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Application of Secondary Analyses on Industrial Data Sets

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APPLICATION OF SECONDARY ANALYSES ON INDUSTRIAL DATA SETS

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Dedication

This work and accomplishments are dedicated rightly to my wife, Maria Guadalupe Perez

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by

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DISSERTATION

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Abstract

Secondary analysis on quantitative data sets is the in-depth analysis of relationships, trends, patterns or behaviors that are not obvious from a superficial examination of data but that can be very germane in the application of that data. The present work presents a framework for investigators to use in applying secondary analysis on big data that correlates to the research topic. The framework can facilitate the illumination of possible data behaviors or patterns that could be useful in arriving at an answer to a question. Behavior of monitored equipment (analyzers, meters, etc.) can easily be depicted and can be used to indicate graphically how patterns in the data support or reject possible outcomes to a question.

This present work illustrates the value of secondary analyses in three different case studies, where this approach is demonstrably used to discover behaviors in operational data of a large gas transmission pipeline, and in sanctioning air quality permit actions for an electric generating facility. The analyses performed provide great insight as to how decisions and responses to regulatory-related actions are being improved upon using big data sets. The tangible results of the application of secondary analysis in environmental science and engineering decision making, exemplified in these case studies, is presented as evidence of its intrinsic value. Moreover, the inherent value of this study is derived by the fact that the tools used to perform these analyses did not require expensive, complex resources.

It is shown that there is substantial, quantifiable value in applying the methods presented here for secondary analysis. Benefits can be quantified not only monetarily but also in improving operations by offering operational flexibility. Querying of available data stores through secondary analysis offers substantial opportunities for industry to gain insights and understanding into previously concealed databased relationships.

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Chapter 1: Preface

The ideas presented here are the outcome of my work in industry for a little over four decades coupled with the associated research. The organizations I worked in dealt in technology and energy. They included IBM, Exxon Company USA, El Paso Natural Gas Company and El Paso Electric Company. The work presented here serves to validate the very basic engineering principles taught in the classroom while at the same time incorporating lessons developed in industry over the years. It serves as useful advice to both new engineers and scientists as well as seasoned veterans that may wish to take advantage of the suggestions presented here. Sometimes, only after we have spent time performing work the "old way" can we fully appreciate suggestions that can make our jobs easier. This work suggests a new way of approaching a problem.

While the basis of this work relates in complete agreement with Bayes' theorem in mathematics, the application of the ideas presented here present a more practical approach to applying these principles to problem solving. In industry, there is often the need to solve a problem quickly, which may result in a solution that is not optimal and may only serve a temporary need. Typically, engineers strive to develop solutions that are quickly implemented, cost effective and reliable. The ideas presented here can be executed without an excessive amount of time invested and offer a methodology that is cost effective. This approach has been accepted as valid by environmental state agencies in both Texas and New Mexico.

A methodology is presented here by which to apply these ideas. Examples are included in both the methodology and the case studies utilized to explain this approach.

Chapter 2: Introduction and Background

2.1 – Introduction

For the purposes of obtaining a broader examination into the topic presented here, a review of existing published work focused on papers using the term “Data Mining” since it is a more general, generic description of this analysis. The term “Secondary Analysis” can be considered a subset of the term “Data Mining”. We can consider it a subset with the assumption that the data stored in the data set was originally intended for a specific purpose other than for the problem being researched. The application discussed in this work is specifically applicable to data sets that are regulatory-related and used to show compliance and presumably associated with regulatory reporting. Therefore, the existing data set is utilized by some pre-existing application so by taking a second look at this stored data new information can be gleaned. This is information that previously had not been recognized. Thus, the term “Secondary Analysis” is a better descriptor of how data mining is being applied in the methodology of this current work but research for the literature review utilized the term “Data Mining”. In this way, a much richer population of possible applications was generated for review.

2.2 – Review of Existing Work

A review of the collection of publications associated with the term “Data Mining” utilizing ProQuest as the search engine shows that an enhanced list of results is retrieved by using this term instead of “Secondary Analysis”. It is noteworthy to point out that other similar analogous descriptors to “Data Mining” are also used in existing publications. Those analogous descriptors also represent subsets of data mining and include terms such as “classification”, “data clustering”, etc.

The variety and breadth of topics of publications describing a given application of data mining covers numerous fields. A good majority of those publications deal with manufacturing issues and finance concerns. It is, however true that the techniques of data mining are applicable to any field where a large number of records describe a given behavior. In addition, the applications are not constrained to only technical fields because, with the relatively recent advent of computers within the last few decades, wherever data stores are available, software makes it accessible regardless of the industry that generates the data. It is therefore understandable that data mining is a field containing a vast number of applications.

It is understandable and reasonable to say that the vast majority of work written on this topic relate to computer science and programming techniques or modeling that require a fair amount of technical expertise in computer science. The applications discussed relate mostly to business but also include telecommunications and manufacturing although this list includes virtually all other industries. Some process control applications are present especially in manufacturing. The energy industries that this present work considers, electric generation permitting and gas transmission, were not seen in the existing literature.

The following is a very short sample of applications observed using ProQuest with the following url: http://search.proquest.com/advanced?selectids=pqdtlocal1006279.

1. Decision Rule Induction for Service Sector Using Data Mining - A Rough Set Theory Approach. This paper writes about DM in a banking sector environment using A Rough Set Theory Approach.

2. Modeling complex manufacturing process activities using data mining: A rough set approach. This paper utilizes Classification, a data-mining task producing rules in which attributes in the data assist in predicting the value of a class attribute.

The object of the study is to address gait dynamics in humans for rehabilitation purposes.

3. Modeling complex manufacturing process activities using data mining: A rough set approach used in the manufacturing of modern electronic circuits using a rough set approach

4. A study and comparison of data clustering techniques studies the various classification techniques in DM used in manufacturing.

5. Performance life of various hot mix asphalt mixtures in Texas evaluates the performance lives of various mixtures of hot mix asphalt.

While the above list is certainly not a completely inclusive list of all data mining applications, it provides some examples of how data mining is treated in today's applications. A commonality that exists between the treatment of data mining in the existing literature and those in the present work is that the use of data mining necessitates that the majority of the work lie in the accumulation and preparation of the data prior to the actual processing of data. ("Industry Applications of Data Mining- Pearson" -1999).

2.3 – Economic Value of Secondary Analysis

A major difference between the applications found during the literature review and the applications described in this work is that in the applications discussed in this work, much of the data accumulation and preparation (Quality Assurance and Quality Control, QA/QC) of the data will have already been performed. This would be because the data would have been collected for regulatory purposes and before it can be reported to the regulatory agencies, it generally requires some form of QA/QC. In some cases, such as in reporting of Continuous Emissions Monitoring Systems (CEMS) data to federal authorities, the QA/QC effort is quite extensive and

may require the investment of a great deal of time. It may even be assigned to a third party for validation. Once the data has been through the QA/QC process, it becomes the official record for the company. It is then used by Operations and other departments in the company as well. Those other departments may include Marketing, Planning and Forecasting, Measurement, and Accounting, along with others. The result of this occurrence is that a major part of the work involved in using data in the specific applications discussed here is that the data has been through the QA/QC process and is almost completely available for immediate use. Attention to dimensional integrity (same units of measurement) is important to ensure quality results.

In terms of economic value, the cost to implement secondary analysis on industries such as the ones discussed here is reduced and the implementation time is significantly minimized.

2.4 – Value Proposition

Given that a very limited number of applications in the energy fields discussed here exist, the opportunities to apply these ideas are extremely attractive. Economically, these ideas discussed here offer savings that could potentially influence the bottom line of a corporation's financial statement, especially if major penalties and fines can be avoided.

2.5 – Goals

Through the utilization of data mining, I believed that it was possible to investigate the value of what might be termed "secondary in-depth analyses" of industrial data sets. The analyses included examining and discovering relationships, trends, and patterns that were not apparent in a primary examination of those industrial large data sets. The characteristics above warranted identification because they could yield very substantial benefits. My objective was to examine how such "deep-down" data analyses can demonstrably lead to new knowledge. Significant to this research is that the product is not just new knowledge that was previously unrecognized, but

also that the value could be demonstrably shown and it can lead to significant financial benefits to the users of the data. Therefore, this work sought to discover behaviors in operational data that can be used to improve the operational application and the effective use of commercial data sets.

In the following chapters, it will be shown that the value of data mining (secondary analysis) can serve as a powerful resource in industry environments, enabling key commercial industries to exceed and improve traditional approaches to meeting objectives set for the operation of those industrial environments. Additionally, the use of these secondary analyses will prove to be effective in helping to comply with local, state, and federal environmental regulations.

The substantiation of the validity of this work will be shown by the use of several case studies. Using test cases from energy-related companies that utilize 24x7 operations in their day-to-day operations, the validity as well as the transportability of this work will be shown. Real life examples based on actual data provide the proof of its application.

A framework describing how this methodology is applied will be described. This framework will define the various steps required for a systematic application and provide examples for each step. Presentation of this framework is both in narrative form as well as in flowchart format. This allows for ease of application on various types of problems which aid greatly in the transportability.

It is commonplace in industrial environments, that in order to comply with environmental regulations, time proven operational report-generating procedures that have been found to be satisfactory are typically used. Those procedures many times are passed on from one operator to the next and serious thought is not normally given as to how well they function. The important value of those procedures is that they do function and get the job done so that whatever report that is needed is generated. In a production environment, it is normally vital that production continue

without interruption and normally report writing is not assigned top priority. It is for this reason that these gold nuggets of information may be just below the surface. This situation is somewhat analogous to the old-time gold rush day scenario whereby the pioneers using wagon trains hurried through Texas and New Mexico in haste to reach California, rolling past valuable liquid gold (oil reserves) as they went along their way.

2.6 – Research Objectives

The following three objectives are the focus of this work:

1. *Present a research review of secondary analysis methods* to demonstrate their potential industry applicability and viability. This recent industry, made more popular with the advent of improved data and computer technological advancements, has opened the possibilities of enhancing and optimizing decision-making opportunities. The basic premise of secondary analysis is that there is a value in the relationship of data beyond what is seen on the surface and it is the digging into (data mining) of these relationships where this value is unearthed. Therefore, in this review, secondary analysis is defined in an industrial context and described how it can be used in that environment.

2. *Provide a demonstration of the applicability* of this methodology in real-life/real-world industry case studies. Discussion of the direct application to industry problems with the realized operational value in each case study will be described in detail. Examples delineated for each step of the methodology (framework) used in its application are provided. The examples will help in understanding the framework so that it can be transferred and used in similar industrial applications.

3. *Identify the measurable benefits and advantages* of the framework described in this paper. The improved efficiencies providing tangible economic value in

operational flexibility are discussed. Associated advantages in the application of this framework is presented from a financial perspective and from one relating to everyday operations.

Chapter 3: Methodology

3.1 – Introduction to Approach

The approach used here was borne out of the need to understand, address and solve dilemmas and problems in industry that presented an unusual situation and for which standard methods of engineering analysis did not really fit. It is important to keep in mind that the environment being studied is comprised of both big data sets as well as ancillary data elements and influences that may exist even outside the principal databases. Like all other engineering problems that are to be solved, a good understanding of the problem itself and what the end objective is for the analysis helped to formulate the approach. In the discussion of the three case studies that follow, they might seem unrelated in that the result of each analysis might appear different. However, they all share the common dynamic that the result is based on the behavior and inter-relationship of the data that reveals patterns of their behavior. So that understanding the question (understanding the problem) being asked and having a general idea of what the answer should look like helped point to where to look. A very simple analogy is in solving word problems. If a word problem asks something like what is the distance of a train travelling at a certain speed for a certain time duration, we can begin by letting "***X***" be the unknown or the distance to be travelled. Once an equation involving "***X***" is solved, we know that the answer is what was sought. In a similar way, by focusing on the basic question to be answered and involving those data elements that contribute to that question, the relationship among the data elements being studied can become more evident. Certainly, with big data sets, even that job can become daunting; however, an understanding of the industrial operation being analyzed can assist in converging on the number of data elements being studied.

Numerous trial and error attempts that originally resulted in meaningless results but slowly and eventually helped formulate the research approach. That approach ultimately became more evident by following the advice shared in the steps above. Similar to entering a query into a search engine and having an appreciation of the data elements being studied, the researcher can begin to develop a feel for which data elements to consider in analyzing data behavior.

3.2 – Discussion of Data Mining and Applications in Context

Data mining has been applied since 1763 when Thomas Bayes' theorem was initially shared posthumously (Bayes and Price 1763). Bayes' work identified and postulated the relationship among occurrences using mathematics as a medium. It is from this relationship among discrete observations and occurrences that all secondary analysis has originated. Today, enabled by digital data base proliferation, secondary analysis, popularly known as "data mining", has expanded enormously in scope and application. It is increasingly used in business, industry, medicine and engineering professions; especially where large volumes of data sets ("big data") exist (Li, 2015). Data mining is used in many successful applications such as LinkedIn and Facebook (Davenport & Patil, 2012). It now has the potential to serve as a powerful tool in leveraging environmental science and engineering decision-making. It is with this context that I present this work as an effective tool to perform analyses in environmental science and engineering problems, with a focus on regional applications.

3.2.1 Secondary Analysis of Industrial Data Sets

Secondary analysis on industrial data sets is the in-depth analysis of relationships, trends, patterns or behaviors that are not obvious from a primary, or superficial, examination of data but that if established can be germane to the application of that data to industrial environmental management. This relatively new field of environmental computer science and engineering is a

natural development of advances in digital technologies, including cloud computing and cloud storage (Chen and He 2010). With the advent of mass storage and big data, secondary analysis of big data experienced widespread application, especially in understanding how information can be perceived and utilized. These digital analyses and enhanced methods are replacing the traditional listing of tables and simple graphs describing the data (Li, 2015).

Li (2015) presents the following chronological series depicting the historical evolution of data mining, relaying advances in the use of the technology over 200 years.

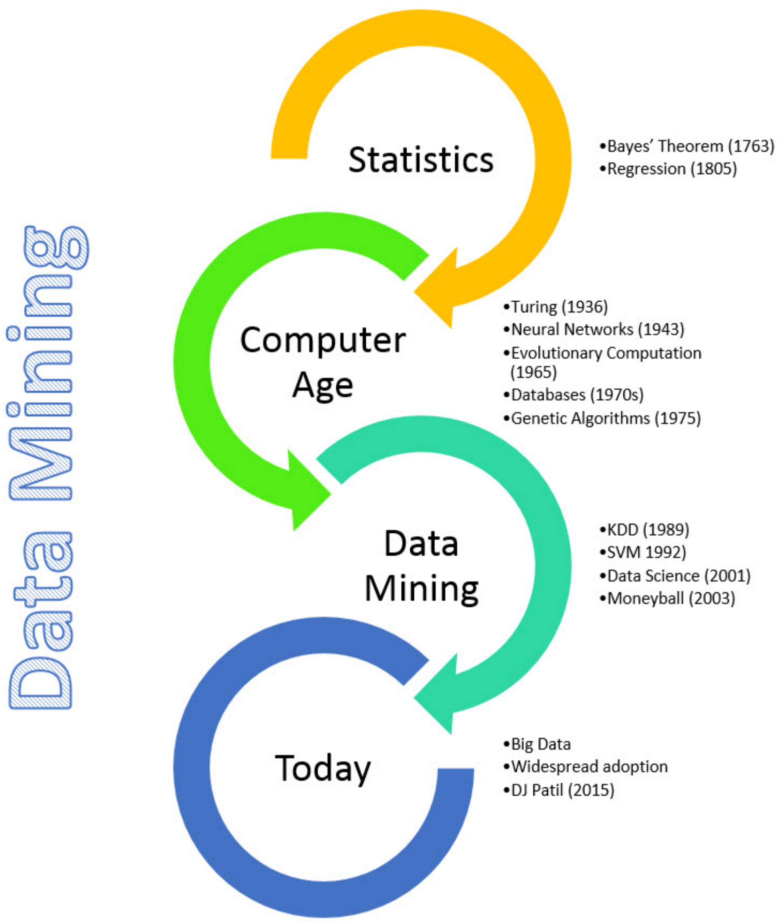

FIGURE 3.1: HISTORICAL DEVELOPMENT OF DATA MINING, ADAPTED FROM LI (2015)

With the advent of supercomputers, powerful database engines and application software now readily available, there are numerous investigation techniques that can be applied to a given target database for data mining. Some major categories of these techniques include Clustering, Association-Rule Learning, Text Analytics, and Interactive data Visualization. Following, these are described hereunder Sas (2016):

3.2.2 Clustering

Clustering forms groups of data that have a commonality that is not readily apparent by the data structure. Sometimes trends and relationships are not obvious in standard reports that may be generated. The technique of clustering allows for the relaxation of traditional views and allows views that are based on similarities or commonalities. It may be clustering on data type, on time related events, on shift schedules, operator shifts, on equipment characteristics and almost anything else that may link data items together through some common attribute.

3.2.3 Association-Rule Learning

Association-rule learning seeks to find relationships created by association such as in marketing of products. This technique differs from clustering because there may not be an apparent relationship and it may be difficult to find that commonality until human behavior is added to the equation. It is widely used in marketing applications (market basket analysis) where we can see that the sale of baby diapers might also accompany another baby product or the sale of beer and hot dogs might accompany the sale of potato chips. In large marketing applications, it is used to forecast the purchase of certain products and possibly send potential patrons discount coupons for those anticipated purchases.

3.2.4 Text Analytics

Text analytics applies to text-based databases. It links commentaries to individual elements to enhance modeling or instructions based on feedback. Text analytics takes textual information and uses it as feedback in literature on products and services being offered to enhance the product or service. This capability adds quality to supporting product literature because consumer feedback is put to practical, relevant use.

3.2.5 Interactive Data Visualization.

The visual side of analytics allows patterns to be easily identified and assists in optimizing the results in relation to the objective function (Sas, 2016). Interactive data visualization is especially powerful because it can visually encompasses the totality of system parameters involved in determining the behavior of the system. This technique graphically integrates multiple factors into the graphical representation and displays individual behaviors in relation to the whole. Variables such as system and human factors are vividly shown in relation to the total mechanical operation. Other factors could include efficiency of a unit, weather conditions, human interaction, etc. It graphically models that which would be almost impossible to present as a mathematical prototype simply due to the large number of variables. Results from this technique enable the data behaviors potentially almost to jump out of the page.

3.3 – Framework for Analysis

The framework used in developing the solutions for the following three case studies is presented below. It provides a general guideline and approach to utilize in solving a problem or answering a question dealing with large industrial data sets where the answer is not apparent or obvious. This framework utilizes the basic engineering approach to problem solving and has elements of linear programming in that a visual representation may be utilized but unlike linear

programming, is not limited to two-dimensional problems. One major benefit to the use of the framework is that in-depth computer programming expertise and associated resources are not required for its use. This framework can be effectively implemented using software such as MS Excel, MS Access, SAS or equivalent programs. In addition to providing a solution to a problem or answering a question, the final result provides strong, defensible and justifiable documentation in support of that answer that will stand up to robust scrutiny.

The flowchart shown below describes the basic approach with a more detailed explanation of each step presented in the following pages. Each step includes an example of the framework application. However, because this framework can be applied to a large assortment of problems whose commonality is that they deal with large data sets, the examples shown do not represent all possible variations of applicability.

Framework

Secondary Analysis of Industrial Data Sets

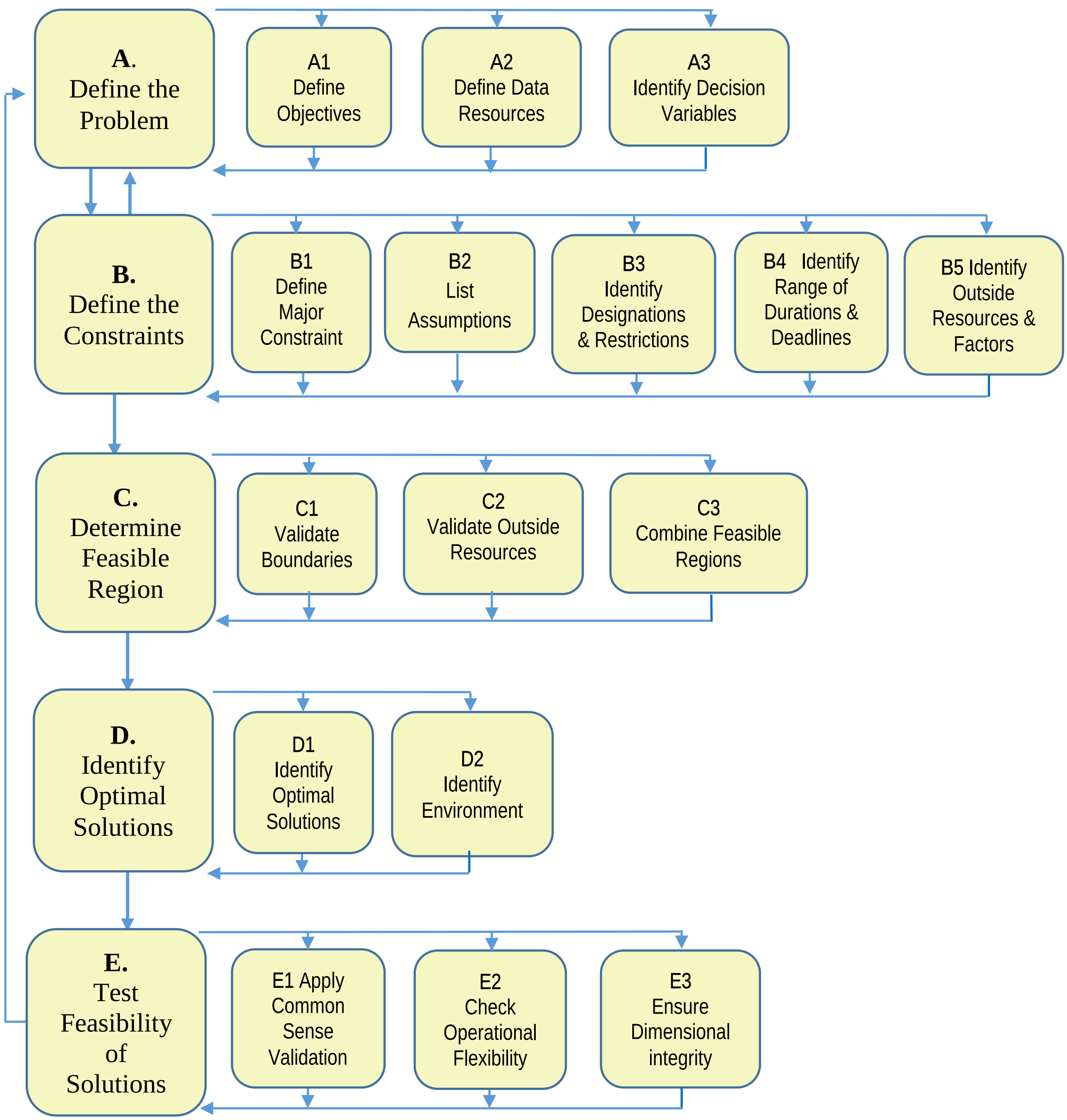

FIGURE 3.2: FLOWCHART FOR SECONDARY ANALYSIS FRAMEWORK

The basic steps in applying the framework use the following process. Each step is discussed in detail later with examples following the list of steps. Additionally, each step that is utilized during the case studies will be annotated in parenthesis at the beginning of the statement using that step. The steps are identified with the respective identifiers in the framework. Each section is identified according to the phase such as A1, A2, B3, B5, etc.

A. Define the problem in as succinct manner as possible
   - A.1. Define the objective (max, min, function, etc.)
   - A.2. Define the data resources available
   - A.3. Identify the decision variables

B. Define the constraints
   - B.1. Major constraints
   - B.2. Assumptions
   - B.3. Sign designations & restrictions
   - B.4. Range of duration, deadlines
   - B.5. Identify possible outside resources, factors

C. Determine feasible region
   - C.1. Validate boundaries
   - C.2. Validate impact of outside resources / factors
   - C.3. Combine feasible regions if multiple regions are involved

D. Identify optimal solutions
   - D.1. Identify optimal solution
   - D.2. Investigate possible solutions in reference to constraints

E. Test feasibility of solution(s)

E.1. Common sense validation

E.2. Operational flexibility/ Economics

E.3. Dimensional Integrity

A. Define the problem in as succinct manner as possible

A.1. Define the objective: The problem definition describes what the desired final answer or outcome should be. It sets the requirements for the rest of the analysis so that options can be included or excluded as part of the study. It should guide any decision-making activities throughout the scope of study because this step provides the direction and scope of the problem. Examples include “what conditions lead to the most effective use of fuel within certain X, Y, and Z parameters”, or “Is it feasible to operate under certain conditions given certain requirements without exceeding A, B, or C”. Another example is “what indicators are present that indicate that a problem exists in operations as outline by normal data representation during the following parameters….” Specific descriptors should be used as much as possible to aid in converging on the answer to the question.

Application Example: Throughout the narrative on the framework, the example shows how each step is applied and uses the example of determining allowable emission rates for a new electric generating unit (EGU). That rate will be submitted as part of the permit application submitted to the approving agency. For the sake of simplicity, this problem considers only one pollutant.

The objective for this problem then reads, *“Based on the need for operational flexibility and the projected utilization profile for this unit, what will the projected emission rates be for NOx and how will it compare to rates issued by the governing regulatory agency?”* The term “operational flexibility” denotes the fact that the mins and maxes required in the operation will be considered (either known or assumed).

A.2. Define the data resources available: Having a good objective described in the first step, it will identify those resources that contain information that is relevant towards achieving an answer to the object question. Those resources may exist in a database or they may exist in text-based documents. Text-based documents could identify the restrictions, boundaries, or historical data that could be valuable in determining the significance of the final solution. An example of a text-based document is an existing permit that describes the norm or characteristic value of a given entity (such as the amount of NO_x permitted by an agency under similar conditions). This information is useful in gauging the success of the solution against a norm. Both the database as well as text-based documents will have a feasibility region or data available for analysis. The list of relevant restrictions or boundaries in the text-based documents can help define the feasibility region for those resources.

Application Example: Based on the objective of step one, then the following data sources must be available for inclusion in the analysis of the example:

- A database containing relevant data that has been acknowledged by the state agency and EPA's Clean Air Market's Division as being Quality Assured and Quality Controlled. The quality of the data described here is that quality normally required by the above agencies. This level of quality aids in knowing that whatever data elements are chosen for analysis, the data elements will contain valid values.
- The projected emission profile by a manufacturer for the specific unit being installed. Ensure that the profile is using the projected emissions

reduction equipment and the associated guarantees provided by the different vendors. Sometimes different vendors will be providing the complete assembly of the EGU.

- A projected operational profile of the expected operation for the unit.is needed

- The identification of a unit identical or similar to the final configuration of the new unit is needed so that actual operational data obtained from this unit can establish a reliable operational profile foundation for new unit.

- The current allowable rate for NOx emissions issued by the regulatory agency approving the permit application.

- An individual familiar with plant operations will be required to verify that whatever assumptions made are reasonable.

A.3. Identify the decision variables: This activity follows the direction, reasoning and logic of the above two steps in selecting resources aimed at answering the problem. It initiates the convergence leading to a selection of relevant data elements (in a database or text-based document) that will contribute towards the selection of possible optimal solution(s). A variety of test cases could be created using different lists of data elements.

Application Example: Assuming that the resource items identified above are available for this study, then the variables to be considered would include:

- Several representative months QA/QC hourly NOx data retrieved from the unit from which the projected operational profile to be used is required.

Depending on the existing or expected permit requirements, hourly data might have to be augmented by smaller increments of data intervals (15 minutes, 3 hour averages), and certainly mins and maxes should be identifiable.

- The product guarantees offered by the vendors should be available and analogous in format and dimensions to the data retrieved in the steps above. It is of major importance to understand all limitations of the guarantees and nothing should be taken for granted. If need be, additional clarification by the vendors on the guarantees should be obtained in writing if there are any ambiguities.

- The current rate of allowables for NOx emissions issued by the regulatory agency approving the permit application will be used to evaluate the projected use of the EGU against the currently permitted allowables for NOx. This will provide a good measure of the amount of operational flexibility of the new unit assuming currently issued allowables.

B. Define Constraints

B.1. Major Constraints: Those requirements that define boundaries or limitations that require adherence by the optimal solutions need to be identified. Constraints can be of a numerical nature (such as only positive numbers) or in narrative form, (such as requirements from a contract, agency, etc.)

Application Example: The determination of the applicable boundaries that apply to the project is very important. Samples of constraints applicable to this example include:

- An acceptance and approval of the proposed profile of operation for the new unit by the approving agency is needed early in the cycle to avoid problems later.
- An acceptance and approval of the proposed profile of operation of an existing unit that closely approximates the new unit's configuration. A good approximation of emissions by an existing unit is far better than tables provided by vendors because a various number of variables may have to be adjusted to serve as good prototypical behavior of the new proposed unit. This profile should be available in the same units (lbs/hr, ppm, or other) as will be assigned in the final permit.
- All standard air permit conditions required by applicable air state and federal regulations according to the category of air permit being requested.
- Anticipated future use of the unit that might alter the projected operations profile. It is wise to employ safety factors in this constraint because operations often expect this added luxury and the re-submittal of an air permit is costly, time consuming and could derail an otherwise successful initial submission. A specific example in this case would be to consider the possibility of using the unit in a combined-cycle mode in the future and not just in simple cycle.

B.2. Assumptions: Care in the selection of assumptions is needed because they represent an unknown quality that will require verification and acceptance in the final approving process. However, a careful selection of assumptions could be very useful

because the complexity of the problem or question to be solved could be significantly simplified.

Application Example: Assumptions applicable to this example include:

- An acceptance by the state agency for the proposed profile of operation for the new unit using another similar unit's profile. As stated above, this should be completed as early as possible and whenever possible, acceptance by the agency should be in writing. Permit writers are often re-assigned and asking for approval twice is not recommended.
- Guarantees made by the product vendors will be reliable.

B.3. Sign Designation & Restrictions: A policy for sign designations, conventions and restrictions that apply to the data are important to the final quality of the answer. Ensure dimensional integrity. Examples include negative values that are not valid or unit incompatibility of measurements without conversion such as inches with meters, etc.

B.4. Range of Duration and Deadlines: An awareness of time limits and deadlines need to be considered and integrated into the analysis.

Application Example: Date restrictions applicable to this example include:

- Plans by the company to be operational by a given date. This requirement would need to account for the approval period of the application.
- Pending new environmental regulations that might cause the application to adhere to requirements that are more stringent.

B.5. Identify Possible Outside Resources, Factors: The analysis might have to consider resources that are external to those at hand. Examples include having to present results to those approving agencies that will be required for the optimal solution or other legal ramifications or requirements. This step does not have to take place all at once. In fact, it is desirable to breakdown the number of approvals to deal with only a few items at a time.

C. Determine Feasible Region

C.1. Validate Boundaries: A list of restrictions and boundaries will need to be identified at this point. The various restrictions and boundaries should be confirmed and validated to ensure that all requirements describing the feasible region are relevant, applicable and that none of them is overlooked.

Application Example: Boundaries applicable to this example include:

- All operational constraints on feeds and speeds of the individual parts of the system such as pumps, tank capacities, etc.
- All equipment required for air permit monitoring requirements that are mandated.
- Ambient temperature ranges that will be present during operation.
- Use of alternate fuels could dictate additional equipment so agreement and concurrence on the type of fuel in advance is necessary.

C.2. Validate Impact of Outside Resources / Factors: A validation of those outside resources and /or factors identified in the previous step should be conducted to ensure their necessity or availability. An example could be agency approval of a certain

testing protocol by which the data was gathered. In this example, the acceptance of a specific test protocol by the approving agency is critical because the agency could invalidate tests and or monitoring protocols planned. The need for a more expensive test could be easily avoided. Other examples could include the availability of weather data internally or by the US Weather Service.

C.3. Combine Feasible Regions if Multiple Regions are Involved. This process describes the combining of multiple feasibility regions to ensure that only true solutions are represented. This process could be compared to solving a system of linear inequalities where multiple feasible regions are mapped and only valid solutions for each inequality are included in the final answer. Examples are preparing the data from different sources for comparison with one another to analyze the various components such as the behavior of vendor product guarantees to the expected unit operation. Dimensional integrity is of critical importance as is required in step 5.3 of the Framework.

D. Identify Optimal Solutions

D.1. Identify Optimal Solutions: Perform this process with reference to problem objective or interpret best indications from the analysis if no optimal solution is apparent. Further consideration and analysis might be necessary if no apparent solution is present. It could indicate a need for continued iteration of the process and another selection of resources or variables to consider.

Application Example: An optimal solution in the example would be that composite region that shows how NOx emissions would or would not comply with

expected emission assignments by the agency. In simple terms, a mapping of allowable limits should be plotted on the same graph together with expected emissions.

- If within permissible limits, then good. If not within permissible limits, then this finding will show which elements need to be analyzed further and if need be, which arguments need to be prepared for presentation during the actual application of the permit to the agency.
- Documentation for agency approvals of assumptions should be well documented and concurrence of their use beforehand is preferable.
- The need for any additional iterations through the framework should have the obstacle clearly identified such as needing an additional data element to be included or a better clarification of a product guarantee.

D.2. Investigate Possible Solutions in Reference to Constraints. Identify the environment under which possible solution points became valid or invalid. An understanding of those conditions that led up to the optimal solution is important. Examples of why the solutions were optimal could include frequency of occurrence, weather, human operator interaction, etc. This information will aid in the validation of the entire process.

<u>Application Example:</u> All possible conditions should be considered and for this example:

- Operating during curtailment of natural gas.

- Operating during different times of the day and year with weather and temperature variations and during holidays.
- Operational use during very high loads or low loads.

E. Test Feasibility of Solution(s)

E.1. Common Sense Validation: Check to see if the solution meets the common sense requirement. Validation of this solution is required if it seems questionable by any means. Approval by individuals responsible for operation of the unit is encouraged.

E.2. Operational Flexibility: This area is always of concern, so quantify the extent to which the optimal solution provides this benefit.

Application Example: The foremost need is the ability to operate in response to actual real events and examples include:

- Response time for the unit to reach full load such as for emergencies.
- Start-up and shutdown requirements of the unit that require special attention.
- What is the proximity of expected emission rates to allowables emission rates? What is the degree of safety factor in this regard?

E.3. Dimensional Integrity: Confirm that dimensional integrity is preserved. This simple exercise precludes embarrassing mistakes that should never be present due to inattention to detail.

Chapter 4: Analysis of Methodology through Case Studies

For the purposes of this doctoral study, I chose to highlight three applications that demonstrate the use and value of applying data mining through secondary analysis. Each example has been chosen to provide insight into the value achieved by undertaking this approach utilizing data mining. Real-life case studies in industry could provide validation in this approach and offer evidence of its value and applicability not only in operational enhancements but also in financial terms.

4.1 – Case Study #1 Natural Gas Linepack, Thruput and Fuel Supply

This case study involves correlating operational characteristics of an interstate natural gas pipeline in order to obtain an enhanced understanding of operations and identify possible areas of improvement in the delivery of product. The research subject of this first case study is natural gas, and in its natural form, is transparent, colorless and odorless with the main constituent being methane.

4.1.1 Case Study #1 Overview

The subject case study deals with the El Paso Natural Gas (EPNG) Interstate Pipeline system that serves a major portion of the western United States. A representative portion of a natural gas pipeline is shown below as it delivers natural gas to its delivery point. .

FIGURE 4.1: SEGMENT OF A NATURAL GAS PIPELINE

It is common for interstate (and even intrastate) pipelines to have several lines running parallel to one another along the same right-of-way and not just a single line. The lines often are in the magnitude of several feet in diameter.

The diagram below shows EPNG's geographical locations throughout the United States. Although other lines are part of EPNG's network, those represented here apply to the subject case study.

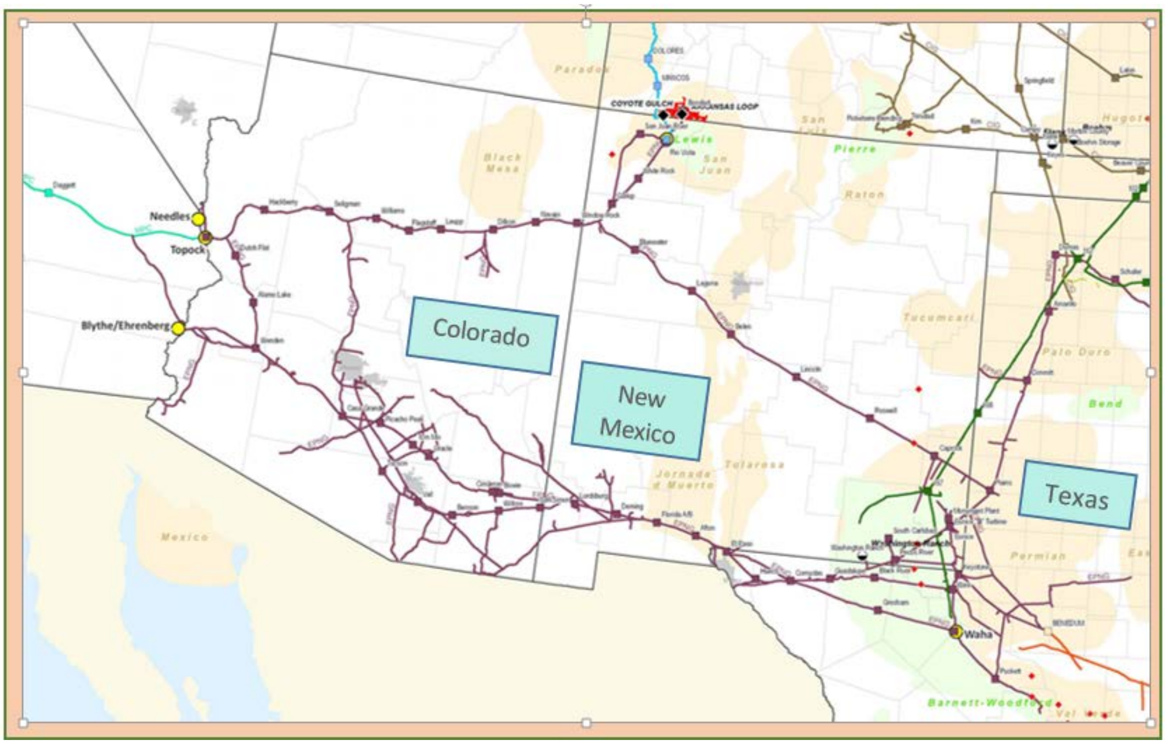

FIGURE 4.2: SCHEMATIC OF EPNG PIPELINE NETWORK ACROSS SOUTH WEST UNITED STATES

The purple colored pipeline in the graphic on the right identifies the line owned and operated by EPNG. This line was later purchased by Kinder Morgan. (Kindermorgan 2015). Natural gas is received in the pipeline from delivery points in the West Texas area. It is then transported across the southwest USA via two basic routes – a southern (so called “South line”) and northern (“North line”) – from where it is delivered into the west coast gas network, at the California border. Both the North and the South lines were comprised of several individual pipelines of varying diameters; the variance is sometimes of the order of several feet in diameter. The journey from receipt point to final delivery point is approximately three days as the gas in the line lumbered along at about 15 mph.

4.1.2 Case Study #1 Problem Defined

The basic role of the interstate pipeline is to aggregate sufficient natural gas from the receipt points to satisfy market demands at the destination, and to transport the product to the

intended markets safely and at the specified quality and pressure. The details involved in accomplishing this objective involve transporting high-pressure volumetrically across a prolonged distance. This requires operating numerous expensive turbine-driven compressor stations, used to move the natural gas and involves continuous (24 h x 7 d) monitoring activity of all critical aspects involved in the gas transportation.

These compressor stations are complex engineering operations. For example, see the subset range of facilities visible at the compressor station shown below.

FIGURE 4.3: AN EXAMPLE OF A COMPRESSOR STATION, OPERATED BY DUKE ENERGY (INGAA, 2013)

Both the inbound gas receipt and exit delivery points fluctuate in volume and pressure from hour to hour, according to well pressures at collection points and customer demand at delivery points. In other words, the job of the Systems Control Unit (the dispatching unit) managing the line is to constantly “balance” receipt and delivery volumes and pressures in order to collect, move, and supply the natural gas efficiently. An indication of the degree of

fluctuation of the volume of natural gas moved over time is represented in the figure below. It measures total values for the EPNG line, as a function of time of year, reported over a four-year period. (Kinder/Morgan 2016).

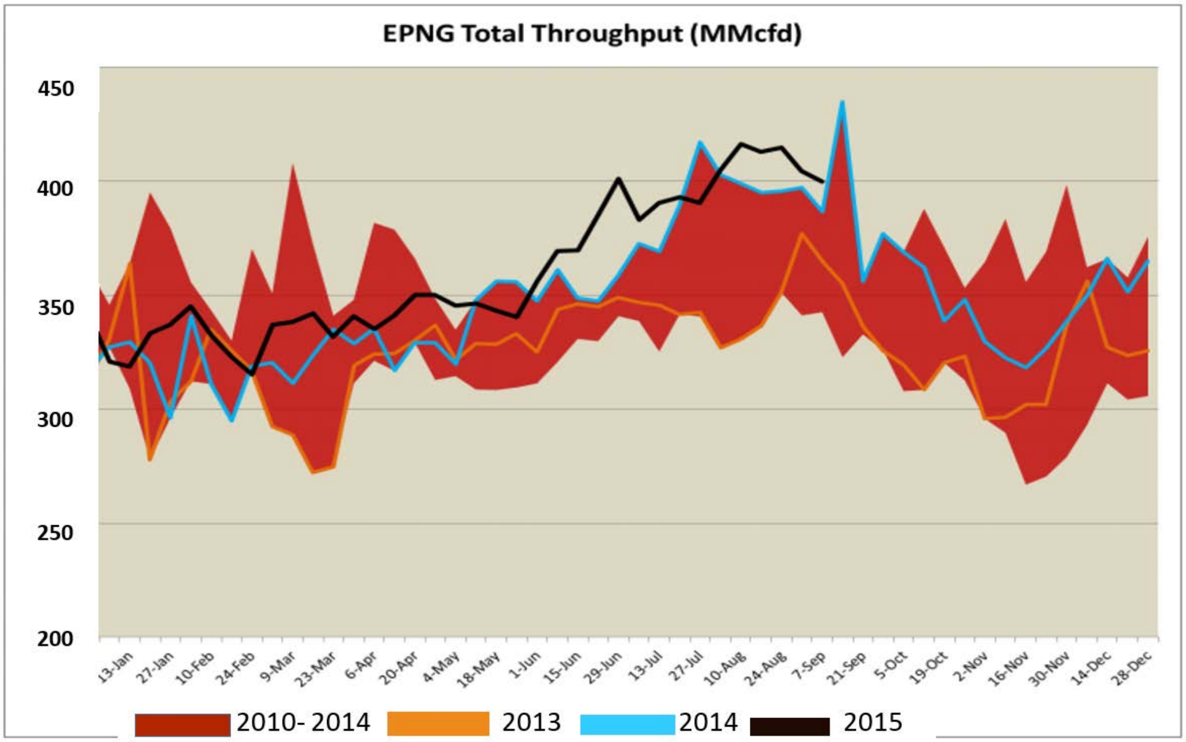

FIGURE 4.4: AN EXAMPLE OF A FLOW DEMAND, AND SUPPLY CURVE

Shown below is a typical dispatching control room used to monitor pipeline conditions. These control rooms go by different names such as systems control, gas control, and operations control but they all have the same function of monitoring the pipeline and making whatever adjustments are necessary to adjust for equipment or marketing requirements. They are manned around the clock and on holidays (24x7).

FIGURE 4.5: EXAMPLE OF OPERATIONS CONTROL ROOM (INGAA, 2013)

In addition to performing this task safely, the optimization of fuel use is a constant objective of the dispatching unit. Because the compressor stations along the line utilize the same natural gas as fuel that they transport, any improvement in the use of fuel expenses allows more product available for sale. The greater the volume of product moved along the line, the greater amount of fuel consumed in the movement. Below is a sample fuel/thruput curve showing this relationship.

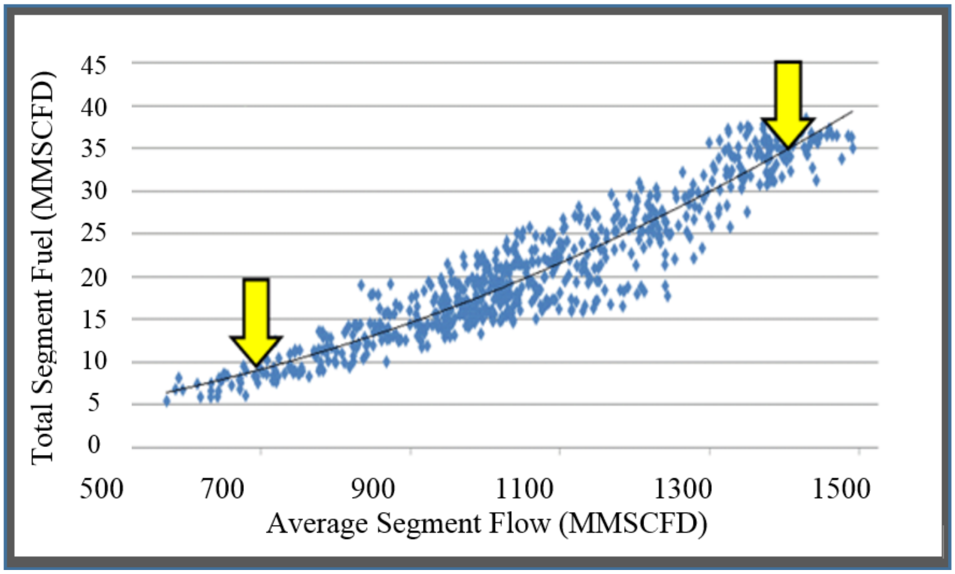

FIGURE 4.6: SAMPLE FUEL / THRUPUT CURVE IN PIPELINE OPERATION

In the figure, the vertical axis represents fuel use (MMcfd) and the horizontal axis represents thruput (MMcfd). Note the exponential fuel consumption resulting from an increased thruput. One obvious safety concern is maintenance of a net positive pressure along the line, not only to move the natural gas along the pipeline but also to prevent accidents. One example of the implications of delivery failure is pilot lights extinguishing. A scenario where pilot lights expire in a populous area due to the lack of natural gas pressure and failed delivery can cause a tremendously dangerous and potentially catastrophic environment. The danger occurs when the gas pressure is restored; the gas flows to the unlighted pilot lights and inundates the surrounding area. When a spark or light is introduced to a gas filled room, an explosion or fire could occur. Health and human lives could be lost simply due to the lack of positive pressure at delivery points.

The task of monitoring the EPNG pipeline involves overseeing more than 23,000 miles of line, utilizing dozens of compressor stations accumulating over 24,000 points of information over a period of 3- to 4-minutes, feeding data into a Supervisory Control and Data Acquisition (SCADA) System. The SCADA system operates 24x7 with triple redundancy being necessary to ensure continuous operating safety.

4.1.3 Case Study #1 Graphics and Solutions

In order to better visualize how the pipeline operates from a system-wide perspective, three basic variables contributing to the overall operation of a natural gas pipeline have been selected. (Framework reference: A). Following analysis, a three dimensional graphic representation of these variables can be produced. In this instance, the three variables chosen for examination are fuel, thruput and linepack (Framework reference: A1). These three variables are generally recognized as key by everyone in the dispatching units, and they are understood widely as contributing to functional gas schedules through overall pipeline operations (Framework reference: A3).

The following steps are the data analysis steps completed to achieve a solution:

1. First, the extraction data period is established, appropriate to extracting data for the model. The shortest period could be a week and perhaps the longest could be a month, so that the size of the data files is manageable. The objective is to have a representative sample of data values with neither too much – nor too little –data. Guidance from operations personnel on data transients is useful in selecting the period (Framework reference: Section B).

2. Depending on the technical level of the developer, a software application appropriate to developing a practical solution is chosen and is used in generating the model. Software may be as uncomplicated as Microsoft Excel™or as sophisticated as SAS; being Statistical Analysis Software; a statistical application developed by North Carolina State University (Service 1972).

3. Using the SCADA system as the source of data, these three variables, (fuel, thruput and linepack for the entire pipeline system) are downloaded into a file repository. SCADA systems typically provide some file extraction capability. Because the file is to be read by software creating the model (in this case presented here, only MS Excel is required), the format of the data used in the download is dictated by the modeling software. When doing this, ensure that all data is relatable to a common timestamp. This is important since the three fields being downloaded may not necessarily come from a single data source. In addition, ensuring that the correct field is downloaded is key, as various data, fields may appear similar in some cases. Then, ensure that all dimensional units from all three variables correlate together; for example, data representing daily values should be reflecting that unit (per day, in this example) for all three downloaded data files in order to establish dimensional integrity. (Framework reference: Section B)

4. Importing the data into the modeling software application then proceeds, selecting the options that will generation of a 3-dimensional graph. Again, in this case, MS Excel was utilized using the following steps (Framework reference: C):

a. Open the Excel application

b. Load the data onto a spreadsheet.

c. Highlight the data range to be used

d. Select Insert > Recommended Charts option, and under a dropdown menu select > All Charts

e. Select Surface

f. A three-dimensional envelope will be created based on the data.

g. Select the appropriate descriptors to enhance the graph.

h. If helpful, a rotational feature is available to view the graph from different perspectives.

Below is shown the actual chart of linepack, fuel and thruput, which was created using SAS and actual operating data from EPNG. (Framework reference: Section D).

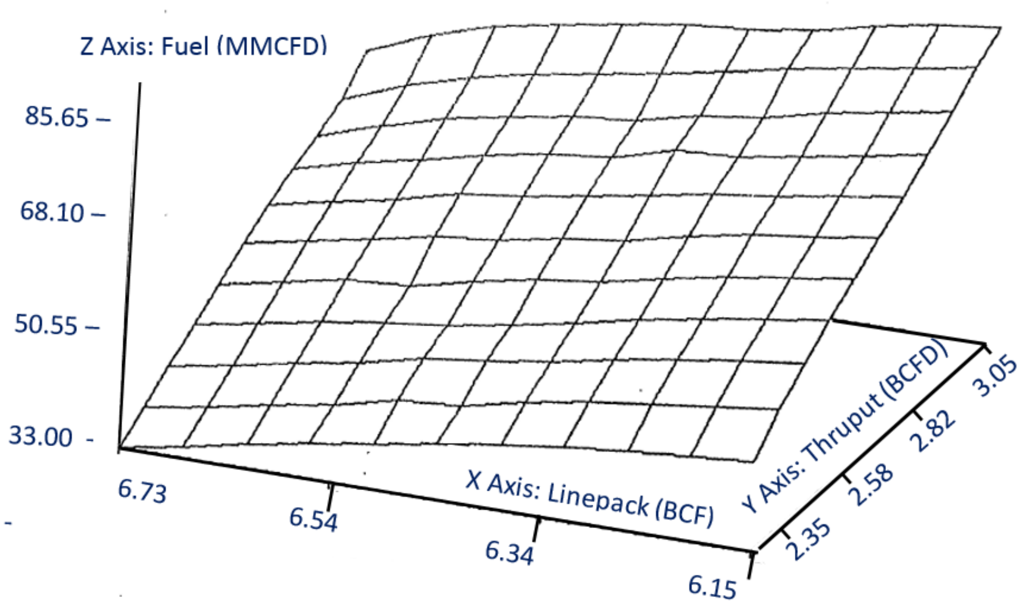

FIGURE 4.7: PLOT OF LINEPACK, THRUPUT, AND FUEL

The figure above is a SAS-generated graph of linepack, thruput, and fuel delivery. The units for the respective axes are: X-axis representing linepack is shown in Billion Cubic Feet (BCF), Y-axis representing thruput is shown in Billion Cubic Feet per Day (BCFD), and the Z-axis showing fuel is shown as Million Cubic Feet per Day (MMCFD) (Framework reference: E3).

Below, in the subsequent graph is a likeness of the original plot developed using the methodology described above, and using MS Excel to generate a valid approximation to the original graph.

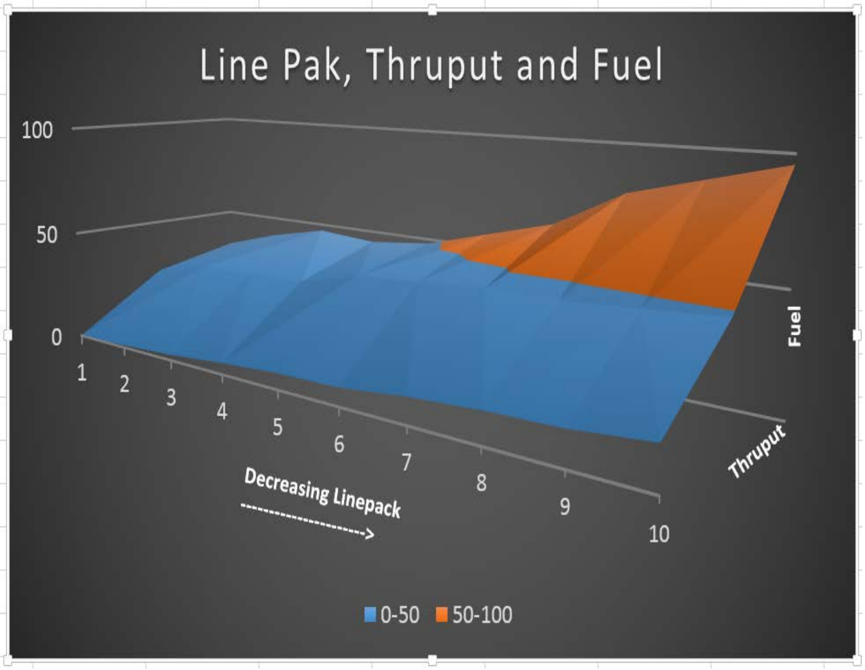

FIGURE 4.8: LINEPACK, THRUPUT, AND FUEL CURVE USING EXCEL.

4.1.4 Case Study #1 Benefits

The value of the ideas presented in the case study #1 include:

- The use of Clustering and Interactive Data Visualization techniques that provide representation of a graphic display showing the effect of all applicable variables (man, machine, environment, etc.) on an ongoing basis. As new conditions change, the summary of changes in terms of measurable effect for each variable is translatable into a net representation of the effect that all variables contribute. A mathematical model of this graph would be inherently difficult, expensive and would ostensibly still leave out some variables that might infrequently play a role but be nonetheless important.

- The benefits available through these techniques provide a heightened view of significant operating conditions from which to advance optimization of the operation. The corresponding values depict where optimal conditions exist in fuel use and serve as indicators of optimal operating conditions. They provide a specific reference point that summarizes what is happening "at this point in time, with these conditions, when optimal operations existed." They can thus point out conditions that should be replicated to enhance and maintain efficiency.

- One specific lesson observed from the use of the model is that fuel consumption is optimized at a higher linepack.

- This approach uses existing computer and monitoring devices already in place and removes the requirement of additional expensive modeling equipment in order to provide this information.

- These techniques have broad applicability to other industrial applications. In the example presented here, in this specific case, it applies directly to a very significant cornerstone of our economy. According to the "Pipeline 101" (n.d), natural gas supplies almost one fourth of all the energy used in the United States at the current time.

4.2 – Case Study #2 Electric power Production: Newman 6A and 6B: A Background

The second case study is that of electric power production within the El Paso region. Here again, an industrial data set comprises the source data from which the analysis is made. Similar to the data set in Case Study #1, this data and that for Case Study #3 is generated on an ongoing basis and is indicative of the operations but instead of natural gas operations, the data for Case studies #2 and #3 reflect the continuous emissions data collected for an electrical generating facility.

El Paso Electric (EPE) Company's role as a provider of electricity began in 1901 as the El Paso Electric Railway Company. The company name was changed to El Paso Electric in 1925. Four years later, the Rio Grande Plant was built. Later, construction was added in 1927, 1928, 1949, 1951, and 1956. The last unit installation was Rio Grande Unit 8, which went into production in 1982. ("The Electric Company", 2016). The total generation capacity of the Rio Grande plant is relatively small (around 80 MW), but it is an important part of the EPE generation portfolio, used for peaking power load management. Regulatory oversight for environmental compliance at the Rio Grande Plant is performed by the New Mexico Environment Department, since most of the plant is physically located just inside of New Mexico's state boundary.

FIGURE 4.9: RIO GRANDE PLANT (CIRCA 1929)

The Rio Grande Plant in Sunland Park, New Mexico, was constructed in 1929. Two exhaust stacks are seen at the top of the plant buildings (Source: "The Electric Company", 2016)

Located in far east El Paso, Newman Unit 1 (80 MW) was constructed in 1960, followed by Newman Unit 2 (80 MW) installed in 1963, and Newman Unit 3 (102 MW) in 1966. In 1975, a new combined cycle unit, Newman Unit 4, was built consisting of a steam turbine added to two combustion turbines for a capacity of 210 MW. This unit offered increased efficiency due to the use of heat from the combustion turbines to help drive the steam turbine ("The Electric Company", 2016). Regulatory oversight for activity at the Newman Plant was performed by the Texas Commission of Environmental Quality (or its equivalent prior to being designated TCEQ) since the plant is located in Texas.

FIGURE 4.10: DEDICATION OF THE NEWMAN POWER PLANT (1960)

The dedication of Newman Power Plant was in 1960. The Newman Unit #1 can be seen in the left background in this photograph (Source: "The Electric Company", 2016)

The map below shows the relative geographical location of both the Newman and the Rio Grande Plant within the El Paso area. Newman Power plant is located at the upper right of the graphic and within the Texas state line while Rio Grande, located at th elower left, is just inside th enEw Mexico state line.

FIGURE 4.11: LOCATION OF EL PASO ELECTRIC'S POWER PLANTS

The above figure shows the relative location of El Paso Electric power production plants. Rio Grande plant is located in Sunland Park, adjacent to the Rio Grande River crossing into Sunland Park, New Mexico and the Newman Power plant is located in Texas, just south of Chaparral, New Mexico. ("The Electric Company", 2016).

The diagram below shows the service area for El Paso Electric. The service area spans two states and delivers power to Juarez, Mexico. ("The Electric Company", 2016).

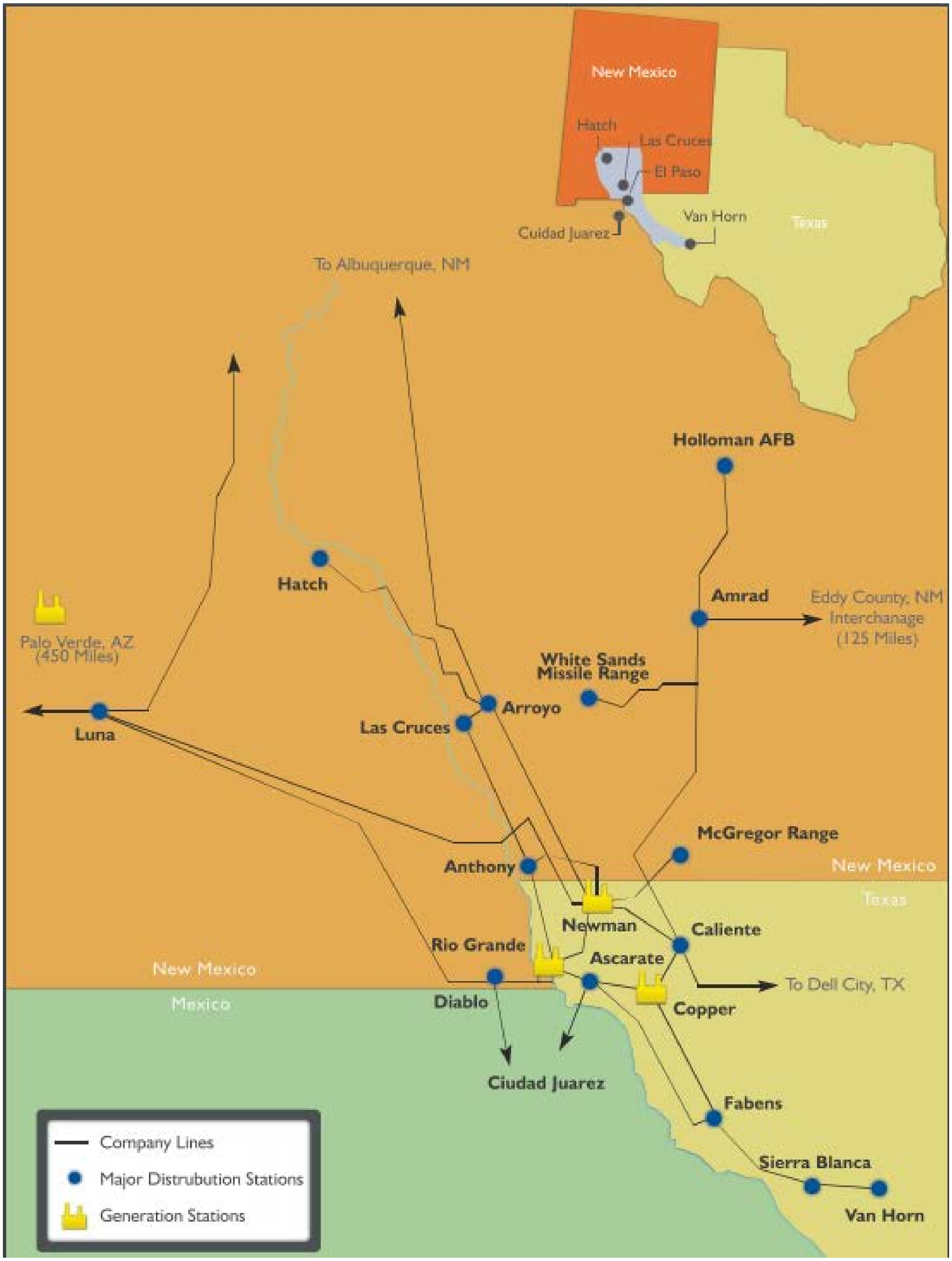

FIGURE 4.12: EL PASO ELECTRIC'S SERVICE AREA

To avail itself of the benefits of nuclear energy-based thermal electric power production, in 1973, El Paso Electric entered into an agreement with other utilities for the construction of the Palo Verde Nuclear Generating Station. The nuclear plant is located adjacent to the Gila River roughly 50 miles west of Phoenix, Arizona. El Paso Electric owned 15.8 % interest when the U.S. Nuclear Regulatory Commission first issued the construction permit in 1976. The full construction of the plant was completed in 1988 consisting of three 1,270-MW units, for a total production capacity of 3.6 GW ("The Electric Company", 2016).

4.2.1 Case Study #2 Power Generation and CEMS Operation

Shown below is a typical diagram of how electricity is generated showing the use of a turbine providing power to the generator via a drive shaft. Air and fuel (natural gas) are combusted in the combustion chamber with the air intake manifolds being the two intake passages at the top and bottom of the diagram. The exhaust gas leaving the turbine contains the various pollutants that are formed during combustion and emitted into the atmosphere. This effluent requires constant and continual monitoring in order to comply with local, state and federal requirements that are described in the air permits for operating the facility. Exhaust gasses exit the facility via the stack with most stacks being circular. El Paso Electric (EPE), however, has a rectangular shaped stack at one of its stations. As a reference, two circular stacks are visible at the top of the plant buildings shown previously.

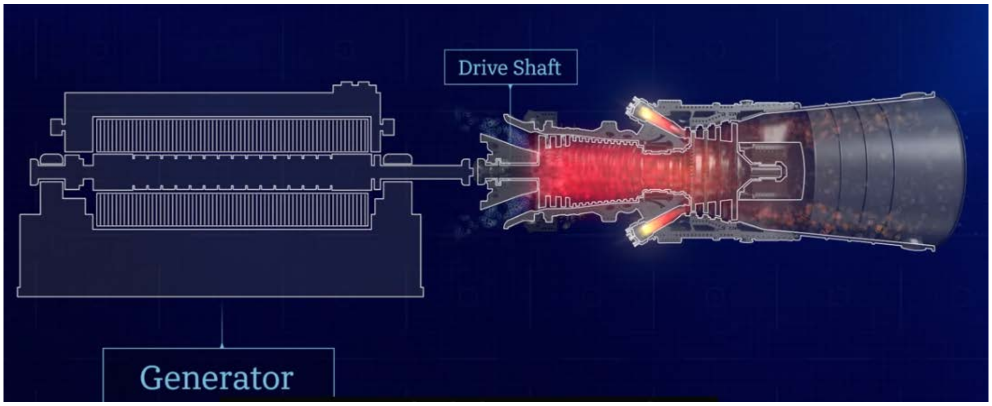

FIGURE 4.13: SCHEMATIC OF A GAS-TURBINE ELECTRIC GENERATOR ("GE GAS TURBINE 101", 2015)

The Continuous Emissions Monitoring System (CEMS) includes all equipment required to monitor emission conditions and the respective air quality of the effluent exiting the stack. The equipment comprising a CEMS system includes probes, umbilical lines, analyzers of different type for the various pollutants, data loggers that store the real-time data for a short period and a dedicated computer controller that captures data and events and archives that information for subsequent analysis and reporting. A diagram of those basic components is shown below.

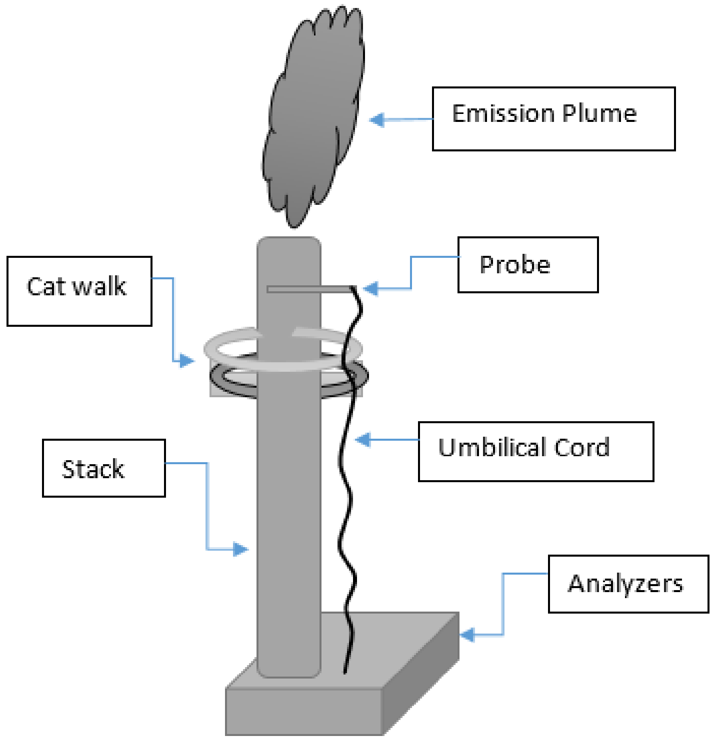

FIGURE 4.14: CONTINUOUS EMISSIONS MONITORING SYSTEM

Summary data from the collected data stream is required by regulations to be archived for several years. Those measurements of data which are gathered at small intervals of time (typically minutes), are “rolled” up in summary fashion to establish conglomerate data values of larger interval size such as 15-min or hourly data. This data is used to prove compliance or show deviations (lack of compliance) with the relevant permitting requirements. All equipment, including the data, must be periodically certified through compliance testing. Aside from periodic reporting that must be completed on a regular basis to state authorities, regulations

require quarterly reports to be submitted to the Environmental Protection Agency's (EPA) Clean Air Markets Division. These reports are scrutinized, kept for future reference, and referenced during annual inspections of the facility. The CEMS data provides the mainstay for demonstrating regulatory compliance to the various agencies that oversee environmental compliance. These databases of operational data ("big data") can be especially useful during permitting actions being sought by the electric generating facility.

4.2.2 Case Study #2 Regulatory Environment

As shown in the diagram below, the electric industry is one of the most regulated industries in the United States ("Mercatus Center George Mason University", 2016). In addition to the Clean Air Act (CAA) of 1990 and the updates to the CAA over the years, a listing more comprehensive than many other industry regulatory requirements covers the air quality aspect of the electric industry. The CAA is the foundational set of regulations for air quality and new subsequent regulations reflect the industry's understanding of current problems and priorities developed by the agencies (Federal, State and sometimes local). A list of some of the additional current federal regulations is shown below. State regulations mirror federal regulations and in many instances require compliance that is more stringent. For brevity, they are not presented here. Federal regulations include:

- Clean Power Plants (Mercury and other hazardous materials)
- Interstate Air Pollution Transport
    - National Emissions Standards for Hazardous Air Pollutants (NESHAPS – air toxic regulations)
- Greenhouse Gas Reporting Program

- Mercury and Air Toxics Standards (MATS): Regulatory Actions ("EPA Environmental Protection Agency", 2016).

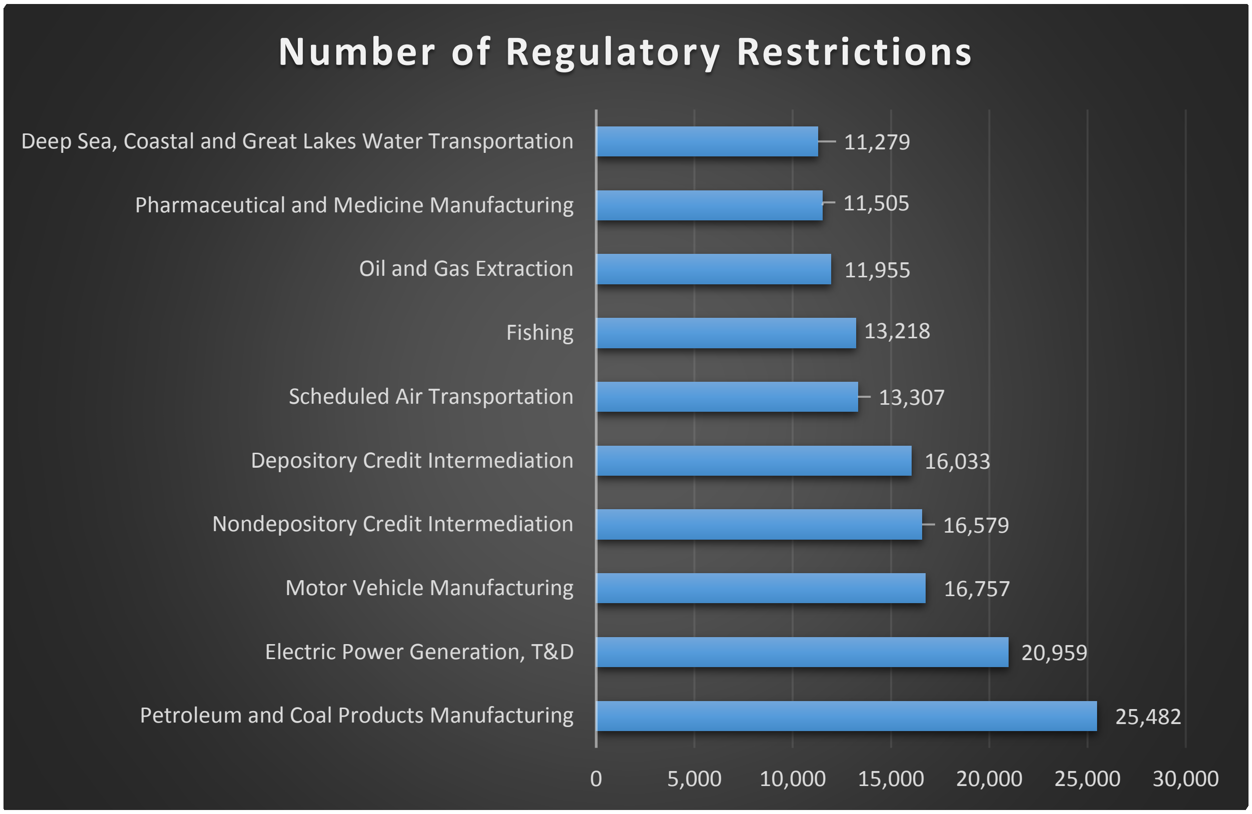

FIGURE 4.15: MOST REGULATED INDUSTRIES IN US ("MERCATUS CENTER GEORGE MASON UNIVERSITY", 2016)

The figure above is the McLaughlin-Sherhouse listing of the most regulated industries in US ("Mercatus Center George Mason University", 2016).

4.2.3 Case Study #2 El Paso Electric's Newman 6A and 6B Electric Generating Units

In April 2007, an application entitled "Amendment to New Source Review Quality Permit No. 1467 for EPEC Newman Station Unit 6A New Combined Cycle Gas Turbine Electric Generation Unit" was submitted to the Texas Commission on Environmental Quality, Office of Permitting, Remediation, and Registration, Air Permits Division in Austin, Texas. Zephyr

Environmental Corporation in Austin, Texas assisted EPEC in the preparation of this permit application. Entitled Unit 6 Project, the purpose of the permit application was to construct and operate Unit 6 and the ancillary equipment at El Paso Electric's Newman power plant, as an amendment to Permit No. 1467.

Since Unit 6 was to be comprised of two natural gas-fired General Electric (GE) Frame 7EA combustion turbines, they were each designated as GT-6A and GT-6B respectively with each having a nominal baseload electric generating capacity of 70-MW. Initially, Unit 6 was to be operated in simple cycle mode and later, it would be transformed into combined–cycle operation, (similar to Newman Unit 4) whereby a steam turbine is added to the two combustion turbines to achieve increased operational efficiency. In this mode, the heat from the combustion turbines is utilized to help drive the steam turbine. At the time of conversion to a combined cycle operation, each combustion turbine was equipped with a Heat Recovery Steam Generator (HRSG), duct burners and a steam generator. The combined total baseload design capacity, when completed, was approximately 288-MW. Permit conditions required that construction of the HRSG equipment begin within 18-months of commencing operation of the simple cycle mode of operation. To provide operational flexibility, EPEC requested that the two new units be allowed to operate in either simple-cycle or combined-cycle mode from TCEQ. This request was granted.

4.2.4 Case Study #2 Problem Defined

After assembling the major components of the permit application together and reviewing the permit application for approval, a close look at the guarantee by the vendor of the selective catalytic Reduction (SCR) for NOx, reduction was realized to become a problem. The vendor

guarantee named certain conditions under which the guarantee could be provided and the permissible allowable limit offered by TCEQ for NOx was not very high. Often the agency will limit the allowable permit limit only to the extent that is guaranteed by the vendor. Additionally, the manner by which the new units would be operated was yet to be decided and the emissions generated by the new turbines was dependent upon how the unit is operated. Emissions can be expected to vary during start-up, variations in load (variance in how much electricity is generated) and/or whether they are operated steady state and during shutdown. The options were to take the allowables offered by the agency and risk non-compliance, notify EPEC of the permit requirements and limit operations only to those actions that would satisfy compliance, or look for an alternate solution to this dilemma ((Framework reference: Section A).

4.2.5 Case Study #2 Graphics and Solutions

A projection of the way in which the new units could be operated was based specifically on how the existing units, Units 4A and 4B, were operated. This assumption led to the formulation of turbine operations for the new units and this allowed a comparison of how their operation vetted against the guarantees provided by the vendor (Framework reference: Section B). A disturbing and revealing picture surfaced that predicted that if the currently proposed allowables by the agency were accepted and the new units were operated in a fashion similar to how units 4A and 4B were operated, EPEC would be operating in non-compliance most of the time (Framework reference: B1). The guarantee by the SCR vendor only applied when the units operated over 65% load and when the units were operated in steady state. The graph below illustrates that operation was well below the 65-% load factor for a good percent of the time and rarely was in steady state (Framework reference: B3)

Using the load profiles of the projected use of the new units, TCEQ was petitioned to raise the allowables for NOx as it was shown that EPEC could reasonably demonstrate the need for a higher allowable and that the current allowable issued by TCEQ was too low in this instance (Framework reference: Section C). TCEQ agreed that current allowable limits for NOx would be problematic and that a higher limit was necessary (Framework reference: C2, D1)

The language in both the letters from the SCR vendor as well as in the final permit issued reflected these conditions to ensure that this condition was present and was defensible for any upcoming inspection or review. The result was that an allowable of 150% of what was typically allowed was granted in this permit application to EPEC. This assignment was well above that normally being allocated by TCEQ to other permit applications (Framework reference: Section E).

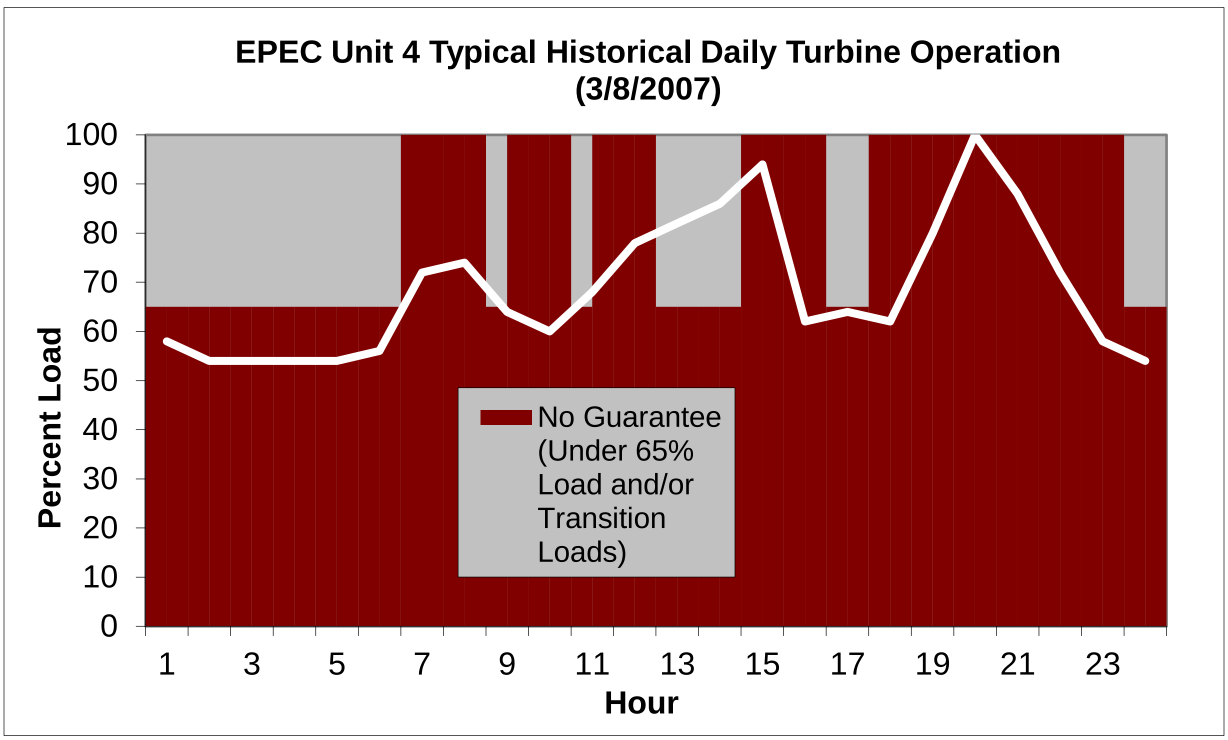

FIGURE 4.16: DAILY GAS TURBINE OPERATION

The figure above displays the historical daily turbine operation typical for the combined cycle gas turbine electric generator # 4 at EPE's Newman Power Plant during 2007.

4.2.6 Case Study #2 Benefits

The benefits obtained by completing this analysis include:

- Providing plant personnel additional operational flexibility for the use of the turbines in order to help meet customer demand for electricity
- Avoiding conditions of non-compliance due regulations that are averages and not conducive to the required method of operation of the plant
- Avoiding paying hefty penalties and fines due to non-compliance
- Reducing administrative headaches for the plant management and environmental engineers, due to having to deal with answering instances of non-compliance
- It offers an excellent example to future engineers as to how to approach problems of this nature and continue reaping the benefits of a well-written air permit.

4.3 – Case Study #3 Permit Deviations Rio Grande 9

Case study #3 deals with data also relating to an electric generating unit. However, this case study comes from EPEC's plant located in New Mexico. It provides another example of the successful application of secondary data analyses in electric power plant air permit applications. Given that the main objective in permit writing was to provide operational flexibility so that the demands for electrical generation could be more easily met while staying within the regulatory limits of the permit, this case study exemplifies that work.

4.3.1 Case Study #3 Regulatory Environment

The El Paso Electric Company (EPEC) had only recently financially settled a Compliance Order issued by the New Mexico Environment Department (NMED) when in 2010; EPEC submitted a new air permit application to the NMED for the construction of a new unit. The cause for the Compliance Order, which initially fined the company potentially more than $9 Million due to noncompliance of approximately 650 air emissions violations ("New Mexico Environment Department", 2016), highlighted the need to ensure that in the future, compliance in air emissions was prioritized by EPEC.

The permit application was to construct a 95.3-MW natural gas fired simple cycle turbine to be constructed in their Rio Grande Plant in Sunland Park NM. It specified the construction of Unit GT-9, a 95.3 MW/142,576 HP natural gas fire simple cycle turbine, model GE LMS 100PA and other associated equipment and cooling tower. The term simple cycle turbine used in the application applies a stationary gas turbine that does not recover heat from the gas turbine exhaust gases to preheat the inlet of the combustion air entering the gas turbine, and does not recover heat from the exhaust gases like a combined cycle unit would. The capability of the plant was to be increased from an annual average production of 245-MW of electricity to a total annual average of 340.3 MW. Because the Rio Grande Plant had been constructed prior to 1972, prior to the New Source Review (NSR) regulations being issued by the EPA, an NSR permit did not already, exist for the Rio Grande Plant. Consequently, the existing boilers (6, 7, and 8) were exempt from much of the NSR provisions, which now did apply to the new unit (Unit GT-9). Also complicating the permitting environment was that coincidentally, effective January 1, 2011, the EPA would begin a regulatory change that also caused the application to be subject to a new set of regulations under

their Prevention of Significant Deterioration (PSD) program dealing with Total Suspended Particulate (TSP) and PM2.5.

4.3.2 Case Study #3 Problem and Objectives Defined

Given the complex set of the existing regulatory entanglement, this permit application was an opportunity to clear the regulatory playing field and start over not only in a regulatory compliance-setting environment but also in an improved interpersonal human communications relationship between EPEC and NMED. As could be expected, both sides were upset with each other due to the issuance of the Compliance Order.

The assignment then was several fold: 1. Analyze the entire plant operation to justify the adjustment and revision of existing permit limits accordingly to gain more operational flexibility. Otherwise, the conditions that caused the Compliance Order in the first place, would continue to cause deviations from the permit allowables. 2. Comply with new requirements which would start the following January. 3. Design the permit conditions for the new unit to allow operational flexibility (Framework reference: Section A).

Therefore, the overall objective of this work was to make sure that installation of the new unit would meet all pertinent regulatory requirements and assist in the remediation of those conditions that had led up to the Compliance Order (Framework reference: Section A).

4.3.2 Case Study #3 Solution

One of the pollutants causing problems that led to the Compliance Order was Carbon Monoxide (CO) (Framework reference: Section A3).

Excessive exceedances of CO contributed greatly to EPEC being fined. The problem initiated when EPEC previously accepted permissible emission limits from NMED for CO, which were very strict and were not conducive for operational flexibility. Specifically, in the area of limits assigned to startup conditions, CO emissions were very problematic.

The analyses that pursued included looking at all variables possibly contributing to these exceedances in CO (Framework reference: Section B).

Analysis of the CEMS data at the Rio Grande station for all three units, Units 6, 7 and 8, showed the following:

1. All three units were experiencing CO exceedances above permit limits. Al three units had the same allowables for CO in their permits.

2. Exceedances normally occurred in the morning during cold weather especially during startup.

3. Duration of the exceedances was not long. Typically measured in minutes, exceedances did not continue into the day as the day became warmer.

In addition, there appeared to be other contributing factors that were investigated which apparently also contributed to the exceedances in CO. They are listed as follow:

4. The dilution-extraction technique of the CEMS could have a role in contributing to this dilemma.

5. Open pit burning was common in Juarez in areas just south of the plant and in higher elevations. This process could expel large amount of CO.

Since the occurrence of exceedances was not limited to one unit but was experienced throughout the plant, it appeared that a systemic contributor coincident to all three units could be the cause. In an effort to eliminate the problem for good, all possible contributors were considered (Framework reference: Section C).

As demonstrated in the figure below is a generic sample graph of turbine emissions during start-up as opposed to baseload conditions, CO during start-up is several times that of

baseload conditions ("Gas Turbines Emissions and Control", 2001). Unless provisions had been made in the prior permit application for startup conditions, the permit allowables would reflect only general operating conditions reflecting a base load environment. The graph below depicts CO Emissions for a facility at start-up and full load. As is evident, general operating conditions are not representative during start-up. ("Gas Turbines Emissions and Control", 2001).

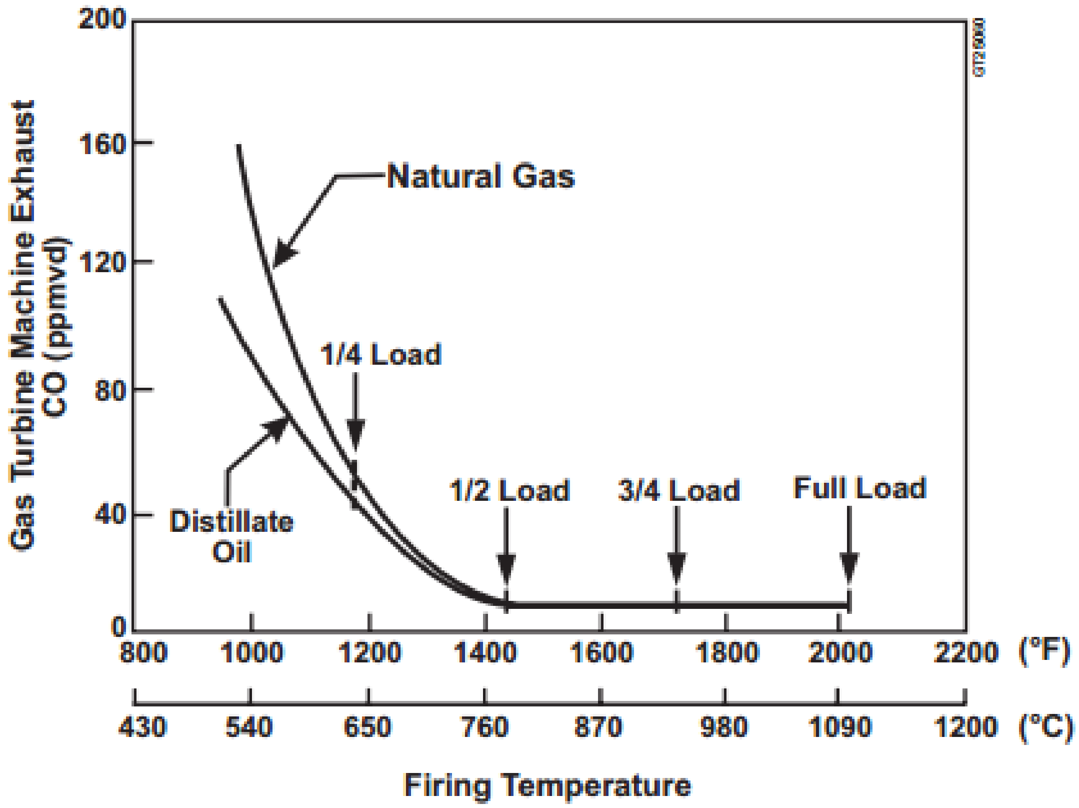

FIGURE 4.17: TYPICAL CO GAS TURBINE EMISSIONS DURING STARTUP

A review of the Minimum/Maximum temperatures for El Paso during the months of January and December 2010 showed that morning temperatures could easily be seen below freezing. During the day, temperatures warmed considerably and rose by 40 to 50 degrees. Those are shown in the figure below.

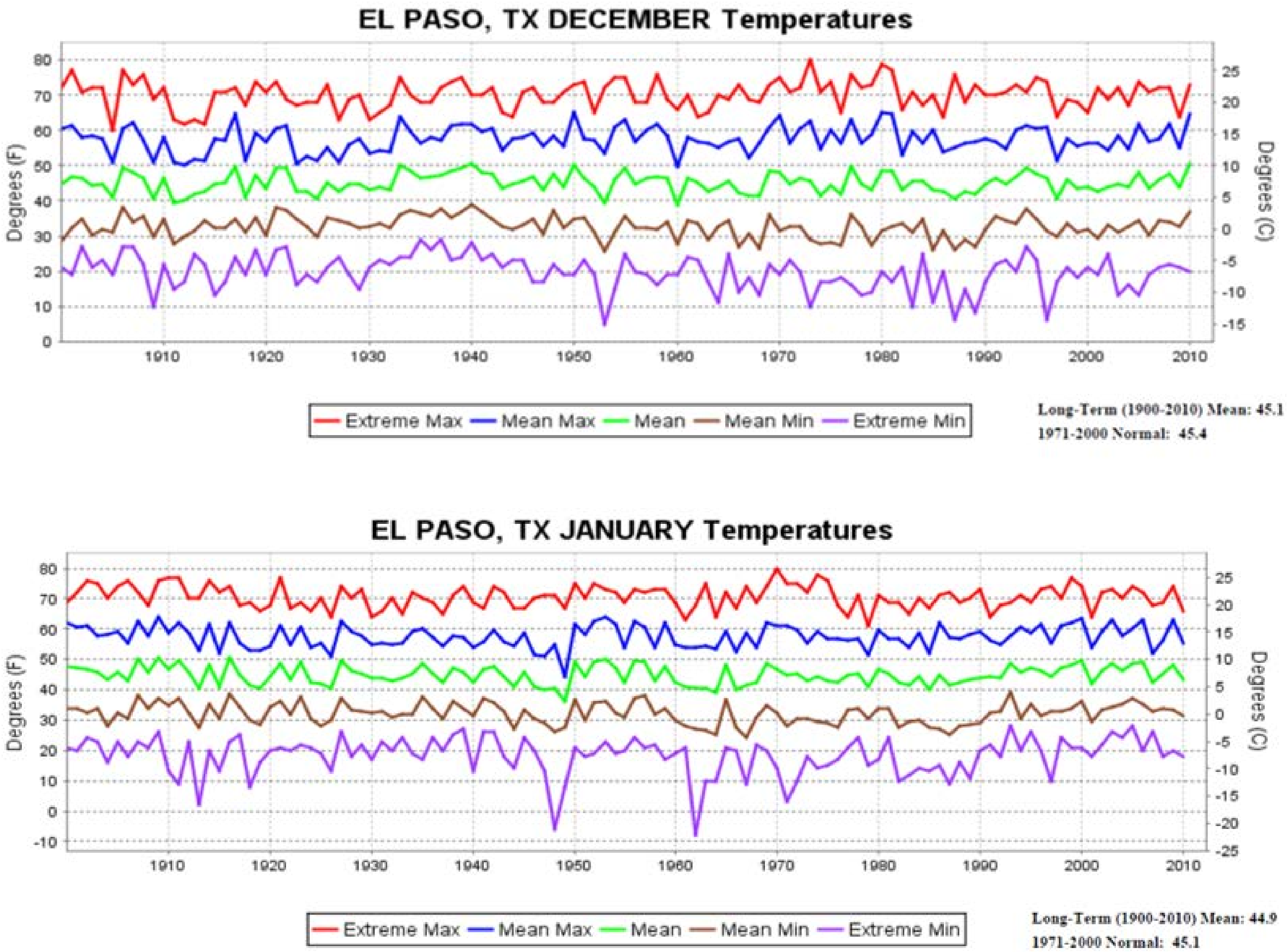

FIGURE 4.18: TEMPERATURE VARIATIONS IN EL PASO TX

The above graphic shows minimum and maximum temperatures for January and December 2010 (D. J. Novlan, personal communication, May 5, 2016 National Weather Service.)

Another contributing factor believed to exacerbate the possibility of causing CO exceedances was the dilution-extraction technique of the CEMS. Once a gas sample of the effluent is taken from the stack, it is transported to the CO analyzer at the base of the EGU. There the sample is diluted to 1/100 parts with atmospheric air. If the atmospheric air should contain an abnormal amount of CO, then prior to the sample be analyzed, the amount of CO

would be artificially raised. Because EPEC had participated in a project involving open-pit burning in Juarez, the team was aware that open pit burning was common in Juarez in areas just south of the plant and in higher elevations. Wind patterns during inversions could have contributed by bringing quantities of CO North and down into the valley from Juarez, Mexico. The dilution-extraction technique utilized by the CO analyzers would then inflate the CO concentrations above the allowable limits in the permits. Several tests of ambient air CO concentrations around the plant showed ambient air to sometimes process higher than normal CO concentrations (Framework reference: Section C).

All these contributing factors were reported to NMED and a reasonable case for an increase in the permit allowable for CO was made and accepted by NMED. In addition, other permit allowables that were very generous (such as for NOx) were modified in to reduce the NOx allowable in certain measurements but increase them in other measurements (such as the duration of time that the allowable required) to allow for additional operational flexibility (Framework reference: Section D).

The result of this effort was that the existing permit was modified by NMED and the incidents of exceedances was greatly reduced and almost eliminated. Below is contained an excerpt from permit 1554M1 issued by NMED.

"Boilers 6, 7, & 8 - Increasing the 1-hr average pph CO emission limit (except unit 6) and removing the 3-hr average CO emission limit; and decreasing the CO ton per year (tpy) emission limit. Limiting short-term emissions per hour, rather than over 3 hrs, is more appropriate to demonstrate compliance with Ambient Air Quality Standards. According to the applicant, the increase in 1-hr CO emissions are due to the type of Continuous Emissions Monitoring (CEMs), which is a dilution-extractive CO CEMs that dilutes stack emissions with ambient air and not

due to a modification. According to the applicant, during winter months, the ambient CO increases due to the geography and weather patterns pulling in higher concentrations from increased open burning in Juarez and winter inversions keep the ambient CO from dispersing" (Framework reference: Section D).

It should be pointed out that not only was a better operational permit for El Paso Electric Co. obtained due to the analysis of the data and contributing factors but also a permit that served the overall aim of improving the environment and serving the community. The new permit relaxed permit limits in certain areas but also reduced permit limits in other areas where improvements were possible and reduced total emission allowables. Not shown in the excerpt was the concession that EL Paso Electric Co. would also perform annual Relative Accuracy Test Audits (RATA) on CO to show compliance. The result was that corrections and adjustments were achieved in correcting troublesome air permit conditions and greatly minimizing the possibility of future deviations from permit conditions that could results in possible huge fines.

This was achieved through a complete analysis of the entire plant operation that began with data mining of the CEMS data to identify relationships not only among the data but also in other possible contributing factors not readily apparent in CEMS database. Once the possible source of those external contributors was suggested by the analysis of the CEMS data, we were able find probable cause as to their contribution to the problem (Framework reference: Section E).

4.3.3 Case Study #3 Why Bother?

The events that led up to NMED issuing the Compliance Order, an eventual lawsuit and finally the content Decree that resolved the differences had an impact in the relationship between EPEC and NMED. The relationship between EPEC and NMED management was not entirely

amiable especially in regards to the interpretation of air permit allowables. A series of poor results during inspections by NMED had exacerbated the problem. Through a series of administrative errors, the relationship between EPEC and NMED deteriorated to the extent that the Compliance Order was issued and a lawsuit by NMED was initiated. When the condition reached the stage when only lawyers (both from EPEC and from NMED) were the only ones negotiating, EPEC was obligated to pay a fine of $525,000. The settlement contained both a monetary settlement and a requirement for repairs in EPEC's Rio Grande Plant.

4.3.4 Case Study #3 Benefits

The benefits obtained through this analysis include:

- Correcting those permit conditions that had contributed to an excessive volume of exceedance in carbon monoxide. This was accomplished by avoiding conditions of non-compliance due to regulations based on averages and not conducive to the required method of plant operations
- Providing plant personnel additional operational flexibility for the use of the turbines in order to help meet customer demand for electricity.
- Avoiding payment of hefty penalties and fines due to non-compliance
- Reducing administrative headaches for the plant management and environmental engineers due to have to deal with answering instances of non-compliance
- Demonstrating to the regulatory agency involved that past exceedances were not due to sloppy operations.
- Offering an excellent example to future engineers as to how to approach problems of this nature and continue reaping the benefits of a well-written air permit.

4.4 – General Discussion on Case Studies

The case studies discussed above are very specific in their application of secondary analysis and are limited to utilities concerning energy transmission in one form or another. Their commonality, however, is that they address very real engineering/business problems and issues that involve a great deal of money either spent or saved. Additionally, the case studies presented allow for a methodology transference to other problems that present an economic consideration to operations. The economic impact of these problems make them highly visible and important. Utilizing the data mining techniques in conjunction with application operational knowledge allows these problems to be solved in a straightforward and hugely effective manner thereby providing defensible justification for research in this arena.

Operational problems that are highly visible and of significant cost can be caused by poorly written air permit applications that detract from effective operations and can cause unwanted penalties and fines. In addressing these problems, an ample supply of resources needed for the solution can often be available. A solution to the above problem can be made feasible using the plant monitoring equipment and data captured which are already required by regulations. This equipment could already be in operation due to the need to comply with existing permit conditions thereby negating the need for additional large capital investments and expenditures. The training needed to implement the methodology and associated Information Technology resources should not be a deterrent, as graduate engineers and scientists should have sufficient proficiency with the type of software that is needed for analysis.

For the reasons given above, it is evident that secondary analysis of large industrial data sets can provide significant economical and operational benefits to industry.

4.4.1 Results

The results representing the three case studies demonstrate emphatically how an operative solution to a difficult problem might be developed and show almost incontrovertible results representing significant economical and operational benefits. In all three cases, the methodology utilized data and information that had been quality controlled, quality assured and accepted by the respective regulatory agencies to formulate the foundational premises. The data used by the case studies was data generated in the normal day-to-day operations. This data was used in official state and federal reports submitted by the owning parties. Using a robust foundation of this quality and the correlation of the data to actual operational behaviors with secondary analysis yields results that possess a high degree acceptability and a high likelihood of being approved by regulatory agencies.

FIGURE 4.19: SUCCESSFUL RESULTS

4.4.2 Continued Application in Analogous or Related Industries: A Broader Impact

Given the wide range of applicability that these case studies have demonstrated, it follows that this methodology has broad transferability to other areas. Therefore, the methodology is not only applicable to issues involving air quality permits, but also to other related industries dealing with regulatory agencies or markets. Both Texas and New Mexico environment departments that issue air quality permits have accepted this approach in permitting actions. This economically

attractive approach has been proven operationally valid. It therefore presents itself as a viable methodology that is applicable to other industries. The value of this application is enhanced when the data in use has already undergone a valid QA/QC process as this quality aids in the acceptance of the data by a permitting agency.

Chapter 5: Conclusion

5.1 – Obfuscation in the Approach to the Solution

Sometimes it is possible to overcomplicate the approach to a problem by subscribing to the rationale that innumerable resources are best in obtaining a solution and ensure success. This might sometimes be true especially when the problem is new or difficult to define clearly. However, this is not always the case. An approach that deserves consideration in addressing this type of problem should simply be to follows the rule of using the right size tool for the job. When the tool has insufficient facility to deal with the problem, obviously the solution will be inadequate to a certain degree. On the other hand, when the tool or the amount of resources concentrated on a problem are in excess, they can also get in the way, cause the solution to be less than adequate, ineffectual and expensive.

The point to be made here is that when it is likely that the data in an industrial data set might be useful in helping to solve the problem, it follows that secondary analysis, as presented in the framework, should be considered as a methodology. The benefit to this approach is that time, money and the results could be optimized with excellent results.

A large number of data mining applications do require dedicated resources in terms of both equipment and personnel. Large retail vendors such as Target have teams of computer science experts, data mining programmers and analysts looking at data to understand market trends and prepare marketing offers to prospective buyers based on their shopping habits captured in big data. (Duhigg, 2014). In those instances, huge resources are justified. Those resources will be required on an ongoing basis because the marketing plans are not specific just to one location for a one-time basis. However, some inquiries of big data that can be answered in a more direct and simpler manner. This is true especially if the question is a one-time occurrence. Good examples include

the questions that might come up when preparing a permit application where once the permit is issued, then the question has been answered until the next time the permit is re-issued as an alteration or amendment. In addition, air quality permitting generally applies to an individual unit or an individual plant and not to numerous plants where the data keeps changing and the same question needs to be answered again due to the change in data.

5.2 – Using an Industry Mindset towards Problem Solving

Working in industry, often an appreciation is developed for the must-do, can-do attitude that is required in resolving a problem. The deadline looming at the end of the day or the need for operations not to be mired by some distraction encourages quick solutions to a given problem. Given that sometimes those solutions may not be optimal or robust, the overriding concern is that some solution (any solution) be put in place so that operations continue. While the immediate problem might be resolved, albeit temporarily, this environment does little to allow focusing on the root of the problem and solving the real problem. The following cartoon brings this point to light in a manner that we can understand. It depicts a theoretical spill that is causing unmitigated pollution and then shows how the problem is fixed and the pollution is contained. The only problem with how the pollution is contained is that the real source of the problem and therefore the true problem is not addressed properly. This is a good example of how "just keeping operations continuing" can lead to solutions that are less than good quality.

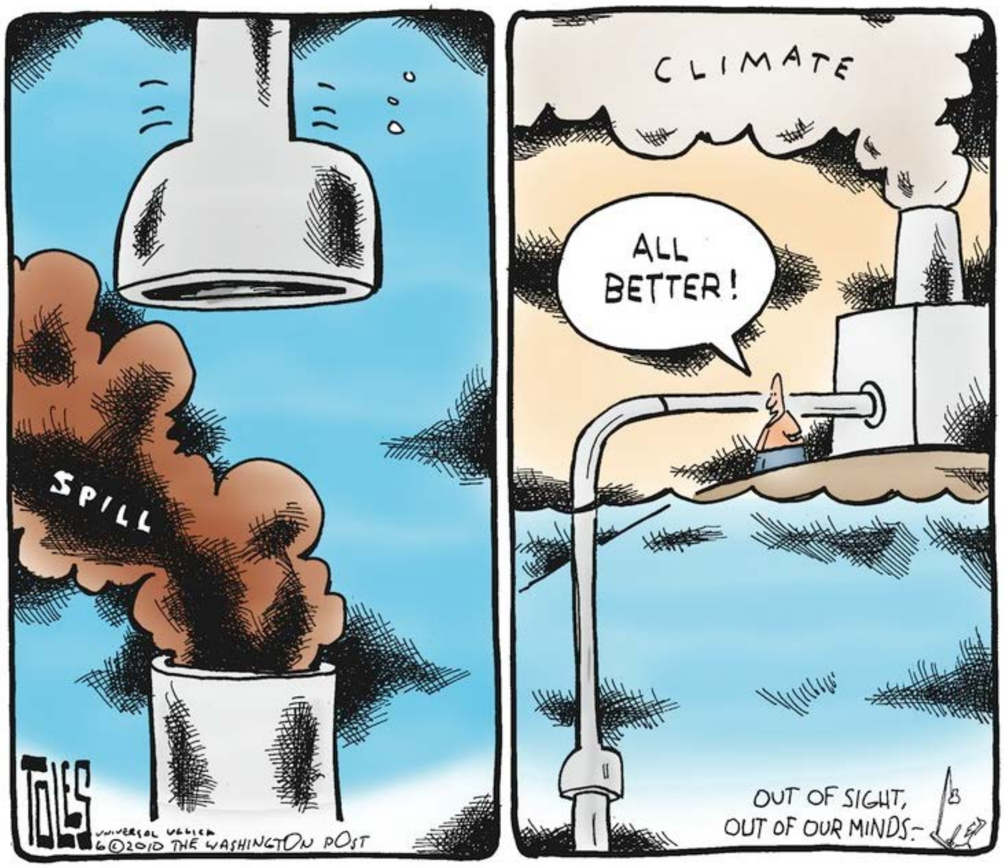

FIGURE 5.1: ONE APPROACH TO HANDLING A SPILL

Focused, concentrated thinking is needed and is desirable in order to look beneath the surface and really understand the root of the problem. In doing so, the selection of the appropriate data resources required to build the right-sized tool for the job is made easier. Once the problem is well thought out, the problem sized up, and the resources surmised, then the basic ingredients are at hand to begin working towards a solution.

Therefore, because the framework described for secondary analysis requires focused, concentrated thinking, significant economic and operational benefits are available to industry utilizing secondary analysis of large data sets by better use of the data already collected for compliance of environmental regulations. The straightforwardness and elegance of the

methodology presented here offer a very attractive means by which some very difficult issues can be addressed in a very economical and effective manner.

5.3 – Characteristics of Method

The range of characteristics that describe this methodology on analyzing a problem is contained in a list of twelve items. Those items delineate the individual contributions that add to the strength of this approach. For clarity, a definition of each characteristic is provided below as it applies to this work. In addition, four aspects, Demonstrated Success, Implementation Properties, Cost Effectiveness, and Relevance, help summarize which characteristics are contained in each of the four respective aspects. Those four aspects are discussed below.

Demonstrated Success: This aspect speaks to the level of success that this methodology achieves and those characteristics that contribute to a successful product. Although all characteristics listed could be counted as contributing to this aspect, the characteristics attributed to Demonstrated Success are those that only directly affected the outcome of the three case studies presented. Other characteristics provide positive offerings that could be valuable in other situations such as in a comparison of other proposed methods of analysis but not all characteristics are listed in the aspect for Demonstrated Success nor in other aspects if not directly contributing.

Implementation Properties: This aspect relates to those characteristics relevant to implementation and performance of the analysis. These characteristics are valuable to know for getting the work accomplished. This is true especially if a transference of this approach is attempted across different industries.

Cost Effectiveness: As with any project, financial considerations are important. Cost effectiveness describes those characteristics of secondary analysis, as described in the framework, that contribute in this manner.

Relevance: Just opposite of cost effectiveness where metrics are very easy to apply in measuring the contribution of a characteristic, relevance describes those characteristics that are intangible and less given to easy measurements. They, however, provide an enormous value in the overall effectiveness of this methodology and are very much a part of the full evaluation and overall positive contribution.

The twelve characteristics describing the functionality of the methodology for secondary analysis are defined as follows.

- Adaptability to Various Industries - The framework used in the application of this methodology allows the user to develop the solution around the problem using the resources that relate to the issues being addressed and the specific industry owning the problem. This provides the framework the ability be transported to whatever the problem is, regardless of the industry. A standard set of resources that always apply is not already pre-determined because those resources will be defined by the objective of the analysis. This characteristic allows for transportability among various industries. The basis for analysis however, is that there exists a data set that describes operations on a continuous basis from which operational behaviors can be extracted.
- Flexibility in Answering Questions – The ability to select the different resources applicable to the question being answered lends itself to addressing any number of questions. The analysis itself will define how well the answer is contained within the dataset. A visual examination will quickly reveal patterns of data behavior that are relevant. For example, if the analysis is looking for anomalies, those anomalies will be readily apparent or it is quite possible that the data show that there are anomalies do not

exist within the dataset being analyzed. This result then prompts the researcher to look at other resources as the possible source of irregularities.

- Standalone or Adapts to Other Resources – The framework allows the researcher to utilize whatever resources apply to the question being answered. This means those resources could include simply the industrial data set or a combination of other resources. It is possible to derive a complete solution or also a partial solution using the industrial dataset. A partial solution then can be applied to another resource such as a document (permit, vendor guarantee, regulation, etc.)

- Successful Business Applications – A very useful characteristic is one where the application has been successfully applied to a business requirement and shown to be of value. The complete contribution then is not only providing a technical advantage but also aiding in a business sense.

- Economical - Low Cost – The financial aspect of this methodology is described by this characteristic. The low cost of implementation of this methodology presents a very attractive financial alternative to costly alternatives.

- Ease of Implementation – Given that the researcher has a basic proficiency with software that is able to work with data sets, the implementation of the methodology is relatively easy to implement. Software such as SAS, Excel, Access, etc. are normally sufficient without having to write custom code.

- Rapid implementation – Using a graphical representation in the analysis assists in greatly decreasing the time to observe the behaviors of the data that will indicate how the analysis is proceeding. The longest period is usually just in the preparation of the data but once that is completed, the solutions come forth quickly.

- Method Accepted by Regulatory Agencies – Critical to any solution that might be arrived at is the need to have it accepted and approved by the respective agency. The framework presented here describes the methodology that has been accepted by two state environmental agencies, New Mexico and Texas.

- Results Accepted by Operations – Regardless of how elegant a proposed solution might appear, the proposed solution has a much better probability of being implemented successfully if it has the support of operations. One of the major benefits of this methodology is that not only does the process use operational data but also it allows the opportunity to maximize operational flexibility as part of the solution. This is especially true if operational flexibility is one of the targeted results of the analysis from the beginning. Operational flexibility makes the operations job easier so getting high marks from operations is inherent to this methodology.

- Visual - Results Easy to Understand – Because current operational data is a main ingredient in this process, then interpretation of the graphical results is very easy by anyone familiar with the operational environment. Management, engineers and operators all relate very well with the environment that they work in and until a change is made that causes the data to change, very little argument can stand up to what is literally being displayed by current data.

- Based on Actual Data – In lieu of basing the analysis on anything other than the data, such as regulations, product manuals or vendor guarantees, current (or even historical data if needed) the methodology generates results that stand up to scrutiny at by regulatory agencies.

- Adopts well to Operational Requirements – Because the methodology is based on operational data, results generated by the methodology are naturally coincident with values representative of operations. In other words, solutions will not offer values that are outside the scope of normal operating boundaries because values used in the analyses will always be within the normal operational constraints. This is especially true once the data has been through the QA/QC process.

A helpful summary of the twelve characteristics and their respective aspects are shown below. Several characteristics apply to more than one aspect and the property is shown.

Summary of Characteristics				
	Demonstrated Success	Implementation Properties	Cost Effectiveness	Relevance
Adaptability to Various Industries		√	√	√
Flexibility in Answering Questions		√	√	√
Standalone or Adapts to Other Resources	√	√		
Successful Business Applications	√	√	√	√
Economical - Low Cost	√		√	√
Ease of Implementation	√	√	√	√
Rapid implementation	√	√	√	
Method Accepted by Regulatory Agencies	√	√		√
Results Accepted by Operations	√	√		√
Visual - Results Easy to Understand	√	√	√	√
Based on Actual Data		√	√	√
Adapts Well to Operational Requirements		√	√	√

FIGURE 5.2: SUMMARY OF FRAMEWORK CHARACTERISTICS

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Glossary

The following is a compilation of terms that are used in the above narrative and are defined here for convenience.

CO – Carbon Monoxide

Distributed System – Following the advent of main frames and before the proliferation of Mini-computers, the major computer vendors such as IBM offered what was known as “distributed systems” because the databases resided on more than one computer instead of a single mainframe.

Newman Plant – An electric generating operated by El Paso Electric Company

NMED – New Mexico Environment Department

NOX – Oxides of nitrogen

QA/QC – Quality Assured and Quality Control designation is applied to data that has been reviewed and prepared in a manner where questionable data is corrected according to federal guidelines so as to present a defensible set of data that can stand up to scrutiny.

Secondary Analysis - The in-depth analysis of relationships, trends, patterns or behaviors in a data set that are not obvious from a superficial examination of data but that can be very germane in the application of that data.

Rio Grande Plant - An electric generating operated by El Paso Electric Company

TCEQ – Texas Commission on Environmental Quality

Appendix 1 Statement of Basis - Narrative
NSR
Permit

Company: El Paso Electric
Company **Facility:** Rio Grande
Generating Station **Permit No(s)**:
1554M1
Tempo/IDEA ID No.: 122 - PRN201000001
Permit Writer: Cember Hardison

Fee Tracking

Tracking	**NSR tracking entries completed:** [x] Yes [] No
	NSR tracking page attached to front cover of permit folder: [x] Yes [] No
	Paid Invoice Attached: [] Yes [x] No
	Balance Due Invoice Attached: [x] Yes [] No
	Invoice Comments: 12,012.00 paid 11-9-10. $7280.00 paid for netting analysis. Paid in full.

Permit Review	**Date to Enforcement:** 12-3-10	**Inspector Reviewing:** Judy Fisher
	Date Enf. Review Completed: 12-10-10	**Date of Reply:** 12-10-10
	Date to Applicant: 12-3-10	**Date of Reply:** 12-13-10
	Date of Comments from EPA: N/A	**Date to EPA:** N/A
	Date of Hearing: 3-29-11	
	Date to Supervisor: 6-8-11	

1.0 **Plant Process Description:**

This facility is an electric power generating station located in Sunland Park, Doña Ana County, NM.

El Paso Electric (EPE) currently uses three dry bottom, wall fired natural gas steam boilers, 6, 7, and 8, to run three turbine generators driven by high pressure, superheated steam. Total electric power production from the boilers is 288 MW gross, and 245 MW annual average. A natural gas fueled simple cycle GE Energy turbine proposed in this application would be used to generate 95.3 MW for a total annual average of 340.3 MW from the entire facility.

Note Regarding PM Regulation Change: Effective January 1, 2011 the Environmental Protection Agency (EPA) implemented a regulation change that caused this application to be subject to further review for Prevention of Significant Deterioration (PSD) for TSP and PM2.5 and Nonattainment permitting for PM10.

EPA's regulation change required that the condensable fraction of particulate matter (PM) emissions be included to determine if a PSD or Nonattainment permit is required. In general, for this facility, a PSD major modification would occur if there was a net emissions increase that met or exceeded the following significance levels: 100 tpy CO, 40 tpy NOx, 40 tpy VOCs, 25

tpy TSP, and 10 tpy PM2.5. The modification would be subject to Nonattainment permitting if the net emissions increase met or exceeded 15 tpy for PM10.

Update Regarding PM Emissions: On February 11, 2011, EPE submitted revised TSP, PM10, and PM2.5 emissions estimates for Turbine GT-9 and a netting analysis to net out of PM2.5. This revision resulted in TSP and PM10 project emission rates below significance levels (25 tpy for TSP and 15 tpy for PM10) and a PM2.5 net emissions increase that is below its significance level of 10 tpy. The Air Quality Bureau approved this submittal. An updated draft permit, after consideration of EPE's comments, is available for review on AQB's website http://www.nmenv.state.nm.us/aqb/permit/ApplicationsPermitswithPublicInterest.htm. Also, on February 16, 2011, copies of the revised emissions estimates, the netting analysis, and updated application tables were sent to the 4 locations where AQB had previously sent copies of the EPE application and include La Casita, the Sunland Park Library, the San Martin de Porres Catholic Church, and the NMED Las Cruces District office.

NSR Applicability to Boilers 6, 7, and 8 and their Cooling Towers: These units were constructed before promulgation of the NSR regulations (20.2.72, 20.2.74. and 20.2.79 NMAC) in 1972 and so are not subject to NSR except for certain specific conditions that apply to Boilers 6 and 8 necessary to comply with this NSR permit. Specifically, Boiler 8 requires limits on the pound per hour NOx emissions to comply with NM and National NO_2 Ambient Air Quality Standards (AAQS). Boiler 6 requires a limit on actual PM2.5 tpy emissions so that the modification to add a turbine is not subject to PM2.5 PSD (20.2.74 NMAC) permitting. The regulatory requirements and emissions limits for Boilers 6, 7, 8 and their cooling towers, other than certain specific conditions and emissions limits required for this NSR permitting action, are enforced through their existing Title V permit No. P127- R1M1 (20.2.70 NMAC).

2.0 Description of Modifications and Revisions:

The permittee wants to construct a 95.3 MW natural gas fired simple cycle turbine used to generate electricity. The turbine would increase the annual average electric power production from 245 MW to a total annual average of 340.3 MW. This facility was constructed before 1972, before promulgation of the NSR regulation, and according to the permittee has not been modified until this project (addition of Turbine GT-9 and Cooling Tower CT-9). Therefore, this is the first NSR permit for this facility.

Project Modifications and Revisions Include:

- Construction of Unit GT-9, a 95.3 MW/142,576 hp natural gas fire simple cycle turbine, model GE LMS 100PA
- Installation of a selective catalytic reduction (SCR) system with associated ammonia system, ammonia tank, and fugitive ammonia emissions from the control device piping. The SCR would reduce turbine NOx emissions.
- Installation of an oxidation catalyst to reduce turbine CO and, at low loads, reduce VOC emissions
- Installation of Unit CT-9, a cooling tower for the new turbine

- Permit additional VOC fugitive emissions from fuel piping for the turbine, Unit FUG 9
- Boiler 8 – A NOx pph emission limit of 460.5 lb/hr for up to but no more than 7 hours per 24-hr period and a maximum 415.00 lb/hr for the rest of each 24 hour period (17 hrs per 24-hr period). These NOx pph limits were necessary to show compliance with ambient air quality standards.
- Boiler 6 – An actual reduction in annual PM2.5 emissions and federally enforceable limit on annual PM2.5 emissions of 2.0 tpy.

Revisions to the Existing Units (Boilers 6, 7, 8) Not Subject to NSR permit 1554M1:

NOTE: The TV renewal application No. P127R2 was submitted before this NSR application and includes the following revisions. The TV renewal permit may or may not be issued before the final decision is made on NSR permit 1554M1. Therefore, a summary of the changes reported in the TV renewal application are listed here for information. Based on the information provided by the applicant, these changes are not modifications as defined by 20.2.72.7.P NMAC.

- Removing 2nd and 3rd operating scenarios that allow the use of diesel fuel with sulfur of 0.05% and 0.26% respectively for Boilers 6, 7, and 8. The applicant is removing the option to use diesel fuel in the boilers which is currently allowed in the existing TV permit for a limited number of hours each year. Diesel has a higher total sulfur content than natural gas, so this reduces the allowable SOx emission rates from the boilers
- Boiler 8 - Adding a flue gas recirculation (FGR) control device to control NOx emissions from Boiler 8 to meet the 20.2.33 NMAC emission limit of 0.30 lb/MMbtu.
- Boiler 8 - Increasing the NOx pound per hour emission limit from 403.4 to 460.5 pph. The increase in pph emissions from 403.5 to 460.5 pph is not a modification since, according to the applicant, there is no increase in capacity and since the original emission limit was erroneously set at 403.4 pph rather than 460.5 pph. If NSR permit 1554M1 is issued, the NOx emissions from Boiler 8 will be limited to 415.0 pounds per hour (pph) for no less than 17 hrs/day and to 460.5 pph for no more than 7 hrs/day. EPE must meet these NOx limits to show compliance with NOx ambient air quality standards.
- Boilers 6, 7, & 8 - Increasing the 1-hr average pph CO emission limit (except unit 6) and removing the 3-hr average CO emission limit; and decreasing the CO ton per year (tpy) emission limit. Limiting short term emissions per hour, rather than over 3 hrs, is more appropriate to demonstrate compliance with Ambient Air Quality Standards. According to the applicant, the increase in 1-hr CO emissions are due to the type of Continuous Emissions Monitoring (CEMs), which is a dilution-extractive CO CEMs that dilutes stack emissions with ambient air and not due to a modification. According to the applicant, during winter months, the ambient CO increases due to the geography and weather patterns pulling in higher concentrations from increased open burning in Juarez and winter inversions keep the ambient CO from dispersing.
- Boiler 8 – Increasing the VOC tpy and PM10 pph and tpy emission limits. According to the applicant, limits are changing only due to a change in the method of estimating these emissions.

Incorporating requirements of Consent Decree D-101-CV-2008-02777 Filed 7-31-09

From Section V.21. of Consent Decree (decree applies only to Boilers 6, 7, & 8):

a. Annual tuning of the 3 boilers (6, 7, & 8) at the Rio Grande Generating Station as required by paragraph 1 (See specific tuning requirements in paragraph 1. Paragraph 1 also requires reporting average NOx (0.30 lb/MMbtu, hourly 3-hr rolling ave) and CO (pph, ave of CEMs data per hr) emissions before and after tuning;

b. Operation and maintenance of the Flue Gas Recirculation (FGR) system at the Unit 8 boiler, provided the FGR system is installed on unit 8 in accordance with paragraph 11 (FGR was approved and operating on July 8, 2010);

c. An averaging time [rolling ave.] of 3 hours for the 0.3 pound per million BTU maximum emission rate for NO2 set forth in Condition 3.1 of the existing operating Permit as provided in Paragraph 19; and

d. A precision of 2 significant figures for the 0.3 (0.30) pound per million BTU maximum emission rate for NO2 set forth in Condition 3.1 of the existing operating permit

Paragraph I of the Consent Decree also requires:

I.B.3. Proper and efficient calibration of CEMs including installation of software so that the calibration periods are clearly indicated in data recorded by the system.

I.C.4. Using actual sulfur content data [in fuel], in accordance with 40 CFR 75, Appendix D, to calculate SO2 emissions for each unit (boiler).

3.0 <u>Emissions Estimates and Compliance</u>

Note Boilers 6, 7, and 8 and their cooling towers were constructed before promulgation of the NSR regulations (20.2.72, 20.2.74. and 20.2.79 NMAC) in 1972 and so are not subject to NSR except for certain specific conditions that apply to Boilers 6 and 8 necessary to comply with NSR permit 554M1.

Boiler NOx pound per hour (pph) and ton per year (tpy) emission limits were determined by converting the limit of 0.30 lb/MMbtu (20.2.33 NMAC limit) using their respective heat rate capacities (MMBtu/hr). Boiler 8 pph emissions used 0.30 lb/MMbtu x 1535 MMBtu/hr and ton per year (tpy) NOx emissions used 0.257 lb/MMbtu x 1345 annual average MMBtu/hr. The TV permit will require the permittee keep Boiler 8 heat rate capacity to 1535 MMbtu/hr maximum and 1345 MMbtu/hr annual average.

Boiler CO pph emission limits were determined using historical continuous emissions monitoring system (CEMS) data and tpy CO emissions were determined with EPA's AP42 1.4-1.

Boiler CO and NOx Compliance: The TV permit will require the permittee use CEMS to monitor NOx, CO, and CO2 from the boilers. 40 CFR 75 requires CEMs for NOx & CO2. Permittee must demonstrate compliance with both the lb/hr and tpy NOx and CO limits using the CEMS hourly emission data and actual number of hours operated over 12 months. NOx and CO start up and shut down emissions have historically been included in the facility emission limits.

Boiler PM and VOC Emission Limits & Compliance: Emissions were determined with EPA's current AP42 1.4-2. Applicant used Total PM emission factor (EF) from AP42 1.4-2 and set TSP = PM10 = PM2.5.

Boiler 6 PM Update: EPE chose to take a reduction in annual PM2.5 tpy emissions from Boiler 6 to net out of PSD permitting. This reduction was necessary to offset the increase in PM2.5 emissions from the addition of Turbine GT-9 and its cooling tower (CT-9). Actual PM2.5 emissions from Boiler
6 shall be measured using EPA method stack testing and Boiler 6's annual heat rate shall be measured with CEMS. The PM2.5 emission factor and heat rate will be used to calculate tpy PM2.5 emissions (MMBtu/yr x lb/MMBtu x 1/2000 lbs = tpy).

Boiler SO2 Emission Limits & Compliance: SO2 emissions for Boilers were determined using the gas analysis sulfur detection limit of 0.03 gr/100 scf plus a safety factor of 1.5 for pph emissions and
1.25 for tpy emissions. Natural gas analyses show non-detectible sulfur, so a safety factor was added to account for possible fluctuation. In the TV permit, the permittee will show compliance with SO2 emission limits for the Boilers by limiting total sulfur content in the fuel to 0.045 gr/100 scf of gas annually.

Boiler HAPs emissions were determined using California's AB2588 emission factors except for Hexane which used data from the Houston and Lighting Power Test report dated May 27, 1994. This test report is available at the EPA web address nepis.epa.gov/Exe/ZyPURL.cgi?Dockey=9100EWMJ.txt or can be found by searching EPA's National Service Center for Environmental Publications (NSCEP) website http://www.epa.gov/nscep/index.html. Boilers are not major for any HAPs and therefore, no maximum achievable control technologies (MACTS) that may be required by 40 CFR 63 apply.

Turbine NOx, CO, VOC, emissions are based upon manufacturer data. The manufacturer provided data for 20 operating conditions that varied ambient temperatures and load. For pound per hour (pph) emissions, the operating condition that created the worst case short term emissions was used which consisted of the lowest ambient operating temperature at 100% load. For ton per year (tpy) emissions, the operating condition using 100% load and the average ambient temperature was used.

Turbine Emissions Controls:

- NOx emissions are to be reduced using a selective catalytic reduction (SCR) system. The SCR will use a homogenous vanadia-titania base metal catalyst plus an ammonia (NH3) reductant (19% aqueous NH3) to convert NOx into nitrogen gas (N2) and water with about an 88.8% average control efficiency. The SCR system will emit NH3, called ammonia slip.
- CO emissions and VOC emissions at low loads are to be reduced with catalytic oxidization (called COR system by GE) made of precious metals with about a 77.5% control efficiency. Per GE, excess O2 in the flue gas and the catalyst are used to convert VOCs and CO to CO2 and water.
- Control of the SCR/COR systems will be by a programmable logic control (PLC) system.
- GE warrantees the SCR and COR catalysts for up to 3 years of operation based on 8760 hrs/yr, 26,280 total hours, or 3.25 years after catalyst delivery which ever comes first.

Turbine Start up and Shut Down NOx & CO:
From start up, until emissions compliance occurs takes no longer than 30 minutes. From time zero minutes (T0) to time ten minutes (T10) there is zero NOx control and from T10 to T29 there is an aggregate 50% NOx control. The selective catalytic reduction (SCR) system catalyst must be heated to 500-540 deg F before achieving permissive to inject ammonia into vaporizer, ammonia piping and AIG must be packed, then ammonia flow trimmed. This all takes 20 to 25 minutes. From T0 to T10 there is zero CO control and full CO control from 10 minutes on. CO catalytic oxidizer begins operating at ~500 deg F and is in full operation above 700 deg F. Manufacturer data showed VOC start up and shut down emissions equivalent to steady state VOC emissions. The CO and NOx pph emission limits reported in Table 2-E of the application include emissions during start up and shut down.

NOx Start Up Emissions determined as follows:

- 3.01 pounds NOx 7 minutes, per manufacturer start up data
- 15.03 pounds NOx 20 minutes rest of start up cycle. Used manufacturer worst case uncontrolled NOx w/ 44% control (81.07pph x (1-0.44) x (20 min/60 min))
- 4.9 pounds NOx 27 minutes steady state. Used manufacturer worst case controlled NOx emissions for 33 minutes (8.92 pph x 33min/60min).
- Total start up NOx for 1 hour: 3.01 + 15.03 + 4.9 = **22.9 pph NOx**

NOx Shut Down emissions:

- 0.44 pounds NOx 10 minutes. 3.97 pph manufacturer shut down data (3.97 pph x (100-88.8% control).

CO Start up Emissions determined as follows:

- 10.21 pounds CO for 7 minutes, per manufacturer start up data
- 7.56 pounds CO for 20 minutes remaining start up cycle. Used manufacturer worst case controlled CO emissions (22.69 pph x 20min/60min)
- 12.5 pounds CO for 33 minutes steady state. Used manufacturer worst case controlled CO emissions for rest of hour (22.68pph x 33 min/60 min)
- Total start up CO for 1 hour: 10.21 + 7.56 + 12.5 = **30.2 pph CO**

CO Shut Down emissions:
2.97 pounds CO 10 minutes. 13.21 pph x (100-77.5% control)

Annual NOx and CO Start up and Shut down Fraction:

Applicant requested one start up/shut down per day plus one additional per week for a total of 417 start up/shut downs per year. Actual operations may not require this many start ups.

- NOx Annual SU/SD: (18.04 lbs SU + 0.44 lbs SD) x 1ton/2000lb x 417 times/yr = 3.85 tons/yr
- CO Annual SU/SD: (17.77 lbs SU + 2.97 lb SD) x 1ton/2000lb x 417 times/yr = 4.33 tons/yr

Turbine NOx & CO compliance with both steady state and start up and shut down emissions will be shown using continuous emissions monitoring system (CEMS), initial EPA Method compliance tests, and periodic Relative Accuracy Test Audit (RATA) tests required by Acid Rain regulations (40 CFR75).

Turbine VOC compliance will be shown by demonstrating compliance with NOx and CO limits.

Turbine NH3 emissions (ammonia slip) & compliance: Ammonia emissions from the turbine's SCR are based upon manufacturer emissions guarantee. Excess ammonia slip can occur when catalyst temperatures are not optimum for chemical reaction and/or too much ammonia is injected. Therefore, compliance with NH3 pph and tpy emission limits will be met by operating the SCR system with optimal temperatures and ammonia injection according to manufacturer recommendations and monitored & recorded using the SCR/COR programmable logic control system (PLC).

TSP, PM10, and PM2.5 Revised Turbine Emissions: Turbine GT-9 manufacturer is GE Energy. Originally El Paso Electric used the GE Energy guarantee for total PM10 emissions at 5.9 lb/hr (5.5 pph from turbine + 0.4 pph from SCR & Cat Oxidizer) to set their TSP, PM10, and PM2.5 emission limits for Turbine GT-9.

To reduce TSP, PM10, and PM2.5 to below PSD and Nonattainment significance levels, EPE reported revised Turbine PM emission rates which are described further below. For additional details see EPE's
2-10-11 letter, Attachment A, and Attachment B. Copies of these documents were sent to La Casita, the Sunland Park Library, the San Martin de Porres Catholic Church, and the NMED Las Cruces District office.

GE's PM emissions guarantee was based on statistical analysis using the upper confidence level of 8
PM test results, rather than the average test results. To establish a lower PM emission rate, EPE's 2-
10-11 submittal reviewed test results from 20 in-stack PM tests (including the GE's 8 tests) for similar
units (simple cycle, aeroderivative-class turbines) and proposed lower PM emission limits for TurbineGT-9.

As a result, Turbine GT-9 TSP, PM10, and PM2.5 emission rates will be limited to 3.6 lb/hr and 14.48 tpy each. Actual PM emissions from the Turbine will be measured with EPA method stack testing and Turbine GT-9's annual heat rate shall be measured with CEMS.

Turbine SO2 emissions & compliance: SO2 emissions were determined using the gas analysis fuel sulfur detection limit plus a safety factor of 1.5 for pph emissions and 1.25 for tpy emissions. Natural gas analyses typically show non-detectible sulfur, therefore, the safety factor was added to account for possible fluctuations. However, GE Energy guaranteed total PM10 emissions of 5.9 lb/hr (5.5 pph from turbine + 0.4 pph from SCR & Cat Oxidizer) based on a sulfur content of no more than 0.25 gr/100 scf in fuel. Therefore, fuel sulfur must be limited to the lower rate of 0.25 gr/100 scf rather than
0.45 gr/100 scf annual
average.

Turbine HAPs emissions were determined using EPA's AP42 3.1-3. No individual HAP or the sum of HAPs are major, therefore, no MACTs from 40 CFR 63 are required.

All cooling tower Particulate Matter (PM) emissions were determined using EPA's AP42 13.4 for TSP and the Frisbee Paper for PM10 and PM2.5. Chlorine is added as a biocide to the cooling towers and results in a HAP byproduct, hydrochloric acid (HCl). HCl emissions from the boiler & turbine cooling towers are insignificant and are not subject to 40 CFR 63. Permit 1554M1 will include operating conditions for the turbine's cooling tower to include monitoring water circulation rate (gpm) and water TDS (ppmw) to ensure that PM emission limits are met.

4.0 <u>Source Determination:</u>

1. The emission sources evaluated by the applicant are the sources listed in regulated equipment Table
2-A and exempt equipment
Table 2-B.

2. Single Source Analysis: Do surrounding or associated sources belong to the same industrial grouping (i.e., same two-digit SIC code grouping, or support activity)? **No. EPE did not indicate that there are any surrounding or associated sources.**

Common Ownership or Control: Are the surrounding or associated facilities under common ownership or control? **No**

Contiguous or Adjacent: Are the surrounding or associated facilities located on one or more contiguous or adjacent properties? **No**

3. Is the source, as described in the application, the entire source for 20.2.70, 20.2.72, or 20.2.74 NMAC applicability purposes? **Yes**

5.0 PSD and Nonattainment Applicability

A. This is an existing PSD Major Source that has never undergone a PSD review. All pollutants in the area are in attainment, however PM10 emissions from the Source affects El Paso's PM10 Nonattinment area.

B. TSP, PM10, and PM2.5 emissions from Turbine GT-9 were re-evaluated and revised estimates submitted on 2-11-11 (see EPE document dated 2-10-11). Rather than using the manufacturer's guaranteed PM emission rate, EPE used a lower PM emission rate. This resulted in TSP and PM10 emissions being lower than PSD and Nonattainment significance levels, but with PM2.5 still above the PSD significance level.

Project Emissions from Addition of Turbine and Cooling Tower		
Pollutant	**Emission increase (tpy)**	**Significance Level (tpy)**
NOx	39.1	40.0
CO	94.1	100.0
VOC	9.2	40.0
SOx	0.36	40.0
TSP filterable + condensable [1]	15.88	25.0
PM10 filterable + condensable [1]	14.57	15.0
PM2.5 filterable + condensable [1]	14.48	10

C. Netting was required since the PM2.5 project emissions were significant (above 10 tpy). EPE chose to reduce Boiler 6 PM2.5 actual emissions to net out of PM2.5 PSD review. The net emissions increase is listed in the following table. The permittee "relied upon" the reduction in Boiler 6 PM2.5 emissions for this permitting action.

Net PM Emissions From Reduction Taken on Boiler 6		
Pollutant	**Emission increase (tpy)**	**Significance Level (tpy)**
TSP filterable + condensable [1]	11.19	25.0
PM10 filterable + condensable [1]	9.87	15.0

PM2.5 filterable + condensable [1]	9.80	10

1. From FR Vol. 73, NO. 96, May 16, 2008, page 28334 - Prevention of Significant Deterioration and NA NSR permits issued after the effective date of this NSR implementation rule but before the end of EPA's transition period for the NSR program are not required to account for condensable emissions in PM2.5 or PM10 emissions limits. **After January 1, 2011** (or any earlier date established in the upcoming rulemaking codifying test methods) EPA will require that NSR permitees include limits of condensable emissions, as appropriate. EPA established the transition period to among other items, allow time to promulgate revised EPA test methods for condensable PM (Test 202) and fine particulate matter (PM2.5) (Test 201A). AQB has required permittees to include the condensable fraction (if estimation method is available) to be reported and included in air dispersion modeling to demonstrate compliance with ambient air quality standards, but followed EPA's transition criteria to exclude condensables in PSD and Nonattainment applicability.

D. Neither BACT (PSD) nor LAER (Nonattainment) are required for this modification since the modification caused neither a significant nor a net significant emissions increase.

E. Federally Enforceable Permit Limits to Comply with PSD & Nonattainment:

Unit No.	TPY TSP/PM10/PM2.5	TPY NOx	TPY CO
Boiler 6	[b] 2.0	n/a	n/a
Turbine GT-9	[a, b] 14.48	[c] 39.1	[c] 94.1

a. Limits proposed by EPE to avoid TSP and PM2.5 PSD and PM10 Nonattainment
b. Limit proposed by EPE to avoid PM2.5 PSD. EPE first lowered project PM2.5 emissions from the turbine and then took an additional net PM2.5 decrease from Boiler 6.
c. EPE installed NOx and CO emissions controls and took annual emission limits to avoid PSD permitting.

NOx and CO Emissions Turbine 9:

- EPE will monitor and record NOx and CO lb/hr emissions and operating hours with CEMS. From that information, they will calculate their annual NOx and CO tpy emissions to ensure that they stay below the permitted emission limits and PSD significance levels. These limits are federally
  result in the modification to add the Turbine being subject to PSD review.

Annual PM Emissions Boiler 6 & Turbine GT-9:

- For Turbine GT-9, TSP, PM10, and PM2.5 tpy emissions will be limited to 14.48 tpy each.
- For Boiler 6, PM2.5 tpy emissions will be limited to 2.0 tpy.
- Meeting or exceeding the Turbine GT-9 or Boiler 6 PM emission limits could result in the addition of Turbine GT-9 and Cooling Tower CT-9 being subject to Nonattainment (20.2.79 NMAC) and/or PSD (20.2.74 NMAC) permitting.
- Filterable TSP (Method 5), filterable PM10 and PM2.5 (Method 201A), and condensable PM (Method 202) will be measured during stack testing. Filterable and condensable PM for each fraction will be combined to determine total TSP, PM10, and PM2.5 emissions. Condensable particulate matter is assumed to be 2.5 microns in diameter or less (PM2.5) (75 FR 80135 (12-21-

10). Heat rate in MMBtu/hr will be measured using CEMS during each test.

- Heat rate MMBtu/hr and corresponding lb/hr test results will be used to determine a lb/MMBtu emission factor (lb/hr x hr/MMBtu = lb/MMBtu).
- The heat rate of Boiler 6 and Turbine GT-9 will be monitored and recorded with CEMS. Monthly totals will be summed (MMBtu/mo), and then rolled into a monthly, 12-month total heat rate (MMBtu/yr).
- EPE will use the actual heat rate (monitoring by CEMS) and actual PM emission factor (measured through stack testing) to determine monthly PM emission rates for Turbine GT-9 and Boiler 6 (lb/MMBtu x MMBtu/mo = ton/mo PM. Each ton/month PM emission rate will be summed into a rolling 12-month total of PM emissions (or a running total of ton per year PM emissions).

Turbine GT-9: EPE chose to take TSP, PM10, and PM2.5 tpy emission limits for Turbine GT-9 using emission rates below that guaranteed by the manufacturer in order to avoid PSD permitting for TSP and PM2.5 and Nonattainment permitting for PM10. To ensure potential PM emission rates are met, the permit must require federally enforceable permit conditions to limit PM emissions (20.2.72.210.A;
210.B(1)(a),(b); 210.C(4); 208.A, 208.F NMAC; and 20.2.74.7.AN
NMAC).

Boiler 6 PM: EPE chose to take a reduction in annual PM2.5 tpy emissions on Boiler 6 to net out of PSD permitting. Without this reduction, PM2.5 emission rates from Turbine GT-9 are significant. EPE estimated the reduction in annual PM2.5 emissions from Boiler 6 using a heat rate of 547,930.0
MMBtu and AP42 1.4-2 PM emission factor of 7.6 lb/MMBtu (547,932.0 MMBtu/yr x 7.6 lb/MMBtu x 1/2000 lbs = 2.0 tpy). To meet the requirements of 20.2.74 NMAC, this reduction in annual PM2.5 emissions must be creditable and contemporaneous. To be creditable, the reduction must be an <u>actual</u> reduction in PM2.5 emissions from Boiler 6 (20.2.74.7.AL(6) NMAC) since there are currently no allowable PM2.5 emission limits for Boiler 6, and must be enforceable as a practical matter at and after the time that actual construction on the particular change begins (20.2.74.7.AL(6)(b) NMAC). To ensure that the reduction in PM2.5 emissions is creditable, actual PM2.5 emissions will be determined through stack testing and actual heat rate through CEMS monitoring. To ensure that the reduction was contemporaneous, EPE agreed to take an effective date on Boiler 6's annual PM2.5 emissions reduction beginning 30 days before first firing of Turbine GT-9 (20.2.74.AL(2) NMAC). the current active NSR and Title V permits that have not been superseded.

Permit Number	Issue Date	Action Type	Description of Action (Changes)

*1554-M1	6-9-11	NSR Permit, minor 20.2.72	First NSR permit issued. Facility was constructed before 1972, before promulgation of the NSR regulation, and had not been modified until the addition of this turbine. Therefore, this is the first NSR permit for this facility. **Facility modifications include:** Construct Unit GT-9, a 95.3 MW/142,576 hp natural gas fire simple cycle turbine, model GE LMS 100PA; add a cooling tower (unit CT-9) and selective catalytic reduction (SCR) system with associated ammonia system, ammonia tank, and fugitive ammonia emissions from the control device piping. Turbine CO and VOC emissions will also be controlled with an oxidation catalyst. VOC fugitive emissions will also be added from fuel piping for the turbine, Unit FUG 9 **PSD/Nonattainment:** To avoid PSD and Nonattainment permitting, EPE took federally enforceable emission limits on Turbine GT-9 on NOx, CO, TSP, PM10, and PM2.5 tpy emissions. To avoid PM2.5 PSD permitting, EPE chose to net out by reducing actual PM2.5 emissions from Boiler 6. **Total Facility Emissions:** NOx 3130.1 tpy, CO 1108.1
*P127-A-R2	Pending	Acid Rain Renewal	Acid Rain Renewal. No modifications.
*P127-R2	Pending	TV Renewal	**Revisions to Boilers and Cooling towers:** Remove 2nd and 3rd operating scenarios that allow diesel fuel with sulfur of 0.05% and 0.26; add induced flue gas recirculation (FGR) to reduce Boiler 8 NOx; increase Boiler 8 NOx pph limit from a 403.4 pph (3-hr average) to a maximum of 460.5 pounds per hour; reduce Boiler 8 NOx tpy limits from 1767 to 1514 tpy; increase Boiler 8 PM emissions; increase Boiler 7 and 8 CO pph emissions and remove 3-hr ave pph limits; decrease Boiler 6, 7, and 8 CO tpy limits;

Permit Number	Issue Date	Action Type	Description of Action (Changes)

D-101 CV-2008-02777	7-31-09	Consent Decree	Consent Decree D-101 CV-2008-02777 for NOV ELP-0122-0501 for violating CO, NOx, and SO2 emissions limits. Corrective Actions: tune each boiler at the Rio Grande Generating Station annually; report performance of tuning and the before and after tuning NOx lb/mmbtu and CO pph emissions; conduct CEMs calibrations, install software that records the calibrations, and submit verification of such in 30 days; monitor sulfur dioxide using actual sulfur content data in accordance with 40 CFR 75, Appendix D to calculate SO2 emissions and notify of such within 30 days; install flue gas recirculation (FGR) on boiler 8 (EPN-1). Implementation of Permit Conditions: maximum allowable NO2 emission rate (20.2.33 NMAC 0.3 lb/mmbtu) for each boiler 6, 7, & 8 shall be interpreted as having an averaging time of 3 hours and shall be interpreted as having 2 significant figures (0.30 lb/mmbtu – vs – 0.3 lb/mmbtu). Integration with Permit - submit application in 180 days to incorporate the following conditions: annual tuning of 3 boilers as required by section 1 of consent
P127R1M1	6-6-08	TV administrative Revision	Change responsible official to Mr. Andres Ramirez.
P127-A-R1	9-22-05	TV Renewal	Issued 5 year T-IV permit for Boiler Units 6, 7, and 8 with 40 CFR 72.9(c)(1) allowances and ORIS code 2444.
P127R1	9-22-05	TV Renewal	Scenario 1 (natural gas): **NOx 3342.4 tpy, CO 3504.0 tpy, VOC 19.8 tpy, SOx 29.1 tpy, PM10 8.7 tpy, Chlorine 4.1 tpy, formaldehyde 1.1 tpy, and hexane 19.9 tpy.** Scenario 2/3 (diesel): NOx 3343.2 tpy, CO 3777.8 tpy, VOC 21.6 tpy, SOx 227.4 tpy, PM10 17.8 tpy, Chlorine 4.1 tpy. Permitted Units 6, 7, and 8. Number 2 diesel fuel is available for backup fuel in the event of a gas supply curtailment.
P127M1-Rev	8-31-05	TV Revision	Scenario 1 (natural gas): **NOx 3343.7 tpy, CO 3504.0 tpy, VOC 60.4 tpy, SOx 6.7 tpy, TSP 83.4 tpy, Chlorine 4.1 tpy.** Scenario 2 (diesel): NOx 3376.2 tpy, CO 3536.9 tpy, VOC 61.1 tpy, SOx 546.8 tpy, TSP 135.7 tpy, Chlorine 4.1 tpy.
Permit Number	**Issue Date**	**Action Type**	**Description of Action (Changes)**

P127M1	6-16-03	TV reopening	Scenario 1: **NOx 3343.7 tpy, CO 3504.0 tpy, SOx 6.7 tpy, TSP 83.4 tpy, VOC 60.4 tpy, and Chlorine 4.1 tpy.** Scenario 2: NOx 3376.8 tpy, CO 3536.9 tpy, SOx 546.8 tpy, TSP 135.7 tpy, VOC 61.1 tpy, and Chlorine 4.1 tpy. Adjust emissions limits to "more accurately reflect" the potential to emit for the 2 operating scenarios. Permitted Units 6, 7, and 8.
P127	1-27-00	New TV	NSR and PSD "Grandfathered" Facility. **Both scenarios: NOx 3,672.9 tpy, CO 21,900.0, SOx 651.8 tpy, TSP 107.9 tpy, VOC 23.0 tpy, and Chlorine 4.1 tpy.** Permitted Units 6, 7, and 8, Babcock and Wilcox boilers that can use either natural gas or diesel as fuel. This facility is an electric power generation station operated by three dry bottom, wall-fired gas steam boilers. There are three turbine generator units driven by high pressure, superheated steam. Total electric power production of the facility from these three generators is **288 MW gross, and 261 MW net.** The primary fuel used at this facility is pipeline quality natural gas. Number 2 diesel oil is available for use as a back-up fuel in the event of gas supply curtailment.
1554	5-28-98	New NSR permit - denied	NSR permit application closed/denied effective 5-28-98. NSR permit application submitted 6-94 to install lo-NOx burners on Unit 8 to meet state limit of 0.3 lb/MMBtu. Unit 8 has always had to run at reduced capacity to meet state emission regulation for gas fired equipment. Application ruled complete 5-28-97 and denied effective 5-28-98.
P127A	12-12-97	New Acid Rain Permit	Effective 1-1-00 to 12-31-04. Permitted Units 6, 7, and 8 with SO2 allowances.
No permit number	4-21-97	Letter of understanding	Letter of understanding between NMED and El Paso Electric Company to install low-NOx burners and **reduce capacity to 145 MW** on unit 8 to meet NOx emissions limit of 0.30 lb/MMBtu and comply with 20.2.33 NMAC. Installation of LNB and operating at reduced firing rate would "result in a net decrease in emissions of NO2 and CO and would not result in an increase in other air contaminants". It was understood that since the LNB and reduced firing rate would result in a decrease in emissions, that this modification to unit 8 would be exempt from 20.2.72. Permittee was to submit monthly reports of weekly averages of hourly NO2 emissions and corresponding MW output to NMED until permittee obtained an air permit for Unit 8 under 20.2.72 or 20.2.70.

7.0 Public Response/Concerns:

Hearing: Based upon the public response received as of November 29, 2010, the AQB recommended
to the Department Secretary that no hearing be held.

Between December 8 and 12, 2010, three additional letters and 62 signatures requesting a hearing were received after the hearing recommendation. AQB has since recommended a hearing with agreement of the Division Director.

A hearing occurred on March 29, 2011 in Sunland Park NM. All public notification requirements for this hearing met 20.20.1.4 NMAC. Additionally, about 200 hearing notifications were mailed or emailed to citizens and local government officials who are on an updated list of citizens associated with the Sunland Park area.

In addition to the applicant's public notice requirements in 20.2.72 NMAC, the applicant sent 172
English language public notice letters to Sunland Park citizens and government authorities on a list from the Camino Real Landfill hearing. No response from any of the applicant's public notice was received.

In addition to AQB's public notice requirements, the AQB contacted a Sunland Park citizen by phone, sent 172 public notice letters in Spanish and English to Sunland Park citizens and government officials, sent 116 notices of a community meeting using an updated address list of Sunland Park citizens and government officials, and held a community meeting on September 25, 2010 in Sunland Park. About 17 adults and 6 children attended the community meeting.

Verification of Applicant's Required Public Notice – the applicant has met all regulatory notification requirements as follows:
NOTE: Per New Mexico State's Office of General Council March 2002 interpretation, when a municipality, Indian Tribe,
or county is located outside of New Mexico, public notification is not required if outside of the state boundaries. This legal interpretation would also apply to property owned outside of New Mexico.
20.2.72.203.B(1)(a) Notified by certified mail all property owners found on the Doña Ana County property assessment records that are located within 100 feet of the facility's property boundary. Rio Grande Generating Station is located in Sunland Park city limits and has a population of more than 2500 persons.
20.2.72.203.B(2) Notified, by certified mail, municipalities, Counties, and Tribes located within 10 miles of the facility. The only County, New Mexico Municipalities, and Tribes within 10 miles are, Doña Ana County and Sunland Park. All other New Mexico communities, such as Santa Teresa and Canutillo, are either not incorporated municipalities, are greater than 10 miles from the property boundary, are located in the State of Texas, or are located in the Country of Mexico.
20.2.72.203.B(3) Published once in a newspaper of general circulation in the [New Mexico] county where the facility is located and should appear in the legal or classified section and in one other location of the newspaper to provide the most effective notice. Applicant published two English language ads in the El Paso Times and two Spanish language ads in the El Diario de El Paso.
20.2.72.203.B(4) The applicant certified that public notice was posted on June 15, 2010 at four publically accessible locations near the source including the facility entrance at Rio Grande Power Station Entrance, Sunland Park Community Library, Sunland Park City Hall, and US Post Office at 3500 McNutt Rd.
20.2.72.203.B(5) The applicant provided an email of the public service announcement request submitted to KGRT, a radio station in Las Cruces. The public notice content shown in the email met the requirements of 20.2.72.203.D.

**AQB
Public
Notice:**

20.2.72.206.A(1) On the AQB website, made available for public inspection a list of all pending permit applications.
20.2.72.206.A(2) Made available copies of the permit application and department's preliminary determination at both the
Department's Santa Fe office and Las Cruces
District office.
20.2.72.206.A(7) Mailed a copy of AQB's public notice on October 7, 2010 to the State of Texas since it is within 50 km of the facility.
20.2.72.206.A(3) Published both an English language and Spanish language public notice in the Las Cruces Sun News on October 10, 2010. The permit writer verified with the Las Cruces Sun News that there were subscribers and newspaper stands in Sunland Park. At the 9-25-10 community meeting, the permit writer stated the PN would probably be published in the El Paso Times, but AQB does not have a purchase order for El Paso Times so had to use the Las Cruces Sun News. **20.2.72.206.A(4)** Public notice was sent to individuals maintained on the department's list of individuals and organizations who have indicated in writing they would like to be notified of all permit applications.

20.2.72.206.A(3) and (5) Allowed citizens 30 days from the Departments public notice to comment on the application and inform citizens that if they have not submitted written comments during the first 30 day comment period that they will not be notified of when the Department's analysis is available and that they have 30 days to comments on the analysis.
20.2.72.206.B(1) Notified each person who expressed an interest in writing as required by 20.2.72.206.A(3) during the first
30 day comment period, that the Department's analysis
was available.
20.2.72.206.C AQB held a public hearing since the Department Secretary determined that there is significant public interest.
20.2.72.206.A(6) Once the permit is issued or denied, the AQB will mail written notice of the action taken on the permit application to any person who expressed interest in writing in the application.

8.0
Compliance Testing:

Unit No.	Compliance Tests Already Completed	Test Dates
Boilers 6, 7, 8	Relative Accuracy Testing Audit (RATA) Tests for NOx and CO2 CEMs as Required by 40 CFR 75, Appendix B Reference Methods found 40 CFR 75.22 Quality Assurance And Control Procedures 4 CFR 75.21	8-13-09
Boilers 6, 7, 8	SO2 RATA or QA/QC per 40 CFR 75.11(d)(2)	8-13-09
Boilers 6, 7, 8	CO CEMs QA/QC Test with EPA Methods 10 a Flow Rate Methods 1 to 4	8-13-09
Unit No.	**Compliance Tests Required in NSR permit 1554M1**	**Test Dates**

Turbine GT-9	Relative Accuracy Testing Audit (RATA) Tests for NOx and CO2 CEMS as Required by 40 CFR 75, Appendix B & NSPS KKKK Reference Methods found 40 CFR 75.22 Quality Assurance And Control Procedures 40 CFR 75.21	Within 180 days after first fuel firing (initial start up). At least Semiannually thereafter. Frequency may be reduced to annually based upon results of accuracy but never more than 8 calendar quarters apart. (Frequency in App B of Part 75, 2.3.1.1 and Figs 1 & 2)
Turbine GT-9	SO2 RATA or QA/QC per 40 CFR 75.11(d)(2)	Per 75.11(d)(2)
Turbine GT-9	Initial CO CEMS certification using 40 CFR 60, Appendix B and CO CEMS QA/QC (periodic Cylinder Gas Audits (CGAs)) using 40 CFR 60, Appendix F	Within 180 days after first fuel firing (initial start up). CO CGA periodic testing to be performed in conjunction with NOx RATA testing in accordance with 40
Turbine GT-9	NOx (Method 7E) and CO (Method 10) Initial compliance Tests	Within 180 days after first fuel firing (initial start up).
Turbine GT-9	TSP (Method 5) & PM10 and PM2.5 filterable fractions (Method 201A), PM2.5 Condensable fraction (Method 202)	Within 180 days after first fuel firing (initial start up).
Turbine GT-9	NOx method test per 40 CFR 60.4400, Subpart KKKK requirements.	Per 40 CFR 60.4400(a) and 40 CFR conduct initial performance tests and subsequent tests on an annual basis, no more than 14 calendar months following the previous test. Per 60.440(b)(5) the CEM performance evaluation (RATA) may be conducted as
Boiler 6	PM2.5 filterable fractions (Method 201A), PM2.5 Condensable fraction (Method 202)	Within 180 days after first fuel firing (initial start up).

9.0 <u>Startup and Shutdown:</u>

A. If applicable, did the applicant indicate that a startup, shutdown, and emergency operational plan was developed in accordance with 20.2.70.300.D(5)(g) NMAC? **Yes**

B. If applicable, did the applicant indicate that a malfunction, startup, or shutdown operational plan was developed in accordance with 20.2.72.203.A.5 NMAC? Not applicable. **Yes**

C. Did the applicant indicate that a startup, shutdown, and scheduled maintenance plan was developed and implemented in accordance with 20.2.7.14.A and B NMAC? **Yes**

D. Were emissions from startup, shutdown, and scheduled maintenance operations calculated and included in the emission tables? **Yes.** Start up and shut down emissions are included in the emission limits in Table 2-E for the boilers and turbine.

10.0 Modeling:

EPE's Modeling: El Paso Electric's modeling shows that ambient air quality standards for NOx, CO, TSP, PM10, PM2.5, and SO2 will be met. Ambient impacts of ammonia emissions (NH3) are less than 1/100th of the occupational exposure limit (OEL) in 20.2.72.502 NMAC. NH3 is a New Mexico TAP and if modeling shows that the 8-hour average ambient concentration of the toxic air pollutant exceeds 1/100th of its OEL, a health assessment is required. For NH3 the OEL is 18mg/m^3 and so 1/100 of the OEL is 0.18mg/m^3. The maximum impact of NH3 emissions from Rio Grande Generating Facility is 0.0286 mg/ m^3, therefore a health assessment is not required.

El Paso Electric modeled NOx, CO, TSP, PM10, PM2.5, and NH3 emissions. AQB determined that modeling SO2 emissions was not required to show compliance with SO2 standards as these emissions are less than 1 pph and were recently modeled at a much higher emission rate. Modeling included emissions from surrounding stationary sources in NM and Texas within 65 km of the facility and included background concentrations for NO2, CO, TSP, PM10, and PM2.5 for Doña Ana County.

AQB's Modeling: Sufi Mustafa of the Air Quality Bureau conducted an air dispersion modeling review and determined that EPE's modeling analysis demonstrates that operation of the facility described in the application neither causes nor contributes to any exceedances of applicable air quality standards. The standards relevant at this facility are NAAQS for CO, NO_2 , $PM_{2.5}$ and PM_{10}; NMAAQS for CO, NO_2 and TSP and Class I and Class II PSD increments for NO_2 and PM_{10}. The analyses also shows that ammonia concentrations will be below 1/100th (1%) of the Occupational Exposure Level (OEL) for ammonia. As part of AQB's review, all input values such as pound per hour emission rates and stack parameters that were used in air dispersion modeling are checked for accuracy.

11.0 State Regulatory Analysis Applicable to both NSR Only and TV Only Units (NMAC/AQCR):

20 NMAC	Title	Applies (Y/N)	C o
2.1	General Provisions	Y	The facility is subject to Title 20 Environmental Protection Chapter 2 Air Quality of the New Mexico Administrative Code so is subject to Part 1 General Provisions,

2.3	Ambient Air Quality Standards	Y	Facility must demonstrate compliance with state ambient
2.7	Excess Emissions	Y	Applies to all facility sources
2.18	Oil Burning Equipment – Particulate Matter	N	**Boilers 6 and 8 may no longer combust diesel fuel, therefore, this regulation no longer applies.** The
2.33	Gas Burning [external combustion] Equipment - Nitrogen Dioxide	Y	**Boilers 6, 7 and 8**
6/EPN-3, 610 MMBtu/hr, constructed 1-1-1957 **7/EPN-2,** 590 MMbtu/hr, constructed 1-1-1958 **8/EPN-1,** 1570 MMBtu/hr, constructed 1-10-1968 **20.2.33.7.A. Existing** (construction commenced or modification commenced before 2-17-72) Per applicant none of the units have been modified since construction and are defined as existing units. **20.2.33.108.B limits NO2 emissions per unit to =< 0.30 lb/MMbtu** of heat input from existing gas burning units with a heat input greater than 1,000,000 million British Thermal Units per year per unit. **Compliance Demonstration:** The permittee will demonstrate compliance with 20.2.33.108.B through			
2.34	Oil Burning Equipment - Nitrogen Dioxide	N	**Boiler 8 may no longer combust diesel fuel, therefore, this regulation no longer applies.** The permittee withdrew the diesel fuel option on
Boiler 8 was allowed to use diesel fuel up to 720 hr/yr (1570 MMBtu/hr x 720 hr/yr = 1,130,400 MMBtu/yr), so therefore, was subject to 20.2.34, but is no longer. **Boiler 6** was also allowed to burn diesel but was not subject because it was permitted to burn diesel for 876 hr/yr thereby limiting the annual heat input below the applicability threshold of 1,000,000			
2.61	Smoke and Visible Emissions	Y	**Boilers 6, 7, 8, and turbine GT-9** **20.2.61.109 limits opacity** from emissions stacks to 20%. **20.2.61.114 Opacity is determined** using
2.70	Operating Permits	Y	PTE **is** > 100 TPY. Source is TV major for NOx, CO,
2.71	Operating Permit Fees	Y	Source is subject to 20.2.70 NMAC as cited at
2.72	Construction Permits	Y	20.2.72.200.A(2) NMAC
2.73	NOI & Emissions Inventory Requirements	Y	Applicable to all facilities that require an NSR and/or a

20 NMAC	**Title**	**Applies (Y/N)**	**Com ment**

2.74	Permits-Prevention of Significant Deterioration	N	This source is PSD major (emissions over 100 tpy), but the modification to the facility does not require PSD review since there is no net emissions increase.
TSP and PM2.5 project emissions from addition of new turbine, cooling tower, and ancillary equipment were significant as of January 1, 2011 (20.2.74.502 NMAC) due to a rule change requiring inclusion of condensable PM. PM10 project emissions were also significant, but this would be subject to non-attainment permitting. On 2-10-11, the applicant revised TSP, PM10, and PM2.5 emission rates from Turbine GT-9 and requested limits on Boiler 6 to net out of PM2.5. According to the applicant, all units, before addition of turbine GT-9, were constructed before and have not been modified since the effective date of this NMAC (7-20-95) and the 1977 CAA Amendments when PSD was first implemented (40 CFR 52.21, 6-19-78). Source is listed in Table 1 of 20.2.74.501 and is a major source as defined in 20.2.74.7.AF(1) but has never undergone a PSD review. Any major modifications to this facility (as defined in 20.2.74.7.AD) will be subject to PSD review			
2.75	Construction Permit Fees	Y	Facility is subject to 20.2.72 NMAC so is subject to permit fees. Since it is a TV source, is not subject to NSR annual fees in accordance with 20.2.75.11.E an
2.77	New Source Performance	Y	Applies to any stationary source constructing or modifying and which is subject to the requirements
2.78	Emissions Standards for HAPs,	N	This regulation applies to all sources emitting hazardous air pollutants, which are subject to the requirements
2.79	Permits − Nonattainment Areas	N	As of January 1, 2011, PM10 project emissions were significant. However, on 2-10-11 the applicant revised PM10 emissions estimates from Turbine GT-9 and therefore, project emissions are no longer significant (over
Ozone Sunland Park: The facility is located in the Sunland Park ozone maintenance area which is not designated as an ozone non-attainment area. AQB Non-attainment Link. In March 2008 the ozone NAAQS was lowered from 0.08 ppm to 0.075 ppm so on 3-11-09, AQB submitted a recommendation to EPA to designate Sunland Park, NM (including the communities of Santa Teresa and La Union) Nonattainment for the 8-hr ozone standard. EPA postponed designation. On January 6, 2010, EPA recommended a more stringent 8-hr primary ozone standard of 0.060 – 0.070 ppm and a cumulative secondary standard of 7-15 ppm-hrs. EPA planned to finalize ozone NAAQS by the end of August, 2010. However, EPA postponed finalizing the air quality standards for Ozone to			

PM10 Moderate Non-Attainment Area in Anthony, New Mexico: Rio Grande Generating Station is not located in the Anthony area PM10 non-attainment area and ambient impacts do not affect this area, therefore

20 NMAC	Title	Applies (Y/N)	Comm ents
PM10 Moderate Non-Attainment Area in El Paso County, El Paso City, TX: As of January 1, 2011 PM10 project emissions were major since EPA promulgated a rule change that requires inclusion of condensable PM. Project PM10 emissions were 25.8 tpy which are greater than the significance level of 15 tpy in 20.2.79.7.AM(1). On 2-10-11, the permittee submitted revised emissions estimates from Turbine GT-9 resulting in less than significant emissions. The Rio Grande Generating Station is not located in El Paso City's PM10 non-attainment area, but the PM10 radius of impact of 3.2 km exceed those in 20.2.79.119.A and would impact the City of El Paso PM10 non-attainment area if this was a major modification (20.2.79.109.A(2)).			
2.80	Stack Heights	N	Boiler stacks were in existence before 1970, but air dispersion techniques were not used for basis of an emission limit. All stacks are currently less than 65 m
2.82	MACT Standards for Source Categories of HAPs.	N	This regulation applies to all sources emitting hazardous air pollutants, which are subject to the requirements of 40 CFR Part 63. This facility is not a major HAP source
2.84	Acid Rain Permits	Y	**Boilers 6, 7, 8 and turbine GT-9.** This facility is subject to Title IV of the federal act and federal acid
20.2.84.8 ADOPTION BY REFERENCE OF FEDERAL ACID RAIN PERMITTING REQUIREMENTS: Except as otherwise provided in 20.2.84.10 NMAC, the portions of the federal acid rain program promulgated by the United States environmental protection agency under 40 CFR Part 72 (including all portions of Parts 73, 74, 75, 77 and 78 referenced therein) and 76, and amended in the federal register through May 18, 2005, to implement Sections 407 (nitrogen oxides emission reduction program), 408 (permits and compliance plans) and 412 (monitoring, reporting and recordkeeping requirements) of the federal act, are hereby incorporated into this part. **20.2.84.10 MODIFICATIONS AND EXCEPTIONS:** The following modifications or exceptions are made to the incorporated federal rules: **A.** for purposes of this part, the term **"permitting authority" shall mean the**			
2.85	Mercury Emission Standards and Compliance Schedules for Electric Generating Units	N	This applies to electric power generation units that combust coal or coal-derived fuel. This facility does not combust coal or coal-derived fuel.

20 NMAC	Title	Applies (Y/N)	Comme nts

2.87	Greenhouse Gas Emissions (GHG) Reporting	N/A	**Regulation repealed November 10, 2010 and replaced with 20.2.300 Reporting of Greenhouse Gas Emissions NMAC. Change effective January 1, 2011. 20.2.300 does not yet include the most recent amendments to the federal rule.** **Under old 20.2.87: Boilers 6, 7, 8** emissions were previously reported. Permittee was required to determine if any trivial, insignificant activities, or any other sources may be subject to 20.2.87 2009 and 2010 GHG reporting years as the reporting requirements changed for the second (2009), third (2010) years.
2.300	Reporting of Greenhouse Gas Emissions – Effective Jan 1, 2011	Y	**Boilers 6, 7, 8, and Turbine GT-9 are subject** as electricity generation sources as defined by
First reporting will be for 2011 emissions: reports due by April 1 2012. 10,000 metric tons CO2e or more in combined emissions from all applicable source categories. (20.2.300.101.A & B) **“20.2.300.100 ADOPTION OF 40 CFR PART 98:** Except as otherwise provided, the following subparts of 40 CFR Part 98, as amended in the federal register through October 28, 2010 (75 FR 66434), are hereby incorporated by reference. **A.** 40 CFR Part 98 Subpart A - General Provisions, which includes Sections 98.1 through 98.8 and Tables A-1 through A-5 of Subpart A. **C.** 40 CFR Part 98 Subpart D - Electricity Generation, which includes Sections 98.40 through 98.48.” 20.2.300 <u>does not</u> incorporate 40 CFR 98 Mandatory Greenhouse Gas Reporting rule into the NM State SIP,			
2.89	Qualified Generating Facility Certification	N	This facility does not meet the definition of a qualified generating facility.

12.0 <u>Federal Regulatory Analysis For both NSR Only and TV Only Units:</u>

Air Programs Subchapter C (40 CFR 50)	**National Primary and Secondary Ambient Air Quality Standards**	**Applies (Y/N)**	**Comme nts**
C	Federal Ambient Air Quality Standards	Y	Defined as applicable at 20.2.70.7.E.11, Any

NSPS Subpart (40 CFR 60)	**Title**	**Applies (Y/N)**	**Comme nts**
A	General Provisions	N	Applies if any other subpart applies.
40 CFR Part 60, Appendix B	Performance Specification 4, 4A, or 4B, Procedures for Carbon Monoxide Continuous Emission Monitoring Systems in Stationary Sources	N/A	**CO CEMS Turbine GT-9:** The permittee is not subject to this part due to a federal NSPS, but uses this procedure to audit the CO CEMS.

NSPS Subpart (40 CFR 60)	Title	Applies (Y/N)	Comme nts
Specifications 4, 4A, and 4B are for evaluating the acceptability of carbon monoxide (CO) continuous emission monitoring systems (CEMS) at the time of installation or soon after. Permittee will need to determine the applicable performance specification for the GT-9 CO CEMS: Performance Specification 4—Specifications and Test Procedures for Carbon Monoxide Continuous Emission Monitoring Systems in Stationary Sources Performance Specification 4A—Specifications and Test Procedures for Carbon Monoxide Continuous Emission			
40 CFR 60, Appendix F	Quality Assurance Procedures for CEMS	N/A	**CO CEMS Turbine GT-9:** The permittee is not subject to this part due to a federal NSPS, but
1.1 Applicability. Procedure 1 is used to evaluate the effectiveness of quality control (QC) and quality assurance (QA) procedures and the quality of data produced by any continuous emission monitoring system (CEMS) that is used for determining compliance with the emission standards on a continuous basis as specified in the			
40 CFR 60, Subpart D	Subpart D--STANDARDS OF PERFORMANCE FOR FOSSIL-FUEL-FIRED STEAM GENERATORS FOR WHICH CONSTRUCTION IS COMMENCED AFTER AUGUST 17, 1971	N	Per Applicant: EPN-3/boiler 6 constructed 1-1-57 EPN-2/boiler 7 constructed 1-1-58 EPN-1/boiler 8 constructed 1-10-68 Per applicant, no units have been reconstructed or modified as defined. All units were constructed before 1971
40 CFR60.40a, Subpart Da	Performance Standards for Electric Utility Steam Generating Units, for which construction commenced after 9-18-78.	N	All units constructed before 1978 Per applicant no units have been reconstructed or modified.
40CFR60.40b, Subpart Db	Electric Utility Steam Generating Units (after 6-19-84)	N	All units constructed before 1984. Per applicant no boilers have been reconstructed or modified.
40 CFR 60.40c, Subpart Dc	PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES Subpart Dc—Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units	N	Applies to units with less than maximum design heat input capacity of 29 megawatts (MW) (100 million British thermal units per hour (MMBtu/hr)) or less. Each of these units has a capacity greater than that.
40 CFR 60, Subpart KKKK	Subpart KKKK--STANDARDS OF PERFORMANCE FOR STATIONARY COMBUSTION TURBINES	Y	**Turbine GT-9.**

<table>
<tr><th>NSPS Subpart
(40 CFR 60)</th><th>Title</th><th>Applies
(Y/N)</th><th>Comments</th></tr>
<tr><td colspan="4">60.4305(a) applies to stationary combustion turbines with a heat input greater than 10 MMBtu/hr at HHV.
Emissions data show GT-9 has a heat rate capacity between 782.5 to 888.1 MMBtu/hr HHV at 100% load.
64.4320(a) Table 1 – NOx emission standard is 15 ppm at 15% O2 or 54 ng/j of useful output (0.43 lb/MWh) since emissions data shows capacity of turbine is > 850 MMBtu/hr and the unit is a new turbine firing natural gas. Manufacturer guarantees after control NOx to 2.8 ppmvd @ 15% O2 site conditions.
60.4330 (a) SO2 emission limit (1) =< 110 ng/J or 0.90 lb/MWh gross output or (2) may not burn fuel containing total potential sulfur emissions in excess of 26 ng SO2/J or 0.060 lb SO2/MMBtu of heat input.
60.4335 NOx Compliance with water/steam injection – does not apply. Not used as a control device but for power augmentation.
60.4340(b) NOx monitoring uses CEMs for NOx so are subject to (b) (1) CEMs as in 60.4335(b) and 60.4345
60.4365(a) SOx monitoring is exempt since the permittee can provide a contract for fuel showing the total sulfur content in the natural gas is less than 20 gr/100 scf.
60.4375 Reporting requirements as they apply
60.4400 Initial Performance Test (a) must conduct initial test per 60.8 and subsequent tests on an annual basis, no more than 14 calendar months following the previous test. (b)(5) If you elect to install a CEMS, the performance evaluation of the CEMS may either be conducted separately or (as described in §60.4405) as part of the initial performance test of the affected unit.</td></tr>
</table>

NESHAP Subpart (40 CFR 61)	Title	Applies (Y/N)	Comments
A	General Provisions	N	Applies if any other subpart applies.

MACT Subpart (40 CFR 63)	Title	Ap	Comments
A	General Provisions		Applies if any other subpart applies.
40 CFR 63 Subpart H	Subpart H--NATIONAL EMISSION STANDARDS FOR ORGANIC HAZARDOUS AIR POLLUTANTS FOR EQUIPMENT LEAKS	N	F-2 fugitive emissions from natural gas piping. According to fuel analysis, natural gas contains less than 5% organic HAPs. (63.160(a) and definition of "in organic hap service" in 63.161)
40 CFR 63 Subpart Q	Subpart Q—National Emission Standards for Hazardous Air Pollutants for Industrial Process Cooling Towers	N	Applicant states that they do not use chromium based water treatment chemicals in their cooling towers. Cooling tower water is treated with chlorine (Cl_2). 63.400(a) The provisions of this subpart apply to all new and existing industrial process cooling towers that are operated with chromium-based water treatment chemicals and are either major sources or are integral parts of facilities that are major sources as defined in §63.401.

MACT Subpart (40 CFR 63)	Title	Applies (Y/N)	Comments
40 CFR 63 Subpart YYYY	Subpart YYYY—National Emission Standards for Hazardous Air Pollutants for Stationary Combustion Turbines	N	Facility is not a major source of HAPs.
Proposed NESHAP	Emission standards for Area	N	**Final rule signed on 2/21/11. Rule will be**
40 CFR 63, Subpart JJJJJJ	Source Boilers and Process Heaters Subpart JJJJJJ (6J)		**effective 60 days after promulgation in the Federal Register.** **Link to 2-21-11 Final Rule.** http://www.epa.gov/airquality/combustion/act ions.html#feb11 III Summary of Final Rule: For natural gas combustion boilers, rule applies if you own or operate a boiler combusting natural gas, located at an area source, which switches to combusting solid fossil fuels, biomass, or liquid fuel after June 4, 2010. Since the facility no longer combusts diesel fuel as a back up fuel, and will not combust solid fossil fuels (e.g. coal), biomass, or liquid fuel (e.g. propane) they are not subject to the
40 CFR 63 Subpart DDDDD	Subpart DDDDD—National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters	N	This is not a major HAP source and according to 63.7491(c) **Boilers 6, 7, and 8** are exempt from this vacated MACT.

The facility is exempt from the vacated MACT since they consist of electric utility steam generating units. Also, the NESHAP applies to major HAP sources only. EPA has completed promulgation of NESHAP for all listed categories in 2005 (per EPA fact sheet Proposed Amendments Outlining Requirements for States to Set Case-by-Case Emission Standards When NESHAP are Not in Place (CAA Section 112(J) Rule) on TTN OAR website 2-17-10). Therefore, the facility is not subject to Case-by-Case MACT per 112(J) (listed source with no MACT promulgated or vacated) or to Case-by-Case MACT per 112(g) (Major HAP source not on list but with no EPA MACT). **From DDDDD:** **§ 63.7485** You are subject to this subpart if you own or operate an industrial, commercial, or institutional boiler or process heater as defined in §63.7575 that is located at, **or is part of, a major source of HAP** as defined in §63.2 or §63.761 (40 CFR part 63, subpart HH, National Emission Standards for Hazardous Air Pollutants from Oil and Natural Gas Production Facilities), except as specified in §63.7491. **§ 63.7491 Are any boilers or process heaters not subject to this subpart?** The types of boilers and process heaters listed in paragraphs (a) through (o) of this section are not subject to this subpart. (c) An electric utility steam generating unit (including a unit covered by 40 CFR part 60, subpart Da) or a Mercury (Hg) Budget unit covered by 40 CFR part 60, subpart HHHH. **This rule was vacated by United States District of Columbia court of appeals on June 8, 2007.**

Miscellaneous	Title	Applies (Y/N)	Comments
40 CFR 64	Compliance Assurance	N	

Miscellaneous	Title	Applies	Comments
	Monitoring		

NOx and CO emissions are monitored with CEMs. The current TV permit will require CEMs to monitor emissions from boilers and the turbine. Per 64.2(b)(vi) an emission limitation or standard for which a Part 70 or 71 permit specifies a continuous compliance determination method, as defined in 64.1, are exempt from CAM. *Continuous compliance determination method* means a method, specified by the applicable standard or an applicable permit condition, which: (1) Is used to determine compliance with an emission limitation or standard on a continuous basis, consistent with the averaging period established for the emission limitation or standard; and

40 CFR 68	Chemical Accident Prevention	N	Applies to owners or operators of stationary sources with more than a threshold quantity of a regulated substance. According to the applicant, the amount of chlorine stored on site (150 lb cylinders used as a biocide in the cooling towers) does note exceed the threshold quantity of 2,500 lbs listed on Table 1 in 68.130 (List of Regulated Toxic Substances and Threshold Quantities for Accidental Release Prevention). 40 CFR 68 applies only when the aqueous ammonia concentration is 20% or more. The aqueous ammonia used for the SCR is 19% aqueous ammonia. Sulfuric acid was not found on Table 1. Sulfuric acid is used to regulate the pH of the cooling tower water.
40 CFR 70	Title V- State Operating Permit Programs	N	Not applicable – New Mexico State has full SIP approved authority and Title V is administered under 20.2.70 NMAC.
40 CFR 72	Title IV – Acid Rain Program	Y	**Boilers 6, 7, and 8 and turbine GT-9 are subject.** [AQB is the permitting authority and EPA is the administrator] **Note:** Acid Rain program identifies units as boilers 6, 7, and 8 and not by EPN-1, 2, and 3. **Turbine GT-9** will be a new unit per 72.6(a)(3)(i). **Note: The permittee is removing the option to operate with diesel fuel. The facility will only operate using natural gas.**
72.6(a) Applicability Boilers 6, 7, and 8 are "existing utility units" (72.2 definitions) and listed in Table 2 – Phase II Allowance Allocations in Subpart 73.10 and are not exempt per 72.6(b). 72.6(a) Each of the following units shall be an affected unit, and any source that includes such a unit shall be an affected source, subject to the requirements of the Acid Rain Program: (2) A unit that is listed in table 2 or 3 of §73.10 of this chapter and any other existing utility unit, except a unit under paragraph (b) of this section. Upon application submittal, permittee certified that they hold SO2 allowances in accordance with			

Miscellaneous	Title	Applies (Y/N)	Comments
Acid Rain Program means the national sulfur dioxide and nitrogen oxides air pollution control and emissions reduction program established in accordance with title IV of the Act, this part, and parts 73, 74, 75, 76, 77, and 78 of this chapter. ***Administrator*** means the Administrator of the United States Environmental Protection Agency or the Administrator's duly authorized representative. ***Permitting authority*** means either: **(1)** When the Administrator is responsible for administering Acid Rain permits under subpart G [phase II			

40 CFR 73	Title IV – Acid Rain Sulfur Dioxide Allowance Emissions	Y	**Boilers 6, 7, and 8 are subject** [EPA is the administrator]

73.2(a) applies to owners, operators, & designated representatives of affected sources subject to 72.6.
73.1 Scope: 40 CFR 73 establishes requirements and procedures for allocating sulfur dioxide allowances and their tracking, holding, transferring, offsetting, selling, and other requirements.
Phase II SO2 allowances are found in 73.10 (b) Table II: Phase II allowances (2) The Administrator will allocate allowances to the compliance account for each source that includes a unit listed in table 2 of this

40 CFR 75	Title IV – Acid Rain Continuous Emissions Monitoring	Y	**Boilers 6, 7, and 8 and Turbine GT-9** Applicant defines, boilers as a gas-fired non-peaking units so Part 75 only requires SO2, NOx, and CO2 emissions monitoring. Although NOx emission reduction (Part 76) is not required for gas-fired units, NOx monitoring is still required in Part 75. Gas-fired units are exempt from opacity monitoring

72.2 Gas-fired means: (2) For purposes of part 75 of this chapter, the combustion of:
(i) Natural gas or other gaseous fuel (including coal-derived gaseous fuel) <u>for at least 90.0 percent of the unit's average annual heat input</u> during the previous three calendar years….; and **(ii)** Fuel oil, for the remaining heat input, if any. **– the permittee is no longer using diesel fuel as a fuel option.**
Gaseous fuel means a material that is in the gaseous state at standard atmospheric temperature and pressure conditions and that is combusted to produce heat.
75.1 Purpose (a) establish requirements for the monitoring, recordkeeping, and reporting of sulfur dioxide (SO2), nitrogen oxides (NOX), and carbon dioxide (CO2) emissions, volumetric flow, and opacity data from affected units under the Acid Rain Program…..
75.2 Applicability (a) Except as provided in paragraphs (b) and (c) of this section, the provisions of this part apply to each affected unit subject to Acid Rain emission limitations or reduction requirements for SO2 or NOX.
75.5 Prohibitions(e) No owner/operator shall disrupt CEMS or other approved emission monitoring avoiding monitoring and recording emissions except for periods of recertification, or periods when calibration, quality assurance, or maintenance is performed per 75.21 and appendix B.
75.10 General operating requirements (a)(1) determine SO2 emissions (see 75.11 Appendix D); **(2)** determine NOx emissions with CEMS **(3)** determine CO2 emissions – 3 options, see below.
SO2 Monitoring

Miscellaneous	Title	Applies (Y/N)	Comments

75.11(d)(2) Specific Provisions for Monitoring SO2 Emissions – Permittee monitors SO2 according to Part 75 Appendix D since the units qualify as a gas-fired as defined in 72.2 of this chapter.

Appendix D - Optional SO2 Emissions Data Protocol for Gas-Fired and Oil-Fired Units

1.2 Initial Certification and Recertification requirements in 75.20 (g) must be completed to certify use of the optional SO2 emissions data protocol in Appendix D –includes meeting applicable general operating requirements of 75.10, requirements of appendix D, and initial certification or recertification requirements in 75.20.

2.1 to 2.1.7.5 Fuel Flowmeter Measurements

For each hour when the unit is combusting fuel, measure and record the flow rate of fuel combusted by the unit, except as provided in section 2.1.4 of this appendix. Measure the flow rate of fuel with an in-line fuel flowmeter, and automatically record the data with a data acquisition and handling system, except as provided in section 2.1.4 of this appendix.

2.2 to 2.2.8 Oil Sampling and Analysis – permittee is longer using diesel fuel as a fuel option. Perform sampling and analysis of oil to determine the following fuel properties for each type of oil combusted by a unit: percentage of sulfur by weight in the oil; gross calorific value (GCV) of the oil; and, if necessary, the density of the oil.

2.3 to 2.3.7 SO2Emissions From Combustion of Gaseous Fuels: (a) Account for the hourly SO2 mass emissions due to combustion of gaseous fuels for each hour when gaseous fuels are combusted by the unit using the procedures in this section.

NOx Monitoring

75.10(a)(2)- Owner/operator must measure both NO & NO2 with a NOx-diluent CEMs system with NOx pollutant concentration monitor, O2 or CO2 diluent gas monitor, and with an automated DAHS to measure and record NOx **in ppm**, O2 or CO2 in percent, **and** NOx emission rate **in lb/MMbtu**. **75.12** are the specific provisions for monitoring NOX emission rate.

CO2 monitor ng

75.10(a)(i) Permittee measures CO2 emissions using the first of 3 options which requires a CO2 CEMs and flow monitoring system with an automated DAHS to measure and record CO2 concentration in ppm, volumetric gas flow in scfh, and CO2 mass emissions in tons/hr.

Note: 75.10(d)(1) CEMs must be capable of completing a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15-min interval. The owner/operator shall reduce all emissions & volumetric flow data collected by the monitors to hourly averages. Hourly averages shall be computed using at least one data point in each fifteen minute quadrant of an hour, where the unit combusted fuel during that quadrant of an hour. **Consent decree requires 20.2.33 NOx lb/MMbtu boiler 6, 7, & 8 emissions be limited as 3-hr averages rather than 1-hour ave (requested by El Paso Electric), 40 CFR 75 requires NOx lb/MMbtu emissions be reported as hourly averages, and maximum lb/hr (not 3-hr ave) emission limits are required**

40 CFR 76	Title IV – Acid Rain Nitrogen Oxides Emission Reduction Program	N	Title IV NOx emission reduction program applies to coal-fired units. This facility does not
40 CFR 77	Title IV – Acid Rain Offset Plans for Excess Emissions SO2	Y	**Applies to boilers 6, 7, & 8 and turbine GT-9. Currently, the boilers 6, 7, and 8 have SO2** **Phase II Allowance.** [EPA is the administrator] (a) *Applicability*. The owners and operators of

Miscellaneous	Title	Applies (Y/N)	Comme nts
			offset the amount of such excess emissions by an equal amount of allowances from the
Title VI – 40 CFR 82	Protection of Stratospheric Ozone	N	According to the applicant, the facility does not “service”, “maintain” or “repair” class I or
40 CFR 98	PART 98--MANDATORY GREENHOUSE GAS REPORTING	Y	**Boilers 6, 7, 8, and turbine GT-9** are subject. (40 CFR 98.2(a)(1)). EPA, not AQB, is the administrator of
Boilers 6, 7, 8, and Turbine GT-9 are subject per **98.40(a), Subpart D** electricity generating units subject to the requirements of the Acid rain Program and any others that are required to monitor and report EPA CO2 emissions year round according to 40 CFR 75. **GHGs to Report 98.42 (a)** must report the annual mass emissions of CO2, N2O, and CH4 **98.47 Records Retention:** Comply with the recordkeeping requirements of §98.3(g) and 98.37 [98.37 applies to Subpart C General Stationary Fuel Combustion Sources] **98.3 subject to (a) through (i) General monitoring, reporting, recordkeeping and verification requirements: (b)** The annual GHG report must be submitted no later than March 31 of each year for GHG emissions in the previous calendar year. **(1)** existing facilities – to be revised **(3)** facilities that become subject due			

13.0 Exempt and/or Insignificant Equipment:

Exempt activities per 20.2.72.202 NMAC apply only to equipment or activities associated with new units
GT-9, CT-9, FUG-9, and AST-9.

NSR Exempt Activities or Equipment:

EXEMPT ACTIVITIES	JUSTIFICATION	Records Required ?

Maintenance: paints and coatings used for buildings; plant cleaning with solvents and chemicals; electrical maintenance using solvents.	20.2.72.202.A(1) activities for maintenance of grounds or buildings. This is not required to be reported in application but applicant reported anyway.	No
Painting/Surface Coating of Equipment	20.2.72.202.B(6) includes spray painting, roll coating, and painting with aerosol spray cans if VOCs do not exceed 10 pph; and facility-wide total VOC content of all coating and clean-up solvent is less than 2 tpy.	Yes 20.2.72.202(B)(6)(c) permittee must keep sufficient records to verify that the requirements are met.

14.0 New/Modified/Unique Conditions (Format: Condition#: Explanation):

All Conditions are NEW

Tables 102A and 102B – These are emissions from the entire facility, including emissions that are subject only to Title V permit P127-R1M1.

Table 103A Applicable Requirements – The table includes only requirements for the new units GT-9, CT-9, and FUG 9. .

Table 104.A Sources Subject to this Permit – The Table lists the units that have applicable requirements in this permit only. It does not include Boiler 7 and the three boiler cooling towers as these units have no applicable requirements in this NSR permit.

A104.B – The applicant requested 45 days from source start up, rather than 15 days from source installation, to submit the TBD values in Table 104.A. Permit writer verified with enforcement that extending the deadline to submit TBD values would not cause enforcement issues due to the source type (not portable or allowed to replace units). Except for submitting the serial numbers of the new units, the permittee is still required to meet the 15 day deadline in Condition B110 since these deadlines are required by 20.2.72.212 NMAC.

Table 105 Control Equipment – Lists controls only for Turbine GT-9.

A106 and Table 106.A Allowable Emissions – Lists the emission limits only subject to NSR 1554- M1. Emission limits not listed here are regulated by TV permit P127-R1M1.

A106.C – Turbine GT-9 NSPS KKKK Requirements. NSPS KKKK limits NOx and SOx emissions.

A108.A - The permit allows the facility to operate 8760 hours per year.

A115.A – Revisions to general conditions B111(7) and (8) requiring sampling lines be installed. Applicant requested that these conditions be deleted since sampling lines require maintenance and due to other issues and it would be unlikely that the department would ever use them for a facility with periodic emissions testing and CEMS. Permit writer verified with enforcement section that the sampling lines are typically used for portable analyzers so would never be

required for this facility. Therefore, conditions B111(7) and (8) were revised by Specific Condition A115.A to require the sampling lines only if requested by the department and within 30 days of request.

A401A – Compliance with Turbine GT-9 Emission limits in Table 106. This condition establishes and clarifies the methods that are required to demonstrate compliance with allowable emission limits for Turbine GT-9 (20.2.72.210.A NMAC).

A401B - Turbine CO and VOC Control device: The permittee chose to install an oxidation catalyst to reduce CO emission to below PSD significance levels of 100 tpy and establish the CO emission limits used in air dispersion modeling. The oxidation catalyst also reduces VOC emissions and was used to establish VOC emission limits. The condition establishes the operational requirements of the oxidation catalyst necessary to meet turbine CO and VOC emission limits (20.2.72.210.A, 210 B(1)(a), and 20.2.74.7.AO NMAC). The oxidation catalyst is not fully functional at operating temperatures lower than 700 deg F which takes up to 10 minutes. The permittee calculated emissions assuming that CO and VOC emissions are not reduced with the oxidation catalyst for the first 7 minutes. Therefore, the condition states that the oxidation catalyst does not need to be reducing CO and VOC emissions the first 7 minutes after startup of the turbine. These additional uncontrolled emissions are included in the pph emission limit in Table 106.

A401C – Turbine NOx Control – The permittee chose to install a Selective Catalytic Reduction System (SCR) to reduce NOx emissions to below PSD significance levels of 40 tpy and establish NOx

emission limits. The condition establishes operational requirements for SCR to meet NOx and NH3 emission (ammonia slip) emission limits (20.2.72.210.A, 210 B(1)(a), and 20.2.74.7.AO NMAC). Anhydrous ammonia is more toxic than aqueous ammonia, and aqueous ammonia at a concentration of 20% or more is subject to 40 CFR 68, therefore, there are limits on the type and concentration of ammonia to that reported in the application.

The SCR is not fully functional at operating temperatures lower than 500-540 deg F which takes up to 30 minutes. The permittee calculated emissions assuming that NOx emissions are not reduced by the SCR for the first 30 minutes. Therefore, the condition states that the SCR does not need to reduce NOx emissions the first 30 minutes after startup of the turbine. These additional uncontrolled emissions are included in the pph emission limit in Table 106

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A401D – NOx and CO CEMS and Emissions Monitoring – The condition establishes the methods used to demonstrate compliance with NOx and CO lb/hr and tpy emission limits (20.2.72.210.C(3) and 20.2.72.208.F NMAC). Title IV Acid Rain requires only NOx and CO2 be monitored with CEMS, but EPE also monitors CO with CEMS. The CO CEMS is not subject to 40 CFR 60, appendices B and F however, those are the procedures the permittee agreed to use for certification and QA/QC. The permit does not CO2, therefore, the permitted CEMS operating and certification requirements do not apply to the CO2 CEMS which is regulated by Acid Rain. The permittee must use the lb/hr NOx and CO emission rates and actual operating

hours from CEMS data to calculate NOx and CO tpy emissions to ensure emission limits are met and PSD permitting is not required.

A401E – 40 CFR 75 SO2 Monitoring Required for Turbine GT-9. Acid Rain Fuel Monitoring is not necessary to show compliance with emission limits in this permit, but is a requirement of Title IV Acid Rain so is referenced here.

A401F – Limits the sulfur content of the natural gas fuel. The fuel sulfur limit (0.25 gr/100scf) is based upon the manufacturer's PM10 guaranteed emission rate and is lower than that used to calculate SO2 emissions (0.45 gr/100scf annual average). The manufacturer qualified the PM10 emission rate on a fuel sulfur content because SO2 emissions (created by the combustion of sulfur in fuel) contributes to the formation of PM.

A401G – Turbine GT-9 PM Limits. This monitoring and recordkeeping establishes federally and practically enforceable conditions to demonstrate compliance with the lb/hr and tpy TSP, PM10, and PM2.5 emission limits. Exceeding the tpy limits could result in the modification to add Turbine GT-9 and cooling tower CT-9 being subject to PSD (20.2.74 NMAC) and/or Nonattainment (20.2.79
NMAC) permitting. From initial start up (first fuel firing) of the Turbine to stack test deadline is 6 months. Therefore, until PM emission factors are determined through stack testing, the permittee shall use 0.0040 lb/MMBtu (the EF used by EPE) to calculate TSP, PM10, and PM2.5 emissions. Once PM emission factors are determined through compliance testing, EPE will re-calculate tpy TSP, PM10, and PM2.5 emission rates from initial start up of the turbine (first fuel firing) to verify the assumptions EPE used to avoid PSD and Nonattainment permitting were valid and to ensure tpy emissions are met.

A401H – NOx, CO, TSP, PM10, and PM2.5 Compliance testing for Turbine GT-9. This verifies allowable emission rates used in air dispersion modeling are met and that the modification to the facility was not a major modification as defined by PSD and Nonattainment (20.2.72.210.A, and
210.C(4); 20.2.74.200; and 20.2.79.109 NMAC). Test results of filterable and condensable particulate
matter shall be combined to verify compliance with TSP, PM10, and PM2.5 emission limits. According to EPA's preamble of final revised test methods for 201A and 202 all condensable particulate matter is assumed to be 2.5 microns in diameter or less (PM2.5). As proposed by EPE, test runs for Methods 201A and 202 are extended up to a minimum of 2 hours to improve the accuracy of these tests since, according to EPE, PM emissions from the turbine are expected to be very low. Typically, each test run must occur for no less than 1 hour.

A401I – 20.2.61 – Requirements of state opacity limits in 20.2.61 NMAC for combustion sources.

A401J – NSPS KKKK – Turbine GT-9 is subject to NSPS KKKK. The manufacturers guaranteed ppmvd limit is 2.75 which is lower than NSPS KKKK emission standard of 15 ppmvd. Permittee will use the NOx CEMS to show compliance and will be exempt from on-going SO2 monitoring due to the low sulfur content of the fuel.

A402A - NOx PPH Emission Limit on Boiler 8. To show compliance with NOx ambient air quality standards in air dispersion modeling, Boiler 8 had to limit NOx pph emissions down to 415.0 pph and for no more than 7 hours per day may emit up to 460.5. Each day, or 24-hr period shall start at 12 midnight.

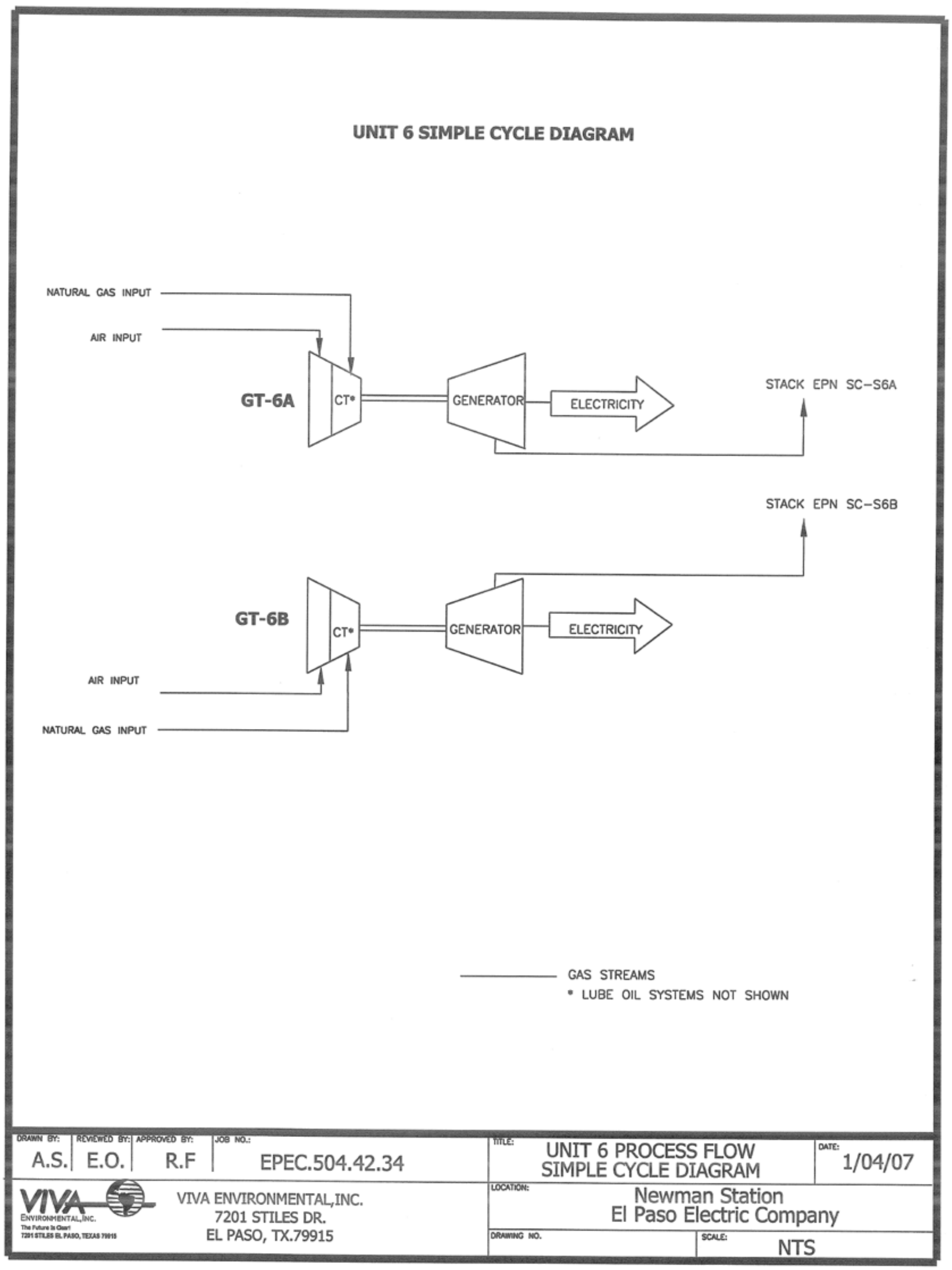
A402B - Boiler 6 TSP, PM10, and PM2.5 tpy Limits. This monitoring and recordkeeping establishes federally and practically enforceable conditions to demonstrate compliance with the tpy PM2.5 emission limit. Exceeding this limit could result in the modification to add Turbine GT-9 and cooling tower CT-9 being subject to PSD (20.2.74 NMAC) permitting. So that the reduction in Boiler 6 PM emissions is contemporaneous with the increase from the change, EPE agreed that the reduction in PM2.5 tpy emissions which are met by reducing the annual heat rate from Boiler 6, would be effective

30 days before first fuel firing of the Turbine. 30 days before first fuel firing of the Turbine to the Boiler stack test deadline is 7 months. Therefore, until the PM2.5 emission factor is determined through stack testing, the permittee shall use 7.6 lb/MMBtu (the EF used in EPE's netting analysis) to calculate PM2.5 emissions. Once the PM2.5 emission factor is determined through stack testing, EPE will re-calculate tpy PM2.5 emission rates using the actual PM2.5 emission factor starting 30 days before initial start up (first fuel firing) of the Turbine to verify the actual emissions reduction from Boiler 6 is creditable (20.2.74.7.AL(6)(a) and (b) NMAC).

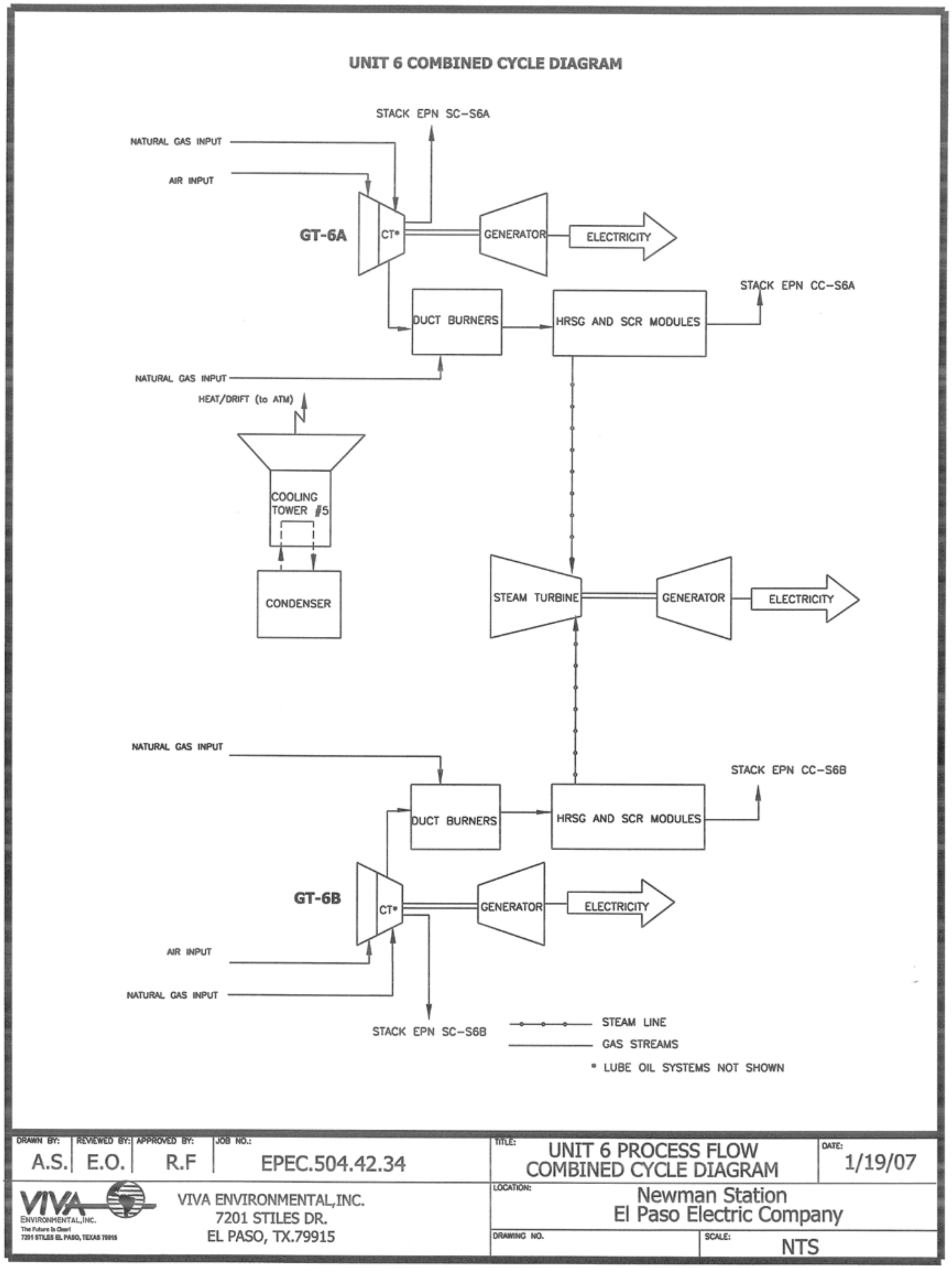
A402.C - Boiler 6 PM2.5 Testing Requirements. This is to verify that the actual PM2.5 emissions reduction from Boiler 6 is creditable (20.2.74.7.AL(6)(a) and (b) NMAC). Test results of filterable PM2.5 and condensable particulate matter shall be combined to verify compliance with PM2.5 emission limits. All condensable particulate matter is assumed to be 2.5 microns in diameter or less (PM2.5).

A405A - Cooling tower requirements. The operational limits (drift rate, TDS, and gpm) in this condition are based upon the parameters used to calculate and set the PM emission limits in this permit. Meeting these requirements demonstrates compliance with limits.

Appendix 2 Unit 6 Simple Cycle Diagram



Appendix 3 Unit 6 Combined Cycle Diagram



Vita

Mr. Luis Perez holds an Associate's degree in Business from Midland College, Bachelor's and Master of Science degree in Civil Engineering from the University of Texas at El Paso. Other graduate studies include advanced physics, environmental engineering, model study, numerical analysis, and cyber security.

He is a Viet Nam era veteran, served as Executive Officer in an Engineering Company with the Corps of Engineers, and was a technical writer for the Engineering School at Ft. Belvoir, VA. Following the military, he joined Exxon Company USA in the Permian Basin as a drilling and production engineer.

He also worked for IBM as a Marketing Representative, El Paso Natural Gas company as a SCADA manager and El Paso Electric as a Principal Environmental Engineer. As a marketing representative for IBM, in 1980, he installed the first distributed computer system in El Paso, TX. He has held various management positions within the El Paso Natural Gas Company in El Paso, Houston and throughout Florida with responsibility for national and international projects. With El Paso Electric Company, Mr. Perez was a Principal Engineer responsible for corporate-wide state and federal compliance of the air quality program.

Mr. Perez has over 40 years of experience integrating engineering and IT fields relating them to energy and the environment. He has developed computer systems designs (software, hardware, communications and interface requirements) for real-time systems and ensuring security for monitoring systems nation-wide. He is currently the Sustainability Coordinator for UTEP.