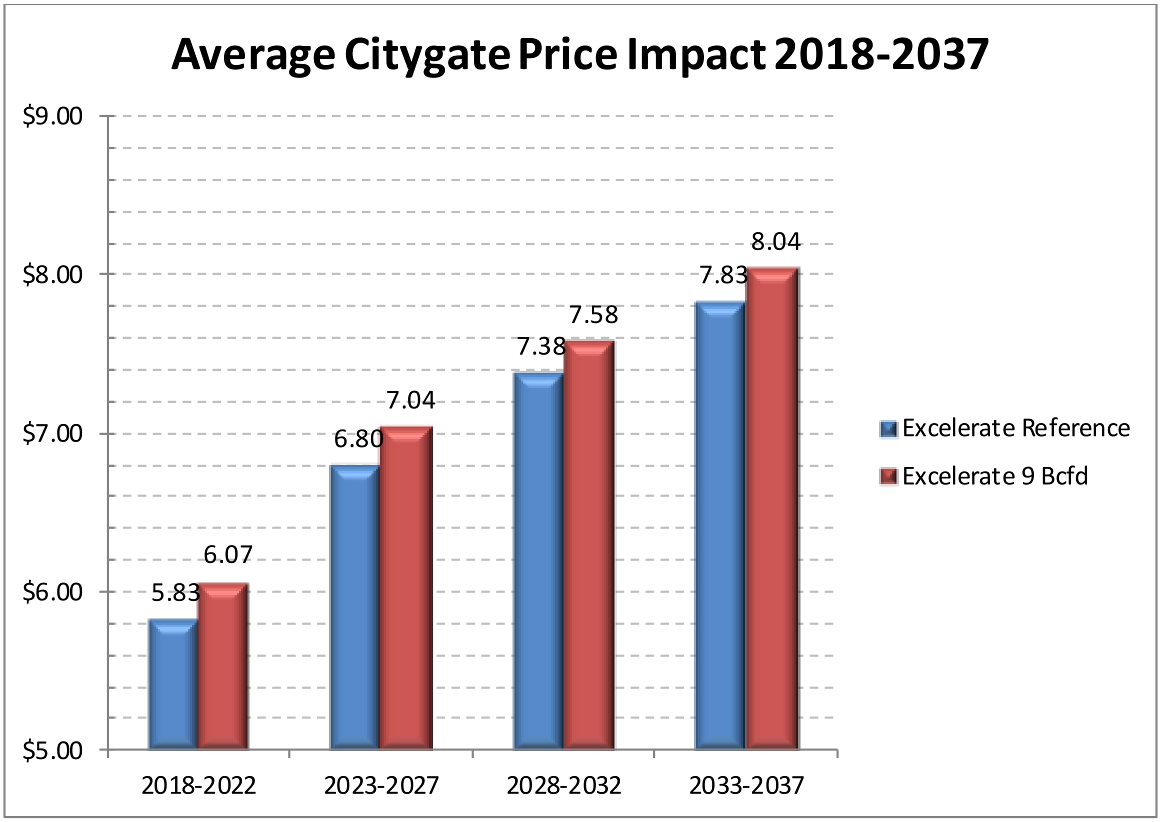


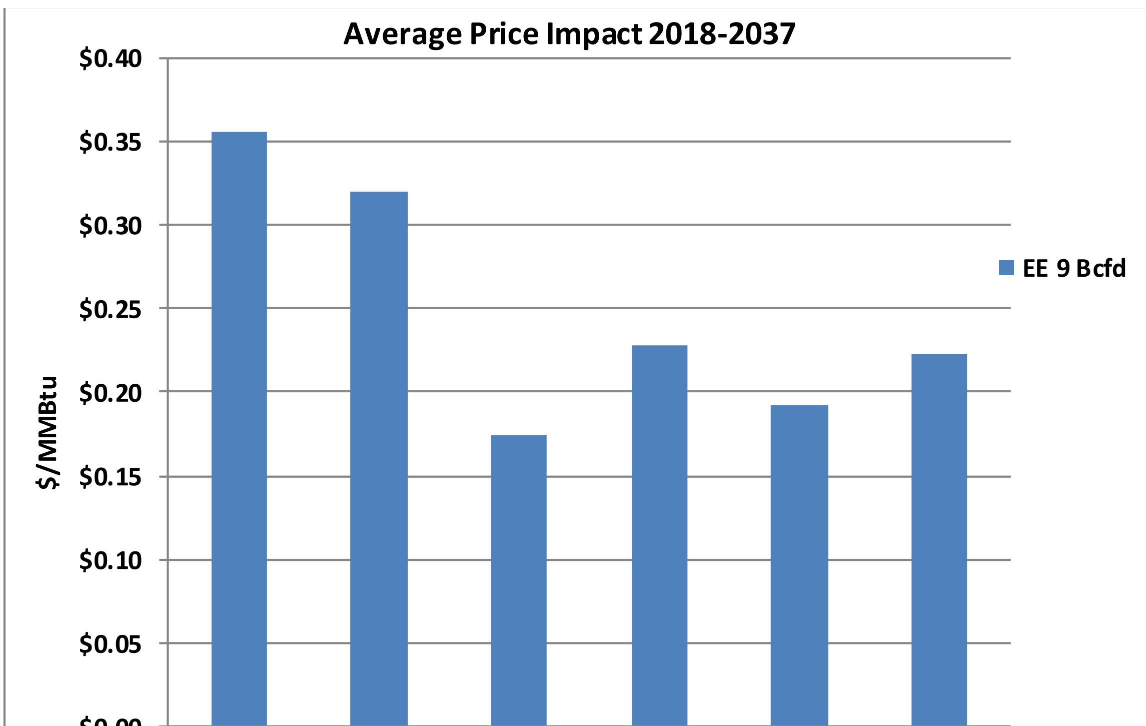




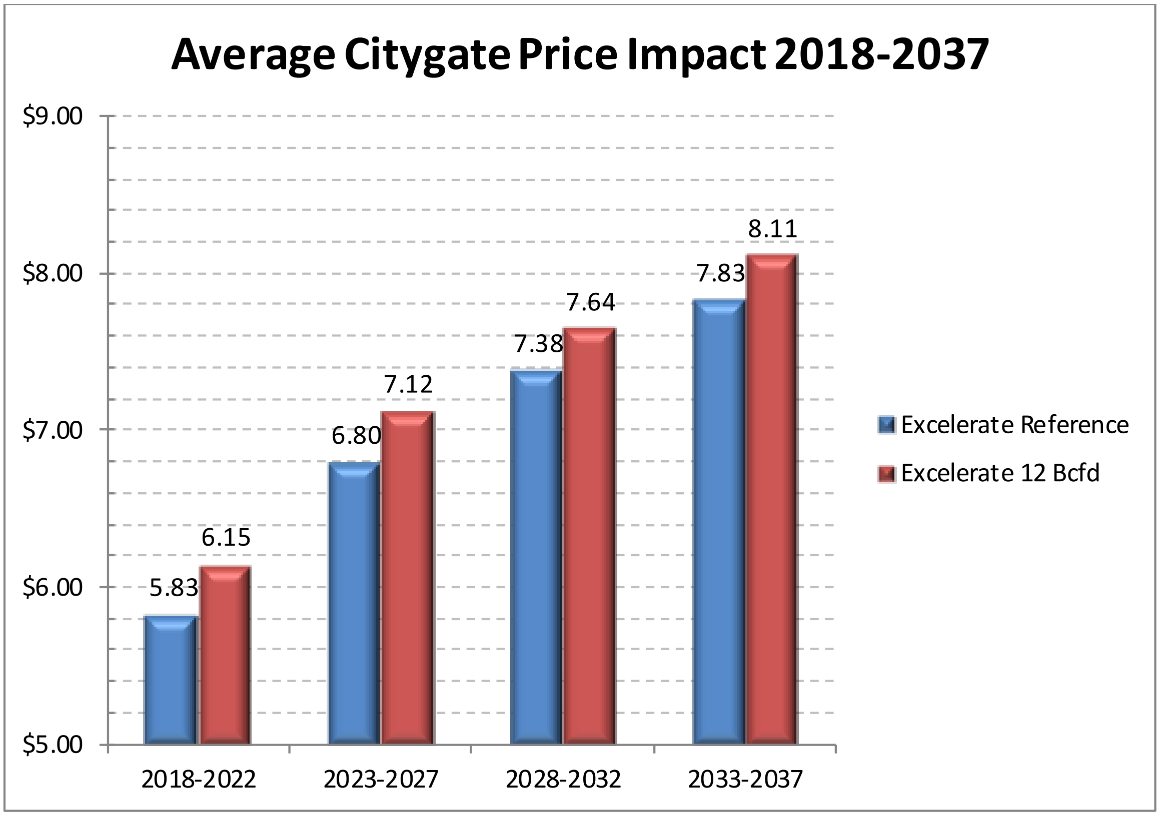


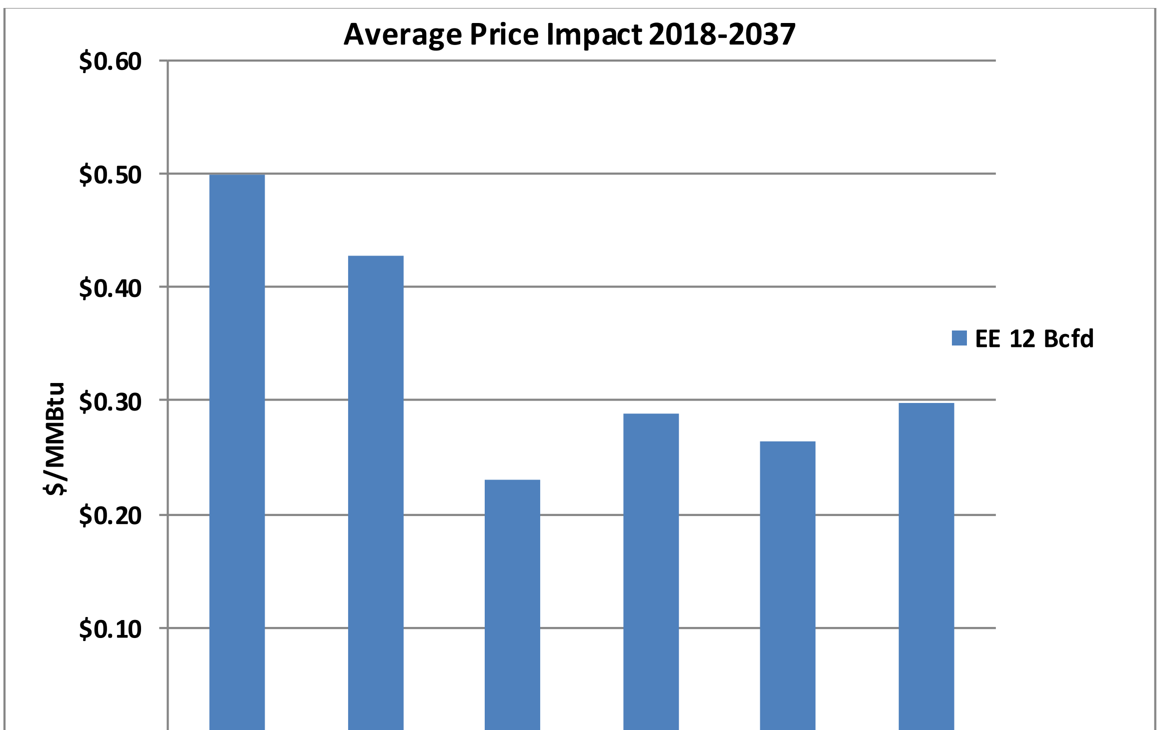
	Henry Hub	HSC	Chicago	New York	California	Average US
EE 3 Bcfd	0.11	0.09	0.06	0.06	0.06	0.07





	Henry Hub	HSC	Chicago	New York	California	Average US
EE 9 Bcfd	0.36	0.32	0.17	0.23	0.19	0.22





	Henry Hub	HSC	Chicago	New York	California	Average US
EE 12 Bcfd	0.50	0.43	0.23	0.29	0.26	0.30

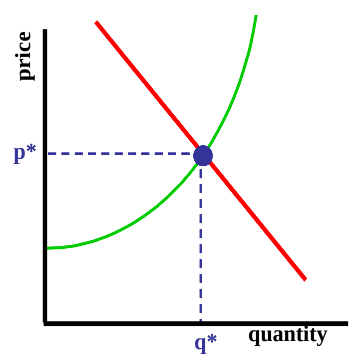
Appendix B: DMP's World Gas Model and data

To help understand the complexities and dynamics of global natural gas markets, DMP uses its World Gas Model ("WGM") developed in our proprietary MarketBuilder software. The WGM, based on sound economic theories and detailed representations of global gas demand, supply basins, and infrastructure, projects market clearing prices and quantities over a long time horizon on a monthly basis. The projections are based on market fundamentals rather than historical trends or statistical extrapolations.

WGM represents fundamental producer decisions regarding the timing and quantity of reserves to develop given the producer's resource endowments and anticipated forward prices. This supply-demand dynamic is particularly important in analyzing the market value of gas supply in remote parts of the world. The WGM uses sophisticated depletable resource logic in which today's drilling decisions affect tomorrow's price and tomorrow's price affects today's drilling decisions. It captures the market dynamics between suppliers and consumers.

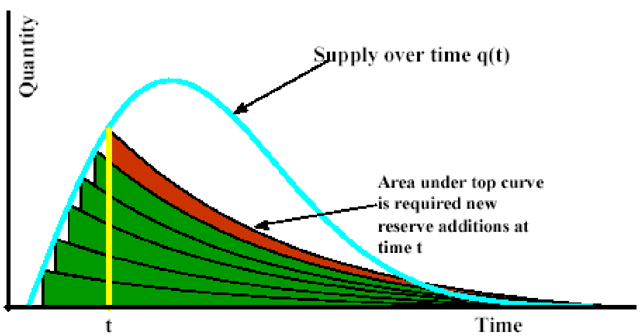
WGM simulates how regional interactions among supply, transportation, and demand interact to determine market clearing prices, flowing volumes, reserve additions, and pipeline entry and exit through 2046. The WGM divides the world into major geographic regions that are connected by marine freight. Within each major region are very detailed representations of many market elements: production, liquefaction, transportation, market hubs, regasification and demand by country or sub area. All known significant existing and prospective trade routes, LNG liquefaction plants, LNG regasification plants and LNG terminals are represented. Competition with oil and coal is modeled in each region. The capability to model the related markets for emission credits and how these may impact LNG markets is included. The model includes detailed representation of LNG liquefaction, shipping, and regasification; pipelines; supply basins; and demand by sector. Each regional diagram describes how market elements interact internally and with other regions.

Agent based economic methodology. MarketBuilder rigorously adheres to accepted microeconomic theory to solve for supply and demand using an "agent based" approach. To understand the benefits of the agent based approach, suppose you have a market comprised of 1000 agents, i.e., producers, pipelines, refineries, ships, distributors, and consumers. If your model of that market is to be correct, how many optimization problems must there be in your model of that 1000 agent market? The answer is clear—there must be 1000 distinct, independent optimization problems. Every individual agent must be represented as simultaneously solving and pursuing his or her own maximization problem, vying for market share and trying to maximize his or her own individual profits. Market prices



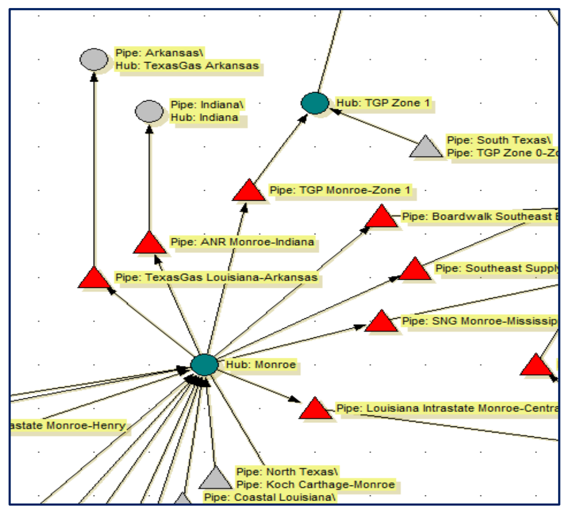
arise from the competition among these 1000 disparate, profit-seeking agents. This is the essence of microeconomic theory and competitive markets — people vying in markets for profits — and MarketBuilder rigorously approaches the problem from this perspective. In contrast, LP models postulate a single optimization problem no matter how many agents there are in the market; they only allow one, overall, global optimization problem. With LP, all 1000 agents are assumed to be manipulated by a "central authority" who forces them to act in lockstep to minimize the worldwide cost of production, shipment, and consumption of oil, i.e., to minimize the total cost of gas added up over the entire world.

Supply methodology and data. Working with data from agencies such as the United States Geological Survey (USGS), Energy Information Administration (EIA), and International Energy Agency (IEA), we have compiled a full and credible database of global supplies. In

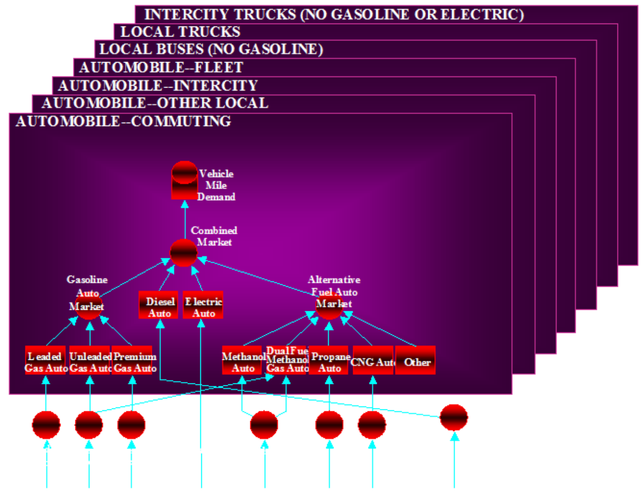


particular, we relied on USGS' world oil and gas supply data including proved reserves, conventional undiscovered resources, growth of reserves in existing fields, continuous and unconventional deposits, deep water potential, and exotic sources. Derived from detailed probabilistic analysis of the world oil and gas resource base (575 plays in the US alone), the USGS data lies at the heart of DMP' reference case resource database. Only the USGS does a worldwide, "bottom up" resource assessment. Customers can easily substitute their own proprietary view where they believe they have better information. MarketBuilder allows the use of sophisticated depletable resource modeling to represent production of primary oil and gas (an extended Hotelling model). The DMP Hotelling depletable resource model uses a "rational expectations" approach, which assumes that today's drilling affects tomorrow's price and tomorrow's price affects today's drilling. Thus MarketBuilder combines a resource model that approaches resource development the same way real producers do given the available data.

Transportation data. DMP maintains a global pipeline and transportation database. DMP and our clients regularly revise and update the transportation data including capacity, tariffs, embedded cost, discounting behavior, dates of entry of prospective new pipelines, and costs of those new pipelines.



Non-linear demand methodology. MarketBuilder allows the use of multi-variate nonlinear representations of demand by sector, without limit on the number of demand sectors. DMP is skilled at performing regression analyses on historical data to evaluate the effect of price, weather, GNP, etc. on demand. Using our methodology, DMP systematically models the impact of price change on demand (demand price feedback) to provide realistic results.



Department of Energy
Washington, DC 20585

May 29, 2014

MEMORANDUM

TO: ADAM SIEMINSKI
ADMINISTRATOR
ENERGY INFORMATION ADMINISTRATION

FROM: CHRISTOPHER SMITH
PRINCIPAL DEPUTY ASSISTANT SECRETARY
OFFICE OF FOSSIL ENERGY

SUBJECT: Request for an Update of EIA's January 2012 Study of Liquefied Natural Gas Export Scenarios

The Office of Fossil Energy (FE) requests the Energy Information Administration (EIA) to evaluate the impact of increased natural gas demand, reflecting possible exports of U.S. natural gas, on domestic energy markets using the modeling analysis presented in the *Annual Energy Outlook 2014 (AEO 2014)* as a starting point. The analysis should focus on the implications of additional natural gas demand on domestic energy consumption, production, and prices.

The updated study should address scenarios reflecting increases in export-related natural gas demand representing total lower-48 liquefied natural gas (LNG) exports of 12 billion standard cubic feet per day (Bcf/d), 16 Bcf/d, and 20 Bcf/d phased in at a rate of 2 Bcf/d per year starting in 2015. Understanding that the domestic natural gas market is sensitive to a number of factors, FE requests that EIA include sensitivity cases to explore some of these uncertainties. We are particularly interested in sensitivity cases relating to alternative recovery economics for shale gas resources, as in the *AEO2014 Low and High Resource* cases, a sensitivity case with additional natural gas use for electric generation, and a sensitivity case with increased baseline natural gas demand as in the *AEO2014 High Economic Growth* case.

The study report should review and synthesize the results obtained in the modeling work and include, as needed, discussions of context, caveats, issues and limitations that are relevant to the study. Please include tables or figures that summarize impacts on annual domestic natural gas prices, domestic natural gas production and consumption levels, domestic expenditures for natural gas and other relevant fuels, and revenues associated with the incremental export demand for natural gas. The standard *AEO 2014* reporting tables should also be provided, with the exception of tables reporting information that EIA considers to be spurious or misleading given the limitations of its modeling tools in addressing the study questions.

We would like to receive the completed analysis as soon as possible. We also recognize that EIA may post the study on its website after providing it to us.

Thank you for your attention to this request.

Long Term Applications Received by DOE/FE to Export

Domestically Produced LNG from the Lower-48 States (as of August 28, 2014)

All Changes Since July 31, 2014 Update Are In Red

Company	Quantity [(a)]	FTA Applications [(b)] (Docket Number)	Non-FTA Applications [(c)] (Docket Number)
Sabine Pass Liquefaction, LLC	2.2 billion cubic feet per day (Bcf/d) [(d)]	Approved (10-85-LNG)	Approved (F) (10-111-LNG)
Freeport LNG Expansion, L.P. and FLNG Liquefaction, LLC	1.4 Bcf/d [(d)]	Approved (10-160-LNG)	Approved (C) (10-161-LNG)
Lake Charles Exports, LLC	2.0 Bcf/d [(e)]*	Approved (11-59-LNG)	Approved (C) (11-59-LNG)
Carib Energy (USA) LLC	0.03 Bcf/d: FTA 0.06 Bcf/d: non-FTA [(f)]	Approved (11-71-LNG)	Under DOE Review (11-141-LNG)
Dominion Cove Point LNG, LP	1.0 Bcf/d: FTA 0.77 Bcf/d: non-FTA	Approved (11-115-LNG)	Approved (C) (11-128-LNG)
Jordan Cove Energy Project, L.P.	1.2 Bcf/d: FTA 0.8 Bcf/d: non-FTA [(g)]	Approved (11-127-LNG)	Approved (C) (12-32-LNG)
Cameron LNG, LLC	1.7 Bcf/d [(d)]	Approved (11-145-LNG)	Approved (C) (11-162-LNG)
Freeport LNG Expansion, L.P. and FLNG Liquefaction, LLC [(h)]	1.4 Bcf/d: FTA 0.4 Bcf/d: non-FTA [(k)]	Approved (12-06-LNG)	Approved (C) (11-161-LNG)
Gulf Coast LNG Export, LLC [(i)]	2.8 Bcf/d[(d)]	Approved (12-05-LNG)	Under DOE Review (12-05-LNG)
Gulf LNG Liquefaction Company, LLC	1.5 Bcf/d[(d)]	Approved (12-47-LNG)	Under DOE Review (12-101-LNG)
LNG Development Company, LLC (d/b/a Oregon LNG)	1.25 Bcf/d[(d)]	Approved (12-48-LNG)	Approved (C) (12-77-LNG)
SB Power Solutions Inc.	0.07 Bcf/d	Approved (12-50-LNG)	n/a
Southern LNG Company, L.L.C.	0.5 Bcf/d[(d)]	Approved (12-54-LNG)	Under DOE Review (12-100-LNG)
Excelerate Liquefaction Solutions I, LLC	1.38 Bcf/d[(d)]	Approved (12-61-LNG)	Under DOE Review (12-146-LNG)
Golden Pass Products LLC	2.0 Bcf/d[(d)]***	Approved (12-88 -LNG)	Under DOE Review (12-156-LNG)
Cheniere Marketing, LLC	2.1 Bcf/d[(d)]	Approved (12-99-LNG)	Under DOE Review (12-97-LNG)
Main Pass Energy Hub, LLC	3.22 Bcf/d**	Approved (12-114-LNG)	n/a
CE FLNG, LLC	1.07 Bcf/d[(d)]	Approved (12-123-LNG)	Under DOE Review (12-123-LNG)
Waller LNG Services, LLC	0.16 Bcf/d: FTA 0.19 Bcf/d: non-FTA	Approved (12-152-LNG)	Under DOE Review (13-153-LNG)

Long Term Applications Received by DOE/FE to Export Domestically Produced LNG from the Lower-48 States (as of August 28, 2014)

All Changes Since July 31, 2014 Update Are In Red

Company	Quantity [a]	FTA Applications [b] (Docket Number)	Non-FTA Applications [c] (Docket Number)
Pangea LNG (North America) Holdings, LLC	1.09 Bcf/d[d]	Approved (12-174-LNG)	Under DOE Review (12-184-LNG)
Magnolia LNG, LLC	0.54 Bcf/d[j]	Approved (12-183-LNG)	n/a
Trunkline LNG Export, LLC	2.0 Bcf/d*	Approved (13-04-LNG)	Under DOE Review (13-04-LNG)
Gasfin Development USA, LLC	0.2 Bcf/d[d]	Approved (13-06-LNG)	Under DOE Review (13-161-LNG)
Freeport-McMoRan Energy LLC	3.22 Bcf/d**	Approved (13-26-LNG)	Under DOE Review (13-26-LNG)
Sabine Pass Liquefaction, LLC	0.28 Bcf/d[d]	Approved (13-30-LNG)	Under DOE Review (13-30-LNG)
Sabine Pass Liquefaction, LLC	0.24 Bcf/d[d]	Approved (13-42-LNG)	Under DOE Review (13-42-LNG)
Venture Global LNG, LLC	0.67 Bcf/d[d]	Approved (13-69-LNG)	Under DOE Review (13-69-LNG)
Advanced Energy Solutions, L.L.C.	0.02 Bcf/d	Approved (13-104-LNG)	n/a
Argent Marine Management, Inc.	0.003 Bcf/d	Approved (13-105-LNG)	n/a
Eos LNG LLC	1.6 Bcf/d[d]	Approved (13-115-LNG)	Under DOE Review (13-116-LNG)
Barca LNG LLC	1.6 Bcf/d[d]	Approved (13-117-LNG)	Under DOE Review (13-118-LNG)
Sabine Pass Liquefaction, LLC	0.86 Bcf/d[d]	Approved (13-121-LNG)	Under DOE Review (13-121-LNG)
Delfin LNG LLC	1.8 Bcf/d[d]	Approved (13-129-LNG)	Under DOE Review (13-147-LNG)
Magnolia LNG, LLC	0.54 Bcf/d: FTA[j] 1.08 Bcf/d: Non-FTA[j]	Approved (13-131-LNG)	Under DOE Review (13-132-LNG)
Annova LNG LLC	0.94 Bcf/d	Approved (13-140-LNG)	n/a
Texas LNG LLC	0.27 Bcf/d[d]	Approved (13-160-LNG)	Under DOE Review (13-160-LNG)
Louisiana LNG Energy LLC	0.28 Bcf/d	Approved (14-19-LNG)	Under DOE Review (14-29-LNG)
Alturas LLC	0.2 Bcf/d	Pending Approval (14-55-LNG)	n/a
Strom Inc.	0.02 Bcf/d[d]	Pending Approval (14-56-LNG)	n/a
Strom Inc.	0.02 Bcf/d[d]	n/a	Under DOE Review (14-57-LNG)
Strom Inc.	0.02 Bcf/d[d]	n/a	Under DOE Review (14-58-LNG)
SCT&E LNG, LLC	1.6 Bcf/d***[d]	Pending Approval (14-89-LNG)	Under DOE Review (14-98-LNG)
Venture Global LNG, LLC	0.67 Bcf/d[d]	Pending Approval (14-88-LNG)	Under DOE Review (14-88-LNG)
Sabine Pass Liquefaction, LLC	0.56 Bcf/d	Pending Approval (14-92-LNG)	n/a

Long Term Applications Received by DOE/FE to Export

Domestically Produced LNG from the Lower-48 States (as of August 28, 2014)

All Changes Since July 31, 2014 Update Are In Red

Company	Quantity [a]	FTA Applications [b] (Docket Number)	Non-FTA Applications [c] (Docket Number)
Total of all Applications Received		**40.96 Bcf/d(*)(**)**	**37.62 Bcf/d (*)(**)**

* Lake Charles Exports, LLC (LCE) and Trunkline LNG Export, LLC (TLNG), the owner of the Lake Charles Terminal, have both filed an application to export up to 2.0 Bcf/d of LNG from the Lake Charles Terminal. The total quantity of combined exports requested between LCE and TLNG does not exceed 2.0 Bcf/d (i.e., both requests are not additive and only 2 Bcf/d is included in the bottom-line total of applications received).

** Main Pass Energy Hub, LLC (MPEH) and Freeport McMoRan Energy LLC (FME), have both filed an application to export up to 3.22 Bcf/d of LNG from the Main Pass Energy Hub. (The existing Main Pass Energy Hub structures are owned by FME). The total quantity of combined FTA exports requested between MPEH and FME does not exceed 3.22 Bcf/d (i.e., both requests are not additive and only 3.22 Bcf/d is included in the bottom-line total of FTA applications received). FME's application includes exports of 3.22 Bcf/d to non-FTA countries and is included in the bottom line total of non-FTA applications received, while MPEH has not submitted an application to export LNG to non-FTA countries.

*** On July 9, 2014, the volume for Golden Pass Products LLC was changed to 2.0 Bcf/d to reflect the average daily amount, instead of the 2.6 Bcf/d peak daily amount included in the application. Also the FTA volume for SCT&E LNG, LLC was changed to 1.6 Bcf/d to reflect a new application and withdrawal of the previous application to export 0.6 Bcf/d.

- **(a)** Actual applications were in the equivalent annual quantities.
- **(b)** FTA – Applications to export to free trade agreement (FTA) countries. The Natural Gas Act, as amended, has deemed FTA exports to be in the public interest and applications shall be authorized without modification or delay.
- **(c)** Non-FTA applications require DOE to post a notice of application in the Federal Register for comments, protests and motions to intervene, and to evaluate the application to make a public interest consistency determination. (F) is a Final Authorization and (C) is a Conditional Authorization
- **(d)** Requested approval of this quantity in both the FTA and non-FTA export applications. Total facility is limited to this quantity (i.e., FTA and non-FTA volumes are not additive at a facility).
- **(e)** Lake Charles Exports, LLC submitted one application seeking separate authorizations to export LNG to FTA countries and another authorization to export to Non-FTA countries. The proposed facility has a capacity of 2.0 Bcf/d, which is the volume requested in both the FTA and Non-FTA authorizations.

(f) Carib Energy (USA) LLC requested authority to export the equivalent of 11.53 Bcf per year of natural gas to FTA countries and 3.44 Bcf per year to non-FTA countries. Carib's requested amendment to its application on 12/12/2012, included a revised volume equivalent to 0.06 Bcf/d from 0.01 Bcf/d of natural gas.

(g) Jordan Cove Energy Project, L.P. requested authority to export the equivalent of 1.2 Bcf/d of natural gas to FTA countries and 0.8 Bcf/d to non-FTA countries.

(h) DOE/FE received a new application (11-161-LNG) by FLEX to export an additional 1.4 Bcf/d of LNG from new trains to be located at the Freeport LNG Terminal, to non-FTA countries, and a separate application (12-06-LNG) to export this same 1.4 Bcf/d of LNG to FTA countries (received January 12, 2012). This 1.4 Bcf/d is in addition to the 1.4 Bcf/d FLEX requested in dockets (10-160-LNG and 10-161-LNG).

(i) An application was submitted by Gulf Coast on January 10, 2012, seeking one authorization to export LNG to any country not prohibited by U.S. law or policy. On September 11, 2012, Gulf Coast revised their application by seeking separate authorizations for LNG exports to FTA countries and Non-FTA countries.

(j) The Magnolia LNG Facility is limited to 1.08 Bcf/d. FTA and Non-FTA volumes are not additive.

(k) FLEX applied for a second authorization to export 1.4 Bcf/d to FTA and Non-FTA countries. DOE/FE authorized 1.4 Bcf/d to FTA countries before FLEX filed with FERC. DOE authorized 0.4 Bcf/d to Non-FTA countries, which authorizes a total volume of 1.8 Bcf/d to Non-FTA countries in the two FLEX Non-FTA orders. The FLEX application with FERC is for a total facility capacity of 1.8 Bcf/d.

(l) The authorization sought by Sabine Pass Liquefaction, LLC (SPL) for 0.56 Bcf/d is for additional exports from the Sabine Pass Liquefaction project, and is additional to other SPL FTA LNG export applications.

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OFFICE OF
ECOSYSTEMS,
TRIBAL AND PUBLIC
AFFAIRS

October 29, 2012

The Honorable Kimberly D. Bose, Secretary
Federal Energy Regulatory Commission
888 First Street, NE, Room 1A
Washington, DC 20426

Re: SCOPING COMMENTS – The Jordan Cove Energy Project LP and the Pacific Connector Gas Pipeline Notice of Intent to Prepare an Environmental Impact Statement. EPA Region 10 Project Number: 12-0042-FRC and 12-0049-AFS. *FERC Docket Nos. PF12-7-000 and PF12-17-000.*

Dear Secretary Bose:

The U.S. Environmental Protection Agency (EPA) would like to provide detailed scoping comments in response to the Federal Energy Regulatory Commission's (FERC's) August 13, 2012 Notice of Intent (NOI) to prepare an Environmental Impact Statement (EIS) for the Jordan Cove Energy Project and Pacific Connector Gas Pipeline. With these comments we are also responding to the September 21, 2012 NOI to prepare an EIS issued by the Forest Service and BLM for Right of Way grants and land use amendments related to the Pacific Connector Gas Pipeline. These comments were prepared in accordance with our authorities pursuant to the National Environmental Policy Act (NEPA), Section 309 of the Clean Air Act, the Clean Water Act, and our responsibilities as a Cooperating Agency. We appreciate the opportunity for early involvement at this step of the NEPA process.

The Clean Air Act Section 309 directs the EPA to review and comment in writing on the environmental impacts resulting from certain proposed actions of other federal agencies and the adequacy of the Draft EIS in meeting the procedural and public disclosure requirements in accordance with NEPA. Please see the EPA's review criteria for rating Draft EISs at the EPA web site: (http://www.epa.gov/compliance/nepa/comments/ratings.html). Our review authorities under Section 309 are independent of our responsibilities as a Cooperating Agency for this EIS.

The FERC's NOI describes Jordan Cove's proposal to construct and operate an LNG export terminal on the North Spit of Coos Bay. The terminal would have the capacity to produce approximately six million metric tons per annum of LNG (equivalent to 0.9 billion cubic feet per day [Bcf/d] of natural gas). Facilities would include:

- 7.3 mile long waterway in Coos Bay for about 80 LNG carriers per year;
- 0.3 mile long access channel and marine berth;
- A cryogenic transfer pipeline;
- Two 160,000 cubic meter LNG storage tanks;
- Four liquefaction trains (each with a capacity of 1.5 million metric tons per annum);
- Two feed gas and dehydration trains with a combined throughput of 1Bcf/d of natural gas; and
- A 350 megawatt South Dunes power plant.

The attendant Pacific Connector pipeline would be 36 inches in diameter and about 230 miles long, extending from interconnections with other interstate pipelines near Malin, Oregon to the Jordan Cove LNG terminal at Coos Bay. The pipeline would have a design capacity of 0.9 Bcf/d of natural gas. Related facilities include:

- Two meter stations at the interconnections with the existing Gas Transmission Northwest and Ruby pipelines near Malin, Oregon;
- A 23,000 horsepower compressor station adjacent to the GTN and Ruby meter stations;
- A meter station at the interconnection with the existing Williams Northwest Pipeline system near Myrtle Creek, Oregon; and
- A meter station at the Jordan Cove terminal.

The enclosed scoping comments were prepared based on our review of the NOIs referenced above and the draft Resource Reports 1 and 10. Our comments reflect a broad range of issues that we believe to be significant and warrant treatment in the EIS. Among these issues is the range of alternatives. We encourage the FERC to consider a broad range of reasonable alternatives in the EIS that are capable of meeting the project's purpose and need and we look forward to continued discussions on this matter. For example, we would be interested in discussing whether an intertie with the Williams pipeline could be considered as a reasonable alternative and examined in the EIS. We also recommend expanding the scope of analysis to capture the non-jurisdictional South Dunes power plant as well as indirect effects related to gas drilling and combustion.

As a Cooperating Agency, we look forward to continued communication with your office throughout the development of the EIS, and we are available to work with FERC to review and comment on preliminary sections of the document. If you have any questions regarding our scoping comments, please do not hesitate to contact me at (206) 553-1601 or by electronic mail at reichgott.christine@epa.gov, or you may contact Teresa Kubo of my staff in the Oregon Operations Office at (503) 326-2859 or by electronic mail at kubo.teresa@epa.gov. We look forward to our continued coordination and involvement in this project.

Sincerely,

Christine B. Reichgott

Christine B. Reichgott, Manager
Environmental Review and Sediment Management Unit

Enclosure

U.S. Environmental Protection Agency
Detailed Scoping Comments to Address the Federal Energy Regulatory Commission's Notice of Intent to Prepare an Environmental Impact Statement for the Jordan Cove Energy Project and Pacific Connector Gas Pipeline
FERC Docket Nos. PF12-7-000 and PF12-17-000

Purpose and Need
The EIS should include a clear and concise statement of the underlying purpose and need for the proposed project, consistent with the implementing regulations for NEPA (see 40 CFR 1502.13). In presenting the purpose and need for the project, the EIS should reflect not only the FERC's purpose, but also the broader public interest and need.

In supporting the statement of purpose and need, we recommend discussing the proposed project in the context of the larger energy market, including existing export capacity and export capacity under application to the Department of Energy, and clearly describe how the need for the proposed action has been determined.

Alternatives Analysis
NEPA requires evaluation of reasonable alternatives, including those that may not be within the jurisdiction of the lead agency[1]. A robust range of alternatives will include options for avoiding significant environmental impacts. The EIS should "rigorously explore and objectively evaluate all reasonable alternatives"[2] by developing a screening process. The screening process should rate each alternative against a set of pre-determined criteria. Each alternative should then be analyzed for its level of impact on a resource (e.g. no effect, negligible effect, minor effect, major effect, significant effect). Only the alternative that effectively meets or best meets all of the screening criteria should be recommended as the preferred alternative. The EIS should provide a clear discussion of the reasons for the elimination of alternatives which are not evaluated in detail.

We appreciate that Resource Report 10 for the Pacific Connector Pipeline Project (Section 10.4) evaluates system alternatives for the pipeline route. In the EIS we would like to see a more rigorous exploration of those alternatives. The basis for conclusions reached in Section 10.4.4 is not clear. Specifically, it is not clear how it was determined that an intertie with the Williams pipeline would result in prohibitive costs, associated rates, and environmental impacts. Because such a route would be significantly shorter than the currently proposed route, we recommend that the EIS give this route alternative additional consideration.

Non-Jurisdictional Facilities
In Section 1.9.2 of Resource Report 1, it is determined that as a non-jurisdictional facility, the South Dunes Power Plant does not need to be included in the DEIS. This assertion is based on the Report's interpretation of FERC's NEPA regulations at 18 CFR § 380.12(c)(2)(ii). Per those regulations, four factors are applied to determine the need for FERC to do an environmental review of project-related non-jurisdictional facilities. These factors include:

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[1] 40 CFR 1502.14(c)
[2] 40 CFR 1502.14(a)

1. Whether or not the regulated activity comprises "merely a link" in a corridor type project (such as a transportation or utility transmission project);
2. Whether there are aspects of the non-jurisdictional facility in the immediate vicinity of the regulated activity which affect the location and configuration of the regulated activity;
3. The extent to which the entire project will be within the FERC's jurisdiction; and
4. The extent of cumulative federal control and responsibility.

Resource Report 1 considers each of these factors and finds that FERC environmental review is not warranted. We believe the Resource Report's interpretation of these criteria to be overly narrow. In particular, because the South Dunes Power Plant and the Jordan Cove Export Facility are interdependent and interconnected, we believe the power plant inherently affects the location of the export facility. Without the power supplied by the power plant, the export facility cannot be built; and without the export facility, there is no need for the power plant to be built.

In addition, CEQ NEPA regulations at 40 CFR 1508.25(a)(1) address connected actions, and clearly call for actions to be considered within the scope of an EIS if they "cannot or will not proceed unless other actions are taken previously or simultaneously" or " are interdependent parts of a larger action and depend on the larger action for their justification"[3]. It is clear from Resource Report 1 that the Power Plant is being constructed for the purpose of supporting the Project. The Power Plant is not being constructed for a purpose independent from the Project. On the contrary, it is being constructed specifically to support the power needs of the Project.

Section 40 C.F.R. 1508.25(a)(3) states that two actions should be evaluated in a single EIS when they are "similar actions, which when viewed with other reasonably foreseeable or proposed agency actions have similarities that provide a basis for evaluating their environmental consequences together, such as common timing and geography." The Power Plant will be built in a timeframe that will coincide with the Project's power needs. The Power Plant is specifically sited in proximity to the Project so that it can operate in conjunction with the Project. Because the South Dunes Power Plan and the Jordan Cove Export Facility are interdependent and interconnected, the locations of the two were selected to enhance the effectiveness of their co-operation. Therefore, we recommend that the FERC include the South Dunes Power Plant within the scope of the EIS.

Environmental Consequences

According to 40 CFR Part 1502.1, an Environmental Impact Statement, "...shall provide full and fair discussion of significant environmental impacts and shall inform decision makers and the public of the reasonable alternatives which would avoid or minimize adverse impacts or enhance the quality of the environment." In order to facilitate a full and fair discussion on significant environmental issues, we encourage the FERC to establish thresholds of significance for each resource of concern, and to analyze environmental consequences in a clear, repeatable manner. For each action, a series of questions should be considered: 1) What is the action? 2) What is the intensity or extent of impacts? 3) Based on identified thresholds, is that significant? If an impact of the action is significant, then the EIS must contain appropriate mitigation measures.

[3] 40 CFR 1508.25(a)(1)(ii) and (iii)

Water Quality
In order to adequately address water quality issues, the EPA recommends the EIS identify water bodies likely to be impacted by the project, the nature of the potential impacts, and the specific discharges and pollutants likely to impact those waters (addressing both Section 402 and 404 discharges and potential impairments to water quality standards). We also recommend the EIS disclose information regarding relevant Total Maximum Daily Load allocations, the water bodies to which they apply, water quality standards and pollutants of concern.

Clean Water Act Section 303(d) listed waters should not be further degraded. If additional pollutant loading is predicted to occur to a 303(d) listed stream as a result of a project, the EIS should include measures to control existing sources of pollution to offset pollutant additions.

Consider implementing watershed or aquatic habitat restoration activities to compensate for past impacts to water resources, particularly in watersheds with 303(d) listed waters where development may have contributed to impairments through past channelization, riverine or floodplain encroachments, sediment delivery during construction, and other activities that may have affected channel stability, water quality, aquatic habitat, and designated waterbody uses. Provisions for antidegradation of water quality apply to water bodies where water quality standards are presently being met. We recommend the EIS describe how antidegradation provisions would be met.

Hydrostatic Test Water
Hydrostatic testing of pipelines and tanks will be required to verify their integrity. We recommend that the EIS identify the water sources and withdrawal rates that would be required for hydrostatic testing. We recommend that the EIS identify and describe the location of these water sources (surface areas, depth, volumes, withdrawal rates, and project requirements). For each water source, we recommend that the EIS discuss the presence of any anadromous and/or resident fish species, including a discussion of any direct and cumulative impacts to fisheries resources. In addition, we recommend that the locations of discharge to land and/or surface waters, and discharge methods be specified in the EIS. Emphasis should be placed on minimizing interbasin transfers of water to the maximum extent practicable in order to minimize the risk of mobilizing invasive species. We recommend that the EIS describe the mitigation measures and control devices that would be implemented to minimize environmental impacts.

Source Water Protection
Public drinking water supplies and/or their source areas often exist in many watersheds. Source water areas may exist within watersheds where the pipeline and associated facilities would be located. Source waters are streams, rivers, lakes, springs, and aquifers used as supply for drinking water. Source water areas are delineated and mapped by the states for each federally-regulated public water system. The 1996 amendments to the Safe Drinking Water Act require federal agencies to protect sources of drinking water for communities. As a result, state agencies have been delegated responsibility to conduct source water assessments and provide a database of information about the watersheds and aquifers that supply public water systems.

Since construction, operation, and maintenance of a buried natural gas pipeline may impact sources of drinking water, the EPA recommends that the FERC work with the Oregon Department of Environmental Quality to identify source water protection areas. Typical databases contain information about the watersheds and aquifer recharge areas, the most sensitive zones within those areas, and the numbers and types of potential contaminant sources for each system. We recommend that the EIS identify source water protection areas within the project area, activities (e.g., trenching and excavation, water withdrawal, etc.) that could potentially affect source water areas, potential contaminants that may result from the proposed project and mitigation measures that would be taken to protect the source water protection areas.

Wetlands and Aquatic Habitats
In the EIS, we recommend describing aquatic habitats in the affected environment (e.g., habitat type, plant and animal species, functional values, and integrity) and the environmental consequences of the proposed alternatives on these resources. Impacts to aquatic resources should be evaluated in terms of the areal (acreage) or linear extent to be impacted and by the functions they perform.

The proposed activities will require a Clean Water Act Section 404 permit from the Army Corps of Engineers. For wetlands and other special aquatic sites, the Section 404(b) (1) guidelines establish a presumption that upland alternatives are available for non-water dependent activities. The 404(b)(1) guidelines require that impacts to aquatic resources be (1) avoided, (2) minimized, and (3) mitigated, in that sequence. We recommend the EIS discuss in detail how planning efforts (and alternative selection) conform with Section 404(b)(1) guidelines sequencing and criteria. In other words, we request the FERC show that impacts to wetlands and other special aquatic sites have been avoided to the maximum extent practicable. The EPA also recommends the EIS discuss alternatives that would avoid wetlands and aquatic resource impacts from fill placement, water impoundment, construction, and other activities before proceeding to minimization/ mitigation measures.

The EPA recommends the EIS describe all waters of the U.S. that could be affected by the project alternatives, and include maps that clearly identify all waters within the project area. We also request the document include data on acreages and channel lengths, habitat types, values, and functions of these waters. As discussed above, projects affecting waters of the U.S. may need to comply with CWA Section 404 requirements. If project alternatives involve discharge of dredged or fill material into waters of the U.S., the EIS should include information regarding alternatives to avoid the discharges or how potential impacts caused by the discharges would be minimized and mitigated. This mitigation discussion would include the following elements:

- acreage and habitat type of waters of the U.S. that would be created or restored;
- water sources to maintain the mitigation area;
- re-vegetation plans, including the numbers and age of each species to be planted, as well as special techniques that may be necessary for planting;
- maintenance and monitoring plans, including performance standards to determine mitigation success;
- size and location of mitigation zones;
- mitigation banking and/or in lieu fees where appropriate;
- parties that would be ultimately responsible for the plan's success; and
- contingency plans that would be enacted if the original plan fails.

Where possible, mitigation should be implemented in advance of the impacts to avoid habitat losses due to the lag time between the occurrence of the impact and successful mitigation.

Water Body Crossing
As noted in Section 1.6.4 of Resource Report 1, the PCGP Project would affect 383 waterbodies. We appreciate the effort that the FERC and the proponent have made in the past to establish appropriate water body crossing procedures. We encourage the FERC to build upon these efforts through the use of risk screening tools that have been developed since the FEIS for the Jordan Cove LNG Export Facility was finalized. Specifically, we encourage the use of 1) a Project Screening Risk Matrix to evaluate the potential risks posed by the project to species or habitat, and to prioritize reviews; 2) a Project Information Checklist to evaluate whether all the necessary information is available to facilitate critical and thorough project evaluation; and 3) the River Restoration Assessment Tool, which can promote consistent and comprehensive project planning and review. These tools are available at www.restorationreview.com.

Maintenance Dredging
Resource Report 1 (Section 1.1.2.2) states that maintenance dredging requirements have been revised based on new modeling. The new estimate is that approximately 37,700 cubic yards would need to be dredged for maintenance at year 1. At year 10 that volume would be expected to decrease to 34,600 cubic yards. This is a substantial reduction from estimates of maintenance dredging included in the FEIS for the Jordan Cove Import Facility. We continue to request the inclusion of an analysis supporting the assertion that the capacity of the EPA's Ocean Disposal Site F would be unaffected by the addition of maintenance dredging material over the next 20 years in the EIS. In order for the EPA to concur with the issuance of a Section 103 permit, this will need to be clearly demonstrated.

In addition, we encourage the development of a Maintenance Dredging Plan in consultation with the U.S. Army Corps of Engineers and the EPA. That plan, including disposal, should be consistent with the site management and monitoring plan and reviewed and approved as part of the Section 103 permit process.

Air Quality
The EPA recommends the EIS provide a detailed discussion of ambient air conditions (baseline or existing conditions), National Ambient Air Quality Standards, criteria pollutant nonattainment areas, and potential air quality impacts of the proposed project (including cumulative and indirect impacts). Such an evaluation is necessary to assure compliance with State and Federal air quality regulations, and to disclose the potential impacts from temporary or cumulative degradation of air quality. The EPA recommends the EIS describe and estimate air emissions from potential construction, operation, and maintenance activities, including emissions associated with LNG carriers at berth. The analysis should also include assumptions used regarding the types of fuel burned and/or the ability for carriers to utilize dockside power (i.e. cold ironing). Emissions at berth are of particular relevance because the deep draft LNG carriers would be required to remain docked between high tides. We also recommend proposing mitigation measures in the EIS to address identified emissions impacts.

Fugitive Dust Emissions
Fugitive dust may contain small airborne particles that have the potential to adversely affect human health and the environment. The EPA defines fugitive dust as "particulate matter that is generated or emitted from open air operations (emissions that do not pass through a stack or a vent)". The most common forms of particulate matter (PM) are known as PM_{10} and $PM_{2.5}$ (particulate matter size less than 10 and 2.5 microns, respectively).

Sources of fugitive dust from this project may include unpaved gravel roads and facility pads, and clearing and construction sites. Effects of fugitive dust to the natural environment may include visibility reduction and haze, surface water impacts, impacts to wetlands, and reduction in plant growth. Fugitive dust may pose a human health risk due to chronic exposure in areas with vulnerable populations, such as infants and the elderly. The EPA recommends the EIS evaluate the magnitude and significance of fugitive dust emissions resulting from this project and potential impacts on human health.

We also recommend that a Dust Control Plan be developed and included as an appendix to the EIS. This plan should include provisions for monitoring fugitive dust during construction and operations, and implementing measures to reduce fugitive dust emissions, such as wetting the source material, installing barriers to prevent dust from leaving the source area, and halting operations during high wind events. We recommend that the EIS identify mitigation measures to avoid and minimize potential adverse impacts to the natural and human environment.

Biological Resources, Habitat and Wildlife
The EPA recommends the EIS identify all petitioned and listed threatened and endangered species under the Endangered Species Act, as well as critical habitat that might occur within the project area. We also recommend the EIS identify and quantify which species or critical habitat might be directly, indirectly, or cumulatively affected by each alternative and mitigate impacts to those species. The EPA recommends that the FERC continue to work with the U.S. Fish and Wildlife Service and the National Marine Fisheries Service. The EPA also recommends that the FERC continue to coordinate with the Oregon Department of Fish and Wildlife to ensure that State sensitive species are adequately addressed within the analysis and that current and consistent surveying, monitoring, and reporting protocols are applied in protection and mitigation efforts.

The EPA recommends the EIS also identify species listed under the Marine Mammal Protection Act. Marine barge/vessel traffic may result in potential conflicts with threatened and/or endangered marine mammals and their migration patterns and routes. We also recommend that the EIS describe the barge/vessel traffic schedule, patterns and marine transportation routes, as well as the migration period, patterns, and routes of potentially affected marine mammals. The direct, indirect and cumulative impacts from barge/vessel traffic on marine mammals, threatened and endangered species, critical habitats, and subsistence resources should be analyzed in the EIS.

Land Use Impacts
Land use impacts would include, but not be limited to, disturbance of existing land uses within construction work areas during construction and creation of permanent right-of-ways for construction, operations, and maintenance of the pipeline and above ground facilities. The EPA recommends the EIS document all land cover and uses within the project corridor, impacts by the project to the land cover and uses, and mitigation measures that would be implemented to reduce the impacts.

The primary impact of construction on forests and other open land use types would be the removal of trees, shrubs, and other vegetation. Although these can be regenerated or replanted, their re-establishment can take up to 20 years or more, making the construction impacts to these resources long term and in some cases permanent. The impact on forest land use, for example, in the permanent right-of-way areas would be a permanent change to open land. We recommend the EIS describe the impacts to forest and open land use types, indicate if the impacts would be permanent or temporary, and state measures that would be taken to compensate landowners for loss of their resources because of the project.

If the project would cross sensitive areas then the EIS should specify the areas, indicate impacts to the areas, and document any easement conditions for use of the areas, including mitigation measures.

Invasive Species

The establishment of invasive nuisance species has become an issue of environmental and economic significance. The EPA recommends consideration of impacts associated with invasive nuisance species consistent with *E.O. 13112 Invasive Species*. In particular, construction activities associated with buried pipelines which disturb the ground may expose areas and could facilitate propagation of invasive species. Mitigation, monitoring and control measures should be identified and implemented to manage establishment of invasive species throughout the entire pipeline corridor right-of-way. We recommend that the EIS include a project design feature that calls for the development of an invasive species management plan to monitor and control noxious weeds, and to utilize native plants for restoration of disturbed areas after construction.

If pesticides and herbicides will be applied during construction, operation, and maintenance of the project, we recommend that the EIS address any potential toxic hazards related to the application of the chemicals, and describe what actions will be taken to assure that impacts by toxic substances released to the environment will be minimized.

Ballast water from barges/vessels is a major source of introducing non-native species into the marine ecosystems where they would not otherwise be present. Non-native species can adversely impact the economy, the environment, or cause harm to human health. Impacts may include reduction of biodiversity of species inhabiting coastal waters from competition between non-native and native species for food and resources. We recommend that the EIS discuss potential impacts from non-native invasive species associated with ballast water and identify mitigation measures to minimize adverse impacts to the marine environment and human health.

Hazardous Materials/Hazardous Waste/Solid Waste

The EPA recommends EIS address potential direct, indirect, and cumulative impacts of hazardous waste from construction and operation of the proposed project. The document should identify projected hazardous waste types and volumes, and expected storage, disposal, and management plans. It should identify any hazardous materials sites within the project's study area and evaluate whether those sites would impact the project in any way.

Seismic and Other Risks

Construction and operation of the proposed facility and pipeline may cause or be affected by increased seismicity (earthquake activity) in tectonically active zones. We recommend that the EIS identify potentially active and inactive fault zones where the proposed pipeline may cross. This analysis should discuss the potential for seismic risk and how this risk will be evaluated, monitored, and managed. A map depicting these geologic faults should be included in the EIS. The construction of the proposed project must use appropriate seismic design and construction standards and practices. Ground movement on these faults can cause a pipeline to rupture, resulting in discharge of gas and subsequent explosion. Particular attention should be paid to areas where the pipeline may cross areas with high population densities. Mitigation measures should be identified in the EIS to minimize effects on the pipeline due to seismic activities.

Blasting Activities
During project construction, blasting may be required in certain areas along the pipeline route corridor and adjacent facilities, resulting in increased noise and related effects to local residents, and disruption and displacement of bird and wildlife species. We recommend that the EIS discuss where blasting in the project area would be required, blasting methods that would be used, and how blasting effects would be controlled and mitigated. Noise levels in the project area should be quantified and the effects of blasting to the public and to wildlife should also be evaluated in the EIS. We recommend that a Blasting Management Plan be developed and the environmental impacts evaluated in the EIS.

National Historic Preservation Act
Consultation for tribal cultural resources is required under Section 106 of the National Historic Preservation Act (NHPA). Historic properties under the NHPA are properties that are included in the National Register of Historic Places or that meet the criteria for the National Register. Section 106 of the NHPA requires a federal agency, upon determining that activities under its control could affect historic properties, consult with the appropriate State Historic Preservation Officer /Tribal Historic Preservation Officer. Under NEPA, any impacts to tribal, cultural, or other treaty resources must be discussed and mitigated. Section 106 of the NHPA requires that federal agencies consider the effects of their actions on cultural resources, following regulation in 36 CFR 800.

Environmental Justice and Impacted Communities
In compliance with NEPA and with Executive Order (EO) 12898 on Environmental Justice, actions should be taken to conduct adequate public outreach and participation that ensures the public and Native American tribes understand the possible impacts to their communities and trust resources.

EO 12898 requires each Federal agency to identify and address disproportionately high and adverse human health or environmental effects of its programs, policies, and activities on minority populations, low-income populations, and Native American tribes.[4] The EPA also considers children, the disabled, the elderly, and those of limited English proficiency to be potential Environmental Justice communities due to their unique vulnerabilities.

According to the Council on Environmental Quality, when determining whether environmental effects are disproportionately high and adverse, agencies should consider the following factors: [5]

- Whether environmental effects are or may be having an adverse impact on minority populations, low-income populations, or Indian tribes that appreciably exceeds or is likely to appreciably exceed those on the general population or other appropriate comparison group
- Whether the disproportionate impacts occur or would occur in a minority population, low-income population, or Indian tribe affected by cumulative or multiple adverse exposures from environmental hazards

[4] EO 12898: Federal Actions to Address Environmental Justice in Minority Populations and Low-income Populations. February 11, 1994.
[5] http://ceq.hss.doe.gov/nepa/regs/ej/justice.pdf

Socioeconomic Impacts
Council on Environmental Quality Regulations at 40 CFR 1500-1508 state that the "human environment" is to be "interpreted comprehensively" to include "the natural and physical environment and the relationship of people with that environment" (40 CFR 1508.14). Consistent with this direction, agencies need to assess not only "direct" effects, but also "aesthetic, historic, cultural, economic, social, or health" effects, "whether direct, indirect, or cumulative" (40 CFR 1508.8).

Social impact assessment variables point to measurable change in human population, communities, and social relationships resulting from a development project or policy change. We suggest that the EIS analyze the following social variables:

- Population Characteristics
- Community and Institutional Structures
- Political and Social Resources
- Individual and Family Changes
- Community Resources

Impacts to these social variables should be considered for each stage of the project (development, construction, operation, decommissioning). With regard to the construction and operation phase of the project, we recommend the analysis give consideration to how marine traffic might change, and how this may affect commercial or recreational use on the bay and travel over the bar.

Greenhouse Gas (GHG) Emissions
On February 18, 2010, the CEQ issued draft guidance to Federal Agencies on analyzing the effects of Greenhouse Gas (GHG) emissions and climate change when describing the environmental effects of a proposed agency action in accordance with NEPA[6].

CEQ's draft guidance defines GHG emissions in accordance with Section 19(i) of *E.O. 13514 Federal Leadership in Environment, Energy, and Economic Performance (October 5, 2009)* to include carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), hydrofluorcarbon (HFCs), perfluorcarbon (PFCs), and sulfurhexafluoride (SF_6). Because CO_2 is the reference gas for climate change based on their potential to absorb heat in the atmosphere, measures of non-CO_2 GHGs should be reflected as CO_2-equivalent (CO_2-e) values.

The EPA supports evaluation and disclosure of GHG emissions and climate change effects resulting from the proposed project during all project phases, including (1) pre-construction (e.g., transportation, mobilization, and staging), (2) construction, (3) operation, (4) maintenance, and (5) decommissioning. We recommend that the GHG emission accounting/inventory include each proposed stationary source (e.g., power plant, liquefaction facility, compressor and metering stations, etc.) and mobile emission source (e.g., heavy equipment, supply barges, rail transports, etc.). We also recommend that the EIS establish reasonable spatial and temporal boundaries for this analysis, and that the EIS quantify and disclose the expected annual direct and indirect GHG emissions for the proposed action. In the analysis of direct effects, we recommend that the EIS quantify cumulative emissions over the life of the project, discuss measures to reduce GHG emissions, including consideration of reasonable alternatives

[6]See http://ceq.hss.doe.gov/current_developments/new_ceq_nepa_guidance.html

We recommend that the EIS consider mitigation measures and reasonable alternatives to reduce action-related GHG emissions, and include a discussion of cumulative effects of GHG emissions related to the proposed action. We recommend that this discussion focus on an assessment of annual and cumulative emissions of the proposed action and the difference in emissions associated with the alternatives.

In addition, greenhouse gas emission sources in the petroleum and natural gas industry are required to report GHG emissions under 40CFR Part 98 (subpart W), the Greenhouse Gas Reporting Program. Consistent with draft CEQ guidance[5], we recommend that this information be included in the EIS for consideration by decision makers and the public. Please see http://www.epa.gov/climatechange/emissions/ghgrulemaking.html.

Climate Change

Scientific evidence supports the concern that continued increases in greenhouse gas emissions resulting from human activities will contribute to climate change. Global warming is caused by emissions of carbon dioxide and other heat-trapping gases. On December 7, 2009, the EPA determined that emissions of GHGs contribute to air pollution that "endangers public health and welfare" within the meaning of the Clean Air Act. Higher temperatures and increased winter rainfall will be accompanied by a reduction in snow pack, earlier snowmelts, and increased runoff. Some of the impacts, such as reduced groundwater discharge, and more frequent and severe drought conditions, may impact the proposed projects. The EPA recommends the EIS consider how climate change could potentially influence the proposed project, specifically within sensitive areas, and assess how the projected impacts could be exacerbated by climate change.

Coordination with Tribal Governments

Executive Order 13175, Consultation and Coordination with Indian Tribal Governments (November 6, 2000), was issued in order to establish regular and meaningful consultation and collaboration with tribal officials in the development of federal policies that have tribal implications, and to strengthen the United States government-to-government relationships with Indian tribes. The EIS should describe the process and outcome of government-to-government consultation between the FERC and tribal governments within the project area, issues that were raised, and how those issues were addressed in the selection of the proposed alternative.

Indirect Impacts

Per CEQ regulations at CFR 1508.8(b), the indirect effects analysis "may include growth inducing effects and other effects related to induced changes in the pattern of land use, population density or growth rate, and related effects on air and water and other natural systems, including ecosystems." The 2012 report from the Energy Information Administration[7] states that, "natural gas markets in the United States balance in response to increased natural gas exports largely through increased natural gas production." That report goes on to say that about three-quarters of that increase production would be from shale resources. We believe it is appropriate to consider available information about the extent to which drilling activity might be stimulated by the construction of an LNG export facility on the west coast, and any potential environmental effects associated with that drilling expansion.

[7] Energy Information Administration, Effects of Increased Natural Gas Exports on Domestic Energy Markets, 6 (January 2012) available at http://www.eia.gov/analysis/requests/fe/pdf/fe_lng.pdf

Cumulative Impacts
The cumulative impacts analysis should identify how resources, ecosystems, and communities in the vicinity of the project have already been, or will be affected by past, present, or future activities in the project area. These resources should be characterized in terms of their response to change and capacity to withstand stresses. Trends data should be used to establish a baseline for the affected resources, to evaluate the significance of historical degradation, and to predict the environmental effects of the project components.

For the cumulative impacts assessment, we recommend focusing on resources of concern or resources that are "at risk" and /or are significantly impacted by the proposed project, before mitigation. For this project, the FERC should conduct a thorough assessment of the cumulative impacts to aquatic and biological resources (including plover habitat), air quality, and commercial and recreational use of the bay. We believe the EIS should consider the Oregon Gateway Marine Terminal Complex as described by the Port of Coos Bay (http://www.portofcoosbay.com/orgate.htm) as reasonably foreseeable for the purposes of cumulative effects analysis. We recognize that uncertainty about future development of the North Spit remains, but we believe the stated aspirations of the Port and the Oregon Department of State Lands' 2011 issuance of a removal-fill permit for the development of an access channel and multi-purpose vessel slip provide sufficient reason for including the marine terminal complex in the effects analysis.

The EPA also recommends the EIS delineate appropriate geographic boundaries, including natural ecological boundaries, whenever possible, and should evaluate the time period of the project's effects. For instance, for a discussion of cumulative wetland impacts, a natural geographic boundary such as a watershed or sub-watershed could be identified. The time period, or temporal boundary, could be defined as from 1972 (when the Clean Water Act established section 404) to the present.

Please refer to CEQ's "Considering Cumulative Effects Under the National Environmental Policy Act"[8] and the EPA's "Consideration of Cumulative Impacts in EPA Review of NEPA Documents"[9] for assistance with identifying appropriate boundaries and identifying appropriate past, present, and reasonably foreseeable future projects to include in the analysis.

Mitigation and Monitoring
On February 18, 2010, CEQ issued draft guidance on the Appropriate Use of Mitigation and Monitoring. This guidance seeks to enable agencies to create successful mitigation planning and implementation procedures with robust public involvement and monitoring programs[10].

We recommend that the EIS include a discussion and analysis of proposed mitigation measures and compensatory mitigation under CWA §404. The EIS should identify the type of activities which would require mitigation measures either during construction, operation, and maintenance phases of this project. To the extent possible, mitigation goals and measureable performance standards should be identified in the EIS to reduce impacts to a particular level or adopted to achieve an environmentally preferable outcome.

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8 http://ceq.hss.doe.gov/nepa/ccenepa/ccenepa.htm
9 http://www.epa.gov/compliance/resources/policies/nepa/cumulative.pdf
10 http://ceq.hss.doe.gov/current_developments/docs/Mitigation_and_Monitoring_Guidance_14Jan2011.pdf

Mitigation measures could include best management practices and options for avoiding and minimizing impacts to important aquatic habitats and to compensate for the unavoidable impacts. Compensatory mitigation options could include mitigation banks, in-lieu fee, preservation, applicant proposed mitigation, etc. and should be consistent with the *Compensatory Mitigation for Losses of Aquatic Resources; Final Rule* (33 CFR Parts 325 and 332 and 40 CFR Part 230). A mitigation plan should be developed in compliance with 40 CFR Part 230 Subpart J 230.94, and included in the EIS.

An environmental monitoring program should be designed to assess both impacts from the project and that mitigation measures being implemented are effective. We recommend the EIS identify clear monitoring goals and objectives, such as what parameters are to be monitored, where and when monitoring will take place, who will be responsible, how the information will be evaluated, what actions (contingencies, triggers, adaptive management, corrective actions, etc.) will be taken based on the information. Furthermore, we recommend the EIS discuss public participation, and how the public can get information on mitigation effectiveness and monitoring results.

ORIGINAL

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION III
1650 Arch Street
Philadelphia, Pennsylvania 19103-2029

November 15, 2012

Kimberly D. Bose, Secretary
Federal Energy Regulatory Commission
888 First Street NE, Room 1A
Washington, DC 20426

RE: EPA Region 3 Scoping Comments in Response to FERC's Notice of Intent to Prepare an Environmental Assessment (EA) for the Planned Cove Point Liquefaction Project; FERC Docket No. PF12-16-000

Dear Secretary Bose:

The U.S. Environmental Protection Agency (EPA), Region III Office, has conducted a review of the above Notice in conjunction with our responsibilities under the National Environmental Policy Act (NEPA), the Clean Water Act (CWA) and Section 309 of the Clean Air Act. As part of the FERC pre-filing process of soliciting public and agency comments for development of the EA, EPA offers the following scoping comments.

The NOI describes Dominion's proposal to add an LNG export terminal to its existing LNG import terminal on the Chesapeake Bay in Lusby, Maryland. The new terminal would have capacity to process and export up to 750 million standard cubic feet of natural gas per day (0.75 billion cubic feet/day). Facilities would include:

- Natural gas fired turbines to drive the main refrigerant compressors;
- One or two LNG drive trains and new processing facilities;
- 29,000 to 34,000 additional horsepower compression at its existing Loudon County, VA
- Compressor Station and/or its existing Pleasant Valley (Fairfax County, VA) Compressor Station;
- Additional on-site power generation
- Minor modifications to the existing off-shore pier;
- Use of nearby properties and possible relocation of administrative functions

The Project would not include new LNG storage tanks or an increase in the size and/or frequency of LNG marine traffic currently authorized for the Cove Point LNG Terminal. The NEPA document should include a clear and robust justification of the underlying purpose and need for the proposed project. In order for the project to move forward, FERC would need to issue a certificate of "public convenience and necessity". We recommend discussing the proposal in the context of the broader energy market, including existing and proposed LNG export capacity, describing the factors involved in determining public convenience and necessity for this facility.

EPA recommends assessing the cumulative environmental effects resulting from implementation of the proposed project, when combined with other past, present and reasonably foreseeable future actions, regardless of whether these actions are energy related or not, or whether or not FERC has jurisdiction over them. We recommend focusing on resources or communities of concern, or resources "at risk" which could be cumulatively impacted by all of the above actions. Please refer to the Council on Environmental Quality (CEQ) guidance on "Considering Cumulative Effects Under the National Environmental Policy Act", and EPA's "Consideration of Cumulative Impacts in EPA Review of NEPA Documents" for further assistance in identifying appropriate spatial and temporal boundaries for this analysis.

We also recommend expanding the scope of analysis to include indirect effects related to gas drilling and combustion. A 2012 report (http://www.eia.gov/analysis/requests/fe/) from the Energy Information Administration (EIA) states that, "natural gas markets in the United States balance in response to increased natural gas exports largely through increased natural gas production." That report also indicated that about three-quarters of that increase production would be from shale resources and that domestic natural gas prices could rise by more than 50% if permitted to be exported. We believe it is appropriate to consider the extent to which implementation of the proposed project, combined with implementation of other similar facilities nationally, could increase the demand for domestic natural gas extraction and increase domestic natural gas prices. As part of this assessment, please discuss the extent to which implementation of the proposed project would create a demand for construction of new gas pipelines or expansion of existing pipelines, in order to accommodate the increased volumes of gas supplied to the Cove Point and other facilities.

In the air impact analysis for the Cove Point Project, we recommend considering the direct, temporary emissions from construction of all facilities, as well as permanent air emission impacts from facility operations, including all compressor stations and any vessel traffic related to LNG exports. Additionally, indirect and reasonably foreseeable cumulative impacts from past, present and future actions, when added to the incremental impacts of the Project proposed should be evaluated. These other actions should include FERC jurisdictional facilities and energy generating and transporting-related facilities, as well as actions or facilities which might have air emissions which could impact the same air receptors as the Project, including downstream combustion.

Please note whether construction or operation of the Project would involve any discharges to Waters of the United States, and whether it would affect the Chesapeake Bay Total Maximum Daily Load (TMDL) or any related Watershed Implementation Plans (WIPs).

As part of any environmental documentation, please include evaluation of the Project's direct and indirect impacts on the nearby Chesapeake Bay fisheries and fishermen (both recreational and commercial). Will any additional dredging of waterways be required to accommodate the vessels exporting LNG? What biosecurity controls and protocols will be instituted to prevent introduction of invasive species due to ballast water releases? Please include a discussion of how the Project will comply with the Magnuson-Stevens Fishery Conservation and Management Act, as amended by the Sustainable Fisheries Act of 1966 (PL 04-267)(Essential Fish Habitat).

Please express the volume of natural gas proposed to be exported in terms that the average reader can more easily understand. For example, in addition to indicating that the Project would be capable of processing an average of 750 million standard cubic feet of natural gas per day, also express that figure as an equivalent number of average homes this amount of gas could heat, or how many tankers, and of what size, this amount of gas would fill. Also, please calculate how many production wells, on average, would need to be drilled in order to produce this amount of gas.

The NOI states that the Project would not increase the size and/or frequency of LNG marine traffic currently authorized for the Cove Point LNG Terminal. Please discuss in the NEPA document whether this would be accomplished by reducing the volume of LNG imports to match the volume of proposed exports, or by employing some other approach.

Please indicate the number, location, size and capacity of the network of bidirectional pipelines from which the proposed Project would or could receive natural gas, and also indicate whether any of those pipelines would need to be expanded or modified in order to provide the volumes of gas anticipated.

Please indicate whether any aspect of the Project would trigger any requirements for hazardous waste management under the Resource Conservation and Recovery Act (RCRA) or other Federal statutes involving management of such waste.

The proposed Dominion Cove Point facility represents one of sixteen (16) applications currently pending before the U.S. Department of Energy (DOE) for approval to export LNG to countries which do not have Free Trade Agreements (FTA) with the United States. At this time, it appears that only one facility has been initially granted full approval (Sabine Pass in Cameron Parish, Louisiana). Although we are aware of the DOE national study in progress on the cumulative *economic* impacts of allowing natural gas exports, EPA believes that the Cove Point NEPA process represents an opportunity for FERC and DOE to jointly and thoroughly consider the indirect and cumulative *environmental* impacts of exporting LNG from Cove Point. The environmental study of the Cove Point Project should be a comprehensive and robust evaluation of potential impacts, which may require a higher level analysis particularly in consideration of the potential for significant cumulative impacts and the level of community interest.

Thank you for the opportunity to comment on this Notice. EPA welcomes the opportunity to discuss these topics by phone or in-person, at your convenience. If you have any questions concerning these comments, please contact Mr. Thomas Slenkamp of this Office at (215) 814-2750.

Sincerely,

Jeffrey D. Lapp, Associate Director
Office of Environmental Programs

Document Content(s)

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION 10
1200 Sixth Avenue, Suite 900
Seattle, WA 98101-3140

OFFICE OF
ECOSYSTEMS,
TRIBAL AND PUBLIC
AFFAIRS

December 26, 2012

The Honorable Kimberly D. Bose, Secretary
Federal Energy Regulatory Commission
888 First Street, NE, Room 1A
Washington, DC 20426

Re: SCOPING COMMENTS – The Oregon LNG Export Project and Washington Expansion Project. EPA Region 10 Project Number: 12-0055-FRC. *FERC Docket Nos. PF12-18-000 and PF12-20-000.*

Dear Secretary Bose:

The U.S. Environmental Protection Agency would like to provide detailed scoping comments in response to the Federal Energy Regulatory Commission's (FERC's) September 24, 2012 Notice of Intent (NOI) to prepare an Environmental Impact Statement (EIS) for the Oregon Liquefied Natural Gas (LNG) Export Project and Washington Expansion. These comments were prepared in accordance with our authorities pursuant to the National Environmental Policy Act (NEPA), Section 309 of the Clean Air Act, the Clean Water Act, and our responsibilities as a Cooperating Agency. We appreciate the opportunity for early involvement at this step of the NEPA process.

The Clean Air Act Section 309 directs the EPA to review and comment in writing on the environmental impacts resulting from certain proposed actions of other federal agencies and the adequacy of the Draft EIS in meeting the procedural and public disclosure requirements in accordance with NEPA. Please see the EPA's review criteria for rating Draft EISs at the EPA web site: (http://www.epa.gov/compliance/nepa/comments/ratings.html). Our review authorities under Section 309 are independent of our responsibilities as a Cooperating Agency for this EIS.

As described in the NOI, the Oregon LNG export project would consist of components new to and modified from the originally proposed import-only LNG terminal and pipeline (Docket Nos. CP09-6-000 and CP09-7-000) to allow Oregon LNG to export LNG. The export project would be capable of liquefying approximately 1.3 billion cubic feet per day (Bcf/d) of pretreated natural gas for the export of approximately 9 million metric tons per annum (MTPA) of LNG via LNG carriers.

Specifically, the Export Project would be comprised of liquefaction and export facilities at Warrenton, Oregon and approximately 39 miles of new pipeline. Liquefaction facilities would include:

- A natural gas pretreatment facility to remove sulfur compounds, water, mercury, and other impurities;
- Two liquefaction process trains, each capable of a liquefaction capacity of approximately 4.5 MTPA;
- Refrigerant storage;
- New flare system;

- New water intake on the Columbia River and water delivery pipeline from the intake to a new water treatment system.

Pipeline facilities would include:

- 39 miles of new pipeline commencing at milepost (MP) 47.5 of the pending proposed Oregon Pipeline; and
- A new compressor station at MP 80.8.

The connected Washington Expansion Project (WEP) would expand the capacity of Northwest Pipeline GP (Northwest) between Sumas and Woodland, Washington, by 750,000 dekatherms per day to provide natural gas to the proposed Oregon LNG terminal, and to markets in the state of Washington.

Pipeline facilities for the WEP would include:

- Approximately 140 miles of 36-inch-diameter pipeline loop along Northwest's existing Northwest Pipeline in 10 segments; and
- An additional 96,000 horsepower (hp) of compression at five existing compressor stations.

The enclosed scoping comments were prepared based on our review of the NOI referenced above and the draft Resource Report 1. Our comments reflect a broad range of issues that we believe to be significant and warrant treatment in the EIS.

As a Cooperating Agency, we look forward to continued communication with your office throughout the development of the EIS, and we are available to work with FERC to review and comment on preliminary sections of the document. If you have any questions regarding our scoping comments, please do not hesitate to contact me at (206) 553-1601 or by electronic mail at reichgott.christine@epa.gov, or you may contact Teresa Kubo of my staff in the Oregon Operations Office at (503) 326-2859 or by electronic mail at kubo.teresa@epa.gov. We look forward to our continued coordination and involvement in this project.

Sincerely,

Christine B. Reichgott

Christine B. Reichgott, Manager
Environmental Review and Sediment Management Unit

Enclosure

U.S. Environmental Protection Agency
Detailed Scoping Comments to Address the Federal Energy Regulatory Commission's Notice of Intent to Prepare an Environmental Impact Statement for the Oregon LNG Export Project and Washington Expansion Project
FERC Docket Nos. PF12-18-000 and PF12-20-000

Purpose and Need
The EIS should include a clear and concise statement of the underlying purpose and need for the proposed project, consistent with the implementing regulations for NEPA (see 40 CFR 1502.13). In presenting the purpose and need for the project, the EIS should reflect not only the FERC's purpose, but also the broader public interest and need.

In supporting the statement of purpose and need, we recommend discussing the proposed project in the context of the larger energy market, including existing export capacity and export capacity under application to the Department of Energy, and clearly describing how the need for the proposed action has been determined.

Alternatives Analysis
NEPA requires evaluation of reasonable alternatives, including those that may not be within the jurisdiction of the lead agency[1]. A robust range of alternatives will include options for avoiding significant environmental impacts. The EIS should "rigorously explore and objectively evaluate all reasonable alternatives"[2] by developing a screening process. The screening process should rate each alternative against a set of pre-determined criteria. Each alternative should then be analyzed for its level of impact on a resource (e.g. no effect, negligible effect, minor effect, major effect, significant effect). Only the alternative that effectively meets or best meets all of the screening criteria should be recommended as the preferred alternative. The EIS should provide a clear discussion of the reasons for the elimination of alternatives which are not evaluated in detail.

Environmental Consequences
According to 40 CFR Part 1502.1, an Environmental Impact Statement, "...shall provide full and fair discussion of significant environmental impacts and shall inform decision makers and the public of the reasonable alternatives which would avoid or minimize adverse impacts or enhance the quality of the environment." In order to facilitate a full and fair discussion on significant environmental issues, we encourage the FERC to establish thresholds of significance for each resource of concern, and to analyze environmental consequences in a clear, repeatable manner. For each action, a series of questions should be considered: 1) What is the action? 2) What is the intensity or extent of impacts? 3) Based on identified thresholds, is that significant? If an impact of the action is significant, then the EIS must contain appropriate mitigation measures.

Water Quality
In order to adequately address water quality issues, the EPA recommends the EIS identify water bodies likely to be impacted by the project, the nature of the potential impacts, and the specific discharges and pollutants likely to impact those waters (addressing both Section 402 and 404 discharges and potential impairments to water quality standards). We also recommend the EIS disclose information regarding

[1] 40 CFR 1502.14(c)
[2] 40 CFR 1502.14(a)

relevant Total Maximum Daily Load allocations, the water bodies to which they apply, water quality standards and pollutants of concern.

Clean Water Act Section 303(d) listed waters should not be further degraded. If additional pollutant loading is predicted to occur to a 303(d) listed stream as a result of a project, the EIS should include measures to control existing sources of pollution to offset pollutant additions.

Consider implementing watershed or aquatic habitat restoration activities to compensate for past impacts to water resources, particularly in watersheds with 303(d) listed waters where development may have contributed to impairments through past channelization, riverine or floodplain encroachments, sediment delivery during construction, and other activities that may have affected channel stability, water quality, aquatic habitat, and designated waterbody uses. Provisions for antidegradation of water quality apply to water bodies where water quality standards are presently being met. We recommend the EIS describe how antidegradation provisions would be met.

Hydrostatic Test Water

Hydrostatic testing of pipelines and tanks will be required to verify their integrity. We recommend that the EIS identify the water sources and withdrawal rates that would be required for hydrostatic testing. We recommend that the EIS identify and describe the location of these water sources (surface areas, depth, volumes, withdrawal rates, and project requirements). For each water source, we recommend that the EIS discuss the presence of any anadromous and/or resident fish species, including a discussion of any direct and cumulative impacts to fisheries resources. In addition, we recommend that the locations of discharge to land and/or surface waters, and discharge methods be specified in the EIS. Emphasis should be placed on minimizing interbasin transfers of water to the maximum extent practicable in order to minimize the risk of mobilizing invasive species. We recommend that the EIS describe the mitigation measures and control devices that would be implemented to minimize environmental impacts.

Source Water Protection

Public drinking water supplies and/or their source areas often exist in many watersheds. Source water areas may exist within watersheds where the pipeline and associated facilities would be located. Source waters are streams, rivers, lakes, springs, and aquifers used as supply for drinking water. Source water areas are delineated and mapped by the states for each federally-regulated public water system. The 1996 amendments to the Safe Drinking Water Act require federal agencies to protect sources of drinking water for communities. As a result, state agencies have been delegated responsibility to conduct source water assessments and provide a database of information about the watersheds and aquifers that supply public water systems.

Since construction, operation, and maintenance of a buried natural gas pipeline may impact sources of drinking water, the EPA recommends that the FERC work with the Oregon Department of Environmental Quality to identify source water protection areas. Typical databases contain information about the watersheds and aquifer recharge areas, the most sensitive zones within those areas, and the numbers and types of potential contaminant sources for each system. We recommend that the EIS identify source water protection areas within the project area, activities (e.g., trenching and excavation, water withdrawal, etc.) that could potentially affect source water areas, potential contaminants that may result from the proposed project and mitigation measures that would be taken to protect the source water protection areas.

Wetlands and Aquatic Habitats
In the EIS, we recommend describing aquatic habitats in the affected environment (e.g., habitat type, plant and animal species, functional values, and integrity) and the environmental consequences of the proposed alternatives on these resources. Impacts to aquatic resources should be evaluated in terms of the areal (acreage) or linear extent to be impacted and by the functions they perform.

The proposed activities will require a Clean Water Act Section 404 permit from the Army Corps of Engineers. For wetlands and other special aquatic sites, the Section 404(b) (1) guidelines establish a presumption that upland alternatives are available for non-water dependent activities. The 404(b)(1) guidelines require that impacts to aquatic resources be (1) avoided, (2) minimized, and (3) mitigated, in that sequence. We recommend the EIS discuss in detail how planning efforts (and alternative selection) conform with Section 404(b)(1) guidelines sequencing and criteria. In other words, we request the FERC show that impacts to wetlands and other special aquatic sites have been avoided to the maximum extent practicable. The EPA also recommends the EIS discuss alternatives that would avoid wetlands and aquatic resource impacts from fill placement, water impoundment, construction, and other activities before proceeding to minimization/ mitigation measures.

The EPA recommends the EIS describe all waters of the U.S. that could be affected by the project alternatives, and include maps that clearly identify all waters within the project area. We also request the document include data on acreages and channel lengths, habitat types, values, and functions of these waters. As discussed above, projects affecting waters of the U.S. may need to comply with CWA Section 404 requirements. If project alternatives involve discharge of dredged or fill material into waters of the U.S., the EIS should include information regarding alternatives to avoid the discharges or how potential impacts caused by the discharges would be minimized and mitigated. This mitigation discussion would include the following elements:

- acreage and habitat type of waters of the U.S. that would be created or restored;
- water sources to maintain the mitigation area;
- re-vegetation plans, including the numbers and age of each species to be planted, as well as special techniques that may be necessary for planting;
- maintenance and monitoring plans, including performance standards to determine mitigation success;
- size and location of mitigation zones;
- mitigation banking and/or in lieu fees where appropriate;
- parties that would be ultimately responsible for the plan's success; and
- contingency plans that would be enacted if the original plan fails.

Where possible, mitigation should be implemented in advance of the impacts to avoid habitat losses due to the lag time between the occurrence of the impact and successful mitigation.

Water Body Crossing
We appreciate the effort that the FERC and the proponent have made in the past to establish appropriate water body crossing procedures. We encourage the FERC to build upon these efforts through the use of risk screening tools that have been developed more recently. Specifically, we encourage the use of 1) a Project Screening Risk Matrix to evaluate the potential risks posed by the project to species or habitat, and to prioritize reviews; 2) a Project Information Checklist to evaluate whether all the necessary information is available to facilitate critical and thorough project evaluation; and 3) the River

Restoration Assessment Tool, which can promote consistent and comprehensive project planning and review. These tools are available at www.restorationreview.com.

Dredging

According to Resource Report 1, Oregon LNG expects that construction of the berth and turning basin will require an estimated 1,275,000 cubic yards of dredge material requiring removal. (Section 1.3.1). Oregon LNG has been actively working with agencies and stakeholders to identify an appropriate location for dredge material disposal. We understand that Oregon LNG priority sites have shifted to the USEPA Deepwater Site, the USEPA Shallow Water Site, the US Army Corps of Engineers (USACE) North Jetty S, and the USACE South Jetty Nearshore Site. We provide the following comments for FERC's consideration as Resource Report 10 and the DEIS are developed:

- Capacity at the USEPA Deep Water Site has been characterized by the proponent as "unlimited"[3]. The EPA agrees that capacity at the site is large, but it is not unlimited. The EPA has asked USACE to conduct an assessment of long term capacity as part of the Annual Use Plan for 2014.
- The USEPA Shallow Water Site is used to capacity every season, and accretion limits are very low. Because shoaling is an unacceptable outcome, disposals at this site would need to be monitored with USACE and the EPA.
- The South Jetty Nearshore Site (Oregon) was accepted by the Lower Columbia Solutions Group (LCSG) on a provisional basis in 2011. Future use of this site would need to be coordinated with the LCSG as well as the USACE. The crab fishing community has requested demonstrable proof over multiple seasons that crabs will not be affected by dredge material disposal activity.

The EPA supports and appreciates the long standing efforts of the proponents and FERC to identify alternative disposal site locations. We will continue to work with the proponent and FERC to identify disposal locations that meet established criteria under Section 103 of the Marine Protection, Research and Sanctuaries Act (MPRSA).

Air Quality

The EPA recommends the EIS provide a detailed discussion of ambient air conditions (baseline or existing conditions), National Ambient Air Quality Standards, criteria pollutant nonattainment areas, and potential air quality impacts of the proposed project (including cumulative and indirect impacts). Such an evaluation is necessary to assure compliance with State and Federal air quality regulations, and to disclose the potential impacts from temporary or cumulative degradation of air quality. The EPA recommends the EIS describe and estimate air emissions from potential construction, operation, and maintenance activities, including emissions associated with LNG carriers at berth. The analysis should also include assumptions used regarding the types of fuel burned and/or the ability for carriers to utilize dockside power (i.e. cold ironing). Emissions at berth are of particular relevance because the deep draft LNG carriers would be required to remain docked between high tides. We also recommend proposing mitigation measures in the EIS to address identified emissions impacts.

Fugitive Dust Emissions

Fugitive dust may contain small airborne particles that have the potential to adversely affect human health and the environment. The EPA defines fugitive dust as "particulate matter that is generated or emitted from open air operations (emissions that do not pass through a stack or a vent)". The most

[3] Attachment 10-1 Table of Dredge Material Disposal Sites

common forms of particulate matter (PM) are known as PM_{10} and $PM_{2.5}$ (particulate matter size less than 10 and 2.5 microns, respectively).

Sources of fugitive dust from this project may include unpaved gravel roads and facility pads, and clearing and construction sites. Effects of fugitive dust to the natural environment may include visibility reduction and haze, surface water impacts, impacts to wetlands, and reduction in plant growth. Fugitive dust may pose a human health risk due to chronic exposure in areas with vulnerable populations, such as infants and the elderly. The EPA recommends the EIS evaluate the magnitude and significance of fugitive dust emissions resulting from this project and potential impacts on human health.

We also recommend that a Dust Control Plan be developed and included as an appendix to the EIS. This plan should include provisions for monitoring fugitive dust during construction and operations, and implementing measures to reduce fugitive dust emissions, such as wetting the source material, installing barriers to prevent dust from leaving the source area, and halting operations during high wind events. We recommend that the EIS identify mitigation measures to avoid and minimize potential adverse impacts to the natural and human environment.

Biological Resources, Habitat and Wildlife

The EPA recommends the EIS identify all petitioned and listed threatened and endangered species under the Endangered Species Act, as well as critical habitat that might occur within the project area. We also recommend the EIS identify and quantify which species or critical habitat might be directly, indirectly, or cumulatively affected by each alternative and mitigate impacts to those species. The EPA recommends that the FERC continue to work with the U.S. Fish and Wildlife Service and the National Marine Fisheries Service. The EPA also recommends that the FERC continue to coordinate with the Oregon Department of Fish and Wildlife to ensure that State sensitive species are adequately addressed within the analysis and that current and consistent surveying, monitoring, and reporting protocols are applied in protection and mitigation efforts.

The EPA recommends the EIS also identify species listed under the Marine Mammal Protection Act. Marine barge/vessel traffic may result in potential conflicts with threatened and/or endangered marine mammals and their migration patterns and routes. We also recommend that the EIS describe the barge/vessel traffic schedule, patterns and marine transportation routes, as well as the migration period, patterns, and routes of potentially affected marine mammals. The direct, indirect and cumulative impacts from barge/vessel traffic on marine mammals, threatened and endangered species, critical habitats, and subsistence resources should be analyzed in the EIS.

Land Use Impacts

Land use impacts would include, but not be limited to, disturbance of existing land uses within construction work areas during construction and creation of permanent right-of-ways for construction, operations, and maintenance of the pipeline and above ground facilities. The EPA recommends the EIS document all land cover and uses within the project corridor, impacts by the project to the land cover and uses, and mitigation measures that would be implemented to reduce the impacts.

The primary impact of construction on forests and other open land use types would be the removal of trees, shrubs, and other vegetation. Although these can be regenerated or replanted, their re-establishment can take up to 20 years or more, making the construction impacts to these resources long term and in some cases permanent. The impact on forest land use, for example, in the permanent right-of-way areas would be a permanent change to open land. We recommend the EIS describe the impacts to forest and open land use types, indicate if the impacts would be permanent or temporary, and state measures that would be taken to compensate landowners for loss of their resources because of the project.

If the project would cross sensitive areas then the EIS should specify the areas, indicate impacts to the areas, and document any easement conditions for use of the areas, including mitigation measures.

Invasive Species
The establishment of invasive nuisance species has become an issue of environmental and economic significance. The EPA recommends consideration of impacts associated with invasive nuisance species consistent with *E.O. 13112 Invasive Species*. In particular, construction activities associated with buried pipelines which disturb the ground may expose areas and could facilitate propagation of invasive species. Mitigation, monitoring and control measures should be identified and implemented to manage establishment of invasive species throughout the entire pipeline corridor right-of-way. We recommend that the EIS include a project design feature that calls for the development of an invasive species management plan to monitor and control noxious weeds, and to utilize native plants for restoration of disturbed areas after construction.

If pesticides and herbicides will be applied during construction, operation, and maintenance of the project, we recommend that the EIS address any potential toxic hazards related to the application of the chemicals, and describe what actions will be taken to assure that impacts by toxic substances released to the environment will be minimized.

Ballast water from barges/vessels is a major source of introducing non-native species into the marine ecosystems where they would not otherwise be present. Non-native species can adversely impact the economy, the environment, or cause harm to human health. Impacts may include reduction of biodiversity of species inhabiting coastal waters from competition between non-native and native species for food and resources. We recommend that the EIS discuss potential impacts from non-native invasive species associated with ballast water and identify mitigation measures to minimize adverse impacts to the marine environment and human health.

Hazardous Materials/Hazardous Waste/Solid Waste
The EPA recommends the EIS address potential direct, indirect, and cumulative impacts of hazardous waste from construction and operation of the proposed project. The document should identify projected hazardous waste types and volumes, and expected storage, disposal, and management plans. It should identify any hazardous materials sites within the project's study area and evaluate whether those sites would impact the project in any way.

As an example, page 1-9 of Draft Resource Report 1 indicates that as a part of the gas conditioning process, sweetened gas will pass through multiple, consumable parallel carbon beds for the removal of any mercury in the gas. Because the carbon beds cannot be regenerated, it will be necessary to replace them after a design life of several years. We recommend the EIS address the expected mercury content of the expended carbon beds, and address disposal requirements consistent with 40 CFR 268.40.

We also note that the proposed pipeline route between MP 3 and MP 4 passes just upstream of the Astoria Marine Construction Company Site. This site and adjacent river sediments are contaminated with tributyltin and heavy metals from ship refurbishment operations from 1926 to present[4]. The Oregon Department of Environmental Quality (DEQ) will oversee the investigation and cleanup of contaminated soil, groundwater and sediments at the site under an agreement signed with the EPA. We recommend that FERC and the proponents collaborate closely with Oregon DEQ as the pipeline route is analyzed. Should additional construction BMPs be required at this location, those measures should be included in the EIS.

Seismic and Other Risks
Construction and operation of the proposed facility and pipeline may cause or be affected by increased seismicity (earthquake activity) in tectonically active zones. We recommend that the EIS identify potentially active and inactive fault zones where the proposed pipeline may cross. This analysis should discuss the potential for seismic risk and how this risk will be evaluated, monitored, and managed. A map depicting these geologic faults should be included in the EIS. The construction of the proposed project must use appropriate seismic design and construction standards and practices. Ground movement on these faults can cause a pipeline to rupture, resulting in discharge of gas and subsequent explosion. Particular attention should be paid to areas where the pipeline may cross areas with high population densities. Mitigation measures should be identified in the EIS to minimize effects on the pipeline due to seismic activities.

Blasting Activities
During project construction, blasting may be required in certain areas along the pipeline route corridor and adjacent facilities, resulting in increased noise and related effects to local residents, and disruption and displacement of bird and wildlife species. We recommend that the EIS discuss where blasting in the project area would be required, blasting methods that would be used, and how blasting effects would be controlled and mitigated. Noise levels in the project area should be quantified and the effects of blasting to the public and to wildlife should also be evaluated in the EIS. We recommend that a Blasting Management Plan be developed and the environmental impacts evaluated in the EIS.

National Historic Preservation Act
Consultation for tribal cultural resources is required under Section 106 of the National Historic Preservation Act (NHPA). Historic properties under the NHPA are properties that are included in the National Register of Historic Places or that meet the criteria for the National Register. Section 106 of the NHPA requires a federal agency, upon determining that activities under its control could affect historic properties, consult with the appropriate State Historic Preservation Officer /Tribal Historic Preservation Officer. Under NEPA, any impacts to tribal, cultural, or other treaty resources must be discussed and mitigated. Section 106 of the NHPA requires that federal agencies consider the effects of their actions on cultural resources, following regulation in 36 CFR 800.

Environmental Justice and Impacted Communities
In compliance with NEPA and with Executive Order (EO) 12898 on Environmental Justice, actions should be taken to conduct adequate public outreach and participation that ensures the public and Native American tribes understand the possible impacts to their communities and trust resources.

EO 12898 requires each Federal agency to identify and address disproportionately high and adverse human health or environmental effects of its programs, policies, and activities on minority populations,

[4] http://www.deq.state.or.us/lq/cu/nwr/AstoriaMarine/AstoriaMarineConstructionCo.pdf

low-income populations, and Native American tribes.[5] The EPA also considers children, the disabled, the elderly, and those of limited English proficiency to be potential Environmental Justice communities due to their unique vulnerabilities.

According to the Council on Environmental Quality, when determining whether environmental effects are disproportionately high and adverse, agencies should consider the following factors: [6]

- Whether environmental effects are or may be having an adverse impact on minority populations, low-income populations, or Indian tribes that appreciably exceeds or is likely to appreciably exceed those on the general population or other appropriate comparison group.
- Whether the disproportionate impacts occur or would occur in a minority population, low-income population, or Indian tribe affected by cumulative or multiple adverse exposures from environmental hazards.

Socioeconomic Impacts

Council on Environmental Quality Regulations at 40 CFR 1500-1508 state that the "human environment" is to be "interpreted comprehensively" to include "the natural and physical environment and the relationship of people with that environment" (40 CFR 1508.14). Consistent with this direction, agencies need to assess not only "direct" effects, but also "aesthetic, historic, cultural, economic, social, or health" effects, "whether direct, indirect, or cumulative" (40 CFR 1508.8).

Social impact assessment variables point to measurable change in human population, communities, and social relationships resulting from a development project or policy change. We suggest that the EIS analyze the following social variables:

- Population Characteristics
- Community and Institutional Structures
- Political and Social Resources
- Community Resources.

Impacts to these social variables should be considered for each stage of the project (development, construction, operation, decommissioning). With regard to the construction and operation phase of the project, we recommend the analysis give consideration to how marine traffic might change, and how this may affect commercial or recreational use within the project area and travel over the bar.

Greenhouse Gas (GHG) Emissions

On February 18, 2010, the CEQ issued draft guidance to Federal Agencies on analyzing the effects of Greenhouse Gas (GHG) emissions and climate change when describing the environmental effects of a proposed agency action in accordance with NEPA[7].

CEQ's draft guidance defines GHG emissions in accordance with Section 19(i) of *E.O. 13514 Federal Leadership in Environment, Energy, and Economic Performance (October 5, 2009)* to include carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), hydrofluorcarbon (HFCs), perfluorcarbon (PFCs),

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[5] EO 12898: Federal Actions to Address Environmental Justice in Minority Populations and Low-income Populations. February 11, 1994.

[6] http://ceq.hss.doe.gov/nepa/regs/ej/justice.pdf

[7] See http://ceq.hss.doe.gov/current_developments/new_ceq_nepa_guidance.html

and sulfurhexafluoride (SF_6). Because CO_2 is the reference gas for climate change based on their potential to absorb heat in the atmosphere, measures of non-CO_2 GHGs should be reflected as CO_2-equivalent (CO_2-e) values.

The EPA supports evaluation and disclosure of GHG emissions and climate change effects resulting from the proposed project during all project phases, including (1) pre-construction (e.g., transportation, mobilization, and staging), (2) construction, (3) operation, (4) maintenance, and (5) decommissioning. We recommend that the GHG emission accounting/inventory include each proposed stationary source (e.g., power plant, liquefaction facility, compressor and metering stations, etc.) and mobile emission source (e.g., heavy equipment, supply barges, rail transports, etc.). We also recommend that the EIS establish reasonable spatial and temporal boundaries for this analysis, and that the EIS quantify and disclose the expected annual direct and indirect GHG emissions for the proposed action. In the analysis of direct effects, we recommend that the EIS quantify cumulative emissions over the life of the project, discuss measures to reduce GHG emissions, including consideration of reasonable alternatives
We recommend that the EIS consider mitigation measures and reasonable alternatives to reduce action-related GHG emissions, and include a discussion of cumulative effects of GHG emissions related to the proposed action. We recommend that this discussion focus on an assessment of annual and cumulative emissions of the proposed action and the difference in emissions associated with the alternatives.

In addition, greenhouse gas emission sources in the petroleum and natural gas industry are required to report GHG emissions under 40CFR Part 98 (subpart W), the Greenhouse Gas Reporting Program. Consistent with draft CEQ guidance[5], we recommend that this information be included in the EIS for consideration by decision makers and the public. Please see http://www.epa.gov/climatechange/emissions/ghgrulemaking.html.

Climate Change
Scientific evidence supports the concern that continued increases in greenhouse gas emissions resulting from human activities will contribute to climate change. Global warming is caused by emissions of carbon dioxide and other heat-trapping gases. On December 7, 2009, the EPA determined that emissions of GHGs contribute to air pollution that "endangers public health and welfare" within the meaning of the Clean Air Act. Higher temperatures and increased winter rainfall will be accompanied by a reduction in snow pack, earlier snowmelts, and increased runoff. Some of the impacts, such as reduced groundwater discharge, and more frequent and severe drought conditions, may impact the proposed projects. The EPA recommends the EIS consider how climate change could potentially influence the proposed project, specifically within sensitive areas, and assess how the projected impacts could be exacerbated by climate change.

Coordination with Tribal Governments
Executive Order 13175, Consultation and Coordination with Indian Tribal Governments (November 6, 2000), was issued in order to establish regular and meaningful consultation and collaboration with tribal officials in the development of federal policies that have tribal implications, and to strengthen the United States government-to-government relationships with Indian tribes. The EIS should describe the process and outcome of government-to-government consultation between the FERC and tribal governments within the project area, issues that were raised, and how those issues were addressed in the selection of the proposed alternative.

Indirect Impacts
Per CEQ regulations at CFR 1508.8(b), the indirect effects analysis "may include growth inducing effects and other effects related to induced changes in the pattern of land use, population density or growth rate, and related effects on air and water and other natural systems, including ecosystems." The 2012 report from the Energy Information Administration[8] states that, "natural gas markets in the United States balance in response to increased natural gas exports largely through increased natural gas production." That report also notes that about three-quarters of that increased production would be from shale resources. We recommend that FERC consider available information about the extent to which drilling activity might be stimulated by the construction of an LNG export facility on the west coast, and any potential environmental effects associated with that drilling expansion.

Cumulative Impacts
The cumulative impacts analysis should identify how resources, ecosystems, and communities in the vicinity of the project have already been, or will be affected by past, present, or future activities in the project area. These resources should be characterized in terms of their response to change and capacity to withstand stresses. Trends data should be used to establish a baseline for the affected resources, to evaluate the significance of historical degradation, and to predict the environmental effects of the project components.

For the cumulative impacts assessment, we recommend focusing on resources of concern or resources that are "at risk" and /or are significantly impacted by the proposed project, before mitigation. For this project, the FERC should conduct a thorough assessment of the cumulative impacts to aquatic and biological resources, air quality, and commercial and recreational use of the Columbia River within the projects area of influence.

The EPA also recommends the EIS delineate appropriate geographic boundaries, including natural ecological boundaries, whenever possible, evaluate the time period of the project's effects. For instance, for a discussion of cumulative wetland impacts, a natural geographic boundary such as a watershed or sub-watershed could be identified. The time period, or temporal boundary, could be defined as from 1972 (when the Clean Water Act established section 404) to the present.

Please refer to CEQ's "Considering Cumulative Effects Under the National Environmental Policy Act"[9] and the EPA's "Consideration of Cumulative Impacts in EPA Review of NEPA Documents"[10] for assistance with identifying appropriate boundaries and identifying appropriate past, present, and reasonably foreseeable future projects to include in the analysis.

Mitigation and Monitoring
On February 18, 2010, CEQ issued draft guidance on the Appropriate Use of Mitigation and Monitoring. This guidance seeks to enable agencies to create successful mitigation planning and implementation procedures with robust public involvement and monitoring programs[11].

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[8] Energy Information Administration, Effects of Increased Natural Gas Exports on Domestic Energy Markets, 6 (January 2012) available at http://www.eia.gov/analysis/requests/fe/pdf/fe_lng.pdf
[9] http://ceq.hss.doe.gov/nepa/ccenepa/ccenepa.htm
[10] http://www.epa.gov/compliance/resources/policies/nepa/cumulative.pdf
[11] http://ceq.hss.doe.gov/current_developments/docs/Mitigation_and_Monitoring_Guidance_14Jan2011.pdf

We recommend that the EIS include a discussion and analysis of proposed mitigation measures and compensatory mitigation under CWA §404. The EIS should identify the type of activities which would require mitigation measures either during construction, operation, and maintenance phases of this project. To the extent possible, mitigation goals and measureable performance standards should be identified in the EIS to reduce impacts to a particular level or adopted to achieve an environmentally preferable outcome.

Mitigation measures could include best management practices and options for avoiding and minimizing impacts to important aquatic habitats and to compensate for the unavoidable impacts. Compensatory mitigation options could include mitigation banks, in-lieu fee, preservation, applicant proposed mitigation, etc. and should be consistent with the *Compensatory Mitigation for Losses of Aquatic Resources; Final Rule* (33 CFR Parts 325 and 332 and 40 CFR Part 230). A mitigation plan should be developed in compliance with 40 CFR Part 230 Subpart J 230.94, and included in the EIS.

An environmental monitoring program should be designed to assess both impacts from the project and that mitigation measures being implemented are effective. We recommend the EIS identify clear monitoring goals and objectives, such as what parameters are to be monitored, where and when monitoring will take place, who will be responsible, how the information will be evaluated, what actions (contingencies, triggers, adaptive management, corrective actions, etc.) will be taken based on the information. Furthermore, we recommend the EIS discuss public participation, and how the public can get information on mitigation effectiveness and monitoring results.

From:	Darby, Joan
To:	LNGStudy
Subject:	2012 LNG Export Study
Date:	Thursday, January 24, 2013 3:20:42 PM
Attachments:	2013-01-24 Jordan Cove Energy Project LP Comments on LNG Export Study.pdf

Please find attached the comments of Jordan Cove Energy Project, L.P. on the LNG Export Study.

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January 24, 2013

By Email
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Re: 2012 LNG Export Study
and
Jordan Cove Energy Project, L.P., FE Docket No. 12-32-LNG

Dear Mr. Anderson and Mr. Myers:

The U.S. Department of Energy (DOE) issued a "Notice of availability of 2012 LNG Export Study and request for comments" (Notice) that was published in the Federal Register on December 11, 2012 (77 Fed. Reg. 73627). The Notice invited "comments regarding the LNG Export Study that will help to inform DOE in its public interest determinations of the authorizations sought in the 15 pending applications" (77 Fed. Reg. at 73629), one of which is the Application of Jordan Cove Energy Project, L.P. (Jordan Cove) pending in the above-referenced docket. In response to DOE's invitation, Jordan Cove submits the following: (1) the overall evaluation of the LNG Export Study by Navigant Consulting, Inc. (Navigant), which is set forth in the January 22, 2012 letter from Navigant to Jordan Cove attached to this letter as an appendix; and (2) comments pertinent to the LNG Export Study as it applies specifically to Jordan Cove's Application, which are also based on an analysis by Navigant and which are set forth immediately below.

Both reports comprising the LNG Export Study – the January 2012 Energy Information Administration analysis focuses on impacts on domestic energy markets and the December 2012 NERA Economic Consulting analysis focused on impacts on the U.S. economy – are devoid of regional assessments. Because the LNG Export Study analyzes LNG exports only from the U.S. Gulf Coast, it tends to overestimate price impacts of exporting LNG and it fails to identify, and consequently overlooks, economic contributions that would be made by LNG exports from an export project like Jordan Cove situated on the U.S. West Coast.

Jordan Cove will export LNG sourced from more abundant and less costly regional gas supplies that are not accessible to Gulf Coast projects, namely resources from Western Canada and the U.S. Rockies. The lower average delivered supply cost of the natural gas supplies available to Jordan Cove means that, had LNG exports from Jordan Cove's West Coast terminal been included in the LNG Export Study, the forecasted price impacts would likely have been mitigated. Stated differently, the underlying assumption of only Gulf-sourced LNG exports likely resulted in price impacts being overestimated in the LNG Export Study

As a U.S. West Coast terminal, Jordan Cove will also have the advantage of shorter distances and less sailing time (without a Panama Canal transit) to the high-demand Asian markets for LNG and consequently the advantage of significantly lower shipping costs. Indeed, the NERA analysis estimated shipping costs to those markets from Canadian West Coast LNG terminals at \$1.23/MMBtu, which is \$1.31 less than (and less than half of) its estimate of \$2.54/MMBtu for shipping costs to Asia from the U.S. Gulf Coast. The NERA analysis found that Canadian exports to Asia would nevertheless have an overall higher cost due to liquefaction capital costs. NERA estimated the loaded liquefaction cost element for Canadian projects at \$3.88/MMBtu and for U.S. Gulf Coast projects at \$2.14/MMBtu. While U.S. West Coast "greenfield" projects would have higher capital costs than U.S. Gulf Coast "brownfield" projects, their costs would not approach those of projects located in remote and rugged Kitimat, British Columbia. Assuming that Jordan Cove's loaded liquefaction cost element would be mid-way between the Canadian and U.S. Gulf Coast figures estimated by NERA, it would be \$3.01/MMBtu or \$0.87 more than the Gulf Coast figure. Jordan Cove's shipping cost advantage of \$1.31/MMBtu more than makes up for its higher liquefaction costs, leaving Jordan Cove with an overall cost advantage of \$0.44/MMBtu over U.S. Gulf Coast projects. Jordan Cove's cost advantage not only means that Asian buyers would benefit from a lower delivered cost of LNG, but also that the U.S. would reap greater economic benefits.

Because the LNG Export Study does not account for U.S. West Coast projects being able to export LNG at a lower overall delivered cost, it underestimates economic benefits in at least two ways. Since NERA's modeling is based only on Gulf-sourced LNG exports that would have higher delivered costs, it potentially understates the equilibrium export volumes, and therefore the associated economic benefits. In addition to such a volume-driven increase in economic benefits, the inclusion of U.S. West Coast projects like Jordan Cove in the LNG Export Study would have produced an increase in economic benefits due to the composition of the delivered cost of LNG. Simply stated, the relative portion of the price paid for a U.S. LNG export flowing to the U.S. terminal, as opposed to the portion flowing to the non-U.S. shipping company, would be greater if the export is from the U.S. West Coast instead of from the U.S. Gulf Coast. Thus, the substitution of Jordan Cove's higher liquefaction capital costs (which lead to economic benefits) for a U.S. Gulf Coast project's higher shipping costs (which do not lead to economic benefits) results in more economic benefits being kept in the U.S.

In sum, DOE should, as the LNG Export Study does not, recognize the economic contributions that would be unique to LNG exports from an export project like Jordan Cove situated on the U.S. West Coast as compared to projects on the other U.S. coasts. Most importantly, DOE should not put Jordan Cove at any disadvantage as it competes in the market, not only with U.S.

projects but also with proposed Canadian projects, to determine which export projects will be constructed and become operational. LNG exports from Canada (which would displace LNG exports from the U.S.) would have the same impacts on North American natural gas prices as LNG exports from the U.S., but the economic benefits of those exports would accrue to Canada and be lost to the United States. On the other hand, exports of Canadian gas via Jordan Cove will have the most limited impacts on U.S. prices of any proposed export terminal and, in constructing and operating its terminal, Jordan Cove will make a tremendous investment in a currently economically depressed region of the country, with the attendant employment and economic benefits accruing to the United States.

Thank you for your consideration of Jordan Cove's comments.

Sincerely,

/s/ Beth L. Webb

Beth L. Webb
Joan M. Darby

Attorneys for
Jordan Cove Energy Project, L.P.

cc: DOE/FE, Marc Talbert, marc.talbert@hq.doe.gov

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NAVIGANT

January 22, 2013

Mr. Bob Braddock
Jordan Cove Energy Project, L.P.
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Dear Mr. Braddock:

As you are aware, Navigant Consulting, Inc. (Navigant) has been involved in a number of liquefied natural gas (LNG) export projects including Jordan Cove Energy Project, L.P. (JCEP) in helping LNG project developers with their applications to the Department of Energy (DOE) for export of LNG to Non-Free Trade Agreement countries. Our involvement with the projects including JCEP has been primarily to assess the market impact of individual export projects as well as to investigate the pipeline infrastructure and natural gas supply that will be used to serve the requirements of the liquefaction terminals as proposed by the projects. In our analysis, we used Navigant's North American market model built on architecture provided by the GPCM® Natural Gas Market Forecasting System to perform analysis of the impact upon the existing market including prices over the long term.

In performing such analysis for JCEP, as well as other projects located on both coasts and in the Gulf of Mexico, Navigant has a number of comments we would like to make to the Office of Fossil Energy (FE) of the Department of Energy (DOE), which invited comments regarding the LNG Export Study commissioned by the DOE. We invite you to include Navigant's comments in your filing to the DOE in the subject proceeding. While we believe such comments are appropriate for JCEP's project, the comments below are relevant to all LNG export projects currently filed before the DOE for Non-Free Trade approval.

1. That the global market is best suited to determine the 'appropriate' level of U.S. LNG exports.

Rather than relying on any artificially-imposed limits on LNG export volumes, the DOE should allow the global marketplace to determine how much LNG export capacity should be built, who should build it, where it should be built, and ultimately what volumes of LNG exports should occur. The detailed, macroeconomic component of the DOE's LNG Export Study[1] analyses serves to confirm that LNG exports will provide positive net economic benefits to the U.S. under all modeled scenarios, with increasing benefits associated with the increasing levels of LNG exports that result under the unconstrained export scenarios.[2]

- <u>Arbitrary export level assumptions can yield infeasible study results.</u>

  Whereas the EIA analysis incorporated static, *a priori* assumptions on LNG export volumes, the subsequent NERA analysis component of the DOE's LNG Export Study determined the LNG export levels within its global natural gas market model. As noted by the NERA analysis, "… in many cases, the world natural gas market would not accept the full amount of exports assumed in the EIA scenarios at export prices high enough to cover the U.S. wellhead domestic prices calculated by the EIA."[3] Thus, "[b]ecause the [NERA] study [in some cases] estimated lower export volumes than were specified by [DOE] for the EIA study, U.S. natural gas prices [projected by NERA] do not reach the highest levels projected by EIA."[4]

  For example, LNG exports as projected by the NERA analysis for the EIA Low Shale case never exceed 2.5 bcfd (well below both the 6 bcfd and the 12 bcfd export assumptions driving the EIA price forecasts), and this is the case that produced the most extreme pricing and price change results in the EIA analysis.[5] Thus, EIA's projected average wellhead price increase of 20 percent over the 20-year study for the 12 bcfd export level in the Low Shale case drops to less than 3 percent in NERA's analysis where global gas market modeling results in only achievable LNG export levels.

- <u>Even if DOE were to permit all the applications, the market will decide which facilities get built.</u>

  Obtaining a permit to export is no guarantee that a facility will be built. Companies routinely make their "final investment decision" subsequent to permitting activities. More importantly, market participants (investors, producers, consumers) will optimize

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[1] DOE uses the term "LNG Export Study" to refer to two reports prepared at its direction: 1) the January 2012 analysis by the Energy Information Administration ("EIA") entitled "Effect of Increased Natural Gas Exports on Domestic Energy Markets," requested by the DOE's Office of Fossil Energy in August 2011 ("EIA analysis"); and 2) the December 2012 analysis by NERA Economic Consulting ("NERA") entitled "Macroeconomic Impacts of LNG Exports from the United States," commissioned by DOE under contract ("NERA analysis").

[2] NERA analysis, p. 1.

[3] NERA analysis, p. 3.

[4] NERA analysis, p. 10.

[5] For example, the Low Shale EUR case with the rapid introduction of 12 bcfd of exports resulted in a 54 percent increase versus the baseline wellhead price for the Low Shale EUR case in 2018 (EIA analysis, p. 9), and the Low Shale EUR case baseline average wellhead price over the term of the analysis was itself 40 percent higher than in the Reference case, at $7.37 versus $5.28/MMBtu (EIA analysis, Table B5).

project development activities more efficiently than would any centralized policy or planning direction via regulatory processes. This reality is confirmed by DOE in its 2011 Order conditionally granting export authorization for the Sabine Pass LNG project, in which DOE reiterated that its policy goals include "minimizing federal control and involvement in energy markets" so as to "minimiz[e] regulatory impediments to a freely operating market."[6]

- <u>Even if some overcapacity occurs (for example, due to changes in the market), the market will still decide what levels of exports should occur.</u>

  NERA's modeling effort indicates competitive export levels (that is, LNG export levels that result from the free interplay of supply and demand conditions) could be more or less than the EIA assumptions, but that price levels would remain in a competitive long-term equilibrium range, not linked to oil prices.

  NERA's analysis shows that even with no constraints on the upper end of LNG exports, there would not be any LNG exports in NERA's Low Shale case (with its higher price forecasts in the EIA analysis) except for in the Supply Shock plus Demand Shock international scenario, where exports peak at only 2.5 bcfd (in 2025).

  With plentiful gas supplies (e.g. High Shale case), while exports could exceed the 12 bcfd assumed by EIA, the U.S. price levels themselves still stayed below $6.00/MMBtu by 2035 for all NERA's international scenarios. Even NERA's Supply Shock plus Demand Shock international scenario, with average exports of about 17 bcfd, resulted in average wellhead prices over the 20-year study term of only $5.23/MMBtu.

  Under the EIA's U.S. Reference case, the only scenario where unconstrained exports ever exceeded 12 bcfd is the Supply Shock plus Demand Shock international scenario, where the average wellhead prices from 2015 through 2035 were still less than $6.30/MMBtu (and about $0.10/MMBtu less than for the EIA's Reference Case at a constant 12 bcfd).

- <u>Regardless of modeling estimates, there are likely practical and competitive limits to how much of new LNG capacity will be located in the U.S.</u>

  The global LNG market size in 2010 was about 27 bcfd in imports and exports[7], and is estimated by the International Energy Agency to roughly double in size by 2035. Assuming new U.S. capacity of about half of worldwide growth would be highly optimistic. Navigant's market view is that U.S. LNG export capacity will likely range from 6 to 8 bcfd. We also suggest export opportunities as being time sensitive, and rather than increasing in the future, the LNG export market for export from the U.S. may

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[6] See DOE/FE Order No. 2961 (Opinion and Order Conditionally Granting Long-Term Authorization to Export Liquefied Natural Gas from Sabine Pass LNG Terminal to Non-Free Trade Agreement Nations), May 20, 2011, at 28.

[7] See NERA analysis, p. 19.

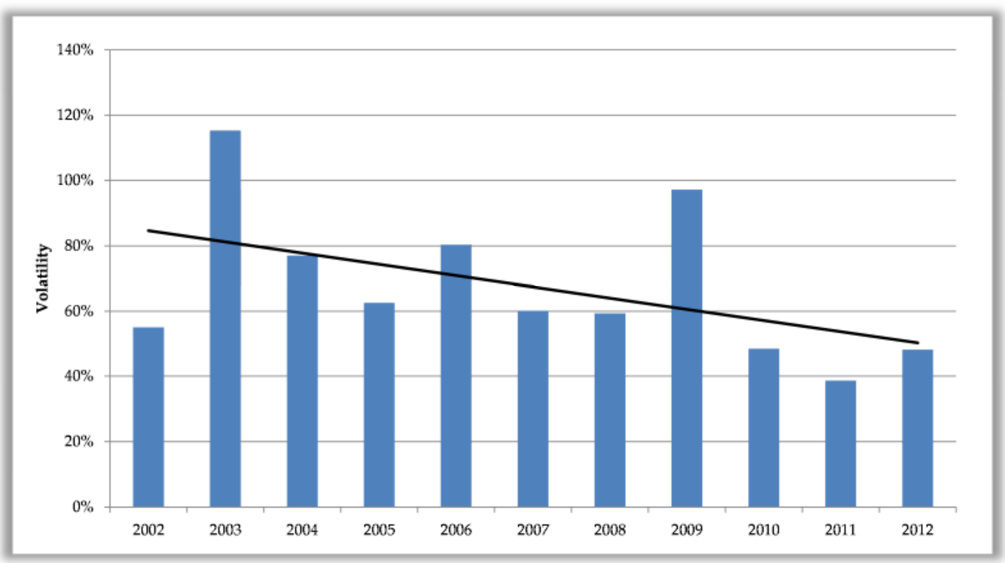
decrease due to supply development in other areas around the world from both known and unknown gas resources.

- <u>There are drawbacks that would result from 'under-permitting' by DOE.</u>

  In addition to the economic benefits of LNG exports, as detailed in the NERA analysis, LNG exports, to the extent they are permitted, will help foster the increasing stability of the domestic natural gas market. Because of the lower exploration and production risk associated with shale gas production resulting from the manufacturing-like nature of shale gas production, once shale plays have been identified, increasing levels of shale gas production should help to lower the volatility of the domestic gas market. LNG exports that increase natural gas demand thus provide two important benefits.

  First, new demand will help stabilize the current over-supply conditions in the domestic marketplace towards a market where supply and demand are in equilibrium. Second, new demand will increase the size of the natural gas market, leading to a continued increase in shale gas' share of total natural gas production, which will lower the price volatility of the gas market by increasing the overall supply responsiveness of the market. As shown in Figure 1 below, recent data seems to support decreasing levels of gas price volatility that correspond well with the recent increases in shale gas production levels. Artificially limiting the amount of LNG exports would be seen to slow the development of shale gas resources, and thus also slow potential future reductions in market price volatility.

Figure 1. Annualized Daily Volatility (Henry Hub)



Source: Navigant

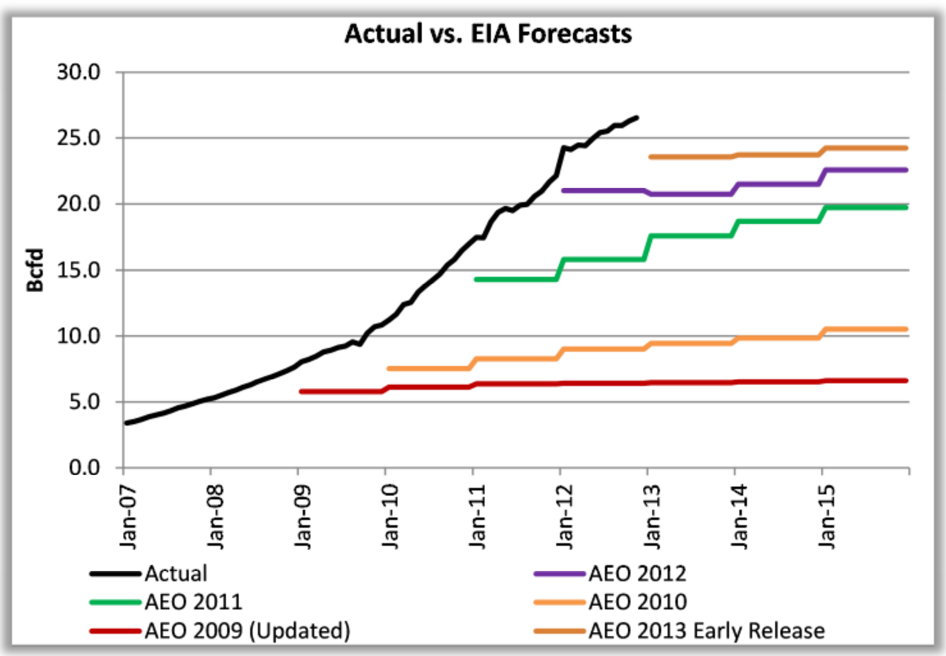
With respect to market policy, a restrictive approach to LNG export approval (i.e., potential under-permitting by DOE) would be inconsistent with the DOE's stated preference[8] for free-market approaches to regulatory oversight. An LNG export authorization process that implies the picking of winners by the regulatory process itself, as opposed to the marketplace, would limit competitive forces and not result in the optimization of project development.

2. The 2011 Reference Case U.S. natural gas supply volume assumptions used in the DOE's LNG Export Study are now drastically understated, and updated assumptions would only strengthen the showing of LNG export benefits.

The EIA's2011 Reference Case supply assumptions used in both analyses drastically understate the reality of today's abundant supply of shale gas. The 2011 Reference Case used was the Annual Energy Outlook (AEO) 2011 forecast shown in Figure Two, below. While the AEO 2011 shale gas production forecasts were already too low with respect to then-existing production levels when made, the continuing strong growth in actual production levels has made the forecast shortfall even larger for subsequent forecast years.

As can be seen in Figure 2, below, the AEO 2011 forecast for 2011 shale gas production (14.3 bcfd) was already eclipsed by actual shale production levels mid-way through 2010; at year-end 2010, actual production levels exceeded the AEO 2011 forecast for 2011 by more than 18 percent. In fact, the AEO 2011 forecast for 2013 shale gas production (17.6 bcfd) was already eclipsed by actual production levels in early 2011. As actual production levels have steadily continued their strong increases, year-end 2012 production levels of 26.5 bcfd were over 50 percent higher than the AEO 2011 forecast for 2013.

Figure 2. U.S. Shale Gas Production (Dry)

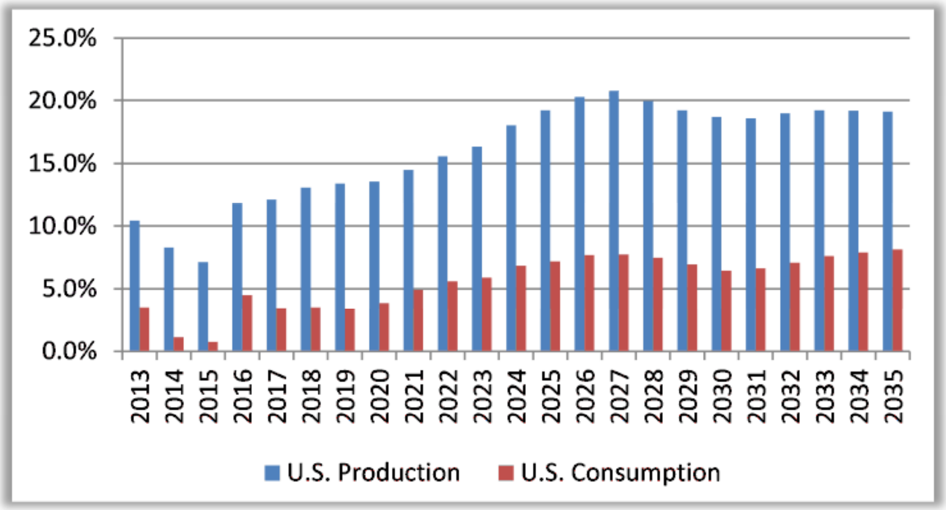


Source: Navigant, EIA

[8] See note 6, supra.

While some criticisms of the DOE's LNG Export Study have focused on the fact that the AEO 2011 *demand assumptions* have been surpassed by those of the AEO 2013, it is important to note that the increase in forecast total natural gas consumption has been far outpaced by the increase in the AEOs' natural gas production forecasts, as shown in Figure 3, below. For the period of 2013-2035, there was an average percentage increase in forecast total domestic natural gas consumption between AEO 2011 and AEO 2013 of 5.6 percent, while the increase in forecast total natural gas production was 16 percent. This important context helps explain why the more recent AEO 2013 assumptions actually indicate the beneficial market impacts that come along with LNG exports.

Figure 3. Percent Increase in Forecasted U.S. Natural Gas Production and Consumption, AEO 2013 vs. DOE Export Study (AEO 2011)



Source: Navigant

Comparing the AEO 2013 forecasts to the AEO 2011 forecasts illustrates an interesting shift in the domestic supply-demand balance. While the entire forecast period of AEO 2011 was characterized by domestic consumption exceeding total production, with a shortfall averaging about 4.0 bcfd from 2013 through 2035 being made up by LNG and pipeline imports to the U.S., in AEO 2013 that situation reverses itself by 2020. More specifically, an initial period of production shortfalls, averaging about 2.7 bcfd, becomes a period of production surpluses averaging about 4.9 bcfd from 2020 through 2035. This period of production surplus, relative to domestic total consumption, coincides generally with the ramping up of LNG exports from about 0.7 bcfd to an average of 3.4 bcfd during 2022 through 2035. Furthermore, the AEO 2013 assumptions of increasing natural gas production relative to domestic consumption and increasing LNG exports, relative to AEO 2011, are associated with a 20 percent lower average natural gas price level from 2013 through 2035 as measured at Henry Hub under AEO 2013 than under AEO 2011.

Thus, the use of a supply forecast more in line with current actual production levels than is the Reference Case (e.g. the AEO 2013 projection) would be expected to result in lower domestic gas prices than estimated in the DOE's LNG Export Study, and consequently increased LNG export volumes to global markets, which would lead to even higher economic benefits to the U.S.

3. Continual increase of production forecasts reflects the underlying natural gas resource abundance.

In any discussion of natural gas production forecasts, it is always instructive to note the key underlying factor behind the continually more optimistic and impressive production forecasts, and that is the reality of today's shale gas boom. The development of horizontal drilling and hydraulic fracturing, existing technologies which were combined together and have been continually improved, has yielded dramatically increased production and fundamentally changed the North American natural gas supply outlook. With U.S. shale gas resources estimated at up to 35 years of annual U.S. natural gas consumption at current levels,[9] pushing U.S. total natural gas resource estimates up to more than 90 years of supply, it is evident that a new era of natural gas sufficiency has arrived. Other estimates of the U.S. and North American natural gas resource base that have been prepared by other industry associations and government institutions are even higher.

Navigant is hopeful that these comments will be helpful for the DOE as it gets set to make decisions of high importance to the LNG export projects, to the natural gas industry, to other parties reliant upon abundant and clean natural gas as a fuel source, and to the country as a whole.

Respectfully submitted,

Gordon Pickering
Director, Energy
Navigant Consulting, Inc.

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[9] See e.g. "Golden Rules for a Golden Age of Gas," International Energy Agency, Special Report, May 29, 2012, Table 3.1, putting U.S. shale gas recoverable resources at 24 tcm, or 840 tcf.

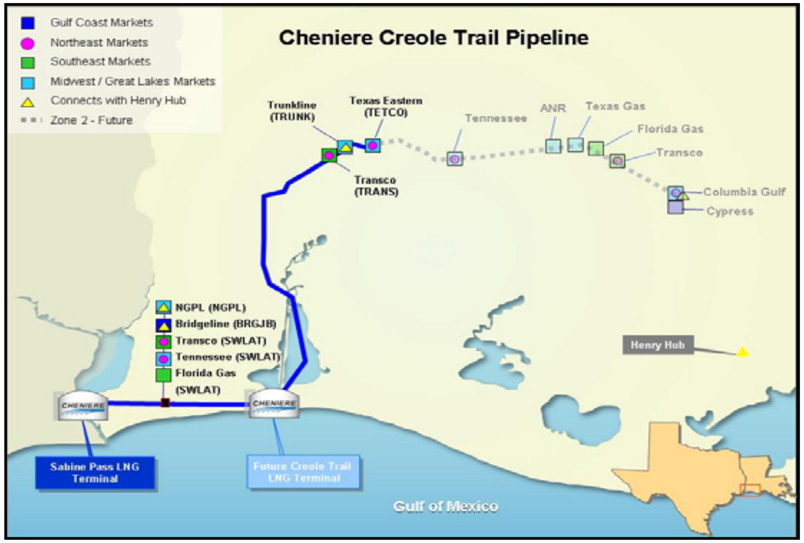
Cheniere Energy
April 2011

Cheniere Operations

- Cheniere is engaged in the development, construction and operation of onshore LNG terminals and pipelines and the marketing of LNG and natural gas
  - Sabine Pass LNG became operational in 2008 and cost ~$1.6 billion, 4.0 Bcf/d capacity
  - Sabine receives LNG arriving by ship and is connected to the U.S. natural gas pipeline grid through the Creole Trail pipeline and other interconnecting pipelines
  - Creole Trail pipeline also became operational in 2008 and cost ~$560 million, 2.0 Bcf/d capacity, 42-inch diameter

Sabine Pass LNG Terminal

Creole Trail Pipeline



CHENIERE

Strategic Focus: Liquefaction Expansion Project

- Cheniere is developing a project to add liquefaction trains, transforming the Sabine Pass LNG facility into the first bi-directional LNG terminal that can import and export LNG
  - 4 liquefaction trains, 16 mtpa total nominal processing capacity
  - Contracting 14 mtpa under 20-yr fixed price contracts
  - Begin construction 2012, begin operations 2015
- LNG value chain:

Expansion Project | **Current Operations**

Field Development

Liquefaction

Shipping

Regasification

Pipeline

End Use

LNG is natural gas cooled to -260ºF in order to be transported by ship to distant markets

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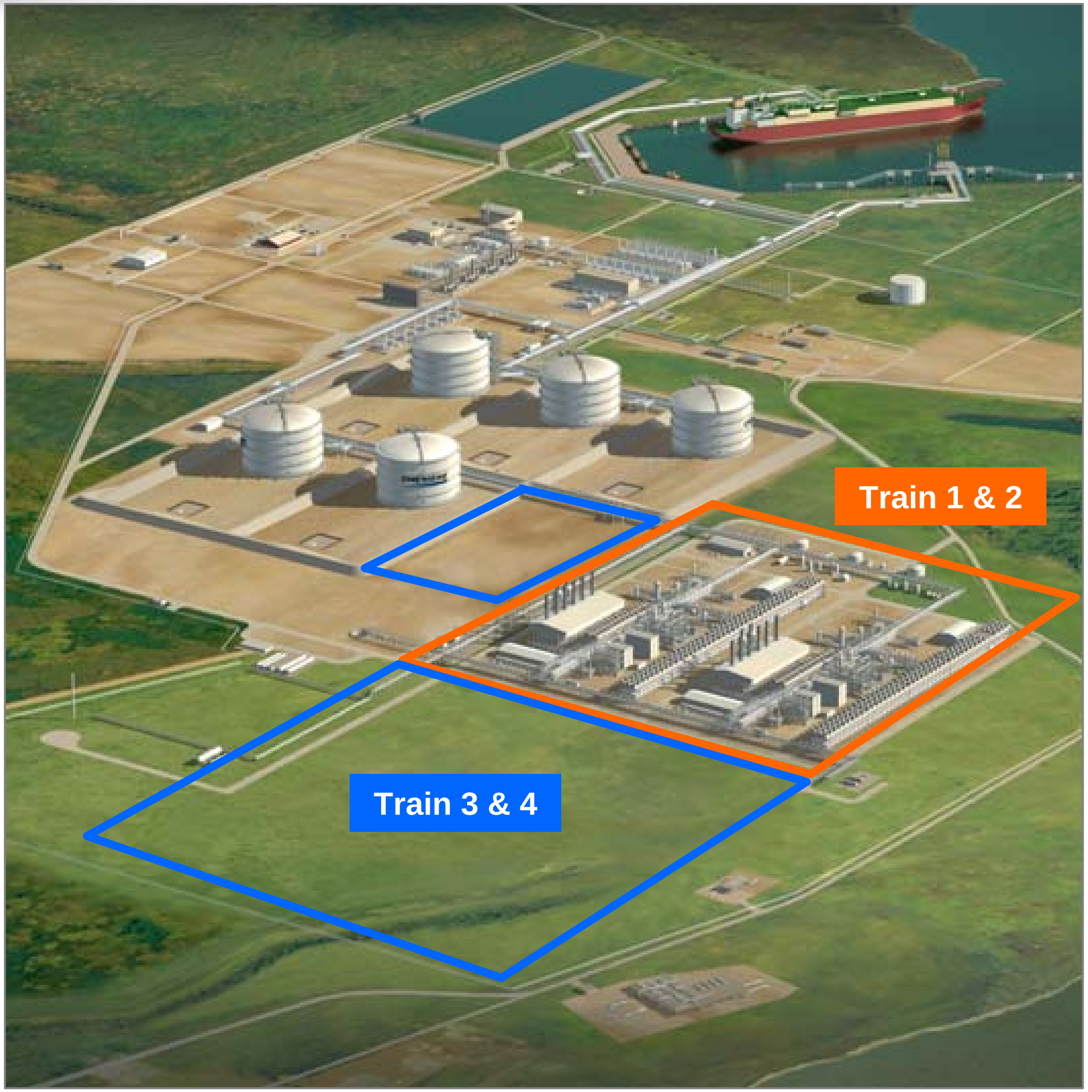
Proposed Liquefaction Project Transforming Sabine into Bi-directional Import / Export Facility



Current Facility

- 853 acres in Cameron Parish, Louisiana
- 40 ft ship channel 3.7 miles from coast
- 2 berths; 4 dedicated tugs
- 5 LNG storage tanks (17 Bcf of storage)
- 4.3 Bcf/d peak vaporization
- LNG export licenses approved

Liquefaction Expansion

- World's first bi-directional LNG facility
- Monthly nomination rights to liquefy for export or regasify for import
- Up to 4 liquefaction trains
  - Each 4.0 mtpa / ~ 500 MMcf/d
  - ConocoPhillips Optimized Cascade technology
- Estimated CAPEX: ~ $400/ton
- Estimated commercial start date: 2015

CHENIERE

Bi-directional Service at Sabine Pass Provides Opportunity to Arbitrage Henry Hub vs. Oil

Worldwide LNG prices predominantly based on oil prices= $10 - $25 / MMBtu

LNG Contract Price Indexation %	11%	15%	11%	15%
at $90/bbl	$ 9.90	$ 13.50	$ 9.90	$ 13.50
at $150/bbl	$ 16.50	$ 22.50	$ 16.50	$ 22.50

Cost to deliver gas from Sabine Pass to Europe & Asia= $7 - $12 / MMBtu

	Europe		Asia	
($/MMBtu)	Low	High	Low	High
Henry Hub	$ 4.00	$ 6.50	$ 4.00	$ 6.50
Processing Fee	1.75	1.75	1.75	1.75
Fuel Shrink	0.40	0.65	0.40	0.65
Shipping	1.00	1.00	2.80	2.80
Delivered Cost	$ 7.15	$ 9.90	$ 8.95	$ 11.70

Current LNG Market	30 – 40 Bcf/d	LNG contracts indexed to oil prices – rule of thumb 11% to 15% of crude oil prices
Growth Market	100 Bcf/d	Power generator switching from oil to gas – paying $13 to $19 / MMBtu for fuel oil and diesel

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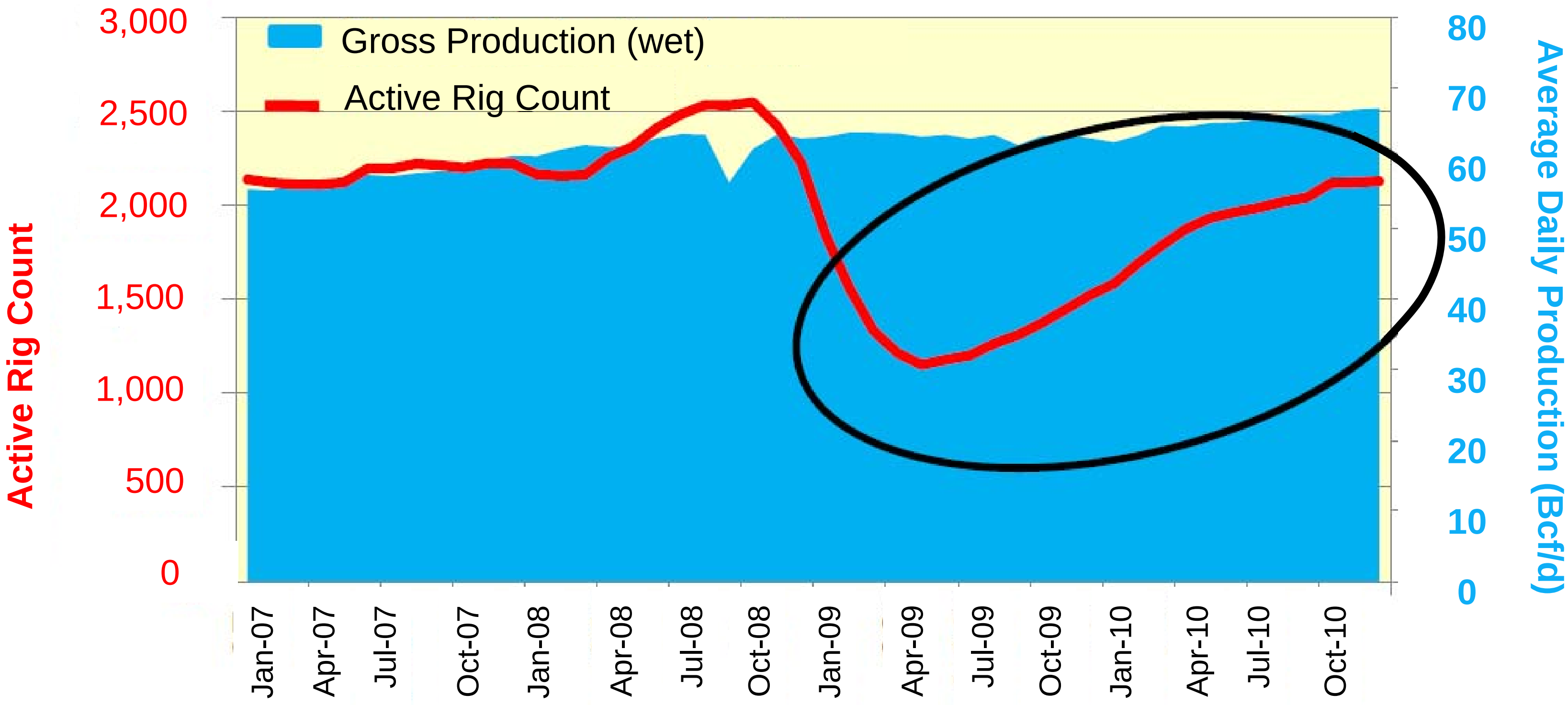
Historic Relationship Between Rig Count and Production No Longer Holds



 Source: Bentek Energy, EIA,Cheniere

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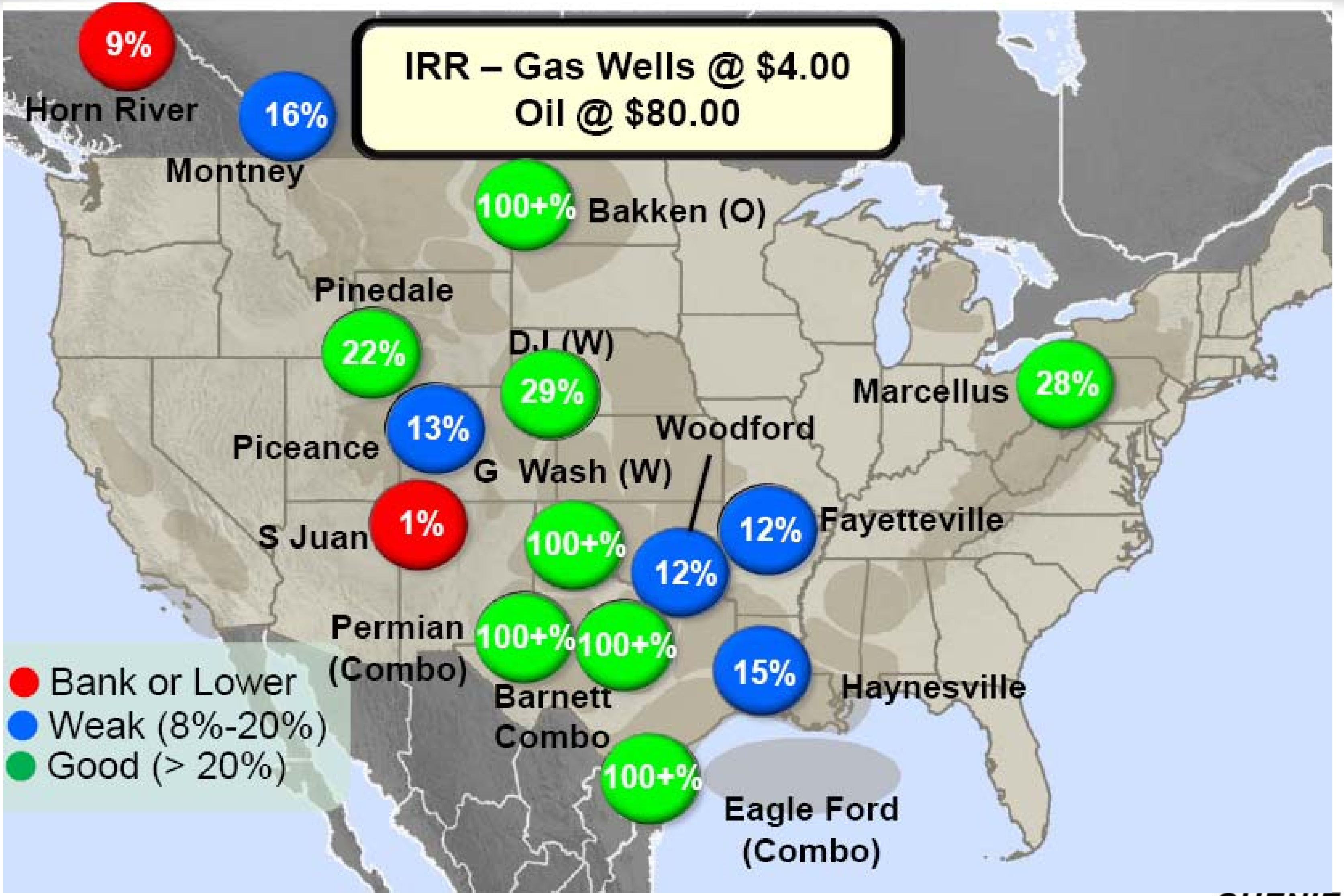
Unconventional Plays - Comparative Rates of Return



Source: Bentek Energy

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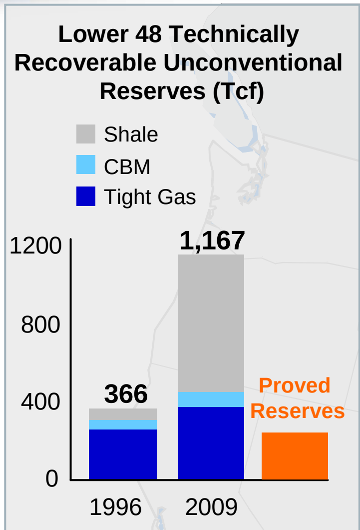
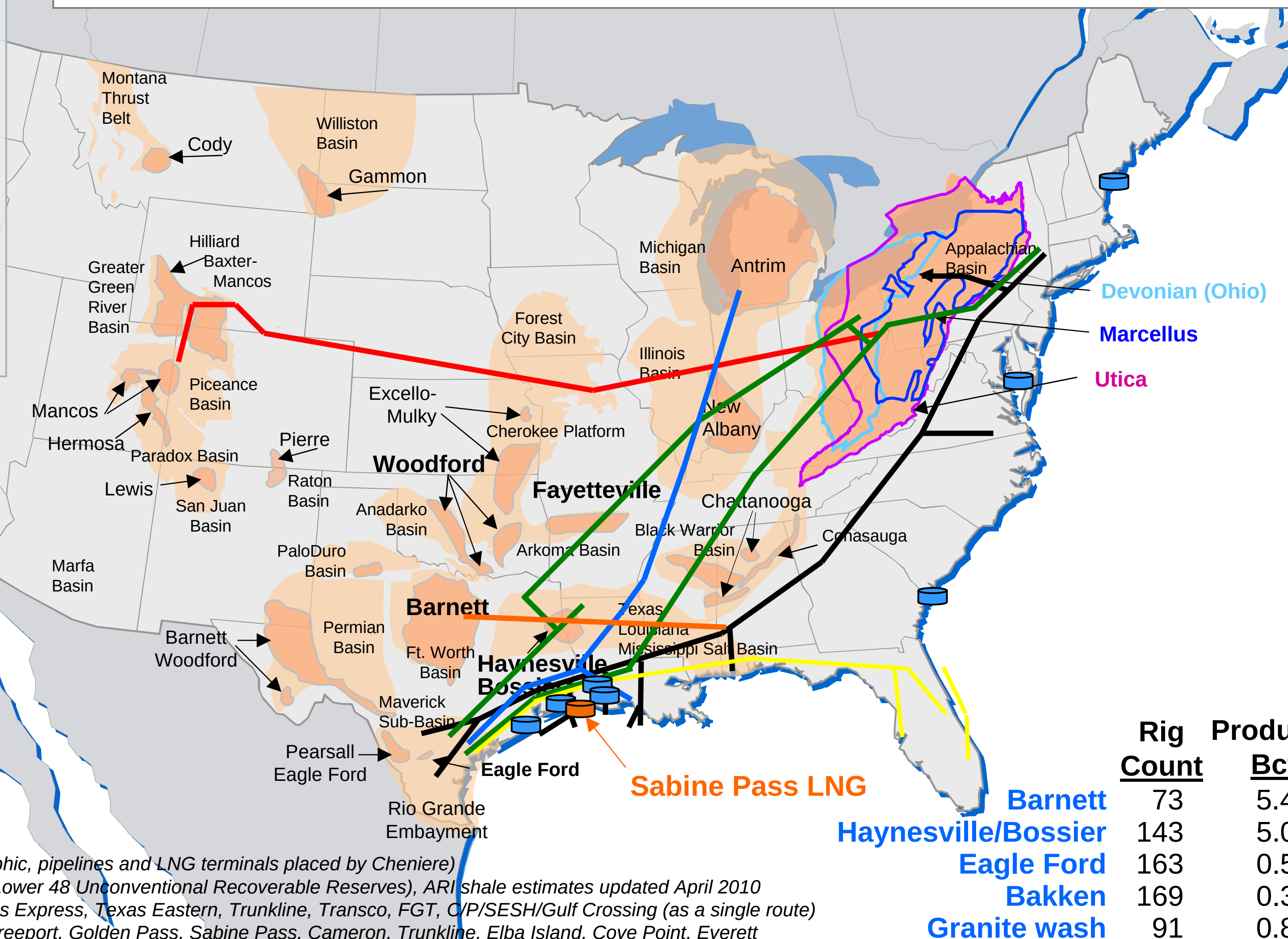
Strategically Located - Extensive Market Access to Gas

Primary Gas Sources for Sabine Pass Liquefaction

Conventional Gulf Coast Onshore; Barnett; Haynesville; Bossier; Eagle Ford

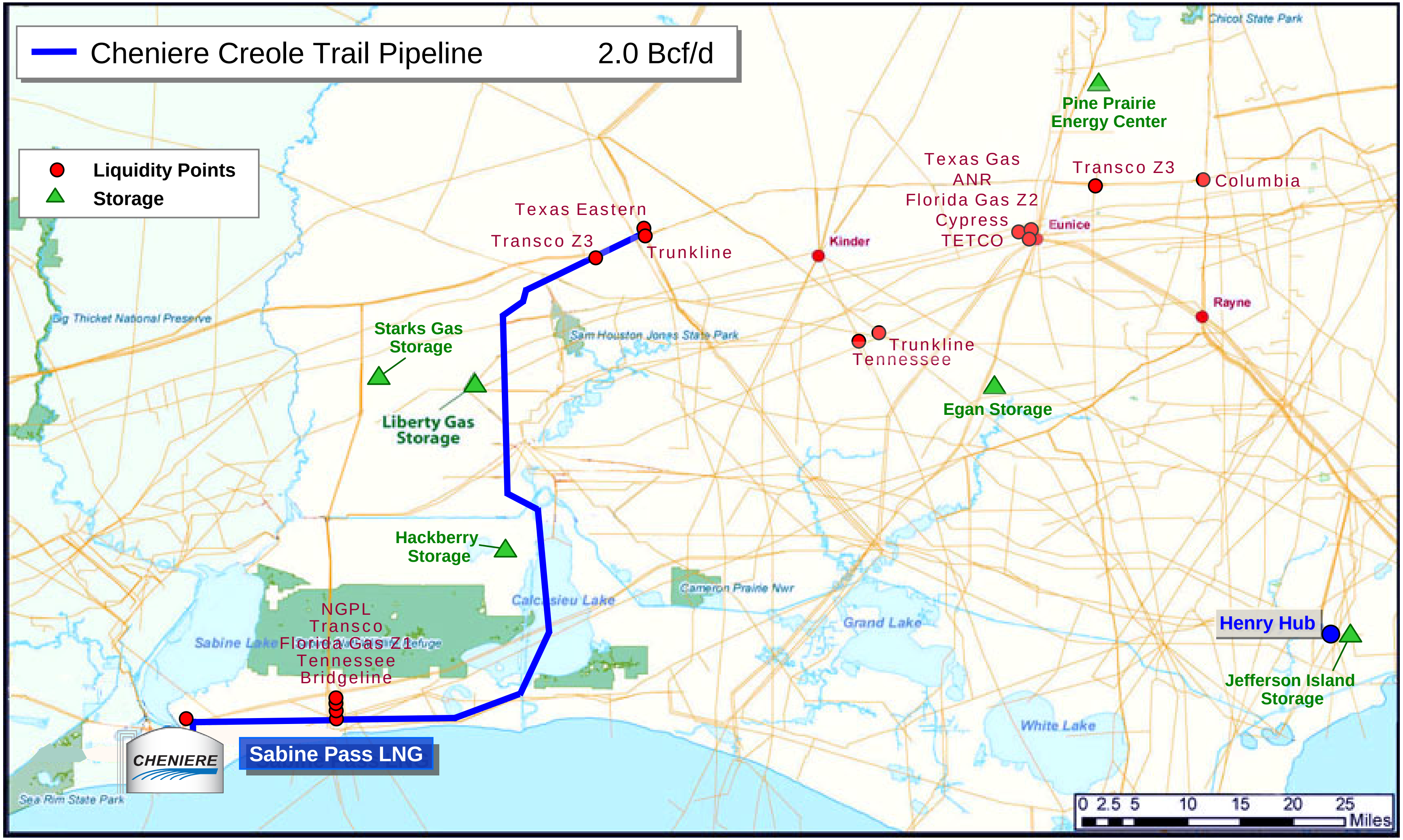




	Rig Count	Production Bcf/d
Barnett	73	5.4
Haynesville/Bossier	143	5.0
Eagle Ford	163	0.5
Bakken	169	0.3
Granite wash	91	0.8

Sources: EIA (US map graphic, pipelines and LNG terminals placed by Cheniere)
Advanced Resources Intl (Lower 48 Unconventional Recoverable Reserves), ARI shale estimates updated April 2010
Depicted Pipelines: Rockies Express, Texas Eastern, Trunkline, Transco, FGT, C/P/SESH/Gulf Crossing (as a single route)
Depicted LNG terminals: Freeport, Golden Pass, Sabine Pass, Cameron, Trunkline, Elba Island, Cove Point, Everett

Strategically Located - Multiple Pipeline Interconnects



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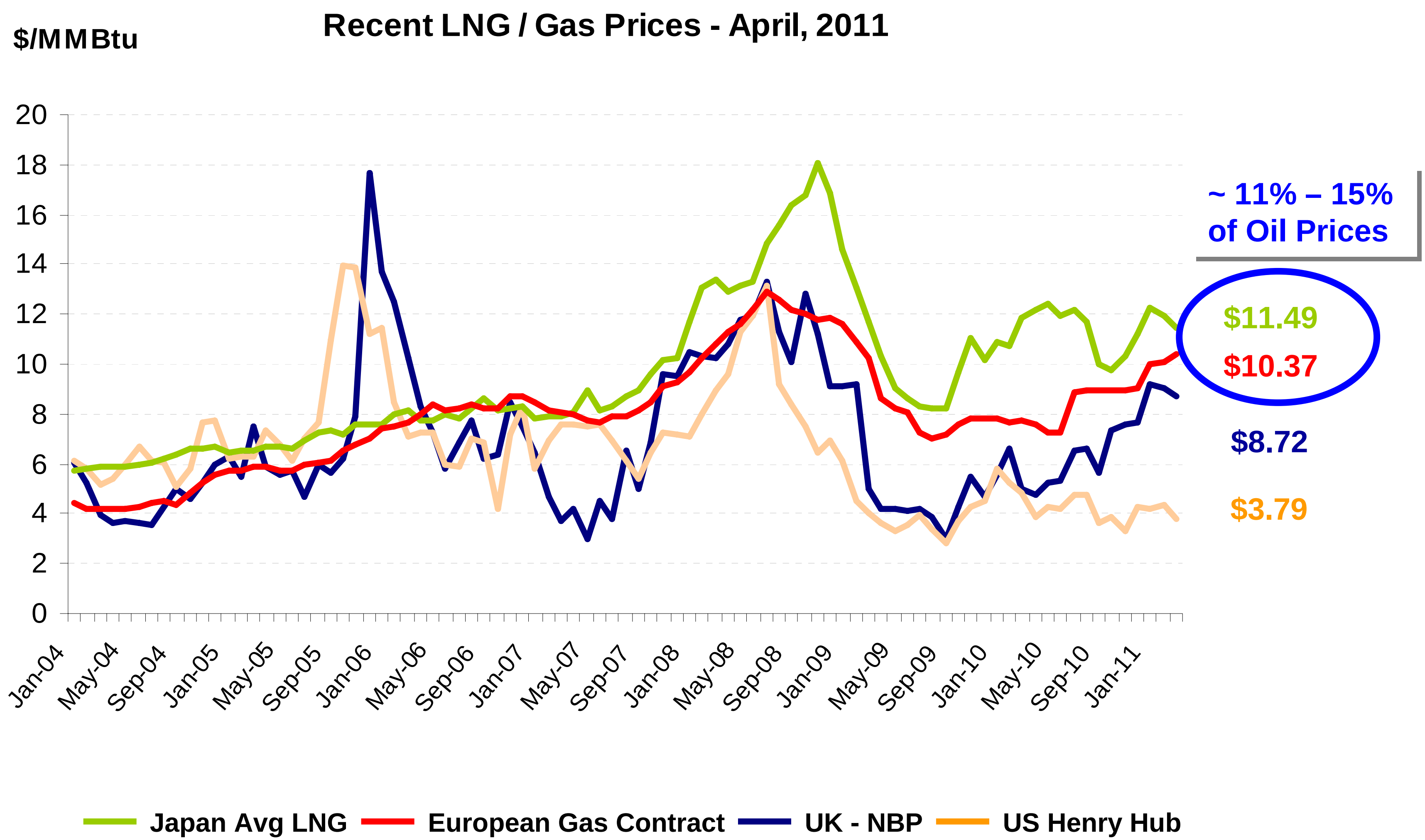
Attractive Oil Linked Market Prices



Source: CME as of March 31, 2011.

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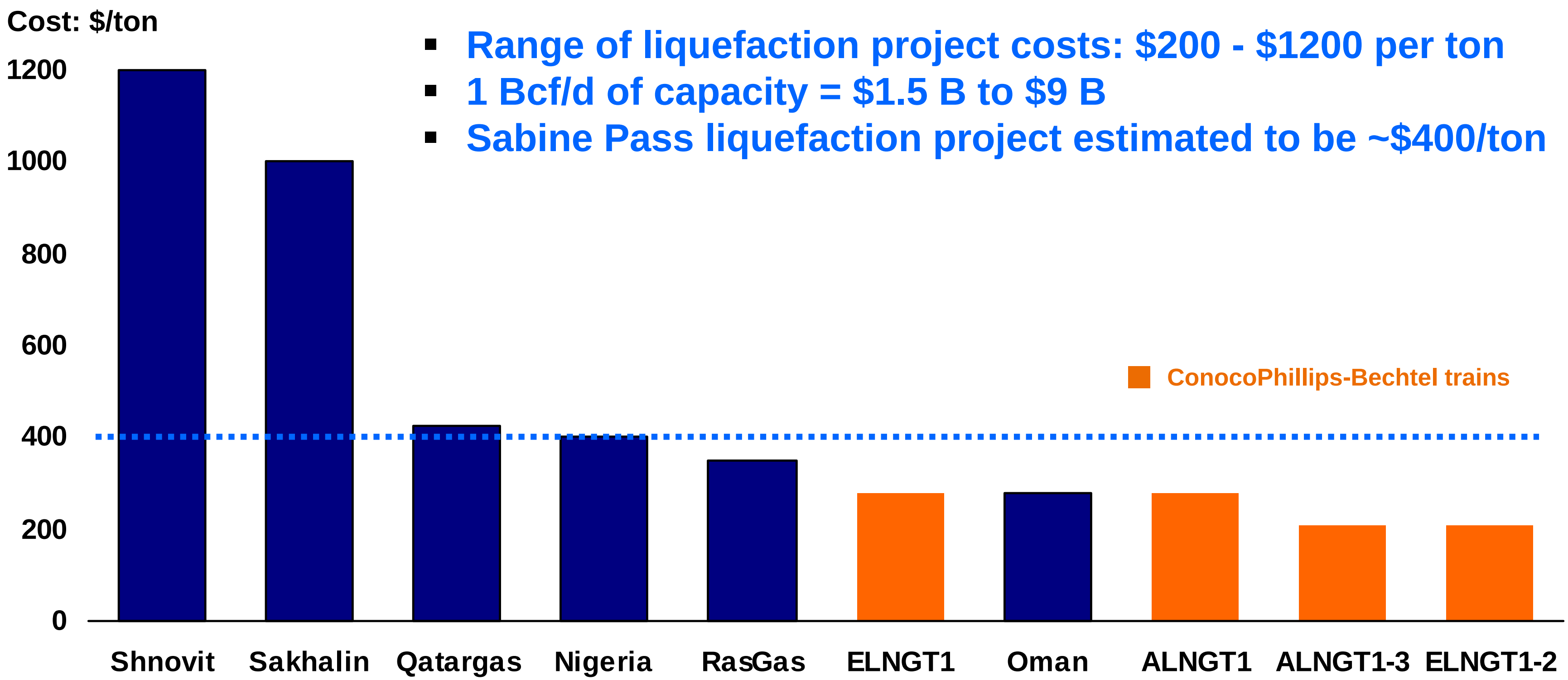
Sabine Pass Liquefaction Project - Brownfield Development, Lower Expected Capital Costs



- **Brownfield development – significant infrastructure already in place**
  – Storage, marine and pipeline interconnection facilities
- **Upstream wells, gathering pipelines and treatment infrastructure not required**
  – Pipeline quality natural gas sourced from U.S. pipeline grid

 Source: ConocoPhillips-Bechtel, Cheniere research

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ConocoPhillips-Bechtel – Global LNG Collaboration

Proven Designs

1969 1999 2006 2007 2012

All Collaboration projects have come onstream ahead of schedule and exceeded expectations

ConocoPhillips BECHTEL

Source: ConocoPhillips, Bechtel

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LNG Regulatory Process Update and Project Support

- Very strong local support: Cameron Parish officials, Louisiana state and federal congressional delegations, parish & state agencies
- Strong support from most gas producing states
- Cheap ethane by-product means added competitiveness for chemical industry
- 30,000 to 50,000 potential job impact
- Balance of trade improvement ~$7 B
- Positive foreign policy implications of U.S. role in global gas markets

Regulatory

FERC: Authorization to Construct	
• Base site permitted	✓
• NEPA pre-filing 7/10 for expansion	✓
• Some agencies already in agreement	✓
• Formal application filed 1/31/11	✓
• Estimated approval 2012	

DOE: Authorization to Export	
• Filing in two applications in 8/10 & 9/10	✓
• Approval to export 2 Bcf/d for 30 years to Free Trade nations received 9/10	✓
• Public comment period to export to non FT nations closed 12/13/10	✓
• Approval to export to non FT nations pending	

**Source: Cheniere DOE application dated 09.07.2010*

Commercial Structure: Estimated Terms of Liquefaction Contracts

Estimated cost for customer to purchase U.S. supply:

+ Capacity Fee: $1.40 - $1.75/MMBtu
  - "Take or Pay", permits lifting or unloading cargoes
+ LNG Export Commodity Charge: $HH/MMBtu
  - Delivery Terms: FOB
  - Prevailing price for eastbound flow in local pipelines
  - Paid on a per-MMBtu basis, per cargo loaded
+ Fuel Surcharge: 8%-12%
  - Projected based on forecast export activity
  - Trued up from period to period

- Customers reserve bi-directional capacity rights, both import and export services, under Liquefaction Processing Agreements (LPAs)
- Customers pay take or pay capacity fee of $1.40 - $1.75/MMBtu plus fuel surcharge of 8-12% (used for processing LNG)
  - 1 Bcf/d = ~$510 million to $640 million of revenues
- Customers responsible for delivering their own feed gas for processing, sourced from pipeline interconnects (including Creole Trail pipeline)

Customer MOUs Signed to Date Exceeds Capacity for Two Trains

Date	Customer	Rating	Capacity (mtpa)
Nov-10	Morgan Stanley (US)	A2 / A	1.7
Oct-10	ENN Energy Holdings (China)	Ba1 / BBB-	1.5
Nov-10	Gas Natural Fenosa (Spain)	Baa2 / BBB	1.5
Jan-11	EDF (France)	A3 / A	1.5
Jan-11	Sumitomo (Japan)	A2 / A	1.5
Feb-11	Basic Energy (Dominican Republic)	NR / B-	0.6
Feb-11	Endesa / Enel (Spain/Italy)	A2 / A-	1.5
	Total signed to date		9.8
	Target capacity for first two trains		7.0

- Sabine has signed non-binding MOUs with customers for up to 9.8 mtpa of bi-directional processing capacity, exceeding the targeted capacity of 7.0 mtpa for the first two trains
- Anticipated contract tenor: 20 years

*Non-binding MOUs entered into with potential customers intending to contract bi-directional processing capacity at the Sabine Pass LNG terminal. Capacity figures are approximate and represent the upper end of the quantity range in certain instances. Ratings listed are company specific or parent ratings.

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Estimated Financial Impact

(Annualized)

	Annual Contracted Cash, $MM[1]	Liquefaction Project Economics: Impact to CQP	Liquefaction Project Economics: Impact to LNG
Current	$253	▪ Stable common unit distributions ▪ ~1 x coverage supported by 20 year fixed price contracts with AA rated counterparties	▪ ~$38 mm paid to CEI as mgmt fees & Common/G.P. distributions
Train 1 500 MMcf/d	$255 - $320	▪ Increases common unit distribution coverage	▪ Distributions to sub units potentially start
Trains 1 & 2 1 Bcf/d	$510 - $640	▪ Allows distributions to subordinated unit holders ($230mm needed to meet annualized IQD) ▪ Potential common distribution growth ▪ Position CQP as a growth MLP	▪ Sub unit distributions to CEI; Sub units may begin 3 year “earned pay” period for conversion to common units
Trains 3 & 4 1 Bcf/d	$510 - $640	▪ Increase distributions to all unit holders	▪ Cash flow to CEI increases including GP IDRs

(1) Contracted cash, Current, based on the Chevron and Total TUAs. Contracted cash for the liquefaction trains based on a capacity fee of $1.40 - $1.75/mcf. Actual net distributable cash flow will depend upon various factors, including debt service payments for amortization and interest, operating expenses, etc.

Note: Estimates represent a summary of internal forecasts, are based on current assumptions and are subject to change. Actual performance may differ materially from, and there is no plan to update the forecast. See “Forward Looking Statements” cautions.

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Expected Timeline

▪ Sign MOUs with interested parties	4Q2010
▪ DOE export authorization	Pending
▪ Definitive commercial agreements	Mid 2011
▪ EPC contract	2H2011
▪ Financing commitments	2H2011
▪ FERC construction authorization	2012
▪ Commence construction	2012
▪ Commence operations	2015

Appendix

Cheniere Overview

Cheniere Energy, Inc.
NYSE Amex US: LNG

Cheniere LNG Holdings, LLC
- 90.6% Ownership of CQP

88.6% (LP interest)
2.0% (GP interest)

Cheniere Marketing
- 2 Bcf/d Regasification Capacity at SPLNG

Creole Trail Pipeline
- 2 Bcf/d Takeaway Capacity for SPLNG

Permitted Projects
- Corpus Christi LNG
- Creole Trail LNG

Cheniere Energy Partners, L.P.
NYSE Amex US: CQP

Sabine Pass LNG, L.P. (SPLNG)
- 4 Bcf/d Regasification Terminal, Fully Contracted

Proposed Project - Liquefaction
- *Up to 2 Bcf/d LNG Processing at SPLNG*

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Estimated CQP Distributable Cash Flows*

(Annualized, $ in mm)

Receipts	
TUAs – Chevron and Total	$ 253
Other Services	7
Total Cash Receipts	260
Costs	
Operating, G&A, Maintenance CapEx	46
Debt Service	165
Total Costs	211
Available for Distributions to Common and G.P.	**$ 49**
Potential Future Cash Flows	
Regas Capacity (from VCRA)	$ 0 – 250
Available for Management Fees(1) & Subordinated Units	**$ 0 – 250**

(1) Not included in disbursements above is an estimate of up to approximately $11 million of fees payable to Cheniere for services provided under a management services agreement. Such fees are payable on a quarterly basis equal to the lesser of 1) $2.5 million (subject to inflation) or 2) such amount of CQP's unrestricted cash and cash equivalents as remains after CQP has distributed in respect of each quarter for each common unit then outstanding an amount equal to the IQD and the related GP distribution and adjusting for any cash needed to provide for the proper conduct of the business of CQP, other than Sabine Pass operating cash flows reserved for distributions in respect of the next four quarters.

* Does not include any estimates for liquefaction.

Note: Estimates represent a summary of internal forecasts, are based on current assumptions and are subject to change. Actual performance may differ materially from, and there is no plan to update the forecast. See "Forward Looking Statements" cautions.

CHENIERE

Ownership - CQP

(in mm)	Cheniere Energy, Inc	Public*	Total
Common Units	10.9	15.5	26.4
Subordinated Units	135.4		135.4
General Partner @ 2%	3.3		3.3
	149.6	15.5	165.1
Percent of total	90.6%	9.4%	100%

*Excludes 1MM shares to be sold by CQP through a strategic equity offering as described in the prospectus supplement filed by CQP on 1/14/2011.

CHENIERE

Estimated LNG Future Cash Flows*
Cheniere Energy, Inc.

($ in MM)	Annualized**
Receipts	
▪ **Distributions from CQP** (Common/GP)	**$ 20**
▪ **Management fees from CQP**	**8 -19*** **
Disbursements	
▪ **G&A, net marketing**	**25 - 35**
▪ **Pipeline & tug services**	**10**
▪ **Other, incl adv tax payments**	**3 - 5**
▪ **Debt service**	**34**
Net cash outflow	**$45 - 55**
Marketing activity	**?**

* Does not include any estimates for liquefaction.

**Estimates represent a summary of internal forecasts, are based on current assumptions and are subject to change. Actual performance may differ materially from, and there is no plan to update the forecast. See "Forward Looking Statements" cautions. Estimates exclude earnings forecasts from operating activities.

***Approximately $11 million is fees for management services provided by Cheniere to CQP payable on a quarterly basis, equal to the lesser of 1) $2.5 million (subject to inflation) or 2) such amount of CQP's unrestricted cash and cash equivalents as remains after CQP has distributed in respect of each quarter for each common unit then outstanding an amount equal to the IQD and the related GP distribution and adjusting for any cash needed to provide for the proper conduct of the business of CQP, other than Sabine Pass operating cash flows reserved for distributions in respect of the next four quarters.

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Organizational Structure
Existing Debt

NYSE Amex US: LNG

CHENIERE

$205 mm 2.25% Convertible Senior Unsecured Notes due August 2012

100% Ownership Interest

Cheniere LNG Holdings, LLC

$298 mm 9.75% Term Loan due May 2012
$263 mm 12.0% Senior Secured Loans due 2018*

88.6% LP Interest
100% of 2% GP Interest

Cheniere Energy Partners, L.P.

9.4% LP Interest

NYSE Amex US: CQP

Public Unitholders

100% Ownership Interest

Cheniere Energy Investments, LLC

100% Ownership Interest

Sabine Pass LNG, L.P.

$550 mm 7.25% Senior Secured Notes due 2013
$1,666 mm 7.50% Senior Secured Notes due 2016

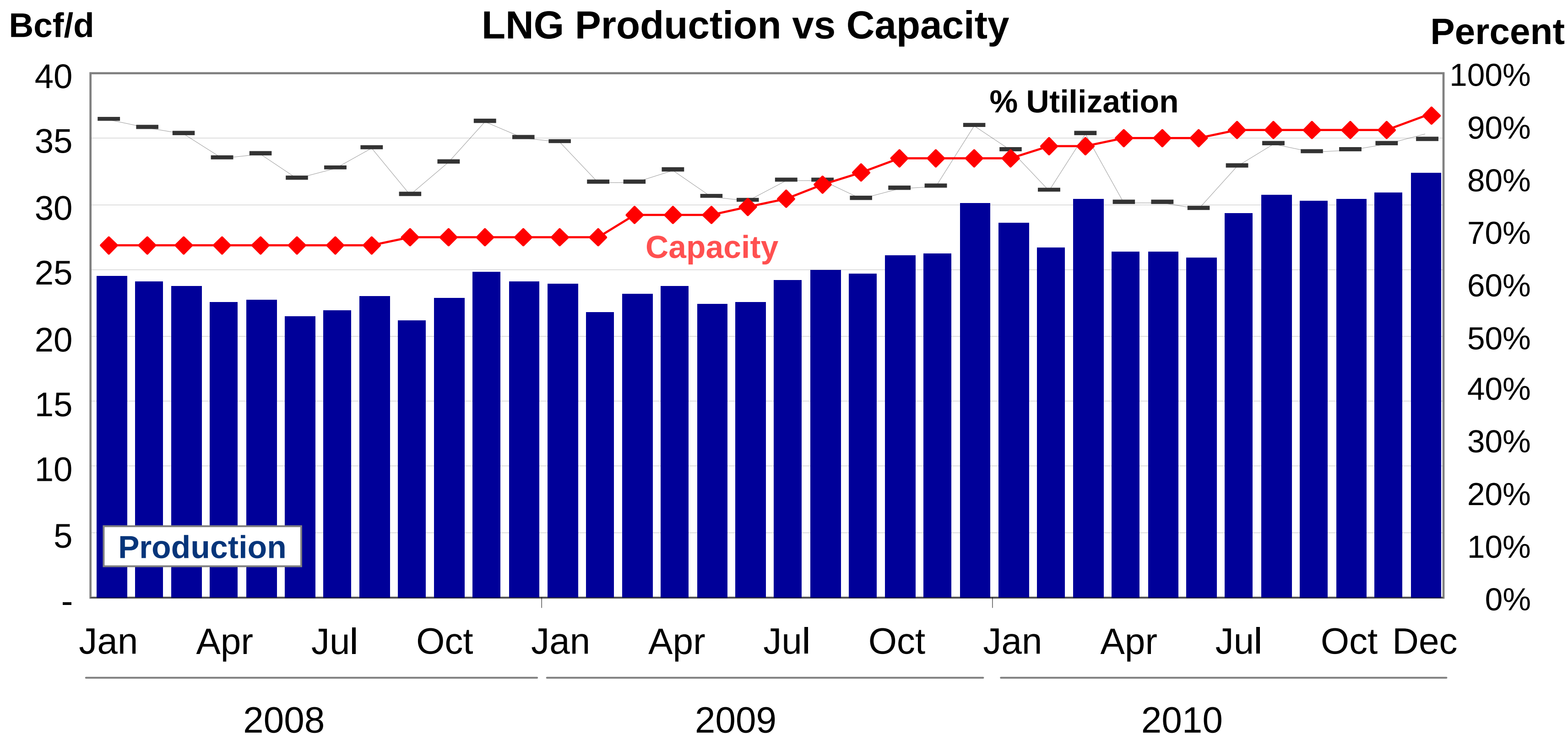
Customer	Annual TUA Pmt
Total	$123MM
Chevron	$128MM
Investments	$252MM

* Put rights removed per credit amendment effective 12/10/2010

Note: Balances as of December 31, 2010

LNG Production, Capacity, Utilization

- **Production +5.1 Bcf/d > 2009, 21% increase YoY in 2010**
- **Utilization rates returning to historical 90% norm**
- **1.6 Bcf/d remaining capacity to bring on line in 1Q2011**



Source: Waterborne, Cheniere Research

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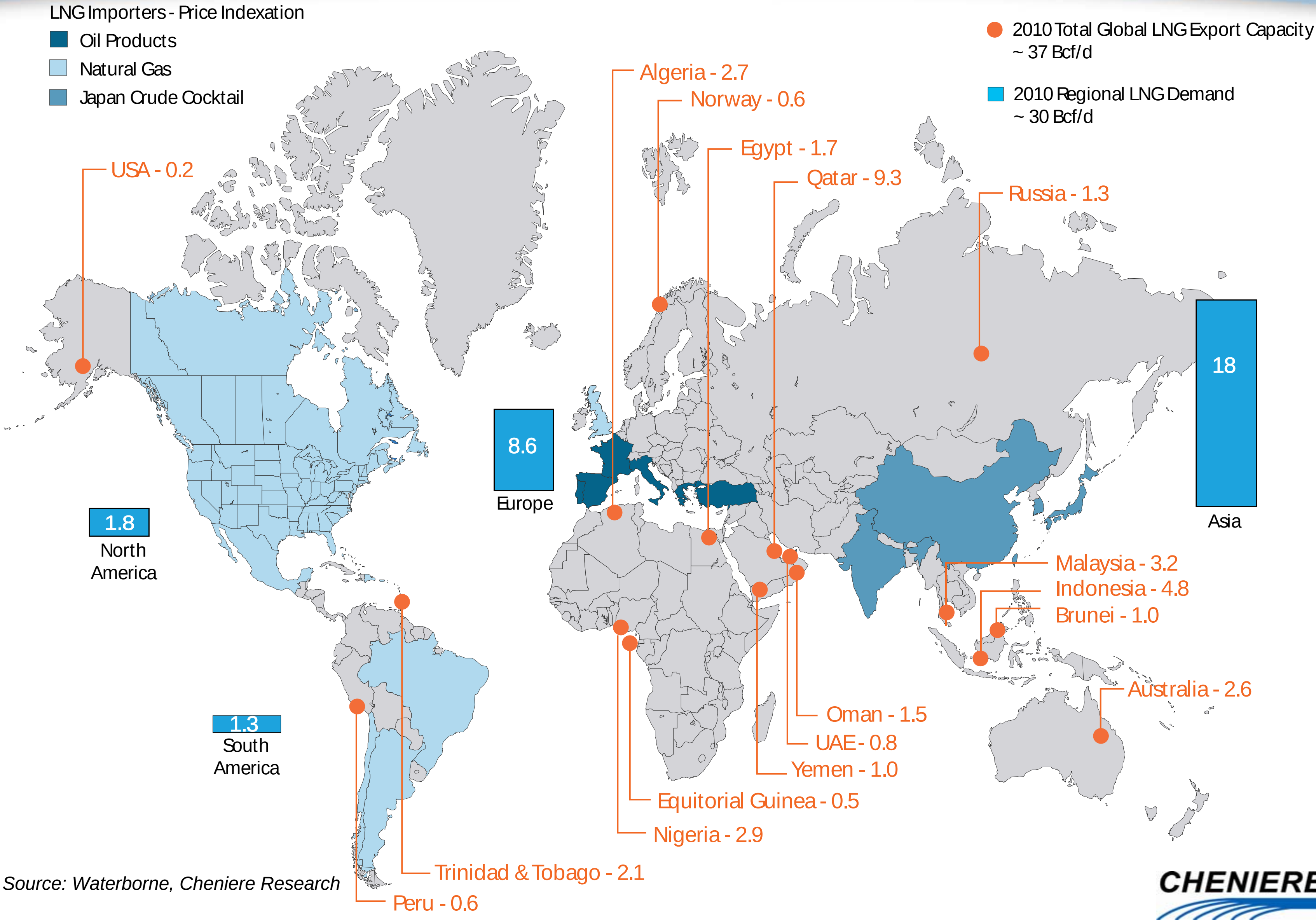
Global LNG Market - 2010



Source: Waterborne, Cheniere Research

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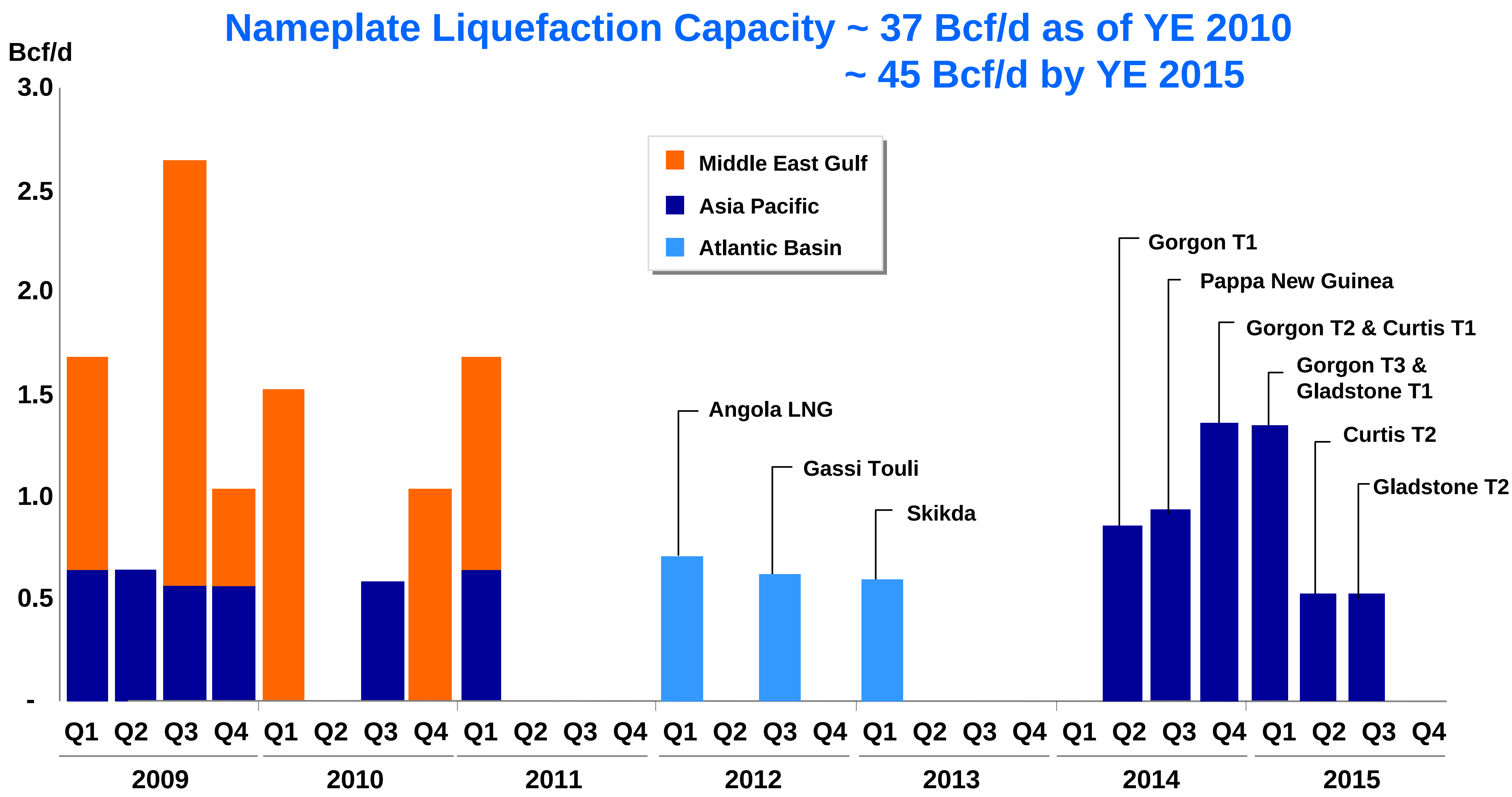
Firm Liquefaction Capacity Additions



Source: Cheniere Research

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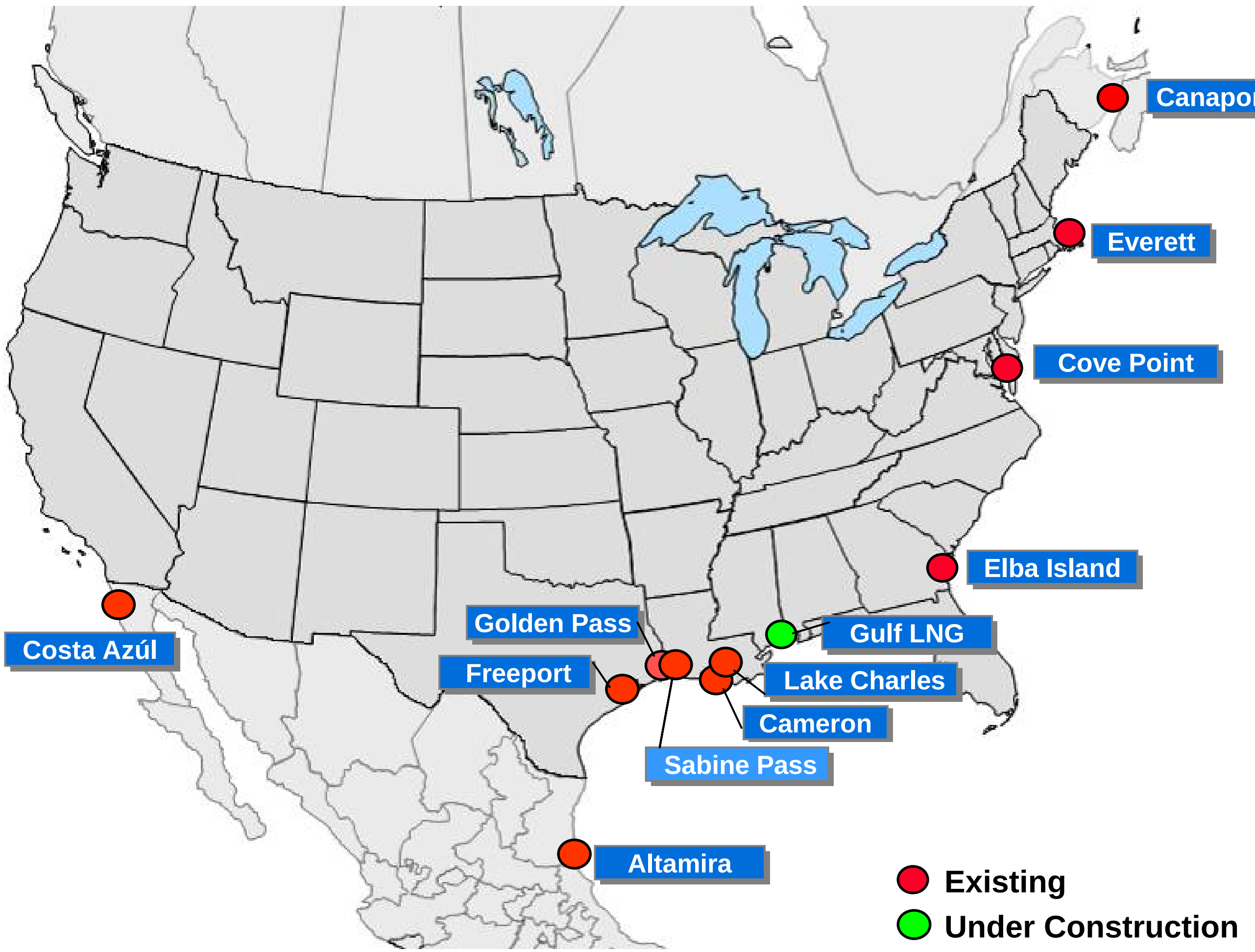
North America Onshore Regasification Capacity



Terminal Capacity Holder	Baseload Sendout (MMcf/d)
Canaport Repsol	1,000
Everett - Suez	700
Cove Point BP, Statoil, Shell	1,800
Elba Island BG, Marathon, Shell	1,800
Gulf LNG Angola LNG, ENI	1,300
Lake Charles - BG	1,800
Freeport ConocoPhillips, Dow, Mitsui	1,500
Sabine Pass Total, Chevron, Cheniere	4,000
Cameron Sempra, ENI	1,500
Golden Pass ExxonMobil, ConocoPhillips, QP	2,000
Altamira Shell, Total	700
Costa Azul Shell, Sempra, Gazprom	1,000
Total	19,100

Source: Websites of Terminal Owners

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Cheniere Energy

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RECEIVED
By Docket Room at 11:26 am, Jan 14, 2013

From:	Tyner, Wallace E.
To:	LNGStudy
Subject:	2012 LNG Export Study
Date:	Monday, January 14, 2013 11:25:34 AM
Attachments:	Comparison of Analysis of Natural Gas Export Impacts w exec sum Jan rev.pdf

Comments attached.

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West Lafayette, IN 47907-2056
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Comparison of Analysis of Natural Gas Export Impacts from Studies Done by NERA Economic Consultants and Purdue University

Wallace E. Tyner, James and Lois Ackerman Professor
Kemal Sarica, Post-doctoral Associate
Purdue University

Executive Summary

The U.S. Department of Energy (DOE) is soon to make decisions on the extent to which natural gas exports will be approved. With the shale gas boom, the US is expected to have very large natural gas resources, so the key question is would it be better to rely completely on free market resource allocations which would lead to large exports of natural gas or to limit natural gas exports so that more could be used in the US. There are two economic studies of the impacts on the U.S. economy of increased natural gas exports – one done for DOE by NERA Economic Consultants and the other by Tyner and Sarica of Purdue University. The NERA study results in a very small income gain for the U.S. from increased natural gas exports, and the Purdue study results in a small economic loss.

Any time trade policy questions are raised, it is often not so much about net gains as about winners and losers. Net gains or losses, whichever may be the case are tiny. The $10 billion gain in the NERA study amounts to 6 hours of U.S. economic activity. In the NERA analysis, the losses are in wage and capital income in energy intensive industries, and the gains are almost exclusively wealth transfers to owners of natural gas resources. Perhaps a more important question is should the nation accept the economic losses in many key economic sectors to provide wealth transfers to natural gas resource owners? In addition, while U.S. industry and consumers would face higher natural gas and electricity prices, foreign competitors would face lower energy costs with increased U.S. natural gas exports.

Beyond the economic and income distribution issues, there are also associated environmental impacts not covered in the NERA study. In the Purdue study, U.S. GHG emissions increase when there are increased natural gas exports. An argument could be made that GHG emissions might fall in other regions as they replace coal or other fossil fuels with cleaner natural gas. However, there likely would be a sort of emissions transactions cost in liquefying, transport, and de-liquefying the gas that would result still in a net GHG increase. In addition, because less natural gas would be used in local fleets because of natural gas exports, there would be an increase in local particulate emissions due to relatively more use of diesel and less use of CNG.

The bottom line is that there are very important issues concerning whether or to what extent there really are any economic gains to the U.S. from exporting natural gas instead of using it domestically. There are income distribution consequences of natural gas export impacts that need to be factored into the export permit decisions, and there are environmental impacts that should be counted as well. The results of these two studies, while showing some similarities are different enough in final outcomes to warrant much more informed debate on this critically important national policy issue.

Comparison of Analysis of Natural Gas Export Impacts from Studies Done by NERA Economic Consultants and Purdue University

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The U.S. Department of Energy (DOE) is soon to make decisions on the extent to which natural gas exports will be approved. With the shale gas boom, the US is expected to have very large natural gas resources, so the key question is would it be better to rely completely on free market resource allocations which would lead to large exports of natural gas or to limit natural gas exports so that more could be used in the US. Exports would be economically attractive because there is a very large price gap at present between US natural gas price (around $3.50/MCF) and prices in foreign markets, which can range up to $15/MCF. On the other side, there is potentially large domestic demand for natural gas in electricity generation, industrial applications, the transportation sector, and for other uses. There is no doubt that exporting a large amount of natural gas would increase the domestic natural gas price for all these potential uses. Higher natural gas prices would, in turn, mean higher electricity prices, so the higher energy costs would go beyond just natural gas users. These higher energy costs would also lead to contraction in energy intensive sectors relative to the reference case with small natural gas exports.

NERA Economic Consulting study

In December 2012, DOE released a commissioned study done by NERA Economic Consultants, a private consulting firm[1]. They used their own proprietary energy-economy model named NewERA for the analysis. Their results suggest that the US achieves economic gains from natural gas exports and that the gains increase as the level of natural gas exports grows. Their result is the classical economic result that free trade provides net gains to the economy under most conditions. While economic theory does not suggest that free trade always produces economic gains for all parties under all conditions, the general argument is that under a wide range of conditions, free trade does provide net benefits with some winners and some losers. The NERA results do show higher natural gas prices due to exports with the magnitude of the increase depending on domestic and global supply and demand factors. The NERA study used input data and information from a companion study done by the Energy information Agency in DOE [2], which estimated the impacts of export levels on US natural gas prices.

The NERA analysis focused on export levels of 6 and 12 BCF per day, but there were many other scenarios and sensitivity analyses. In general, the welfare or net income increases estimated in the NERA scenarios were very small, generally ranging from 0.01 to 0.025 percent over the reference case. There were considerable losses in capital and wage income in sectors affected by the higher natural gas prices, and income gains to natural gas resource owners through export earnings and wealth transfers to resource owners. By 2030 the total net increase in GDP amounted to about $10 billion 2010$, which could be perceived as being quite small in a $15 trillion economy [3]. Wage income falls in agriculture, energy intensive sectors, and the electricity sector. The percentage declines in wages in these sectors were generally much greater than the percentage increases in net national income. Natural gas price increases did not exceed 20 percent in any of the simulations. The NewERA energy-economy model takes inputs from the EIA NEMS natural gas projections [2] and from a global natural gas model.

Purdue MARKAL-Macro Analysis

The Purdue approach was to use a well-established bottom-up energy model named MARKAL (MARKet ALlocation). Bottom-up means that the model is built upon thousands of current and future prospective energy technologies and resources. These energy resources supply projected energy service demands for the various sectors of the economy. In addition to the standard MARKAL model, we also have adapted a version of the MARKAL-Macro model which permits us to include feedbacks between energy prices and economic activity. Thus the GDP effects of alternative energy policies are captured as well as technology and supply impacts. For these reasons, MARKAL-Macro is an ideal tool for this kind of analysis. The Purdue analysis was done for the two levels from the EIA and NERA reports (6 BCF/day and 12 BCF/day plus 18 BCF per day). The EIA NEMS model is a bottom-up model somewhat similar to MARKAL. Details of the analysis are available in Sarica and Tyner [4].

The Purdue analysis shows that increasing natural gas exports actually results in a slight decline in GDP. Essentially the gains from exports are less than the losses in electricity and energy intensive sectors in the economy. The GDP losses are around 0.04%, 0.11%, and 0.17% for the 6, 12, and 18 BCF/day cases respectively for the year 2035.

The general trends in the change in energy resource mix for 2035 are as follows: 1)the domestic energy share for natural gas falls from 25 to 22 percent) as exports of natural gas increase; 2)domestic use of coal increases from 21 to 23 percent as natural gas exports increase; 3)the fraction of oil in total consumption increases from 36 to 37 percent; 4)there are small increases in nuclear and renewables (hydro, solar, wind, and biomass).

The impacts on the electricity sector come in higher electricity prices and higher GHG emissions. In 2035, electricity price is up compared with the reference case by 1.1%, 4.3%, and 7.2% for the 6 BCF, 12 BCF, and 18 BCF cases respectively. Of course, these higher electricity prices are passed through the entire economy through industrial, commercial, and residential sectors. Electricity GHG emissions in the early years of the simulation horizon are around 2% higher for the 6 BCF case, and 7-12% higher for the 12 and 18 BCF cases.

In 2035, CNG use in transportation for the reference case is 1.3 bil. gal. gasoline equivalent, but it drops to 0.2-0.3 in the three export cases. CNG use in heavy duty vehicles disappears in the 12 BCF case, and CNG use in most of the vehicle categories drops considerably. The bottom line is that while CNG use in transport is not large even in the reference case, it plummets in the export cases.

We examined impacts on the metals, non-metals, paper, and chemical sectors. Total energy use and thus also economic output declines from 1 to 4 percent in all the energy intensive sectors depending on the sector and the level of natural gas exports. Thus, it is easy to see how the Purdue results show a decline in GDP since there are declines in several key sectors in the economy driven by the higher natural gas prices.

Comparison

These studies use different models, somewhat different data sets, and different modeling parameters. The results are different, but there are some important similarities. On GDP impacts, the sign of the change is different. NERA gets a very small but positive welfare impact, and Purdue MARKAL-Macro gets a small negative impact. Our view is that because the net income impacts are so small, it is not appropriate to place much emphasis on that outcome. What is important is to explain the differences and to understand the drivers of the differences.

Purdue MARKAL-Macro gets larger natural gas price increases, which, in-turn leads to electricity price increases and to declines in energy use and output for key energy intensive sectors. The decline in economic activity of these sectors is a key driver in the decline in GDP. In fact, since neither the Purdue nor the NERA model are complete global CGE models, the estimated decline in economic activity of these sectors is probably an underestimate because all these sectors would face higher costs and would be less competitive on the global market with higher natural gas exports. In other words, U.S, economic losses likely would be larger than estimated by either model. Also, other nations would face lower energy costs with our LNG exports.

Any time trade policy questions are raised, it is often not so much about net gains as about winners and losers. Net gains or losses, whichever may be the case are tiny. The $10 billion gain in the NERA study amounts to 6 hours of U.S. economic activity. In the NERA analysis, the losses are in wage and capital income in energy intensive industries, and the gains are almost exclusively wealth transfers to owners of natural gas resources. Perhaps a more important question is should the nation accept the economic losses in many key economic sectors to provide wealth transfers to natural gas resource owners?

In addition to the economic and income distribution issues, there are also associated environmental impacts not covered in the NERA study. In the Purdue study, U.S. GHG emissions increase when there are increased natural gas exports. An argument could be made that GHG emissions might fall in other regions as they replace coal or other fossil fuels with cleaner natural gas. However, there likely would be a sort of emissions transactions cost in liquefying, transport, and de-liquefying the gas that would result still in a net GHG increase. In addition, because less natural gas would be used in local fleets because of natural gas exports, there would be an increase in local particulate emissions due to relatively more use of diesel and less use of CNG.

Conclusions

Beyond the analysis conducted here, it is important to note that neither the model used in this analysis nor the NERA model are global in scope. Thus, neither includes the trade impacts of US natural gas exports. However, we can describe those impacts qualitatively. Increased US natural gas exports will reduce energy costs for industry and consumers in foreign countries and increase those costs for the US. Thus, US industry will be rendered less competitive compared with foreign industry. This loss of export revenue would be in addition to the GDP loss estimated in this analysis. Moreover, US consumers lose due to higher energy prices, and foreign consumers gain.

Given all the results of this analysis, it is clear that policy makers need to be very careful in approving US natural gas exports. While we are normally disciples of the free trade orthodoxy, one must examine the evidence in each case. We have done that, and the analysis shows that this case is different. Using the natural gas in the US is more advantageous than exports, both economically and environmentally.

The bottom line is that there are very important issues concerning whether or to what extent there really are any economic gains to the U.S. from exporting natural gas instead of using it domestically. There are income distribution consequences of natural gas export impacts that need to be factored into the export permit decisions, and there are environmental impacts that should be counted as well. The results of these two studies, while showing some similarities are different enough in final outcomes to warrant much more research and informed debate on this critically important national policy issue.

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U.S. LNG Exports:

State-Level Impacts on Energy Markets and the Economy

November 13, 2013

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Key Findings on State-Level Economic Impacts of U.S. LNG Exports

This state-level study follows a national-level study on the economic and employment impacts of liquefied natural gas (LNG) exports from the United States done on behalf of the American Petroleum Institute (API).[1]

National study assessed LNG export impacts on three export levels:

- ***ICF Base Case (4 Bcfd)***
- ***Middle Exports Case (8 Bcfd)***
- ***High Exports Case (16 Bcfd)***

Note: Bcfd denotes billion cubic feet per day.

This state-level analysis allocates national-level LNG export impacts among each U.S. state. Similar to the national-level study, which found overwhelmingly positive economic and employment impacts associated with LNG exports, this study concludes that LNG exports have a net positive impact, or negligible net impact, across all states.

Largest impacts found in states with:

- ***Natural gas, oil, and natural gas liquids (NGL) production***
- ***LNG production***
- ***Ethylene manufacturing***
- ***Industries supplying materials, products, and services to the oil and gas and petrochemical industries***
- ***Consumer spending activity generated by gas- and petrochemical-related activities***

Economic Impacts: Of the up to $115 billion net Gross Domestic Product (GDP) value added generated by LNG exports in 2035, natural gas-producing states such as Texas, Louisiana and Pennsylvania are expected to see increases in state income up to $10-$31 billion that year. Non-natural-gas-producing states with a large manufacturing base, such as Ohio, California, New York, and Illinois, see significant impacts, up to $2.6-$5.0 billion in 2035.

Employment Impacts: LNG exports are expected to contribute up to 665,000 net job gains nationwide in 2035, with all states seeing net positive employment impacts from LNG exports.[1] As with state income impacts, gas-producing states are expected to see the largest employment impacts, with Texas, Louisiana, and Pennsylvania expected to achieve up to 60,000-155,000 job gains in 2035. Large manufacturing states such as California and Ohio could see up to 30,000-38,000 job gains in 2035.

2035 State Income and Employment Impacts for Top Ten States

State	2035 Maximum State Income Changes ($2010 Billion)			2035 Maximum State Employment Changes (No.)		
	ICF Base Case	Middle LNG Exports Case	High LNG Exports Case	ICF Base Case	Middle LNG Exports Case	High LNG Exports Case
TX	$5.2	$12.1	$31.4	28,019	61,752	155,713
LA	$5.0	$11.8	$16.2	21,795	52,568	74,218
PA	$2.8	$6.7	$10.3	16,650	38,565	59,289
AK	$0.0	$0.0	$10.0	99	88	36,622
OH	$1.2	$2.6	$5.1	7,483	14,819	30,124
CA	$1.1	$2.3	$5.0	8,756	15,701	38,981
NY	$0.8	$1.6	$3.3	5,688	10,602	24,985
WY	$0.7	$1.7	$3.3	4,302	9,454	17,854
AR	$0.9	$2.1	$3.1	5,321	12,438	18,285
IL	$0.6	$1.2	$2.6	3,995	7,117	17,341

Note: Calculated using an economic multiplier of 1.9.

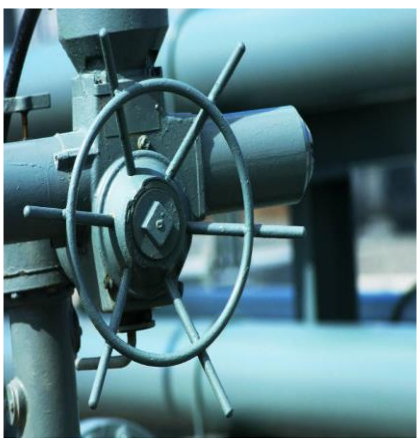
[1] Study available at http://www.api.org/~/media/Files/Policy/LNG-Exports/API-LNG-Export-Report-by-ICF.pdf.

Manufacturing Across the LNG Value Chain

Upstream
- **Natural gas and liquids drilling and production manufacturing needs: Drill pipe and steel casing, cement, compressor equipment, tanks, control systems**

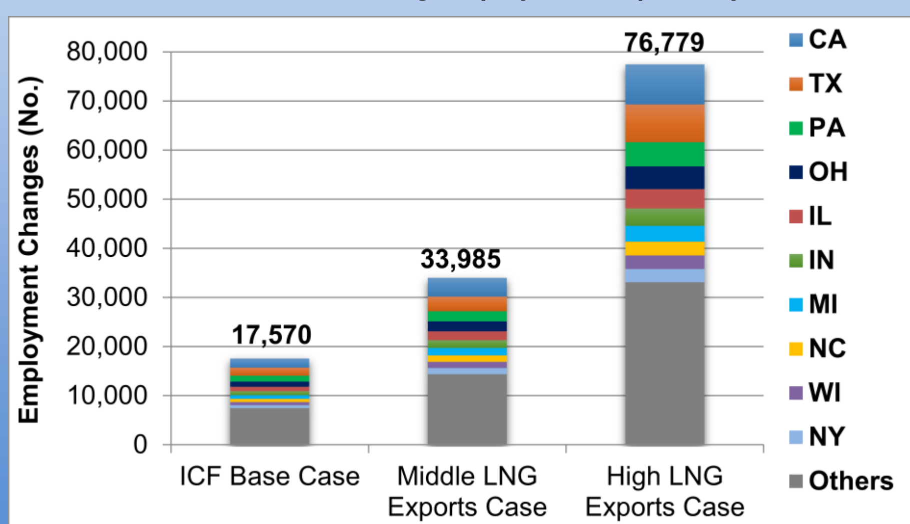
Midstream
- **Natural gas processing and transport manufacturing needs: Pipeline, materials for processing facility construction**

Down-stream
- **Liquids refining, petrochemical processing, liquefaction plant manufacturing needs: Construction materials and equipment, LNG port facilities**



Manufacturing Employment Impacts: Of the up to net 77,000 manufacturing jobs generated by LNG exports by 2035, states such as California, Texas, Pennsylvania, and Ohio are expected to see gains of up to 4,600-8,200 in 2035. In addition to the in-state construction and maintenance generating manufacturing jobs for gas-producing states such as Texas and Pennsylvania, out-of-state manufacturing is required for production of steel, cement, and equipment.

2035 State Manufacturing Employment Impacts by State



Note: Calculated using an economic multiplier of 1.9. The table shows maximum impacts for all states, and shows maximum impacts for states with a potential LNG export terminal.

Key Takeaways:

- ***Economic and employment impacts to states positive, or negligible***
- ***Manufacturing of natural gas production equipment and materials is expected to generate significant job gains in a number of states***
- ***The largest overall impacts are found in states with natural gas production, liquefaction plants, and petrochemical industries, as well as states providing goods and services (e.g., manufacturing) to those sectors***

Glossary

Abbreviations

AEO	EIA Annual Energy Outlook
Bcf/day (or Bcfd)	Billion cubic feet of natural gas per day
Btu	British thermal unit, used to measure fuels by their energy content.
DES	Delivered Ex Ship
EIA	U.S. Energy Information Administration, a statistical and analytical agency within the U.S. Department of Energy
FOB	Free on Board
GDP	Gross Domestic Product
GTL	Gas-to-liquids
LNG	Liquefied Natural Gas
Mcf	Thousand cubic feet (volume measurement for natural gas)
MMcf	Million cubic feet (of natural gas)
MMBtu	Million British Thermal Units. Equivalent to approximately one thousand cubic feet of gas
MMBOE	Million barrels of oil equivalent wherein each barrel contains 5.8 million Btus.
MMbbl	Million barrels of oil or liquids
NAICS Codes	North American Industrial Classification System Codes
NGL	Natural Gas Liquids
Tcf	Trillion cubic feet of natural gas

Terms Used

Consumer Surplus – an economic concept equal to the area below the demand curve down to a horizontal line drawn at the market price. Used in this report to measure the benefits provided to consumers brought about by lower natural gas prices, lower electricity costs, and lower manufacturing prices.

Direct Impacts – immediate impacts (e.g., employment or value added changes) in a sector due to an increase in output in that sector.

Horizontal Drilling – the practice of drilling a horizontal section in a well (used primarily in a shale or tight oil well), typically thousands of feet in length.

Indirect Impacts – impacts due to the industry inter-linkages caused by the iteration of industries purchasing from other industries, brought about by the changes in direct output.

Induced Impacts – impacts on all local and national industries due to consumers' consumption expenditures rising from the new household incomes that are generated by the direct and indirect effects flowing through to the general economy. The term is used in industry-level input-output modeling and is similar to the term Multiplier Effect used in macroeconomics.

Multiplier Effect – describes how an increase in some economic activity produces a cascading effect through the economy by producing "induced" economic activity. The multiplier is applied to the total of direct and indirect impacts to estimate the total impact on the economy. The term is used in macroeconomics and is similar to the term Induced Impacts as used in industry-level input-output modeling.

Natural Gas Liquids – components of natural gas that are in gaseous form in the reservoir, but can be separated from the natural gas at the wellhead or in a gas processing plant in liquid form. NGLs include ethane, propane, butanes, and pentanes.

Original Gas-in-Place – industry term that specifies the amount of natural gas in a reservoir (including both recoverable and unrecoverable volumes) before any production takes place.

Original Oil-in-Place – industry term that specifies the amount of oil in a reservoir (including both recoverable and unrecoverable volumes) before any production takes place.

Oil and Gas Value Chain

- **Upstream Oil and Gas Activities –** consist of all activities and expenditures relating to oil and gas extraction, including exploration, leasing, permitting, site preparation, drilling, completion, and long term well operation.
- **Midstream Oil and Gas Activities –** consist of activities and expenditures downstream of the wellhead, including gathering, gas and liquids processing, and pipeline transportation.

- **Downstream Oil and Gas Activities** – activities and expenditures in the areas of refining, distribution and retailing of oil and gas products.

Oil and Gas Resource Terminology

- **Conventional gas resources** – generally defined as those associated with higher permeability fields and reservoirs. Typically, such as reservoir is characterized by a water zone below the oil and gas. These resources are discrete accumulations, typified by a well-defined field outline.

- **Economically recoverable resources** – represent that part of technically recoverable resources that is expected to be economic, given a set of assumptions about current or future prices and market conditions.

- **Proven reserves** – the quantities of oil and gas that are expected to be recoverable from the developed portions of known reservoirs under existing economic and operating conditions and with existing technology.

- **Technically recoverable resources** – represent the fraction of gas in place that is expected to be recoverable from oil and gas wells without consideration of economics.

- **Unconventional gas resources** – defined as those low permeability deposits that are more continuous across a broad area. The main categories are coalbed methane, tight gas, and shale gas, although other categories exist, including methane hydrates and coal gasification.

- **Shale gas and tight oil** – recoverable volumes of gas, condensate, and crude oil from development of shale plays. Tight oil plays are those shale plays that are dominated by oil and associated gas, such as the Bakken in North Dakota.

- **Coalbed methane** (CBM) – recoverable volumes of gas from development of coal seams (also known as coal seam gas, or CSG).

- **Tight gas** – recoverable volumes of gas and condensate from development of very low permeability sandstones.

Conversion Factors

Volume of Natural Gas

1 Tcf = 1,000 Bcf

1 Bcf = 1,000 MMcf

1 MMcf = 1,000 Mcf

Energy Content of Natural Gas (1 Mcf is one thousand cubic feet)

1 Mcf = 1.025 MMBtu

1 Mcf = 0.177 barrels of oil equivalent (BOE)

1 BOE = 5.8 MMBtu = 5.65 Mcf of gas

Energy Content of Crude Oil

1 barrel = 5.8 MMBtu = 1 BOE

1 MMBOE = 1 million barrels of crude oil equivalent

Energy Content of Other Liquids

Condensate

1 barrel = 5.3 MMBtu = 0.91 BOE

Natural Gas Plant Liquids

1 barrel = 4.0 MMBtu = 0.69 BOE (actual value varies based on component proportions)

Example Gas Compositions and Conversion Factors (based on 14.7 psi pressure base)

Natural Gas Component	US Pipeline Gas Composition (%)	LNG Made from US Pipeline Gas (%)	LNG from Australia NWS Gas Composition (%)	Btu/scf	Pounds/ Mscf
Methane	95.91%	97.56%	87.3%	1,030	42.3
Ethane	1.45%	1.48%	8.3%	1,743	79.3
Propane	0.48%	0.49%	3.3%	2,480	116.3
C_4+	0.16%	0.16%	1.0%	3,216	153.3
CO_2 *	1.70%	0.00%	0.0%	-	116.0
N_2	0.30%	0.31%	0.0%	-	73.8
Sum	100.00%	100.00%	100.00%		
Btu/scf	1,030	1,048	1,159		
Pounds / Mscf	44.50	43.26	48.95		
Metric tonnes per million scf	20.18	19.62	22.20		
Bil. scf per million metric tonnes	49.54	50.96	45.04		
Bil scf/day per mm MT/year (Bcfd/MTPA)	0.136	0.140	0.123		
MTPA/Bcfd	7.37	7.16	8.10		

Source: ICF estimates

* US pipelines have 2% or 3% limit on inerts (carbon dioxide and nitrogen). To make LNG all CO_2 must be removed.

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List of Exhibits

1 Executive Summary

In order to inform the current policy debate surrounding the granting of licenses for U.S. exports of liquefied natural gas (LNG), the American Petroleum Institute (API) commissioned ICF International to undertake a study of the energy market and economic impacts of LNG exports. That study was released in May 2013. The original national-level study assessed the economic and employment impacts of three LNG export scenarios: the ICF Base Case of 4 Bcfd, the Middle LNG Exports Case of 8 Bcfd, and the High LNG Exports Case of 16 Bcfd.

More recently, API tasked ICF with undertaking a follow-up study to assess the economic and employment impacts on a state-level basis, allocating the national-level impacts among states. This study concludes that LNG exports have a net positive, or negligible, impact across all states.[2]

Economic Impacts of LNG Exports

Largest economic gains found in states with the largest natural gas production impacts. However, states with LNG export terminals and states with equipment manufacturing would also see significant positive impacts.

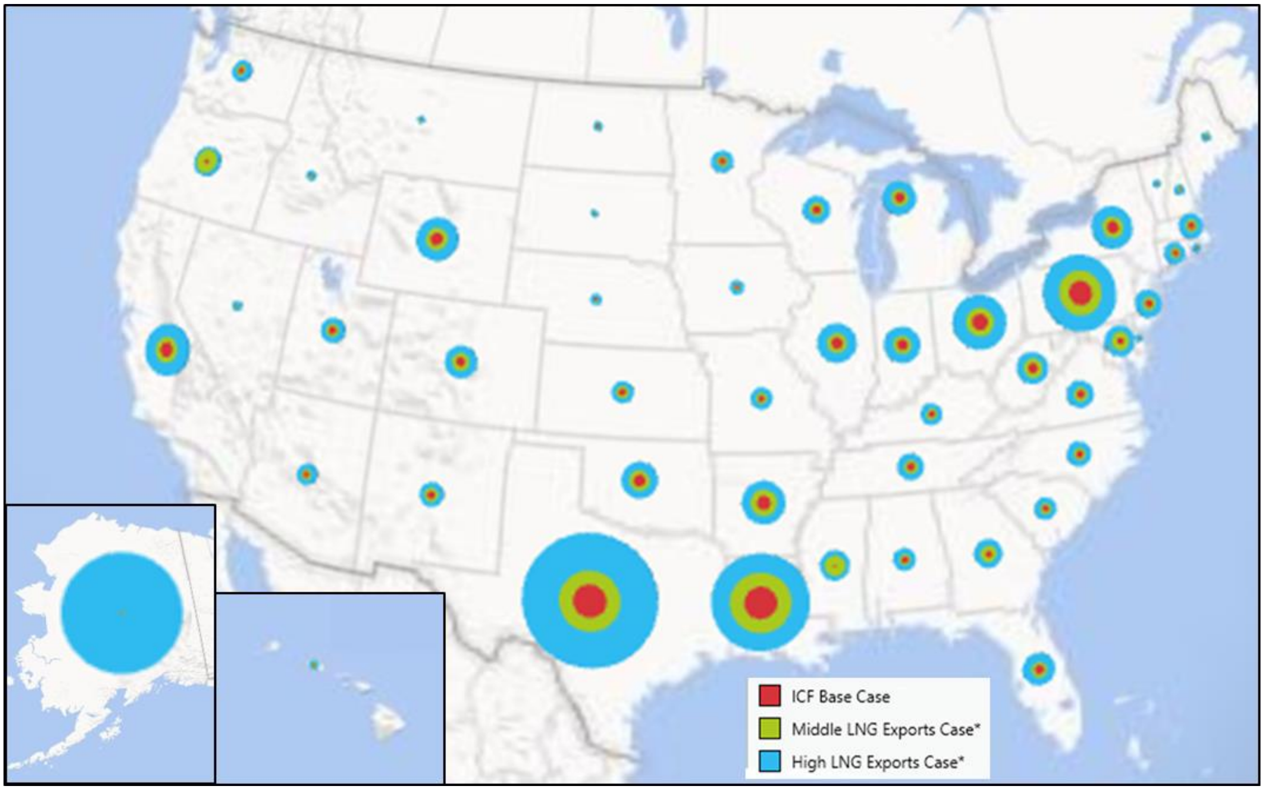
- Significant economic gains found across states: Economic impacts for natural gas-producing states such as Texas, Louisiana and Pennsylvania see increases ranging from \$10-\$31 billion in 2035. Non-producing states such as California, New York, and Illinois see state income gains up to \$2.6-\$5.0 billion in 2035.[3]
- Largest level impacts are seen across a diverse number of states: Texas, Louisiana, and Alaska benefit from large-scale hydrocarbon production and in-state LNG export terminals. Other large hydrocarbon producers such as Pennsylvania, Wyoming, Arkansas, and Oklahoma also experience large gains as do manufacturing-intensive states, such as Ohio, Indiana, and California.
- LNG terminals generate significant in-state economic activity: LNG terminals are a long-term investment, requiring significant capital outlays and continuing labor and material inputs. States with LNG terminals see large increases in state incomes resulting from LNG exports. Alaska is a good example. Without an in-state LNG terminal, Alaska shows negligible income and employment impacts from LNG exports. The construction of a 2.25 Bcfd terminal which begins to export in 2023 in the High LNG Export Case generates significant income for the state. Alaska could see up to \$10 billion in state income and over 36,000 jobs in 2035 resulting from LNG exports.

[2] "Negligible" defined for this report as less than 0.05% (positive or negative) of the base year state income (2010) or state employment (2012) as projected for the year 2035.

[3] State income is the sum of all income earned in the state, including employee compensation, proprietors' income, other property-type income, and indirect business taxes. State income can differ from gross state product (GSP) in that state income includes proprietor and other property-type income based on the location of business owners and shareholders, rather than the location of the economic activity as measured in GSP.

Exhibit 1-1 below shows the general economic impacts by state for each of the three LNG export cases by state. While states such as Alaska have a significant impact only in one case, Texas shows significant impacts in all three LNG export cases.

Exhibit 1-1: Map of 2035 Relative Income Impacts from LNG Exports (By State Income)



Source: ICF estimates

Note: Calculated using an economic multiplier of 1.9. The circle sizes represent the relative income impact of each state for each LNG export case.

* The Middle Case values are the average of four Terminal Location Cases (TLCs) and the High Case values are an average of five TLCs except that values for the seven LNG terminal states (AK, GA, LA, MD, MS, OR, TX) show impacts with at least one in-state LNG export terminal.

Employment Impacts

- Net positive employment impacts: Nationwide, LNG exports are expected to generate a net increase of up to 665,000 job gains by 2035, with all states expected to see net positive employment impacts from LNG exports.[4]
- Oil and gas jobs generate the largest impacts: The largest job gains are in states with natural gas production, liquefaction plants, and petrochemical industries. Texas and

[4] Calculated assuming an economic multiplier of 1.9. Given the significant uncertainty surrounding the actual level of consumer spending generated by a change in the economy (such as LNG exports), ICF developed a range of potential impacts, based on previous ICF work. The multiplier effect in the original study ranged from 1.3 to 1.9, meaning that every $1 of direct and indirect income generated would produce an addition $0.30 to $0.90 in consumer spending throughout the economy. The 1.3 multiplier represents the lower-bound estimate of total economic impacts, and the 1.9 multiplier represents the upper-bound estimate. Annual values for the seven LNG terminal states (AK, GA, LA, MD, MS, OR, TX) show impacts with an in-state LNG export terminal. All dollar amounts herein are in 2010 dollars, unless otherwise specified.

Louisiana, benefiting from natural gas production, LNG export terminals, and petrochemical facility construction are expected to see gains up to 74,000-155,000 jobs in 2035.

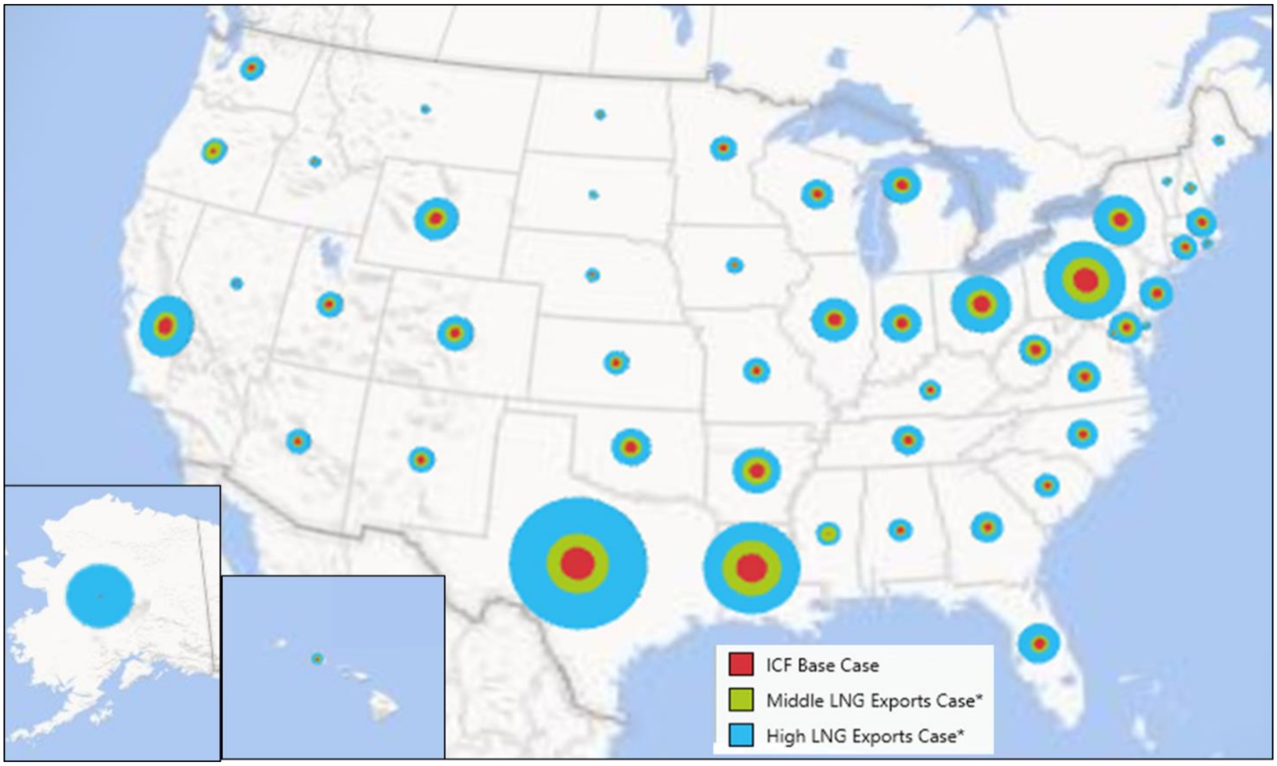
- Significant multiplier effect generated in consumer-oriented states: States such as California and New York that do not directly participate significantly in unconventional natural gas production and/or LNG-related industries see positive net job gains, reaching up to 40,000 and 25,000 jobs, respectively, by 2035. This comes about because job gains from a larger U.S. economy offset job losses stemming from higher energy costs. Job losses occur in consumer-related activities such as retail, housing, food, entertainment, and consumer products as more of consumers' income goes to natural gas and electricity bills due to a slight increase in natural gas and electricity costs.

States with natural gas production, liquefaction plants, and petrochemical processing are expected to see significant employment gains with LNG exports.

- However, the positive economic impacts in states such as New York would be significantly greater if unconventional energy production were allowed.

Exhibit 1-2 below shows the relative employment impacts of LNG exports by state for each case. Similar to the state income impacts, employment gains are concentrated in areas with large natural gas production (e.g., Texas, Louisiana, Pennsylvania), as well as large manufacturing states (such as California, Ohio, New York, and Indiana).

Exhibit 1-2: Map of 2035 Relative Employment Impacts from LNG Exports (By State Employment)



Source: ICF estimates

Note: Calculated using an economic multiplier of 1.9. The circle sizes represent the relative employment impact of each state for each LNG export case.

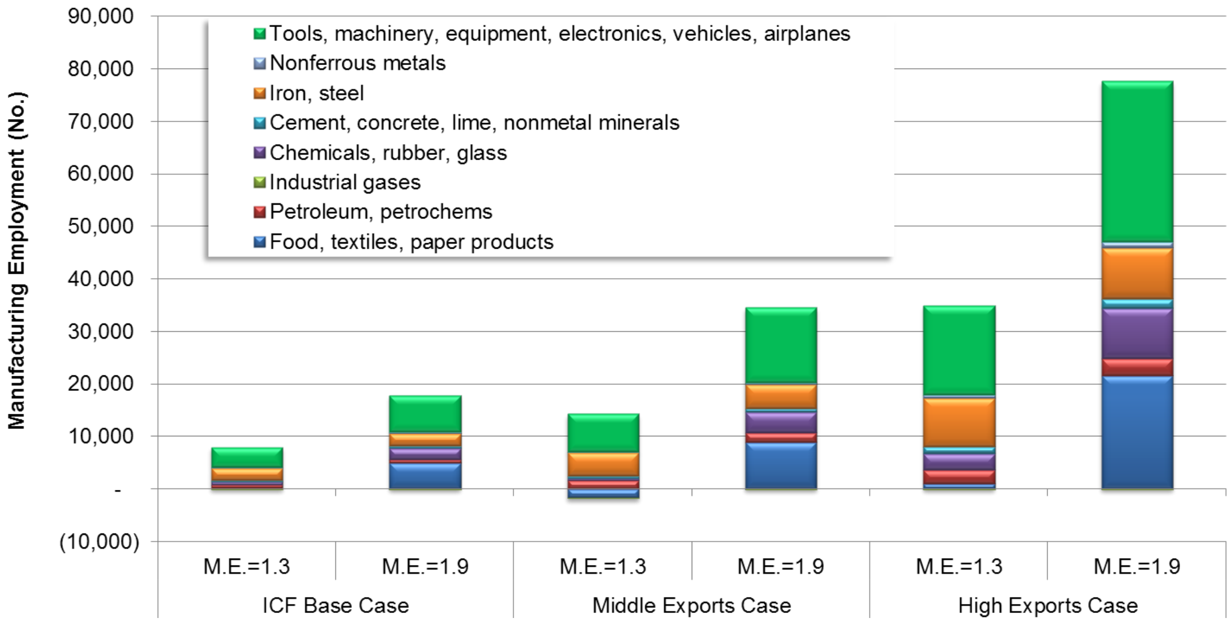
* The Middle Case values are the average of four Terminal Location Cases (TLCs) and the High Case values are an average of five TLCs except that values for the seven LNG terminal states (AK, GA, LA, MD, MS, OR, TX) show impacts with at least one in-state LNG export terminal.

Manufacturing Impacts

Manufacturing of gas/oil equipment and servicing are expected to generate the largest manufacturing impacts, though consumer spending will generate demand for consumer goods, further stimulating manufacturing.

- Manufacturing-intensive states show strong gains associated with natural gas-related activities: Consumer spending also generates manufacturing job gains: Manufacturing states, such as Ohio and Indiana, benefit from LNG exports by manufacturing steel products (e.g., drill pipe, casing and structural steel), cement (for well and industrial plant construction), and various kinds of production equipment (pumps compressors, turbines, heat exchangers, pressure vessels, tanks, meters, control systems, etc.) required for natural gas/oil production, processing, transport, and construction of LNG export terminals. Ohio and Indiana see up to 4,600 and 3,500 manufacturing employment gains from LNG exports by 2035, respectively. Exhibit 1-3 below shows the general categories of manufacturing job impacts attributable to LNG exports. Machinery and tools make up the largest share of manufacturing.

Exhibit 1-3: 2035 Manufacturing Jobs Changes



Source: ICF

- Consumer spending generates manufacturing job gains: As employees of natural gas production companies, LNG export terminals, and equipment manufacturers generate additional consumer spending, demand for consumer-related manufacturing (such as cars and electronics) will further stimulate U.S. manufacturing. California, with the largest number of U.S. manufacturing jobs for consumer-oriented products such as food, textiles, paper products, tools, machinery, electronics, and vehicles is expected to see manufacturing employment gains exceeding 8,000 by 2035.[5]

Factors Driving Changes by State

Economic and employment impacts of LNG exports varies across states for a number of reasons:

- Natural gas and hydrocarbon liquids production changes: LNG exports lead to an increase in natural gas production, which also results in additional oil and natural gas liquids (NGL) productions; thus states with production activities see significant economic and employment impacts.
- LNG export facility location: LNG export terminals require billions of dollars in long-term investment. ICF assumed a range of potential locations for the LNG export terminals

[5] Based on 2012 employment data by sector from the U.S. Bureau of Labor Statistics. Data based on North American Industry Classification System (NAICS) codes including manufacturing of food, textile, paper products, tools, machinery, equipment, electronics, vehicles, and airplanes.

throughout the U.S., given the uncertainty surrounding export permits. States assumed for LNG exports in at least one case in this study include Alaska, Georgia, Louisiana, Maryland, Mississippi, Oregon, and Texas.

> ***Economic and employment impacts of LNG exports varied by state primarily due to:***
> - ***Location of natural gas production increases***
> - ***LNG export facilities' location***
> - ***Where supporting industries are located***
> - ***Size of natural gas and electricity consumer base***
> - ***Size of the state economy***

- Location of natural gas-related industries: Natural gas processing and petrochemical facilities are typically located near natural gas production areas; thus, states with natural gas production benefited from these increases. Drilling equipment and production materials are often located out-of-state. States manufacturing these types of equipment (e.g., Ohio, Wisconsin, Michigan) benefit from gas production activities.
- Natural gas and electricity consumer base: LNG exports may lead to a slight increase in natural gas and electricity costs, or an increase of roughly $0.10 per million British Thermal Units (MMBtu) for every one billion cubic feet per day (Bcfd) of LNG exports. Thus, states with large natural gas and electricity consumer bases with little or no offsetting direct natural gas industry impacts do not experience as large of a positive impact from the induced impact of LNG exports.
- Size of the state economy: Most income from natural gas-related activities remains within the producing state and in states supplying needed materials, and products and services. Income is also earned throughout the country in the form of stockholder dividends and capital gains (see Section 3 for more details). Thus, a portion of natural gas-related earnings was assumed to move out-of-state, and were apportioned by the relative size of each state's economy. For example, it is assumed that New York has more natural gas-related stockholders than Montana, based on the relative sizes of the two economies.
- Consumer spending generates job gains: Additional consumer spending is created as employees of natural gas production companies, LNG export terminals, and equipment manufacturers purchase consumer-related goods and services. This activity further stimulates the U.S. economy, with larger states such as California and New York seeing the greatest impacts.

2 Introduction

In order to inform the current policy debate surrounding the granting of licenses for U.S. exports of liquefied natural gas (LNG), the American Petroleum Institute (API) commissioned ICF International to undertake a study of the energy market and economic impacts of LNG exports. That study was released in May 2013. More recently, API tasked ICF with undertaking a follow-up study to assess the economic and employment impacts on a state-level basis.

The scope of this study is to estimate the state-level impacts of LNG exports on the U.S. economy for the timeframe through the year 2035 using the databases, algorithms, and models typically employed by ICF in analyzing U.S. and international natural gas markets.

The original U.S. LNG exports study assessed four fixed LNG export scenarios, which were analyzed in ICF's proprietary Gas Market Model (GMM), providing forecasts of North American natural gas markets. Cases include one assuming no exports, another case based upon ICF's own Second Quarter 2013 Base Case, and two additional LNG export cases that assumed moderately higher and significantly higher amounts of LNG exports as compared to the ICF Base Case.

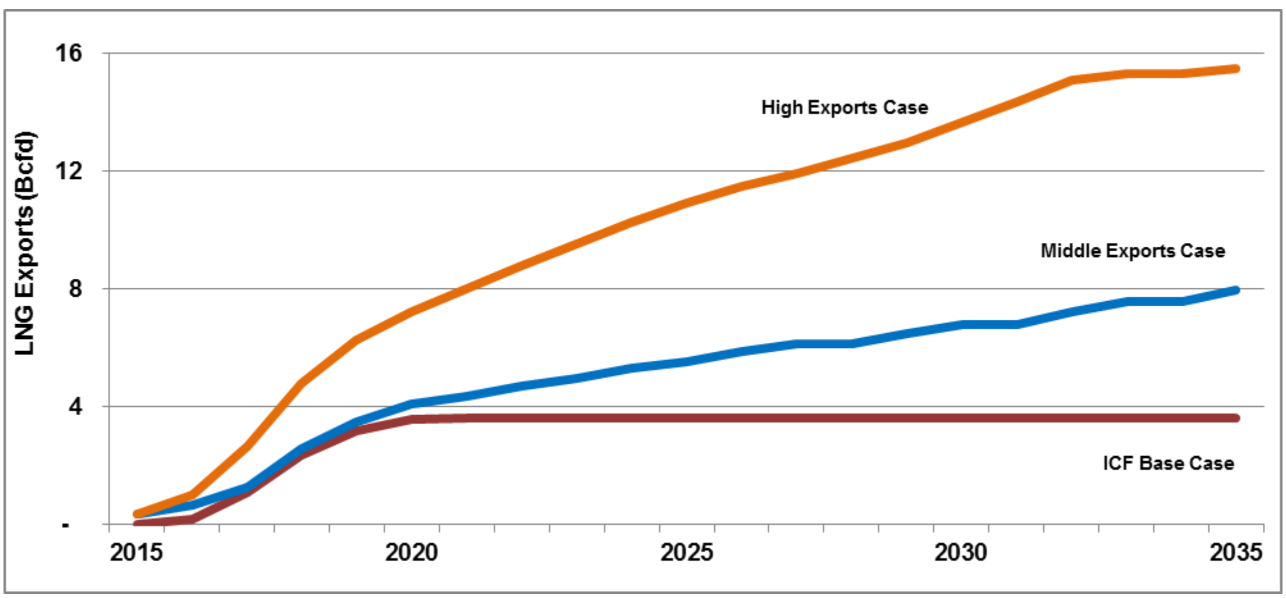
i. *Zero Exports Case:* designated as the "Reference Case" for this study

ii. *ICF Base Case:* ~4 Bcfd of U.S. LNG exports in 2035

iii. *Middle Exports Case:* ~8 Bcfd of U.S. LNG exports in 2035

iv. *High Exports Case:* ~16 Bcfd of U.S. LNG exports in 2035

Exhibit 2-1: LNG Export Cases Relative to Zero LNG Exports Case (Bcfd)



Source: ICF estimates

The national-level impacts of LNG exports from the original API study are included in Exhibit 2-2. This follow-on study allocates these national economic and employment changes by state.

Exhibit 2-2: Key Economic Impacts Relative to the Zero Exports Case

Impact (2016-2035 Averages)*	LNG Export Case (Change from Zero Exports Case)		
	ICF Base Case (up to ~4 Bcfd)	Middle Exports Case (up to ~8 Bcfd)	High Exports Case (up to ~16 Bcfd)
Employment Change (No.)	73,100-145,100	112,800-230,200	220,100-452,300
GDP Change (2010$ Billion)	$15.6-$22.8	$25.4-$37.2	$50.3-$73.6
Henry Hub Price (2010$/MMBtu)	$5.03	$5.30	$5.73
Henry Hub Price Change (2010$/MMBtu)	$0.32	$0.59	$1.02

*Source: ICF estimates. Note: * Includes direct, indirect, and induced impacts*

This report is organized in the following sections:

- Section 1: Executive Summary
- Section 2: Introduction
- Section 3: Study Methodology and Assumptions
- Section 4: Economic and Employment Impacts on the U.S. Economy
- Section 5: Key Conclusions
- Section 6: Bibliography

3 Study Methodology and Assumptions

This follow-on state-level study distributes national-level impacts of LNG exports among 50 U.S. states. The following section describes ICF's methodology for allocating these impacts among states. Note that, as with the national-level impacts in the original study, all state-level impacts are the *incremental* impacts associated with LNG exports, relative to the Zero LNG Exports Case, rather than absolute levels in the state.

Assessing national-level impacts is a more straightforward process than allocating impacts among each state, given the significant uncertainty surrounding which states the LNG exports terminals will be located and from which states materials, equipment, and services will be purchased. For example, LNG export terminals require turbines to power compressors used for refrigeration. There are multiple states (in addition to international manufacturers) producing turbines and turbine parts. Thus, determining which state will receive the economic gain associated with turbine purchases is difficult. In addition, impacts allocated among the states exclude a certain level of assumed imports, the level of which is also uncertain. This study assumed 16% of value added from LNG exports will go toward imported materials, equipment, and services, and thus, do not contribute to U.S. economic gains. This was also assumed in the national impacts assessment.[6]

Significant uncertainty surrounding actual inter-state purchases makes state-level analysis a more difficult process than conducting national-level economic analysis.

For this study, in order to distribute national-level economic and employment impacts across states, a number of state-level "allocators" were needed. The allocation matrices were based either on model results (e.g., changes in natural gas production by year and state), historical relationships between national and state incomes (e.g., location of the iron and steel factories), or published industry plans (e.g., location of new ethylene plants). There were several allocation matrices that were applied individually or in combination to allocate each type of projected GDP and job change.

ICF used proprietary modeling or publicly available state-level data as "allocators" to distribute national-level economic and employment impacts of LNG exports across 50 U.S. states and the District of Columbia.

State-by-state allocations for gas-related activities are based on both the physical location of activities (e.g., locations of LNG export terminals and petrochemical plants) and the location of gas-related company stockholders. For the former, ICF relied on forecasts on gas-related activity, such as locations of LNG export terminals, oil and gas production activity, gas-related processing and petrochemical plants, and gas-related equipment manufacturing facilities. For the latter, ICF assumed that large-scale companies such as oil and gas producers, LNG export terminal operators, owners of petrochemical plants have shareholders throughout the country. Thus, the portion of economic impacts of these activities related to company stockholders was allocated among states using the distribution of state income. For example, while a major U.S. oil and gas producer may focus production in a small number of

[6] Based on the U.S. national average ratio of imports to GDP.

states, the company's stockholders are distributed throughout the country. Thus, ICF uses a number of allocators to account for the economic activity generated in production states, as well as economic gains to the firm's stockholders outside the state.

The methodology for this study consisted of 8 main steps, which are highlighted in Exhibit 3-1 and explained in further detail in this section.

Exhibit 3-1: Study Steps

Step #	Description
1	Extract GDP and employment data by sector from prior API study for allocation by state.
2	Extract gas production from prior API study to estimate gas production increases by state.
3	Create state-level allocators for economic and employment data.
4	Create state-level allocators for gas-to-liquids (GTLs), chemicals, and petrochemicals based on data for actual and planned plants.
5	Create state-level allocators for all planned LNG export terminal locations.
6	Create alternative cases based on the original LNG export scenarios, varying location of the liquefaction terminals.
7	Create alternative case for inclusion of Alaska LNG project in only the High LNG Exports Case.
8	Process each of the three export scenarios (approximately 4, 8, or 16 Bcfd) across the various terminal location cases to determine the range of possible state-level income and employment impacts.

Each task for this study is discussed below.

Step 1: Extract GDP and employment data by sector from prior API work and organize into matrices.

The original LNG exports study assessed the GDP value added and employment contributions of LNG exports, dividing up impacts by source. The main sources of economic and employment changes are as follows:

1) Direct and indirect changes

i. <u>Impacts associated with an increase in physical volumes of oil, gas, and NGLs</u>: The positive economic impacts are led by LNG production (i.e., the value of LNG exports), followed by gains to natural gas and electricity producers, and

<u>Direct Impacts</u> represent the impacts (e.g., employment or output changes) in Sector A due to greater demand for and output from Sector A (e.g., LNG exports).

<u>Indirect Impacts</u> represent the impacts outside of Sector A in those industries that supply or contribute to the production of intermediate goods and services to Sector A (e.g., natural gas production equipment required to generate natural gas and later LNG).

hydrocarbon liquids production. Gas, oil, and NGL production (e.g., value of LNG, value of liquids, value of petrochemicals produced), the manufacturing equipment required for production, the materials manufacturing required for production (e.g., sand for hydraulic fracturing proppants, steel for drill pipe, cement for drilling, construction materials for LNG export terminals, among others). In addition, gains to stockholder dividends and capital gains from LNG export activities also generate activity around the country.

ii. Impacts associated with increasing natural gas costs due to LNG exports: The negative economic impacts are associated with the consumer impacts of slightly higher natural gas and electricity costs that result from LNG exports. Natural gas cost increases reduce natural gas demand (and gas-fired electricity consumption), meaning consumers must allocate an increasing share of income to natural gas and electricity outlays (rather than on other consumer purchases). In addition, with higher energy costs, economic contributions from energy-intensive industrial producers (e.g., chemical and petrochemicals, glass, industrial gases) may decrease.

The sources from which impacts arise include the change in GDP and employment from LNG exports, NGL production, additional petrochemicals production (due to increased NGL volumes), and consumer impacts. While increased natural gas and NGL production will generate additional value added and employment, the increase in natural gas costs associated with LNG exports will translate to higher natural gas and electricity costs for consumers. Higher costs will reduce consumption of natural gas and electricity, particularly in the case of energy-intensive consumers.

2) Multiplier effect changes

i. Cumulative impacts, including additional consumer spending generated by direct and indirect activities: The cumulative impacts of spending of income earned in the direct and indirect sectors and subsequent spending of income in each successive round. The net positive direct and indirect changes in economic and employment activity will generate additional consumer spending, producing induced economic and employment activity.

***Induced or "Multiplier Effect" Impacts* represent the cumulative impacts of spending of income earned in the direct and indirect sectors and subsequent spending of income in each successive round. Examples include a restaurant worker who takes a vacation to Florida, or a store owner who sends children to college, based on higher income that arises from the initial activity of LNG exports.**

After assessing these direct and indirect impacts, ICF then applied a range of multiplier effects to assess the induced economic activity from people earning higher income through the direct and indirect activity spending that income. There is significant uncertainty surrounding the actual level of multiplier effect impacts generated in the economy; thus, ICF developed a range to show the potential impacts on the larger economy generated by direct and indirect LNG export activities. ICF quantified the net economic impacts of an exogenous change to the U.S. economy (i.e., a policy to permit LNG exports) by calculating the resulting output change in various products (e.g., increasing LNG exports, liquids production, petrochemical manufacturing, and decreases in electricity consumption and consumer spending). Then, the multiplier effect range is applied – the lower-bound (1.3) representing significant crowding out effect, while the upper-bound (1.9) is consistent with a very slack economy and/or an elastic supply of labor and other factors of production. Both measures of GDP impacts (direct and indirect alone *versus* direct, indirect, and induced) are then converted to job impacts using input-output relationships, wherein the number of jobs per dollar of value added vary among economic sectors.

Estimation of Multiplier Effect

This study employs a range of multiplier effects to estimate the lower-bound and upper-bound for "induced" activities in the U.S. economy, resulting from the spending of personal income generated by the direct and indirect activities. The equation below shows the hypothetical GDP multiplier effect from any incremental increase of purchases (from business investment, exports, government spending, etc.) MPC is marginal propensity to consume, and is estimated at 0.900 using a post-World War II average for the U.S. This means that for every dollar of personal income generated, $0.90 goes toward consumption, and the remaining $0.10 is saved. The MPI is the marginal propensity to import, estimated at 0.162, based on the average for recent years. The effective tax rate is $0.269 per dollar of income/GDP. Inputting the MPC, MPI, and tax rate into the equation below shows that every dollar of income stemming from direct and indirect activity hypothetically could produce a total of $1.984, meaning that $0.984 is "induced" economic activity, or the amount produced as the multiplier effect.

$$\Delta GDP = \Delta Exports * 1 / (1-MPC*(1-TAX) + MPI)$$

Multiplier Effect Input	Value
Marginal Propensity to Consume after Taxes (MPC)	0.900
Marginal Propensity to Import (MPI)	0.162
Tax Rate	0.269
Resulting Multiplier	**1.984**

Because of this uncertainty in the multiplier effect, a range is used in this study. A value of1.9 is used as the multiplier for the upper-bound limit, and 1.3 [1.6 – (1.9-1.6)] for the lower-bound estimate.

Source: American Clean Skies Foundation (ACSF), based on analysis conducted by ICF International. "Tech Effect: How Innovation in Oil and Gas Exploration is Spurring the U.S. Economy." ACSF, October 2012: Washington, D.C. Available at: http://www.cleanskies.org/wp-content/uploads/2012/11/icfreport_11012012_web.pdf

Exhibit 3-2 lists the major categories of GDP and employment changes that were distributed among the states.

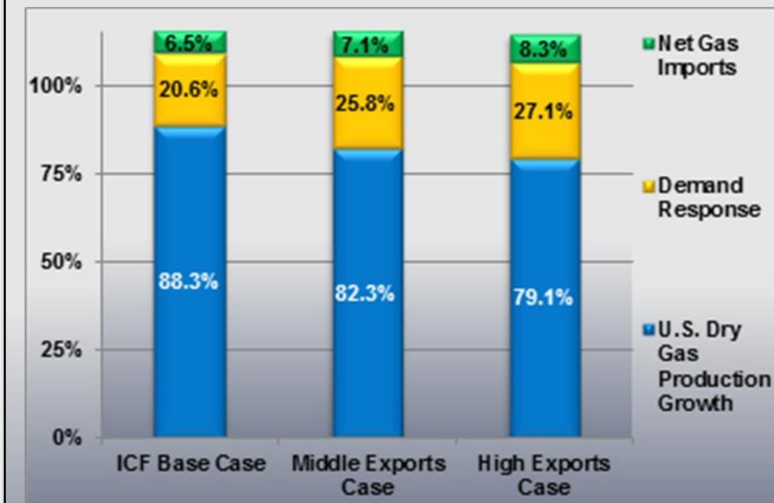
Exhibit 3-2: Key Economic and Employment Impacts

1) GDP by Source	2) Jobs by Source
LNG's Contribution to US GDP	Related to Oil, Gas, NGL Production Changes
Liquids Contribution to GDP (value added in US)	Related to LNG Production
Methanol Production	Related to Switch to Coal
Ammonia Production	Related to Gas Consumer Accounts: Consumers
GTL Production	Related to Gas Consumer Accounts: Producers
Ethylene/Polyethylene Production	Related to Electricity Consumer Accounts: Consumers
Propylene/Polypropylene Production	Related to Electricity Consumer Accounts: Producers
Contribution to GDP from Reduced Industrial Production	Related to Power Generation (switch to coal, lower demand)
Net US GDP Effect to Natural Gas Consumers	Methanol Production
Net US GDP Effect to Natural Gas Producers	Ammonia Production
Net US GDP Effect to Electricity Consumers	GTL Production
Net US GDP Effect to Electricity Producers	Ethylene/Polyethylene Production
	Propylene/Polypropylene Production
	Other Industrial Output Changes
Direct and Indirect Total	***Direct and Indirect Total***
Multiplier Effect at 1.3	Multiplier Effect at 1.3
Total GDP Change with Multiplier Effect at 1.3	**Total Employment Change with Multiplier Effect at 1.3**
Multiplier Effect at 1.9	Multiplier Effect at 1.9
Total GDP Change with Multiplier Effect at 1.9	**Total Employment Change with Multiplier Effect at 1.9**

Step 2: Extract gas production data by basin/node from prior API study and estimate gas production by state and organize into matrices.

LNG exports require a combination of additional supplies, in the form of domestic production increases, a reduction in consumption (i.e., demand response), and changes in pipeline trade with Canada and Mexico. ICF's original modeling showed that for each of the three export cases, the majority of the incremental LNG exports (79%-88%) are offset by increased domestic natural gas production. Another 21%-27% in consumer demand response (i.e., cost increases lead to a certain decrease in domestic gas demand), and an additional 7%-8% comes from shifts in the trade with Canada (more exports into the U.S.) and Mexico (fewer imports from the U.S.). The sum of the three supply sources exceed actual LNG export volumes by roughly 15% to account for fuel used during processing, transport, and liquefaction, as shown in the text box below.

Exhibit 3-3: Supply Sources that Rebalance Markets



Source: ICF estimates

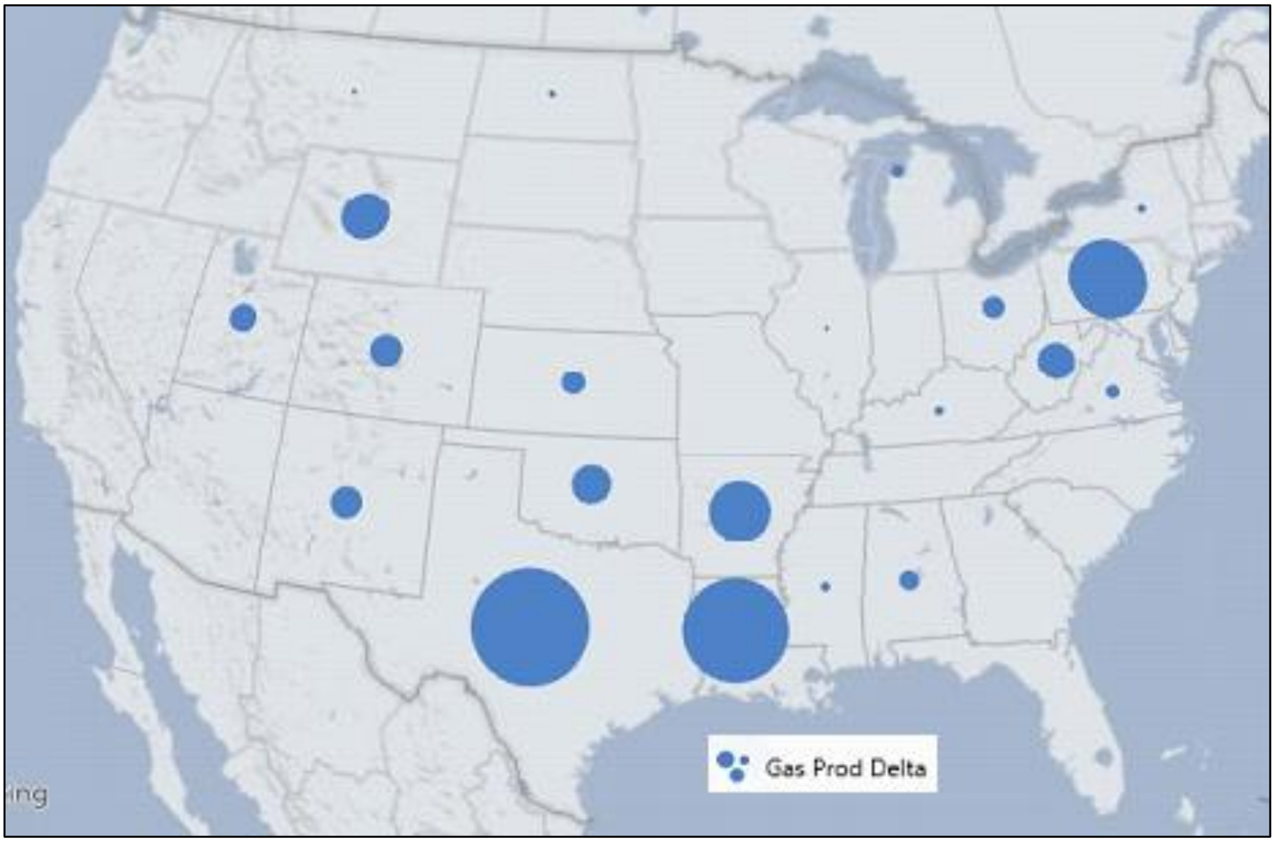
Note: Each 1.0 Bcfd of LNG exports requires total dry wellhead supplies of 1.15 Bcfd for liquefaction, lease and plant fuel, and LNG exports.

The original LNG export cases included assumptions on natural gas requirements for the LNG export plants. These production factors, along with a range of gas market changes, such as gas consumption and pricing changes, were modeled in ICF's Gas Market Model (GMM). The specific market effects of LNG exports quantified in the GMM included:

- Gas production changes in various North American basins caused by shifts in natural gas costs.
- Gas consumption changes by region and sector caused by shifts in gas costs (including fuel substitution, conservation, and reduced industrial output).
- Gas flow adjustments among regions caused by the new demand for gas at liquefaction plants, cost-induced changes in regional gas production and in regional gas consumption.
- Changes in regional delivered-to-pipeline natural gas costs and changes to regional end-user costs.
- Adjustments to regional electricity costs, sales volumes, and power generation input fuel mix.

Exhibit 3-4 illustrates the general trend in gas production by state. The exhibit shows the relative natural gas production changes in the ICF Base Case in 2025 by states. States with the most natural gas production changes in the ICF Base Case, such as Texas, Louisiana, and Pennsylvania, which together comprise 67% of the change in U.S. natural gas production that year for the ICF Base Case, have the largest circles.

Exhibit 3-4: Map of Relative Natural Gas Production Changes by State in 2025



Source: ICF GMM

Note: The map above shows the relative natural gas production changes in the ICF Base Case in 2025 (relative to the Zero LNG Exports Case).

Step 3: Create state-level allocators by GDP and employment categories using ICF's proprietary models and other data sources.

Exhibit 3-5 shows the 20 allocator categories used to distribute GDP value added and employment associated with LNG exports across each state. In most GDP and employment categories, multiple allocators were used. The actual allocations across all GDP and employment categories are done in step 8.

Exhibit 3-5: Allocator Methods for GDP and Jobs by Source

Allocator #	Allocator Name	*Allocator Source by State*
1	Ammonia	*Planned ammonia production plant locations as compiled by ICF*[7]
2	Coal Mining	*Coal mining and coal-mining support jobs in the base year of 2010*[8]
3	Coal to Gas Switching	*Price-sensitive coal demand of coal-switching economics by state*[9]
4	Crude Production Delta (yr)	*ICF GMM crude and condensate production forecasts by year through 2035*
5	Electricity All Consumers 2011	*EIA 2011 end-use electricity consumption*[10]
6	Ethylene	*Planned ethylene production plant locations as compiled by ICF*[11]
7	Gas All Consumers 2011	*EIA 2011 end-use natural gas consumption*[12]
8	Gas Industrial Consumers 2011	*EIA 2011 industrial sector natural gas consumption (volume delivered to industrial consumers)*[13]
9	Gas Production 2011	*EIA 2011 U.S. natural gas production*[14]
10	Gas Production Delta (yr)	*ICF GMM condensate production forecasts by year through 2035*
11	GTL	*Planned GTL production plant locations as assumed by ICF*[15]
12	Indirect Industrial Jobs	*Weighted average of industries that support construction and equipping industrial activities based on IMPLAN input-output model and U.S. Bureau of Labor statistics data*
13	Indirect Oil Gas Jobs	*Weighted average of industries that support oil and gas activity based on IMPLAN input-output model and U.S. Bureau of Labor statistics data*
14	LNG	*Based on LNG exports terminals by state; study includes various cases based on 7 states, based on U.S. Department of Energy (DOE) list by LNG exports filing dates (see Exhibit* 3-8) *and explained in Task 5*
15	Methanol	*Planned methanol production plant locations as compiled by ICF*[16]
16	NGPL Prod Delta (yr)	*ICF GMM NGL production forecasts by year through 2035*
17	Propylene	*Planned propylene production plant locations as compiled by ICF*[17]
18	MECS Job Losses	*2012 annual manufacturing employment by state from the U.S. Bureau of Labor Statistics*[18]
19	State Personal Income 2010	*State personal income in 2010*[19]
20	Calculated Direct + Indirect	*State-by-state distributions based on total direct and indirect state-level allocations (used, in part, to calculated state-level multiplier effects)*

[7] Appendix C of original API LNG export report (May 2013). ICF International. "U.S. LNG Exports: Impacts on Energy Markets and the Economy." ICF International, 17 May, 2013: Washington, DC. Available at: http://www.api.org/~/media/Files/Policy/LNG-Exports/API-LNG-Export-Report-by-ICF.pdf

[8] PricewaterhouseCoopers. "The Economic Contributions of U.S. Mining in 2008." PricewaterhouseCoopers, prepared for the National Mining Association: October 2010.

[9] ICF estimates

[10] U.S. Energy Information Administration (EIA). "End-use electricity consumption." EIA: Washington, DC. Available at: http://www.eia.gov/state/seds/hf.jsp?incfile=sep_fuel/html/fuel_use_es.html

[11] Appendix C of original API LNG export report (May 2013)

[12] U.S. Energy Information Administration (EIA). "Natural Gas Consumption by End Use." EIA: Washington, DC. Available at: http://www.eia.gov/dnav/ng/ng_cons_sum_a_EPG0_vgt_mmcf_a.htm

[13] U.S. Energy Information Administration (EIA). "Natural Gas Consumption by End Use." EIA: Washington, DC. Available at: http://www.eia.gov/dnav/ng/ng_cons_sum_a_EPG0_vgt_mmcf_a.htm

[14] U.S. Department of Energy (DOE). "Applications Received by DOE/FE to Export Domestically Produced LNG from the Lower-48 States (as of September 19, 2013)." DOE, September 11, 2013: Washington, DC. Available at: http://energy.gov/sites/prod/files/2013/09/f2/LNG%20Export%20Summary_1.pdf

[15] Appendix C of original API LNG export report (May 2013)

[16] *Ibid.*

[17] *Ibid.*

[18] U.S. Bureau of Labor Statistics (BLS). "Quarterly Census of Employment and Wages." BLS: Washington, DC. Available at: ftp://ftp.bls.gov/pub/special.requests/cew/2012/state/

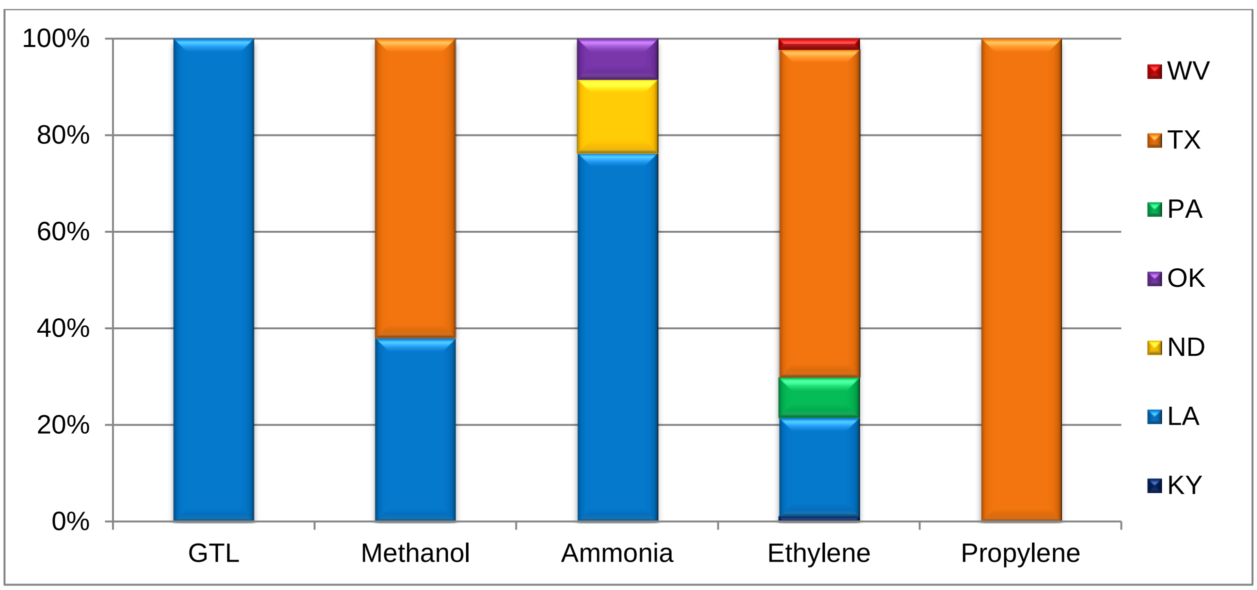
[19] Tax Policy Center (Urban Institute and Brookings Institution). "State and Local General Revenue as a Percentage of Personal Income 2004-2011." Tax Policy Center, 20 September, 2013: Washington, DC. Available at: http://www.taxpolicycenter.org/taxfacts/displayafact.cfm?Docid=510

Step 4: Create state-level allocators for gas-to-liquids (GTLs), chemicals, and petrochemicals using data for actual and planned plants.

ICF compiled a list of planned petrochemical plants and plant expansions to provide the basis for allocating petrochemical use for additional natural gas, NGLs, and oil (i.e., methanol, ammonia, GTL, ethylene/polyethylene, and propylene/polypropylene production). The list of planned plants and plant expansions are found in Appendix C of the original API LNG export report.

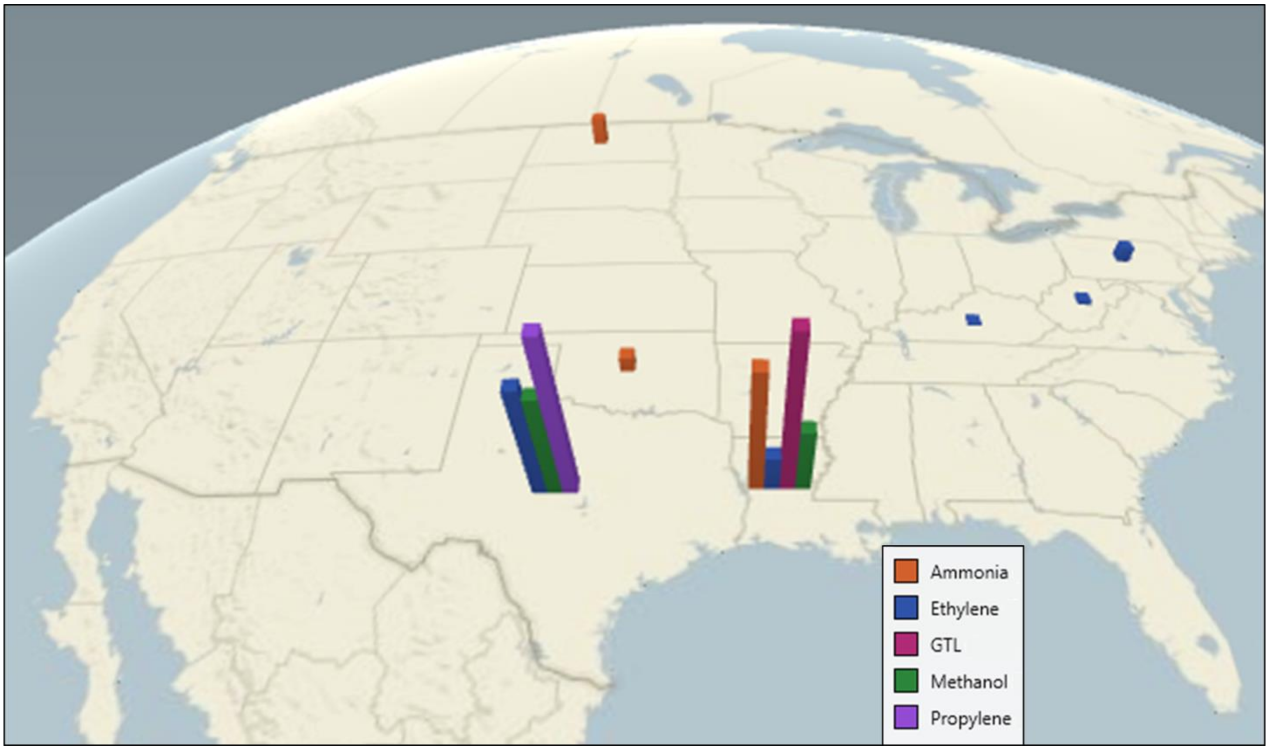
These plant location-specific allocators were used in conjunction with other allocators such as indirect industrial jobs and natural gas/NGL production by state to allocate each petrochemical category across the states. While the location of these plants generates a certain level of economic activity for that state, the indirect industrial jobs allocator reflects the impact of the plant construction on industrial sectors throughout the country, as many such indirect industrial jobs (e.g., manufacturing plant equipment) takes place outside the host state. In addition, natural gas and NGL production by state are additional allocators used to show the economic activity generated to produce the physical volumes of natural gas and NGLs used in the petrochemical facilities. Exhibit 3-6 and Exhibit 3-7 highlight the locations of petrochemical facilities assumed for this study, based on the list compiled in Appendix C of the original API study. Exhibit 3-7 shows the location and relative capacity volume additions of anticipated petrochemical plants, indicated by the relative height of columns. The map is meant to show spatially the information illustrated in Exhibit 3-6.

Exhibit 3-6: Assumed Methanol, Ammonia, GTL, Ethylene, and Propylene Plant Additions, Conversions, and Expansions (By Relative Proportion of Capacity)



Source: Various compiled by ICF

Exhibit 3-7: Map of Assumed Methanol, Ammonia, GTL, Ethylene, and Propylene Plant Additions, Conversions, and Expansions (By Relative Proportion of Capacity)



Source: Various compiled by ICF

Note: The height of each column represents the relative capacity increases of each plant type assumed for this study.

Step 5: Create state-level allocators for LNG export terminal locations.

ICF developed LNG terminal location allocators to apportion the impacts of LNG exports among the states. ICF used a combination of its GMM assumptions in the original LNG export cases (i.e., ICF Base Case, Middle LNG Exports Case, High LNG Exports Case) and the U.S. Department of Energy's (DOE) list of LNG export terminal applications by filing date. ICF made no assumptions on which applications will be approved or denied, and used the filing dates as the primary indicator of the order in which the terminals might be built. In addition to the physical LNG export terminal locations (explained in further detail in Task 6), allocating LNG contributions to economic and employment activity also took into account which states would experience increases in natural gas production and which states would see additional economic activity due to indirect purchases from the oil and gas sector and other affected industries.

Exhibit 3-8 shows the list of potential LNG export terminals ranked by filing date.

Exhibit 3-8: Potential LNG Export Terminals Ranked by DOE Filing Order

Rank	Company	Owners	Location	Year In-Service	Est. Export Capacity (Bcfd)*
1	Sabine Pass Liquefaction, LLC	Cheniere	Sabine, LA	2015	2.20
2	Freeport LNG Expansion, L.P. and FLNG Liquefaction, LLC	Freeport LNG Investments, Zachry Hastings, Dow Chemical, Osaka Gas	Freeport, TX	2017	1.40
3	Lake Charles Exports, LLC	BG, Energy Transfer Partners	Lake Charles, LA	2018	2.00
4	Carib Energy (USA) LLC	Carib Energy	N/A	Unknown	0.03
5	Dominion Cove Point LNG, LP	Dominion	Cove Point, MD	2017	1.00
6	Jordan Cove Energy Project, L.P.	Veresen, Energy Projects Development	Coos Bay, OR	2018	1.20
7	Cameron LNG, LLC	Sempra	Hackberry, LA	2017	1.70
8	Freeport LNG Expansion, L.P. and FLNG Liquefaction, LLC	Freeport LNG Investments, Zachry Hastings, Dow Chemical, Osaka Gas	Freeport, TX	2017	1.40
9	Gulf Coast LNG Export, LLC (i)	Gulf Coast LNG Export	Brownsville, TX	Unknown	2.80
10	Gulf LNG Liquefaction Company, LLC	Kinder Morgan, GE	Pascagoula, MS	2018	1.50
11	LNG Development Company, LLC (d/b/a Oregon LNG)	Leucadia Corporation	Astoria, OR	2018	1.25
12	SB Power Solutions Inc.	Seaboard Corporation	N/A	Unknown	0.07
13	Southern LNG Company, L.L.C.	Kinder Morgan	Elba Island, GA	2016	0.50
14	Excelerate Liquefaction Solutions I, LLC	George Kaiser, RWE Supply & Trading	Lavaca Bay, TX	2018	1.38
15	Golden Pass Products LLC	ExxonMobil, Qatar Petroleum	Sabine Pass, TX	2018	2.60
16	Cheniere Marketing, LLC	Cheniere	Corpus Christi, TX	2018	2.10
17	Main Pass Energy Hub, LLC	Freeport-McMoran, United LNG	Offshore LA	2018	3.22
18	CE FLNG, LLC	Cambridge Energy	Plaquemines Parish, LA	2018	1.07
19	Waller LNG Services, LLC	Waller Marine	Cameron Parish, LA	Unknown	0.16
20	Pangea LNG (North America) Holdings, LLC	Statoil, Pangea LNG	Corpus Christi, TX	2017	1.09
21	Magnolia LNG, LLC	LNG Limited	Lake Charles, LA	2018	0.54
22	Trunkline LNG Export, LLC (same facility as Lake Charles)	BG, Energy Transfer Partners	Lake Charles, LA	2018	2.00

Rank	Company	Owners	Location	Year In-Service	Est. Export Capacity (Bcfd)*
23	Gasfin Development USA, LLC	Gasfin Development	Cameron Parish, LA	Unknown	0.20
24	Freeport-McMoRan Energy LLC (same facility as Main Pass)	Freeport-McMoran	Offshore LA	2018	3.22
25	Sabine Pass Liquefaction, LLC	Cheniere	Sabine Pass, LA	2018	0.28
26	Sabine Pass Liquefaction, LLC	Cheniere	Sabine Pass, LA	2018	0.24
27	Venture Global LNG, LLC	Venture Global	Cameron Parish, LA	Unknown	0.67
28	Advanced Energy Solutions	Advanced Energy Solutions	Baltimore, MD	Unknown	0.02
29	Argent Marine Management	Argent Marine, Maersk Line	Unknown	Unknown	0.003
30	Eos LNG LLC	Eos LNG	Brownsville, TX	Unknown	1.60
31	Barca LNG LLC	Barca LNG	Brownsville, TX	2016	1.60
32	Sabine Pass Liquefaction, LLC	Cheniere	Sabine Pass, LA	2015	0.86
33	Delfin LNG	Fairwood Group, Peninsula Group	Offshore GOM	2017	1.80
34	Magnolia LNG, LLC	LNG Limited	Lake Charles, LA	2018	1.08

Sources: Various compiled by ICF
* Includes export volume estimates for Free Trade Agreement (FTA) export applications and non-FTA export applications
** Lake Charles Exports, LLC (LCE) and Trunkline LNG Export, LLC (TLNG), the owner of the Lake Charles Terminal, have both filed an application to export up to 2.0 Bcf/d of LNG from the Lake Charles Terminal. The total quantity of combined exports requested between LCE and TLNG does not exceed 2.0 Bcf/d (i.e., both requests are not additive and only 2 Bcf/d is included in the bottom-line total of applications received).
*** Main Pass Energy Hub, LLC (MPEH) and Freeport McMoRan Energy LLC (FME), have both filed an application to export up to 3.22 Bcf/d of LNG from the Main Pass Energy Hub. (The existing Main Pass Energy Hub structures are owned by FME). The total quantity of combined FTA exports requested between MPEH and FME does not exceed 3.22 Bcf/d (i.e., both requests are not additive and only 3.22 Bcf/d is included in the bottom-line total of FTA applications received). FME's application includes exports of 3.22 Bcf/d to non-FTA countries and is included in the bottom line total of non-FTA applications received, while MPEH has not submitted an application to export LNG to non-FTA countries.
(a) Actual applications were in the equivalent annual quantities.
(b) FTA – Applications to export to free trade agreement (FTA) countries. The Natural Gas Act, as amended, has deemed FTA exports to be in the public interest and applications shall be authorized without modification or delay.
(c) Non-FTA applications require DOE to post a notice of application in the Federal Register for comments, protests and motions to intervene, and to evaluate the application to make a public interest consistency determination.
(d) Requested approval of this quantity in both the FTA and non-FTA export applications. Total facility is limited to this quantity (i.e., FTA and non-FTA volumes are not additive at a facility).
(e) Lake Charles Exports, LLC submitted one application seeking separate authorizations to export LNG to FTA countries and another authorization to export to Non-FTA countries. The proposed facility has a capacity of 2.0 Bcf/d, which is the volume requested in both the FTA and Non-FTA authorizations.
(f) Carib Energy (USA) LLC requested authority to export the equivalent of 11.53 Bcf per year of natural gas to FTA countries and 3.44 Bcf per year to non-FTA countries.
(g) Jordan Cove Energy Project, L.P. requested authority to export the equivalent of 1.2 Bcf/d of natural gas to FTA countries and 0.8 Bcf/d to non-FTA countries.
(h) DOE/FE received a new application (11-161-LNG) by FLEX to export an additional 1.4 Bcf/d of LNG from new trains to be located at the Freeport LNG Terminal, to non-FTA countries, and a separate application (12-06-LNG) to export this same 1.4 Bcf/d of LNG to FTA countries (received January 12, 2012). This 1.4 Bcf/d is in addition to the 1.4 Bcf/d FLEX requested in dockets (10-160-LNG and 10-161- LNG).
(i) An application was submitted by Gulf Coast on January 10, 2012, seeking one authorization to export LNG to any country not prohibited by U.S. law or policy. On September 11, 2012, Gulf Coast revised their application by seeking separate authorizations for LNG exports to FTA countries and Non-FTA countries.
(j) Total does not include 2.0 Bcf/d.

Step 5: Create alternative cases based on the original four LNG export scenarios, varying location of the liquefaction terminals in such states as Oregon, Mississippi, Georgia, and Alaska (on the Outer Continental Shelf, OCS).

An LNG export terminal is a large-scale, long-term investment, providing thousands of jobs and billions of dollars in capital expenditures. ICF estimates that a typical 1-Bcfd LNG export terminal costs roughly $4.8 billion (2010$), and requires 34,300 person-years for direct and indirect construction and operations.[20] This estimate includes all labor required for manufacturing the materials and equipment, and approximately 200 annual (direct) jobs for plant operation and another 350 annual (indirect) jobs for maintenance and non-feedstock supplies. The construction of a new LNG export terminal can have a significant impact on a state's economy. Given the large number of LNG export terminal applications currently in the DOE's queue, ICF opted to provide a number of terminal location cases (TLCs) to provide a range of impacts for a number of states. The ICF Base Case is made up of only one terminal location case, given that LNG exports of 4 Bcfd are approved from Louisiana and Texas. On the other hand a number of terminal location cases for the Middle LNG Exports Case (8 Bcfd) and the High LNG Exports Case (16 Bcfd) are provided. The 10 case assumptions include Louisiana and Texas as terminal locations in all cases. The Middle and High Cases alternate between a number of other states for the remaining LNG export volumes, based largely on the DOE application queue. The terminal location cases are as follows:

1) ICF Base Case include only terminals in LA and TX

2) Middle LNG Exports Case includes 4 TLC scenarios:

    i. TLC 1 +MD: LA, MD, TX

    ii. TLC 2 +OR: LA, OR, TX

    iii. TLC 3 +GA: GA, LA, TX

    iv. TLC 4 +MS: LA, MS, TX

3) High LNG Exports Case includes 5 TLC scenarios:

    i. TLC 1 +MD: LA, MD, TX

    ii. TLC 2 +OR: LA, OR, TX

    iii. TLC 3 +GA: GA, LA, TX

    iv. TLC 4 +MS: LA, MS, TX

    v. TLC 5 +AK: AK, LA, TX

[20] Based on greenfield project.

Exhibit 3-9 illustrates the 10 terminal location cases, including the associated minimum and maximum values. Minimum values assume an LNG export terminal is not located in-state, while maximum values include at least one LNG export terminal in the state.

Exhibit 3-9: Terminal Location Cases (TLCs)

State Terminal Assumed	ICF BASE CASE	MIDDLE EXPORTS CASES				HIGH EXPORTS CASES				
		1: MD	2: OR	3: GA	4: MS	1: MD	2: OR	3: GA	4: MS	5: AK
TX	X	X	X	X	X	X	X	X	X	X
LA	X	X	X	X	X	X	X	X	X	X
MD		X				X				
OR			X				X			
GA				X				X		
MS					X				X	
AK										X

X: Indicates terminal located in-state for that case

No min/max across LNG export case (i.e., all states in ICF Base Case (only one scenario); TX, LA, MD (included in all other cases), AK mid cases)

Mid Exports cases MIN VALUES

Mid Exports cases MAX VALUES

High Exports cases MIN VALUES

High Exports cases MAX VALUES

Exhibit 3-10 shows the relative location of LNG terminal location cases assumed in this study, based upon the DOE filings, with the relative heights indicating the export volume capacities.

Exhibit 3-10: Map of Potential LNG Export Terminals Assumed in this Study (By Export Volume)

Sources: Various compiled by ICF

Note: The height of each column represents the relative volume of terminal export capacity.

Step 7: Create alternative case for inclusion of Alaska LNG project in the High LNG Exports case.

As mentioned above, the High LNG Export Case also includes a terminal location case in Alaska. While the other six states assumed for LNG export terminals have similar specifications with regard to natural gas production locations, employment mix, and other factors, the Alaska case is quite different for a number of reasons:

1) Natural gas production: Given Alaska's prolific level of proven natural gas resources on the North Slope, all natural gas production for Alaska's LNG export facility would be produced in-state, whereas an LNG export facility in states such as Oregon would rely on gas imports from other states and Canada. In addition, U.S. natural gas costs would not rise as much as if production took place in the lower 48 states. This would mean a smaller natural gas and electricity consumption decrease, including among energy-intensive industrial consumers. The North Slope natural gas reserves are isolated from U.S. natural gas markets, and thus, production of the North Slope natural gas reserves would have little to no impact on U.S. Lower 48 natural gas costs.

2) Pipeline and gas processing requirements: Alaska will require a substantial investment in a gas-processing plant to remove carbon dioxide from the natural gas and a very large pipeline to deliver the gas to the liquefaction plant.

3) Employment mix: In contrast to the lower 48 states in terms of LNG export terminals, there will be fewer upstream (production) oil and gas jobs because most of the natural gas is already being produced and recycled now. However, because of the need to construct the natural gas processing plant and pipeline, there will be more jobs in the construction sector.

Alaska LNG Project

Among terminal projects already proposed or being discussed, the South Central Alaska LNG Export Project holds a unique position. Alaska has vast natural gas resources and already has a long history of exporting LNG through the small ConocoPhillips export terminal in Kenai using Cook Inlet gas in South Alaska. Recent interest in LNG export has brought the state's attention to commercializing natural gas in the North Slope, which could hold up to 200 Tcf of potential resource (of which 35 Tcf is proven) of gas recoverable, to boost economic development and job creation. Although North Slope gas potential is well-known, the distance from North Slope producing fields to demand centers in Alaska and the lower 48 states, as well as difficult geology and climate conditions make the resource expensive to monetize without the high appetite of Asian importers.

The South Central Alaska LNG export project, if built, will consist of a 800-mile, 42-inch natural gas pipeline running from Point Thomson to South Alaska and a LNG terminal with capacity of three 5.8 mtpa trains (or 17.4 mtpa in total). The project is jointly developed by ExxonMobil, BP, ConocoPhillips and TransCanada. Alaska LNG may take a long time to complete, requiring 9-10 years after the pre-FEED stage.[21] Nevertheless, being closer to Asia than any other state means Alaska LNG will still hold an advantage in lower transportation costs as the project comes online.

There are multiple studies on the potential economic benefits of the South Central Alaska LNG Export Project. A 2011 study was carried out by Wood Mackenzie to evaluate the economics of the Alaska LNG project. [22] This study concluded that Alaska LNG could be delivered to Japan economically at an advantage over Lower-48 LNG. The study also concluded that revenues to the state would range from $220 to $419 billion over a 30 year period. [23]

In a 2012 study, the Brookings Institute evaluated the economics of U.S. LNG export projects, including Alaska LNG, and found that such exports were very competitive with other world projects. [24]

Recently, Alaska's Department of Natural Resources stated that Alaska LNG exports could be delivered to Asia at a cost of under $10 per MMBtu, while most Australian projects were in the range of $10 to $12 per MMBtu. [25]

[21] Alaska South Central LNG Project. "Alaska South Central LNG Project – Overview for Alaska Legislators," presentation by North Slope project sponsors, February, 2013. Available at: http://gasline.alaska.gov/newsroom/Presentations/SCLNG%20-%20HRES%20Lunch%20&%20Learn%202.19.13.pdf

[22] Wood Mackenzie, 2011. "Alaska LNG Exports Competitiveness Study." July, 2011. Available at: http://www.arlis.org/docs/vol1/AlaskaGas/Present/Present_WoodM_2011_AK_LNG.pdf

[23] Walker, B. "Recent Studies Supports All-Alaska Gas Line". Anchorage Daily News, March 3, 2012: Anchorage, AK. Available at: http://www.adn.com/2012/03/03/2350478/recent-studies-support-all-alaska.html

[24] Brookings Institution. "Assessing the Case for U.S. Exports of Liquefied Natural Gas." Brookings Institution, May 2012: Washington, DC. Available at: http://www.brookings.edu/~/media/research/files/reports/2012/5/02%20lng%20exports%20ebinger/0502_lng_exports_ebinger.pdf

[25] Alaska Department of Natural Resources. "Commercializing Alaska LNG." DNR, 17 April, 2013, presented at the LNG 17 Conference in Houston, TX. Available at: http://www.gasline.alaska.gov/newsroom/Presentations/LNG_17_4_17_13.pdf

Step 8: Modify state allocation model and run cases through the state allocation processor. This step includes 10 alternatives for liquefaction plant location (among the 3 study cases.

Exhibit 3-11 shows the allocation methods for each source of GDP and employment attributable to LNG exports. For example, the LNG contributions to the GDP category includes three allocators: the location of LNG terminals has 20% of the allocation, the location of natural gas production has 47%, and indirect oil and gas jobs generated by LNG export terminals has 33%. The proportions of each allocator are based on a combination of ICF proprietary modeling, publicly-available data where available, and previous ICF work. Thus, for every $1 of LNG export sales adding value to the U.S. economy, $0.20 will be allocated among states based on the location of LNG export terminals, $0.47 allocated among states based on the location of gas production (which changes annually through 2035), and $0.33 allocated among states by the location of industries that provide indirect materials, equipment and services to the oil and gas production and terminal operations sectors.

Exhibit 3-11: Allocation Methodologies

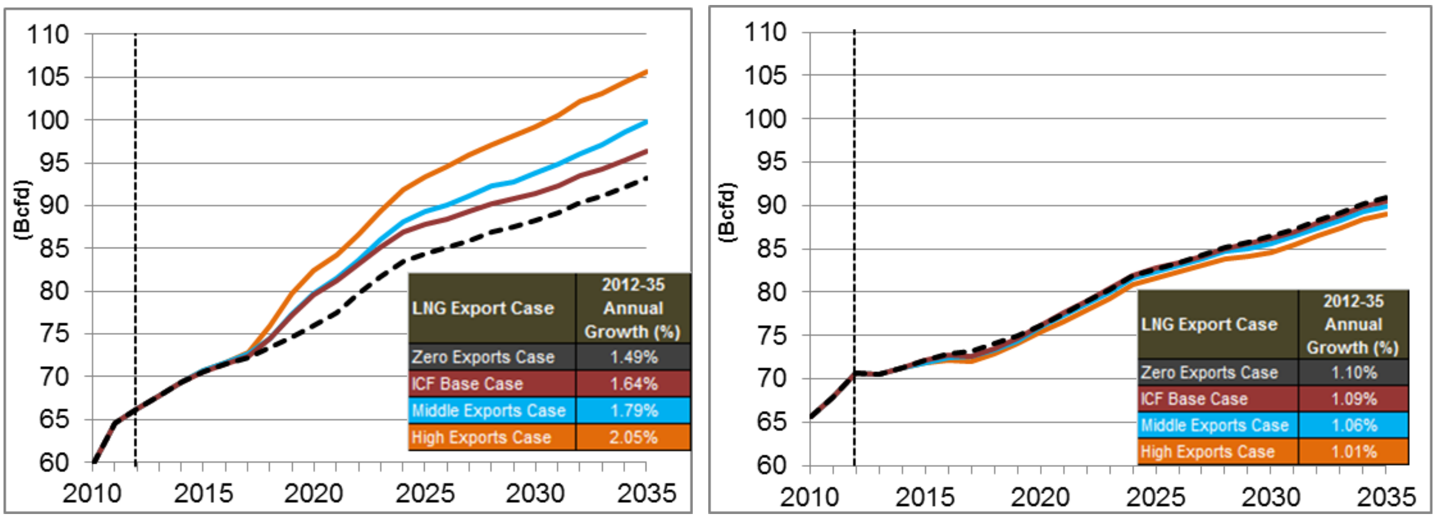
Source to be Allocated	Allocation Method #1	Fraction #1	Allocation Method #2	Fraction #2	Allocation Method #3	Fraction #3
GDP Categories (Income Earned)						
LNG's Contribution to US GDP	LNG	20%	Gas Prod Delta (yr)	47%	Indirect Oil Gas Jobs	33%
Liquids Contribution to GDP (value added in US)	NGPL Prod Delta (yr)	60%	Indirect Industrial Jobs	40%	NONE	0%
Methanol Production	Methanol	29%	Indirect Industrial Jobs	45%	Gas Prod Delta (yr)	26%
Ammonia Production	Ammonia	29%	Indirect Industrial Jobs	45%	Gas Prod Delta (yr)	26%
GTL Production	GTL	29%	Indirect Industrial Jobs	45%	Gas Prod Delta (yr)	26%
Ethylene/Polyethylene Production	Ethylene	29%	Indirect Industrial Jobs	45%	NGPL Prod Delta (yr)	26%
Propylene/Polypropylene Production	Propylene	29%	Indirect Industrial Jobs	45%	NGPL Prod Delta (yr)	26%
Contribution to GDP from Reduced Industrial Production	MECS Job Losses	80%	Indirect Industrial Jobs	20%	NONE	0%
Net US GDP Effect to Natural Gas Consumers	Gas All Consum 2011	60%	State Personal Income 2010	40%	NONE	0%
Net US GDP Effect to Natural Gas Producers	Gas Prod Delta (yr)	40%	State Personal Income 2010	60%	NONE	0%
Net US GDP Effect to Electricity Consumers	Elec All Consum 2011	60%	State Personal Income 2010	40%	NONE	0%
Net US GDP Effect to Electricity Producers	Elec All Consum 2011	60%	State Personal Income 2010	40%	NONE	0%
Multiplier Effect GDP	Calculated Direct + Indirect	40%	State Personal Income 2010	60%	NONE	0%
Employment Categories						
Related to Oil, Gas, NGL Production Changes	Gas Prod Delta (yr)	52%	NGPL Prod Delta (yr)	8%	Indirect Oil Gas Jobs	40%
Related to LNG Production	LNG	40%	Indirect Industrial Jobs	60%	NONE	0%
Related to Switch to Coal	Coal to Gas Switching	70%	Indirect Oil Gas Jobs	30%	NONE	0%
Related to Gas Consumer Accounts: Consumers	Gas All Consum 2011	60%	State Personal Income 2010	40%	NONE	0%
Related to Gas Consumer Accounts: Producers	Gas Prod Delta (yr)	40%	State Personal Income 2010	60%	NONE	0%
Related to Electricity Consumer Accounts: Consumers	Elec All Consum 2011	60%	State Personal Income 2010	40%	NONE	0%
Related to Electricity Consumer Accounts: Producers	Elec All Consum 2011	60%	State Personal Income 2010	40%	NONE	0%
Related to Power Generation (switch to coal, lower demand)	Coal Mining	100%	NONE	0%	NONE	0%
Methanol Production	Methanol	40%	Indirect Industrial Jobs	60%	NONE	0%
Ammonia Production	Ammonia	40%	Indirect Industrial Jobs	60%	NONE	0%
GTL Production	GTL	40%	Indirect Industrial Jobs	60%	NONE	0%
Ethylene/Polyethylene Production	Ethylene	40%	Indirect Industrial Jobs	60%	NONE	0%
Propylene/Polypropylene Production	Propylene	40%	Indirect Industrial Jobs	60%	NONE	0%
Other Industrial Output Changes	MECS Job Losses	80%	Indirect Industrial Jobs	20%	NONE	0%
Multiplier Effect Jobs	Calculated Direct + Indirect	40%	State Personal Income 2010	60%	NONE	0%

4 Economic and Employment Impacts on the U.S. Economy

The following section describes the economic and employment impacts of LNG exports, relative to the Zero Export Case on a state-level basis. Exhibit 4-1 shows the total natural gas production and consumption changes in volume terms. The economic impacts of LNG exports are derived from these volumetric changes. The exhibit illustrates that while domestic natural gas production increases significantly to account for LNG exports, U.S. consumption changes are much more subtle.

Exhibit 4-1: U.S. Domestic Natural Gas Market Changes by LNG Export Case

U.S. Domestic Gas Production Changes *U.S. Domestic Gas Consumption Changes*



Source: ICF estimates

Note: "U.S. Domestic Gas Consumption Changes" chart (right) does not include LNG export volumes, but does include domestic fuel used for liquefaction.

While the national-level study identified the sources of activity, the state-level analysis attempted to identify both the source of activity by state and estimate where the income is earned. For instance, while most income from natural gas, oil, and NGL production remains within the producing state, there is income earned throughout the country in the form of stockholder dividends and capital gains. ICF allocated each GDP source through use of multiple allocators to capture the various components of income earned, as mentioned in Section 3.

This study concludes that LNG exports have a net positive, or negligible, impact across all states.[26] In general, the largest impacts are found in states with gas, oil, and NGL production; LNG production; ethylene manufacturing; and industries that supply materials, products, and services to the oil and gas and petrochemical industries. Additionally, consumer spending

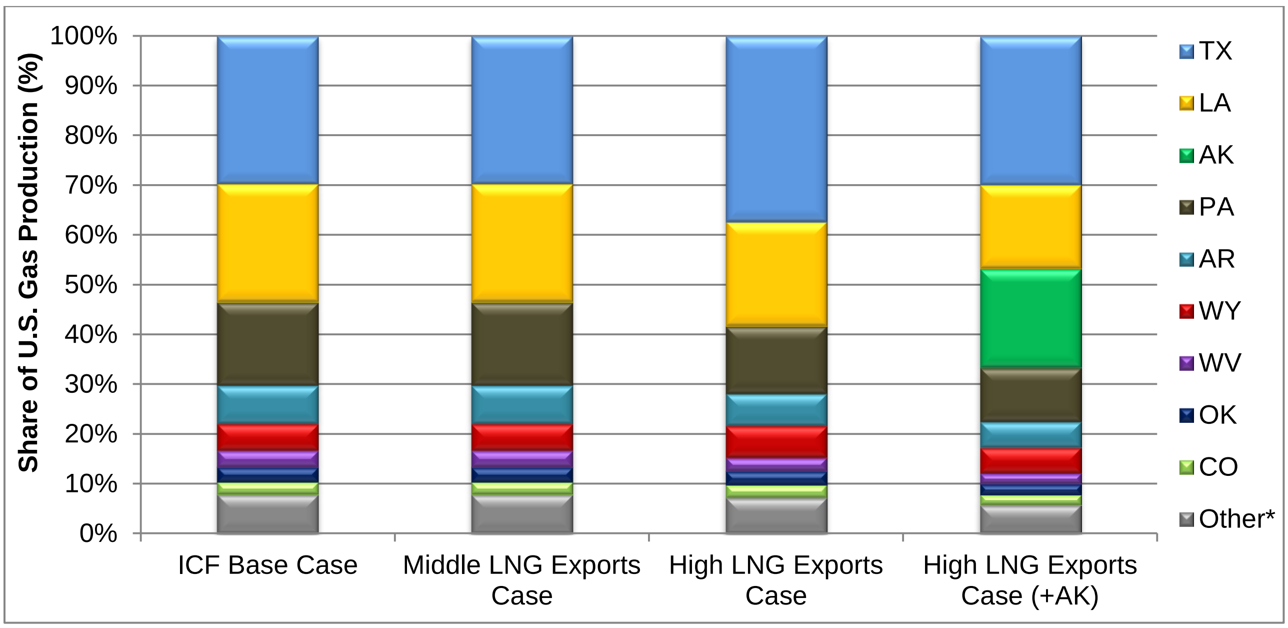
[26] "Negligible" defined for this report as less than 0.05% (positive or negative) of the base year state income (2010) or state employment (2012) as projected for the year 2035.

activity generated by these gas- and petrochemical-related activities contributes significant inter-state activity, providing economic and employment gains to states with little to no gas- or petrochemical-related activity. Economic and employment impacts of LNG exports vary considerably by state for a number of reasons, which are discussed below.

Natural gas and hydrocarbon liquids production changes

LNG exports require an increase in natural gas production, which also results in additional oil and natural gas liquids (NGL) productions. States with production activities see significant increases in economic and employment impacts, as production requires significant capital outlays and labor. For example, some of the largest gas-producing states such as Texas, Louisiana, Pennsylvania, Colorado, and Wyoming see large economic and employment impacts attributable to LNG exports due largely to the state's hydrocarbon production. Exhibit 4-2 shows the main natural production states by LNG export case (including a separate High LNG Exports Case that includes Alaska as an export terminal site, which would source gas in-state). These states see significant economic and employment gains attributable to the increase in hydrocarbon production required for LNG exports.

Exhibit 4-2: 2035 Share of U.S. Natural Gas Production Changes by LNG Export Case (%)



Source: ICF estimates

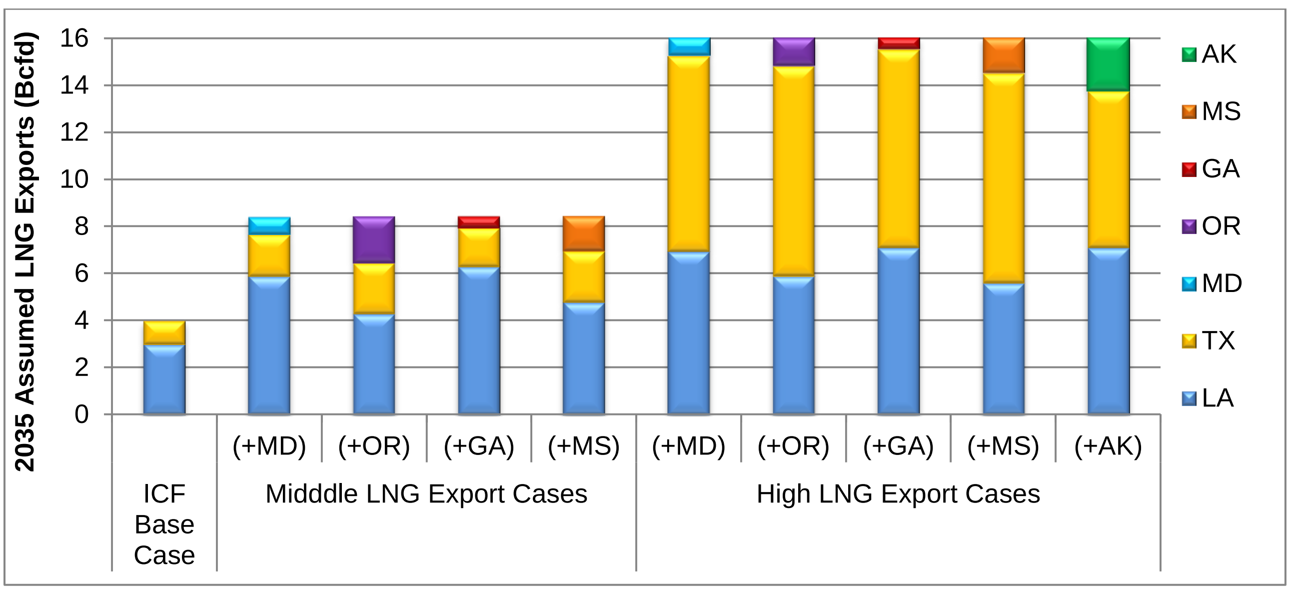
* Includes states with 2% of U.S. total gas production or less (AL, IL, KS, KY, MI, MS, MT, NM, NY, ND, OH, UT, VA).

LNG export facility location

ICF estimates that a typical 1-Bcfd LNG export terminal costs roughly $4.8 billion (2010$), and requires thousands of jobs to construct and operate the plant. LNG export terminals are large-scale, long-term investments that provide significant economic and employment gains to a state's economy. Thus, states that are assumed to have LNG export terminals in this study see significant impacts. As there is significant uncertainty over LNG export locations, ICF assumed a range of potential locations within seven states (Alaska, Georgia, Louisiana, Maryland, Mississippi, Oregon, and Texas). Exhibit 4-3 shows the proportion of LNG export volumes for each case.

As selected terminals in Louisiana and Texas already have approval for LNG exports (Cheniere Energy - Sabine Pass, LA; Freeport LNG – Freeport, TX; Southern Union/BG Group – Lake Charles, LA), these states provide the basis for the ICF Base Case. The Middle LNG Exports Case includes four subcases, altering LNG exports between Maryland[27], Oregon, Georgia, and Mississippi (in addition to Louisiana and Texas). The High LNG Exports Case includes the same four terminal location subcases, as well as Alaska as a potential LNG export location. ICF makes no assumptions on LNG export locations among these states. Thus, the economic and employment impacts for these seven states reports the impacts *including* an LNG export facility in-state to show the potential impacts. For example, rather than illustrating four Middle LNG Export Cases (reflecting the changing states), the exhibits herein show the maximum impacts for each of these states (i.e., assuming an in-state LNG export terminal in each of the seven states). The LNG export distributions assumed for each case are included below. Exhibit 4-4 includes a map of natural gas production assumed in 2035 for each LNG export case.

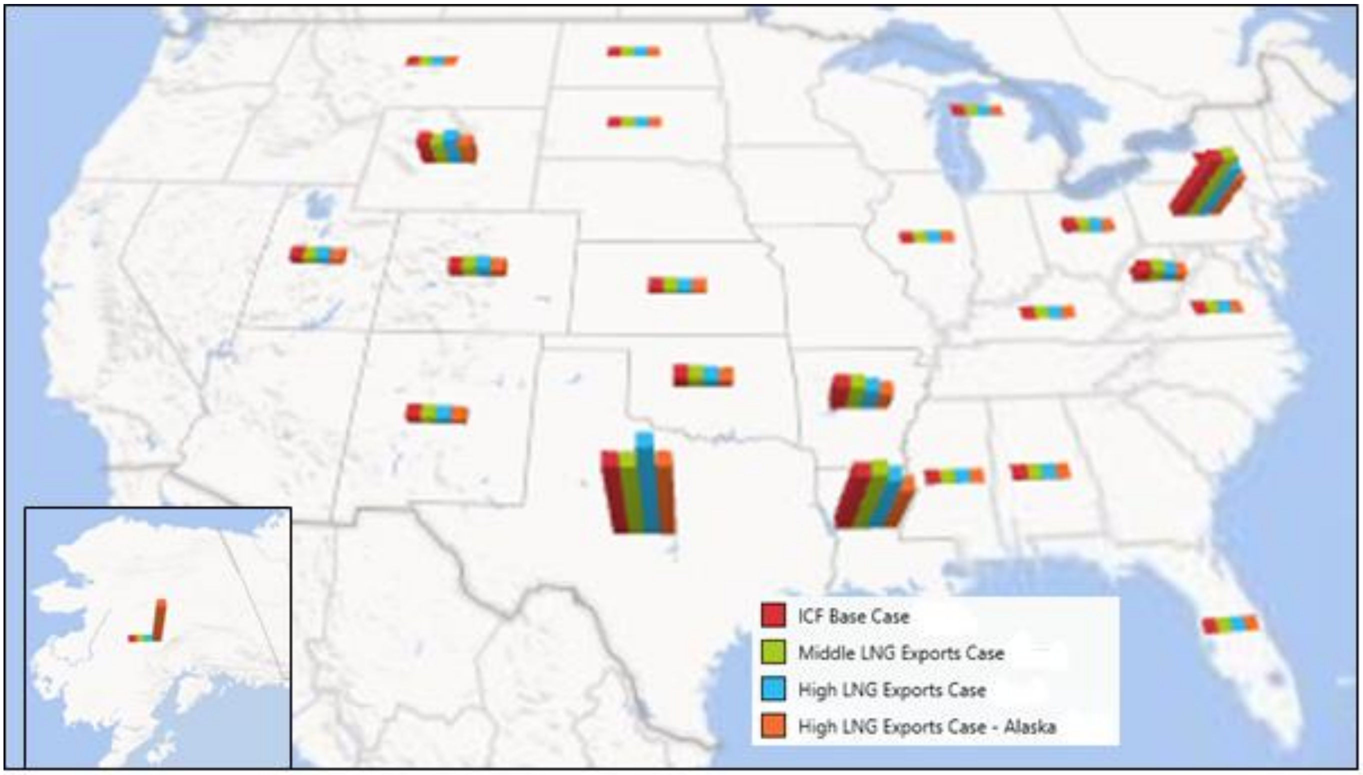
Exhibit 4-3: 2035 LNG Exports by State and Case (Bcfd)



Source: ICF estimates

[27] Dominion Resource recently gained DOE export approval from its Cove Point, MD terminal.

Exhibit 4-4: 2035 Change in Natural Gas Production by State and Case (By Bcfd Volume)



Source: ICF estimates

Location of gas-related industries

Gas processing and petrochemical facilities are typically located near gas production areas; thus, states containing and near gas production largely benefited from these increases. However, drilling equipment, drilling services, and production materials such as steel products, sand and other proppants, drilling and stimulation equipment, and cement typically come from manufacturing-intensive states (e.g., Ohio, Wisconsin, Michigan). These states benefit from gas production activities.

Natural gas and electricity consumer base

As detailed in the original study, LNG exports may lead to a slight increase in natural gas and electricity costs, potentially reducing total economic and employment gains associated with LNG exports. Thus, states with large gas and electricity consumption were more adversely affected by cost increases to residential, commercial and industrial users. But in all states, the size of this impact was offset by positive impacts.

Size of the state economy

While most income from gas-related activities remains within the producing state and in states supplying needed materials, products and services, there is income earned throughout the country in the form of stockholder dividends and capital gains. Thus, a portion of gas-related earnings was assumed to move out-of-state, and apportioned by the relative size of each state's economy. In addition, as income earned through gas-related activities multiplies, through the economy, additional consumer spending is created. States such as New York and California, with diverse but large economies, benefit from LNG exports from resident gas-related stockholders, as well as the inter-state consumer spending purchases.

4.1 Economic Impacts on the U.S. Economy

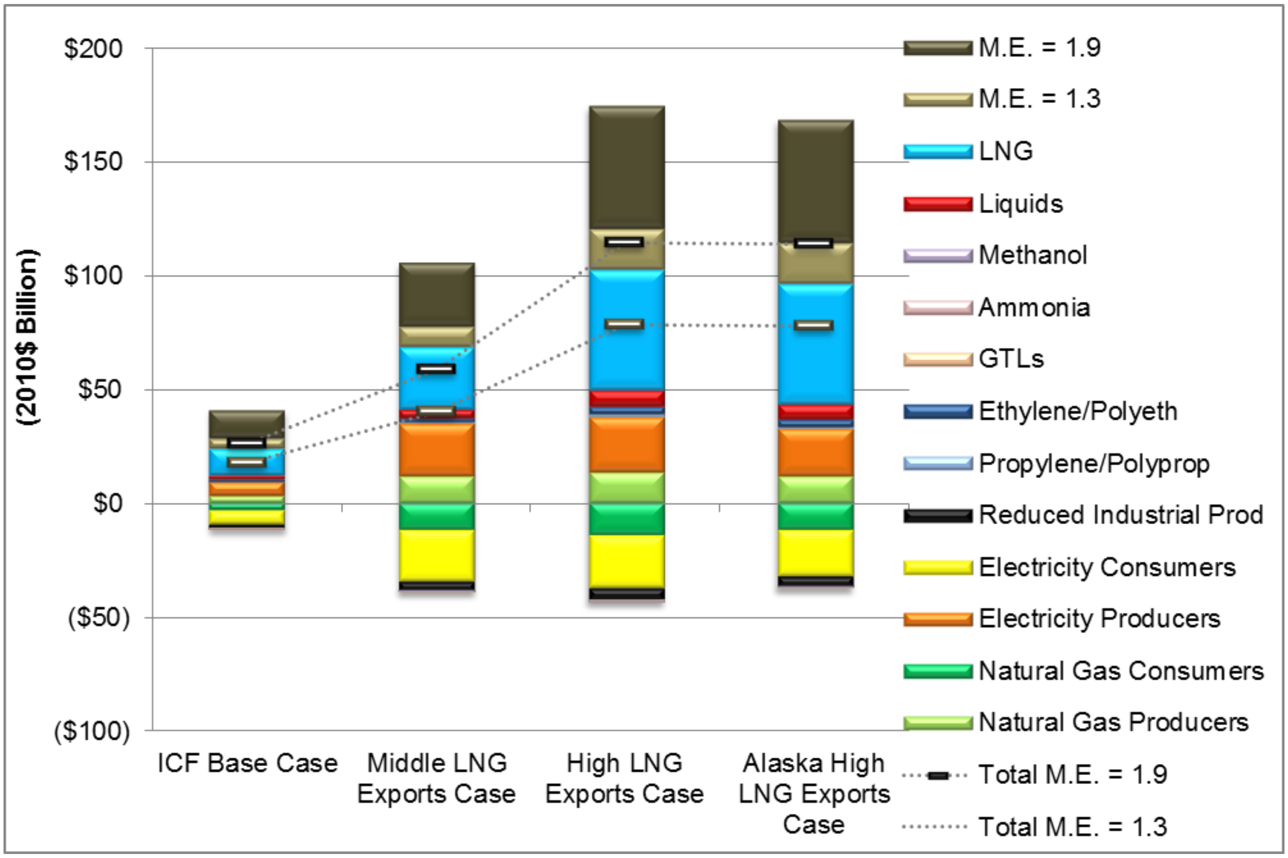
Economic impacts in the original study were computed first by the source of activity and then using input/output matrices allocated to the ultimate sectors within which the jobs take place. For example, ICF quantified the natural gas production increase that will take place for a given LNG export scenario, the required capital and operating and maintenance expenditures, and the resulting economic impact changes. Some gas-production-related impacts will take place in the manufacturing sector (e.g., sand mining for hydraulic fracturing, steel production for drill pipe). While these activities are not considered oil and gas production sectors, they are included in the job totals that are "sourced" by these activities.

This state-level analysis identifies both the source of activity by state and estimate where the income is earned from that activity. For instance, while most income from natural gas, oil, and NGL production remains within the producing state, there is income earned throughout the country in the form of stockholder dividends and capital gains. ICF allocated each GDP source through use of multiple allocators to capture the various components of income related to each GDP source. The total state impacts are calculated by combining the positive economic impacts with the potential negative impacts for each state. The total economic impacts for this study are comprised of production-related factors (such as gas production and LNG export terminals), demand response factors (such as consumer responses to increase natural gas and electricity prices), and multiplier effects (as the additional income generated by LNG exports reverberates through the economy).

Exhibit 4-5 shows the breakouts of each economic impact category, each of which was allocated among the 50 U.S. states and the District of Columbia to assess the economic impacts of LNG exports by state. While there are both positive and negative economic impacts associated with LNG exports, the net impacts are overwhelmingly positive. The positive economic impacts are attributable to an increase in natural gas production, while the economic losses are associated with a loss in consumer spending.

The positive economic impacts are led by LNG production (i.e., the value of LNG exports), which comprised the bulk of direct and indirect impacts (i.e., excluding multiplier effects), followed by gains to natural gas and electricity producers, and liquids production. The negative economic impacts are associated with the natural gas and electricity cost increases. As a result, gas-fired heating and electricity bills for residential/commercial consumers rise, as do energy-intensive manufacturers, translating to a reduction in consumption and industrial output.

Exhibit 4-5: 2035 U.S. GDP Contributions from LNG Exports by Source



Source: ICF estimates

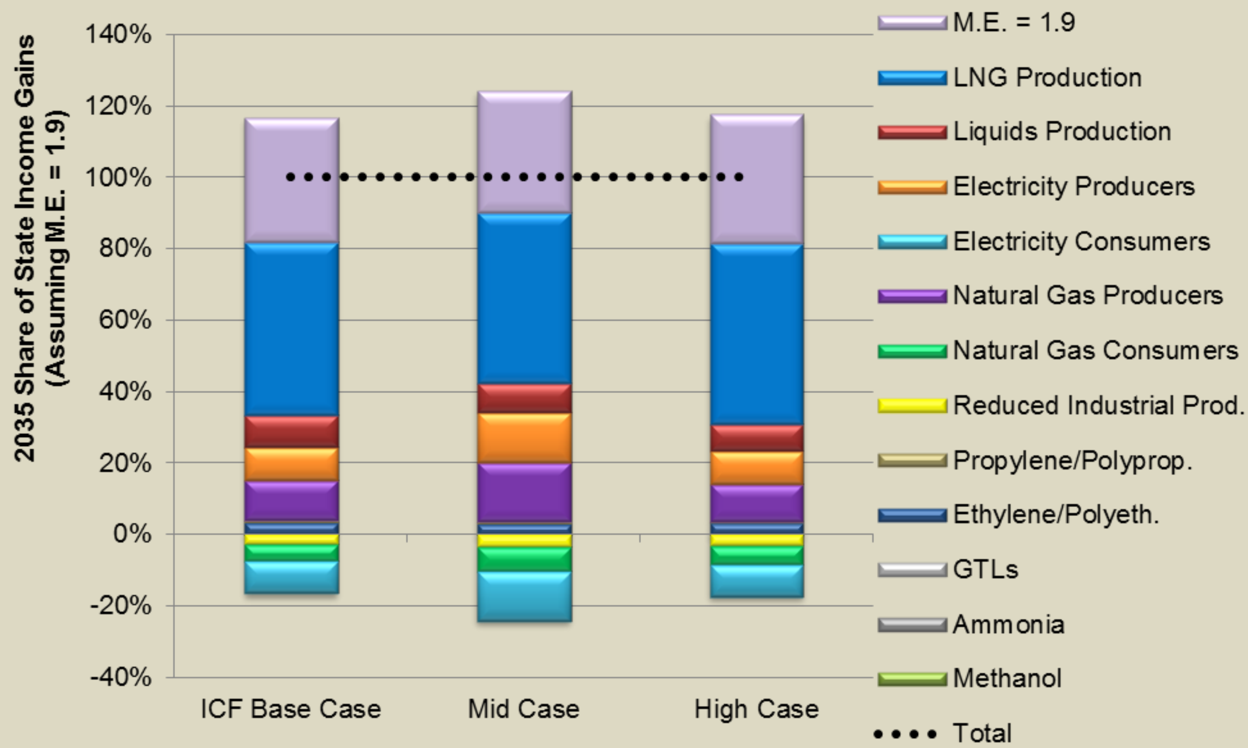
Of the total U.S. GDP changes attributable to LNG exports, ranging from $18b-$115b annually by 2035, all states see positive, or negligible in a few cases, net changes, despite slight losses in consumer-oriented sectors, which experience lower activity caused by higher natural gas and electricity costs.

States with the largest economic impacts from LNG exports include Texas, Louisiana, and Alaska benefit from large-scale oil and gas production, as well as in-state LNG export terminals (only in the High LNG Export Case for Alaska). Alaska could see up to $10 billion in state income in 2035 resulting from LNG exports (assuming an in-state LNG export terminal). Other large hydrocarbon producers such as Pennsylvania, Wyoming, Arkansas, and Oklahoma also see large gains, as do manufacturing-intensive states such as Ohio and Indiana. California, with a large manufacturing presence and diverse economy also sees large gains from LNG exports.

The largest economic impacts are generated in gas-producing states. The production of natural gas, oil, and natural gas liquids (NGLs) generates significant economic impacts for producing states, including Texas, Louisiana, Pennsylvania, and Alaska (if an LNG terminal is built in Alaska, requiring in-state gas production).

Producing-State Profile: Pennsylvania

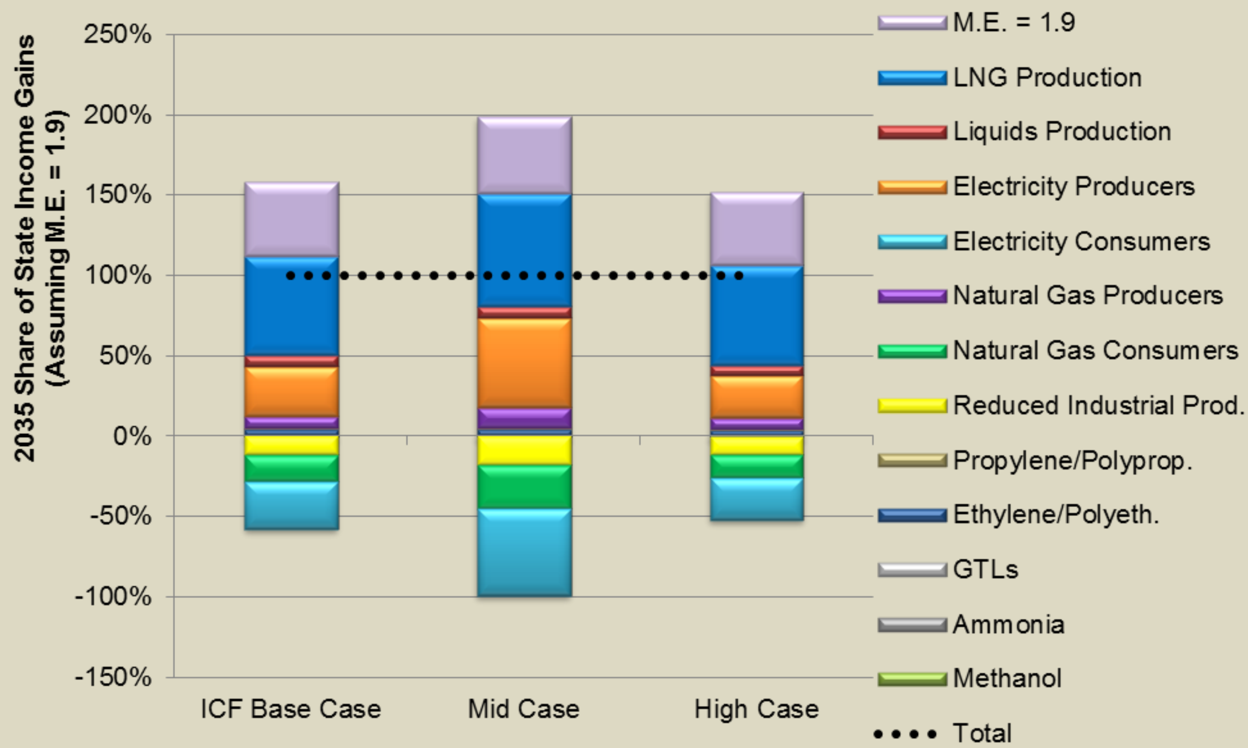
LNG and liquids production comprise a significant share of net economic impacts for Pennsylvania, or nearly 60% of total state income changes for the state in 2035, with total state income impacts reaching $2.1-$10.5 billion that year.



However, gas production activities also require materials, services, personnel, processing, and transportation, benefiting manufacturing-intensive states such as Ohio, Indiana, and Illinois, as well. In particular, non-natural gas-producing states with a large manufacturing base, such as Indiana and Wisconsin, see significant impacts, with the total economic gains in 2035 reaching $2.6 billion and $1.3 billion, respectively.

Manufacturing State Profile: Indiana

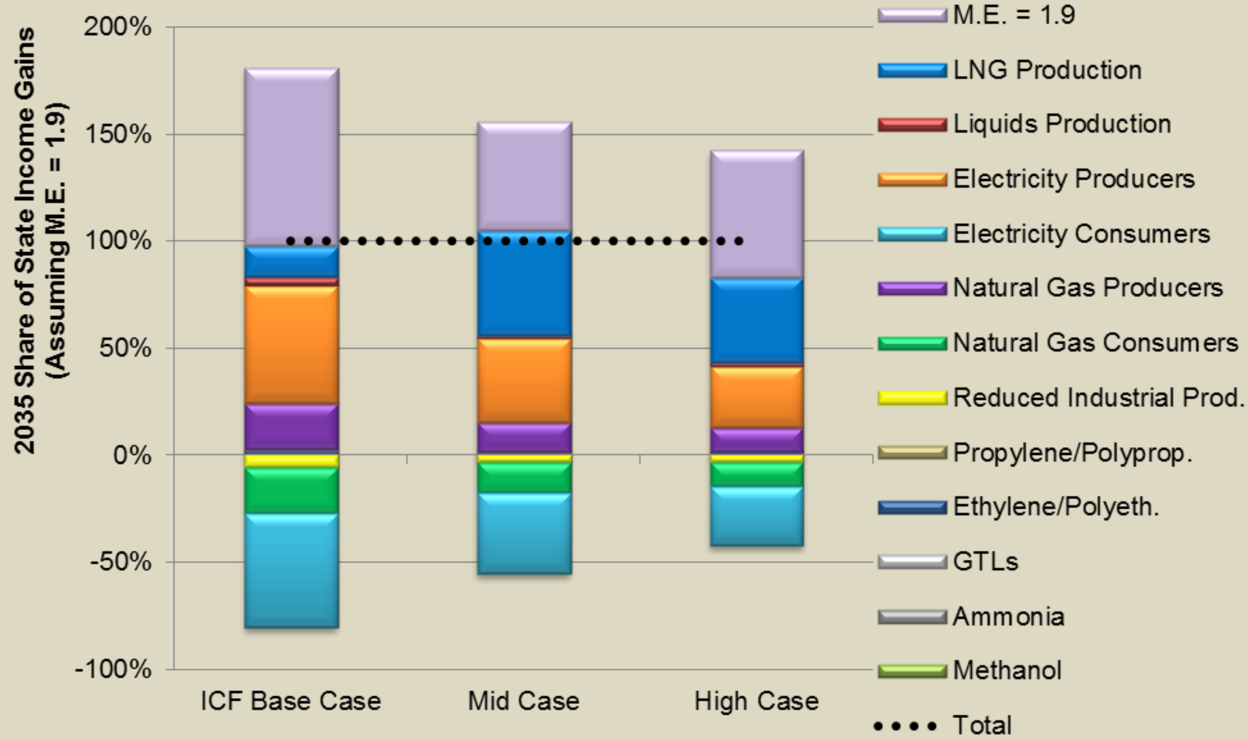
Indiana sees net positive economic impacts ranging from $300 million to $2.2 billion annually by 2035, attributable in large part by the manufacturing equipment required for hydrocarbon production and liquefaction operations.



In addition, states in which LNG terminals are located see significant economic impacts, as well. LNG terminals are a long-term investment, requiring significant capital outlays, labor, materials, and services. States with LNG terminals see significant increases in state incomes resulting from LNG exports.

LNG Export State Profile: Maryland

LNG comprises between 40%-50% of net economic impacts for Maryland in the Mid and High cases assuming an in-state LNG export facility, with total state income impacts reaching between $100 million to $1.6 billion by 2035 over the three LNG export cases.

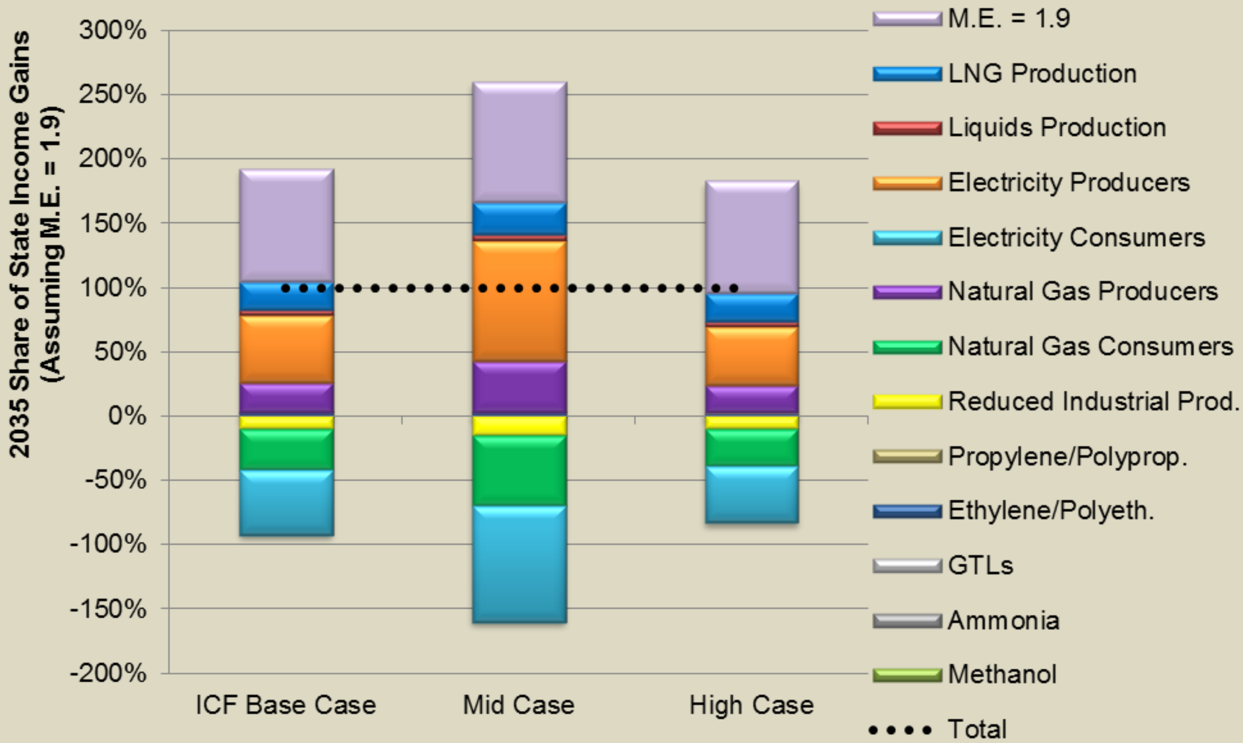


The one High LNG Export Case with the Alaska terminal generates significant income for the state, given that the LNG export terminal of 2.25 Bcfd starting in 2023 will require large capital outlays and rely exclusively on Alaskan natural gas as feedstock (as opposed to using gas production from the lower 48 states). Alaska could see over 36,000 jobs in 2035 resulting from LNG exports (assuming an in-state LNG export terminal). In the other cases wherein no Alaskan LNG terminal is assumed, Alaska shows negligible income and employment impacts.

California, with a large manufacturing presence and diverse economy also sees large gains from LNG exports.

State Profile of Large Economy: California

California comprised nearly 13% of the U.S. GDP in 2010, the largest share of any U.S. state. This study found net state income impacts of between $500 million to $5.0 billion in 2035. LNG-related activities (e.g., engineering services, equipment manufacturing) contribute roughly one-quarter of net state income impacts that year.



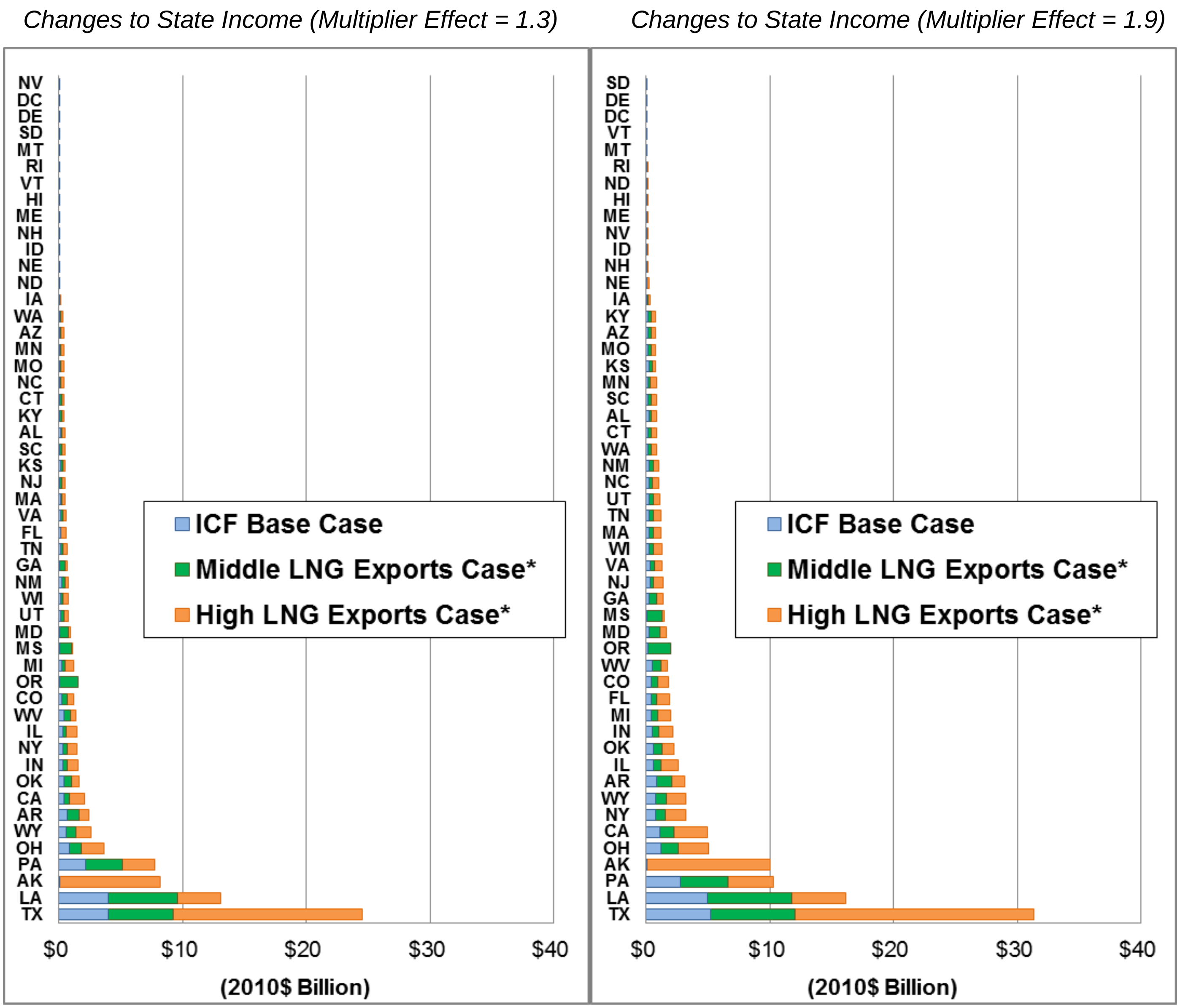
States with little exposure to gas-related activities or associated manufacturing see net positive impacts of LNG exports through the multiplier effect. States with large natural gas and electricity consumption, while most adversely affected by the increase in natural gas and electricity costs, see net positive economic impacts. When oil and gas employees, for instance, spend additional earnings through inter-state consumer purchases, these activities further generate economic activity elsewhere.

State Profile of Large Gas and Electricity Consumption: Florida

Florida consumes a higher proportion of U.S. natural gas and electricity consumption than average (5% and 6% in 2011, respectively - EIA). Despite this, Florida shows net economic gains of $100 million to $1.9 billion by 2035.

Exhibit 4-6 and Exhibit 4-7 show the distribution of total state income changes associated with LNG exports. Exhibit 4-7 is meant to show spatially the information illustrated in Exhibit 4-6.

Exhibit 4-6: 2035 State Income Impacts from LNG Exports (relative to Zero Exports Case)

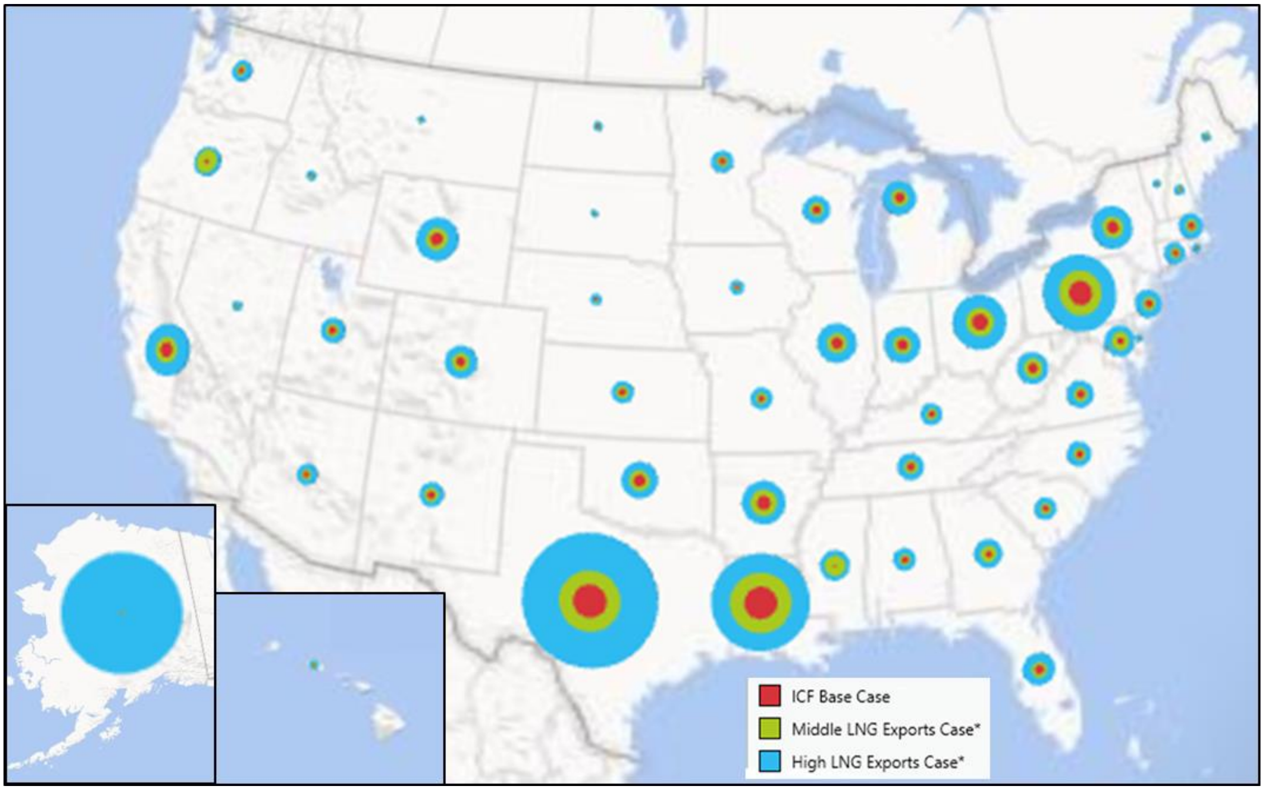


Source: ICF estimates

Note: Ranked by High LNG Exports Case.

* The Middle Case values are the average of four Terminal Location Cases (TLCs) and the High Case values are an average of five TLCs except that values for the seven LNG terminal states (AK, GA, LA, MD, MS, OR, TX) show impacts with at least one in-state LNG export terminal.

Exhibit 4-7: Map of 2035 Relative Income Impacts from LNG Exports (By State Income)



Source: ICF estimates

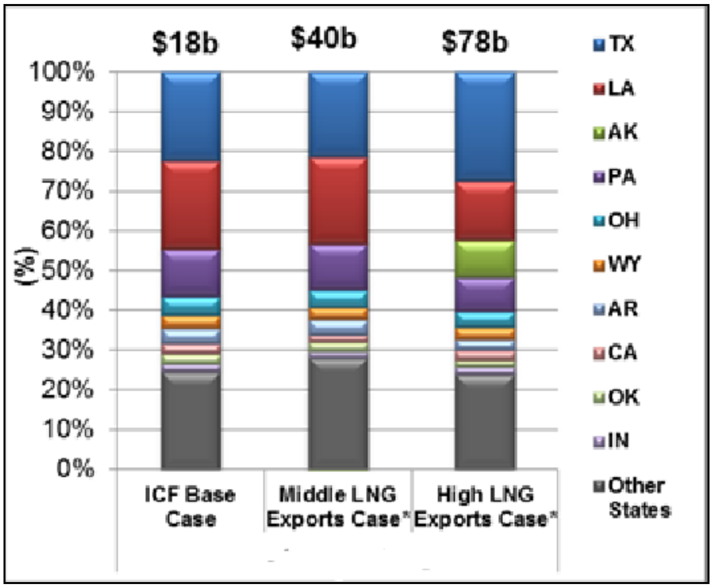
Note: Calculated using an economic multiplier of 1.9. The circle sizes represent the relative income impact of each state for each LNG export case.

* The Middle Case values are the average of four Terminal Location Cases (TLCs) and the High Case values are an average of five TLCs except that values for the seven LNG terminal states (AK, GA, LA, MD, MS, OR, TX) show impacts with at least one in-state LNG export terminal.

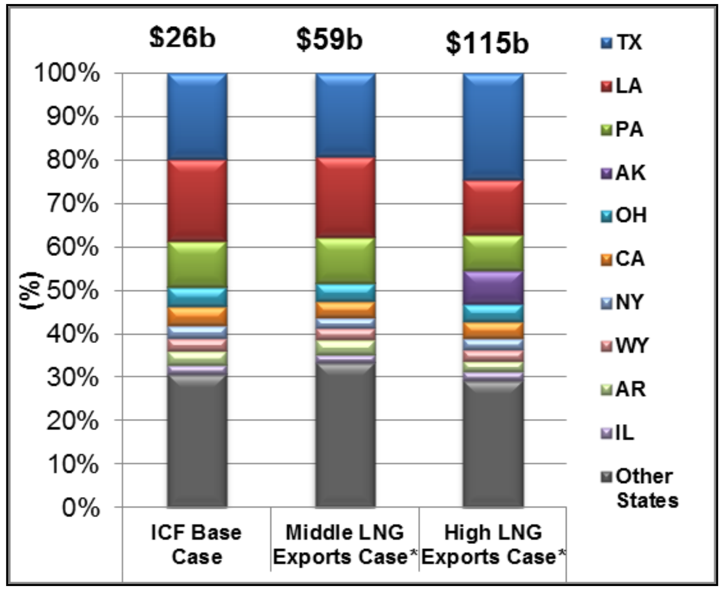
Exhibit 4-8 shows the proportion of income impacts by the 10 states that capture the bulk of the economic impacts in both the 1.3 and 1.9 multiplier effect cases. While large gas producers such as Texas, Louisiana, and Alaska (in the High Alaska Case) capture a large share of the total economic impacts, non-producing states such as California, Indiana, and New York see significant positive impacts, as shown below.

Exhibit 4-8: 2035 State Income Impacts Share of Top 10 States

Changes to State Income (Multiplier Effect = 1.3)



Changes to State Income (Multiplier Effect = 1.9)



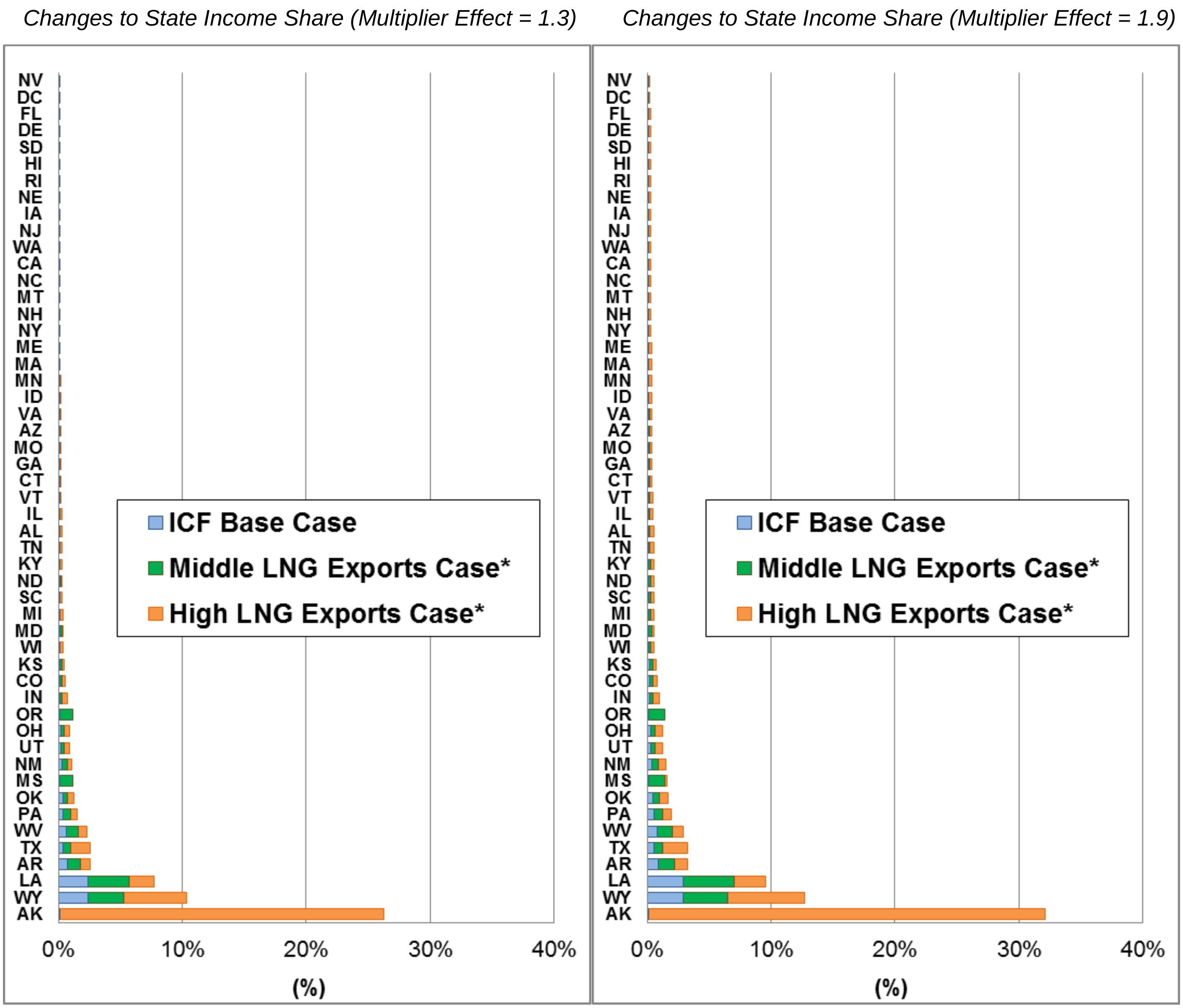
Source: ICF estimates

Note: Ranked by High LNG Exports Case.

* The Middle Case values are the average of four Terminal Location Cases (TLCs) and the High Case values are an average of five TLCs except that values for the seven LNG terminal states (AK, GA, LA, MD, MS, OR, TX) show impacts with at least one in-state LNG export terminal.

The 2010 state income is used here to illustrate the relative economic impacts on states. Exhibit 4-9 shows 2035 total economic impacts by state as a proportion of 2010 state income. While economic impacts for producing states such as Texas, Louisiana and Pennsylvania see 2035 total economic impacts ranging from 5%-10% of 2010 state income, states such as Indiana, and Wisconsin, among others, see significant impacts, as well.

Exhibit 4-9: 2035 State Income Impacts as a Proportion of 2010 State Income



Source: ICF estimates

Note: Ranked by High LNG Exports Case.

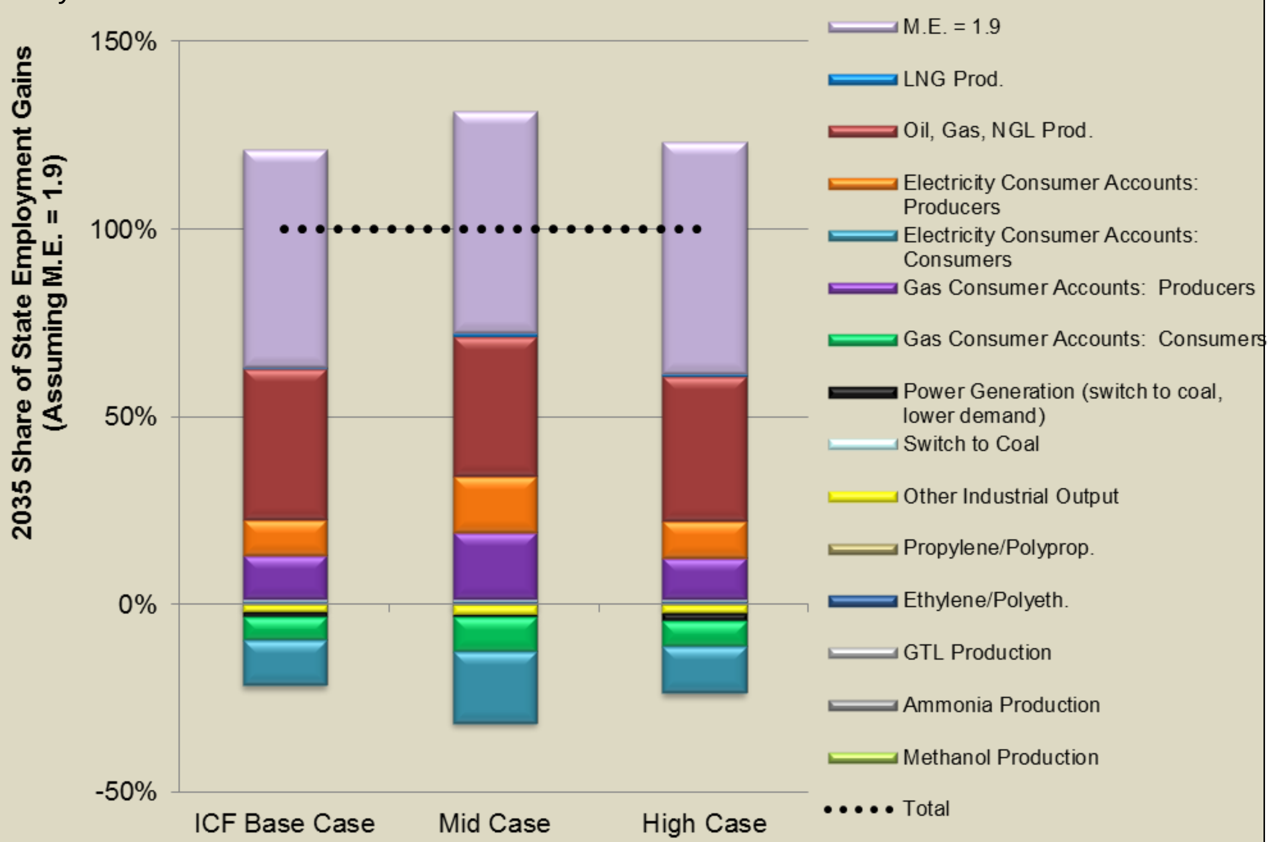
* The Middle Case values are the average of four Terminal Location Cases (TLCs) and the High Case values are an average of five TLCs except that values for the seven LNG terminal states (AK, GA, LA, MD, MS, OR, TX) show impacts with at least one in-state LNG export terminal.

4.2 Employment Impacts on the U.S. Economy

As mentioned in the national-level report, the ICF methodology calculates direct and indirect job impacts (relative to no LNG exports) by multiplying the change in production in a given sector (measured in dollars or physical units) times the labor needed per unit of production. Employment impacts in this study (as with the original study) were computed first by the source of activity and then using input/output matrices allocated to the ultimate sectors within which the jobs take place. Just as with the economic impacts, ICF quantified the employment impacts resulting from natural gas production increases that will take place for a given LNG export scenario and the required capital and operating and maintenance expenditures. Some gas-production-related employment will take place in the manufacturing sector (e.g., sand mining for hydraulic fracturing, steel production for drill pipe). While these activities are not considered part of the oil and gas production sectors, they are included in the job totals that are "sourced" by these activities.

Producing-State Profile: Pennsylvania

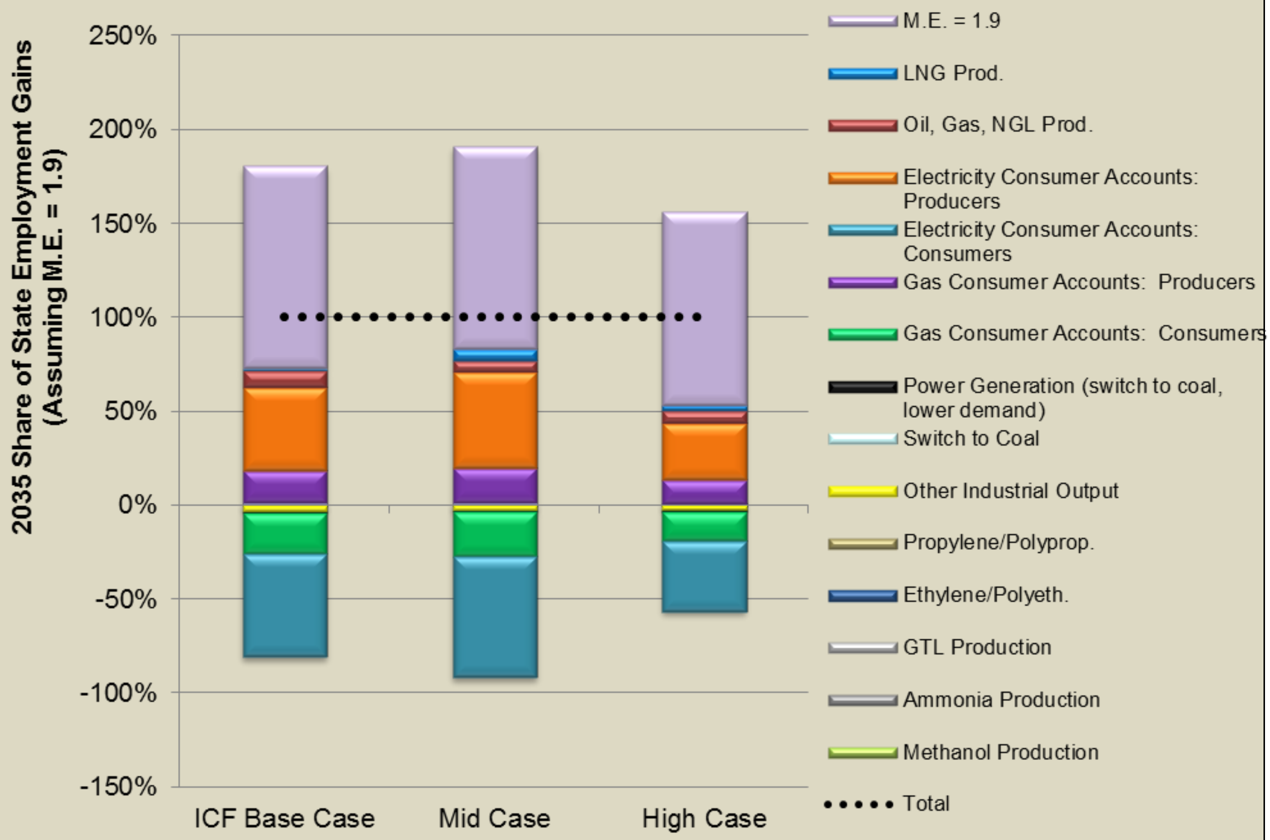
Natural gas and other hydrocarbon production comprise roughly 60% of Pennsylvania's total employment changes by 2035, with total state employment impacts ranging from 10,000-61,000 that year.



Of the 72,000-665,000 net job gains from LNG exports by 2035 nationwide, all states see net positive employment impacts from LNG exports, including states with a potential LNG export terminal, such as Maryland.[28]

LNG Export State Profile: Maryland

Total employment impacts to Maryland range from 480 to 9,500 jobs in 2035 over the three LNG export cases.



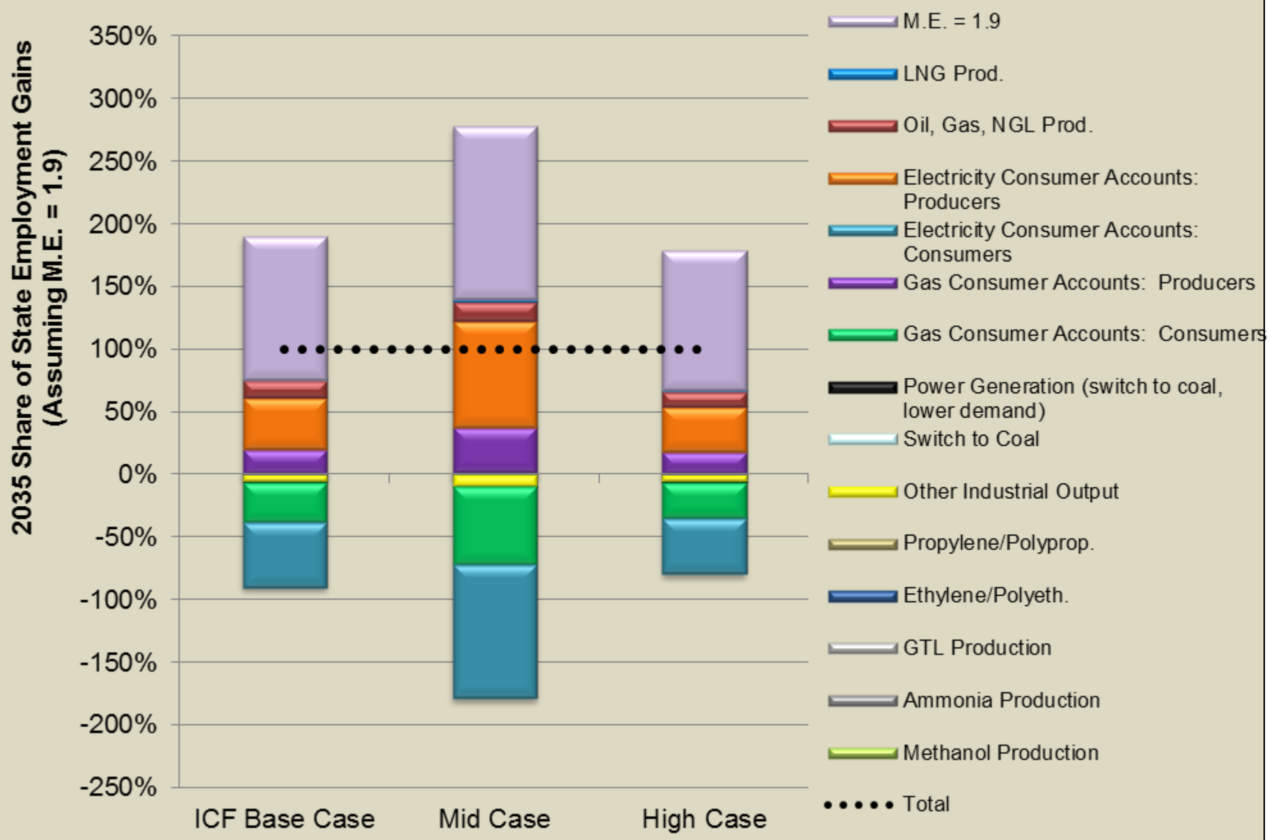
As with economic activity, the biggest job gains are in states with natural as production, liquefaction plants and petrochemical industries. However, states providing indirect goods and services to the natural gas producers, liquefaction plants, and petrochemical industries (such as steel from Ohio, machinery from Indiana, etc.) also see significant job gains, as well.

Generally, producing states saw the largest benefits, though a certain portion of income generated by LNG exports is spent out-of-state, such as the inter-state sale of goods and services (e.g., tourism, cars, and other manufactured goods). Thus, it is possible for states with little direct and indirect employment to benefit in terms of multiplier effect activity. In addition, the stockholder income from gas-related activities is distributed throughout the country, rather than concentrated within a state. This generates further spending and employment throughout the U.S.

[28] Calculated assuming an economic multiplier of 1.9.

State Profile of Large Economy: California

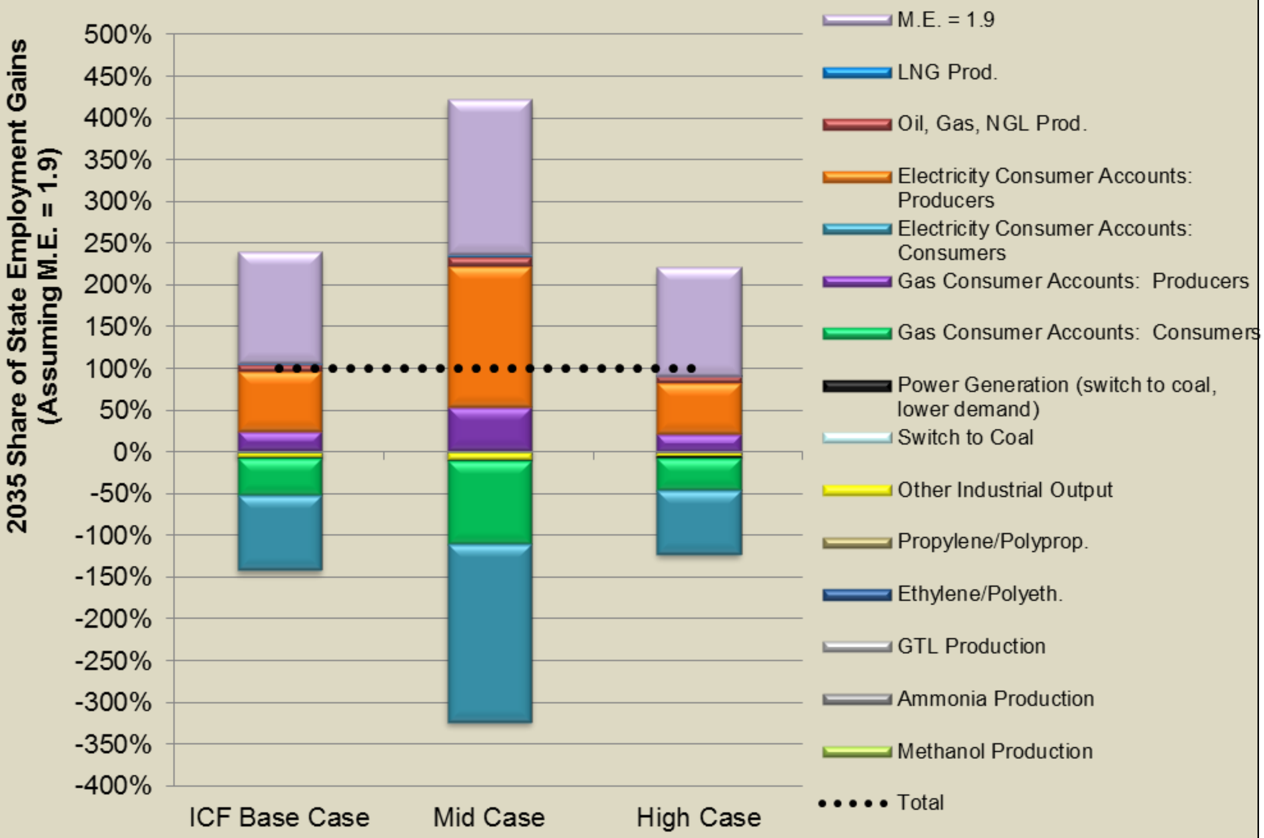
California comprised nearly 12% of total U.S. employment in 2012, the largest share of any U.S. state. This study found net employment impacts of between 2,000 and nearly 40,000 jobs in 2035.



The majority of states that do not directly participate in LNG-related industries see small, net job gains. This comes about because job losses (stemming from higher energy costs) are offset by job gains from a larger US economy. The job gains come from higher indirect purchases from the LNG-related industries; higher income of in-state stockholders of LNG- and petrochemical-related industries; and consumer spending of out-of-state employees of oil, gas, and related industries. A small number of states, however, see negligible job contractions in some cases, as employment gains do not fully offset the consumer impacts from slightly higher natural gas and electricity costs.

State Profile of Large Gas and Electricity Consumption: Florida

Florida consumes a higher proportion of U.S. natural gas and electricity consumption than average (5% and 6% in 2011, respectively - EIA). While Florida sees net positive employment gains reaching over 3,000 in the ICF Base Case and up to nearly 15,000 jobs in the High Case, the Mid Case net jobs ranges from a reduction of 1,200 to a net increase of 5,000.



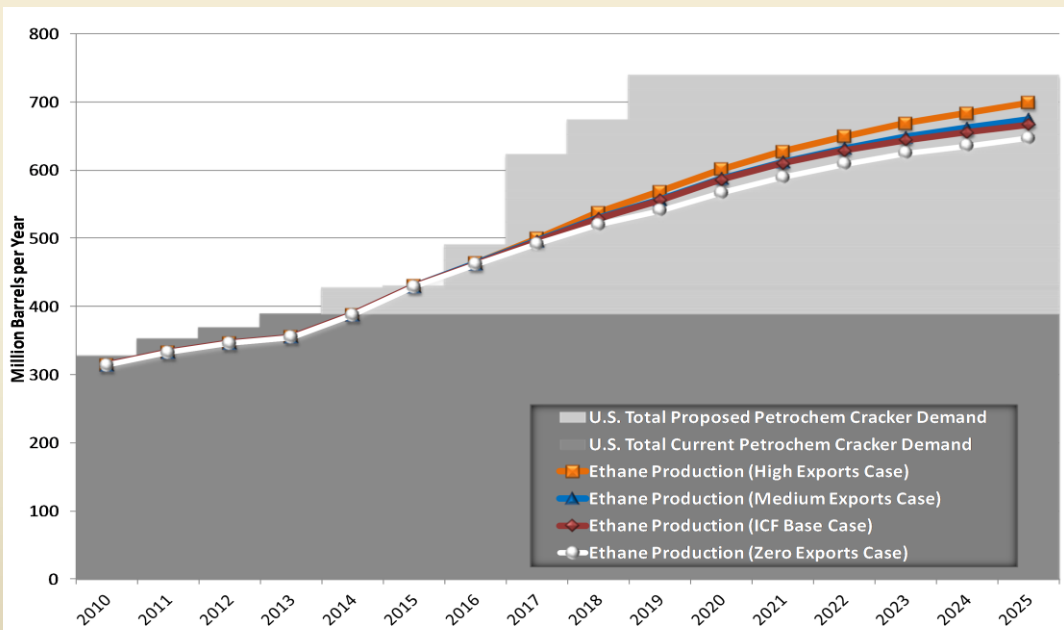
Increased LNG exports lead to increased availability of ethane for the petrochemical industry

The natural gas production levels ICF forecasts for the three LNG export scenarios also lead to different production levels of associated natural gas liquids, and particularly ethane, the largest component of the NGL mix. Used primarily as a feedstock for the petrochemical industry, ethane is “cracked” into ethylene, an essential building blocks in organic chemistry. As precursor to such materials as polyethylene or monoethylene glycol, ethylene is by far the most commonly produced chemical in the world, and a vital feedstock in manufacturing materials that eventually make their way to the consumer market. Form plastic bottles and home insulation to antifreeze and pantyhose, ethylene finds its way into a wide variety of every-day products.

Winners in this space will not be limited to just the plants located in the traditional petrochemical cluster on the Gulf of Mexico coast. With shale resources found throughout the country, and natural gas liquids production forecasted to grow in areas as wide-spread as the Bakken in North Dakota/Montana, Eagle Ford in Texas, and Marcellus/Utica in the Northeast, there is scope for manufacturers to locate their facilities in myriad locations. ICF’s list of planned petrochemical facilities (see Appendix C of national-level report) shows projects well outside the Gulf Coast region. The Northeast, for example, is in line for at least two major petrochemical facilities. A region more accustomed to the hollowing-out of its industrial base is being reenergized by its proximity to a prolific supply basin. While the draw for the ethylene crackers is the ready supply of cost-advantaged feedstock, the benefits will spread far and wide – from the employees at these plants and the municipalities benefiting from the income and property taxes, to the companies that use these precursor chemicals in their processes.

The surge in ethane production since 2009, after decades of falling output, and forecasts for continuing growth, have led petrochemical producers to plan for an unprecedented level of capacity expansion. Between 2012 and 2020, should all projects proceed to completion, the U.S. will see its ethylene production capacity grow by over 40%. Using ethane as their feedstock, rather than the naphtha used by most of their international competitors, will give companies operating in the United States a cost advantage relative to their global peers. That lower costs of production will in turn be passed on to their customers, creating a ripple effect that will spur not only the development of derivatives production, but also lead to lower prices of consumer goods derived from these intermediate products.

U.S. Historical and Forecast Ethane Supply and Demand

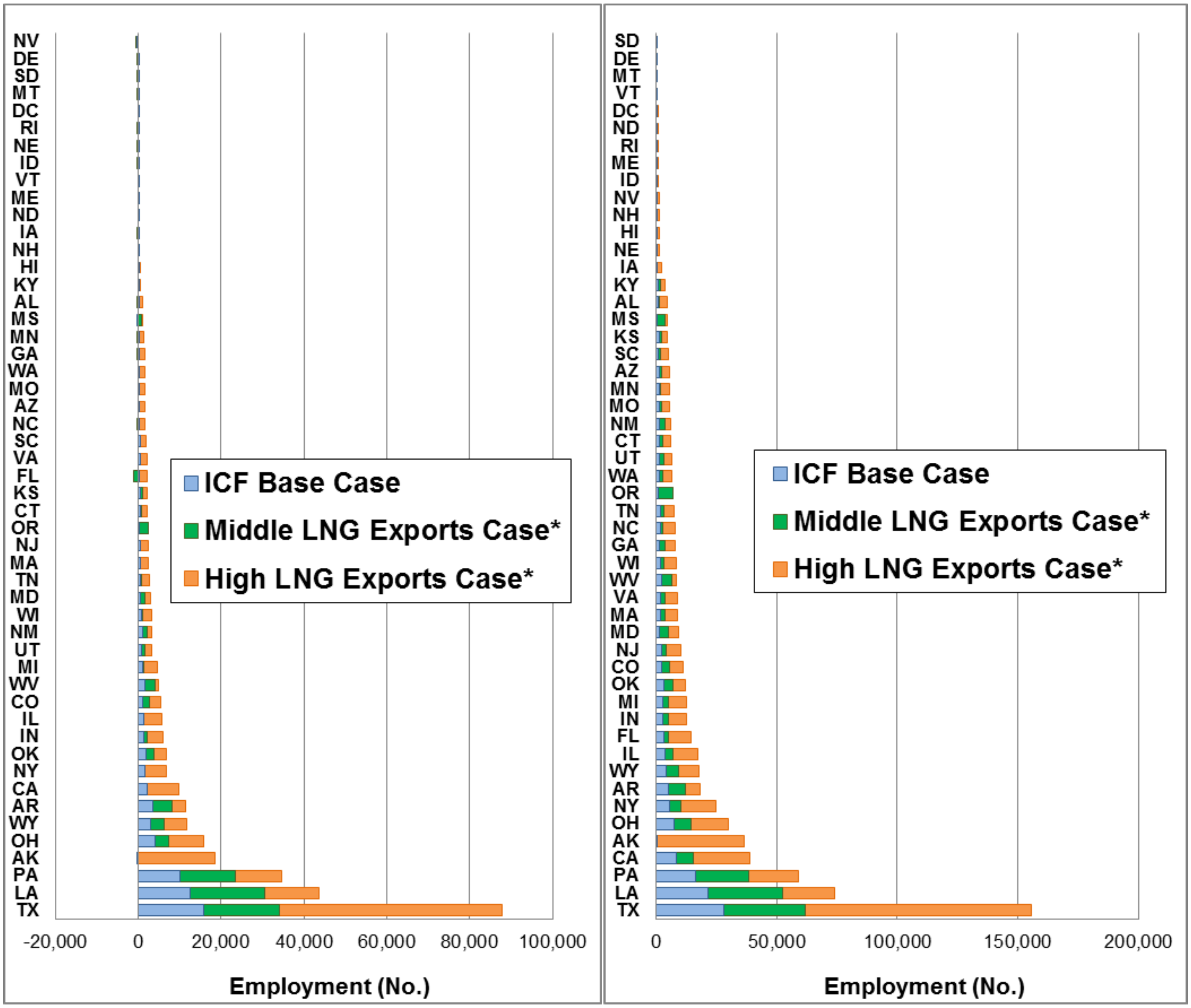


As shown in the chart above, potential demand for ethylene brought about by proposed ethylene production capacity between 2013 and 2020 will easily exceed supply past 2016. While supply is expected to grow organically even in the Zero Exports case, by the end of the forecast period the difference in supply between the Zero Exports case and the ICF Base Case and the Medium Exports Case will amount to the equivalent of at least one world-scale ethylene cracker. With the price-tag for such facility nearing $1.5 billion, this is a significant amount of foregone investment. Moving up to the High Exports case, the incremental supply of ethane grows by the equivalent of another two world-scale crackers. With each such project bringing with it not only the ethylene plant but also derivatives production, ICF estimates that in 2025 the impact of increased availability of ethane stemming from increased natural gas production will range between $1.1 and $3.2 billion, and generate an additional 1,800 to 6,000 jobs above the Zero Exports case.

Exhibit 4-10 and Exhibit 4-11 show the distribution of total state employment impacts of LNG exports in 2035. Exhibit 4-11 is meant to show spatially the information illustrated in Exhibit 4-10.

Exhibit 4-10: 2035 Total Employment Impacts from LNG Exports (relative to Zero Exports Case)

Changes to State Employment (Multiplier Effect = 1.3) *Changes to State Employment (Multiplier Effect = 1.9)*

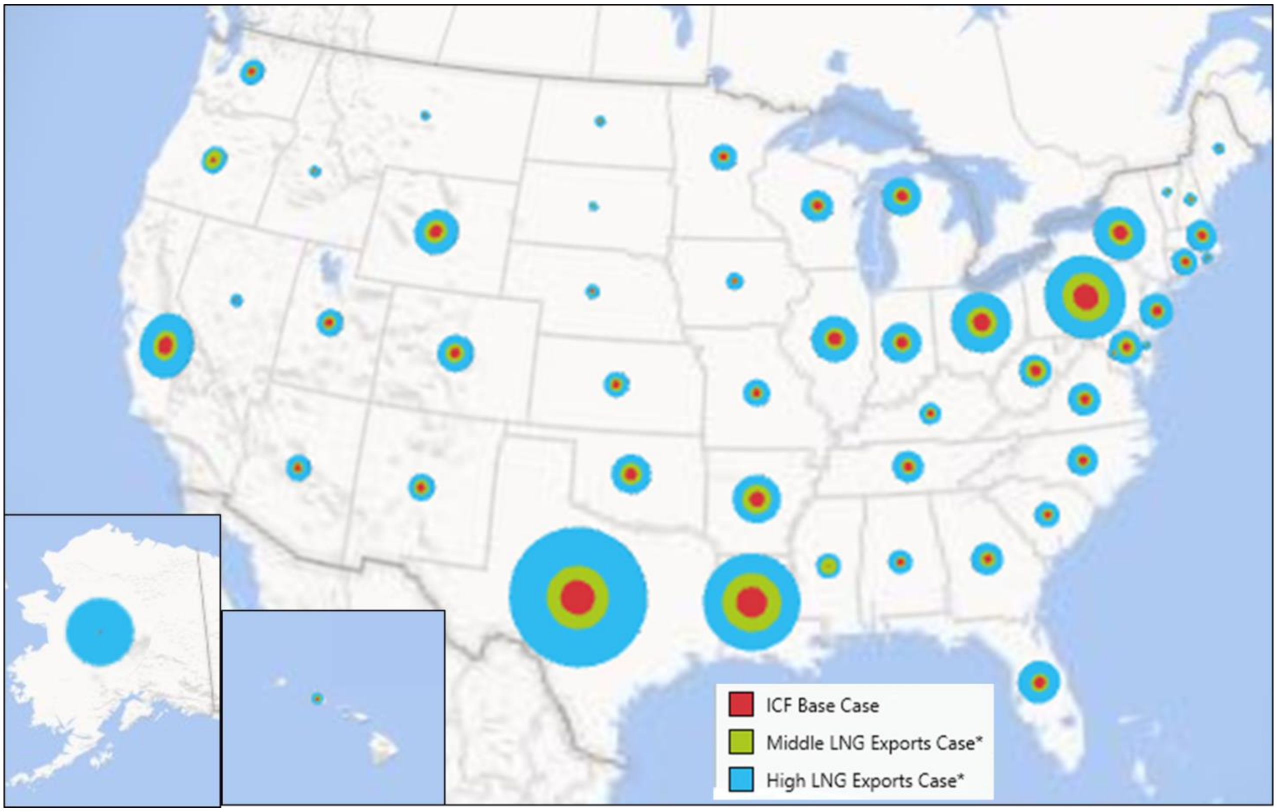


Source: ICF estimates

Note: Ranked by High LNG Exports Case.

* The Middle Case values are the average of four Terminal Location Cases (TLCs) and the High Case values are an average of five TLCs except that values for the seven LNG terminal states (AK, GA, LA, MD, MS, OR, TX) show impacts with at least one in-state LNG export terminal.

Exhibit 4-11: Map of 2035 Relative Employment Impacts from LNG Exports (By State Employment)



Source: ICF estimates

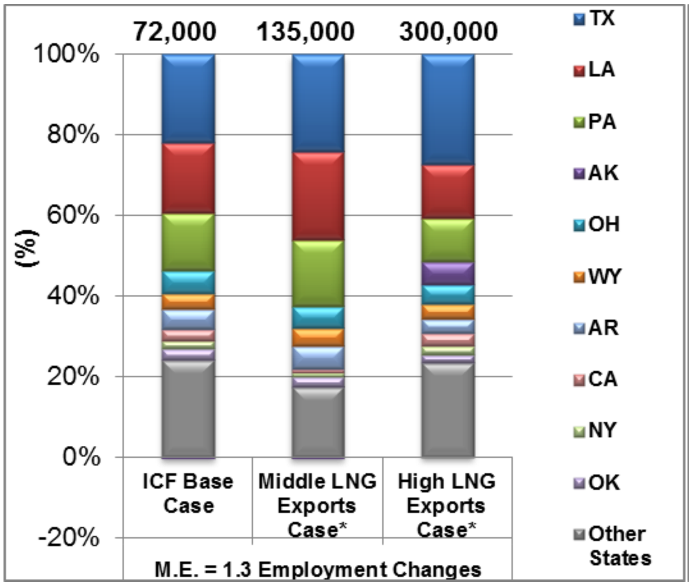
Note: Calculated using an economic multiplier of 1.9. The circle sizes represent the relative employment impact of each state for each LNG export case.

* The Middle Case values are the average of four Terminal Location Cases (TLCs) and the High Case values are an average of five TLCs except that values for the seven LNG terminal states (AK, GA, LA, MD, MS, OR, TX) show impacts with at least one in-state LNG export terminal.

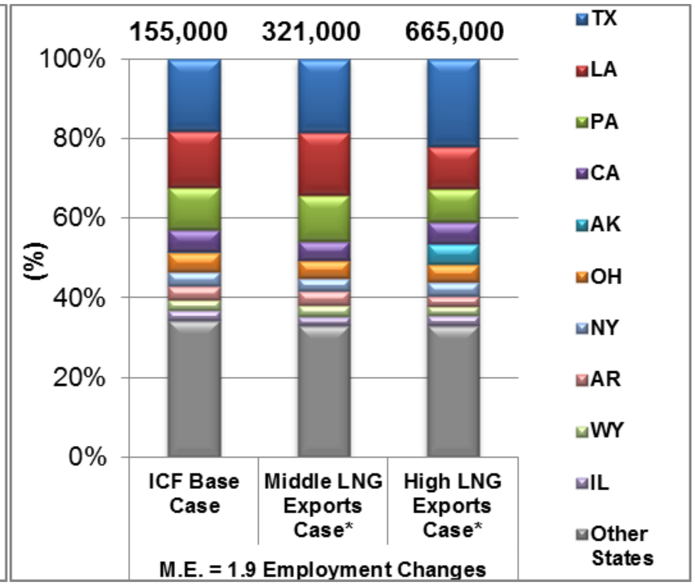
Exhibit 4-12 shows the distribution of total employment by the top 10 states and the other states. The top 10 states receive the bulk of total employment impacts, and include large-scale natural gas producers such as Texas, Louisiana, and Pennsylvania (due to the large direct and indirect impacts and the large portion of multiplier effect activity that remains in-state). States such as California and New York that do not directly participate significantly in LNG-related industries see small net job gains. This comes about because job losses (stemming from higher energy costs) are offset by job gains from a larger US economy. The job gains come from higher indirect purchases from the LNG-related industries, higher income of in-state stockholders of LNG-related industries, and consumer spending of out-of-state employees of oil, gas, and related industries.

Exhibit 4-12: 2035 Total Employment Impacts Share of Top 10 States

Changes to State Employment (Multiplier Effect = 1.3)



Changes to State Employment (Multiplier Effect = 1.9)



Source: ICF estimates

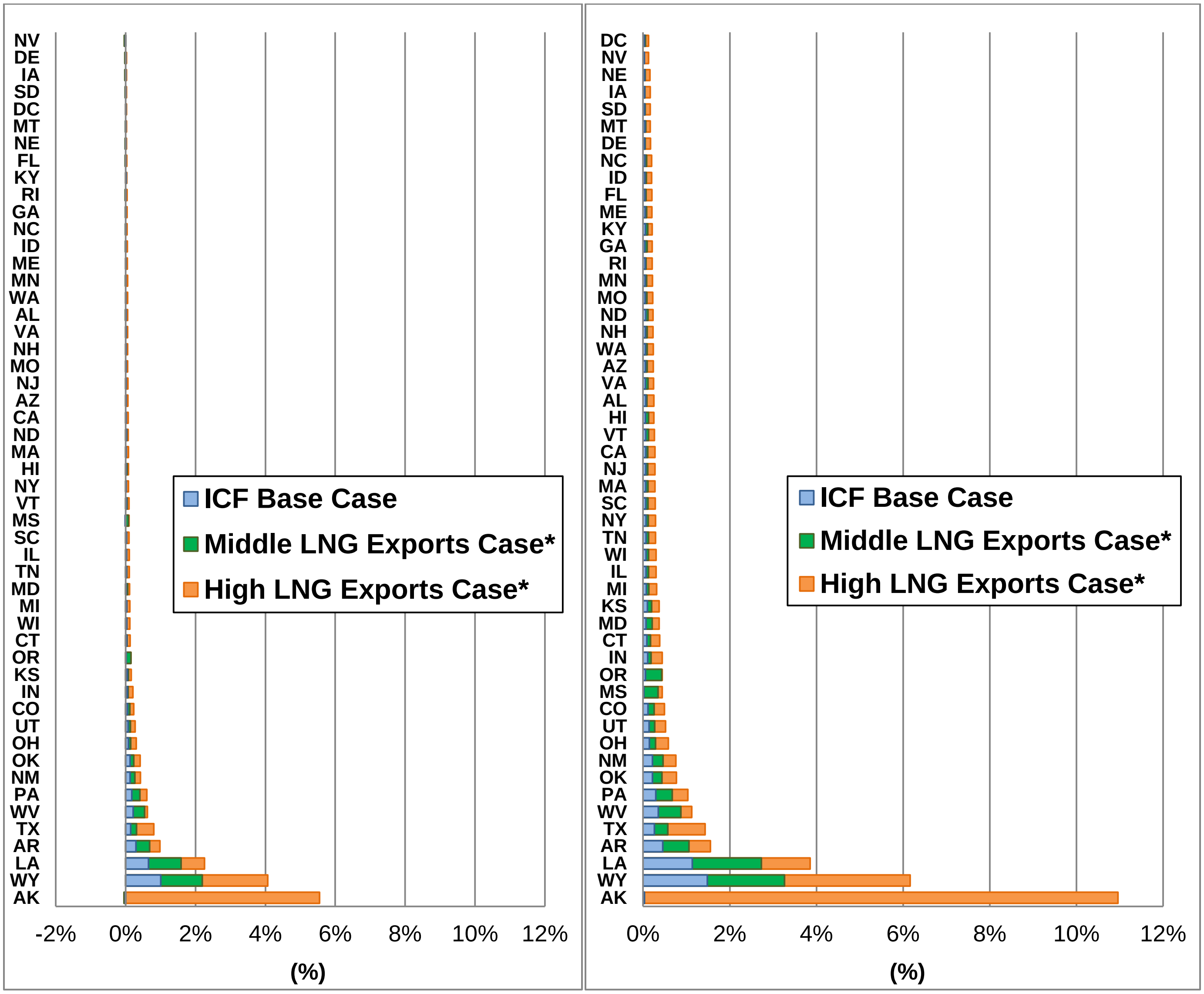
Note: Ranked by High LNG Exports Case.

* The Middle Case values are the average of four Terminal Location Cases (TLCs) and the High Case values are an average of five TLCs except that values for the seven LNG terminal states (AK, GA, LA, MD, MS, OR, TX) show impacts with at least one in-state LNG export terminal.

ICF used 2012 state employment levels to illustrate the relative employment impacts on states. Exhibit 4-13 shows 2035 total employment impacts by state as a proportion of 2012 state employment. Employment impacts for producing states such as Alaska, Wyoming, and Louisiana range from 2%-11% of 2012 state employment.

Exhibit 4-13: 2035 Employment Impacts as a Proportion of 2012 State Employment

Changes to State Employment Share (Multiplier Effect = 1.3) *Changes to State Employment Share (Multiplier Effect = 1.9)*



Source: ICF estimates

Note: Ranked by High LNG Exports Case.

* The Middle Case values are the average of four Terminal Location Cases (TLCs) and the High Case values are an average of five TLCs except that values for the seven LNG terminal states (AK, GA, LA, MD, MS, OR, TX) show impacts with at least one in-state LNG export terminal.

4.2.1 Manufacturing Employment Impacts on the U.S. Economy

LNG exports lead to increases in manufacturing-related jobs. In particular, manufacturing of natural gas production equipment such as metals, cement, and machinery drives manufacturing changes. However, consumer-oriented manufacturing sectors such as food and textile manufacturing see a decline (relative to no LNG exports), as higher natural gas costs cause consumers to allocate a higher share of spending toward natural gas and electricity consumption rather than miscellaneous consumer goods and services.

LNG exports affect U.S. manufacturing in three key areas:

1) Increased manufacturing in producing states and LNG export locations: Gas and other hydrocarbon production, as well as construction of LNG export facilities, will require in-state labor and a large number of supplies such as steel, cement, machinery.

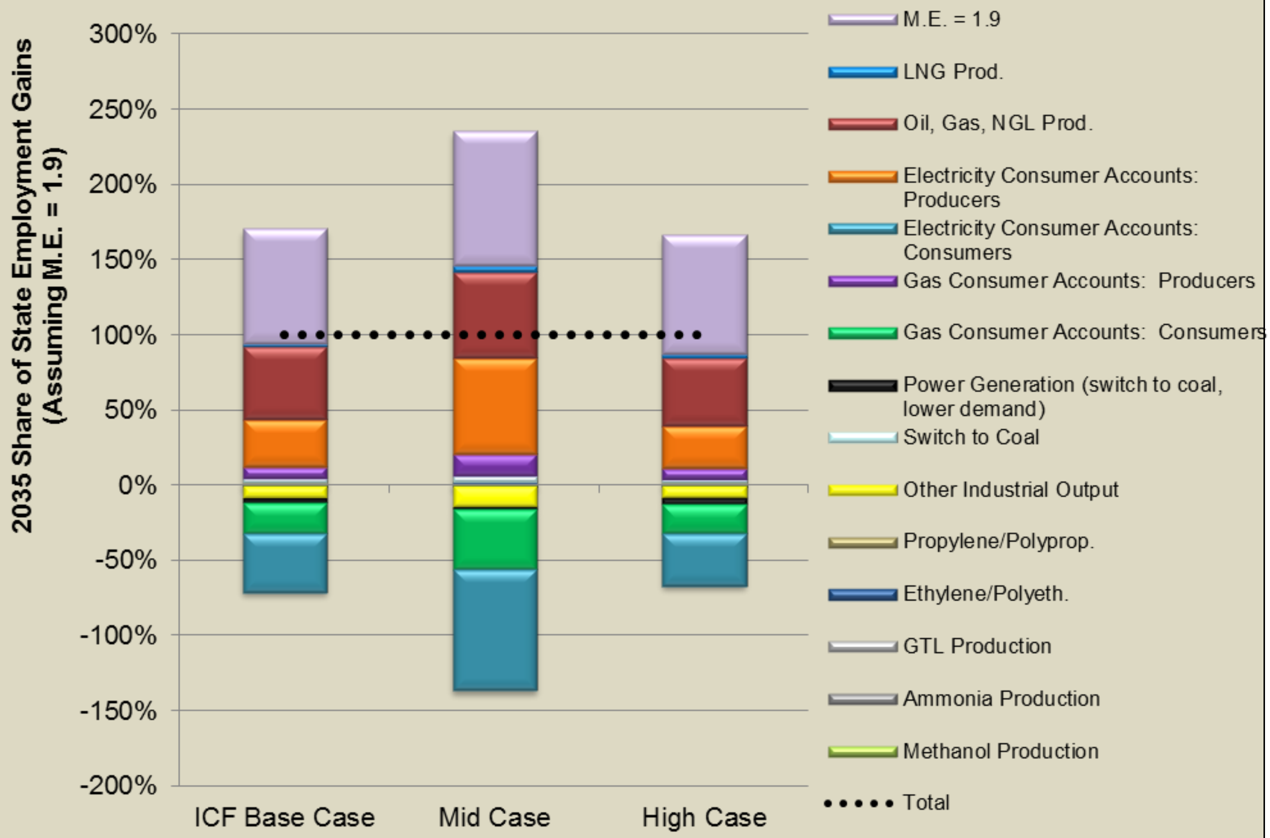
2) Increased activity in manufacturing-intensive states: The equipment needed for production and plant construction is typically produced out-of-state, and thus provides manufacturing employment in states without terminals. These states manufacture goods such as steel products (e.g., drill pipe, casing and structural steel), cement (for well and industrial plant construction), and various kinds of production equipment (pumps compressors, turbines, heat exchangers, pressure vessels, tanks, meters, control systems, etc.). In addition, as employees of LNG export terminals, gas production companies, and equipment manufacturers generate additional consumer spending, demand for consumer-related manufacturing (such as cars and electronics) will further stimulate U.S. manufacturing in these states.

3) Reduced industrial production attributable to higher gas/electricity input costs: Consumer-oriented manufacturing sectors such as food and textile manufacturing, as well as energy-intensive industries such as some petrochemical processing see production input costs rise (i.e., fuel and feedstocks), as higher natural gas costs cause consumers to allocate a higher share of spending toward natural gas and electricity consumption, rather than miscellaneous consumer goods and services.

The manufacturing industry sees net employment gains from LNG exports because the positive impact of increases in the demand for manufacturing output outweighs the adverse impacts of slightly higher natural gas and electricity costs for manufacturers. In particular, manufacturing to supply materials and equipment necessary for natural gas production, processing and transport, liquefaction plant construction and maintenance, and olefin plant construction and maintenance drives manufacturing job growth. While producing states capture a large share of the employment growth from LNG exports, manufacturing states, such as Ohio and Indiana also benefit from LNG exports, as well.

Manufacturing State Profile: Indiana

Employment changes attributable to LNG exports in Indiana range from 1,500-12,800 annual jobs by 2035 in sectors such as oil and gas production and sees net positive economic impacts ranging from $300 million to $2.2 billion annually by 2035.

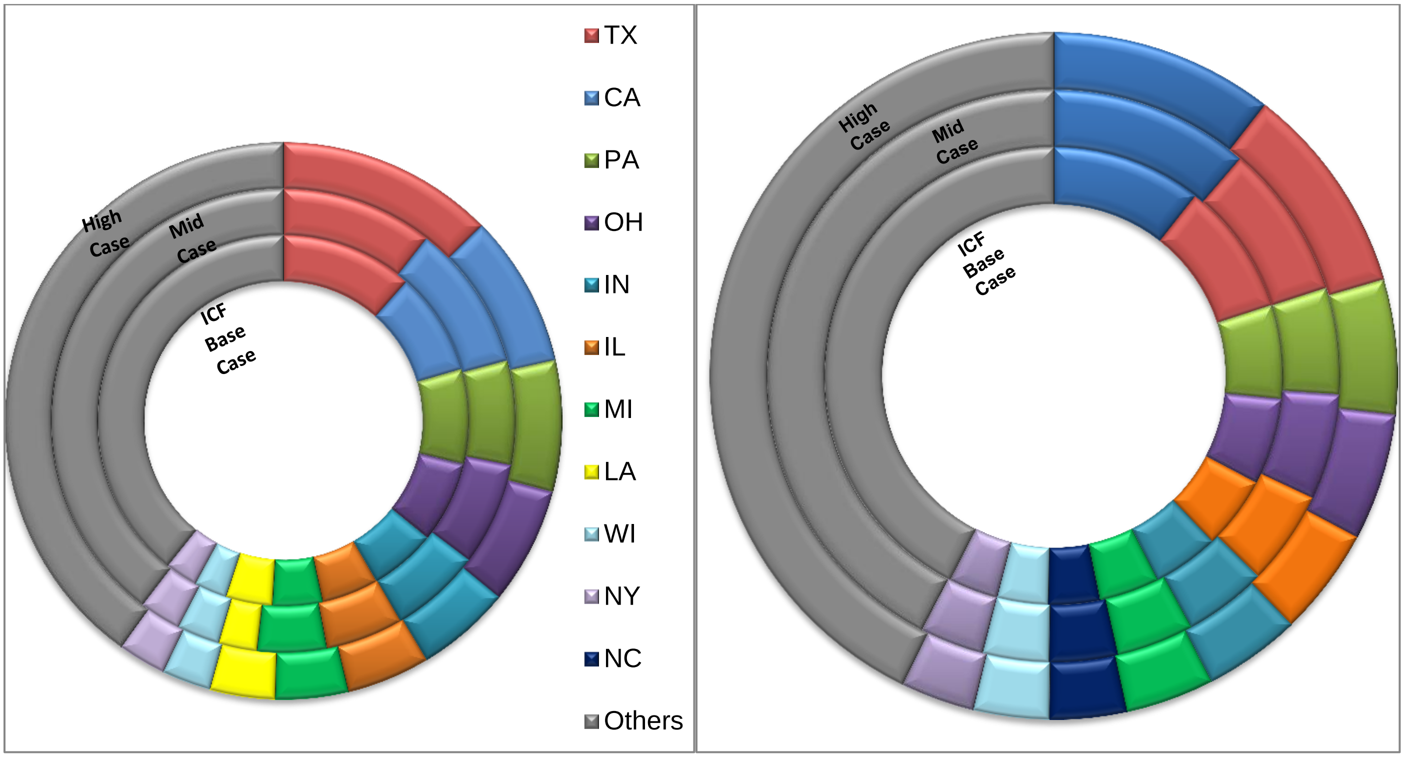


States with large manufacturing bases also benefit considerably. For example, California sees significant gains in manufacturing employment resulting from LNG exports. While manufacturing employment makes up just 8% of state's total employment, compared with manufacturing-intensive states such as Indiana, Wisconsin, Michigan, and Ohio (where manufacturing makes up 12%-17% of total state employment), California has a significant manufacturing presence. California comprises roughly 12% of total U.S. manufacturing, with manufacturing employment increasing up to 40,000 jobs in 2035 due to LNG exports.[29] Exhibit 4-14 shows the states with the largest manufacturing employment changes. This includes natural gas producers such as Texas and Pennsylvania, large economies (with large manufacturing employment sectors) such as California, and manufacturing-intensive states such as Ohio, Indiana, Illinois, and Michigan.

[29] U.S. Bureau of Labor Statistics (BLS). "Quarterly Census of Employment and Wages." BLS: Washington, DC. Available at: ftp://ftp.bls.gov/pub/special.requests/cew/2012/state/

Exhibit 4-14: 2035 Largest Manufacturing Employment Impacts from LNG Exports (relative to Zero Exports Case)

Changes to Manufacturing Employment (Multiplier Effect = 1.3) *Changes to Manufacturing Employment (Multiplier Effect = 1.9)*



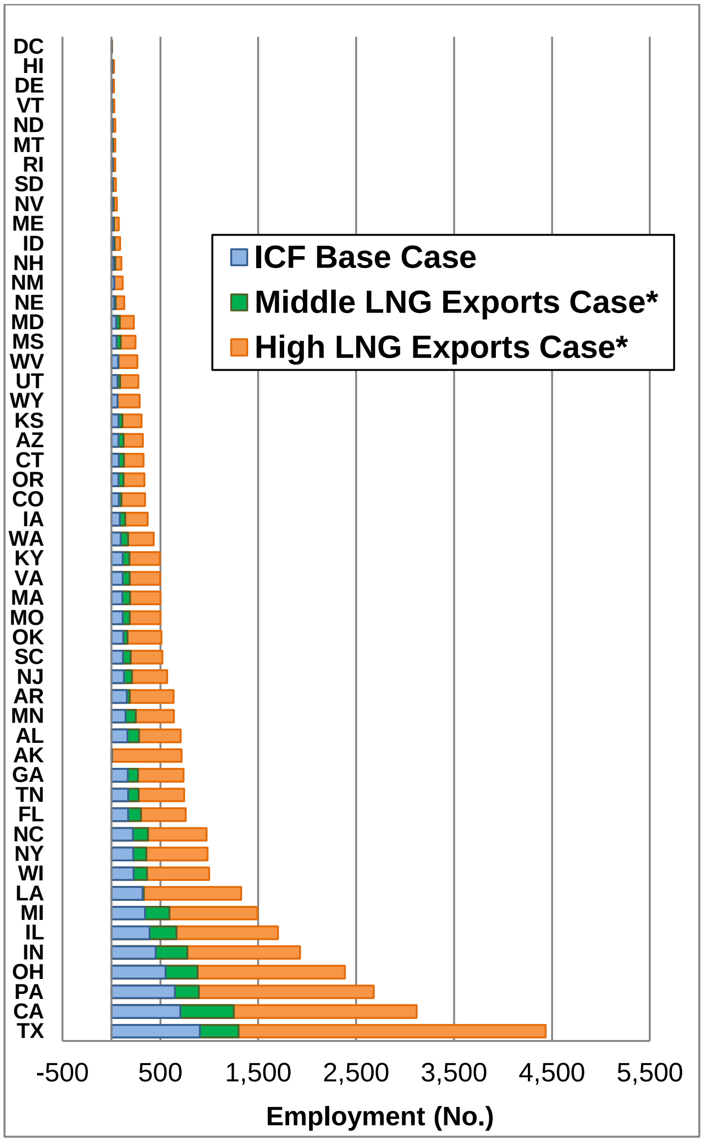
Source: ICF estimates

Note: The Middle Case values are the average of four Terminal Location Cases (TLCs) and the High Case values are an average of five TLCs except that values for the seven LNG terminal states (AK, GA, LA, MD, MS, OR, TX) show impacts with at least one in-state

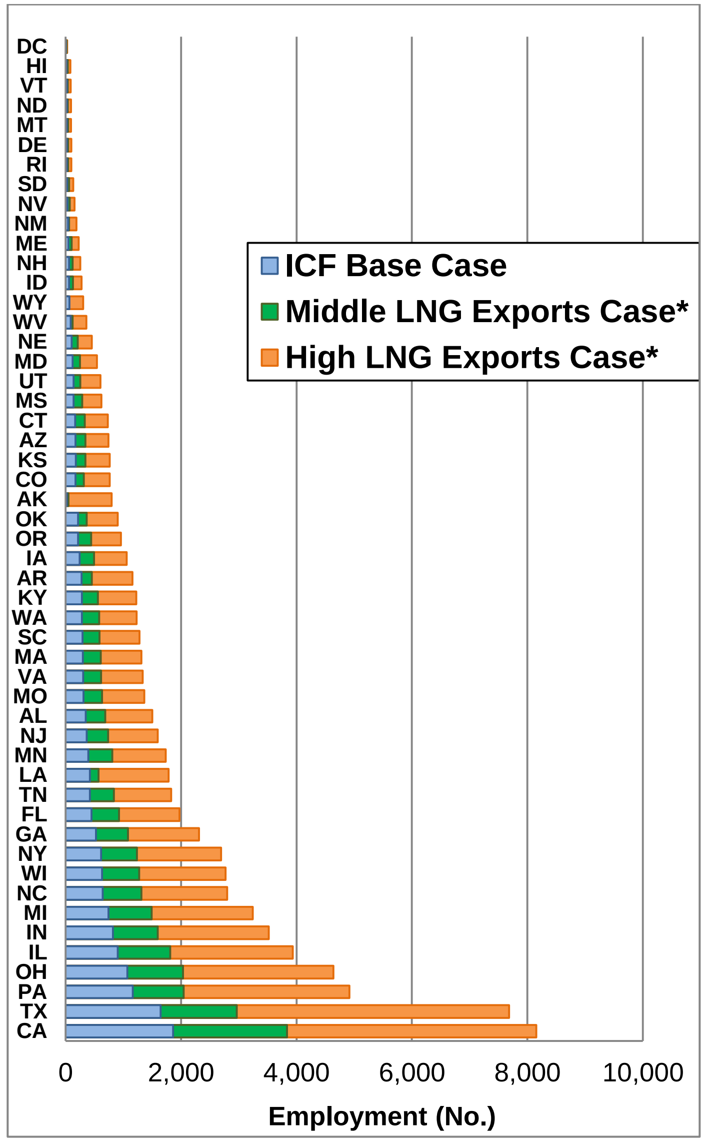
Exhibit 4-15 highlights the potential impact of consumer spending-driven manufacturing, as California makes up the largest share of manufacturing jobs. This means that despite having little in-state gas production impact or LNG export terminals, the state still sees significant manufacturing job gains.

Exhibit 4-15: 2035 Total Manufacturing Employment Impacts from LNG Exports (relative to Zero Exports Case)

Changes to Manufacturing Employment (Multiplier Effect = 1.3)



Changes to Manufacturing Employment (Multiplier Effect = 1.9)



Source: ICF estimates

Note: Ranked by High LNG Exports Case.

* The Middle Case values are the average of four Terminal Location Cases (TLCs) and the High Case values are an average of five TLCs except that values for the seven LNG terminal states (AK, GA, LA, MD, MS, OR, TX) show impacts with at least one in-state LNG export terminal.

5 Key Conclusions

This study concludes that LNG exports have a net positive, or negligible, impact across all states. In general, the largest impacts are found in states with gas, oil, and NGL production, LNG production, ethylene manufacturing and industries that supply the oil and gas and petrochemical industries. However, consumer spending activity generated by these gas- and petrochemical-related activities contributes significant inter-state activity, providing economic and employment gains to states with little to no gas- or petrochemical-related activity.

Economic Impacts

Of the total U.S. GDP changes attributable to LNG exports, ranging from \$18-\$115 billion annually by 2035, all states see positive, or negligible in a few cases, net income changes. State income impacts for producing states such as Texas, Louisiana and Pennsylvania in 2035 range from 5%-10% of 2010 state income, estimated at up to \$10-\$31 billion that year.

Texas, Louisiana, and Alaska benefit from significant oil and gas production, as well as in-state LNG export terminals (only in the High LNG Export Case for Alaska). Non-natural-gas-producing states with a large manufacturing base, such as California, see state income gains up to \$5.0 billion in 2035.

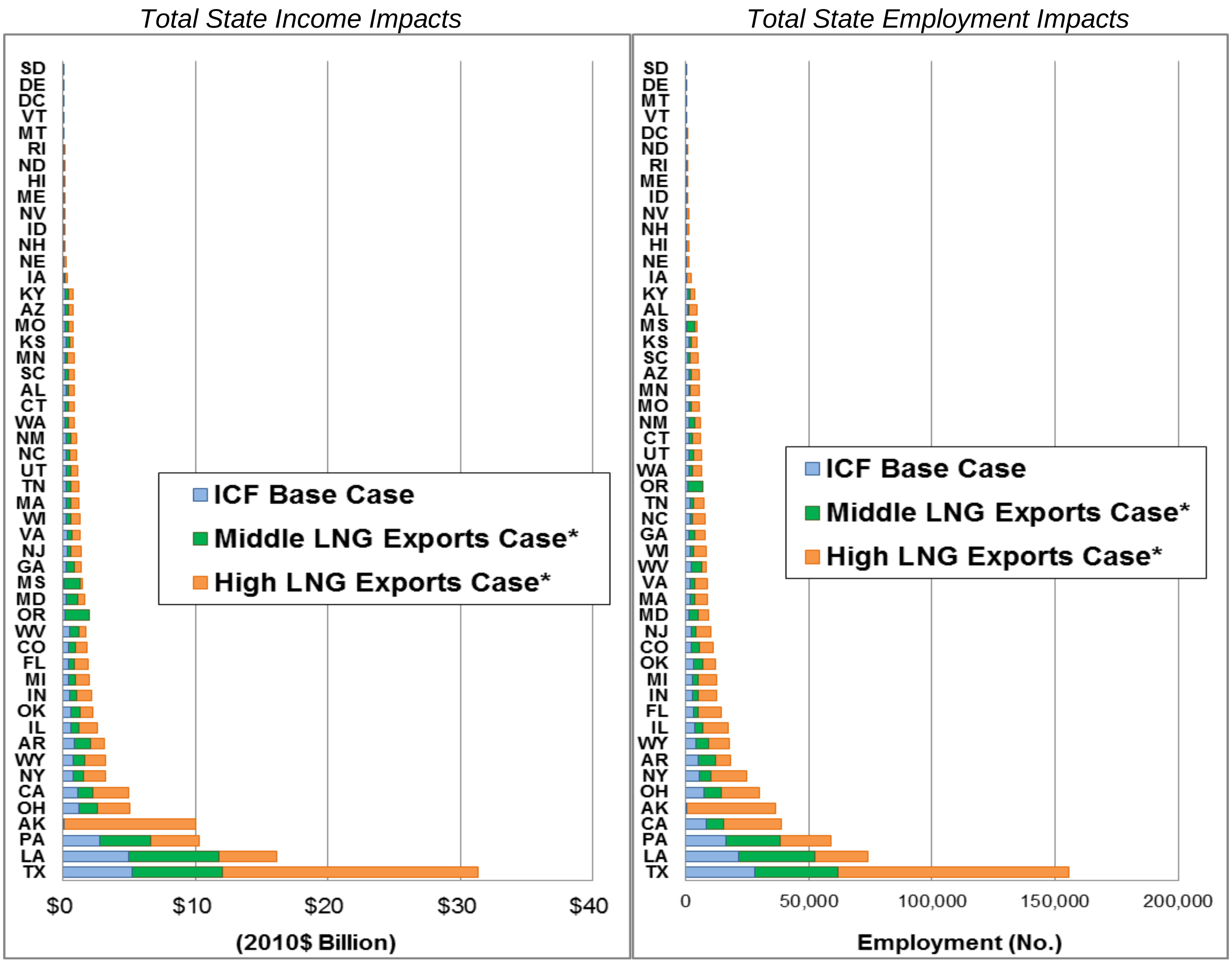
Employment Impacts

Of the 72,000-665,000 national net job gains from LNG exports by 2035, all states see net positive employment impacts from LNG exports.[30] The largest job gains are in states with natural gas production, liquefaction plants and petrochemical industries. Natural gas-consuming states, such as Massachusetts, benefit from significant multiplier-induced economic activity, due to the inter-state consumer spending. Employment impacts for producing states such as Alaska, Wyoming, and Louisiana range from 2%-11% of 2012 state employment.

States such as California and New York that do not directly participate in LNG-related industries see positive, albeit small, net job gains. This comes about because job gains from a larger U.S. economy are more than enough to offset any job losses associated with higher energy costs. Exhibit 5-1 shows 2035 state income and employment changes attributable to LNG exports.

[30] Calculated assuming an economic multiplier of 1.9.

Exhibit 5-1: 2035 Total Impacts from LNG Exports (relative to Zero Exports Case)



Source: ICF estimates

Note: Calculated using an economic multiplier of 1.9. Ranked by High LNG Exports Case.

* The Middle Case values are the average of four Terminal Location Cases (TLCs) and the High Case values are an average of five TLCs except that values for the seven LNG terminal states (AK, GA, LA, MD, MS, OR, TX) show impacts with at least one in-state LNG export terminal.

Manufacturing Impacts

The manufacturing industry sees net employment gains from LNG exports. In particular, manufacturing to supply materials and equipment for natural gas production processing and transport, liquefaction plant construction and maintenance, and olefin plant construction and maintenance drives manufacturing job growth. While producing states capture a large share of the employment growth from LNG exports, manufacturing states, such as California, could see up to 8,200 manufacturing jobs in 2035.

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Natural gas fugitive emissions rates constrained by global atmospheric methane and ethane

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Abstract

The amount of methane emissions released by the natural gas (NG) industry is a critical and uncertain value for various industry and policy decisions, such as for determining the climate implications of using NG over coal. Previous studies have estimated fugitive emissions rates (FER)

– the fraction of produced NG (mainly methane and ethane) escaped to the atmosphere – between 1-9%. Most of these studies rely on few and outdated measurements, and some may represent only temporal/regional NG industry snapshots. This study estimates NG industry representative FER using global atmospheric methane and ethane measurements over three decades, and literature ranges of (i) tracer gas atmospheric lifetimes, (ii) non-NG source estimates, and (iii) fossil fuel fugitive gas hydrocarbon compositions. The modeling suggests an upper bound global average FER of 5% during 2006–2011, and a most likely FER of 2-4% since 2000, trending downward. These results do not account for highly uncertain natural hydrocarbon seepage, which could lower the FER. Further emissions reductions by the NG industry may be needed to ensure climate benefits over coal during the next few decades.

Introduction

The effectiveness of mitigating climate change using natural gas (NG) as a bridge to a renewable energy-dominated economy has been challenged by some[1,2], suggesting that methane (CH_4) emissions from NG systems could outweigh reduced CO_2 emissions compared to coal use. Other studies[3–6] indicate that U.S. emissions inventories underestimate CH_4 emissions from the oil and gas industry. The increased tapping of shale formations and other unconventional NG sources – increasing production in North America and exploration activities worldwide using new technologies – adds urgency to the problem.

The U.S. Environmental Protection Agency recently amended air regulations for the oil and gas industry including targets for capturing NG that currently escapes to the atmosphere[7]. Accurately determining CH_4 emissions that are representative of the NG industry is key for this and future policies, but it is also challenging due to the size and complexity of the NG industry[8,9]. CH_4 is released to the atmosphere, intentionally (e.g., venting) and unintentionally (leaks), throughout the NG life cycle, which includes extraction, processing, transport, and distribution. The magnitude of life cycle CH_4 emissions is sometimes reported as the NG fugitive emissions rate (FER), defined here as the percentage of dry production – mainly CH_4 – that is lost throughout its life cycle.

Most literature FER estimates were generated using bottom-up approaches, i.e., aggregating measurements and engineering estimates at different life cycle stages. Previous bottom-up studies by these[10,11] and other authors[1,8,9] showed that outdated and small sample size measurement data largely contribute to FER uncertainty. Local air sampling studies near NG production facilities complement the bottom-up studies[3,4], but they only represent a regional and temporal snapshot of the larger industry. High FER of 6-9% were reported recently using both approaches[1,4].

This work estimates global average FER with a top-down approach that uses long-term (1984-2011) global atmospheric CH_4 and ethane (C_2H_6) measurements to evaluate the representativeness of previous bottom-up results. These tracer gas species are the main hydrocarbon components of NG[12]. Unlike CH_4, C_2H_6 is not thought to have microbial sources[13,14], so its atmospheric abundance can be a useful constraint on FER. A third tracer – the carbon isotope $\delta^{13}C\text{-}CH_4$ – was employed, which provides a stronger constraint for FER than CH_4 alone. $\delta^{13}C\text{-}CH_4$ observations[15] were used to exploit the fact that the isotopic values of observed atmospheric CH_4 are the result of the magnitudes and the distinct isotopic signatures of the various CH_4 sources. For instance, CH_4 emissions from fossil fuel (FF) sources are significantly less depleted in $\delta^{13}C\text{-}CH_4$ compared to microbial sources, such as wetlands[16]. Previous top-down studies have estimated global or national FF CH_4 and C_2H_6 emissions[5,13,17] using complex 3D models of the atmosphere based on (i) *a priori* knowledge of the approximate locations of different emissions, and (ii) spatially distributed atmospheric measurements. However, using observations to distinguish emissions from NG, oil, and coal is difficult due to close relative proximity of these sources[6]. Quantifying the NG source is necessary to estimate FER. A detailed global bottom-up oil and coal CH_4 and C_2H_6 emissions inventory[18] was developed for this study to isolate NG emissions from those associated with oil and coal.

Methods

Global NG CH_4 and C_2H_6 emissions and uncertainties were estimated annually over the period 1985-2011 using a top-down mass balance as the difference between total emissions and other anthropogenic and natural sources. The mass balance model treats the global atmosphere as a single box, which conserves the global mass of the emissions sources and sinks (and resulting atmospheric mixing ratios), eliminating the need for complex global transport of emissions. Total annual emissions ranges were based on (i) CH_4 and C_2H_6 atmospheric measurement data from NOAA's[19] and UC-Irvine's[13] global observation networks (see SI section 1 for global average annual mixing ratios), respectively, (ii) literature atmospheric $\delta^{13}C$-CH_4 data[15], and (iii) literature ranges of global average atmospheric CH_4 and C_2H_6 lifetimes (both largely dependent on reaction with OH)[20–24] summarized in the following subsection. The magnitudes of the uncertain anthropogenic and natural CH_4 and C_2H_6 sources were derived using a wide range of literature estimates (SI section 2) and the above-mentioned oil and coal inventory[18]. Given the resulting annual NG CH_4 and C_2H_6 top-down estimates, FER was estimated using global NG production statistics in combination with thousands of NG composition samples specifying NG CH_4 and C_2H_6 contents worldwide.

Inter-annual variability in the OH abundance and the non-FF source strength affects FER estimates in a given year. For instance, declining OH or non-FF emissions would increase FER. This study is primarily interested in the long-term FER trajectory. We therefore only accounted for inter-annual variations in the above model parameters where the literature indicates a long-term trend (such as in CH_4 and C_2H_6 mixing ratios shown in SI section 1). Given the lack of evidence for long-term trends in the global OH abundance[25] and non-FF emissions[13,17] (for details see SI sections 1 and 2, respectively), inter-annual variation in non-FF emissions sources was neglected.

Using a relatively simple model, a range of scenarios was explored in order to evaluate what may be learned from the atmospheric observations, including the maximum possible global average FER. Finally, mass balance FER estimates were substantiated using the existing 3D global chemistry transport model TM5[26] implemented in the CarbonTracker-CH_4 (CT-CH_4) assimilation system[27]. This was achieved by simulating transport of emissions throughout the global atmosphere for selected FER scenarios. The resulting CH_4 mixing ratios were then compared with observations from the global networks[13,19], thereby adding spatial information not available using the mass balance model.

Global mass balance (box-model)

The global annual mass balance for CH_4 and C_2H_6 in year *t* was formulated as:

$$z_{CH4,t} = z_{CH4,t,AgW} + z_{CH4,t,Nat} + z_{CH4,t,BBM} + z_{CH4,t,Oil} + z_{CH4,t,NG} + z_{CH4,t,Coal/Ind} \quad \textbf{Eq. 1,}$$

$$z_{C2H6,t} = z_{C2H6,t,BBE} + z_{C2H6,t,BFC} + z_{C2H6,t,Oil} + z_{C2H6,t,NG} + z_{C2H6,t,Coal} \quad \textbf{Eq. 2,}$$

where $z_{CH4,t}$ and $z_{C2H6,t}$ are the total annual global CH_4 and C_2H_6 emissions, respectively. The CH_4 emissions sources include agriculture/waste/landfills (*AgW*), natural sources (*Nat*), biomass burning methane (*BBM*), oil life cycle fugitive emissions (*Oil*; CH_4 and C_2H_6), NG life cycle fugitive emissions (*NG*; CH_4 and C_2H_6), and coal life cycle fugitive and "other energy and industry" emissions (*Coal/Ind*). The C_2H_6 emissions sources also include biomass burning ethane

(*BBE*; savanna and grassland fires, tropical and extratropical forest fires, agricultural residue burning), biomass fuel combustion (*BFC*), and coal life cycle C_2H_6 emissions (*Coal*; see below for "other energy and industry" C_2H_6 emissions). The literature-based CH_4 and C_2H_6 emissions ranges are summarized in the Methods subsections (non-FFs and FFs) below. The system boundaries for the CH_4 sources vary slightly among studies, but are largely consistent with those described for modeling with TM5 (SI Table S1). Mass balances were solved for $z_{CH4,t,NG}$ and $z_{C2H6,t,NG}$ independently using the ranges for all other source categories. The annual emissions $z_{CH4,t}$ were estimated using Eq. 4, which is the solution to differential Eq. 3, giving $z_{CH4,t}$. The annual emissions $z_{C2H6,t}$ were estimated using Eq. 5:

$$dC_{CH4}/dt = z_{CH4,t} - 1/\tau * C_{CH4,t} \quad \textbf{Eq. 3,}$$

$$z_{CH4,t} = \left(C_{CH4,t} - C_{CH4,t-1} * e^{-\frac{1}{\tau}}\right) * \left(\tau * \left(1 - e^{-\frac{1}{\tau}}\right)\right)^{-1} \quad \textbf{Eq. 4,}$$

$$z_{C2H6,t} = C_{C2H6,t} * SF_{C2H6} \quad \textbf{Eq. 5,}$$

where $C_{CH4,t}$ is the annually observed global average CH_4 dry air mole fraction (in ppb) in year t multiplied by the conversion factor 2.767 Tg CH_4/ppb[28] in order to convert mole fractions to mass units for the global atmosphere (see SI section 1 for details). For the global average atmospheric lifetime of CH_4, τ, a range of 9.1-9.7 years was chosen, which includes the mean values from four recent studies[20–23]. The scaling factor SF_{C2H6} converts the annually observed global average C_2H_6 dry air mole fraction $C_{C2H6,t}$ into the annual emissions burden $z_{C2H6,t}$, which is based on 3D-modeling[24] and has been applied recently elsewhere[13]. Given uncertainties of up to 45% due to the reaction rate with and mixing ratios of OH[24], the average and upper bound values of SF_{C2H6} (corresponding to a higher global budget for estimating upper bound FER), 0.018 and 0.026 Tg C_2H_6/ppt, respectively, were used.

The global mass balance using atmospheric $\delta^{13}C$-CH_4 measurements constrains FER based on the fact that the various CH_4 sources carry distinct isotopic CH_4 signatures. The ^{13}C:^{12}C ratio of CH_4, δ (in ‰), can be expressed as[29]:

$$\delta = \left(R_{Sample}/R_{Standard} - 1\right) * 1000 \quad \textbf{Eq. 6,}$$

where $R = (Rare\ isotope\ /\ Abundant\ isotope)$. The global mass balance for three CH_4 source categories can be formulated for each year as[16]:

$$z_{CH4,t} = z_{Mic,t} + z_{FF,t} + z_{BBM,t} \quad \textbf{Eq. 7,}$$

$$\delta_q z_{CH4,t} = \delta_{Mic} * z_{Mic,t} + \delta_{FF} * z_{FF,t} + \delta_{BBM} * z_{BBM,t} \quad \textbf{Eq. 8,}$$

where $z_{Mic,t}$, $z_{FF,t}$, and $z_{BBM,t}$ refer to the microbial, FF, and BBM fraction of total annual CH_4 emissions, respectively, and $z_{Mic,t}$ includes all natural and agriculture/waste/landfills sources. The different CH_4 emissions sources are aggregated to only three emissions categories in order to avoid an under-constrained system of two linear equations (Eq. 7 and Eq. 8). The equation system is solved for $z_{Mic,t}$ and $z_{FF,t}$ as an optimization problem (Eq. 10 through Eq. 15), and $z_{BBM,t}$ is considered at least 25 Tg CH_4/yr (see literature review in SI section 2). The literature provides wide ranges of source- (and geography-) specific isotopic signatures. For instance, Finnish subarctic wetlands range between –65 ‰ and –69 ‰[30] compared to –51 ‰ and –53 ‰ from landfills[16]. West Siberian NG associated with oil production (high CH_4 content) has been measured around -50 ‰[30], whereas mature dry gas can range approximately -20 ‰[31]. The isotopic signatures δ_{Mic}, δ_{FF}, and δ_{BBM} in this model are based on weighted averages of each emissions category from 13 literature sources[16], and lie within the range of –59 to –63 ‰, –38 to –42 ‰, and –22 to –26

‰, respectively. The total annual CH_4 emissions burden $z_{CH4,t}$ is the same as in Eq. 4, and the flux weighted mean isotopic ratio of all CH_4 sources[29] is:

$$\delta_{q,t} = \alpha\delta_a + \varepsilon - \frac{\varepsilon(1+\delta_a/1000)}{z_{CH4,t}} * \frac{dC_{CH4,t}}{dt} + \frac{d\delta_a}{dt} * \frac{C_{CH4,t}}{z_{CH4,t}} \qquad \textbf{Eq. 9},$$

where $\alpha = (1 + \varepsilon / 1000)$ is the isotopic fractionation factor associated with photochemical CH_4 destruction, for which ε = -6.3 ‰[16]. As described in more detail in SI section 1, the global annual means of measured δ_a range between -47.0 ‰ and -47.3 ‰ throughout 1988–2011[15,32,33]. Given (i) the lack of pre–1988 data, (ii) the reliance on unpublished post-2006 data[32], (iii) and the low sensitivity of the above δ_a range on FER (see SI section 3.1), this model assumes a constant δ_a of -47.1 ‰. Eq. 7 and Eq. 8 were re-arranged to give:

$$z_{FF,t} = \frac{\delta_{q,t} * z_{CH4,t} - \delta_{Mic} * \left(z_{CH4,t} - z_{BBM,t}\right) - \delta_{BBM} * z_{BBM,t}}{\delta_{FF} - \delta_{Mic}} \qquad \textbf{Eq. 10,}$$

$$z_{Mic,t} = z_{CH4,t} - z_{FF,t} - z_{BBM,t} \qquad \textbf{Eq. 11},$$

where units for $z_{CH4,t}$ and δ are Tg CH_4/yr and ‰, respectively. The optimization problem is to minimize Eq. 10, such that:

$$z_{BBM,t} \geq 25 \qquad \textbf{Eq. 12,}$$

$$-59 \geq \delta_{Mic} \geq -63 \qquad \textbf{Eq. 13},$$

$$-38 \geq \delta_{FF} \geq -42 \qquad \textbf{Eq. 14},$$

$$-22 \geq \delta_{BBM} \geq -26 \qquad \textbf{Eq. 15}.$$

Eq. 12 ensures that there are only two unknowns in the problem of two linear equations. CH_4 emissions from NG $z_{C13CH4,t,NG}$ (based on isotope observations) are the difference between FF emissions from the isotope mass balance and coal/oil emissions, which are described in more detail below:

$$z_{C13CH4,t,NG} = z_{FF,t} - z_{CH4,t,Coal/Ind} - z_{CH4,t,Oil} \qquad \textbf{Eq. 16}.$$

Finally, FER is estimated using Eq. 17 through Eq. 19:

$$FER_{CH4,t} = z_{CH4,t,NG}/\left(P_{dry,t} * WF_{down,CH4,t}\right) \qquad \textbf{Eq. 17,}$$

$$FER_{C2H6,t} = z_{C2H6,t,NG}/\left(P_{dry,t} * WF_{down,C2H6,t}\right) \qquad \textbf{Eq. 18},$$

$$FER_{C13CH4,t} = z_{C13CH4,t,NG}/\left(P_{dry,t} * WF_{down,CH4,t}\right) \qquad \textbf{Eq. 19},$$

where $P_{dry,t}$ is the global dry production of NG[34] converted from volume to weight units (see our bottom-up inventory[18] for details), and $WF_{down,CH4,t}$ and $WF_{down,C2H6,t}$ are the downstream NG weight fractions of CH_4 and C_2H_6, respectively.

Global 3D model

Three-dimensional forward simulations of CH_4 emissions using the global chemistry transport model TM5[26] complement the box-model approach. Forward simulations in this work cover the period 1989-2011, and measurements are the same as used for the box-model. The following five different zones were distinguished in order to analyze the spatial differences ignored in the box-model: polar Northern Hemisphere (PNH, 53.1°N-90°N), temperate Northern Hemisphere (TNH, 17.5°N-53.1°N), the tropics (17.5°S-17.5°N), temperate Southern Hemisphere (TSH, 17.5°S-53.1°S), and polar Southern Hemisphere (PSH, 53.1°S-90°S). These zones are pre-defined in CT-

CH_4[27], and briefly discussed in SI section 3.2. Emissions were simulated for 11 individual CH_4 source/sink categories including NG, oil, coal/industry, wetlands, soils, oceans, termites, wild animals, agriculture/waste/landfills, and biomass burning methane (all as described above). Emissions were simulated for each source separately, which allows tracking the individual contributions of total CH_4 mixing ratios. Estimating source-specific contributions is key for analyzing the underlying causes of potential spatial differences between simulations and observations. These spatial differences mainly occur because the various sources emit in specific world regions, which helps to distinguish emissions sources using the measurements from the global monitoring networks.

Model values of non-fossil fuel emissions categories based on literature review

This section describes the range of non-NG CH_4 and C_2H_6 emissions values chosen as inputs in the box-model (Eq. 1, Eq. 2, Eq. 10, and Eq. 11) and the 3D-model. Non-FF CH_4 emissions ranges were selected based on five of the most recent inversion studies[27,35–38] and two literature reviews[39,40], which is described in more detail in the SI (section 2), and summarized in Table 1. In the box-model, most likely FER assumes total non-FF CH_4 sources of 400 Tg/yr (medium non-FF scenario), and upper bound FER is associated with non-FF CH_4 sources of 265 Tg/yr (low non-FF scenario). The corresponding medium and low scenario C_2H_6 estimates are 5.9 Tg/yr and 2.2 Tg/yr, respectively. High CH_4 and C_2H_6 scenarios were selected such that low and high values represent a normal distribution around the medium values. Three-dimensional forward simulations were carried out with TM5 for 8 individual non-FF CH_4 source/sink categories (totaling on average 385 Tg/yr). The global soil CH_4 sinks used in both models cover the range of literature values: 25 Tg/yr[36], 30 Tg/yr[35], and 38 Tg/yr[38]. The total non-FF emissions in the 3D simulation and in the medium box-model scenario are very similar (difference is ~3% of global CH_4 budget), which allows direct comparison of box-model results with the 3D-model (the same oil and coal estimates were used in both models).

Table 1: Summary of global non-FF emissions estimates used in 3D-forward-modeling (TM5) and ranges for box-modeling. Units are Tg/yr.

	CH_4					C_2H_6		
	Natural	**Ag/waste/ landfills**	**BBM**	**Soil sink [i]**	**Total**	**BBE**	**BFC**	**Total**
Box-model (const. over time [ii])								
low	130	130	25	-25	260	1.6	0.6	2.2
medium	182	200	43	-25	400	3.6	2.3	5.9
high	235	270	60	-25	540	5.2	4.0	9.2
3D-model (avg. 1980-2011)	215 [iii]	194 [iv]	16 [v]	-40	385	n/a	n/a	n/a

Notes: Ag – Agriculture; BBM - Biomass burning methane; BBE - Biomass burning ethane; BFC - Biomass fuel combustion; [i] Box-model data from[17], 3D-model data from[41]; [ii] Inter-annual variations during 1980-2011 were ignored due to lack of long-term trends in OH and non-FF sources, and focus on long-term FER trajectory (see also text above); [iii] Annual emissions and seasonal cycle from[42]; [iv] Annual emissions from[43], seasonal cycle from[44]; [v] Annual emissions from[45,46], seasonal cycle from[47].

Model values of fossil fuel emissions categories from bottom-up inventory

This section briefly summarizes the methods and data used to estimate CH_4 and C_2H_6 emissions from oil and coal production, processing and transport (in Eq. 1 and Eq. 2) as well as downstream NG composition (Eq. 17 through Eq. 19) applied in the box-model and the 3D-model. This summary is based on a global bottom-up FF inventory developed by these authors[18]. Here, only the general methodology and major parameters are reviewed. The inventory is based on country-level NG, oil, and coal production data[34], a range of literature emissions factors (EFs, see below for literature sources), and observational gas flaring data[48,49]. EFs describe the amount of hydrocarbon gas emitted to the atmosphere per unit of fuel produced, and EFs are the basis for comparing greenhouse gas (GHG) emissions among different fuels or technologies in life cycle assessment. The inventory also includes hydrocarbon composition data from thousands of samples including NG and oil wells, both of which produce NG and oil[12]. The hydrocarbon composition data is necessary for deriving FER from estimated total amounts of global NG CH_4 ($z_{CH4,t,NG}$) and C_2H_6 ($z_{C2H6,t,NG}$) emissions.

Emissions factors (EF) related to the oil life cycle were reviewed from four studies[50–53], which span an order of magnitude. The EFs include fugitive emissions from oil production, processing, and shipping as well as hydrocarbon emissions from incompletely flared gas. The EF selected from these studies[51] is 50% below the mean of the lowest[52,53] and highest[50] literature EF. This selection assures that the upper bound FER from the box-model is a conservative estimate, i.e., box-model FER could be lower if oil emissions were in fact higher. Emissions from marketed (i.e., not flared/vented or repressured) associated NG production at oil wells are counted towards FER. The detailed procedure for allocating emissions between oil and NG production is described in the bottom-up inventory[18]. Country-specific EFs related to the coal life cycle[50,54–56] distinguish different types of coal production. Comparison of different global coal production estimates (and Chinese coal production in particular) suggests that the total emissions estimate in the inventory may be an underestimate. Thus, analogously to the oil emissions estimates above, FER could be lower than box-model results if coal emissions were in fact higher.

Table 2 summarizes the results from the bottom-up inventory[18] including oil and coal CH_4 and C_2H_6 emissions over different time periods as well as global average downstream NG hydrocarbon composition (related to dry production statistics). Medium oil CH_4 emissions increase from 14 Tg/yr (mean during 1985-1999) to 17 Tg/yr (mean during 2006-2011), and medium coal/industry

CH_4 emissions increase from 48 Tg/yr to 61 Tg/yr over the same periods. Medium oil C_2H_6 emissions increase from 5.5 Tg/yr to 6.6 Tg/yr over the same periods, and coal/industry C_2H_6 emissions are relatively small given the low coal-bed gas C_2H_6 content[18]. Downstream NG CH_4 and C_2H_6 contents averaged throughout 1984-2011 range from 85-87 wt-% and 7.2-7.7 wt-%, respectively, while C_2H_6 content decreased from 7.8–6.8 wt-% over this period due to increased C_2H_6 extraction for NG liquids[18].

Table 2: Summary of oil and coal/industry CH_4 and C_2H_6 emissions, and downstream NG composition in the bottom-up inventory[18].

		Units	CH_4			C_2H_6 [i]		
			1985-1999	2000-2005	2006-2011	1985-1999	2000-2005	2006-2011
Emissions								
Oil	low	Tg/yr	5	6	6	4.4	5.0	5.2
	medium		14	16	17	5.5	6.3	6.6
	high		41	48	51	7.6	8.8	9.2
Coal/Industry	low		43	44	55	0.0	0.0	0.0
	medium		48	49	61	0.3	0.3	0.4
	high		56	57	71	0.6	0.6	0.8
Composition								
Downstream NG [ii]	low	wt-%		85		7.2		
	medium			86		7.4		
	high			87		7.7		

Notes: [i] Ranges of oil and coal/industry C_2H_6 emissions are due to uncertainties in C_2H_6 content of fugitive hydrocarbon emissions. [ii] Downstream NG composition was estimated for use with dry production statistics (shows averages over 1985-2011) to estimate life cycle FER (as described above). Results are based on a mass balance of upstream NG, downstream NG, and natural gas liquids at the processing stage (see box-model Methods). Low and high values represent 95%-C.I.

Industry (public power and heat, other energy industries, transportation, residential and other sectors, industrial processes, FF fires) emissions were adopted from EDGAR v4.2[43]. C_2H_6 emissions estimates from this source were unavailable, and were not accounted for in the box-model. FER could in fact be lower than box-model results if industry is a significant C_2H_6 source.

Three different FER scenarios (ranging from 2-6% FER; see SI for details) were simulated in TM5 to analyze which FER is most consistent with spatially distributed observations.

Spatial distribution of CH_4 emissions

Spatial CH_4 emissions grid maps were developed in order to perform 3D simulations of the global atmosphere in TM5. A detailed description of the grid map development as well as the results is provided in the bottom-up inventory[18], and briefly summarized here. The spatial distribution of FF emissions *within* each country was adopted from EDGAR v4.2[43], which is based on population density and other proxies. The absolute FF emissions in the grid maps were scaled based on the FF estimates summarized in the previous subsection. Due to the emissions differences between this work and EDGAR for a given country, the spatial distribution of the scaled grid maps differs from EDGAR on a global scale, but not within individual countries. In contrast to FF, other source categories have a distinct seasonal emissions cycle. EDGAR's agriculture/waste/landfills category annual emissions grid maps were decomposed into monthly grid maps, and scaled to a seasonal cycle as defined in SI Table S1. Agriculture/waste/landfills annual totals were linearly extrapolated from 2008 (last year in EDGAR) to 2011 using the last 10 years available in EDGAR. Literature spatial CH_4 emissions distribution was adapted for natural[57,58] and BBM[47] categories.

Results

Global average FER from the NG life cycle was estimated in a top-down approach to better understand industry representative CH_4 emissions. This study is based on global spatially distributed CH_4, $\delta^{13}C$-CH_4, and C_2H_6 measurements over three decades. A global box-model was developed and an existing 3D emissions transport model was used to attribute total emissions to different sources, thereby taking into account uncertainties in atmospheric lifetimes of measured species as well as non-NG source estimates.

Global box-model

The most likely global FER of 2-4% on average during 2004-2011 (Figure 1) is consistent for CH_4, $\delta^{13}C\text{-}CH_4$, and C_2H_6 observations. These estimates assume (i) mean literature emissions values for each of the other source categories listed above, and (ii) global total oil and coal CH_4 emissions from this study's emissions inventory (medium values in Table 2), which agree well (2.5% difference) with EDGAR[43], i.e., the commonly used *a priori* FF database in global top-down CH_4 modeling. The upper bound global FER averaged over the last five years of observations is 5.0% (4.4% in 2011) based on C_2H_6 observations (Figure 1). The upper bound assumes (i) a C_2H_6 lifetime corresponding to the largest global average sink in the literature, (ii) a lower bound FF C_2H_6 content (Table 2), and (iii) a lower bound BBE/BFC C_2H_6 source estimate (Table 1). Details of the budgetary implications of the upper bound FER relative to the literature are illustrated in SI Figure S8. Results indicate upper bound FER of ~6% in the early 2000s, mainly due to lower FF production compared to later years. Note that FER peaks shown for some years in Figure 1 are likely due to inter-annual variation in natural sources[13]. Our upper bound throughout 1985-1999 is on average 9.3% (SI Figure S7). This temporal decline in FER is consistent with earlier work suggesting a decrease in FF C_2H_6 emissions[13,14]. Emissions reductions per unit of production (FER) in this work imply industry efficiency improvements, although the decline would be less steep if coal and oil EFs also declined over time (increased oil and coal production over time are accounted for). Global average CH_4 and $\delta^{13}C\text{-}CH_4$ data provide weaker constraints for upper bound FER, mainly due to literature source estimate uncertainties. Assuming lower bound estimates for natural, agriculture/waste/landfills, and BBM sources *simultaneously* would lead to FER of 8% or higher averaged during 2004-2011 (SI Figure S5). Yet, Figure 1 shows that such high FER is inconsistent with the C_2H_6 data.

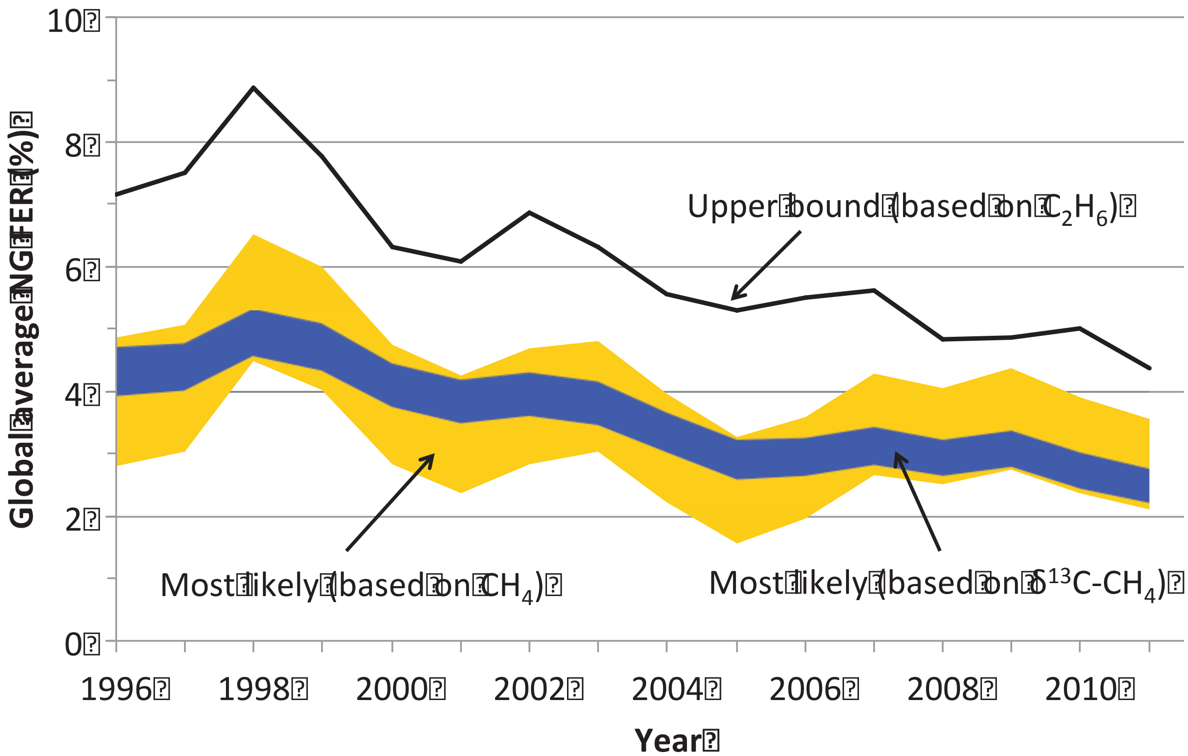

Figure 1: Summary of possible global NG fugitive emissions rates (FER) – in % of dry production – based on a global mass balance using different tracer gases. The upper bound represents a combination of assumptions from the literature including high global emissions (totaling 16.2 Tg C_2H_6/yr on average since 2000 using UC-Irvine observations[13] and Rudolph[24] C_2H_6 lifetime uncertainty) and low magnitude of other C_2H_6 sources (7.4 Tg C_2H_6/yr on average since 2000). The orange and blue bands mark the range for CH_4 lifetimes between 9.1-9.7 years and mean literature values of other CH_4 sources (totaling 467 Tg CH_4/yr on average since 2000 including soil sink) using NOAA observations[19]. FER is shown for the longest consecutive observation time series available (pre-1996 data are shown in SI Figures S5, S7).

Natural hydrocarbon seepage may be an additional significant source of atmospheric CH_4 and C_2H_6 not currently accounted for in most top-down studies[17]. Visible macro-seeps, marine seepage, micro-seepage, and geothermal/volcanic areas may contribute between 40-60 Tg CH_4/yr and 2-4 Tg C_2H_6/yr globally[59]. While not included in Figure 1, adding 40 Tg CH_4/yr and 2 Tg C_2H_6/yr in the model would reduce FER by about two percentage points (constant over time). The magnitude of the above seepage estimates have been challenged[13]. Yet, having excluded any seepage in our main results (Figure 1) emphasizes that our FER may be overestimated.

The decline in global FER is 0.1 and 0.3 percentage points per year since 1985 based on most likely (CH_4 and $\delta^{13}C$-CH_4 observations) and upper bound results (C_2H_6 observations), respectively. This assumes that the declines in measured C_2H_6 levels (or CH_4 growth rates[60]) are attributed to NG emissions reductions. Kirschke *et al.*[17] find little if any long-term natural, agriculture/waste/landfill, and BBM emissions reductions over this period. Kirschke *et al.*[17] results, along with the findings presented here, suggest that the declines in measured mixing ratios (or growth rates thereof) can be attributed to NG emissions reductions. This is also consistent with recent top-down C_2H_6 studies[13,14] suggesting reductions in total FF emissions where Aydin *et al*.[14] concluded that global declines in the C_2H_6 mixing ratios were due to decreased flaring and venting of NG (see also SI Figure S8). Also, recent direct CH_4 measurements at 190 NG production sites in the U.S. by Allen *et al*.[8] indicate lower overall CH_4 emissions from production (well pad) activities than previous measurement data used in EPA's 2013 GHG inventory[51]. Note that increased NG, oil, and coal production over time[61] was incorporated in the modeling presented here. The FER decline may be less pronounced if oil and coal emissions per unit of production also decreased since 1985. Atmospheric chemistry may also explain changes in CH_4 and C_2H_6 mixing ratios. However, Montzka *et al*.[62] recently found a small inter-annual atmospheric OH variability of 2.3 ± 1.5% during 1998–2007, which suggests that increased sink strength is an unlikely alternative explanation for declining FER.

Global 3D-model

Most-likely FER estimates from the mass balance are supported by the global chemistry transport model TM5[26] and the spatial distribution of CH_4 mixing ratios as an indicator of source strength[63]. Using three different FER scenarios ranging from about 2-6% FER (see SI Table S4 and Figure S9), the TM5 was used to simulate spatially distributed CH_4 sources and sinks from 1989-2011. As shown in Figure 2a, the medium FER scenario is a reasonable fit globally throughout the 1990s (3-4% FER) compared to 3% and 5% in the box-model (SI Figure S5) for CH_4 lifetimes (τ) of 9.7 and 9.1, respectively. In the 2000s, TM5 suggests a most likely FER of ~3% dropping to just over 2% in 2010 compared to 2-4% in the box-model depending on τ. Given that τ used in TM5 is approximately 9.45, most likely estimates of both models agree within one percentage point FER.

The following spatial analysis is useful for investigating whether the *a priori* emissions source attribution (Tables 1 and 2) is reasonable, or if – for instance – underestimated FER scenarios were compensated by overestimated other source categories. Simulations and measurements across 41 latitudinal bands (intervals of 0.05 sine of latitude) are shown in Figure 2b as an indicator of the inter-hemispheric gradient (for year 2000; see SI Figure S10 for additional years). The spatial fit of simulations and measurements can be used as a proxy for the attribution of sources. About 96% of NG CH_4 emissions in the emissions grid maps simulated with TM5 are released in the Northern Hemisphere. The equivalent CH_4 emissions values in the Northern Hemisphere for oil, coal, agriculture/waste/landfills, and natural sources are 91%, 88%, 82%, and 54%, respectively. The observed difference between the most Southern (90°S-72°S) and Northern (72°N-90°N) latitudinal band is 134 ppb (7.6% of the global average CH_4 mixing ratio) compared to 177 ppb (10.1%) in the simulation (medium FER scenario) averaged over 1990-2010, which is qualitatively consistent with previous studies[35,64]. This small North-South (N-S) gradient mismatch between observations and simulation suggests that the simulated CH_4 estimates for each source category could be plausible.

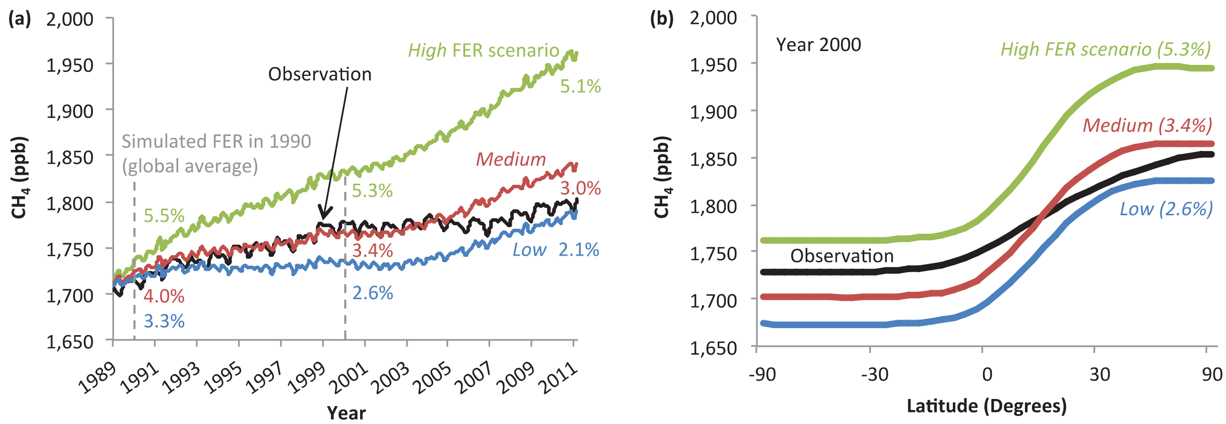

Figure 2: TM5 global average forward modeling results for three regionally and temporally distinct FER scenarios (see SI Table S4 and Figure S9) as well as NOAA's measurements[19]. (**a**) Global average dry air mole fractions; see[65,66] for estimating global averages from spatial distributions. (**b**) CH_4 dry air mole fractions across 41 latitudinal bands in year 2000 (see SI Figure S10 for additional years).

The inter-hemispheric gradient indicates that total emissions in the medium FER scenario (best global fit in 2000; see Figure 2a) are too high in the North and too low in the South (relative to the simulated *a priori* dataset). Also, the simulated inter-hemispheric gradient is significantly higher than the observation in all FER scenarios. Because (i) reducing FER alone is not sufficient to match the observed inter-hemispheric gradient, and (ii) coal and oil CH_4 totals are considered a low estimate (i.e., Northern emissions could be even higher), misallocation of non-FF CH_4 emissions across hemispheres must at least partially explain the N-S mismatch. This is consistent with previous atmospheric inversions, which tend to reduce high latitudinal sources compensated by increases at lower latitudes[35,64]. Tropical wetlands may be underestimated in particular[35]. Further evidence is provided in the SI (section 3.2), which illustrates that NG (or other FFs) are unlikely causes of the N-S mismatch between simulations and observations. Instead, seasonal observations suggest that wetlands (a reduction in the North and an increase in the South) and/or agriculture/waste/landfills (an increase in the North) were biased in the *a priori* estimates.

Influence of FER on life cycle GHG emissions of power generation compared with coal

The life cycle GHG emissions from power generation are frequently estimated to assess the feasibility of replacing coal with NG to mitigate climate change[10,11,67–69]. Note, however, that other comparisons, e.g., use as a transportation fuel[70], are also policy-relevant. Corresponding to previous work[10,11,67–69], this study estimates the climate implications of NG in terms of CO_2-equivalent (CO_2e) emissions per unit of generated electricity. This metric accounts for the differences in cumulative radiative forcing of CH_4 relative to CO_2 over a given period – commonly 100 and 20 years – using global warming potentials (GWP)[71]. Figure 3 compares total life cycle GHG emissions of power generation from coal and NG assuming 39% and 50% efficiency, respectively. Given a GWP of 28 (100-yr period), and assuming 3% FER (i.e., the mean value of the most likely FER range since 2000 from this study), total NG emissions are about 39% lower than coal. After including climate-carbon feedbacks (CC FB), which account for the impact of the GHGs on other gaseous and aerosol forcing species[71], this value decreases to 36% (GWP 34). The FER would need to be 10% (excluding CC FB; 8.5% FER including CC FB) in order to reach the same total emissions as coal (break-even point). However, over a 20-yr period, NG already breaks even with coal at 3.4% FER, thus well within the most likely FER range in this study. Results for

GWP 84 (20-yr, no CC FB) are not shown in Figure 3 because differences are negligibly small (3.5% break-even FER). Note that this coal-NG comparison excludes potential direct climate effects from non-GHG climate forcers, such as sulfate aerosols from coal combustion, which may have a cooling effect[2].

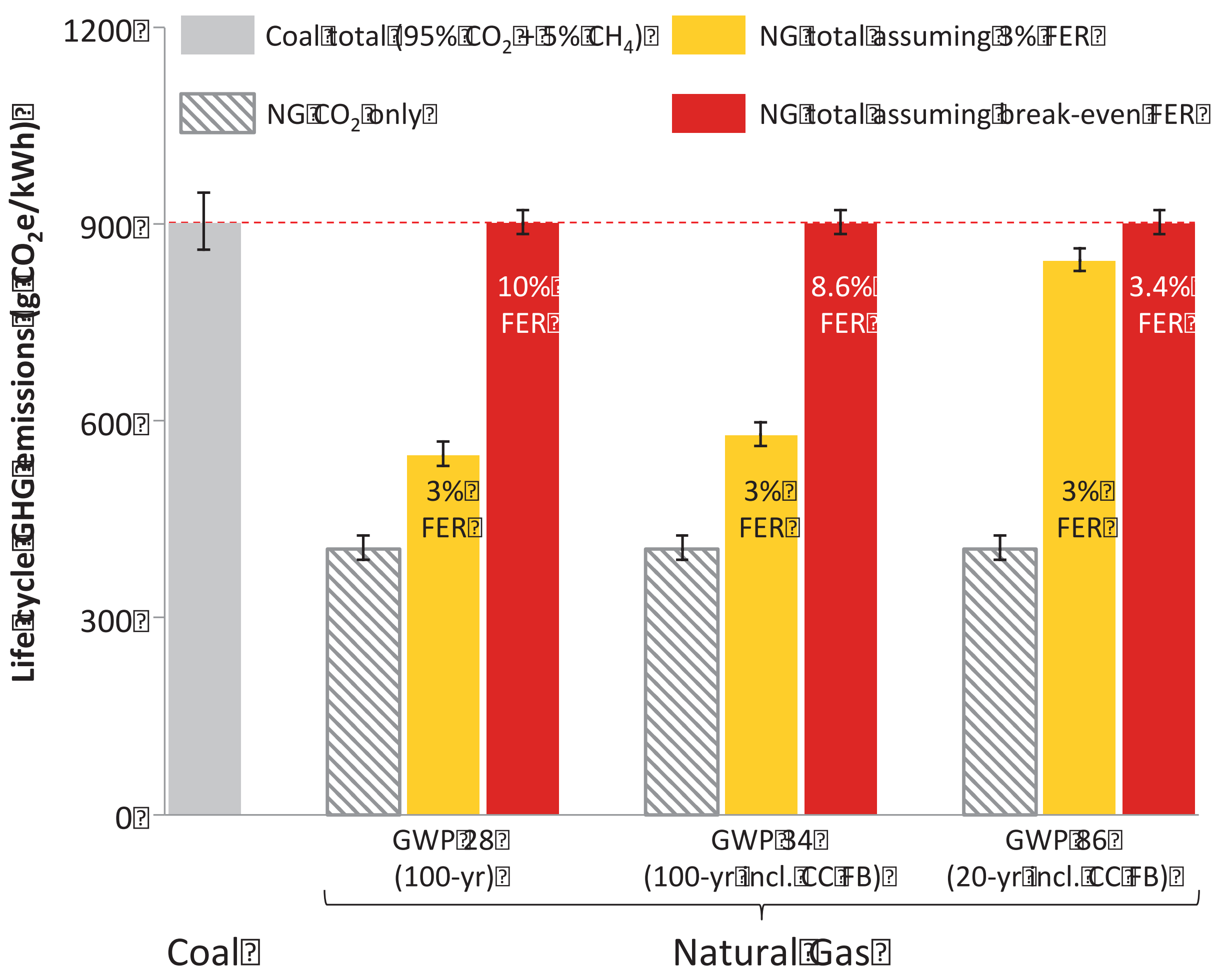

Figure 3: Comparison of life cycle GHG emissions of power generation from coal and NG assuming 39% and 50% conversion efficiency, respectively. Literature estimates for coal[1,2,11] and NG[1,2,10,72] CO_2 were used. Yellow and red columns assume 3% FER (mean value of most likely FER range since 2000 from this study) and break-even FER (required to match coal emissions), respectively, using 48 g CO_2e/kWh per percentage point FER from[68]. NG is shown for three

different global warming potentials (GWP; see text). Coal is shown for GWP 28 only because CH_4 contributes only 5% to total emissions. NG error bars include CO_2 only. Coal error bars pertain to combined uncertainty in CO_2 and CH_4 emissions. CC FB: climate-carbon feedbacks (see text).

Discussion

The objective of this top-down study was to estimate global average FER related to the NG life cycle in order to better understand whether recently reported high FER of 6-9%[1,4] are representative of the larger NG industry. Using a global box-model and well-known quantities of global average atmospheric CH_4, $\delta^{13}C$-CH_4, and C_2H_6 mixing ratios, the most likely FER was found to be 2-4% since 2000, and currently (2006-2011) having an upper bound FER of 5%. Both results are potentially overestimated because these estimates exclude highly uncertain emissions from natural hydrocarbon seepage. Taking into account increasing NG (and other FF) production, the FER (in % of dry production) has been declining steadily over time.

The box-model results (most likely FER of 2-4% since 2000) are consistent with those from 3D modeling. The low magnitude of the difference in the inter-hemispheric gradient between simulations and measurements (less than 5% of the global budget) indicates a minor bias in the simulated emissions sources. The inter-hemispheric gradient and seasonal comparisons show that an improved spatial emissions allocation includes (i) an emissions transfer from Northern to Southern wetland emissions and/or (ii) increased Northern agriculture/waste/landfills emissions in combination with FER lower than 2-4%. Thus neither the inter-hemispheric gradient nor the seasonal comparisons suggest that a global average FER of 2-4% over the period 2000-2011 is too low. This conclusion is subject to potential imprecision of the TM5 emissions transport model, which may lead to uncertainties in the simulated spatial allocation of CH_4 emissions. However, this is unlikely given the independent C_2H_6 based box-model upper bound FER of 5%.

The study results lead to both research recommendations and policy implications. A more formal uncertainty analysis of key parameters (atmospheric lifetimes, natural emissions and NG composition) would provide a more detailed characterization of FER uncertainties. This requires composition data by well type (NG, oil) that are not currently available at this level of detail. Policies aimed at providing such data, e.g., publishing international well sample data collected from the oil and gas industry in a central database, would improve the accuracy of FER estimates.

The most likely global FER range (2-4%) is slightly higher than many recent bottom-up estimates (1.1-3.2%; full life cycle) in the U.S. and elsewhere[10,51,68,73]; however, potentially unaccounted natural seepage could reduce our estimate. Our most recent (2011) *global* upper bound of 4.4% FER suggests that two recent high estimates of 6-9% in the U.S.[1,4] may be possible at individual sites, but do not appear representative of the national average unless U.S. NG industry practices are significantly worse than in the rest of the world. When used for power generation, combined NG CH_4 and CO_2 emissions break even with coal at 8.6% FER using a 100-year CH_4 GWP (including CC FB), but the break-even is only 3.4% over 20 years (Figure 3). Thus, despite our relatively low FER estimates, policies to further reduce fugitive emissions appear justified. Shale gas production was too small globally (increasing from 1.5% of global production in 2007 to 5.9% in 2011[61]) to yield a signal *even if* FER from shale gas is higher than from conventional NG. However, few bottom-up studies indicate significantly higher FER from shale compared to conventional gas[68]. Local and regional top-down studies using field measurements can complement global modeling. These may provide more basin specific FER estimates unattainable with the current global observational network. The NG industry average FER estimates from this work can be used as a reference, and basin specific studies may point to areas with local or regional hot spots.

Supporting Information. Literature review of simulated non-FF emissions, observational data description, additional box-model and 3D-model results, and comparison of GHG emissions impacts from NG and coal power generation using global warming potentials. This material is available free of charge via the Internet at http://pubs.acs.org.

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Author Contributions

S.S. was responsible for study design, development of box-model and emissions inventory, analysis of 3D-model results, and manuscript preparation. W.M.G. and H.S.M. helped with study design, model analysis, and improved the manuscript. L.B. did 3D-modeling, helped with model analysis, and improved the manuscript. All authors have given approval to the final version of the manuscript.

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Abbreviations

CH_4, methane; C_2H_6, ethane; EF, emissions factor; FER, fugitive emissions rate (% of dry production of NG); FF, fossil fuels (natural gas, oil, coal); GWP, global warming potential; NG, natural gas.

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TOC/Abstract art

FY 2012 - FY 2013
UPWP 3.3

MPO
SAN ANTONIO – BEXAR COUNTY
METROPOLITAN PLANNING ORGANIZATION

Development of the Extended June 2006 Photochemical Modeling Episode

Technical Report

October 2013

Prepared by the Alamo Area Council of Governments

Title: Development of the Extended June 2006 Photochemical Modeling Episode

Report Date: October 2013

Authors: AACOG Natural Resources Department

Type of Report: Technical Analysis

Performing Organization Name & Address:
Alamo Area Council of Governments
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Abstract: The photochemical modeling episode currently being refined and used for the San Antonio, Austin, and Dallas regions is based on a period of high ozone from May 31st to July 2nd, 2006. This episode was chosen for the most recent modeling effort as it represents a variety of meteorological conditions are commonly associated with ozone exceedance days. Once the base case emission inventory was completed, the June 2006 model was projected to 2012 and 2018 using forecasted changes in anthropogenic emissions. The largest source of NO_X emissions in 2006 are on-road vehicles, 134.7 tons per weekday, followed by point, 71.3 tons per weekday, and non-road, 43.6 tons per weekday in the San Antonio New Braunfels MSA. By 2018, the largest sources of NO_X emissions are projected to be point, 50.8 tons per weekday, followed by on-road, 43.0 tons per weekday, and area, 15.9 tons per weekday. Using the June 2006 base case inventory, the CAMx model over predicted ozone concentrations at monitors on the northwest side of San Antonio, C23, C25, and C505, on two of the episode's exceedance days: June 13 and 14th, 2006. On other days of the episode, the model's ozone estimations correlated well with observed peak hourly ozone values. Once the emission inventory in the model was projected to 2018, an attainment test was conducted on the modeling results. These results indicate that all regulatory-sited monitors meet the 75 ppb 8-hour ozone standard for every 2018 projection case. However, the 2018 design value at C58 is very close to the current 75 ppb 8-hour ozone NAAQS. If the EPA lowers the 8-hour ozone standard, it will be difficult for the San Antonio-New Braunfels MSA to meet that lower attainment threshold.

Related Reports:
FY 2008 - FY 2009, UPWP 3.3, June 2006 Ozone Episode Photochemical Modeling Development

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Executive Summary

Ground-level ozone is one of the most common air pollutants in the country as well as one of the six "criteria" pollutants for which the EPA established standards. Ozone concentrations measured in the San Antonio-New Braunfels MSA in 2012 and 2013 were high enough to place the area in violation of the federal standard based on the three-year calculations on which attainment is determined. While the area has not been designated by the EPA as a non-attainment region for ozone, local and state agencies conduct air quality planning, modeling, and analyses that could provide support for attainment demonstrations or control strategy analyses, should the region's attainment status change in the future. These analyses involve development of emissions inventories that identify local sources of the chemicals that form ozone and quantify their emission rates; identification of the meteorological and atmospheric conditions conducive to the accumulation of high ozone concentrations; and development of models that simulate those conditions in order to allow planners to predict future ozone values and evaluate pollution control strategies.

Ozone analysis is conducted using photochemical models that simulate actual high ozone episodes which prevailed in a region over the course of several days. The modeling episode currently used for the San Antonio, Austin, and Dallas regions, and undergoing refinement by the Alamo Area Council of Governments, is based on the period of high ozone that occurred from May 31st to July 2nd, 2006. This episode was chosen for the most recent modeling effort as it represents a variety of meteorological conditions that are commonly associated with ozone exceedance days.

In addition to meteorological conditions, an important input to the model is an emissions inventory that spatially and temporally allocates emissions throughout the photochemical model domain. Detailed emissions inventories were developed by the Texas Commission on Environmental Quality (TCEQ) for Texas. Emission inventories were also developed by the EPA for other states in the modeling domain and Mexico. Local updates to the San Antonio-New Braunfels MSA emission inventory were obtained from AACOG's emission inventory, TCEQ, Eastern Research Group (ERG), and Texas Transportation Institute (TTI).

Once complete, the June 2006 model was projected to 2012 and 2018 using forecasted changes in anthropogenic emissions. As part of these projections, several different emission inventory scenarios were developed for Eagle Ford Shale oil and gas production in 2018. Since photochemical models simulate the atmospheric and meteorological conditions that helped produce high ozone values during a particular episode, an important advantage the models provide is the ability to test various scenarios, such as changes in emission rates, under the same set of meteorological conditions that favor high ozone concentrations. The largest source of nitrogen oxides (NO_X) emissions in 2006 were on-road vehicles, 134.7 tons per weekday, followed by point, 71.3 tons per weekday, and non-road, 43.6 tons per weekday. By 2018, the largest sources of NO_X emissions are projected to be point, 50.8 tons per weekday, followed by on-road, 43.0 tons per weekday, and area, 15.9 tons per weekday. The largest contributors of volatile organic compounds (VOC) emissions are area sources: 147.2 tons per weekday in 2006 and 153.8 tons per weekday in 2018. Other significant sources of VOC emissions in the San Antonio-New Braunfels MSA are on-road, 22.1 tons per weekday in 2018, and non-road, 19.0 tons per weekday in 2018.

Once the emission inventories, chemistry, and meteorological data were input into the CAMx photochemical model, the model was run to produce several 2006 base case and projection case runs. The CAMx model over predicted 8-hour ozone concentrations at monitors on the northwest side of San Antonio, C23, C25, and C505, on two of the episode's exceedance days: June 13 and 14th, 2006. On other days, the model's ozone estimations correlated well with observed peak hourly ozone. When examining the diurnal bias, model results for C58 over predicted diurnal ozone on most exceedance days during the episode. The model also over predicted diurnal hourly ozone in the second part of the episode at monitors located in rural areas of the San Antonio-New Braunfels MSA, C502, C503, C504, and C506.

Although there were several significant differences in the local emission inventory for each run, model results are similar for each run at every monitor. Every modeling run exhibited similar performance for unpaired peak accuracy, paired peak accuracy, peak bias, peak error, normalized bias, and normalized error. Results for paired peak accuracy were very good for C58, C622, C501, C502, C503, and C506 and paired peak accuracy for the remaining monitors also met EPA recommended guidelines. Tile plots indicated that there were no unusual patterns of ozone formation predicted by the model runs. Ozone plumes were produced in the vicinity of San Antonio and Austin. As expected, these urban plumes were predicted for each urban core and areas downwind of the cities.

Once the emission inventory was projected to 2018 and applied to the photochemical model, an attainment test was conducted on the modeling results. The model attainment test requires the calculation of a daily relative response factor (RRF). For the Eagle Ford Shale low production scenario, the 2018 design value was 70.9 ppb at C23, 73.8 ppb at C58, and 65.0 ppb at C59. Under the Eagle Ford high scenario, the design values were 71.4 ppb at C23, 74.3 ppb at C58, and 65.6 ppb at C59. Therefore, the design value increased by 0.5 ppb at C23, 0.6 ppb at C58, and 0.7 ppb at C59 under the Eagle Ford high production scenario, compared to the low production scenario. All regulatory-sited monitors meet the 75 ppb 8-hour ozone standard for every 2018 projection case. However, the 2018 design value at C58 is very close to the current 75 ppb 8-hour ozone NAAQS. If the EPA lowers the 8-hour ozone standard, it will be difficult for the San Antonio-New Braunfels MSA to meet that lower attainment threshold.

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1 Background

The U.S. Environmental Protection Agency (EPA) is charged with the maintenance of regional air quality across the United States through a series of standards, the National Ambient Air Quality Standards (NAAQS). When regions fail to comply with these standards, the Clean Air Act requires that the state, in consultation with local governments, revise the state implementation plan (SIP) to address the violation. The SIP is a blueprint for the methodology that the region and state will follow to attain and maintain the federal air quality standards.[1]

Ground-level ozone is one of the most common air pollutants in the country as well as one of the six "criteria" pollutants for which the EPA established standards. A region is in violation of the Clean Air Act if the annual fourth highest 8-hour average ozone concentration, averaged over three consecutive years, exceeds 75 parts per billion (ppb).[2] This average is referred to as the ***design value***. The fourth highest 8-hour averages and design values for the three most recent complete years of data, 2010-2012, from the regulatory continuous ambient monitoring stations (CAMS) in the San Antonio region are listed in Table 1-1.

Table 1-1: 4th Highest Ozone Values[3] and Design Values at San Antonio Regional Monitors, 2010-2012

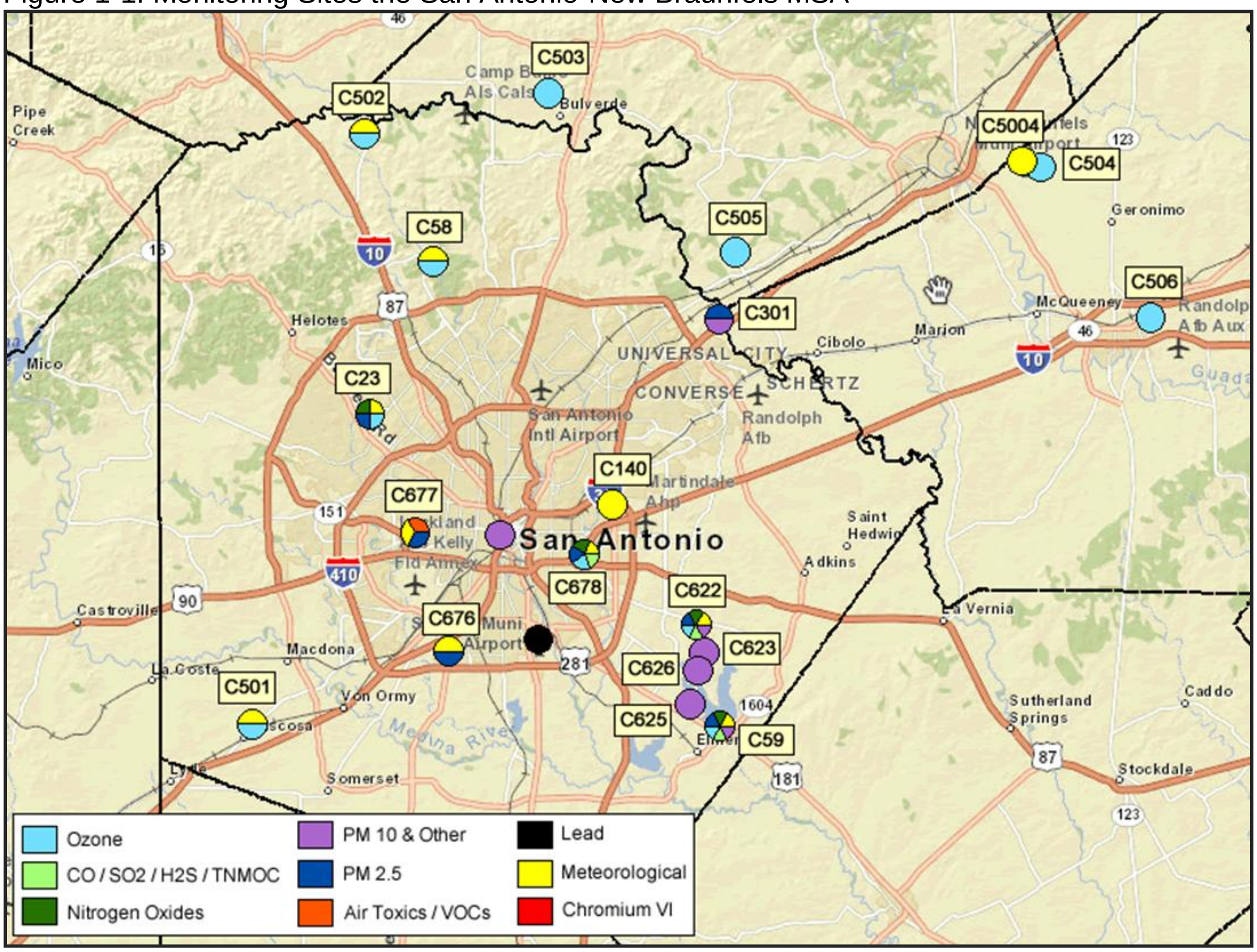
CAMS	2010 (ppb)	2011 (ppb)	2012 (ppb)	**2010-2012 Design Value**
C23	**72**	**79**	**81**	**77**
C58	**78**	**75**	**87**	**80**
C678	67	71	70	**69**
C59	69	**79**	74	**74**
C622	64	**75**	70	**69**

Under the 1997 revision to the Clean Air Act, a region was in violation of the NAAQS if the design value for ozone was equal to or greater than 85 ppb. A 2008 revision to the Clean Air Act modified the ozone standard to improve the law's ability to protect human health and the environment. Under the 2008 revision, a region is in violation of the ozone NAAQS when the design value exceeds 75 ppb. As shown in Table 1-1, the 2010 - 2012 design value (truncated average) is 80 ppb at C58 and 77 ppb at C23, indicating that the San Antonio region has two monitors measuring concentrations in violation of the 75 ppb eight hour ozone NAAQS.

[1] Environmental Protection Agency (EPA), "The Plain English Guide to the Clean Air Act." Available online: http://www.epa.gov/air/caa/peg/. Accessed 06/26/13.
[2] EPA, March 2008. "Fact Sheet: Final Revisions to the National Ambient Air Quality Standards For Ozone". Available online: http://www.epa.gov/groundlevelozone/pdfs/2008_03_factsheet.pdf. Accessed 06/26/13.
[3] Texas Commission on Environmental Quality (TCEQ). "Four Highest Eight-Hour Ozone Concentrations." Austin, Texas. Available online: http://www.tceq.state.tx.us/cgi-bin/compliance/monops/8hr_4highest.pl. Accessed 06/26/13.

There are 17 regulatory and non-regulatory air quality monitors in the San Antonio region that record meteorological data and air pollutant concentrations, including ozone levels. The data collected at these sites is processed for quality assurance by the Texas Commission on Environmental Quality (TCEQ) and is accessible via the Internet.[4] Figure 1-1 displays the location of the CAMS within the San Antonio region. Meteorological data measured at these sites includes temperature, wind speed, wind direction, precipitation, solar radiation, and relative humidity. Most stations measure one or more air pollutants including ozone (O_3), carbon monoxide (CO), nitrogen oxides (NO, NO_2), particulate matter equal to or less than 2.5 micrometers in diameter (PM2.5), particulate matter greater than 2.5 but less than 10 micrometers in diameter (PM10), and volatile organic compounds (VOCs).

Figure 1-1: Monitoring Sites the San Antonio-New Braunfels MSA



[4] TCEQ, "Air and Water Monitoring". Austin, Texas. Available online: http://www.tceq.state.tx.us/assets/public/compliance/monops/graphics/clickable/region13.gif. Accessed 06/26/13.

Ozone is monitored at C23, C58, C59, C501, C502, C503, C504, C505, C506, C622, and C678. Other ambient air monitors include C27 (CO and NO_X), C140 (meteorological data), C301 (PM 2.5), C676 (meteorological data and PM 2.5), C677 (meteorological data, PM 2.5, and VOC sampling), and C5004 (meteorological data). In addition, there are three water quality monitors displayed on the map: C623, C625, and C626.

The Alamo Area Council of Governments conducts ozone analysis using photochemical models that simulate actual high ozone episodes which prevailed in the region over the course of several days. The modeling episode currently being refined and used for the San Antonio, Austin, and Dallas regions is based on the May 31st to July 3rd, 2006 time period. This episode included several periods of high ozone across Texas.[5]

Once complete, the June 2006 model was projected to 2012 and 2018 using forecasted changes in anthropogenic emissions. The years 2012 and 2018 were selected because of the availability of several forecasted emissions inventories from previous work completed by TCEQ. As part of these projections, several different emission inventory scenarios were developed for Eagle Ford production in 2018. Since photochemical models simulate the atmospheric and meteorological conditions that helped produce high ozone values during a particular episode, an important advantage the models provide is the ability to test various scenarios, such as changes in emission rates, under the same set of meteorological conditions that favor high ozone concentrations.

[5] TCEQ. "Daily Maximum Eight-Hour Ozone Averages." Austin, Texas. Available online: http://www.tceq.state.tx.us/cgi-bin/compliance/monops/8hr_monthly.pl. Accessed 06/24/13.

2 Meteorological and Photochemical Modeling Development

2.1 EPA Modeling Guidance

EPA modeling guidance provides a detailed process, from the planning stage through control strategy development and evaluation, for developing and analyzing photochemical modeling episodes. If a region fails to meet the National Ambient Air Quality Standards (NAAQS), EPA can declare the region in non-attainment. The region must submit a State Implementation Plan revision with an attainment demonstration designed to achieve attainment of the ozone NAAQS. The EPA outlines nine recommended steps for applying photochemical models to generate the information used in attainment demonstrations:

1. "Develop a conceptual description of the problem to be addressed.
2. Develop a modeling/analysis protocol.
3. Select an appropriate model to support the demonstration.
4. Select appropriate meteorological time periods to model.
5. Choose an appropriate area to model with appropriate horizontal/vertical resolution and establish the initial and boundary conditions that are suitable for the application.
6. Generate meteorological inputs to the air quality model.
7. Generate emissions inputs to the air quality model.
8. Run the air quality model with base case emissions and evaluate the performance. Perform diagnostic tests to improve the model, as necessary.
9. Perform future year modeling (including additional control strategies, if necessary) and apply the attainment test."[6]

The following chapters describe this process as followed by AACOG in the development and analysis of the June 2006 AACOG modeling episode.

2.2 Conceptual Description

An initial step in model development for attainment demonstrations requires creating a conceptual description and model of ambient ozone in the San Antonio region. The conceptual model provided a basis for determining subsequent steps in episode selection and model development. One of the intents of the conceptual model is to summarize both the local meteorological conditions and associated synoptic weather patterns typically experienced during periods of elevated ozone concentrations. Assembling and reviewing available ambient air quality data, meteorological data, upper air measurements, and previous photochemical modeling efforts facilitate this process.

Ozone formation in the San Antonio region is influenced by many of the same factors as in other regions of Texas and ozone concentrations peak during the warm weather that predominates in the San Antonio region from May through October. These factors include sunny skies, high-pressure

[6] EPA, April 2007. "Guidance on the Use of Models and Other Analyses for Demonstrating Attainment of Air Quality Goals for Ozone, PM2.5, and Regional Haze," EPA -454/B-07-002. Research Triangle Park, North Carolina. p. 2. Available online: http://www.epa.gov/scram001/guidance/guide/final-03-pm-rh-guidance.pdf. Accessed 06/24/13.

systems, low wind speeds, wind directions that facilitate transport from urban areas and industrial sites, and low humidity. Low mixing heights and low nocturnal wind speeds allow local ozone precursor pollutants to concentrate. With a rapid rise in mixing height during the morning, local and transport pollutants can combine to form elevated ozone levels.

The 2008 Conceptual Model defines the factors that influence ozone formation in the San Antonio region as:

- Temperature – Days with ozone exceedances tended to have peak temperatures above 83^{o}F.
- Precipitation – Days with ozone exceedances had little to no precipitation.
- Humidity and Cloud Cover – Days with ozone exceedances had clear skies and relative humidity below 50% at 2 p.m.
- Wind Direction – Morning wind direction on high ozone days tended to be from the northwest in the early mornings at C58 and northwest to northeast at C23. Early afternoon wind direction tended to be from the southeast on ozone exceedance days.
- Wind Speed – Ozone exceedance days had calm winds that were below 7 mph.
- Mixing Heights – Mixing heights were typically lower in the early morning hours, followed by a rapid rise in late morning through early afternoon on days of high ozone concentrations.
- Ozone Seasonal Peaks – San Antonio region was shown to have three ozone peaks (late May – June, early August, and September) during the ozone season of April - October.
- Diurnal Ozone Patterns – There was a strong correlation between one-hour and eight-hour readings, indicating no significant one-hour peaks resulting from large VOC plumes from industrial or other sources. Urban core monitors recorded lower nighttime diurnal ozone measurements on average than monitors outside the urban core.
- Regional Air Masses – Air masses over central Texas were stagnant on days of high ozone with few frontal movements, characteristic of high pressure cells.
- Surface Back Trajectories – Air parcels on ozone exceedance days tended to originate from the northeast, east, and southeast; while, on days with low ozone, air parcels were predominately from the southeast.
- Seasonal Pattern of Surface Back Trajectories – On ozone exceedance days, back trajectories in June tended to originate from the southeast; while back trajectories in September on ozone exceedance days tended to originate from the northeast.
- 24-hour Back Trajectory Origins – On high ozone days, back trajectories originated closer to San Antonio and traveled fewer miles to arrive at local ozone monitoring stations, indicating an association between low wind speeds/stagnated conditions and ozone exceedances.
- Maximum Ozone Readings – The difference between the San Antonio MSA maximum peak ozone readings and the minimal peak ozone readings at monitors on ozone exceedance days was 21.2 ppb or 25.2 percent.
- Aircraft Sampling – Aircraft sampling between Houston and San Antonio indicated large ozone plumes from Houston could impact areas hundreds of miles downwind including San Antonio and Austin. This may affect local ozone levels and increase the difficulty of attaining the 75 ppb 8-hour ozone standard at downwind monitors.

- Local Ozone Contribution – The 2013 ozone design value was reduced 19.1 ppb when all local anthropogenic emissions from the San Antonio MSA were removed from the CAMx photochemical model simulation (25.2% reduction).
- New Point Sources – Power plants being built in Texas between 2007 and 2013 could affect future ozone levels in San Antonio. These power plants may release an additional 76.9 tons of NO_X per year in areas upwind from San Antonio. The impact of these power plants may make it more difficult for the San Antonio region to attain the 75 ppb 8-hour ozone standard[7].

2.3 Modeling/Analysis Protocol

As stated by the EPA, "the most important function of a protocol is to serve as a means for planning and communicating up front how a modeled attainment demonstration will be performed".[8] Many stakeholders were involved in the modeling protocol process that led to the development of the June 2006 ozone episode. Decisions as to which modeling episode, air quality simulation model, and modeling consultant(s) to use were made by TCEQ staff and representatives of two Texas NNAs: Austin (Capital Area Planning Council and Central Texas Clean Air Force), and San Antonio (Alamo Area Council of Governments). The decision to model the June 2006 episode was also approved by the AACOG Board of Directors during their April 2, 2008 meeting. The AACOG board consists of elected officials representing the 12-county AACOG region: Atascosa, Bandera, Bexar, Comal, Frio, Gillespie, Guadalupe, Karnes, Kendall, Kerr, Medina, and Wilson counties.

Modeling decisions were reviewed by AACOG's Air Improvement Resources Technical Committee and the San Antonio-Bexar County Metropolitan Planning Organization (SA-BC MPO) Technical Advisory Committee (TAC), which are composed of technical staff representing local governments and stakeholders. Recommendations from the AIR Technical Committee were forwarded to the Air Improvement Resources (AIR) Executive and Advisory Committee during regularly scheduled public meetings for final approval of modeling decisions at the local level. Executive members (voting members) of the AIR Committee included one representative each from Atascosa County, Bexar County, Comal County, City of Floresville, Guadalupe County, City of New Braunfels, City of San Antonio, City of Seguin, Wilson County, the Alamo Area Council of Governments Board of Directors, Greater Bexar County Council of Cities (GBCCC), and the San Antonio-Bexar County Metropolitan Planning Organization (SA-BC MPO). The Advisory committee, although not consisting of voting members, includes representatives of governmental entities, industries, and private citizens.

2.4 Model Selection

The EPA recommends that regions consider five factors as criteria for choosing qualifying air quality models:

1. "Documentation and Past Track Record of Candidate Models.
2. Advanced Technical Features.

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[7] Alamo Area Council of Governments (AACOG), April 2009. "Conceptual Model - Ozone Analysis of the San Antonio Region: Updates through Year 2008". San Antonio, Texas.
[8] EPA, April 2007. "Guidance on the Use of Models and Other Analyses for Demonstrating Attainment of Air Quality Goals for Ozone, PM2.5, and Regional Haze." EPA -454/B-07-002. Research Triangle Park, North Carolina. p. 133. Available online: http://www.epa.gov/scram001/guidance/guide/final-03-pm-rh-guidance.pdf. Accessed 06/24/13.

3. Experience of Staff and Available Contractors.
4. Required vs. Available Time and Resources.
5. Consistency of a Proposed Model with Models Used in Adjacent Regions."[9]

An important component of selecting peer-reviewed meteorological and photochemical models includes evaluating these five factors and demonstrating that the models perform satisfactorily in similar applications.

According to the EPA, "Ozone chemistry is complex, involving more than 80 chemical reactions and hundreds of chemical compounds. As a result, ozone cannot be evaluated using simple dilution and dispersion algorithms. Due to the chemical complexity and the requirement to evaluate the effectiveness of future controls, the EPA's guidance strongly recommends using photochemical computer models to analyze ozone issues. While photochemical grid modeling has uncertainties, EPA strongly supports the use of photochemical grid modeling as the most sophisticated and scientifically sound tool available to develop attainment demonstrations."[10]

WRF v3.2, released in April 2010,[11] was used to calculate the meteorological inputs for the June 2006 photochemical model. The "WRF Model is a next-generation mesoscale numerical weather prediction system designed to serve both operational forecasting and atmospheric research needs. It features multiple dynamical cores, a 3-dimensional variational (3DVAR) data assimilation system, and a software architecture allowing for computational parallelism and system extensibility. WRF is suitable for a broad spectrum of applications across scales ranging from meters to thousands of kilometers."[12] The highlights of WRF v3.2 include:

1. "fully compressible nonhydrostatic equations with hydrostatic option
2. complete coriolis and curvature terms
3. two-way nesting with multiple nests and nest levels
4. one-way nesting
5. moving nest
6. mass-based terrain following coordinate (note that the height-based dynamic core is no longer supported)
7. vertical grid-spacing can vary with height

[9] EPA, April 2007. "Guidance on the Use of Models and Other Analyses for Demonstrating Attainment of Air Quality Goals for Ozone, PM2.5, and Regional Haze." EPA -454/B-07-002. Research Triangle Park, North Carolina. p. 137. Available online: http://www.epa.gov/scram001/guidance/guide/final-03-pm-rh-guidance.pdf. Accessed 06/24/13.

[10] Erik M. Snyder and Biswadev (Dev) Roy, July 2008. "Technical Support Document For Dallas Fort Worth Modeling and Other Analyses Attainment Demonstration (DFW-MOAAD)". EPA-R06-OAR-2007-0524. Air Quality Modeling Group Air Programs Branch-Planning Section Multimedia Planning & Permitting Division, U.S. EPA Region-6. Dallas, Texas. p. 63. Available online: http://www.regulations.gov/search/redirect.jsp?objectId=090000648066d902&disposition=attachment&contentType=pdf. Accessed 03/08/09.

[11] Jimy Dudhia, NCAR/NESL/MMM. "WRF Version 3.2: New Features and Updates". Presented at the 11th Annual WRF Users' Workshop, June 21 - 25, 2010. Available online: http://www.mmm.ucar.edu/wrf/users/workshops/WS2010/presentations/session%201/1-1_wrf10.pdf. Accessed 06/21/13.

[12] National Center for Atmospheric Research. "The Weather Research and Forecasting Model". Available online: http://www.wrf-model.org/index.php. Accessed 06/21/13.

8. map-scale factors for conformal projections:
9. Arakawa C-grid staggering
10. Runge-Kutta 2nd and 3rd order timestep options
11. scalar-conserving flux form for prognostic variables
12. 2nd to 6th order advection options (horizontal and vertical)
13. time-split small step for acoustic and gravity-wave modes:
    a. small step horizontally explicit, vertically implicit
    b. divergence damping option and vertical time off-centering
    c. external-mode filtering option
14. lateral boundary conditions
    a. idealized cases: periodic, symmetric, and open radiative
    b. real cases: specified with relaxation zone
15. upper boundary absorbing layer option
    a. increased diffusion
    b. Rayleigh relaxation
    c. implicit gravity-wave damping
16. rigid upper lid option
17. positive definite and monotonic advection scheme for scalars (microphysics species, scalars and tke)
18. adaptive time stepping (new in V3.0)"[13]

CAMx is a non-proprietary model developed by ENVIRON to be used in analysis of pollutants including ozone, PM2.5, PM10, air toxins, and mercury. The model "is an Eulerian photochemical dispersion model that allows for an integrated 'one-atmosphere' assessment of gaseous and particulate air pollution over many scales ranging from sub-urban to continental. It is designed to unify all of the technical features required of state-of-the-science air quality models into a single system that is computationally efficient, easy to use, and publicly available."[14] To increase the compatibility between WRF and CAMx, there are readily available FORTRAN programs to convert raw output data from WRF into CAMx ready file formats. Wrf2camx with YSU Kv and the 100m kvpatch were used to convert the WRF output into CAMx format for the extended June 2006 episode.

The latest version of CAMx 5.40 was used in all the photochemical model runs performed by AACOG. The updates for the new version of CAMx include:

1. "Version 6 of the Carbon Bond photochemical mechanism (CB6).
2. Improved MPI efficiency by reducing the amount of data passed back to the master node each hour.
3. Two internal and transparent structural modifications:
    a) Dimensions and MPI passing of "height" and "depth" arrays are handled similarly as all other met variables;

[13] National Center for Atmospheric Research. "WRF Model Version 3.2" http://www.mmm.ucar.edu/wrf/users/wrfv3.2/wrf_model.html. Accessed 06/21/13.

[14] ENVIRON International Corporation, September 2011. "User's Guide: Comprehensive Air Quality Modeling with Extensions, Version 5.40". Novato, CA. p. 1-1.

b) Radicals and 'state' species concentrations are combined into a single vector.

4. PiG puff growth rates were modified to ignore growth contributions from horizontal and vertical shear during stable/nighttime conditions. Shear effects remain during neutral/unstable/daytime conditions. Reduced minimum limits on vertical diffusivity, turbulent flux moment, and nighttime PBL depth."[15]

CAMx advanced technical features were used to model the June 2006 episode and are described in the CAMx user guide.[16] The advanced CAMx features include:

1.	Two-Way nested grid structure:	for the 36-, 12-, and 4-km grid system
2.	Plume-in-grid (PiG):	to track chemistry and dispersion of large individual point source NO_X emission plumes
3.	Horizontal advection solver:	Piecewise Parabolic Method (PPM)[17]
4.	Gas Phase Chemistry Mechanism:	Carbon Bond Version 6 (CB6)[18]
5.	Chemical Kinetics Solver:	set to ENVIRON's CMC solver to increase the speed of the chemistry solution and model performance

All the CAMx advanced settings used to simulate the extended June 2006 episode are the same as settings that are being used to conduct SIP modeling for other areas in Texas. Both the CAMx and WRF models are being used to develop attainment demonstrations for multiple Texas regions including Dallas and Houston. Both WRF and CAMx met all EPA recommendations regarding the selection of a model.

2.5 Meteorological Time Period of Episode Selection

The EPA recommends four criteria for selecting periods of elevated ozone concentrations that are appropriate to model. The recommendations favor ozone episodes that:

1) "Simulate a variety of meteorological conditions: 8-Hour Ozone - choose time periods which reflect a variety of meteorological conditions which frequently correspond with observed 8-hour daily maxima > 84 ppb at multiple monitoring sites.
2) Model time periods in which observed concentrations are close to the appropriate baseline design value or visibility impairment.
3) Model periods for which extensive air quality/meteorological databases exist.
4) Model a sufficient number of days so that the modeled attainment test applied at each monitor violating the NAAQS is based on multiple days."[19]

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[15] ENVIRON, Oct 10, 2011. "RELEASE NOTES for CAMx v5.40". Novato, CA. Available online: http://www.camx.com/camx/files/2f/2f85f4aa-dfa9-4492-96a2-0c931b0dba5c.txt. Accessed 06/21/13.

[16] ENVIRON International Corporation, September 2011. "User's Guide: Comprehensive Air Quality Modeling with Extensions, Version 5.40". Novato, CA. p. 1-1.

[17] Colella, P. and P.R. Woodward, 1984. "The Piecewise Parabolic Method (PPM) for Gas-Dynamical Simulations." Journal of Computation Physics. Volume 54, pp. 174-201. Available online: http://seesar.lbl.gov/anag/publications/colella/A_1_4_1984.pdf. Accessed: 06/24/13.

[18] Yarwood. G, Whitten G. Z., Gookyoung, H, Mellberg, J. and Estes, M. 2010. "Updates to the Carbon Bond Mechanism for Version 6 (CB6)". Presented at the 9th Annual CMAS Conference, Chapel Hill, NC, October 11-13, 2010. Available online: http://www.cmascenter.org/conference/2010/abstracts/emery_updates_carbon_2010.pdf. Accessed 06/10/13.

The San Antonio region typically experiences three seasonal peaks during the ozone season: late May – June, early August, and the month of September. Selecting a modeling episode during one of these peaks is recommended. Work conducted on the 2008 Conceptual Model identified ten potential candidate episodes for modeling purposes, eight of which occurred during these peaks. By applying EPA's guidance for the selection process, the field of potential candidates was narrowed and eventually led to the selection of the June 2006 episode.

The June 2006 high ozone episode was chosen for the most recent modeling effort as it represents a variety of meteorological conditions that occur on typical ozone exceedance days. The June 2006 episode meets all four recommended EPA criteria for modeling time period selection. Detailed episode selection analysis of all candidate episodes is provided in the 2008 Conceptual model.[20] A review of the conceptual model in 2009 confirmed that the June 2006 exceedances were still typical of current ozone exceedance events in San Antonio.[21]

A variety of meteorological conditions on ozone exceedance days are simulated in the extended June 2006 episode. EPA recommends "modeling 'longer' episodes that encompass full synoptic cycles to improve model performance and modeling responses to emission control strategies. Time periods, which include a ramp-up to a high ozone period and a ramp-down to cleaner conditions, allow for a more complete evaluation of model performance under a variety of meteorological conditions."[22] The extended June 2006 model contains several full ozone synoptic cycles.

The June 2006 meteorological episode consists of one ramp-up day, May 31st, thirty primary episode days, June 1st - 30th and two ramp-down days, July 1st and 2nd. As shown in Figure 2-1, there was a period of high ozone from June 3 to June 14 and from June 26 to June 29 in San Antonio. In between periods of high ozone, the area experienced lower ozone from May 29 to June 2, June 15 to June 25, and June 30 to July 2. On two episode days, June 14 and 29, eight-hour average ozone levels exceeded 75 ppb at all area monitors. Since all local monitors – upwind and downwind – exceeded 75 ppb, transported ozone concentrations were high enough to cause exceedances in the San Antonio area without the impact of local emissions. Attaining the NAAQS is extremely difficult under such conditions and demonstrates the region's dependence on local as well as national and state implemented control measures.

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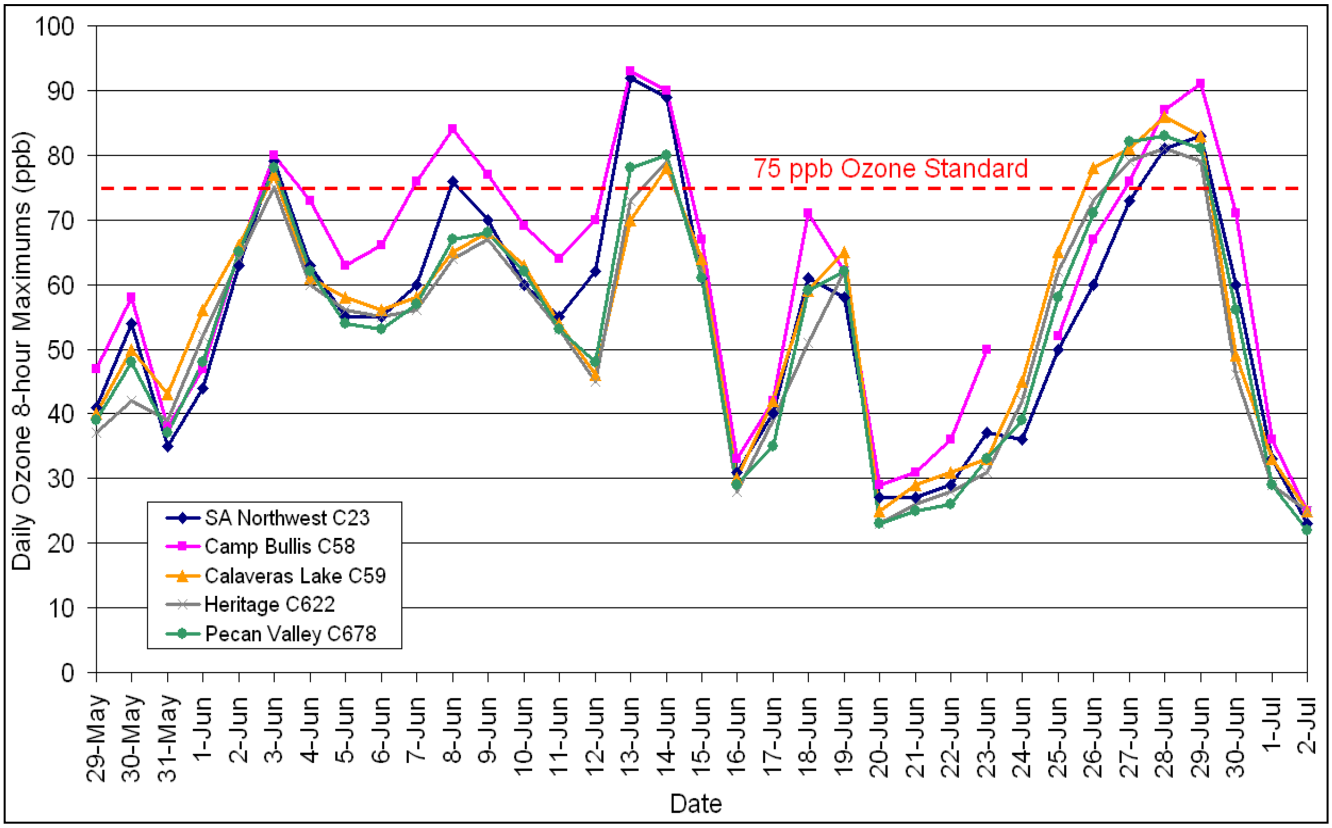
[19] EPA, April 2007. "Guidance on the Use of Models and Other Analyses for Demonstrating Attainment of Air Quality Goals for Ozone, PM2.5, and Regional Haze." EPA -454/B-07-002. Research Triangle Park, North Carolina. p. 140. Available online: http://www.epa.gov/scram001/guidance/guide/final-03-pm-rh-guidance.pdf. Accessed 06/24/13

[20] AACOG, April 2007. "Conceptual Model - Ozone Analysis of the San Antonio Region: Updates through Year 2006". San Antonio, Texas.

[21] AACOG, April 2009. "Conceptual Model - Ozone Analysis of the San Antonio Region: Updates through Year 2008". San Antonio, Texas.

[22] EPA, April 2007. "Guidance on the Use of Models and Other Analyses for Demonstrating Attainment of Air Quality Goals for Ozone, PM2.5, and Regional Haze." EPA -454/B-07-002. Research Triangle Park, North Carolina. p. 140. Available online: http://www.epa.gov/scram001/guidance/guide/final-03-pm-rh-guidance.pdf. Accessed 06/24/13.

Figure 2-1: Daily Ozone 8-hour Maximums for the June 2006 Episode at Regulatory Sited Monitors



2.5.1 June 2006 – Monitors Measuring High Ozone

During the extended June 2006 episode, 8-hour ozone averages exceeded 75 ppb on nine days at C58 and six days at C23. As provided in Table 2-1, every regulatory sited monitor recorded 8-hour averages in excess of 75 ppb on at least five days, and averages above 70 ppb on seven days of the 2006 episode. The highest number of ozone exceedances in the San Antonio region occurred at C58, C23, C501, C502, and C503 on the northwest, north, and southwest side of the city (Table 2-2). These monitors typically record the highest ozone concentrations on exceedance days as transported pollutants arrive from the northeast, east, and southeast. Transported ozone and precursor pollutants combine with local emissions resulting in higher ozone measurements downwind of the city core. The June 26th exceedance occurred at C59 in southeast Bexar County, which is unusual for the San Antonio region. Back trajectory analysis on this day indicated winds and transported pollutants came from the north and passed over San Antonio before arriving at CAMS 59.[23]

[23] TCEQ. *Daily Maximum Eight-Hour Ozone Averages*. Available online: http://www.tceq.state.tx.us/cgi-bin/compliance/monops/8hr_monthly.pl. Accessed 06/21/13.

Table 2-1: Regulatory Sited Monitor-specific Eight-Hour Ozone Data during the Extended June 2006 Episode

Monitor	Max 8-hour Ozone (ppb)	Days > 80 ppb	Days > 75 ppb	Days > 70 ppb	Site-Specific Baseline Design Value (ppb)
San Antonio Northwest C23	92	4	6	8	77.3
Camp Bullis C58	93	6	9	13	80.0
Calaveras Lake C59	86	3	6	7	69.3
Heritage C622	81	1	5	7	68.0
CPS Pecan Valley C678	83	4	6	7	70.6

2.5.2 *June 2006 – Wind Speed and Direction at the Monitors*

Periods of high ozone during the 2006 episode were usually dominated by light winds and high-pressure systems over Texas. In contrast, several days of low ozone during the episode were associated with winds greater than 8 mph. On most ozone exceedance days, early morning winds were from the southwest, west, northwest, and north, while morning winds on days of low ozone were from the south, southeast, and east (Table 2-2). During the afternoon, winds tended to be from the south, southeast, and east on both days of high and low ozone. These dominating wind patterns match the results from the conceptual model for typical days of high and low ozone. During several days of the episode, afternoon winds blew from the northeast, which did not match typical patterns but are not considered exceptional. Several fronts passed through the region before exceedances occurred during the episode.

Days in which ozone exceedances occurred during the June 2006 episode were associated with meteorological conditions typical of high-ozone events (Table 2-3).[24] Peak temperatures on exceedance days ranged from 87.9^{o} F degrees on June 26th to 98.0^{o} F on June 13th. Typical of ozone exceedance days, humidity was below 32%, solar radiation was above 1.1 Langleys/min, and there was no precipitation. On the June 26, 2006 exceedance day, there were unusually high wind speeds (up to 9.5 mph) for an ozone exceedance day and the 250-mile back trajectory indicated the winds traveled a significant distance from the north before arriving at C58. Since other monitors, C622, C506, C501, C678, and C504, on the eastern and southern sides of San Antonio recorded higher ozone measurements, this is an indication of significant transport of pollutants into the region on this day.

[24] AACOG, April 2009. “Conceptual Model - Ozone Analysis of the San Antonio Region: Updates through Year 2008”. San Antonio, Texas.

Table 2-2: May 31st-July 2nd, 2006 Daily Maximum Ozone and Number of Monitors with Exceedances

Day of the Week	Date	Max. Ozone	CAMS with Highest Reading	Number of Monitors with Exceedances	Morning Wind Direction at C58 (6-9)	Afternoon Wind Direction at C58 (12-15)	Remarks
Wed	May 31	43	C59	0	NE	E	Ramp - up, low Ozone
Thu	June 1	56	C59	0	NE	NE	
Fri	June 2	66	C59	0	NW	NE	Weak Front
Sat	**June 3**	**80**	**C58**	**5**	**NW**	**SE**	High Pressure System
Sun	June 4	73	C58	0	SW	SE	Light Winds
Mon	June 5	63	C58	0	SW	SE	
Tue	June 6	68	C502	0	S	S	
Wed	**June 7**	**76**	**C58**	**1**	**SW**	**S**	High Pressure System - Light Winds
Thu	**June 8**	**84**	**C58**	**4**	**SW**	**SE**	
Fri	**June 9**	**77**	**C58 & C502**	**1**	**NW**	**SE**	
Sat	June 10	71	C503	0	SW	S	
Sun	June 11	64	C58 & C502	0	S	SE	
Mon	June 12	70	C58	0	S	SE	
Tue	**June 13**	**93**	**C58**	**6**	**NW**	**E**	Weak Front in Morning
Wed	**June 14**	**90**	**C58**	**10**	**NE**	**E**	
Thu	June 15	69	C502	0	SE	SE	Strong Winds
Fri	June 16	35	C502	0	S	S	
Sat	June 17	44	C504	0	N	SE	
Sun	June 18	71	C58	0	E	S	Light Winds
Mon	June 19	65	C59	0	W	N	
Tue	June 20	29	C58 & C502	0	E	SE	
Wed	June 21	32	C502	0	SE	SE	Strong Winds
Thu	June 22	36	C58 & C502	0	SE	SE	
Fri	June 23	50	C58	0	S	S	
Sat	June 24	45	C59	0		N	Front
Sun	June 25	65	C59	0	NW	NE	Strong Winds
Mon	**June 26**	**78**	**C59**	**1**	**N**	**NE**	
Tue	**June 27**	**88**	**C501**	**7**	**N**	**NE**	High Pressure System - Light Winds
Wed	**June 28**	**90**	**C501**	**10**	**NW**	**E**	
Thu	**June 29**	**91**	**C58**	**11**	**W**	**SE**	
Fri	June 30	71	C58	0	SE	SE	Ramp - down, low Ozone, light winds
Sat	July 1	38	C503	0	NW	SE	
Sun	July 2	26	C505	0	E	E	

Table 2-3: Comparison of Episode Exceedance Day Conditions to Typical Meteorological Conditions in the San Antonio Region on Ozone Exceedance Days

Existing Episode	Day	Peak 1-hour ppb Ozone at regulatory monitors	Peak 8-hour ppb Ozone at regulatory monitors	Peak Temperature at C58 > 83°F	Wind Speed 6 am – 2 pm at C58 < 7.0 mph	Precipitation (inches) at C678 - None	Max. Solar Radiation at C58 > 0.9 langleys/min.	Relative Humidity at C5004 2p.m. < 50%	Morning Wind Direction at C58 (6-9)	Afternoon Wind Direction at C58 (12-15)	Back Trajectory Classification
June 2006	3	86	80	89.7	4.9	0	1.148	27.5%	NW	SE	Stagnated
	7	87	76	94.3	5.0	0	1.309	31.8%	SW	S	Weak Transport
	8	96	84	92.6	4.4	0	1.291	29.6%	SW	SE	Weak Transport
	9	86	77	92.5	5.5	0	1.369	29.6%	NW	SE	Weak Transport
	13	106	93	98.0	5.3	0	1.301	20.2%	NW	E	Weak Transport
	14	94	90	93.9	**7.4**	0	1.305	29.4%	NE	E	Stagnated
	26	86	78	89.6	**9.5**	0	1.324	26.1%	N	**NE**	Transport
	27	88	82	87.9	5.8	0	1.238	23.1%	N	**NE**	Weak Transport
	28	97	87	90.0	5.9	0	1.338	22.3%	NW	E	Weak Transport
	29	94	91	89.4	4.9	0	1.174	27.8%	W	SE	Stagnated

Bolded values represent unusual meteorological conditions on ozone exceedance days

2.5.3 Transport Classification Using Back Trajectories

Back trajectories and daily weather maps were reviewed to classify episode winds as "stagnated," "weak transport," or "transport" during the episode. Back trajectories were categorized by the distance air parcels, at heights of 100 meters and 1,000 meters, traveled from origin to C58 monitor in San Antonio: within 250 kilometers, 251 – 500 kilometers, and >500 kilometers. Days when the 48-hour 100-meter height back trajectories stayed within approximately 250 kilometers of San Antonio were considered "stagnated" days. If the 48-hour back trajectory originated farther than 500 kilometers from San Antonio, the back trajectory was labeled as "transport." All other back trajectories were labeled as "weak transport." Of the episode 10 exceedance day back trajectories listed in Table 2-3, three fell within the stagnated category: June 3, 14, and 29. One back trajectory, June 26, was classified as transport and the rest were classified as weak transport.

During the June 2006 episode, 55 percent of the 48-hour back trajectories originated within 150 km of CAMS 58. These back trajectories represent meteorological conditions on ozone exceedance days in San Antonio. By developing an episode with a variety of back trajectories directions and speeds, effectiveness of control strategies can be tested under different meteorological conditions. The 1,000 meter back trajectories indicate transported pollutants arrived in San Antonio primarily from the east and northeast on ozone exceedance days during the episode. However, on three exceedance days during the June 2006 episode, June 7th, 8th, and 9th, elevated winds arrived at C58 from the south.

2.5.4 Peak Ozone and Local Ozone Contribution

On ozone exceedance days during the 2006 episode, the average difference between maximum peak ozone and minimum peak ozone readings at San Antonio monitors was 16.3 ppb. This indicates that local emissions accounted for 19% and transported pollutants contributed 81% to the ambient ozone levels recorded at San Antonio area monitors on exceedance days during the 2006 episode. Consequently, local sources of ozone precursors contributed less to regional ambient ozone levels than the 2008 conceptual model findings based on the older June 2006 modeling episode, which attribute 20% to 25% of average ambient ozone concentrations to local sources on exceedance days in 2013.

2.5.5 Plume Animation and Urban Emissions

TCEQ develops plume animation showing the length of the vectors "corresponds to the distance traveled by the air during the hour of measurement. The vectors are plotted from the station circle toward the direction from which the wind was blowing and show approximately where the air that arrived at the end of the hour was located at the beginning of the hour." In reference to the 2006 episode, TCEQ states "plume animation shows the estimated plume tracks from large industrial sources of oxides of nitrogen (NO_X) and/or volatile organic compounds (VOC), as well as plume tracks for the center of the broad urban plumes coming from downtown Austin, downtown San Antonio, and other major urban centers. The plume animation suggests that urban and industrial emissions from the San Antonio area were in the vicinity of the highest ozone measurements in the San Antonio area and that the highest ozone levels may have been well downwind to the west and southwest of the San Antonio area where there are no monitoring sites."[25]

2.5.6 Wind Speed and Direction

An episode's value as a candidate for modeling increases if the exceedance days of the episode exhibited a variety of wind speeds and directions. Figure 2-2 demonstrates that the June 2006 250-km 100-meter back trajectories are from the east (33.2%), southeast (29.8%), and northeast (17.3%) on ozone exceedance days. Another strong component of the back trajectory analysis is the presence of winds from the south (15.0 percent) during the extended June 2006 episode. Although wind direction on average ozone exceedance days from 2005 to 2010 tend to originate from the north and northeast in a greater percentage when compared to the June 2006 episode, there is still a strong correlation between the 2006 episode 250-mile 100-meter back trajectories and 250-mile back trajectories for average ozone exceedance days.

A similar pattern occurred when comparing the average 250-mile 1,000-meter back trajectories on ozone exceedance days and the ozone exceedances during the June 2006 episode. As shown on Figure 2-3, a higher percentage of 1,000-meter back trajectories originated from the east during the 2006 episode (41%) than for exceedance days on average, but there is a similar pattern between all exceedance days and the episode exceedance days. Individual 250-mile 100-meter back trajectories, displayed in Figure 2-4, during the June 2006 episode provide a variety of directions and speeds on ozone exceedance days.

[25] TCEQ. "2006 Air Pollution Events." Austin, Texas. Available online: http://www.tceq.state.tx.us/compliance/monitoring/air/monops/sigevents06.html. Accessed 12/10/08.

Figure 2-2: Statistical Analysis of San Antonio's 250-mile 100-meter Back Trajectory Wind Directions: All Exceedance Days 2000-2008 and June 2006 Exceedance Days

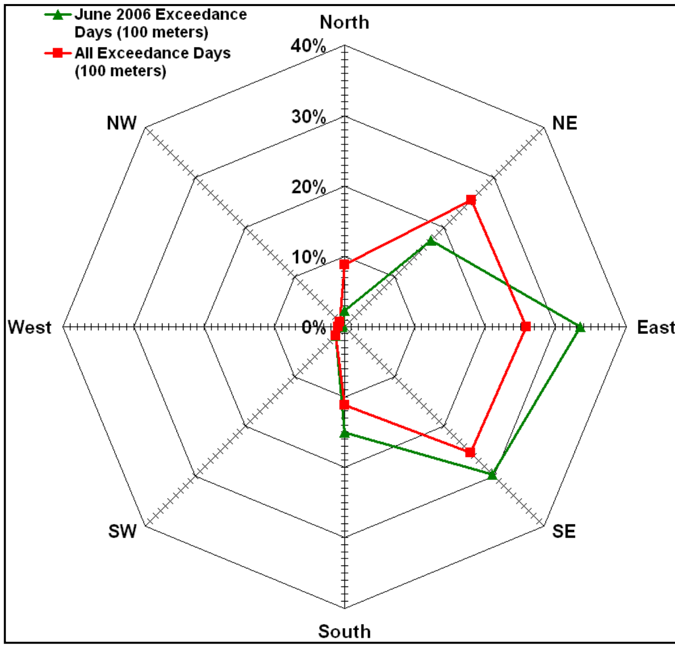
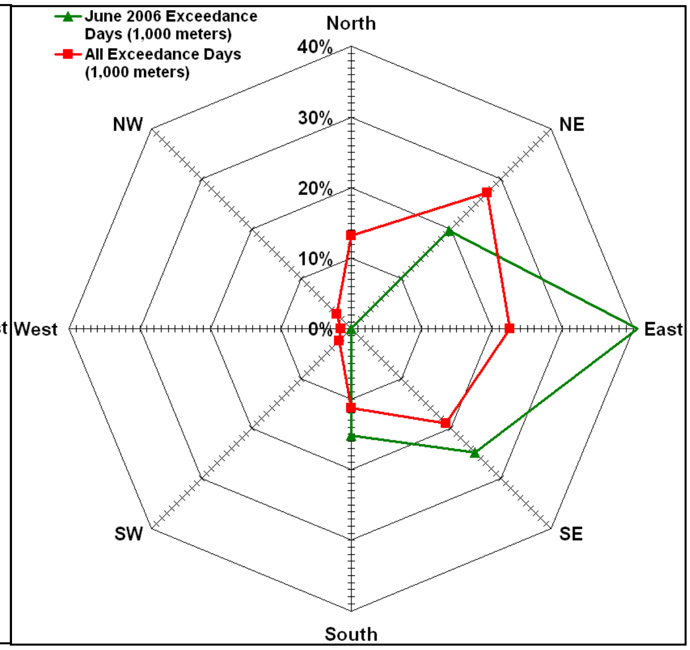


Figure 2-3: Statistical Analysis of San Antonio's 250-mile 1,000-meter Back Trajectory Wind Directions: All Exceedance Days 2005-2008 and June 2006 Exceedance Days

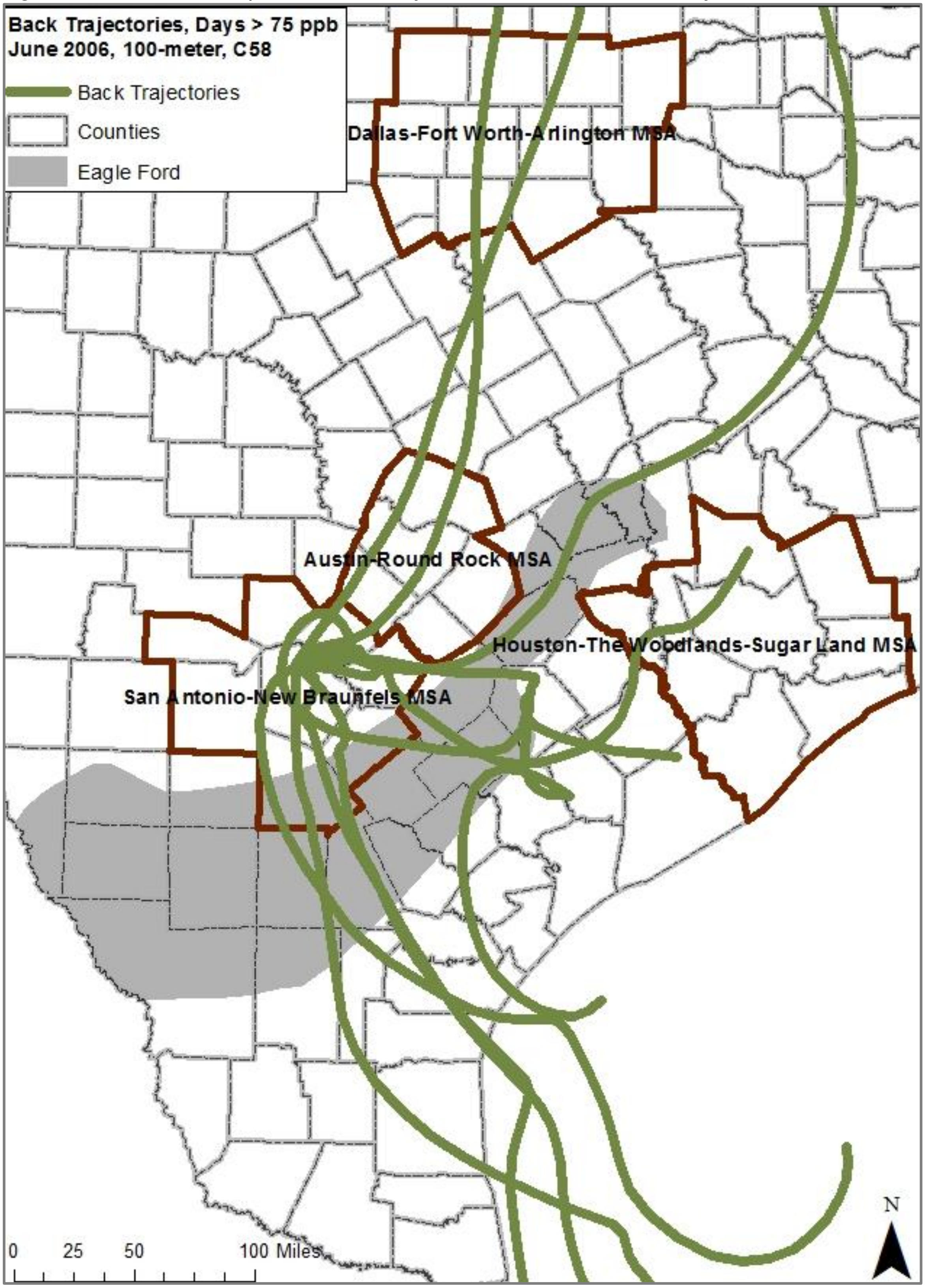


2.5.7 Mixing Height

Mixing heights were also examined to determine if typical meteorological conditions occurred during the June 2006 episode. In 2005, a profiler was installed near New Braunfels, Texas in Guadalupe County for the purpose of recording meteorological data aloft. The profiler operated from June 29 to August 31, 2005 and from May 30 to October 16, 2006. Mixing height at the profiler was available on all 10 exceedance days during the June 2006 episode and 19 exceedance days total between 2005 and 2006. Figure 2-5 compares the hourly mixing height measures for all exceedance days when the profiler was operating, June 2006 exceedance days, and days when peak 8-hour ozone was less than 40 ppb.

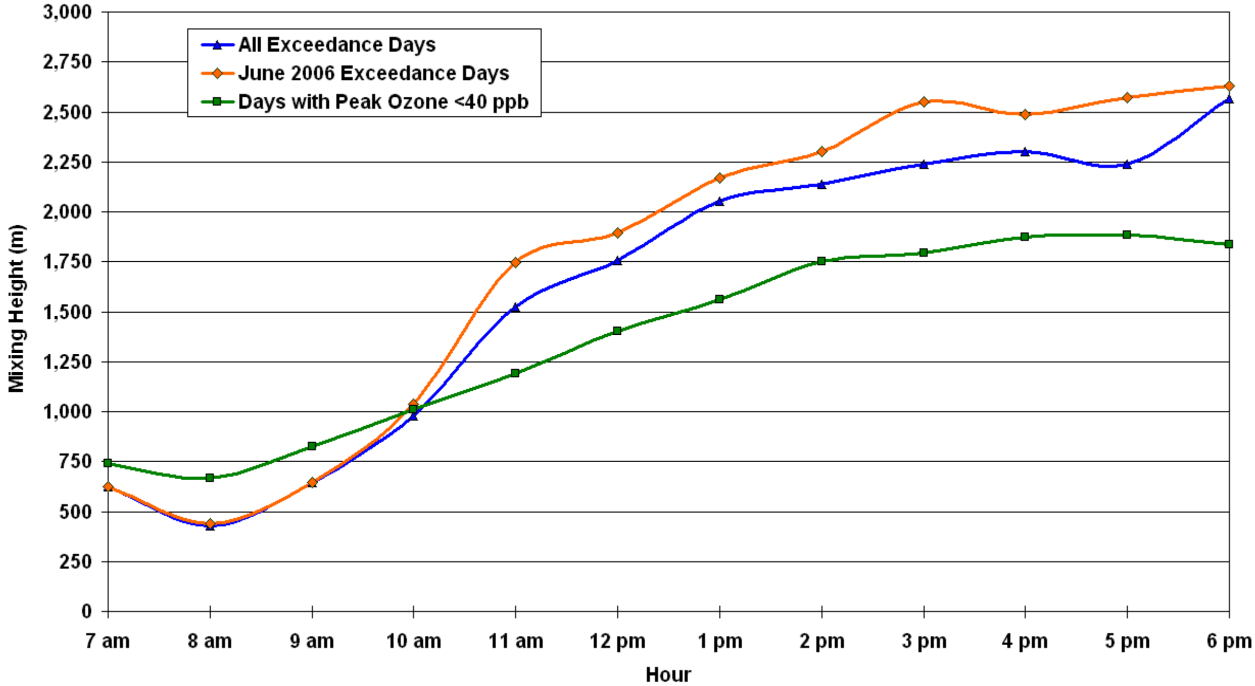
The mixing height pattern during the June 2006 episode corresponded with mixing heights for all exceedance days. In both cases, the mixing height on ozone exceedance days was lower at night than average, which can result in a concentration of pollutants near the surface. As temperatures increased in the morning, there was a rapid rise in mixing height that allowed transported pollutants aloft to mix with local concentrations and form elevated ozone at surface monitors. During days in which peak 8-hour average ozone concentrations were less than 40 ppb between 2005 and 2006, mixing heights before 9 a.m. were higher and the mixing height rose more gently during the morning than on exceedance days.

Figure 2-4: June 2006 Episode Back Trajectories on Exceedance Days



Plot Date: June 21, 2013
Map Compilation: June 21, 2013
Source: Hysplit Model

Figure 2-5: Hourly Mixing Height Measures for all Exceedance days, June 2006 Exceedance days, and Days with Peak Ozone < 40 ppb at New Braunfels Profiler



2.5.8 High Ozone Values and Design Values

During the June 2006 episode, observed ozone concentrations were close to the baseline site-specific design value. The June 2006 episode contains ozone exceedances in which observed concentrations are close to the site-specific design values. Of the 31 exceedances recorded at regulatory monitors during the episode, 28 were within 10 ppb of the site-specific modeling design value (Table 1-4). On June 13th, C23 and C58 measured ozone exceedances that were11 ppb and 13 ppb greater than the site-specific design value. Significantly higher temperatures were observed on this day compared to other exceedance days and there were strong indications of a large local contribution to ozone measurements at both monitors.

Table 2-4: June 2006 Site-Specific Weighted Modeling Design Values and Percentage of Daily Ozone Readings within ±10 ppb

Monitoring Site	Weighted 2006 Modeling Design Value	Number of Exceedance Days (>75 ppb)	Number of Exceedance Days within 10 pbb	% of Days within 10 ppb
SA Northwest C23	79	6	5	83%
Camp Bullis C58	82	9	8	89%
Calaveras Lake C59	75	6	5	83%
Heritage C622	74	5	5	100%
Pecan Valley C678	74	6	6	100%
Total		31	28	90%

2.5.9 *One-hour and Eight-hour Average Ozone Correlation*

There is a strong correlation between peak one-hour and eight-hour average ozone concentrations during the June 2006 modeling episode. The average difference between peak one-hour and eight-hour ozone on all exceedance days between 2000 and 2008 is 10.87 ppb with a standard deviation of 5.25 ppb at regulatory monitors. The correlation between one-hour and eight-hour peak ozone concentrations was within one standard deviation on all but two modeling days, June 14th and June 29th (Table 2-5). On both days, the peak one-hour ozone reading was close to the peak eight-hour average. C23 and C58 recorded high, sustained ozone readings for seven to nine hours on these days.

Table 2-5: Observed and Predicted Correlation with Trend Line, June 2006

Exceedance Day	Peak 1-hr O_3 at Regulatory Monitors (ppb)	Peak 8-hr O_3 at Regulatory Monitors (ppb)	Diff. between 1-hr and 8-hr O_3 (ppb)	Within 1 Standard Deviation	Predicted 1-Hr Daily High O_3 (ppb)	Observed 1-Hr - Predicted 1-Hr O_3 (ppb)
3	86	80	6.0	Yes	90.5	-4.5
7	87	76	11.0	Yes	86.0	1.0
8	96	84	12.0	Yes	94.9	1.1
9	86	77	9.0	Yes	87.1	-1.1
13	106	93	13.0	Yes	105.0	1.0
14	94	90	4.0	**No**	101.7	-7.7
26	86	78	8.0	Yes	88.2	-2.2
27	88	82	6.0	Yes	92.7	-4.7
28	97	87	10.0	Yes	98.3	-1.3
29	94	91	3.0	**No**	102.8	-8.8

2.5.10 *TexAQSII Data*

Extensive air quality and meteorological databases were available to enhance modeling of the June 2006 episode as a result of the Texas Air Quality Study II (TexAQSII) conducted by TCEQ during the 2005 and 2006 ozone seasons. "TexAQSII is a comprehensive research initiative to better understand the causes of air pollution. The study gathers technical information for policy makers to help them design plans that will clean the air in Texas." [26] Information collected during TexAQSII provided additional meteorological data, including local wind profiler data, useful for improving meteorological model performance.

2.5.11 *Secondary Selection Criteria*

The decision to model the June 2006 episode was supported by secondary selection criteria, i.e., the episode coincides with ozone exceedances in other urban areas and the episode includes a weekend exceedance. Multiple regions of Texas experienced elevated ozone levels during the June 2006 episode including Austin, Dallas, Houston, and San Antonio. The benefits of developing a model covering four regions included cost sharing and a consistent base case on which to model clean air strategies. TCEQ conducted the initial work on the June 2006 meteorological modeling, which lowered the cost of model development.

[26] TCEQ, Nov. 2007. "TexAQS II." Austin, Texas. Available online: http://www.tceq.texas.gov/airquality/research/texaqs. Accessed 06/24/13.

The June 2006 ozone episode included one weekend exceedance day, June 3rd. Ozone exceedances that occur on weekend days often result from a different mix of emissions and 8-hour ozone spatial patterns compared to weekdays. To properly test control strategy effectiveness, which is the ultimate goal of developing photochemical model simulations, it is advisable to include weekends as well as weekdays in the modeled episode.[27]

2.6 Modeling Domain

The modeling domain identifies the geographic boundaries of the study area including the horizontal grid, vertical layers, and initial and boundary conditions. When selecting the modeling domain, all major upwind continental emission sources should be included in the model. The June 2006 meteorological and photochemical modeling domains include all of the eastern and central U.S. as well as parts of southeastern Canada and northern Mexico. The modeling domains are large enough to capture major sources that would be upwind from San Antonio, as winds tend to arrive from the southeast, east, and northeast on ozone exceedance days.[28]

The CAMx photochemical model utilizes a nested grid system that geographically distributes emissions. The fine grid (or 4 kilometer grid) allows for high spatial resolution at the local level. Data from regions outside the 4-kilometer grid are assigned to coarser grids where geographic accuracy is less important. This allows the majority of the computer resources be used to run the model at the 4-km fine-grid level. The EPA recommends establishing the size of the fine grid based on several factors including:

1) "The size of the non-attainment area.
2) Proximity to other large source areas and/or non-attainment areas.
3) Proximity of topographical features, which appear to affect observed air quality.
4) Whether the model application is intended to cover multiple non-attainment areas.
5) Typical wind speeds and re-circulation patterns.
6) Whether the photochemical model utilizes one-way or two-way nested grids.
7) Computer and time resource issues."[29]

2.6.1 Meteorological Horizontal Grid

For development of the WRF model, TCEQ used a nested 4-km grid that encompasses eastern Texas and portions of Louisiana, the Gulf of Mexico, Oklahoma, and Arkansas. The coarse grid covers all of the continental US, southern Canada, northern Mexico, and parts of the Caribbean.

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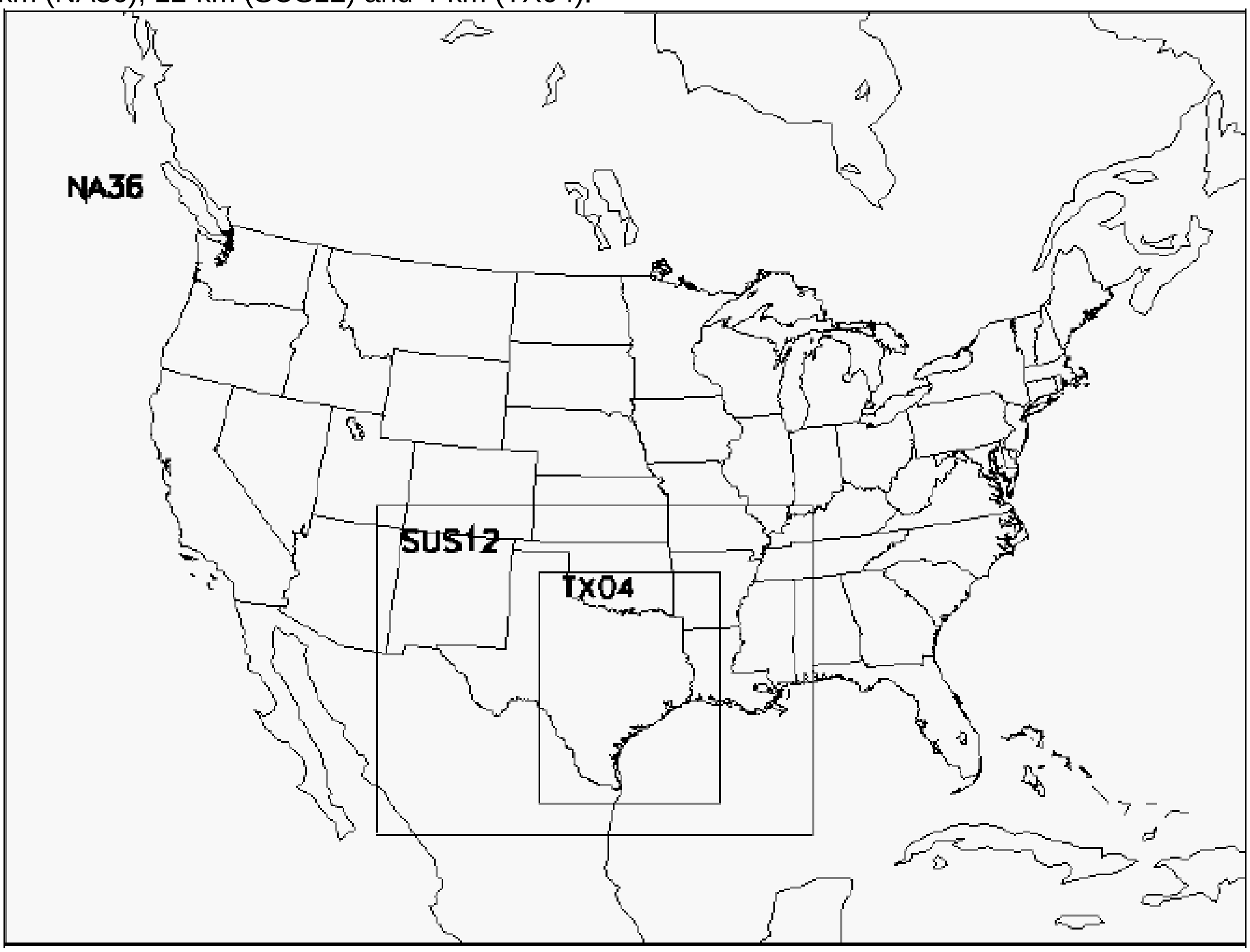
[27] EPA, April 2007. "Guidance on the Use of Models and Other Analyses for Demonstrating Attainment of Air Quality Goals for Ozone, PM2.5, and Regional Haze." EPA -454/B-07-002. Research Triangle Park, North Carolina. pp. 150 - 151. Available online: http://www.epa.gov/scram001/guidance/guide/final-03-pm-rh-guidance.pdf. Accessed 06/24/13.

[28] AACOG, April 2009. "Conceptual Model - Ozone Analysis of the San Antonio Region: Updates through Year 2008". San Antonio, Texas.

[29] EPA, April 2007. "Guidance on the Use of Models and Other Analyses for Demonstrating Attainment of Air Quality Goals for Ozone, PM2.5, and Regional Haze." EPA -454/B-07-002. Research Triangle Park, North Carolina. p. 153. Available online: http://www.epa.gov/scram001/guidance/guide/final-03-pm-rh-guidance.pdf. Accessed 06/24/13.

The grids have resolutions of 36-km, 12-km, and 4-km, and the number of rows and columns for each grid is 162x128, 174x138, and 216x218, respectively (Figure 2-6).[30] The two coarse domains were run with two-way nesting using 1 point feedback with light smoothing, while the 4-km domain was run with one-way nesting. The MM5 model was run with overlaps between the grid domains to avoid adverse boundary effects at the edges of the 4-km, 12-km, and 36-km nested grids. To ensure accurate modeling results, the photochemical modeling domains at each grid level are contained within the meteorological grid domains.

Figure 2-6: WRF domains used for model simulations in three different spatial resolutions: 36-km (NA36), 12-km (SUS12) and 4-km (TX04).



Domain name	**NA36**	**SUS12**	**TX04**
Resolution	36 km	12 km	4 km
Domain coverage	Continental US	Texas & adjoined states	Eastern Texas
Horizontal grid	162 x 128	174 x 138	216 x 288

30 Pius Lee, Hyun-Cheol Kim, and Fantine Ngan, Air Resources Laboratory National Oceanic and Atmospheric Administration U.S. Department of Commerce, March 15, 2012. "Investigation of nocturnal surface wind bias by the Weather Research and Forecasting (WRF)/ Advanced Research WRF (ARW) meteorological model for the Second Texas Air Quality Study (TexAQS-II) in 2006". Silver Spring, Maryland P. 8. Available online: http://www.tceq.texas.gov/assets/public/implementation/air/am/contracts/reports/mm/5820886246FY12-20120315-noaa-wrf_wind_bias.pdf. Accessed 06/21/13.

2.6.2 Photochemical Horizontal Grid

The photochemical modeling domain covers a much larger geographical area than southern Texas alone to reduce the influence of boundary conditions (Figure 2-7). The larger domain is necessary to simulate the effects of meteorological and atmospheric processes, including transport of precursors and background concentrations of ozone, on the San Antonio region. The 48-hour back trajectories for the 2006 episode originated as far away as Kansas, Oklahoma, and the Gulf of Mexico. Consequently, the 36-km coarse grid used in the model simulation (US 36km) extends throughout the central and eastern U.S. to reduce the impact from boundary conditions on the 4-km grid. The larger 36 km grid, RPO 36km, will be used in the future to improve modeling performance.

The 4km grid includes ozone pre-cursor emissions from all major cities in Eastern Texas including San Antonio, Austin, Corpus Christi, Dallas, and Houston. The grid system used in the model is consistent with EPA's Regional Planning Organizations (RPO) Lambert Conformal Conic map projection with the following parameters:

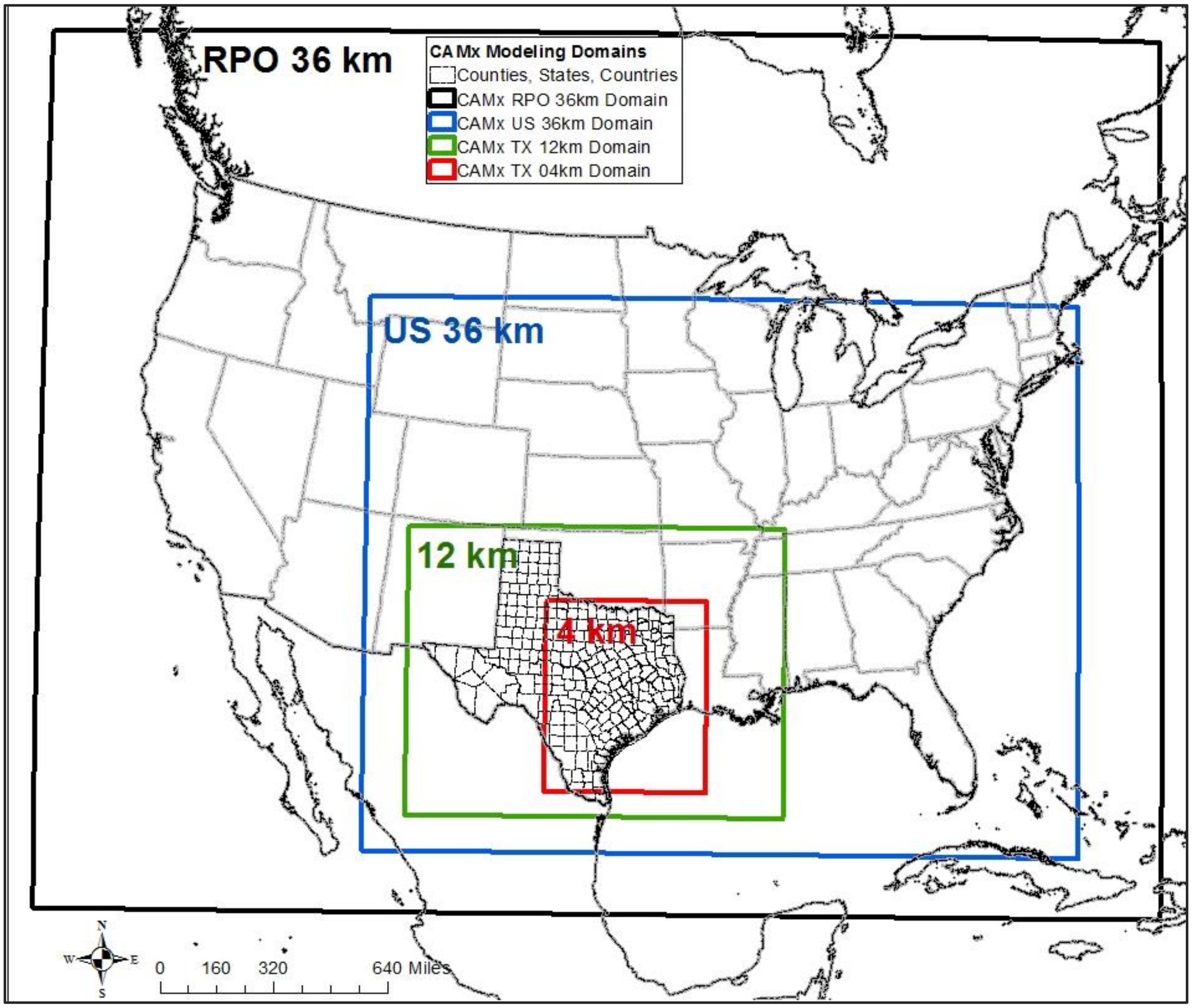
- First True Latitude (Alpha): 33°N
- Second True Latitude (Beta): 45°N
- Central Longitude (Gamma): 97°W
- Projection Origin: (97°W, 40°N)
- Spheroid: Perfect Sphere, Radius: 6,370 km[31]

2.6.3 Vertical Layers

The vertical structures used in the WRF and CAMx models are listed in Table 2-6. The meteorological model has 38 vertical layers extending from the surface up to approximately 15-km, while the CAMx model uses 28 vertical layers up to approximately 13.6 km. The surface layer is roughly 34-m thick.[32] The meteorological and photochemical layers are finer at the surface to capture vertical gradients as the mixing height changes during the day and to model pollutant concentrations at the surface.

[31] TCEQ. "Rider 8 State and Local Air Quality Planning Program - Modeling Domains". Austin, Texas. Available online: http://www.tceq.texas.gov/airquality/airmod/rider8/modeling/domain. Accessed 06/10/13.
[32] Susan Kemball-Cook, Yiqin Jia, Ed Tai, and Greg Yarwood August 31, 2007. "Performance Evaluation of an MM5 Simulation of May 29-July 3, 2006." Prepared for Texas Commission on Environmental Quality. ENVIRON International Corporation, Novato, CA. p. 2-1. Available online: http://www.tceq.state.tx.us/assets/public/implementation/air/am/contracts/reports/mm/2006_MM5_Modeling_Final_Report-20070830.pdf. Accessed 06/24/13.

Figure 2-7: Nested Photochemical Modeling Grids for June 2006 Episode[33]
Coordinates from NW to SE corners:



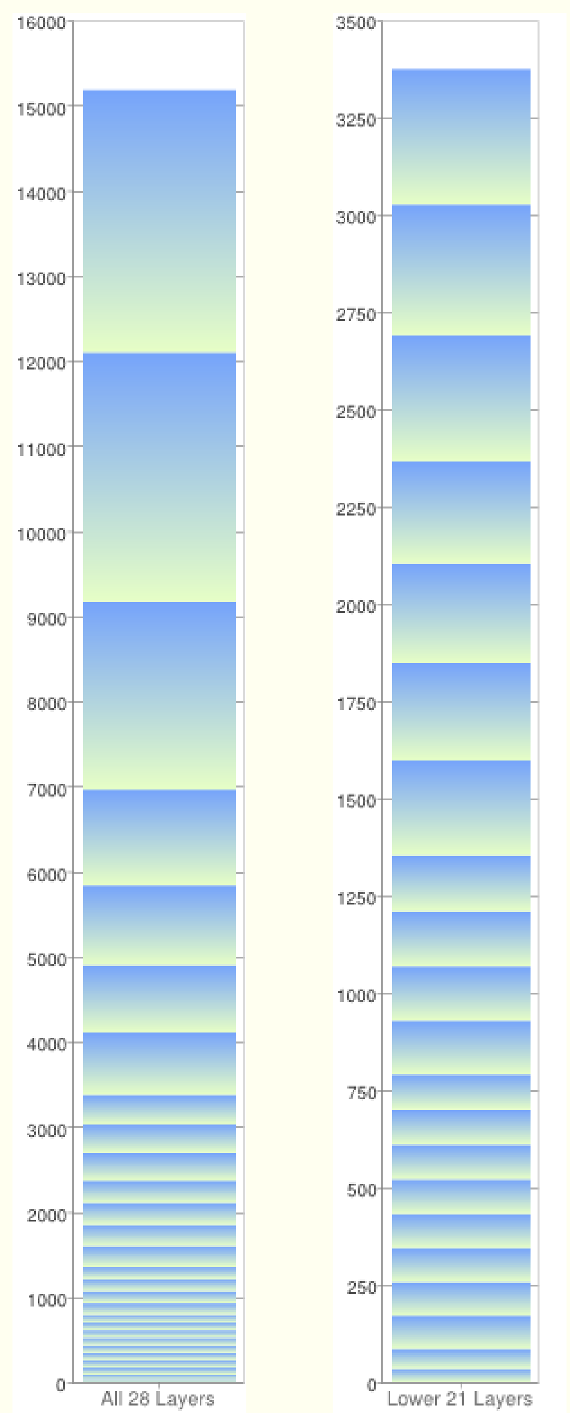
CAMx RPO 36-km	= 148 x 112	(-2,736, 1,944) to	(2,592, -2,088)
CAMx US 36-km	= 94 x 70	(-1,188, 720) to	(2,196, -1,800)
CAMx TX 12-km	= 149 x 110	(-984, -312) to	(804, -1,632)
CAMx TX 4-km	= 191 x 218	(-328, -644) to	(436, -1,516)

Plot Date: June 10, 2013
Map Compilation: June 10, 2013
Source: TCEQ.

[33] ENVIRON, June 30, 2009. "Application of CAMx for the Austin San Antonio Joint Meteorological Model Refinement Project". prepared by Chris Emery, Jeremiah Johnson, and Piti Piyachaturawat of ENVIRON International Corporation, Air Sciences Group, Novato, CA, p. 1-2.

Table 2-6: WRF and CAMx Vertical Layer Structure[34]

Corresponding WRF Layer	Layer Top (m AGL)	CAMx Layer	Layer Center (m AGL)	Thickness (m)
38	15179.1	28	13637.9	3082.5
36	12096.6	27	10631.6	2930.0
32	9166.6	26	8063.8	2205.7
29	6960.9	25	6398.4	1125.0
27	5835.9	24	5367.0	937.9
25	4898.0	23	4502.2	791.6
23	4106.4	22	3739.9	733.0
21	3373.5	21	3199.9	347.2
20	3026.3	20	2858.3	335.9
19	2690.4	19	2528.3	324.3
18	2366.1	18	2234.7	262.8
17	2103.3	17	1975.2	256.2
16	1847.2	16	1722.2	249.9
15	1597.3	15	1475.3	243.9
14	1353.4	14	1281.6	143.6
13	1209.8	13	1139.0	141.6
12	1068.2	12	998.3	139.7
11	928.5	11	859.5	137.8
10	790.6	10	745.2	90.9
9	699.7	9	654.7	90.1
8	609.7	8	565.0	89.3
7	520.3	7	476.1	88.5
6	431.8	6	387.9	87.8
5	344.0	5	300.5	87.1
4	256.9	4	213.8	86.3
3	170.6	3	127.8	85.6
2	85.0	2	59.4	51.0
1	33.9	1	17.0	33.9



AGL - Above Ground Level

[34] TCEQ. "Rider 8 State and Local Air Quality Planning Program - Modeling Domains". Austin, Texas. Available online: http://www.tceq.texas.gov/airquality/airmod/rider8/modeling/domain. Accessed 06/10/13.

2.7 Meteorological Model Parameters

A meteorological model was developed to simulate the meteorological conditions that occurred during the 2006 high ozone episode. This process involved selecting the meteorological model (WRF), determining the time period, defining the region, and obtaining data inputs. The data output from the meteorological model was used as input for the photochemical model in order to simulate processes that form, transport, and remove ozone and ozone pre-cursor pollutants. Meteorological inputs into the photochemical model include mixing heights, wind speeds, wind direction, vertical mixing, temperature, and other meteorological parameters. .

The WRF model was run using a diffusion package called the Yonsei University planetary boundary layer (YSU PBL) at each grid level. "The YSU PBL increases boundary layer mixing in the thermally induced free convection regime and decreases it in the mechanically induced forced convection regime, which alleviates the well-known problems in the Medium-Range Forecast (MRF) PBL."[35] The Kain-Fritsch cumulus one-dimensional cloud model was used to simulate cloud formation in each grid level.[36] The WRF-Single-Moment 5-clasee Microphysics scheme (WSM5) was used for the 36km and 12km grids, while the WRF-Single-Moment 6-clasee Microphysics scheme (WSM6) was used for the 4km grid. The WSM5 and WSM6 microphysics were used to determine condensation, precipitation, and thermodynamic effects of latent heat release

The WRF model includes a 5 layer thermal diffusion and no land use model. Wind data from the National Oceanic and Atmospheric Administration (NOAA) Profiler Network (NPN) troposphere profilers[37] were used to perform nudging in the updated meteorological runs. The process was performed "to nudge model predictions towards observational analysis and/or discrete measurements to control model 'drift' from conditions that actually occurred."[38]

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[35] Hong, Song-You, Yign Noh, Jimy Dudhia, 2006. "A New Vertical Diffusion Package with an Explicit Treatment of Entrainment Processes ".Mon. Wea. Rev., 134, 2318–2341. Available online: http://journals.ametsoc.org/doi/full/10.1175/MWR3199.1. Accessed 06/21/13.

[36] Kain, John S., J. Michael Fritsch, 1990. "A One-Dimensional Entraining/Detraining Plume Model and Its Application in Convective Parameterization". J. Atmos. Sci., 47, 2784–2802. Available online: http://journals.ametsoc.org/doi/abs/10.1175/1520-0469%281990%29047%3C2784%3AAODEPM%3E2.0.CO%3B2. Accessed 06/21/13.

[37] National Oceanic and Atmospheric Administration. "NOAA Profiler Network." Available online: http://www.profiler.noaa.gov/npn/. Accessed 06/21/13.

[38] Susan Kemball-Cook, Yiqin Jia, Ed Tai, and Greg Yarwood August 31, 2007. "Performance Evaluation of an MM5 Simulation of May 29-July 3, 2006." Prepared for Texas Commission on Environmental Quality. ENVIRON International Corporation, Novato, CA. p. 2-3. Available online: http://www.tceq.state.tx.us/assets/public/implementation/air/am/contracts/reports/mm/2006_MM5_Modeling_Final_Report-20070830.pdf. Accessed 06/24/13.

3 Base Case Emissions Inventory

Three anthropogenic emission inventories were created for the June 2006 modeling episode: 2006 base line inventory, 2012 projection case, and 2018 projection case. The model was run with each of these emission inventories to predict the impact of emissions changes over time – both quantitative and spatial – on ozone formation and dispersion. Model inputs accounted for the chemical and meteorological characteristics associated with the May 31st to July 2nd, extended 2006 episode. Also, three different projection scenarios for emissions from oil and gas development and production in the Eagle Ford Shale region were developed for the 2018 projection case. The meteorological inputs, chemistry parameters, and biogenic emissions were identical for every model run.

The 2006 base case inventory was used to validate the meteorological and photochemical model. To determine if the meteorological model and emission inventory are representative of the May 31st to July 2nd, 2006 episode, photochemical model performance was reviewed and analyzed. Precursor emissions and ozone concentrations in the photochemical model were evaluated to determine if locations, concentrations, and timing of emissions met performance criteria. The 2006 base case inventory was projected to 2012 and 2018 using EPA approved methodologies, local emissions, point sources added since 2006, and proposed new power plants to calculate future emissions. The 2012 and 2018 future year inventories were developed using the same hourly adjustment and emission calculation methodologies used in the base case inventory.

Before the emission inventories were entered into the photochemical model, the emissions were pre-processed using the Emissions Processor version 3 (EPS3)[39] to allocate the data to the proper spatial and temporal resolutions used by the photochemical model. The Emissions Processor allocates emissions to account for monthly, weekly, and hourly variations in emission rates, assigns emissions to the appropriate grid cells, and disaggregates or speciates chemical compounds for the photochemical model's chemical mechanism. To accurately predict ozone formation, the photochemical model requires a detailed emission inventory for every grid used in the model.

3.1 Emission Inventory Parameters

CO, speciated NO_X, and speciated VOC emissions from all anthropogenic and biogenic sources were included in the model for all grid domains. Emissions data was processed through EPS3 for the following source categories:

1. Biogenic Sources
2. Point Sources
3. Area
4. Non-Road
5. Off-Road

[39] ENVIRON International Corporation, August 2009. "User's Guide Emissions Processor Version 3". Novato, CA. Available online: ftp://amdaftp.tceq.texas.gov/pub/HGB8H2/ei/EPS3_manual/EPS3UG_UserGuide_200908.pdf. Accessed 06/27/13.

6. Mobile Sources
7. Eagle Ford

The emissions for each of these categories were temporally allocated to the appropriate hours, week days, and seasons based on data obtained from surveys of local sources. In the absence of survey data, EPA defaults or other appropriate surrogates were used.

Monthly Adjustments

Since the National Emissions Inventories (NEI)[40] was estimated based on average ozone season day, emissions sources, including on-road, recreational marine vessels, pesticides, agriculture equipment, fertilizers, and defoliants, were adjusted to account for seasonal differences in usage and temperatures. For example, use of agricultural pesticides increases during the spring and summer growing seasons. Monthly adjustment values were based on survey results from local emissions sources or EPA defaults.[41]

Weekly and Daily Adjustments

The release of pollutants does not occur at a steady rate per unit of time, so allocation of emissions to a desired weekly time-period is recommended. "Under actual conditions, emissions sources may not operate on Sundays, or their activity may peak during certain hours of the day. Temporal allocations allows for emissions variability during the desired modeling periods to be modeled correctly. The desired modeling periods vary depending upon the purpose of the inventory."[42]

Weekly adjustment values were based on survey results from local emissions sources and EPA Defaults.[43] On-road vehicles, extended diesel truck idling, quarry equipment, industrial equipment, construction equipment, and commercial lawn and garden equipment are examples of emissions sources that typically operate more frequently on weekdays as compared to weekend days. Other sources, including recreational marine vessels and recreational equipment, operate more often on weekends.

Hourly Adjustments

Hourly adjustment factors were calculated based on the results of locally conducted surveys or obtained from values published by TTI, ERG, ENVIRON, TCEQ, and EPA. CPS Energy provided hourly emissions data for each power plant. San Antonio International Airport (SAIA) and other regional airport emissions were allocated hourly based on operational data from the Airport IQ Data center.[44]

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[40] EPA. March 15, 2013. "The National Emissions Inventory. Available online: http://www.epa.gov/ttnchie1/eiinformation.html. Accessed 06/27/13.
[41] EPA. May 3, 2007. "Emissions Modeling Clearinghouse Temporal Allocation". Available online: http://www.epa.gov/ttn/chief/emch/temporal/. Accessed 6/27/13.
[42] *Ibid*.
[43] EPA. May 3, 2007. "Emissions Modeling Clearinghouse Temporal Allocation." Available Online: http://www.epa.gov/ttn/chief/emch/temporal/. Accessed 06/27/13.
[44] GCR & Associates, Inc., 2005. "Airport IQ Data Center". Available Online: http://www.airportiq.com/. Accessed 09/17/2009

3.2 Conversion of Inventory Data into the Photochemical Model Ready Files

Spatial Allocation

The coarse 36km grid used in the photochemical model encompasses all anthropogenic and biogenic emissions in the continental United States, southern Canada, and northern Mexico. Emissions data was allocated to each grid cell for the entire domain; elevated point sources emissions and SAIA aircraft operations were allocated both spatially and vertically.

Local emissions were allocated spatially using Google Earth[45] and ArcGIS. These programs were used to calculate the fraction of county total emissions in each grid cell based on surrogate data. Local data included roadway types, truck stops, employment, population, navigable lake acreage, and data collected for industrial sites, landfills, quarries, and highway construction projects. When emission sources were insignificant or local data was not available, EPA default spatial allocation factors were used.

Chemical Speciation

All VOC and NO_X emissions were chemically speciated in EPS3 based on the latest version of the carbon bond mechanism design, Carbon Bond 6 (CB6). This mechanism is critical because it provides the link between ozone precursors and ozone formation in the CAMx model. CB6 was developed in 2010 by ENVIRON and is now being used in SIP applications across the United States. As noted by ENVIRON, the updates to the CB6 mechanism from the previous chemical speciation mechanism, version 5 of the Carbon Bond Mechanism (CB05), are:

1. "Incorporating new scientific information released since the previous mechanism update in 2005 (CB05)
2. Reviewing and updating reactions for alkanes, alkenes and aromatics with the most changes resulting for isoprene and aromatics.
3. Adding explicitly several long-lived VOCs that form ozone at regional scales, specifically propane, benzene, acetone and other ketones.
4. Adding explicitly acetylene and benzene because they are precursors to Secondary organic aerosol (SOA) formation and useful as anthropogenic emission tracers.
5. Adding explicitly VOC degradation products that can produce SOA via aqueous-phase reactions, specific"[46]

By updating to CB6 in the model, "The number of reactions is about 40% greater and the number of species about 50% greater in CB6 than CB05".[47]

3.3 Quality Assurance

"An overall QA program comprises two distinct components. The first component is that of quality control (QC), which is a system of routine technical activities implemented by inventory development

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[45] Google. "Google Earth". Available online: http://www.google.com/earth/index.html. Accessed 06/27/13.

[46] Greg Yarwood, Jaegun Jung, Gary Z. Whitten, Gookyoung Heo, Jocelyn Mellberg, and Mark Estes, Oct. 2010. "Updates to the Carbon Bond Mechanism for Version 6 (CB6)". Presented at the 9th Annual CMAS Conference, Chapel Hill, NC, October 11-13, 2010. p. 2. Available online: http://www.cmascenter.org/conference/2010/abstracts/emery_updates_carbon_2010.pdf. Accessed 06/27/13.

[47] *Ibid*.

personnel to measure and control the quality of the inventory as it is being developed. The QC system is designed to:

1. Provide routine and consistent checks and documentation points in the inventory development process to verify data integrity, correctness, and completeness;
2. Identify and reduce errors and omissions;
3. Maximize consistency within the inventory preparation and documentation process; and
4. Facilitate internal and external inventory review processes.

QC activities include technical reviews, accuracy checks, and the use of approved standardized procedures for emission calculations. These activities should be included in inventory development planning, data collection and analysis, emission calculations, and reporting."[48]

Equations, data sources, and methodologies were checked throughout the processing of each emission source. "Simple QA procedures, such as checking calculations and data input, can and should be implemented early and often in the process. More comprehensive procedures should target:

- Critical points in the process;
- Critical components of the inventory; and
- Areas or activities where problems are anticipated"[49]

Quality assurance (QA) procedures used to check emissions inventory preparation for the photochemical mode included:

- Examination of raw data files for inconsistencies in emissions and/or locations,
- Review of message files from EPS3 scripts for errors and warnings,
- Verification of consistency between input and output data, and
- Creation of output emissions tile plots for visual review.

Special emphasis was placed on critical components, such as on-road vehicles, Eagle Ford emission sources, and point sources, for quality checks.

All raw data files were checked to ensure emissions were consistent by county and source type. Any inconsistencies were noted, checked, and corrected. When running the EPS3 job scripts, several message files are generated from each script that record data inputs, results, and errors. As part of the QA procedure, modeling staff reviewed all error messages and corrected the input data accordingly.

Errors can occur in EPS3 and go unnoticed by the built-in quality assurance mechanisms; therefore further QA methods were applied. Input and output emissions by source category were compared. If there were inconsistencies between values, input data was reviewed and any necessary corrections were made. Emission tile plots by source category were also developed and reviewed for

[48] Eastern Research Group, Inc, Jan. 1997. "Introduction: The Value of QA/QC'. Quality Assurance Committee Emission Inventory Improvement Program, U.S. Environmental Protection Agency. p. 1.2-1. Available online: http://www.epa.gov/ttn/chief/eiip/techreport/volume06/vi01.pdf. Accessed 06/04/2012.
[49] *Ibid*., p. 1.2-2.

inconsistencies in emissions and spatial allocation. When errors and omissions were identified, they were corrected and all documentation was updated with the corrections.

3.4 Base Case Inventory

The modeling grid used in the photochemical model covers the eastern United States, southern Canada, and northeastern Mexico. To accurately predict local ozone concentrations and to determine the impact of transport, emission inventories were calculated for the complete photochemical model domain. Figure 2-7, located in the previous section, displays the photochemical modeling domain used to simulate the May 31st to July 2nd, 2006 high ozone episode. The figure indicates the boundaries of the 36-km, 12 km, and 4-km modeling grids.

Providing accurate emission rates, locations, and timing for all emission inputs in the modeling domain is essential for predicting ozone levels at local monitors. Following EPA guidelines, the most critical emission inventory is the local San Antonio-New Braunfels MSA emissions inventory[50] because these emissions are emitted near San Antonio's regulatory monitors and previous modeling predicted that local emissions account for 25 percent of recorded ozone at C23 and C58 monitors.[51] Local emissions were calculated using the most current, accurate, and practical methods available including the use of local data and surveys.

Adjacent and nearby areas with large emission sources can also have a significant impact on local ozone monitors. Back trajectory analysis indicates Austin, Houston, Dallas, Corpus Christi, and other large, southern United States cities can significantly influence local ozone readings.[52] Determining accurate emissions inventories for these areas are essential for good model performance. Detailed emissions inventories were developed by TCEQ for other counties in Texas. Emission inventories were also developed by the EPA for other states in the modeling domain[53] and Mexico[54]. The detailed emission inventory for Canada was developed by Environment Canada.[55] Since EPA lowered the ozone standard to a 75 ppb threshold, the impact of long-range transport can have a greater impact on local ozone concentrations.

Local emissions in the San Antonio-New Braunfels MSA were obtained from AACOG EI updates, TCEQ, ERG, and Texas Transportation Institute (TTI). All emission inventory inputs in the modeling domain were calculated using EPA approved methodologies and data sources. Data sources for the modeled emissions inventory in the United States are listed in Table 3-1.

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[50] EPA, April 2007. "Guidance on the Use of Models and Other Analyses for Demonstrating Attainment of Air Quality Goals for Ozone, PM2.5, and Regional Haze," EPA -454/B-07-002. Research Triangle Park, North Carolina. p. 172. Available online: http://www.epa.gov/scram001/guidance/guide/final-03-pm-rh-guidance.pdf. Accessed 06/24/13.

[51] Alamo Area Council of Governments, April 2009. "Conceptual Model –Ozone Analysis of the San Antonio Region: Updates through Year 2008." San Antonio TX.

[52] *Ibid*.

[53] EPA. "National Emissions Inventory (NEI) Air Pollutant Emissions Trends Data". Available online: http://www.epa.gov/ttnchie1/trends/. Accessed 07/01/13.

[54] EPA, Oct. 2006. "North American Emissions Inventories – Mexico". Available online: http://www.epa.gov/ttnchie1/net/mexico.html. Accessed 07/08/13.

[55] Environment Canada. "National Pollutant Release Inventory". Available online: http://www.ec.gc.ca/inrp-npri/default.asp?lang=En&n=4A577BB9-1. Accessed 07/08/13.

3.5 Biogenic Emissions

Biogenic emissions originate from natural sources due to chemical processes in vegetation and soil. These include emission of ozone precursor chemicals: NO_X, VOC and CO. Day-specific, gridded, hourly biogenic emissions for the 4 km and 12 km grids were developed by the Department of Ecosystem Science & Management at the Texas A&M University. To create the necessary biogenic emissions inventory, an "expansion of Texas Land Use/Land Cover through Class Crosswalking and light detection and ranging (lidar) Parameterization of Arboreal Vegetation project" was used.[56]

"This expansion was used to provide a more detailed and accurate map of land cover necessary for air quality modeling for the 12km Comprehensive Air Quality Model with Extensions (CAMx) domain. The project consisted of crosswalking classes from the LANDFIRE and Texas Parks and Wildlife Vegetation classes and classifying LandSat imagery to the Texas Land Classification System, and to derive forest composition characteristics with lidar for more accurate biogenic emission modeling. Lidar was used to estimate tree height, canopy base height, diameter at breast height, individual tree biomass, and canopy bulk density. Individual trees were identified through lidar and the TreeVaw software, which uses a local maxima varying filter".[57] "LANDFIRE is a program that provides over 20 national geo-spatial layers (e.g. vegetation, fuel, disturbance, etc.), databases, and ecological models that are available to the public for the US and territories."[58] The temperatures used to calculate biogenic emissions are based on calculated modeling surface temperatures from the WRF meteorological model for the June 2006 modeling episode.

For the 36km grid, biogenic emissions were developed by TCEQ using BEIS. The BEIS model "requires a land use database known as the Biogenic Emissions Landuse Database, version 3 (BELD3). BELD3 data provides distributions of 230 vegetation classes at 1km resolution over most of North America."[59]

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[56] Sorin C. Popescu "Expansion of Texas Land Use/Land Cover through Class Crosswalking and Lidar Parameterization of Arboreal Vegetation". Texas A&M University. TCEQ Grant # 582-5-64593-FY09-25. p. 1. Available online: http://www.tceq.texas.gov/assets/public/implementation/air/am/contracts/reports/oth/5820564593FY0925-20110419-tamu-expension_tx_lulc_arboreal_vegetation.pdf. Accessed 06/28/13.

[57] *Ibid*.

[58] "LandFire". Available online: http://www.landfire.gov/. Accessed 06/28/13.

[59] EPA, Nov. 7, 2007. "Emissions Modeling Clearinghouse Biogenic Emission Sources". Available online: http://www.epa.gov/ttnchie1/emch/biogenic/. Accessed 06/28/13.

Table 3-1: Emission Inventory Sources by Type for 2006

Type	Sub Category	Source
Point	Electric Generating Units (EGU)	- Texas and US hourly acid rain database (EGU emissions) - CB6 Chemical Speciation
	Non-Electric Generating Units (NEGU)	- Texas Ozone Season Day (OSD) 2006 based on 01Jun-01Sep2006 STARS - US OSD based on NEI 2008 annual emissions. - HGB 2006 generic day extra alkenes. - HGB 2006 generic day hourly tank landing losses. - Offshore platforms monthly emissions from 2005 GWEI. - Mexico 1999 generic day from NEI phase III. - Canada 2006 annual National Pollutant Release Inventory (NPRI) and Upstream Oil and Gas (UOG) inventories from Environment Canada. - CB6 Chemical Speciation for NEGUs in Texas and the United States - CB05 Chemical Speciation for other sources.
Area	Area Sources	-TexAER v4 area09c for Texas - nei2008v2-based for other sates - CB6 Chemical Speciation
	Oil and Gas	- DFW SIP special oil and gas production emission inventory - New TX 2008 offshore oil and gas production - Other areas in Texas use TexAER v4 area09c - nei2008v2-based for other sates - CB6 Chemical Speciation
Mobile	All Categories	- MOVES2010a model was used to estimate 2006 on-road emissions for all U.S. portions of the modeling domain. - Within Texas, the vehicle miles traveled (VMT) estimates are based on travel demand modeling (TDM) for major metropolitan areas and the Highway Performance Monitoring System (HPMS) for more rural areas. - MOVES2010a was run in default mode for all non-Texas U.S. states. - On-road emission estimates for Canada and Mexico are based on MOBILE6-Canada and MOBILE6-Mexico, respectively. - Profiles from EPA's SPECIATE Version 4.3 Database were used to allocate VOC exhaust and evaporative emission estimates with CB6 mechanism. - Local data for Extended Diesel Truck Idling

Type	Sub Category	Source
Non-Road	All Categories	- TexN model - Drill rigs are based on TexAER data back cast to 2006 - Local data for construction equipment, quarry equipment, mining equipment, landfill equipment, agricultural tractors, and combines - CB6 Chemical Speciation
Off-Road	Locomotives	- ERG contract 2011-based switcher and line-haul locomotives - NEI2008v2 locos (switchers as points) - CB6 Chemical Speciation
	Marine	- NEI2008v2 harbor vessels - limited to 3.0 tpd max per county in port; 6.0 tpd max. underway. - CB6 Chemical Speciation
	Aircraft	- ERG airport specific 2011-based EI with new surrogates for hgb8co and attainment counties - DFW airports based on NCTCOG data for the DFW SIP - new NEI2008v2 airports as points (with ground support equipment - GSE). - local data for San Antonio International Airport (SAIA) - CB6 Chemical Speciation
Eagle Ford	All Categories	- None
Biogenic	All Categories	- 4 km and 12 km grid emissions were developed by Department of Ecosystem Science & Management at the Texas A&M University. - 36km grid were developed by TCEQ using BIES - WRF calculated modeling surface temperature - CB6 Chemical Speciation[60]

[60] TCEQ. Austin, Texas. Available online: ftp://amdaftp.tceq.texas.gov/pub/Rider8/ei/basecase/. Accessed 07/02/13.

3.6 Area Source Emissions

Area sources are small industrial, commercial, and residential sources that are widely distributed and include refueling, painting, asphalt, surface coating, landfills, and wastewater treatment emissions. Area sources outside of Texas are based on EPA's National Emissions Inventory 2008 v2.[61] Emissions for other states were back cast to 2006 based on EPA's Economic Growth and Analysis System (EGAS).[62] EGAS 5.0 "is an economic activity forecast tool designed by EPA that generates credible growth factors used in the development of emissions inventories. This tool is intended for use by States, Regional Planning Organizations, local governments, and the EPA so these entities may project air pollution emissions and design appropriate policies to control them."[63]

Emissions for Texas were based on the 2008 Texas Air Emissions Repository (TexAER) v4 database. "TexAER contains historical, current, and projected future case emissions inventory data, as well as control strategy information. You can customize your report to include specific locations, source classification codes (SCCs), time periods, units of measure, and other parameters."[64] Texas area source emissions were back cast to 2006 based on an ERG study completed for TCEQ.[65]

3.6.1 Oil and Gas Production Emissions

Emissions from oil and gas production were obtained from the ERG 2008 emission inventory. ERG's efforts included work to "identify and characterize area source emissions from upstream onshore oil and gas production sites that operated in Texas in 2008" and develop a 2008 base year air emissions inventory from these sites. "ERG was able to compile the 2008 area source emissions inventory from upstream onshore oil and gas production sites by obtaining both county-level activity data, and specific emissions and emission factor data for each source type. This data was obtained from a variety of sources, including existing databases (such as the Texas Railroad Commission (TRC) oil and gas production data), point source emissions inventory reports submitted to TCEQ (for dehydrators), vendor data (for compression engines and pumpjack engines), and published emission factor and activity data from the Houston

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[61] EPA. "National Emissions Inventory (NEI) Air Pollutant Emissions Trends Data". Available online: http://www.epa.gov/ttnchie1/trends/. Accessed 07/01/13.

[62] TCEQ. Austin, Texas. Available online: ftp://amdaftp.tceq.texas.gov/pub/Rider8/ei/basecase/. Accessed 07/02/2013.

[63] Abt Associates Inc. January 2006. "The Economic Growth and Analysis System EGAS 5.0 User Manual and Documentation". Office of Air Quality Planning and Standards U.S. Environmental Protection Agency, Research Triangle Park, NC. Available online: http://www.epa.gov/ttnecas1/egas5.htm. Accessed 02/03/13.

[64] TCEQ. "TexAER (Texas Air Emissions Repository)". Austin, Texas. Available online: http://www.tceq.texas.gov/airquality/areasource/TexAER.html. Accessed 07/03/13.

[65] TCEQ. Austin, Texas. Available online: ftp://amdaftp.tceq.texas.gov/pub/Rider8/ei/basecase/. Accessed 07/02/2013.

Advanced Research Center (HARC), the Central Regional Air Planning Association (CENRAP), and the U.S. Environmental Protection Agency (EPA)."[66]

Emission files for oil and gas are allocated appropriately to the Barnett Shale, Haynesville Shale, and other regions in Texas. "The spatial distribution within counties for oil and gas production was built from Texas Railroad Commission data for active wellhead density. The number of active wells in a given model grid cell over the total number of active wells in the county assigned the proportionate amount of the county's total emissions to that cell. Active wells for year-end 2006 were used for the base case."[67]

3.7 Non-Road Emissions

Non-road sources are equipment used for off road purposes and include construction equipment, recreational marine vessels, industrial equipment, agricultural equipment, recreational vehicles, lawn and garden equipment, railroad maintenance equipment, and commercial equipment. Non-road sources outside of Texas are based on EPA's National Emissions Inventory 2008 v2.[68] The EPA's National Mobile Inventory Model (NMIM) was used to back cast non-road emissions to 2006. NMIM "is a consolidated emissions modeling system for EPA's MOBILE6 and NONROAD models. It was developed to produce, in a consistent and automated way, national, county-level mobile source emissions inventories for the National Emissions Inventory (NEI) and for EPA rule making."[69]

Non-road emissions for Texas were calculated using the TexN model. The "Texas NONROAD Model (TexN) provides emissions estimates for a large number of non-road equipment categories operating in Texas." "The TexN model calculates emissions estimates for the same equipment categories included in EPA's NONROAD model."[70] "The TexN model incorporates the unmodified NONROAD2005 model to generate its core emission estimates, utilizing region-specific adjustment factors in order to refine the NONROAD outputs for Texas. The model also incorporates geographic and equipment-specific improvements to the NONROAD model,

[66] ERG, 2010. "Characterization of Oil and Gas Production Equipment and Develop a Methodology to Estimate Statewide Emissions". Final Report to the Texas Commission on Environmental Quality (TCEQ), Contract No. 582-7-84003-FY10-26. p. IV-V. http://www.tceq.texas.gov/assets/public/implementation/air/am/contracts/reports/ei/5820784003FY1026-20101124-ergi-oilGasEmissionsInventory.pdf. Accessed 07/03/13.

[67] TCEQ, "TexAER (Texas Air Emissions Repository)". Austin, Texas. Available online: http://www.tceq.texas.gov/airquality/areasource/TexAER.html. Accessed 07/16/13

[68] EPA. "National Emissions Inventory (NEI) Air Pollutant Emissions Trends Data". Available online: http://www.epa.gov/ttnchie1/trends/. Accessed 07/01/13.

[69] EPA, April 2009. "National Mobile Inventory Model (NMIM)". Available online: http://www.epa.gov/oms/nmim.htm. Accessed 07/03/13.

[70] Eastern Research Group, Inc. April 26, 2013. "Texas NONROAD (TexN) Model". Austin, Texas. Available online: ftp://amdaftp.tceq.texas.gov/pub/Nonroad_EI/TexN/. Accessed 07/03/13.

reflecting the efforts of numerous TCEQ studies."[71] All Diesel equipment in eastern Texas was adjusted by TCEQ to take into account TXLED.

3.7.1 Drill Rigs

Drill rig emissions were based on ERG's drill rig emission inventory for Texas. The purpose of ERG's "study was to develop a comprehensive emissions inventory for drilling rig engines associated with onshore oil and gas exploration activities occurring in Texas in 2008."[72] "While drilling activities are generally short-term in duration, typically covering a few weeks to a few months, the associated diesel engines are usually very large, from several hundred to over a thousand horsepower. As such, drilling activities can generate a substantial amount of NO_X emissions."[73] "In order to gain a more accurate understanding of emissions from drilling rig engines, data regarding typical rig profiles (number of engines, engine sizes, and engine load factors) were collected through phone and email surveys for drilling operations for the 2008 base year."[74] Drill Rig emissions were back cast to 2006 using BakerHughes.com and RigData.com drill rig counts.[75]

3.7.2 Construction Equipment

The local construction equipment inventory includes emissions from the equipment used to build roads, highways, buildings, houses, and utility lines in the San Antonio-New Braunfels MSA. When calculating local construction equipment populations, surrogate factors were used to adjust TexN equipment populations for each county. To determine surrogate factors for the MSA, each Diesel Construction Equipment (DCE) subsector was calculated separately based on comparisons of industry trends and other data closely related to diesel construction

[71] Eastern Research Group, Inc. April 26, 2013. "Texas NONROAD (TexN) Model". Austin, Texas. Available online: ftp://amdaftp.tceq.texas.gov/pub/Nonroad_EI/TexN/. Accessed 07/03/13.

[72] Eastern Research Group, Inc. July 15, 2009. "Drilling Rig Emission Inventory for the State of Texas". Austin, Texas. p. 2-1. Available online: http://www.tceq.state.tx.us/assets/public/implementation/air/am/contracts/reports/ei/5820783985FY0901-20090715-ergi-Drilling_Rig_EI.pdf. Accessed 07/03/13.

[73] Eastern Research Group, Inc. July 15, 2009. "Drilling Rig Emission Inventory for the State of Texas". Austin, Texas. p. 2-1. Available online: http://www.tceq.state.tx.us/assets/public/implementation/air/am/contracts/reports/ei/5820783985FY0901-20090715-ergi-Drilling_Rig_EI.pdf. Accessed 07/03/13.

[74] Eastern Research Group, Inc. July 15, 2009. "Drilling Rig Emission Inventory for the State of Texas". Austin, Texas. p. 2-1. Available online: http://www.tceq.state.tx.us/assets/public/implementation/air/am/contracts/reports/ei/5820783985FY0901-20090715-ergi-Drilling_Rig_EI.pdf. Accessed 07/03/13.

[75] Doug Boyer, TCEQ, Nov. 5, 2010. "2006/2012 DFW Modeling Update". Presented to the DFW Photochemical Modeling Technical Committee. p. 6. Available online http://www.tceq.texas.gov/assets/public/implementation/air/am/committees/pmt_dfw/20101105/20101105_PMTC_modeling_update.pdf. Accessed 07/01/13.

equipment populations. Data sources for the surrogate factors included employment[76], population[77], TxDOT[78], and Census Building permits[79].

To allocate construction equipment emissions accurately in the photochemical model, emissions were spatially allocated by subsector based on type and purpose of equipment used. Local departments of transportation, utility companies, government agencies, and private companies were contacted to collect data on size and location of construction projects. Residential building permits, commercial building permits, and demolition permits were also collected to geo-code construction emissions.

3.7.3 Quarry, Landfill, and Mining Equipment

Due to the abundance of limestone, aggregate, granite, sand, and gravel deposits, there are numerous quarries in the AACOG region. In addition, there are 6 active landfills in the AACOG region and one lignite mine. Data on quarry, landfill, and mining equipment was collected using a "bottom-up" methodology to refine equipment populations, equipment horsepower, activity profiles, and spatial allocation of emissions. A survey questionnaire was sent to local quarries, landfills, and mines to collect data on:

1. Equipment Populations
2. Activity Rates – total annual hours of use by type of equipment
3. Temporal Profiles – equipment use on weekdays and weekend days
4. Engine Characteristics

Ozone season day emissions from equipment were estimated based on survey responses and existing data from the TexN model. Emissions were geo-coded to the location of quarries, landfills, and mines identified through TCEQ permits[80], Mineral Locations Database[81], Find the Best directory[82], and aerial photographs.

3.7.4 Agricultural Tractors and Combines

To calculate tractor and combine emissions, crop acres planted and harvested for every county was collected. Volume I of the 2007 Census of Agriculture, which was made available by the

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76 U.S. Census Bureau. June 30, 2011. "County Business Patterns (CBP)". Available online: http://www.census.gov/econ/cbp/index.html. Accessed 07/12/11.
77 U.S. Census Bureau, Population Division. "Population Estimates". Available online: http://www.census.gov/popest/counties/. Accessed 07/13/11.
78 Texas Department of Transportation. "TxDOT Letting Schedule". Finance Division. Austin, Texas. Available online: http://www.dot.state.tx.us/business/schedule.htm. Accessed 07/11/11.
79 U.S. Census Bureau. "Building Permits". Available online: http://censtats.census.gov/bldg/bldgprmt.shtml. Accessed 07/13/11.
80 TCEQ. Permit Database". Austin Texas. Available online: https://webmail.tceq.state.tx.us/gw/webpub. Accessed 07/27/11.
81 MineralMundi. "Mineral Locations Database". United States Geological Survey Mineral Resources Program. Available online: http://www.mineralmundi.com/texas.htm. Accessed 07/27/11.
82 Find the Best, 2011. "Texas Active Mines". Available online: http://active-mines.findthebest.com/directory/d/Texas. Accessed 07/27/11.

United States Department of Agriculture (USDA), contained acreage of hay by county.[83] Crop acreages for all other crop types were retrieved from the 2008 Texas Agricultural Statistics report published by the USDA (Table 5-1).[84]

Agricultural tasks that use tractors include soil preparation, plowing, planting, fertilizing, cultivating, and applying pesticides, while combines are used for harvesting. For each crop type, the climate of south-central Texas influences the time of the year for each agricultural activity. Emissions from agricultural tractors and combines for the June modeling period were based on estimates of equipment usage during the activities of plowing, planting, fertilizing, cultivating, and harvesting each crop. Activity data was provided via correspondence from local Texas Agricultural Service County Extension agents who have observed farm activity over the past 20 years in the AACOG region

Local activity data and existing data in the TexN Model were used to calculate tractor and combine emissions. Emissions estimates were based on activity data, horsepower, load factor, emission factors, and fuel ratio. Data from the Natural Agricultural Statistics Service was used to geo-code tractor and combine emissions.[85] Once crop locations were identified, tractor and combine emissions were spatially allocated to the 4-km photochemical grid system. VOC and NO_X average ozone season day emissions from tractors and combines were allocated to the location of each crop type.

3.8 Off-Road

Off-road emission sources consist of marine vessels, locomotives/switchers, and aircraft/GSE. Emissions from these sources are not included in the TexN model, NMIM model, or EPA's NonRoad model.

3.8.1 Marine Vessels

Emissions from marine vessels were split into 2 groups: in-port harbor vessels and ocean going marine vessels. "Slow turnover to new vessels/engines combined with regulation under international law means fewer emission reductions for ocean-going vessels."[86] Emissions from

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[83] United States Department of Agriculture, Updated December 2009. "2007 Census of Agriculture". AC-07-A-51. National Agricultural Statistics Service. Available online: http://www.agcensus.usda.gov/Publications/2007/Full_Report/Volume_1,_Chapter_2_County_Level/Texas/st48_2_027_027.pdf. Accessed 12/20/10.
[84] United States Department of Agriculture, Updated December 2009. "Texas Agricultural Statistics, 2008". National Agricultural Statistics Service, Texas Field Office". Available online: http://www.nass.usda.gov/Statistics_by_State/Texas/Publications/Annual_Statistical_Bulletin/index.asp. Accessed 12/20/10.
[85] National Agricultural Statistics Service. "CropScape – Cropland Data Layer". United States Department of Agriculture. Available online: http://nassgeodata.gmu.edu/CropScape/. Accessed 06/06/11.
[86] ENVIRON International Corporation, August 18, 2010. "Implement Port of Houston's Current Inventory and Harmonize the Remaining 8-county Shipping Inventory for TCEQ Modeling". Novato, CA. Work Order No. 582-7-84006-FY10-5. p. 1. Available online:

marine vessels outside of Texas are based on EPA's National Emissions Inventory 2008 v2.[87] Emissions were projected to 2006 by TCEQ based on EPA's "Proposal to Designate an Emission Control Area for Nitrogen Oxides, Sulfur Oxides and Particulate Matter".[88]

For Texas, "contract work by Environ and data from the Port of Houston were integrated to update the HGB shipping emission inventory to 2007 ship movements. Environ work also allowed improved emissions treatment for the Gulf of Mexico and the Atlantic Ocean in the modeling domains to be based on actual ship location data and ship traffic data rather than simple shipping lanes."[89] ENVIRON created a "marine vessels emission inventory for the most significant commercial marine vessel categories including ocean going vessels, tugs, push boats, and large support vessels. Vessel activity for the Ports of Texas City, Galveston, and Freeport and the Intracoastal Waterway was combined with Port of Houston vessel activity to create a complete Houston-Galveston-Brazoria 8-county area commercial marine emission inventory."[90] Elevated stack emissions from marine vessels were included in the point source processing step.

3.8.2 Locomotives

"Locomotive emissions were separated into line-haul and switchers to allow different spatial allocation. Switcher emissions were allocated to railyards and line-haul emissions were based on a Gross Ton Miles (GTM) distribution."[91] Emission data from EPA's National Emissions Inventory 2008 v2 was used to estimate locomotive emissions outside of Texas.[92] Emissions

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http://www.tceq.texas.gov/assets/public/implementation/air/am/contracts/reports/ei/5820784006FY1005-20100818-environ-HGBShipsEI.pdf. Accessed 07/03/13.

[87] EPA. "National Emissions Inventory (NEI) Air Pollutant Emissions Trends Data". Available online: http://www.epa.gov/ttnchie1/trends/. Accessed 07/01/13.

[88] EPA, April 2009. "Proposal to Designate an Emission Control Area for Nitrogen Oxides, Sulfur Oxides and Particulate Matter". EPA-420-R-09-007. Available online: http://www.epa.gov/nonroad/marine/ci/420r09007.pdf. Accessed 07/05/13.

[89] TCEQ. "Appendix B: Emissions Modeling for the Dfw Attainment Demonstration Sip Revision for the 1997 Eight-Hour Ozone Standard". Austin, Texas. p. B-110. Available online: http://www.tceq.texas.gov/assets/public/implementation/air/sip/dfw/ad_2011/AppB_EI_ado.pdf. Accessed 07/03/13.

[90] ENVIRON International Corporation, August 18, 2010. "Implement Port of Houston's Current Inventory and Harmonize the Remaining 8-county Shipping Inventory for TCEQ Modeling". Novato, CA. Work Order No. 582-7-84006-FY10-5. p. 27. Available online: http://www.tceq.texas.gov/assets/public/implementation/air/am/contracts/reports/ei/5820784006FY1005-20100818-environ-HGBShipsEI.pdf. Accessed 07/03/13.

[91] TCEQ. "Appendix B: Emissions Modeling for the Dfw Attainment Demonstration Sip Revision for the 1997 Eight-Hour Ozone Standard". Austin, Texas. p. B-93. Available online: http://www.tceq.texas.gov/assets/public/implementation/air/sip/dfw/ad_2011/AppB_EI_ado.pdf. Accessed 07/03/13.

[92] EPA. "National Emissions Inventory (NEI) Air Pollutant Emissions Trends Data". Available online: http://www.epa.gov/ttnchie1/trends/. Accessed 07/01/13.

were projected to 2006 by TCEQ using EGAS and adjustments were applied based on EPA's locomotive control regulations.[93]

For Texas, "TCEQ created county-level surrogates of railyards to best allocate switcher locomotives spatially. Diesel categories county-specific NO_X-humidity corrections were applied, as was TxLED."[94] Emissions from line-haul locomotives were allocated on a virtual link base in the 4km modeling grid.

3.8.3 Aircraft Emissions

Aircraft and GSE emission inputs were based on EPA's National Emissions Inventory 2008 v2 for areas outside of Texas.[95] Emissions for other states were projected to 2006 using EGAS.[96] Emissions for airports in the 12-county Dallas-Fort Worth Area were developed by the North Central Texas Council of Governments (NCTCOG). NCTCOG developed the "annual emissions inventory and activity data for airports for 1996, 2000, 2002, 2008, 2011, 2014, 2017, 2020, 2023, 2026, and 2029 analysis years. This inventory was developed for the 12-County Metropolitan Statistical Area (MSA) that covers Collin, Dallas, Denton, Ellis, Henderson, Hood, Hunt, Johnson, Kaufman, Parker, Rockwall, and Tarrant Counties."[97]

Emissions for other airports in Texas were based on ERG's annual emission inventory and activity data for airports in Texas. ERG developed "statewide annual emission inventories for Texas airport activities for the calendar years 1996, 2000, 2002, 2011, 2014, 2017, 2020, 2023, 2026, 2029, and the base year 2008." ERG used "publically available 2008 activity data that was compiled and supplemented with 2008 activity data provided by local airports. Two approaches were used to estimate emissions from the compiled activity data. If the activity data had aircraft specific data, the Federal Aviation Administration's (FAA) Emissions Dispersion Modeling System (EDMS) was employed. If such detailed data was not available, then ERG applied a more general approach for different aircraft types (i.e., air taxis, general aviation, and military aircraft) using available generic emission estimating procedures. Once the base year of

[93] EPA, Sept. 2012. "Locomotives". Available online: http://www.epa.gov/otaq/locomotives.htm. Accessed 07/05/13.
[94] TCEQ. "Appendix B: Emissions Modeling for the Dfw Attainment Demonstration Sip Revision for the 1997 Eight-Hour Ozone Standard". Austin, Texas. p. B-93. Available online: http://www.tceq.texas.gov/assets/public/implementation/air/sip/dfw/ad_2011/AppB_EI_ado.pdf. Accessed 07/03/13.
[95] EPA. "National Emissions Inventory (NEI) Air Pollutant Emissions Trends Data". Available online: http://www.epa.gov/ttnchie1/trends/. Accessed 07/01/13.
[96] TCEQ. Austin, Texas. Available online: ftp://amdaftp.tceq.texas.gov/pub/Rider8/ei/basecase/. Accessed 07/02/13.
[97] North Central Texas Council of Governments, August 2011. "Development of Annual Emissions Inventories and Activity Data for Airports in the 12-County Dallas-Fort Worth Area". Dallas, Texas. p. i.

2008 was established, the inventory was backcasted and forecasted based on FAA's Terminal Area Forecast (TAF) data."[98]

3.8.4 San Antonio International Airport

AACOG updated and expanded the following emission inventory categories for the San Antonio International Airport:

- Aircraft Operations (commercial, military operations, and general aviation)
- Ground Support Equipment (GSE)
- Parking Garages
- Aircraft Evaporative Loss
- Fuel Storage & Transfer
- Stationary Sources
- Auxiliary Power Units (APU)
- Non-road Equipment (Lawn and Garden, Commercial, and Light Industrial)

To calculate emissions based on a "bottom-up" approach, local data from the above sources were collected. Emissions from aircraft landing and take-off (LTO) cycles at SAIA were calculated using the EDMS model, version 5.1.3.[99] The EDMS model uses EPA approved emission factors and methodologies to estimate emissions from aircraft operations. October 2008 flight schedules for commercial airliners, obtained from "FlightStats"[100] and the general avaiation (GA) flight data obtained from GCR Inc, was analyzed to determine the hourly arrival and departure patterns for commercial and GA operations at SAIA. Hourly emissions were allocated in the photochemical model by aircraft category based on the percentage of flights occurring during that hour.

To allocate elevated and ground level emissions spatially, information on runway usage patterns for each aircraft category was obtained from the San Antonio Department of Aviation. The data provides the percentage of landings and take-offs occurring at each runway annually by aircraft category. The aircraft 2006 surface and elevated emissions were spatially and temporally allocated to a 3-dimensional (3-D) photochemical modeling grid cell system using GIS software. Elevated aircraft emissions generated from landing, take-off, and climb-out were allocated to the 3-D grid cells containing multiple nodes, with specific height, latitude, and longitude at incremental ground distances from the end of the runway.

[98] Eastern Research Group, Inc. July 15, 2011. "Development of Statewide Annual Emissions Inventory and Activity Data for Airports". 582-11-99776. Morrisville, North Carolina. p. ES-1.
[99] FAA, Nov. 2010. "Emissions & Dispersion Modeling System". Available online: http://www.faa.gov/about/office_org/headquarters_offices/aep/models/edms_model/. Accessed 09/21/11.
[100] FlightStats, Conducive Technology Corp, 2005. Available online: http://www.flightstats.com/go/FlightStatus/flightStatusByAirport.do . Accessed 12/15/11.

A list of GSE equipment was compiled from a survey that was sent to all tenants at SAIA. Other necessary information such as horsepower output (HP), emission factors, and load factors for the equipment were compiled from equipment user's manuals and existing data in the EDMS model. After the survey forms were completed and returned, tenants at SAIA and the COSA's Department of Aviation were contacted and consulted to determine the accuracy and completeness of the data. To estimate emissions from non-road equipment, a survey was conducted to determine population, equipment type, and activity data for equipment used by tenants and the COSA at SAIA.

Vehicles owned by employees, businesses, vacationers, and business travelers frequently use parking lots at SAIA. Emissions from parking lots at SAIA were calculated using on-road and idling emission factors generated by the MOVES2010a[101] model and the EPA. Data on the number of vehicles using each facility, emission factors, idling time, and average distance traveled in the parking lot were used to calculate CO, NO_X, and VOC emissions.

3.9 On-Road Emissions

On-road emissions are mobile source emissions that are produced during operation of vehicles on urban and rural roadway networks. Due to their significant contribution, on-road emissions are regulated by the EPA and subject to federal standards and control. EPA's MOVES2010a model was used to calculate on-road emissions for every county in the United States. To run the model, "the user specifies vehicle types, time periods, geographical areas, pollutants, vehicle operating characteristics, and road types to be modeled. The model then performs a series of calculations, which have been carefully developed to accurately reflect vehicle operating processes, such as cold start or extended idle, and provide estimates of bulk emissions or emission rates. Specifying the characteristics of the particular scenario to be modeled is done by creating a Run Specification, or RunSpec."[102]

3.9.1 On-Road Vehicle Emissions

"For all non-Texas areas contained within the modeling domain, EPA's MOVES model is run in default mode to develop daily emission estimates by county for an average Summer Weekday. These emissions are processed with EPS3 and adjustments are applied to develop Friday, Saturday, and Sunday day type inventories based on pollutant-specific ratios from the Texas on-road inventories for Friday/Weekday, Saturday/Weekday, and Sunday/Weekday. In

101 U.S. Environmental Protection Agency, December 2009. "Motor Vehicle Emission Simulator". Office of Transportation and Air Quality Washington, DC. Available online: http://www.epa.gov/otaq/models/moves/index.htm. Accessed 12/15/11.

102 EPA, Dec. 2009. "Motor Vehicle Emission Simulator (MOVES) 2010 User Guide". p. 4. Available online: http://www.epa.gov/otaq/models/moves/420b09041.pdf. Accessed 07/09/13.

addition, the hourly distributions of the Texas on-road inventories by both pollutant and day type are applied to the non-Texas portions of the modeling domain."[103]

For the Mexico portions of the modeling domain, the on-road portion of the 1999 Mexican National Emissions Inventory (NEI)[104] "is projected to specific years using a combination of the MOBILE6-Mexico model and an assumed annual VMT growth rate of 2%."[105] In a similar way, the 2006 Canadian National Pollutant Release Inventory (NPRI)[106] "is used and projected with MOBILE6-Canada and a 2% annual VMT growth rate assumption. The end result of this process is a gridded and speciated inventory for photochemical model input with relatively high spatial and temporal resolution of on-road emissions."[107]

The Texas Transportation Institute (TTI) "developed hourly, photochemical model preprocessor ready, on-road mobile summer (June 1 through August 31) Weekday, Friday, Saturday, and Sunday EIs for"[108] 2006, 2012, and 2018 using the MOVES 2010a model. "TTI used an hourly, Highway Performance Monitoring System (HPMS) virtual link, MOVES 'rates-peractivity' emissions inventory method to produce hourly emissions estimates by MOVES source use type (SUT) and fuel type, pollutant, and pollutant process for all 254 Texas counties for each year and day type. The methods TTI used to produce these inventories were consistent with EPA guidance on the production of photochemical modeling emissions inventories."[109]

Hourly VMT estimates by roadway type are multiplied by emissions rates from MOVES that vary as a function of

1. speed,
2. meteorological inputs (temperature, humidity, and barometric pressure), and
3. drive cycle (i.e., high-speed freeway driving versus stop-and-go arterial driving).[110]

[103] TCEQ, Dec. 2012. "Introduction to Air Quality Modeling: Emissions Modeling". Austin, Texas. Available online: http://www.tceq.texas.gov/airquality/airmod/overview/am_ei.html. Accessed 07/03/13.
[104] EPA, Oct. 2006. "North American Emissions Inventories – Mexico". Available online: http://www.epa.gov/ttnchie1/net/mexico.html. Accessed 07/08/13.
[105] TCEQ, Dec. 2012. "Introduction to Air Quality Modeling: Emissions Modeling". Austin, Texas. Available online: http://www.tceq.texas.gov/airquality/airmod/overview/am_ei.html. Accessed 07/03/13.
[106] Environment Canada. "National Pollutant Release Inventory". Available online: http://www.ec.gc.ca/inrp-npri/default.asp?lang=En&n=4A577BB9-1. Accessed 07/08/13.
[107] TCEQ, Dec. 2012. "Introduction to Air Quality Modeling: Emissions Modeling". Austin, Texas. Available online: http://www.tceq.texas.gov/airquality/airmod/overview/am_ei.html. Accessed 07/03/13.
[108] TTI, July 2011. "Production of Statewide Non-Link-Based, On-Road Emissions Inventories with the Moves Model for the Eight-Hour Ozone Standard Attainment Demonstration Modeling". College Station, Texas. College Station, Texas. p. 1. Available online: ftp://amdaftp.tceq.texas.gov/pub/Mobile_EI/Statewide/mvs/reports/. Accessed 07/05/13.
[109] TTI, July 2011. "Production of Statewide Non-Link-Based, On-Road Emissions Inventories with the Moves Model for the Eight-Hour Ozone Standard Attainment Demonstration Modeling". College Station, Texas. College Station, Texas. p. 1. Available online: ftp://amdaftp.tceq.texas.gov/pub/Mobile_EI/Statewide/mvs/reports/. Accessed 07/05/13.
[110] TCEQ, Dec. 20, 2012. "Introduction to Air Quality Modeling: Emissions Modeling". Austin, Texas. Available online: http://www.tceq.texas.gov/airquality/airmod/overview/am_ei.html. Accessed 07/09/13.

The emissions were calculated for each on-road segment by fuel type, emission process, and the source use type (SUT) listed in Table 3-2.[111] MOVES 2010a emission estimates were broken into running exhaust, crankcase running exhaust, start exhaust, crankcase start exhaust, extended idle exhaust, crankcase extended idle exhaust, evaporative permeation, evaporative fuel vapor venting, and evaporative fuel leaks.[112]

Table 3-2: MOVES2010a Source Use Type

Source Use Type ID	Source Use Type Description	Source Use Type Abbreviation
11	Motorcycle	MC
21	Passenger Car	PC
31	Passenger Truck	PT
32	Light Commercial Truck	LCT
41	Intercity Bus	IBus
42	Transit Bus	TBus
43	School Bus	SBus
51	Refuse Truck	RT
52	Single Unit Short-Haul Truck	SUShT
53	Single Unit Long-Haul Truck	SULhT
54	Motor Home	MH
61	Combination Short-Haul Truck	CShT
62	Combination Long-Haul Truck	CLhT

Age distribution and VMT mix by MOVES2010a vehicle class was based on data from TxDOT or the Texas Department of Motor Vehicles (TxDMV). The vehicle age distribution for TxDOT's San Antonio district is shown in Figure 3-1.[113]

[111] TTI, July 2011. "Production of Statewide Non-Link-Based, On-Road Emissions Inventories with the Moves Model for the Eight-Hour Ozone Standard Attainment Demonstration Modeling". College Station, Texas. College Station, Texas. pp. 7-8. Available online: ftp://amdaftp.tceq.texas.gov/pub/Mobile_EI/Statewide/mvs/reports/. Accessed 07/05/13.

[112] TTI, July 2011. "Production of Statewide Non-Link-Based, On-Road Emissions Inventories with the Moves Model for the Eight-Hour Ozone Standard Attainment Demonstration Modeling". College Station, Texas. College Station, Texas. p. 2. Available online: ftp://amdaftp.tceq.texas.gov/pub/Mobile_EI/Statewide/mvs/reports/. Accessed 07/05/13.

[113] TTI, July 2011. "Production of Statewide Non-Link-Based, On-Road Emissions Inventories with the Moves Model for the Eight-Hour Ozone Standard Attainment Demonstration Modeling: Appendix H: Source Type Age and Fuel Engine Fractions Inputs to MOVES". College Station, Texas. College Station, Texas. p. 63. Available online: ftp://amdaftp.tceq.texas.gov/pub/Mobile_EI/Statewide/mvs/reports/. Accessed 07/05/13.

Figure 3-1: TxDOT's San Antonio District 2006 Age Distribution Inputs to MOVES

Age	MC	PC	PT	LCT	IBus	TBus	SBus	RT	SUShT	SULhT	MH	CShT	CLhT
0	0.12681	0.06181	0.04266	0.04266	0.08288	0.0684	0.0795	0.04963	0.11057	0.12564	0.07721	0.07202	0.05684
1	0.13462	0.08278	0.06430	0.0643	0.08365	0.06904	0.08024	0.04527	0.15618	0.15905	0.07794	0.06153	0.05897
2	0.09173	0.07452	0.07937	0.07937	0.06755	0.05575	0.06479	0.03679	0.12151	0.1103	0.06293	0.03595	0.04217
3	0.11063	0.07556	0.08391	0.08391	0.05482	0.04524	0.05258	0.02766	0.09215	0.09163	0.05107	0.03957	0.03840
4	0.08696	0.07876	0.08497	0.08497	0.04810	0.03969	0.04613	0.02817	0.08104	0.07282	0.04481	0.03462	0.03826
5	0.06887	0.0754	0.08277	0.08277	0.05545	0.04576	0.05319	0.02979	0.07789	0.07793	0.05166	0.05296	0.05608
6	0.05676	0.07583	0.06701	0.06701	0.06027	0.04974	0.05781	0.04216	0.05882	0.06614	0.05615	0.07842	0.07349
7	0.04446	0.06539	0.06316	0.06316	0.05966	0.04924	0.05723	0.04785	0.05695	0.06101	0.05558	0.06527	0.07225
8	0.03196	0.05600	0.04886	0.04886	0.04616	0.05900	0.04611	0.03703	0.02631	0.03018	0.03337	0.05501	0.06008
9	0.02414	0.05120	0.05334	0.05334	0.03835	0.05505	0.04386	0.03076	0.03391	0.03769	0.05245	0.03716	0.04558
10	0.02262	0.04335	0.03922	0.03922	0.03238	0.05178	0.03863	0.06652	0.01889	0.02076	0.03317	0.04572	0.04637
11	0.01942	0.04642	0.04162	0.04162	0.04298	0.04334	0.05039	0.07789	0.02362	0.02560	0.03997	0.05887	0.05998
12	0.01719	0.03707	0.04000	0.04000	0.03381	0.03861	0.02484	0.04923	0.01889	0.01722	0.03893	0.04464	0.04052
13	0.01379	0.03264	0.02915	0.02915	0.02843	0.03271	0.03030	0.04295	0.01643	0.01313	0.02737	0.04259	0.03922
14	0.01063	0.02558	0.02208	0.02208	0.02162	0.02932	0.02524	0.01880	0.00930	0.00980	0.02479	0.02618	0.02752
15	0.00668	0.02245	0.01934	0.01934	0.02503	0.03031	0.03292	0.05219	0.01023	0.00955	0.01884	0.02618	0.03269
16	0.00781	0.01748	0.01590	0.01590	0.02871	0.04532	0.03799	0.04541	0.01041	0.00951	0.02521	0.02944	0.03062
17	0.00746	0.01447	0.01576	0.01576	0.02910	0.03524	0.02215	0.03622	0.00941	0.00802	0.03329	0.02340	0.02516
18	0.00598	0.01099	0.01329	0.01329	0.02767	0.02835	0.02692	0.04981	0.00824	0.00690	0.03017	0.02075	0.02118
19	0.00629	0.00859	0.00958	0.00958	0.02907	0.02652	0.02757	0.04033	0.00515	0.00485	0.02979	0.02232	0.01848
20	0.01281	0.00727	0.01224	0.01224	0.02493	0.02283	0.0246	0.05090	0.00678	0.00651	0.02246	0.02123	0.01709
21	0.01172	0.00644	0.01094	0.01094	0.02226	0.02003	0.02159	0.02737	0.00696	0.00587	0.02437	0.02292	0.01852
22	0.00844	0.00522	0.0094	0.0094	0.01771	0.01579	0.01686	0.02873	0.00602	0.00422	0.02499	0.01508	0.01421
23	0.00957	0.00309	0.00602	0.00602	0.00715	0.01531	0.00630	0.00842	0.00310	0.00213	0.01656	0.00820	0.00647
24	0.01199	0.00213	0.00618	0.00618	0.00616	0.00844	0.00471	0.00958	0.00456	0.00389	0.00988	0.01315	0.01001
25	0.00938	0.00185	0.00529	0.00529	0.00541	0.00371	0.00560	0.00859	0.00333	0.00290	0.00549	0.00977	0.01009
26	0.00492	0.00173	0.00388	0.00388	0.00712	0.01019	0.00556	0.00218	0.00266	0.00198	0.00073	0.00438	0.00501
27	0.00637	0.00123	0.00397	0.00397	0.00433	0.00305	0.00465	0.00227	0.00278	0.00183	0.00572	0.00503	0.00426
28	0.00482	0.00113	0.00349	0.00349	0.00339	0.00133	0.00397	0.00221	0.00204	0.00150	0.00762	0.00448	0.00472
29	0.00387	0.00092	0.00196	0.00196	0.00364	0.00027	0.00399	0.00000	0.00215	0.00129	0.01044	0.00362	0.00463
30	0.0213	0.01271	0.02034	0.02034	0.00221	0.00067	0.00377	0.00531	0.01369	0.01017	0.00704	0.01954	0.02112

Since the emission factors from MOVES are speed dependent, the congested speed for each link is required. "There are three critical parameters for estimating operation speeds: hourly lane capacity, free-flow speed, and hourly volume by direction. The hourly lane capacity is the maximum flow past a given point on a roadway, which varies by road type (or functional classification). The free-flow speed is the maximum speed that traffic will move along a given roadway if there are no impediments (e.g., congestion, bad weather). The hourly volume by direction is the hourly link VMT by direction divided by the link's centerline miles." [114]

"To estimate a link's directional, time-of-day congested speed, a speed model involving both the estimated free-flow speed and estimated directional delay as a function of volume and capacity for the link and time period (i.e., hour) was applied. The model was applied to each link for each hour and direction."[115] Weekday hourly speed by urban road type for the San Antonio-New Braunfels MSA is provided in Figure 3-2. Average speed is reduced during the morning and afternoon rush periods on every roadway type except local roads. Average hourly weekday speeds for interstate freeways vary between 56 mph and 69 mph, while freeway speeds vary between 51 mph and 59 mph. For other road types, the average weekday speeds varied between 29 mph and 39 mph.

The 2006 temperature distribution for TxDOT's San Antonio district is provided in Figure 3-3 while hourly relative humidity is provided in Figure 3-4. The diurnal temperature profile varies between 74 degrees and 94 degrees Fahrenheit. During the night, average humidity is above 70 percent, but in the afternoon humidity varies between 34 and 44 percent. The temperature distribution and relative humidity are based on June 1st through August 31st, 2006 monitored hourly averages.[116] TCEQ developed the input data based on "June through August hourly temperature and relative humidity, and 24-hour barometric pressure averages by district using hourly data from numerous weather stations within each" TxDOT district.[117]

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[114] TTI, July 2011. "Production of Statewide Non-Link-Based, On-Road Emissions Inventories with the Moves Model for the Eight-Hour Ozone Standard Attainment Demonstration Modeling". College Station, Texas. College Station, Texas. p. 18. Available online: ftp://amdaftp.tceq.texas.gov/pub/Mobile_EI/Statewide/mvs/reports/. Accessed 07/05/13.

[115] TTI, July 2011. "Production of Statewide Non-Link-Based, On-Road Emissions Inventories with the Moves Model for the Eight-Hour Ozone Standard Attainment Demonstration Modeling". College Station, Texas. College Station, Texas. p. 18. Available online: ftp://amdaftp.tceq.texas.gov/pub/Mobile_EI/Statewide/mvs/reports/. Accessed 07/05/13.

[116] TTI, July 2011. "Production of Statewide Non-Link-Based, On-Road Emissions Inventories with the Moves Model for the Eight-Hour Ozone Standard Attainment Demonstration Modeling". College Station, Texas. College Station, Texas. p. 161 and 167. Available online: ftp://amdaftp.tceq.texas.gov/pub/Mobile_EI/Statewide/mvs/reports/. Accessed 07/05/13.

[117] TTI, July 2011. "Production of Statewide Non-Link-Based, On-Road Emissions Inventories with the Moves Model for the Eight-Hour Ozone Standard Attainment Demonstration Modeling". College Station, Texas. College Station, Texas. p. 39. Available online: ftp://amdaftp.tceq.texas.gov/pub/Mobile_EI/Statewide/mvs/reports/. Accessed 07/05/13.

Figure 3-2: Weekday Hourly Speed for the San Antonio-New Braunfels MSA by Urban Road Type, 2006

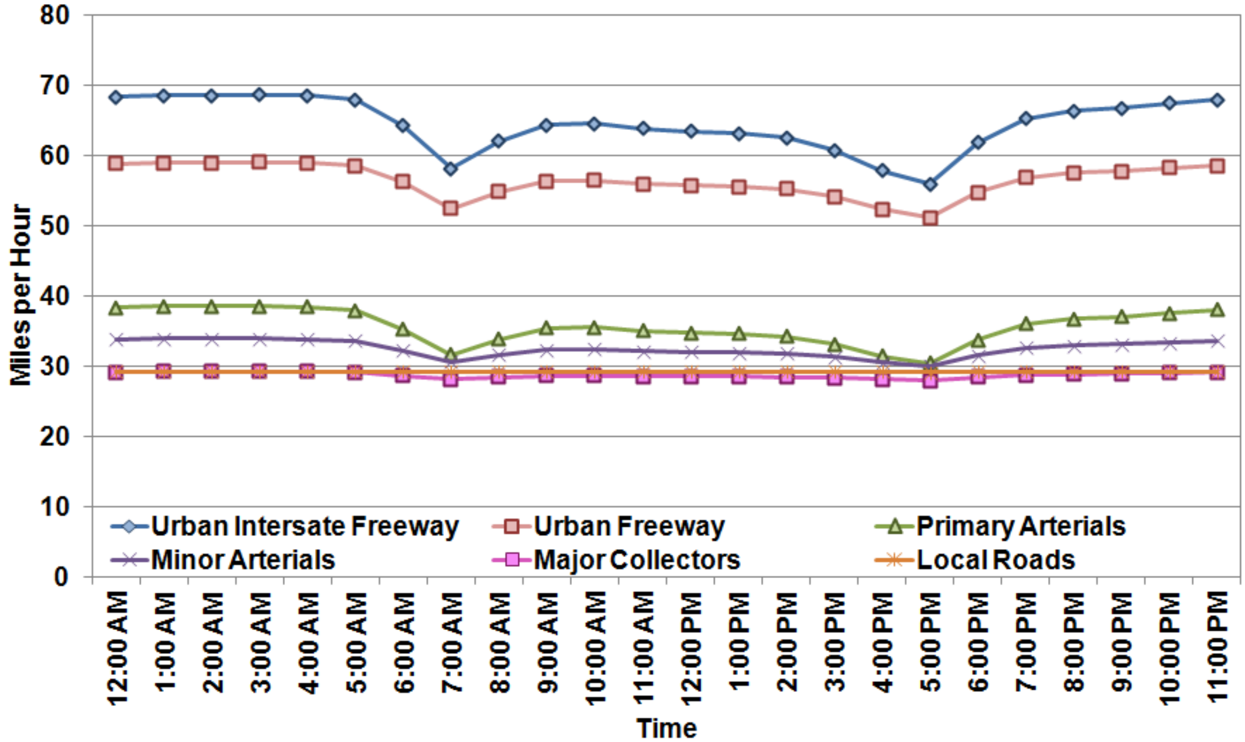


Figure 3-3: Temperature Inputs to MOVES for Summer, San Antonio TxDOT District 2006

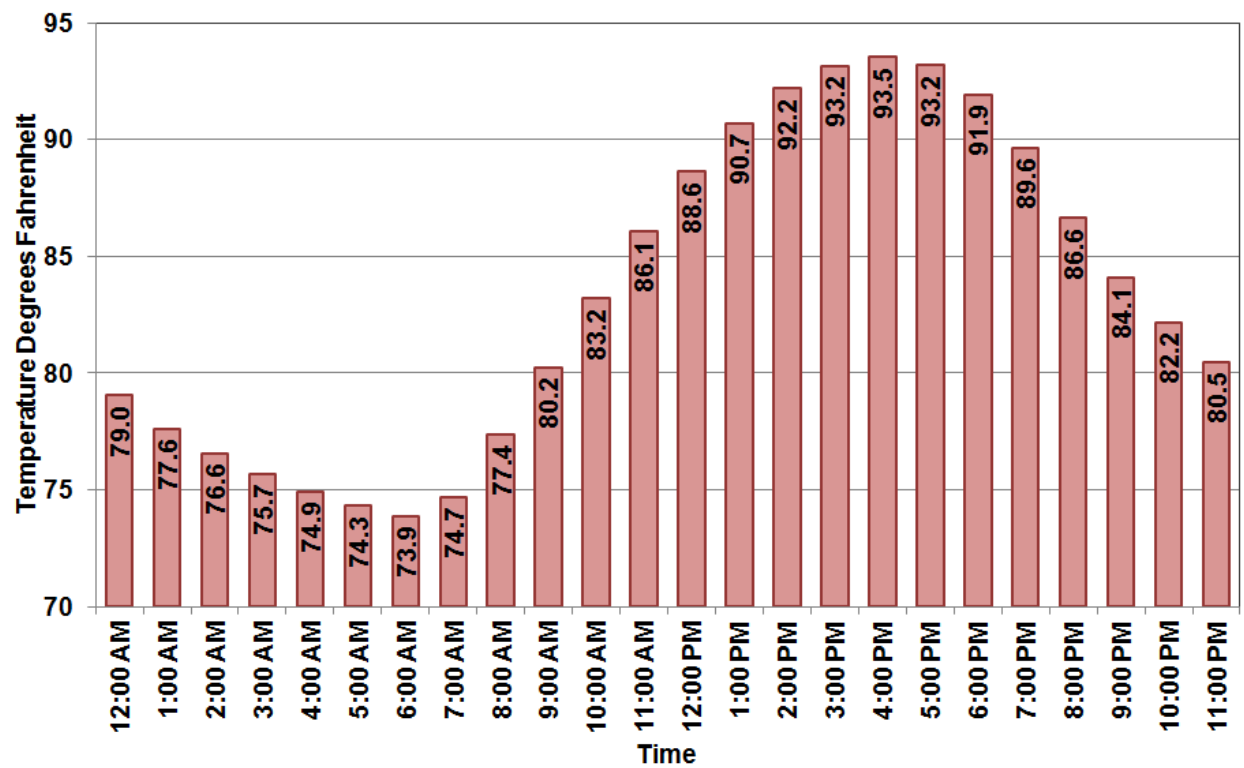
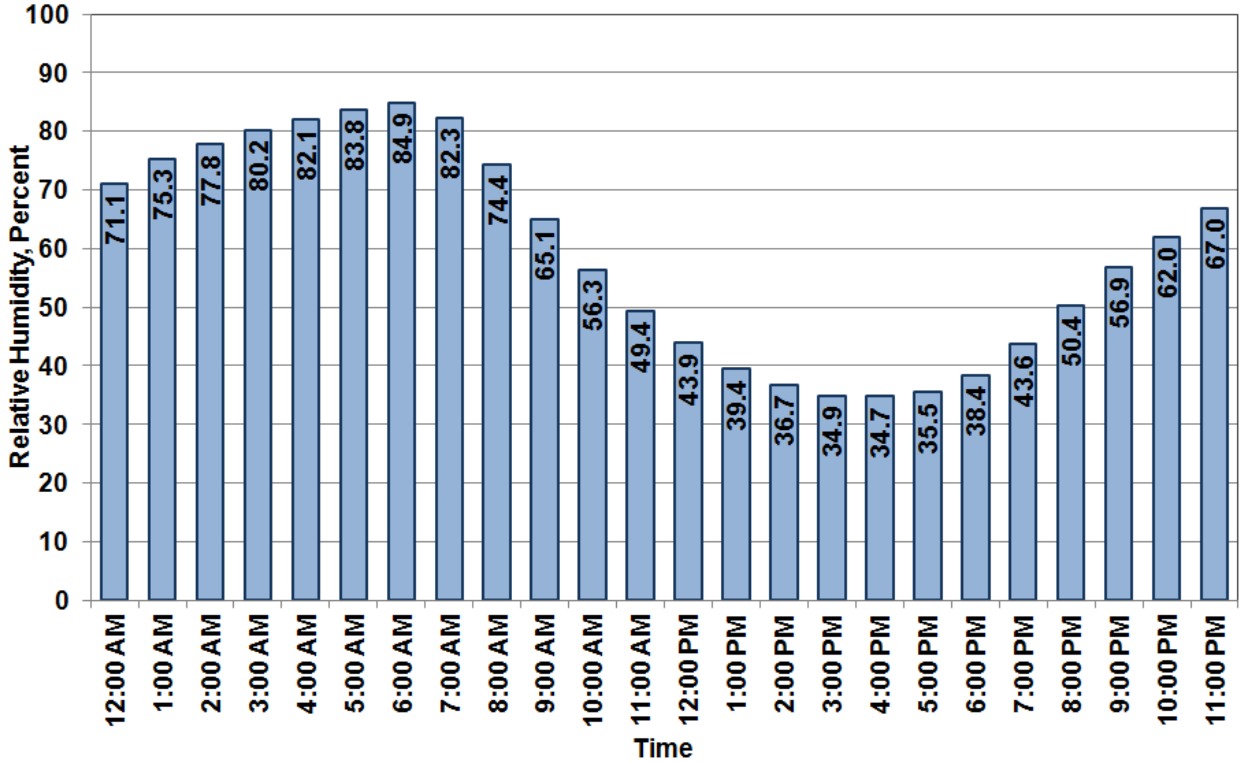
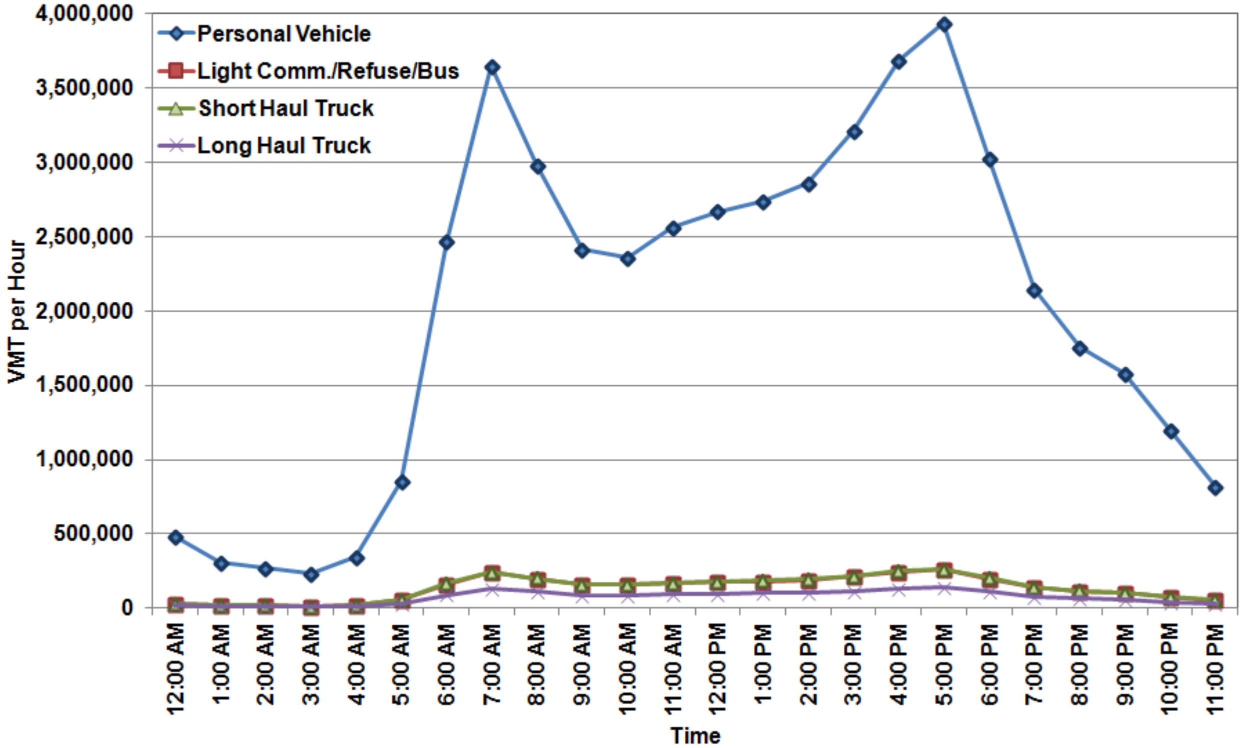


Figure 3-4: Relative Humidity Inputs to MOVES for Summer, San Antonio TxDOT District 2006



As shown in Figure 3-5, VMT varies greatly by hour of the day with a morning rush hour peak and afternoon rush hour peak. Personal vehicles contribute 85% of the 56,869,253 total daily VMT on an average summer weekday in the San Antonio-New Braunfels MSA. Light commercial trucks, refuse trucks, buses, short haul trucks, and long haul trucks have significantly lower VMT.

Figure 3-5: Weekday Hourly VMT by Vehicle Class, San Antonio-New Braunfels MSA, 2006



All federal requirements for vehicles and fuel were accounted for by the MOVES2010a runs. Fuel properties used in the model runs were based on surveys of retail gasoline and diesel fuel sold in Texas. The Low Reid Vapor Pressure (RVP) gasoline control strategy for 95 counties in eastern Texas was included in the modeling.[118] "Low RVP gasoline is fuel that is refined to have a lower evaporation rate and lower volatility than conventional gasoline. It also reduces the evaporative emissions generated during vehicle refueling and therefore decreases the emissions of volatile organic compounds (VOCs) and other ozone-forming emissions."[119] Diesel sulfur content was based on survey data and MOVES default values.[120] To calculate 2006 emissions in TxDOT's San Antonio district, fuel properties of RVP of 7.54 and sulfur content of 39.6 was used.[121]

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[118] TTI, July 2011. "Production of Statewide Non-Link-Based, On-Road Emissions Inventories with the Moves Model for the Eight-Hour Ozone Standard Attainment Demonstration Modeling". College Station, Texas. College Station, Texas. p. 4. Available online: ftp://amdaftp.tceq.texas.gov/pub/Mobile_EI/Statewide/mvs/reports/. Accessed 07/05/13.

[119] TCEQ, Jan. 3, 2012. Motor Vehicle Fuel Programs in Texas". Austin, Texas. Available online: http://www.tceq.texas.gov/airquality/mobilesource/vetech/fuelprograms.html. Accessed 07/09/13.

[120] TTI, July 2011. "Production of Statewide Non-Link-Based, On-Road Emissions Inventories with the Moves Model for the Eight-Hour Ozone Standard Attainment Demonstration Modeling". College Station, Texas. College Station, Texas. p. 31. Available online: ftp://amdaftp.tceq.texas.gov/pub/Mobile_EI/Statewide/mvs/reports/. Accessed 07/05/13.

[121] TTI, July 2011. "Production of Statewide Non-Link-Based, On-Road Emissions Inventories with the Moves Model for the Eight-Hour Ozone Standard Attainment Demonstration Modeling". College Station,

Diesel vehicle NO_X emissions factors were post-processed "for the 110 Eastern Texas counties subject to the Texas Low Emission Diesel (TxLED) program". NO_X adjustment factors used were provided by TCEQ using reductions of 4.8 percent for 2002-and-newer model year vehicles, and 6.2 percent for 2001-and-older model year vehicles." (Table 3-3)[122] The San Antonio-New Braunfels MSA counties under the low RVP and TxLED rule are Atascosa, Bexar, Comal, Guadalupe, and Wilson.

NO_X emissions display a similar hourly pattern to VMT with morning and afternoon rush hour peaks (Figure 3-6). Although short haul and long haul trucks have low VMT compared to passenger trucks, these trucks contribute 65 tons (49%) of total weekday on-road NO_X emissions. Passenger cars contribute 57 tons or 43% of weekday on-road NO_X emissions (Table 3-4). Hourly NO_X emissions, plotted in Figure 3-7 are similar between a weekday (Monday through Thursday) and a Friday with slightly higher emissions on Friday. Both Saturday and Sunday NO_X emissions have a different temporal profile with peak emissions occurring between noon and 4 pm.

Table 3-3: TxLED Adjustment Factor for Diesel Fuel, 2006

Source Use Type	2006 TxLED Reduction
Passenger Car	5.06%
Passenger Truck	5.68%
Light Commercial Truck	5.56%
Intercity Bus	5.97%
Transit Bus	5.94%
School Bus	5.92%
Refuse Truck	5.85%
Single Unit Short-Haul Truck	5.31%
Single Unit Long-Haul Truck	5.35%
Motor Home	5.77%
Combination Short-Haul Truck	5.82%
Combination Long-Haul Truck	5.83%

Texas. College Station, Texas. p. 41. Available online: ftp://amdaftp.tceq.texas.gov/pub/Mobile_EI/Statewide/mvs/reports/. Accessed 07/05/13.

[122] TTI, July 2011. "Production of Statewide Non-Link-Based, On-Road Emissions Inventories with the Moves Model for the Eight-Hour Ozone Standard Attainment Demonstration Modeling". College Station, Texas. College Station, Texas. p. 4. Available online: ftp://amdaftp.tceq.texas.gov/pub/Mobile_EI/Statewide/mvs/reports/. Accessed 07/05/13.

Figure 3-6: Hourly NO_X Emissions by Vehicle Class, San Antonio-New Braunfels MSA, 2006

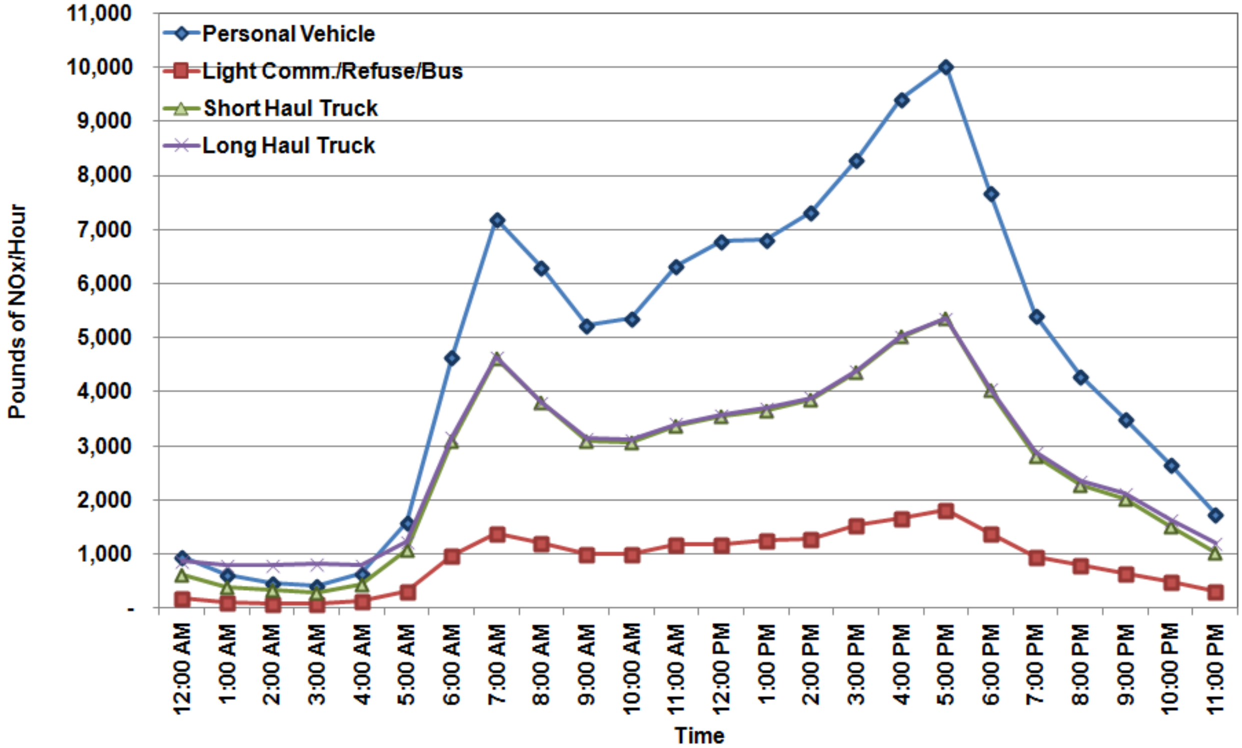


Figure 3-7: Hourly NO_X Emissions by Day of the Week, San Antonio-New Braunfels MSA, 2006

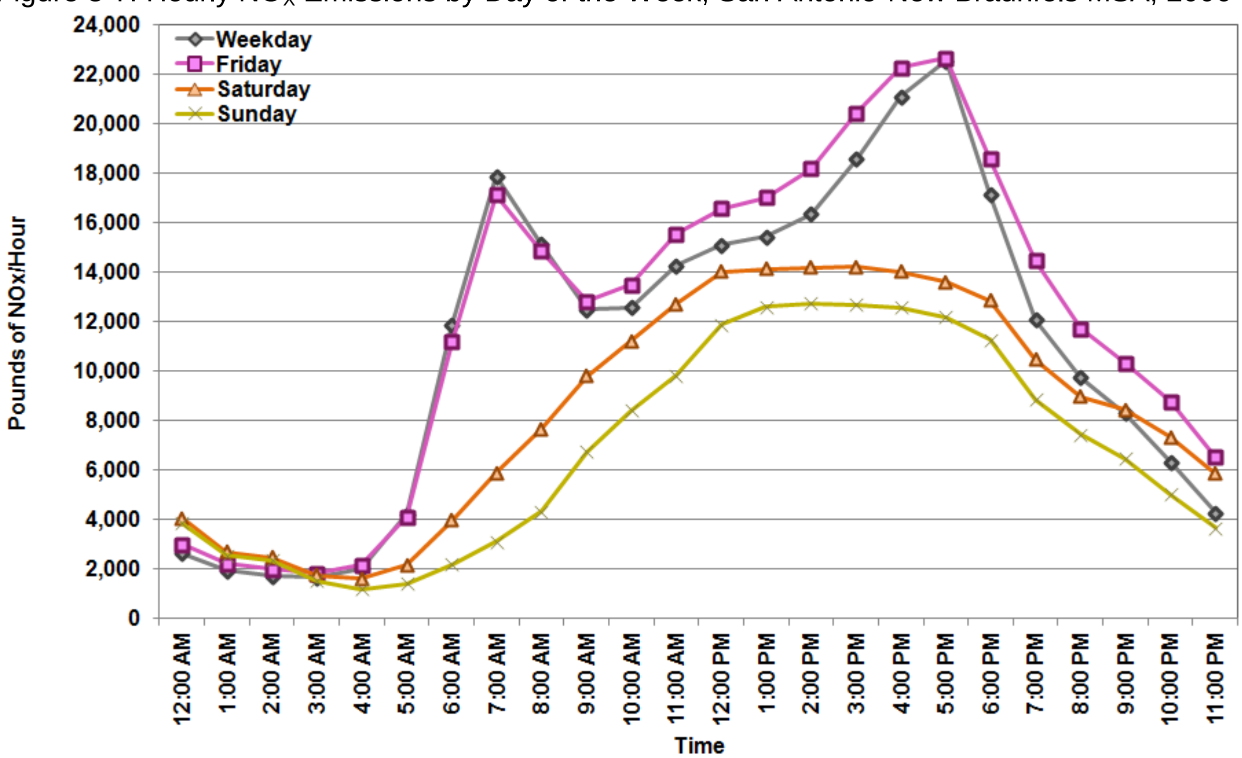


Table 3-4: VMT, NO_X and VOC emissions by Time of The Day, San Antonio-New Braunfels MSA, 2006

Time	Personal Vehicle			Light Comm./Refuse/Bus			Short Haul Truck			Long Haul Truck		
	VMT	Tons of NO_X	Tons of VOC	VMT	Tons of NO_X	Tons of VOC	VMT	Tons of NO_X	Tons of VOC	VMT	Tons of NO_X	Tons of VOC
12:00 AM	488,937	0.48	0.36	32,557	0.09	0.04	33,200	0.31	0.02	18,093	0.44	0.06
1:00 AM	309,566	0.31	0.31	20,613	0.05	0.03	21,020	0.19	0.02	11,456	0.40	0.08
2:00 AM	270,779	0.23	0.23	18,031	0.05	0.02	18,386	0.17	0.01	10,020	0.40	0.09
3:00 AM	233,449	0.21	0.23	15,545	0.04	0.02	15,852	0.15	0.01	8,639	0.41	0.10
4:00 AM	347,188	0.32	0.30	23,118	0.06	0.04	23,575	0.22	0.02	12,848	0.40	0.07
5:00 AM	854,620	0.79	0.58	56,907	0.15	0.06	58,030	0.54	0.05	31,626	0.62	0.05
6:00 AM	2,464,928	2.32	1.62	164,134	0.48	0.26	167,373	1.55	0.13	91,215	1.58	0.08
7:00 AM	3,646,687	3.60	2.65	242,824	0.70	0.33	247,617	2.32	0.20	134,947	2.32	0.11
8:00 AM	2,983,185	3.15	2.43	198,643	0.60	0.31	202,564	1.90	0.19	110,394	1.91	0.09
9:00 AM	2,411,335	2.62	1.82	160,565	0.51	0.23	163,734	1.55	0.13	89,232	1.57	0.08
10:00 AM	2,359,975	2.69	1.94	157,145	0.50	0.22	160,247	1.54	0.13	87,332	1.56	0.07
11:00 AM	2,558,084	3.16	2.32	170,337	0.59	0.28	173,699	1.68	0.15	94,663	1.71	0.08
12:00 PM	2,668,716	3.40	2.47	177,704	0.60	0.27	181,211	1.77	0.15	98,757	1.79	0.08
1:00 PM	2,737,163	3.40	2.35	182,261	0.63	0.29	185,859	1.83	0.15	101,290	1.86	0.08
2:00 PM	2,861,339	3.66	2.46	190,530	0.64	0.26	194,290	1.93	0.16	105,885	1.95	0.09
3:00 PM	3,214,110	4.15	2.69	214,020	0.77	0.35	218,244	2.18	0.18	118,939	2.19	0.10
4:00 PM	3,685,571	4.70	2.84	245,413	0.84	0.33	250,257	2.51	0.20	136,386	2.51	0.11
5:00 PM	3,936,399	5.02	2.98	262,116	0.90	0.36	267,289	2.68	0.21	145,668	2.68	0.12
6:00 PM	3,022,409	3.84	2.49	201,255	0.69	0.30	205,227	2.01	0.16	111,845	2.04	0.09
7:00 PM	2,147,157	2.71	1.86	142,974	0.48	0.21	145,796	1.41	0.11	79,456	1.45	0.07
8:00 PM	1,753,124	2.15	1.49	116,736	0.40	0.19	119,040	1.14	0.09	64,875	1.18	0.06
9:00 PM	1,575,356	1.76	1.13	104,899	0.32	0.12	106,970	1.01	0.08	58,297	1.06	0.06
10:00 PM	1,197,585	1.33	0.92	79,744	0.25	0.11	81,318	0.76	0.06	44,317	0.82	0.05
11:00 PM	816,513	0.87	0.65	54,370	0.15	0.06	55,443	0.52	0.04	30,215	0.60	0.05
Total	48,544,177	56.87	39.11	3,232,442	10.49	4.70	3,296,241	31.86	2.64	1,796,393	33.46	1.92

*Note: totals do not include long term idling emissions from long haul diesel combination trucks or traffic from the Eagle Ford

As shown in Table 3-5, Bexar County has the highest NO_X emissions in the San Antonio-New Braunfels MSA: 93 tons per weekday in 2006. Guadalupe County's, 11 tons per weekday, and Comal County's, 10 tons per weekday, are also significant sources of on-road NO_X emissions. Summer weekday on-road emissions accounted for 133 tons of NO_X and 48 tons of VOC in the San Antonio-New Braunfels MSA.

Table 3-5: Weekday VMT, NO_X Emissions, and VOC Emissions by County, San Antonio New Braunfels MSA, 2006

County	VMT	Tons of NO_X	Tons of VOC
Atascosa	1,645,740	5.44	1.24
Bandera	493,632	1.41	0.53
Bexar	43,339,519	93.28	37.17
Comal	4,062,411	10.40	3.13
Guadalupe	3,661,652	10.67	3.04
Kendall	1,108,735	4.09	1.03
Medina	1,526,961	4.66	1.20
Wilson	1,030,604	2.73	1.02
Total	56,869,254	132.68	48.36

The Emissions Preprocessor System (EPS3) was used "to convert the on-road inventory data into a gridded format appropriate for photochemical model input. Grid cell allocation is based on the X-Y locations of the link endpoints."[123] "Grid cell allocation is based on spatial surrogates specific to each county and roadway type. For example, if a single grid cell contains 15% of the interstate highway miles in a specific county, then 15% of the interstate highway emissions are assigned to that grid cell. In addition to gridding the hourly emissions, EPS3 assigns speciation profiles to appropriately group the exhaust and evaporative hydrocarbon emissions estimates based on reactivity for ozone formation."[124] "Profiles from EPA's SPECIATE Version 4.3 Database were used to allocate VOC exhaust and evaporative emission estimates with the Carbon Bond 6 (CB6) mechanism."[125]

3.9.2 *Heavy Duty Diesel Vehicles Idling Emissions*

The trucking industry is a major contributor to North America's economy, transporting over 80% of the nation's goods, and truck traffic is growing rapidly. The population of large trucks is estimated at 4.2 million, 1.3 million of which are "long haul" trucks equipped with sleeper cabs and powered by diesel engines. The Department of Transportation requires rest of 10 hours after every 11 hours driving for property-carrying commercial motor vehicle (CMV) drivers.

[123] TCEQ, Dec. 2012. "Introduction to Air Quality Modeling: Emissions Modeling". Austin, Texas. Available online: http://www.tceq.texas.gov/airquality/airmod/overview/am_ei.html. Accessed 07/03/13.
[124] TCEQ, Dec. 2012. "Introduction to Air Quality Modeling: Emissions Modeling". Austin, Texas. Available online: http://www.tceq.texas.gov/airquality/airmod/overview/am_ei.html. Accessed 07/03/13.
[125] TCEQ. Austin, Texas. Available online: ftp://amdaftp.tceq.texas.gov/pub/Rider8/ei/basecase/. Accessed 07/02/13.

Since IH-35, IH-10, and other major highways converge in San Antonio, truck drivers frequently use truck stops, rest areas, picnic areas, and other facilities in the San Antonio area to comply with the mandatory rest breaks. Truck drivers sometimes idle their engines throughout their rest periods to provide electricity for cooling and heating their cabins, or to keep their engine fluids warm. This extended idling consumes fuel, creates air and noise pollution, and is an inefficient use of the nation's energy supply. According to an estimate by the US Department of Energy, each year in the U.S., trucks consume over 25 million barrels of fuel a year for overnight truck idling.

A survey was conducted between October 2010 and June 2011 that involved observing and documenting the incidence of extended (30 minutes or more) engine idling at truck stops and rest areas in the San Antonio-New Braunfels MSA. Survey results provided inputs that were used to estimate extended idling emissions for the combination (tractor/trailer) long-haul trucks, the only source use type within the current version of the EPA's Motor Vehicle Emission Simulator model (MOVES) for which extended idling emissions can be estimated. This vehicle category is more commonly referred to as diesel-powered five-axle "eighteen-wheelers", but other four-axle and six-axle configurations are also included in this category. Combination long-haul trucks are classified in MOVES as trucks with a majority of their operation outside a 200-mile radius of home base. The primary inputs needed by MOVES to estimate idling emissions from long-haul trucks are the number of source hours operating (SHO) in extended idling mode by source type.

Drivers idle their trucks' engines at the following locations:

- Truck Stops
- Rest Stops
- Picnic Areas
- Other Idling Locations

Extensive research was conducted to identify and locate all such facilities in the San Antonio-New Braunfels MSA. All identified truck stops, rest stops, and picnic areas were included in this survey. Additional truck stops that were not listed on maps or other information sources were identified during the survey and were added to the inventory of facilities surveyed.

Table 3-6: Truck Stops in the San Antonio-New Braunfels MSA

Truck Stop	Address	Exit Number	County	Parking Spaces*
Kuntry Korner Steak & Eggs	IH 37 / Jim Brite Rd, Pleasanton	104	Atascosa	45
ZS Super Stop	IH 37 / FM 97, Pleasanton	109	Atascosa	24
EZ Mart	15537 IH 37, Elmendorf	125	Bexar	25
Tex Best Travel Center	20290 IH 37, Elmendorf	125	Bexar	30
Valero Ram Travel Center	IH 37, Elmendorf	130	Bexar	12
Texas Best Fuel Stop (Exxon)	14650 IH 35, Von Ormy	140	Bexar	15
Valero AAA Travel Center	14555 IH 35, Von Ormy	140	Bexar	70
Shell Time Wise Landmark	13437 IH 35, Von Ormy	141	Bexar	24
Love's Country Store	11361 IH 35, S Von Ormy	145	Bexar	108
Valero	IH 35, S Von Ormy	145	Bexar	50
Shell Truck Stop	11607 N IH 35, San Antonio	169	Bexar	45
PICO	25284 IH 10, San Antonio	550	Bexar	15
Petro Travel Plaza	1112 Ackerman Rd, San Antonio	582	Bexar	320
Pilot Travel Center	5619 IH 10 E, San Antonio	582	Bexar	50
Flying J Travel Plaza	1815 Foster Rd., San Antonio	583	Bexar	283
TA Travel Center	6170 IH 10 E, San Antonio	583	Bexar	258
Shell Truck Stop	8755 IH 10 E, Converse	585	Bexar	60
Alamo Travel Center	13183 IH 10, Converse	591	Bexar	40
Texaco	IH 10, Converse	593	Bexar	30
Trainer Hale Truck Stop	14462 IH 10, Converse	593	Bexar	25
Pilot Travel Center	4142 Loop 337, New Braunfels	184	Comal	80
Tex Best Travel Center	2735 N IH 35, New Braunfels	191	Comal	28
TA Truck Stop	4817 IH 35, New Braunfels	193	Comal	250
Sunmart No 167	6150 W IH 10, Seguin	601	Guadalupe	40
Jud's Food and Fuel - Shell	IH10/Hwy 123, Seguin	610	Guadalupe	40
Chevron	IH 10, Comfort	523	Kendall	20
Exxon Valley Mart	US 90, Hondo	533	Medina	10
Total				1,997

***Data on number of parking spaces are from truck stop surveys**

TxDOT's new generation of Safety Rest Areas feature regional designs, modern restrooms, interpretive displays, exhibits of local features, separate parking for cars and trucks, and wireless Internet access."[126] Construction of new rest stops with designated truck parking spaces and better amenities, such as air conditioned rooms and wireless Internet access, have made rest stops suitable resting places for long-haul truckers. All the rest stops and picnic areas that were surveyed, with the number of estimated parking spaces, are provided in Table 3-7.

[126] TxDOT, Sept. 2009. "Texas Safety Rest Area Program". Available online: ftp://ftp.dot.state.tx.us/pub/txdot-info/library/pubs/travel/sra_brochure.pdf. Accessed 07/11/11.

Table 3-7: Rest Areas and Picnic Areas in the San Antonio Region

Type	Location	Mile Marker	County	Parking Spaces*
Rest Areas	Northbound - IH 35	180	Comal	18
	Southbound - IH 35	180	Comal	18
	Eastbound - IH 10	619	Guadalupe	26
	Westbound - IH 10	619	Guadalupe	32
	Northbound - IH 35	130	Medina	17
	Southbound - IH 35	130	Medina	20
	Eastbound - US 90	518	Medina	15
	Westbound - US 90	518	Medina	13
Picnic Areas	Northbound - IH 37	112	Atascosa	28
	Southbound - IH 37	111	Atascosa	28
	Eastbound - IH 10	529	Kendall	17
	Westbound - IH 10	531	Kendall	25
	US 90	548	Medina	6

*****Data on number of parking spaces are from surveys

Each truck stop, rest area, and picnic area in the San Antonio-New Braunfels MSA was surveyed at least 6 times: 3 times on weekdays and 3 times on weekends and for each of three time periods. Since every site was surveyed multiple times, the results are statistically significant.

Observations of truck engine idling were collected during the following three time periods:

- Morning (5 am – 10 am)
- Daytime (10 am – 10 pm)
- Evening/Night (10 pm – 5 am)

For data collected on weekdays, the morning and daytime periods included observations during local “rush hours” for consistency with how travel demand modeling is conducted. The largest number of surveys occurred between 5 am to 9 am and from 10 pm to midnight, but at least 4 surveys were collected for each hour of the day. Overall, 184 truck stop, 57 rest area, and 31 picnic area surveys were collected. Each facility was surveyed for time periods of weekday, weekend, morning, daytime, and nighttime. The number of sites and parking spaces surveyed by time period are provided in Table 3-8.

Table 3-8: Data Collection Summary by Facility Type

Type	Time Period	Number of Surveys Conducted			Truck Parking Spaces Surveyed		
		Weekday	Weekend	Total	Weekday	Weekend	Total
Truck Stops	Morning	34	30	64	2,543	2,063	4,606
	Day	32	30	62	2,940	2,390	5,330
	Night	27	31	58	2,017	2,234	4,251
Rest Areas	Morning	10	8	18	195	159	354
	Day	10	11	21	196	201	397
	Night	8	10	18	180	196	376
Picnic Areas	Morning	5	7	12	104	160	264
	Day	5	4	9	104	90	194
	Night	4	6	10	76	132	208
Total		135	137	272	8,355	7,625	15,980

The primary inputs needed by MOVES to estimate long-haul truck idling emissions were the number of source hours operating (SHO) in extended idling mode, which were obtained from the survey's results. Other local input data came from Texas Transportation Institute's (TTI) 2008 report entitled "On-Road Mobile Source Emissions Trends for all 254 Texas Counties: 1990 through 2040".[127] Idling emission factors for heavy duty long-haul trucks are provided in Table 3-9.

Table 3-9: Heavy Duty Truck Idling Emission Factors from the MOVES Model

Year	NO_X	VOC
2006	226.01 grams/hour	57.90 grams/hour

Truck parking spaces in the San Antonio-New Braunfels MSA included 1,997 parking spaces at truck stops, 159 parking spaces at rest areas, and 104 parking spaces at picnic areas. Idling rates used to calculate emissions per parking space by facility type and time of the day are provided in Table 3-10. Data for picnic areas are limited because there are only five picnic areas on major highways in the San Antonio-New Braunfels MSA.

[127] TCEQ, August 2008. "On-Road Mobile Source Emissions Trends for all 254 Texas Counties: 1990 Through 2040". TTI. College Station, Texas.

Table 3-10: Percentage of Time each Parking Space is Occupied by an idling vehicle by Day Type, Facility Type, and Time Period

Day Type	Statistical Test	Weekday			Weekend		
		Truck Stops	Rest Areas	Picnic Areas	Truck Stops	Rest Areas	Picnic Areas
Total Morning	Low	17%	15%	1%	11%	11%	11%
	Mean	22%	24%	11%	15%	19%	25%
	High	27%	33%	20%	19%	27%	39%
	Standard Dev.	14%	14%	11%	11%	12%	19%
	N	34	10	5	30	8	7
	Confidence Level	5%	9%	10%	4%	8%	14%
Total Day	Low	9%	6%	2%	10%	3%	0%
	Mean	13%	17%	6%	14%	8%	2%
	High	17%	28%	10%	18%	13%	5%
	Standard Dev.	10%	18%	5%	11%	9%	3%
	N	32	10	5	30	11	4
	Confidence Level	4%	11%	4%	4%	5%	3%
Total Night	Low	19%	17%	9%	18%	7%	8%
	Mean	25%	32%	24%	26%	16%	14%
	High	32%	46%	38%	35%	26%	19%
	Standard Dev.	17%	21%	15%	25%	15%	7%
	N	27	8	4	31	10	6
	Confidence Level	7%	14%	15%	9%	9%	6%

Based on 95 % confidence level

The following equation was used to calculate county level total daily emissions for extended truck idling at each facility type for the photochemical model.

Equation 3-1, Daily emissions for each facility type and time period per county

$DE_{ABC} = RATE_{BC} \times SP_{AC} \times HRS \times EF_{MOVES} / 907{,}184.74$ grams/ton

Where,

DE_{ABC} = Daily Emissions from County A for Time Period B and Facility Type C (tons)

$RATE_{BC}$ = Idling Rates per Parking Space for Time Period B and Facility Type C (from survey data located in Table 3-10)

SP_{AC} = Number of Truck Parking Spaces in County A for Facility Type C (from survey data located in Table 3-6 and Table 3-7)

HRS = Number of Hours per Time Period B (Morning – 5 hrs, Daytime – 12 hrs, and Nighttime – 12 hrs)

EF_{MOVES} = Idling Emissions factor for Combination Long-Haul Trucks in 2006, 226.01 grams of NO_X-hr and 57.90 grams of VOC-hr (from the MOVES model)

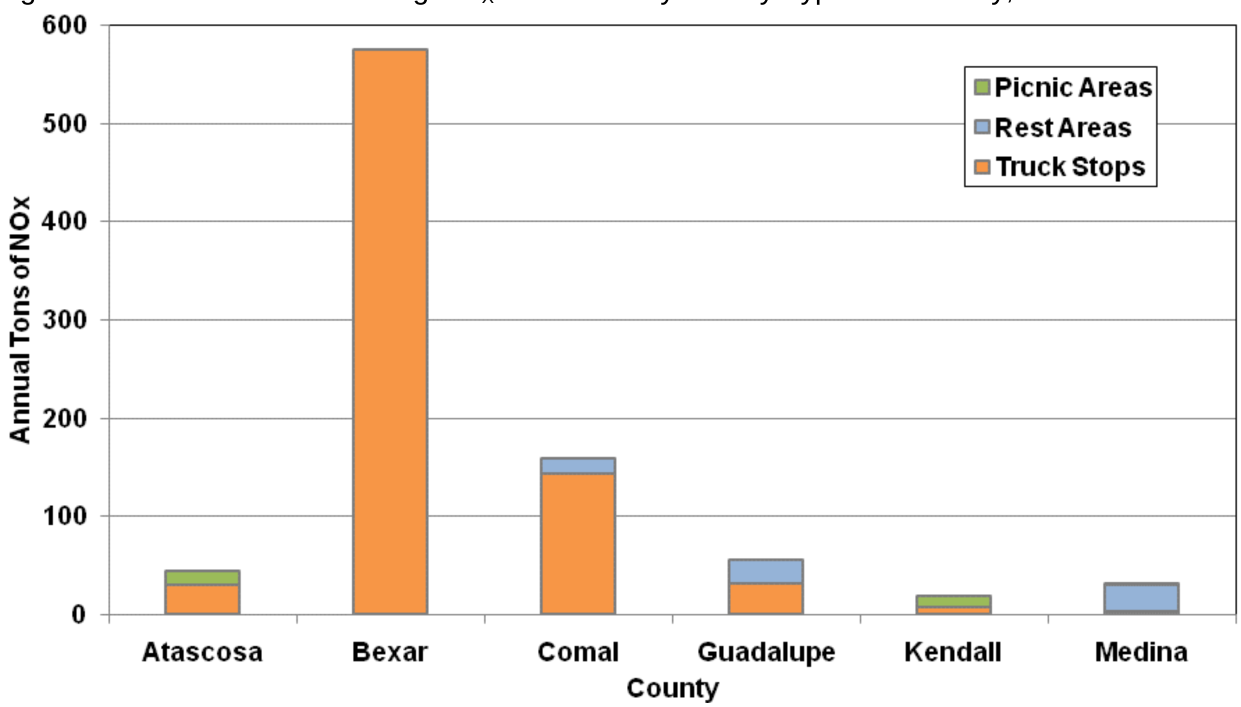
Sample calculation for morning NO_X emissions from truck stops in Bexar County

DE_{ABC} = 22.02% Idling Rate per Parking Space During Weekday Mornings x 1,434 Truck Stop Parking Spaces x 5 hours x 226.01 grams of NO_X-hr / 907,184.74 grams/ton
= 0.39 tons of NO_X/weekday morning emissions from truck stops in Bexar County

Extended truck idling emission totals for each facility type and county is provided in Figure 3-8. Total annual NO_X emissions from extended truck idling in the San Antonio-New Braunfels MSA were estimated to be 883 tons per year while total VOC emissions were estimated to be 226 tons per year. Bexar County dominates total idling emissions, because there is a concentration of large truck stops on the east side of the city near the IH-410 and IH-10 interchange. In addition, there are concentrations of truck stops on IH-35 in the southwest part of the county and on IH-37 in south Bexar County.

Comal County also has several large truck stops where significant amounts of NO_X emissions, 144 tons of NO_X a year, are generated from idling truck engines. These truck stops are concentrated along IH-35 between San Antonio and Austin. Rest areas are located in Comal, Guadalupe, and Medina counties. Truck idling also occurs at picnic areas, which are located in Atascosa and Kendall counties.

Figure 3-8: Extended Truck Idling NO_X Emissions by Facility Type and County, 2006*



*Bandera and Wilson County are not included because they do not have any significant truck parking facilities

3.10 Point Source Emissions

According to the Texas Administrative Code, “the owner or operator of an account or source in the State of Texas or on waters that extend 25 miles from the shoreline meeting one or more of the following conditions shall submit emissions inventories and/or related data as required in subsection (b) of this section to the commission on forms or other media approved by the commission:

(1) an account which meets the definition of a major facility/stationary source, as defined in §116.12 of this title (relating to Nonattainment Review Definitions), or any account in an ozone nonattainment area emitting a minimum of ten tons per year (tpy) volatile organic compounds (VOC), 25 tpy nitrogen oxides (NO_X), or 100 tpy or more of any other contaminant subject to national ambient air quality standards (NAAQS);
(2) any account that emits or has the potential to emit 100 tpy or more of any contaminant;
(3) any account which emits or has the potential to emit 10 tons of any single or 25 tons of aggregate hazardous air pollutants (HAPS); and
(4) any minor industrial source, area source, non-road mobile source, or mobile source of emissions subject to special inventories under subsection (b)(3) of this section. For purposes of this section, the term "area source" means a group of similar activities that, taken collectively, produce a significant amount of air pollution."[128]

Any sources that meet the Texas Administrative Code definition were processed in the photochemical model as point sources.

To collect data on point sources, "TCEQ mails annual emissions inventory questionnaires (EIQs) to all sources identified as meeting the reporting requirements. Subject entities are required to report levels of emissions subject to regulation from all emissions-generating units and emissions points, and also must provide representative samples of calculations used to estimate the emissions. Descriptive information is also required on process equipment, including operating schedules, emission control devices, abatement device control efficiencies, and emission point discharge parameters such as location, height, diameter, temperature, and exhaust gas flow rate. All data submitted in the EIQ are subjected to quality assurance (QA) procedures."[129]

In the photochemical modeling files, point sources are categorized according to electric generating units (EGU) and non-electric generating units (NEGU). Hourly EGU point source emissions were obtained by EPA's acid rain database for every modeling day130, while NEGUs were based on the State of Texas Air Reporting System (STARS). "The TCEQ processes industrial point source emissions for use in photochemical modeling in several steps. The first

[128] "Texas Administrative Code: Title 30, Part 1, Chapter 101, Subchapter A, Rule §101.10". Available online: http://info.sos.state.tx.us/pls/pub/readtac$ext.TacPage?sl=R&app=9&p_dir=&p_rloc=&p_tloc=&p_ploc=&pg=1&p_tac=&ti=30&pt=1&ch=101&rl=10. Accessed 07/11/13.

[129] TCEQ. "Appendix B: Emissions Modeling for the DFW Attainment Demonstration Sip Revision for the 1997 Eight-Hour Ozone Standard". Austin, Texas. p. B-12. Available online: http://www.tceq.texas.gov/assets/public/implementation/air/sip/dfw/ad_2011/AppB_EI_ado.pdf. Accessed 07/03/13.

[130] EPA. "Acid Rain". Available online: http://www.epa.gov/acidrain/related.html. Accessed 07/11/13.

step is to acquire a point source emissions inventory for the year being modeled. Point source emissions are retrieved from the agency's database, the State of Texas Air Reporting System (STARS). STARS data extracted include reported daily average emission rates, location coordinates, stack parameters, chemical species, standard industrial classification (SIC), source classification code (SCC), and other data needed to model each source. Location coordinates (for example, longitude and latitude) allow the emissions to be placed at the appropriate location in the modeling grid. Depending on stack parameters (stack height, discharge velocity, temperature, etc.), the emissions may also be placed directly into elevated layers of the three-dimensional grid."[131]

NEGU point source emissions outside of Texas are based on EPA's NEI 2008 annual emissions.132 For point sources located in Mexico, the 1999 Mexican National Emissions Inventory (NEI)133 phase III was used. The 2006 Canadian National Pollutant Release Inventory (NPRI) and the upstream oil and gas inventories from Environmental Canada[134] were used for Canadian point sources. The 2005 offshore emissions[135] were "developed by Eastern Research Group (ERG) under contract to the Minerals Management Service (MMS). The report and data are divided into two parts, oil and gas exploration and production platform (point) sources and non-platform (area) sources."[136]

"Additionally, a supplemental 'extra olefins' file was developed to account for reconciled HRVOC emissions in the HGB area. HRVOC include ethylene, propylene, 1,3-butadiene, and all isomers of butene "[137] "The reconciled extra emissions were placed at a single pseudo point in each affected modeling cell, in modeling cells that contain point sources, and assigned an emission rate for each HRVOC to best offset the difference between modeled and calculated concentrations. A new VOC AFS record was created for each pseudo point source. The pseudo

[131] TCEQ, Dec. 2012. "Introduction to Air Quality Modeling: Emissions Modeling". Austin, Texas. Available online: http://www.tceq.texas.gov/airquality/airmod/overview/am_ei.html. Accessed 07/03/2013.
[132] EPA. "National Emissions Inventory (NEI) Air Pollutant Emissions Trends Data". Available online: http://www.epa.gov/ttnchie1/trends/. Accessed 07/01/13.
[133] EPA, Oct. 2006. "North American Emissions Inventories – Mexico". Available online: http://www.epa.gov/ttnchie1/net/mexico.html. Accessed 07/08/13.
[134] Environment Canada. "National Pollutant Release Inventory". Available online: http://www.ec.gc.ca/inrp-npri/default.asp?lang=En&n=4A577BB9-1. Accessed 07/08/13.
[135] Darcy Wilson, Eastern Research Group, Inc. Dec. 2007. "Year 2005 Gulfwide Emission Inventory Study". Morrisville, NC. Available online: http://www.boem.gov/Environmental-Stewardship/Environmental-Studies/Gulf-of-Mexico-Region/Air-Quality/2005-Gulfwide-Emission-Inventory.aspx. Accessed 07/11/13.
[136] TCEQ. "Appendix B: Emissions Modeling for the DFW Attainment Demonstration Sip Revision for the 1997 Eight-Hour Ozone Standard". Austin, Texas. p. B-22. Available online: http://www.tceq.texas.gov/assets/public/implementation/air/sip/dfw/ad_2011/AppB_EI_ado.pdf. Accessed 07/03/13.
[137] TCEQ. "Appendix B: Emissions Modeling for the DFW Attainment Demonstration Sip Revision for the 1997 Eight-Hour Ozone Standard". Austin, Texas. p. B-11. Available online: http://www.tceq.texas.gov/assets/public/implementation/air/sip/dfw/ad_2011/AppB_EI_ado.pdf. Accessed 07/03/13.

point source was placed in the middle of each affected cell and assigned default stack parameters (e.g., 5.0 meter stack height). Since these reconciled points do not exist in the STARS database, unique plant, stack and point identifiers were assigned to new speciation cross reference and profile files." [138]

"Episode-specific survey results of HGB floating roof tank landing losses (TLL) were averaged and used to develop files of hourly Texas Point Sources emissions for the 2006 episode."[139] "Land Loss emissions come from most tanks storing moderate or high vapor pressure liquids and are controlled with the use of floating roofs equipped with seals to prevent the direct contact of the stored liquid with the ambient air. Air emissions from tanks are greater while the tank roof is landed and remain so until the tank is either completely emptied and/or purged of organics or the tank is refilled and the roof is again floating. Air emissions that occur during this period are referred to as landing loss emissions."[140]

CB6 chemical speciation was used for Texas and other states while CB05 chemical speciation was used for other point sources.[141] "Because the composition of VOC emissions is critically important to accurately simulating ozone formation, the TCEQ asks industries to provide detailed breakdowns of the hydrocarbon species emitted at each reported emission point. In cases where this information is unavailable or incomplete, default speciation profiles are used to complete the speciation of each point based on its reported SCC. TCEQ occasionally conducts special inventory surveys to obtain hourly speciated emissions from specific sources. The TCEQ conducted such a survey during the Second Texas Air Quality Study (TexAQS II) intensive period, collecting hourly emissions from major point sources in East Texas from August 15 through September 15, 2006. A 2011 survey of certain flare operations in the Houston-Galveston-Brazoria area was recently conducted as well."[142]

3.11 2006 Base Case Emission Inventory Development

Development of the 2006 emissions database for the extended May 31st to July 2nd, 2006 photochemical modeling episode required the review and adoption of data from a variety of

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[138] TCEQ. "Appendix B: Emissions Modeling for the DFW Attainment Demonstration Sip Revision for the 1997 Eight-Hour Ozone Standard". Austin, Texas. p. B-17. Available online: http://www.tceq.texas.gov/assets/public/implementation/air/sip/dfw/ad_2011/AppB_EI_ado.pdf. Accessed 07/03/13.

[139] TCEQ. "Appendix B: Emissions Modeling for the DFW Attainment Demonstration Sip Revision for the 1997 Eight-Hour Ozone Standard". Austin, Texas. p. B-11. Available online: http://www.tceq.texas.gov/assets/public/implementation/air/sip/dfw/ad_2011/AppB_EI_ado.pdf. Accessed 07/03/13.

[140] Eden, Dan. "Letter on Air Emissions During Tank Floating Roof Landings." December 5, 2006. Available online: http://www.tceq.state.tx.us/assets/public/permitting/air/memos/tank_landing_final.pdf. Accessed 07/11/13

[141] TCEQ. Austin, Texas. Available online: ftp://amdaftp.tceq.texas.gov/pub/Rider8/ei/basecase/. Accessed 07/02/13.

[142] TCEQ, Dec. 2012. "Introduction to Air Quality Modeling: Emissions Modeling". Austin, Texas. Available online: http://www.tceq.texas.gov/airquality/airmod/overview/am_ei.html. Accessed 07/03/2013.

sources. A major step in the development and refinement process entailed developing/obtaining improved emission inventories and adjusting emissions to the correct time periods, speciating the emissions, and converting the results to model-ready format. Emissions data was obtained from a variety of sources including AACOG data, TCEQ, EPA, TxDOT, TTI, FAA, North Central Texas Council of Governments, United States Department of Agriculture, Environment Canada, and other entities.

Daily 2006 NO_X and VOC emissions for the San Antonio MSA, used in the photochemical model, are summarized in Table 3-11, Figure 3-9, and Figure 3-10. The source category with the largest amount of VOC emitted per day was area, followed by on-road and non-road. Emissions on the weekends are lower for every source except point source emissions. Point sources usually operate 7 days a week and the emissions vary greatly from day to day. Eagle Ford emissions are zero during the 2006 episode because most production in the Eagle Ford did not start until 2008.

The largest source of NO_X emissions in 2006 were on-road vehicles: 135 tons of NO_X per weekday in the San Antonio-New Braunfels MSA. Point sources are the second largest emitter of NO_X at 80 tons per day. Non-road, area, and off-road NO_X emissions are lower than the other two categories.

Table 3-11: NO_X and VOC Emissions (ton/day) for the San Antonio-New Braunfels MSA, 2006

Date	Date	NO_X						VOC					
		On-Road	Point	Area	Non-Road	Off-Road	Eagle Ford	On-Road	Point	Area	Non-Road	Off-Road	Eagle Ford
31-May	Wednesday	134.7	77.6	16.5	43.6	7.9	0.0	49.2	8.4	147.2	26.4	1.6	0.0
1-Jun	Thursday	134.7	71.3	16.5	43.6	7.9	0.0	49.2	8.3	147.2	26.4	1.6	0.0
2-Jun	Friday	144.4	74.9	16.5	43.6	7.9	0.0	51.1	8.4	147.2	26.4	1.6	0.0
3-Jun	Saturday	101.2	76.5	13.9	29.7	3.4	0.0	39.8	8.5	94.6	45.0	0.5	0.0
4-Jun	Sunday	81.8	76.0	12.3	13.7	3.4	0.0	37.6	8.5	73.4	40.3	0.5	0.0
5-Jun	Monday	134.7	80.9	16.5	43.6	7.9	0.0	49.2	8.8	147.2	26.4	1.6	0.0
6-Jun	Tuesday	134.7	81.1	16.5	43.6	7.9	0.0	49.2	8.7	147.2	26.4	1.6	0.0
7-Jun	Wednesday	134.7	80.9	16.5	43.6	7.9	0.0	49.2	8.7	147.2	26.4	1.6	0.0
8-Jun	Thursday	134.7	84.1	16.5	43.6	7.9	0.0	49.2	8.8	147.2	26.4	1.6	0.0
9-Jun	Friday	144.4	81.5	16.5	43.6	7.9	0.0	51.1	8.7	147.2	26.4	1.6	0.0
10-Jun	Saturday	101.2	80.4	13.9	29.7	3.4	0.0	39.8	8.6	94.6	45.0	0.5	0.0
11-Jun	Sunday	81.8	79.6	12.3	13.7	3.4	0.0	37.6	8.6	73.4	40.3	0.5	0.0
12-Jun	Monday	134.7	81.6	16.5	43.6	7.9	0.0	49.2	8.7	147.2	26.4	1.6	0.0
13-Jun	Tuesday	134.7	83.2	16.5	43.6	7.9	0.0	49.2	8.7	147.2	26.4	1.6	0.0
14-Jun	Wednesday	134.7	82.3	16.5	43.6	7.9	0.0	49.2	8.7	147.2	26.4	1.6	0.0
15-Jun	Thursday	134.7	83.2	16.5	43.6	7.9	0.0	49.2	8.7	147.2	26.4	1.6	0.0
16-Jun	Friday	144.4	80.4	16.5	43.6	7.9	0.0	51.1	8.7	147.2	26.4	1.6	0.0
17-Jun	Saturday	101.2	79.4	13.9	29.7	3.4	0.0	39.8	8.6	94.6	45.0	0.5	0.0
18-Jun	Sunday	81.8	78.7	12.3	13.7	3.4	0.0	37.6	8.5	73.4	40.3	0.5	0.0
19-Jun	Monday	134.7	83.9	16.5	43.6	7.9	0.0	49.2	8.8	147.2	26.4	1.6	0.0
20-Jun	Tuesday	134.7	78.1	16.5	43.6	7.9	0.0	49.2	8.5	147.2	26.4	1.6	0.0
21-Jun	Wednesday	134.7	81.6	16.5	43.6	7.9	0.0	49.2	8.6	147.2	26.4	1.6	0.0
22-Jun	Thursday	134.7	83.6	16.5	43.6	7.9	0.0	49.2	8.7	147.2	26.4	1.6	0.0
23-Jun	Friday	144.4	85.3	16.5	43.6	7.9	0.0	51.1	8.8	147.2	26.4	1.6	0.0
24-Jun	Saturday	101.2	87.1	13.9	29.7	3.4	0.0	39.8	8.7	94.6	45.0	0.5	0.0
25-Jun	Sunday	81.8	87.0	12.3	13.7	3.4	0.0	37.6	8.8	73.4	40.3	0.5	0.0
26-Jun	Monday	134.7	83.7	16.5	43.6	7.9	0.0	49.2	8.7	147.2	26.4	1.6	0.0
27-Jun	Tuesday	134.7	78.9	16.5	43.6	7.9	0.0	49.2	8.6	147.2	26.4	1.6	0.0
28-Jun	Wednesday	134.7	83.1	16.5	43.6	7.9	0.0	49.2	8.7	147.2	26.4	1.6	0.0
29-Jun	Thursday	134.7	80.8	16.5	43.6	7.9	0.0	49.2	8.6	147.2	26.4	1.6	0.0
30-Jun	Friday	144.4	80.5	16.5	43.6	7.9	0.0	51.1	8.6	147.2	26.4	1.6	0.0
1-Jul	Saturday	101.2	72.1	13.9	29.7	3.4	0.0	39.8	8.3	94.6	45.0	0.5	0.0
2-Jul	Sunday	81.8	71.5	12.3	13.7	3.4	0.0	37.6	8.3	73.4	40.3	0.5	0.0

Figure 3-9: Daily Graph of 2006 VOC Emissions (ton/day) for the San Antonio-New Braunfels MSA

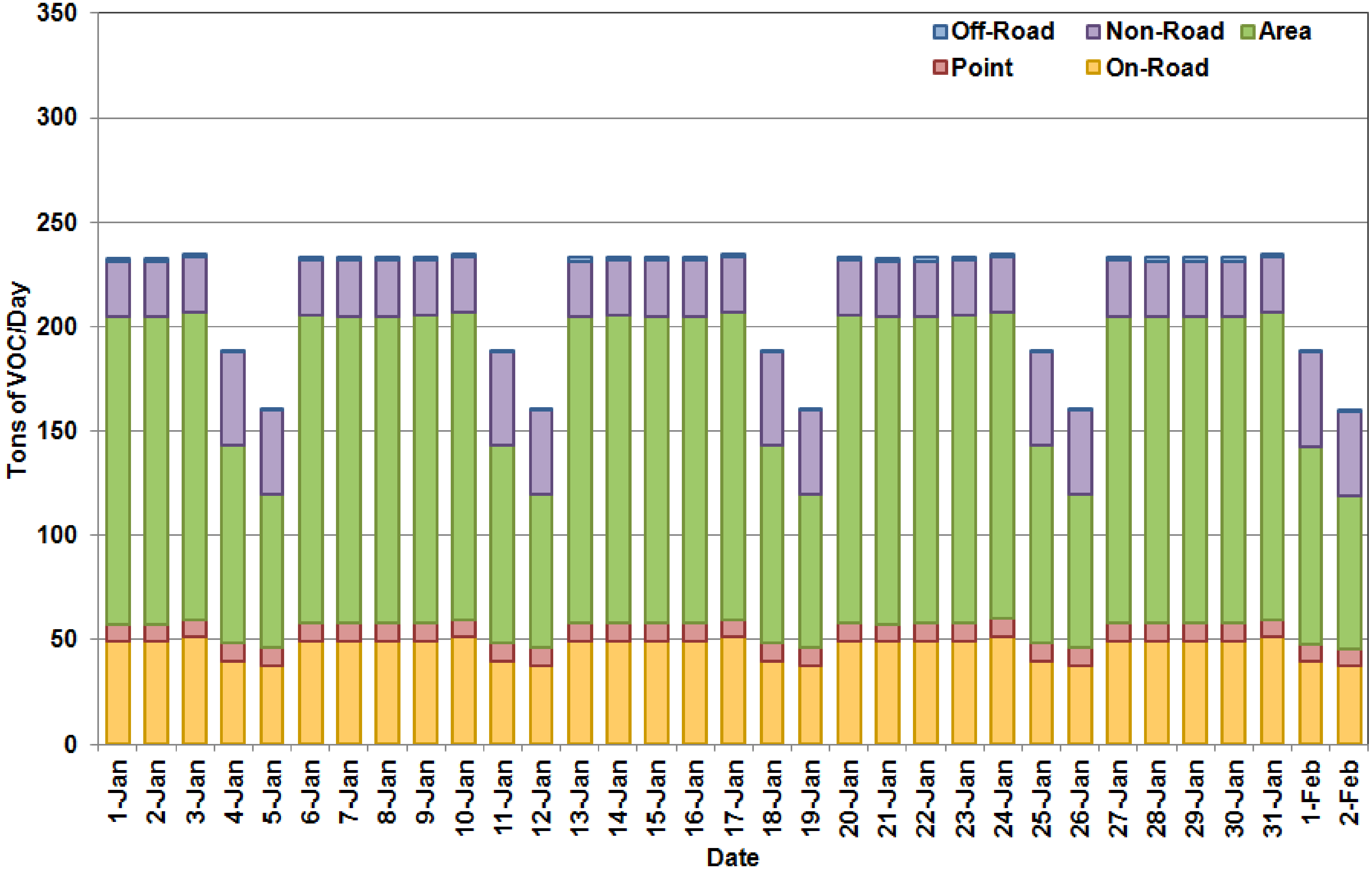
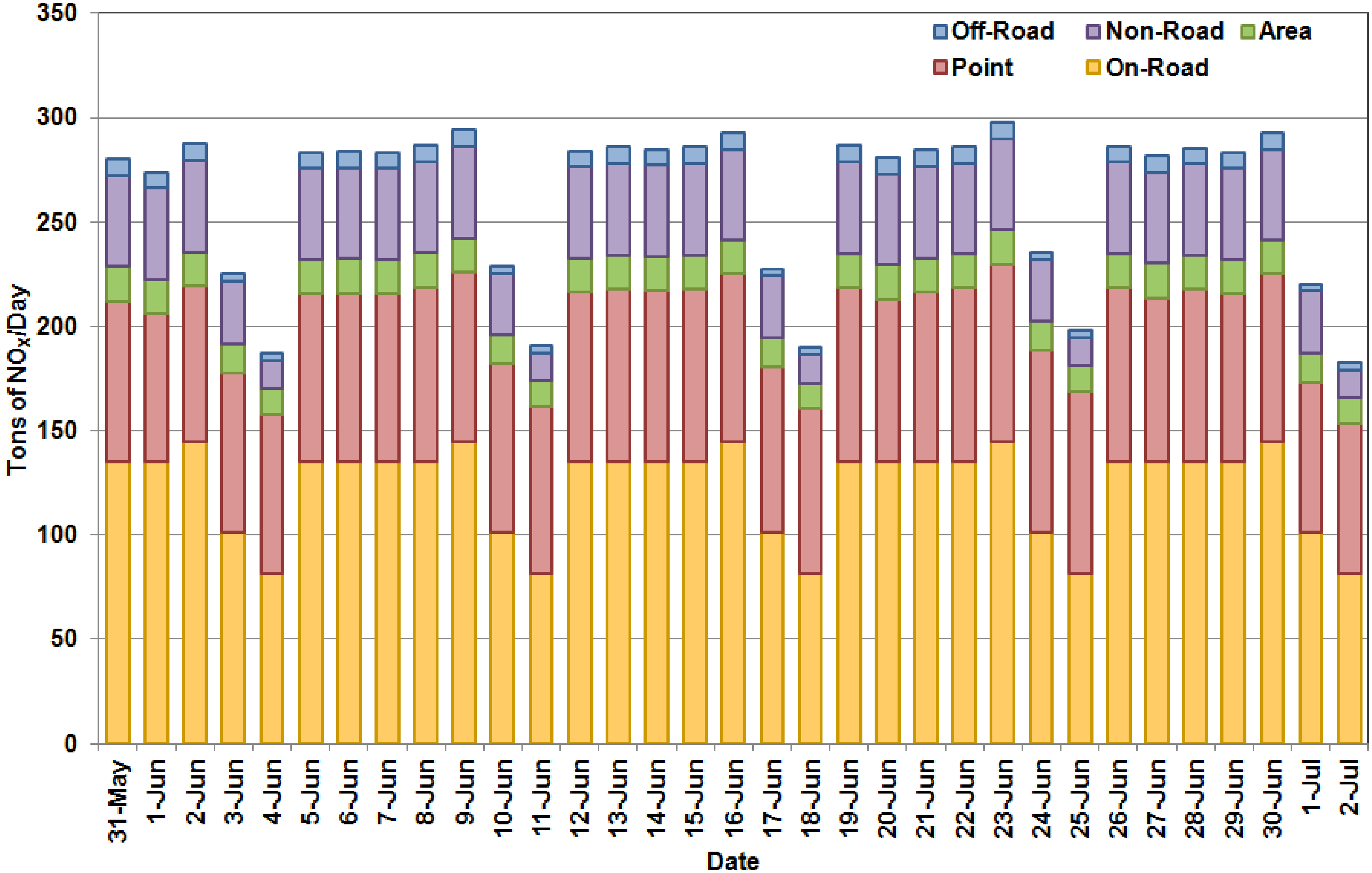


Figure 3-10: Daily Graph of 2006 NO_X Emissions (ton/day) for the San Antonio-New Braunfels MSA



4 Future-Year Inventory, 2012 and 2018

4.1 Development of the Future Year Inventory

To predict future impacts on air quality in the San Antonio-New Braunfels MSA, emission inventories for 2012 and 2018 were developed for the extended June 2006 modeling episode. The 2012 and 2018 projection inventories were used as inputs in the photochemical model to calculate future ozone concentrations. Future Year Inventories were developed using the same temporal, chemical speciation, and methodologies used to develop the Base Case Inventory, as described in Chapter 3. To predict future air quality, it is important to maintain consistency in developing all photochemical modeling emission inventories.

EPA's emission inventory guidance for ozone advises modelers to follow a four-step process when developing a Future Year Inventory.

- "Identify sectors of the inventory that require projections and sectors for which projections are not advisable, and prioritize these sectors based on their expected impact on the modeling region. (Section 17.6.1 of Guidance Document (U.S. EPA, 2005/2007)).
- Collect the available data and models that can be used to project emissions for each of the sectors (Section 17.6.2 of Guidance Document (U.S. EPA, 2005/2007)).
- For key sectors, determine what information will impact the projection results the most, and ensure that the data values reflect conditions or expectations of the modeling region (Section 17.6.3 of Guidance Document (U.S. EPA, 2005/2007)).
- Create inputs needed for emissions models, create future year inventories, quality assure them, and create air quality model inputs from them (Section 17.6.4 of Guidance document (U.S. EPA, 2005/2007))."[143]

These four steps were used to develop the 2012 and 2018 Future Year Inventories and used as input to project the June 2006 photochemical modeling episode to 2012 and 2018. CO, NO_X, and VOC emissions from all anthropogenic sources were projected from 2006 to 2012 and 2018. Biogenic emissions, meteorology inputs, and chemical speciation remained the same for every base case and projection year. All new emissions sources including new point sources and the Eagle Ford shale emissions were included in the future year emission inventory projections. Table 4-1 shows the data sources for the 2012 Emissions Inventory, while Table 4-2 provides the data sources for 2018.

[143] EPA. November 2005. "The Emission Inventory Guidance for Implementation of Ozone and Particulate Matter National Ambient Air Quality Standards (NAAQS)." Available online http://www.epa.gov/ttn/chief/eidocs/eiguid/index.html. Accessed 07/15/13.

Table 4-1: Emission Inventory Sources by Type for 2012

Type	Sub Category	Source
Point	Electric Generating Units (EGU)	- Generic OSD emissions from TCEQ - each modeling day has the same emissions - Local data for EGUs in the San Antonio-New Braunfels MSA (CPS Energy and San Miguel) - EGUs for other Texas counties and other states based on data from county totals from the Dallas SIP - Canadian and Mexico EGU emissions are the same as the 2006 Base Line - CB6 Chemical Speciation
	Non-Electric Generating Units (NEGU)	- Local data for Cement Kilns in the San Antonio-New Braunfels MSA and Austin–Round Rock–San Marcos MSA (Alamo Cement, Chemical Lime, Capitol Cement, TXI, CEMEX, and Texas Lehigh) - NEGUs for other Texas counties and other states based on data from county totals from the Dallas SIP - HGB 2006 generic day extra alkenes. - HGB 2006 generic day hourly tank landing losses. - Offshore platforms monthly emissions from 2005 GWEI. - Mexico 1999 generic day from NEI phase III. - Canada 2006 annual National Pollutant Release Inventory (NPRI) and Upstream Oil and Gas (UOG) inventories from Environment Canada. - CB6 Chemical Speciation for NEGUs in Texas and the United States - CB05 Chemical Speciation for other sources.
Area	Area Sources	- TexAER v4 area09c for Texas projected to 2012 using EGAS - nei2008v2-based for other states projected to 2012 using EGAS - Canadian and Mexico area sources remain the same as the 2006 base line - CB6 Chemical Speciation
	Oil and Gas	- DFW SIP special oil and gas production emission inventory - New TX 2008 offshore oil and gas production projected to 2012 by TCEQ - 2012 Louisiana Haynesville Shale Emissions - nei2008v2-based for other states projected to 2012 using EGAS - CB6 Chemical Speciation

Type	Sub Category	Source
Mobile	All Categories	- MOVES2010a model was used to estimate 2012 on-road emissions for all U.S. portions of the modeling domain. - Within Texas, the vehicle miles traveled (VMT) estimates are based on the Highway Performance Monitoring System (HPMS) for more rural areas. - MOVES2010a was run in default mode for all non-Texas U.S. states. - On-road emission estimates for Canada and Mexico are based on 2006 MOBILE6-Canada and MOBILE6-Mexico, respectively. - Profiles from EPA's SPECIATE Version 4.3 Database were used to allocate VOC exhaust and evaporative emission estimates with CB6 mechanism. - Local data for Extended Diesel Truck Idling
Non-Road	All Categories	- Emissions in Texas projected to 2012 using the TexN model - Drill rigs projected to 2012 based on ERG drill rig emission inventory - Local data for construction equipment, quarry equipment, mining equipment, landfill equipment, agricultural tractors, and combines projected to 2012 using TexN model - Emissions for other states projected to 2012 using NMIM Model - Canadian and Mexico non-road emissions are the same as the 2006 Base Line - CB6 Chemical Speciation
Off-Road	Locomotives	- ERG contract 2011-based switcher and line-haul locomotives - Texas locomotives projected to 2012 using Pechan & Associates, Inc Locomotive emission inventory - NEI2008v2 locos (switchers as points) for other states projected to 2012 using EPA’s Draft Regulatory Impact Analysis: Control of Emissions of Air Pollution from Locomotive Engines and Marine Compression-Ignition Engines Less than 30 Liters per Cylinder - CB6 Chemical Speciation
	Marine	- NEI2008v2 marine vessels projected to 2012 using EPA’s Draft Regulatory Impact Analysis: Control of Emissions of Air Pollution from Locomotive Engines and Marine Compression-Ignition Engines Less than 30 Liters per Cylinder - CB6 Chemical Speciation
	Aircraft	- hgb8co and attainment counties aircraft projected to 2012 using ERG’s Development of Statewide Annual Emissions Inventory and Activity Data for Airports - DFW airports based on NCTCOG data for the DFW SIP projected to 2012 using ERG’s Development of Statewide Annual Emissions Inventory and Activity Data for Airports - new NEI2008v2 airports (with ground support equipment - GSE) for other states projected to 2012 using projected operations by aircraft type from Terminal Area Forecast (TAF) - local data for San Antonio International Airport (SAIA) - CB6 Chemical Speciation

Type	Sub Category	Source
Eagle Ford	All Categories	- Draft Eagle Ford Emission Inventory for 2012 - Exploration, Pad Constriction, Drilling, Hydraulic Fracturing, Completion, Production, Mid-Stream, and On-Road emissions
Biogenic	All Categories	- Same emissions as 2006 - 4 km and 12 km grid emissions were developed by Department of Ecosystem Science & Management at the Texas A&M University. - 36km grid were developed by TCEQ using BIES - WRF calculated modeling surface temperature - CB6 Chemical Speciation[144]

[144] TCEQ. Austin, Texas. Available online: ftp://amdaftp.tceq.texas.gov/pub/Rider8/ei/basecase/. Accessed 07/02/13.

Table 4-2: Emission Inventory Sources by Type for 2018

Type	Sub Category	Source
Point	Electric Generating Units (EGU)	- Generic OSD emissions from TCEQ - Each modeling day has the same emissions - Local data for EGUs in the San Antonio-New Braunfels MSA (CPS Energy and San Miguel) - EGUs for other Texas counties and other states based on data from county totals from the Dallas SIP for 2012 (there was no projection of existing EGU units) - Canadian and Mexico EGU emissions are the same as the 2006 Base Line - CB6 Chemical Speciation
	Non-Electric Generating Units (NEGU)	- Local data for Cement Kilns in the San Antonio-New Braunfels MSA and Austin–Round Rock–San Marcos MSA (Alamo Cement, Chemical Lime, Capitol Cement, TXI, CEMEX, and Texas Lehigh) - NEGUs for other Texas counties and other states based on data from county totals from the Dallas SIP for 2012 (there was no projection of existing NEGUs) - HGB 2006 generic day extra alkenes. - HGB 2006 generic day hourly tank landing losses. - Offshore platforms monthly emissions from 2005 GWEI. - Mexico 1999 generic day from NEI phase III. - Canada 2006 annual National Pollutant Release Inventory (NPRI) and Upstream Oil and Gas (UOG) inventories from Environment Canada. - CB6 Chemical Speciation for NEGUs in Texas and the United States - CB05 Chemical Speciation for other sources.
Area	Area Sources	- TexAER v4 area09c for Texas projected to 2018 using EGAS - nei2008v2-based for other states projected to 2018 using EGAS - Canadian and Mexico area sources remain the same as the 2006 base line - CB6 Chemical Speciation
	Oil and Gas	- DFW SIP special oil and gas production emission inventory - New TX 2008 offshore oil and gas production projected to 2012 by TCEQ - 2012 Louisiana Haynesville Shale Emissions - Texas data projected from 2012 to 2018 using EGAS - nei2008v2-based for other states projected to 2018 using EGAS - CB6 Chemical Speciation

Type	Sub Category	Source
Mobile	All Categories	- MOVES2010a model was used to estimate 2018 on-road emissions for all U.S. portions of the modeling domain. - Within Texas, the vehicle miles traveled (VMT) estimates are based on the Highway Performance Monitoring System (HPMS) for more rural areas. - MOVES2010a was run in default mode for all non-Texas U.S. states. - On-road emission estimates for Canada and Mexico are based on 2006 MOBILE6-Canada and MOBILE6-Mexico, respectively. - Profiles from EPA's SPECIATE Version 4.3 Database were used to allocate VOC exhaust and evaporative emission estimates with CB6 mechanism. - Local data for Extended Diesel Truck Idling
Non-Road	All Categories	- Emissions in Texas projected to 2018 using the TexN model - Drill rigs projected to 2018 based on ERG drill rig emission inventory - Local data for construction equipment, quarry equipment, mining equipment, landfill equipment, agricultural tractors, and combines projected to 2018 using TexN model - Emissions for other states projected to 2018 using NMIM Model - Canadian and Mexico non-road emissions are the same as the 2006 Base Line - CB6 Chemical Speciation
Off-Road	Locomotives	- ERG contract 2011-based switcher and line-haul locomotives - Texas locomotives projected to 2018 using Pechan & Associates, Inc Locomotive emission inventory - NEI2008v2 locos (switchers as points) for other states projected to 2018 using EPA’s Draft Regulatory Impact Analysis: Control of Emissions of Air Pollution from Locomotive Engines and Marine Compression-Ignition Engines Less than 30 Liters per Cylinder - CB6 Chemical Speciation
	Marine	- 2018 Texas marine emissions inventory from the Houston SIP - NEI2008v2 harbor vessels projected to 2018 using EPA’s Draft Regulatory Impact Analysis: Control of Emissions of Air Pollution from Locomotive Engines and Marine Compression-Ignition Engines Less than 30 Liters per Cylinder - CB6 Chemical Speciation
	Aircraft	- 2018 Texas airport emissions inventory from the Houston SIP - new NEI2008v2 airports (with ground support equipment - GSE) for other states projected to 2018 using projected operations by aircraft type from Terminal Area Forecast (TAF) - local data for San Antonio International Airport (SAIA) - CB6 Chemical Speciation

Type	Sub Category	Source
Eagle Ford	All Categories	- Draft 2018 Eagle Ford Emission Inventories - Exploration, Pad Constriction, Drilling, Hydraulic Fracturing, Completion, Production, Mid-Stream, and On-Road emissions - Emission projection based on projected number of drill rigs, well decline curves, estimate ultimate recover (EUR), MOVES2010b, TexN model, Tier4 standards, and other sources - Three scenarios: Low, Moderate, High
Biogenic	All Categories	- Same emissions as 2006 - 4 km and 12 km grid emissions were developed by Department of Ecosystem Science & Management at the Texas A&M University. - 36km grid were developed by TCEQ using BIES - WRF calculated modeling surface temperature - CB6 Chemical Speciation[145]

[145] TCEQ. Austin, Texas. Available online: ftp://amdaftp.tceq.texas.gov/pub/Rider8/ei/basecase/. Accessed 07/02/13.

The modeling projection years of 2012 and 2018 were selected because of the availability of emission inventory data from the latest Dallas and Houston SIP submittals. If San Antonio goes into non-attainment, 2012 could be one of the modeling design value years and 2018 could be the attainment year. Data for the 2012 future year emission inventory is based on the DFW Attainment Demonstration Sip Revision for the 1997 Eight-Hour Ozone Standard[146], while the 2018 emission inventory is based on the HGB Attainment Demonstration SIP Revision for the 1997 Eight-Hour Ozone Standard[147]. The 2012 and 2018 modeling emission inventories include the benefits of the Federal Motor Vehicle Control Program (FMVCP), TexLED, Tier 4 emission standards, Mass Emissions Cap and Trade (MECT) Program, the Highly Reactive VOC Emission Cap and Trade (HECT) Program in the Houston-Galveston-Brazoria (HGB) area, and Phase One of the Clean Air Interstate Rule (CAIR).[148]

The 2012 and 2018 projection year emission inventories were based on generic ozone season days instead of day-specific emissions. The projection year emission inventory is based on weekday (Monday-Thursday), Friday, Saturday, and Sunday emission estimates. The main difference between the 2006 base line emission inventory and the future projections are emissions from electric generating units (EUG). In the base case, EGU emissions are day specific, while the future emission inventories used average OSD emissions for every day of the modeling episode. All emissions from Mexico, Canada, and off-shore sources in the projection cases were the same as those used in the 2006 base line emission inventory.

4.2 Biogenic Emissions

Biogenic emissions are the same in the 2012 and 2018 projection as in the 2006 Base Case Inventory, following EPA guidance. Biogenic emissions remain consistent across modeled years so the photochemical model's response to changes in anthropogenic emissions can be measured.

4.3 Area Source Emissions

All area source emissions were projected to 2012 and 2018 from the 2006 Base Case using EGAS 5.0. Equation 4-1 was used to project area source emissions for Texas and other states.

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[146] TCEQ. "Appendix B: Emissions Modeling for the Dfw Attainment Demonstration Sip Revision for the 1997 Eight-Hour Ozone Standard". Austin, Texas. p. B-10. Available online: http://www.tceq.texas.gov/assets/public/implementation/air/sip/dfw/ad_2011/AppB_EI_ado.pdf. Accessed 07/03/13.

[147] TCEQ. "Emissions Modeling for the HGB Attainment Demonstration SIP Revision for the 1997 Eight-Hour Ozone Standard". Austin, Texas. Available online: http://www.tceq.texas.gov/airquality/sip/HGB_eight_hour.html#AD. Accessed 07/23/13.

[148] TCEQ. "Appendix B: Emissions Modeling for the Dfw Attainment Demonstration Sip Revision for the 1997 Eight-Hour Ozone Standard". Austin, Texas. p. B-10. Available online: http://www.tceq.texas.gov/assets/public/implementation/air/sip/dfw/ad_2011/AppB_EI_ado.pdf. Accessed 07/03/13.

Equation 4-1, Ozone season day area source emissions, 2012 or 2018

$E_{Local.FY.A.B} = E_{Local.06.A.B} \times (E_{EGAS.FY.A.B} / E_{EGAS.06.A.B})$

Where,

$E_{Local.FY.A.B}$ = Ozone season day 2012 or 2018 emissions in county A for SCC code B (NO_X, VOC, or CO)

$E_{Local.06.A.B}$ = Ozone season day 2006 emissions in county A for SCC code B (NO_X, VOC, or CO)

$E_{EGAS.FY.A.B}$ = EGAS 5.0 ozone season day 2012 or 2018 emissions in county A for SCC code B (NO_X, VOC, or CO)

$E_{EGAS.06.A.B}$ = EGAS 5.0 ozone season day 2006 emissions in county A for SCC code B (NO_X, VOC, or CO)

Sample Equation: 2012 NO_X emissions from Distillate Oil fuel combustion in Bexar County, SCC code 2102004000

$E_{Local.FY.A.B}$ = 0.0088 tons of NO_X in 2006 x (0.0200 tons of NO_X in 2012 / 0.0100 tons of NO_X in 2006)

= 0.0176 tons of NO_X per day from Distillate Oil fuel combustion in Bexar County, 2012

4.3.1 Oil and Gas Production Emissions

Calculated 2012 oil and gas production emissions were based on an Eastern Research Group report using 2006 and June 2010 natural gas production.[149] TCEQ projected oil and gas production emissions from 2010 to 2012 "using the simple assumption of 10% growth for the 23 Barnett shale counties, 10% growth for the 10 Haynesville shale counties. 10% growth was also assigned to the remainder of the Texas counties in the domain. No additional controls were assumed between 2010 and 2012."[150]

"The spatial distribution within counties for oil and gas production was built from Texas Railroad Commission data for active wellhead density. The number of active wells in a given model grid cell over the total number of active wells in the county assigned the proportionate amount of the county's total emissions to that cell. Year-end 2010 wellhead densities were used to distribute the 2012 future case emissions"[151] Texas oil and gas production emissions for 2018 were

[149] Eastern Research Group, Inc., November 24, 2010. "Characterization of Oil and Gas Production Equipment and Develop a Methodology to Estimate Statewide Emissions". Morrisville, NC. TCEQ Contract No. 582-7-84003. Available online: http://www.tceq.texas.gov/assets/public/implementation/air/am/contracts/reports/ei/5820784003FY1026-20101124-ergi-oilGasEmissionsInventory.pdf. Accessed 07/25/13.

[150] TCEQ. "Appendix B: Emissions Modeling for the Dfw Attainment Demonstration Sip Revision for the 1997 Eight-Hour Ozone Standard". Austin, Texas. p. B-76. Available online: http://www.tceq.texas.gov/assets/public/implementation/air/sip/dfw/ad_2011/AppB_EI_ado.pdf. Accessed 07/03/13.

[151] TCEQ. "Appendix B: Emissions Modeling for the Dfw Attainment Demonstration Sip Revision for the 1997 Eight-Hour Ozone Standard". Austin, Texas. p. B-76. Available online: http://www.tceq.texas.gov/assets/public/implementation/air/sip/dfw/ad_2011/AppB_EI_ado.pdf. Accessed 07/03/13.

projected from 2012 using EGAS. Likewise, oil and gas production emissions in other states were projected to 2012 and 2018 using EGAS.

4.4 Non-Road

Non-road NO_X, VOC, and CO emissions in Texas were projected using the TexN model[152] using Equation 4-2. The TexN Model run specifications were:

- Analysis Year = 2006, 2012, and 2018
- Max Tech. Year = 2018
- Met Year = Typical Year
- Period = Ozone season day
- Summation Type = Typical weekday
- Post Processing Adjustments = All
- Rules Enabled = All
- Regions = All Texas Counties
- Sources = All Equipment

All control strategies were selected in the model including the Texas Low Emission Diesel (TxLED) program, Tier 1 to Tier 4 diesel rules, small spark ignition rule, large spark ignition rule, diesel recreation marine rule, small spark ignited (SI)/ SI Marine rule, and reformulated gasoline.

Equation 4-2, Ozone season day non-road emissions in Texas, 2012 or 2018

$$E_{Local.FY.A.B} = E_{Local.06.A.B} \times (E_{TexN.FY.A.B} / E_{TexN.06.A.B})$$

Where,

$E_{Local.FY.A.B}$ = Ozone season day 2012 or 2018 emissions in county A for non-road equipment type B (NO_X, VOC, or CO)

$E_{Local.06.A.B}$ = Ozone season day 2006 emissions in county A for non-road equipment type B (NO_X, VOC, or CO)

$E_{TexN.FY.A.B}$ = TexN model ozone season day 2012 or 2018 emissions in county A for non-road equipment type B (NO_X, VOC, or CO)

$E_{TexN.06.A.B}$ = TexN model ozone season day 2006 emissions in county A for non-road equipment type B (NO_X, VOC, or CO)

Sample Equation: 2012 NO_X emissions from diesel construction pavers, SCC code 2270002003, in Bexar County

$E_{Local.FY.A.B}$ = 0.100 tons of NO_X per day x (0.080 tons of NO_X per day in 2012 from TexN Model / 0.110 tons of NO_X per day in 2006 from TexN Model)
= 0.073 tons of NO_X per day from diesel construction pavers in Bexar County in 2012

For areas outside of Texas, the NMIM 2008 model[153] was used to project non-road emissions following the same formula listed above.

[152] Eastern Research Group, Inc. April 26, 2013. “Texas NONROAD (TexN) Model”. Austin, Texas. Available online: ftp://amdaftp.tceq.texas.gov/pub/Nonroad_EI/TexN/. Accessed 07/03/13.

4.4.1 Drill Rigs

Drill rig emissions were projected to 2012 and 2018 based on ERG's drill rig emission inventory for Texas. "Based on the projected oil and gas production levels in Texas from the EIA, drilling activity is estimated to remain relatively constant across the state from 2011 through 2035. However, the continued phase-in of more stringent Non-Road diesel engine emission standards should cause a steady decrease in drilling-related emissions over time."[154]

4.4.2 AACOG local data

San Antonio-New Braunfels MSA emissions for construction equipment, quarry equipment, landfill equipment, mining equipment, agricultural tractors, and agricultural combines were projected to 2012 and 2018 using the TexN model.

4.5 Off-Road

4.5.1 Commercial Marine Vessels

The Environmental Protection Agency (EPA) proposed "a comprehensive three-part program to reduce emissions of particulate matter (PM) and oxides of nitrogen (NO_X) from locomotives and marine diesel engines below 30 liters per cylinder displacement. This proposal is part of EPA's ongoing National Clean Diesel Campaign (NCDC) to reduce harmful emissions from diesel engines of all types."[155] Emissions and adjustment factors for commercial[156] and recreational[157] marine vessels are provided in Table 4-3. To project marine vessels in other states to 2012 and 2018, Equation 4-3 was used.

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[153] EPA "National Mobile Inventory Model (NMIM) 2008". Available online: http://www.epa.gov/oms/nmim.htm. Accessed 08/02/13.

[154] Eastern Research Group, Inc. August 15, 2011. "Development of Texas Statewide Drilling Rigs Emission Inventories for the Years 1990, 1993, 1996, and 1999 through 2040". Austin, Texas. Work Order No. 582-11-99776-FY11-05. p. 1-5. Available online: http://www.tceq.texas.gov/assets/public/implementation/air/am/contracts/reports/ei/5821199776FY1105-20110815-ergi-drilling_rig_ei.pdf. Accessed 07/01/13.

[155] U.S. Environmental Protection Agency, U.S. Environmental Protection Agency, March 2007. "Draft Regulatory Impact Analysis: Control of Emissions of Air Pollution from Locomotive Engines and Marine Compression-Ignition Engines Less than 30 Liters per Cylinder". p. ES-1. Available online: http://www.epa.gov/nonroad/420d07001.pdf. Accessed 08/02/13.

[156] U.S. Environmental Protection Agency, U.S. Environmental Protection Agency, March 2007. "Draft Regulatory Impact Analysis: Control of Emissions of Air Pollution from Locomotive Engines and Marine Compression-Ignition Engines Less than 30 Liters per Cylinder". p. 26-28. Available online: http://www.epa.gov/nonroad/420d07001chp3.pdf. Accessed 07/29/13.

[157] U.S. Environmental Protection Agency, U.S. Environmental Protection Agency, March 2007. "Draft Regulatory Impact Analysis: Control of Emissions of Air Pollution from Locomotive Engines and Marine Compression-Ignition Engines Less than 30 Liters per Cylinder". p. 61. Available online: http://www.epa.gov/nonroad/420d07001chp3.pdf. Accessed 07/29/13.

Table 4-3: U.S. Commercial and Recreational Marine Emissions and Adjustment Factors, 2006, 2012, and 2018

Type	Year	NO_X		VOC		CO	
		tons/year	factor	tons/year	factor	tons/year	factor
Commercial Marine Vessels	2006	820,269	1.0000	17,278	1.0000	153,928	1.0000
	2012	742,453	0.9051	16,344	0.9459	146,227	0.9500
	2018	591,991	0.7217	12,851	0.7438	140,443	0.9124
Recreational Marine Vessels	2006	44,089	1.0000	1,720	1.0000	7,161	1.0000
	2012	44,931	1.0191	2,104	1.2233	8,150	1.1381
	2018	43,742	0.9921	2,379	1.3831	9,073	1.2670

Equation 4-3, Ozone season day marine vessel emissions, 2012 or 2018

$E_{Local.FY.A.B} = E_{Local.06.A.B} \times (E_{EPA.FY.B} / E_{EPA.06.B})$

Where,

$E_{Local.FY.A.B}$ = Ozone season day 2012 or 2018 emissions in county A for marine vessel type B (NO_X, VOC, or CO)

$E_{Local.06.A.B}$ = Ozone season day 2006 emissions in county A for marine vessel type B (NO_X, VOC, or CO)

$E_{EPA.FY.B}$ = EPA Annual 2012 or 2018 emissions for marine vessel type B (NO_X, VOC, or CO from Table 4-3)

$E_{EPA.06.B}$ = EPA Annual 2006 emissions for marine vessel type B (NO_X, VOC, or CO from Table 4-3)

Sample Equation: 2012 NO_X emissions from commercial marine vessels in St. John the Baptist Parish in Louisiana

$E_{Local.FY.A.B}$ = 10.0 tons of NO_X per day in 2006 x (742,453 tons of NO_X per year in 2012 from EPA / 820,269 tons of NO_X per year in 2006 from EPA)

= 9.1 tons of NO_X per day from commercial marine vessels in St. John the Baptist Parish in Louisiana, 2012

The above formula was also used to project Texas marine vessel emissions to 2012. Commercial and recreational marine vessel emissions for all regions in Texas for 2018 were obtained from the Houston SIP.[158] According to the TCEQ, "starting in 2000, NO_X emissions from large Category 3 engines have been regulated under international rules, so baseline emissions reductions are used to estimate the historic year NO_X emissions. Interpolation of the baseline NO_X estimates were used to estimate emission control factors through 2014. In 2015, under the ECA regulations, more stringent NO_X controls and significant particulate matter (PM)

[158] TCEQ. March 10, 2010. "Emissions Modeling for the HGB Attainment Demonstration SIP Revision for the 1997 Eight-Hour Ozone Standard". Available online: http://www.tceq.texas.gov/airquality/sip/HGB_eight_hour.html. Accessed 08/02/13.

controls begin, so more significant emission reduction should begin in 2015."[159] "Smaller craft are found in a number of occupations including assist tugs, tow boats (tug and barge), and push boats. EPA provides forecasted emissions that include a growth rate of 0.9% per year. By accounting for the growth rate and comparing the emission estimates to those for year 2007, a relative emission control factor was calculated."[160]

4.5.2 Locomotive

Emissions from locomotives in Texas were projected to 2012 and 2018 using Pechan & Associates locomotive emission inventory. "Pechan developed statewide annual and ozone season daily emissions inventories for Class I line haul and switchyard locomotives. Annual and daily inventories were developed for every year between 1990 and 2040." "For this effort, Pechan compiled existing data on Class I line haul and switchyard operations in the state of Texas. Special emphasis was placed on the Houston-Galveston-Brazoria (HGB) and Dallas-Fort Worth (DFW) nonattainment areas. These areas had also been the focus of previous projects to obtain detailed fuel consumption data from Class I companies operating in these areas, namely Burlington Northern Santa Fe (BNSF) and Union Pacific (UP). Data for these companies had been obtained and compiled for the TCEQ's Texas Railroad Emission Inventory Model (TREIM)."[161]

"The activity data used as the base year activity for this project were derived in part from available estimates, and also from newly acquired data (e.g., for BNSF). Growth factors were then applied to base year activity to estimate annual activity for all 51 years of interest. Annual emission rates applied to activity estimates based on updated Environmental Protection Agency (EPA) guidance (2009) reflect revised Federal Tier 0, Tier 1, and Tier 2, as well as new Tier 3 and 4 federal emission standards."[162] Emissions were projected to 2012 and 2018 using the following equation:

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[159] ENVIRON International Corporation, August 18, 2010. "Implement Port of Houston's Current Inventory and Harmonize the Remaining 8-county Shipping Inventory for TCEQ Modeling". Novato, CA. Work Order No. 582-7-84006-FY10-5. p. 12. Available online: http://www.tceq.texas.gov/assets/public/implementation/air/am/contracts/reports/ei/5820784006FY1005-20100818-environ-HGBShipsEI.pdf. Accessed 07/03/13.

[160] ENVIRON International Corporation, August 18, 2010. "Implement Port of Houston's Current Inventory and Harmonize the Remaining 8-county Shipping Inventory for TCEQ Modeling". Novato, CA. Work Order No. 582-7-84006-FY10-5. p. 13. Available online: http://www.tceq.texas.gov/assets/public/implementation/air/am/contracts/reports/ei/5820784006FY1005-20100818-environ-HGBShipsEI.pdf. Accessed 07/03/13.

[161] Ms. Kirstin B. Thesing. E.H. Pechan & Associates, Inc., July 2010. "Development of Locomotive and Commercial Marine Emissions Inventory - 1990 TO 2040". Durham, NC. TCEQ Grant Agreement No. 582-07-84008. p. 1. Available online: ftp://amdaftp.tceq.texas.gov/pub/Offroad_EI/Locomotives/. Accessed 08/04/13.

[162] Ms. Kirstin B. Thesing. E.H. Pechan & Associates, Inc., July 2010. "Development of Locomotive and Commercial Marine Emissions Inventory - 1990 TO 2040". Durham, NC. TCEQ Grant Agreement No. 582-07-84008. p. 1. Available online: ftp://amdaftp.tceq.texas.gov/pub/Offroad_EI/Locomotives/. Accessed 08/04/13.

Equation 4-4, Ozone season day railway emissions for Texas, 2012 or 2018

$$E_{Local.FY.A.B} = E_{Local.06.A.B} \times (E_{Pechan.FY.A.B} / E_{Pechan.06.A.B})$$

Where,

$E_{Local.FY.A.B}$ = Ozone season day 2012 or 2018 emissions in county A for railway type B (NO_X, VOC, or CO)

$E_{Local.06.A.B}$ = Ozone season day 2006 emissions in county A for railway type B (NO_X, VOC, or CO)

$E_{Pechan.FY.A.B}$ = Annual 2012 or 2018 emissions in county A for railway type B from Pechan & Associates (NO_X, VOC, or CO)

$E_{Pechan.06.A.B}$ = Annual 2006 emissions in county A for railway type B from Pechan & Associates (NO_X, VOC, or CO)

Sample Equation: 2018 NO_X emissions from large line-haul locomotives in Bexar County

$E_{Local.FY.A.B}$ = 1.00 tons of NO_X per day in 2006 x (215.46 tons of NO_X per year in 2018 from Pechan & Associates / 328.20 tons of NO_X per year in 2006 from Pechan & Associates)

= 0.66 tons of NO_X per day from large line-haul locomotives in Bexar County, 2018

For areas outside of Texas, EPA's "Draft Regulatory Impact Analysis: Control of Emissions of Air Pollution from Locomotive Engines and Marine Compression-Ignition Engines Less than 30 Liters per Cylinder" was used. EPA calculated locomotive emissions "based on estimated current and projected fuel consumption rates. Emissions were calculated separately for the following locomotive categories:

- Large Railroad Line-Haul Locomotives
- Other Line-Haul Locomotives (i.e., local and regional railroads)
- Other Switch/Terminal Locomotives
- Passenger/Commuter Locomotives
- Large Railroad Switching (including Class II/III Switch railroads owned by Class I railroads)"[163]

Table 4-4 lists the annual NO_X and VOC emissions from each locomotive type and the adjustment factored used to project emissions. CO emissions stayed the same for each projection year. These adjustment factors were used in Equation 4-5, to project emissions to 2012 and 2018.

[163] U.S. Environmental Protection Agency, U.S. Environmental Protection Agency, March 2007. "Draft Regulatory Impact Analysis: Control of Emissions of Air Pollution from Locomotive Engines and Marine Compression-Ignition Engines Less than 30 Liters per Cylinder". p. 77-79. Available online: http://www.epa.gov/nonroad/420d07001chp3.pdf. Accessed 07/29/13.

Table 4-4: U.S. Railroad and Adjustment Factors, 2006, 2012, and 2018

Type	SCC	Year	NO_X		VOC	
			tons/year	factor	tons/year	factor
Large Line-haul	2285002006	2006	779,842	1.0000	43,874	1.0000
		2012	692,606	0.8881	35,890	0.8180
		2018	608,010	0.7797	23,607	0.5381
Small Railroads	2285002007	2006	37,690	1.0000	2,891	1.0000
		2012	41,456	1.0999	3,179	1.0996
		2018	44,299	1.1754	3,497	1.2096
Passenger/ Commuter	2285002008 2285002009	2006	38,466	1.0000	1,609	1.0000
		2012	25,933	0.6742	1,301	0.8086
		2018	19,496	0.5068	771	0.4792
Large Switch	2285002010	2006	86,861	1.0000	5,501	1.0000
		2012	86,614	0.9972	5,364	0.9751
		2018	84,612	0.9741	5,066	0.9209

Equation 4-5, Ozone season day railway for other states, 2012 or 2018

$$E_{Local.FY.A.B} = E_{Local.06.A.B} \text{ x } (E_{EPA.FY.B} / E_{EPA.06.B})$$

Where,

$E_{Local.FY.A.B}$ = Ozone season day 2012 or 2018 emissions in county A for railway type B (NO_X or VOC)

$E_{Local.06.A.B}$ = Ozone season day 2006 emissions in county A for railway type B (NO_X or VOC)

$E_{EPA.FY.B}$ = EPA Annual 2012 or 2018 emissions for railway type B (NO_X or VOC from Table 4-4)

$E_{EPA.06.B}$ = EPA Annual 2006 emissions for railway type B (NO_X or VOC from Table 4-4)

Sample Equation: 2012 NO_X emissions from large line-haul locomotives in Clayton County, Alabama

$E_{Local.FY.A.B}$ = 2.00 tons of NO_X per day in 2006 x (692,606 tons of NO_X per year in 2012 from EPA / 779,842 tons of NO_X per year in 2006 from EPA)
= 1.78 tons of NO_X per day from large line-haul locomotives in Clayton County, 2012

4.5.3 Aircraft Emissions

Texas aircraft emissions in 2012 were based on ERG's annual emission inventory and activity data for airports in Texas. ERG developed "statewide annual emission inventories for Texas airport activities for the calendar years 1996, 2000, 2002, 2011, 2014, 2017, 2020, 2023, 2026, 2029, and the base year 2008." ERG's report indicated that "publically available 2008 activity data was compiled and supplemented with 2008 activity data provided by local airports. Two approaches were used to estimate emissions from the compiled activity data. If the activity data had aircraft specific data, the Federal Aviation Administration's (FAA) Emissions Dispersion

Modeling System (EDMS) was employed. If such detailed data were not available, then ERG applied a more general approach for different aircraft types (i.e., air taxis, general aviation, and military aircraft) using available generic emission estimating procedures. Once the base year of 2008 was established, the inventory was backcasted and forecasted based on FAA's Terminal Area Forecast (TAF) data."[164] Texas aircraft emissions in 2012 were projected using the following equation:

Equation 4-6, Ozone season day aircraft emissions in Texas for 2012

$$E_{Local.FY.A.B} = E_{Local.06.A.B} \times (E_{ERG.FY.A.B} / E_{ERG.06.A.B})$$

Where,

$E_{Local.FY.A.B}$ = Ozone season day 2012 emissions in county A for SCC code B (NO_X, VOC, or CO)

$E_{Local.06.A.B}$ = Ozone season day 2006 emissions in county A for SCC code B (NO_X, VOC, or CO)

$E_{ERG.FY.A.B}$ = ERG annual 2012 emissions in county A for SCC code B (NO_X, VOC, or CO)

$E_{ERG.06.A.B}$ = ERG annual 2006 emissions in county A for SCC code B (NO_X, VOC, or CO)

Sample Equation: 2012 NO_X emissions from general aviation aircraft in Bexar County

$E_{Local.FY.A.B}$ = 0.200 tons of NO_X in 2006 x (31.48 tons of NO_X in 2012 from ERG / 86.15 tons of NO_X in 2006 from ERG)

= 0.073 tons of NO_X per day from general aviation aircraft in Bexar County, 2012

With the exception of emission estimates for the San Antonio International Airport (SAIA), 2018 airport emissions for all regions in Texas were obtained from the Houston SIP[165]. Aircraft emissions for other states were projected based on total number of aircraft operations per state, as listed in the TAF, using Equation 4-7.[166]

Equation 4-7, Ozone season day aircraft emissions for other states, 2012 or 2018

$$E_{Local.FY.A.B} = E_{Local.06.A.B} \times (OPS_{TAF.FY.B} / OPS_{TAF.06.B})$$

Where,

$E_{Local.FY.A.B}$ = Ozone season day 2012 or 2018 emissions in county A for aircraft type B (NO_X, VOC, or CO)

$E_{Local.06.A.B}$ = Ozone season day 2006 emissions in county A for aircraft type B (NO_X, VOC, or CO)

$OPS_{TAF.FY.B}$ = Number of aircraft operation from TAF for the state in 2012 or 2018 for aircraft type B

$OPS_{TAF.06.B}$ = Number of aircraft operation from TAF for the state in 2006 for aircraft type B

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[164] Eastern Research Group, Inc. July 15, 2011. "Development of Statewide Annual Emissions Inventory and Activity Data for Airports". 582-11-99776. Morrisville, North Carolina. p. ES-1.

[165] TCEQ. March 10, 2010. "Emissions Modeling for the HGB Attainment Demonstration SIP Revision for the 1997 Eight-Hour Ozone Standard". Available online: http://www.tceq.texas.gov/airquality/sip/HGB_eight_hour.html. Accessed 08/02/13.

[166] Federal Aviation Administration. "Terminal Area Forecast". Washington, DC. Available online: https://aspm.faa.gov/main/taf.asp. Accessed 07/29/13.

Sample Equation: 2012 NO_X emissions from General Aviation aircraft in Clayton County in Alabama

$E_{Local.FY.A.B}$ = 0.50 tons of NO_X from general aviation emissions from Clayton County in 2006 x (1,851,463 general aviation operation in Alabama for 2012 from TAF / 1,713,651 general aviation operation in Alabama for 2006 from TAF)
= 0.54 tons of NO_X per day in 2012 from general aviation emissions in Clayton County

4.6 On-Road Emissions

4.6.1 On-Road Vehicle Emissions

The Texas Transportation Institute (TTI) "developed hourly, photochemical model preprocessor ready, on-road mobile summer (June 1 through August 31) Weekday, Friday, Saturday, and Sunday EIs for"[167] 2006, 2012, and 2018 using the MOVES 2010a model. "TTI used an hourly, Highway Performance Monitoring System (HPMS) virtual link, MOVES 'rates-peractivity' emissions inventory method to produce hourly emissions estimates by MOVES source use type (SUT) and fuel type, pollutant, and pollutant process for all 254 Texas counties for each year and day type. The methods TTI used to produce these inventories were consistent with EPA guidance on the production of photochemical modeling emissions inventories."[168] The 30-year age distribution estimates used in MOVES for 2012 and 2018 are provided in Figure 3-1 for TxDOT's San Antonio district.[169]

[167] TTI, July 2011. "Production of Statewide Non-Link-Based, On-Road Emissions Inventories with the Moves Model for the Eight-Hour Ozone Standard Attainment Demonstration Modeling". College Station, Texas. College Station, Texas. p. 1. Available online: ftp://amdaftp.tceq.texas.gov/pub/Mobile_EI/Statewide/mvs/reports/. Accessed 07/05/13.
[168] TTI, July 2011. "Production of Statewide Non-Link-Based, On-Road Emissions Inventories with the Moves Model for the Eight-Hour Ozone Standard Attainment Demonstration Modeling". College Station, Texas. College Station, Texas. p. 1. Available online: ftp://amdaftp.tceq.texas.gov/pub/Mobile_EI/Statewide/mvs/reports/. Accessed 07/05/13.
[169] TTI, July 2011. "Production of Statewide Non-Link-Based, On-Road Emissions Inventories with the Moves Model for the Eight-Hour Ozone Standard Attainment Demonstration Modeling: Appendix H: Source Type Age and Fuel Engine Fractions Inputs to MOVES". College Station, Texas. College Station, Texas. p. 65. Available online: ftp://amdaftp.tceq.texas.gov/pub/Mobile_EI/Statewide/mvs/reports/. Accessed 07/05/13.

Figure 4-1: San Antonio TxDOT District 2012 and 2018 Age Distributions Inputs to MOVES

Age	MC	PC	PT	LCT	IBus	TBus	SBus	RT	SUShT	SULhT	MH	CShT	CLhT
0	0.04927	0.07586	0.02421	0.02421	0.07151	0.06398	0.06992	0.03103	0.08842	0.09911	0.06948	0.03549	0.03826
1	0.05263	0.06567	0.0418	0.04180	0.06680	0.05977	0.06532	0.02966	0.11468	0.13601	0.06490	0.02619	0.03098
2	0.03916	0.06136	0.03923	0.03923	0.06148	0.05501	0.06012	0.02844	0.04274	0.04725	0.05973	0.01456	0.01922
3	0.09724	0.05031	0.02965	0.02965	0.05906	0.05284	0.05775	0.0285	0.03882	0.04461	0.05738	0.03206	0.03344
4	0.09169	0.07449	0.05699	0.05699	0.06438	0.05761	0.06296	0.03168	0.11490	0.12800	0.06256	0.04394	0.04608
5	0.11319	0.07440	0.06287	0.06287	0.06522	0.05836	0.06377	0.03316	0.07490	0.07834	0.06337	0.11051	0.09874
6	0.09823	0.06846	0.05884	0.05884	0.06452	0.05773	0.06309	0.05515	0.08961	0.08649	0.06269	0.08910	0.07450
7	0.07328	0.06697	0.05815	0.05815	0.06317	0.05653	0.06177	0.04879	0.08688	0.07753	0.06138	0.06291	0.06429
8	0.05303	0.06008	0.06978	0.06978	0.04948	0.04427	0.04838	0.03847	0.06817	0.05467	0.04807	0.04271	0.04397
9	0.06387	0.05715	0.07235	0.07235	0.03895	0.03485	0.03809	0.02805	0.04759	0.04426	0.03784	0.03708	0.03689
10	0.04784	0.05551	0.07162	0.07162	0.03314	0.02965	0.03240	0.02770	0.04213	0.03482	0.03202	0.03304	0.03588
11	0.03744	0.04988	0.06802	0.06802	0.03743	0.03349	0.03660	0.02870	0.03882	0.03637	0.03636	0.04773	0.04942
12	0.02943	0.04686	0.05335	0.05335	0.03943	0.03529	0.03856	0.03937	0.03227	0.02938	0.03832	0.07086	0.06045
13	0.02417	0.03773	0.04750	0.04750	0.03823	0.03421	0.03738	0.04376	0.02709	0.02641	0.03715	0.05422	0.05301
14	0.01747	0.02905	0.03433	0.03433	0.02897	0.04015	0.02950	0.03316	0.01306	0.01239	0.02184	0.04381	0.04290
15	0.01353	0.02432	0.03515	0.03515	0.02332	0.03630	0.02719	0.02670	0.01554	0.01387	0.03327	0.02643	0.03308
16	0.01118	0.01813	0.02484	0.02484	0.01928	0.03343	0.02345	0.05654	0.00932	0.00800	0.02060	0.02717	0.03003
17	0.00996	0.01729	0.02517	0.02517	0.02480	0.02711	0.02964	0.06413	0.00910	0.00869	0.02405	0.03757	0.03814
18	0.00738	0.01277	0.02358	0.02358	0.01909	0.02364	0.01430	0.03968	0.00701	0.00570	0.02293	0.02289	0.02485
19	0.00649	0.01001	0.01642	0.01642	0.01555	0.01940	0.01690	0.03353	0.00594	0.00398	0.01561	0.02252	0.02235
20	0.00498	0.00761	0.01215	0.01215	0.01145	0.01684	0.01363	0.01421	0.00349	0.00281	0.01369	0.01346	0.01610
21	0.00289	0.0062	0.01016	0.01016	0.01298	0.01703	0.01740	0.03861	0.00385	0.00303	0.01019	0.01407	0.01775
22	0.00344	0.00466	0.00809	0.00809	0.01441	0.02466	0.01944	0.03252	0.00392	0.00293	0.01320	0.01444	0.01531
23	0.00334	0.00370	0.00797	0.00797	0.01429	0.01876	0.01109	0.02538	0.00302	0.00236	0.01705	0.01089	0.01189
24	0.00263	0.00274	0.00598	0.00598	0.01329	0.01477	0.01319	0.03416	0.00234	0.00194	0.01512	0.00955	0.00984
25	0.00297	0.00226	0.00425	0.00425	0.01367	0.01351	0.01321	0.02705	0.00183	0.00121	0.01461	0.00930	0.00808
26	0.00459	0.00195	0.00523	0.00523	0.01146	0.01138	0.01153	0.03340	0.00158	0.00146	0.01077	0.00930	0.00780
27	0.00415	0.00174	0.00456	0.00456	0.01001	0.00977	0.00990	0.01757	0.00205	0.00117	0.01143	0.00832	0.00711
28	0.00334	0.00149	0.00395	0.00395	0.00779	0.00753	0.00756	0.01804	0.00158	0.00097	0.01147	0.00551	0.00544
29	0.00360	0.00092	0.00260	0.00260	0.00307	0.00714	0.00276	0.00517	0.00104	0.00059	0.00743	0.00294	0.00248
30	0.02761	0.01041	0.02122	0.02122	0.00378	0.00499	0.00319	0.00769	0.00831	0.00565	0.00533	0.02142	0.02101

Diesel vehicle NO_X emissions factors were post-processed "for the 110 Eastern Texas counties subject to the Texas Low Emission Diesel (TxLED) program".[170] "NO_X adjustment factors used were provided by TCEQ for 2012 and 2018 using reductions of 4.8 percent for 2002-and-newer model year vehicles, and 6.2 percent for 2001-and-older model year vehicles." (Table 4-5)[171] The San Antonio-New Braunfels MSA counties under the low RVP and TxLED rule are Atascosa, Bexar, Comal, Guadalupe, and Wilson. To calculate 2012 and 2018 emissions in the TxDOT's San Antonio district, fuel properties with a RVP of 7.80 and sulfur content of 22.91 were used.[172]

Table 4-5: TxLED Adjustment Factor for Diesel Fuel, 2012 and 2018

Source Use Type	2012 TxLED Reduction	2018 TxLED Reduction
Passenger Car	5.02%	4.84%
Passenger Truck	5.32%	5.02%
Light Commercial Truck	5.29%	5.07%
Intercity Bus	5.80%	5.64%
Transit Bus	5.77%	5.52%
School Bus	5.76%	5.59%
Refuse Truck	5.69%	5.38%
Single Unit Short-Haul Truck	5.04%	4.90%
Single Unit Long-Haul Truck	5.08%	4.93%
Motor Home	5.53%	5.35%
Combination Short-Haul Truck	5.47%	5.17%
Combination Long-Haul Truck	5.45%	5.11%

As shown on Table 4-6, on-road emissions are projected to decrease rapidly from 2006 to 2018. NO_X emissions in the San Antonio-New Braunfels MSA are projected to decrease from 133 tons/weekday in 2006 to 43 tons/weekday in 2018 (Figure 4-2). Similarly, weekday VOC emissions are projected to decrease from 48 tons to 24 tons. These reductions are occurring even though weekday VMT increases from 57 million in 2006 to 63 million in 2018. Emission reductions are occurring because of engine controls being placed on new cars that have significantly reduced emissions.

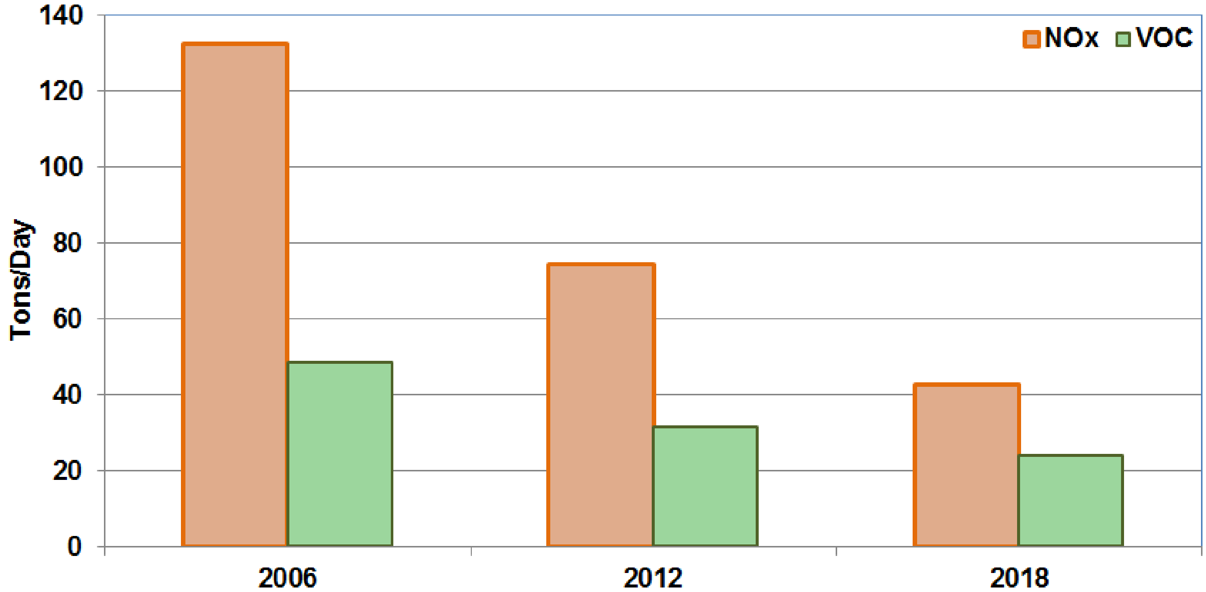
[170] TTI, July 2011. "Production of Statewide Non-Link-Based, On-Road Emissions Inventories with the Moves Model for the Eight-Hour Ozone Standard Attainment Demonstration Modeling". College Station, Texas. College Station, Texas. p. 4. Available online: ftp://amdaftp.tceq.texas.gov/pub/Mobile_EI/Statewide/mvs/reports/. Accessed 07/05/13.
[171] TTI, July 2011. "Production of Statewide Non-Link-Based, On-Road Emissions Inventories with the Moves Model for the Eight-Hour Ozone Standard Attainment Demonstration Modeling". College Station, Texas. College Station, Texas. p. 4. Available online: ftp://amdaftp.tceq.texas.gov/pub/Mobile_EI/Statewide/mvs/reports/. Accessed 07/05/13.
[172] TTI, July 2011. "Production of Statewide Non-Link-Based, On-Road Emissions Inventories with the Moves Model for the Eight-Hour Ozone Standard Attainment Demonstration Modeling". College Station, Texas. College Station, Texas. p. 36. Available online: ftp://amdaftp.tceq.texas.gov/pub/Mobile_EI/Statewide/mvs/reports/. Accessed 07/05/13.

Table 4-6: Weekday VMT, NO_X Emissions, and VOC Emissions by County, San Antonio New Braunfels MSA, 2006, 2012, and 2018

County	VMT			Tons of NO_X			Tons of VOC		
	2006	2012	2018	2006	2012	2018	2006	2012	2018
Atascosa	1,645,740	1,713,192	1,956,427	5.44	3.10	1.81	1.24	0.77	0.59
Bandera	493,632	531,410	511,131	1.41	0.88	0.45	0.53	0.40	0.30
Bexar	43,339,519	43,171,178	46,619,601	93.28	52.74	29.94	37.17	23.80	18.05
Comal	4,062,411	4,268,618	5,277,660	10.40	5.67	3.58	3.13	2.10	1.69
Guadalupe	3,661,652	3,605,424	4,120,938	10.67	5.34	3.15	3.04	1.99	1.60
Kendall	1,108,735	1,292,394	1,329,894	4.09	2.34	1.23	1.03	0.80	0.60
Medina	1,526,961	1,580,167	1,639,215	4.66	2.73	1.50	1.20	0.86	0.62
Wilson	1,030,604	1,095,406	1,316,568	2.73	1.66	1.02	1.02	0.70	0.56
Total	56,869,254	57,257,789	62,771,434	132.68	74.45	42.68	48.36	31.43	24.00

*Note: totals do not include long term idling emissions from long haul diesel combination trucks or traffic from the Eagle Ford

Figure 4-2: On-Road NO_X and VOC Emissions, San Antonio New Braunfels MSA, 2006, 2012, and 2018



"Profiles from EPA's SPECIATE Version 4.3 Database were used to allocate VOC exhaust and evaporative emission estimates with the Carbon Bond 6 (CB6) mechanism."[173] On-road emissions from Mexico and Canada were kept the same as the 2006 base line emission inventory.

4.6.2 Heavy Duty Diesel Vehicles Idling Emissions

The same EPA-recommended 2006 NO_X and VOC emission factors for Class 8 truck idling were used for the 2012 and 2018 Forecast Year Inventories. The 2012 and 2018 projections also used the same activity data as the 2006 base line emission inventory.

4.7 Point Source Emissions

EGU and NEGU point source emissions outside of the San Antonio-New Braunfels MSA are based on the TCEQ's Dallas and Houston attainment demonstration SIP revision for the 1997 eight-hour ozone standard. To develop the 2012 EGU emission projection, TCEQ based the projections on the 2008 Acid Rain database. "To develop the Acid Rain EGU 2008 baseline, the TCEQ averaged the Acid Rain NO_X for each hour of the day for each unit for the third quarter of 2008 (3Q2008). The TCEQ chose this dataset from which to project because it is newer and contains more of the actual emissions growth from newer units. Not all EGUs are Acid Rain sources and not all NO_X point sources at EGU facilities are Acid Rain sources. The non-Acid Rain EGUs were modeled at their 2008 emissions along with the NEGU point sources. The complete set of 2012 EGUs consists of the 3Q2008 ARD EGUs, the 2008 non-Acid Rain EGUs, and post-2008 EGUs that have approved TCEQ

[173] TCEQ. Austin, Texas. Available online: ftp://amdaftp.tceq.texas.gov/pub/Rider8/ei/basecase/. Accessed 07/02/13.

permits. As with previous SIP revisions, the TCEQ assumes that the EGU growth in the state comes from the TCEQ newly-permitted EGUs."[174]

"Emissions from NEGUs in the attainment areas of the state were projected to 2012 using a combination of projection factors. Projection factors derived from the Dallas Federal Reserve Bank's Texas Industrial Production Index (TIPI) exist for growth from 2006 to 2018 and are based on an industry's Standard Industrial Classification (SIC). For SICs not covered by TIPI, projection factors from EPA's Economic Growth Analysis System version 5.0 (EGAS5) with a Texas-specific version of the Regional Economic Models, Inc (REMI) update were used. This version of EGAS with Texas-specific REMI is hereafter referred to as REMI-EGAS which, like the TIPI growth factors exists for growth from 2006 to 2018. No individual new permits were modeled as growth for NEGUs. The TCEQ modeled 2008 to 2012 by interpolating the 2006-2018 data, using one third of the growth for the shorter time span."[175]

"The 2012 NEGU emissions for states beyond Texas were interpolated from the 2018 CenRAP/RPO file after the EGUs were removed. Growing 2006 emissions to 2012 would not have captured the controls that were built into the regional modeling files." [176] Equation 4-8 was used to project the 2006 point source emissions to 2012 and 2018.

Equation 4-8, Ozone season day point source emissions for other states, 2012 or 2018

$$E_{Local.FY.A.C} = E_{Local.06.A.C} \times (E_{TCEQ.FY.B} / E_{TCEQ.06.B})$$

Where,

$E_{Local.FY.A.C}$ = Ozone season daily 2012 or 2018 emissions in county A for point source C (NO_X, VOC, or CO)

$E_{TCEQ.06.A.C}$ = Ozone season daily 2006 emissions in county A for point source C (NO_X, VOC, or CO from the Dallas or Houston SIP)

$E_{TCEQ.FY.A.B}$ = Ozone season daily 2012 or 2018 emissions in county A for point source type B (NO_X, VOC, or CO from the Dallas or Houston SIP)

$E_{TCEQ.06.A.B}$ = Ozone season daily 2006 emissions in county A for point source type B (NO_X, VOC, or CO from the Dallas or Houston SIP)

174 TCEQ. "Appendix B: Emissions Modeling for the Dfw Attainment Demonstration Sip Revision for the 1997 Eight-Hour Ozone Standard". Austin, Texas. p. B-10. Available online: http://www.tceq.texas.gov/assets/public/implementation/air/sip/dfw/ad_2011/AppB_EI_ado.pdf. Accessed 07/03/13.

175 TCEQ. "Appendix B: Emissions Modeling for the Dfw Attainment Demonstration Sip Revision for the 1997 Eight-Hour Ozone Standard". Austin, Texas. p. B-43. Available online: http://www.tceq.texas.gov/assets/public/implementation/air/sip/dfw/ad_2011/AppB_EI_ado.pdf. Accessed 07/03/13.

176 TCEQ. "Appendix B: Emissions Modeling for the Dfw Attainment Demonstration Sip Revision for the 1997 Eight-Hour Ozone Standard". Austin, Texas. p. B-56. Available online: http://www.tceq.texas.gov/assets/public/implementation/air/sip/dfw/ad_2011/AppB_EI_ado.pdf. Accessed 07/03/13.

Sample Equation: Ozone season daily 2012 NO_X emissions from a NEGU point source in Floyd County, GA (FIPS Code 13115)

$E_{Local.FY.A.C}$ = 2.00 tons of NO_X per day in 2006 from NEGU C x (11.969 tons of NO_X per day in 2012 from TCEQ / 8.0925 tons of NO_X per day in 2006 from TCEQ)
= 2.96 tons of NO_X per day from NEGU C in Floyd County, 2012

Flares, "extra olefins" emissions in the HGB area, elevated ships, SAIA, HGB floating roof tank landing losses, offshore, Mexican, and Canadian point source emissions remained the same for each projection year. CB6 chemical speciation was used for Texas and other states while CB05 chemical speciation was used for point sources outside the USA.

4.7.1 CPS Energy

"CPS Energy is the nation's largest municipally owned energy utility providing both natural gas and electric service. Acquired by the City of San Antonio in 1942, today CPS Energy serve more than 728,000 electric customers and 328,000 natural gas customers in and around the seventh-largest city in the nation. CPS Energy serves customers in Bexar County and portions of Atascosa, Bandera, Comal, Guadalupe, Kendall, Medina, and Wilson Counties."[177]

In 2012, CPS Energy signed a contract with Tenaska Capital Management LLC "to purchase Rio Nogales, an 800-megawatt combined-cycle gas plant" in Guadalupe County.[178] With this addition to the organization's facilities, ozone season average daily emissions from CPS Energy in 2012 and 2018 were determined to be 26.46 tons of NO_X, 0.41 tons of VOC, and 17.62 tons of CO (Table 4-7). The average hourly emissions profile for CPS Energy is provided in Figure 4-3.[179] Emission projections for 2018 may vary from 2012 levels because of market demand. Since the 2012 emission rates for CPS Energy are the most recent data available, however, they are considered the best estimates of future generation. It is not reasonable to base emissions estimates on an equal distribution of CPS Energy's annual permitted emissions because actual daily emissions fluctuate with some days that have higher generation and some days that have lower generation. CPS Energy complies with short-term and long-term emissions limitations; however multiplying daily figures by 365 does not compare well with annual emissions rates.

[177] CPS Energy, 2013. "Who We Are: CPS Energy Works for You". San Antonio, Texas. Available online: http://cpsenergy.com/About_CPS_Energy/Who_We_Are/. Accessed: 08/07/13.

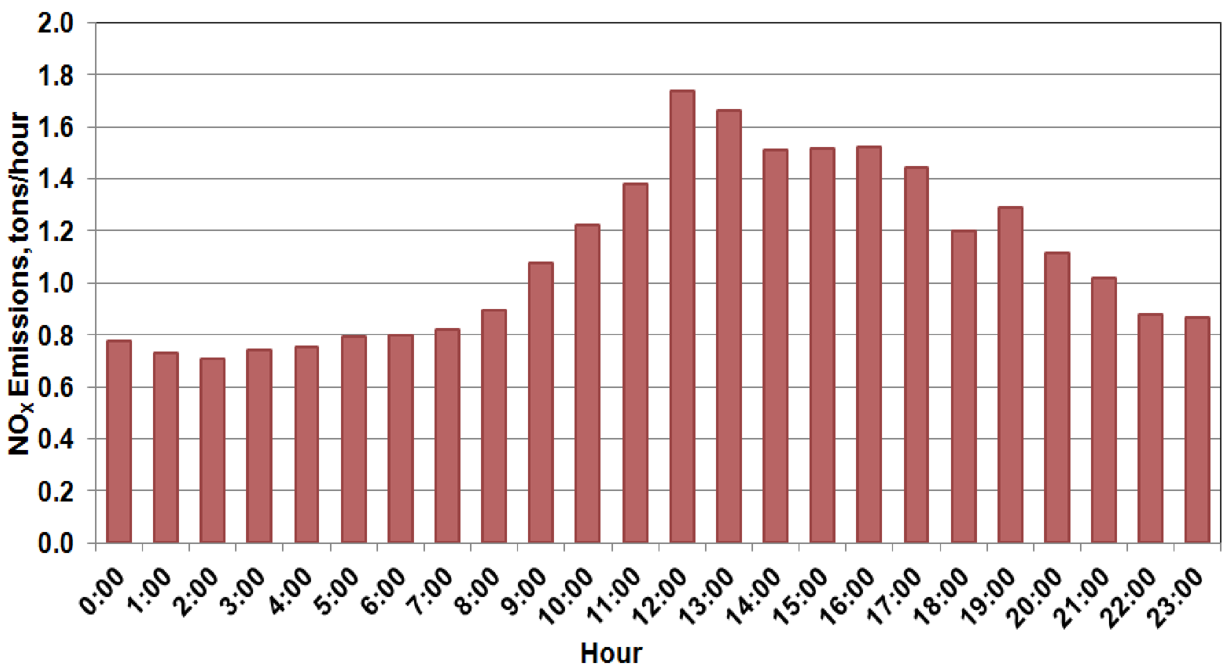
[178] Bob Thaxton, Seguin Gazette, April 11, 2012 "CPS finishes Rio Nogales acquisition". Seguin, TX. Available online: http://seguingazette.com/news/article_2edfc6fc-836d-11e1-9470-001a4bcf887a.html. Accessed 08/07/13.

[179] CPS Energy, San Antonio, Texas. "For AACOG NOx CO VOC Dec 2012.xls". Email to Steven Smeltzer. 11/29/12

Table 4-7: Emissions (ton/day) from CPS Energy Power Plant Units. 2012 and 2018

CPS Energy Plant	NO_X	VOC	CO
Leon Creek CGT #2	0.01	0.00	0.01
Leon Creek CGT #3	0.01	0.00	0.00
V. H. Braunig #1	0.43	0.03	0.01
V. H. Braunig #2	0.49	0.02	0.03
V. H. Braunig #3	1.99	0.08	0.35
A V Rosenberg CT#1	0.14	0.00	0.01
A V Rosenberg CT#2	0.14	0.00	0.01
V. H. Braunig CGT #5	0.01	0.00	0.01
V. H. Braunig CGT #6	0.01	0.00	0.01
V. H. Braunig CGT #7	0.02	0.00	0.01
V. H. Braunig CGT #8	0.02	0.00	0.01
O. W. Sommers #1	2.52	0.08	1.84
O. W. Sommers #2	1.42	0.07	0.02
J. T. Deely #1 & #2	6.84	0.00	7.67
J. K. Spruce #1	7.86	0.06	6.96
J. K. Spruce #2	3.50	0.03	0.12
Rio CT#1	0.29	0.01	0.23
Rio CT#2	0.46	0.02	0.03
Rio CT#3	0.29	0.01	0.29
Total	26.46	0.41	17.62

Figure 4-3: CPS Energy Hourly NO_X Emissions for the June 2006 Modeling Episode, 2012 and 2018



4.7.2 *San Miguel Electric Cooperative*

"San Miguel Electric Cooperative, Inc. (San Miguel) was created on February 17, 1977, under the Rural Electric Cooperative Act of the State of Texas, for the purpose of owning and operating a 400-MW mine-mouth, lignite-fired generating plant and associated mining facilities that furnish power and energy to Brazos Electric Power Cooperative, Inc. (BEPC) and South Texas Electric Cooperative, Inc. (STEC)."[180] Projected 2012 emissions for San Miguel Electric Cooperative are 10.18 tons/day of NO_X, 0.22 tons/day of VOC, and 8.50 tons/day of CO. For 2018, the projected emissions are 7.98 tons/day of NO_X, 0.22 tons/day of VOC, and 8.50 tons/day of CO.[181]

4.7.3 *Cement Kilns*

There are 9 cement kilns operating in the San Antonio-New Braunfels MSA and Hays County. "Cement kilns are used for the pyroprocessing stage of manufacture of Portland and other types of hydraulic cement, in which calcium carbonate reacts with silica-bearing minerals to form a mixture of calcium silicates."[182] The main fuel for the cement kilns in the region is coal, but other sources of fuel are used including natural gas, wood, and used tires. In 2006, these kilns emitted 29.15 tons of NO_X per day, while in 2012 and 2018 the NO_X emissions are 30.34 tons per day

[180] San Miguel Electric Cooperative, Inc. Available online: http://www.smeci.net/index2.htm. Accessed 08/05/13.
[181] Eutizi, Joe. San Miguel Electric Cooperative. Atascosa County, Texas. "Projected San Miguel Power Plant Emissions". Email to Steven Smeltzer. 11/29/12.
[182] Wikipedia, Sept. 9, 2013. "Cement kiln". Available online: http://en.wikipedia.org/wiki/Cement_kiln. Accessed 09/17/13.

Table 4-8: Local Cement Kilns Emissions, 2006, 2012, and 2018 (ton/day)

Plant	County	Kiln	2006			2012			2018		
			VOC	NO_X	CO	VOC	NO_X	CO	VOC	NO_X	CO
APG Lime Corp	Comal	Kiln 1	0.00	1.07	0.64	0.00	1.07	0.64	0.00	1.07	0.64
		Kiln 2	0.00	0.74	0.46	0.00	0.74	0.46	0.00	0.74	0.46
Alamo Cement	Bexar		0.11	6.57	2.00	0.11	6.57	2.00	0.11	6.57	2.00
Capital Cement	Bexar	Kiln 1	0.31	2.48	1.44	0.28	2.48	1.44	0.28	2.48	1.44
		Kiln 2	0.12	2.33	0.49	-	-	-	-	-	-
CEMEX	Comal	Kiln 1	0.01	5.99	2.73	0.01	5.99	2.73	0.01	5.99	2.73
TXI	Comal	Kiln 1	0.16	3.72	1.95	0.24	2.78	7.92	0.24	2.78	7.92
		Kiln 2	-	-	-	0.18	3.51	2.84	0.18	3.51	2.84
Texas Lehigh	Hays		0.55	6.25	9.32	0.56	7.20	10.89	0.56	7.20	10.89

4.7.4 *New Point Sources*

Growth in EGU and NEGU point sources are based on new permitted point sources or major proposed power plants from 2007 to 2012 and from 2013 to 2018. The databases used to collect data on the new point sources were obtained from:

- TCEQ Point Source database (for new EGUs from 2007 to 2011)[183]
- Public Utility Commission of Texas[184]
- Electric Reliability Council of Texas (ERCOT)[185]
- TCEQ air permitting projects with combustion turbines[186], and
- TCEQ document server for newly-permitted point sources[187]

For all the newly-permitted EGUs, emissions are based on the Maximum Allowable Emission Rates Table (MAERT) from the permit. When available, the 30-day emissions limitation was used. As stated by TCEQ, "these were most often available for solid fuel-fired units. This time frame represents a good compromise between the standard short-term allowable, which sometimes includes MSS, and the standard long-term permit allowable. The short term allowable in pph, when converted to tpd, is often substantially more than a unit would realistically emit in any day; the long-term allowable in tpy, when converted to tpd, may under-represent what a unit could emit during any one day, especially during a summer day during the ozone season."[188]

Maintenance, startup and shutdown (MSS) "activities help provide a more realistic operating scenario than the maximum of the short-term or long-term emission rates. This is especially important for those units that have many MSS events during a typical summer, such as the peaking units, which operate only during the peak demand times. MSS limits vary between permits on how they are represented."[189] "The emission rates calculated represent worst

[183] TCEQ, Jan. 2013. "Detailed Data from the Point Source Emissions Inventory". Austin, Texas. Available online: http://www.tceq.texas.gov/airquality/point-source-ei/psei.html. Accessed 08/08/13.
[184] Public Utility Commission of Texas, January 23, 2013. "New Electric Generating Plants in Texas Since 1995 (excluding renewable)". Austin, Texas. Available online: http://www.puc.texas.gov/industry/maps/elecmaps/gentable.pdf. Accessed 02/25/13.
[185] Electric Reliability Council of Texas. Available online: http://www.ercot.com/. Accessed 08/04/13.
[186] TCEQ, March 15, 2012. "Turbines Rated 20 MW and Greater Electric Output". Available online: http://m.tceq.texas.gov/assets/public/permitting/air/memos/turbine_lst.pdf. Accessed 02/25/13.
[187] TCEQ. "Document Server". Available online: https://webmail.tceq.state.tx.us/gw/webpub. Accessed 08/04/13.
[188] TCEQ. "Appendix B: Emissions Modeling for the DFW Attainment Demonstration Sip Revision for the 1997 Eight-Hour Ozone Standard". Austin, Texas. p. B-40. Available online: http://www.tceq.texas.gov/assets/public/implementation/air/sip/dfw/ad_2011/AppB_EI_ado.pdf. Accessed 07/03/13.
[189] TCEQ. "Appendix B: Emissions Modeling for the DFW Attainment Demonstration Sip Revision for the 1997 Eight-Hour Ozone Standard". Austin, Texas. p. B-40. Available online: http://www.tceq.texas.gov/assets/public/implementation/air/sip/dfw/ad_2011/AppB_EI_ado.pdf. Accessed 07/03/13.

case for some units, but for most units they represent a typical summer day during the ozone season."[190]

New EGUs from 2007 to 2012 are presented in Figure 4-4, while new proposed EGUs between 2013 and 2018 are provided on the map in Figure 4-5. The three large coal power plants that went into operation between 2007 and 2012 are V.H. Braunig in Bexar County, Sand Hill Energy northeast of Austin, and Oak Grove in east central Texas. As indicated, several new natural gas plants and one new pet coke plant also began operations during this time period. Total daily emissions from these new EGUs are 34.82 tons of NO_X, 6.94 tons of VOC, and 81.88 tons of CO (Table 4-9).

From 2013 to 2018, most new power plants will be natural gas or biomass. Of the two new coal plants indicated in Figure 4-5, Trailblazer Energy and Sandy Creek, the Sandy Creek power plant is already in operation. On June 21st, 2013, Tenaska announced plans that it will be abandoning plans to build Trailblazer Energy plant.[191] However, the modeling runs were started before the announcement was made and the plant is included in the 2018 projection year emission inventory. As listed on Table 4-10, daily emissions from new proposed EGUs between 2013 and 2018 are only 16.43 tons of NO_X, 16.73 tons of VOC, and 163.85 tons of CO.

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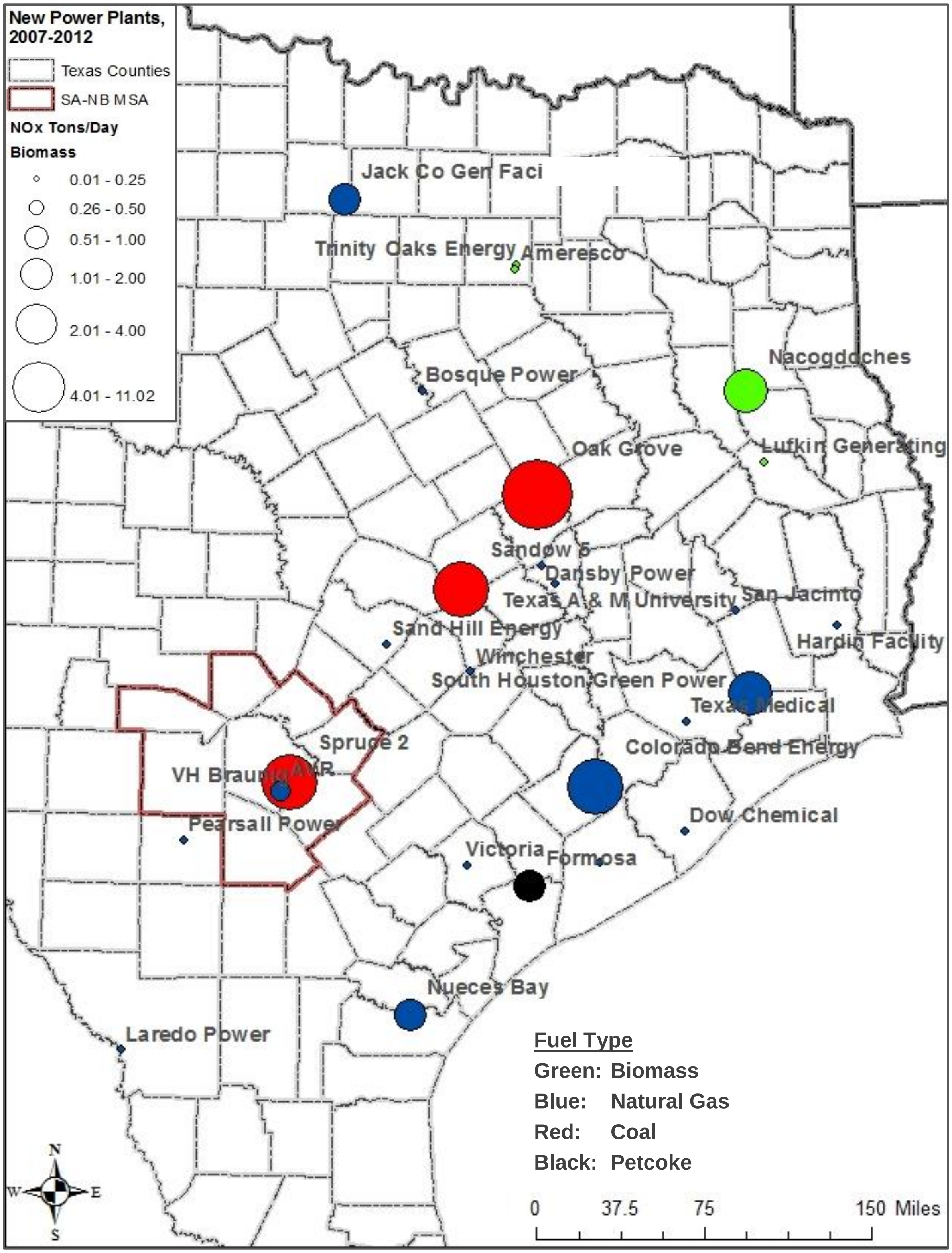
[190] TCEQ. "Appendix B: Emissions Modeling for the DFW Attainment Demonstration Sip Revision for the 1997 Eight-Hour Ozone Standard". Austin, Texas. p. B-41. Available online: http://www.tceq.texas.gov/assets/public/implementation/air/sip/dfw/ad_2011/AppB_EI_ado.pdf. Accessed 07/03/13.

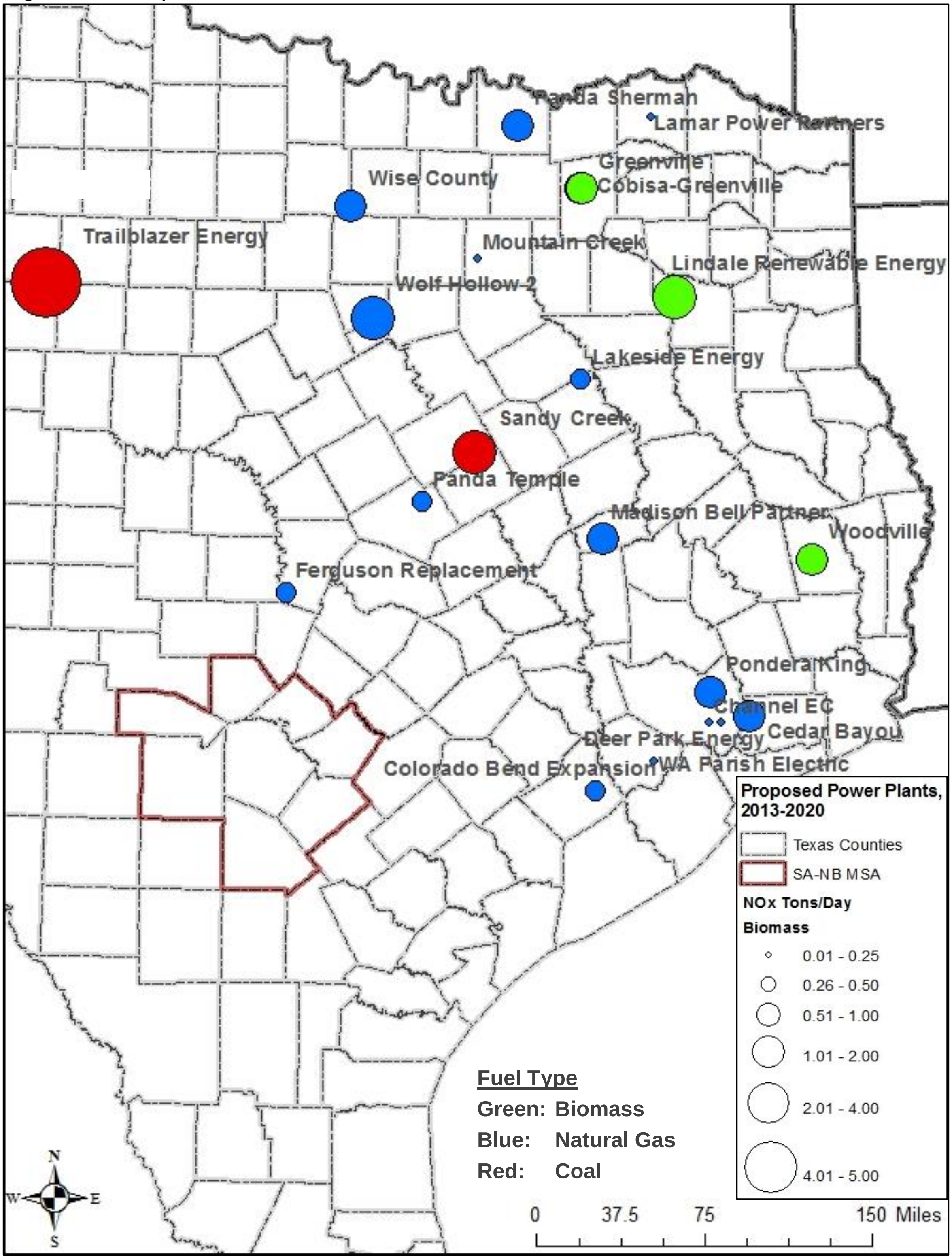
[191] John Mangalonzo, June 21, 2013. "Tenaska abandons coal plant project near Sweetwater". Abilene Reporter-News. Available online: http://www.reporternews.com/news/2013/jun/21/tenaska-abandons-coal-plant-project-near/. Accessed 08/08/13.

Figure 4-4: New Power Plants in Texas, 2007-2012



Plot Date:	May 29, 2013
Map Compilation:	May 5, 2013
Source:	Public Utility Commission of Texas, ERCOT, TCEQ air permitting projects with combustion turbines, and TCEQ document server

Figure 4-5: Proposed Power Plants in Texas, 2013-2018



Plot Date:	June 3, 2013
Map Compilation:	May 5, 2013
Source:	Public Utility Commission of Texas, ERCOT, TCEQ air permitting projects with combustion turbines, and TCEQ document server

Table 4-9: Newly Permitted EGUs in Texas and OSD Emissions, 2007-2012

Plant	County	In Operation	Capacity (MW)	Energy	NO_X	VOC	CO
Dow Chemical Cogen	Brazoria	2007	236	Natural Gas	0.16	0.66	4.32
Colorado Bend Energy	Wharton	2007	138	Natural Gas	0.66	0.04	0.11
Colorado Bend Energy	Wharton	2007	138	Natural Gas	0.66	0.04	0.11
Laredo Power Station	Webb	2008	97	Natural Gas	0.06	0.05	0.34
Laredo Power Station	Webb	2008	97	Natural Gas	0.06	0.05	0.34
Colorado Bend Energy	Wharton	2008	138	Natural Gas	0.66	0.04	0.11
Colorado Bend Energy	Wharton	2008	138	Natural Gas	0.66	0.04	0.11
Texas A & M University	Brazos	2008	33	Natural Gas	0.15	0.01	0.07
Oak Grove 1	Robertson	2009	855	Coal	5.51	0.02	13.51
J K Spruce Unit 2	Bexar	2009	750	Coal	3.50	0.03	0.12
Sandow 5	Milam	2009	291	Coal	1.76	0.00	0.55
Sandow 5	Milam	2009	291	Coal	1.76	0.00	0.55
Barney M Davis	Nueces	2009	180	Natural Gas	0.14	0.02	0.02
Barney M Davis	Nueces	2009	180	Natural Gas	0.14	0.02	0.02
Nueces Bay WLE	Nueces	2009	351	Natural Gas	0.28	0.47	6.09
Nueces Bay WLE	Nueces	2009	351	Natural Gas	0.28	0.47	6.09
East TX Elec Coop Ha	Hardin	2009	84	Natural Gas	0.03	0.00	0.03
Hardin Facility	Hardin	2009	84	Natural Gas	0.03	0.00	0.03
San Jacinto Facility	San Jacinto	2009	84	Natural Gas	0.04	0.00	0.05
San Jacinto Facility	San Jacinto	2009	84	Natural Gas	0.04	0.00	0.05
Dansby Power Plant	Brazos	2009	48	Natural Gas	0.07	0.03	1.03
Winchester PowerPark	Fayette	2009	45	Natural Gas	0.01	0.01	0.00
Winchester PowerPark	Fayette	2009	45	Natural Gas	0.01	0.01	0.00
Winchester PowerPark	Fayette	2009	45	Natural Gas	0.01	0.01	0.00
Winchester PowerPark	Fayette	2009	45	Natural Gas	0.01	0.01	0.00
Trinity Oaks Energy	Dallas	2009	3	Biomass	0.04	0.00	0.29
South Houston Green Power	Chambers	2009	244	Natural Gas	1.06	0.41	3.94
Bosque Power Company, LLC	Bosque	2009	255	Natural Gas	0.23	0.03	0.34
Oak Grove 2	Robertson	2010	855	Coal	5.51	0.02	13.51

Plant	County	In Operation	Capacity (MW)	Energy	NO_X	VOC	CO
Lufkin Generating Pl	Angelina	2010	50	Biomass	0.14	0.08	0.62
TECO Central Plant	Harris	2010	25	Natural Gas	0.08	0.10	1.63
TECO Central Plant	Harris	2010	25	Natural Gas	0.08	0.10	1.63
Sand Hill Energy Ctr	Travis	2010	47	Natural Gas	0.07	0.06	1.41
Sand Hill Energy Ctr	Travis	2010	47	Natural Gas	0.07	0.06	1.41
Ameresco Dallas	Dallas	2010	4	Biomass	0.03	0.04	0.14
Jack Co Gen Facility	Jack	2011	310	Natural Gas	0.40	0.53	7.67
Jack Co Gen Facility	Jack	2011	310	Natural Gas	0.40	0.53	7.67
Formosa Pt. Comfort	Calhoun	2011	150	Petcoke	4.29	0.77	1.16
Formosa Pt. Comfort	Calhoun	2011	150	Petcoke	4.29	0.77	1.16
Victoria Power Plant	Victoria	2011	332	Natural Gas	0.14	0.71	0.09
South Texas Project	Matagorda	2011	20	Natural Gas	0.14	0.01	0.04
Pearsall Power Plant	Frio	2011	200	Natural Gas	0.17	0.14	0.17
Nacogdoches Power	Nacogdoches	2012	50	Biomass	0.68	0.34	2.72
Nacogdoches Power	Nacogdoches	2012	50	Biomass	0.37	0.24	2.63
Total					34.82	6.94	81.88

Table 4-10: Proposed EGUs in Texas and OSD Emissions, 2013-2018

Plant	County	In Operation	Capacity (MW)	Energy	NO_X	VOC	CO
Sandy Creek	Mclennan	2013	925	Coal	0.18	0.02	0.06
WA Parish	Fort Bend	2013	89	Natural Gas	0.05	0.01	0.15
Wolf Hollow	Hood	2013	508	Natural Gas	1.57	0.98	15.96
Greenville Generating Plant	Hunt	2013	63	Biomass	0.65	0.07	0.65
Deer Park Energy Cen	Harris	2014	130	Natural Gas	0.10	0.87	6.68
Deer Park Energy Cen	Harris	2014	130	Natural Gas	0.10	0.87	6.68
Lakeside Energy Center	Freestone	2014	640	Natural Gas	0.46	0.23	1.72
Ferguson Replacement Project	Llano	2014	590	Natural Gas	0.41	0.19	0.83
Panda Sherman Power LLC	Grayson	2014	809	Natural Gas	0.63	0.69	10.28
Woodville	Tyler	2014	50	Biomass	0.58	0.17	1.32
Channel EC expansion	Harris	2014	180	Natural Gas	0.17	0.07	0.64
Tenaska Trailblazer	Nolan	2014	600	Coal	4.98	0.36	9.97
Cobisa-Greenville	Hunt	2016	299	Natural Gas	0.15	1.24	5.90
Cobisa-Greenville	Hunt	2016	299	Natural Gas	0.15	1.24	5.90
Cobisa-Greenville	Hunt	2016	299	Natural Gas	0.15	1.24	5.90
Cobisa-Greenville	Hunt	2016	299	Natural Gas	0.15	1.11	4.43
Cobisa-Greenville	Hunt	2016	299	Natural Gas	0.15	1.11	4.43
Cobisa-Greenville	Hunt	2016	299	Natural Gas	0.15	1.11	4.43
Panda Temple Power	Bell	2016	405	Natural Gas	0.10	0.60	5.78
Panda Temple Power	Bell	2016	405	Natural Gas	0.10	0.60	5.78
Panda Temple Power	Bell	2016	390	Natural Gas	0.10	0.60	5.78
Panda Temple Power	Bell	2016	390	Natural Gas	0.10	0.60	5.78
Pondera King Power Project	Harris	2016	1380	Natural Gas	0.98	0.72	2.08
Madison Bell Partner	Madison	2018	138	Natural Gas	0.22	0.13	2.10
Madison Bell Partner	Madison	2018	138	Natural Gas	0.22	0.13	2.10
Madison Bell Partner	Madison	2018	138	Natural Gas	0.22	0.13	2.10
Madison Bell Partner	Madison	2018	138	Natural Gas	0.22	0.13	2.10
Wise County Power Pl	Wise	2018	175	Natural Gas	0.19	0.07	3.62
Wise County Power Pl	Wise	2018	175	Natural Gas	0.19	0.07	3.62

Plant	County	In Operation	Capacity (MW)	Energy	NOX	VOC	CO
Wise County Power Pl	Wise	2018	175	Natural Gas	0.19	0.07	3.62
Wise County Power Pl	Wise	2018	175	Natural Gas	0.19	0.07	3.62
Cedar Bayou	Chambers	2018	270	Natural Gas	0.18	0.15	6.50
Cedar Bayou	Chambers	2018	270	Natural Gas	0.16	0.15	6.50
NRG Cedar Bayou	Chambers	2018	300	Natural Gas	0.14	0.20	6.22
NRG Cedar Bayou	Chambers	2018	300	Natural Gas	0.14	0.20	6.22
Lamar Power Partners	Lamar	2018	310	Natural Gas	0.12	0.10	0.89
Lamar Power Partners	Lamar	2018	310	Natural Gas	0.12	0.10	0.89
Colorado Bend expansion	Wharton	2018	275	Natural Gas	0.29	0.06	1.46
Lindale Renewable Energy	Smith	2018	50	Biomass	1.23	0.14	0.09
Mountain Creek	Dallas	2018	400	Natural Gas	0.23	0.13	1.08
Total					16.43	16.73	163.85

Sometimes stack parameters were not available from TCEQ's permit database for the smaller EGUs built after 2006. If the parameters were not available, the height, stack diameter, temperature, and velocity were based on the averages of existing EGUs by fuel type and size (Table 4-11).

Table 4-11: Stack parameters for small EGUs if permit data is not available, 2012 and 2018.

Energy	Size (MW)	Height (m)	Diameter (m)	Temp (K)	Velocity (m/s)
Natural Gas	Less Than 100	33	4	616	28
	100 - 200	38	5	475	25
	200 +	45	6	361	20
Biomass		58	4	415	25
Coal		128	9	361	16

Several new NEGU point sources were added to the 2018 modeling scenario. For the San Antonio-New Braunfels MSA, daily emissions from these NEGUs were estimated to be 0.056 tons of NO_X, 0.216 tons of VOC, and 0.084 tons of CO (Table 4-12). Similar to EGUs, if stack parameters where not available from the permits, they were based on the averages of existing NEGUs by SCC code for each process.

Table 4-12: New NEGUs in the San Antonio-New Braunfels MSA, tons per day.

Company	County	SCC Code	Stack height (m)	Stack diameter (m)	Temperature (K)	Velocity (m/s)	NO_X	VOC	CO
Travis Industry's	Bexar	40202501	12	0.6	487	8	-	0.014	-
Texas Scenic Company, Inc.	Bexar	40202501	12	0.6	487	8	-	0.020	-
Monterrey Iron & Metal, LTD	Bexar	20100102	8	0.3	679	21	0.056	0.000	0.084
Avanzar Interior Technologies	Bexar	40202501	12	0.6	487	8	-	0.068	-
M7 Aerospace LLC	Bexar	40202501	12	0.6	487	8	-	0.034	-
Salof Refrigeration Co., Inc.	Guadalupe	40202501	12	0.6	487	8	-	0.066	-
Fox Tank Company	Kendall	40202501	12	0.6	487	8	-	0.013	-

4.8 Eagle Ford Emissions

"The Eagle Ford Shale is a hydrocarbon producing formation of significant importance due to its capability of producing both gas and more oil than other traditional shale plays. It contains a much higher carbonate shale percentage, upwards to 70% in south Texas, and becomes shallower and the shale content increases as it moves to the northwest. The high percentage of carbonate makes it more brittle and 'fracable'."[192] Hydraulic fracturing is a technological advancement which allows producers to recover natural gas and oil resources from these shale formations. "Experts have known for years that natural gas and oil deposits existed in deep shale formations, but until recently the vast quantities of natural gas and oil in these formations were not able to be technically or economically recoverable."[193] Today, significant amounts of natural gas and oil from deep shale formations across the United States are being produced through the use of horizontal drilling and hydraulic fracturing.[194]

Hydraulic fracturing is the process of creating fissures, or fractures, in underground formations to allow natural gas and oil to flow up the wellbore to a pipeline or tank battery. In the Eagle Ford Shale, a company engaged in extraction "pumps water, sand and other additives under high pressure into the formation to create fractures. The fluid is approximately 98% water and sand, along with a small amount of special-purpose additives. The newly created fractures are "propped" open by the sand, which allows the natural gas and oil to flow into the wellbore and be collected at the surface. Variables such as surrounding rock formations and thickness of the targeted shale formation are studied by scientists before fracking is conducted."[195]

Locations of the Eagle Ford and other Shale Plays in the lower 48 states are provided in Figure 4-6.[196] Unlike the Haynesville and Barnett Shale formations in northern Texas that primarily produce gas, the Eagle Ford Shale features high oil yields and wet gas/condensate across much of the play. Consequently, equipment types, processes, and activities in the Eagle Ford may differ from those employed in more traditional shale formations. Emission processes addressed in the inventory include exploration and pad construction, drilling,

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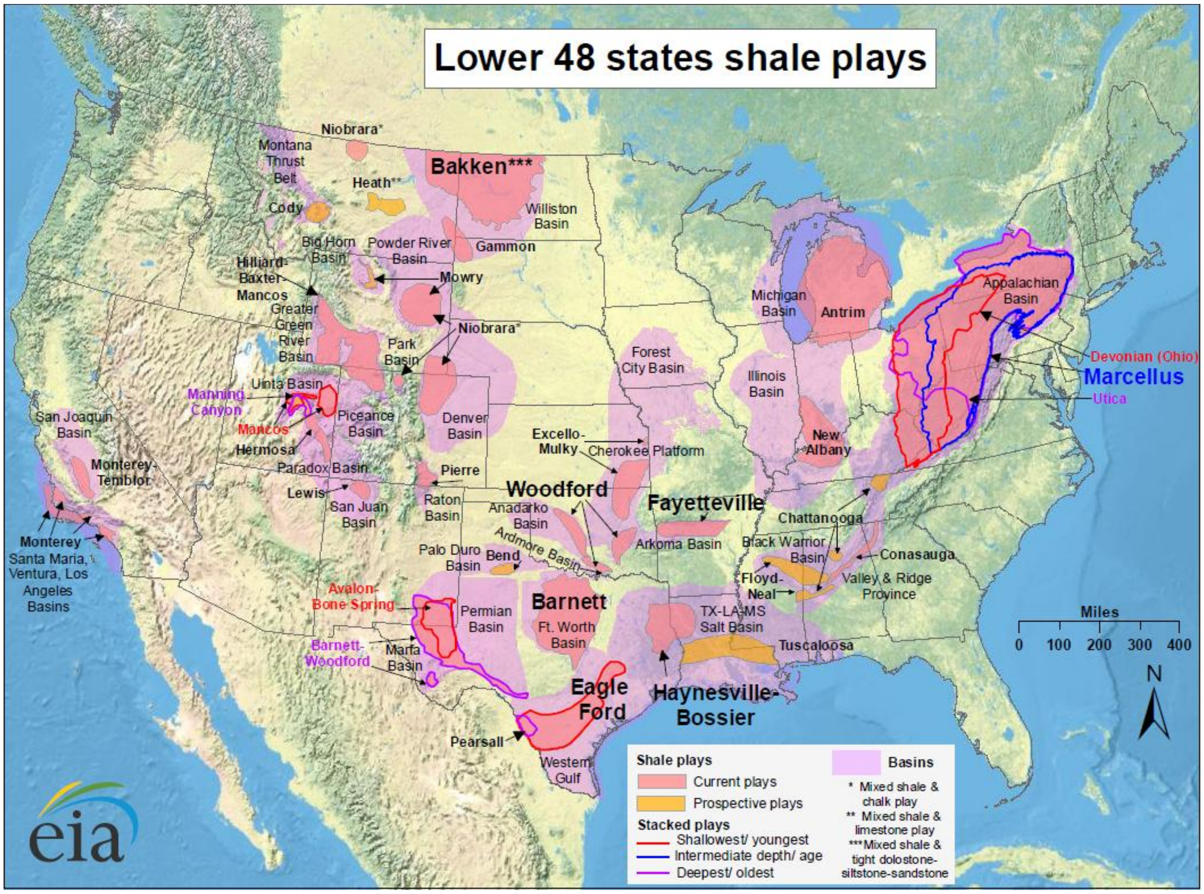
[192] Railroad Commission of Texas, May 22, 2012. "Eagle Ford Information". Austin, Texas. Available online: http://www.rrc.state.tx.us/eagleford/index.php. Accessed 05/30/12.
[193] Chesapeake Energy, Sept. 2011. "Eagle Ford Shale Hydraulic Fracturing". Available online: http://www.chk.com/Media/Educational-Library/Fact-Sheets/EagleFord/EagleFord_Hydraulic_Fracturing_Fact_Sheet.pdf. Accessed: 04/12/12.
[194] Chesapeake Energy, Sept. 2011. "Eagle Ford Shale Hydraulic Fracturing". Available online: http://www.chk.com/Media/Educational-Library/Fact-Sheets/EagleFord/EagleFord_Hydraulic_Fracturing_Fact_Sheet.pdf. Accessed: 04/12/12.
[195] *Ibid*.
[196] Energy Information Administration (EIA), May 9, 2011. "Maps: Exploration, Resources, Reserves, and Production". Available online: ftp://www.eia.doe.gov/pub/oil_gas/natural_gas/analysis_publications/maps/maps.htm. Accessed 06/04/12.

hydraulic fracturing and completion operations, production, and midstream facilities. Emissions sources can include heavy duty trucks, light duty trucks, drill rigs, compressors, pumps, heaters, other non-road equipment, process emissions, flares, storage tanks, and fugitive emissions.

Figure 4-6: Lower 48 States Shale Plays



Existing oil and gas drilling inventories in Texas and data from the Railroad Commission of Texas was used to develop an emissions inventory of the Eagle Ford. These studies include: Eastern Research Group's (ERG) "Characterization of Oil and Gas Production Equipment and Develop a Methodology to Estimate Statewide Emissions", ERG's Drilling Rig Emission Inventory for the State of Texas, and ENVIRON's "An Emission Inventory for Natural Gas Development in the Haynesville Shale and Evaluation of Ozone Impacts". TCEQ also conducted a mail survey through the Barnett Shale area for the special inventory phase two study on natural gas fracturing operations west of Dallas.

Eagle Ford activities produce oil, natural gas, and condensate during five main phases.

- Exploration and Pad Construction: Exploration uses vibrator trucks to produce sound waves beneath the surface that are useful in the exploration for oil and natural gas. Construction of the drill pad requires clearing, grubbing, and grading, followed by placement of a base material by construction equipment and trucks. Reserve pits are also usually required at each well pad because the drilling and hydraulic fracturing process uses a large volume of fluid that is circulated through the well and back to the surface.

- Drilling Operation: "Drilling of a new well is typically a two to three week process from start to finish and involves several large diesel-fueled generators."[197] Other emission sources related to drilling operations include construction equipment and trucks to haul supplies, equipment, fluids, and employees.
- Hydraulic Fracturing and Completion Operation: Hydraulic fracturing "is the high pressure injection of water mixed with sand and a variety of chemical additives into the well to fracture the shale and stimulate natural gas production from the well. Fracking operations can last for several weeks and involve many large diesel-fueled generators"[198] "Once drilling and other well construction activities are finished, a well must be completed in order to begin producing. The completion process requires venting of the well for a sustained period of time to remove mud and other solid debris in the well, to remove any inert gas used to stimulate the well (such as CO_2 and/or N_2) and to bring the gas composition to pipeline grade".[199] In the Eagle Ford, vented gas from the completion process is usually flared.
- Production: Once the product is collected from the well, emissions can occur at well sites from compressors, flares, heaters, and pneumatic devices. There can also be significant emissions from equipment leaks, storage tanks, and loading operation fugitives. Trucks are often used to transport product to processing facilities and refineries; consequently, emissions generated during production may also originate from on-road sources.
- Midstream Sources: Midstream sources in the Eagle Ford consist mostly of compressor stations and processing facilities, but may also include cryogenic plants, saltwater disposal facilities, tank batteries, and other facilities. "The most significant emissions from compressor stations are usually from combustion at the compressor engines or turbines. Other emissions sources may include equipment leaks, storage tanks, glycol dehydrators, flares, and condensate and/or wastewater loading. Processing facilities generally remove impurities from the natural gas, such as carbon dioxide, water, and hydrogen sulfide. These facilities may also be designed to remove ethane, propane, and butane fractions from the natural gas for downstream marketing. Processing facilities are usually the largest emitting natural gas-related point sources including multiple emission sources such as, but

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[197] University of Arkansas and Argonne National Laboratory. "Fayetteville Shale Natural Gas: Reducing Environmental Impacts: Site Preparation". Available online: http://lingo.cast.uark.edu/LINGOPUBLIC/natgas/siteprep/index.htm. Accessed: 04/20/12.

[198] *Ibid*.

[199] Amnon Bar-Ilan, Rajashi Parikh, John Grant, Tejas Shah, Alison K. Pollack, ENVIRON International Corporation. Nov. 13, 2008. "Recommendations for Improvements to the CENRAP States' Oil and Gas Emissions Inventories". Novato, CA. p. 48. Available online: http://www.wrapair.org/forums/ogwg/documents/2008-11_CENRAP_O&G_Report_11-13.pdf. Accessed: 04/30/12.

not limited to equipment leaks, storage tanks, separator vents, glycol dehydrators, flares, condensate and wastewater loading, compressors, amine treatment and sulfur recovery units."[200]

4.9 On-Road Emissions in the Eagle Ford

4.9.1 Well Pad Construction On-Road Emissions

On-road emissions associated with gas and oil production in the Eagle Ford Shale originate from heavy duty diesel trucks that carry equipment and light duty trucks that transport employees and supplies to the well pads. Surveys from other regions found between 20 and 75 heavy duty truck trips are required for pad construction, while there was a wide variation in the number of trips by light duty trucks needed during the construction process. ENVIRON provided detailed information on activity rates, speeds, and idling hours need for each trip for well pad construction in the Piceance Basin of Northwestern Colorado. There were 22.86 trips by heavy duty vehicles and 82.46 trips by light duty trucks to construct each well pad. The study found that idling times by heavy duty trucks was 0.40 hours for each trip and light duty trucks varied between 2.00 and 2.15 idling hours per trip.[201] TxDOT reported an average of 70 heavy duty truck loads were needed for pad construction in the Barnett shale development.[202]

A study by New York City's Department of Environmental Protection on the Marcellus Shale Gas Development found 20 to 40 heavy duty diesel truck trips were needed for pad construction, which was similar to ENVIRON's survey.[203] Other studies by Cornell University[204], the National Park Service[205], and All Consulting[206], regarding development of

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[200] Eastern Research Group Inc. July 13, 2011. "Fort Worth Natural Gas Air Quality Study Final Report". Prepared for: City of Fort Worth, Fort Worth, Texas. p. 3-2. Available online: http://fortworthtexas.gov/gaswells/?id=87074. Accessed: 04/09/12.

[201] Amnon Bar-Ilan, John Grant, Rajashi Parikh, Ralph Morris, ENVIRON International Corporation, July 2011. "Oil and Gas Mobile Sources Pilot Study". Novato, California. pp. 11-12. Available online: http://www.wrapair2.org/pdf/2011-07_P3%20Study%20Report%20(Final%20July-2011).pdf. Accessed: 04/12/12.

[202] Richard Schiller, P.E. Fort, Worth District. Aug. 5, 2010. "Barnett Shale Gas Exploration Impact on TxDOT Roadways". TxDOT, Forth Worth. Slide 15.

[203] Haxen and Sawyer, Environmental Engineers & Scientists, Sept. 2009. "Impact Assessment of Natural Gas Production in the New York City Water Supply Watershed Rapid Impact Assessment Report". New York City Department of Environmental Protection. p. 47. Available online: http://www.nyc.gov/html/dep/pdf/natural_gas_drilling/rapid_impact_assessment_091609.pdf. Accessed: 04/20/12.

[204] Santoro, R.L.; R.W. Howarth; A.R. Ingraffea. 2011. Indirect Emissions of Carbon Dioxide from Marcellus Shale Gas Development. A Technical Report from the Agriculture, Energy, & Environment Program at Cornell University. June 30, 2011. p. 8. Available online: http://www.eeb.cornell.edu/howarth/IndirectEmissionsofCarbonDioxidefromMarcellusShaleGasDevelopment_June302011%20.pdf. Accessed: 04/02/12.

[205] National Park Service U.S. Department of the Interior, Dec. 2008. "Potential Development of the Natural Gas Resources in the Marcellus Shale: New York, Pennsylvania, West Virginia, and Ohio". p. 9. Available online: http://www.nps.gov/frhi/parkmgmt/upload/GRD-M-Shale_12-11-2008_high_res.pdf. Accessed: 04/22/12.

the Marcellus Shale had similar results for the number of trips by heavy duty trucks. ENVIRON's study of the Southern Ute Indian Reservation reported slightly more heavy duty truck trips: 56 heavy duty truck loads.[207]

With regard to light duty vehicle use, the Pinedale Anticline Project in Wyoming[208] reported significantly more trips[209] during the pad construction phase than ENVIRON's survey, while studies about the San Juan Public Lands Center in Colorado[210], Tumbleweed II in Utah[211], Jonah Infill in Wyoming [212]. and West Tavaputs Plateau in Utah[213] found less light duty truck trips compared to ENVIRON's report in tin the Piceance Basin of Northwestern Colorado. Since data for development in the Eagle Ford Shale area is not available, the number of trips by vehicle type and the idling time per vehicle trip was based on TxDOT findings in the Barnett shale and ENVIRON's report's in Colorado. These reports were selected because

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[206] All Consulting, Sept. 16, 2010. "NY DEC SGEIS Information Requests". Prepared for Independent Oil & Gas Association, Project no.: 1284. Available online: http://catskillcitizens.org/learnmore/20100916IOGAResponsetoDECChesapeake_IOGAResponsetoDEC.pdf. Accessed: 04/16/12.

[207] ENVIRON, August 2009. "Programmatic Environmental Assessment for 80 Acre Infill Oil and Gas Development on the Southern Ute Indian Reservation". Novato, California. Appendix A, p. 62. Available online: http://www.suitdoe.com/Documents/Appendix_G_AirQualityTSD.pdf. Accessed: 04/25/12.

[208] U.S. Department of the Interior, Bureau of Land Management, Sept. 2008. "Final Supplemental Environmental Impact Statement for the Pinedale Anticline Oil and Gas Exploration and Development Project: Pinedale Anticline Project Area Supplemental Environmental Impact Statement". Sheyenne, Wyoming. p. F42. Available online: http://www.blm.gov/pgdata/etc/medialib/blm/wy/information/NEPA/pfodocs/anticline/rd-seis/tsd.Par.13395.File.dat/07appF.pdf. Accessed: 04/12/12.

[209] U.S. Department of the Interior, Bureau of Land Management, Sept. 2008. "Final Supplemental Environmental Impact Statement for the Pinedale Anticline Oil and Gas Exploration and Development Project: Pinedale Anticline Project Area Supplemental Environmental Impact Statement". Sheyenne, Wyoming. pp. F39-F40. Available online: http://www.blm.gov/pgdata/etc/medialib/blm/wy/information/NEPA/pfodocs/anticline/rd-seis/tsd.Par.13395.File.dat/07appF.pdf. Accessed: 04/12/12.

[210] BLM National Operations Center, Division of Resource Services, December, 2007. "San Juan Public Lands Center Draft Land Management Plan & Draft Environmental Impact Statement: Air Quality Impact Assessment Technical Support Document". Bureau of Land Management, San Juan Public Lands Center, Durango, Colorado. p. A-4. Available online: http://ocs.fortlewis.edu/forestplan/DEIS/pdf/120507_TSD&App%20A.pdf. Accessed: 04/03/2012.

[211] U.S. Department of the Interior, Bureau of Land Management. June 2010. "Tumbleweed II Exploratory Natural Gas Drilling Project". East City, Utah. DOI-BLM-UTG010-2009-0090-EA. p. 12 of 29. Available online: http://www.blm.gov/pgdata/etc/medialib/blm/ut/lands_and_minerals/oil_and_gas/november_2011.Par.24530.File.dat/. Accessed: 04/12/12.

[212] Amnon Bar-Ilan, ENVIRON Corporation, June 2010. "Oil and Gas Mobile Source Emissions Pilot Study: Background Research Report". UNC-EMAQ (3-12)-006.v1. Novato, CA. p. 17. Available online: http://www.wrapair2.org/documents/2010-06y_WRAP%20P3%20Background%20Literature%20Review%20(06-06%20REV).pdf. Accessed: 04/03/12.

[213] Buys & Associates, Inc., Sept. 2008. "APPENDIX J: Near-Field Air Quality Technical Support Document for the West Tavaputs Plateau Oil and Gas Producing Region Environmental Impact Statement". Prepared for: Bureau of Land Management Price Field Office Littleton, Colorado. Available online: http://www.blm.gov/ut/st/en/fo/price/energy/Oil_Gas/wtp_final_eis.html. Accessed: 04/20/12.

the TxDOT report provided data from well pad construction in a similar area in Texas and the ENVIRON's report is the only report with specific data on idling rates.

4.9.2 Drilling On-Road Emissions

Energy in Depth, a research, education, and outreach program created by the Independent Petroleum Association of America, states that it takes approximately 35-45 semi trucks (10,000 foot well) trips to move and assemble a rig.[214] This result is very similar to TxDOT's findings that 44 heavy duty trucks are needed to move a rig in the Barnett Shale.[215] TxDOT also states that an additional 73 heavy duty truck trips are needed to move drilling rig equipment and deliver supplies. The results are similar to most other studies that predicted between 80 and 235 truck trips are needed including Cornell University's report about the Marcellus[216], Buys & Associates' research in Utah[217], and Jonah Infill's field study in Wyoming.[218] Data from NCTCOG on the number of heavy duty truck trips, 187, in the Barnett was used to estimate emissions generated by on-road sources during the process of moving and assembling rigs in the Eagle Ford.[219] The TxDOT report was used because it contains data in Texas from a comparable area.

4.9.3 Hydraulic Fracturing On-Road Emissions

Heavy duty trucks are needed to provide equipment, water, sand/ proppant, chemicals, and supplies, while trucks are sometimes also needed to remove flowback from the well site. Previous studies found between 15 and 2,100 truck trips are needed during hydraulic fracturing and completion of the well site. Jonah Infill in Wyoming[220] and NCTCOG[221] found

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[214] Energy in Depth: A coalition led by Independent Petroleum Association of America. Available online: http://www.energyindepth.org/rig/index.html. Accessed: 04/18/12.

[215] Richard Schiller, P.E. Fort, Worth District. Aug. 5, 2010. "Barnett Shale Gas Exploration Impact on TxDOT Roadways". TxDOT, Forth Worth. Slide 15.

[216] Santoro, R.L.; R.W. Howarth; A.R. Ingraffea. 2011. Indirect Emissions of Carbon Dioxide from Marcellus Shale Gas Development. A Technical Report from the Agriculture, Energy, & Environment Program at Cornell University. June 30, 2011. p. 8. Available online: http://www.eeb.cornell.edu/howarth/IndirectEmissionsofCarbonDioxidefromMarcellusShaleGasDevelopment_June302011%20.pdf. Accessed: 04/02/12.

[217] Buys & Associates, Inc., Sept. 2008. "APPENDIX J: Near-Field Air Quality Technical Support Document for the West Tavaputs Plateau Oil and Gas Producing Region Environmental Impact Statement". Prepared for: Bureau of Land Management Price Field Office Littleton, Colorado. Available online: http://www.blm.gov/ut/st/en/fo/price/energy/Oil_Gas/wtp_final_eis.html. Accessed: 04/20/12.

[218] Amnon Bar-Ilan, ENVIRON Corporation, June 2010. "Oil and Gas Mobile Source Emissions Pilot Study: Background Research Report". UNC-EMAQ (3-12)-006.v1. Novato, CA. pp. 17-18. Available online: http://www.wrapair2.org/documents/2010-06y_WRAP%20P3%20Background%20Literature%20Review%20(06-06%20REV).pdf. Accessed: 04/03/12.

[219] Lori Clark, Shannon Stevenson, and Chris Klaus North Central Texas Council of Governments, August 2012. "Development of Oil and Gas Mobile Source Inventory in the Barnett Shale in the 12-County Dallas-Fort Worth Area". Arlington, Texas. Texas Commission on Environmental Quality Grant Number: 582-11-13174. p. 11. Available online: http://www.nctcog.org/trans/air/barnettshale.asp. Accessed 01/23/13.

[220] Amnon Bar-Ilan, ENVIRON Corporation, June 2010. "Oil and Gas Mobile Source Emissions Pilot Study: Background Research Report". UNC-EMAQ (3-12)-006.v1. Novato, CA. p. 17. Available

between 400 and 440 heavy duty truck trips are needed during hydraulic fracturing. A Cornell University report determined that 790 heavy duty truck trips are used in the Marcellus during the fracturing process.[222] These results are similar to All Consulting's vehicle count of 868 heavy duty trucks[223] and the National Park Service's average of 695 heavy duty truck trips in the Marcellus.[224]

Data from TxDOT's study of the Barnett Shale indicating use of 807 heavy duty truck trips during hydraulic fracking was used for calculating fracturing-related on-road emissions in the Eagle Ford. When calculating truck trips, TxDOT assumed that 50% of the freshwater used during the fracturing process was provided by pipeline. This is similar to operations conducted by some companies in the Eagle Ford. For example, Rosetta Resources, one of the companies operating in the Eagle Ford, "has built water gathering pipelines to eliminate the need to truck water to the fracturing crew". [225]

The number of trips made with light duty vehicles during the fracturing process ranged from 30 found in the San Juan Public Lands Center study in Colorado[226] to All Consulting's estimation of 461 in the Marcellus. Most of the studies found approximately 140 light duty vehicle trips were needed including ENVIRON's Southern Ute[227] and Buys & Associates'

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online: http://www.wrapair2.org/documents/2010-06y_WRAP%20P3%20Background%20Literature%20Review%20(06-06%20REV).pdf. Accessed: 04/03/12.

[221] North Central Texas Council of Governments. "Barnett Shale Truck Traffic Survey". Dallas, Texas. Slide 9. Available online: http://www.nctcog.org/trans/air/barnettshale.asp. Accessed 05/04/12.

[222] Santoro, R.L.; R.W. Howarth; A.R. Ingraffea. 2011. Indirect Emissions of Carbon Dioxide from Marcellus Shale Gas Development. A Technical Report from the Agriculture, Energy, & Environment Program at Cornell University. June 30, 2011. p. 8. Available online: http://www.eeb.cornell.edu/howarth/IndirectEmissionsofCarbonDioxidefromMarcellusShaleGasDevelopment_June302011%20.pdf. Accessed: 04/02/12.

[223] All Consulting, Sept. 16, 2010. "NY DEC SGEIS Information Requests". Prepared for Independent Oil & Gas Association, Project no.: 1284. Available online: http://catskillcitizens.org/learnmore/20100916IOGAResponsetoDECChesapeake_IOGAResponsetoDEC.pdf. Accessed: 04/16/12.

[224] National Park Service U.S. Department of the Interior, Dec. 2008. "Potential Development of the Natural Gas Resources in the Marcellus Shale: New York, Pennsylvania, West Virginia, and Ohio". p. 9. Available online: http://www.nps.gov/frhi/parkmgmt/upload/GRD-M-Shale_12-11-2008_high_res.pdf. Accessed: 04/22/12.

[225] Colter Cookson. June, 2011. "Operators Converge On Eagle Ford's Oil and Liquids-Rich Gas". The American Oil and Gas Reporter. p. 3. Available online: http://www.laredoenergy.com/sites/default/files/0611LaredoEnergyEprint.pdf. Accessed: 04/12/12.

[226] BLM National Operations Center, Division of Resource Services, December, 2007. "San Juan Public Lands Center Draft Land Management Plan & Draft Environmental Impact Statement: Air Quality Impact Assessment Technical Support Document". Bureau of Land Management, San Juan Public Lands Center, Durango, Colorado. p. A-9. Available online: http://ocs.fortlewis.edu/forestplan/DEIS/pdf/120507_TSD&App%20A.pdf. Accessed: 04/03/12.

[227] ENVIRON, August 2009. "Programmatic Environmental Assessment for 80 Acre Infill Oil and Gas Development on the Southern Ute Indian Reservation". Novato, California. Appendix A, p. 68. Available online: http://www.suitdoe.com/Documents/Appendix_G_AirQualityTSD.pdf. Accessed: 04/25/12.

research in Utah[228]. To calculate on-road vehicle emissions associated with fracturing activities in the Eagle Ford, the number of light duty vehicles and idling rates per trip were based on ENVIRON's survey in the Piceance Basin of Northwestern Colorado.[229] This report contains the most comprehensive data on vehicles used for hydraulic fracturing and there was very little data available in Texas.

4.9.4 Production On-Road Emissions

Documentation on annual truck traffic per well pad during the production phase varies widely: from 2 - 3 trucks per year according to New York City's study of the Marcellus[230] to 365 trucks per year as reported by the BLM for the Pinedale Anticline Project in Wyoming.[231] Cornell University estimated only 15 truck trips per well pad in the Marcellus,[232] while San Juan Public Lands Center estimated the use of 158 truck trips in Colorado.[233]

For light duty vehicle use during production, the Tumble-weed II study in Utah reported 365 vehicles annually[234], while Jonah Infill in Wyoming stated that there were 122 light duty

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[228] Buys & Associates, Inc., Sept. 2008. "APPENDIX J: Near-Field Air Quality Technical Support Document for the West Tavaputs Plateau Oil and Gas Producing Region Environmental Impact Statement". Prepared for: Bureau of Land Management Price Field Office Littleton, Colorado. Available online: http://www.blm.gov/ut/st/en/fo/price/energy/Oil_Gas/wtp_final_eis.html. Accessed: 04/20/12.

[229] Amnon Bar-Ilan, John Grant, Rajashi Parikh, Ralph Morris, ENVIRON International Corporation, July 2011. "Oil and Gas Mobile Sources Pilot Study". Novato, California. p. 11. Available online: http://www.wrapair2.org/documents/2011-07_P3%20Study%20Report%20(Final%20July-2011).pdf. Accessed: 04/12/12.

[230] Haxen and Sawyer, Environmental Engineers & Scientists, Sept. 2009. "Impact Assessment of Natural Gas Production in the New York City Water Supply Watershed Rapid Impact Assessment Report" New York City Department of Environmental Protection. p. 47. Available online: http://www.nyc.gov/html/dep/pdf/natural_gas_drilling/rapid_impact_assessment_091609.pdf. Accessed: 04/20/12.

[231] U.S. Department of the Interior, Bureau of Land Management, Sept. 2008. "Final Supplemental Environmental Impact Statement for the Pinedale Anticline Oil and Gas Exploration and Development Project: Pinedale Anticline Project Area Supplemental Environmental Impact Statement". Sheyenne, Wyoming. pp. F51-52. Available online: http://www.blm.gov/pgdata/etc/medialib/blm/wy/information/NEPA/pfodocs/anticline/rd-seis/tsd.Par.13395.File.dat/07appF.pdf. Accessed: 04/12/12.

[232] Santoro, R.L.; R.W. Howarth; A.R. Ingraffea. 2011. Indirect Emissions of Carbon Dioxide from Marcellus Shale Gas Development. A Technical Report from the Agriculture, Energy, & Environment Program at Cornell University. June 30, 2011. Available online: http://www.eeb.cornell.edu/howarth/IndirectEmissionsofCarbonDioxidefromMarcellusShaleGasDevelopment_June302011%20.pdf Accessed: 04/02/12.

[233] BLM National Operations Center, Division of Resource Services, December, 2007. "San Juan Public Lands Center Draft Land Management Plan & Draft Environmental Impact Statement: Air Quality Impact Assessment Technical Support Document". Bureau of Land Management, San Juan Public Lands Center, Durango, Colorado. p. A-16. Available online: http://ocs.fortlewis.edu/forestplan/DEIS/pdf/120507_TSD&App%20A.pdf. Accessed: 04/03/2012.

[234] U.S. Department of the Interior, Bureau of Land Management. June 2010. "Tumbleweed II Exploratory Natural Gas Drilling Project". East City, Utah. DOI-BLM-UTG010-2009-0090-EA. p. 24 of 29. Available online: http://www.blm.gov/pgdata/etc/medialib/blm/ut/lands_and_minerals/oil_and_gas/november_2011.Par.24530.File.dat/. Accessed: 04/12/12.

vehicles used during production.[235] Data from ENVIRON's report in the Piceance Basin of Northwestern Colorado, 73.2 light duty vehicles trips annually per pad site, was used to estimate emissions from light duty vehicles during well production in the Eagle Ford. ENVIRON's report was the only study that had detailed light duty vehicle counts and idling hours.

TxDOT's estimation of 353 heavy duty truck trips per year for each well in the Barnett Shale was used to calculate heavy duty truck emissions from production in the Eagle Ford.[236] The TxDOT report was used because it contains data in Texas from a comparable area. The number of trucks provided by TxDOT match very closely to Chesapeake Energy's statement that there is one truck per well pad per day during production.[237] Data on idling rates from the ENVIRON report was used to estimate idling emissions. In the report, ENVIRON estimated that heavy duty trucks idle between 0.9 hours to 3 hours, while light duty vehicles idle approximately 2.5 hours per trip.[238]

An analysis of 66 wells in the Eagle Ford found that almost all oil and condensate was transported by truck. Only three wells transported condensate by pipeline and no oil was transported by pipeline.[239] Over time, the number of trips by trucks will decrease during production as the number of pipelines to haul product increases in the Eagle Ford. However, many of the wells will not be directly connected to the pipelines. Also, the number of truck trips will decrease over time due to steep liquid decline curves at wells in the Eagle Ford. As the well ages, production will significantly decline and fewer truck visits will be needed for each well. The parameters used to calculate emissions for each stage of the Eagle Ford are provided in Table 4-13.

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[235] Amnon Bar-Ilan, ENVIRON Corporation, June 2010. "Oil and Gas Mobile Source Emissions Pilot Study: Background Research Report". UNC-EMAQ (3-12)-006.v1. Novato, CA. p. 18. Available online: http://www.wrapair2.org/documents/2010-06y_WRAP%20P3%20Background%20Literature%20Review%20(06-06%20REV).pdf. Accessed: 04/03/12.

[236] Richard Schiller, P.E. Fort, Worth District. Aug. 5, 2010. "Barnett Shale Gas Exploration Impact on TxDOT Roadways". TxDOT, Forth Worth. Slide 18.

[237] Chesapeake Energy Corporation, 2012. "Part 1 – Drilling". Available online: http://www.askchesapeake.com/Barnett-Shale/Multimedia/Educational-Videos/Pages/Information.aspx. Accessed: 04/22/12.

[238] Amnon Bar-Ilan, John Grant, Rajashi Parikh, Ralph Morris, ENVIRON International Corporation, July 2011. "Oil and Gas Mobile Sources Pilot Study". Novato, California. pp. 11-12. Available online: http://www.wrapair2.org/documents/2011-07_P3%20Study%20Report%20(Final%20July-2011).pdf. Accessed: 04/12/2012.

[239] Railroad Commission of Texas. "Specific Lease Query". Austin, Texas. Available online: http://webapps.rrc.state.tx.us/PDQ/quickLeaseReportBuilderAction.do. Accessed 06/01/2012.

Table 4-13: On-Road Vehicle Parameters used in the Eagle Ford

Vehicle Type	Parameter	Pad Construction	Drilling	Hydraulic Fracturing and Completion	Production
Heavy Duty Diesel Trucks (HDDV)	Number/pad	70	187	807	353/year
	Distance (miles)	50	50	50	22
	Speed (mph)	35	35	35	35
	Idling Hours/Trip	0.4	0.7	1.1	0.9
Light Duty Trucks (LDT)	Number/pad	12.86 (Construction) 69.60 (Employees)	68.1 (Rig and Eq.), 66 (Employees)	41 (Eq. and Supplies), 86.7 (Employees)	68.5 (Production), 4.7 (Maintenance)
	Distance (miles)	To the nearest Town	To the nearest Town	To the nearest Town	To the nearest Town
	Speed (mph)	35	35	35	35
	Idling Hours/Trip	2.00 (Eq. and supplies), 2.15 (Employees)	1.55 (Rig and Eq.), 2.1 (Employees)	2.0 (Eq. and Supplies), 2.1 (Employees)	2.5 (Production), 2.55 (Maintenance)

4.9.5 *On-Road Emission Factors*

Light duty truck emission factors were based on MOVES2010b categories of gasoline and diesel passenger trucks and light commercial trucks (Table 4-14).[240] For heavy duty trucks, emissions were calculated using local data and emissions factors from MOVES for diesel short haul combination trucks. Combination short-haul trucks are classified in MOVES as trucks that conduct the majority of their operations within 200 miles of home base.[241] Idling emissions factors for heavy duty trucks and light duty trucks were provided by EPA.[242]

On-road VOC, NO_X, and CO emission factors for vehicles were calculated using the formula provided below (Equation 4-9), while idling emissions were calculated using formula in Equation 4-10. The inputs into the formula were obtained from local data, MOVES output emission factors, TxDOT, and data from ENVIRON's survey in Colorado. Data from the Railroad Commission of Texas on average distance from the well site to the nearest town was used as an approximation of the traveling distance for light duty vehicles trips by county because resources and housing are usually centrally located in towns.

NO_X emission reductions from the use of TxLED were included in the calculations of on-road emissions. According to TCEQ, "TxLED requirements are intended to result in reductions in NO_X emissions from diesel engines. Currently, reduction factors of 5.7% (0.057) for on-road use and 7.0% (0.07) for non-road use have been accepted as a NO_X reduction estimate resulting from use of TxLED fuel. However, this reduction estimate is subject to change, based on the standards accepted by the EPA for use in the Texas State Implementation Plan (SIP)."[243]

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240 Office of Transportation and Air Quality, August 2010. "MOVES". U.S. Environmental Protection Agency, Washington, DC. Available online: http://www.epa.gov/otaq/models/moves/index.htm. Accessed: 04/02/12.

241 John Koupal, Mitch Cumberworth, and Megan Beardsley, June 9, 2004. "Introducing MOVES2004, the initial release of EPA's new generation mobile source emission model". U.S. EPA Office of Transportation and Air Quality, Assessment and Standards Division. Ann Arbor, MI. Available online: http://www.epa.gov/ttn/chief/conference/ei13/ghg/koupal.pdf. Accessed: 07/11/11.

242 Brzezinski, Office of Transportation and Air Quality, U.S. Environmental Protection Agency, Washington, DC, e-mail dated 05/19/12.

243 TCEQ, July 24, 2012. "Texas Emissions Reduction Plan (TERP) Emissions Reduction Incentive Grants Program". Austin, Texas. Available online: http://www.tceq.texas.gov/assets/public/implementation/air/terp/techsup/2012onvehicle_ts.pdf. Accessed 8/27/13.

Table 4-14 MOVES2011b 2011 Ozone Season Day Emission Factors for On-Road Vehicles in Eagle Ford Counties, 2012 and 2018

Vehicle Type	Fuel Type	Location	Speed	2012			2018		
				VOC EF	NO_X EF	CO EF	VOC EF	NO_X EF	CO EF
Light Duty Trucks	Diesel and Gasoline	On-Road	35 mph	1.00 g/mile	1.55 g/mile	12.85 g/mile	0.62 g/mile	0.97 g/mile	9.29 g/mile
		Idling	-	4.09 g/hr	11.11 g/hr	N/A	4.09 g/hr	11.11 g/hr	N/A
Heavy Duty Trucks	Diesel	On-Road	35 mph	0.45 g/mile	8.43 g/mile	2.64 g/mile	0.37 g/mile	3.73 g/mile	1.26 g/mile
		Idling	-	40.09 g/hr	177.11 g/hr	88.67 g/hr	29.88 g/hr	170.98 g/hr	88.75 g/hr

N/A – not available from MOVES2010b and not provided by EPA

Equation 4-9, Ozone season day on-road emissions during pad construction

$E_{pad.road.ABC}$ = NUM_{BC} x $TRIPS_{A.TXDOT}$ x ($DIST_{B.RCC}$ x 2) x (1 - $TxLED_{TCEQ}$) x $OEF_{A.MOVES}$ / $WPAD_{B.RCC}$ / 907,184.74 grams per ton / 365 days/year

Where,

- $E_{pad.road.ABC}$ = Ozone season day NO_X, VOC, or CO emissions from type A on-road vehicles in county B for Eagle Ford development type C wells (Gas or Oil)
- NUM_{BC} = Annual number of wells drilled in county B for Eagle Ford development type C wells (from Schlumberger Limited)
- $TRIPS_{A.TXDOT}$ = Annual number of trips for vehicle type A, 70 for heavy duty trucks (from TxDOT 's Barnett report) and 82.46 for light duty trucks in Table 4-13 (from ENVIRON's Colorado report)
- $DIST_{B.RCC}$ = Distance, 25 miles (25 miles one way, 50 miles per round trip) for heavy duty trucks and to the nearest town for light duty vehicles in county B (from Railroad Commission of Texas)
- $TxLED_{TCEQ}$ = On-road emission reductions from TxLED, 0.057 for NO_X from Heavy Duty Diesel Trucks, 0.0 for VOC, 0.0 for CO, and 0.0 for Gasoline Light Duty Vehicles (from TCEQ)
- $OEF_{A.MOVES}$ = NO_X, VOC, or CO on-road emission factor for vehicle type A in Table 4-14 (from MOVES2010b Model)
- $WPAD_{B.RCC}$ = Number of wells per pad for county B (calculated from data provided by the Railroad Commission of Texas)

Sample Equation: 2012 Wilson County NO_X emissions for Heavy Duty Truck Exhaust during the construction of oil well pads

$E_{pad.road.ABC}$ = 62 oil wells x 70 trips x (25 miles x 2) x (1 - 0.057) x 8.43 g/mile / 1.1 wells per well pad / 907,184.74 grams per ton / 365 days/year

= 0.005 tons of NO_X per day from heavy duty truck exhaust in Wilson County during the construction of oil well pads

Equation 4-10, Ozone season day idling emissions during pad construction

$E_{pad.idling.ABC}$ = NUM_{BC} x $TRIPS_{A.TXDOT}$ x $IDLE_A$ x (1 - $TxLED_{TCEQ}$) x $IEF_{A.EPA}$ / $WPAD_{BC.RCC}$ / 907,184.74 grams per ton / 365 days/year

Where,

- $E_{pad.idling.ABC}$ = Ozone season day NO_X, VOC, or CO emissions from idling vehicles in county B for Eagle Ford development type C wells (Gas or Oil)
- NUM_{BC} = Annual number of wells drilled in county B for Eagle Ford development type C wells (from Schlumberger Limited)
- $TRIPS_{A.TXDOT}$ = Annual number of trips for vehicle type A, 70 for heavy duty trucks (from TxDOT 's Barnett report), 12.86 for light duty trucks for equipment, and 69.6 light duty trucks for employees in Table 4-13 (from ENVIRON's Colorado report)
- $IDLE_A$ = Number of idling hours/trip for vehicle type A, 0.4 hours for heavy duty trucks, 2.0 for light duty trucks for equipment, and 2.15 light duty trucks for employees (from ENVIRON's Colorado report)
- $TxLED_{TCEQ}$ = On-road emission reductions from TxLED, 0.057 for NO_X from Heavy Duty Diesel Trucks, 0.0 for VOC, 0.0 for CO, and 0.0 for Gasoline Light Duty Vehicles (from TCEQ)
- $IEF_{A.EPA}$ = NO_X, VOC, or CO idling emission factor for vehicle type A in Table 4-14 (from EPA based on the MOVES model)

$WPAD_{B.RCC}$ = Number of wells per pad for county B (calculated from data provided by the Railroad Commission of Texas)

Sample Equation: 2012 NO_X emissions from Heavy Duty Truck Idling in Wilson County during the construction of oil well pads

$E_{pad.road.ABC}$ = 62 oil wells x 70 trips x 0.4 hours idling x (1 - 0.057) x 177.11 g/hour / 1.1 wells per well pad / 907,184.74 grams per ton / 365 days/year

= 0.001 tons of NO_X per day from heavy duty truck idling in Wilson County during the construction of oil well pads

4.9.6 Temporal Adjustment of On-Road Emissions

Temporal distribution for on-road vehicles in the Eagle Ford are based on North Central Texas Council of Governments work on a heavy duty truck mobile source inventory in the Barnett Shale. "To develop a diurnal distribution of emissions, NCTCOG staff utilized automatic traffic recorder (ATR) data which distributes volume of trips across 24 hours in a day. Use of this data is standard NCTCOG process for travel demand modeling. NCTCOG staff did not expect industry operating patterns to vary depending on school or summer seasons. Indeed, survey results did not indicate any seasonal variation in operation. Therefore, Annual Average Daily adjustment factors were applied with no seasonal adjustment. The diurnal distribution is derived from vehicle classification counts of multi-unit trucks from year 2004."[244] Figure 4-7 shows the diurnal distribution for multi-unit trucks from the Barnett Shale used to temporally allocate on-road emissions in the Eagle Ford.

4.10 Non-Road and Area Source Emissions in the Eagle Ford

A variety of data sources were used to estimate emissions from Eagle Ford oil and gas production. Whenever possible, local data was used to calculate emissions and project future production. Counts of drill rigs operating in the Eagle Ford and number of wells drilled are provided by Schlumberger.[245] Similarly, well characteristics and production data were collected from Schlumberger and the Railroad Commission of Texas[246]. Non-road equipment was calculated using local industry data, emission factors from the TexN model, manufacturers' information, TCEQ, and the results of surveys conducted by the Texas Center for Applied Technology (TCAT).

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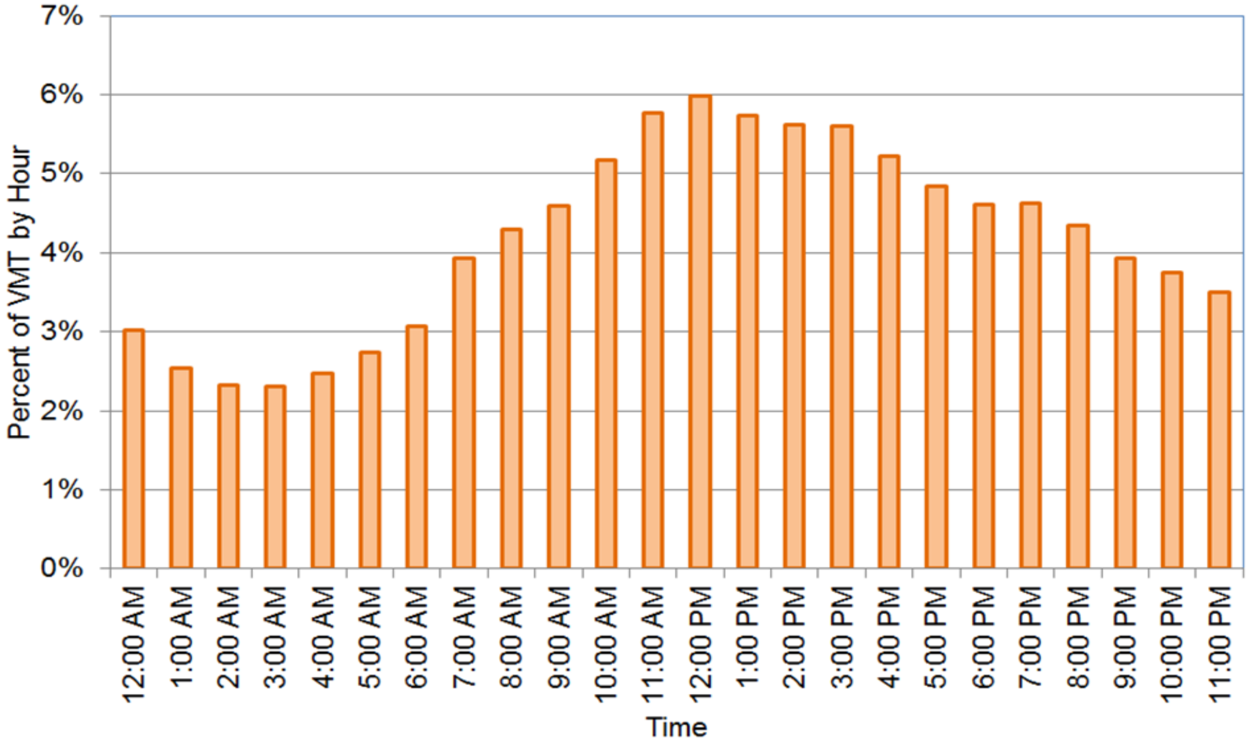
[244] Lori Clark, Shannon Stevenson, and Chris Klaus North Central Texas Council of Governments, August 2012. "Development of Oil and Gas Mobile Source Inventory in the Barnett Shale in the 12-County Dallas-Fort Worth Area". Arlington, Texas. Texas Commission on Environmental Quality Grant Number: 582-11-13174. pp. 34-35. Available online: http://www.nctcog.org/trans/air/barnettshale.asp. Accessed 01/23/13.

[245] Schlumberger Limited. "STATS Rig Count History". Available online: http://stats.smith.com/new/history/statshistory.htm. Accessed: 04/21/12.

[246] Railroad Commission of Texas, April 3, 2012. "Eagle Ford Information". Austin, Texas. Available online http://www.rrc.state.tx.us/eagleford/index.php. Accessed: 05/01/12.

Figure 4-7: Distribution of Multi-Unit Trucks by Time of Day in the Barnett Shale



Production emissions calculations were based on data produced by TCEQ's Barnett Shale special inventory. Other sources for production emissions included local industry data, ERG's Texas emission inventory[247], ENVIRONS CENRAP emission inventory[248], and AP42 emission factors for flares[249].

4.11 Eagle Ford Projection Scenarios

Emissions from Eagle Ford production are projected to continue growing as oil and gas development increases over the next few years. Projections of activity in the Eagle Ford were developed using a methodology similar to ENVIRON's Haynesville Shale emission inventory which was based on three scenarios: low development, moderate development, and high

[247] Mike Pring, Daryl Hudson, Jason Renzaglia, Brandon Smith, and Stephen Treimel, Eastern Research Group, Inc. Nov. 24, 2010. "Characterization of Oil and Gas Production Equipment and Develop a Methodology to Estimate Statewide Emissions". Prepared for: Texas Commission on Environmental Quality Air Quality Division. Austin, Texas. Available online: http://www.tceq.texas.gov/assets/public/implementation/air/am/contracts/reports/ei/5820784003FY1026-20101124-ergi-oilGasEmissionsInventory.pdf. Accessed: 04/10/12.

[248] Amnon Bar-Ilan, Rajashi Parikh, John Grant, Tejas Shah, Alison K. Pollack, ENVIRON International Corporation. Nov. 13, 2008. "Recommendations for Improvements to the CENRAP States' Oil and Gas Emissions Inventories". Novato, CA. Available online: http://www.wrapair.org/forums/ogwg/documents/2008-11_CENRAP_O&G_Report_11-13.pdf. Accessed: 04/30/12.

[249] EPA, Sept. 1991. "AP42: 13.5 Industrial Flares". Available online: http://www.epa.gov/ttn/chief/ap42/ch13/final/c13s05.pdf. Accessed 05/16/2012.

development.[250] The scenarios cover a range of potential growth in the Eagle Ford based on best available information including local data, industrial projections, and projected price of petroleum products. Projected VOC, NO_X, and CO emissions are derived by drilling activity in the region and production estimations for each well. Since hydraulic fracturing of oil reserves on a wide scale is a relatively new occurrence, activity and emission projections will have a high uncertainty factor.

Daily on-road emissions from the Eagle Ford are estimated to be 6.935 tons of NO_X and 0.908 tons of VOC in 2012 (Table 4-15). NO_X emissions from these vehicles are expected to be from 6.519 to 10.449 tons in 2018 while VOC emissions are expected to be from 0.961 to 1.523 tons. Heavy duty trucks are the main source of NO_X emissions from on-road vehicles operating in the Eagle Ford.

Figure 4-8 provides estimated 2018 NO_X emissions by source type under the three Eagle Ford projection scenarios, while Figure 4-9 shows estimated 2018 VOC emissions for the three scenarios. Mid-steam sources, wellhead compressors, flares, drill rigs, and on-road vehicles are the major sources of NO_X emissions. Total NO_X emissions are 87.5 tons per day for the low scenario and 152.6 tons per day under the high scenario. VOC emissions are primarily from storage tanks, mid-stream sources, flares, and fugitive sources. Under the development scenarios, VOC emissions vary from 144.2 tons per day to 276.9 tons per day.

[250] John Grant, Lynsey Parker, Amnon Bar-Ilan, Sue Kemball-Cook, and Greg Yarwood, ENVIRON International Corporation. August 31, 2009. “Development of an Emission Inventory for Natural Gas Exploration and Production in the Haynesville Shale and Evaluation of Ozone Impacts”. Novato, CA. p. 13. Available online: http://www.netac.org/UserFiles/File/NETAC/9_29_09/Enclosure_2b.pdf. Accessed: 04/19/12.

Table 4-15: Daily On-Road Vehicles Emissions in the Eagle Ford

Phase	Scenario	Heavy Duty Trucks On-Road		Heavy Duty Trucks Idling		Light Duty Trucks On-Road		Light Duty Trucks Idling	
		VOC	NO_X	VOC	NO_X	VOC	NO_X	VOC	NO_X
Pad Construction	2012	0.015	0.241	0.009	0.041	0.016	0.025	0.006	0.016
	2018 Low	0.004	0.065	0.004	0.024	0.006	0.009	0.004	0.010
	2018 Moderate	0.007	0.103	0.007	0.038	0.010	0.015	0.006	0.015
	2018 High	0.010	0.140	0.009	0.051	0.013	0.021	0.008	0.021
Drilling	2012	0.040	0.644	0.043	0.189	0.026	0.040	0.008	0.022
	2018 Low	0.012	0.174	0.020	0.112	0.010	0.015	0.005	0.014
	2018 Moderate	0.019	0.275	0.031	0.177	0.016	0.024	0.008	0.021
	2018 High	0.026	0.375	0.042	0.241	0.022	0.034	0.011	0.029
Hydraulic Fracturing and Completion	2012	0.171	2.779	0.295	1.284	0.025	0.039	0.009	0.024
	2018 Low	0.052	0.752	0.132	0.758	0.009	0.014	0.005	0.015
	2018 Moderate	0.082	1.189	0.209	1.197	0.015	0.023	0.009	0.023
	2018 High	0.111	1.620	0.285	1.631	0.021	0.033	0.012	0.032
Production	2012	0.051	0.822	0.162	0.706	0.024	0.037	0.010	0.026
	2018 Low	0.104	1.517	0.497	2.842	0.057	0.090	0.040	0.108
	2018 Moderate	0.120	1.741	0.570	3.261	0.066	0.103	0.046	0.124
	2018 High	0.142	2.071	0.678	3.879	0.079	0.123	0.054	0.148
Total	2012	0.276	4.485	0.509	2.220	0.090	0.141	0.032	0.088
	2018 Low	0.172	2.509	0.653	3.735	0.082	0.129	0.054	0.146
	2018 Moderate	0.227	3.308	0.817	4.673	0.106	0.166	0.068	0.184
	2018 High	0.289	4.206	1.014	5.802	0.135	0.211	0.085	0.229

Figure 4-8: Daily NO_X Emissions in the Eagle Ford for the Three Scenarios, 2018

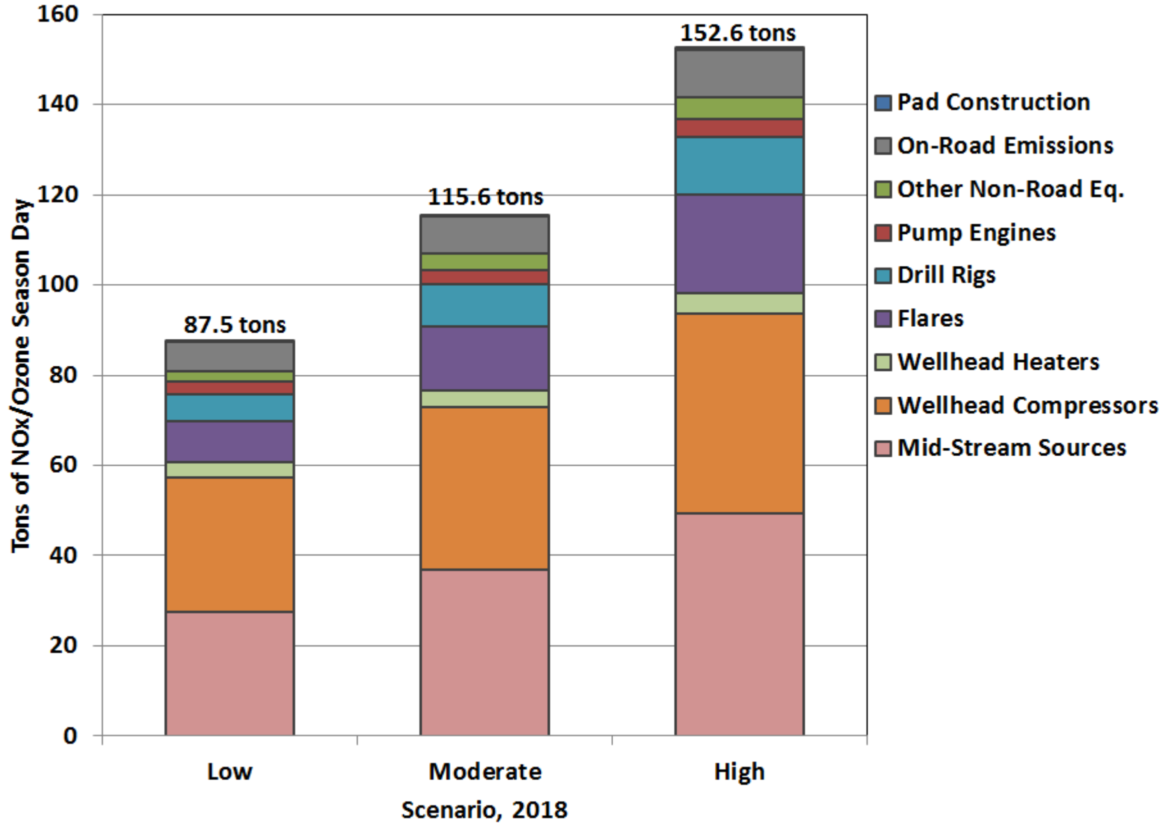
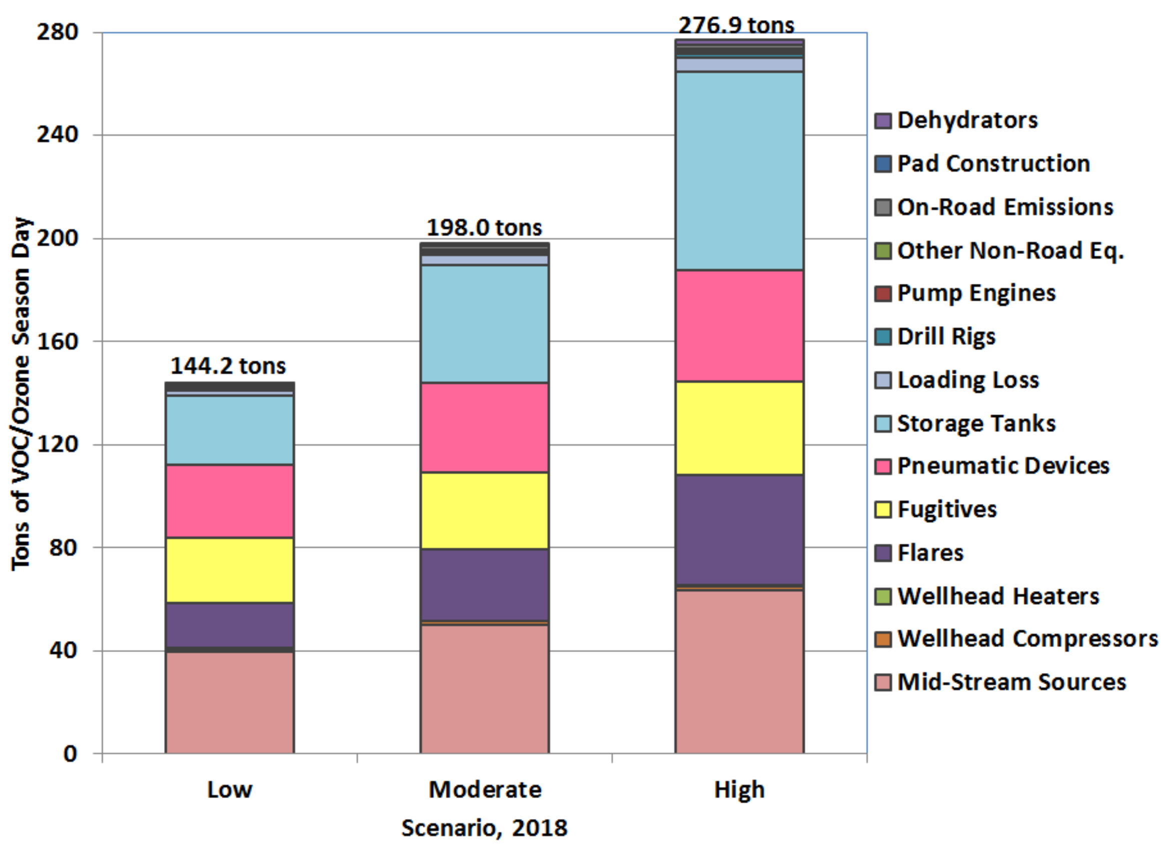


Figure 4-9: Daily VOC Emissions in the Eagle Ford for the Three Scenarios, 2018



4.12 Summary of the 2012 and 2018 Projection Year Emission Inventory Development

Projected NO_X and VOC emissions (tons/day) for the San Antonio-New Braunfels MSA region are provided in Figure 4-10 and Figure 4-11. Emissions are lower on Saturday and Sunday compared to weekdays. Estimated NO_X emissions are significantly lower in 2018: emissions decreased from 273.9 tons per weekday in 2006 to 134.0 tons per weekday in 2018. VOC emissions are reduced from 232.7 tons per weekday in 2006 to 208.4 tons per weekday in 2018.

The largest source of NO_X emissions in 2006 are on-road vehicles, 134.7 tons per weekday, followed by point, 71.3 tons per weekday, and non-road, 43.6 tons per weekday (Table 4-16). By 2018, the largest sources of NO_X emissions are point, 50.8 tons per weekday, followed by on-road, 43.0 tons per weekday, and area, 15.9 tons per weekday. As expected, the largest contributors of VOC emissions are area sources: 147.2 tons per weekday in 2006 and 153.8 tons per weekday in 2018 (Table 4-17). Other significant sources of VOC emissions in the San Antonio-New Braunfels MSA are on-road, 22.1 tons per weekday in 2018, and non-road, 19.0 tons per weekday in 2018. Eagle Ford emissions are not a large contributor to emissions, 4.0 tons of NO_X and 7.4 tons of VOC per day under the moderate scenario in 2018, in the San Antonio-New Braunfels MSA because most of the production is occurring outside of the MSA.

Figure 4-10: NO_X Emissions (tons/day) for the San Antonio-New Braunfels MSA, 2006, 2012, and 2018 Eagle Ford Moderate Scenario

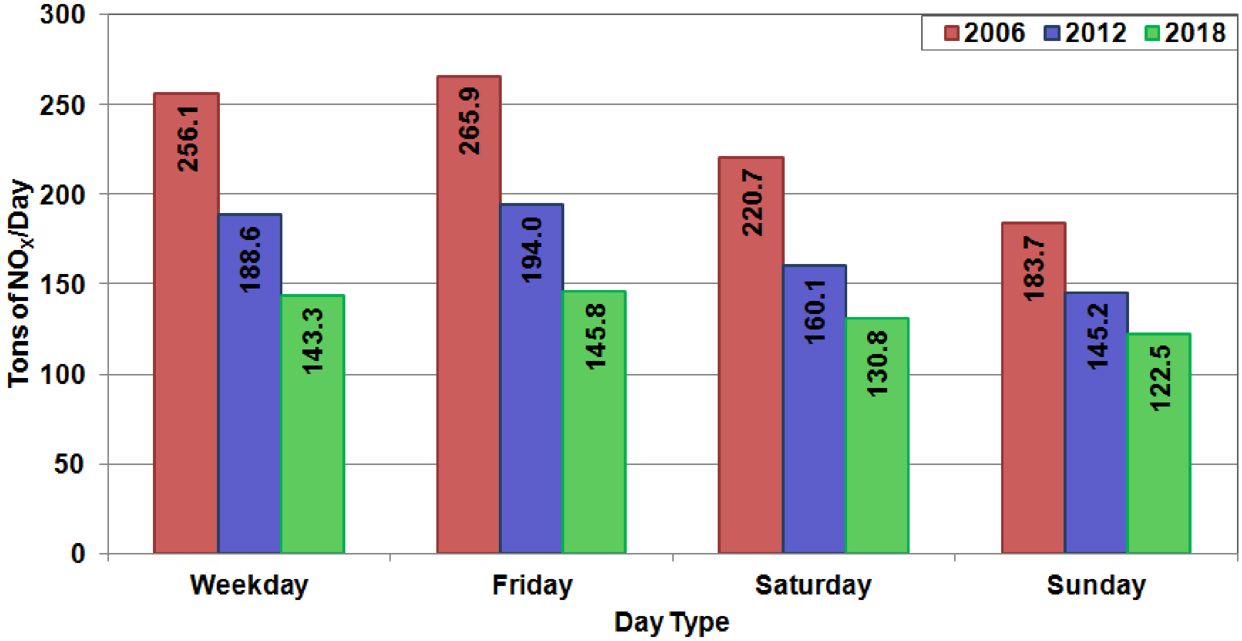


Figure 4-11: VOC Emissions (tons/day) for the San Antonio-New Braunfels MSA, 2006, 2012, and 2018 Eagle Ford Moderate Scenario

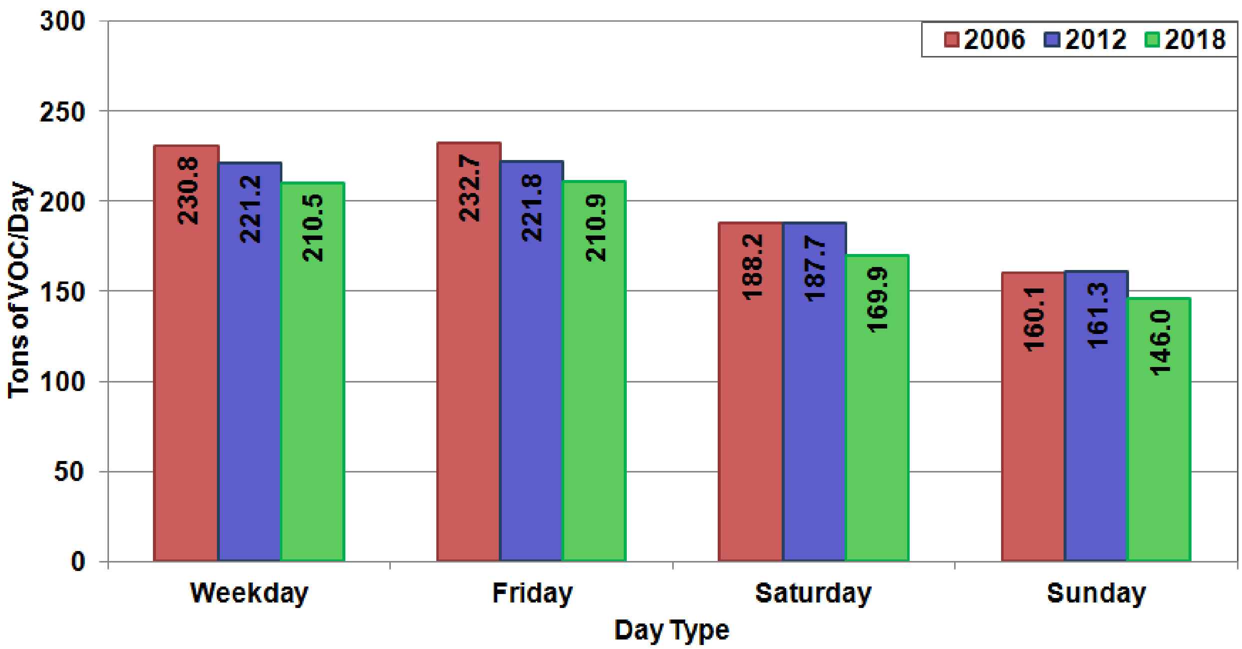


Table 4-16: NO_X Emissions (tons/day) for the San Antonio-New Braunfels MSA, 2012 and 2018 Eagle Ford Moderate Scenario

Year	Day of Week	On-Road	Point	Area	Non-Road	Off-Road	Eagle Ford	Total NO_X
2006	Weekday	134.7	71.3	16.5	25.7	7.9	0.0	256.1
	Friday	144.4	71.3	16.5	25.7	7.9	0.0	265.9
	Saturday	101.2	71.3	15.0	29.7	3.4	0.0	220.7
	Sunday	81.8	71.3	13.4	13.7	3.4	0.0	183.7
2012	Weekday	75.4	68.1	15.6	19.6	6.0	3.9	188.6
	Friday	80.8	68.1	15.6	19.6	6.0	3.9	194.0
	Saturday	57.8	68.1	13.9	13.5	2.9	3.9	160.1
	Sunday	47.2	68.1	12.3	11.0	2.9	3.9	145.2
2018	Weekday	41.4	65.3	15.9	11.3	5.2	4.1	143.3
	Friday	44.0	65.3	15.9	11.3	5.2	4.1	145.8
	Saturday	31.7	65.3	14.2	8.5	7.1	4.1	130.8
	Sunday	26.1	65.3	12.4	7.5	7.1	4.1	122.5

Table 4-17: VOC Emissions (tons/day) for the San Antonio-New Braunfels MSA, 2012 and 2018 Eagle Ford Moderate Scenario

Year	Day of Week	On-Road	Point	Area	Non-Road	Off-Road	Eagle Ford	Total VOC
2006	Weekday	49.2	8.3	147.2	24.5	1.6	0.0	230.8
	Friday	51.1	8.3	147.2	24.5	1.6	0.0	232.7
	Saturday	39.8	8.3	94.6	45.0	0.5	0.0	188.2
	Sunday	37.6	8.3	73.4	40.3	0.5	0.0	160.1
2012	Weekday	32.1	6.6	151.2	27.1	1.1	3.1	221.2
	Friday	32.7	6.6	151.2	27.1	1.1	3.1	221.8
	Saturday	27.2	6.6	95.7	54.2	0.9	3.1	187.7
	Sunday	25.5	6.6	73.7	51.5	0.9	3.1	161.3
2018	Weekday	21.8	7.5	153.8	19.0	0.9	7.4	210.5
	Friday	22.2	7.5	153.8	19.0	0.9	7.4	210.9
	Saturday	18.6	7.5	97.4	38.0	1.0	7.4	169.9
	Sunday	17.6	7.5	74.6	37.9	1.0	7.4	146.0

4.13 Emission Inventory Tile Plots

The graphic software, Package for Analysis and Visualization of Environmental data (PAVE),[251] was used to display EPS3 formatted 4-km fine grid emissions by source type. Tile plots are used to visually verify the distribution of emissions in the photochemical model compared to actual locations. Also, hourly tile plots were checked to make sure there were no unusual patterns of emissions. Through the use of emission tile plots, the photochemical modeling emission inputs were evaluated spatially for accuracy using EPA modeling guidance.[252]

Non-road/off-road NO_X emissions tile plots are provided in Figure 4-12 for 2006, 2012, and 2018, while VOC plots are provided in Figure 4-13. These plots show concentrations of high NO_X and VOC emissions in the population centers of Eastern Texas. The highest emissions are in Houston, Dallas, San Antonio, and Austin, while the less populated counties in west and south Texas tend to have the lowest emissions. In the 2018 projected emission inventory, non-road/off road emissions decreased in the urban areas and across the 4km modeling domain. Area source NO_X and VOC emissions are concentrated in the urban areas and oil producing regions of Texas. When comparing projection years, area source emissions are similar for 2006, 2012, and 2018 (Figure 4-14 and Figure 4-15).

On-road NO_X emissions for 2006, 2012, and 2018 are presented in Figure 4-16 and on-road VOC emissions are provided in Figure 4-17. The largest concentrations of on-road emissions are in Dallas, Houston, Austin, and San Antonio. On-road emissions are also concentrated in other urban areas and along major highways including I-10, I-35, and I-37. There is a significant decrease in NO_X and VOC emissions from on-road sources in the 2018 projection emission inventory. The main reason for these decreases are emissions standards for both gasoline and diesel engines that are significantly stricter for cars built after 2006.

Figure 4-18 and Figure 4-19 shows NO_X and VOC low elevation point source emissions tile plots for each modeling year. As shown on the three plots, point source emissions are highest in Houston, Beaumont, Dallas, and Corpus Christi. These urban areas have the highest concentrations of large industrial point sources. There are also numerous low level off-shore point sources in the 4km grid. Eagle Ford emission inventory plots (Figure 4-20 and Figure 4-21) show no emissions in 2006 and NO_X and VOC emissions across the 25 county Eagle Ford development in 2012 and 2018. Emissions from Eagle Ford are concentrated southeast, south and southwest of the San Antonio-New Braunfels MSA.

[251] The University of North Carolina at Chapel Hill, UNC Institute for the Environment. “PAVE User's Guide - Version 2.3”. Available online http://www.ie.unc.edu/cempd/EDSS/pave_doc/index.shtml#TOC. Accessed 08/07/13.
[252] EPA, April 2007. “Guidance on the Use of Models and Other Analyses for Demonstrating Attainment of Air Quality Goals for Ozone, PM2.5, and Regional Haze.” Research Triangle Park, NC: Office of Air Quality Planning and Standards.” Available online. http://www.epa.gov/scram001/guidance/guide/final-03-pm-rh-guidance.pdf. Accessed 08/07/13.

Emissions for offshore sources, Figure 4-22, shows NO_X emissions concentrated along main shipping channels to Corpus Christi, Galveston, Houston, Beaumont, and Lake Charles. These cities have major port facilities for transporting raw materials and finished products. Emissions from Mexico, shown in Figure 4-23, are concentrated in Nuevo Laredo and along Mexico's Highway 85. Emissions for off-shore and Mexican sources remain the same for each projection year.

Figure 4-12: Non-Road/Off-Road NO_X Emissions 4-km grid Tile Plots, Weekday, 12:00PM – 1:00PM (Grams Mole/Hr)

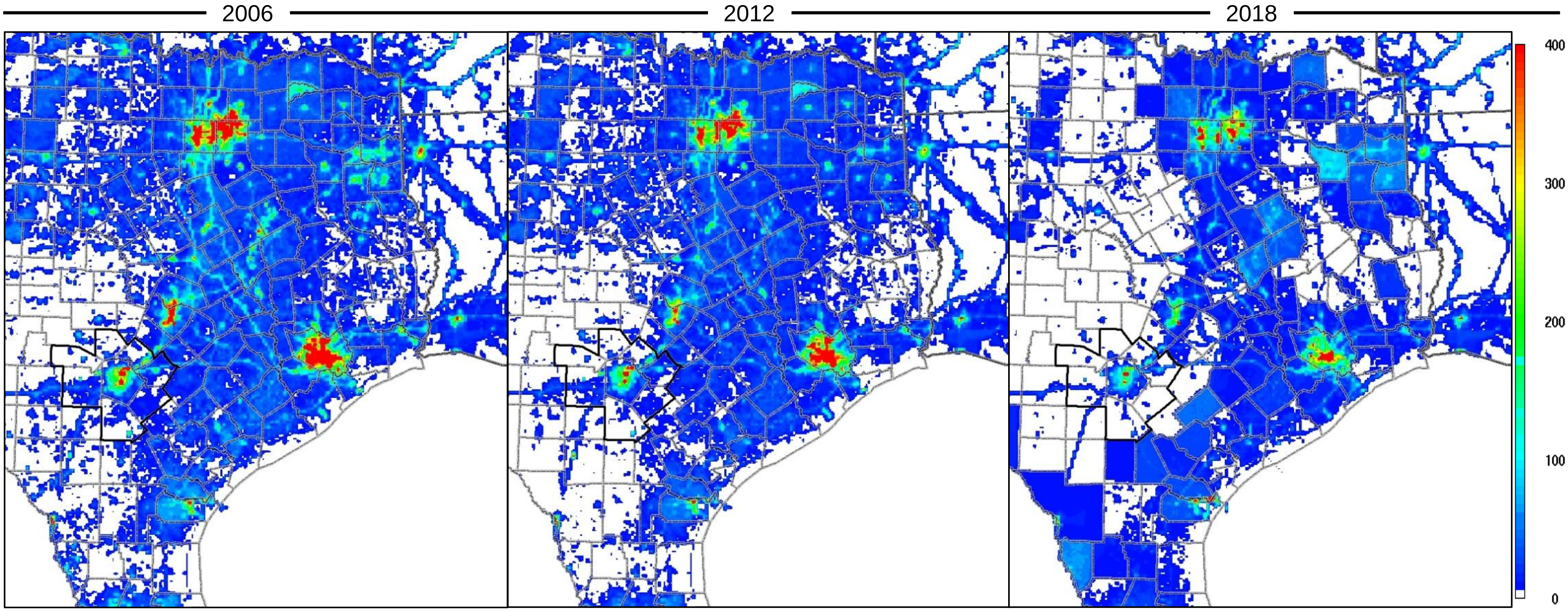


Figure 4-13: Non-Road/Off Road VOC Emissions 4-km grid Tile Plots, Weekday, 12:00PM – 1:00PM (Grams Mole/Hr)

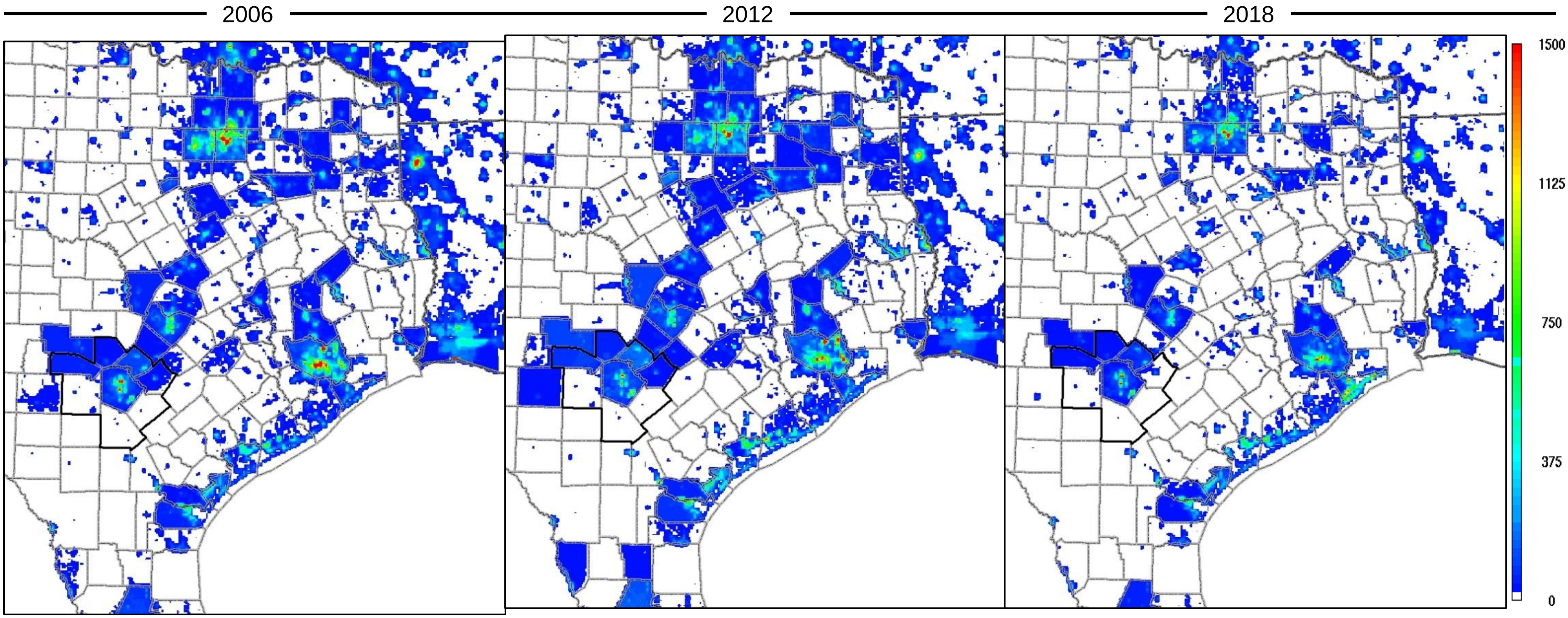


Figure 4-14: Area NO_X Emissions 4-km grid Tile Plots, Weekday, 12:00PM – 1:00PM (Grams Mole/Hr)

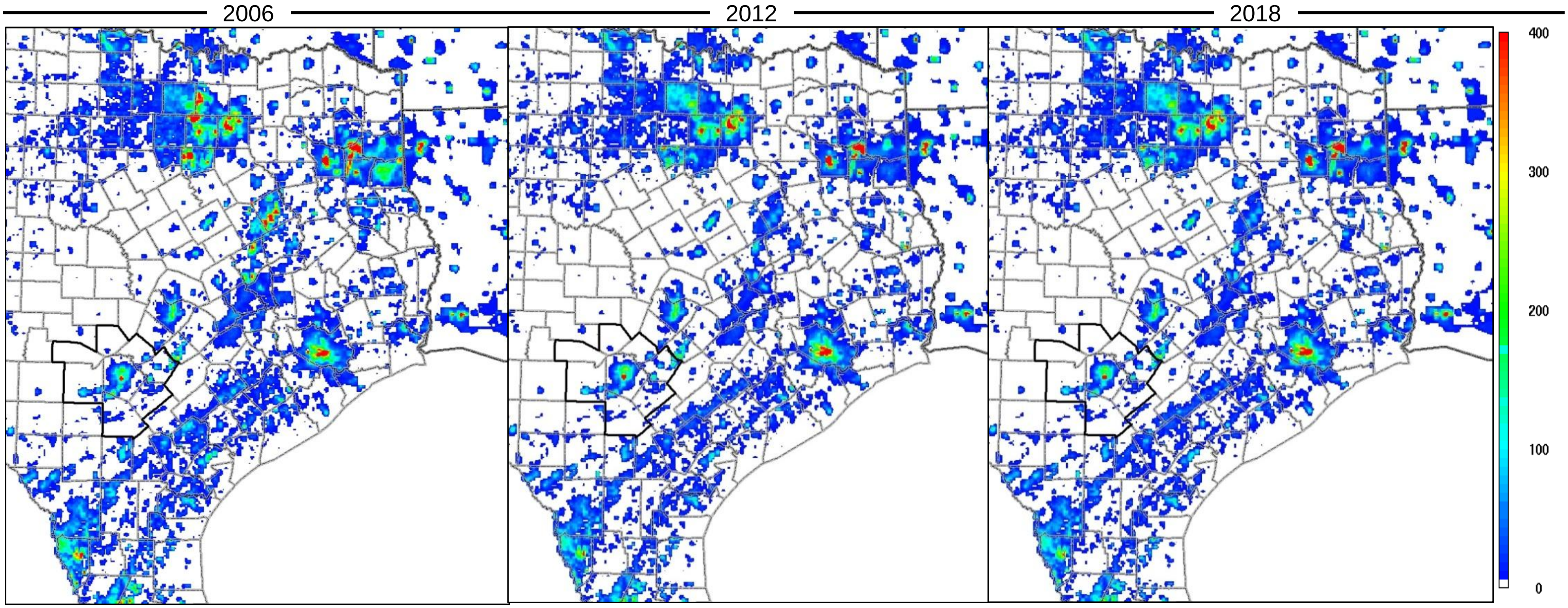


Figure 4-15: Area VOC Emissions 4-km grid Tile Plots, Weekday, 12:00PM – 1:00PM (Grams Mole/Hr)

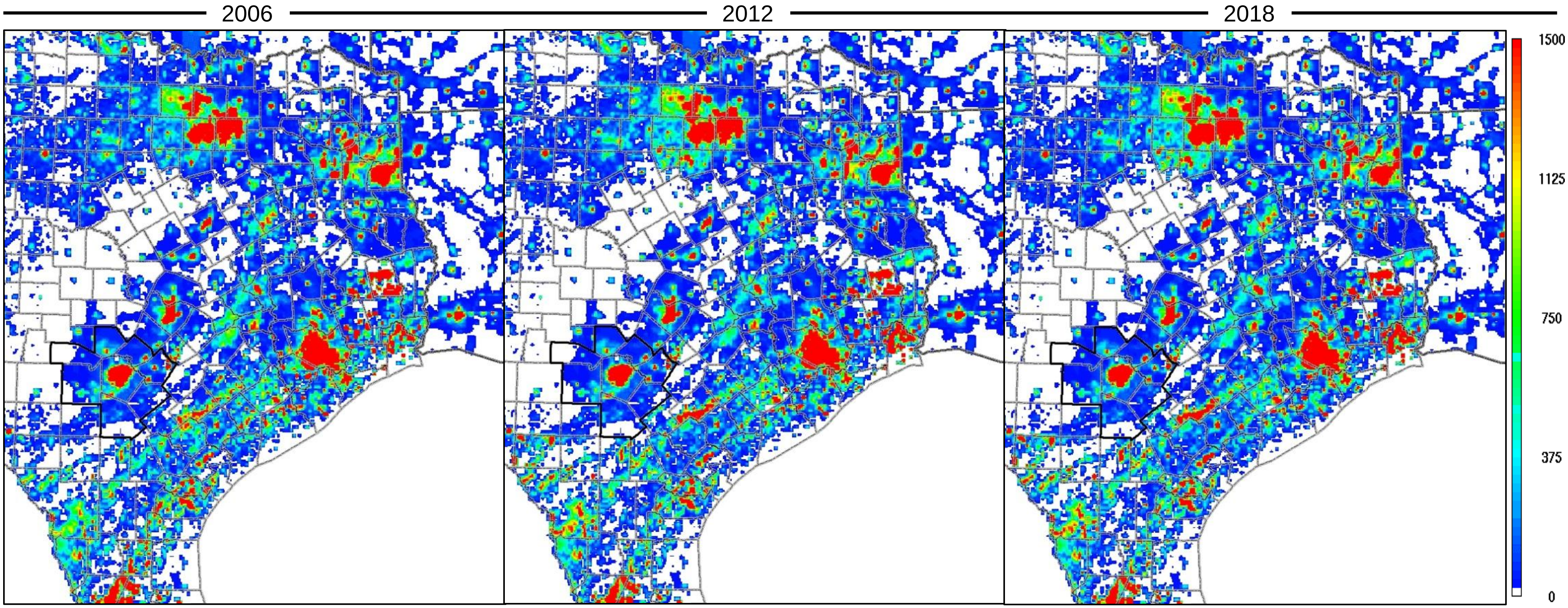


Figure 4-16: On-Road NO_X Emissions 4-km grid Tile Plots, Weekday, 12:00PM – 1:00PM (Grams Mole/Hr)

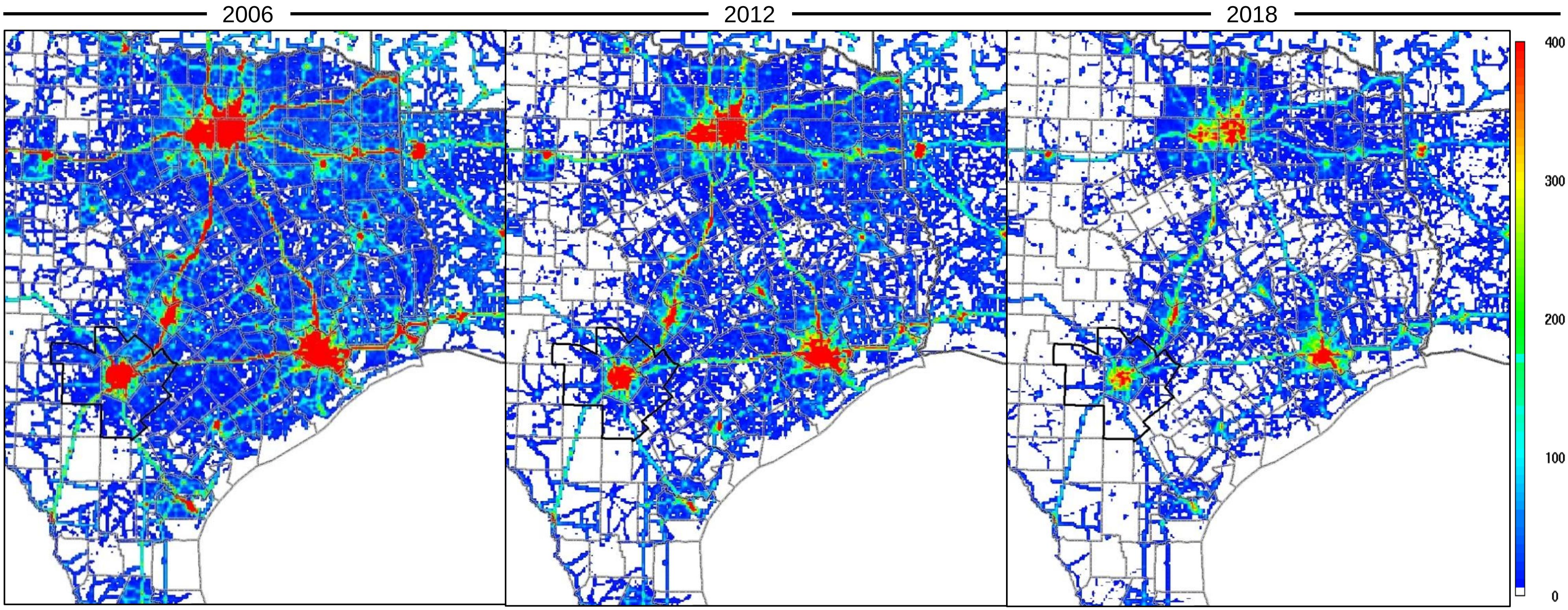


Figure 4-17: On-Road VOC Emissions 4-km grid Tile Plots, Weekday, 12:00PM – 1:00PM (Grams Mole/Hr)

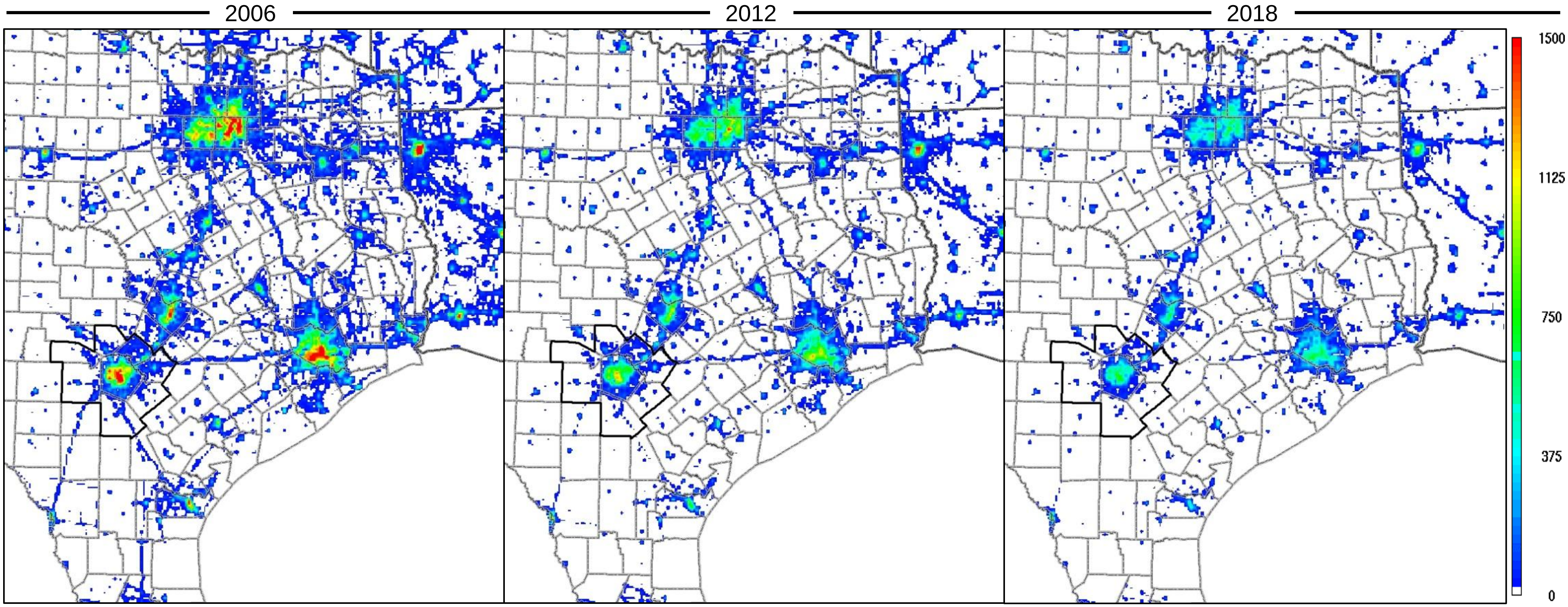


Figure 4-18: Low Point NO_X Emissions 4-km grid Tile Plots, Weekday, 12:00PM – 1:00PM (Grams Mole/Hr)

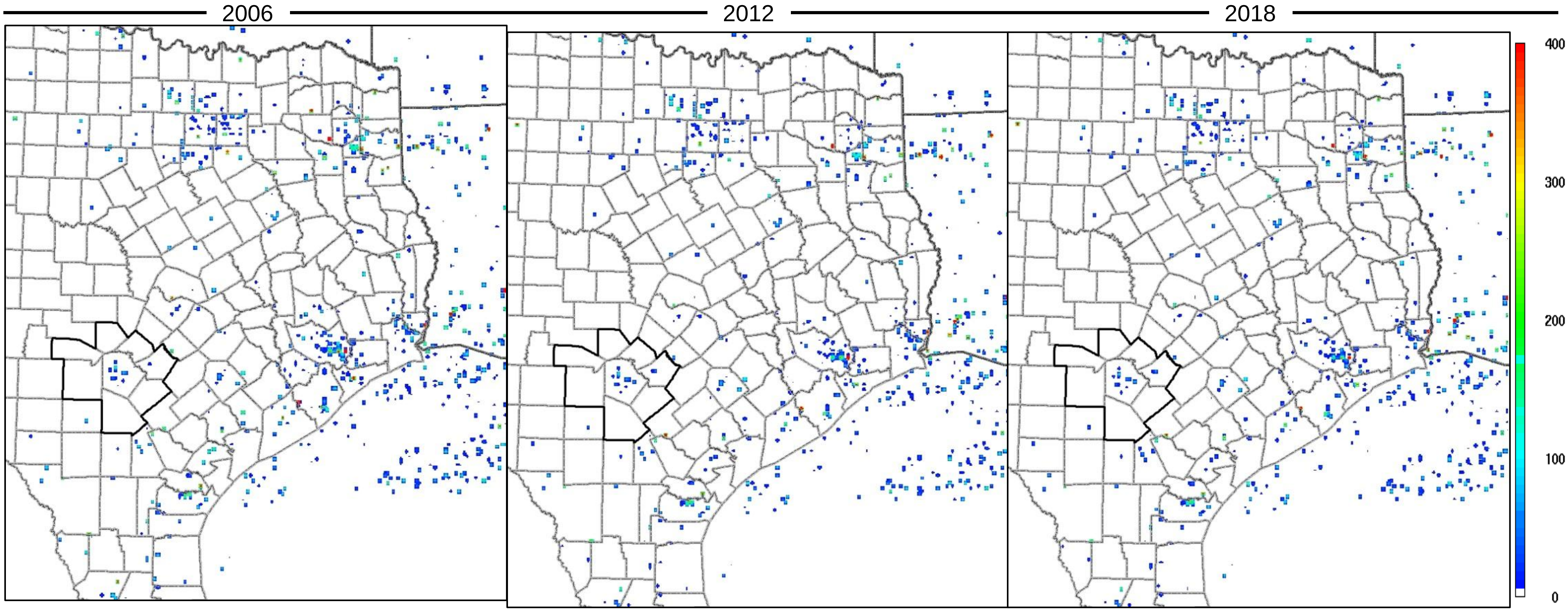


Figure 4-19: Low Point VOC Emissions 4-km grid Tile Plots, Weekday, 12:00PM – 1:00PM (Grams Mole/Hr)

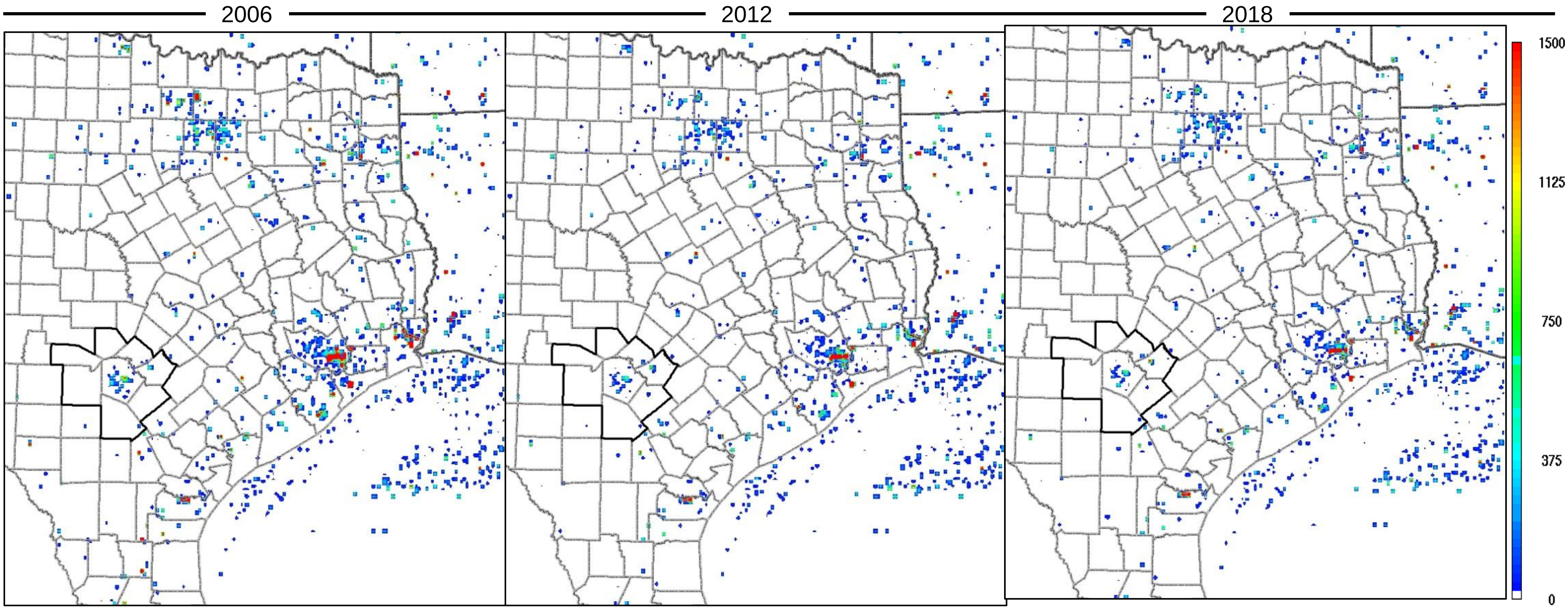


Figure 4-20: Eagle Ford NO_X Emissions 4-km grid Tile Plots, Moderate Scenario, Weekday, 12:00PM – 1:00PM (Grams Mole/Hr)

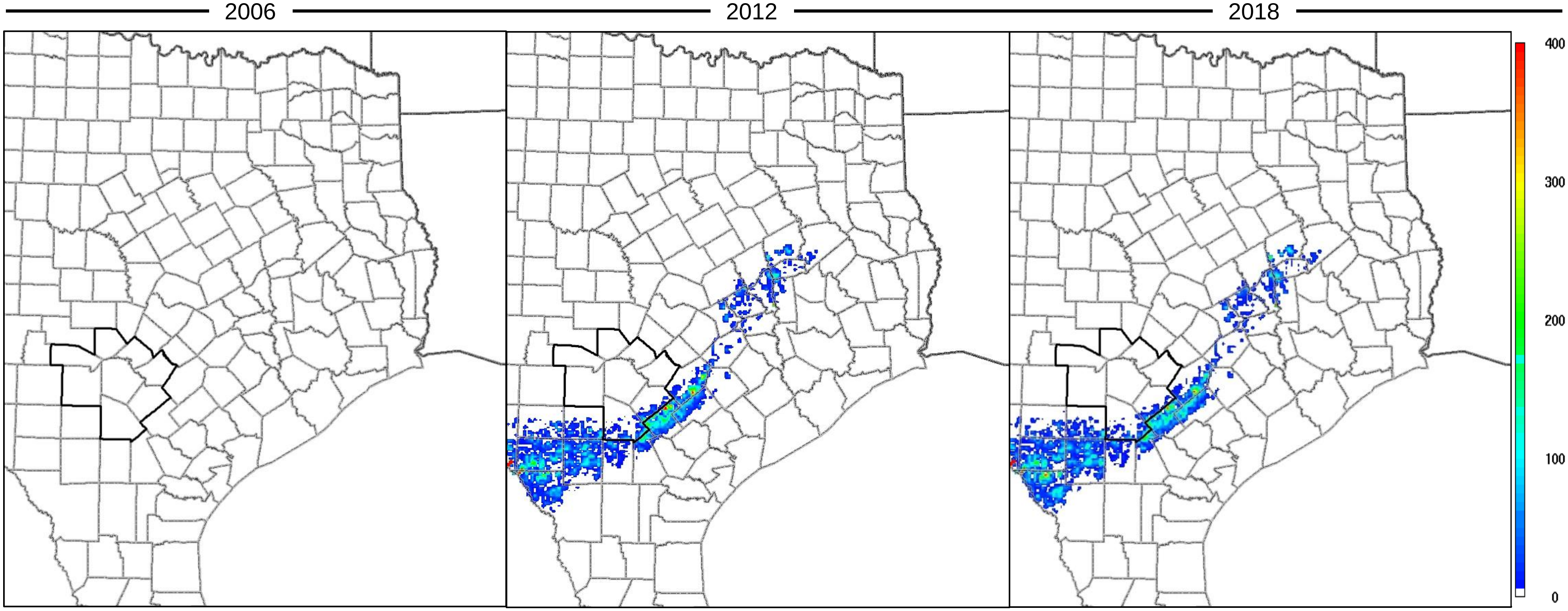


Figure 4-21: Eagle Ford VOC Emissions 4-km grid Tile Plots, Moderate Scenario, Weekday, 12:00PM – 1:00PM (Grams Mole/Hr)

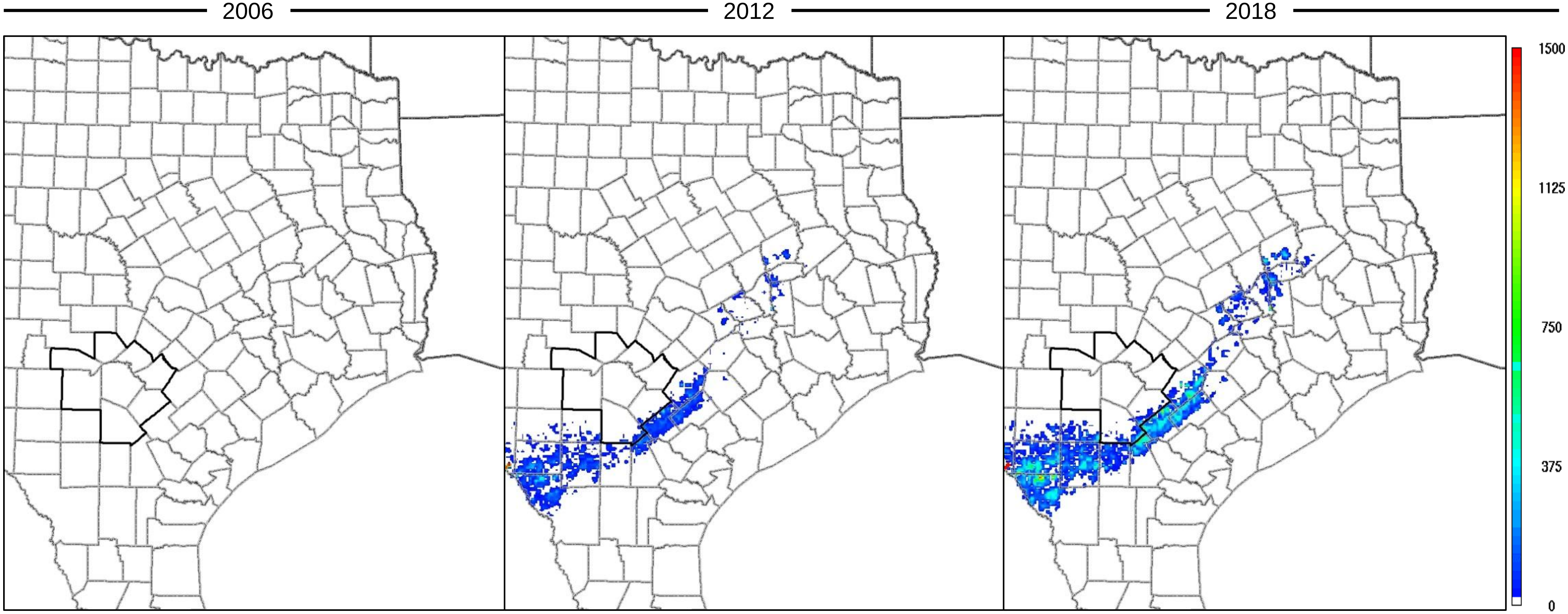
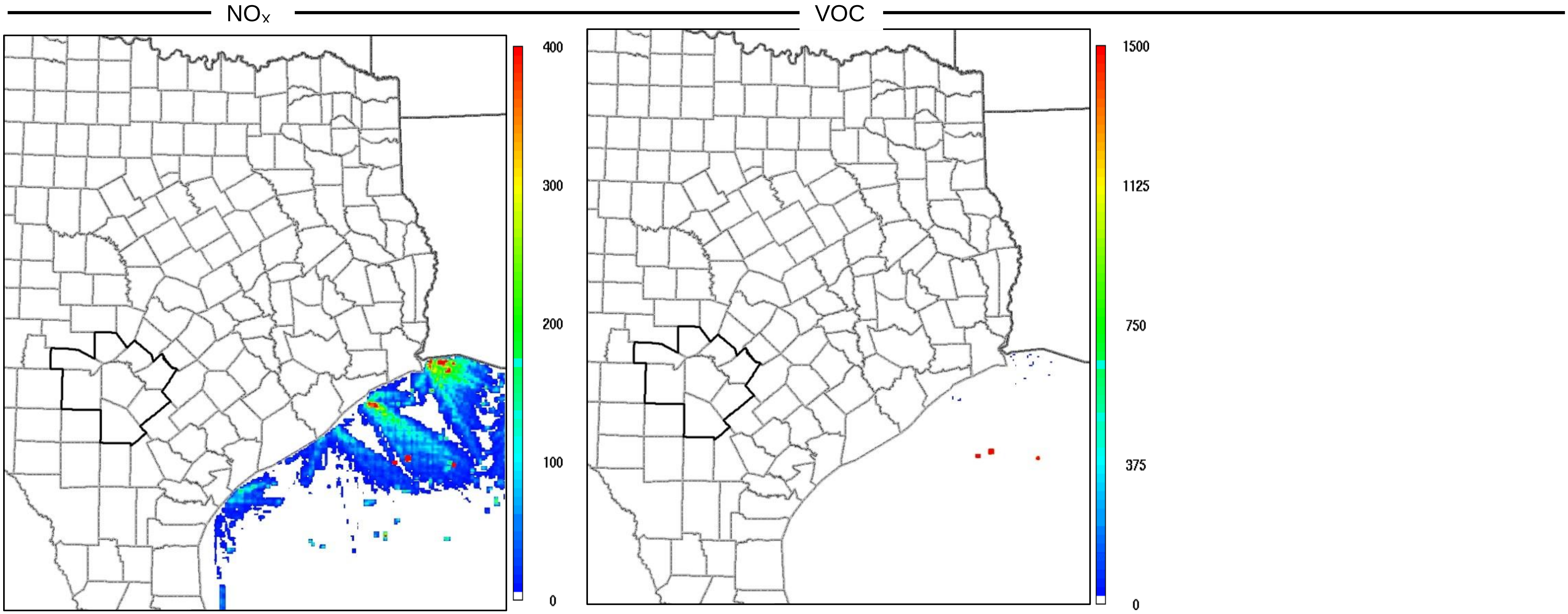
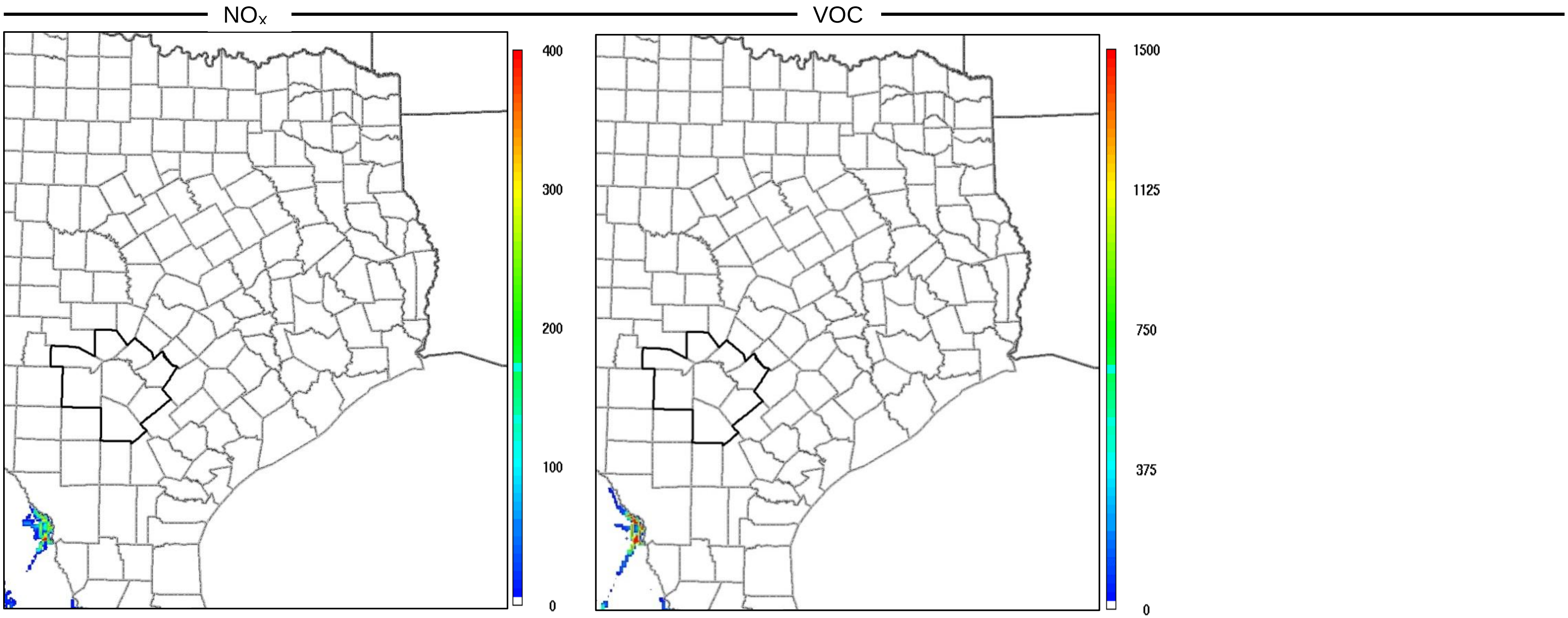


Figure 4-22: Offshore Emissions 4-km grid Tile Plots, Weekday, 12:00PM – 1:00PM (Grams Mole/Hr)



Note: Offshore emissions are the same for each projection year.

Figure 4-23: Mexico Emissions 4-km grid Tile Plots, Weekday, 12:00PM – 1:00PM (Grams Mole/Hr)



Note: Mexico emissions are the same for each projection year.

5 Base Case Modeling

5.1 CAMx Model Development

The base case CAMx simulation was developed for an elevated ozone episode in the San Antonio region that extended from May 31st to July 2nd 2006. To simulate ozone formation, transport, and dispersion for the June 2006 episode, CAMx required several inputs including:

- Three-dimensional hourly meteorological fields generated by WRF via the WRF2CAMx interface tool;
- Land use distribution fields;
- Three-dimensional hourly emissions generated by EPS3 by pollutant (latitude, longitude, and height);
- Initial conditions and boundary conditions (IC/BC);
- Photolysis rate inputs, including ultraviolet (UV) albedo, haze opacity, and total atmospheric ozone column fields.

5.1.1 CAMx Configurations

CAMx version 5.40 was used to model the 2006 episode to match the current TCEQ platform being developed for Texas. The configurations used for the extended June 2006 CAMx episode were:

- Duration: May 31st – July 2nd, 2006
- Time zone: CST (central standard time)
- I/O frequency: 1 hour
- Map projection: Lambert Conformal Conic
- Nesting: 2-way fully interactive 36/12/4-km computational grids
- Chemistry mechanism: CB6
- Chemistry solver: EBI (Euler-Backward Iterative)
- Advection solver: PPM (Piecewise Parabolic Method)
- Dry deposition model: ZHANG03[253]
- Plume-in-Grid model: On for large NO_X sources, parameters set by TCEQ
- Probing Tools: None
- Dry deposition: On
- Wet deposition: On
- 3-D output: Off (2-D surface output only)
- PiG sampling grids: Off
- Asymmetric Convective Model 2 (ACM2) Diffusion[254]
- TUV Cloud Adjustment

[253] L. Zhang, J. R. Brook, and R. Vet, 2003. "A revised parameterization for Gaseous Dry Deposition in Air-Quality Models". Atmos. Chem. Phys., 3, 2067–2082. Available online: http://www.atmos-chem-phys.net/3/2067/2003/acp-3-2067-2003.pdf. Accessed 06/24/13.

[254] Jonathan Pleim. "A New Combined Local and Non-Local Pbl Model for Meteorology and Air Quality Modeling". U.S. Environmental Protection Agency, Research Triangle Park, NC. Available online: http://www.cmascenter.org/conference/2006/abstracts/pleim_session1.pdf. Accessed 06/24/13

- Photolysis rate adjusted by cloud cover
- BC/IC from GEOS-CHEM model

The sampling grid was turned off during the model run because it's used solely to produce a graphical display of plume animation at the fine grid level and does not impact CAMx ozone predictions. These fine grid levels are typically less than 1 km and are smaller than the finest grid resolution, 4 km, used in this modeling application.

5.1.2 Plume-in-Grid Sub-model

The photochemical model runs developed for the June 2006 episode utilize the Plume-in-Grid sub-model (PiGs) to track individual plume sources and help reduce the artificial diffusion of point source emissions in the modeling grid. The PiGs accounts "for plume-scale dispersion and chemical evolution, until such time as puff mass can be adequately represented within the larger grid model framework."[255] All CAMx runs employed the PiGs option for large NO_X point sources using TCEQ PiGs threshold values. These PiGs threshold values are:

- Texas — 5 tons/day NO_X
- Mexico, Oklahoma, Louisiana, Arkansas — 7.5 tons/day NO_X
- Mississippi — 10 tons/day NO_X
- Alabama, Tennessee, Ohio — 15 tons/day NO_X
- Other states — 25 tons/day NO_X

5.1.3 Boundary Conditions, Initial Conditions, and Land Use File

Boundary and initial conditions used for the 36 km domain were provided by the GEOS–Chem Model. "GEOS–Chem is a global 3-D chemical transport model (CTM) for atmospheric composition driven by meteorological input from the Goddard Earth Observing System (GEOS) of the NASA Global Modeling and Assimilation Office. It is applied by research groups around the world to a wide range of atmospheric composition problems."[256] Boundary conditions were developed for each grid cell at the edge of the 36km grid for every layer and hour of the modeling episode.

The land use distribution file is used to determine the dry deposition rates of all gases and surface albedo. The fraction of land use in each grid for the 4 km, 12 km, and 36 km grids was based on the Leaf Area Index (LAI) database. The GLASS Leaf Area Index (LAI) product is described as a "global LAI product with long time series, generated and released by the Center for Global Change Data Processing and Analysis of Beijing Normal University." [257]

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[255] ENVIRON International Corporation, May 2008. "User's Guide: Comprehensive Air Quality Modeling with Extensions, Version 5.40". Novato, CA. p. 4-1.

[256] Harvard University and Dalhousie University, April 12, 2013. "GEOS–Chem Model". Available online: http://geos-chem.org/. Accessed 06/24/13.

[257] Shunlin Liang, Zhiqiang Xiao, 2012. "Global Land Surface Products: Leaf Area Index Product Data Collection (1985-2010)". Beijing Normal University. Available online: http://glcf.umd.edu/data/lai/index.shtml. Accessed 06/24/13.

5.2 CAMx Base Case Runs

Once all the data was input into CAMx, the model was run to produce several 2006 base case and projection case runs. Four base case runs were tested with different emission inventories to determine modeling performance before the photochemical model was projected to 2012 and 2018. A fifth base case run with MM5 was also included in the analysis to provide a comparison to previous modeling results. All CAMx base case runs utilized WRF data with 4-km grid 1-way nesting with 3D upper-air and surface nudging using NWS data with time shift.[258]

MM5 Base Case Run 7

- Met run 11 with MM5 and MRF
- CAMx 4.53
- 5-layer soil model
- 1-hour surface wind analysis nudging using a 1-hour ADP observation dataset in conjunction with 3-hour EDAS analyses
- MM5CAMx "OB70" diffusivity option

WRF TCEQ Base Case Run 1

- WRF v3.2
- CAMx 5.40
- 5 layer thermal diffusion and no LSM
- YSU PBL scheme
- Kain-Fritsch cumulus
- WSM5 microphysics for us_36km and tx_12km domains
- WSM6 microphysics for tx_4km domain
- 3D upper-air and surface nudging using NWS data with time shift (ts) for tx_4km domain
- WRF to CAMx conversion: wrf2camx v3.2 with YSU Kv, and 100m kvpatch (kv100)
- Existing merged TCEQ emission files
- US 36km grid system

WRF TCEQ Base Case Run 2

- WRF v3.2
- CAMx 5.40
- 5 layer thermal diffusion and no LSM
- YSU PBL scheme
- Kain-Fritsch cumulus
- WSM5 microphysics for us_36km and tx_12km domains
- WSM6 microphysics for tx_4km domain
- 3D upper-air and surface nudging using NWS data with time shift (ts) for tx_4km domain
- WRF to CAMx conversion: wrf2camx v3.2 with YSU Kv, and 100m kvpatch (kv100)

[258] TCEQ. Austin, Texas. Available online: ftp://amdaftp.tceq.texas.gov/pub/Rider8/camx/basecase/bc06_06jun.reg2a.2006ep0ext_5layer_YSU_WSM6_3dsfc_fddats/. Accessed 06/12/13.

- AACOG EPS3 processed and merged TCEQ Emission Files
- US 36km grid system

WRF AACOG Base Case Run 3

- WRF v3.2
- CAMx 5.40
- 5 layer thermal diffusion and no LSM
- YSU PBL scheme
- Kain-Fritsch cumulus
- WSM5 microphysics for us_36km and tx_12km domains
- WSM6 microphysics for tx_4km domain
- 3D upper-air and surface nudging using NWS data with time shift (ts) for tx_4km domain
- WRF to CAMx conversion: wrf2camx v3.2 with YSU Kv, and 100m kvpatch (kv100)
- Local San Antonio-New Braunfels MSA emission data including construction equipment, landfill equipment, quarry equipment, agricultural tractors, combines, commercial airports, point sources, and heavy duty truck idling
- US 36km grid system

WRF AACOG RPO Base Case Run 4

- WRF v3.2
- CAMx 5.40
- 5 layer thermal diffusion and no LSM
- YSU PBL scheme
- Kain-Fritsch cumulus
- WSM5 microphysics for us_36km and tx_12km domains
- WSM6 microphysics for tx_4km domain
- 3D upper-air and surface nudging using NWS data with time shift (ts) for tx_4km domain
- WRF to CAMx conversion: wrf2camx v3.2 with YSU Kv, and 100m kvpatch (kv100)
- Local San Antonio-New Braunfels MSA emission data including construction equipment, landfill equipment, quarry equipment, agricultural tractors, combines, commercial airports, point sources, and heavy duty truck idling
- RPO 36km grid system

5.3 Diagnostic and Statistical Analysis of CAMx Runs

Each CAMx run was compared to observed data from eleven monitors in the San Antonio - New Braunfels MSA, C23, C58, C59, C501, C502, C503, C504, C505, C506, C622, and C678, to evaluate the model's performance in predicting ozone concentrations. The performance of the June 2006 modeling episode was evaluated in two ways: (1) how well was the model able to replicate observed concentrations of ozone and (2) how accurate was the model in characterizing the sensitivity of ozone to changes in emissions?[259]

The first question was answered by a series of operational evaluations including time series comparisons, daily ozone plots, statistical analyses, scatter plots, and plots of daily maximum 8-hour ozone fields. These operation tests specifically address the accuracy of the model's predictions as compared to actual ozone concentrations observed at AACOG monitors. [260]

5.3.1 Hourly Ozone Time Series

Time series plots of observed and predicted hourly ozone were constructed for each potential non-attainment regulatory monitor located in the San Antonio New Braunfels MSA. EPA recommends creating these plots because they "can indicate if there are particular times of the day or days of the week when the model performs especially poorly".[261] Figure 5-1 through Figure 5-11 provide a comparison of the hourly observed and predicted data for every ozone monitor in the San Antonio-New Braunfels MSA. The data for these time series plots was derived solely from AACOG base case run 3, as all four WRF runs had similar results.

Using the inputs described earlier, the CAMx model over predicted ozone concentrations at the monitors on the northwest side of San Antonio, C23, C25, and C505 on two of the episode's exceedance days: June 13 and 14th. On other days of the episode, the model's ozone estimations correlated well with observed peak hourly ozone values and predicted peak hourly ozone values. For most monitors, there was an excellent correlation between observed peak hourly ozone and predicted hourly ozone in the second half of the episode, with some under prediction at C503.

When examining the diurnal bias, model results for C58 over predicted diurnal ozone on most exceedance days during the episode. The model also over predicted diurnal hourly ozone in the second part of the episode at monitors located in rural areas of the San Antonio-New Braunfels MSA, C502, C503, C504, and C506, .

[259] EPA, April 2007. "Guidance on the Use of Models and Other Analyses for Demonstrating Attainment of Air Quality Goals for Ozone, PM2.5, and Regional Haze." U.S. EPA Office of Air Quality Planning and Standards, Air Quality Analysis Division, Air Quality Modeling Group, Research Triangle Park, NC. Section 18.0, p. 190.
[260] *Ibid*.
[261] *Ibid*., p. 200.

Figure 5-1: 1-Hour Ozone Time Series Observed (C23) v. Predicted (CAMx) for WRF AACOG Base Case Run 3, 2006

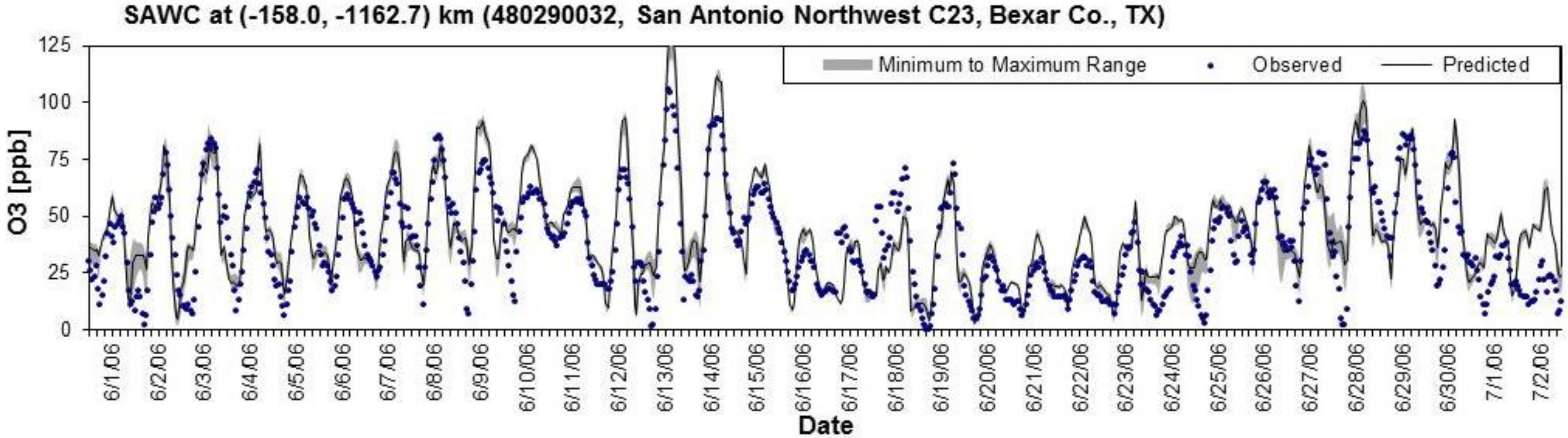


Figure 5-2: 1-Hour Ozone Time Series Observed (C58) v. Predicted (CAMx) for WRF AACOG Base Case Run 3, 2006

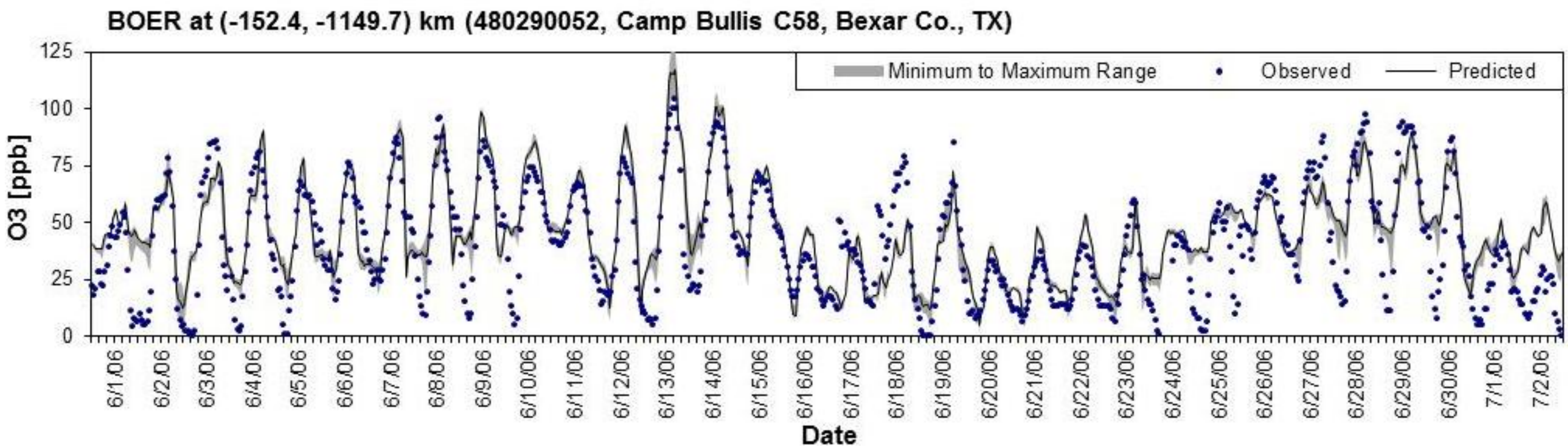


Figure 5-3: 1-Hour Ozone Time Series Observed (C59) v. Predicted (CAMx) for WRF AACOG Base Case Run 3, 2006

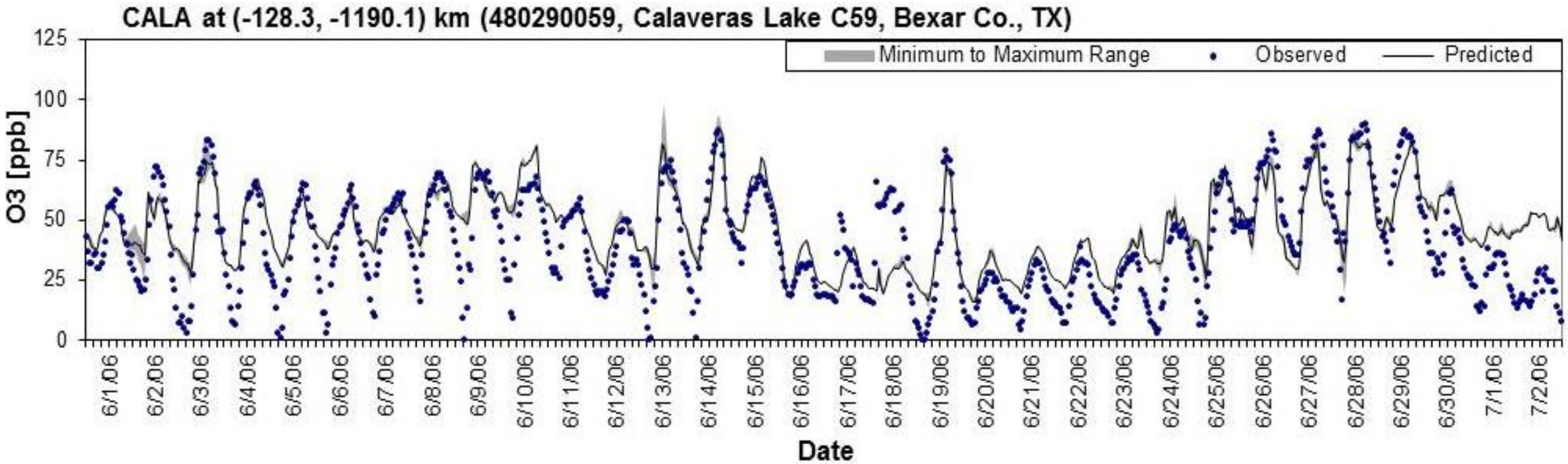


Figure 5-4: 1-Hour Ozone Time Series Observed (C622) v. Predicted (CAMx) for WRF AACOG Base Case Run 3, 2006

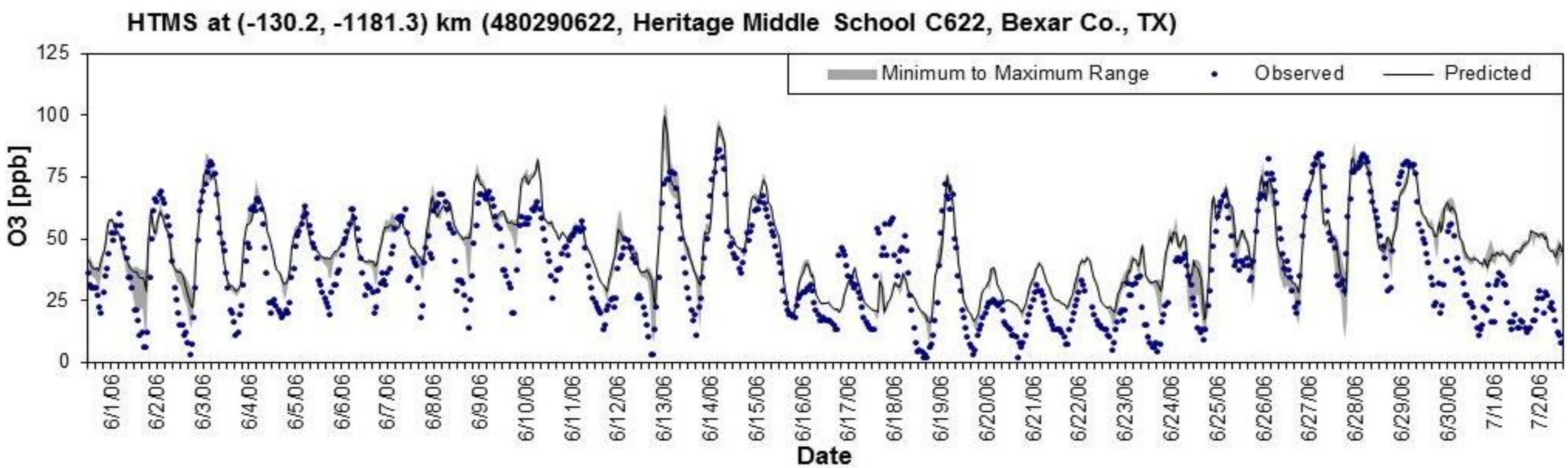


Figure 5-5: 1-Hour Ozone Time Series Observed (C678) v. Predicted (CAMx) for WRF AACOG Base Case Run 3, 2006

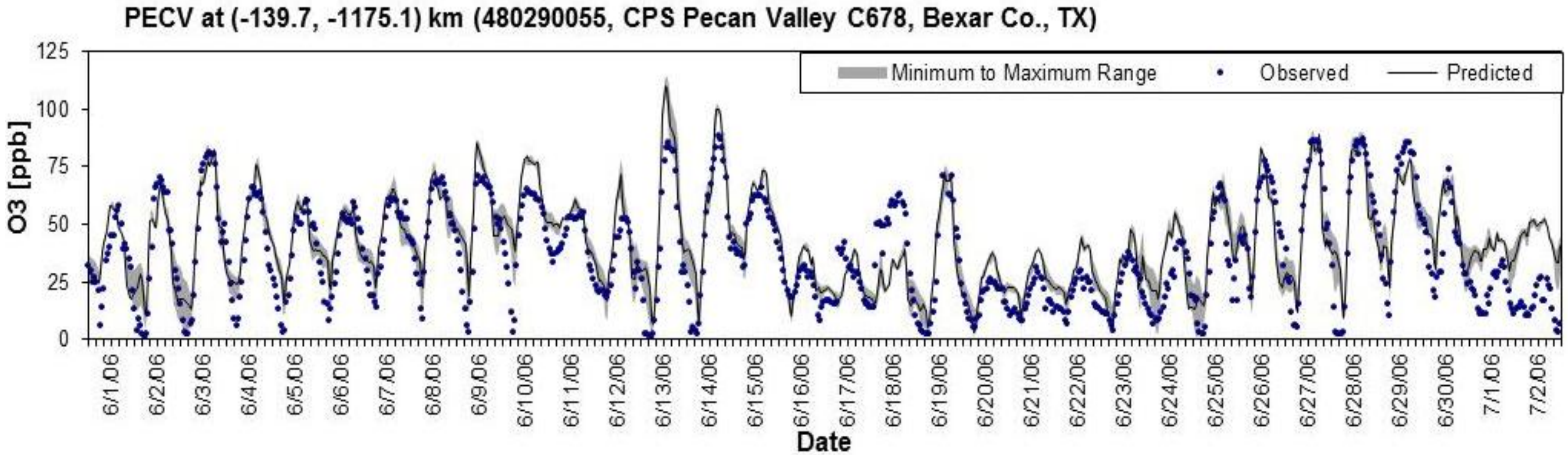


Figure 5-6: 1-Hour Ozone Time Series Observed (C501) v. Predicted (CAMx) for WRF AACOG Base Case Run 3, 2006

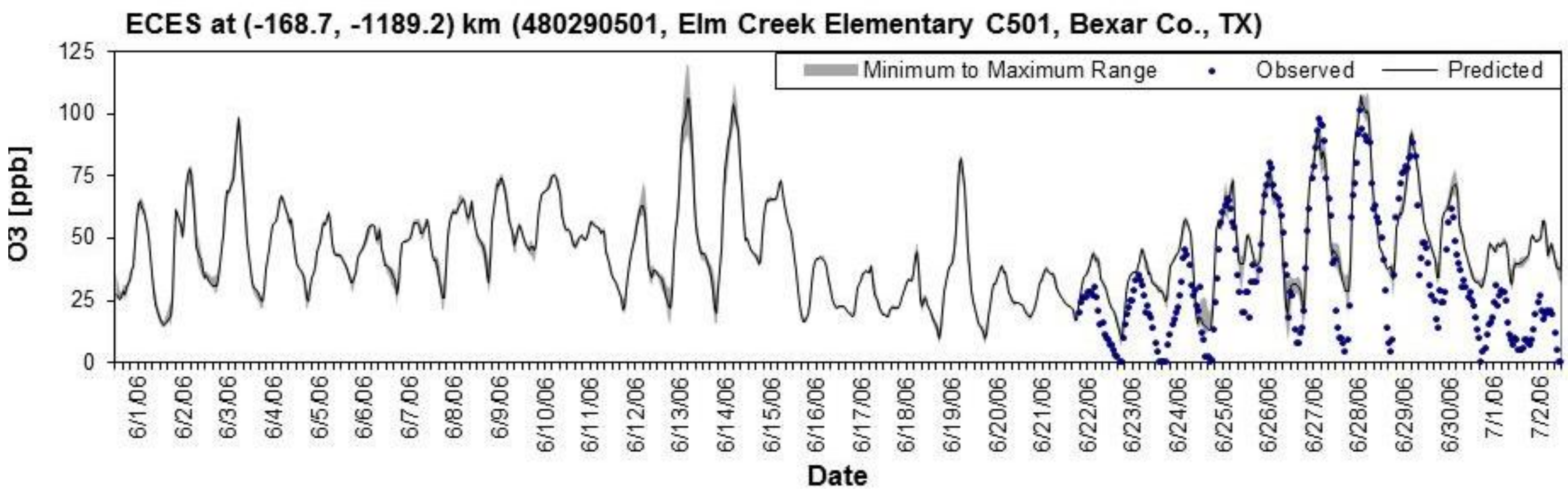


Figure 5-7: 1-Hour Ozone Time Series Observed (C502) v. Predicted (CAMx) for WRF AACOG Base Case Run 3, 2006

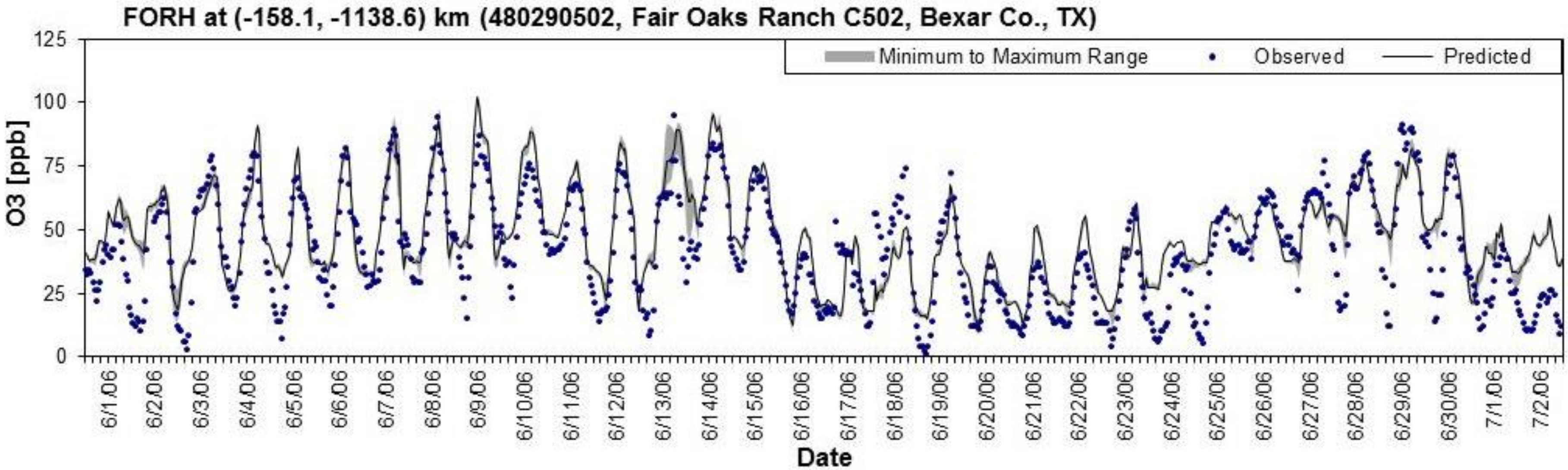


Figure 5-8: 1-Hour Ozone Time Series Observed (C503) v. Predicted (CAMx) for WRF AACOG Base Case Run 3, 2006

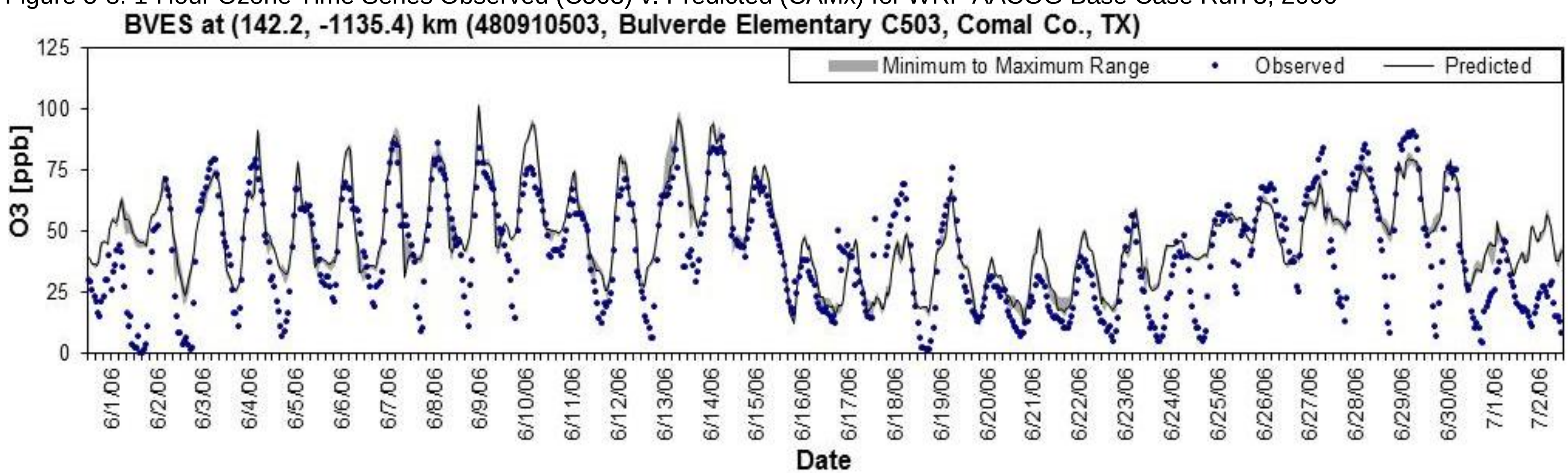


Figure 5-9: 1-Hour Ozone Time Series Observed (C504) v. Predicted (CAMx) for WRF AACOG Base Case Run 3, 2006

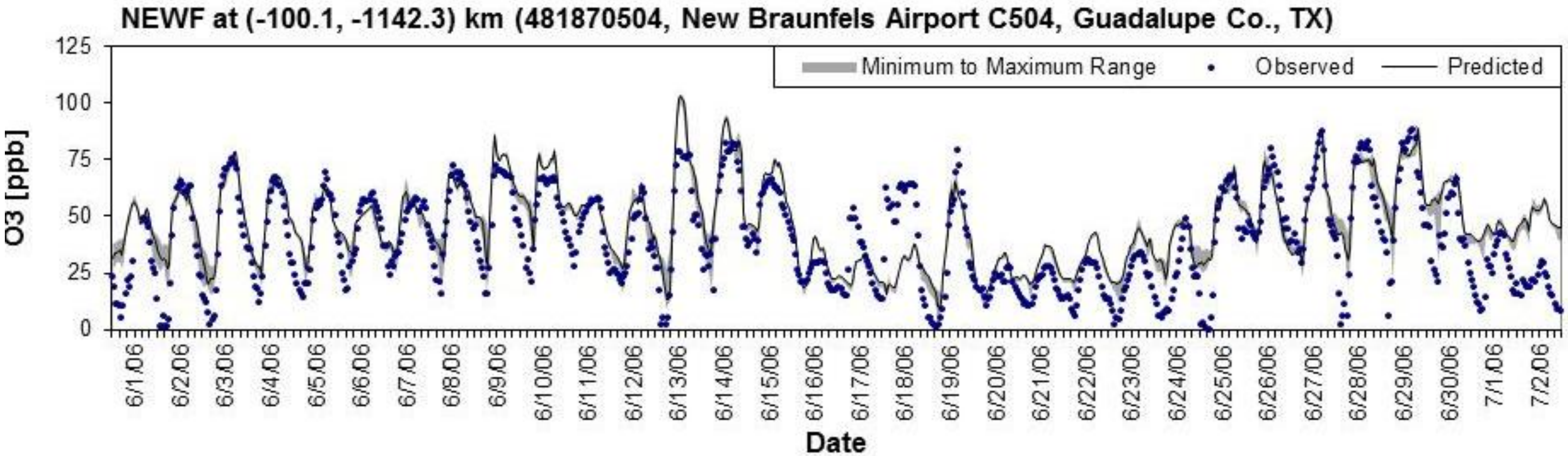


Figure 5-10: 1-Hour Ozone Time Series Observed (C505) v. Predicted (CAMx) for WRF AACOG Base Case Run 3, 2006

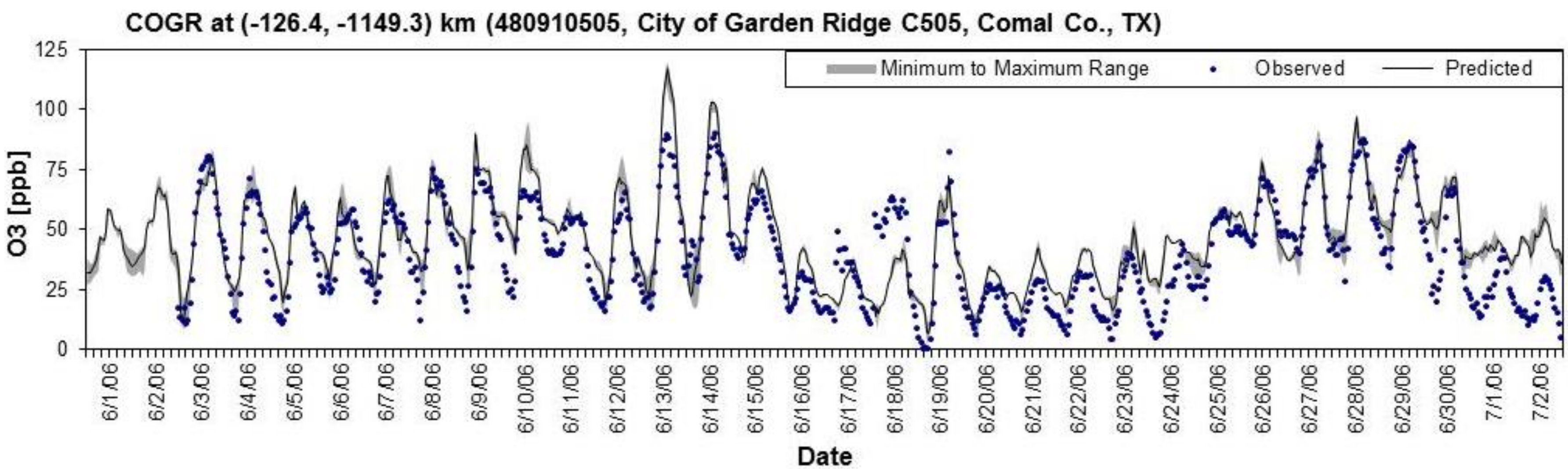
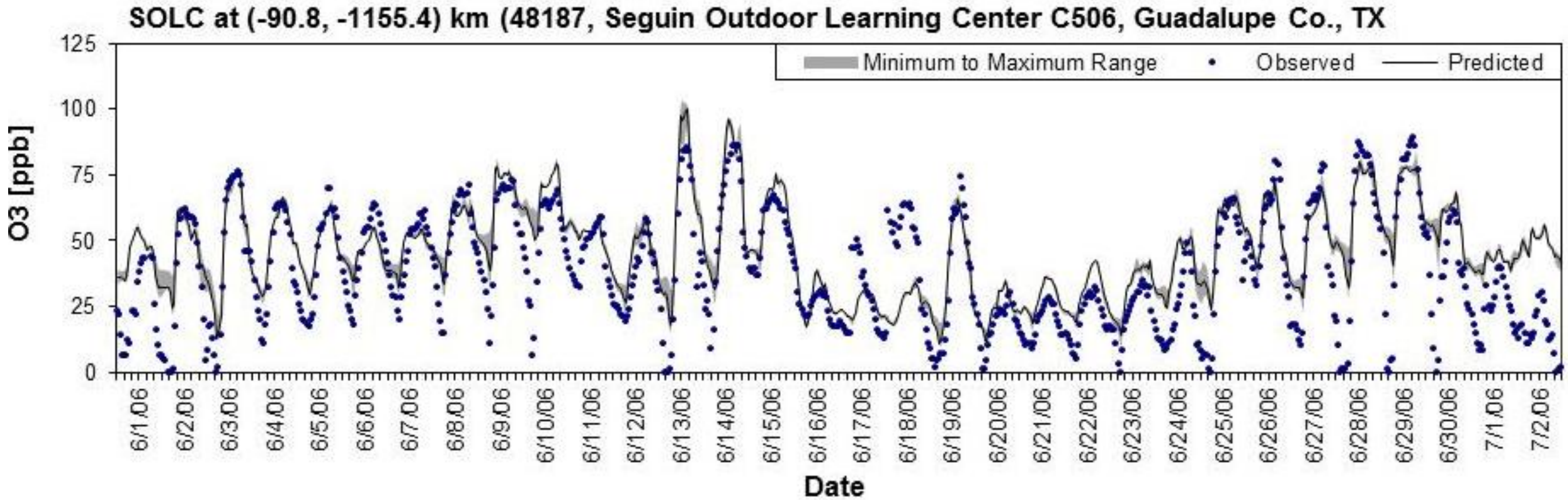


Figure 5-11: 1-Hour Ozone Time Series Observed (C506) v. Predicted (CAMx) for WRF AACOG Base Case Run 3, 2006

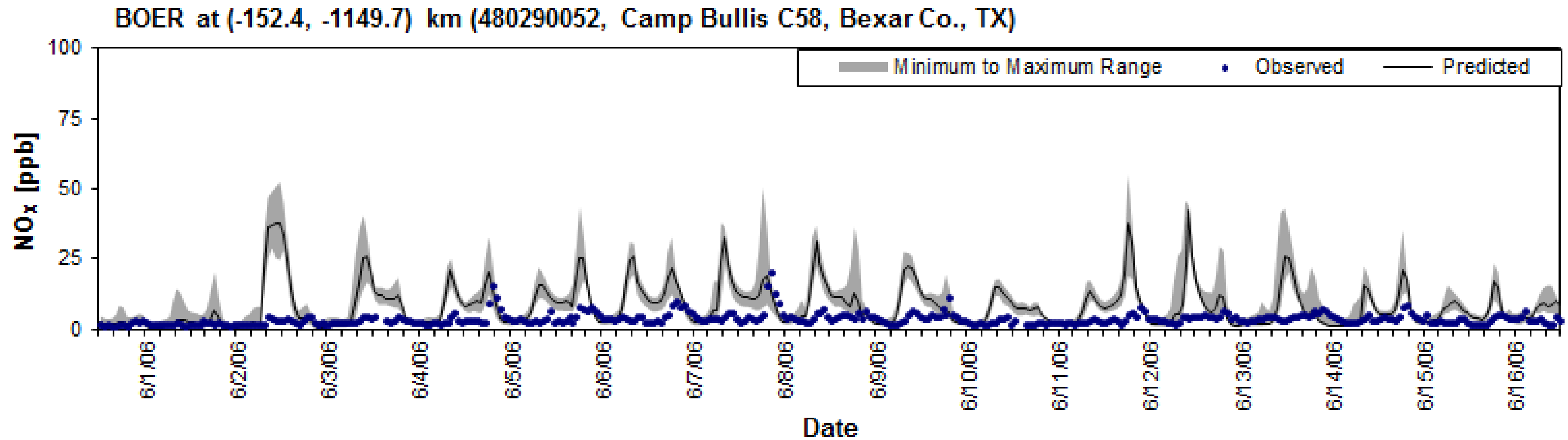


5.3.2 Hourly NO_X Time Series

Time series plots of modeled and predicted hourly NO_X for each monitor located in the San Antonio MSA were constructed. The model over predicted NO_X emissions at the C58 monitor on almost every day during the June 2006 episode. The average predicted hourly NO_X was 7.3 ppb, while the average observed hourly NO_X was only 3.9 ppb. Likewise, the average predicted maximum NO_X was 20.1 ppb, whereas the average observed maximum NO_X was 8.5 ppb. This over prediction of NO_X at C58 probably caused the poor model performance of predicted diurnal ozone at the monitor.

In contrast, C59 under predicted NO_X on several days including the ozone exceedance days of June 7th, 8th, 9th, 13th, and 14th. Model performance was good for most days at the C622 and C678 NO_X monitors in southeast Bexar County. However, the model over predicted ozone at the C678 monitor on several days, although most of these days were not associated with elevated ozone levels. The average predicted NO_X was higher at C678, and lower at both the C59 and C622 monitors on the southeast side of San Antonio.

Figure 5-12: 1-Hour NO_X Time Series Observed (C58) v. Predicted (CAMx) for WRF AACOG Base Case Run 3, 2006



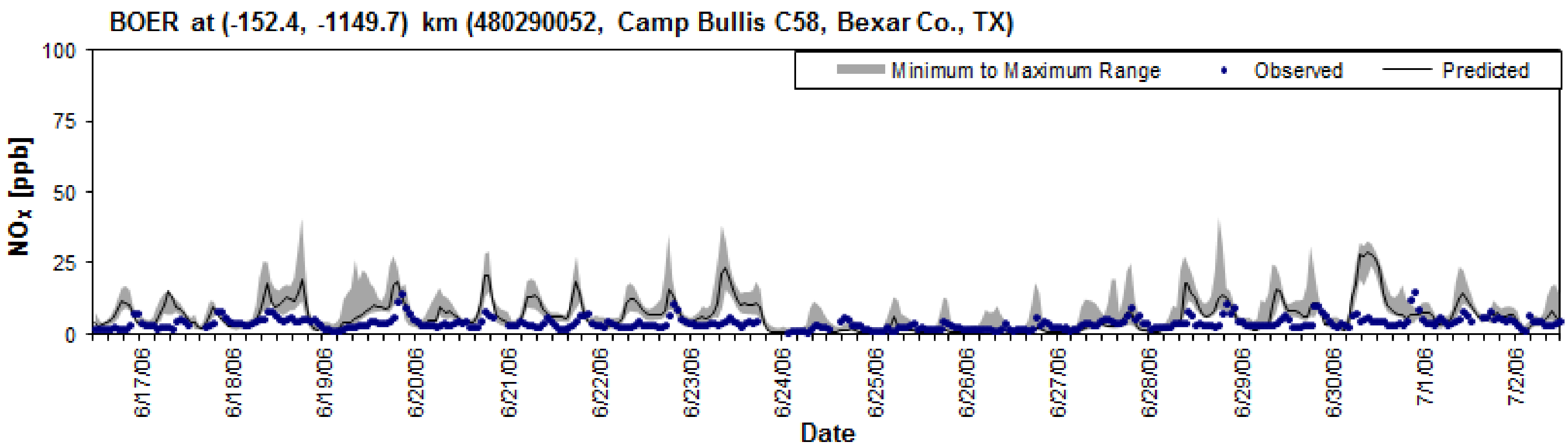
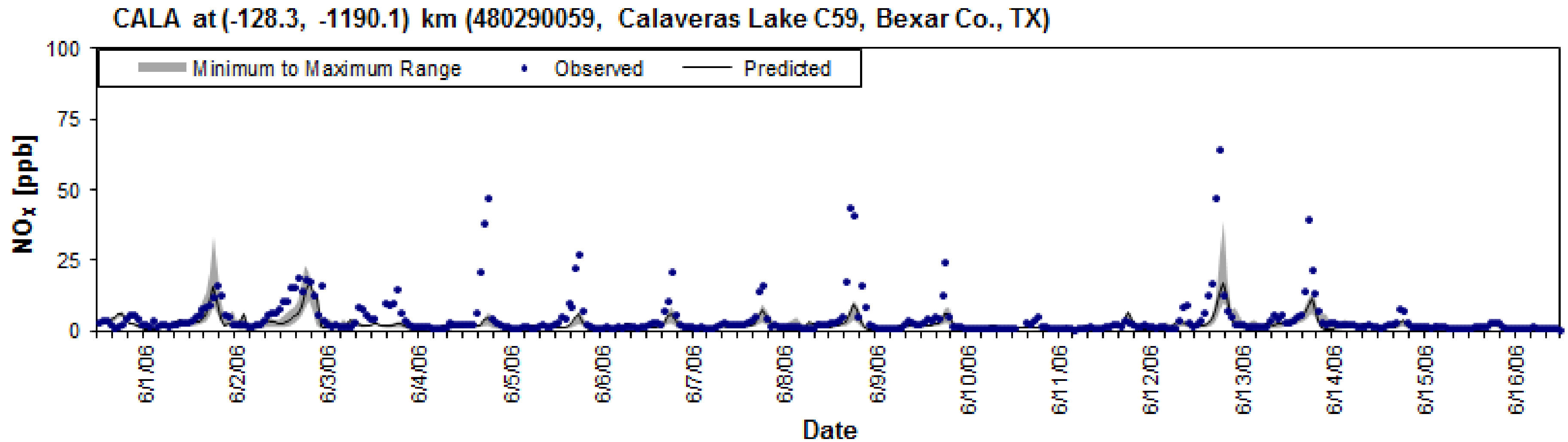


Figure 5-13: 1-Hour NO_X Time Series Observed (C59) v. Predicted (CAMx) for WRF AACOG Base Case Run 3, 2006



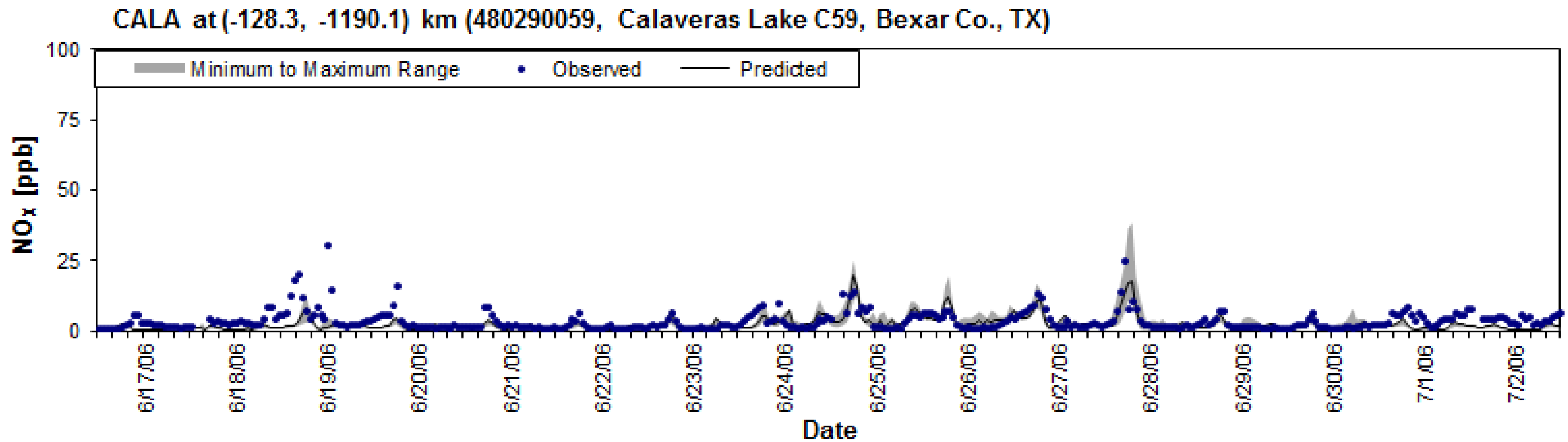


Figure 5-14: 1-Hour NO_X Time Series Observed (C622) v. Predicted (CAMx) for WRF AACOG Base Case Run 3, 2006

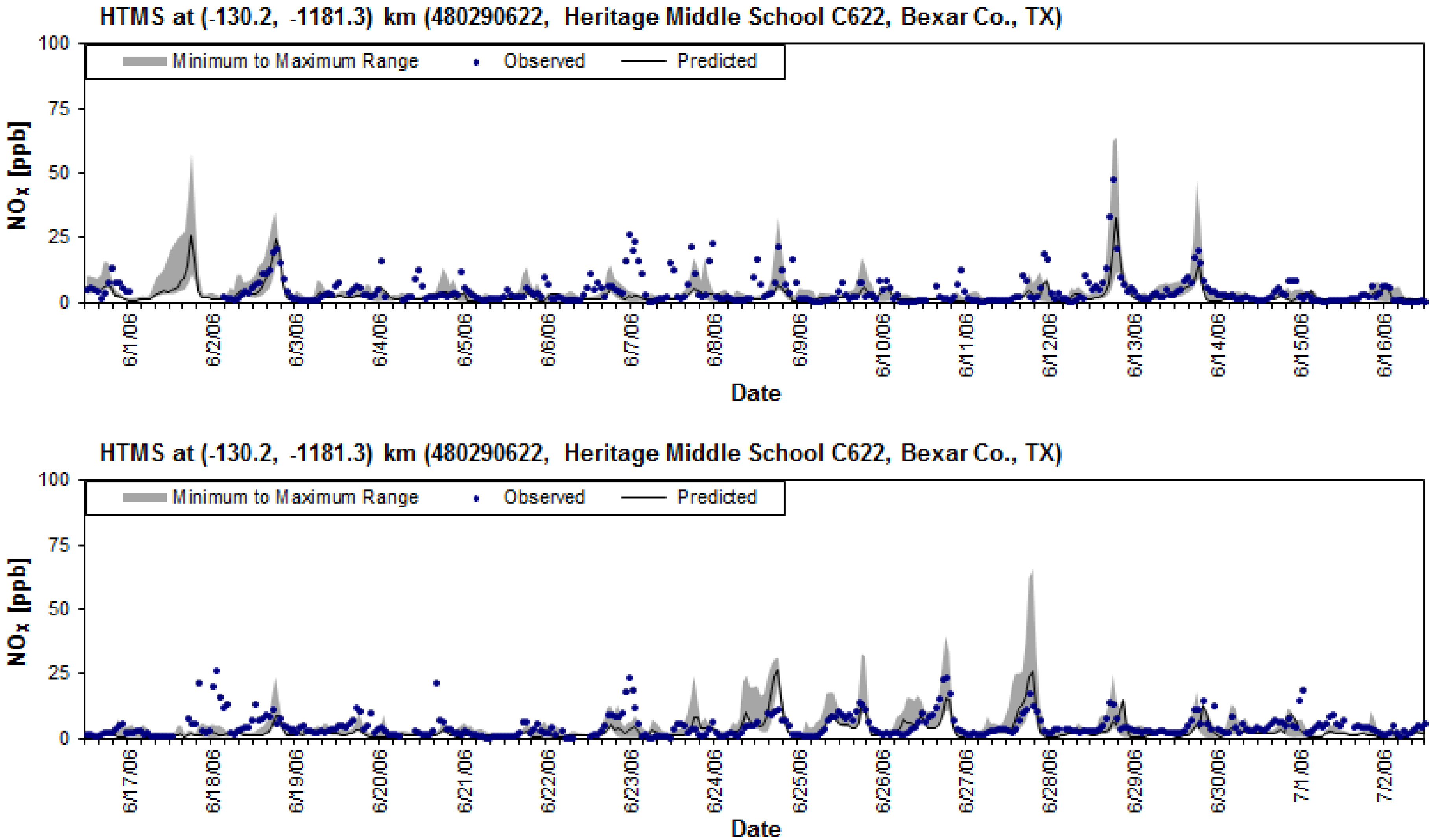
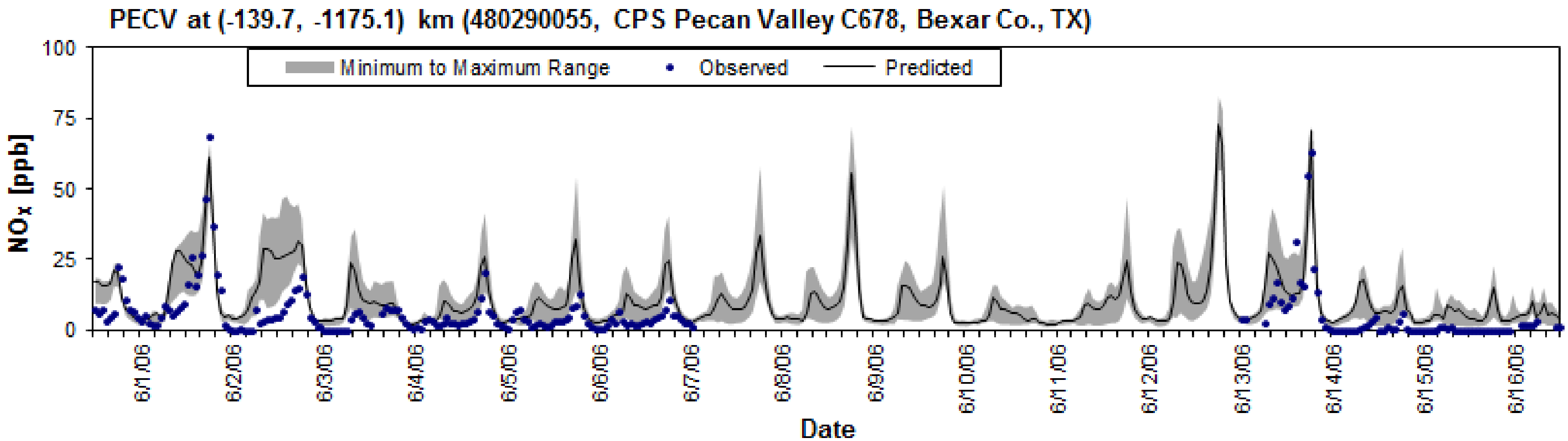
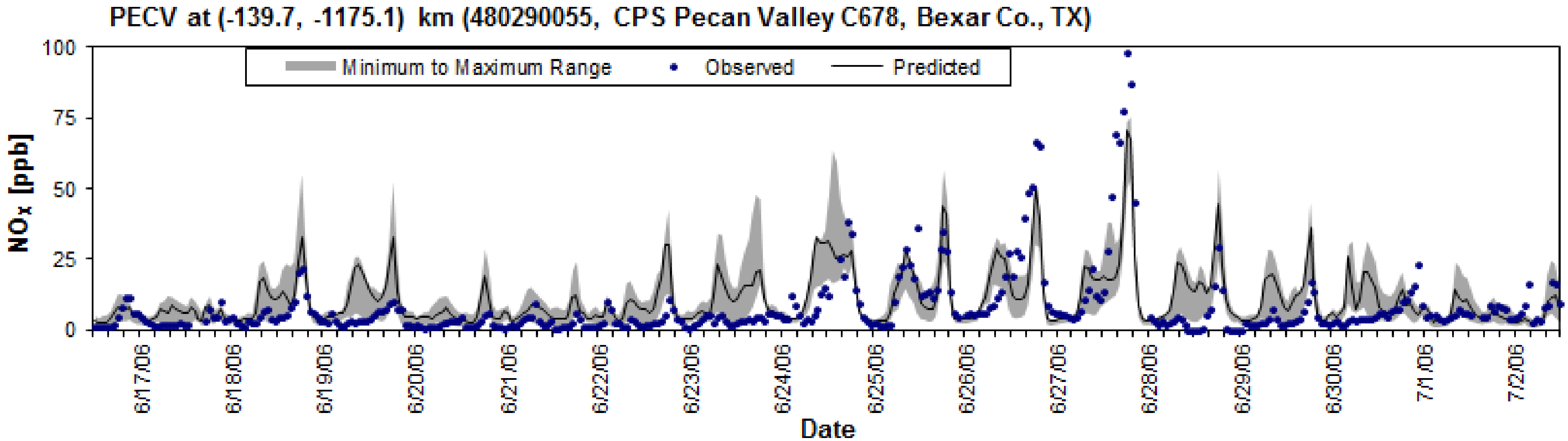


Figure 5-15: 1-Hour NO_X Time Series Observed (C678) v. Predicted (CAMx) for WRF AACOG Base Case Run 3, 2006





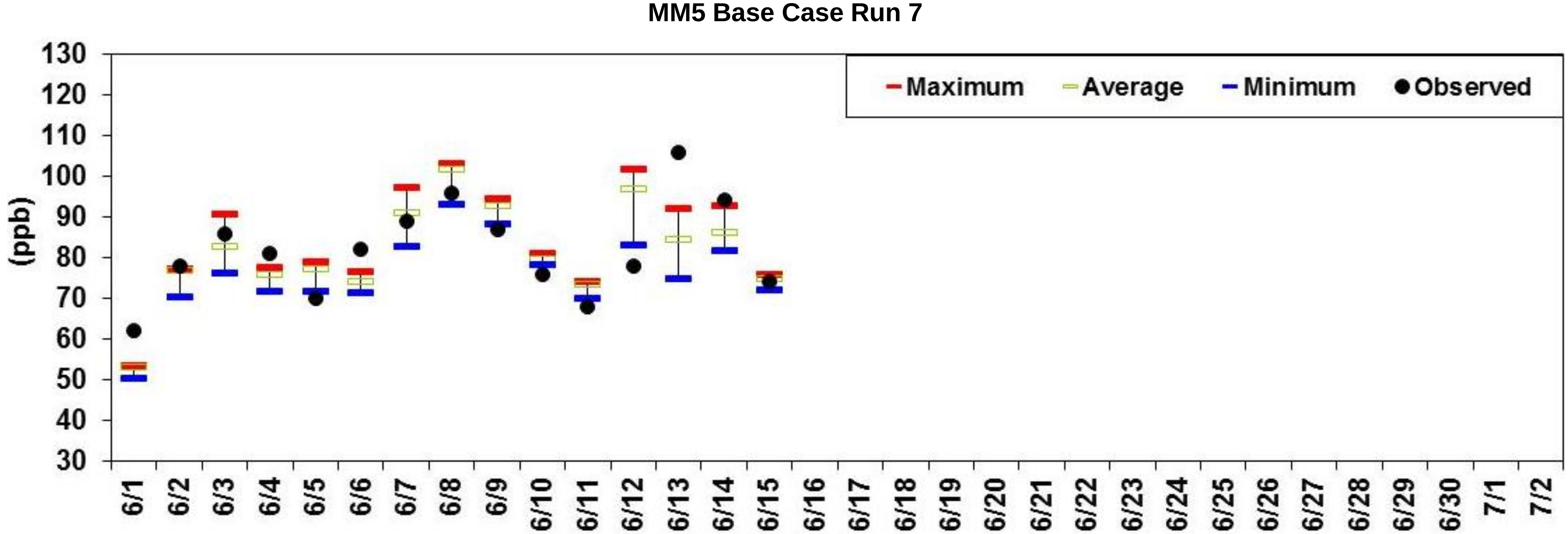
5.3.3 Daily Ozone Plots

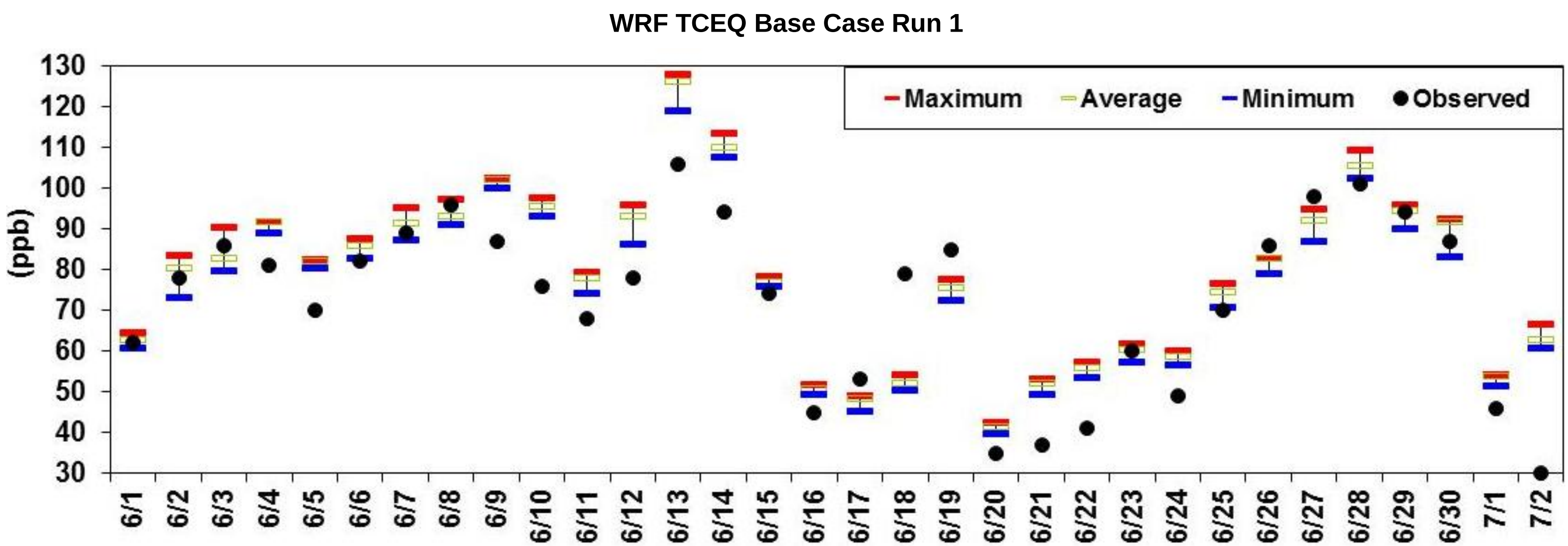
Daily peak predicted maximum, peak average, and peak minimum ozone in a 7 x 7 4-km grid around all monitors, C23 monitor, and C58 monitor are plotted in Figure 5-16, Figure 5-17, and Figure 5-18. MM5 base case run 7 exhibited poor modeling performance when predicting ozone formation on the June 13 exceedance day. Data is not available for the second half of the episode because MM5 was only run during the May 29th to June 15th, 2006 time period.

Runs using WRF over predicted hourly ozone on June 13th and June 14th. There was also a slight over prediction on the June 9th exceedance day. The WRF runs slightly under predicted ozone at C58 on June 3rd, but model performance was good overall. Modeling performance for the exceedance days in the second half of the episode, June 26th, 27th, 28th, and 29th, was good. Overall, modeling performance was improved when using WRF instead of MM5.

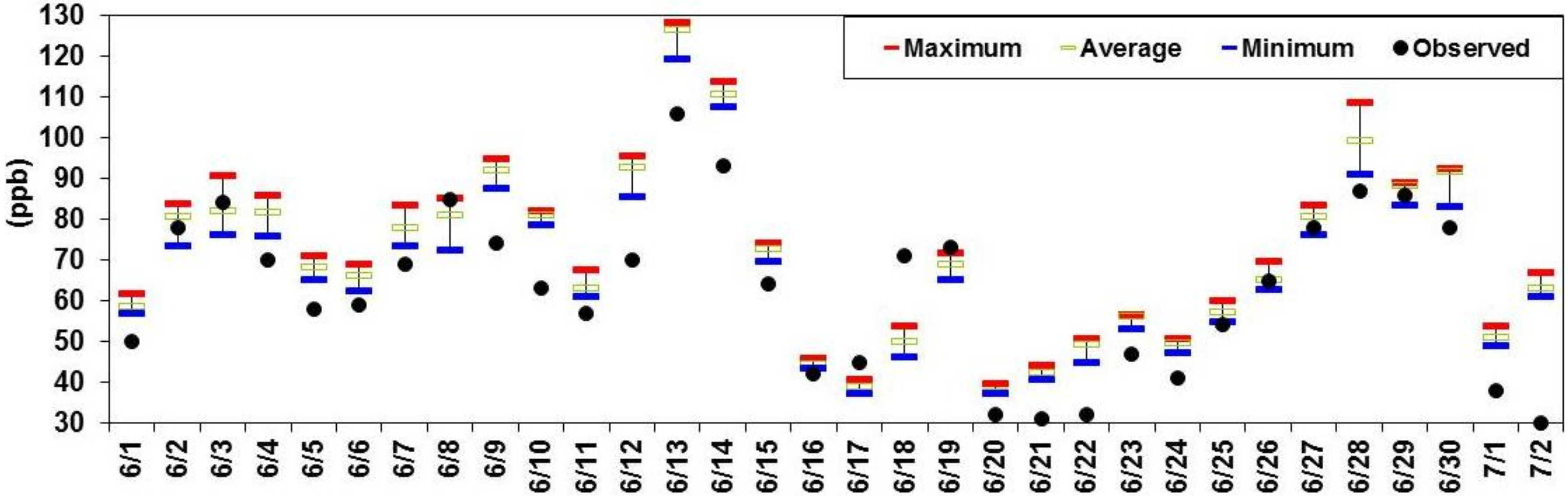
Although there were several significant differences in the local emission inventory, model results are similar for TCEQ run 1, TCEQ run 2, and AACOG run 3 for every monitor. Changes in meterological conditions had a greater impact on the model's predicted ozone formation than changes to the emission inventories. For AACOG run 4 using the RPO grid, predicted ozone on some exceedance days was higher than the other 3 runs. Notably, AACOG run 4 predicted higher ozone on both the June 13th and 14th exceedance days.

Figure 5-16: San Antonio Observed Ozone for All CAMS Daily Maximum 1-hr Average

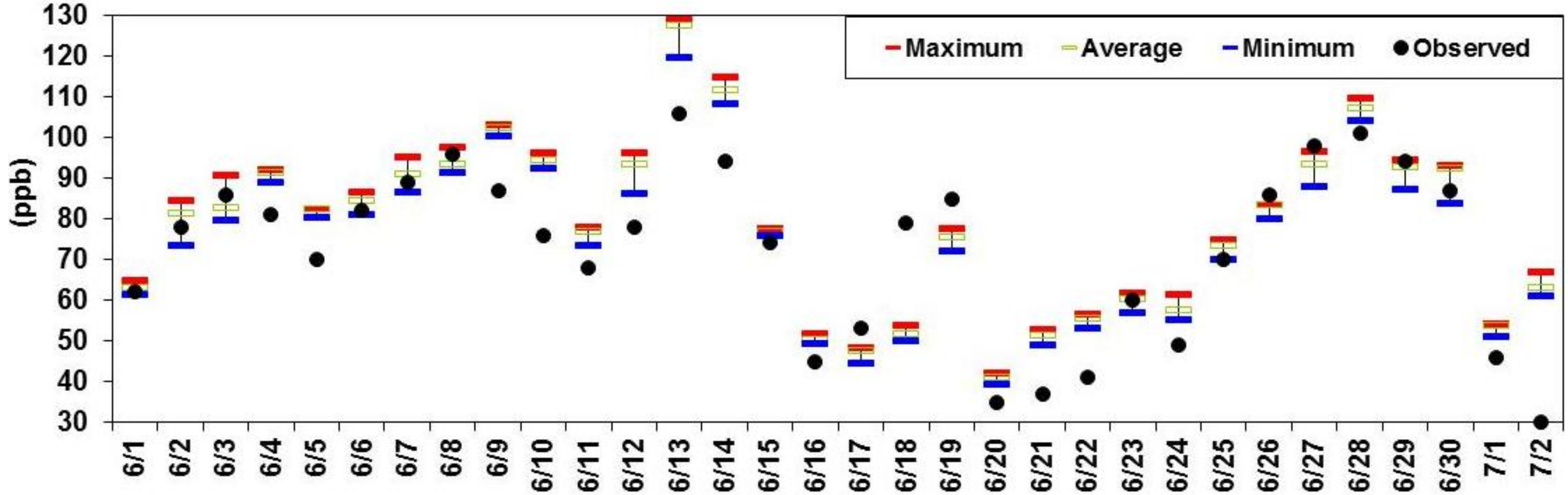




WRF TCEQ Base Case Run 2



WRF AACOG Base Case Run 3



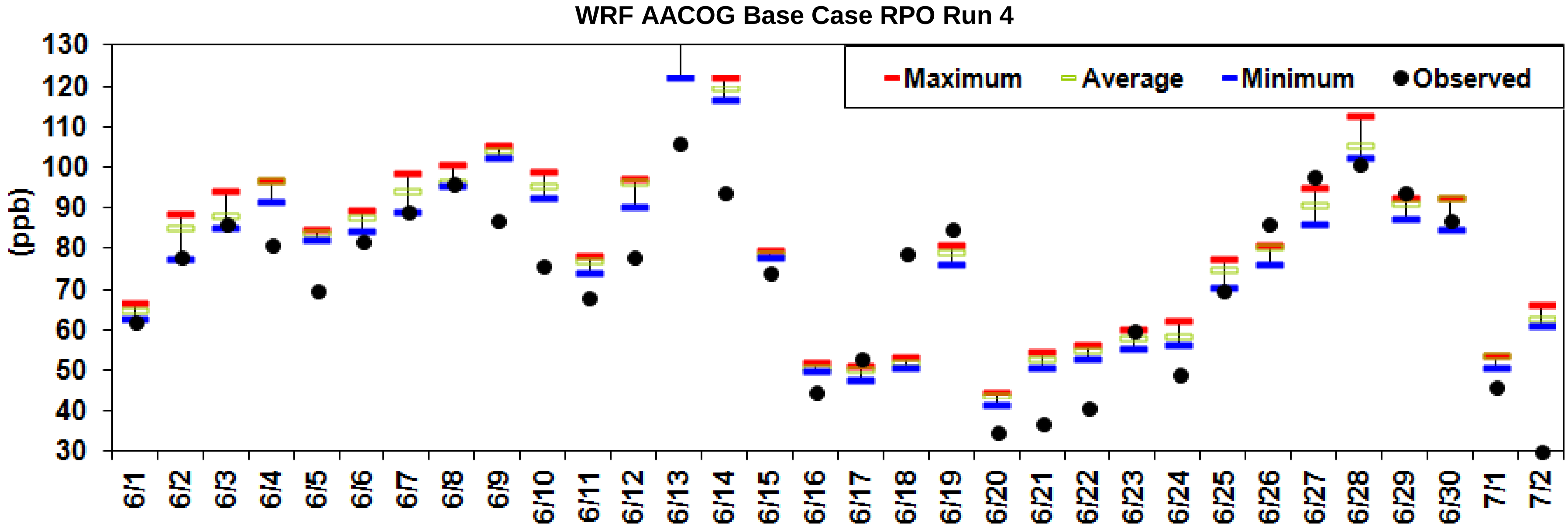
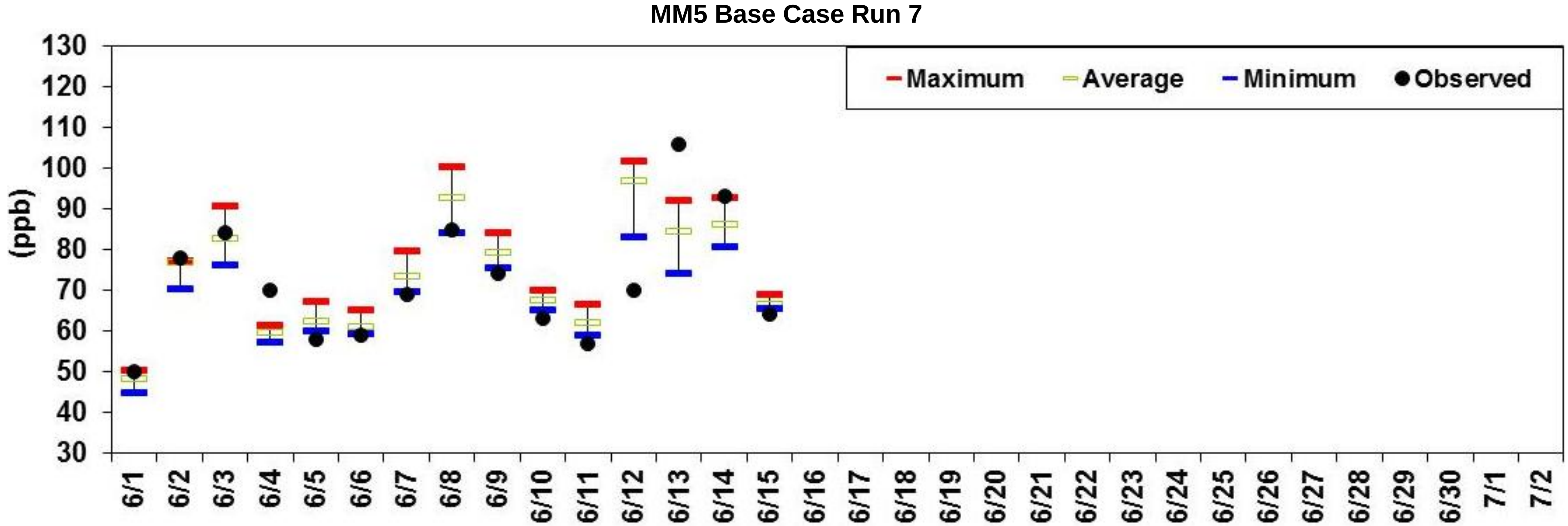
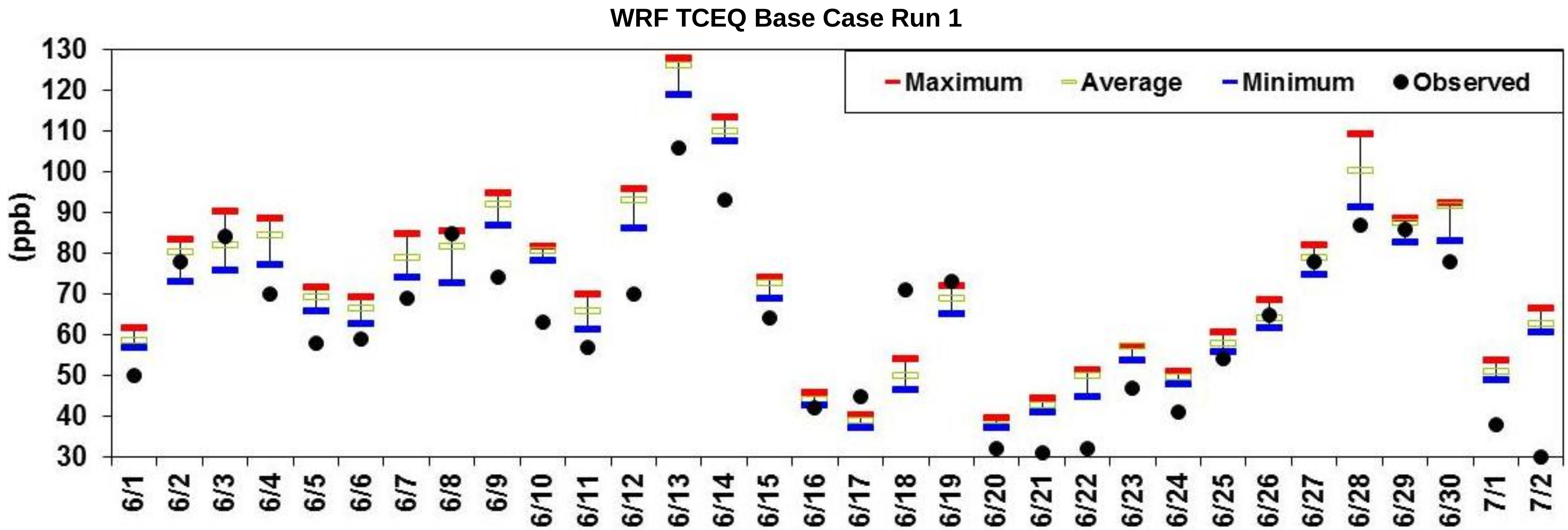
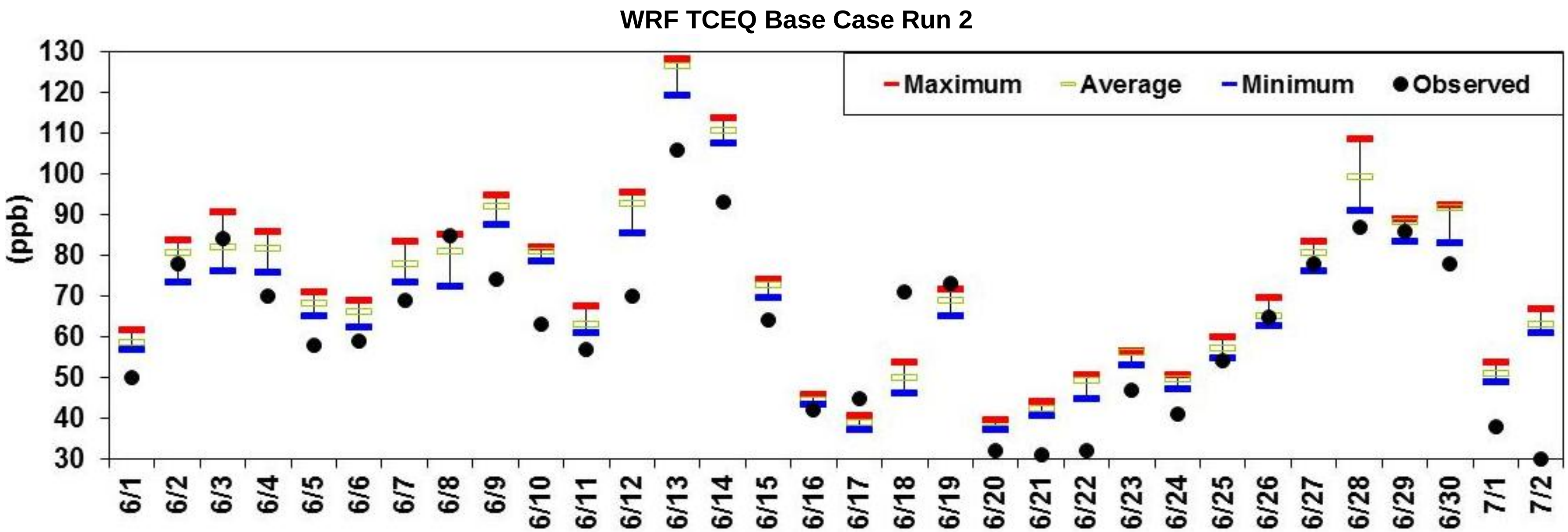

WRF AACOG Base Case RPO Run 4
Maximum
Average
Minimum
Observed
(ppb)
130
120
110
100
90
80
70
60
50
40
30
6/1
6/2
6/3
6/4
6/5
6/6
6/7
6/8
6/9
6/10
6/11
6/12
6/13
6/14
6/15
6/16
6/17
6/18
6/19
6/20
6/21
6/22
6/23
6/24
6/25
6/26
6/27
6/28
6/29
6/30
7/1
7/2

Figure 5-17: San Antonio Observed Ozone for CAMS 23 Daily Maximum 1-hr Average






WRF TCEQ Base Case Run 2
Maximum
Average
Minimum
Observed
(ppb)
130
120
110
100
90
80
70
60
50
40
30
6/1
6/2
6/3
6/4
6/5
6/6
6/7
6/8
6/9
6/10
6/11
6/12
6/13
6/14
6/15
6/16
6/17
6/18
6/19
6/20
6/21
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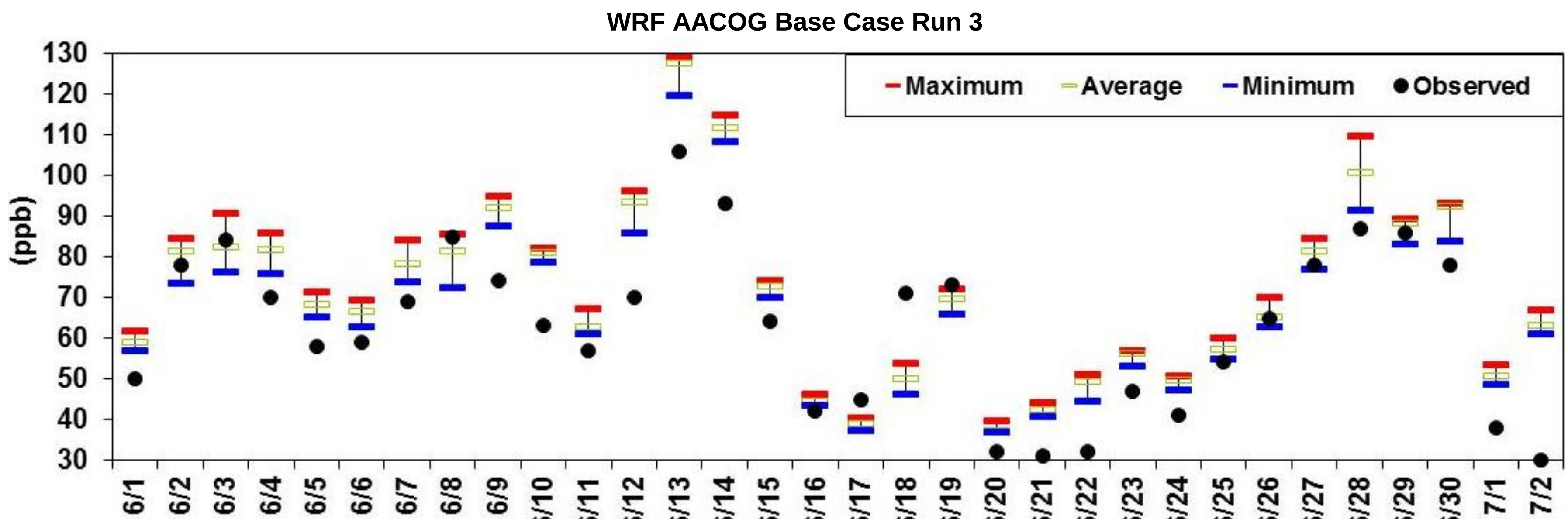
6/28
6/29
6/30
7/1
7/2


WRF AACOG Base Case Run 3
Maximum
Average
Minimum
Observed
(ppb)
130
120
110
100
90
80
70
60
50
40
30
6/1
6/2
6/3
6/4
6/5
6/6
6/7
6/8
6/9
6/10
6/11
6/12
6/13
6/14
6/15
6/16
6/17
6/18
6/19
6/20
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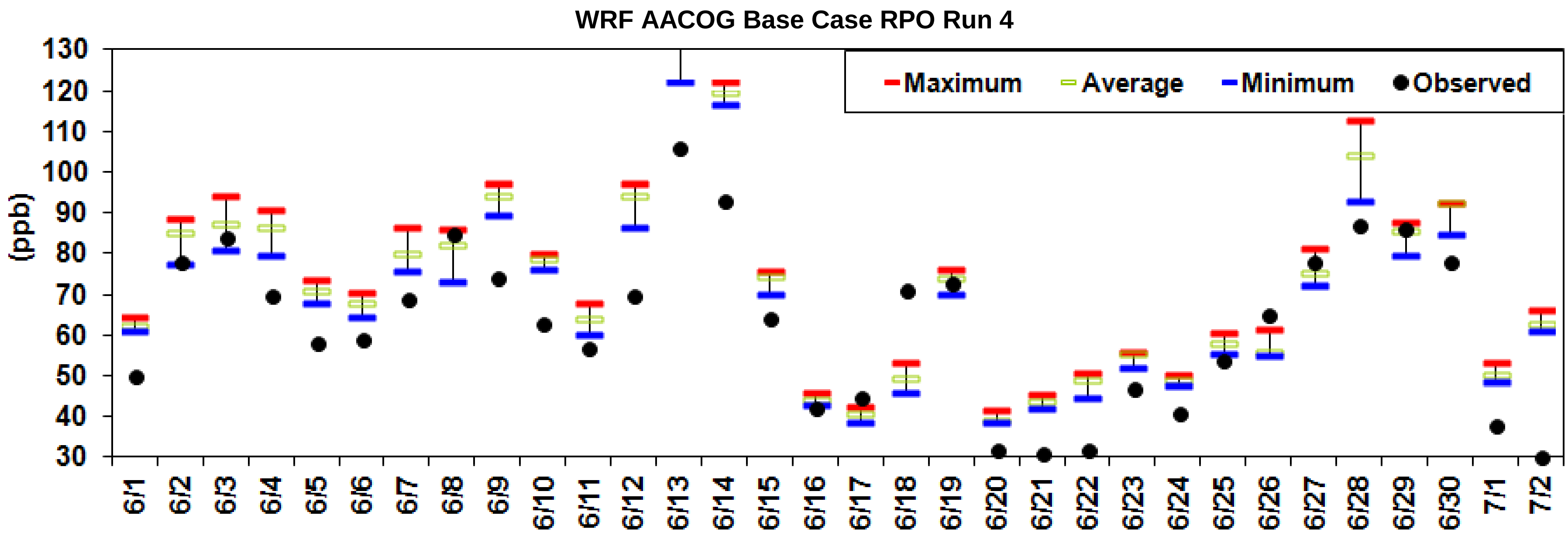
6/27
6/28
6/29
6/30
7/1
7/2



WRF AACOG Base Case RPO Run 4
Maximum
Average
Minimum
Observed
(ppb)
130
120
110
100
90
80
70
60
50
40
30
6/1
6/2
6/3
6/4
6/5
6/6
6/7
6/8
6/9
6/10
6/11
6/12
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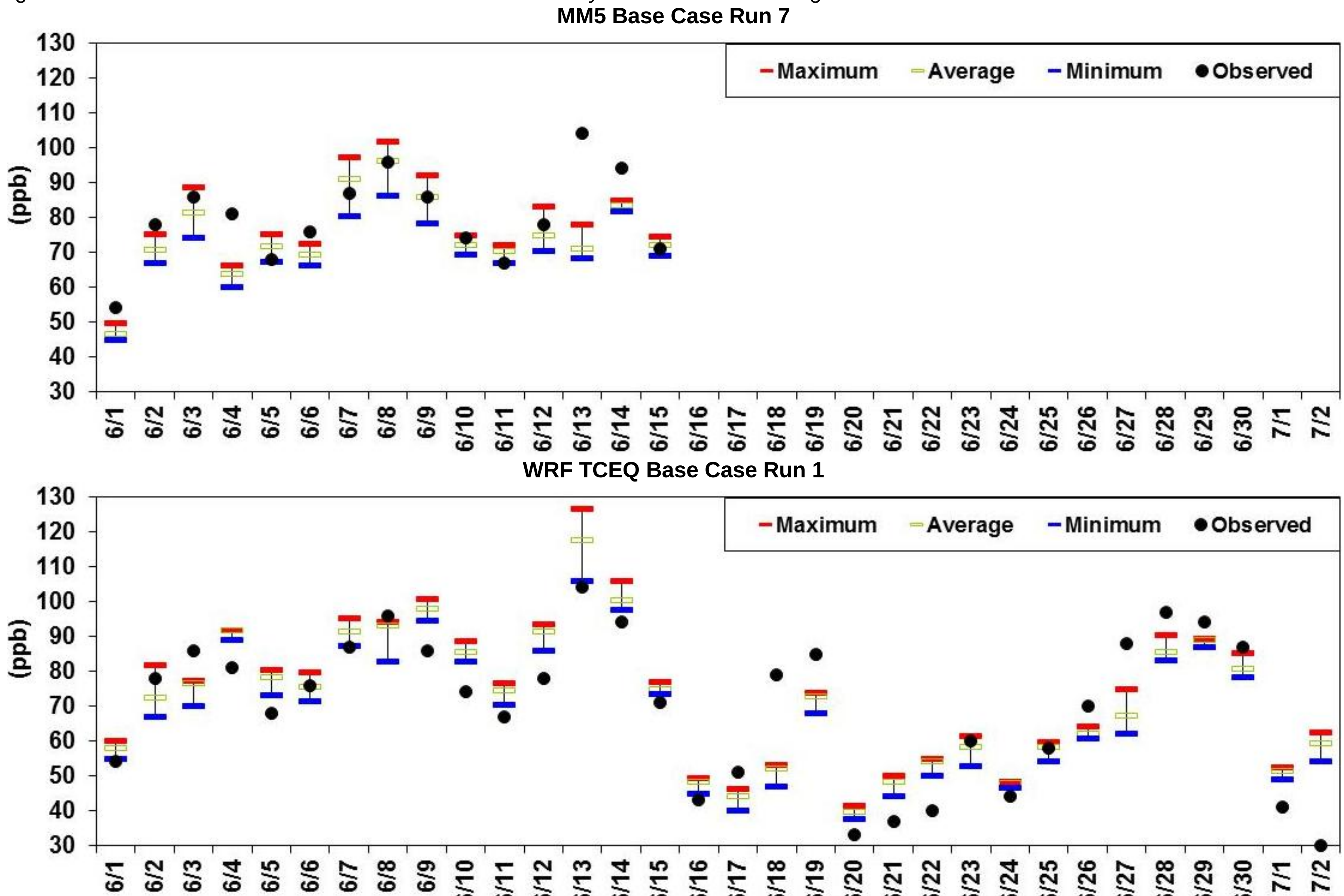
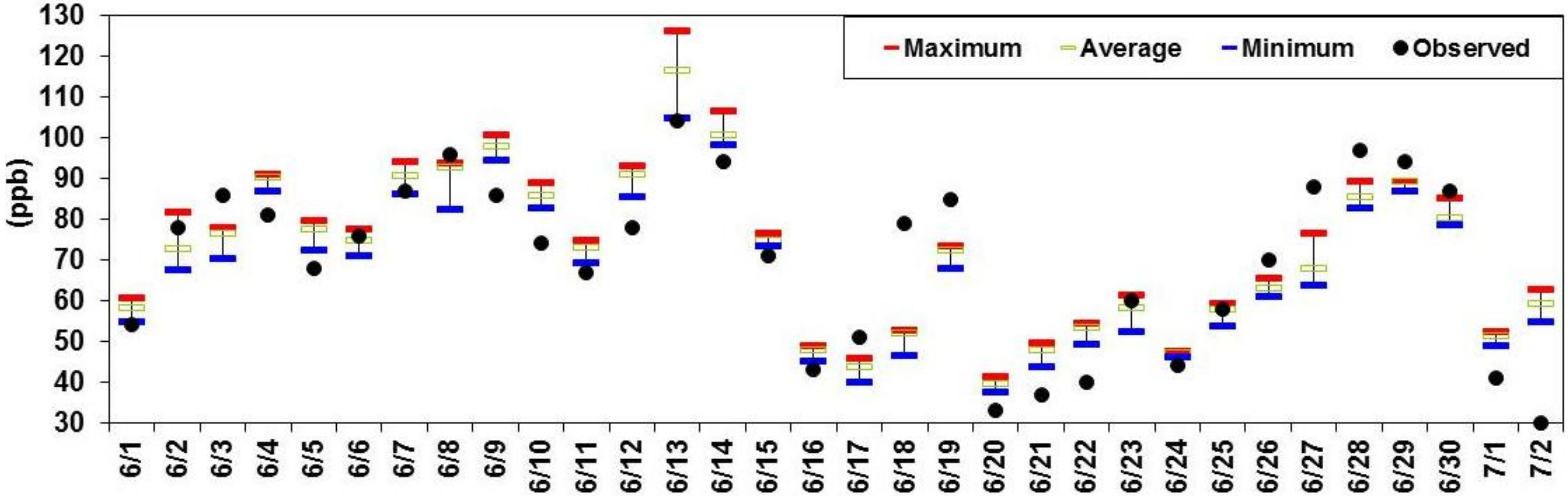
6/28
6/29
6/30
7/1
7/2

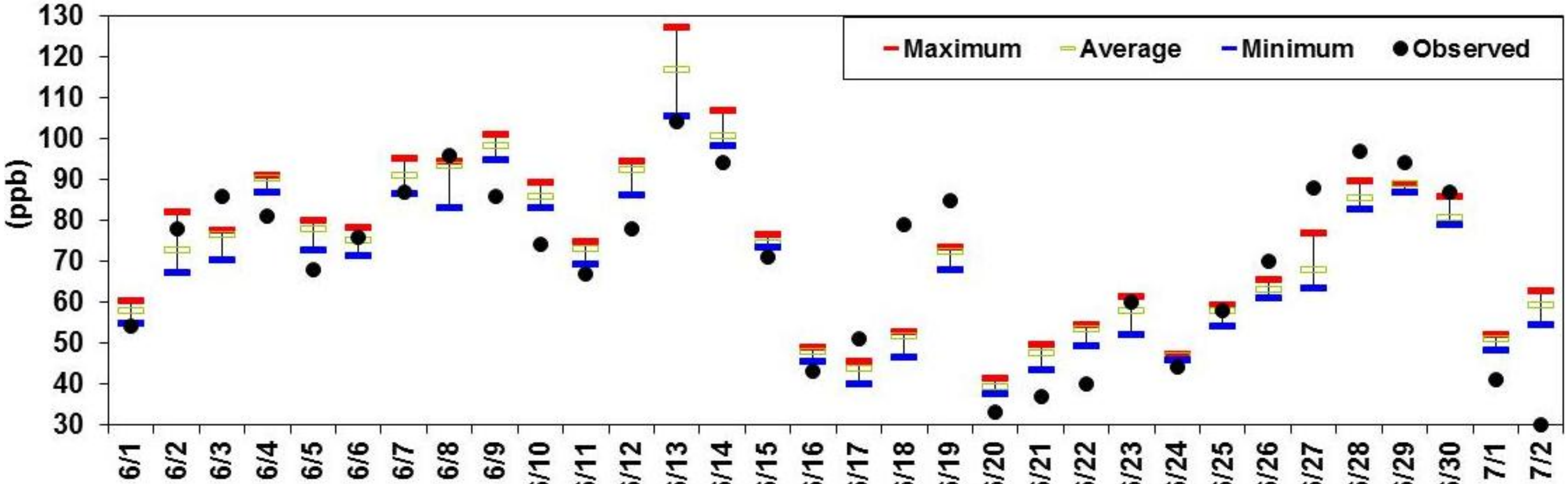
Figure 5-18: San Antonio Observed Ozone for CAMS 58 Daily Maximum 1-hr Average

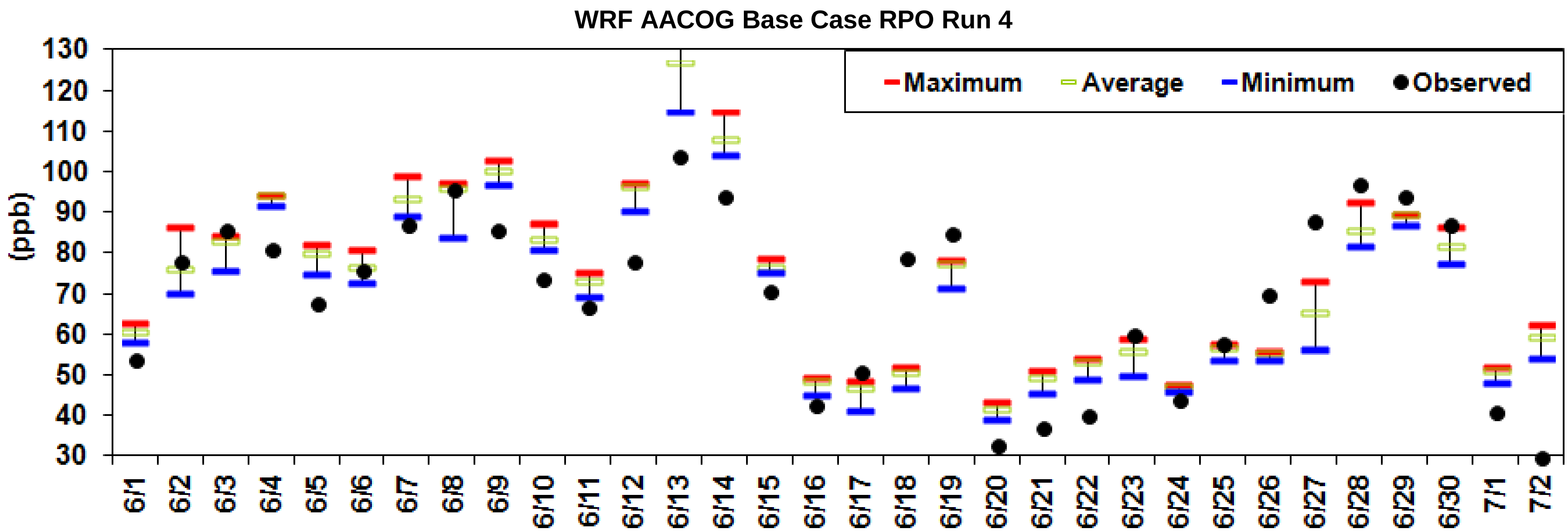


WRF TCEQ Base Case Run 2



WRF AACOG Base Case Run 3




WRF AACOG Base Case RPO Run 4
Maximum
Average
Minimum
Observed
(ppb)
130
120
110
100
90
80
70
60
50
40
30
6/1
6/2
6/3
6/4
6/5
6/6
6/7
6/8
6/9
6/10
6/11
6/12
6/13
6/14
6/15
6/16
6/17
6/18
6/19
6/20
6/21
6/22
6/23
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6/29
6/30
7/1
7/2

5.4 Statistical Analysis

There are several statistical measures recommended by the EPA for the purpose of evaluating performance of each base case run. This section will describe each statistical measurement, the statistical results for the modeled runs, and what the statistics indicate about overall model performance. The following six statistical measures were calculated to analyze the model's ability to predict ozone concentrations for the June 2006 episode: unpaired peak prediction accuracy, paired peak predicted accuracy, mean normalized bias, mean normalized gross error, average peak predicted bias, and average peak predicted error. All results are based on predicted hourly ozone values above 60 ppb at each monitor.

Unpaired Peak Prediction Accuracy (***PPAu***)

This statistical evaluation "compares the peak concentration modeled anywhere in the selected area against the peak ambient concentration anywhere in the same area. The difference of the peaks (model - observed) is then normalized by the peak observed concentration."[262] EPA recommends that the unpaired peak prediction accuracy be within 20 percent of the observed hourly ozone. The main purpose of this statistical analysis is to determine if the model is under predicting ozone formation at each monitor.

Equation 5-1, Unpaired Peak Prediction Accuracy

$$\text{PPAu} = 100 \times [(\text{peak}_{\text{pred}} \div \text{peak}_{\text{obs}})] - 1)$$

Mean Normalized Bias (**MB**)

"This performance statistic averages the model/observation residual, paired in time, normalized by observation, over all monitor times/locations. A value of zero would indicate that the model over-predictions and model under-predictions exactly cancel each other out."[263] The calculation of this measure is shown in Equation 5-2. According to the EPA, mean normalized bias should be within 15 percent.

Equation 5-2, Mean Normalized Bias

$$\text{MNB} = 1/n \sum_{1}^{n} \left[\frac{(\text{Model} - \text{Obs.})}{\text{Obs.}} \right] \bullet 100\%$$

[263] EPA, April 2007. "Guidance on the Use of Models and Other Analyses for Demonstrating Attainment of Air Quality Goals for Ozone, PM2.5, and Regional Haze." EPA Office of Air Quality Planning and Standards, Air Quality Analysis Division Air Quality Modeling Group Research Triangle Park, NC. EPA - 454/B-07-002. p. 198. Accessed online: http://www.epa.gov/scram001/guidance/guide/final-03-pm-rh-guidance.pdf. Last accessed 06/24/13.

Mean Normalized Gross Error (ME)

"Mean Normalized Gross Error (MNGE): This performance statistic averages the absolute value of the model/observation residual, paired in time, normalized by observation, over all monitor times/locations. A value of zero would indicate that the model exactly matches the observed values at all points in space/time."[264] The calculation of this measure is shown in Equation 5-3. The recommended maximum value for mean normalized gross error should be 35 percent.

Equation 5-3, Mean Normalized Gross Error

$$ME = 1/n \sum_{1}^{n} \left(\frac{|\text{Model} - \text{Obs.}|}{\text{Obs.}} \right) \bullet 100\%$$

Average Peak Predicted Bias and Error (*APPB* and *APPE*)

"Average Peak Prediction Bias and Error: These are measures of model performance that assesses only the ability of the model to predict daily peak 1-hour and 8-hour ozone. They are calculated essentially the same as the mean normalized bias and error …, except that they only consider daily maxima data (predicted versus observed) at each monitoring location."[265] These statistical measurements use Equation 5-2 for APPB and Equation 5-3 for APPE.

Following EPA guidance, these statistical measures were calculated for all hourly ozone pairs, ozone pairs on days that the 8-hour peak observed concentrations are greater than 60 ppb, and ozone exceedance days.[266] The statistical measures were also calculated for individual monitors averaged over all days in the June 2006 modeling episode. Days without complete observed datasets were removed from the statistics.

The results of these statistical analyses indicate the model over predicted peak ozone on most exceedance days except the June 26th exceedance day. Statistical results for the June 13th and 14th exceedance days were above the level recommended by EPA. Although, the statistics indicated significant over prediction on June, 20th, 21st, and 22nd, none of these days had peak ozone levels observed or predicted above 60 ppb. For model performance, over prediction of peak accuracy is considered better than under prediction because the calculations are based on the highest value in the grids cells surrounding the monitors. Figure 1-19 compares unpaired peak accuracy, mean normalized bias, and mean normalized error for each base case run.

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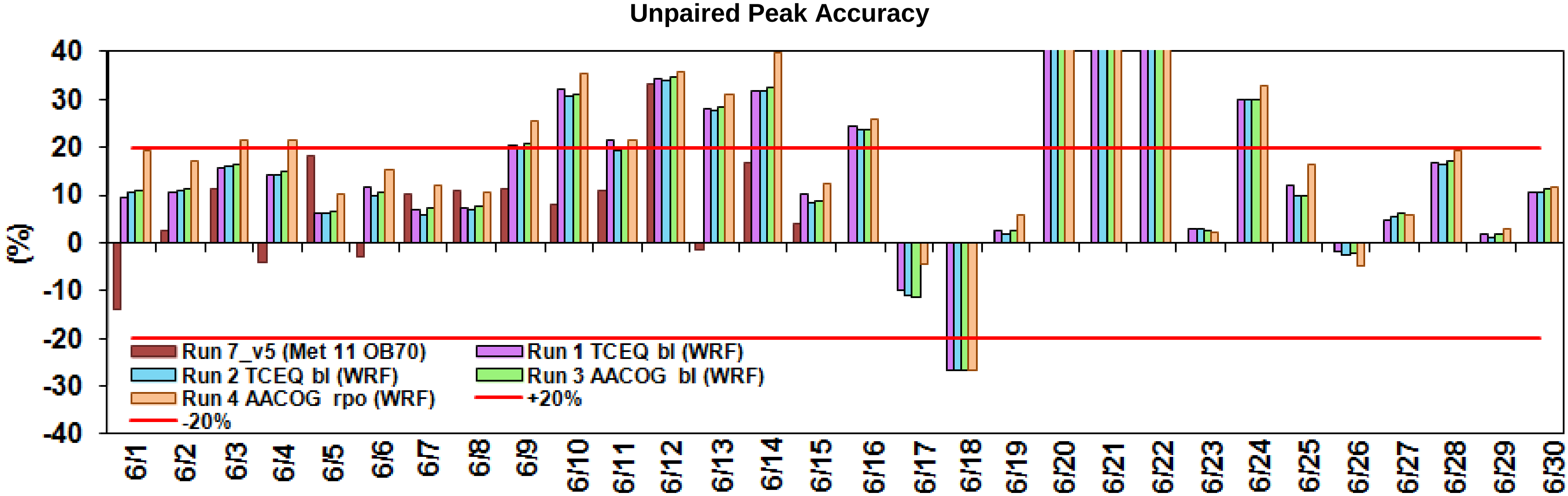
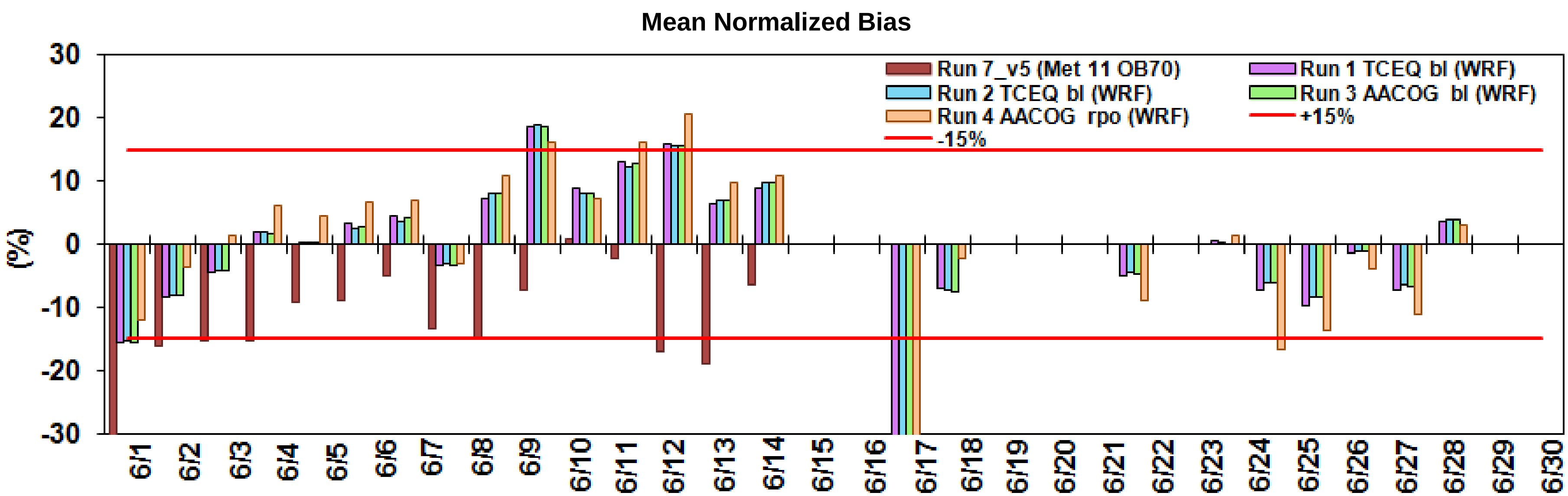
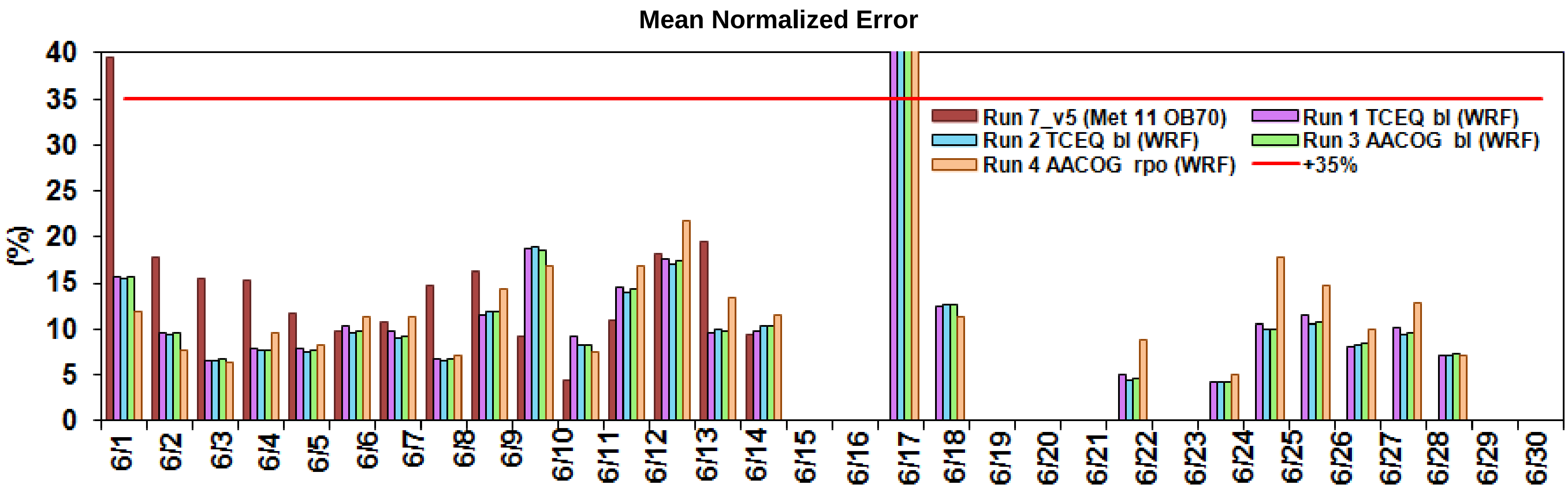
264 *Ibid*., p. 198.
265 *Ibid*., pp. 198 – 199.
266 *Ibid*., p. 199.

Figure 5-19: Daily performance for 1-hour Ozone in San Antonio on all Days for MM5 Base Case Run 7, WRF TCEQ Base Case Run 1, WRF TCEQ Base Case Run 2, WRF AACOG Base Case Run 3, and WRF AACOG RPO Base Case Run 4







Mean Normalized Error
(%)
40
35
30
25
20
15
10
5
0
Run 7_v5 (Met 11 OB70)
Run 1 TCEQ bl (WRF)
Run 2 TCEQ bl (WRF)
Run 3 AACOG bl (WRF)
Run 4 AACOG rpo (WRF)
+35%
6/1
6/2
6/3
6/4
6/5
6/6
6/7
6/8
6/9
6/10
6/11
6/12
6/13
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6/30

Table 5-1: Daily performance for 1-hour Ozone in San Antonio on all Days for WRF TCEQ Base Case Run 1, WRF TCEQ Base Case Run 2, WRF AACOG Base Case Run 3, and WRF AACOG RPO Base Case Run 4

Statistical Analysis	**Average All Days**				**Days > 60 ppb observed**				**Average On Exceedance Days**			
	WRF TCEQ Run 1	WRF TCEQ Run 2	WRF AACOG Run 3	WRF AACOG Run 4	WRF TCEQ Run 1	WRF TCEQ Run 2	WRF AACOG Run 3	WRF AACOG Run 4	WRF TCEQ Run 1	WRF TCEQ Run 2	WRF AACOG Run 3	WRF AACOG Run 4
Unpaired Peak Prediction Accuracy	16.1	15.5	16.0	19.6	13.1	11.7	12.3	15.5	12.4	12.7	13.7	16.4
Peak Bias (unpaired time)	*-0.4*	-0.3	-0.4	**0.2**	**0.1**	0.2	0.1	*0.8*	*0.5*	0.4	0.3	**0.2**
Peak Error (unpaired time)	7.9	**7.7**	7.8	*8.7*	8.0	**7.9**	7.9	*8.9*	7.5	**7.3**	7.4	*9.5*
Bias (normalized)	*-0.7*	-0.6	-0.7	**0.2**	**0.2**	0.3	0.2	*1.2*	*0.8*	0.6	0.5	**0.2**
Error (normalized)	11.5	**11.3**	11.4	*12.7*	11.7	**11.4**	11.5	*12.9*	10.3	**9.9**	10.0	*12.9*

The performance of MM5 run 7 version 5 was degraded as indicated by mean normalized bias and mean normalized error on most modeling days. However, model performance was good on most exceedance days for every WRF run. The only exceedance day on which every run failed to meet the EPA recommended value for mean normalized bias was on June 13^{th} . Every exceedance day exhibited normalized error within EPA recommended levels. As shown in Table 5-1, every WRF modeling runs exhibited similar performance for unpaired peak accuracy, paired peak accuracy, peak bias, peak error, normalized bias, and normalized error. Model performance on all days was improved with TCEQ run 2 and exceedance day performance was best for AACOG run 1. Performance for AACOG run 4 using the RPO grid was degraded for peak error and normalized error. This run predicted higher peak 1-hour ozone concentrations compared to the other 3 WRF runs.

The soccer-style plot in Figure 5-20 show most days are within EPA's recommendation for statistical analysis for values greater than 60 ppb for the first three WRF runs. To meet EPA's guidance for error and bias, values should be within the plots' blue squares. The one day for which measures of error and bias were near to the blue box in the graphs was June 18^{th} (upper left hand corner of the plot). The model significantly under-predicted ozone on this day, however June 18^{th} is not an exceedance day in the San Antonio New Braunfels MSA. June 13^{th} was the only exceedance day for which the normalized gross error-normalized bias was just outside of the box because the model over-predicted ozone on this day. For AACOG run 4 using the RPO grid, model performance was slightly degraded and two exceedance days - June 13^{th} and June 26^{th} - did not fall within the blue box.

When statistical analysis was performed on data for individual monitors (Figure 5-22), model performance was significantly improved for the WRF runs compared to MM5. Results for paired peak accuracy were very good for C58, C622, C501, C502, C503, and C506 and paired peak accuracy for the remaining monitors also met EPA recommended guidelines. Normalized error on exceedance days was between 8.64% and 17.37% for every monitor in the AACOG region: these values are well below EPA's recommendation of 35%. TCEQ run 2 with WRF demonstrated the best modeling performance overall, with the best performance for normalized error at every monitor except C505 on exceedance days (Table 5-3). WRF run 4 with the RPO grid had degraded performance for normalized error. Additionally, peak prediction accuracy was higher for most monitors.

Figure 5-20: Soccer-style Plot of Normalized Gross Error and Normalized Bias by Day, WRF AACOG Base Case Run 3

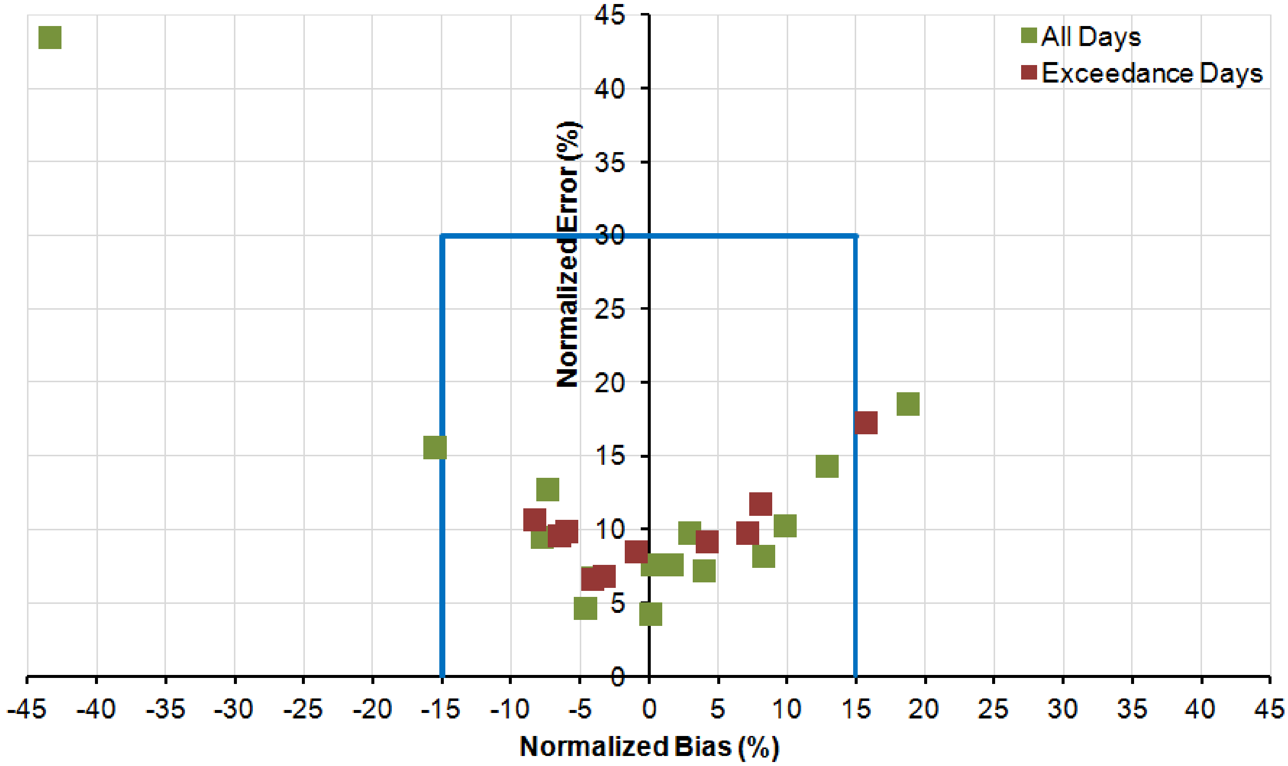


Figure 5-21: Soccer-style Plot of Normalized Gross Error and Normalized Bias by Exceedance Days, WRF AACOG RPO Base Case Run 4

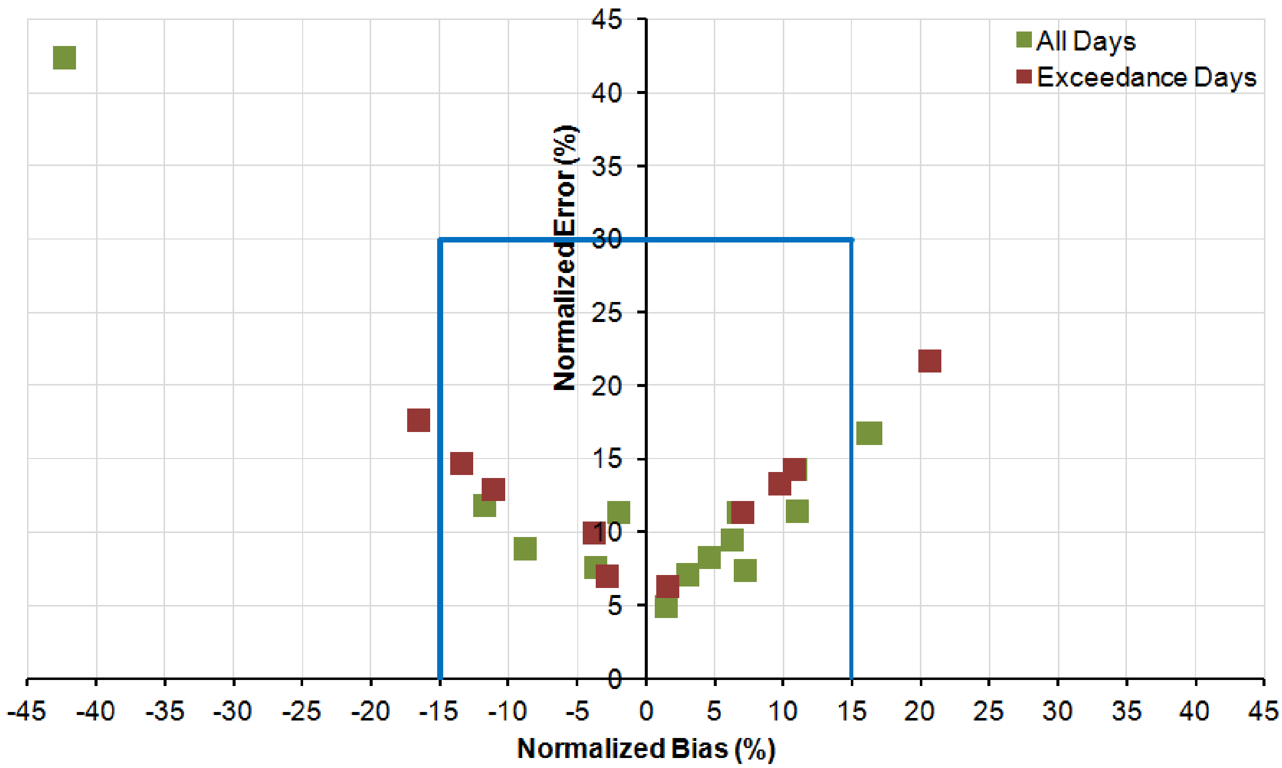
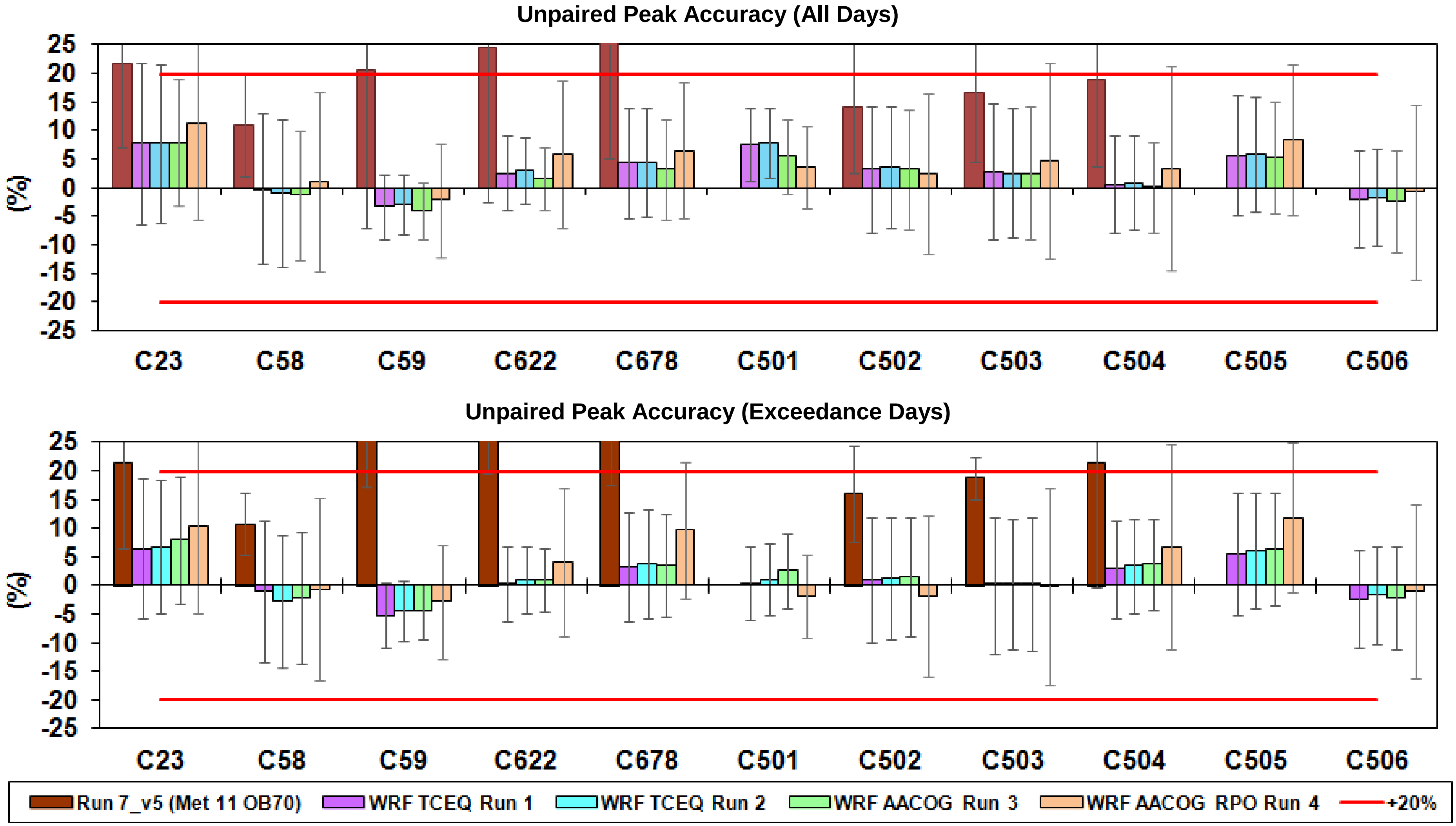
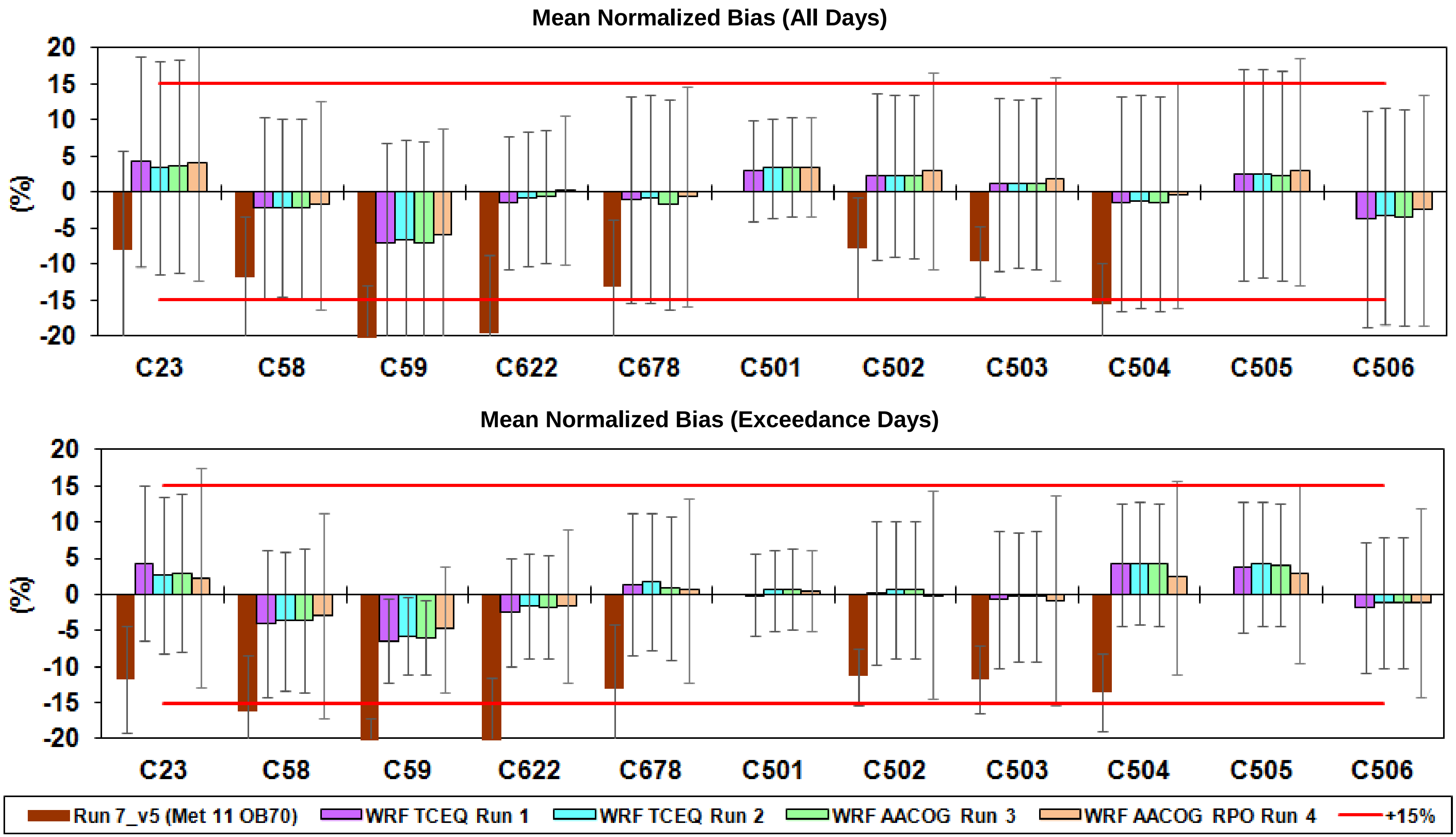


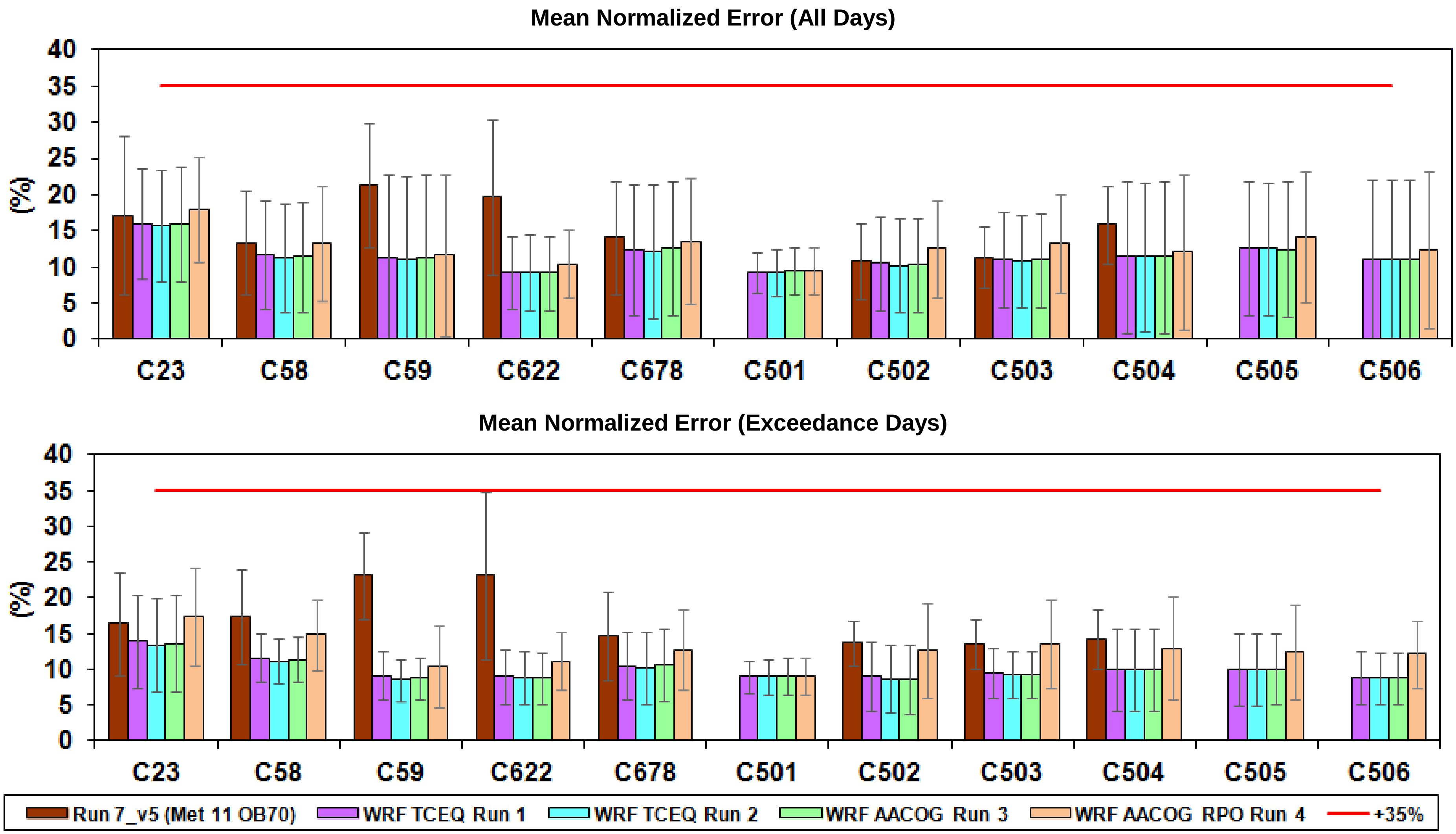
Figure 5-22: San Antonio CAMs performance for MM5 Base Case Run 7, WRF TCEQ Base Case Run 1, WRF TCEQ Base Case Run 2, WRF AACOG Base Case Run 3, and WRF AACOG RPO Base Case Run 4



Note: Data for C501, C505, and C506 is not available for run MM5 Base Case Run 7



Note: Data for C501, C505, and C506 is not available for run MM5 Base Case Run 7



Note: Data for C501, C505, and C506 is not available for run MM5 Base Case Run 7

Figure 5-23: Soccer-style Plot of Normalized Gross Error and Normalized Bias by Monitor for Every Day, WRF AACOG Base Case Run 3

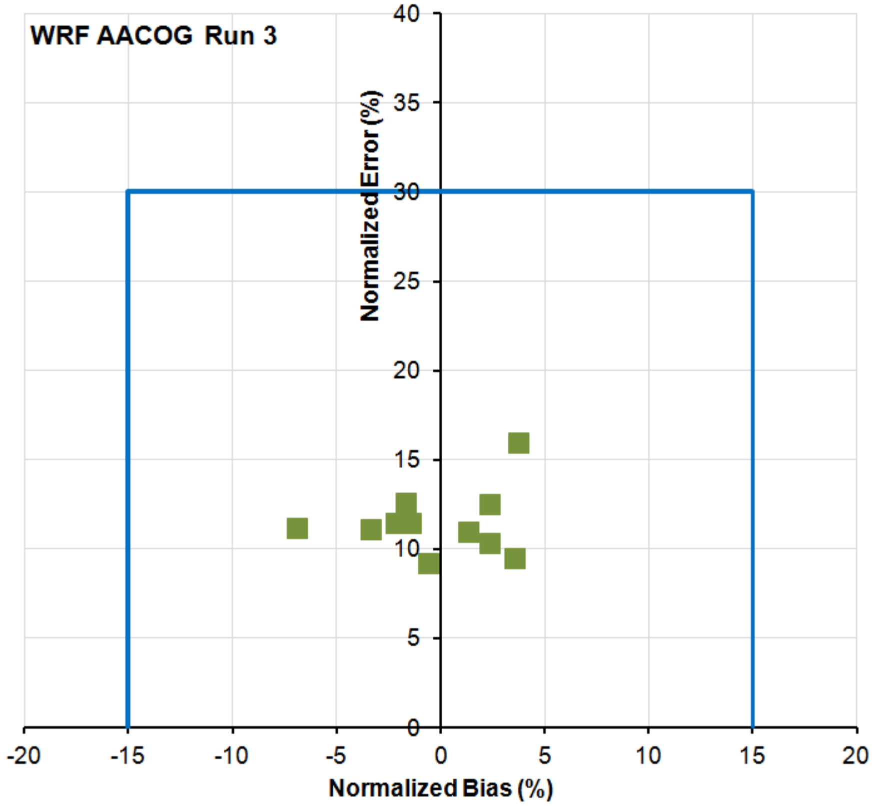


Figure 5-24: Soccer-style Plot of Normalized Gross Error and Normalized Bias by Monitor for Every Day, WRF AACOG RPO Base Case Run 4

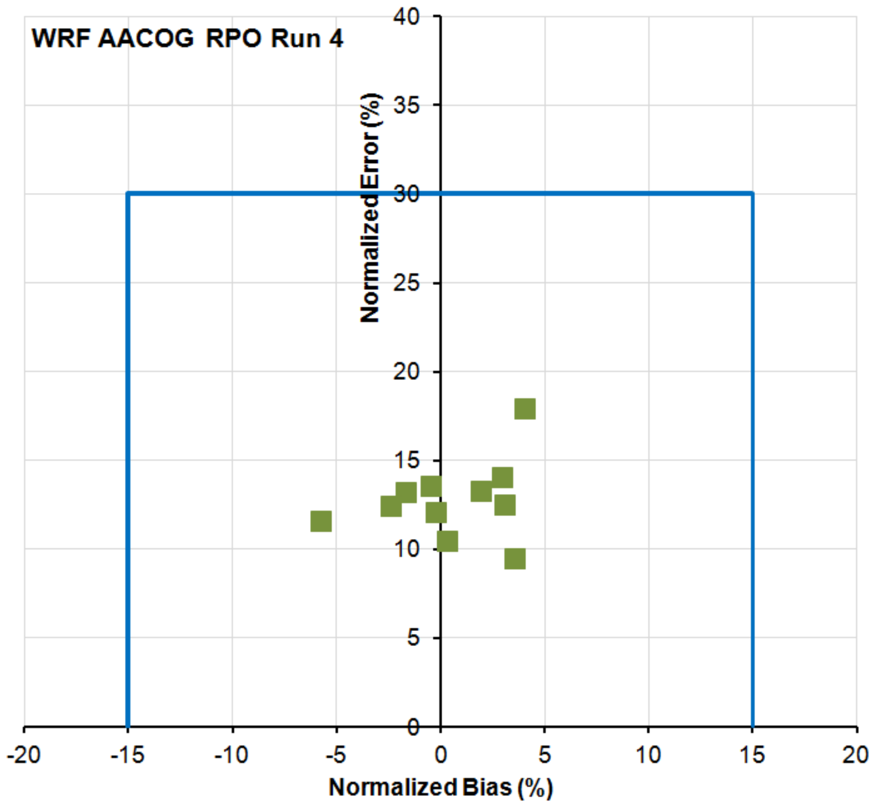


Figure 5-25: Soccer-style Plot of Normalized Gross Error and Normalized Bias by Monitor for Exceedance Days, WRF AACOG Base Case Run 3

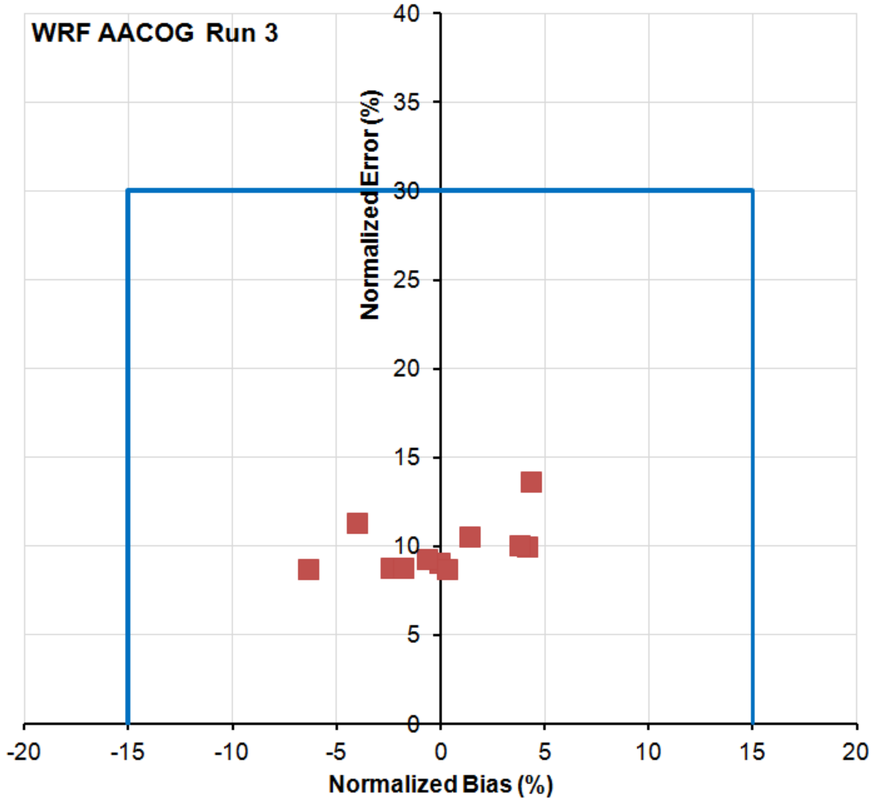


Figure 5-26: Soccer-style Plot of Normalized Gross Error and Normalized Bias by Monitor for Exceedance Days, WRF AACOG RPO Base Case Run 4

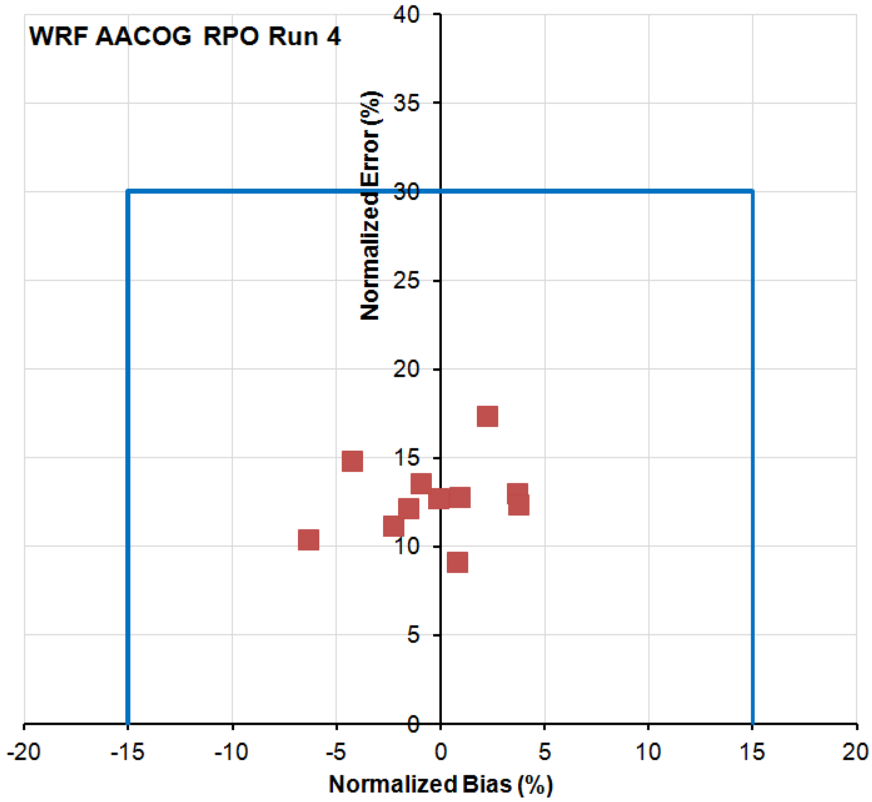


Table 5-2: San Antonio 8-hour Ozone CAMs performance in San Antonio, All Days average for MM5 Base Case Run 7, WRF TCEQ Base Case Run 1, WRF TCEQ Base Case Run 2, WRF AACOG Base Case Run 3, and WRF AACOG RPO Base Case Run 4

Statistical	CAMS Station	Average All Days				
		Run 7_v5 (Met 11 OB70)	WRF TCEQ Run 1	WRF TCEQ Run 2	WRF AACOG Run 3	WRF AACOG RPO Run 4
Unpaired Peak Prediction Accuracy	C23	21.87	7.73	7.77	7.93	11.33
	C58	11.04	-0.10	-0.94	-1.33	1.04
	C59	20.55	-3.29	-2.86	-4.02	-2.17
	C622	24.63	2.57	3.03	1.53	5.81
	C678	28.56	4.36	4.48	3.17	6.51
	C501		7.57	7.85	5.48	3.52
	C502	14.14	3.22	3.47	3.23	2.49
	C503	16.76	2.85	2.57	2.48	4.64
	C504	18.83	0.50	0.81	0.10	3.45
	C505		5.67	5.86	5.32	8.35
	C506		-2.04	-1.68	-2.35	-0.73
Peak Bias (unpaired time)	C23	**2.45**	*3.22*	2.52	2.71	3.06
	C58	*-5.56*	-1.70	-1.69	-1.68	**-1.22**
	C59	*-15.27*	-4.90	-4.59	-4.80	**-4.06**
	C622	*-11.83*	-0.97	-0.54	-0.43	**0.24**
	C678	*-6.31*	-0.66	-0.47	-1.04	**-0.31**
	C501		1.82	2.07	*2.23*	**0.32**
	C502	*-3.68*	**1.44**	**1.44**	1.49	2.07
	C503	*-3.24*	**0.69**	0.75	0.81	1.27
	C504	*-7.99*	-0.91	-0.77	-0.91	**-0.14**
	C505		1.76	1.92	**1.72**	*2.11*
	C506		*-2.43*	-2.14	-2.21	**-1.60**
Peak Error (unpaired time)	C23	**10.74**	11.24	11.04	11.19	*12.67*
	C58	**7.92**	8.67	8.37	8.47	*9.84*
	C59	*15.27*	7.61	**7.48**	7.56	7.90
	C622	*11.83*	6.18	6.15	**6.11**	7.16
	C678	**7.67**	8.38	8.24	8.49	*9.26*
	C501		6.70	**6.67**	6.80	*7.18*
	C502	*10.09*	7.28	**7.09**	7.15	8.66
	C503	**5.63**	7.65	7.46	7.56	*9.22*
	C504	*9.46*	7.67	**7.66**	7.67	8.21
	C505		8.70	8.64	**8.63**	*9.76*
	C506		7.47	**7.43**	**7.43**	*8.44*

Statistical	CAMS Station	Average All Days				
		Run 7_v5 (Met 11 OB70)	WRF TCEQ Run 1	WRF TCEQ Run 2	WRF AACOG Run 3	WRF AACOG RPO Run 4
Bias (normalized)	C23	*-8.08*	4.34	**3.47**	3.71	4.01
	C58	*-11.71*	-2.15	-2.15	-2.16	**-1.70**
	C59	*-21.32*	-7.10	-6.65	-6.93	**-5.80**
	C622	*-19.59*	-1.45	-0.82	-0.62	**0.25**
	C678	*-13.03*	-1.04	-0.86	-1.68	**-0.52**
	C501		3.02	3.37	*3.55*	**0.97**
	C502	*-7.79*	**2.25**	2.26	2.30	3.04
	C503	*-9.55*	**1.15**	1.24	1.30	1.92
	C504	*-15.60*	-1.47	-1.25	-1.47	**-0.26**
	C505		2.45	2.64	**2.34**	2.89
	C506		-3.69	-3.29	-3.39	**-2.43**
Error (normalized)	C23	*17.20*	16.06	**15.77**	15.97	17.96
	C58	*13.38*	11.73	**11.30**	11.44	13.28
	C59	*21.32*	11.27	**11.07**	11.19	11.63
	C622	*19.72*	9.27	9.26	**9.18**	10.49
	C678	*14.15*	12.46	**12.26**	12.62	13.61
	C501		9.33	**9.32**	9.50	*10.00*
	C502	*10.79*	10.52	**10.24**	10.31	12.57
	C503	*11.33*	11.06	**10.80**	10.95	13.28
	C504	*15.88*	**11.46**	**11.46**	**11.46**	12.10
	C505		12.62	12.54	**12.51**	*14.11*
	C506		11.16	11.16	**11.15**	*12.45*

Although the results of the paired prediction accuracy analyses were similar for each of the 4 WRF runs, there were some differences for individual monitors. The first run, TCEQ run 1, exhibited the lowest paired prediction accuracy at most monitors besides C58. Peak prediction accuracy was between 6.48% and 10.23% at C23 and between -0.57% and -2.81% at C58 on exceedance days. As shown in Figure 5-23 to Figure 5-26, these analyses were well within the criteria area (“goal box”) on the soccer plots for all monitors and on all days.

Table 5-3**:** San Antonio 8-hour Ozone CAMs performance in San Antonio, Exceedance Days average for MM5 Base Case Run 7, WRF TCEQ Base Case Run 1, WRF TCEQ Base Case Run 2, WRF AACOG Base Case Run 3, and WRF AACOG RPO Base Case Run 4

Statistical	CAMS Station	Average All Days				
		Run 7_v5 (Met 11 OB70)	WRF TCEQ Run 1	WRF TCEQ Run 2	WRF AACOG Run 3	WRF AACOG RPO Run 4
Unpaired Peak Prediction Accuracy	C23	21.43	6.48	6.79	8.06	10.23
	C58	10.77	-1.09	-2.81	-2.10	-0.57
	C59	34.42	-5.16	-4.45	-4.54	-2.72
	C622	36.65	0.36	1.02	1.08	4.21
	C678	35.13	3.27	3.78	3.66	9.70
	C501		0.55	1.13	2.63	-1.93
	C502	16.05	0.98	1.30	1.54	-1.84
	C503	18.77	0.01	0.37	0.29	-0.21
	C504	21.44	2.87	3.46	3.73	6.77
	C505		5.57	6.06	6.45	11.93
	C506		-2.35	-1.64	-2.19	-0.99
Peak Bias (unpaired time)	C23	**-1.13**	3.64	2.34	2.56	2.33
	C58	-7.25	-2.97	-2.71	**-2.64**	-2.88
	C59	-17.68	-4.73	**-4.24**	-4.44	-4.77
	C622	-14.30	-1.63	**-1.06**	-1.19	-1.53
	C678	-6.98	0.94	1.32	0.63	**0.62**
	C501		**-0.10**	0.35	0.50	*-2.43*
	C502	-6.17	0.07	0.29	0.30	**-0.04**
	C503	-6.83	-0.70	-0.42	**-0.39**	-0.80
	C504	-6.38	**2.77**	2.86	2.77	**2.41**
	C505		**2.87**	*3.24*	3.12	2.88
	C506		*-1.29*	**-0.76**	-0.79	-1.12
Peak Error (unpaired time)	C23	**8.57**	10.49	10.17	10.35	*13.05*
	C58	**8.82**	9.13	8.83	8.98	*11.62*
	C59	*17.68*	6.64	**6.27**	6.37	7.59
	C622	*14.30*	6.32	**6.17**	**6.17**	7.90
	C678	*9.48*	7.64	**7.43**	7.71	9.35
	C501		6.93	**6.90**	7.03	*7.65*
	C502	*11.10*	6.57	**6.32**	6.35	9.05
	C503	*9.60*	6.99	**6.71**	6.79	9.81
	C504	*9.90*	7.17	**7.13**	7.17	9.38
	C505		**7.37**	7.38	7.43	*9.13*
	C506		6.47	**6.32**	6.33	*8.85*

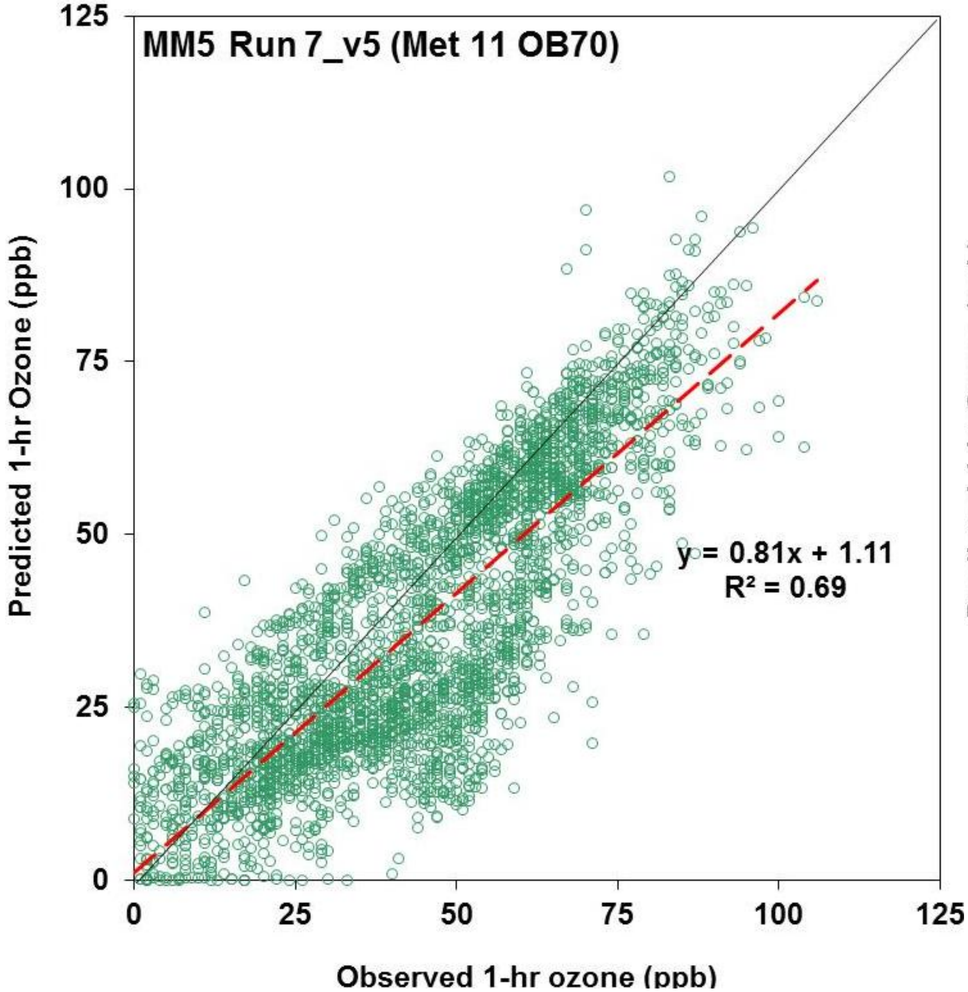
Statistical	CAMS Station	Average All Days				
		Run 7_v5 (Met 11 OB70)	WRF TCEQ Run 1	WRF TCEQ Run 2	WRF AACOG Run 3	WRF AACOG RPO Run 4
Bias (normalized)	C23	*-11.68*	4.33	2.69	2.96	**2.18**
	C58	*-16.25*	-4.01	-3.62	**-3.58**	-4.30
	C59	*-23.15*	-6.37	**-5.70**	-5.97	-6.40
	C622	*-23.15*	-2.38	**-1.59**	-1.75	-2.32
	C678	*-13.00*	1.41	1.81	**0.86**	0.88
	C501		**-0.05**	0.60	0.75	*-3.25*
	C502	*-11.37*	0.29	0.64	0.65	**-0.13**
	C503	*-11.78*	-0.67	-0.28	**-0.25**	-0.98
	C504	*-13.58*	4.16	4.28	4.16	**3.63**
	C505		**3.80**	*4.29*	4.16	3.63
	C506		*-1.82*	**-1.10**	-1.16	-1.59
Error (normalized)	C23	16.48	13.96	**13.48**	13.69	*17.37*
	C58	*17.35*	11.60	**11.19**	11.40	14.84
	C59	*23.15*	9.17	**8.64**	8.77	10.39
	C622	*23.18*	9.02	**8.81**	8.83	11.19
	C678	*14.72*	10.53	**10.18**	10.62	12.78
	C501		**9.00**	**9.00**	9.15	*9.95*
	C502	*13.73*	9.09	**8.71**	8.73	12.73
	C503	*13.55*	9.61	**9.23**	9.32	*13.55*
	C504	*14.24*	10.03	**10.02**	10.03	13.01
	C505		**10.00**	10.03	10.11	*12.37*
	C506		*8.96*	**8.77**	8.80	12.15

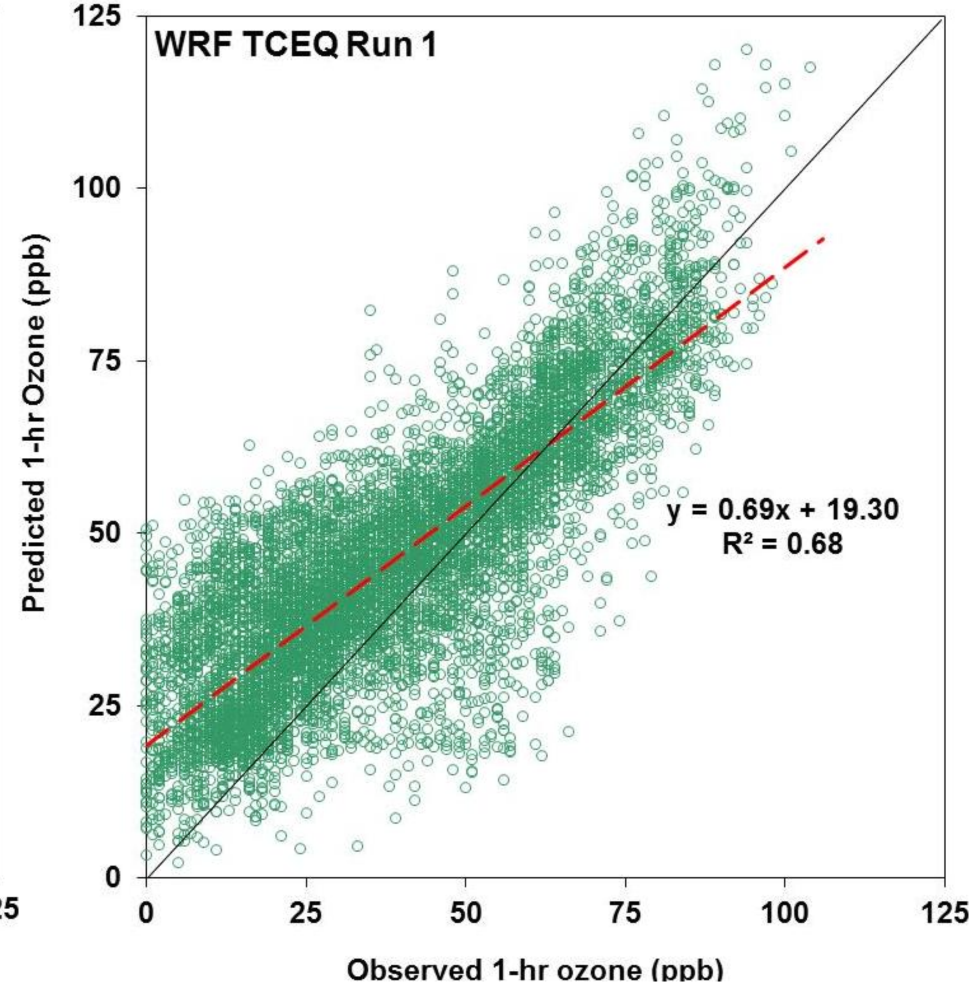
5.5 Ozone Scatter Plots

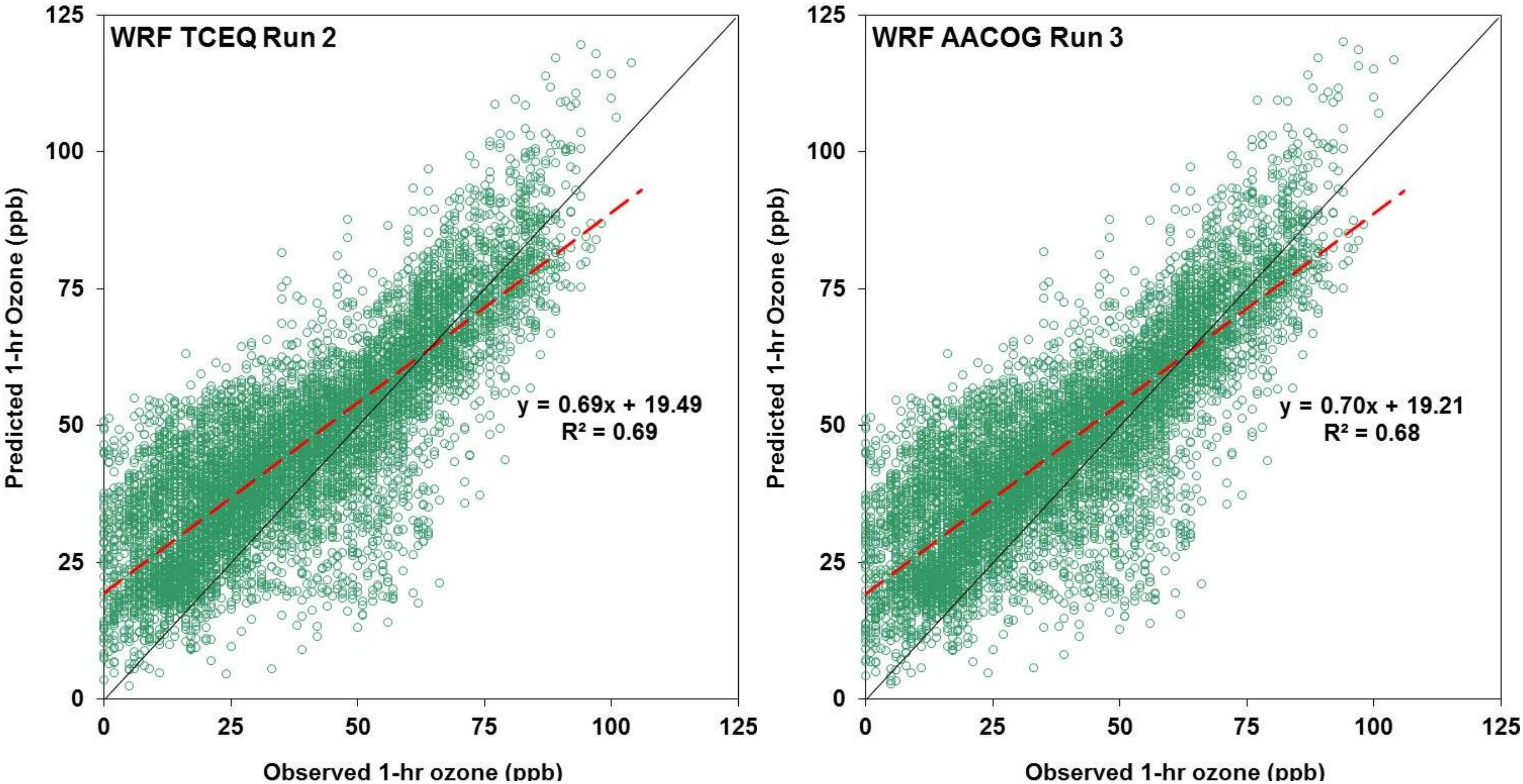
Scatter plots of hourly predicted and observed ozone readings at CAMS stations were plotted to determine how well the base case runs represented observed ozone (Figure 5-27). The scatter plots are based on hourly observed and predicted data from all the ozone monitors in the San Antonio-New Braunfels MSA. Each run tended to over predict ozone below 60 ppb, but correlated well for higher ozone values. Figure 5-28 provides the scatter plots for 8-hour daily maximum ozone for each run. Eight-hour observed and predicted ozone correlated well, although values below 60 ppb tended to be slightly over predicted.

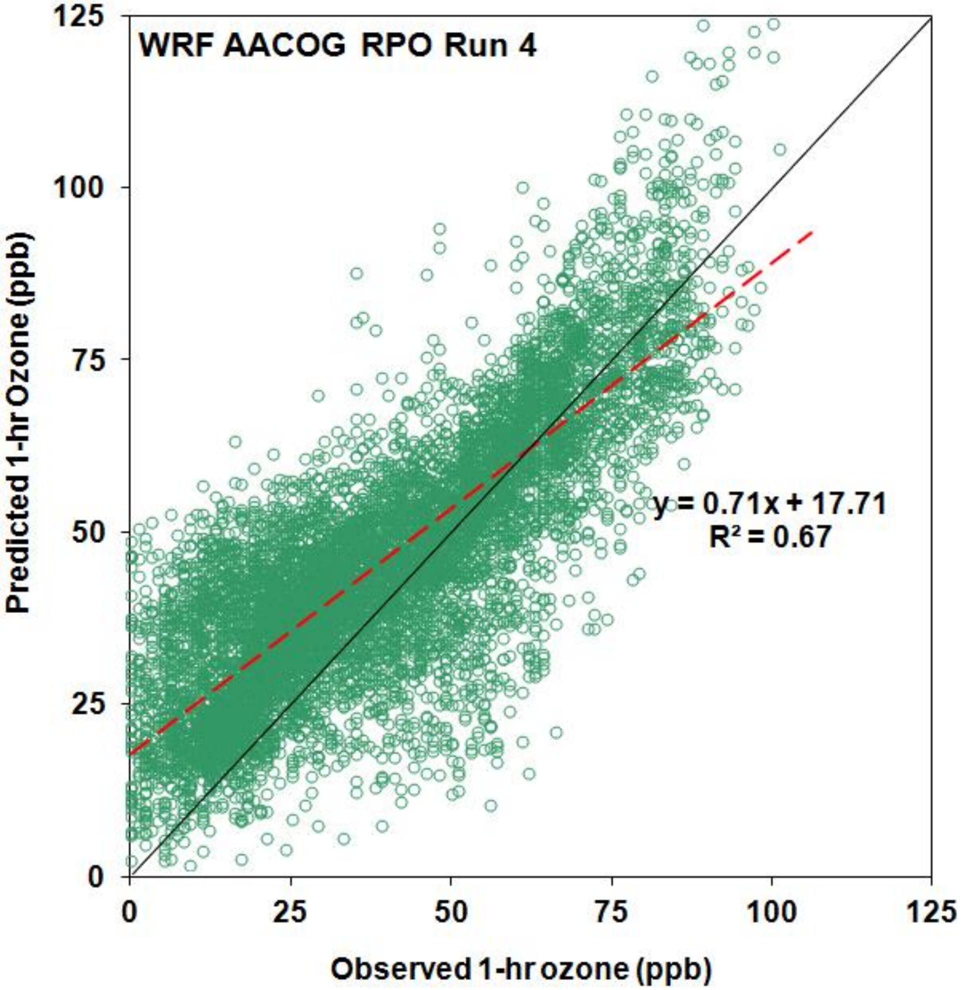
The R^2 values for predicted 8-hour ozone ranged from 0.74 to 0.75. Correlation between predicted and observed hourly ozone was good for both C23 and C58: R^2 values ranged from 0.67 to 0.70. Overall TCEQ run 2 demonstrated the best correlation for both 1 hour and 8 hour ozone (Table 5-4). Surprisingly, performance was slighted degraded when local emission inventory inputs were included in AACOG run 3. AACOG run 4 with the RPO grid, had degraded performance for hourly ozone values for all monitors, C23 and C58. Although performance was degraded for 1 hour values and on days > 60 ppb, ACCOG run 4 had the best performance for 8 hour values at C23 and C58 (R^2 was 0.75 and 0.73).

Figure 5-27: San Antonio Hourly Ozone Scatter Plots in San Antonio for MM5 Base Case Run 7, WRF TCEQ Base Case Run 1, WRF TCEQ Base Case Run 2, WRF AACOG Base Case Run 3, and WRF AACOG RPO Base Case Run 4



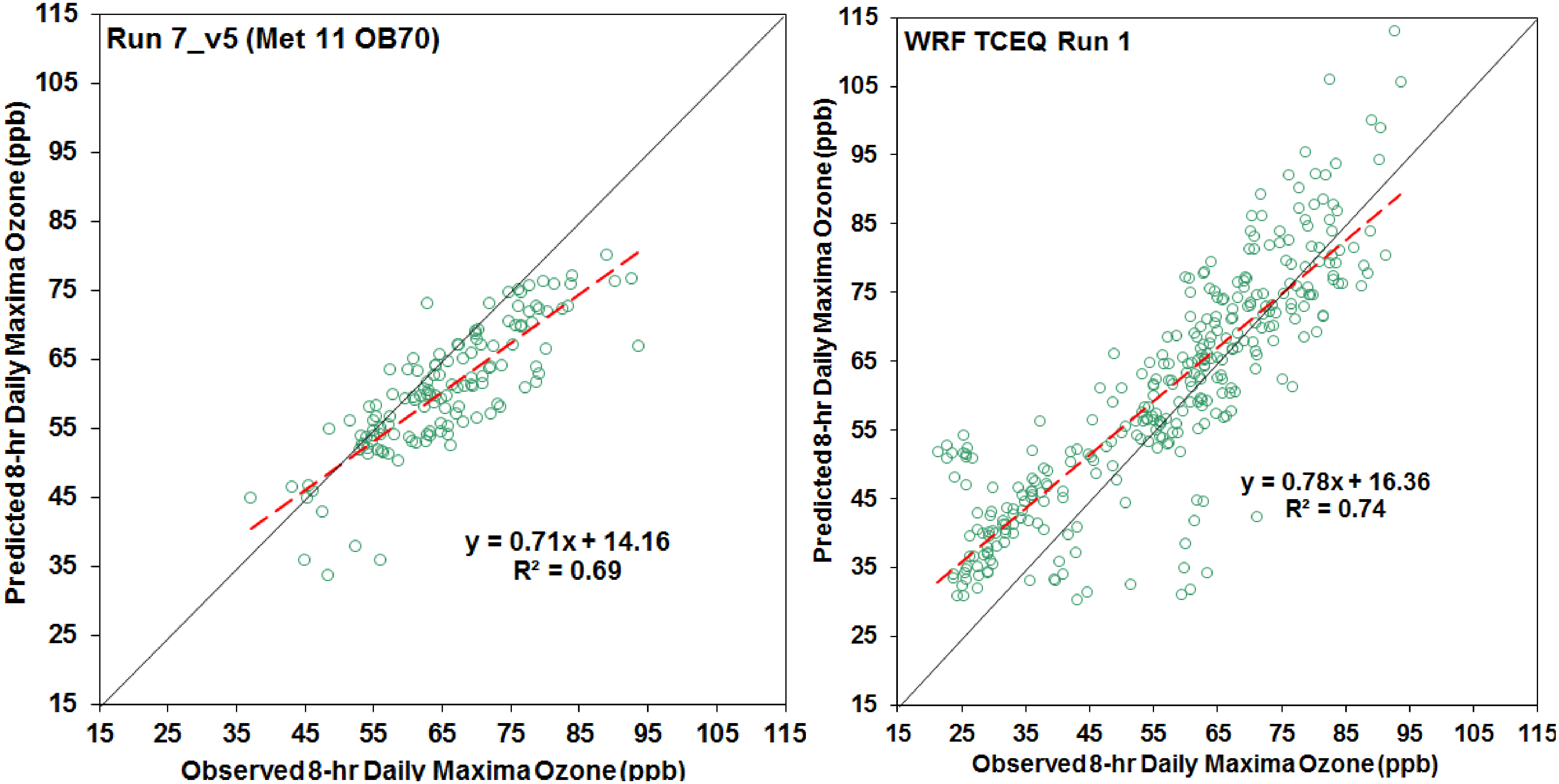


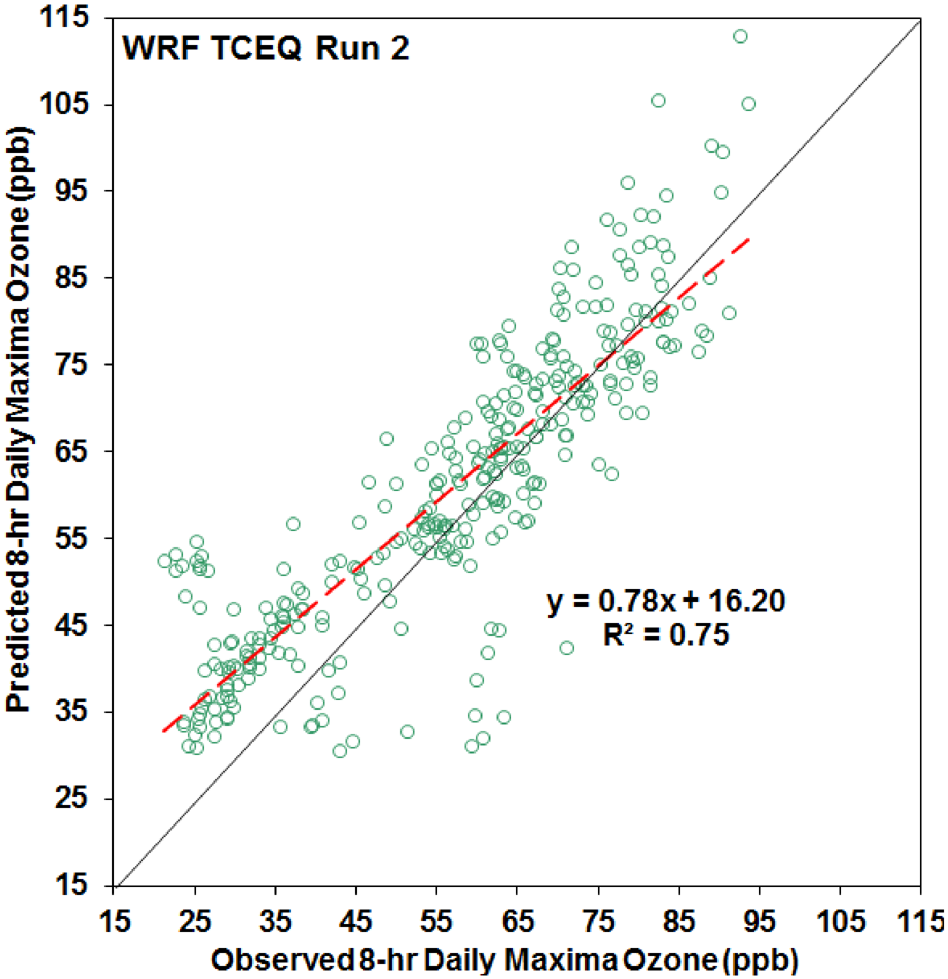

WRF TCEQ Run 2
y = 0.69x + 19.49
R² = 0.69
Predicted 1-hr Ozone (ppb)
Observed 1-hr ozone (ppb)
0
25
50
75
100
125
WRF AACOG Run 3
y = 0.70x + 19.21
R² = 0.68
Predicted 1-hr Ozone (ppb)
Observed 1-hr ozone (ppb)

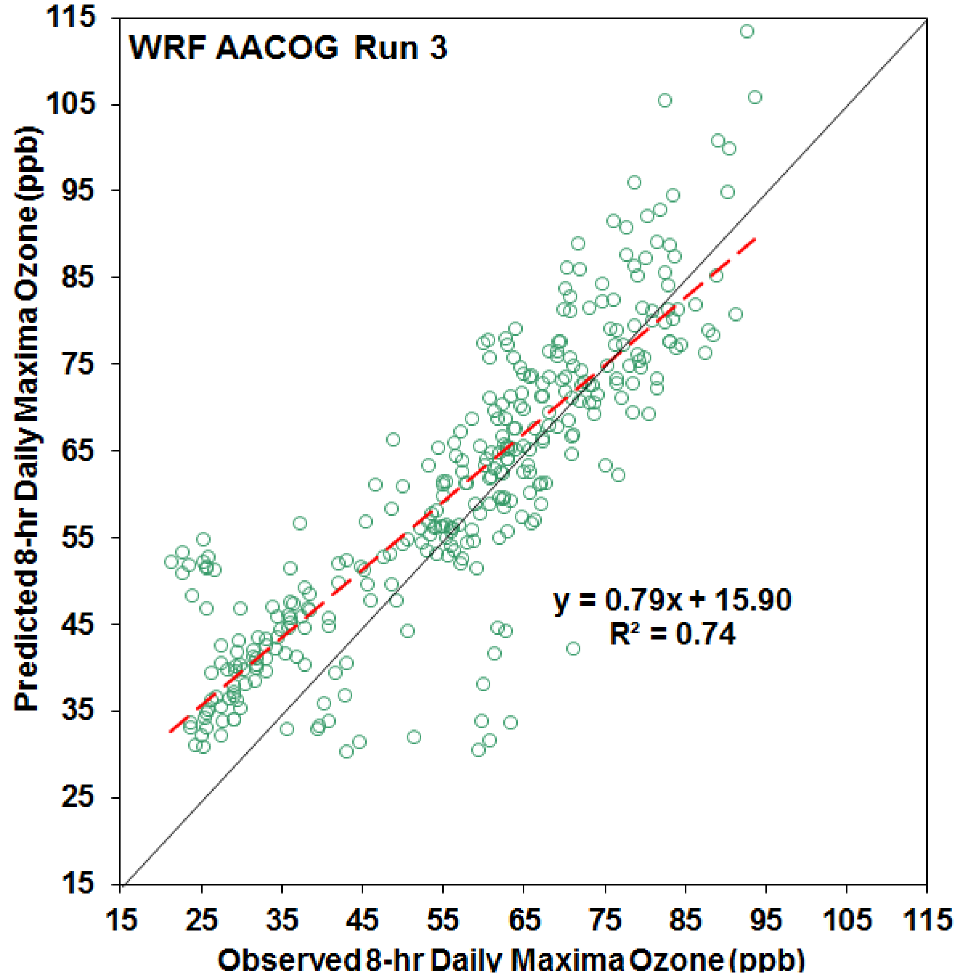


WRF AACOG RPO Run 4
y = 0.71x + 17.71
R² = 0.67
Predicted 1-hr Ozone (ppb)
Observed 1-hr ozone (ppb)
0
25
50
75
100
125

Figure 5-28: San Antonio 8-Hour Daily Maximum Ozone Scatter Plots in San Antonio for MM5 Base Case Run 7, WRF TCEQ Base Case Run 1, WRF TCEQ Base Case Run 2, WRF AACOG Base Case Run 3, and WRF AACOG RPO Base Case Run 4




WRF TCEQ Run 2
y = 0.78x + 16.20
R² = 0.75
Predicted 8-hr Daily Maxima Ozone (ppb)
Observed 8-hr Daily Maxima Ozone (ppb)
15
25
35
45
55
65
75
85
95
105
115


WRF AACOG Run 3
y = 0.79x + 15.90
R² = 0.74
Predicted 8-hr Daily Maxima Ozone (ppb)
Observed 8-hr Daily Maxima Ozone (ppb)
15
25
35
45
55
65
75
85
95
105
115

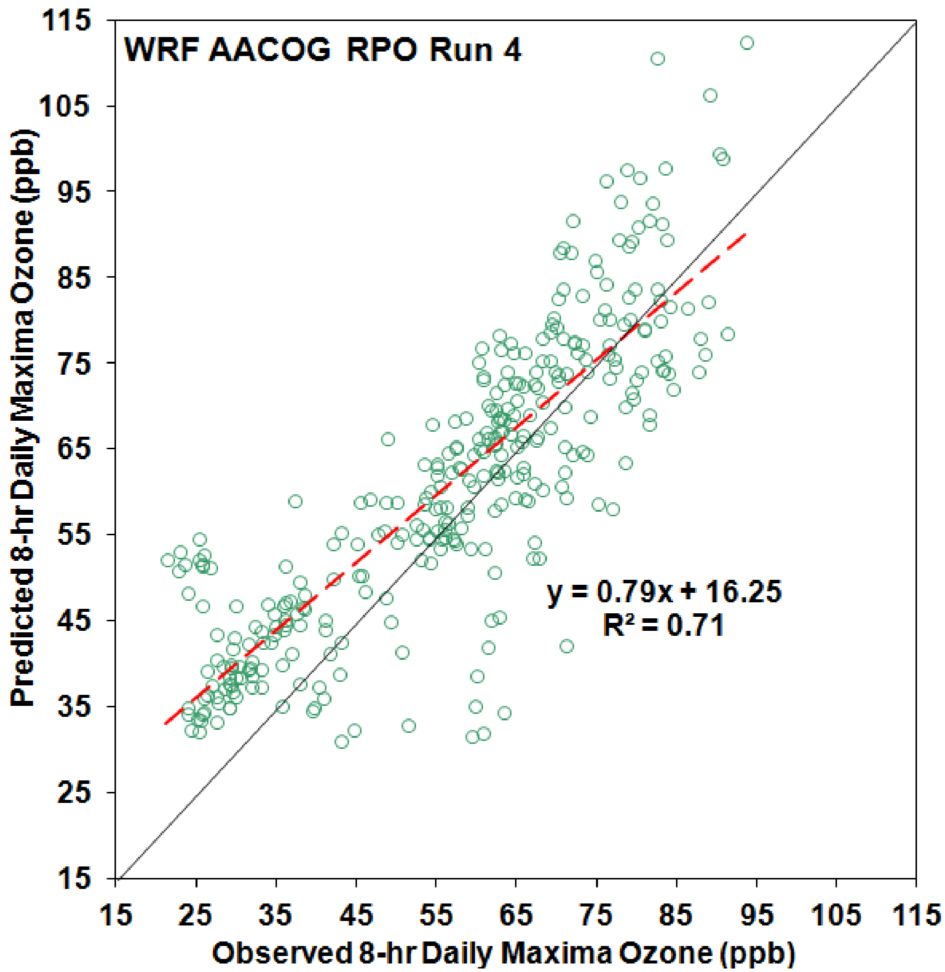

WRF AACOG RPO Run 4
y = 0.79x + 16.25
R² = 0.71
Predicted 8-hr Daily Maxima Ozone (ppb)
Observed 8-hr Daily Maxima Ozone (ppb)
115
105
95
85
75
65
55
45
35
25
15
15 25 35 45 55 65 75 85 95 105 115

Table 5-4: R^2 values for San Antonio Ozone Scatter Plots: MM5 Base Case Run 7, WRF TCEQ Base Case Run 1, WRF TCEQ Base Case Run 2, WRF AACOG Base Case Run 3, and WRF AACOG RPO Base Case Run 4

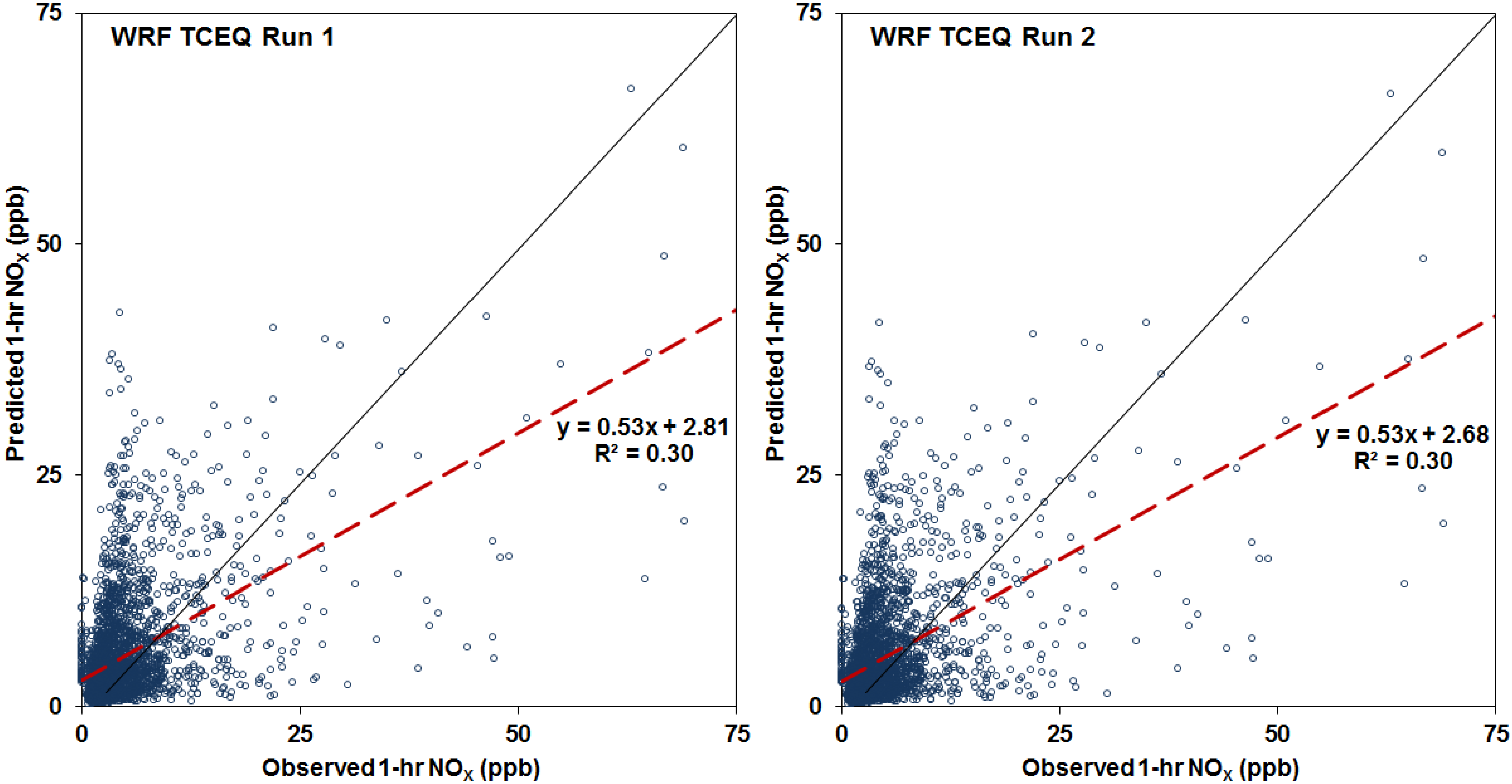
Date	Run	Hourly Ozone R^2						8-hour Daily Maxima Ozone R^2					
		All Hours			>60 ppb			All Hours			>60 ppb		
		All CAMS	C23	C58	All CAMS	C23	C58	All CAMS	C23	C58	All CAMS	C23	C58
June 1-15, 2006	MM5 Run 7_v5	*0.688*	*0.629*	*0.719*	*0.274*	*0.145*	*0.299*	*0.690*					
	WRF TCEQ Run 1	**0.737**	0.742	0.738	0.436	0.643	0.498	**0.775**	0.777	0.784	0.469	0.574	*0.540*
	WRF TCEQ Run 2	0.737	**0.744**	**0.741**	0.441	0.648	0.508	0.774	**0.778**	**0.785**	0.470	0.574	0.544
	AACOG Run 3	0.733	0.738	0.737	0.439	0.649	0.502	0.771	*0.773*	0.781	*0.463*	*0.569*	0.541
	AACOG RPO Run 4	0.734	0.741	0.738	**0.469**	**0.672**	**0.522**	0.772	**0.778**	*0.778*	**0.516**	**0.633**	**0.563**
June 1-July 2, 2006	WRF TCEQ Run 1	0.685	0.693	0.680	0.290	0.392	0.318	0.719	0.730	0.725	0.342	0.411	0.351
	WRF TCEQ Run 2	**0.686**	**0.697**	**0.681**	**0.298**	0.401	**0.328**	**0.720**	0.733	0.726	**0.355**	**0.416**	**0.360**
	AACOG Run 3	0.684	0.693	0.679	0.295	**0.403**	0.325	0.718	*0.730*	*0.724*	0.347	0.412	0.358
	AACOG RPO Run 4	*0.672*	*0.681*	*0.668*	*0.252*	*0.371*	*0.300*	*0.702*	**0.753**	**0.727**	*0.269*	*0.395*	*0.311*

5.6 NO_X Scatter Plots

Scatter plots of hourly predicted and observed NO_X concentrations at CAMS stations were plotted to determine how well the base case runs represented observed ozone (Figure 5-29). The scatter plots are based on observed and predicted data from C58, C59, C622, and C678 NO_X monitors for June 1st – July 2nd. The model over predicted NO_X when the observed value was below 10 ppb and under predicted when higher NO_X readings were recorded. The model performance for NO_X was poorer compared to the performance for ozone.

Model performance was poor for the C58 NO_X monitor in northwest San Antonio with an R^2 value between 0.12 and 0.13 (Table 5-5). The model significantly over predicted NO_X at C58 during most days of the modeling episode. Model performance was slightly improved at C59 and C622 with good performance at C678. AACOG run 4 with the RPO grid had improved performance at C58 and C622, but degraded performance at C59.

Figure 5-29: San Antonio Hourly NO_X Scatter Plots in San Antonio for WRF TCEQ Base Case Run 1, WRF TCEQ Base Case Run 2, WRF AACOG Base Case Run 3, and WRF AACOG RPO Base Case Run 4



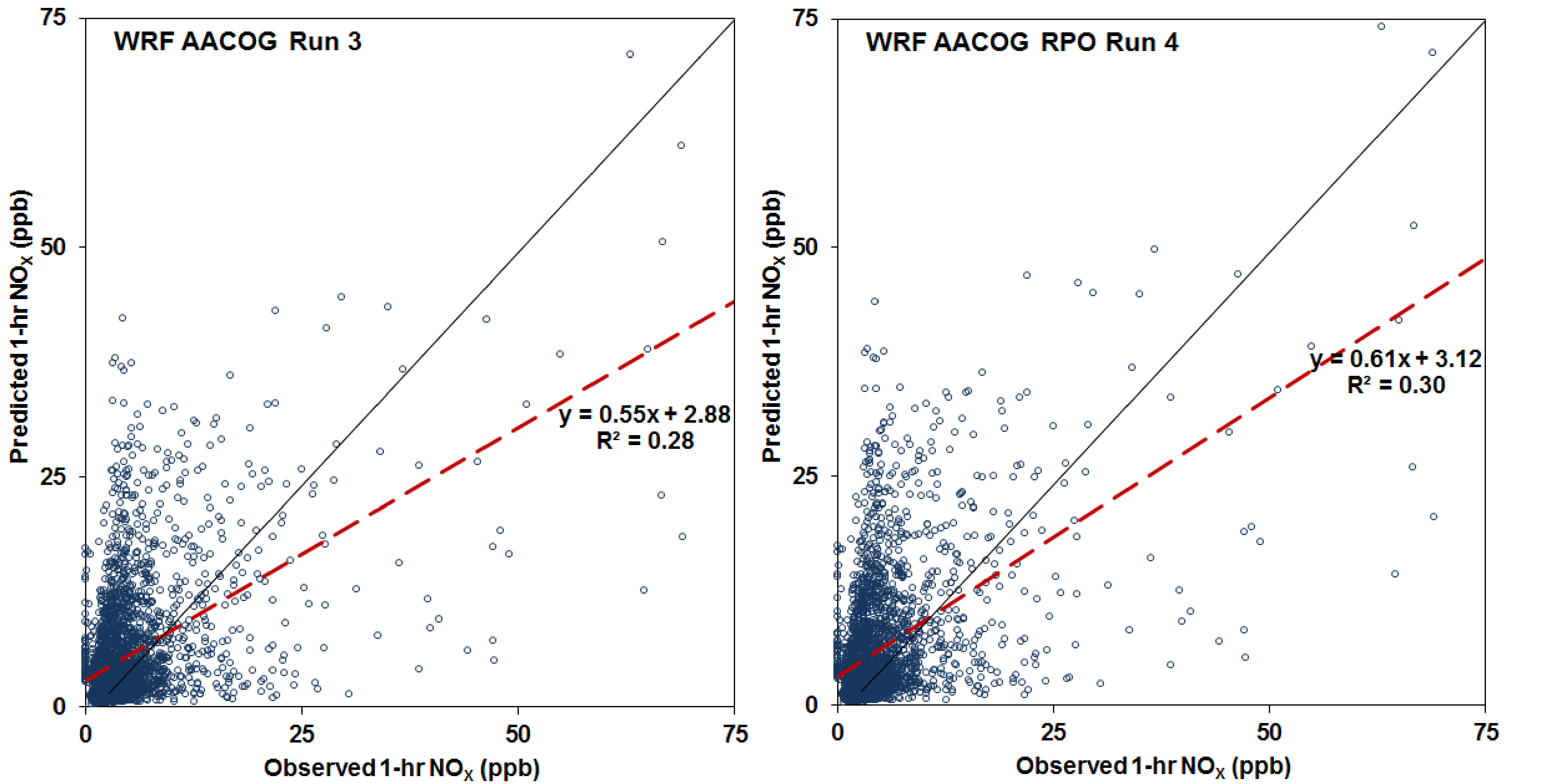

WRF AACOG Run 3
y = 0.55x + 2.88
R² = 0.28
Predicted 1-hr NOX (ppb)
Observed 1-hr NOX (ppb)
0
25
50
75
WRF AACOG RPO Run 4
y = 0.61x + 3.12
R² = 0.30

Table 5-5: R^2 values for San Antonio NO_X Scatter Plots, June 1-July 2, 2006: WRF TCEQ Base Case Run 1, WRF TCEQ Base Case Run 2, WRF AACOG Base Case Run 3, and WRF AACOG RPO Base Case Run 4

Run	All	C58	C59	C622	C678
TCEQ Run 1 (WRF)	0.298	*0.121*	0.270	*0.254*	0.573
TCEQ Run 2 (WRF)	**0.301**	0.123	**0.286**	0.265	**0.573**
AACOG Run 3 (WRF)	*0.281*	0.128	0.281	0.264	*0.500*
AACOG RPO Run 4 (WRF)	0.296	**0.131**	*0.261*	**0.266**	0.534

5.7 EPA Quantile-Quantile Plots

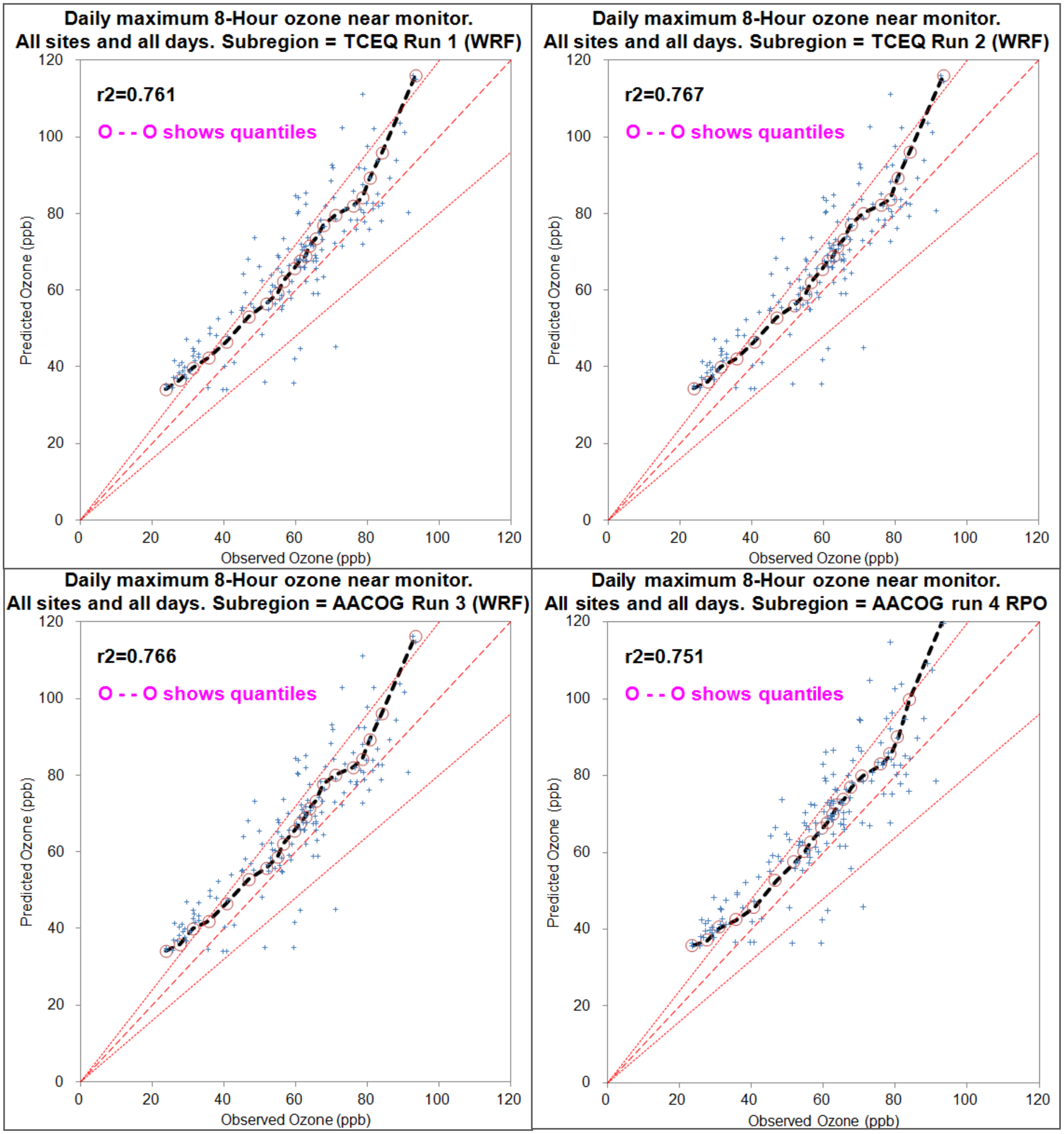
"The quantile-quantile (q-q) plot is a graphical technique for determining if two data sets come from populations with a common distribution. A q-q plot is a plot of the quantiles of the first data set against the quantiles of the second data set. By a quantile, we mean the point below which a given fraction (or percent) of points lies. That is, the 0.3 (or 30%) quantile is the point at which 30% percent of the data fall below and 70% fall above that value. A 45-degree reference line is also plotted. If the two sets come from a population with the same distribution, the points should fall approximately along this reference line. The greater the departure from this reference line, the greater the evidence for the conclusion that the two data sets have come from populations with different distributions."[267]

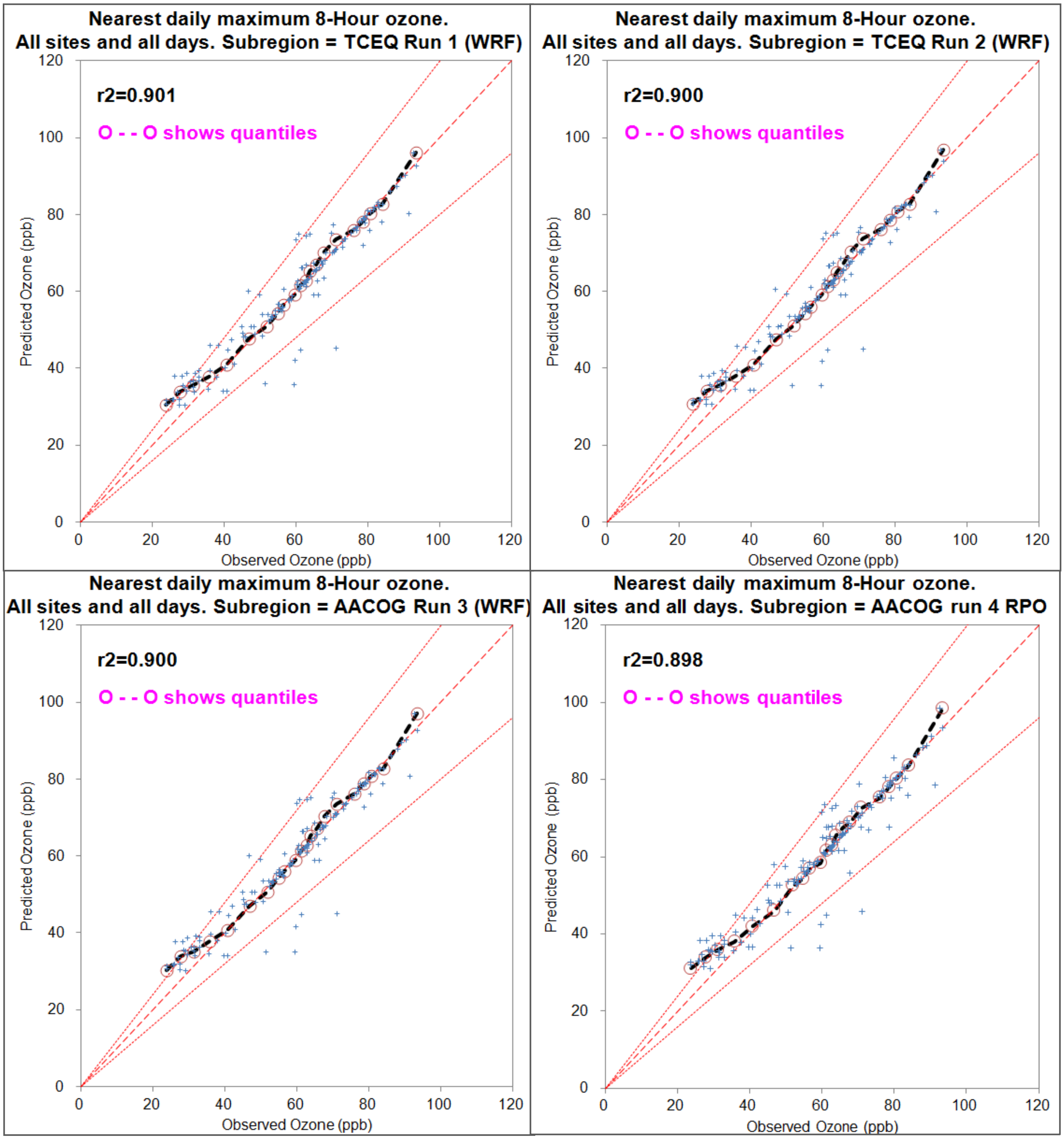
EPA quantile-quantile plots are provided in Figure 5-30 for daily maximum 8-hour ozone at each monitor, nearest daily maximum 8-hour ozone, and daily maximum 8-hour ozone near monitor. If the Q-Q plot results are close to the 1-1 line on each plot, the same number of low, medium, and high ozone values are predicted by the model as was measured at the monitor. For both 8-hour and 1-hour ozone plots, TCEQ run 2 had the best results. The R^2 value was similar for all 4 WRF runs and improved compared to the MM5 run 7. The R^2 value varied from 0.72 to 0.92 for the WRF runs which indicates good model performance with some degradation of performance for AACOG run 4 with the RPO grid.

Caution should be used when elevating the results from quantile-quantile plots. According to the EPA, quantile-quantile "plots may also provide additional information with regards to the distribution of the observations vs. predictions. But due to the fact that Q-Q plots are not paired in time, they may not always provide useful information. Care should be taken in interpreting the results."[268]

[267] NIST/SEMATECH, April, 2012. "e-Handbook of Statistical Methods". Available online: http://www.itl.nist.gov/div898/handbook/eda/section3/qqplot.htm. Accessed 06/12/13.
[268] EPA, April 2007. "Guidance on the Use of Models and Other Analyses for Demonstrating Attainment of Air Quality Goals for Ozone, PM2.5, and Regional Haze." EPA -454/B-07-002. Research Triangle Park, North Carolina. p. 201. Available online: http://www.epa.gov/scram001/guidance/guide/final-03-pm-rh-guidance.pdf. Accessed 06/24/13.

Figure 5-30: Quantile-Quantile Plots of daily peak 8-hour ozone for San Antonio: WRF TCEQ Base Case Run 1, WRF TCEQ Base Case Run 2, WRF AACOG Base Case Run 3, and WRF AACOG RPO Base Case Run 4.




Nearest daily maximum 8-Hour ozone.
All sites and all days. Subregion = TCEQ Run 1 (WRF)
r2=0.901
O - - O shows quantiles
Predicted Ozone (ppb)
Observed Ozone (ppb)
Nearest daily maximum 8-Hour ozone.
All sites and all days. Subregion = TCEQ Run 2 (WRF)
r2=0.900
O - - O shows quantiles
Predicted Ozone (ppb)
Observed Ozone (ppb)
Nearest daily maximum 8-Hour ozone.
All sites and all days. Subregion = AACOG Run 3 (WRF)
r2=0.900
O - - O shows quantiles
Predicted Ozone (ppb)
Observed Ozone (ppb)
Nearest daily maximum 8-Hour ozone.
All sites and all days. Subregion = AACOG run 4 RPO
r2=0.898
O - - O shows quantiles
Predicted Ozone (ppb)
Observed Ozone (ppb)
0
20
40
60
80
100
120

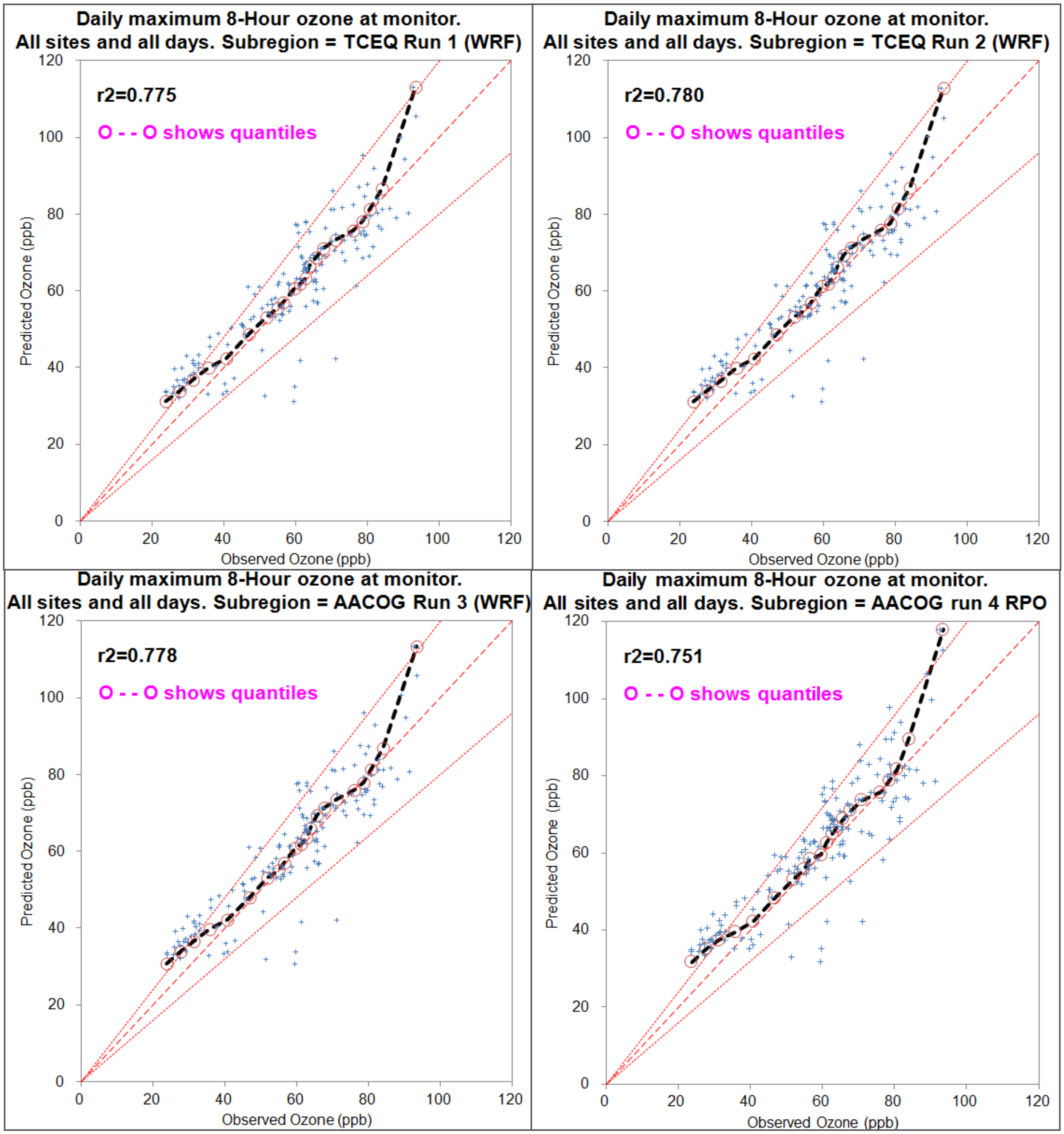

Daily maximum 8-Hour ozone at monitor.
All sites and all days. Subregion = TCEQ Run 1 (WRF)
r2=0.775
O - - O shows quantiles
Predicted Ozone (ppb)
Observed Ozone (ppb)
Daily maximum 8-Hour ozone at monitor.
All sites and all days. Subregion = TCEQ Run 2 (WRF)
r2=0.780
O - - O shows quantiles
Predicted Ozone (ppb)
Observed Ozone (ppb)
Daily maximum 8-Hour ozone at monitor.
All sites and all days. Subregion = AACOG Run 3 (WRF)
r2=0.778
O - - O shows quantiles
Predicted Ozone (ppb)
Observed Ozone (ppb)
Daily maximum 8-Hour ozone at monitor.
All sites and all days. Subregion = AACOG run 4 RPO
r2=0.751
O - - O shows quantiles
Predicted Ozone (ppb)
Observed Ozone (ppb)

Table 5-6: R^2 values for San Antonio Quantile-Quantile Plots: MM5 Base Case Run 7, WRF TCEQ Base Case Run 1, WRF TCEQ Base Case Run 2, and WRF AACOG Base Case Run 3

Run	Daily Maximum 1-Hour Ozone at Monitor R^2	Nearest Daily Maximum 1-Hour Ozone R^2	Daily Maximum 1-Hour Ozone Near Monitor R^2	Daily Maximum 8-Hour Ozone at Monitor R^2	Nearest Daily Maximum 8-Hour Ozone R^2	Daily Maximum 8-Hour Ozone Near Monitor R^2
Run 7_v5 (Met 11 OB70)	*0.582*	*0.908*	*0.585*	*0.689*	*0.881*	*0.658*
TCEQ Run 1 (WRF)	0.745	**0.922**	0.737	0.779	**0.901**	0.761
TCEQ Run 2 (WRF)	**0.751**	0.919	**0.742**	**0.780**	0.900	**0.767**
AACOG Run 3 (WRF)	0.748	0.920	0.742	0.778	0.900	0.766
AACOG RPO Run 4 (WRF)	0.724	0.919	0.736	0.751	0.898	0.751

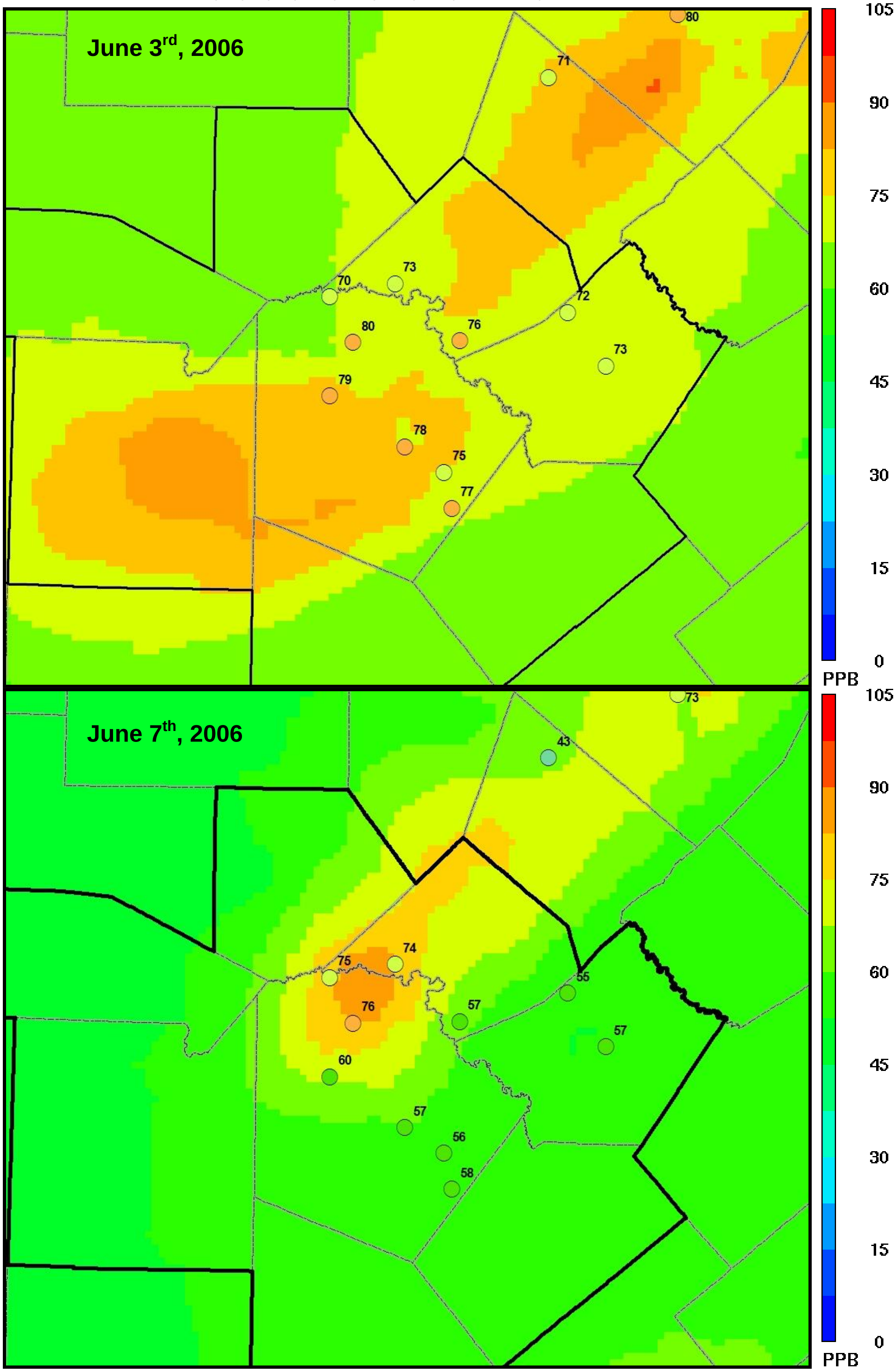
5.8 Daily Maximum 8-Hour Ozone Fields

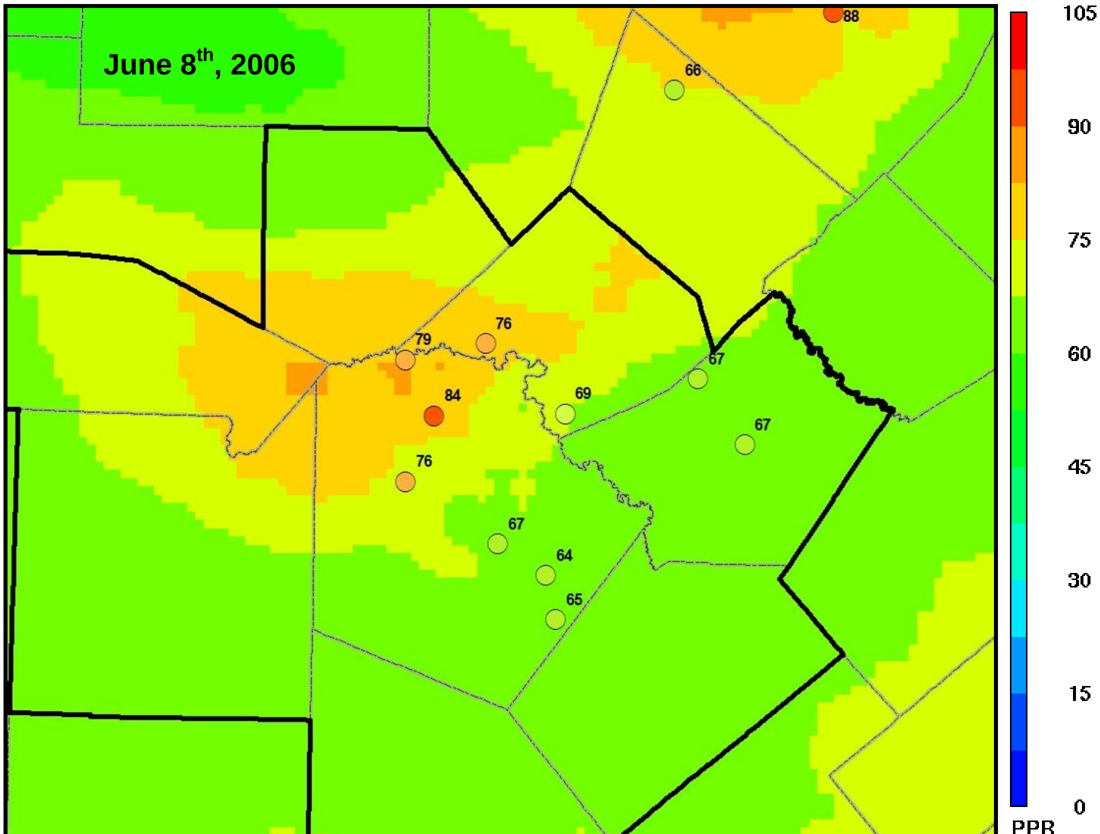
Another means of analyzing model performance recommended by the EPA is use of tile plot graphics. Figure 5-31 shows tile plots of predicted maximum ozone across the modeling domain for AACOG run 3 for each exceedance day. The plots for AACOG run 3 are similar to TCEQ run 1 and TCEQ run 2. These plots display the geographic distribution of the model's ozone predictions. Observed ozone at each monitor is plotted, color coded, and overlaid above the map of predicted ozone. The tile plots indicated that there were no unusual patterns of ozone formation. As seen on the plots for ozone exceedance days, ozone plumes were produced in the vicinity of San Antonio and Austin. These urban plumes were predicted for each urban core and downwind areas of the cities. The plots were also animated to examine the timing and location of ozone formation. The animation of the tile plots indicated that there was adequate model performance on all days.

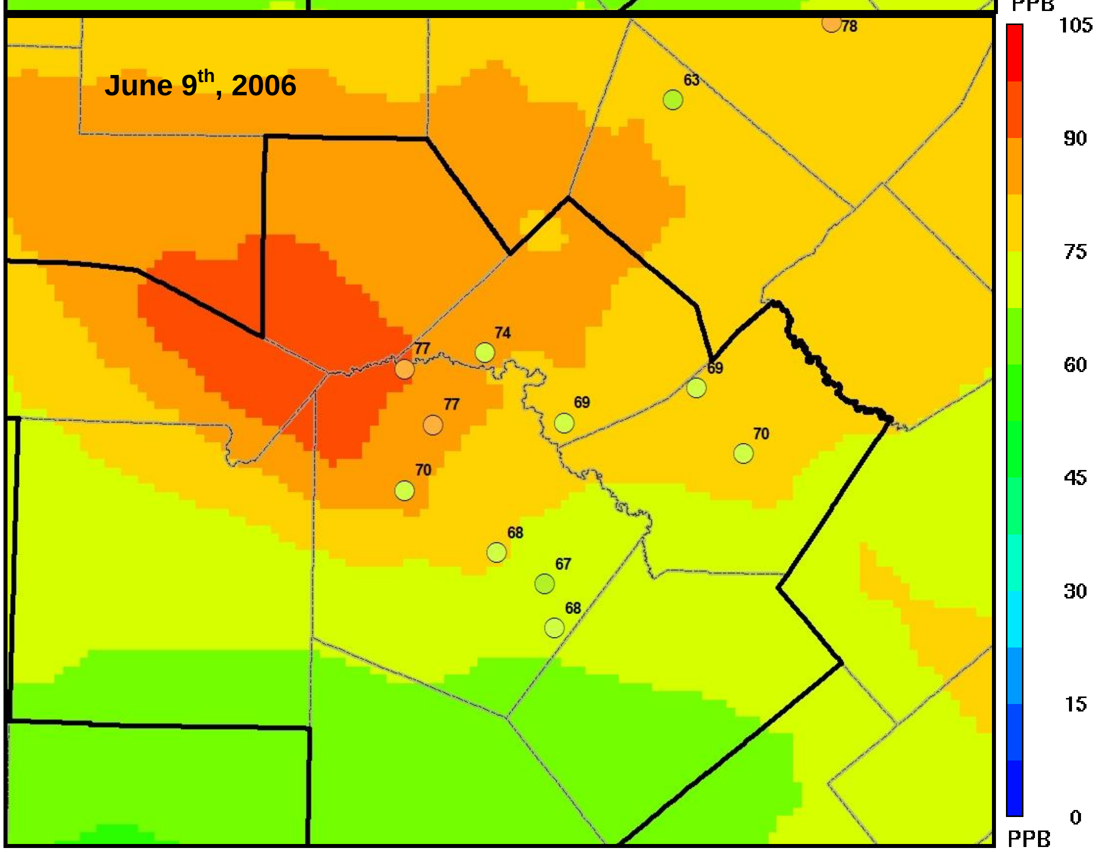
The daily tile plots for June 3rd, June 27th, and June 28th indicate good correlation between predicted and observed peak ozone. The model accurately predicted the locations of high ozone located at C58 and low ozone at C23 and the monitors southeast of San Antonio on June 7th. There was a slight over prediction of ozone in the San Antonio region on June 9th and on June 13th at C502. Ozone was over predicted at the monitors in northwest San Antonio, C23, C58, C502, and C504, on June 29th.

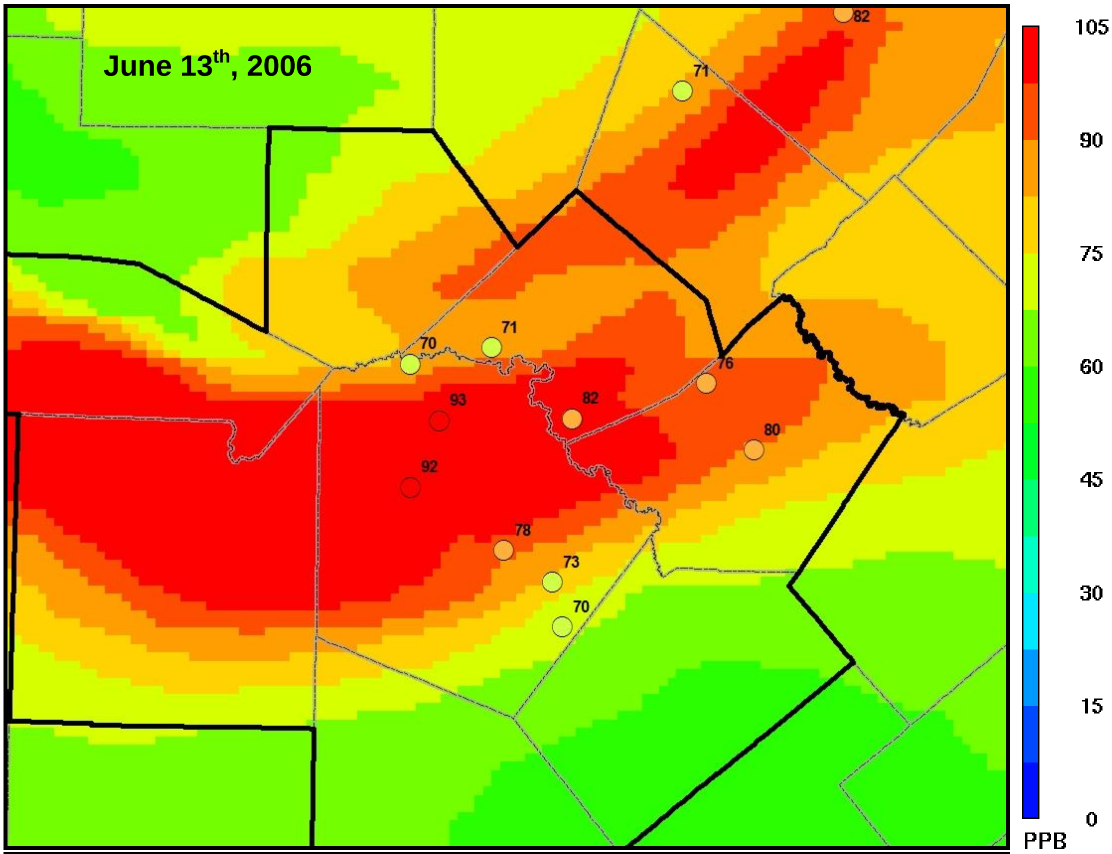
On Table 5-7, the predicted daily maximum 1-hour ozone concentrations within the San Antonio MSA are listed for each run. There was good correlation between observed and predicted ozone on the June 3rd, June 7th, June 8th, June 26th, June 27th, and June 29th exceedance days. On these days, there was only a -3.2 ppb to 6.3 ppb difference between predicted and observed hourly ozone. Every WRF run over-predicted ozone formation on the June 9th, 13th, and 14th exceedance days. Over prediction on these days ranged from 15.4 ppb to 23.0 ppb. Model performance was improved using WRF compared to MM5, especially on the exceedance days of June 7th and 8th. When comparing the WRF runs, TCEQ run 2 exhibited the best performance for all days and days greater than 74 ppb, while AACOG run 3 exhibited the best performance on days when the maximum hourly ozone was greater than 84 ppb.

Figure 5-31: Predicted Daily Maximum 8-hour Ozone Concentrations for WRF AACOG Base Case Run 3: June 3, 7, 8, 9, 13, 14, 27, 28, and 29, 2006

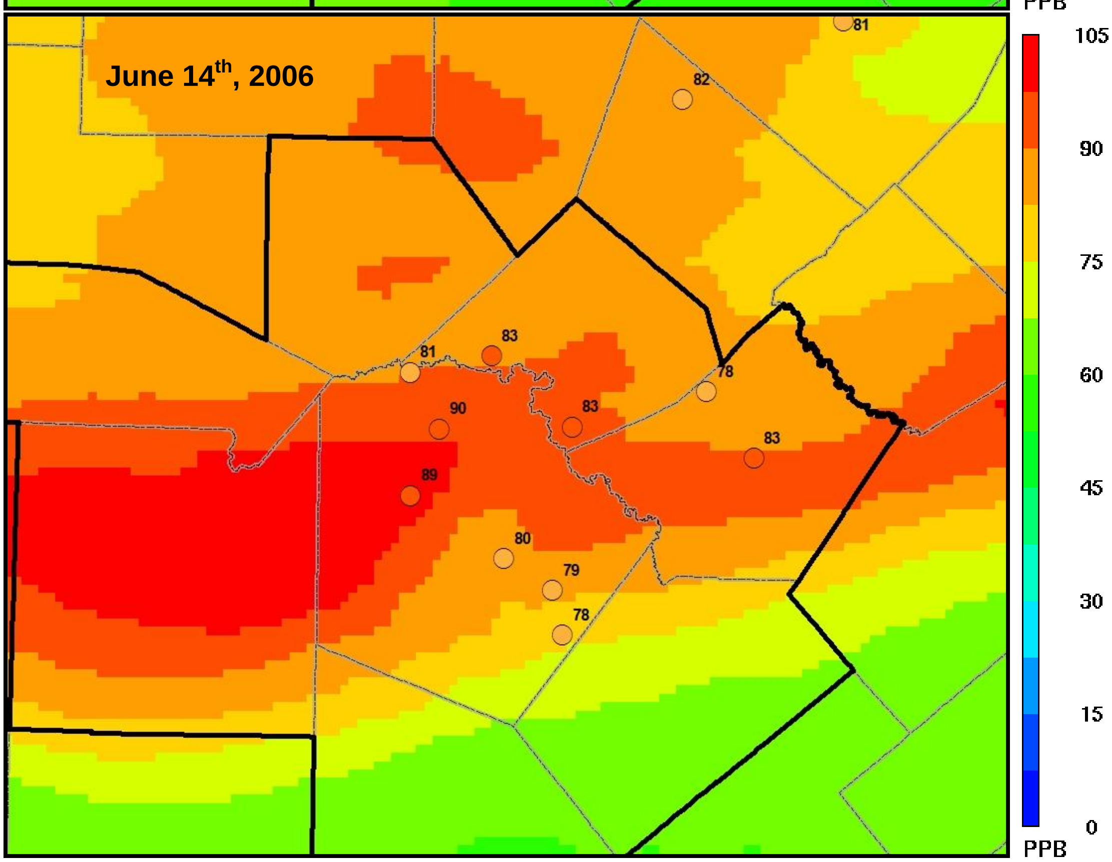



June 8th, 2006
88
66
76
79
84
69
67
67
76
67
64
65
105
90
75
60
45
30
15
0
PPB

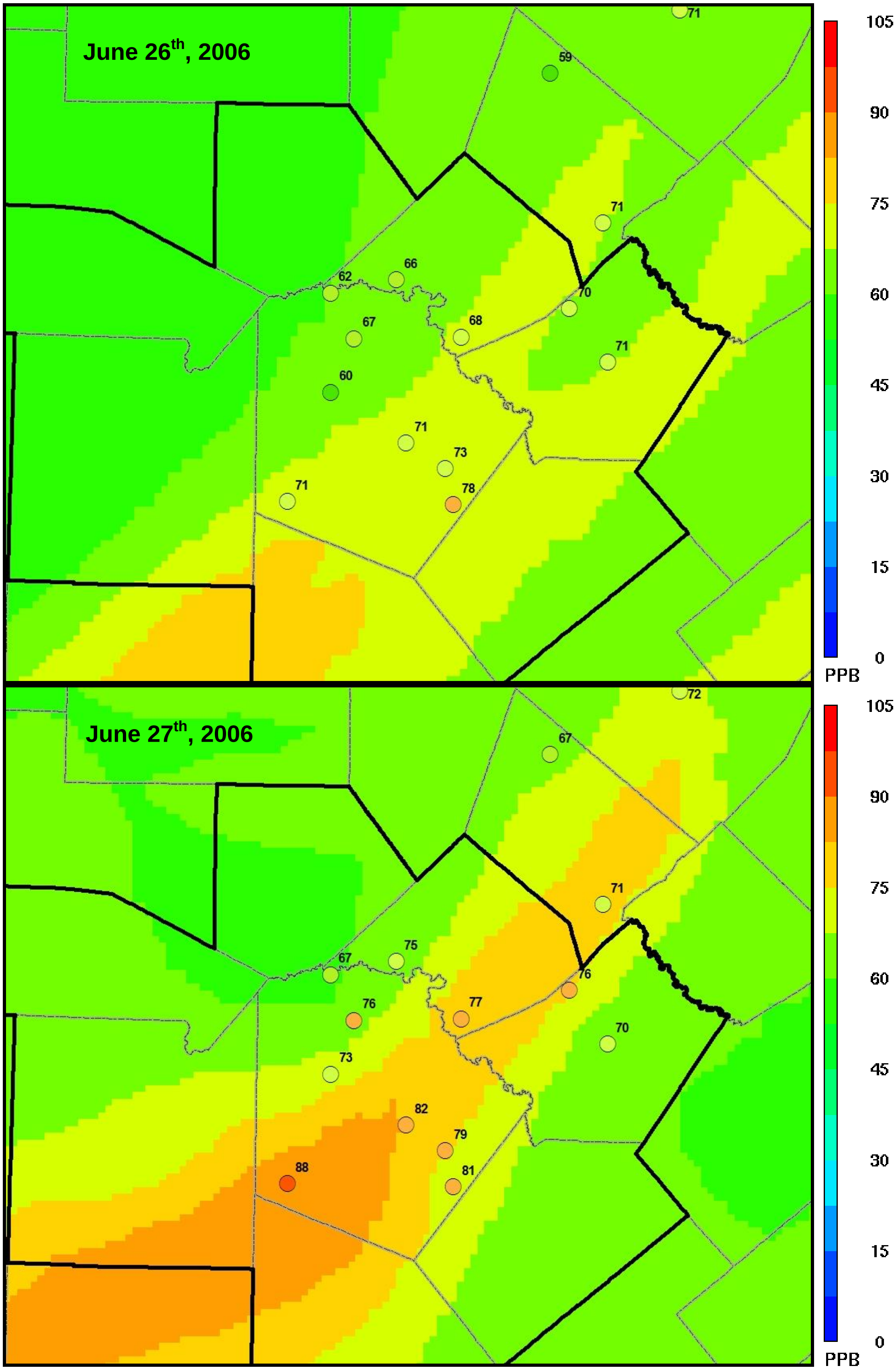

June 9th, 2006
78
63
74
77
77
69
69
70
70
68
67
68
105
90
75
60
45
30
15
0
PPB

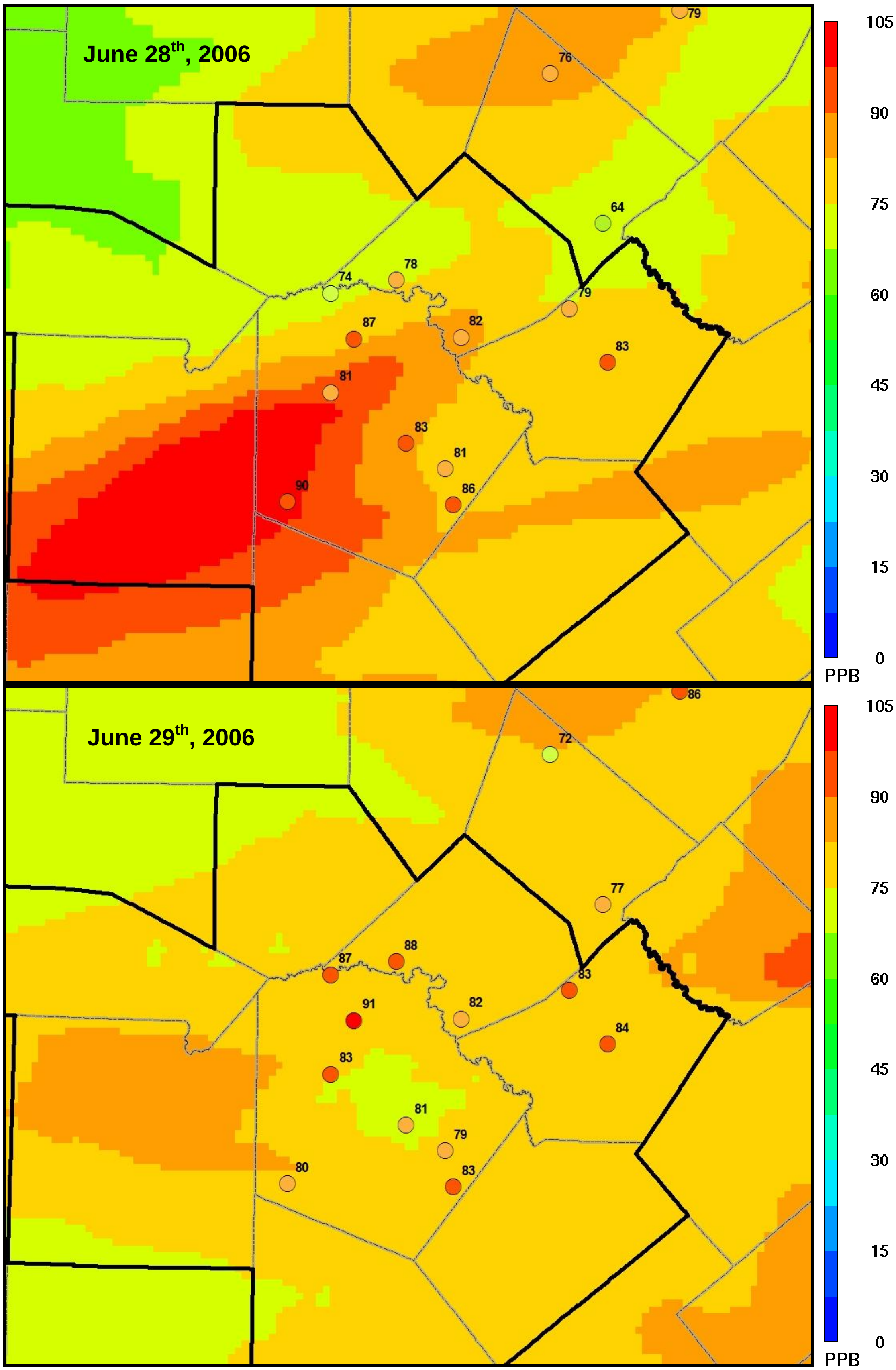


June 13th, 2006
82
71
71
70
93
82
76
80
92
78
73
70
105
90
75
60
45
30
15
0
PPB



June 14th, 2006
81
82
83
81
90
83
78
83
89
80
79
78
105
90
75
60
45
30
15
0
PPB


June 26th, 2006
71
59
71
66
62
70
67
68
71
60
71
73
71
78
105
90
75
60
45
30
15
0
PPB
June 27th, 2006
72
67
71
75
67
76
76
77
70
73
82
79
88
81
105
90
75
60
45
30
15
0
PPB



June 28th, 2006
79
76
64
74
78
79
87
82
83
81
83
81
90
86
105
90
75
60
45
30
15
0
PPB
June 29th, 2006
86
72
77
87
88
83
91
82
84
83
81
79
80
83
105
90
75
60
45
30
15
0
PPB

Table 5-7: Predicted Daily Maximum 1-hour Ozone Concentrations within the San Antonio MSA for MM5 Base Case Run 7, WRF TCEQ Base Case Run 1, WRF TCEQ Base Case Run 2, WRF AACOG Base Case Run 3, and WRF AACOG RPO Base Case Run 4

Modeling Day	Peak 1-hr Monitored ozone in SA	Run 7_v5 (Met 11 OB70)		Run 1 TCEQ bl (WRF)		Run 2 TCEQ bl (WRF)		Run 3 AACOG bl (WRF)		Run 4 AACOG RPO (WRF)	
		ppb	Diff.	ppb	Diff.	ppb	Diff.	ppb	Diff.	ppb	Diff.
1-Jun-06	62	*53*	*-8.6*	**64**	**2.4**	65	2.9	65	2.9	67	4.9
2-Jun-06	78	**77**	**-0.7**	84	5.6	84	5.9	85	6.5	*89*	*11.2*
3-Jun-06	**86**	91	4.5	**90**	**4.4**	91	4.7	91	4.7	*95*	*8.5*
4-Jun-06	81	**78**	**-3.4**	92	10.8	92	10.7	*92*	*11.1*	*97*	*16.1*
5-Jun-06	70	**79**	**9.0**	82	12.3	82	12.0	*83*	*12.5*	*85*	*15.3*
6-Jun-06	82	76	-5.6	88	5.7	**86**	**3.9**	86	4.5	*90*	*7.9*
7-Jun-06	**89**	97	8.2	95	6.3	**94**	**5.1**	95	6.3	*99*	*9.9*
8-Jun-06	**96**	*103*	*7.0*	97	1.1	**97**	**0.6**	98	1.5	101	5.3
9-Jun-06	**87**	**94**	**7.4**	102	15.4	103	15.5	103	16.2	*106*	*18.9*
10-Jun-06	76	**81**	**5.2**	98	21.7	96	20.0	96	20.2	*99*	*23.1*
11-Jun-06	68	**74**	**6.0**	*79*	*11.2*	78	9.8	78	10.0	79	10.5
12-Jun-06	78	*102*	*23.7*	96	17.7	95	17.4	96	18.2	97	19.4
13-Jun-06	**106**	**92**	**-14.0**	128	22.1	128	22.3	129	23.0	*135*	*28.7*
14-Jun-06	**94**	**93**	**-1.3**	113	19.4	114	19.7	115	20.7	*122*	*28.4*
15-Jun-06	74	**76**	**1.8**	78	4.2	77	3.4	77	3.4	*80*	*5.9*
16-Jun-06	45			52	6.8	**52**	**6.5**	52	6.6	*52*	*7.3*
17-Jun-06	53			49	-4.1	48	-4.8	*48*	*-4.9*	**51**	**-1.6**
18-Jun-06	79			**54**	**-24.9**	54	-25.1	54	-25.1	*54*	*-25.3*
19-Jun-06	85			77	-7.5	*77*	*-7.8*	78	-7.4	**81**	**-3.7**
20-Jun-06	35			42	7.3	42	7.2	**42**	**7.1**	*45*	*10.1*
21-Jun-06	37			53	16.0	**53**	**15.5**	53	15.7	*55*	*18.0*
22-Jun-06	41			*57*	*16.2*	**56**	**15.3**	56	15.5	56	15.5
23-Jun-06	60			62	1.6	*62*	*1.7*	62	1.6	**61**	**0.5**
24-Jun-06	49			**60**	**11.2**	61	12.2	62	12.5	*63*	*13.6*
25-Jun-06	70			76	6.4	**75**	**4.6**	75	4.8	*78*	*7.7*
26-Jun-06	**86**			83	-3.2	83	-2.7	**83**	**-2.6**	*81*	*-4.9*

Modeling Day	Peak 1-hr Monitored ozone in SA	Run 7_v5 (Met 11 OB70)		Run 1 TCEQ bl (WRF)		Run 2 TCEQ bl (WRF)		Run 3 AACOG bl (WRF)		Run 4 AACOG RPO (WRF)	
		ppb	Diff.	ppb	Diff.	ppb	Diff.	ppb	Diff.	ppb	Diff.
27-Jun-06	**98**			*95*	*-3.1*	96	-2.1	**96**	**-1.6**	95	-2.5
28-Jun-06	**101**			109	8.2	**109**	**7.7**	110	8.7	*113*	*12.2*
29-Jun-06	**94**			*96*	*1.7*	**94**	**0.3**	94	0.3	93	-1.2
30-Jun-06	87			**92**	**5.3**	92	5.5	*93*	*6.0*	93	5.8
1-Jul-06	46			*54*	*8.3*	*54*	*8.3*	**54**	**8.1**	**54**	**8.1**
2-Jul-06	30			*66*	*36.4*	*67*	*36.9*	**67**	**36.8**	**67**	**36.8**
Avg. All Days			2.6		7.6		7.3		7.6		9.7
Avg. on Days > 74 ppb			3.4		6.4		6.0		6.2		8.8
Avg. on Days > 84 ppb			2.0		7.2		7.1		6.3		8.8

Table 5-8: Predicted Daily Maximum 8-hour Ozone Concentrations within the San Antonio MSA for MM5 Base Case Run 7, WRF TCEQ Base Case Run 1, WRF TCEQ Base Case Run 2, WRF AACOG Base Case Run 3, and WRF AACOG RPO Base Case Run 4

Modeling Day	Peak 8-hr Monitored ozone in SA	Run 7_v5 (Met 11 OB70)		*Run 1 TCEQ bl (WRF)*		Run 2 TCEQ bl (WRF)		Run 3 AACOG bl (WRF)		Run 4 AACOG RPO (WRF)	
		ppb	Diff.	*ppb*	*Diff.*	ppb	Diff.	ppb	Diff.	ppb	Diff.
1-Jun-06	56	**55.8**	**-0.2**	59.1	3.1	59.6	3.6	59.6	3.6	*61.8*	*5.8*
2-Jun-06	66	**65.0**	**-1.0**	68.3	2.3	68.5	2.5	68.8	2.8	*72.1*	*6.1*
3-Jun-06	**80**	78.9	-1.1	79.3	-0.7	**79.5**	**-0.5**	79.4	-0.6	*83.5*	*3.5*
4-Jun-06	73	68.5	-4.5	75.5	2.5	**75.3**	**2.3**	75.4	2.4	*78.7*	*5.7*
5-Jun-06	63	**63.1**	**0.1**	68.2	5.2	68.1	5.1	68.0	5.0	*70.4*	*7.4*
6-Jun-06	68	**66.6**	**-1.4**	77.5	9.5	76.5	8.5	76.9	8.9	*78.9*	*10.9*
7-Jun-06	**76**	**79.2**	**3.2**	85.3	9.3	84.6	8.6	85.4	9.4	*88.6*	*12.6*
8-Jun-06	**84**	*79.1*	*-4.9*	82.8	-1.2	82.6	-1.4	82.8	-1.2	**84.5**	**0.5**
9-Jun-06	**77**	**76.9**	**-0.1**	91.2	14.2	91.5	14.5	91.8	14.8	*95.0*	*18.0*
10-Jun-06	71	**73.8**	**2.8**	*89.6*	*18.6*	89.1	18.1	89.3	18.3	89.2	18.2
11-Jun-06	64	**65.8**	**1.8**	*71.8*	*7.8*	71.2	7.2	71.3	7.3	70.8	6.8
12-Jun-06	70	**77.2**	**7.2**	81.5	11.5	81.0	11.0	81.5	11.5	*83.8*	*13.8*
13-Jun-06	**93**	**83.3**	**-9.7**	114.0	21.0	113.8	20.8	114.3	21.3	*118.9*	*25.9*
14-Jun-06	**90**	**94.9**	**4.9**	101.0	11.0	101.0	11.0	101.5	11.5	*106.9*	*16.9*
15-Jun-06	69	**70.5**	**1.5**	73.7	4.7	73.7	4.7	73.8	4.8	*74.7*	*5.7*
16-Jun-06	35			47.4	12.4	47.3	12.3	**47.3**	**12.3**	*48.0*	*13.0*
17-Jun-06	44			41.7	-2.3	41.6	-2.4	*41.4*	*-2.6*	**43.2**	**-0.8**
18-Jun-06	71			45.8	-25.2	45.7	-25.3	*45.6*	*-25.4*	**46.8**	**-24.2**
19-Jun-06	65			66.0	1.0	65.9	0.9	**65.7**	**0.7**	*68.7*	*3.7*
20-Jun-06	29			36.2	7.2	36.2	7.2	**36.1**	**7.1**	*37.6*	*8.6*
21-Jun-06	32			45.2	13.2	45.1	13.1	**45.0**	**13.0**	*46.1*	*14.1*
22-Jun-06	36			48.6	12.6	**48.3**	**12.3**	48.3	12.3	*48.3*	*12.3*
23-Jun-06	50			**49.8**	**-0.2**	49.6	-0.4	49.6	-0.4	*48.0*	*-2.1*
24-Jun-06	45			*53.1*	*8.1*	52.9	7.9	53.0	8.0	**52.6**	**7.6**
25-Jun-06	65			**67.0**	**2.0**	67.6	2.6	67.6	2.6	*67.9*	*2.9*
26-Jun-06	**78**			72.6	-5.4	73.3	-4.8	**73.4**	**-4.6**	*68.1*	*-9.9*
27-Jun-06	**88**			86.5	-1.5	87.5	-0.5	**88.0**	**0.0**	*85.5*	*-2.5*

Modeling Day	Peak 8-hr Monitored ozone in SA	Run 7_v5 (Met 11 OB70)		*Run 1 TCEQ bl (WRF)*		Run 2 TCEQ bl (WRF)		Run 3 AACOG bl (WRF)		Run 4 AACOG RPO (WRF)	
		ppb	Diff.	*ppb*	*Diff.*	ppb	Diff.	ppb	Diff.	ppb	Diff.
28-Jun-06	**90**			**102.5**	**12.5**	103.0	13.0	*103.3*	*13.3*	102.9	12.9
29-Jun-06	**91**			83.1	-8.0	**83.2**	**-7.8**	83.1	-7.9	*80.5*	*-10.5*
30-Jun-06	71			77.8	6.8	78.1	7.1	*78.5*	*7.5*	**77.4**	**6.4**
1-Jul-06	38			**48.1**	**10.1**	*48.5*	*10.5*	*48.5*	*10.5*	*48.5*	*10.5*
2-Jul-06	26			**56.2**	**30.2**	*56.7*	*30.7*	*56.7*	*30.7*	*56.7*	*30.7*
Avg. All Days			-0.1		6.0		6.0		6.2		7.2
Avg. on Days > 60 ppb			-0.1		4.4		4.4		4.7		6.0
Avg. on Ozone Exceedance days			-1.3		5.1		5.3		5.6		6.5

When looking at the results for maximum 8-hour ozone, there was a slight under-prediction of ozone on June 3rd, June 8th, June 26th, and June 29th. As expected, 8 hour ozone maximums were over predicted on June 9th, June 13th, June 14th, and June 28th. In the San Antonio-New Braunfels MSA, prediction of 8-hour maximums ranged from -10.5 ppb to 25.9 ppb of monitored values on exceedance days. TCEQ run 1 demonstrated the best average prediction for maximum 8-hour ozone on all days (6.0 ppb) and exceedance days (5.1 ppb). AACOG run 4 with the RPO grid had the highest average over predictions for 8-hour maximum values for all days and for exceedance days. "Since the modeled peak is taken across every grid cell in the domain and the observed peak is from only a limited number of monitoring sites, it is expected that the domain-wide peak simulated by a good-performing model will exceed the monitored peak."[269]

5.9 Summary of CAMx Base Case Runs

The CAMx model over predicted ozone concentrations at monitors on the northwest side of San Antonio, C23, C25, and C505, on two of the episode's exceedance days: June 13 and 14th. On other days of the episode, the model's ozone estimations correlated well with observed peak hourly ozone values and predicted peak hourly ozone values. For most monitors, there was an excellent correlation between observed peak hourly ozone and predicted hourly ozone in the second half of the episode, with some under prediction at C503. When examining the diurnal bias, model results for C58 over predicted diurnal ozone on most exceedance days during the episode. The model also over predicted diurnal hourly ozone in the second part of the episode at monitors located in rural areas of the San Antonio-New Braunfels MSA, C502, C503, C504, and C506. The model over predicted NO_X emissions at C58 on almost every day of the June 2006 episode. This over prediction of NO_X at C58 provides a plausible explanation for the model's poor performance regarding diurnal ozone forecasts for the monitor.

Although there were several significant differences in the local emission inventory, model results are similar for TCEQ run 1, TCEQ run 2, and AACOG run 3 for every monitor. Changes in meteorological conditions had a greater impact on the model's ozone predictions than changes to the emission inventories. For AACOG run 4 using the RPO grid, predicted ozone on some exceedance days was higher than the other 3 WRF runs.

Every WRF modeling run exhibited similar performance for unpaired peak accuracy, paired peak accuracy, peak bias, peak error, normalized bias, and normalized error. Model performance on all days was improved with TCEQ run 2 and exceedance day performance was best for AACOG run 1. Performance for AACOG run 4 using the RPO grid was degraded for

[269] TCEQ, Dec. 7, 2011. "Appendix C: Photochemical Modeling for the DFW Attainment Demonstration Sip Revision for the 1997 Eight-Hour Ozone Standard". Austin, Texas. P. C-45. Available online: http://www.tceq.texas.gov/assets/public/implementation/air/sip/dfw/ad_2011/AppC_CAMx_ado.pdf. Accessed 06/26/13.

peak error and normalized error. This run provided higher peak 1-hour ozone predictions compared to the other 3 WRF runs. Results for paired peak accuracy were very good for C58, C622, C501, C502, C503, and C506 and paired peak accuracy for the remaining monitors also met EPA recommended guidelines.

Tile plots indicated that there were no unusual patterns of ozone formation predicted by the model runs. Ozone plumes were produced in the vicinity of San Antonio and Austin. As expected, these urban plumes were predicted for each urban core and areas downwind of the cities. AACOG run 3 was used as the 2006 base case because it has the latest and most accurate emission inventory. When the base case was completed, the emission inventory in the model was projected to 2012 and 2018. There were three different emission inventory scenarios in 2018, low, moderate, and high, based on projected activity in the Eagle Ford. Future work will include continued evaluation of using the RPO grid for the emission inventory and evaluating the newly released CAMx6.0 model performance with the extended June 2006 modeling episode.

6 Future Year Modeling

The photochemical model developed to simulate the extended June 2006 high-ozone episode was updated with 2012 and 2018 projected anthropogenic emission inventories to estimate future ozone concentrations under the same meteorological conditions as the 2006 base case. The projected emission inventories account for existing local, state, and federal air quality control strategies to determine whether such measures are sufficient to help the region meet the 2008 NAAQS 8-hour ozone standard. The 2018 projection case was compared to the 2012 projection to determine future ozone design values.

6.1 Projections Cases

A total of 6 future year scenarios were developed from the June 2006 modeling episode.

<u>2012 Without Eagle Ford</u>

- WRF v3.2
- CAMx 5.40
- Local 2012 San Antonio-New Braunfels MSA emission data including construction equipment, landfill equipment, quarry equipment, agricultural tractors, combines, commercial airports, point sources, and heavy duty truck idling

<u>2012 With Eagle Ford Emission Inventory</u>

- WRF v3.2
- CAMx 5.40
- Local 2012 San Antonio-New Braunfels MSA emission data including construction equipment, landfill equipment, quarry equipment, agricultural tractors, combines, commercial airports, point sources, and heavy duty truck idling
- Eagle Ford 2012 Emission Inventory

<u>2018 Without Eagle Ford Emission Inventory</u>

- WRF v3.2
- CAMx 5.40
- Local 2018 San Antonio-New Braunfels MSA emission data including construction equipment, landfill equipment, quarry equipment, agricultural tractors, combines, commercial airports, point sources, and heavy duty truck idling

<u>2018 Low Scenario Eagle Ford Emission Inventory</u>

- WRF v3.2
- CAMx 5.40
- Local 2018 San Antonio-New Braunfels MSA emission data including construction equipment, landfill equipment, quarry equipment, agricultural tractors, combines, commercial airports, point sources, and heavy duty truck idling
- Eagle Ford 2018 Emission Inventory Low Scenario

2018 Moderate Eagle Ford Emission Inventory

- WRF v3.2
- CAMx 5.40
- Local San Antonio-New Braunfels MSA emission data including construction equipment, landfill equipment, quarry equipment, agricultural tractors, combines, commercial airports, point sources, and heavy duty truck idling
- Eagle Ford 2018 Emission Inventory Moderate Scenario

2018 High Eagle Ford Emission Inventory

- WRF v3.2
- CAMx 5.40
- Local 2018 San Antonio-New Braunfels MSA emission data including construction equipment, landfill equipment, quarry equipment, agricultural tractors, combines, commercial airports, point sources, and heavy duty truck idling
- Eagle Ford 2018 Emission Inventory High Scenario

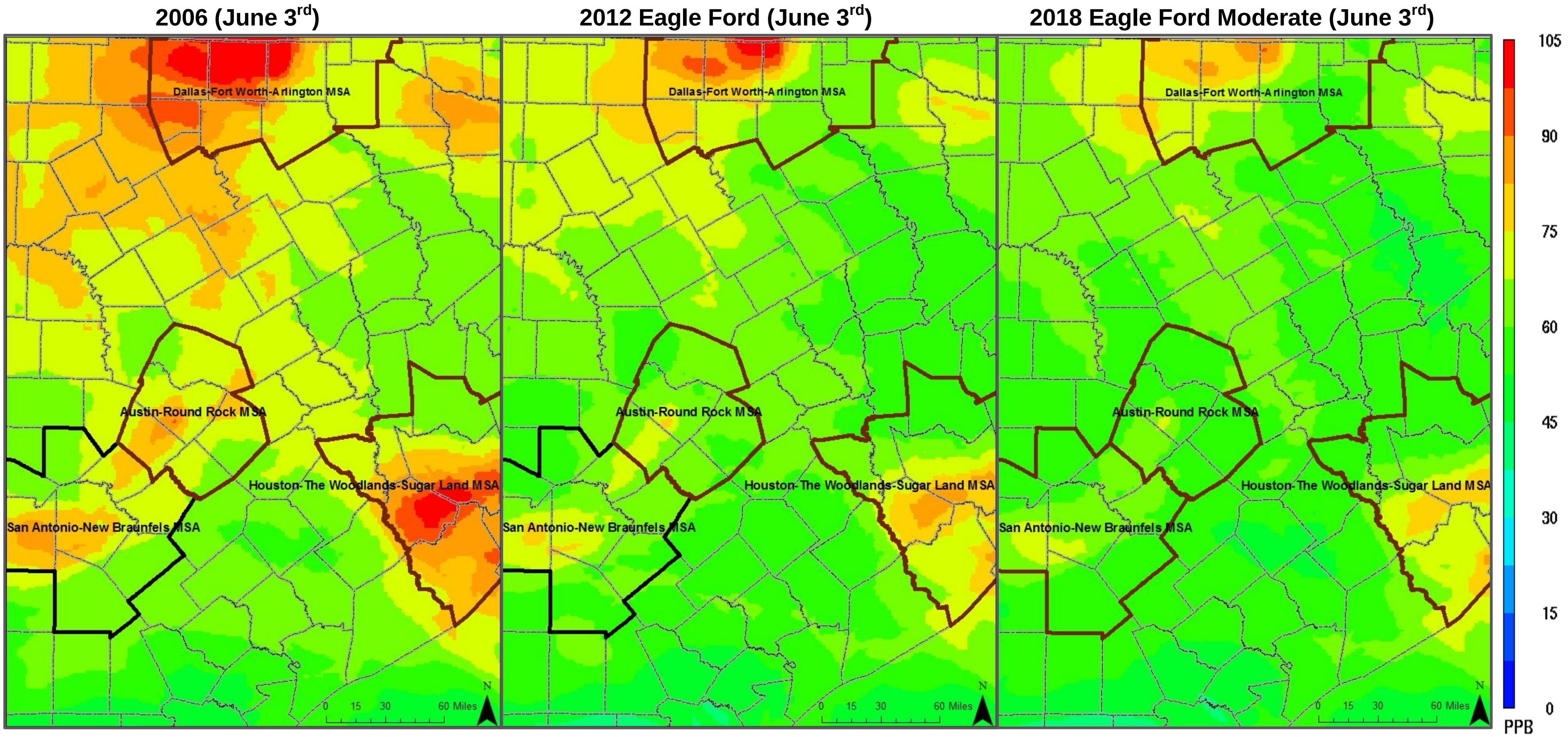
6.2 Tile Plots – Ozone Concentration: 2006, 2012, and 2018

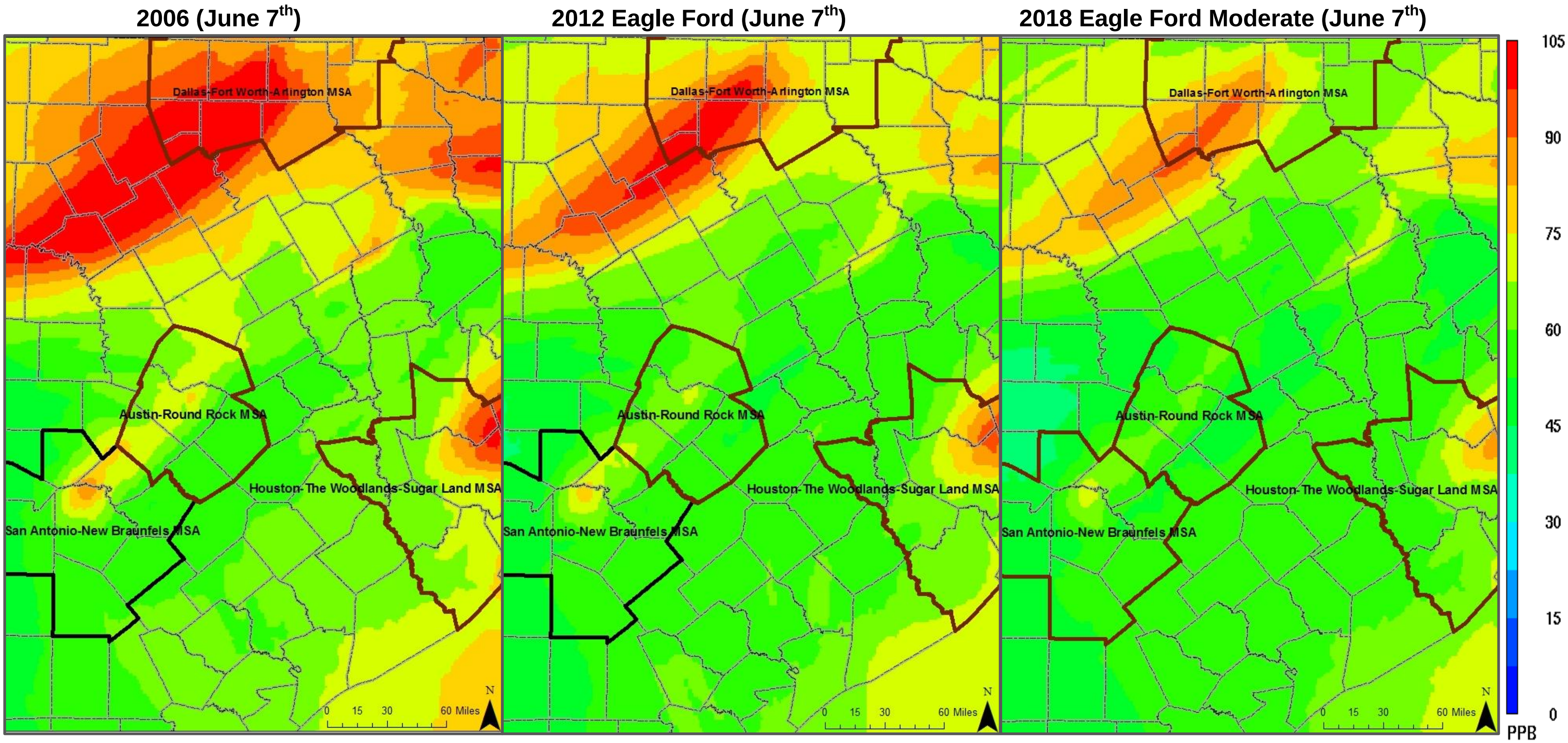
Tile plots can be used as a means of determining if there is an error in the input data or model performance. The plots are visual representations of the model output, displaying ozone concentrations by hour for the episode day or the maximum ozone by day. The following tile plots (Figure 6-1) represent comparisons between the model results for 2006, 2012 Eagle Ford, and 2018 Moderate Eagle Ford 8-hour daily maximum ozone concentrations in the 4km grid for each day.

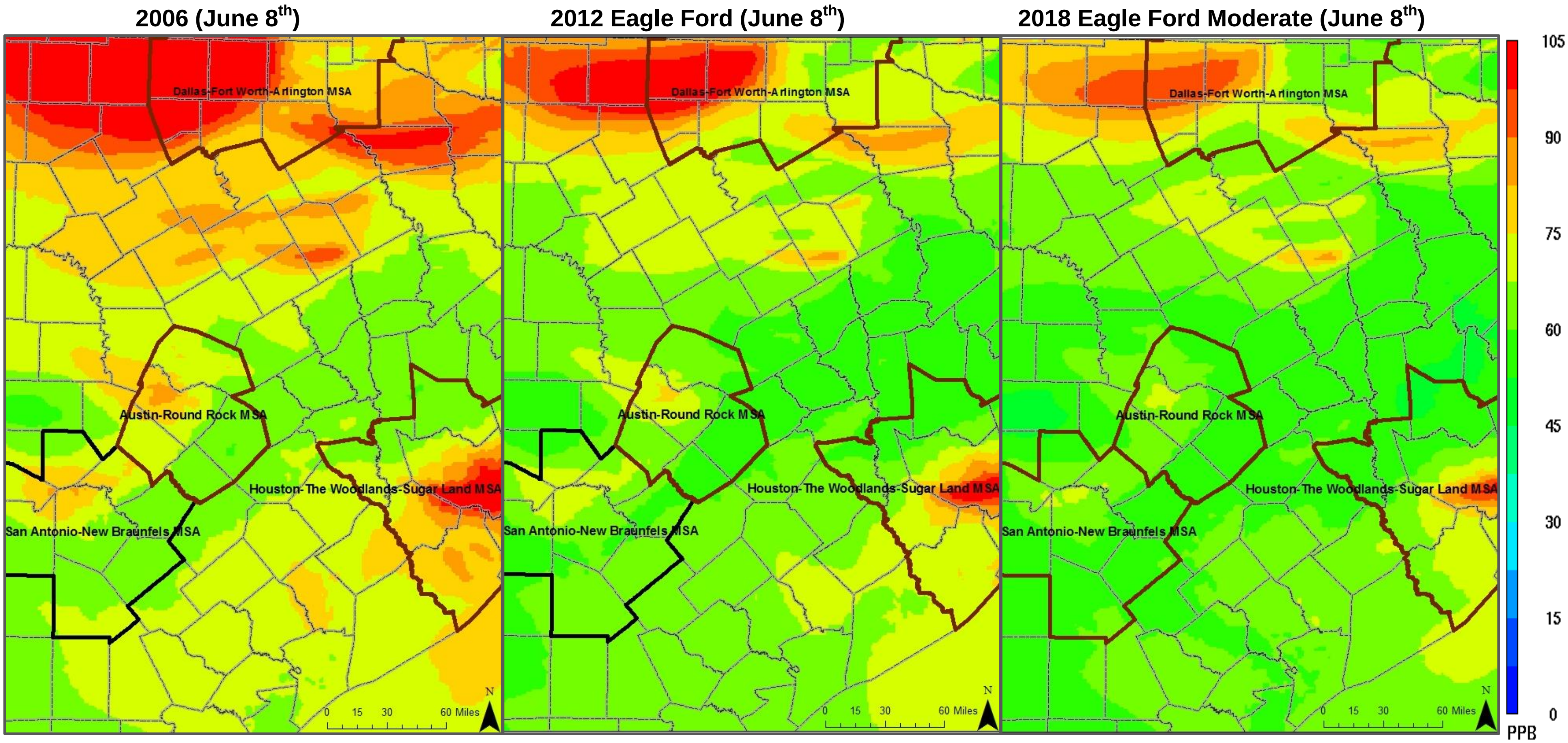
Peak ozone concentrations are predicted downwind of city centers and major point sources in these tile plots. In addition, the overall reduction in total NO_X, VOC, and CO emissions (local and regional) between 2006 and 2018 diminishes the magnitude of the urban plumes each day of the 2018 projection compared to its 2006 counterpart. Likewise, the spatial extent of 8-hour ozone plumes greater than 75 ppb are significantly reduced for every exceedance day in the San Antonio region in 2018.

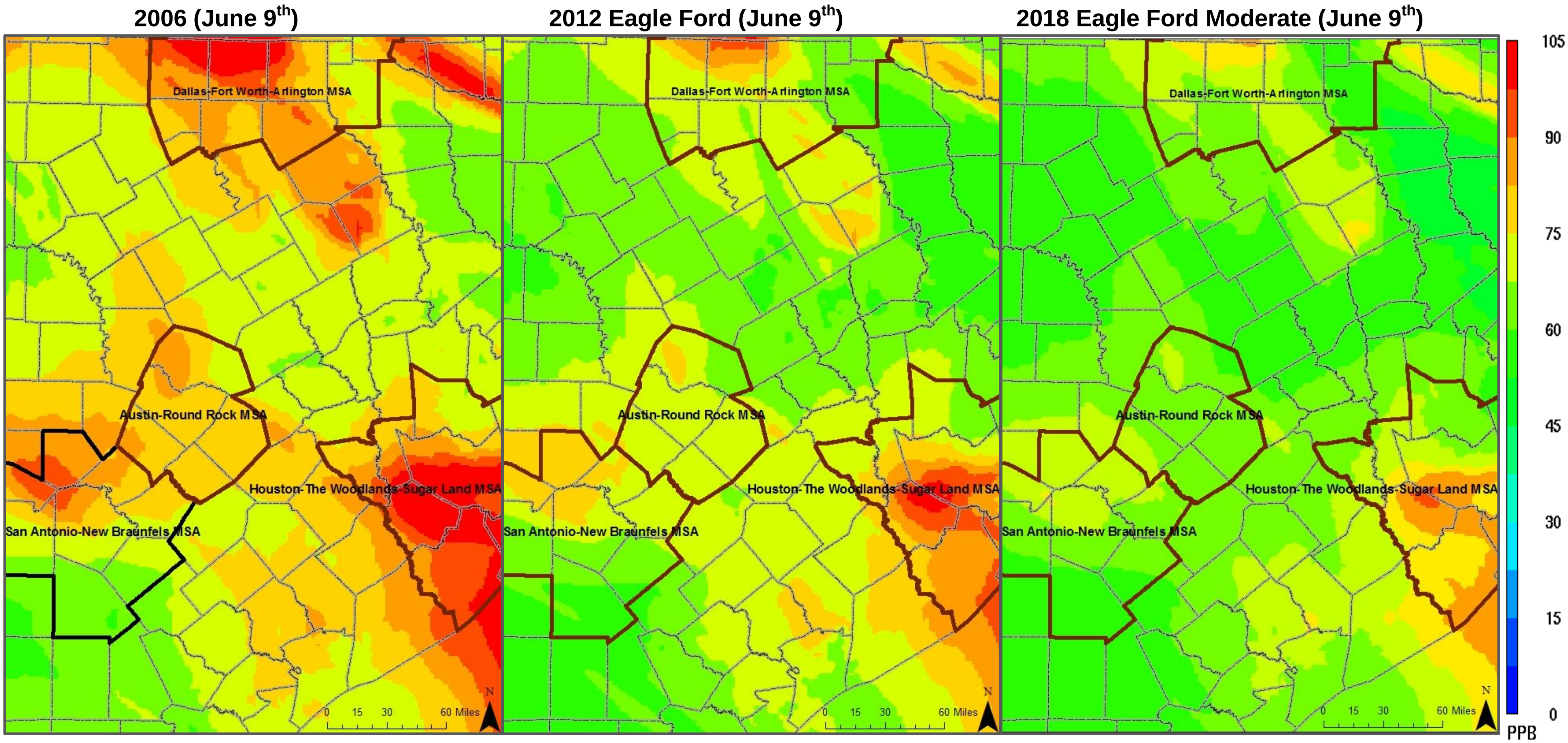
Although there is an overall reduction of ozone on every exceedance day in the San Antonio-New Braunfels MSA when comparing the 2018 simulation with the 2006 model results, significant transport still occurs. On the June 14^{th} plots, Houston's elevated ozone plume can be observed reaching the San Antonio-New Braunfels MSA. Although the concentration of the Houston plume diminishes between the 2006 and 2018 model runs, the tile plots indicate the 8-hour ozone levels in the 2018 scenario remain above 65 ppb. A similar pattern occurs on June 27^{th} where the Austin plume has a significant impact on ozone levels in the San Antonio-New Braunfels MSA.

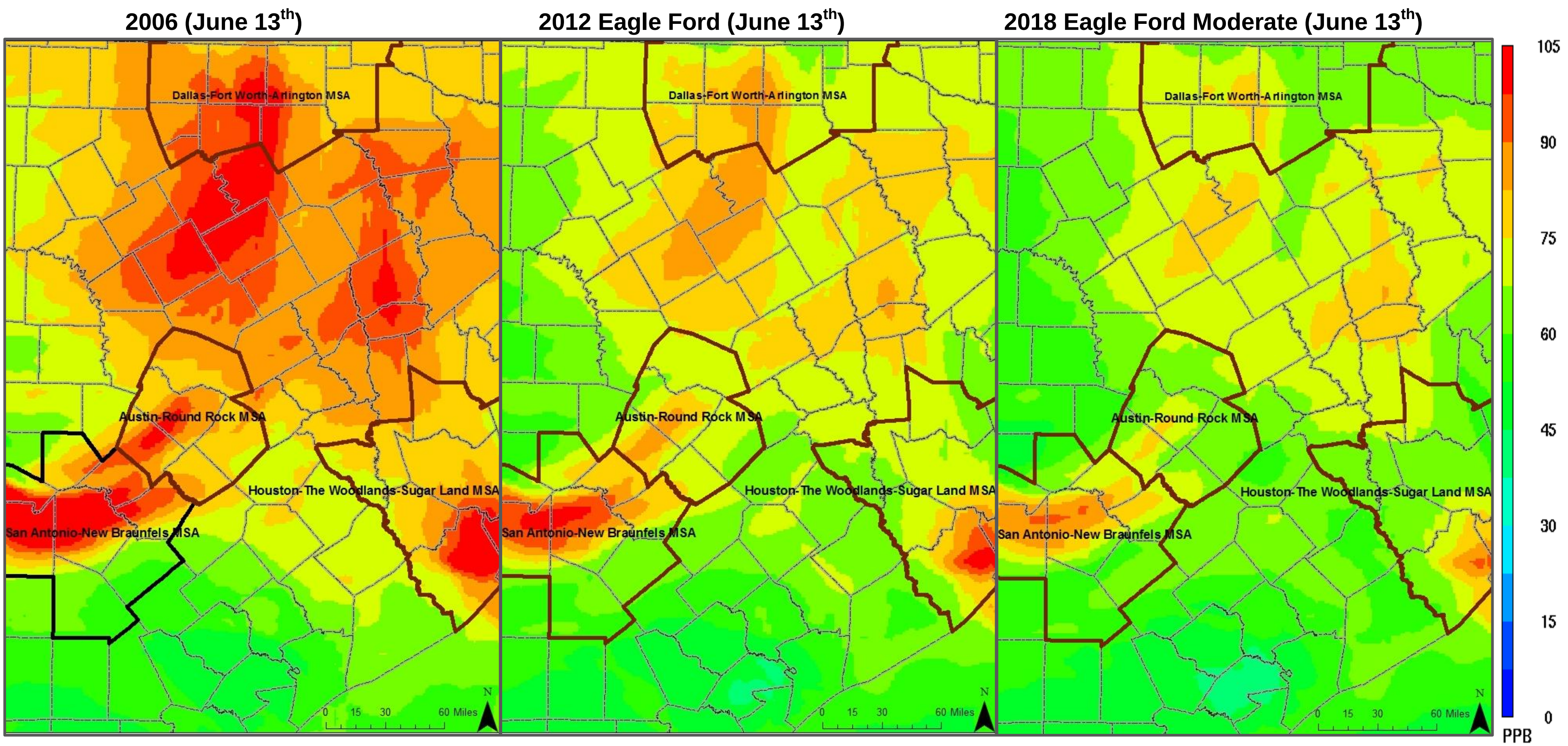
Figure 6-1: Predicted Daily Maximum 8-hour Ozone Concentrations in the 4-km Subdomain, 2006, 2012 Eagle Ford, and 2018 Eagle Ford Moderate Scenario



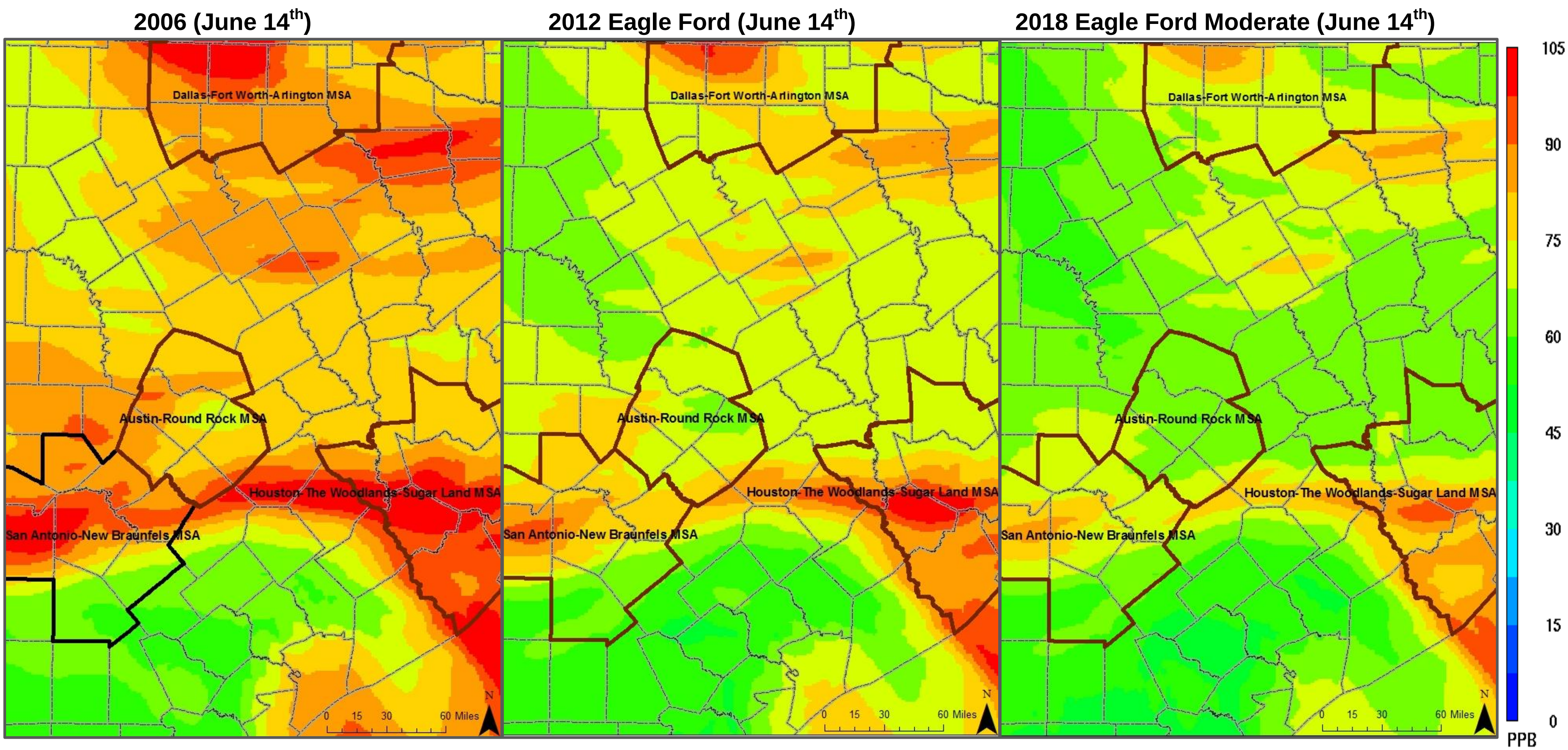

2006 (June 7th)
2012 Eagle Ford (June 7th)
2018 Eagle Ford Moderate (June 7th)
Dallas-Fort Worth-Arlington MSA
Austin-Round Rock MSA
Houston-The Woodlands-Sugar Land MSA
San Antonio-New Braunfels MSA
0 15 30 60 Miles
N
105
90
75
60
45
30
15
0
PPB


2006 (June 8th)
2012 Eagle Ford (June 8th)
2018 Eagle Ford Moderate (June 8th)
Dallas-Fort Worth-Arlington MSA
Austin-Round Rock MSA
Houston-The Woodlands-Sugar Land MSA
San Antonio-New Braunfels MSA
0 15 30 60 Miles
N
105
90
75
60
45
30
15
0
PPB

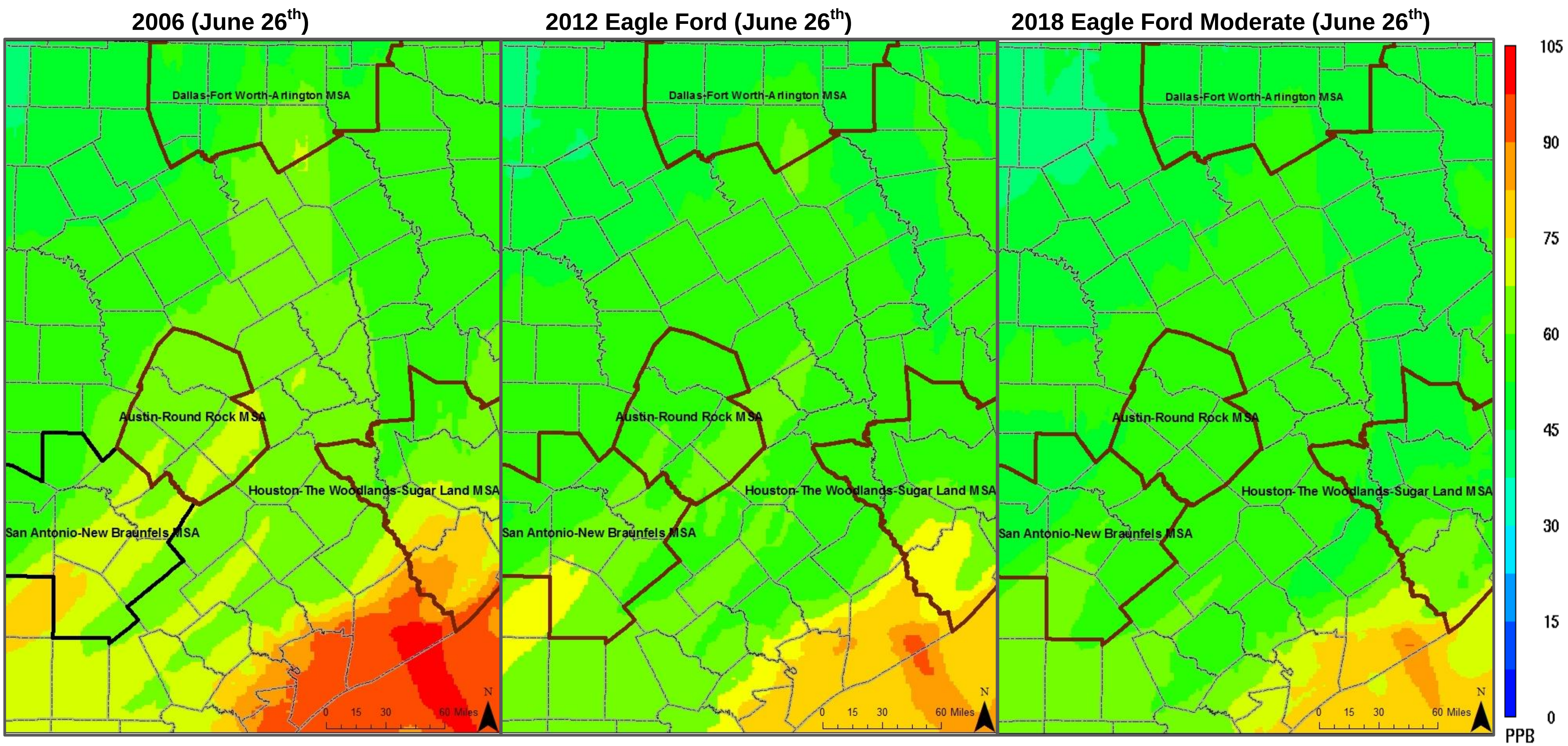

2006 (June 9th)
2012 Eagle Ford (June 9th)
2018 Eagle Ford Moderate (June 9th)
Dallas-Fort Worth-Arlington MSA
Austin-Round Rock MSA
Houston-The Woodlands-Sugar Land MSA
San Antonio-New Braunfels MSA
0 15 30 60 Miles
N
105
90
75
60
45
30
15
0
PPB

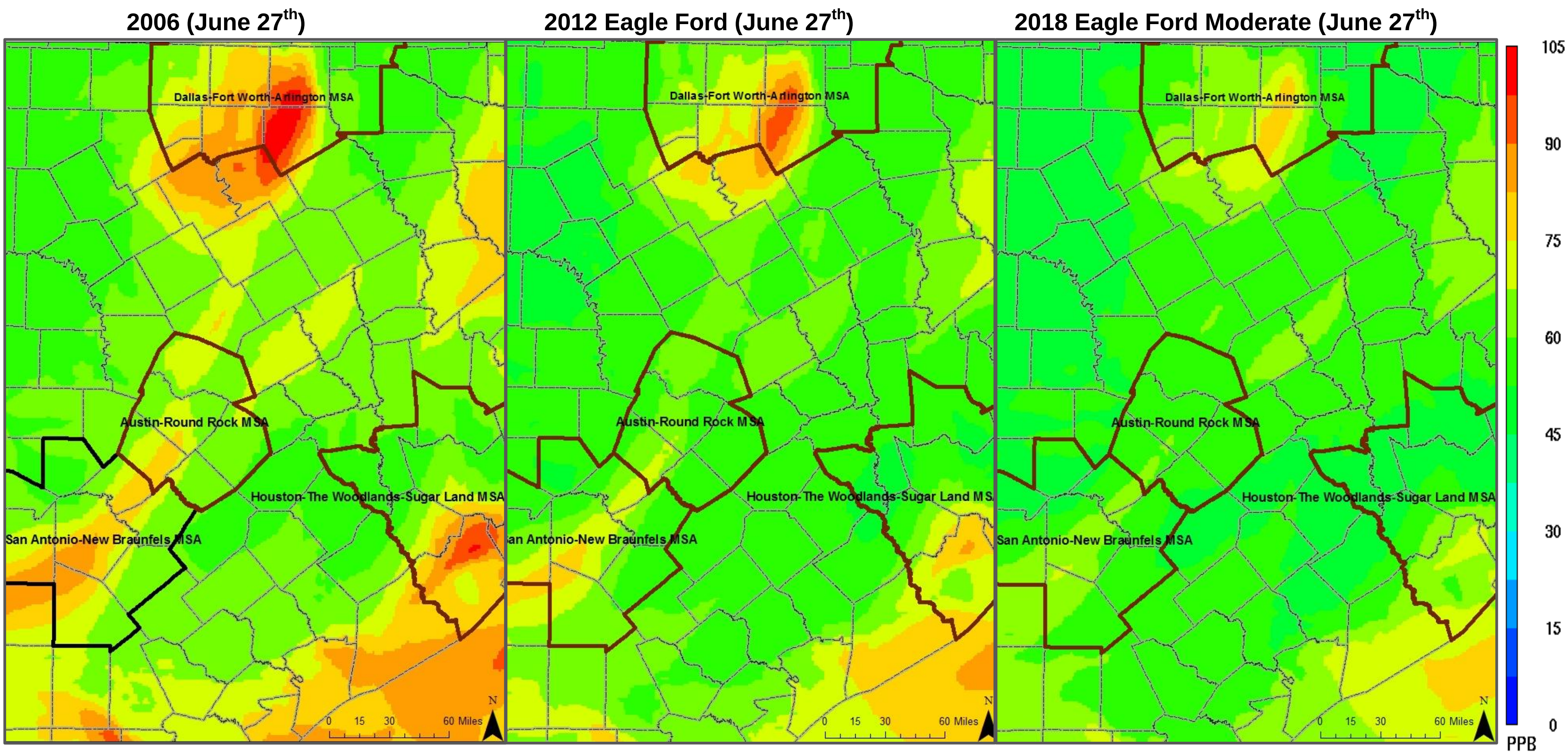


2006 (June 13th)
2012 Eagle Ford (June 13th)
2018 Eagle Ford Moderate (June 13th)
Dallas-Fort Worth-Arlington MSA
Austin-Round Rock MSA
Houston-The Woodlands-Sugar Land MSA
San Antonio-New Braunfels MSA
0 15 30 60 Miles
N
105
90
75
60
45
30
15
0
PPB

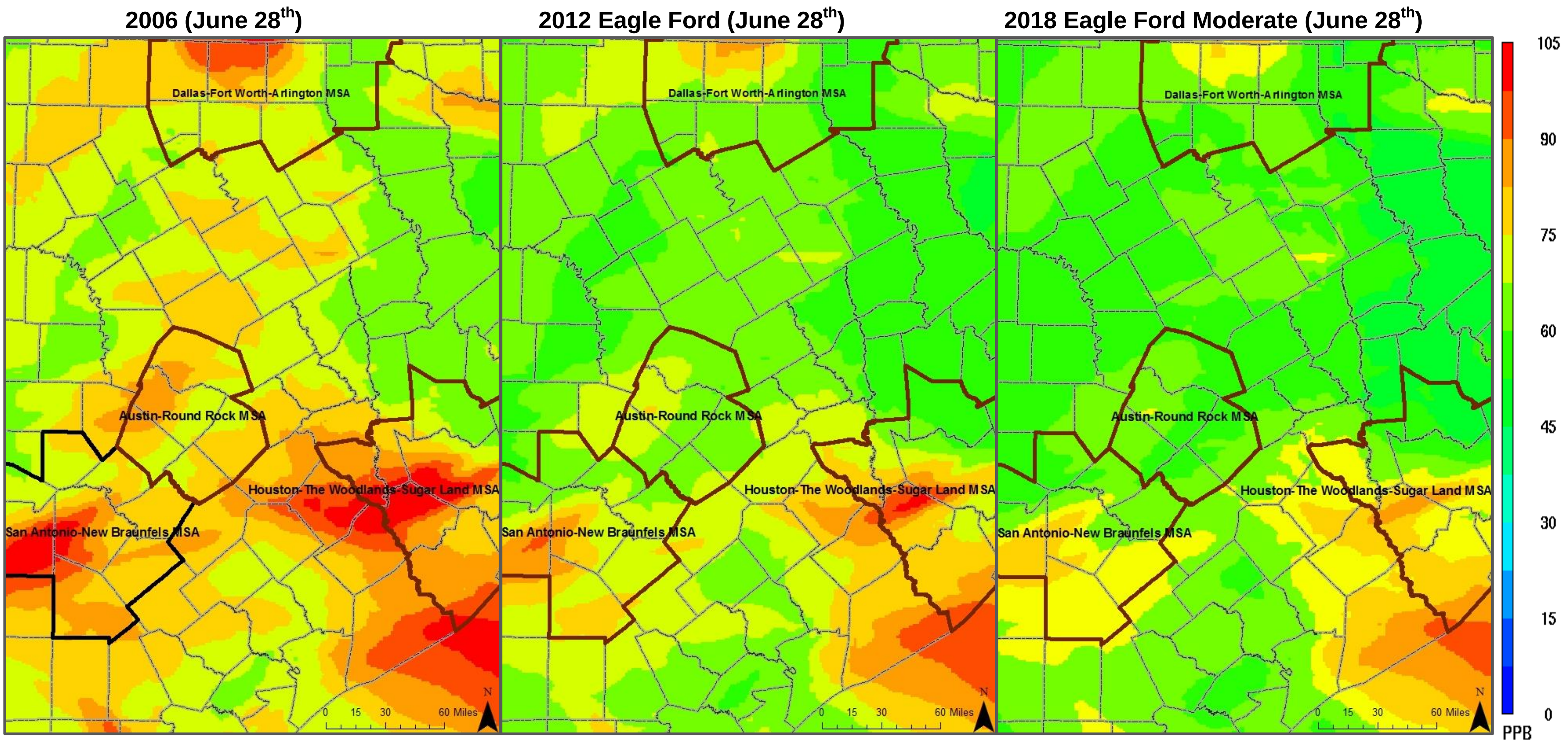


2006 (June 14th)
2012 Eagle Ford (June 14th)
2018 Eagle Ford Moderate (June 14th)
Dallas-Fort Worth-Arlington MSA
Austin-Round Rock MSA
Houston-The Woodlands-Sugar Land MSA
San Antonio-New Braunfels MSA
0 15 30 60 Miles
N
105
90
75
60
45
30
15
0
PPB

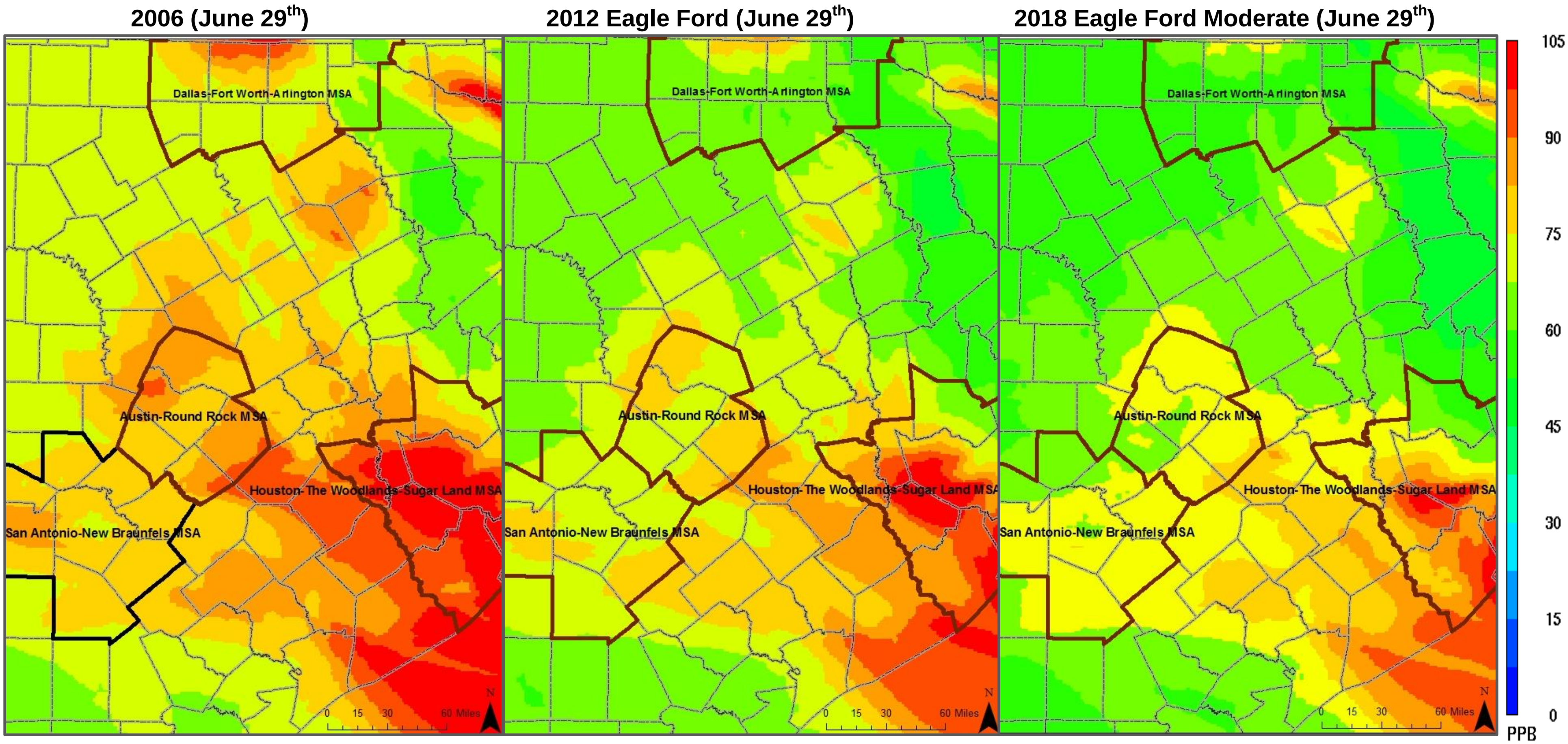

2006 (June 26th)
2012 Eagle Ford (June 26th)
2018 Eagle Ford Moderate (June 26th)
Dallas-Fort Worth-Arlington MSA
Austin-Round Rock MSA
Houston-The Woodlands-Sugar Land MSA
San Antonio-New Braunfels MSA
0 15 30 60 Miles
N
105
90
75
60
45
30
15
0
PPB



2006 (June 27th)
2012 Eagle Ford (June 27th)
2018 Eagle Ford Moderate (June 27th)
Dallas-Fort Worth-Arlington MSA
Austin-Round Rock MSA
Houston-The Woodlands-Sugar Land MSA
San Antonio-New Braunfels MSA
0 15 30 60 Miles
N
105
90
75
60
45
30
15
0
PPB



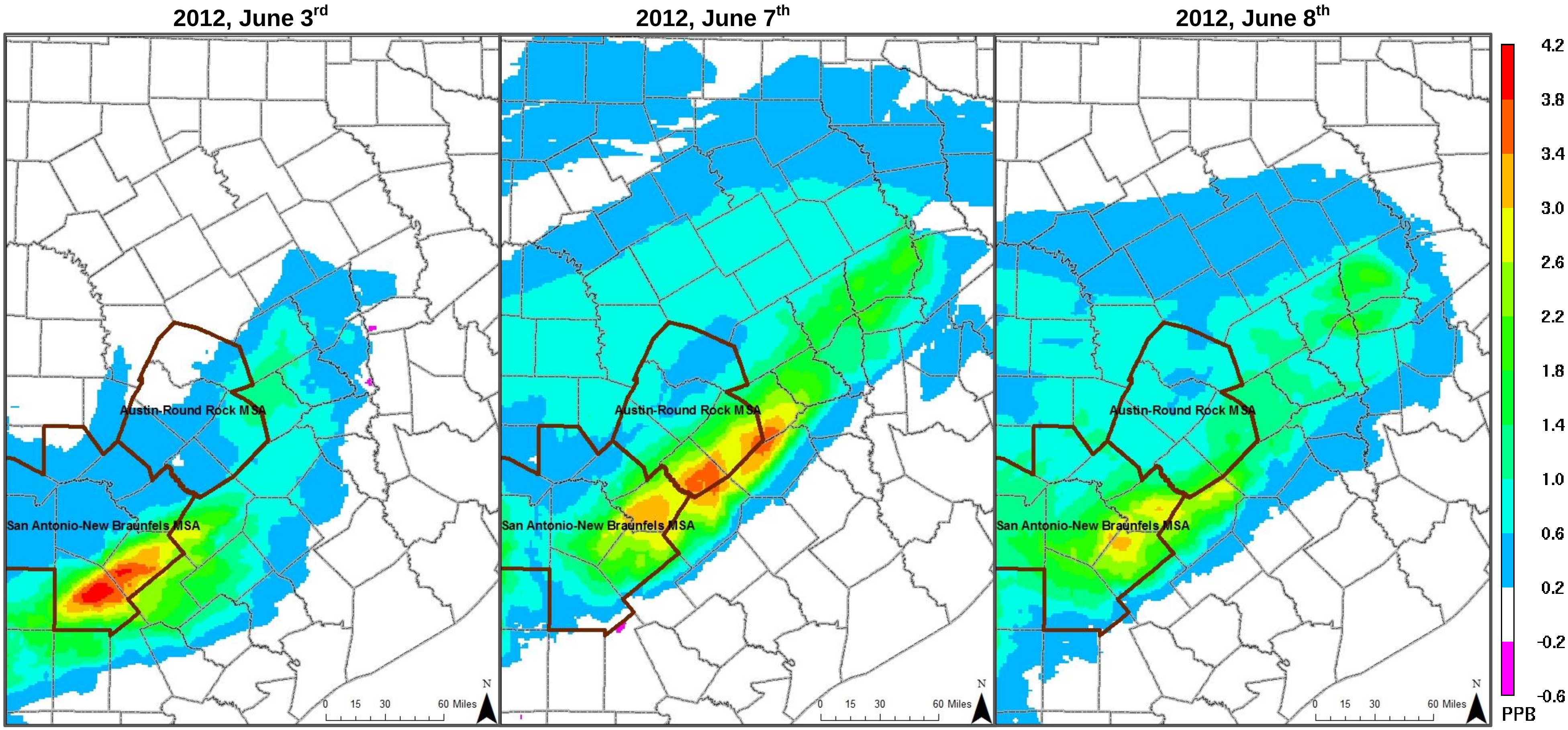
2006 (June 28th)
2012 Eagle Ford (June 28th)
2018 Eagle Ford Moderate (June 28th)
Dallas-Fort Worth-Arlington MSA
Austin-Round Rock MSA
Houston-The Woodlands-Sugar Land MSA
San Antonio-New Braunfels MSA
0 15 30 60 Miles
N
105
90
75
60
45
30
15
0
PPB

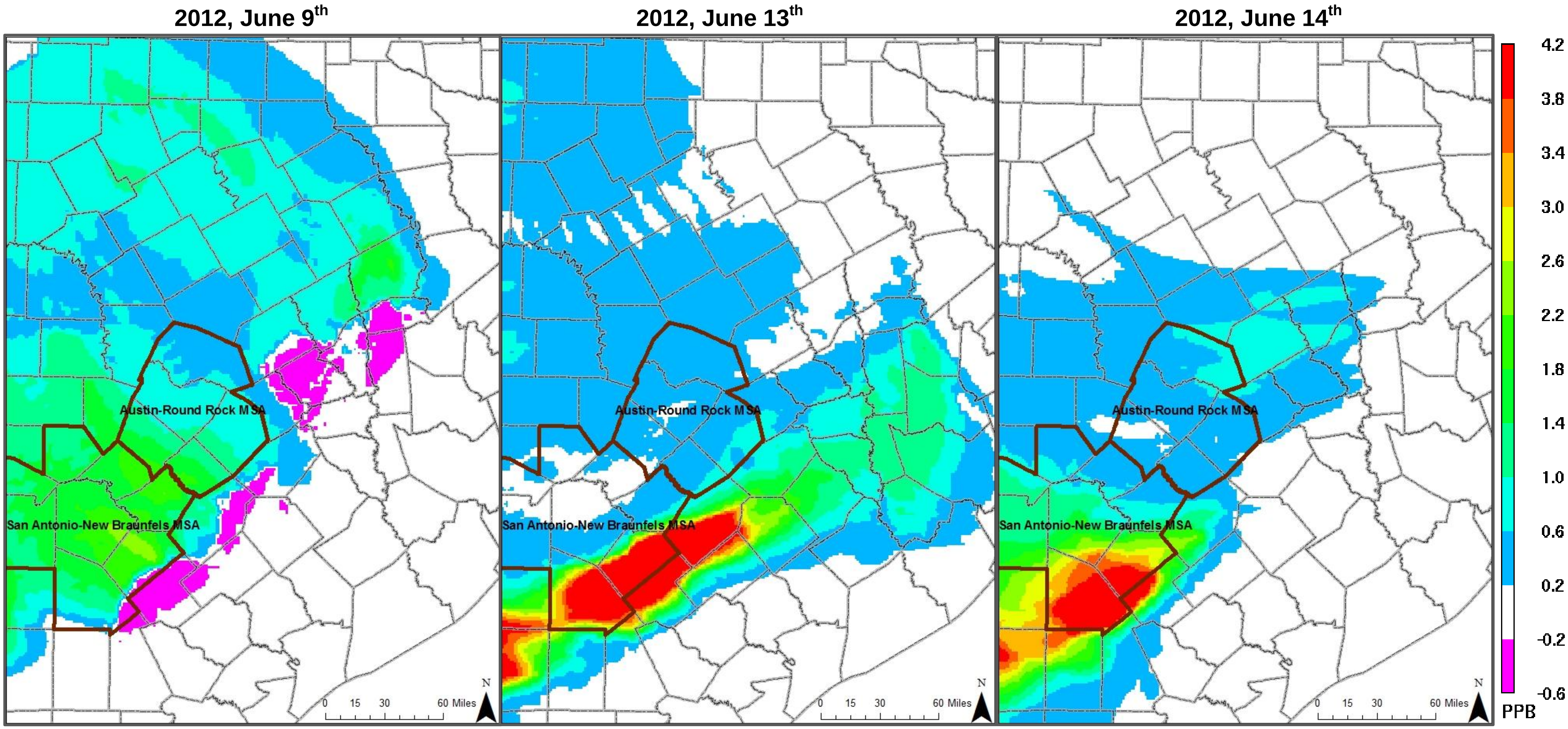

2006 (June 29th)
2012 Eagle Ford (June 29th)
2018 Eagle Ford Moderate (June 29th)
Dallas-Fort Worth-Arlington MSA
Austin-Round Rock MSA
Houston-The Woodlands-Sugar Land MSA
San Antonio-New Braunfels MSA
0 15 30 60 Miles
N
105
90
75
60
45
30
15
0
PPB

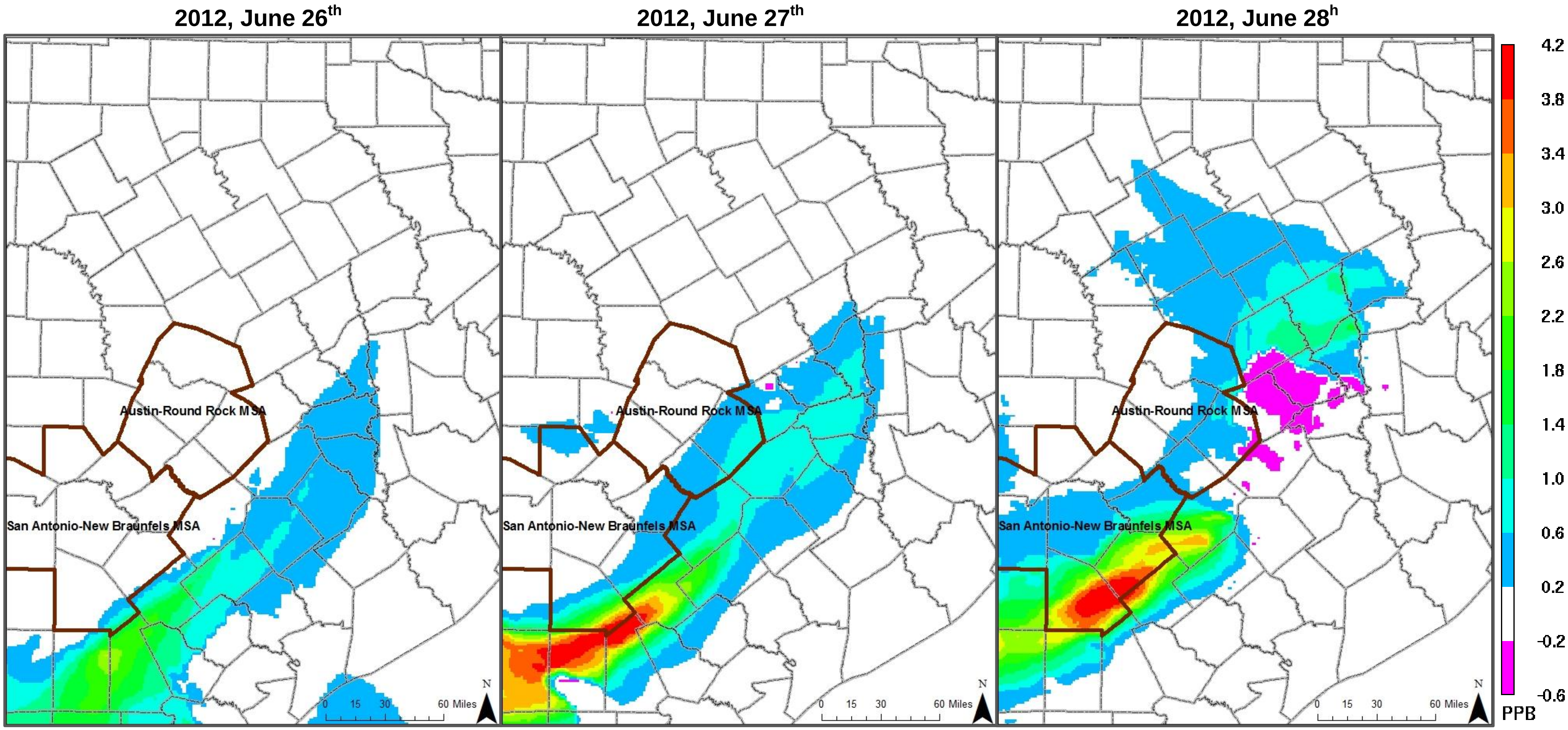
A 2012 base case run was performed with and without the 2012 Eagle Ford emission inventory. Tile plots of the difference in predicted maximum ozone levels for these runs are provided in Figure 6-2. On most days, the model predicts that the maximum impact of the Eagle Ford is southeast of Bexar County, with ozone levels increasing from 3.1 ppb to 9.3 ppb depending on the modeling day. The greatest maximum impact occurred on June 13th (9.3 ppb) and the June 14th (8.4 ppb) exceedance days.

Although the maximum predicted impact is southeast of Bexar County, emissions from the Eagle Ford increase ozone levels in Bexar County and at the regulatory monitors in the region. Significant impacts on Bexar County ozone concentrations occurred on June 7th, 8th, 9th, 14th and June 29th of the modeled episode. The impact from the Eagle Ford development was insignificant on June 26th and 27th exceedance days because the prevailing winds were from the northeast which pushed the ozone impact of the Eagle Ford south of Bexar County. Figure 6-3 shows the difference in 2018 8-hour ozone from Eagle Ford emissions for each modeling day

Figure 6-2: Predicted Daily Maximum Difference in 8-hour Ozone Concentrations in the 4-km Subdomain, 2012 Eagle Ford - Base Case




2012, June 9th
2012, June 13th
2012, June 14th
Austin-Round Rock MSA
San Antonio-New Braunfels MSA
Austin-Round Rock MSA
San Antonio-New Braunfels MSA
Austin-Round Rock MSA
San Antonio-New Braunfels MSA
0 15 30 60 Miles
N
4.2
3.8
3.4
3.0
2.6
2.2
1.8
1.4
1.0
0.6
0.2
-0.2
-0.6
PPB


2012, June 26th
2012, June 27th
2012, June 28h
Austin-Round Rock MSA
San Antonio-New Braunfels MSA
0 15 30 60 Miles
N
4.2
3.8
3.4
3.0
2.6
2.2
1.8
1.4
1.0
0.6
0.2
-0.2
-0.6
PPB

2012, June 29th

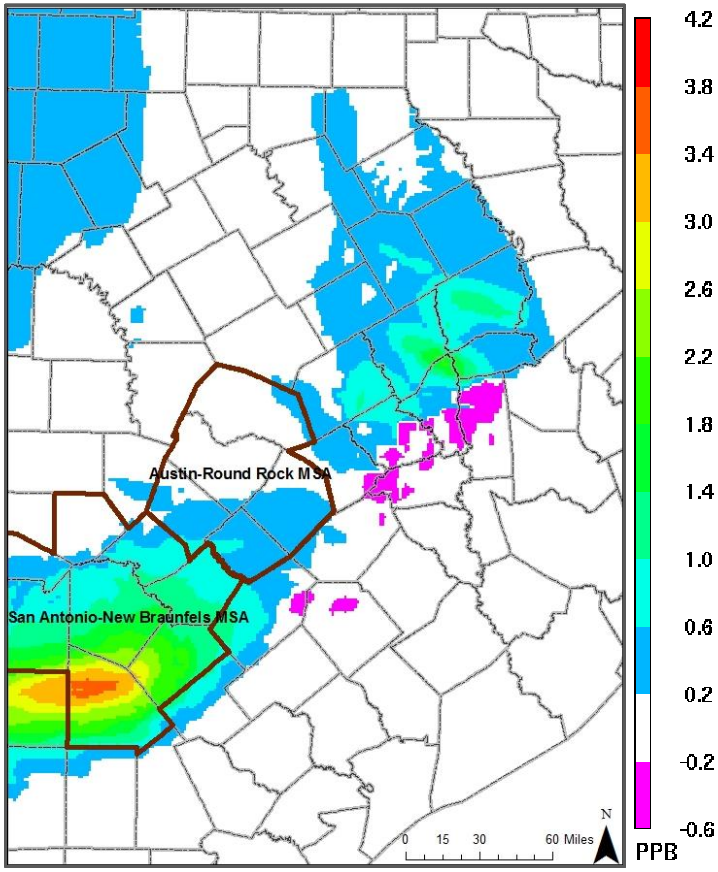
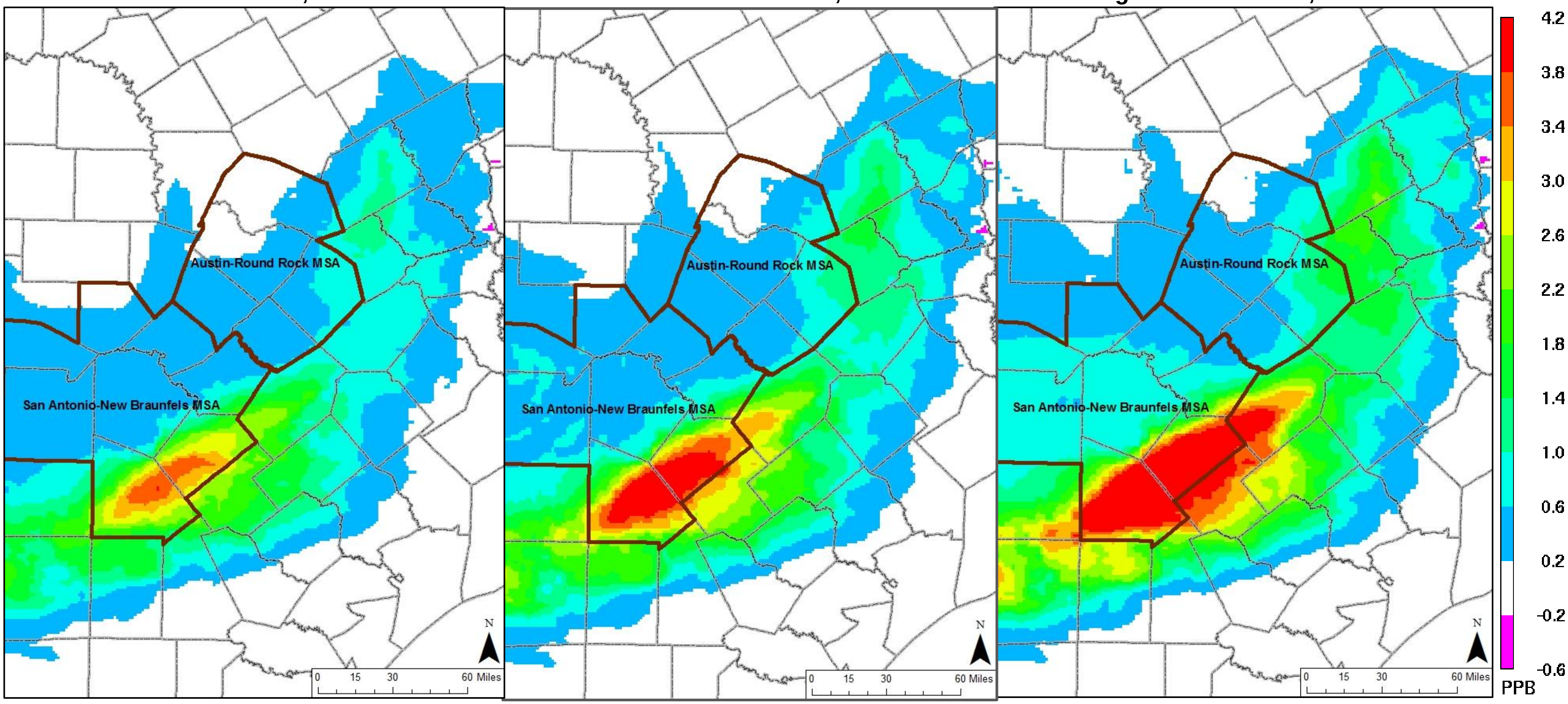
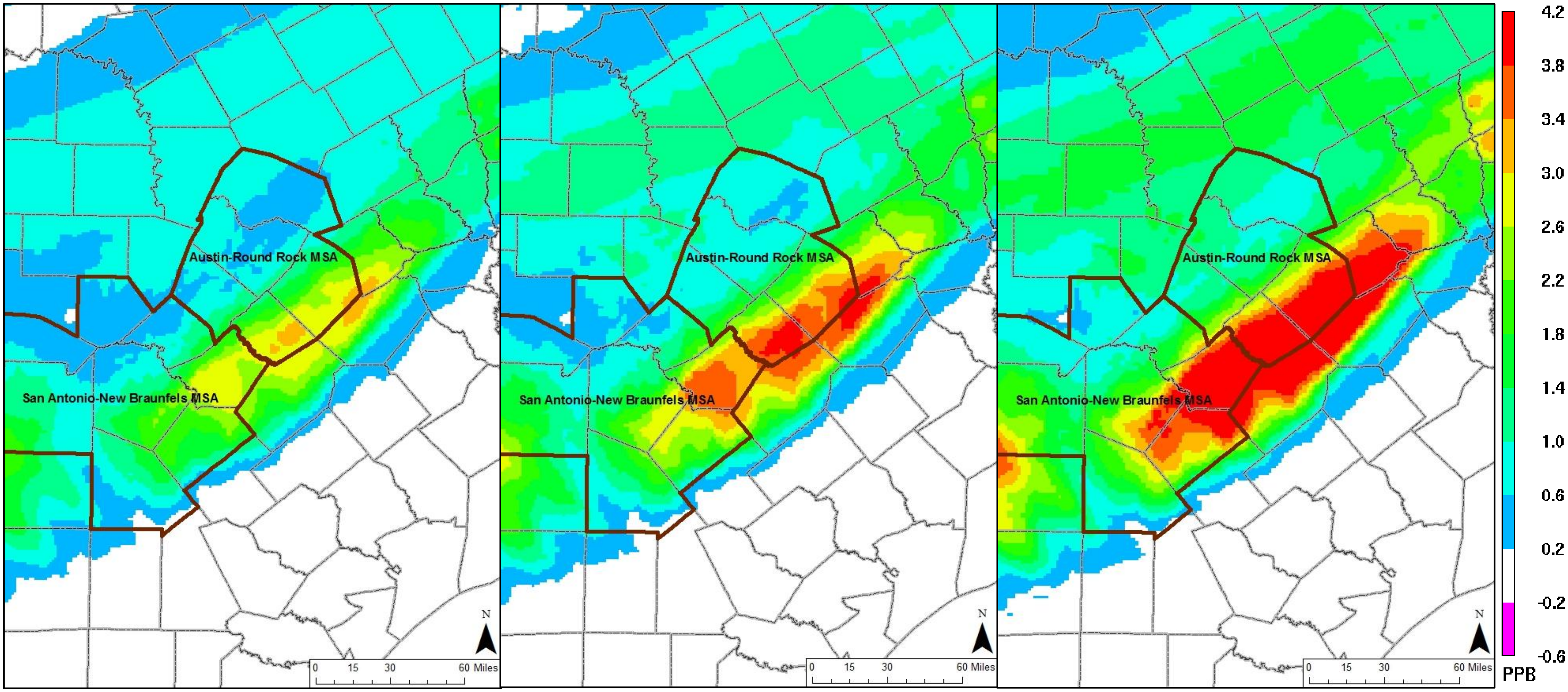


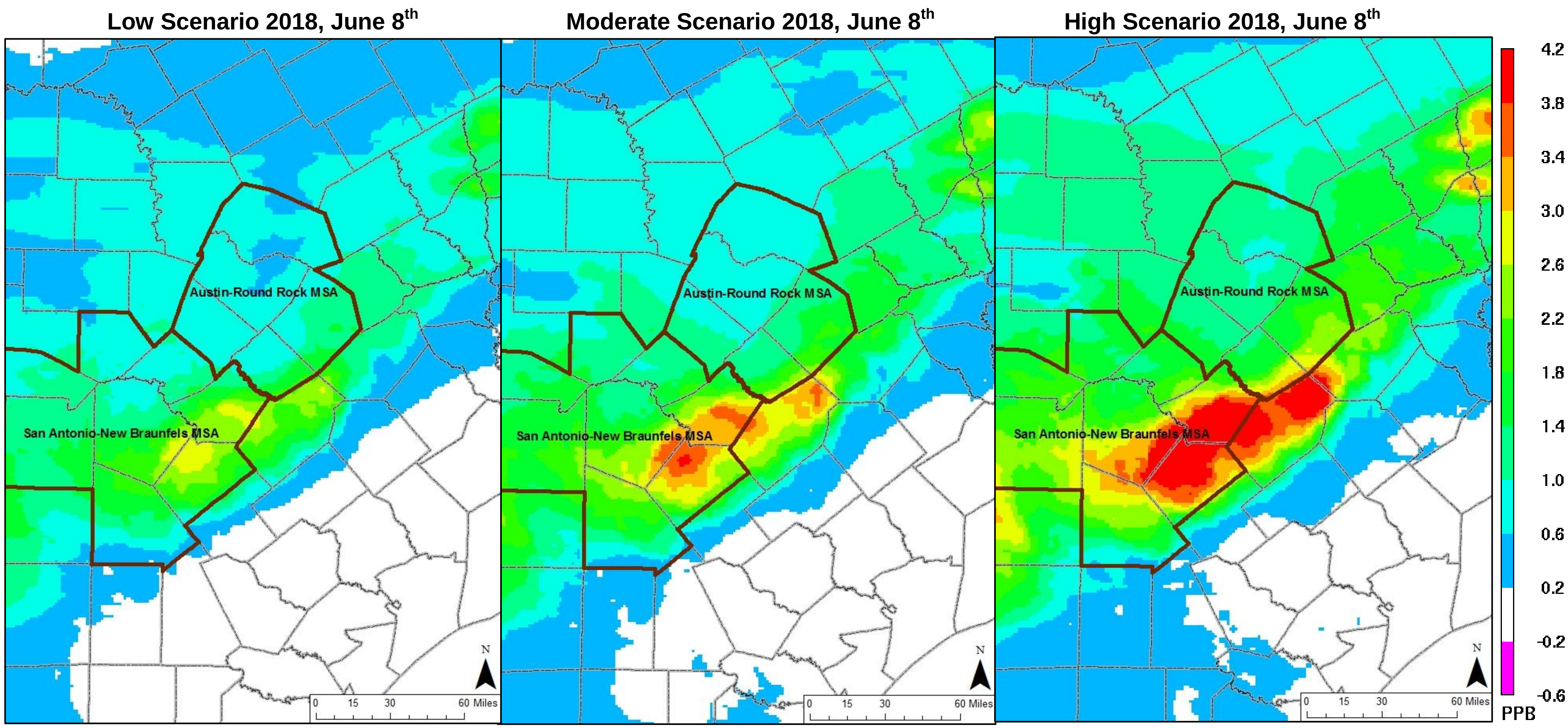
Figure 6-3: Predicted Daily Maximum Difference in 8-hour Ozone Concentrations in the 4-km Subdomain, 2018 Eagle Ford - Base Case

Low Scenario 2018, June 3rd **Moderate Scenario 2018, June 3rd** **High Scenario 2018, June 3rd**

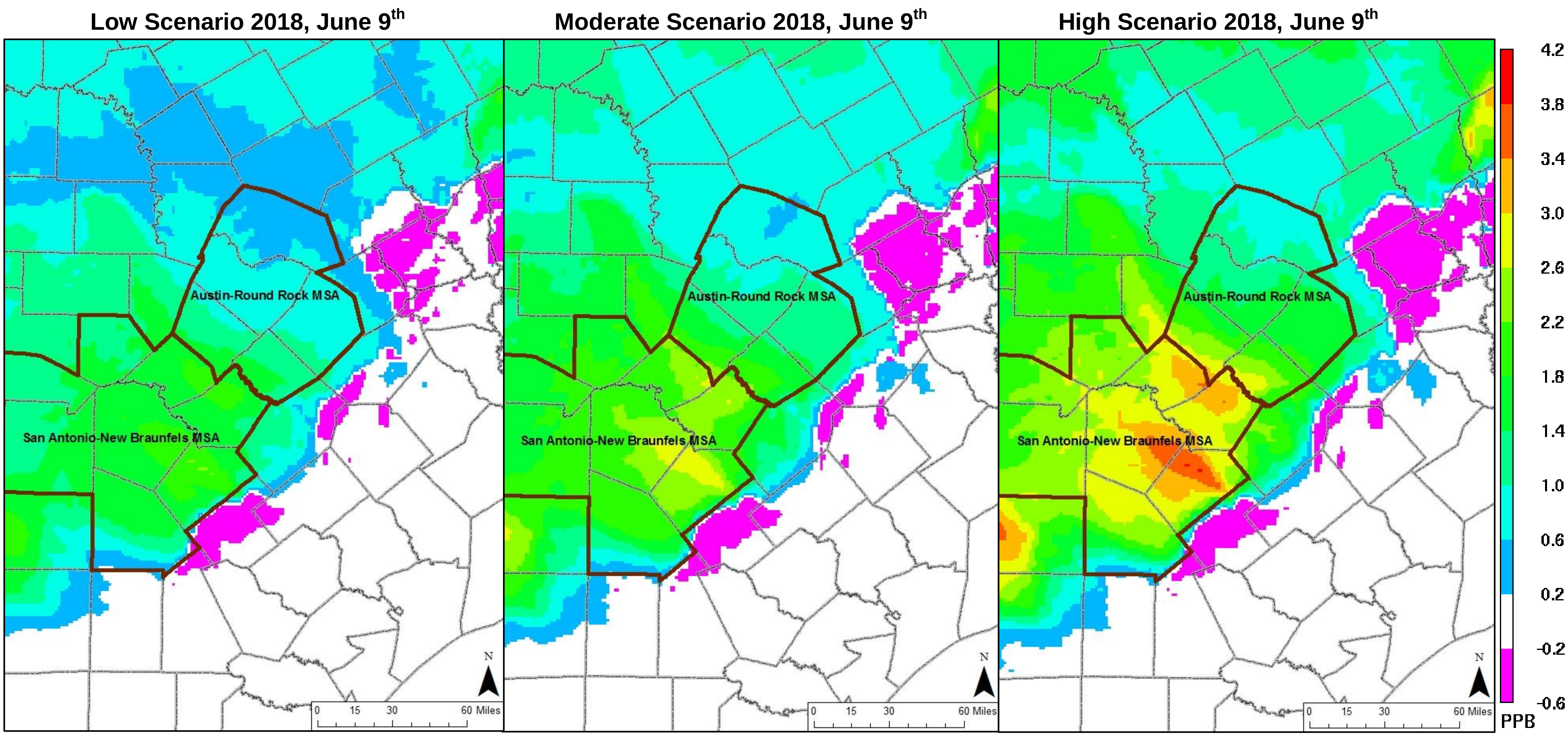


Low Scenario 2018, June 7th | Moderate Scenario 2018, June 7th | High Scenario 2018, June 7th



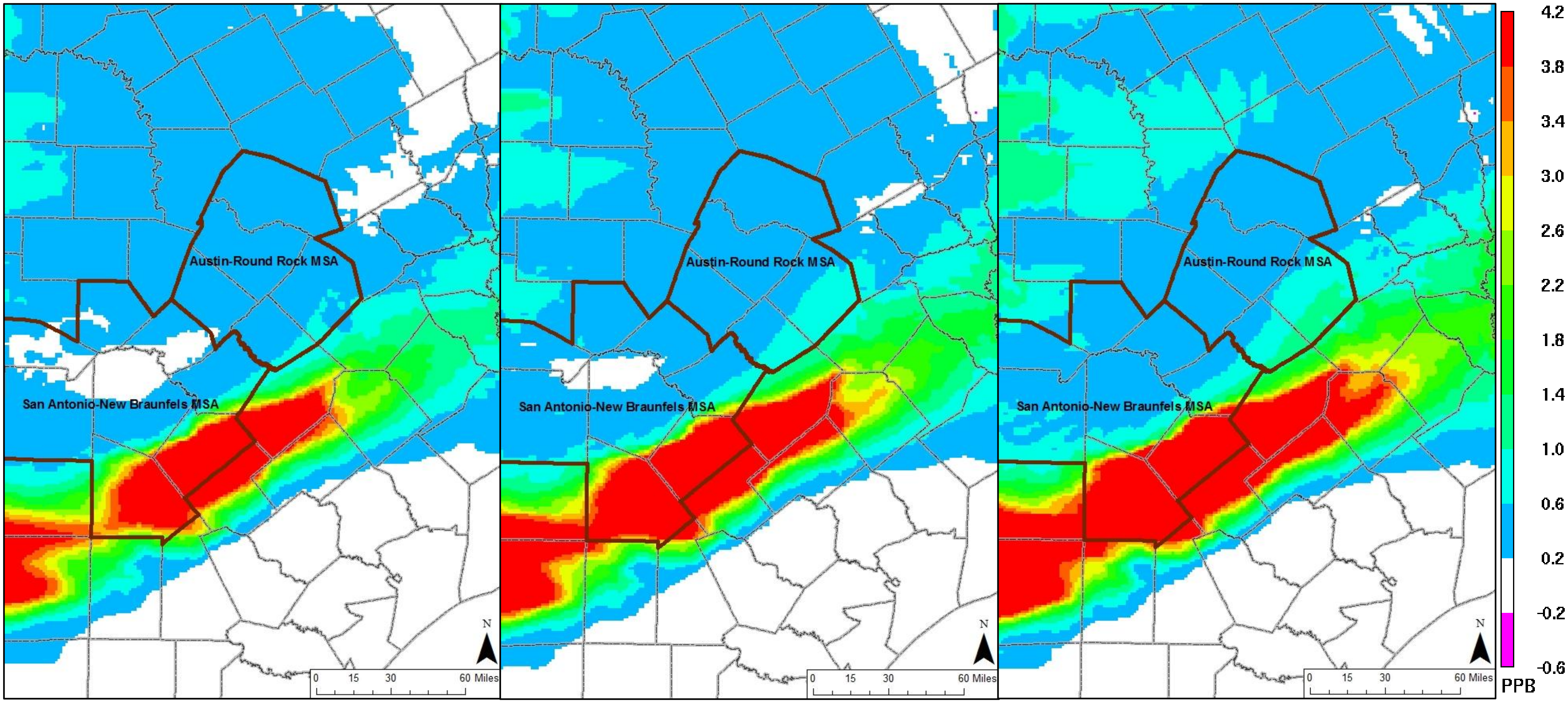


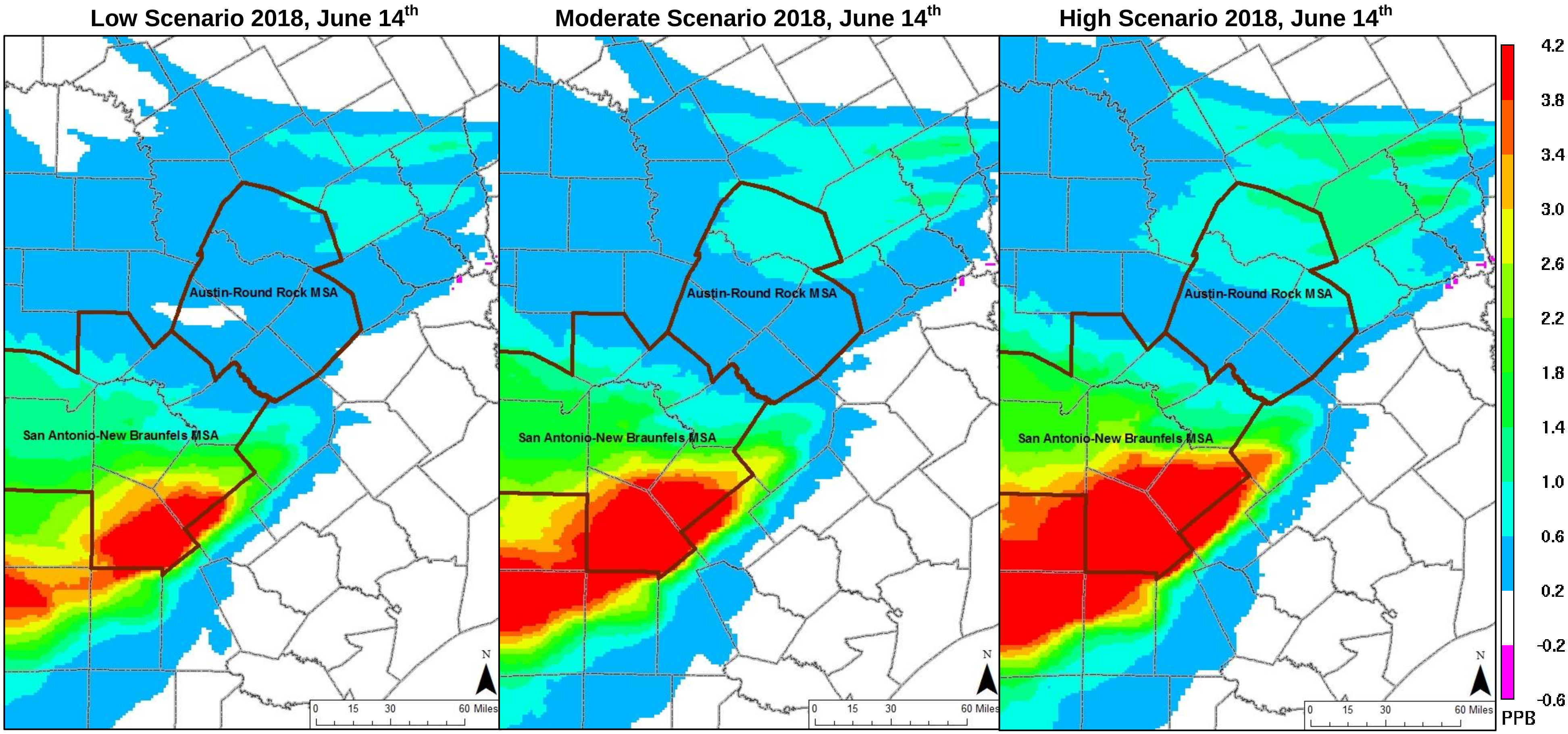
Low Scenario 2018, June 8th
Moderate Scenario 2018, June 8th
High Scenario 2018, June 8th
Austin-Round Rock MSA
San Antonio-New Braunfels MSA
N
0 15 30 60 Miles
4.2
3.8
3.4
3.0
2.6
2.2
1.8
1.4
1.0
0.6
0.2
-0.2
-0.6
PPB



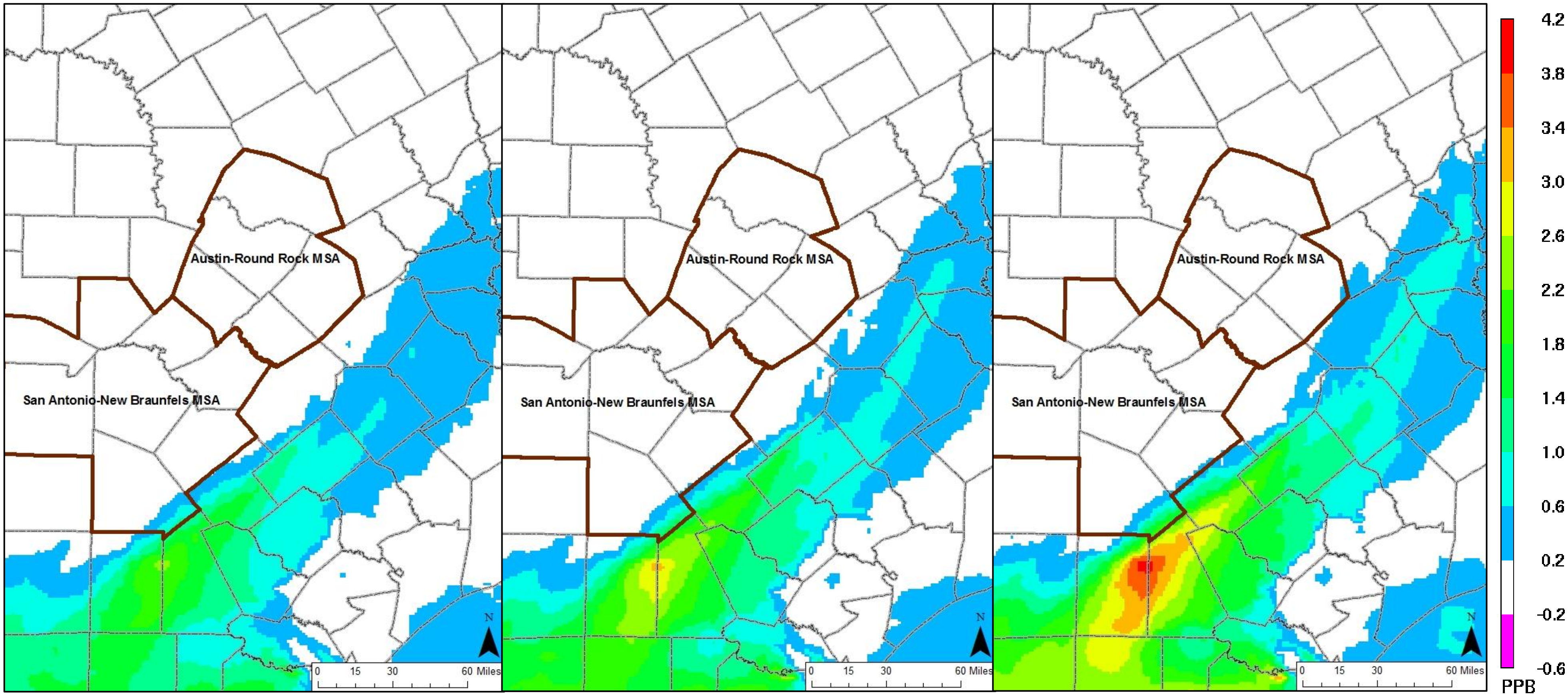
Low Scenario 2018, June 9th
Moderate Scenario 2018, June 9th
High Scenario 2018, June 9th
Austin-Round Rock MSA
San Antonio-New Braunfels MSA
N
0 15 30 60 Miles
4.2
3.8
3.4
3.0
2.6
2.2
1.8
1.4
1.0
0.6
0.2
-0.2
-0.6
PPB

Low Scenario 2018, June 13th **Moderate Scenario 2018, June 13th** **High Scenario 2018, June 13th**

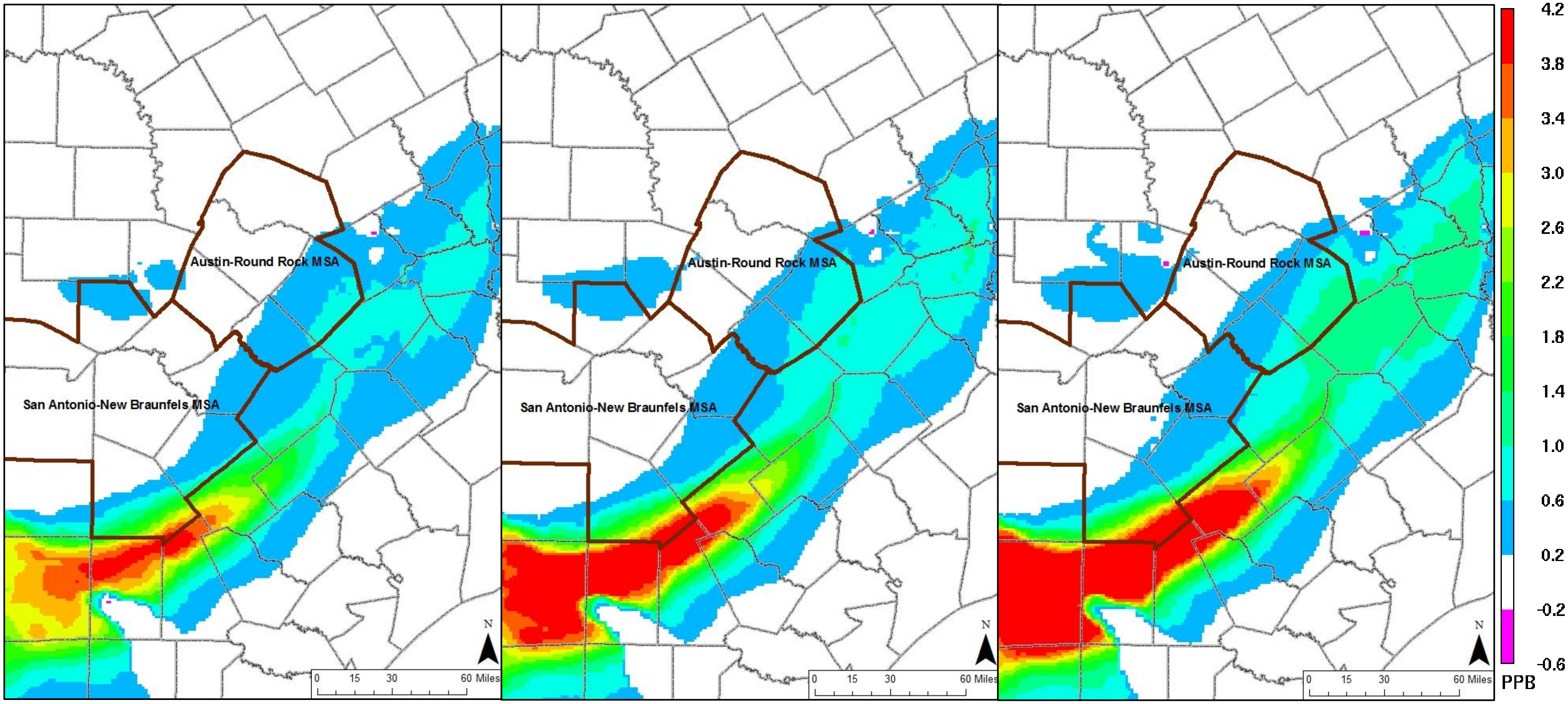


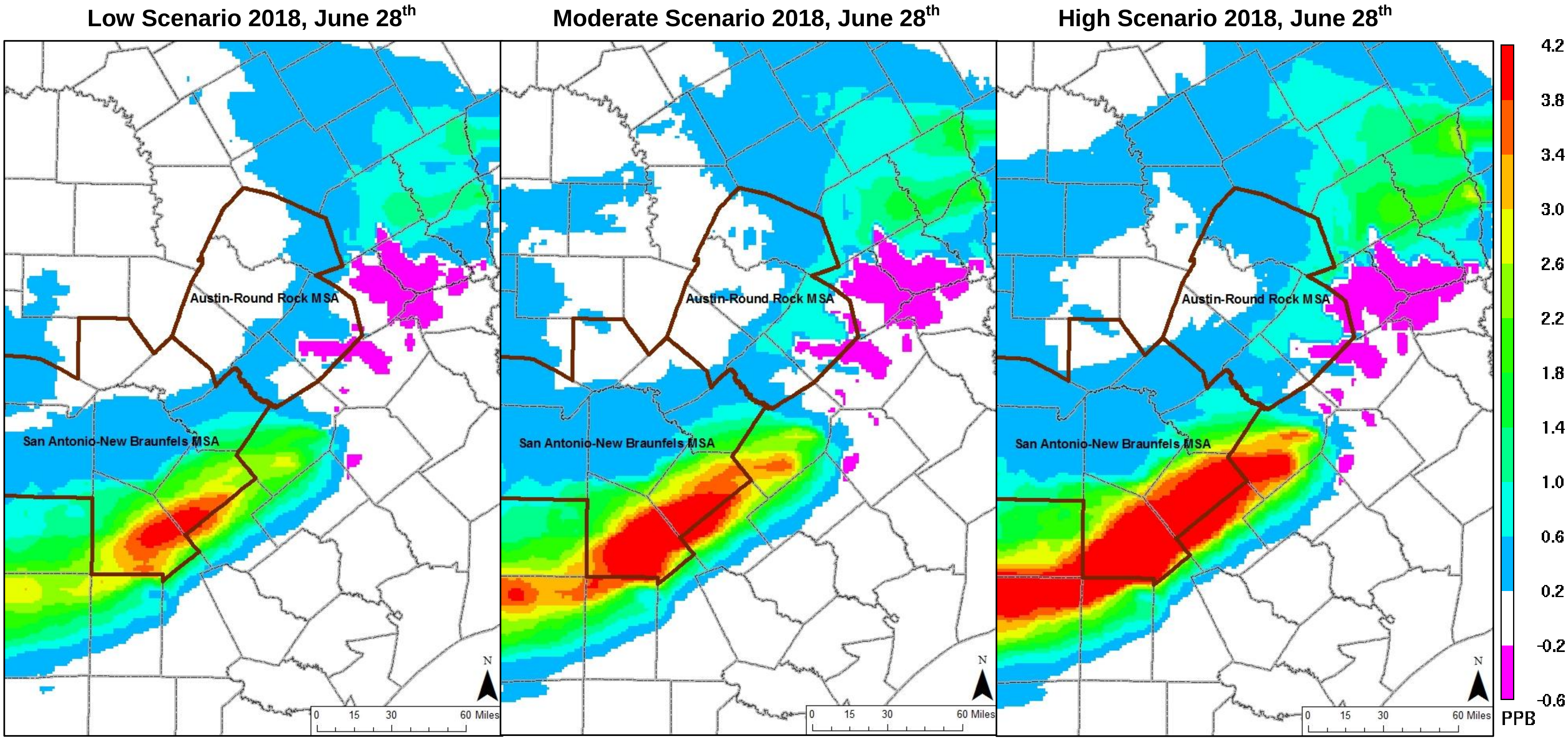

Low Scenario 2018, June 14th
Moderate Scenario 2018, June 14th
High Scenario 2018, June 14th
Austin-Round Rock MSA
San Antonio-New Braunfels MSA
0 15 30 60 Miles
N
4.2
3.8
3.4
3.0
2.6
2.2
1.8
1.4
1.0
0.6
0.2
-0.2
-0.6
PPB

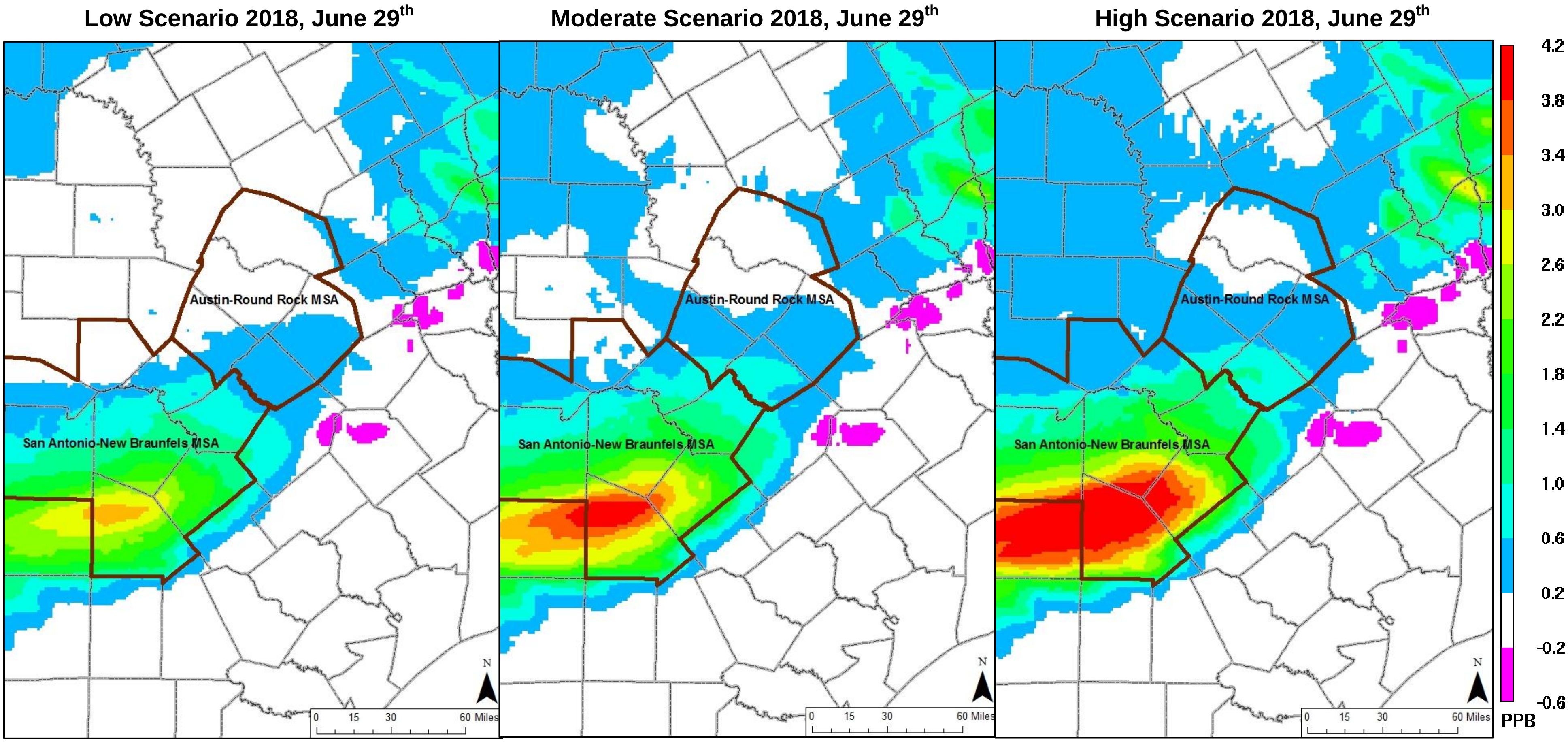
Low Scenario 2018, June 26th **Moderate Scenario 2018, June 26th** **High Scenario 2018, June 26th**



Low Scenario 2018, June 27th **Moderate Scenario 2018, June 27th** **High Scenario 2018, June 27th**




Low Scenario 2018, June 28th
Moderate Scenario 2018, June 28th
High Scenario 2018, June 28th
Austin-Round Rock MSA
San Antonio-New Braunfels MSA
N
0 15 30 60 Miles
4.2
3.8
3.4
3.0
2.6
2.2
1.8
1.4
1.0
0.6
0.2
-0.2
-0.6
PPB



Low Scenario 2018, June 29th
Moderate Scenario 2018, June 29th
High Scenario 2018, June 29th
Austin-Round Rock MSA
San Antonio-New Braunfels MSA
N
0 15 30 60 Miles
4.2
3.8
3.4
3.0
2.6
2.2
1.8
1.4
1.0
0.6
0.2
-0.2
-0.6
PPB

For the 2012 modeling projection, the greatest impact anywhere in the modeling domain from Eagle Ford Emissions was 9.3 ppb on June 13th (Table 6-1). In 2018, the greatest impact was 8.7 ppb for the Eagle Ford low scenario and 14.2 ppb for the Eagle Ford high scenario. The maximum impact ranged from 3.0 ppb on June 9th to 14.2 ppb on June 13th in 2018.

Table 6-1: Maximum Predicted Change in 8-Hour Ozone in the Modeling Domain, Eagle Ford 2012 and 2018, ppb.

Year	Scenario	6/3	6/7	6/8	6/9	6/13	6/14	6/26	6/27	6/28	6/29
2012	Eagle Ford	4.2	3.7	3.1	2.8	9.3	8.4	3.2	4.9	4.5	3.6
2018	Eagle Ford Low	3.8	3.5	3.2	3.0	8.7	7.3	3.3	4.6	4.3	3.2
	Eagle Ford Moderate	5.0	4.4	4.1	3.8	11.3	9.4	4.3	6.1	5.7	4.2
	Eagle Ford High	6.4	5.6	5.3	4.9	14.2	11.9	5.6	7.8	7.4	5.4

The maximum predicted impacts of the Eagle Ford at monitors in the AACOG region are listed in Table 6-2. Predicted ozone at C23, which is one of two monitors in Bexar County that typically measures the highest ozone concentrations in the region, increased by as much as 1.89 ppb in 2012 and between 1.81 to 3.09 ppb in 2018. The 2018 results at C58 were the same as C23 with the Eagle Ford contribution being between 1.81 to 3.09 ppb at the monitor. Since the C59 monitor is in southeast Bexar County and closer to the Eagle Ford, the impact was greater in 2018: 4.45 ppb to 7.82 ppb.

Table 6-2: Maximum Change in 8-Hour Ozone at each Monitor, Eagle Ford Emission Inventories 2012 and 2018, ppb.

Monitor	Year	Scenario	6/3	6/7	6/8	6/9	6/13	6/14	6/26	6/27	6/28	6/29	Maximum Change	Percentage of Total Ozone
C23	2012	Eagle Ford	0.44	1.20	1.52	1.89	0.18	1.90	0.00	0.06	0.30	1.18	1.89	1.9%
	2018	Eagle Ford Low	0.44	1.30	1.46	1.81	0.24	1.70	0.00	0.06	0.30	1.16	1.81	1.8%
		Eagle Ford Moderate	0.58	1.69	1.96	2.38	0.31	2.24	0.00	0.08	0.40	1.53	2.38	2.6%
		Eagle Ford High	0.76	2.19	2.59	3.09	0.41	2.92	0.00	0.11	0.53	2.00	3.09	3.4%
C58	2012	Eagle Ford	0.47	0.91	1.35	1.82	0.17	1.37	0.00	0.06	0.26	1.08	1.82	1.8%
	2018	Eagle Ford Low	0.46	1.02	1.19	1.81	0.20	1.35	0.00	0.06	0.27	0.90	1.81	2.0%
		Eagle Ford Moderate	0.61	1.32	1.55	2.38	0.24	1.77	0.00	0.08	0.36	1.18	2.38	2.6%
		Eagle Ford High	0.76	2.19	2.59	3.09	0.41	2.92	0.00	0.11	0.53	2.00	3.09	3.4%
C59	2012	Eagle Ford	2.81	2.66	3.06	2.37	3.95	3.55	0.00	0.18	2.44	2.50	3.95	4.7%
	2018	Eagle Ford Low	2.53	2.31	2.83	2.20	4.45	2.99	0.00	0.17	2.13	2.45	4.45	4.9%
		Eagle Ford Moderate	3.34	3.02	3.77	2.90	5.99	3.90	0.00	0.22	2.84	3.23	5.99	7.7%
		Eagle Ford High	4.35	3.93	4.92	3.77	7.82	5.06	0.00	0.30	3.72	4.19	7.82	10.1%
C622	2012	Eagle Ford	1.87	2.73	3.06	2.37	1.24	2.73	0.00	0.15	2.16	2.19	3.06	3.4%
	2018	Eagle Ford Low	1.81	2.32	2.83	2.20	1.18	2.31	0.00	0.15	1.78	2.15	2.83	2.9%
		Eagle Ford Moderate	2.46	3.06	3.77	2.90	2.20	3.08	0.00	0.20	2.42	2.83	3.77	4.5%
		Eagle Ford High	3.26	3.98	4.92	3.77	3.44	4.05	0.00	0.26	3.22	3.67	4.92	5.9%
C678	2012	Eagle Ford	0.79	2.66	2.99	2.36	0.45	2.31	0.00	0.12	1.16	1.87	2.99	3.0%
	2018	Eagle Ford Low	0.72	2.31	2.80	2.18	0.47	2.07	0.00	0.12	0.51	1.82	2.80	3.4%
		Eagle Ford Moderate	0.99	3.02	3.66	2.87	0.62	2.72	0.00	0.16	0.90	2.39	3.66	4.1%
		Eagle Ford High	1.38	3.93	4.72	3.73	0.82	3.54	0.00	0.21	1.44	3.09	4.72	5.3%

Based on the maximum difference in the 7x7 4km grids around each monitor

6.3 Modeled Attainment Demonstration

The modeled attainment demonstration at San Antonio-New Braunfels MSA's regulatory sited monitors was conducted by completing a series of steps that are described in the EPA Guidance on the Use of Models.[270] Two procedures were used to perform the model attainment demonstration: "…analyses which estimate whether selected emissions reductions will result in ambient concentrations that meet the NAAQS and identified set of control measures which will result in the required emissions reductions".[271]

To determine if a regulatory monitor meets the NAAQS, three calculations were performed:

1. determine the baseline five year weighted modeling site-specific design value (DV),
2. calculate the daily relative response factor, and
3. calculate of the future site-specific design values.

These calculations were performed for all monitors that meet EPA regulatory sitting requirements for days when the 8-hour predicted DV is equal or greater than 70 ppb: C23, C58, C59, C622, and C678.[272] Non-regulatory monitors operated by AACOG were not included in the calculations.

The period that was used to determine the baseline DV is the five years that straddle the 2012 baseline inventory year. The design value for 2010-2012 was used to determine the baseline modeling DV. The 2011-2013 and 2012-2014 design values were not included because the 2013 and 2014 ozone seasons are not completed. As determined by the EPA, "the average DV methodology is weighted towards the inventory year (which is the middle year) and also takes into account the emissions and meteorological variability that occurs over the full five year period".[273] The baseline modeling DV was calculated for each regulatory monitor that meets EPA's modeling guideline recommendations (Table 6-3). As shown, C58 has the highest baseline modeling DV at 80 ppb. The baseline modeling DVs at the other regulatory monitors are 77 ppb at C23, 74 ppb at CAMS 622, 69 ppb at C59, and 69 ppb at C678.

Table 6-3: Calculated Baseline Modeling Site-Specific Design Value, 2012

Monitoring Site	2010-2012 DV, ppb	Baseline DV Used in the Modeling Attainment Test, ppb
CAMS 23	77.3	77.3
CAMS 58	80.0	80.0
CAMS 59	69.3	69.3
CAMS 622	74.0	74.0
CAMS 678	69.6	69.6

[270] EPA, April 2007. "Guidance on the Use of Models and Other Analyses for Demonstrating Attainment of Air Quality Goals for Ozone, PM2.5, and Regional Haze." EPA -454/B-07-002. Research Triangle Park, North Carolina. p. 39. Available online: http://www.epa.gov/scram001/guidance/guide/final-03-pm-rh-guidance.pdf. Accessed 06/04/13.
[271] *Ibid*., p. 15.
[272] *Ibid*., p. 146.
[273] *Ibid*., p. 22.

The model attainment test requires the calculation of a daily relative response factor (RRF). Instead of using the absolute photochemical model output, a RRF is calculated using the baseline and future case modeling. The ratio between future and baseline modeling 8-hour ozone predictions near each monitor was multiplied by the monitor-specific modeling DV. The formula used to calculate the RRF is:

Equation 6-1, Design Value Calculation

$$(DVF)_I = (RRF)_I\ (DVB)_I$$

Where,

$(DVF)_I$ = the baseline ozone modeling DV at site I (ppb)
$(RRF)_I$ = the relative response factor, calculated near site I
$(DVB)_I$ = the estimated future ozone DV for the time attainment is required (ppb) [274]

Since the June 2006 photochemical modeling episode uses a 4-km fine grid system, the area near a monitor was defined as the 7x7 array of grid cells surrounding the monitor.[275] The highest predicted 8-hour daily ozone was selected in the 7x7 array for each monitor for both the 2012 projection year and the 2018 projection year. The grid cell selected in the baseline year and the future year was not always the same cell. Once the monitor-specific RRF was calculated for each day, the RRF was averaged for days with a peak monitor value greater than 70 ppb in the 2012 base case. The future site-specific DV for each monitor is provided in Table 6-4. The gray strike-through numbers are values that fall below the EPA requirement of 70 ppb.

For the Eagle Ford low scenario, the 2018 design value was 70.9 ppb at C23, 73.8 ppb at C58, and 65.0 ppb at C59. Under the Eagle Ford high scenario, the design values increase to 71.4 ppb at C23, 74.3 ppb at C58, and 65.6 ppb at C59 (Figure 6-4). The design value increased 0.5 ppb at C23, 0.6 ppb at C58, and 0.7 ppb at C59 under the Eagle Ford high scenario. All regulatory-sited monitors meet the 75 ppb 8-hour ozone standard for every 2018 projection case. However, the 2018 design value at C58 is very close the current 75 ppb 8-hour ozone NAAQS. If the EPA lowers the 8-hour ozone standard, it would be difficult for the San Antonio-New Braunfels MSA to attain the new standard.

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[274] EPA, April 2007. "Guidance on the Use of Models and Other Analyses for Demonstrating Attainment of Air Quality Goals for Ozone, PM2.5, and Regional Haze." EPA -454/B-07-002. Research Triangle Park, North Carolina. p. 20. Available online: http://www.epa.gov/scram001/guidance/guide/final-03-pm-rh-guidance.pdf. Accessed 06/04/13.

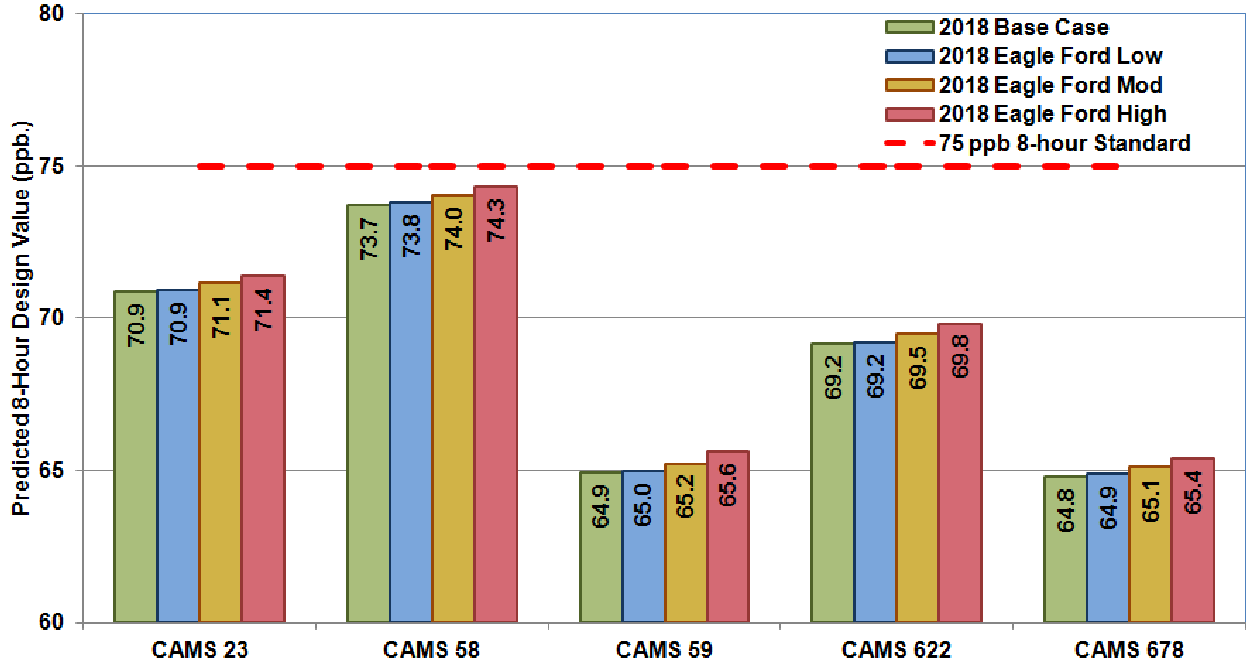
[275] *Ibid*., p. 26.

Table 6-4: Peak 8-hour Ozone (ppb) Predictions at C23, C58, C59, C622, and C678: 2012 and 2018 Modeled Cases

CAMS	Year	Run Label	Episode days														
			1st	2nd	3rd	4th	5th	6th	7th	8th	9th	10th	11th	12th	13th	14th	15th
C23	2012	Base Case	~~51.9~~	~~61.4~~	72.5	~~66.4~~	~~60.0~~	~~64.3~~	76.1	73.5	79.8	76.2	~~63.6~~	76.0	101.6	89.9	~~64.1~~
	2012	Eagle Ford	~~52.0~~	~~61.5~~	72.9	~~67.4~~	~~61.3~~	~~65.3~~	76.6	74.4	81.4	77.0	~~64.7~~	76.9	101.7	91.1	~~64.8~~
	2018	Base Case	-	-	67.2	-	-	-	69.9	67.5	72.9	70.0	-	69.5	91.1	82.0	-
	2018	Eagle Ford Low	-	-	67.6				70.5	68.4	74.5	70.9		70.4	91.3	83.3	
	2018	Eagle Ford Mod	-	-	67.7	-	-	-	70.7	68.7	75.1	71.2	-	70.7	91.3	83.7	-
	2018	Eagle Ford High	-	-	67.8	-	-	-	70.9	69.0	75.7	71.6	-	71.1	91.4	84.2	-
C58	2012	Base Case	~~51.3~~	~~61.4~~	~~69.1~~	~~67.2~~	~~60.5~~	69.0	77.1	74.1	79.7	79.7	~~65.5~~	75.6	100.6	88.8	~~64.9~~
	2012	Eagle Ford	~~51.4~~	~~61.5~~	~~69.5~~	~~68.2~~	~~61.9~~	70.2	77.6	74.9	81.2	80.4	~~66.6~~	76.4	100.7	90.1	~~65.7~~
	2018	Base Case	-	-	-	-	-	64.5	70.3	68.0	72.7	73.1	-	69.3	90.6	81.8	-
	2018	Eagle Ford Low	-	-	-	-	-	65.7	70.9	68.8	74.2	73.9		70.3	90.8	83.1	-
	2018	Eagle Ford Mod	-	-	-	-	-	66.0	71.0	69.1	74.7	74.1	-	70.6	90.8	83.5	-
	2018	Eagle Ford High	-	-	-	-	-	66.5	71.3	69.4	75.3	74.5	-	71.0	90.9	84.0	-
C59	2012	Base Case	~~51.6~~	~~54.5~~	71.2	~~60.7~~	~~54.0~~	~~52.5~~	~~57.3~~	~~62.8~~	69.8	70.9	~~54.1~~	~~55.1~~	83.7	76.3	~~63.7~~
	2012	Eagle Ford	~~51.8~~	~~54.7~~	71.7	~~62.3~~	~~55.4~~	~~54.5~~	~~59.0~~	~~64.5~~	71.8	72.4	~~55.9~~	~~57.0~~	83.9	77.7	~~64.5~~
	2018	Base Case	-	-	67.0	-	-	-	-	-	66.5	66.7	-	-	77.1	71.6	-
	2018	Eagle Ford Low	-	-	67.5	-	-	-	-	-	68.3	68.3	-	-	77.3	72.9	-
	2018	Eagle Ford Mod	-	-	67.7	-	-	-	-	-	68.8	68.8	-	-	77.4	73.3	-
	2018	Eagle Ford High	-	-	67.9	-	-	-	-	-	69.6	69.4	-	-	77.5	74.2	-
C622	2012	Base Case	~~51.6~~	~~54.5~~	71.2	~~62.3~~	~~54.5~~	~~53.8~~	~~61.6~~	~~62.8~~	71.1	73.7	~~56.8~~	~~59.5~~	90.8	79.6	~~63.7~~
	2012	Eagle Ford	~~51.8~~	~~54.7~~	71.7	~~63.8~~	~~55.9~~	~~55.7~~	~~63.0~~	~~64.5~~	73.1	75.4	~~58.5~~	~~60.8~~	91.0	80.4	~~64.5~~
	2018	Base Case	-	-	67.0	-	-	-	-	-	67.5	69.6	-	-	82.6	74.1	-
	2018	Eagle Ford Low	-	-	67.5	-	-	-	-	-	69.4	71.3	-	-	82.8	75.0	-
	2018	Eagle Ford Mod	-	-	67.7	-	-	-	-	-	69.9	71.8	-	-	82.9	75.3	-
	2018	Eagle Ford High	-	-	67.9	-	-	-	-	-	70.7	72.5	-	-	83.0	75.7	-
C678	2012	Base Case	~~51.8~~	~~57.6~~	71.8	~~64.6~~	~~56.0~~	~~57.5~~	~~66.0~~	~~64.8~~	74.1	75.2	~~60.3~~	~~67.8~~	98.6	85.4	~~63.4~~
	2012	Eagle Ford	~~52.0~~	~~57.8~~	72.2	~~65.9~~	~~57.4~~	~~59.5~~	~~66.8~~	~~66.0~~	75.9	76.6	~~61.6~~	~~68.7~~	98.7	86.7	~~64.4~~
	2018	Base Case	-	-	67.3	-	-	-	-	-	69.8	71.0	-	-	89.5	79.5	-
	2018	Eagle Ford Low	-	-	67.7	-	-	-	-	-	71.5	72.6	-	-	89.6	80.8	-
	2018	Eagle Ford Mod	-	-	67.8	-	-	-	-	-	72.0	73.0	-	-	89.7	81.2	-
	2018	Eagle Ford High	-	-	67.8			66.0	71.0	69.1	75.1	74.1		70.7	91.3	83.7	-

CAMS	Year	Run Label	Episode days															Design Value
			16th	17th	18th	19th	20th	21st	22nd	23rd	24th	25th	26th	27th	28th	29th	30th	
C23	2012	Base Case	~~43.6~~	~~37.2~~	~~42.0~~	~~55.2~~	~~36.4~~	~~38.2~~	~~44.6~~	~~46.9~~	~~45.2~~	~~54.9~~	~~63.3~~	73.8	90.1	75.8	73.0	77.3
	2012	Eagle Ford	~~44.0~~	~~38.2~~	~~43.1~~	~~55.6~~	~~37.6~~	~~38.9~~	~~45.4~~	~~47.5~~	~~45.5~~	~~55.3~~	~~63.3~~	73.9	90.3	76.6	73.3	77.3
	2018	Base Case	-	-	-	-	-	-	-	-	-	-	-	67.3	82.2	71.0	67.8	70.9
	2018	Eagle Ford Low	-	-	-	-	-	-	-	-	-	-	-	67.4	82.4	71.7	68.1	70.9
	2018	Eagle Ford Mod	-	-	-	-	-	-	-	-	-	-	-	67.4	82.5	72.0	68.2	71.1
	2018	Eagle Ford High	-	-	-	-	-	-	-	-	-	-	-	67.4	82.6	72.3	68.3	71.4
C58	2012	Base Case	~~44.8~~	~~39.0~~	~~42.0~~	~~54.4~~	~~36.3~~	~~41.7~~	~~45.2~~	~~46.9~~	~~42.7~~	~~51.8~~	~~59.1~~	70.2	83.9	74.4	71.7	80.0
	2012	Eagle Ford	~~45.3~~	~~40.3~~	~~43.1~~	~~54.8~~	~~37.5~~	~~42.5~~	~~46.0~~	~~47.4~~	~~43.1~~	~~51.9~~	~~59.1~~	70.2	84.1	75.3	72.0	80.0
	2018	Base Case	-	-	-	-	-	-	-	-	-	-	-	64.7	78.3	70.3	67.1	73.7
	2018	Eagle Ford Low	-	-	-	-	-	-	-	-	-	-	-	64.7	78.5	71.1	67.4	73.8
	2018	Eagle Ford Mod	-	-	-	-	-	-	-	-	-	-	-	64.7	78.6	71.3	67.5	74.0
	2018	Eagle Ford High	-	-	-	-	-	-	-	-	-	-	-	64.8	78.7	71.7	67.6	74.3
C59	2012	Base Case	~~38.1~~	~~32.8~~	~~34.4~~	~~56.6~~	~~33.2~~	~~35.0~~	~~40.1~~	~~40.6~~	~~51.1~~	~~61.6~~	~~66.2~~	74.2	80.4	74.1	~~62.1~~	69.3
	2012	Eagle Ford	~~38.7~~	~~34.1~~	~~36.5~~	~~57.0~~	~~34.4~~	~~36.1~~	~~40.8~~	~~42.3~~	~~51.2~~	~~61.9~~	~~66.2~~	74.3	80.8	75.9	~~63.5~~	69.3
	2018	Base Case	-	-	-	-	-	-	-	-	-	-	-	67.1	75.6	71.1		64.9
	2018	Eagle Ford Low	-	-	-	-	-	-	-	-	-	-	-	67.2	76.0	72.9		65.0
	2018	Eagle Ford Mod	-	-	-	-	-	-	-	-	-	-	-	67.2	76.1	73.4		65.2
	2018	Eagle Ford High	-	-	-	-	-	-	-	-	-	-	-	67.2	76.3	74.1		65.6
C622	2012	Base Case	~~38.1~~	~~32.8~~	~~35.4~~	~~56.9~~	~~33.2~~	~~35.1~~	~~39.8~~	~~40.6~~	~~50.1~~	~~61.1~~	~~65.8~~	74.2	80.4	74.1	~~64.3~~	74.0
	2012	Eagle Ford	~~38.7~~	~~34.1~~	~~37.4~~	~~57.3~~	~~34.4~~	~~36.1~~	~~40.8~~	~~42.3~~	~~50.2~~	~~61.4~~	~~65.8~~	74.3	80.8	75.9	~~64.7~~	74.0
	2018	Base Case	-	-	-	-	-	-	-	-	-	-	-	67.2	75.6	71.1		69.2
	2018	Eagle Ford Low	-	-	-	-	-	-	-	-	-	-	-	67.3	76.0	72.9		69.2
	2018	Eagle Ford Mod	-	-	-	-	-	-	-	-	-	-	-	67.3	76.1	73.4		69.5
	2018	Eagle Ford High	-	-	-	-	-	-	-	-	-	-	-	67.4	76.3	74.1		69.8
C678	2012	Base Case	~~39.9~~	~~33.3~~	~~40.2~~	~~56.9~~	~~33.8~~	~~35.7~~	~~40.5~~	~~41.3~~	~~48.4~~	~~58.9~~	~~66.5~~	77.0	83.9	76.7	~~69.6~~	69.6
	2012	Eagle Ford	~~40.5~~	~~34.6~~	~~41.7~~	~~57.3~~	~~35.0~~	~~36.8~~	~~41.5~~	~~42.3~~	~~48.6~~	~~59.2~~	~~66.5~~	77.0	84.1	78.3	~~69.8~~	69.6
	2018	Base Case	-	-	-	-	-	-	-	-	-	-	-	69.5	78.3	73.6		64.8
	2018	Eagle Ford Low	-	-	-	-	-	-	-	-	-	-	-	69.5	78.5	75.2		64.9
	2018	Eagle Ford Mod	-	-	-	-	-	-	-	-	-	-	-	69.6	78.6	75.7		65.1
	2018	Eagle Ford High	-	-	-	-	-	-	-	-	-	-	-	69.6	78.7	76.3		65.4

Figure 6-4: Change in San Antonio-New Braunfels MSA Eight-Hour Design Values, 2018



6.4 Minimum Threshold Analysis:

The methodology used above follows the EPA's guidance on calculating future design values. However, other methodologies may be used to calculate future design values, so that model sensitivity can be tested.[276] The minimum threshold used in the design value calculation was based on EPA's recommended lowest threshold of 70 ppb. The change in 2018 RRFs, the future design values, and the number of days that meet each criterion are provided in Table 6-5.

By raising the minimum threshold from 70 ppb, used in the above attainment demonstration, to 75 ppb and 80 ppb, the applicable days drop below EPA's guidance that suggests at least 10 days be included in the analysis. While the calculation then uses days that modeled higher baseline ozone concentrations, the calculation becomes less statistically robust. When the minimum threshold was raised to 75 ppb, the maximum design value at C58 was lowered 0.1 ppb. Under the minimum threshold of 80 ppb, the maximum design value was lowered 0.4 ppb to 73.6 ppb, though there are only five days included in the calculation. A similar reduction in the future design value occurred for the other monitors when the minimum threshold was increased to 80 ppb.

[276] TCEQ. "Appendix C: Photochemical Modeling for the DFW Attainment Demonstration SIP Revision for the 1997 Eight-Hour Ozone Standard". Austin, Texas. p. c-127. Available online: http://www.tceq.texas.gov/assets/public/implementation/air/sip/dfw/ad_2011/AppC_CAMx_ado.pdf. Accessed 06/20/13.

Table 6-5: Minimum Threshold Analysis, 2012-2018.

Site	2012 DV	70 ppb			75 ppb			80 ppb		
		RRF	DVF	# Days	RRF	DVF	# Days	RRF	DVF	# Days
C23	77.3	0.920	71.1	12	0.932	72.0	8	0.912	70.5	4
C58	80.0	0.925	74.0	12	0.923	73.9	8	0.920	73.6	5
C59	69.3	0.941	65.2	8	0.943	65.4	4	0.932	64.6	2
C622	74.0	0.939	69.5	8	0.941	69.6	5	0.929	68.7	3
C678	69.6	0.935	65.1	8	0.935	65.1	7	0.926	64.4	3

6.5 Grid Cell Array Size Analysis

"The grid cell array size is chosen as an area around a monitor to be spatially representative of that site. For the RRF calculation the maximum concentration in the grid cell array around a monitor from the baseline and future case modeling is used, which may not be at the cell where the monitor is located. The EPA guidance states that this method is beneficial for many reasons, including that the model may displace the peak around a monitor."[277]

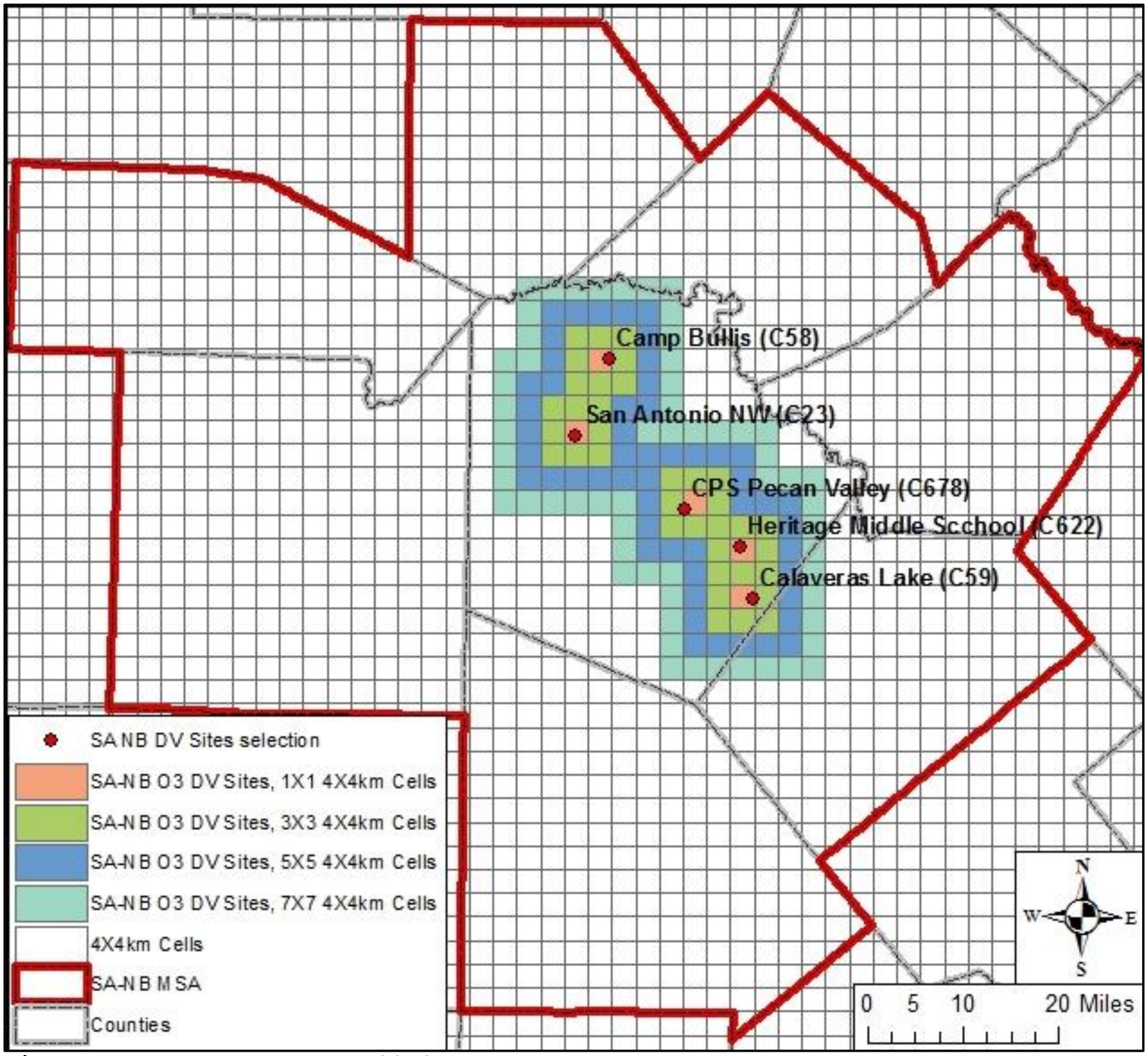
The 3X3, 5X5, and 7X7 grid cell arrays used in the alternative DV calculations for the regulatory sited monitors in the San Antonio-New Braunfels MSA are shown in Figure 6-5. A 5x5 or 7x7 grid cell array shows overlap among several of San Antonio monitors. The maximum DV at C58 increases from 74.0 ppb to 75.0 ppb when a 3X3 grid cell array is used (Table 6-6). For the other four monitors, the design value decreases from 0.8 ppb to 6.2 ppb when using the 3X3 grid cell array. The model is more sensitive to changes in predicted ozone nearer to the monitoring sites.

Table 6-6: RRFs and DVFs using 3X3, 5X5, and 7X7 Grid Cell Arrays, 2012-2018

Site	2012 DV	3X3 Grid Cell Array		5X5 Grid Cell Array		7X7 Grid Cell Array	
		RRF	DV	RRF	DV	RRF	DV
Area Max	80.0	0.938	75.0	0.923	73.8	0.941	74.0
C23	77.3	0.908	70.2	0.901	69.7	0.920	71.1
C58	80.0	0.938	75.0	0.923	73.8	0.925	74.0
C59	69.3	0.891	61.7	0.877	60.8	0.941	65.2
C622	74.0	0.928	68.7	0.910	67.4	0.939	69.5
C678	69.6	0.847	58.9	0.826	57.5	0.935	65.1

[277] TCEQ. "Appendix C: Photochemical Modeling for the DFW Attainment Demonstration SIP Revision for the 1997 Eight-Hour Ozone Standard". Austin, Texas. p. c-127. Available online: http://www.tceq.texas.gov/assets/public/implementation/air/sip/dfw/ad_2011/AppC_CAMx_ado.pdf. Accessed 06/20/2013.

Figure 6-5: Grid Cell Array Size around Regulatory Sited San Antonio-New Braunfels Ozone Monitors



Plot Date: June 14, 2013
Map Compilation: June 14, 2013
Source: Monitor Locations based on TCEQ data.

An evaluation of the spatio-temporal characteristics of meteorologically-adjusted ozone trends in North Texas

A preliminary analysis

by

Mahdi Ahmadi and Kuruvilla John

Department of Mechanical and Energy Engineering
University of North Texas

Air Quality Technical Meeting, NCTCOG
Arlington, TX. April 17, 2014

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The Research

- Study objective: Evaluate the meteorologically adjusted trends in the measured ozone concentrations in north Texas
- Study area: North Texas region including DFW *metroplex*
- Study period: 1997-2014 (12-17 years worth of data)
- Air quality data: Ozone and meteorological parameters
- Number of air quality monitoring sites: 16 CAMS operated by TCEQ
- Method: Statistical analysis of raw ozone data (*part I*) and meteorologically adjusted ozone trend using KZ-filtering method (*part II*)

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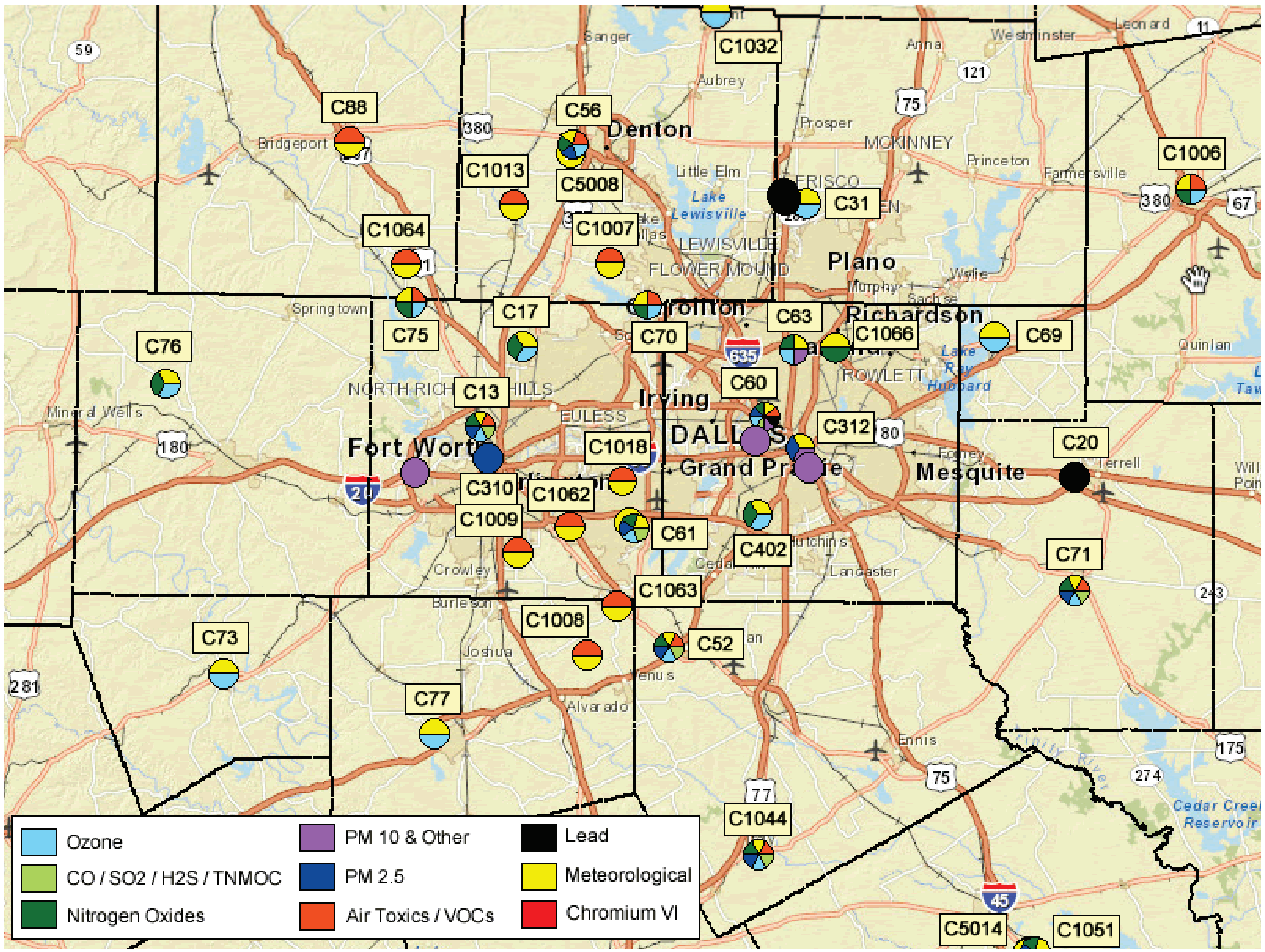
TCEQ CAMS : North Texas Sites

Current ozone level



Source: https://www.tceq.texas.gov

Data

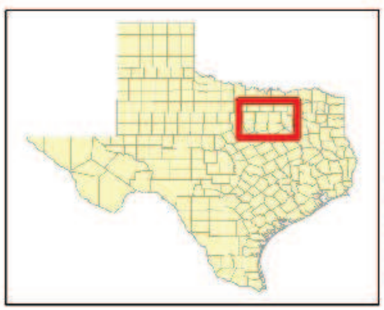
- Time series of 8-hr average ozone concentrations were extracted from TCEQ's Texas Air Monitoring Information System (TAMISWeb) for the 1997-2014 period (some of the monitoring stations were activated later than 1997) at sixteen state operated Continuous Ambient Monitoring Stations (CAMS).

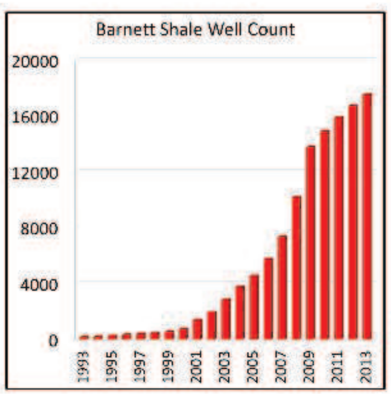
- In addition to the 8-hr ozone data, hourly and 8-hr averaged values of meteorological parameters for the same period were also acquired. Meteorological data include ambient temperature (T), solar radiation (SR), relative humidity (RH), and wind speed and direction (W).

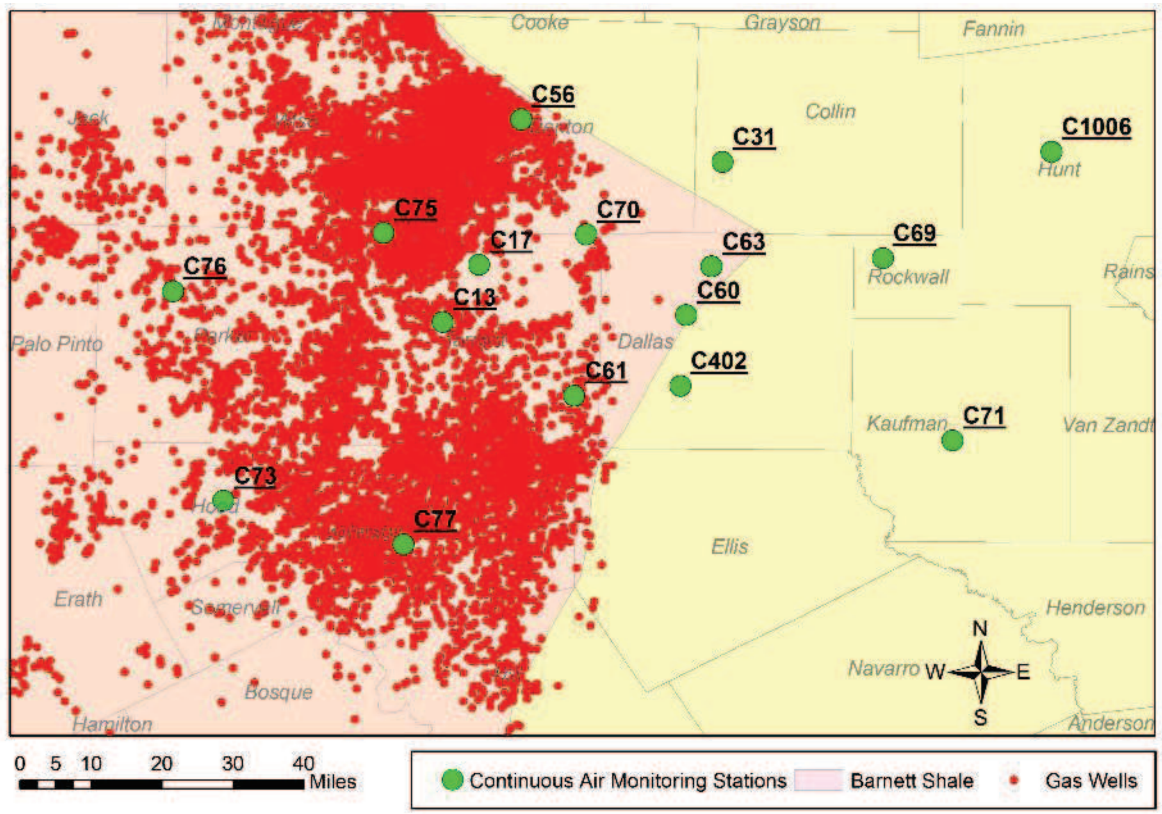
- Time series of the daily maxima of all parameters were compiled and used in this study to evaluate the meteorologically adjusted trends in the ozone concentrations over the north Texas region.

Study Area

- Total number of gas wells:
  - At the end of 2007: 5720 wells
  - At the end of 2013: 17,494 wells
- Rate: 713 wells/year (between 2000-2006), and 1682 wells/year (2007-2013)







Source: RRC and TCEQ

Monitoring Sites

CAMS #	Name	County	Parameters	No. of wells - 10 mi
C76	Parker County	Parker	O_3, SR, T, W	158
C73	Granbury	Hood	O_3, SR, T, W	428
C75	Eagle Mountain	Tarrant	O_3, SR, T, W	2723
C77	Cleburne Airport	Johnson	O_3, SR, T, W	1474
C13	Ft. Worth Northwest	Tarrant	O_3, SR, T, RH, W	1092
C17	Keller	Tarrant	O_3, SR, T, W	1364
C56	Denton Municipal Airport	Denton	O_3, SR, T, RH, W	1362
C61	Arlington Muni. Airport	Tarrant	O_3, SR, T, W	862
C70	Grapevine Fairway	Grapevine	O_3, SR, T, RH, W	299
C402	Dallas Executive Airport	Dallas	O_3, T, W	1
C60	Dallas Hinton St.	Dallas	O_3, SR, T, RH, W	2
C63	Dallas North No. 2	Dallas	O_3, SR, T, W	2
C31	Frisco	Collin	O_3, SR, T, W	0
C69	Rockwall Heat	Rockwall	O_3, SR, T, W	0
C71	Kaufman	Kaufman	O_3, SR, T, RH, W	0
C1006	Greenville	Hunt	O_3, SR, T, W	0

“Fracking region” (FR)

“Non-fracking region” (NFR)

Methods

- **Part I:** Statistical evaluation of trends in the raw ozone data
  - *Ozone design value*: "the 3-year average annual fourth-highest daily maximum 8-hour average ozone concentration"
  - *Ozone exceedances*: Number of days with maximum 8-hour ozone concentration exceeding NAAQS threshold (75 ppb)
- Evaluations performed for the **FR** and **NFR** regions over two contiguous periods: 2000-2006 (**B07**) and 2007-2013 (**A07**)

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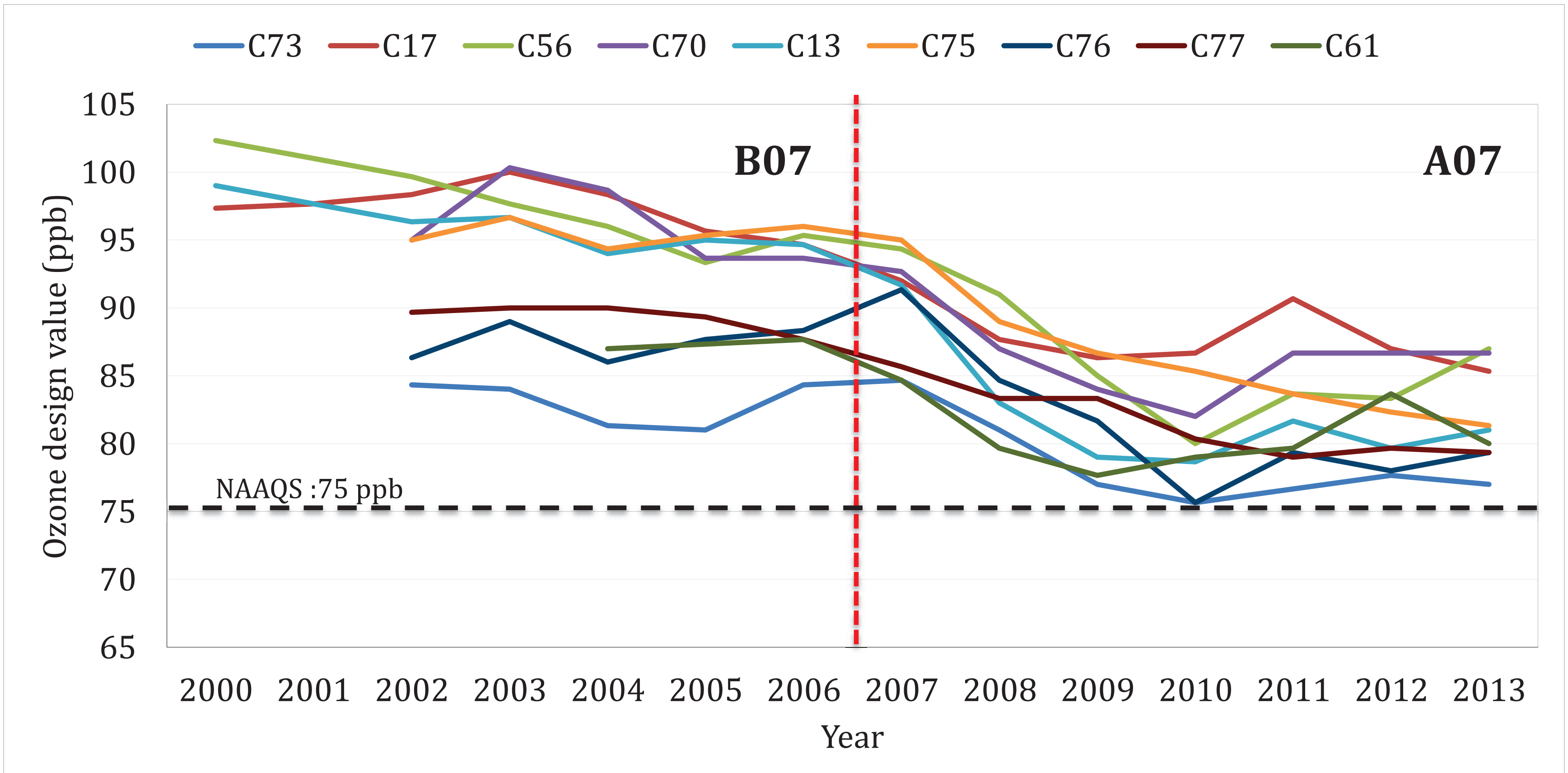
Results – Part I

- Trend in the ozone design values within **FR**



- Average percent change from **B07** (2000-2006) to **A07** (2007-2013): **-10%**

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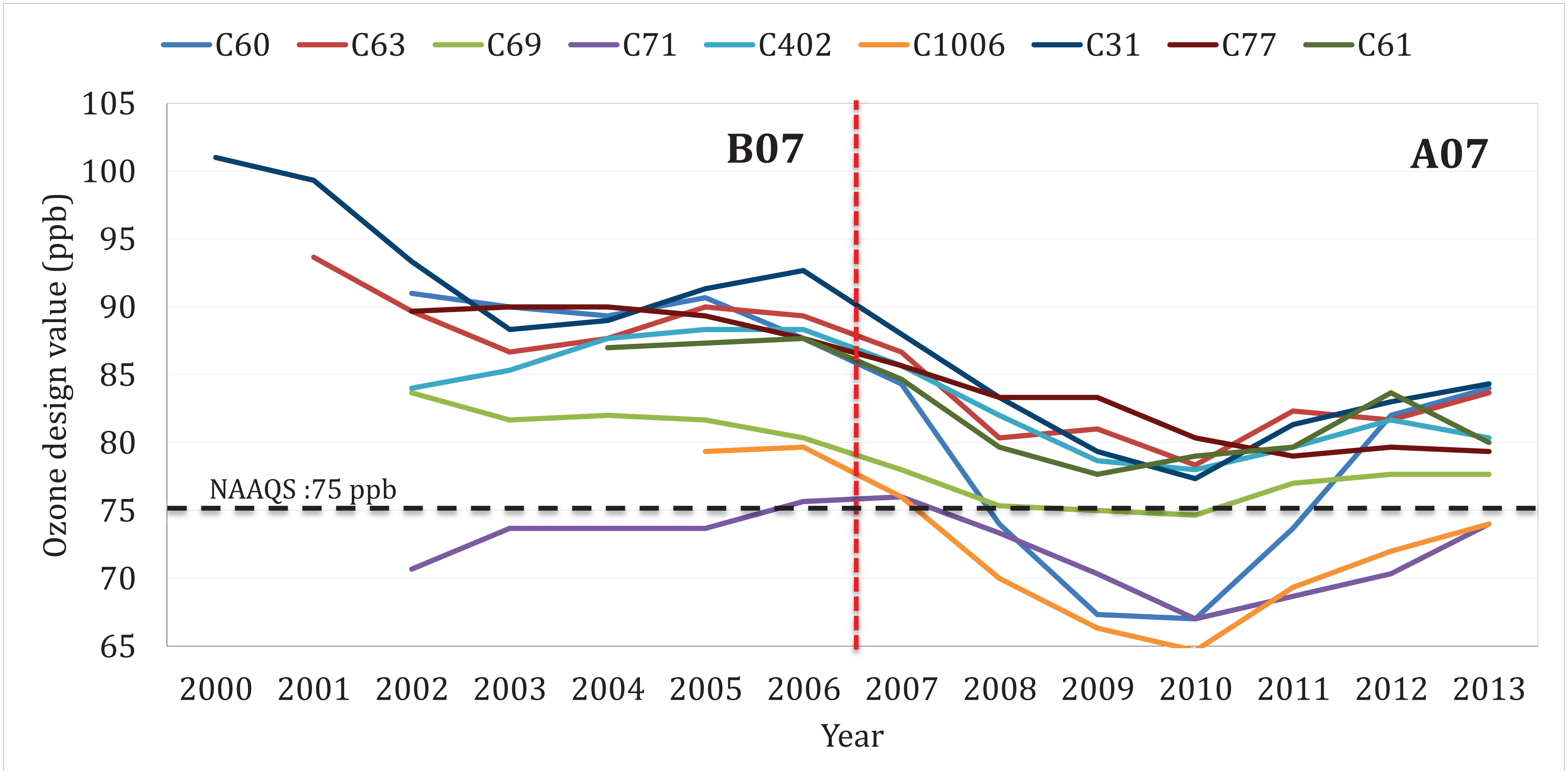
Results – Part I

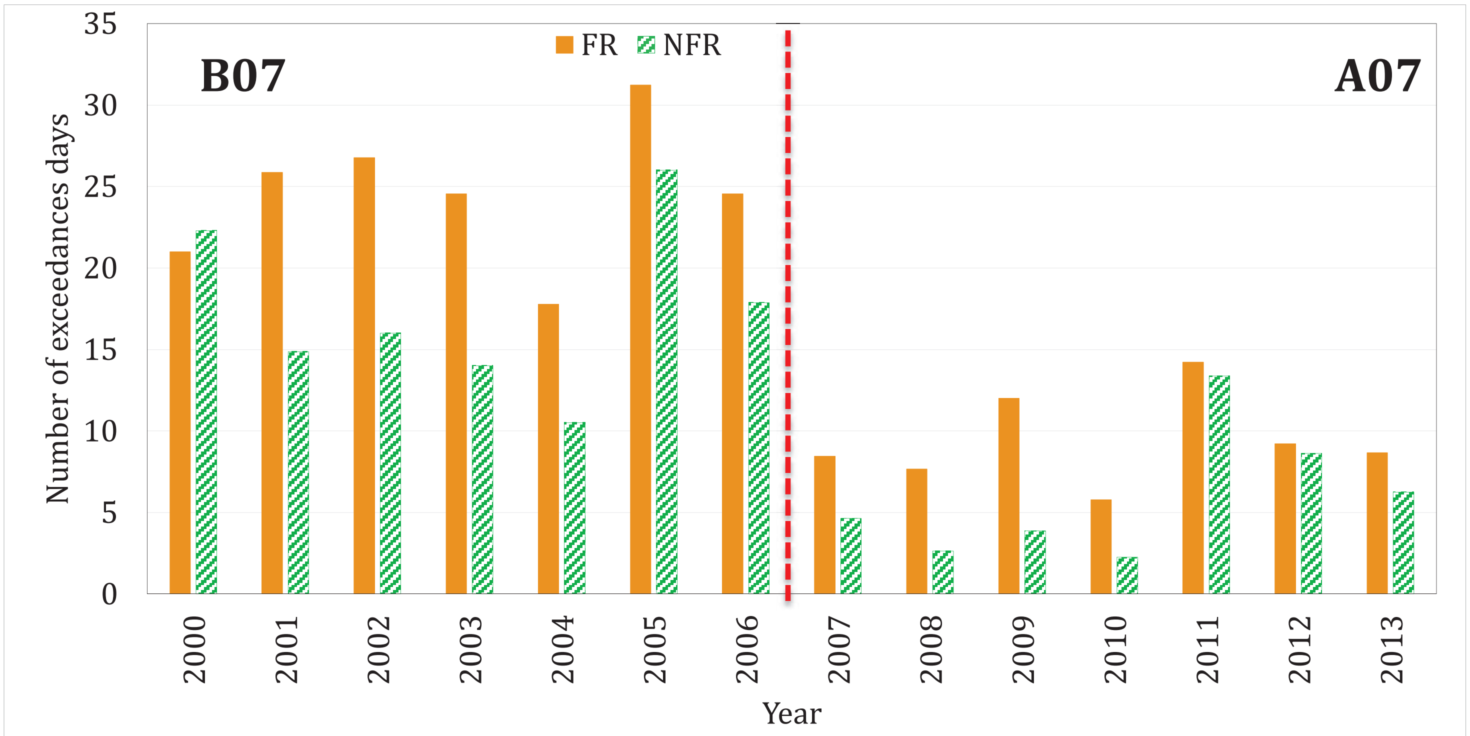
- Trend in the ozone design values within **NFR**



- Average percent change from **B07** (2000-2006) to **A07** (2007-2013): **-10%**

Results – Part I

➢ Annual trend in the average number of exceedance days (> 75 ppb)



➢ Average percent change from **B07** (2000-2006) to **A07** (2007-2013):
- Fracking region: **-61.6%**
- Non-fracking region: **-65.7%**

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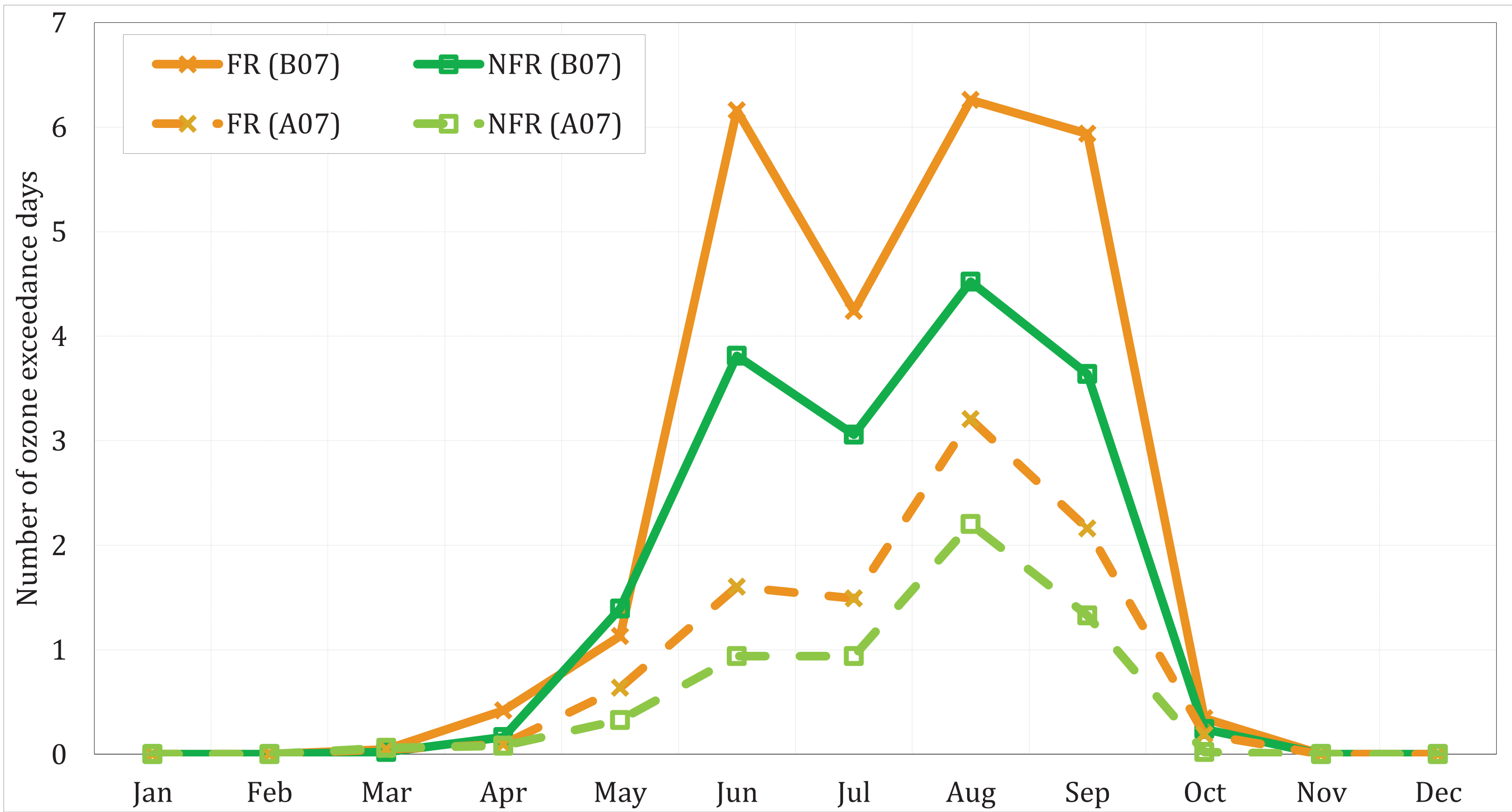
Results – Part I

- Number of average ozone exceedance days by month (> 75 ppb)



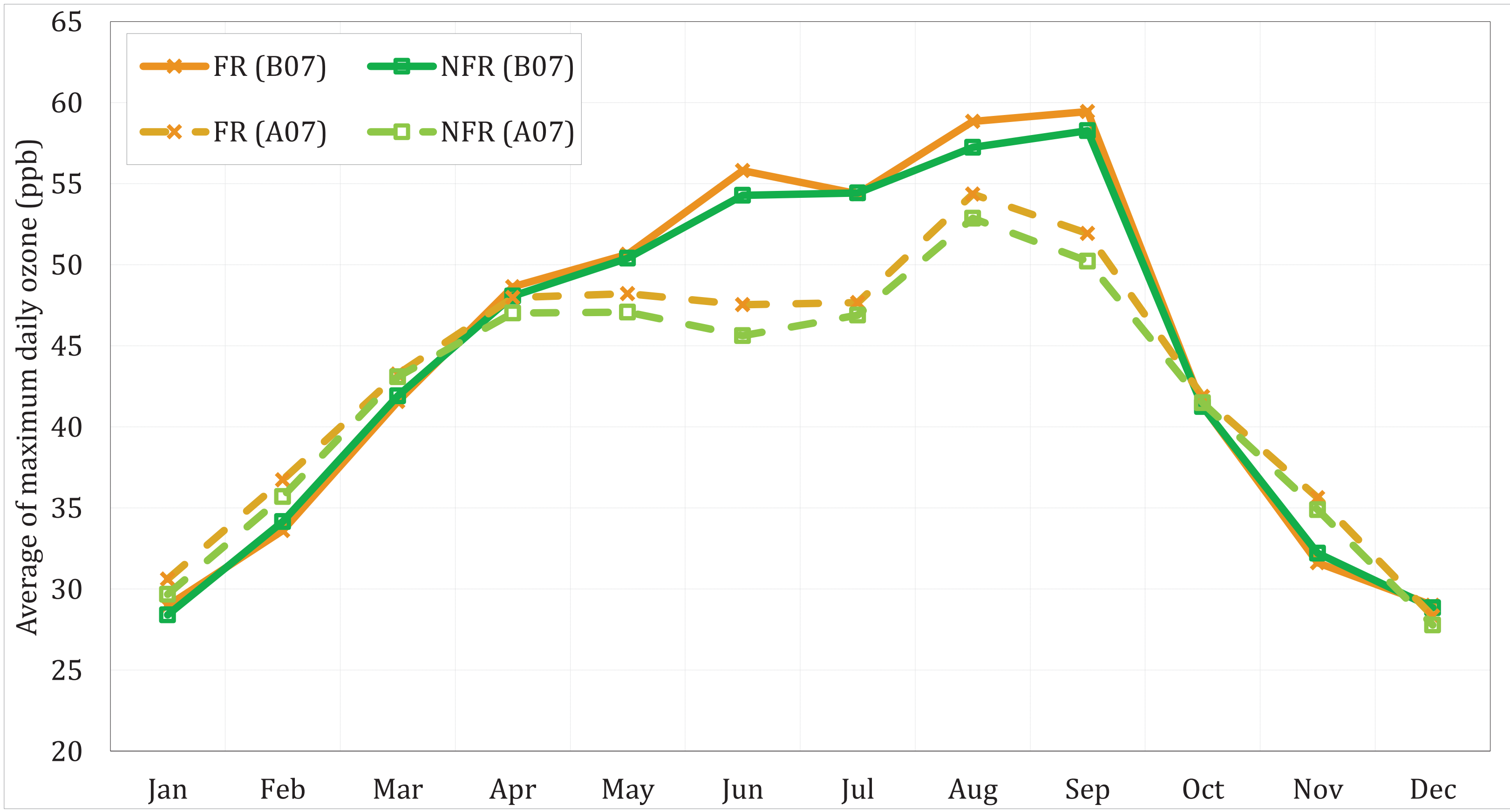
Results – Part I

- Average percent change of ozone exceedances between 2000-2006 (**B07**) and 2007-2013 (**A07**)

Time period	Ozone exceedances (75 ppb threshold)	
	FR	NFR
May	-47%	-78%
Jun	-74%	-76%
Jul	-66%	-72%
Aug	-49%	-54%
Sep	-64%	-64%
Whole year	-61.6%	-65.7%

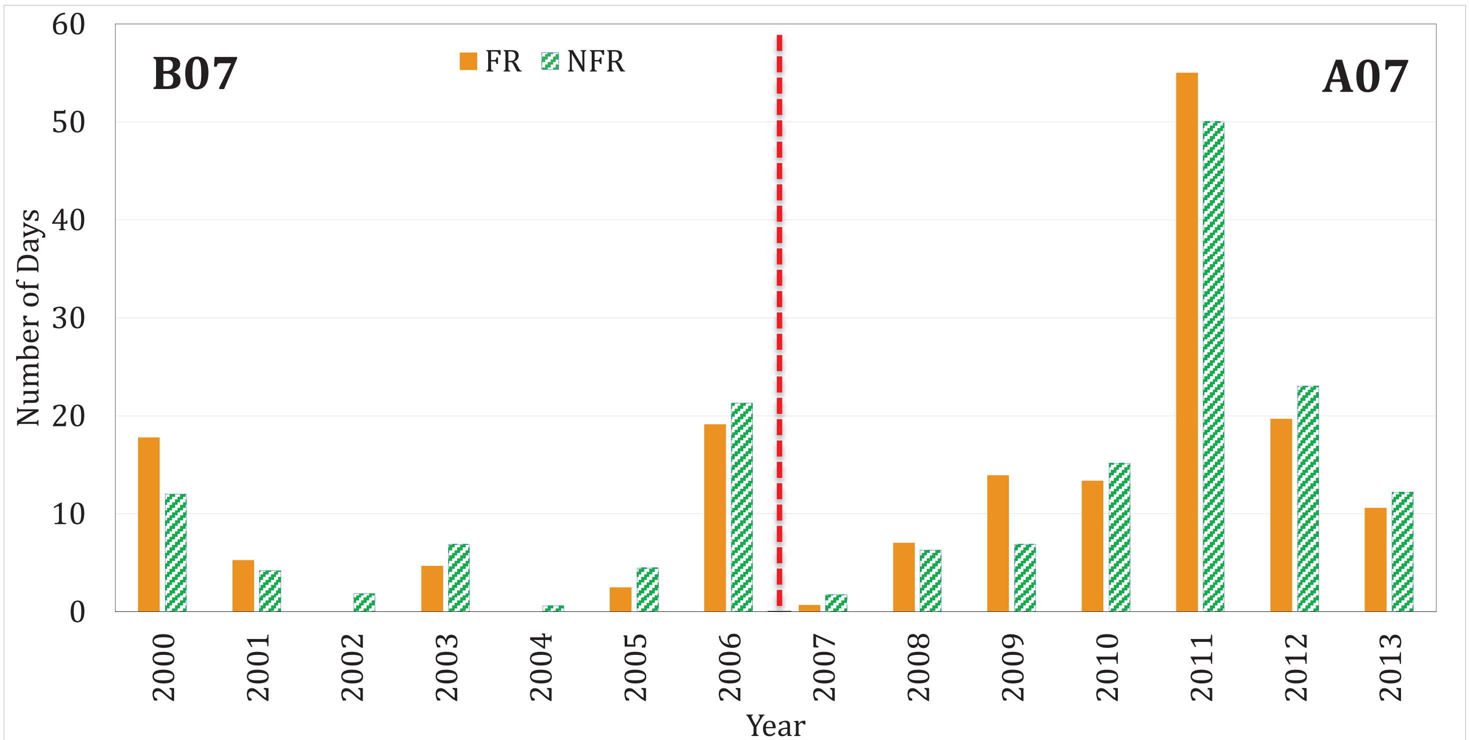
Results – Part I

- Trend of the average of maximum daily ozone values by month



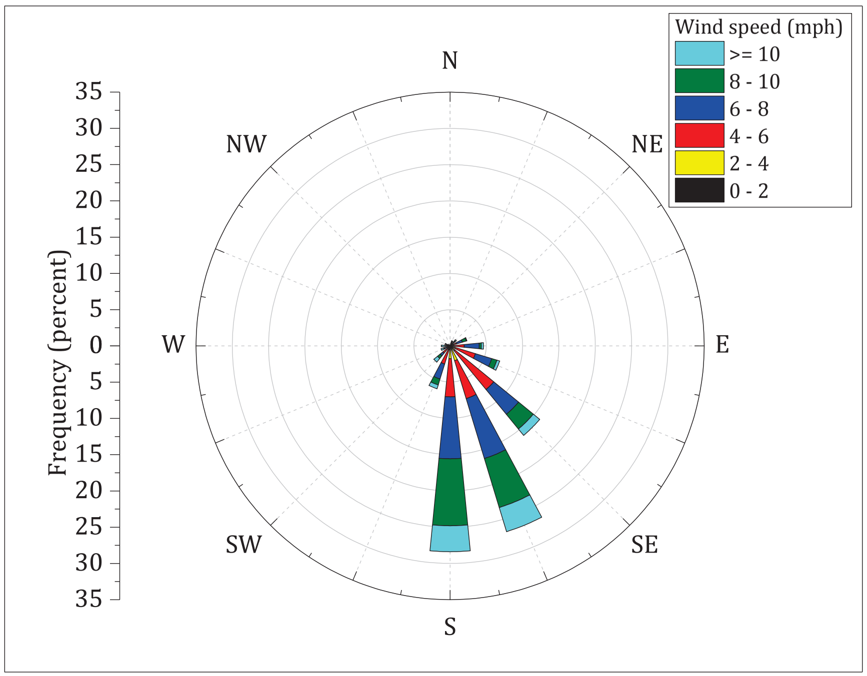
Results – Part I

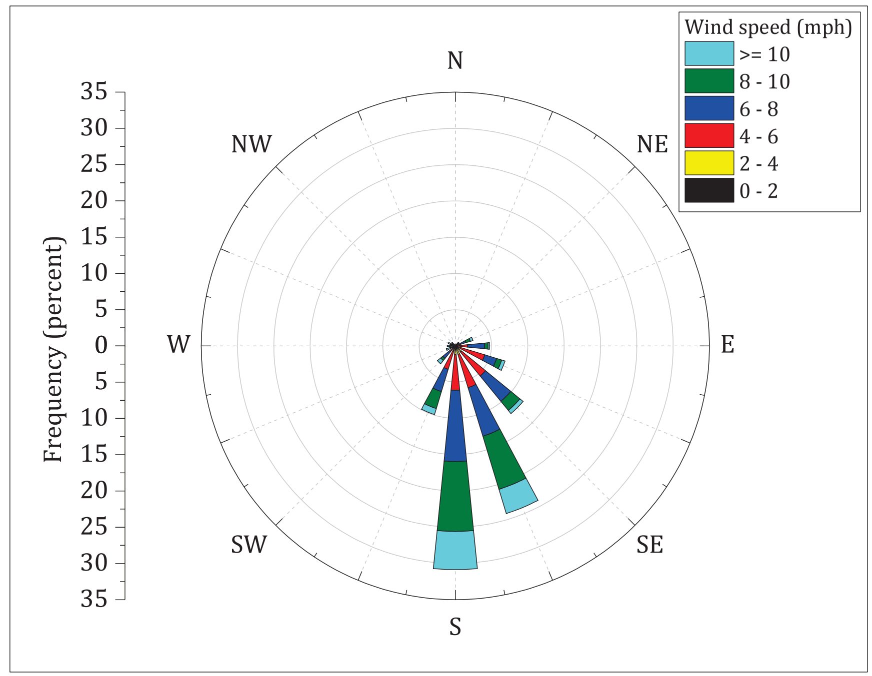
- Number of days with temperatures exceeding 100 F



Results – Part I

- Wind rose for **CAMS 13** (Ft. Worth Northwest) (May, Jun, Jul, Aug, Sep)

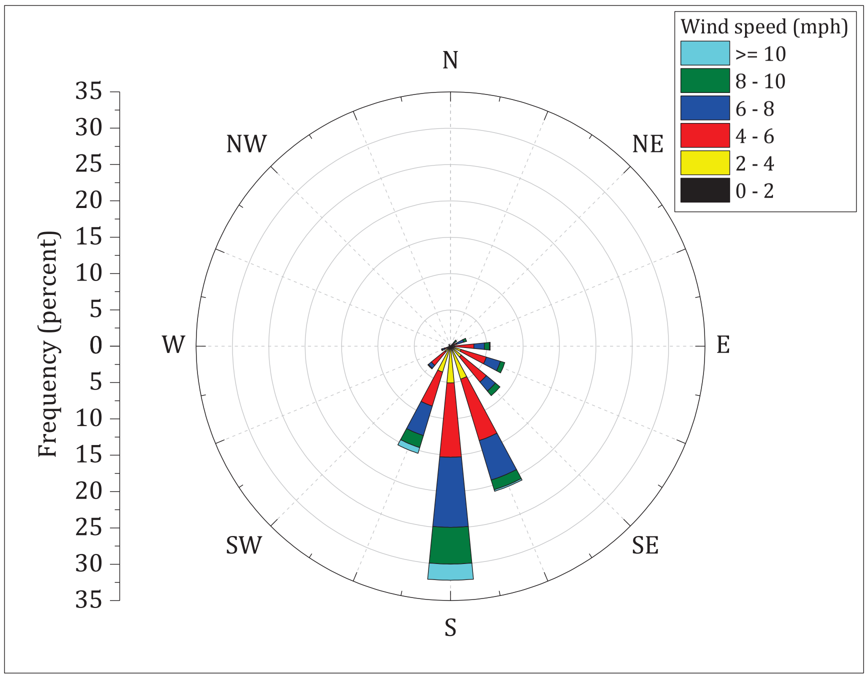


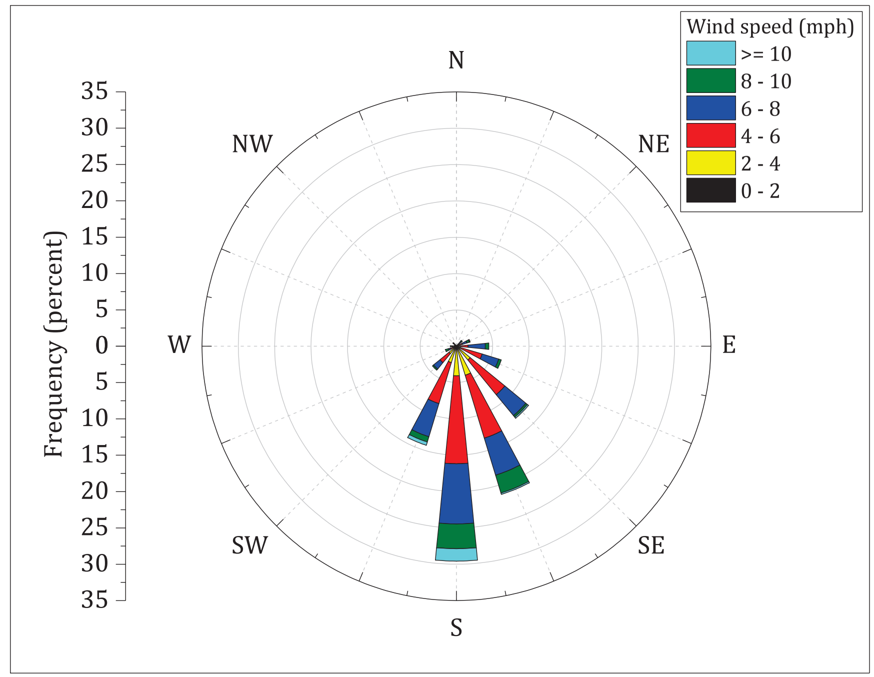


- **B07** (2000-2006)
- **A07** (2007-2013)

Results – Part I

- Wind rose at **CAMS 60** (Dallas, Hinton St.) (May, Jun, Jul, Aug, Sep)





- **B07** (2000-2006)
- **A07** (2007-2013)

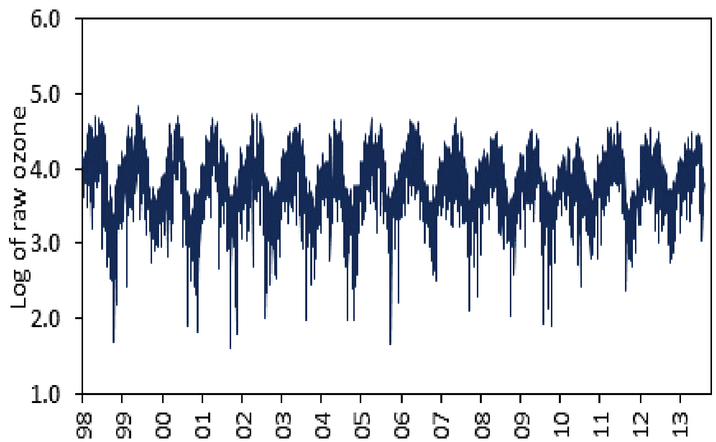
Meteorologically Adjusted Ozone

- **Part II:** Statistical evaluation of trends of meteorologically adjusted (M.A.) ozone
  - *Construction of M.A. ozone:* application of Kolmogorov-Zurbenko (KZ) filter
  - *M.A. ozone trends*: statistical evaluation of total, long-term, and baseline M.A. ozone
- Evaluations performed for the **FR** and **NFR** regions over two contiguous periods: 2000-2006 (**B07**) and 2007-2013 (**A07**)

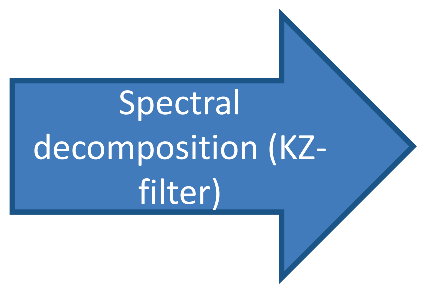
Method – KZ-filter

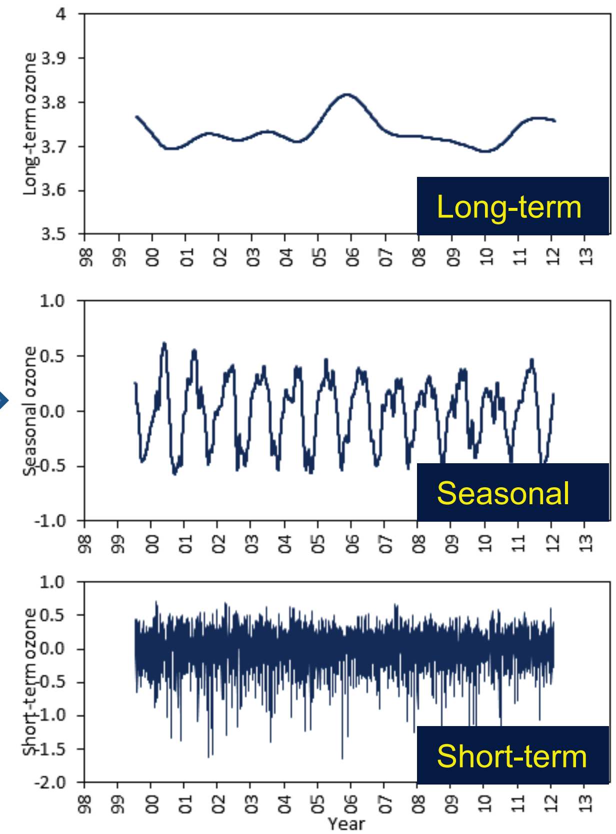
- **KZ-filter** is a robust low-pass filter used for spectral (frequency-based) decomposition of time-series*
- Computationally KZ-filter is a simple iterative moving average technique

$$Y_i = \frac{1}{m}\sum_{j=-k}^{k} X_{i+j}$$



Log-transformed raw ozone time series





* Rao ST, Zurbenko IG. Detecting and tracking changes in ozone air quality. Air & waste 1994; 44: 1089-1092.
Rao ST, Zalewsky E, Zurbenko IG. Determining temporal and spatial variations in ozone air quality. Journal of the Air & Waste Management Association 1995; 45: 57-61.

Meteorologically Adjusted Ozone

- **Step 1**: Spectral decomposition of the ozone and meteorological time series by applying KZ-filter $X(t) = e(t) + S(t) + W(t)$

$$\begin{cases} e(t) = X_{365,3}(t) \\ S(t) = X_{15,5}(t) - X_{365,3}(t) \\ W(t) = X(t) - X_{15,5}(t) \\ BL(t) = e(t) + S(t) \end{cases}$$

- **Step 2**: Baseline and short-term components of ozone time-series are calculated using a three variable linear regression model (with temperature and solar radiation)
- **Step 3**: Meteorologically adjusted ozone time-series is calculated as the residuals of linear regressions $O(t) = F(T, SR) + O_{\mathrm{MA}}(t)$

$$O_{\mathrm{MA}}(t) = \epsilon_{\mathrm{BL}}(t) + \epsilon_{W}(t)$$

- **Step 4**: KZ-filter is applied again to M.A. ozone time-series to calculate long-term and baseline components of M.A. ozone

Results – Part II

- Because all expressions are given for the natural logarithm of raw ozone data, M.A. ozone values have multiplicative effects in original ozone time series
- Also since $O_{M.A.}$ values are sufficiently small therefore:

$$\exp(O_{M.A.}) \approx 1 + O_{M.A.}$$

- Therefore $O_{\mathrm{MA}}(t) \times 100$ values represent change in mean value of the original ozone time series

- Statistical evaluation of all components of M.A. ozone (mean value, long-term, short-term, and baseline) is performed to evaluate the contribution of non-meteorological variables including anthropogenic influences affecting ozone formation and destruction.

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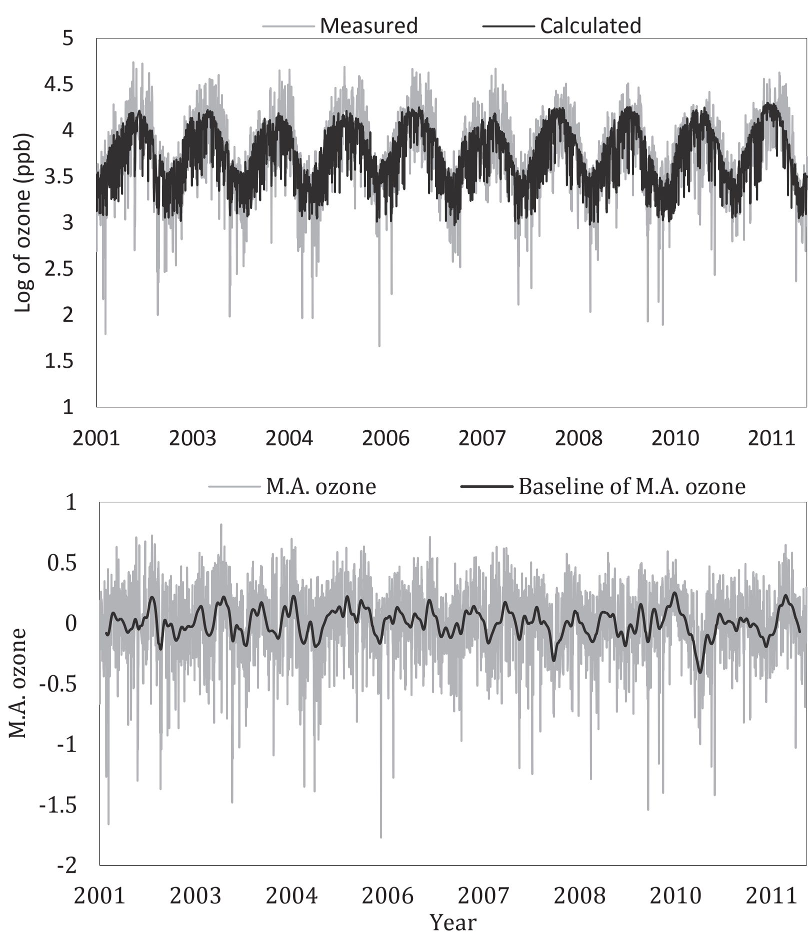
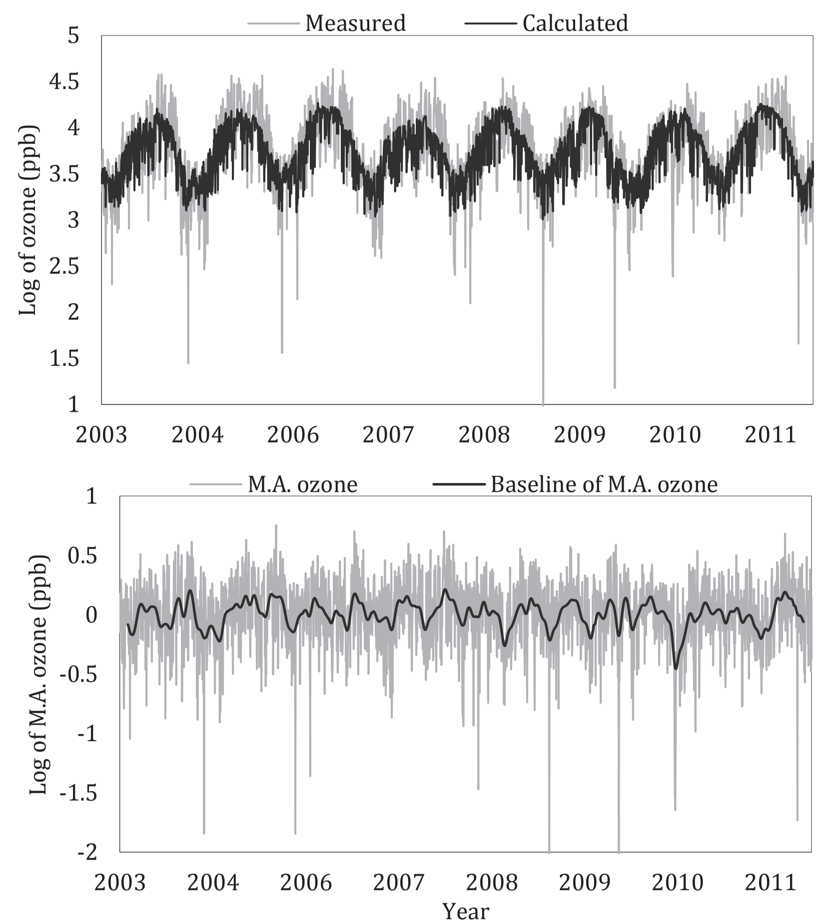
Results – Part II

- Examples of calculated and measure ozone time series and residuals (M.A. ozone)



Constructing M.A. ozone for C56 (Denton)



Constructing M.A. ozone for C31 (Frisco)

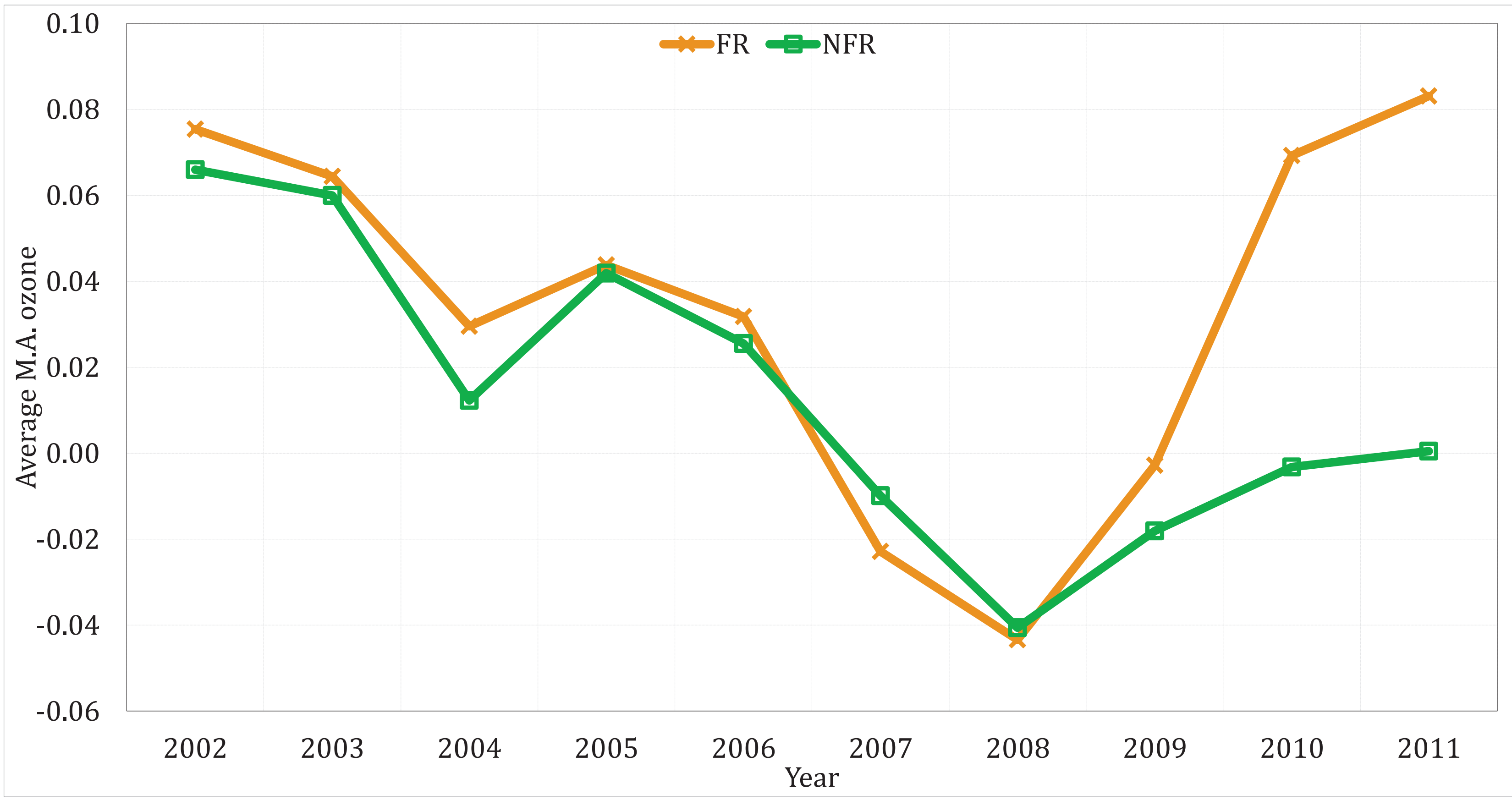
Results – Part II

- Box plot presentation of $O_{\mathrm{MA}}(t)$ (the maximum, 75$^{\text{th}}$ percentile, median, mean, 25$^{\text{th}}$ percentile, and minimum) for **FR** and **NFR**

- $O_{\mathrm{MA}}(t) \times 100$ values represent change in mean value of the original ozone time series

Results – Part II

- Mean values of $O_{\mathrm{MA}}(t)$



- $O_{\mathrm{MA}}(t) \times 100$ values represent change in mean value of the original ozone time series

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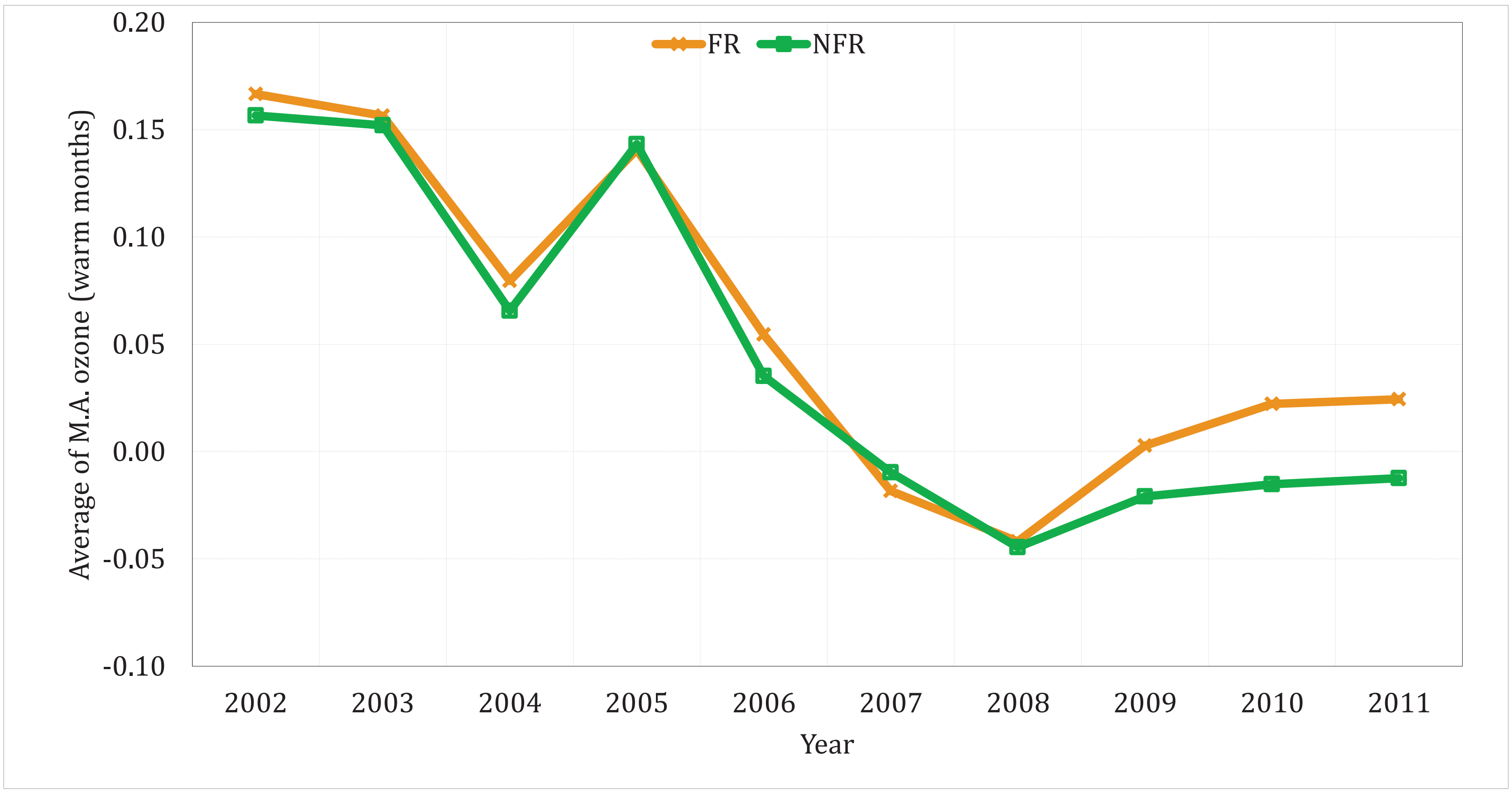
Results – Part II

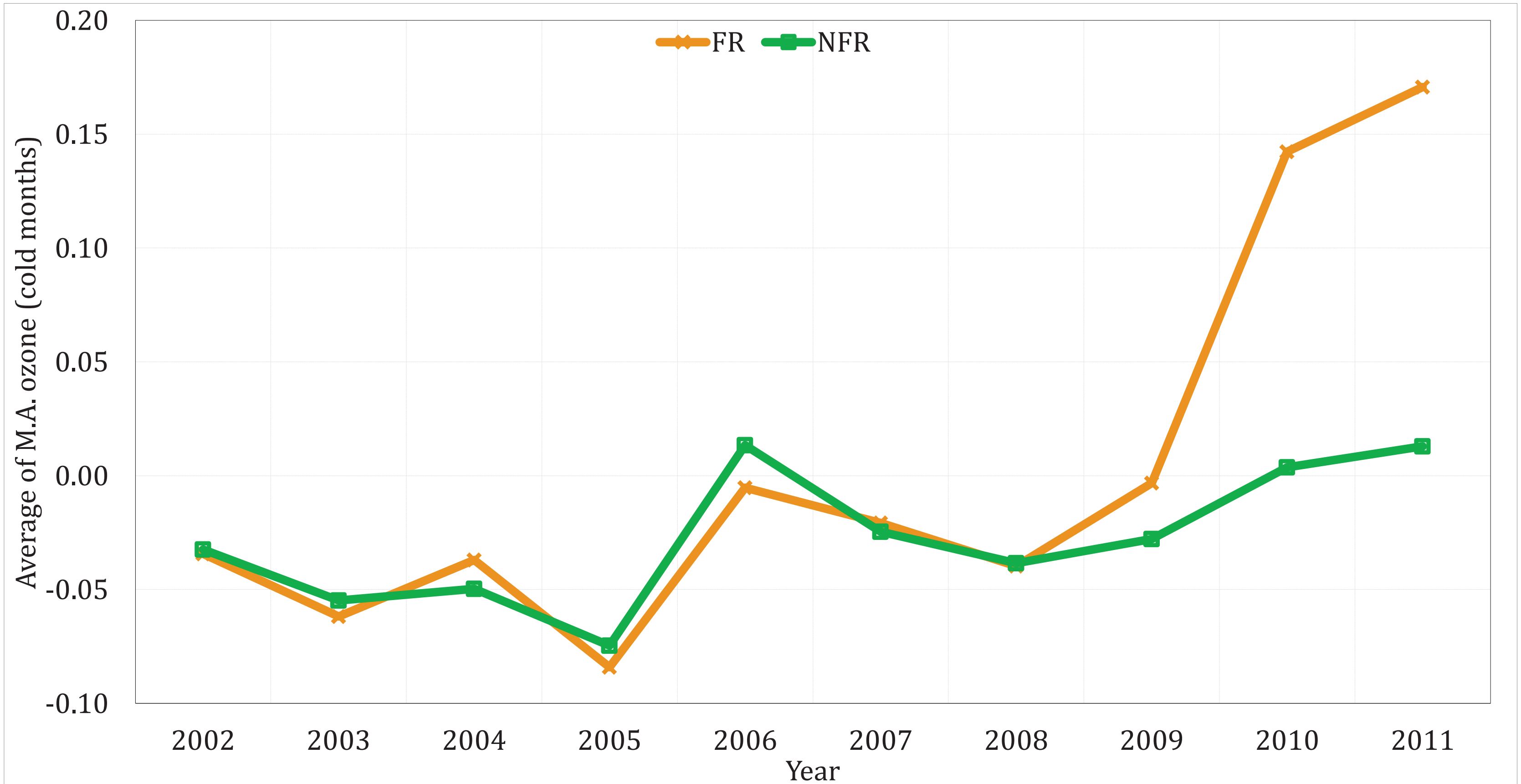
- Mean value of of $O_{\mathrm{MA}}(t)$ during ozone season (May, Jun, Jul, Aug, Sep)



- $O_{\mathrm{MA}}(t) \times 100$ values represent change in mean value of the original ozone time series

Results – Part II

- Mean values of $O_{\mathrm{MA}}(t)$ in **FR** and **NFR** during winter time (Nov, Dec, Jan, Feb)



- $O_{\mathrm{MA}}(t) \times 100$ values represent change in mean value of the original ozone time series

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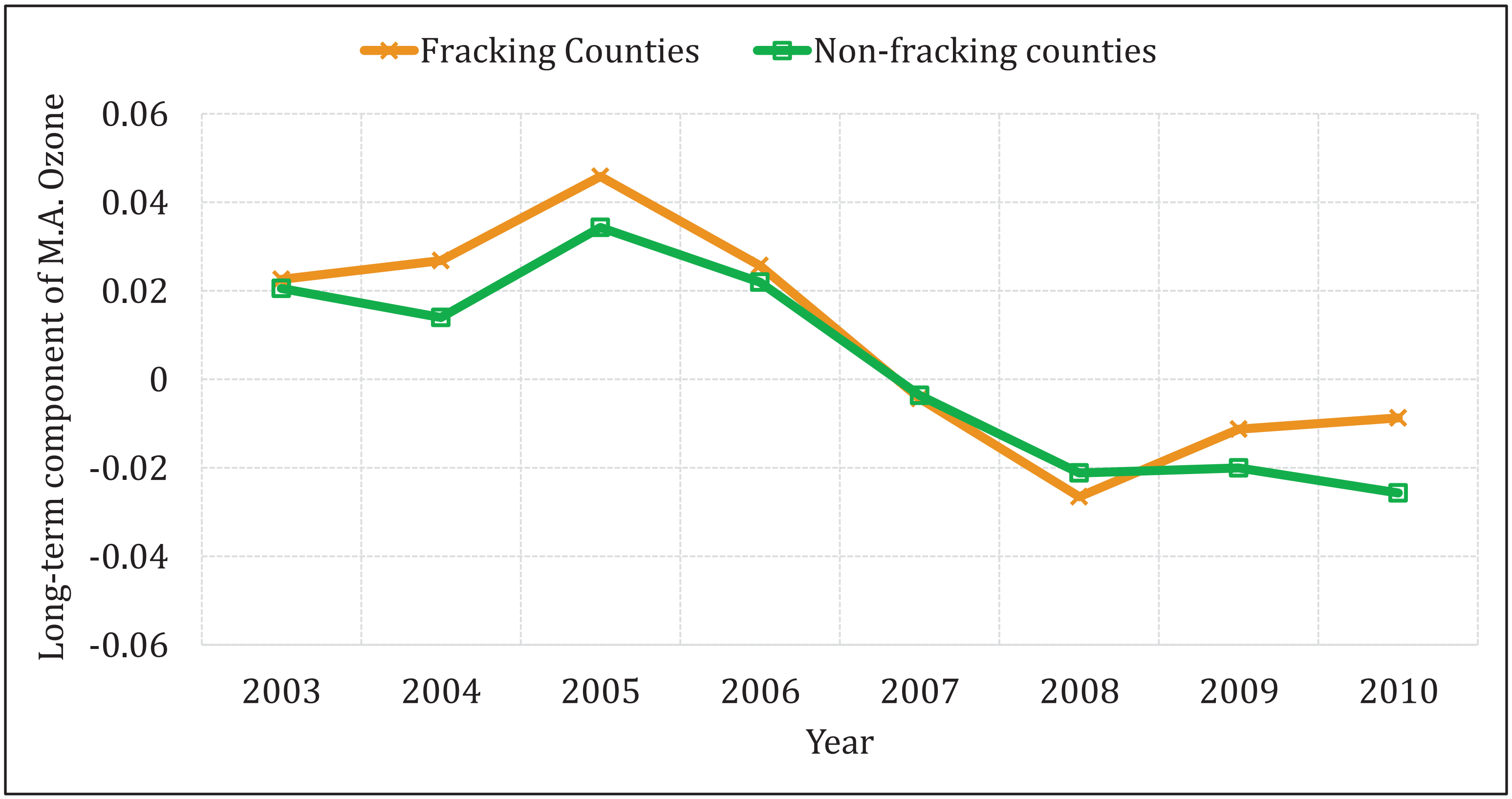
Results – Part II

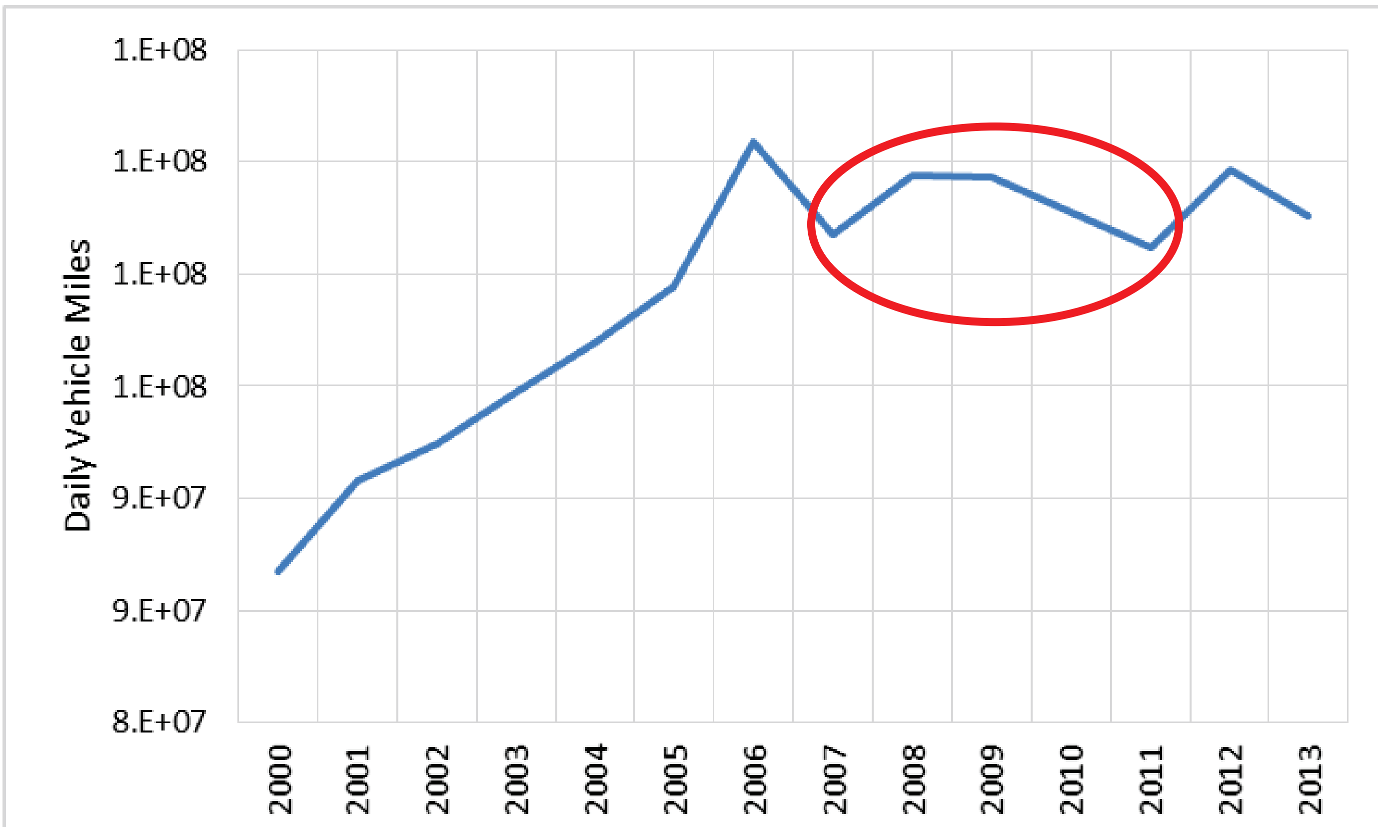
- Mean values of long-term component of $O_{\mathrm{MA}}(t)$ (that is devoid of meteorological influence)



- $O_{\mathrm{MA}}(t) \times 100$ values represent change in mean value of the original ozone time series

Remarks

- Daily vehicle miles traveled (VMT) is relatively flat during 2007-2010.



Source: TxDOT (Total VMT for Dallas, Denton, Wise, Tarrant, Hood, Parker, Hunt, Ellis, Collin, Rockwall & Kaufman counties)

Remarks

- Based on raw ozone data (B07 vs. A07):
  - Sites located in NFR show about 4% more reduction in the number of average ozone exceedances than in FR
  - Average of winter time daily maximum ozone values in FR is 3% more than in NFR

- Based on the mean value of meteorologically-adjusted ozone $O_{\mathrm{MA}}(t)$ (post-2008):
  - 12% increase within FR and a 4% increase in NFR was noted
  - During the winter time, 21% increase within FR and a 5% increase in NFR was noted

Future Research Needs

- Conduct similar adjusted trend analyses using long-term measurements of NOx, VOC and $PM_{2.5}$ in the region.
- Additional rural monitoring of NOx, VOC and $PM_{2.5}$ may be needed.
- Perform source-receptor and source apportionment analyses using measured concentrations.
- Develop a comprehensive regional emissions inventory for a more recent base year.
- Conduct photochemical modeling for a recent episode as well as a year-round modeling using revised estimates of emissions and perform source apportionment analysis for various regions.

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Thank you!
Any questions?

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