PUBLIC SERVICE OF NEW MEXICO

SAN JUAN GENERATING STATION UNITS 1-4

NATURAL GAS CONVERSION CONCEPTUAL STUDY

SL-010560
Draft

February 15, 2011
Project 11278-025

Prepared by

Sargent & Lundy LLC

55 East Monroe Street • Chicago, IL 60603 USA • 312-269-2000

LEGAL NOTICE

This Deliverable was prepared by Sargent & Lundy, L.L.C. (S&L), at the request of and expressly for the sole use of Public Service of New Mexico (Client) in accordance with the agreement between S&L and Client. This Deliverable was prepared using the degree of skill and care ordinarily exercised by engineers practicing under similar circumstances. Client acknowledges: (1) S&L prepared this Deliverable subject to the particular scope limitations, budgetary and time constraints, and business objectives of the Client; (2) information and data provided by others may not have been independently verified by S&L; and (3) the information and data contained in this Deliverable are time sensitive and changes in the data, applicable codes, standards, and acceptable engineering practices may invalidate the findings of this Deliverable. Any use or reliance upon this Deliverable by third parties shall be at their sole risk.

SL-010560 REPORT CONTRIBUTORS

Prepared by:	**Reviewed by:**
Marc E. Lemmons Mechanical Engineer	**William C. Stenzel** Manager/Consultant

Approved by:

Anthony L. Lunardini Project Manager	Date

CONTENTS

Section | Page

TABLES

Table **Page**

EXECUTIVE SUMMARY

Public Service of New Mexico (PNM) authorized Sargent & Lundy, L.L.C (S&L) to perform a preliminary, high-level study to evaluate the conversion of San Juan Generating Station (SJGS) Units 1 through 4 from firing coal to firing natural gas. The results of the study as presented in this report provide PNM with estimated natural gas firing boiler performance data and conversion costs.

This report provides a high-level/preliminary development of scope, design, performance and cost information, including the following:

OVERVIEW

Firing natural gas instead of coal causes significant boiler heat absorption changes that result in higher steam / tube metal temperatures. Often the tube metal temperatures of certain boiler tubes (usually the final superheater tubes) result in exceeding ASME Boiler Code Allowable stresses. This is determined by a boiler designer performing a computer thermal study to determine required pressure part modifications for full boiler steam output.

This study, however, utilizes S&L's experience and preliminary assessment to provide initial conceptual design information and costs for PNM's use in planning for future operation of the SJGS units.

BOILER/UNIT OPTIONS

Two boiler/unit options were evaluated:

- **Option 1**: Reduced natural gas firing rate based on no boiler pressure part modifications, resulting in reduced boiler steam flows and unit output to minimize 2017 natural gas firing capital expenditures. It is expected that Units 1-4 will be derated to 70% unit output.
- **Option 2**: Full natural gas firing rate, resulting in full boiler and unit output based on S&L initial/preliminary assessment of required boiler modifications. Boiler modifications include:
  - Flue gas recirculation (FGR) system.
  - Convection-pass modifications for full-unit output (e.g., superheater material changes).

Design performance summary sheets and recent plant data were used in the estimated performance calculations. The SJGS estimated performance calculations for the natural gas-fired case are summarized in Table ES-1.

Table ES-1. Natural Gas Firing Performance Summary (per Unit)

Parameter	Units 1 and 2 Per Unit	Units 3 and 4 Per Unit
Option 1:		
Gross plant output (MW)	245	385
Natural gas feed rate (scfm)	41,247	64,834
Boiler efficiency (%)	86.2	84.7
Boiler heat input (MBtu/hr)	2,475	3,890
Combustion air flow (lbs/hr)	1,912,430	2,994,527
Flue gas flow (lbs/hr)	2,322,396	3,840,643
Option 2:		
Gross plant output (MW)	350	550
Natural gas feed rate (scfm)	59,524	93,086
Boiler efficiency (%)	85.31	84.23
Boiler heat input (MBtu/hr)	3,571	5,585
Combustion air flow (lbs/hr)	2,756,617	4,297,088
Flue gas flow (lbs/hr)	3,347,551	5,511,249

Preliminary estimated NO_X emission data for natural gas firing at full unit output with options for FGR, selective catalytic reduction (SCR), or selected non-catalytic reduction (SNCR) systems are provided in the Table ES-2. These values are based on S&L experience and industry data; i.e., calculations and other analyses were not prepared. NO_X emissions at SJGS Units 1-4 currently are controlled to 0.30 lbs/MBtu.

Table ES-2. Estimated NO_X Emissions at Full-Unit Output

Parameter	Unit 1 & 2	Unit 3 & 4
Option 1	Below 0.20 to 0.23	Below 0.14 to 0.17
Option 2		
Without FGR	0.20 to 0.23	0.14 to 0.17
With FGR	0.13 to 0.18	0.10 to 0.12
SNCR (with FGR)	0.11 to 0.15	0.09 to 0.10
SCR (with FGR)	≤ 0.05	≤ 0.05

Table ES-3 and Table ES-4 summarize the preliminary costs developed in this study based on the parameters listed below. Both options include removal of the coal burners and adjacent coal piping, new natural gas burners and piping, and other components and control modifications. Removal of asbestos and lead paint and other similar requirements are not included in the cost estimates provided in this report as these are station-unique requirements.

- The boiler natural gas conversion costs are mainly based on prior S&L studies and project work.
- Estimated derate and 100% unit boiler output emission rates.
- Boiler modifications required for 100% steam output.
- Existing coal equipment will be abandoned in place.
- Capital cost estimates are based on an order-of magnitude level of accuracy of ±40%, which is usually an acceptable range for the evaluation of coal versus natural gas because the fuel costs over the forecasted future years of operations are the dominant cost impact.
- The natural gas piping preliminary costs are based on a single pipe supplying each boiler. If more than one boiler is converted to natural gas firing, a single larger pipe line could supply multiple units at reduced cost. The resulting cost difference is insignificant and is not reflected in the current cost estimate.
- The boiler thermal model costs are on a per unit basis. If more than one boiler is converted to natural gas firing, one thermal model is required for Units 1 and 2 and a separate thermal model for Units 3 and 4 (i.e., $140,000 for Units 1 and 2 and $140,000 for Units 3 and 4, total).
- The Option 2 cost estimate does not include capital costs for a SCR or SNCR.

Table ES-3. Option 1 Cost Estimate ($1000)

Parameter	Unit 1	Unit 2	Unit 3	Unit 4
Natural Gas Boiler Modifications				
Natural Gas Piping from Fence to Boiler Front	$1,100	$1,100	$1,450	$1,450
Natural Gas Piping at Boiler Front	$740	$740	$970	$970
New Natural Gas Burners	$7,320	$7,320	$9,600	$9,600
New BMS / Upgraded DCS	$2,010	$2,010	$2,640	$2,640
Boiler Thermal Model	$140	$140	$140	$140
Option 1 Unit Total	**$11,310**	**$11,310**	**$14,800**	**$14,800**

Table ES-4. Option 2 Cost Estimate ($1000)

Parameter	Unit 1	Unit 2	Unit 3	Unit 4
Natural Gas Boiler Modifications				
Natural Gas Piping from Fence to Boiler Front	$1,100	$1,100	$1,450	$1,450
Natural Gas Piping at Boiler Front	$740	$740	$970	$970
New Natural Gas Burners	$7,320	$7,320	$9,600	$9,600
New BMS / Upgraded DCS	$2,010	$2,010	$2,640	$2,640
FGR System	$2,890	$2,890	$3,790	$3,790
Boiler Convection Modifications	$5,080	$5,080	$6,660	$6,660
Boiler Thermal Model	$140	$140	$140	$140
Option 2 Unit Total	**$19,280**	**$19,280**	**$25,250**	**$25,250**

The fixed O&M for a typical coal unit is about $25 per kilowatt per year (kW/yr), based on several variables, e.g., number of units, age of units, degree of unionization, management practices, and other factors. S&L preliminary estimates show that about one third of that cost would be eliminated for a coal plant converted to operation on natural gas. The cost reduction would be associated with elimination of the ash handling and coal handling and a reduction in water treatment and other expenses. Based on prior S&L studies and evaluations, the total O&M savings are estimated at $9/kW/year in fixed O&M cost. Difference in fuel cost is not included. This is based on unit annual operating hours in the range of 50% per year or more. If the unit is cycled and operates about 15% per year, this savings would increase to about $12/kW/yr.

Cycling operation is often required based on fuel costs and grid dispatch ranking with natural gas firing. Cycling modifications would include turbine bypass systems, water treatment modifications (e.g., a polisher), control upgrades, fan motor replacements for frequent starts, and based on age of existing motors. Based on general experience, the estimated capital cost for installing cycling capability with gas firing at SJGS Units 1 and 2 is $41/kW (or $14.35M for each unit) and for Units 3 and 4 is $39/kW (or $21.45M for each unit); all current-day costs and at full-unit output.

One operating plan option for these units being considered by PNM to operate these units on coal until 2017 and then convert to natural gas is incorporated into this study. Major capital expenditures for repairs (e.g., boiler furnace wall and reheater replacements, turbine and balance-of-plant equipment repairs, etc.) between current and 2017 with continued coal firing would initially be minimized. Decisions to implement all the needed repairs for natural gas firing would be made at appropriate times ahead of 2017. Therefore, this report incorporates applicable boiler component "harvesting" assessments and estimated costs. The optional plan for gas turbine repowering is not addressed in this report.

The costs and justifications for each unit, plant common, and switchyard are based on reviewing Generating Availability Generating System (GADS) information, limited condition assessment reports (i.e., NOTIS reports), Capital Budget Items (CBI), and the SJGS Five-Year Project Plan (see Table ES-5). Cost expenditures for operation beyond 2017 are the difference from the original Five-Year Project Plan and what is included in the separate S&L Harvesting Study (SL-010560). Coal-related costs were not removed from these expenditures (e.g., pulverizer upgrades, material handling, etc.) and all boiler components (e.g., convection pass) should be replaced per the Five-Year Project Plan.

Table ES-5. Cost Expenditures for Operation Beyond 2017 ($1000)

Parameter	Original Capital Cost	Harvesting Study Cost	Cost for Operation Beyond 2017
Unit 1	$69,271	$37,305	$31,966
Unit 2	$70,967	$48,965	$22,002
Unit 3	$59,859	$21,318	$38,541
Unit 4	$94,041	$28,742	$65,299
Unit 1&2 Common	$12,303	$4,848	$7,455
Unit 3&4 Common	$14,507	$5,976	$8,531
Unit 1 through 4 Plant Common	$43,250	$18,029	$25,221
Switchyard	$9,062	$2,025	$7,037

SUMMARY

PNM has advised that the information from this study will be used in an evaluation determining future unit operating requirements. Therefore, PNM has to include the following cost categories in the evaluation for natural gas firing for each of these units, as applicable:

- Natural gas fuel and O&M costs.
- Boiler natural gas firing burner and other related costs.
- Cost expenditures for operation beyond 2017 are the difference from the original Five-Year Project Plan and what is included in the Harvesting Study. Coal-related costs were not removed from these expenditures (e.g., pulverizer upgrades, material handling, etc.) and all boiler components (e.g., convection pass) should be replaced per the Five-Year Project Plan.
- Additionally, PNM might need to consider costs for cycling operation.

For example PNM's dispatch / generating cost computer modeling might show that natural gas fuel costs dictate that cycling operation is required. This determination could result in PNM including all five of the above cost categories in the computer model and evaluations. Also, adjustments to some of the above estimated costs might be appropriate; e.g., O&M costs and repair costs could probably be reduced based a low average annual unit capacity factor.

1. INTRODUCTION

1.1 GENERAL

Public Service of New Mexico (PNM) authorized Sargent & Lundy, L.L.C (S&L) to perform a preliminary, high-level study to evaluate the conversion of San Juan Generating Station (SJGS) Units 1-4 from firing coal to firing natural gas. The results of the study as presented in this report provide PNM with estimated natural gas firing boiler performance data and conversion costs.

San Juan Generating Station is located 15 miles west of Farmington, New Mexico and comprises Units 1 and 2 (350 MW each) and Units 3 and 4 (550 MW each). All four units fire coal produced in an adjacent mine. The steam generating units for Units 1 and 2 were manufactured by Foster Wheeler Corporation (Foster Wheeler); and, the steam generating units for Units 3 and 4 were manufactured by The Babcock & Wilcox Company (B&W). All four units include electrostatic precipitators (ESPs), powdered activated carbon (PAC) injection systems, pulse jet fabric filters (baghouses), and wet flue gas desulfurization (FGD) systems. All four steam turbine generators (STGs) were manufactured by General Electric Company (GE). Units 1, 3, and 4 were upgraded by GE and Unit 2 was upgraded by Siemens. SJGS Units 1-4 had furnace flue gas recirculation (FGR) to control main steam and reheat temperatures as the original design. The FGR system has been decommissioned and has been abandoned. NO_X emissions at Units 1-4 currently are controlled to 0.30 lbs/MBtu.

This report provides a preliminary, high-level development of scope, performance, and cost information, covering:

- Option 1: Minimize 2017 natural gas capital expenditures by derating unit output. This includes no FGR system and no convection-pass modifications to obtain full unit output. Cost for continued operation for 10-15 years beyond 2017 will be provided from the Harvesting Study. It is expected that Units 1-4 will be derated to 70% unit output.
- Option 2: Full-unit output based on S&L initial/preliminary assessment of required boiler modifications (e.g., boiler tube modifications and FGR).
- Expected boiler performance, including boiler efficiency and natural gas fuel flow rates based on Options 1 and 2.
- Expected NO_X emissions for Options 1 and 2 with and without selective catalytic reduction (SCR) and selective non-catalytic reduction (SNCR) technologies.
- An overview of cycling operation.

- Capital cost estimates that are based on an order-of magnitude level of accuracy of ±40%, which is usually an acceptable range for the evaluation of coal versus natural gas because the fuel costs over the forecasted future years of operations are the dominant cost impact.
- Estimated operations and maintenance (O&M) reductions.

1.2 STUDY METHODOLOGY

S&L used information such as design plant reference drawings/data from prior projects/studies and industry open-access references in preparing this study. This information obtained was sufficient to conduct this preliminary, high-level development study.

Boiler and other suppliers were not contacted for specific information. S&L prepared only preliminary calculations for a preliminary estimate of boiler natural gas consumption, unit output, steam temperatures, air and flue gas flows. Emissions are estimated based on S&L experience and industry information.

2. NATURAL GAS CONVERSION TECHNOLOGY DISCUSSION

~~This section of the report provides a preliminary, high-level description of natural-gas-firing equipment and other systems required for the fuel conversion. Fuel switching to natural gas from coal generally changes boiler and other~~ plant operations significantly.

2.1 GENERAL

Firing natural gas eliminates slagging/fouling conditions, which improves boiler cleanliness and tends to increase heat absorption. However, combustion zone radiation rates to the furnace walls tend to be lower. There are a variety of heat transfers modes in the boiler that are fairly complicated. Achieving design steam temperatures and full boiler output in a boiler designed for coal can be difficult when firing natural gas. A boiler thermal/convection-pass study performed by a boiler equipment manufacturer is required. The cost estimate provided in this study includes boiler computer modeling and a cost allowance for pressure part modifications based on an initial assessment of these boilers.

Coal and ash handling equipment are no longer required if firing natural gas fuel. As such, San Juan Generating Units operating staff could likely be reduced, which would reduce operating costs, but natural gas fuel costs are usually significant. Forced draft (FD) Fans and other boiler auxiliary equipment are usually compatible with firing natural gas.

2.2 NATURAL GAS FIRING IMPACTS ON BOILER

2.2.1 Boiler Modifications and Natural Gas Piping

Fuel switching from coal to natural gas would require the following:

- New natural gas low-NO_X burners.
- Coal piping near the burners would be removed and the remainder would be left in place.
- New natural gas igniters, scanners, cooling air, and associated equipment/components would be required.
- The existing overfire air (OFA) system would be reused.

- New Unit Common main natural gas supply piping from the source to the fence line would be included.
- New main natural gas supply piping from the existing natural gas header to the burners and burner system piping per NFPA 85 Code would be installed.
- All boiler coal firing, coal handling system equipment, sootblowers, and ash handling equipment would be retired in place. The scope to remove this equipment is not included in the cost estimate.
- The boiler would be converted to fire only natural gas, with no provisions to fire other fuels in the future.
- A boiler thermal computer analysis should be conducted by a boiler supplier to verify that the heat absorption rates and tube and steam temperatures are proper. The boiler thermal study will provide the necessary input for pressure part modification through the convection pass. It is expected that pressure parts will need to be modified with converting to natural gas for full unit output.

2.2.2 Main Natural Gas Piping

A new gas regulating station and main natural gas supply piping and burner system piping per NFPA from the property line to the boiler are provided for in the capital cost estimate.

2.2.3 Fuel Trip Furnace Negative Pressure Transients - Boiler Implosions

Conversion to firing natural gas will result in greater furnace negative pressure excursions when the boiler trips from 70% or higher unit output. The fuel cutoff and furnace flame collapse, when firing natural gas, will be much faster compared to firing coal. Therefore, boiler furnace and other structural modifications are typically needed for firing natural gas. Boiler manufacturers typically recommend reinforcing the furnace to -35" WG, but insurance companies do not typically require furnace reinforcement to -35" WG.

Units 1-4 are pressurized boilers with original furnace design pressures of 0-25" WG. The furnace section of the boiler for each unit was recently modified for a steady-state design pressure of -18" WG for the recent installation of baghouses and wet FGD systems.

An estimated budgetary capital cost for furnace reinforcement to negative 35" WG was completed by Black and Veatch. However, based on a brief review of the current draft system configuration, S&L suggests that for natural gas firing the fabric filters and the baghouse should be removed and the boiler flue gas system should be reconnected to the original stack. The ID/booster fans, wet FGD, and new chimney would not be used. Based on these changes and S&L's preliminary review of the fan pressure curves, the current furnace reinforcement modifications (current steady-state design pressure of -18" to +25" WG) and a full boiler output furnace operating pressure of approximately +15" WG should be adequate. This approach would minimize or eliminate the need for additional furnace and duct reinforcements/modifications/costs.

2.2.4 Flue Gas Recirculation

Flue gas flow rates through the boiler, without the use of FGR fans, when firing natural gas typically are lower than when firing coal. Introducing up to 20% of recirculating flue gas into the windbox will increase flue gas flow rates through the furnace and convection/backpass, which will increase heat absorption and tube metal temperatures. Excessive flue gas flow velocity through the superheater, reheater, and economizer should not be a significant issue since no ash would be present to cause erosion. Costs for a thermal/convection-pass engineering study of the boiler surface are included in the cost estimate to determine if any boiler tube modifications (material and/or additions) are needed with higher tube metal temperatures.

2.2.5 Boiler Convection Pass - Pressure Parts

Fuel switching to natural gas from coal will significantly affect boiler operation, primarily by improving boiler cleanliness and heat absorption. Improved boiler cleanliness and increased furnace exit gas temperature (FEGT) causes concern regarding boiler tube metal temperatures at full unit output. Overall, it is anticipated that main and reheat temperatures would increase with firing natural gas and an increase in attemperation would be expected to help maintain design main steam/reheat outlet temperatures. It is assumed that the current attemperators, valves, and piping are capable of operating at their original design condition and will be of sufficient capacity to control steam temperatures.

2.2.6 Furnace and Convection Pass Heat Absorption Differences

Firing with natural gas will eliminate furnace and convection pass slagging/fouling, which will tend to improve boiler cleanliness and increase heat absorption. Major performance changes for the main boiler heat absorbing surfaces are briefly described below. It is important to understand that the combustion flue gas flow from the furnace through the superheater, reheater and economizer is a fairly complex series of heat absorption stages. Accurately determining boiler performance with natural gas firing is the result of the applicable relationships of this series of heat-absorbing surfaces, which will require computer modeling and detailed boiler design. FGR, burner location and heat release, and other factors also have to be considered. The preliminary observations discussed below are provided based on maintaining the current boiler output, on S&L's experience, and on an initial assessment of this boiler.

2.2.6.1 Furnace Heat Absorption

The natural gas combustion zone heat energy radiation rate to the furnace walls is lower than with coal, tending to lower furnace heat absorption, but the furnace walls are cleaner without the coal ash and slagging that tends to increase heat absorption. These two offsetting characteristics tend to result in similar furnace heat absorption rates as for firing coal with clean furnace walls. Therefore, with natural gas firing, steam generation rates and the FEGT are often similar to coal firing.

2.2.6.2 Radiant Steam Surface

Radiant steam surfaces and the initial convection surfaces near the exit of the furnace tend to have higher heat absorption rates than with coal. This tends to cause high superheater metal and steam temperatures that require increased attemperation, FGR, steam tube replacement, and/or boiler output derating.

2.2.6.3 Convection Pass Superheater, Reheater and Economizer Surface

With natural gas firing, the superheater, reheater and convection surfaces tend to have higher absorption rates because the slagging, fouling, and ash coatings that inhibited heat transfer are not present. Improvements to design steam temperatures are expected, although modifications to the tube materials are needed.

2.2.6.4 Steam Temperature Control

Boiler cleaning with sootblowers would be discontinued with natural gas firing. When firing coal, steam temperatures are partially controlled by operating the appropriate sootblowers. When firing natural gas, this option to control boiler heat absorption would be eliminated, thereby, heightening the importance of flue gas recirculation and attemperation.

2.2.6.5 Attemperation

Increased feedwater superheater attemperation flow usually is required with natural gas firing because of the increased tubing heat absorption rate without slagging, fouling, and ash coating. Increasing attemperation rates can reduce superheat temperatures to minimize the boiler modifications needed to achieve full boiler main steam flows.

Reheat attemperation generally is low or at zero based on heat rate considerations but appreciable attemperation flow rates might be required with natural gas firing to minimize capital cost.

2.2.6.6 Computer Modeling

Computer modeling is needed to determine the new boiler operating parameters. However, the input to these models is important. Furnace heat absorption rates for new boilers are often inputted values because computer modeling / calculations have not been sufficiently developed for accurate detailed design.

Boiler thermal modeling provides calculated tube temperatures and stresses and a comparison with boiler code requirements for each boiler surface and the specific tube material and wall thickness. This information shows where modifications are required. Additionally, the current metallurgical condition and the extent of erosion and corrosion of these surfaces have to be analyzed. Typically, higher-alloy or thicker tubes are required for the final superheater and, sometimes, the reheater.

2.2.7 Fan Performance

Based on limited review of FD fan design and operating information, it is assumed that the FD fans are operating at design conditions and have sufficient pressure margin for up to 20% FGR.

2.2.8 Air Heater Leakage

Data from a recent S&L study for SJGS indicates an average air heater leakage of 14% for Units 1 and 2 and 21% for Units 3 and 4. Current air heater performance should be adequate for firing natural gas.

2.2.9 Balance-of-Plant, Electrical, and Instrumentation and Controls

The unit DCS controls would have to be reprogrammed and a new burner management system (BMS) is required for firing natural gas. New control and electrical cables would be required for the new natural gas burners and associated equipment.

2.2.10 Harvesting Study - Boiler Pressure Part Modifications

Preliminary cost estimates are provided for the repair expenditures for extended operation beyond 2017. The required expenditures for each unit will depend on how long PNM's plans, to be determined at a future date, to operate the SJGS units. Also, these expenditures will be in addition to the expenses required for operating these units until 2017 as identified in the Harvesting Study.

The costs and justifications for each unit, plant common, and switchyard are based on reviewing Generating Availability Generating System (GADS) information, limited condition assessment reports (i.e., NOTIS reports), Capital Budget Items (CBI), and the SJGS Five-Year Project Plan (see Table 2-1). Cost expenditures for operation beyond 2017 are the difference from the original Five-Year Project Plan and what is included in the separate S&L Harvesting Study (SL-010560). Coal-related costs were not removed from these expenditures (e.g., pulverizer upgrades, material handling, etc.) and all boiler components (e.g., convection pass) should be replaced per the Five-Year Project Plan.

Table 2-1. Harvesting Study – Major Boiler Pressure Part Modifications ($1000)

Parameter	Original Capital Cost	Harvesting Study Cost	Cost for Operation Beyond 2017
Unit 1	$69,271	$37,305	$31,966
Unit 2	$70,967	$48,965	$22,002
Unit 3	$59,859	$21,318	$38,541
Unit 4	$94,041	$28,742	$65,299
Unit 1&2 Common	$12,303	$4,848	$7,455
Unit 3&4 Common	$14,507	$5,976	$8,531
Unit 1 through 4 Plant Common	$43,250	$18,029	$25,221
Switch Yard	$9,062	$2,025	$7,037

2.2.11 Expected NO_X Emissions

S&L prepared a preliminary estimate of NO_X and CO emissions with new natural gas burners, existing OFA, and with/without FGR when converted to firing 100% natural gas.

Note that firing 100% natural gas will produce only thermal NO_X emissions. Thermal NO_X is formed by gas-phase chain reactions initiated between oxygen radicals and molecular nitrogen. Combustion calculations show that thermal NO_X will be produced at a rate less than 10 ppm/sec. when the combustion temperature is less than 2500°F and O_2 is 0.04 (mole fraction). Temperatures less than 2,500°F, consequently, have minimal affect on the production of thermal NO_X emissions. Therefore, FGR has a significant impact on thermal NO_X production by reducing peak flame temperatures. The limitation to the percentage of FGR introduced in the combustion air stream is the minimum windbox O_2 (%) that will have a cutoff of approximately 17% due to the impact on flame stability.

2.2.11.1 Expected Emissions without Flue Gas Recirculation System

Estimated NO_X emissions achievable on SJGS Units 1-4 with the combination of new natural gas low-NO_X burners and existing OFA system are shown in Table 2-2.

Table 2-2. Expected Emissions without FGR

Parameter	Units 1 and 2	Units 3 and 4
Expected NO_X emission (lbs/MBtu)	0.20 to 0.23	0.14 to 0.17
Expected CO emission (ppm)	≤200	≤200

2.2.11.2 Expected Emissions with Flue Gas Recirculation System

The installation of new natural gas low-NO_X burners with the existing OFA and with the introduction of FGR would reduce NO_X emissions. The limitations would be the amount of FGR that can be introduced without lowering the windbox O_2 level below 17% due to the impact on flame stability. Therefore, it is conservatively estimated that there will be a maximum level of 20% FGR. This will also result in the existing fans having sufficient capacity.

Based on the results of this initial analysis, the estimated NO_X emissions limit achievable on SJGS Units 1-4 with the combination of new natural gas low-NO_X burners, existing OFA, and FGR are as shown in Table 2-3.

Table 2-3. Expected Emission with FGR

Parameter	Units 1 and 2	Units 3 and 4
Expected NO_X emission (lbs/MBtu)	0.13 to 0.18	0.10 to 0.12
Expected CO emission (ppm)	≤200	≤200

2.2.11.3 Expected NO_X Emissions with SCR/SNCR

SCR is a process in which ammonia reacts with NO_X in the presence of a catalyst to reduce the NOx to nitrogen and water. The catalyst enhances the reactions between NO_X and ammonia, according to the following reactions:

$$4\ NO + 4\ NH_3 + O_2 \rightarrow 4\ N_2 + 6\ H_2O$$

$$4\ NO_2 + 8\ NH_3 + 2\ O_2 \rightarrow 6\ N_2 + 12\ H_2O$$

The location for this process in a typical boiler is downstream of the economizer and upstream of the air heater.

NO_X emissions resulting from the conversion of a unit to natural gas, new natural gas low-NO_X burners, FGR, and OFA are expected to range from 0.13-0.18 and 0.10-0.12 lbs/MBtu for Units 1 and 2 and Units 3 and 4, respectively. At this inlet NO_X concentration, the SCR would be expected to achieve a controlled outlet NO_X emission rate of 0.05 lbs/MBtu or lower at full unit output.

Similar to SCR, the SNCR process utilizes an ammonia reagent, primarily urea-based, which reacts with NO_X in the flue gas to form elemental nitrogen and water vapor. Unlike SCR, the SNCR process does not require catalyst to drive the reaction; instead, the driving force of the reaction is the high temperature within the boiler. NH_3 is injected into the hot flue gas at a location in the unit that provides optimum reaction temperature and residence time. The overall reactions of the SNCR process are as follows:

$$NH_2CONH_2 + H_2O \rightarrow 2NH_3 + CO_2 \text{ (occurs between 1,600°F and 2,200°F)}$$

$$2NH_3 + 2NO + 0.5O_2 \rightarrow 2N_2 + 3H_2O$$

$$2NH_3 + 2.5O_2 \rightarrow 2NO + 3H_2O \text{ (occurs above 2,000°F)}$$

The preferred temperature range for this reaction is between 1,600°F and 2,000°F, but optimal NO_X removal is achieved between 1700°F and 1850°F. At temperatures over 2,000°F, NH_3 will start to oxidize and increase NO_X emissions, which would be counter-productive and should be considered when selecting the optimal injection locations. At temperatures below 1,700°F, unreacted NH_3 will generate higher ammonia slip. Typically, NO_X removal efficiencies of 10-40% can be achieved with SNCR technology with a higher NO_X emission. NO_X removal efficiencies with SNCR tend to be lower when the uncontrolled NO_X emission is at or below 0.15 lbs/MBtu. NO_X removal efficiency of 10-15% is expected for Units 1-4.

With new natural gas low- NO_X burners, FGR, and OFA, an SNCR would be expected to achieve a controlled NO_X emission rate of 0.11-0.15 lbs/MBtu for Units 1 and 2 and 0.09-0.10 lbs/MBtu for Units 3 and 4 at full-unit output.

Table 2-4. Expected Emissions with SNCR and SCR

Parameter	Units 1 and 2	Units 3 and 4
SNCR (with FGR)	0.11 to 0.15	0.09 to 0.10
SCR (with FGR)	≤0.05	≤0.05

2.2.12 Estimated Boiler Performance

Design performance summary sheets and recent plant data were used in the estimated performance calculations. The SJGS estimated performance calculations for the natural gas-fired case are summarized in Table 2-5.

Table 2-5. Natural Gas Firing Performance Summary (per Unit)

Parameter	Units 1 and 2 Per Unit	Units 3 and 4 Per Unit
Option 1:		
Gross plant output (MW)	245	385
Natural gas feed rate (scfm)	41,247	64,834
Boiler efficiency (%)	86.2	84.7
Boiler heat input (MBtu/hr)	2,475	3,890
Combustion air flow (lbs/hr)	1,912,430	2,994,527
Flue gas flow (lbs/hr)	2,322,396	3,840,643
Option 2:		
Gross plant output (MW)	350	550
Natural gas feed rate (scfm)	59,524	93,086
Boiler efficiency (%)	85.31	84.23
Boiler heat input (MBtu/hr)	3,571	5,585
Combustion air flow (lbs/hr)	2,756,617	4,297,088
Flue gas flow (lbs/hr)	3,347,551	5,511,249

2.2.13 Cycling

Cycling operation might be required when switching to natural gas firing because of cost and availability considerations. Cycling of units that are designed for base load operation typically requires major modifications to the boiler, turbine, water treatment system, controls, large motors, piping systems, and other plant components to avoid long startup times that require appreciable fuel and operator time. The capability to accurately predict that the unit will be needed approximately 30 hours before full output is needed is another consideration.

One of many cycling operation impacts is increased boiler header and tubing stress cycling. During a warm re-start, the superheater and reheater tubing and headers will experience differential surface temperatures compared to the interface surface at wall and roof penetration sealing points, which will remain near the saturation temperature. The headers will shrink/retract as temperatures decrease during a load reduction or shutdown "bottled" condition (and the opposite upon re-starting). This differential expansion will increase the stresses and number of stress cycles on the tube to header connections, particularly at the end points, where the differential movements will be greatest. A flexible header connection design is often necessary in order to "take up" this extra movement and not transfer undue stresses to the header and tube attachment points.

Determining the requirements for cycling operation requires analysis of the boiler, turbine, water treatment system, controls, large motors, piping systems, and other unit components. A boiler/turbine bypass startup system and control system modifications may be required to reduce unit startup costs and to minimize thermal stresses. A more detailed study would be required on a unit-specific basis to determine the limitations and changes that would be required for cycling operation. Based on general experience, the estimated capital cost for installing cycling capability with gas firing at SJGS Units 1 and 2 is $41/kW (or $14.35M for each unit) and for Units 3 and 4 is $39/kW (or $21.45M for each unit); all current-day costs and at full-unit output.

2.2.14 Schedule

The scope of work for a natural gas conversion requires approximately 30 months from initiation of the preparation of the burner procurement specifications start of work to commercial operation, with an outage duration of approximately two months, which includes burner and pressure part modifications. Natural gas piping and flue gas recirculation ductwork and fan installation is typically accomplished during pre-outage.

2.2.15 Impact on O&M Costs and Labor

The fixed O&M for a typical coal unit is about $25/kW/yr, based on several variables, e.g., number of units, age of units, degree of unionization, management practices, and other factors. S&L estimates that about one third of that cost would be eliminated for a coal plant converted to operation on natural gas. The cost reduction would include elimination of the ash handling and coal handling and a reduction in water treatment and other expenses. Based on prior S&L studies and evaluations, the total O&M savings are estimated at $9/kW/year in fixed O&M cost. Difference in fuel cost is not included. This is based on unit annual operating hours in the range of 50% per year or more. If the unit is cycled and operates about 15% per year, this savings would increase to about $12/kW/yr.

3. COST ESTIMATE

Capital cost estimate line items for converting SJGS Units 1-4 to firing 100% natural gas are listed below. The preliminary engineering and design development for this cost estimate is consistent with an initial assessment and an order-of-magnitude level of accuracy of ±40%. Key notes and assumptions for the estimate are as follows:

- Limited review of equipment design information and operating data was performed.
- This study was developed without specific solicitations to the boiler supplier or other equipment suppliers based on confidentiality requirements.
- Cost estimates were prepared based on previous estimates, i.e., no preliminary design and no detailed cost estimating development was prepared for this study.
- Costs for new natural gas low-NO_X burners and equipment are based on a previous project and on discussions with boiler suppliers.
- FGR fans and ductwork costs are included. FGR fan costs are based on estimates from S&L's recent natural gas studies. It is assumed that most of the existing FGR ductwork is in place.
- Boiler component modifications for continued operation beyond 2017. Costs are from the Harvesting Study.
- The burner area natural gas piping costs are based on an estimate for a prior study.
- Reprogrammed DCS modifications and a new BMS are included.
- Electrical power cabling for new burners and integration of existing BOP equipment, such as for the igniters, flame scanner power cable, and drives, is included.
- Coal-related equipment will be retired in place. No costs are included for removal of this equipment.
- Cost for achieving 100% boiler output is included.
- Costs for asbestos or lead paint removal are not included.
- Option 2 cost estimate does not include capital costs for a SCR or SNCR.

Table 3-1 and Table 3-2 summarize the capital costs for the unit modifications. Estimated capital costs include the equipment, material, and labor based on $2011. Prices include a 30% contingency. The installed capital costs are based on past S&L natural gas studies.

Table 3-1. Option 1 Cost Estimate ($1000)

Parameter	Unit 1	Unit 2	Unit 3	Unit 4
Natural Gas Boiler Modifications				
Natural Gas Piping from Fence to Boiler Front	$1,100	$1,100	$1,450	$1,450
Natural Gas Piping at Boiler Front	$740	$740	$970	$970
New Natural Gas Burners	$7,320	$7,320	$9,600	$9,600
New BMS / Upgraded DCS	$2,010	$2,010	$2,640	$2,640
Boiler Thermal Model	$140	$140	$140	$140
Option 1 Unit Total	**$11,310**	**$11,310**	**$14,800**	**$14,800**

Table 3-2. Option 2 Unit Cost Estimate ($1000)

Parameter	Unit 1	Unit 2	Unit 3	Unit 4
Natural Gas Boiler Modifications				
Natural Gas Piping from Fence to Boiler Front	$1,100	$1,100	$1,450	$1,450
Natural Gas Piping at Boiler Front	$740	$740	$970	$970
New Natural Gas Burners	$7,320	$7,320	$9,600	$9,600
New BMS / Upgraded DCS	$2,010	$2,010	$2,640	$2,640
FGR System	$2,890	$2,890	$3,790	$3,790
Boiler Convection Modifications	$5,080	$5,080	$6,660	$6,660
Boiler Thermal Model	$140	$140	$140	$140
Option 2 Unit Total	**$19,280**	**$19,280**	**$25,250**	**$25,250**