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Richard B. Miller
Assistant General Counsel

October 26, 2006

Via Overnight Express

Hon. Jaclyn A. Brilling
Secretary
New York Public Service Commission
3 Empire State Plaza
Albany, NY 12223-1350

Re: Case 03-S-1672 – Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Consolidated Edison Company of New York, Inc. for Steam Service.

Dear Secretary Brilling:

Consolidated Edison Company of New York, Inc. ("Con Edison") hereby submits a redacted version of the Steam Production Cost Study ("Study") that was conducted by WorleyParsons Group, Inc. ("WP"), an independent engineering consulting firm, pursuant to the terms of the September 27, 2004, Order Adopting the Terms of a Joint Proposal in the above-captioned proceeding ("Order"). Con Edison is submitting today, under separate cover, an original and five copies of the unredacted Study with the Commission's Records Access Officer.

The Order required that Con Edison select an independent engineering consulting firm through a request for proposal ("RFP") process after a scope of Study was developed in coordination with the Department of Public Service Staff ("Staff"), the New York City Economic Development Corporation ("EDC") (collectively "Core Members") and other members of the Steam Business Development Task Force. In accordance with the Order, a Task Force was formed in late 2004, and numerous meetings were held to develop the scope of the Study. After the scope was completed, Con Edison issued an RFP for an engineering consulting firm to conduct the Study. WP was selected by the Core Members after an evaluation that examined credentials, references, experience, and technical competence. The Core Members also collectively supervised the Study performed by WP.

Consolidated Edison Company of New York, Inc.
4 Irving Place New York NY 10003 212 460 3389 millerrich@coned.com

The Order also provided that only the Core Members would have access to the cost projections contained in the Study report (and the Study report contains information that is otherwise confidential). Accordingly, Con Edison is filing this redacted version as the publicly available document and is simultaneously filing the original and five copies of the unredacted version with the Commission's Records Access Officer.

Please contact the undersigned if you have any questions.

Very truly yours,

Richard B. Miller

Attachments
cc: Task Force Members (via e-mail)

WorleyParsons

resources & energy

Long Term Con Edison Steam Production Options Study - Phase 1

Final Report

Prepared for

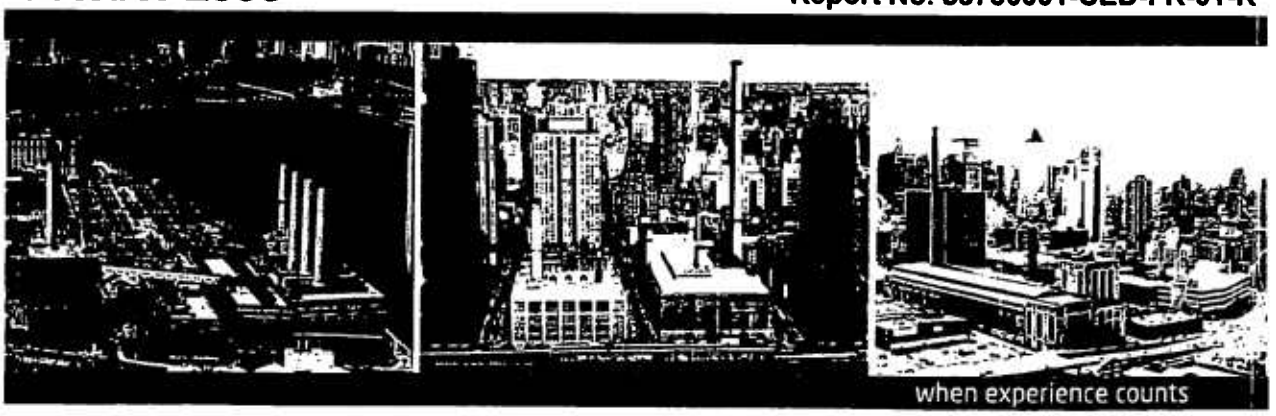
Consolidated Edison Company of New York, Inc.

In conjunction with the

Steam Business Development Core Task Force

October 2006

Report No. 53780001-CED-FR-01-R



WorleyParsons

resources & energy

Long Term Con Edison Steam Production Options Study - Phase 1

Final Report

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October 2006

Report No. 53780001-CED-FR-01-R



NOTICE

This report reflects the work performed by WorleyParsons, using technical and financial inputs provided by Consolidated Edison and others, relating to the existing condition, environment, energy demands, and other data from selected Consolidated Edison Steam Generating Stations and other steam and power generating facilities. The report is based also on information, facts, assumptions and representations provided by Con Edison and others, which have not been independently verified by WorleyParsons, and is provided solely for information purposes, and there is no representation or warranty, expressed or implied, regarding for the fairness, accuracy or completeness of the information. The information also represents WorleyParsons understanding of an approach to potential feasible Projects that will provide the most economic solution; however, every possible combination or scenario has not been considered, and no liability, howsoever arising, is or will be accepted by WorleyParsons for the fairness, accuracy or completeness of the information contained in, or any omissions from, the report, or any other information supplied or made available regarding the Project, in writing or orally, in connection with any decisions to be taken by Consolidated Edison with respect to a proposed Project, or for the consequences of any reliance upon, or other use of, any such information or the report. WorleyParsons does not take direct responsibility for decisions which are based on the findings and results presented herein. Consolidated Edison, or any other third person is responsible for making its own decisions, and we cannot predict the actions of third parties whose actions may be required to execute projects discussed herein.

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Terminology

ACC	Air Cooled Condenser
ADI	Applicability Determination Index
AFUDC	Allowance for Funds During Construction
ANSI	American National Standards Institute
BACT	Best Available Control Technology
bar	0.98692 atmospheres
BFW	Boiler Feedwater
BMS	Burner Management System
BNYCP	Brooklyn Navy Yard Cogeneration Partners
BOOS	Burners Out of Service
BOP	Balance of Plant
Btu	British thermal unit
CAMPD	Compliance Assessment Media Programs Division
CC	Combined Cycle
CEMS	Continuous Emissions Monitoring System
CERA	Cambridge Energy Research Associates
CO	Carbon Monoxide
CO_2	Carbon Dioxide
COE	U.S. Army Corps of Engineers
CT	Combustion Turbine
DC	Dump Condenser
DEC	Department of Environmental Conservation
DLN	Dry Low NOx Combustor
EPA	Environmental Protection Agency (United States)
EPC	Engineer Procure Construct
EPCM	Engineer Procure Construct Manage
ERRP	East River Repowering Project
FD	Forced Draft
°F	Degrees Fahrenheit
ft	Foot or Feet
h, hr	Hour
HHV	Higher Heating Value
HP	High Pressure (Steam)
HRSG	Heat Recovery Steam Generator
ICIP	Industrial and Commercial Incentive Program
ID	Induced Draft (Fan)
ISO	International Standards Organization
I&C	Instrumentation and Control
KPPH, klb/hr	Thousand lb/hr
kW	Kilowatts
LAER	Lowest Achievable Emission Rate
lb	Pound
LEA	Low Excess Air
LHV	Lower Heating Value
LNB	Low NOx Burner
LP	Low Pressure (Steam)
LBMP	Locational Based Marginal Pricing
MACT	Maximum Available Control Technology
Mlb/hr, MPH	Thousand lb/hr
MOU	Memorandum of Understanding
MMBH, MMBtu/hr	Million Btu/hr
MMlb/hr, MMPPH	Million lb/h
MM	Million
MMSCFD	Million Standard Cubic Feet per Day
MP	Medium Pressure (Steam)
MW	Megawatts
MWH	Megawatt-Hours
NEMA	National Electrical Manufacturers Association
NESHAP	National Emission Standards for Hazardous Air Pollutants
NGCC	Natural Gas-Fired Combined Cycle
NOx	Nitrogen Oxide

NPV	Net Present Value
NSPS	New Source Performance Standards
NSR	New Source Review
NYISO	New York Independent System Operator
OECA	Office of Enforcement and Compliance Assurances
OEM	Original Equipment Manufacturer
O&M	Operation & Maintenance
O&T	Operating & Technical
OTR	Ozone Transport Region
PFD	Process Flow Diagram
PM	Particulate Matter
PM2.5	Particulate Matter with aerodynamic diameter ≤ 2.5 microns
PM10	Particulate Matter with aerodynamic diameter ≤ 10 microns
PPH, pph	lbs/hr
PSC	Public Service Commission
PSD	Prevention of Significant Deterioration
psi	lb/square inch (14.696 psi = 1 atm)
Q	Heat
RACT	Reasonably Available Control Technology
RVM	Rearview Mirror
S	Sulfur Content of Fuel
SCFD	Standard Cubic Feet per Day
SCR	Selective Catalytic Reduction
SO_2	Sulfur Dioxide
SPDES	State Pollutant Discharge Elimination System
T&D	Transmission & Distribution (Electrical)
SOG	Shades of Green
ST	Steam Turbine
t	Ton (2000 lbs)
TCLP	Toxicity Characteristic Leaching Procedure
TGE	TransGas Energy
t/h	Tonne/hour
ton	Short Ton, (2000 lbs)
tpd	Ton per Day
US, U.S.	United States
USD, US$	the United States Dollar
VOC	Volatile Organic Compounds
VSD	Variable Speed Drive
y, yr	Year

1.0 EXECUTIVE SUMMARY

In September of 2004, the Public Service Commission issued an order adopting a Joint Proposal that called for the Consolidated Edison Company of New York, Inc. (Con Edison) to work with a newly formed Steam Business Development Task Force (Task Force) to develop the scope of a steam production cost study of long-term steam production options to be performed by an independent engineering firm selected through a competitive bid process. WorleyParsons responded to Con Edison"s solicitation for the study, and in October 2005 Gilbert/Commonwealth, Inc., doing business as WorleyParsons Group, Inc. (WorleyParsons), was contracted to perform the Phase 1 study. WorleyParsons has completed the Phase 1 study, and this report documents the work performed, results, and WorleyParsons recommendations based on the results of the study.

The Phase 1 study was a conceptual level study with a technical level of detail sufficient to estimate costs to an accuracy of ± 30%. The scope of work was limited to technical considerations within the specific facility boundaries (e.g., plant capacity, construction and installation requirements, plant performance, etc.) and their impact on the cost of steam production, and did not include considerations outside the boundaries of the facilities such as steam network interconnections, overall system impact and reliability. It also did not include land use potentials for retired facilities and policy issues.

The objectives of the Phase 1 study were to:

- Assess the condition and operation of four Con Edison facilities: the Hudson Avenue Station, the 74th Street Station, the 59th Street Station, and the Ravenswood Steam Generating Station;
- Estimate the cost of steam production at the four facilities over the next 20 years;
- Identify and initially screen, based on technical and economic criteria, repowering options that have the potential of reducing the cost of steam production at the four stations;
- Obtain information from three potential merchant steam suppliers (KeySpan Ravenswood, LLC's Ravenswood Unit 40 cogeneration plant, TransGas Energy's proposed combined cycle plant, and Brooklyn Navy Yard Cogeneration Partners (BNYCP) cogeneration plant) with respect to steam supply capability and price for supply of steam, or additional steam in the case of BNYCP;
- Estimate the cost to produce steam for the Con Edison steam system by two "proxy" customers, one with a boiler and one with a cogen system; and

- Estimate the impact of repowering options and steam supply by the alternative facilities on steam production costs and emissions City-wide.

The Phase 1 study consisted of seven technical tasks, two reporting/presentation tasks, and a project management task. The tasks performed are as follows:

- Task 1-1 – Program Management
- Task 1-2 – Assess Existing Plant & Operation
- Task 1-3 – Establish Economic and Environmental Criteria for the Study
- Task 1-4 – Inception Report/Presentation
- Task 1-5 – Develop Current & Projected Cost of Operation
- Task 1-6 – Investigate the Feasibility of Re-Powering Con Edison Facilities
- Task 1-7 – Investigate the Cost of Steam from Alternative Facilities
- Task 1-8 – Evaluate Customer Supplied Steam
- Task 1-9 – Phase 1 Report to Task Force
- Task 1-10 – Presentation of Phase 1 Results

This Executive Summary provides a summary of the key results, and the sections that follow provide details of the approach and results of these tasks.

ASSESSMENT OF EXISTING PLANT & OPERATION

The objective of this task was to assess the physical conditions and identify the operational issues of the existing equipment at the four Con Edison facilities: Hudson Avenue Station, 74th Street Station, 59th Street Station, and Ravenswood Steam Generating Station.

The results of the assessment are summarized below. Details of the results are presented in Section 4 for the Hudson Avenue, 59th Street, and 74th Street Stations and in Appendix G for the Ravenswood Steam Generating Station. It is to be noted that WorleyParsons' assessment is based on the review of inspection reports and other documents pertaining to the operation and maintenance of the facilities provided by Con Edision, physical walk down of the facilities, and various interviews with Con Edison personnel. In accordance with the Core Team's scope of work, it did not include internal inspection of equipment to verify conditions.

- The Boilers at the 59th and 74th street stations are performing well. They are expected to provide reliable operation for the next 20 years with the current ongoing and planned upgrades and maintenance program.

- The operating low pressure boilers and auxiliaries at the Hudson Avenue Station are old and are not considered suitable for 20 year operation without replacement. The existing boiler house buildings and structures are not considered suitable for installing new equipment for re-powering options.

- One of the four boilers at the Ravenswood Steam Generating Station has been shutdown since 2001, and the remaining three boilers are currently operating at about 20% to 30% below their design capacities due to various maintenance issues. The boilers need either rebuilding or replacement to provide reliable and efficient steam supply over the next 20 years.

DEVELOPMENT OF CURRENT & PROJECTED COST OF OPERATION WITH AND WITHOUT RE-POWERING AND EMISSIONS ASSESSMENT

The four facilities were evaluated with respect to repowering options that have the potential for reducing the cost of steam production at the Stations. The steam production costs over 20 years for each of the options were evaluated. The costs included capital costs for equipment; materials and labor for installation and construction; demolition, remediation, and relocation of existing equipment; engineering and permitting costs; owner's costs such as overhead, property taxes, and income taxes; and operating and maintenance costs (fuel and non-fuel); and credits (revenue) associated with electric power sales and emissions reduction credits. Fuel and electricity price projections developed by Cambridge Energy Research Associates (CERA) were used in the evaluation. The CERA 2005 Rearview Mirror price projection scenario was initially used for the evaluations, and a sensitivity analysis using CERA's Shades of Green scenario was performed. A summary of the themes, primary inputs, and key outputs for the scenarios provided by CERA is presented in Exhibit 3-1 in Section 3.1. The major difference in prices between the two scenarios is that the fuel and electric energy prices beyond the year 2010 are significantly higher in the Shades of Green scenario than in the Rearview Mirror. The Shades of Green scenario prices are [REDACTED] than the Rearview Mirror scenario prices beyond 2010.

The repowering options evaluated and the projected costs of operation for the options for the four Stations are summarized in the following sections.

Hudson Avenue Station

Fourteen Options were considered for this facility as follows:

- Four Combustion Turbine (Gas Turbine) Cogeneration (CG) Options: Each of these options uses a new natural gas-fired (primary fuel) combustion turbine with supplementally fired heat recovery steam generator (HRSG) and multiple package boilers. Option CG-1 uses a Siemens 501D5 Gas Turbine model (117 MWe net); CG-2 uses a GE 7EA (84 MWe net); CG-3 uses a GE LM-6000 (42 MWe net); and CG-4 uses a Siemens GTX 100 (43 MWe net). The combustion turbine/HRSG systems are sized to allow for baseload operation, with the package boilers used to satisfy additional steam demand.
- Six Combustion Turbine Combined Cycle (CC) Options: Five of these options use a new natural gas-fired combustion turbine with HRSG, a steam turbine, and multiple package boilers. One option uses 2 combustion turbines with HRSGs and one steam turbine. Option CC-1 uses a Siemens 501D5 Gas Turbine model (146 MWe net), CC-2 uses a GE 7EA (104 MWe net), CC-3 uses a GE LM-6000 (43 MWe net), CC-4 uses a Siemens GTX 100 (48 MWe net), CC-5 uses a Siemens 501F (258 MWe net), and CC-6 uses two GE 7FAs (479 MWe net). The combustion turbine systems are sized for baseload

operation, with package boilers used to satisfy additional steam demand if required.

- Four Boiler (BP) Options: Two of these options (BP-1 and BP-1A) involve refurbishing the currently retired Unit 10/100 boiler with topping steam turbine at the facility, conversion of the boiler to natural gas firing as the primary fuel, retrofitting the system with a dump condenser to increase annual electric energy generation within the projected steam sendout profile, and addition of new package boilers to meet the facility steam capacity criterion. One option (BP-2) uses all new package natural gas-fired (primary fuel) boilers, and the fourth option (BP-3) uses all new package natural gas-fired boilers and a small back pressure Steam Turbine.

For more details on electric and steam capacity of these 14 cases, see Exhibit 4-8, Exhibit 4-9, and Exhibit 4-10 in Section 4.0 of the report.

The potential advantages and disadvantages of these options are summarized in Exhibit 1-1.

The estimated steam production costs are summarized in Exhibit 1-2 and Exhibit 1-3 using the CERA 2005 Rearview Mirror price projections. Exhibit 1-2 shows the net present value (NPV) of the 20 years of net total cost of steam production; that is, the annual costs including credits for emission reduction, electricity sales, and NYISO blackstart tariff. Exhibit 1-3 shows the NPV of the 20 years of net total cost of steam production divided by the discounted annual steam sendout (Unit NPV), a Figure of Merit used by WorleyParsons to identify the promising options.

Since the existing boilers need to be replaced at the Hudson Avenue Station, Option BP-2 represents the projected current system cost of operation.

[REDACTED]

[REDACTED]

A summary of the Unit NPV of 20 years of net total steam production costs for the repowering options using the CERA 2005 Shades of Green price projections is shown in Exhibit 1-4. [REDACTED].

Exhibit 1-1 Advantages and Disadvantages of Hudson Avenue Station Repowering Options

	Pros	Cons
Cogeneration Relative to Combined Cycle	♦ Lower capital cost ♦ Smaller footprint for same steam sendout capacity ♦ Lower maintenance costs	♦ Lower electric generation capacity ♦ Lower electric generation efficiency ♦ Require dumping of steam for some options that cannot be effectively used ♦ No flexibility to increase/optimize electric generation versus steam sendout
Cogeneration Relative to Boiler Only Options	♦ Electric generation capability ♦ Higher overall energy efficiency	♦ Larger space requirement ♦ Higher capital cost ♦ More complex operation ♦ Higher maintenance costs ♦ Electric market risk
Cogeneration Relative to Unit 10/100 Boiler/ST Option	♦ Higher average electric generation capability ♦ Higher energy efficiency	♦ Higher capital cost ♦ Extensive demolition/remediation required ♦ Higher maintenance costs
Large Cogeneration Relative to Small Cogeneration	♦ Higher electric generation capacity ♦ Higher efficiency ♦ Fewer package boilers for peak loads	♦ Higher capital cost ♦ Larger space requirement ♦ Higher maintenance costs
Combined Cycle Relative to Boiler Only Options	♦ Electric generation capability ♦ Higher overall energy efficiency ♦ Provides flexibility of generation of both electric and steam to maximize revenue	♦ Larger space requirement ♦ Higher capital cost ♦ More complex operation ♦ Higher maintenance costs ♦ Electric market risk
Combined Cycle Relative to Unit 10/100 Boiler/ST Option	♦ Higher electric generation capacity ♦ Higher energy efficiency	♦ Higher capital cost ♦ Extensive demolition/remediation required ♦ Higher maintenance costs
Large Combined Cycle Relative to Small Combined Cycle	♦ Higher electric generation capacity ♦ Higher efficiency ♦ Fewer package boilers for peak loads ♦ Lower overall cost of steam	♦ Higher capital cost ♦ Larger space requirement ♦ Higher maintenance costs

Exhibit 1-2 NPV of Cost of Steam Production for Hudson Avenue Repowering Options (2006 to 2025) based on CERA 2005 Rearview Mirror Fuel and Electric Price Projections

[REDACTED]

Exhibit 1-3 Unit NPV of Cost of Steam Production for Hudson Avenue Repowering Options (2006 to 2025) based on CERA 2005 Rearview Mirror Fuel and Electric Price Projections

[REDACTED]

Exhibit 1-4 Unit NPV of Cost of Steam Production for Hudson Avenue Repowering Options (2006 to 2025) based on CERA 2005 Shades of Green Fuel and Electric Price Projections

[REDACTED]

The emissions resulting from the repowering options were evaluated with respect to New Source Performance Standards (NSPS), National Emissions Standards for Hazardous Air Pollutants (NESHAP), and Prevention of Significant Deterioration/New Source Review (PSD/NSR) requirements. All of the repowering options were designed to meet NSPS and NESHAP requirements. Results of the evaluation indicate that some level of capacity factor limitation would be required for all of the combustion turbine cogeneration and combined cycle options to maintain the CO and PM10 emissions below levels of significant emissions triggering PSD/NSR; however, none of the capacity limitations would be below 69%, and all well above the approximate [REDACTED] annual capacity factor projection for all of the options based on the annual steam projections provided by Con Edison for the study.

Estimates of the expected annual emissions for each of the repowering options evaluated are compared to the expected annual emissions from the existing boiler systems (Base), based on the annual steam sendout projections provided by Con Edison, in Exhibit 1-5. The options considered to be promising from a cost of steam production viewpoint also result in significant emission reductions relative to the existing boilers at the projected annual steam sendout provided by Con Edison for the study.

Exhibit 1-5 Summary of Expected Annual Emissions for Hudson Avenue Station Repowering Options

[REDACTED]

59th Street Station

In addition to the current operating configuration (Existing) at 59th Street Station, two Re-powering Cogeneration Options were considered as follows:

- Option CG-1 consists of a GE LM-6000 combustion turbine and supplementally-fired HRSG, and
- CG-2 consists of a Siemens GTX 100 Gas Turbine model and supplementally-fired HRSG.

The combustion turbines are sized for baseload operation; however, since the existing package boilers at the facility are expected to be able to provide reliable operation over the study period with the planned maintenance activities, no additional new package boiler is contemplated with either option for meeting peak steam demand. No existing boilers are planned to be taken out of service.

A summary of the estimated steam production costs for the Existing and Repowering Options over 20 years, based on the CERA 2005 Rearview Mirror scenario price projections, are summarized in Exhibit 1-6 and Exhibit 1-7. A summary of the Unit NPV of steam production costs based on the CERA 2005 Shades of Green scenario price projections are shown in Exhibit 1-8. As can be seen from in the Exhibits, continued operation of the existing system has the lowest NPV of steam production costs for both CERA price projection scenarios.

Exhibit 1-6 NPV of Cost of Steam Production for 59th Street Repowering Options (2006 to 2025) Based on CERA 2005 Rearview Mirror Price Projections

[REDACTED]

Exhibit 1-7 Unit NPV of Cost of Steam Production for 59th Street Repowering Options (2006 to 2025) Based on CERA 2005 Rearview Mirror Scenario Price Projections

[REDACTED]

Exhibit 1-8 Unit NPV of Cost of Steam Production for 59th Street Repowering Options (2006 to 2025) Based on CERA 2005 Shades of Green Scenario Price Projections

[REDACTED]

The expected annual emissions from the 59th Street options based on the annual steam sendout projections provided by Con Edison are summarized in Exhibit 1-9. The annual emissions from both repowering options are expected to satisfy current NSPS and NESHAP requirements, and the annual emission increases would not exceed levels triggering PSD/NSR.

Exhibit 1-9 Summary of Expected Annual Emissions for 59th Street Station Repowering Options

[REDACTED]

74th Street Station

Major considerations in the evaluation of potential repowering options for 74th Street Station included the following;

- The site has limited available space for addition of new equipment – space exists on the turbine deck, but Con Edison has plans for installing a substation and new battery room on the turbine deck that will take up about 50% of the available space;
- There is currently no gas supply available at the station, and emissions regulations that would become applicable if repowering would require natural gas as the primary fuel;
- Available head room in the facility poses a challenge to the installation of any HRSG associated with a medium or large as turbine (similar to other plants);
- Stack draft issues would likely require installation of a new stack; and
- Deliver of large pieces of equipment would likely require the temporary closing of the FDR Drive and off the eastern end of 74th and/or 75 Streets.

Based upon these considerations and the details presented later in the Report, WorleyParsons is of the opinion that the current system will provide the lowest cost of steam production compared to other feasible re-powering options considered in the Hudson Avenue and 59th Street facilities. Therefore, the estimated steam production

cost presented in Exhibit 1-10 represents the current operation only, based on the CERA 2005 Rearview Mirror scenario price projections.

The expected annual emissions from the facility based on the annual steam sendout projections provided by Con Edison are shown in Exhibit 1-11.

Exhibit 1-10 NPV of Cost of Steam Production for 74th Street Station Based on CERA 2005 Rearview Mirror Scenario Price Projections

	Existing 74th Street Station System
NPV of Cost of Steam Production, MM$	
Unit NPV of Cost of Steam Production, $/Mlb steam	

Exhibit 1-11 74th Street Station Projected Annual Emissions Summary

[REDACTED]

Ravenswood Steam Generating Station

Eight repowering options, as identified by Con Edison, were evaluated for the Ravenswood Steam Generating Station. Four of the options considered the rebuilding of the existing boilers at the facility and converting them to natural gas firing (as the primary fuel), and four of the options considered replacement of the existing boilers with new natural gas-fired (primary fuel) package boilers. The options are summarized as follows:

- Option RB-1: In this option, one of the existing boilers is rebuilt to its original steam generating capacity [REDACTED], and the other three boilers are retired from service;

- Option RB-2: In this option, two of the existing boilers are rebuilt to their original steam generating capacity, and the other two boilers are retired from service;
- Option RB-3: In this option, three of the existing boilers are rebuilt to their original steam generating capacity, and the other boiler retired from service;
- Option RB-4: In this option, all four of the existing boilersare rebuilt to their original steam generating capacity;
- Option NB-1: In this option, one of the existing boilers is replaced with a new package boiler with the same steam generating capacity, and the other three existing boilers are retired from service;
- Option NB-2: In this option, two of the existing boilers are replaced with two new package boilers with the same steam generating capacity, and the other two existing boilers are retired from service;
- Option NB-3: In this option, three of the existing boilers are replaced with three new package boilers with the same steam generating capacity, and the other existing boiler is retired from service;
- Option NB-4: In this option, all four of the existing boilers are replaced with new package boilers with the same generating capacity.

The estimated steam production costs for the options evaluated are compared in Exhibit 1-12 and Exhibit 1-13, based on the CERA 2005 Rearview Mirror scenario fuel and electricity price projections. Exhibit 1-12 shows the NPV of steam production costs over the 20 year evaluation period. Exhibit 1-13 shows the Unit NPV of steam production costs over the 20 year period. A summary of the Unit NPV of steam production costs based on the CERA 2005 Shades of Green scenario price projections are shown in Exhibit 1-14. [REDACTED]

The Unit NPV of steam production costs over the 20 year evaluation period is expected to be lowest for the [REDACTED] for both CERA price projections.

As can be seen in Exhibit 1-12, the emissions reductions credits (ERCs) have little impact on the NPV of cost of steam production. The ERCs are based on the expected annual emissions at the projected annual steam sendout, which is equivalent to an annual capacity factor of about [REDACTED]. Therefore, taking the ERCs would limit the annual operating capacity to about [REDACTED]. Therefore, it would likely be more advantageous to not take the ERCs to allow for operation at higher capacity factors should steam demand be greater than projected.

Exhibit 1-12 NPV of Steam Production Cost for Ravenswood Steam Generating Station Repowering Options (2006 to 2025) Based on CERA 2005 Rearview Mirror Price Projections

[REDACTED]

Exhibit 1-13 Unit NPV of Steam Production Cost for Ravenswood Steam Generating Station Repowering Options (2006 to 2025) Based on CERA 2005 Rearview Mirror Price Projections

[REDACTED]

Exhibit 1-14 Unit NPV of Cost of Steam Production for Ravenswood Steam Generating Station Repowering Options (2006 to 2025) based on CERA 2005 Shades of Green Fuel and Electric Price Projections

[REDACTED]

Summaries of the emissions requirements and expected emissions from the repowering options based on the annual steam sendout projections for the facility provided by Con Edison are shown in Exhibit 1-15 (rebuild options) and Exhibit 1-16 (replacement options). No increase in emissions relative to the current boilers' emissions are expected for the rebuild options based on natural gas as the primary fuel and No. 6 fuel oil as the backup fuel (maximum of 30 days oil firing). Therefore, NSR would not be expected to be triggered by the rebuild options. This is discussed in more detail in Appendix G.

The PM10 annual emission increase for the [REDACTED] would trigger PSD/NSR. However, a 90% annual capacity factor for [REDACTED] would result in emissions being below PSD/NSR requirements. This is significantly greater than the annual capacity factor used as a basis for the option evaluations (REDACTED).

Exhibit 1-15 Emissions Requirements and Expected Emissions for Boiler Rebuild Options at Ravenswood Steam Plant

		CO				SO2				PM10				PM				NOx				VOC			
		Lbs/MMBtu		Tons/Year		Lbs/MMBtu		Tons/Year		Lbs/MMBtu		Tons/Year		Lbs/MMBtu		Tons/Year		Lbs/MMBtu		Tons/Year		Lbs/MMBtu		Tons/Year	
		Limit	Expected	Limit	Expected	Limit	Expected	Limit	Expected	Limit	Expected	Limit	Expected	Limit	Expected	Limit	Expected	Limit	Expected	Limit	Expected	Limit	Expected	Limit	Expected
Option - RB1	Natural Gas																								
	No. 6 Oil																								
Option - RB2	Natural Gas																								
	No. 6 Oil	[ALL DATA REDACTED]				[ALL DATA REDACTED]				[ALL DATA REDACTED]				[ALL DATA REDACTED]				[ALL DATA REDACTED]				[ALL DATA REDACTED]			
Option - RB3	Natural Gas																								
	No. 6 Oil																								
Option - RB4	Natural Gas																								
	No. 6 Oil																								

Rebuild Option - RB1 – One boiler rebuilt (assuming lowest "paired" emissions, which includes emissions from one boiler)
Rebuild Option - RB2 – Two boilers rebuilt (assuming highest "paired" emissions, which includes emissions from two boilers)
Rebuild Option - RB3 – Three boilers rebuilt (assuming all "paired" emissions, which includes emissions from three boilers)
Rebuild Option - RB4 – Four boilers rebuilt (Non-operating Boiler 3 actual emissions assumed at zero)

Emission comparison based on current actual emissions to future actual emissions ([REDACTED]).
Tons/Year Limit includes Significant Net Emission Increase requirement

/1/ Based on MACT limit of 400 ppmvd corrected to 3% oxygen
/2/ NSPS limit includes an exception for low sulfur oil (0.3% S).
/3/ MACT limit of 0.03 lbs/MMBtu allows firing of No. 6 oil only during gas curtailment (natural gas primary fuel with No. 6 oil backup)
/4/ NSPS limit of 0.20 lbs/MMBtu requires additional 25% reduction in NOx emissions beyond LNB for No. 6 oil firing. This is accomplished with SCR.

Exhibit 1-16 Emissions Requirements and Expected Emissions for Boiler Replacement Options at Ravenswood Steam Plant

		CO					SO2					PM10					PM					NOx					VOC				
		Lbs/MMBtu		Tons/Year			Lbs/MMBtu		Tons/Year			Lbs/MMBtu		Tons/Year /7/			Lbs/MMBtu		Tons/Year			Lbs/MMBtu		Tons/Year			Lbs/MMBtu		Tons/Year		
		Limit	Expected /1/	Limit	Potential	Expected	Limit	Expected	Limit	Potential	Expected	Limit	Expected	Limit	Potential	Expected	Limit	Expected	Limit	Potential	Expected	Limit	Expected /5/	Limit	Potential	Expected	Limit	Expected /6/	Limit	Potential	Expected
Option - NB1	Natural Gas																														
	No. 6 Oil																														
Option - NB2	Natural Gas																														
	No. 6 Oil	[ALL DATA REDACTED]					[ALL DATA REDACTED]					[ALL DATA REDACTED]					[ALL DATA REDACTED]					[ALL DATA REDACTED]					[ALL DATA REDACTED]				
Option - NB3	Natural Gas																														
	No. 6 Oil																														
Option - NB4	Natural Gas																														
	No. 6 Oil																														

Rebuild Option 1 – One new boiler (existing A-House Boilers shutdown and/or removed)
Rebuild Option 2 – Two new boilers (existing A-House Boilers shutdown and/or removed)
Rebuild Option 3 – Three new boilers (existing A-House Boilers shutdown and/or removed)
Rebuild Option 4 – Four new boilers (existing A-House Boilers shutdown and/or removed)

Emission comparison based on current actual emissions to future potential emissions (i.e., 8,760 hours/year at 100% capacity factor).
Tons/Year Limit includes Significant Net Emission Increase requirement

/1/ Expected emission based on oxidation catalysts: 80% reduction firing natural gas and 50% reduction firing No. 6 oil.
/2/ Based on MACT limit of 400 ppmvd corrected to 3% oxygen
/3/ NSPS limit includes an exception for low sulfur oil (0.3% S).
/4/ MACT limit of 0.03 lbs/MMBtu allows firing of No. 6 oil only during gas curtailment (natural gas primary fuel with No. 6 oil backup)
/5/ Expected emission based on selective catalytic reduction: 70% reduction firing natural gas and 35% reduction firing No. 6 oil.
/6/ Expected emission based on oxidation catalysts: 50% reduction firing natural gas and 25% reduction firing No. 6 oil.
/7/ PM10 emissions for the four replacement boilers would result in NSR applicability. ~90% capacity factor for all four replacement boilers or one boiler with ~40% capacity factor and others at 100% capacity factor would result in emissions below NSR applicability requirements.

COST OF STEAM FROM ALTERNATIVE STEAM SUPPLIERS

KeySpan Ravenswood, LLC Combined Cycle Unit 40 Alternative

Information was obtained from KeySpan Ravenswood, LLC with respect to the potential for KeySpan's Ravenswood Combined Cycle Unit 40 to provide steam to the Con Edison steam system. KeySpan provided indicative pricing formulas for purchase of steam [REDACTED] by Con Edison as a function of fuel and electric energy cost. [REDACTED]

[REDACTED]. The three options provided by KeySpan are as follows:

Option 1 – [REDACTED].

Option 2: [REDACTED].

Option 3: [REDACTED].

The KeySpan Alternative would replace the steam provided by Con Edison's Ravenswood Steam Generating Station (A-House). The interconnection between the KeySpan Unit 40 steam supply and the Con Edison steam system would be at the existing headhouse at the A-House. The existing steam distribution piping from the headhouse has sufficient capacity to handle the [REDACTED] maximum steam sendout proposed by KeySpan; however, the steam flow rate is currently limited to 860,000 lb/hr maximum due to piping restrictions at 71st Street and at the 74th Street Generating Station in Manhattan. Modifications to the piping at 71st Street and 74th Street would be required to allow distribution of up to [REDACTED] of steam, and the costs are included in the net cost of steam for the KeySpan Alternative.

WorleyParsons used the indicative pricing provided by KeySpan to evaluate the net cost of steam for the KeySpan alternative and also included the cost of modifications to the 71st Street and 74th Street piping system, the cost of firm gas reinforcements for KeySpan Unit 40, the cost of operating Con Edison's Ravenswood Steam Plant at its current steam sendout until KeySpan's Unit 40 is ready to supply steam, and the subsequent cost to retire Con Edison's Ravenswood Steam Plant. Fuel and electricity prices used in the evaluation were based on the CERA Rearview Mirror fuel and electricity price projections, as were the evaluations for all alternatives in this study.

The estimated NPV of net projected costs of steam over the 20 year evaluation period (2006 to 2025) for the [REDACTED] KeySpan Alternative Options [REDACTED] are summarized in Exhibit 1-17, based on the CERA 2005 Rearview Mirror Sceanario fuel and electricity price projections.

Exhibit 1-17 Net Cost of Steam Production for the KeySpan Alternative Supply of Steam Based on the CERA 2005 Rearview Mirror Scenario Price Projections

	Option 2 [REDACTED]	Option 3 [REDACTED]
NPV of Cost of Steam, MM$	[REDACTED]	[REDACTED]
Unit NPV of Cost of Steam, $/Mlb	[REDACTED]	[REDACTED]

A comparison of the estimated cost of steam production associated with the two compliant KeySpan Alternative options to the estimated cost of steam production from the Con Edison Ravenswood Steam Generating Station for the [REDACTED] option ([REDACTED]) is presented in Exhibit 1-18. A direct comparison can be made because both alternatives have the capability of supplying up to 976,000 lb/hr of steam to the Con Edison steam system, and both alternatives interconnect with the steam network from the Ravenswood Steam Generating Station headhouse. [REDACTED].

Exhibit 1-18 Comparison of Unit NPV of Steam Production Cost for KeySpan Alternative Options with Ravenswood Steam Generating Station Repowering Options Based on CERA 2005 Rearview Mirror Price Projections

[REDACTED]

TransGas Energy (TGE) Proposed Cogeneration Alternative

WorleyParsons requested the information identified in WorleyParsons' scope of work from TransGas Energy (TGE), via Alternative Facilities Data/Information Request (DIR) document, with respect to a TGE cogeneration facility providing steam to the Con Edison steam system. TGE responded with a completed spreadsheet with the technical data requested by WorleyParsons and a copy of a summary of results of an assessment previously performed by TGE of the benefits to New York City of a TGE proposed 824 MW electric power and steam cogeneration facility in New York City, providing steam to the Con Edison steam system. A copy of the summary document is included in the Appendix F.

WorleyParsons then had a follow-up meeting with TGE in New York City to discuss the information provided and request additional information required to complete WorleyParsons' task with respect to evaluating the TGE supply option. The additional information requested included TGE's proposed price of steam to Con Edison as a function of steam sendout (to meet Con Edison's requirement for control over dispatchability from zero to maximum proposed steam sendout), and price of fuel and electricity in order for WorleyParsons to evaluate the cost of TGE supplied steam to Con Edison over the next 20 years using CERA projected fuel and electricity prices.

In response to WorleyParsons' request for additional information, TGE provided a matrix of indicative steam price as a function of natural gas price and combined electricity energy and capacity price for one TGE supplied steam sendout, that is, 2

million lb/hr. This information, however, was not in compliance with Con Edison's O&T requirements. Upon further request by WorleyParsons, TGE still did not provide a compliant offer for the study.

Based on the technical, price, and economic data that TGE provided to WorleyParsons for the 2 million lb/hr steam supply, WorleyParsons estimated the cost of TGE steam to Con Edison over 20 years and the net present value of the cost of steam, using the CERA 2005 Rearview Mirror Scenario price projections for fuel and electricity prices, as best possible with the data provided. A major difference between the TGE alternative and other alternatives evaluated by WorleyParsons as a part of this study is that the quantity of steam supply by the other alternatives evaluated is the same as that currently being supplied by the particular facility being evaluated; whereas, the quantity of steam supply proposed by TGE (2 million lb/hr) requires an evaluation of the Con Edison steam distribution network to determine if reinforcements and/or enhancements are necessary to distribute the steam to end-users and the potential costs of reinforcements. Additionally, WorleyParsons did not evaluate whether the steam system can be operated and dispatched to permit the base load delivery of 2 million lb/hr on a 24/7 basis. Such evaluations were beyond WorleyParsons scope of work for the study, and, therefore, steam distribution network reinforcement costs, if necessary, are not included in WorleyParsons evaluation of the cost of TGE steam supply. Accordingly, a comparison between the TGE Alternative and the other alternatives considered in this study would not be meaningful.

Customer Sell Back Options

WorleyParsons in consultation with the Core Task Force Members postulated two representative customer supplied steam facilities and the underlying assumptions regarding the options. Two steam supply options, one utilizing a cogeneneration system and the other utilizing boilers only, to supply steam to Con Edison were considered from proxy-facilities with characteristics considered to be representative of these type options. In the first option, the facility generates electricity and produces steam simultaneously to support internal demands first and then export excess steam to Con Edison. In the Boiler Only Option, the facility will buy all electricity from the grid and sell steam to Con Edison. In both cases, steam supply will meet Con Edison's O&T requirements and no steam import from Con Edison is contemplated. The two options were evaluated with economic factors (e.g., equity capitalization ratio, required rate of return on equity, loan interest rate, and cost of capital) representative of a commercial facility and with economic factors representative of an academic facility.

The cost of steam from these options depends on the export steam capacity factor of the facilities. Therefore, the evaluation of this option included an export steam capacity factor sensitivity analysis. The potential costs of steam from these facilities as a function of export steam capacity factor are summarized in Exhibit 1-19 and Exhibit 1-20 for the CERA 2005 Rearview Mirror Scenario fuel and electricity price projections. Currently, Con Edison steam generating stations operate at an average annual capacity factor of 27%.

Exhibit 1-19 NPV of Net Steam Production Cost per Mlb Discounted Steam Sendout for Commercial Customer Supplied Steam Options Versus Annual Steam Sendout Capacity Factor Based on CERA 2005 Rearview Mirror Scenario Price Projections

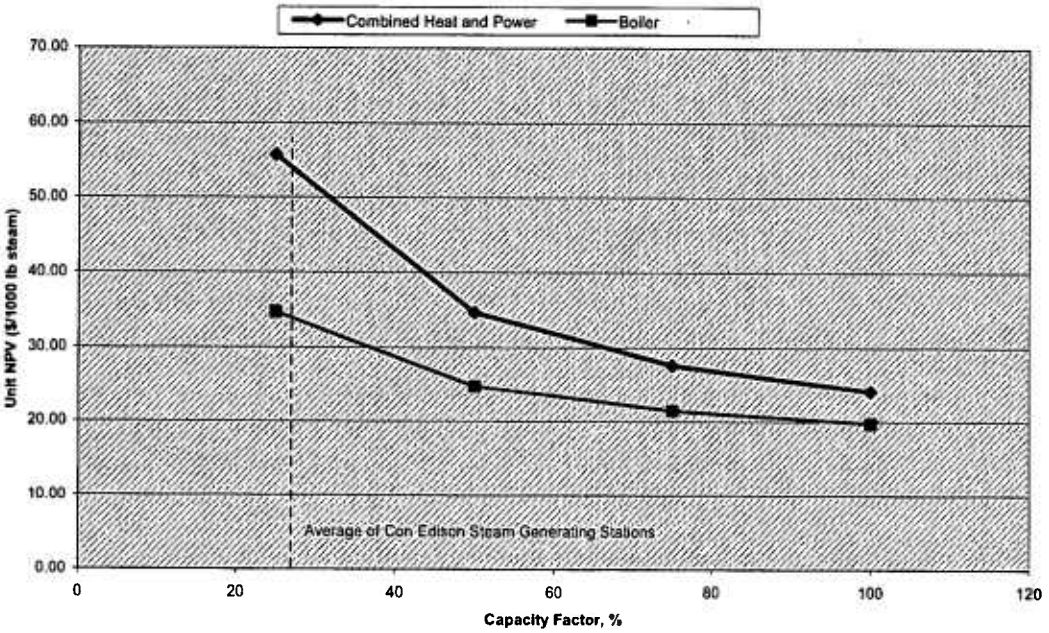
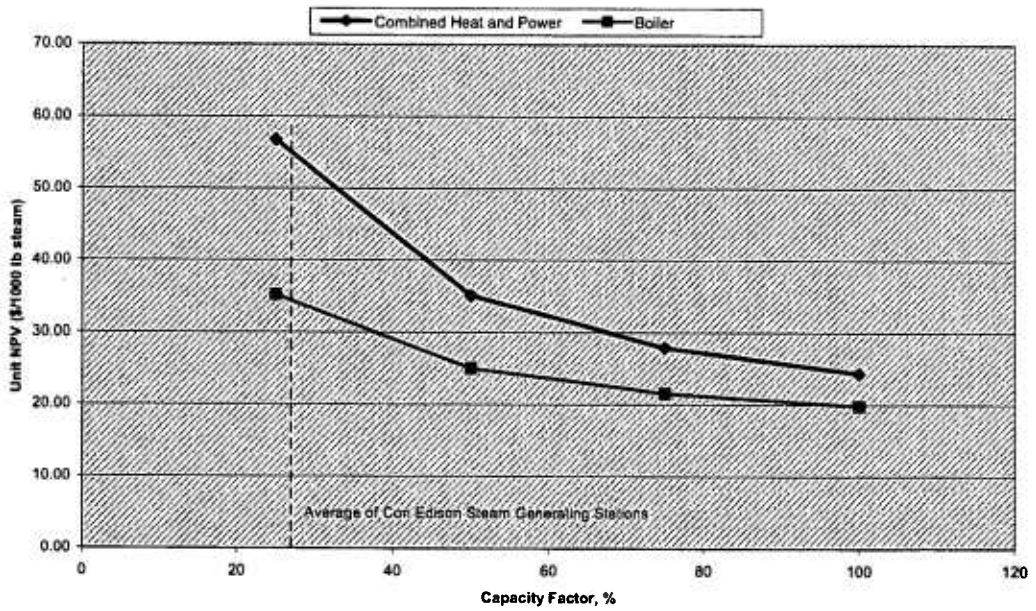


Exhibit 1-20 NPV of Net Cost of Steam Production per Mlb Discounted Steam Sendout for Academic Customer Supplied Steam Options Versus Annual Steam Sendout Capacity Factor Based on CERA 2005 Rearview Mirror Scenario Price Projections



IMPACT OF OPTIONS AND ALTERNATIVE SUPPLIES OF STEAM ON EMISSIONS AND ELECTRIC AND STEAM PRODUCTION COSTS CITY-WIDE DUE TO VARIABLE FUEL AND EMISSION COSTS

Hudson Avenue Station

The impact of the Hudson Avenue cogeneration repowering options on electric and steam production costs City-wide due to variable fuel and emission costs are summarized in Exhibit 1-21, Exhibit 1-22, and Exhibit 1-23. The boiler only repowering option (BP2) was used as the base since it is WorleyParsons opinion that the existing boilers at the Hudson Avenue Station would not operate reliably over the 20 year study period. The evaluation took into consideration the avoided fuel cost of an electric power generating unit in Zone J associated with the portion of electric energy that would be displaced by the Hudson Avenue cogeneration options. It should be emphasized that the evaluation did not consider non-fuel and emissions operating costs nor other annual costs, including the contribution of capital to annual costs. In addition, because the purpose of this study is to determine the options that will lower steam production costs, the recommendations presented later in this report are based on the results shown in Exhibit 1-3.

The impact of the Hudson Avenue repowering option BP-1 and CG-1 on emissions City-wide is summarized in Exhibit 1-24 and Exhibit 1-25, respectively, for NOx, SO_2, PM10, PM, VOC, and CO. Similar evaluations and comparisons were performed for the other repowering options at Hudson Avenue and are presented in Section 7.1.2.

Exhibit 1-21 Impact of Hudson Avenue Cogeneration Repowering Options on Net Electric and Steam Production Costs City-Wide Due to Variable Fuel and Emissions Costs (NPV)

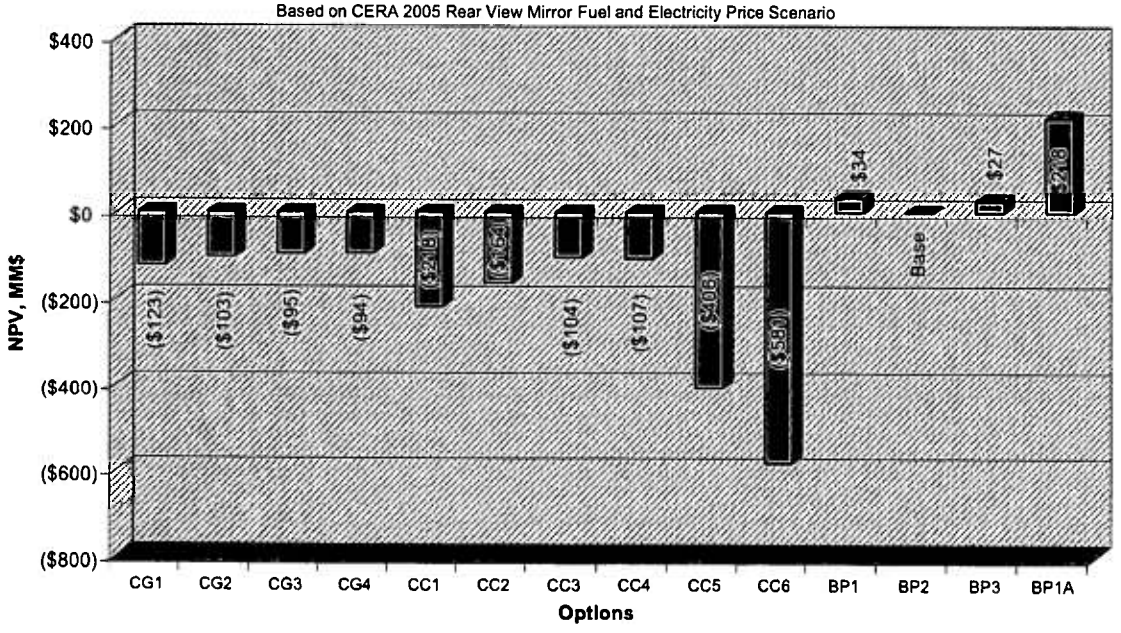


Exhibit 1-22 Impact of Hudson Avenue Cogeneration Repowering Options on Net Electric and Steam Production Costs City-Wide Due to Variable Fuel and Emissions Costs (Unit NPV)

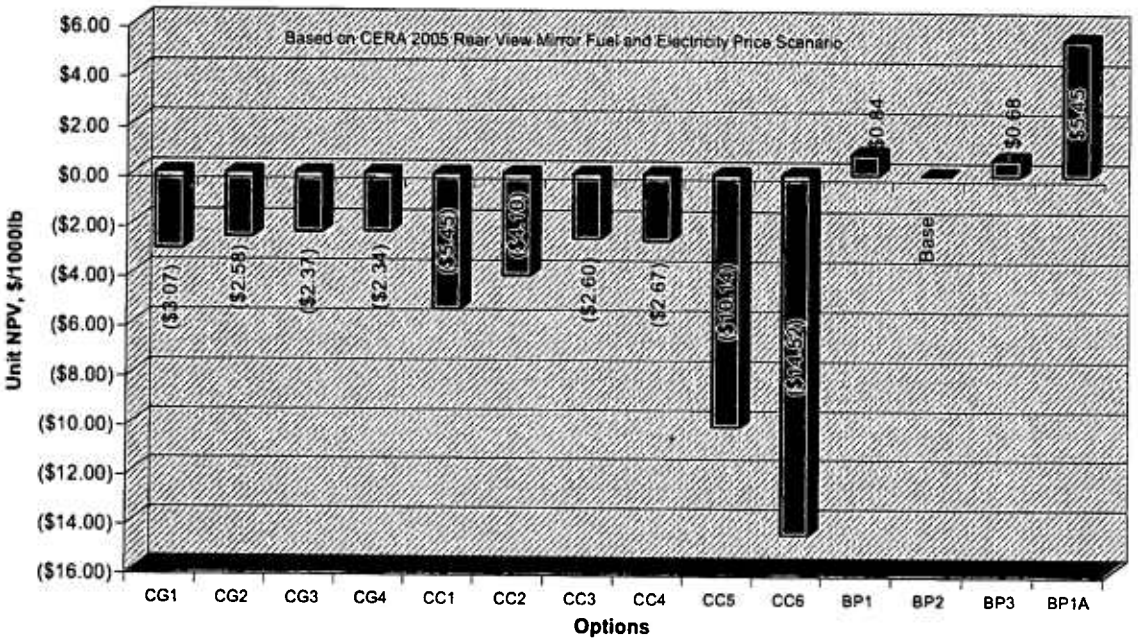


Exhibit 1-23 Contribution of Fuel and Emissions to Hudson Avenue Options Net Electric and Steam Production Costs City-Wide Due to Variable Fuel and Emissions Costs (Unit NPV)

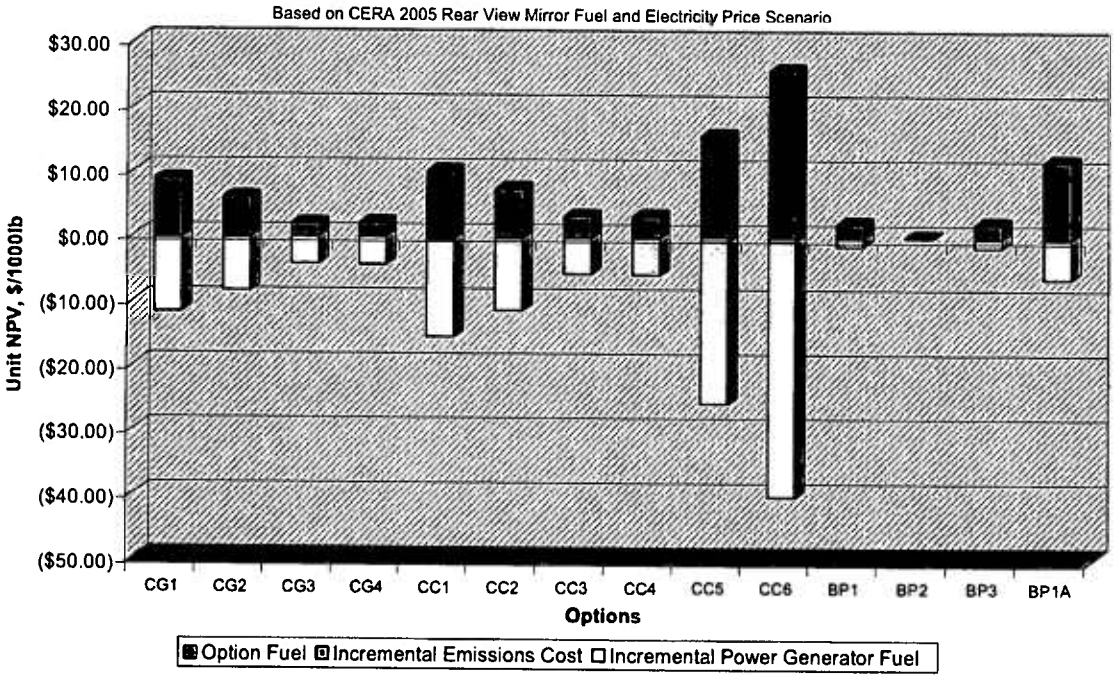


Exhibit 1-24 Impact of Hudson Avenue Repowering Option BP-1 on Emissions City-Wide

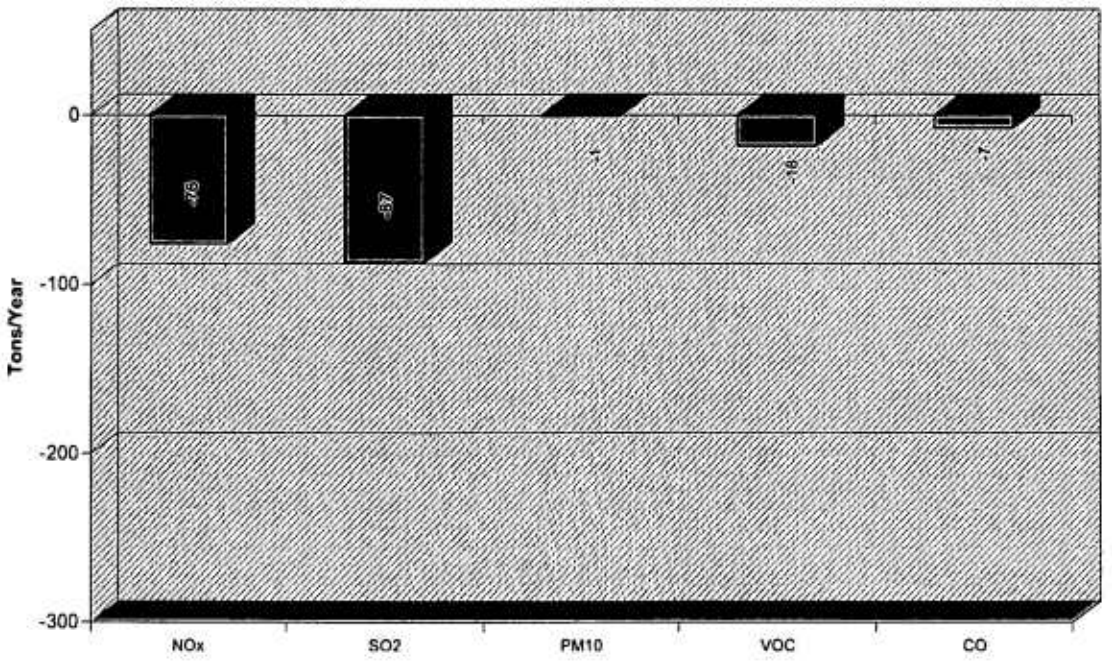
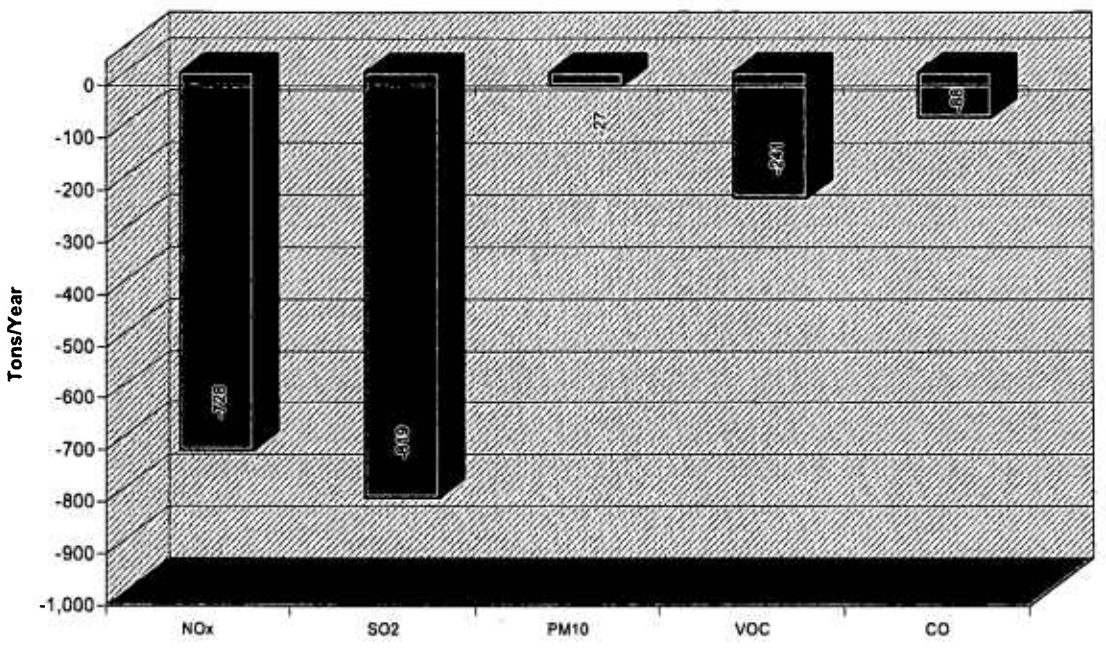


Exhibit 1-25 Impact of Hudson Avenue Repowering Option CG-1 on Emissions City-Wide



KeySpan Ravenswood, LLC Steam Supply Alternatives

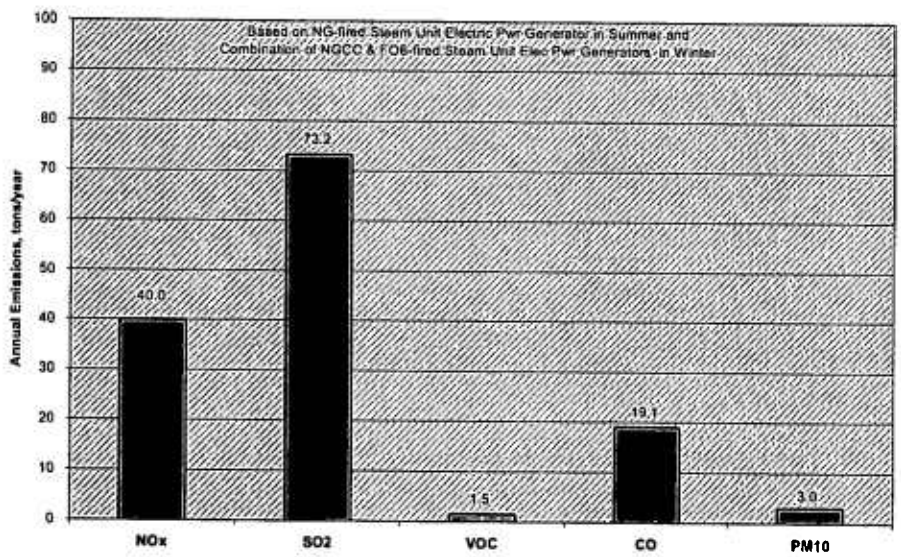
The results of the evaluation of the KeySpan steam supply alternative on electric and steam production costs City-wide due to variable fuel and emissions costs are summarized in Exhibit 1-26. The evaluation was based on the CERA 2005 Rearview Mirror Scenario fuel price projections. The fuel and emissions costs are the same for each of the KeySpan Alternative options. The results of the evaluation of the impact of the alternative on emissions City-wide are summarized in Exhibit 1-27.

The evaluation took into consideration the additional fuel costs, emissions, and emissions costs of electric power generating units in Zone J associated with generating the portion of electric energy that could not be generated at the KeySpan Unit 40 because of steam export to Con Edison. The evaluation also included a cost credit associated with savings in fuel costs by retiring the Ravenswood Steam Generating Station, based on the [REDACTED]. [REDACTED], the evaluation did not consider non-fuel and emissions operating costs nor other annual costs. In addition, because the purpose of this study is to determine the options that will lower steam production costs, the recommendations presented later in this report are based on the results shown in Exhibit 1-17.

Exhibit 1-26 Impact of KeySpan Steam Supply Alternatives on Electric and Steam Energy Production Cost City-Wide Due to Variable Fuel and Emissions Costs Based on CERA 2005 Rearview Mirror Scenario Price Projections

NPV of Net Incremental Cost of Electric and Steam, MM$	3.26
Unit NPV of Net Incremental Cost of Electric and Steam, $/Mlb	0.16

Exhibit 1-27 Net Impact of KeySpan Steam Supply Alternatives on Emissions City-Wide



STUDY CONCLUSIONS

Key conclusions from the Phase 1 study are as follows:

- Hudson Avenue Station:
  - In WorleyParsons opinion, the existing operating boilers at the Station will not provide reliable service for 20 years and need to be replaced, and it would not be economical to continue use of the building housing the boilers for 20 years.
  - [REDACTED].
  - [REDACTED].
  - [REDACTED].
  - Options BP-1, BP-2, and CG-1 would all result in significant emission reductions relative to the existing boilers at the projected annual steam sendout provided by Con Edison for the study.
  - The Unit NPV of the cost of steam production for all the combustion turbine cogeneration and combined cycle options, except for CC5 and CC6, are within [REDACTED] of each other based on the CERA 2005 Rearview Mirror Scenario projections. Option CC5 is also within about [REDACTED] of all the cogen and combined cycle options based on the Shades of Green price projections. The Unit NPV for options CC5 and CC6 are [REDACTED] than that of option BP-1, respectively, based on the Rearview Mirror Scenario projections and about [REDACTED], respectively, based on the Shades of Green price projections.
- 59th Street
  - In WorleyParsons opinion, with the present operation of the boilers and the ongoing capital replacement and maintenance program, these boiler systems should provide satisfactory operation over the 20 year study period.

- The NPV and Unit NPV of the cost of steam production over the 20 year study period for the existing system are significantly less ([REDACTED]) than the cogeneration repowering options evaluated based on both the CERA 2005 Rearview Mirror Scenario and Shades of Green Scenario price projections.

- 74th Street Station
  - In WorleyParsons opinion, site specific constraints inhibit the repowering of this facility.
  - With the present operation of the boilers and the ongoing capital replacement and maintenance program, the existing boiler systems should provide satisfactory operation over the 20 year study period.
- KeySpan Steam Supply Alternative
  - [REDACTED]
- Customer Supplied Steam
  - The cost of steam production estimated for the customer supplied steam options based on economic factors applicable to both commercial interests and academic interests do not appear to be competitive at the capacity factors typical of Con Edison steam generating stations (the average annual capacity factor for Con Edison steam production facilities is 27%).

Summary Recommendations:

Based on the above conclusions, WorleyParsons recommends the following

- **Hudson Avenue Plant**: Select three Re-powering Options for more detailed evaluation. WorleyParsons recommends BP-1, BP-2 and CG-1 Options which have the lowest Unit NPV of cost of steam production used as the Figure of Merit, based on the CERA 2005 Rearview Mirror scenario price projections, and represent one each of a boiler/steam turbine cogeneration system, combustion turbine cogeneration system, and boiler only system.
- **59th Street Plant**: Maintain current operation with planned future upgrades and modifications.
- **74th Street Plant**: Maintain current operation with planned future upgrades and modifications.
- **Alternative Facility:** Consider the KeySpan Steam and Electric supply Option as a potential alternative to Ravenswood Steam Generating Station (A-House) repowering.

2.0 BACKGROUND AND OBJECTIVES OF THE STUDY

2.1 BACKGROUND

In September of 2004 the Public Service Commission issued an order adopting a Joint Proposal that calls for the Consolidated Edison Company of New York, Inc. (Con Edison) to work with a newly formed Steam Business Development Task Force (Task Force) to develop the scope of a steam production cost study of long-term steam production options to be performed by an independent engineering firm selected through a competitive bid process.. Members of the Task Force include the New York State Department of Public Service, Con Edison, the New York City Economic Development Corporation, Empire State Development Corporation, the New York State Energy Research and Development Authority, and representatives of consumer, public interest and steam producer groups.

The Task Force has formed a specific Working Group that is responsible for preparation of the request for proposals, the selection of the Consultant and the review of the steam production cost study results, within the constraints of the confidentiality restrictions specified in the Joint Proposal. The Task Force also includes a sub-group of certain select members designated as Core Task Force Members, who are the only ones entitled to review cost projections and other confidential information. These Core Members will participate in the review of all of the Consultant's work products.

Gilbert/Commonwealth, Inc., doing business as WorleyParsons Group, Inc. (WorleyParsons), was selected to perform the Phase 1 conceptual level steam production cost study of long-term steam production options in support of Con Edison and the Steam Business Development Task Force.

2.2 OBJECTIVES

The objective of the Phase 1 study initially awarded to WorleyParsons was to develop a conceptual level (± 30%) estimate of the current and projected cost of producing steam at three existing Con Edison steam stations: the Hudson Avenue Station, the 74th Street Station, and the 59th Street Station. These stations currently have oil-fired and natural gas-fired boilers (in select stations) for producing steam and oil-fired combustion turbines for peaking generation of electric power for Con Edison's customers. The study scope includes consideration of ways in which the cost of producing steam may be reduced, either through modification of these facilities or re-powering. The scope also includes addressing the probable cost of steam from other potential merchant steam production facilities, which are considered representative proxies of potential alternatives to Con Edison facilities. Finally, the study scope includes an analysis of the technical (e.g., dispatchability and steam quality and/or purity) and economic feasibility of obtaining steam from customer-owned boilers and

cogeneration systems. This includes existing and new facilities that serve one or more buildings, but might benefit from a connection to the Con Edison district steam system.

An evaluation of repowering options at Con Edison's Ravenswood Steam Generation Station with the objective of developing conceptual level estimates of the projected cost of producing steam was later added to the Phase 1 study scope, with the results included as an Appendix to the Phase 1 final report (Appendix G).

3.0 ESTABLISH ECONOMIC AND ENVIRONMENTAL CRITERIA

3.1 FUEL AND POWER PRICE ASSUMPTIONS

For the economic analyses, WorleyParsons used the 15 year fuel and electricity price forecasts provided by the Cambridge Energy Research Associates (CERA). WorleyParsons linearly extrapolated the CERA data to estimate the fuel and electricity prices for the last 5 years of the study 20-year analysis period. CERA provided price forecasts for four scenarios:

- Rearview Mirror,
- Technology Enhanced,
- World in Turmoil, and
- Shades of Green.

A summary of the themes, primary inputs, and key outputs for the four scenarios, provided by CERA, is shown in Exhibit 3-1. WorleyParsons used the Rearview Mirror scenario for the initial economic evaluation. A sensitivity was then performed using the Shades of Green scenario.

The CERA forecast provides the following data that was used in the projection of cost of steam production and the impact of steam supply by alternative facilities on City-wide emissions:

- Regional monthly average fuel (natural gas, residual oil, and distillate oil) prices
- Regional annual average electricity prices (energy and capacity)
- Technology type, fuel type, heat rate, NOx and SO_2 emissions, projected capacity, projected MWhr dispatch, and projected fuel and dispatch costs for power generators in NYISO Zone J.
- Regional forecast basis description (i.e. new capacity, retirements, etc.)

Since the electric capacity price varies significantly between summer and winter (peak and off peak demand periods), and since the economic feasibility of some of the repowering options are strongly dependant on electric capacity price, monthly electric capacity price projections were developed by WorleyParsons based on the CERA data and NYISO ICAP data for 2005 for use in the economic evaluations.

Exhibit 3-1 Key Assumptions and Results of CERA 2005 North American Gas and Power Scenarios

[REDACTED]

One of the Alternative Facilities being evaluated as an option for steam supply to Con Edison provided a steam price formula that was a function of the NYISO Location Based Marginal Price (LBMP). An LBMP projection for the study evaluation period (2006 through 2025) was developed by WorleyParsons for use in the evaluations based on the NYISO 2005 LBMP data, the CERA electricity price projections, and the extrapolated CERA data.

The CERA natural gas fuel price projections are based on 30-day interruptible gas supply and delivery to the City-gate. WorleyParsons estimated local gas transportation costs for interruptible natural gas supply, and uninterruptible natural gas supply for options requiring HRSGs and for Customer Supplied Steam alternatives, based on information provided by KeySpan Energy Delivery and Con Edison.

3.2 ENVIRONMENTAL FRAMEWORK

Any reconstructed or new power plant must be designed with environmental emissions levels that meet or are superior to U.S. Environmental Protection Agency (EPA) environmental regulations, state regulations and local regulations. This section describes the environmental regulations/permit limitations that govern the existing Consolidated Edison combustion units at Hudson Avenue Station, 59th Street Station, and 74th Street Station.

The Hudson Avenue Station is located in Brooklyn, New York, while the 59th Street Station and 74th Street Station are located in New York (Manhattan), New York, all of which are in the Northeast Ozone Transport Region (OTR). Stringent state nitrogen oxides (NOx) emission regulations are required in order to meet ozone ambient air quality standards. The Stations are included in a system-wide averaging plan for NOx emissions with Con Edison's other large (>100 and ≤250 MMBtu/hr) and very large (>250 MMBtu/hr) boilers.

The Stations are located in the New Jersey-New York-Connecticut Interstate Air Quality Control Region (AQCR-043). A review of the ambient air quality for AQCR-043 indicates that the EPA has designated that ambient air quality standards for all pollutants are being met (40 CFR 81.333) except for ozone (1-hr severe nonattainment and 8-hr moderate nonattainment), PM10 (New York County), and PM2.5.

A description of the existing combustion equipment, emission limitations, and a list of the NOx reduction equipment that has been installed on the boilers at the Stations included in the study, based on the Title V Air Permits and the NO_x RACT Plants, are shown in Exhibit 3-2.

3.2.1 Air Quality Regulations

The environmental approach for any Technology Screening Study is to evaluate each technology on the same regulatory design basis. In the case of air emissions, a starting point for defining the emission control technology would be New Source Performance Standards (NSPS) and National Emission Standards for Hazardous Air Pollutants (NESHAP). NSPS reflect the maximum degree of emission control achievable by an industry through direct emission control, operation, and other

methods available. However, permitting a new plant with emissions controlled to NSPS requirements will probably not be acceptable to the EPA and/or the State of New York. NESHAP regulates specific categories of stationary sources that emit (or have the potential to emit) one or more hazardous air pollutants. Exhibit 3-3 and Exhibit 3-4 present NSPS and NESHAP emission limits for liquid and gaseous fuel fired combustion units and combustion turbines, respectively. NSPS Subpart Da is applicable to electric utility steam generating units, and NSPS Subpart Db is applicable to industrial-commercial-institutional steam generating units.

Exhibit 3-2 Existing Combustion Equipment, Emission Limitations, and NOx Control Technology

Facility	Description	Fuel	Heat Input, MMBtu/hr	Gross Load	Emission Unit	PM Limit, lb/MMBtu	Fuel Sulfur Content	NOx Control Technology	NOx Targets, lb/MMBtu
Hudson Avenue	Boilers 71, 72, and 81	#6 Oil	688, ea	460 klb/hr, ea	H-A0001	0.10	0.3 % sulfur oil by weight	BOOS/LEA with NOx Reducing Oil Burner Tips and Swirlers	0.32
	Boiler 82	#6 Oil	664	460 klb/hr	H-A0001	0.10	0.3 % sulfur oil by weight	LEA	0.36
	Turbines 3, 4, and 5	Distillate	235, ea	14 MWe, ea	H-A0005	0.10	0.2 % sulfur oil by weight	Peaking Use Only	0.514
59th Street	Boilers 114, 115	~13% Gas, #6 Oil	805, ea	550 klb/hr, ea	5-90020	0.10	0.3 % sulfur oil by weight	BOOS	0.29 0.29
	Boilers 116 - 118	Gas, #6 Oil	180, ea	150 klb/hr, ea	5-90020	0.10	0.3 % sulfur oil by weight	LNB	0.25 0.32
	Turbine	Distillate	220	14 MWe	5-90005	0.10	0.2 % sulfur oil by weight	Peaking Use Only	0.583
74th Street	Boilers 120 - 122	#6 Oil	836, ea	450 klb/hr, ea	7-40020	0.10	0.3 % sulfur oil by weight	BOOS	0.23
	Boilers 123 – 128 (PB1 – PB6)	#6 Oil	180, ea	150 klb/hr, ea	7-40020	0.10	0.3 % sulfur oil by weight	LEA with NOx Reducing Oil Burner Tips and Swirlers	0.45
	Turbines 1 and 2	Distillate	223, ea	18 MWe, ea	7-40020	0.10	0.2 % sulfur oil by weight	Peaking Use Only	0.772

Legend: Gas – Natural Gas
BOOS – Burners Out of Service
LEA – Low Excess Air
LNB – Low NOx Burners

Exhibit 3-3 New or Reconstructed Liquid or Gaseous Fired Combustion Units Air Emissions Design Criteria

Pollutant	Emission Limit	Governing Regulation
New Source Performance Standards – 40CFR60, Subpart Da		
PM	0.14 lb/MWh gross energy output or 0.015 lb/MMBtu heat input or 0.03 lb/MMBtu and 99.9% reduction (solid fuel)	NSPS 60.42Da (c) for (d)
NOx	1.0 lb/MWh	NSPS 60.44Da (e) (1) for construction
NOx	1.0 lb/MWh or 0.11 lb/MMBtu	NSPS 60.44Da (e) (2) for reconstruction
NOx	1.4 lb/MWh or 0.15 lb/MMBtu	NSPS 60.44Da (e) (3) for modification
SO_2	1.4 lb/MWh or 95% reduction	NSPS 60.43Da (i) (1) for construction
SO_2	1.4 lb/MWh, 0.15 lb/MMBtu, or 95% reduction	NSPS 60.43Da (i) (2) for reconstruction
SO_2	1.4 lb/MWh, 0.15 lb/MMBtu, or 90% reduction	NSPS 60.43Da (i) (3) for modification
New Source Performance Standards – 40CFR60, Subpart Db		
PM	0.030 lb/MMBtu	ICI NSPS 60.43b (h), except for (5) when combusting only very low sulfur oil (0.3% sulfur by weight, or 0.32 lb/MMBtu)
NOx	0.20 lb/MMBtu	ICI NSPS 60.44b (l) (1) for high heat release rate (>70,000 Btu/hr-ft^3) natural gas or distillate oil units
NOx	0.10 lb/MMBtu	ICI NSPS 60.44b (l) (2) for low heat release rate (≤70,000 Btu/hr-ft^3) natural gas or distillate oil units
SO_2	0.20 lb/MMBtu or 92% reduction of potential SO_2 emissions and 1.2 lb/MMBtu	ICI NSPS 60.42b (k), except for (1) when combusting only very low sulfur oil (0.3% sulfur by weight, or 0.32 lb/MMBtu)
National Emission Standards for Hazardous Air Pollutants		
PM	0.03 lb/MMBtu	ICI NESHAP, New Boiler, liquid fuel, large unit
HCl	0.0005 lb/MMBtu	ICI NESHAP, New Boiler, liquid fuel, large unit
CO	400 ppm*	ICI NESHAP, New Boiler, liquid fuel, large unit
CO	400 ppm*	ICI NESHAP, New Boiler, gaseous fuel, large unit

* Carbon monoxide (CO) is measured in parts per million (ppm) by volume on a dry basis corrected to 3 percent oxygen; averaging time is 30-day rolling average
Large unit - >10 MMBtu/hr

Exhibit 3-4 New or Reconstructed Liquid or Gaseous Fired Combustion Turbines Air Emissions Design Criteria

Pollutant	Emission Limit	Governing Regulation
New Source Performance Standards		
SO_2	0.90 lb/MWh or 0.060 lb/MMBtu	CT NSPS 60.4330
NOx	42 ppmvd at 15% O_2 (≤ 50 MMBtu/hr, HHV, NG, elec gen) 2.3 lb/MWh 25 ppmvd at 15% O_2 (>50 and ≤ 850 MMBtu/hr, NG) 1.2 lb/MWh 15 ppmvd at 15% O_2 (>850 MMBtu/hr, NG) 0.43 lb/MWh 96 ppmvd at 15% O_2 (≤ 50 MMBtu/hr, HHV, other, elec gen) 5.5 lb/MWh 74 ppmvd at 15% O_2 (>50 and ≤ 850 MMBtu/hr, other) 3.6 lb/MWh 42 ppmvd at 15% O_2 (>850 MMBtu/hr, other) 1.3 lb/MWh 54 ppmvd at 15% O_2 (HRSG unit independent of turbine) 0.86 lb/MWh	CT NSPS 60.4325
National Emission Standards for Hazardous Air Pollutants		
Formaldehyde	91 ppbvd	CT NESHAP, at 15% O_2

Permits for the construction of new major stationary sources or for major modifications at existing major stationary sources will be subject to Prevention of Significant Deterioration/New Source Review (PSD/NSR) permitting requirements. A "major modification" means any physical change in or change in the method of operation of a major stationary source that would result in a significant net emissions increase (i.e., taking into account any contemporaneous emission reductions, e.g., curtailing operation of existing boilers) of any pollutant subject to regulation under the Clean Air Act. In reference to a net emissions increase, "significant" means a rate of emissions exceeding those in Exhibit 3-5 would be subject to PSD or NSR (for ozone nonattainment areas, volatile organic compounds (VOC) and NOx are precursors to ozone; for PM2.5 nonattainment areas, SO_2 is and NOx is presumed precursors to PM2.5).

The PSD/NSR permitting process is expected to result in allowable emission rates more stringent than NSPS. The PSD/NSR process will require the installation of emission control technology meeting either Best Available Control Technology (BACT) for new or modified sources being located in areas meeting ambient air quality standards (attainment areas), or Lowest Achievable Emission Rate (LAER) technology for new or modified sources being located in areas not meeting ambient air quality standards (nonattainment areas). BACT is the maximum degree of emission reduction determined on a case-by-case basis for new sources in clean air areas with cost, energy, and technical feasibility taken into account, but in no case is BACT less stringent than NSPS. LAER is similar to BACT except that the cost of a technology is not taken into account. For assessing emission values previously accepted by regulatory agencies, the EPA's RACT/BACT/LAER Clearinghouse database was reviewed. Exhibit 3-6 presents a range of control technology determinations made nationwide for the liquid and gaseous fuel-fired boilers and combustion turbines.

Based on the above review, Exhibit 3-7 presents air emission control systems that are more representative of BACT needed for a new source being located in New York.

Exhibit 3-5 PSD/NSR Applicability Thresholds

Pollutant	Significant Emission Rate (tons per year)	
	PSD	NSR
CO	100	N/A
SO_2	40	N/A
NOx	40	25
Ozone/VOC	40	25
Total particulate matter (PM)	25	N/A
PM10	15	15
PM2.5	10	15
Lead	0.6	N/A
Fluorides	3	N/A
Sulfuric acid mist	7	N/A
Total reduced sulfur compounds	10	N/A

PSD means Prevention of Signification Deterioration these are net emission rate increase requirements for modifications in areas meeting ambient air quality standards.

NSR means New Source Review for nonattainment areas these are net emission rate increase requirements for modifications in areas not meeting ambient air quality standards.

N/A means that the area in the vicinity of the plant meets ambient air quality standards, or there is no emission rate applicable for that pollutant.

Particulate matter (PM) means any finely divided solid or liquid material, other than uncombined water, as measured by the reference methods specified under each applicable subpart, or an equivalent or alternative method.

Particulate matter (PM2.5 and PM10) emissions include gaseous emissions from a source or activity which condense to form particulate matter at ambient temperatures. (Includes both filterable and condensable particles.)

Exhibit 3-6 Control Technology Determinations for Other Projects

Process	Pollutants	Emissions Limitation	Type of Technology
Natural Gas - Boiler	PM/PM-10	0.0022 – 0.005 lb/10^6 Btu	Good Combustion Practices
	Sulfur Dioxide	0.0006 – 0.0018 lb/10^6 Btu	Low Sulfur Fuel
	Nitrogen Oxides	0.012 – 0.05 lb/10^6 Btu	LNB, FGR & SCR
	Carbon Monoxide	0.016 – 0.10 lb/10^6 Btu	Combustion Controls, Oxidation Catalyst
Residual Oil - Boiler	PM/PM-10 (Filt)	0.05 – 0.125 lb/10^6 Btu	Good Combustion Practices Fabric Filter, ESP, MC FGD
	Sulfur Dioxide	0.4 – 0.8 lb/10^6 Btu	Low-Sulfur Fuel, MC FGD
	Nitrogen Oxides	0.3 – 0.7 lb/10^6 Btu	LNB FGR
	Carbon Monoxide	0.033 – 0.10 lb/10^6 Btu	Combustion Controls
Simple Cycle Combustion Turbine (NG)	PM/PM-10	0.0072 – 0.012 lb/10^6 Btu	Combustion Controls
	Sulfur Dioxide	0.0006 – 0.02 lb/10^6 Btu	Low-Sulfur Fuel
	Nitrogen Oxides	5 – 9 ppmvd @ 15% O_2	LNB, Water Injection, SCR
	Carbon Monoxide	6 – 10 ppmvd @ 15% O_2	Combustion Controls, Oxidation Catalyst
Combined Cycle Combustion Turbine (NG)	PM/PM-10	0.01 – 0.014 lb/10^6 Btu	Combustion Controls
	Sulfur Dioxide	0.0006 – 0.0023 lb/10^6 Btu	Low-Sulfur Fuel [1gr/100scf]
	Nitrogen Oxides	2 – 3.5 ppmvd @ 15% O_2	LNB, Water/Steam Injection, SCR
	Carbon Monoxide	2 – 25 ppmvd @ 15% O_2	Combustion Controls, Oxidation Catalyst
Simple Cycle Combustion Turbine (Oil)	PM/PM-10	0.0127 – 0.037 lb/10^6 Btu	Combustion Controls
	Sulfur Dioxide	0.032 – 0.055 lb/10^6 Btu	Low-Sulfur Fuel
	Nitrogen Oxides	5 – 6 ppmvd @ 15% O_2	LNB, Water Injection, SCR
	Carbon Monoxide	6 – 20 ppmvd @ 15% O_2	Combustion Controls, Oxidation Catalyst
Combined Cycle Combustion Turbine (Oil)	PM/PM-10	0.016 – 0.03 lb/10^6 Btu	Combustion Controls
	Sulfur Dioxide	0.0154 – 0.05 lb/10^6 Btu	Low-Sulfur Fuel [0.015% S]
	Nitrogen Oxides	5 – 10 ppmvd @ 15% O_2	LNB, Water Injection, SCR
	Carbon Monoxide	6 – 15.7 ppmvd @ 15% O_2	Combustion Controls, Oxidation Catalyst

Exhibit 3-7 Expected Control Technologies

Emission Source Type	Control Technology
Boiler (Natural Gas/Oil)	LNB-FGR/OX-CAT/SCR
Combustion Turbine (Simple Cycle)	LNB/OX-CAT
Combustion Turbine (Combined Cycle)	LNB/SCR/OX-CAT

Acronyms:
LNB – low NOx Burner (Nitrogen Oxides Control Device)
FGR – Flue Gas Recirculation (Nitrogen Oxides Control Device)
SCR – Selective Catalytic Reduction (Nitrogen Oxides Control Device)
OX-CAT – Oxidation Catalyst (Carbon Monoxide/Volatile Organic Compound Control)

In addition to installing LAER technology, the pollutant emissions from new major sources or major modifications for which the area is not meeting air quality standards must be offset by a ratio of greater than one-for-one. Offsets to escape PSD/NSR permitting are based on the Future Potential emissions from the Project versus Past Actual emissions from existing sources. Offsets to escape PSD/NSR permitting are based on the Future Potential emissions from the Project versus Past Actual emissions from existing sources. Exhibit 3-8 is a tabulation of the 2000 through 2004 Emission Statements for the three Stations.

The following presents a summary of the reconstruction regulations:

Reconstruction Under New Source Performance Standards. (See 40 CFR 60.15 for actual wording, the following is paraphrased)

> *An existing facility, upon reconstruction, becomes an affected facility, irrespective of any change in emission rate. "Reconstruction" means the replacement of components of an existing facility to such an extent that: (1) The fixed capital cost of the new components exceeds 50 percent of the fixed capital cost that would be required to construct a comparable entirely new facility, and (2) It is technologically and economically feasible to meet the applicable standards set forth in this part. "Fixed capital cost" means the capital needed to provide all the depreciable components.*

The purpose of the reconstruction provision is to prevent circumvention of the New Source Performance Standards (NSPS) by recognizing that replacement of many of the components of a facility can be equivalent to totally replacing the facility at the end of its useful life.

The EPA maintains an Applicability Determination Index (ADI), which is a Web-based database that contains memoranda issued by EPA on applicability and compliance issues associated with the NSPS. The Office of Enforcement and Compliance Assurances (OECA), Compliance Assessment Media Programs Division (CAMPD) maintains the database. The following presents a summary of determinations related to reconstruction and NSPS applicability.

Exhibit 3-8 Tabulation of 2000 through 2004 Emissions Statements

Station Emission Summary, 2000-2004, lbs/yr						
	CO	SO2	PM10	PM	NOx	VOC
59th Street Station						
GT001						
Range	751-4,445	277-1,639	143-844	143-844	3,344-18,009	38-227
5-Year Average	2,690	992	511	510	11,463	137
Average 2003 / 2004	1,507	556	286	286	6,707	77
116, 117, 118						
Range	109,249-132,747	931-81,653	12,041-21,590	12,041-24,714	274,387-408,633	7,596-9,472
5-Year Average	122,322	32,594	14,871	16,099	334,346	8,320
Average 2003 / 2004	120,998	64,019	18,453	20,898	301,632	8,534
114, 115						
Range	89,201-128,881	666193-973,365	78,492-114,233	99,733-145,269	529,284-1,070,027	14,411-20,729
5-Year Average	107,210	818,781	95,718	121,826	785,231	17,166
Average 2003 / 2004	125,061	942,688	110,708	140,766	925,292	20,130
74th Street Station						
GT1 & GT2						
Range	127-1,081	47-398	24-205	24-205	513-4,455	6-55
5-Year Average	521	192	99	99	2,190	32
Average 2003 / 2004	1,041	384	198	198	4,417	53
120, 121, 122						
Range	177,952-229,061	1,570,166-2,021,129	290,167-373,505	387,308-498,545	1,160,519-1,495,635	26,693-34,359
5-Year Average	199,351	1,758,979	325,059	433,881	1,318,928	29,903
Average 2003 / 2004	203,507	1,795,648	331,836	442,927	1,328,077	30,526
123 – 128 (PB1 – PB6)						
Range	42,893-59,593	378,470-525,818	48,444-67,305	63,078-87,636	517,242-743,156	6,434-8,939
5-Year Average	49,452	436,341	55,852	72,724	629,625	7,418
Average 2003 and 2004	54,889	484,314	61,993	80,719	691,877	8,234
Hudson Avenue Station						
GT3, GT4, & GT5						
Range	1,584-4,494	1,403-3,982	639-1,813	639-1,813	12,978-36,820	195-552
5-Year Average	3,062	2,713	1,236	1,236	24,450	376
Average 2003 / 2004	1,890	1,167	763	763	16,385	233
71, 72, 81, 82						

Station Emission Summary, 2000-2004, lbs/yr						
	CO	SO2	PM10	PM	NOx	VOC
Range	147,376-227,827	1,300,374-2,010,242	123,362-190,705	156,045-241,229	1,197,534-2,331,881	22,106-34,174
5-Year Average	179,174	1,580,945	149,979	189,713	1,562,640	26,876
Average 2003 / 2004	156,637	1,382,089	131,114	165,851	1,211,144	23,496
100						
Range	0-62,031	0-547,331	0-74,802	0-96,695	0-474,353	0-9,305
5-Year Average	36,906	325,641	44,504	57,530	268,282	5,536
Average 2003 / 2004	46,490	410,207	56,062	72,470	355,057	6,974

The December 16, 1975 preamble to the reconstruction regulations defines fixed capital cost as the capital needed to provide all the depreciable components, including the costs of engineering, purchase and installation of major process equipment, contractor fees, instrumentation, auxiliary facilities, building and structures. Costs associated with the purchase and installation of air pollution control equipment are only included in the fixed capital cost to the extent that the equipment is required as part of the manufacturing/operating process and the equipment is included in the existing repaired boiler. When determining reconstruction cost, care should be exercised to include only those costs associated with the reconstructed affected facility.

Only the costs of items included in, and activities associated with, the affected facility are to be included in the reconstruction costs. The affected facility for fossil-fuel-fired steam electric plants consists only of the steam generating unit.

The definition of steam generating unit: "...A steam generating unit includes the following systems: (1) Fuel combustion system (including bunker, coal pulverizer, crusher, stoker, and fuel burners, as applicable); (2) Combustion air system; (3) Steam generating system (firebox, boiler tubes, etc.); (4) Draft system (excluding the stack)." The affected facility then starts at the coal bunkers, and ends at the stack breeching. The affected facility for a coal-fired boiler begins at the feed water pump inlet and ends at the boiler's steam outlet. Based upon the definition of a steam generating unit in Subpart Dc, the primary components of the affected facility would be the equipment needed to combust fuel (i.e., burners and combustion chamber), the heat exchanger, and the combustion air supply system.

The following items are included in the affected facility: boilers and equipment, breeching, draft equipment, lighting systems, oil-burning equipment, boiler controls (DCS, BMS, etc.) pulverized fuel equipment, stoker or equivalent feeding equipment, and pressure oil systems. The following equipment would only be included in reconstruction costs to the extent that they directly service the boiler: foundations and structural steel, buildings, ash handling equipment (generally only the discharge valves to the ash hopper), boiler feed water system, coal handling and storage equipment (only the coal bunker and pulverizer), instruments and devices, ventilating equipment, wood fuel equipment (wood chipper), circulating pumps (just at the boiler), cooling system, fire extinguishing systems, mechanical meters, platforms, railings, steps,

gratings, and steelwork. Likewise, engineering, purchase cost, installation, and contractor fees should be included in the affected facility reconstruction costs (i.e., fixed capital cost) only to the extent that they are associated with reconstruction of affected process equipment (the steam generating unit).

The following items are not part of the affected facility and should not, therefore, be included in reconstruction costs as follows: land, site preparation, demolition, boiler plant cranes, stacks, station piping, water purification equipment, water-supply systems, air cleaning and cooling apparatus, condensers, generator hydrogen, cranes and hoists, excitation systems identified with the main generating units, foundations and settings for turbogenerator, governors, lubricating systems, main exhaust and main steam piping, throttle and inlet valve, intake and discharge tunnels, turbogenerators, water screens, motors, and moisture separator for turbine steam. Auxiliary boilers should also be excluded from reconstruction cost calculations.

The term "comparable entirely new facility" would consist of a new boiler with identical components to the repaired boiler. Reconstruction calculations do not include air pollution control equipment; therefore, the source would not include the cost of installing low NOx burners on the new facility unless they are being added to the existing facility.

A determination covered whether seven cost components should be included in the reconstruction cost. The cost components are provided below, followed by EPA's response.

- Internal safety compliance - dual safety/emergency controls and separation of a black liquor firing system for two of the recovery boilers in question, which would include additional black liquor process tanks, motors, and pumps? These components would be considered part of the fuel combustion system and may be considered in the fixed capital cost of the reconstructed facility and the cost of a comparable entirely new facility.
- Electrical components - wire and cable, conduit, and grounding? The electrical components directly associated with the operation of affected facility may be considered in the reconstruction costs.
- Fire protection - Fire protection or extinguishing systems would only be included in the reconstruction costs to the extent they directly service the recovery boiler.
- Tools and equipment - Tools and equipment used to construct or maintain an affected facility are not considered components of the affected facility and are not considered in the reconstruction costs.
- Process piping - Process piping used to deliver material to or away from the recovery furnace or smelt dissolving tank is not considered a part of the affected facility and should not be included in the reconstruction costs.
- Auxiliary building used for project contractor and engineering staff - This is not a component of an affected facility regulated by Subpart BB and has no effect on the emissions from an affected facility. This building does not directly service the operation of the affected facilities.

The thrust of the NSPS modification provisions is to compare actual maximum capacity before and after the change in question. Thus, original design capacity is irrelevant. The original design capacity of a unit, to the extent it differs from actual maximum capacity at the time of the test due to physical deterioration -- and, hence, derating -- of the facility, is immaterial to this calculation. Operational changes include both increases in hours of operation and increases in production rate. Section 60.14(e)(3) provides that an increase in hours of operation is not, by itself, a modification. However, an increase in production rate at an existing facility constitutes a modification, unless it can be accomplished without a capital expenditure on that facility.

The modification and reconstruction provisions of NSPS are independent. The former provisions are intended to apply in circumstances where physical or operational changes which increase emissions make NSPS coverage appropriate at levels well below 50 percent of the capital cost of a replacement unit. Conversely, the reconstruction provisions are aimed at changes to an existing unit irrespective of associated emissions increases, but trigger NSPS requirements only if the higher 50 percent level is reached.

It is important to note in this regard that not all renovation, repair, or "life extension" projects would properly be characterized as modifications potentially subject to PSD and NSPS. For example, nonroutine repairs to correct unexpected equipment outages, even of major components such as steam drums, would not be subject to NSPS if they did not increase the maximum capacity of the affected facility as it existed prior to the outage. Conversely, undertaking a program of repair and maintenance properly characterized as routine would not subject a facility to the Act's requirements. To the extent that repairs go beyond the normal maintenance activity necessary to maintain a boiler during its useful life and results in a substantial life extension of the boilers; to determine if a reconstruction has occurred, EPA believes it is reasonable to aggregate the costs of the renovations since life extension activities began, including the future planned repairs.

If there is doubt about applicability, the Administrator will make a determination of whether action taken or intended to be taken by such owner or operator constitutes construction (including reconstruction) or modification or the commencement thereof within the meaning of this part.

3.2.2 Water Quality Regulations

Water use, thermal discharge, and liquid waste discharges for the reconstructed plant will need to meet Federal and local regulations for magnitude and contaminant limits. Specifically, an increase in water usage by a reconstruction technology would require increased water allocations. Also, a change in thermal discharge to a water body could violate water temperature limits provided by the State Pollutant Discharge Elimination System (SPDES) permit as summarized in Exhibit 3-9 through Exhibit 3-11 for the 74th Street, Hudson Avenue, and 59th Street Steam Stations, respectively.

Exhibit 3-9 74th Street Steam Station SPDES Effluent Limits

74th Street Steam Station
SPDES No: NY 000 5177
Exp. Date: 10/1/06
East River

Outfall & Parameter	Daily Avg.	Daily Max.	Units
001-Combined Discharge – Service Cooling Water & Low Volume Wastes			
Calculated Discharge Temperature		91°F	
pH	6.0 – 9.0		SU
Total Residual Chlorine			
001A – Boiler Blowdown From Package Boilers 1-6			
Oil & Grease	NA	15	Mg/l
Solids, Suspended	30	100	Mg/l
001B – Softener Regeneration Wastes from Sodium Zeolite Softeners			
Oil & Grease	NA	15	Mg/l
Solids, Suspended	30	100	Mg/l
001C – Floor Drains			
Oil & Grease	NA	15	Mg/l
Solids, Suspended	30	100	Mg/l
001D – Boiler Blowdown - Boilers 120-122			
Oil & Grease	NA	15	Mg/l
Suspended Solids, Total	30	100	Mg/l
001E – Neutralization Tank Effluent			
Oil & Grease	NA	15	Mg/l
Suspended Solids, Total	30	100	Mg/l
pH			
001F – Flue Gas Condensate			
Suspended Solids, Total	30	100	Mg/l
Nickel	NA	1.3	Mg/l
001G – Storm Water Runoff (Uncontaminated)			
No Monitoring Required.			

Exhibit 3-10 Hudson Avenue Station SPDES Effluent Limits

Hudson Avenue Station
SPDES No: NY 000 5151
Exp. Date: 5/1/06
East River

Outfall & Parameter	Daily Avg.	Daily Max.	Units
001 – Service Cooling Water & Low Volume Wastes			
Calculated Discharge Temperature		94°F	
pH	6.0 – 9.0		SU
Total Residual Chlorine			
001A – Floor and Equipment Drains (retired)			
Solids, Suspended	NA	100	Mg/l
Oil & Grease	NA	15	Mg/l
002 – Service Cooling Water & Low Volume Wastes and boiler drain			
Calculated Discharge Temperature		94°F	
pH	6.0 – 9.0		SU
Total Residual Chlorine			
002A – Unit 70/80 Floor and Equipment Drains		100	gpm
Oil & Grease	NA	15	Mg/l
Solids, Suspended	30	100	Mg/l
002B – Unit 70/80 and 100 Boiler Blowdown			
Oil & Grease	NA	15	Mg/l
Solids, Suspended	30	100	Mg/l
002C – Settling Pit Overflow (Includes Waste Neutralization System Discharge)		600	gpm
Solids, Suspended	30	100	Mg/l
Oil & Grease	NA	15	Mg/l
002E – Tank Farm Steam Condensate and Service and storm Water		400	gpm
Solids, Suspended	30	100	Mg/l
Oil & Grease	NA	15	Mg/l
002F – Tunnel Headhouse Sump		600	gpm
Solids, Suspended	30	100	Mg/l
Oil & Grease	NA	15	Mg/l
002G – Stores Building Oil/Water Separator		10	gpm
Oil & Grease	NA	15	Mg/l
Solids, Suspended	30	100	Mg/l
003 - Tank Farm Secondary Containment (Direct Discharge on East River)			
Oil & Grease	NA	15	Mg/l
pH	6.0 – 9.0		SU
		Action Level	
Benzene		0.10	Mg/l
Toluene		0.10	Mg/l
Xylenes (Total)		0.10	Mg/l
Ethylbenzene		0.10	Mg/l

Exhibit 3-11 59th Street Steam Station SPDES Effluent Limit

59th Street Steam Station
SPDES No: NY 000 5134
Exp. Date: 5/1/06
Hudson River

Outfall & Parameter	Daily Avg.	Daily Max.	Units
001-Combined Discharge			
pH (Range)	6.0 – 9.0		SU
Temperature		Monitor	
001A – Boiler Blowdown (Units #114 & #115)			
Solids, Suspended	30	100	Mg/l
Oil & Grease	NA	15	Mg/l
001B – Floor and Equipment Drainage			
Oil & Grease	NA	15	Mg/l
Solids, Suspended	30	100	Mg/l
002-Combined Discharge			
Discharge Temperature		Monitor	
pH (Range)	6.0 – 9.0		SU
002A – Boiler Blowdown (Units #116, 117, & 118)			
Solids, Suspended	30	100	Mg/l
Oil & Grease	NA	15	Mg/l
002B – Hydrogen Softener Regeneration Wastewater			
Solids, Suspended	30	100	Mg/l
Oil & Grease	NA	15	Mg/l
003 – Heat Exchanger Cooling Water			
Temperature		104°F	
Oil-Water Separator			
Suspended Solids	30	50	Mg/l
Oil & Grease	NA	15	Mg/l
pH (Range)	6.0 – 9.0		SU
Benzene	NA	0.10	Mg/l
Toluene	NA	0.10	Mg/l
Xylenes (Total)	NA	0.10	Mg/l
Ethylbenzene	NA	0.10	Mg/l
Aroclor 1016		**	Ug/l
Aroclor 1221 *		**	Ug/l
Aroclor 1232		**	Ug/l
Aroclor 1242		**	Ug/l
Aroclor 1248		**	Ug/l
Aroclor 1254		**	Ug/l
Aroclor 1260		**	Ug/l

There may be minor changes to other wastewater streams internal to the plant. Effluent limitations applicable to the reconstructed or upgraded unit are expected to be similar to those which currently apply to the Stations. It is not expected that any reconstruction options will result in significant water impacts that would require the use of different wastewater treatment systems or cooling towers. Of course, the wastewater characteristics of the effluent from the reconstructed unit will need to be investigated for any significant changes in quantity or quality.

3.2.3 Solid Waste Disposal Regulations

All solid waste disposal will be at an off-site location. (Disposal of any solid and liquid hazardous waste generated resulting from the decommission and/or demolition of an option (Lead, Mercury, Asbestos, PCBS, etc.) will be at an off-site disposal location licensed to accept the waste.)

Changes to the characteristics of the waste generated by a reconstruction project will need to be investigated. The quality of the waste may also change as a result of the reconstruction project. Most states require the use of the toxicity characteristic leaching procedure (TCLP) test to evaluate if the waste generated is considered to be hazardous or not. The waste is anticipated to not be hazardous.

3.2.4 Noise Abatement Regulations

Noise levels of the reconstructed plant may be considered in the review of environmental impact statements required by the State of New York and the City of New York.

3.2.5 Other Environmental Regulations

Depending on the specifics of the final re-powered plant design, there may be other applicable environmental regulations should the project involve activities in or affecting wetlands, flood plains, or navigable water. An asbestos assessment may be required.

3.2.6 Permitting, Licensing and Regulatory Approval Requirements

Exhibit 3-12 is a preliminary list of activities and permits often required for a power plant project. The specific applicability of each is established when details of the project develop.

For a reconstruction project, the necessary construction permits would usually be expected within 18 months of the start of the project, provided design information is available to support the preparation of applications.

This permitting period represents a considerable time savings over the permitting needed to develop a "greenfield" location. Similar projects planned for a "greenfield" location are expected to take significantly longer because of the need for siting approval and approval of the transmission line

Exhibit 3-12 Preliminary List of Activities and Permits Often Required

Approval	Agency	Activity
Environmental Justice Program	DEC	Public Notice and Meetings regarding the Project to secure local community participation
State Environmental Quality Review	DEC	Review of environmental impacts associated with the Project
Construction in Flood Hazard Area Permit	DEC	Construction within 100-year flood plain
Permit to Construct Sources of Air Contamination	DEC	Construction or modification of an air contaminant source or an indirect source, including PSD/NSR requirements
Certificate to Operate for Sources of Air Contamination	DEC	Operation of an air contaminant source or an indirect source
State Pollutant Discharge Elimination System Permit	DEC	Any proposed or existing discharge of sewage, industrial wastes, or other wastes to surface water or groundwater
Water Supply Permit	DEC	Water supply and water allocation
Construction Permit	DEC	Construction or modification to solid waste management facility, including storage, transfer, processing, recovering, reclaiming and disposal
Operating Permit	DEC	Operating a solid waste management facility, including storage, transfer, processing, recovering, reclaiming and disposal
Hazardous Waste Facility Permit	DEC	Construction, modification or operation of a hazardous waste management facility
Freshwater Wetlands Permit	DEC	Any activity in a wetlands or within 100 feet of a wetland boundary affecting a wetland
Protection of Waters Permit	DEC	Any activity in or affecting navigable water of the states including any marshes, estuaries and wetlands adjacent to navigable water
Corps of Engineers Permit	COE	Any activity in or affecting navigable water of the United States
401 Certification	DEC	Required for any federal permit indicating that approval will not cause a violation of state water quality standards
Building Permit, Zoning Approval	Local	Any building permit required for occupancy of a structure including electrical, plumbing, HVAC, fire protection, life safety

Notes: PSC -State Public Service Commission
DEC - Department of Environmental Conservation
COE - U.S. Army Corps of Engineers

3.3 FINANCIAL ASSUMPTIONS

The basic economic/financial assumptions utilized in the economic evaluations of the Con Edison facilities include the following:

- Capitalization Ratio: 48% equity and 52% debt;
- Depreciation rate for steam production is 3.33%;
- Property tax rate of 5.4% for 2006 and escalated for future years;
- Escalation rate of 3% per year;
- AFUDC is estimated at 6.7%;
- Rate of return for equity of 10.3% per year,
- Long term debt of 6.15%
- Federal and State Income Tax Rate of 40%
- Carrying Charge calculated based on income tax rate, capitalization ratio, long term debt rate, rate of return on equity, and depreciation rate
- Present Worth Factor of 6.87% based on weighted cost of capital
- Emissions reduction credits: NOx $12,500/ton, VOC $5,000/ton
- Emissions allowances: NOx $1,600, SO_2 $643

To provide a Figure of Merit for comparison of repowering alternatives, a net present value (NPV) per thousand pounds of steam was calculated for each option based on a discounted steam sendout rate. The discounted steam sendout rate was calculated based on the following:

$$Discounted\ Steam\ Exported = \sum_{i=1}^{n} \left[(SSO)_i / (1+DF)^i \right]$$

Where:
SSO = annual steam sendout
n = evaluation period in years (20 years for this study), and
DF = Real Discount Factor = {[1 + {(EQ x RE) + [(1 – ITR) x (Loan x LR)]}] / (1 + r)} – 1
Where:
EQ = Equity Capitalization
RE = Return on Equity
ITR = Income Tax Rate
Loan = Loan Capitalization
LR = Loan Interest Rate
R = Inflation Rate

An economic model was developed at the beginning of the project and was reviewed with Con Edison. As the study progressed, the model was modified and combined with the preliminary repowering option screening model based on discussions with the Core Task Force Members.

3.4 CAPITAL COST DEVELOPMENT

WorleyParsons used in-house cost models to develop conceptual level capital costs for repowered systems (± 30%). The format for direct capital costs includes separate evaluation of major systems and sub-systems for the entire plant with separate values for equipment and construction labor. These costs are determined with several levels of complexity depending on the specific system being estimated. The direct capital cost of the plant includes equipment; materials; reinforcement, interconnection, and infrastructure costs for steam, gas, and electric; demolition/remediation/relocation, if required; construction labor; and indirect construction costs.

The specific approach to developing the various capital cost estimates for upgrades or re-powering options at each station consisted of initially developing an estimate for each technology at one of the plants. This technology estimate was then adjusted for scope and site conditions at the other plant locations so that results for each case have a good relative consistency and accuracy. Capital costs were initially estimated using in-house model(s) and cost database of vendor furnished cost data adjusted to study specific criteria for other equipment and materials costs. Specific equipment and system costs were then replaced by more project specific costs. In addition, if specific significant systems and site specific impacts were not consistent with the model basis, high level conceptual estimates were developed and results incorporated into the model. Vendor quotations were obtained for some major equipment items. The Multiple Contracts approach to performing the construction was utilized, similar to EPCM (depends on whether major equipment is procured by Con Edison or as part of the Professional Services). Labor rates on a fully burdened contract basis were developed for the plant site locations. Results of this rate development were used to determine labor costs or to define a factor to adjust the model based labor costs. Similarly, a factor for labor productivity was applied to man-hours, unit man-hours and labor costs to adjust results for the local labor conditions. At this conceptual level of estimating, the absolute accuracy is projected to be no better than +/- 30 percent while the relative accuracy is expected to be in the range of +/- 20 to 25 percent. Experience with costs, permitting, and site specific information for Con Edison's East River Repowering Project provided to WorleyParsons by Con Edison were considered, along with other publicly available information with respect to construction costs in New York City, in estimating costs for the repowering options.

Project indirect costs included Professional Services (engineering, construction management, and start-up assistance). Costs were also provided for Con Edison Overheads consisting of Central Engineering, Administrative and Supervisory, Pension, Payroll, Taxes, Life/Health Insurance, AFUDC, and Project Management. The determination of the various Con Edison costs were based on factors that were provided by Con Edison. Indirect costs also included Other Costs consisting of freight (not included with vendor equipment prices) and heavy haul and spare parts used during start-up (allowance). In addition, an allowance for contingency was applied to the direct and indirect costs (based on Con Edison factors).

During the data collection task in the study, historical and projected O&M costs and projected capital improvement costs for the next 20 years for the Hudson Avenue Station, 59th Street Station, and 74th Street Station were provided by Con Edison. Additionally, WorleyParsons interviewed plant personnel during a site visit at each

plant. The O&M Costs and information obtained through observations at the facilities (no dismantling or internal inspections at the facility were performed) were used to make a comparison between the O&M costs provided by Con Edison and those that WorleyParsons has incurred at a confidential client's facility in the Southeast as well as different O&M budgets that were analyzed as part of other O&M assessments. It was determined that the labor and non-labor fixed O&M costs appeared to be within 25% of what was experienced in multiple facilities located across the United States. Considering increased wages and costs for New York City compared the Southeast, it was determined that these O&M costs provided by Con Edison were in line with the cost of operations and maintenance, excluding water and electricity, of similar facilities.

A review of the project capital improvement costs were performed and then compared to costs to maintain facilities that have been incurred at one of the power plants that WorleyParsons operates and maintains, as well as the other assessment data that we have received. The cost validation steps included the use of one of our maintenance managers and a verification of cost data with turbine and boiler repair company representatives to determine if the costs were out of line by more than 20%. The costs were determined to be fairly accurate and they were definitely within a plus or minus 30% range. Any costs that were different were discussed and our estimate was then adjusted as needed to ensure that, as best could be determined, all the required maintenance costs were covered based upon the different cases proposed at each facility.

Demolition, remediation, equipment relocation, and structural alteration cost estimates and the bases for these estimates were also provided to WorleyParsons by Con Edison based on requests made by WorleyParsons after our site visits and discussions with Con Edison personnel. WorleyParsons reviewed the bases for the cost estimates and discussed any major concerns with Con Edison in the process of developing cost estimates associated with these activities.

3.5 SENSITIVITY ANALYSIS

The major area of concern for sensitivity analyses is the impact of the fuel and electricity price projections due to the volatile market prices. Based on discussions between WorleyParsons and the Core Task Force Members, the approach to sensitivity analysis is to evaluate the repowering options first using the Rearview Mirror price scenario provided by CERA and then using the Shades of Green price scenario. If the different scenarios have a major impact on the results of the evaluations, for example if the relative ranking of the options based on net present value per thousand pounds of steam product changes, then further sensitivity analyses may be conducted.

For the Customer Supplied Steam options, WorleyParsons evaluated the sensitivity of the cost of steam production to the steam sendout capacity factor.

4.0 ASSESSMENT OF CON EDISON PLANTS

4.1 ASSESSMENT OF EXISTING PLANT AND OPERATION

This section covers the methodology and basis for the study, including preliminary findings of the plant visits.

4.1.1 Methodology

In order to assess the physical conditions and identify the operational issues of the existing equipment at the three identified facilities, WorleyParsons took the following approach:

- Developed a detailed Data/Information Request (DIR) document and sent to Con Edison for inputs;
- Reviewed the information provided by Con Edison in response to the DIR inputs;
- Met with the Core Task Force to discuss potential operation, maintenance and other related issues;
- Toured the 59th, Street, 74th Street and Hudson Avenue Generating Stations, including a physical walkdown of each facility, visual inspection, and meetings with the Operating/ Maintenance Personnel and Technical/Engineering Personnel to discuss site specific issues; and
- Interviewed Con Edison corporate and plant personnel, including Engineering, Environmental, and Financial disciplines to have a better understanding of the current and future mode of operations of these facilities.

The results of the assessment are presented in the following sections. However; it is noted that WorleyParsons' assessment is based on the review of inspection reports and other documents pertaining to the operation and maintenance of the facilities provided by Con Edision, physical walk down of the facilities, and various interviews with Con Edison personnel. It did not include internal inspection of equipment to verify conditions.

4.1.2 Documents/Data Reviewed

The following documents / data were reviewed as part of the assessment of the existing plants and operations:

General:

- Steam Sendout Ratings in million lb/h (MMPPH) as of 09/10/2005.
- Steam Business Development Plan for the Con Edison Steam System.
- 5 Year Outage Schedule (2006-2011) All Plants.

59th Street Station:

- Unit 116, 117, & 118 Package Boiler Condition Assessment dated January 28, 1999.
- 114 Boiler Condition Assessment dated January 28, 1999.
- 115 Boiler Condition Assessment dated January 28, 1999.
- Boilers 114, 115 – Predicted Performance.
- Boiler #114 and #115, 2 Type VU-60 Boilers, C-E Contract 22665, Predicted Performance.
- Completed WorleyParsons Appendix A Boiler/Turbine Data Sheets for Boilers No. 114, 115,116, 117, & 118.
- Foster Wheeler Summary Performance Sheet for 59th Street. (Boilers 116, 117, & 118)
- 59th Street Station Boiler Trip Listing from January 2000 to October 2004.
- C-E Drawing No. E-382-751-10.
- VU-60 Arranged for Tangential Firing Date: 11-10-67, Page: 6:86.
- 59th Street Station Data Book, September 2005.

74th Street Station:

- C-E Dwg. No. 20-344.
- Foster Wheeler Summary Performance Sheet for 74th Street. (Only for the Package Boilers)
- Completed WorleyParsons Appendix A Boiler/Turbine Data Sheets for Boilers No. PB 2 & 5; PB 1, 3, 4 & 6; 120 & 121; and 122.
- Contract Data Sheet Dated October 23, 1953 for Boiler Nos. 120 & 121.
- Contract Data Sheet Dated October 23, 1953 for Boiler No. 122.
- 120 Boiler Condition Assessment dated January 28, 1999.
- 121 Boiler Condition Assessment dated January 28, 1999.

- 122 Boiler Condition Assessment dated January 28, 1999.
- Units PB 1-6 Boiler Condition Assessment dated January 28, 1999.
- Results Engineering Bureau, Summary Sheet, Boiler No. 120.
- Results Engineering Bureau, Summary Sheet, Boiler No. 121.
- Results Engineering Bureau, Summary Sheet, Boiler No. 122.
- Figure 5-1: Combined Operational Limits.

Hudson Avenue Station:

- Hudson Avenue Boilers 71, 72, 81, 82 Side Sectional Elevation Drawing No. 94791-2.
- Hudson Avenue Boilers 71, 72, 81, 82 C-E Power Systems, Insulation, Refractory and Casing, Key Arrangement, Side Elevation.
- Babcock & Wilcox, Figure 2, Boiler Elevation Diagram from Visual Inspection Report, April 14, 2004 for the Low Pressure Boilers.
- Data provided by Con Edison in response to WorleyParsons Data/Information Request Boiler Feed Pump #17, # 18, #19.
- Data provided by Con Edison in response to WorleyParsons Data/Information Request Boiler Feed Pump #20.
- Data provided by Con Edison in response to WorleyParsons Data/Information Request Deaerators.
- Brooklyn Edison Company Drawing No. 3004548, Floor Plan for Units 7 & 8 Induced Draft Fans.
- Consolidated Edison Co. Drawing No. 22610-C, Plot Plan.
- Drawing - Longitudinal Section through Boiler House.
- Consolidated Edison Co. Drawing No.121261-0, Heat Balance Diagram Unit #10 280 psig Exhaust Pressure.
- Consolidated Edison Co. Drawing No.121262-0, Heat Balance Diagram Unit #10 410 psig Exhaust Pressure.
- Hudson Avenue Unit #100 Boiler (Cross Section).
- Figure 1-1, HA100.
- September 2005 Boiler Performance Data.
- Layout Sketch of Hudson Avenue Station.
- Unit Condition, Hudson Avenue – LP Boilers dated 7/12/2004.
- Data provided by Con Edison in response to WorleyParsons Appendix A Boiler/Turbine Data Sheets for Boilers No. 71, 72, 81.
- Data provided by Con Edison in response to WorleyParsons Appendix A Boiler/Turbine Data Sheets for Boiler No. 82.

- Data provided by Con Edison in response to WorleyParsons Appendix A Boiler/Turbine Data Sheets for Boiler No. 100.
- Data provided by Con Edison in response to WorleyParsons Appendix C Steam Turbine and Generator Questionnaire

4.1.3 59th Street Station Assessment

4.1.3.1 Performance Issues

The gross and net capacity of the boilers are shown in Exhibit 4-1.

Exhibit 4-1 59th Street Boiler Capacities

Boiler	Gross Design Steam Capacity (lb/hr)	Net Steam Capacity (lb/hr)
114	[REDACTED]	475,000
115	[REDACTED	475,000
116	[REDACTED	127,000
117	[REDACTED	127,000
118	[REDACTED	127,000

Presently the boilers are operating close to their original design efficiency. WorleyParsons has independently verified the efficiency of Boiler #114 and the calculated data are in close agreement of the reported efficiency data. The continuing monitoring of the exhaust gas temperatures and cleaning of the boilers when possible, when the temperatures exceed preset limits, helps to keep the boilers operating near their design efficiency.

All the boilers are being operated at reduced pressure well below their design value. This operation should extend the useful life of the pressure parts.

With the present operation of the boilers and the ongoing capital replacement program, these boiler systems should provide satisfactory operation for many more years.

4.1.3.2 Operation and Maintenance Considerations and Issues

Presently the 59th Street Station is used for steam dispatch only. The existing Combustion Turbine has been upgraded for black start capability. They have recently installed a new UPS system, Boiler Feed Pump Turbine Governors, and a new Combustion Turbine Control System. The pier for docking the barge from which fuel is provided to the 59th Street Station is in deteriorating condition. This pier is rented from New York City and it is WorleyParsons understanding that Con Edison is planning to repair the piers. Water chemistry and boiler near drum corrosion caused by acidic ash on the exterior of the tubes are issues that are being addressed by Con Edison's current capital improvements program. There seem to be no operational restrictions with the plant based upon the information reviewed and personal observations.

4.1.3.3 Site Specific Considerations, Issues, and Constraints

The Turbine Building Roof is in the process of being replaced. There is a frequency changer still in place on the turbine deck that would require removal. According to plant maintenance personnel, boilers are cleaned about every 8 weeks, if possible, when there is heavy steam demand. The boilers and support equipment seem to be in good condition based upon the information reviewed and visual external inspection. Support steel issues in the plant include the floor of the Package Boilers. This would need part replacement for continued operation for 20 years or more, and according to Con Edison personnel, they have plans to make needed repairs.

As noted previously, the fuel pier requires some repair work and Con Edison has plans to make the necessary repairs. The station is a single building occupying an entire square city block. [REDACTED].

Some egress point upgrades would be required if new codes were applied and the plant was not "grandfathered". The Fire Protection System would require upgrade if re-powering is done and not grandfathered. The 11th Avenue side and other architectural surroundings on the outside are potentially considered historical. Personnel at the plant stated that the application for consideration as historical was submitted, but they do not know the results of the request. This would need to be determined prior to using any windows as new access points for bringing in new equipment. 59th Street Station still has an old retired boiler and other retired equipment on the 12th Avenue Side. Removal of this equipment would provide potential room for re-powering options.

Due to the extensive building and residential areas around the facility, permitting may be a significant issue with respect to upgrades and/or repowering, as it likely would anyplace in New York City, especially if a new stack is required.

4.1.4 74th Street Station Assessment

4.1.4.1 Performance Issues

The gross and net capacities of various Boilers are shown on Exhibit 4-2.

Presently the boilers are operating close to their original design efficiency. WorleyParsons has independently verified the efficiency of Boiler # 120 and the calculated data are in close agreement of the reported efficiency data. The continuing monitoring of the exhaust gas temperatures and cleaning the boilers, when possible, when the temperatures exceed preset limits helps to keep the boilers operating near their design efficiency.

The high pressure boilers (Boilers #120, 121, and #122) are being operated well below their design operating pressure. This operation should extend the useful life of the pressure parts. The Package Boilers on the other hand are being operated near their design pressure.

Considering the present operation of the boilers and the ongoing capital replacement program, these boiler systems should provide satisfactory operation for many more years.

Exhibit 4-2 74th Street Station Boiler Capacities

Boiler	Gross Design Steam Capacity (lb/hr)	Net Steam Capacity (lb/hr)
1	[REDACTED]	110,000
2	[REDACTED]	110,000
3	[REDACTED]	110,000
4	[REDACTED]	110,000
5	[REDACTED]	110,000
6	[REDACTED]	110,000
120	[REDACTED]	434,000
121	[REDACTED]	433,000
122	[REDACTED]	433,000

4.1.4.2 Operation and Maintenance Considerations and Issues

Presently the 74th Street Station is being operated for electrical dispatch as well as steam dispatch. The exhaust systems of the existing gas turbines share the common stack connected to the boilers. Currently there is an operational issue involved with the flue gas system draft that actually limits the operation of the boilers when gas turbines operate concurrently to satisfy the electric dispatch requirements. Plant personnel stated that electrical dispatch was previously required every other day during summer peak. This causes operational restrictions due to loss of draft on the Package Boilers when the combustion turbines are loaded. This also provides some impact on operation of the HP Boilers. This stack draft issue mainly occurs in July and August, when steam demand is not at its peak. Thought should be given to providing the combustion turbines with their own stack which would then eliminate this operational restriction; however, DEC permitting issues might prevent this from occurring.

The currently installed air compressors are not reliable according to two Package Boiler operators. It is recommended that the compressors be evaluated for potential upgrades and/or replacement. [Note: subsequent to the site visit by WorleyParsons engineers, Con Edison replaced the air compressors.]

4.1.4.3 Site Specific Considerations, Issues, and Constraints

The current fuel supply situation is satisfactory, but currently there is only a single 6" line available to provide the boiler fuel. The pier is in disrepair, is rented from New York City, and would require some repair to increase fuel supply or provide a backup method of obtaining No. 6 fuel oil. Space exists on the Turbine Deck where the T9, T10, & T11 turbines were removed. Additional space would be available if the frequency changers were removed. Con Edison currently has a substation installation scheduled for 2009 as well as a new battery room. These items will be installed on the

Turbine Deck and will take up approximately 50% of the available space. The other portion of the turbine deck would be available for equipment installation, but based upon existing common exhaust stack issues between the combustion turbines and the boilers, tapping into the existing stack is a major issue. An additional stack would be required to provide for addition of new equipment.

There is currently no natural gas line to the 74th Street Station. The addition of gas powered equipment would require installation of an appropriate sized gas line to the station boundary as well as internal fuel piping to the equipment.

Currently installed air compressors for the Package Boilers are not considered reliable by Boiler Operators. Replacement of these compressors should be considered. [Note: subsequent to the site visit by WorleyParsons engineers, Con Edison replaced the air compressors.]

Floor support issues below the Package Boilers would need to be evaluated and addressed for safe, continued operation of the Package Boilers, and Con Edison personnel indicate that they are currently developing an engineering package to address this.

Currently scheduled capital projects and improvements support continued operation of the existing facility for the next 20 years understanding that the above operational restrictions would still apply.

Due to the heavy residential areas around the facility, permitting may be a significant issue, as it likely would anyplace in New York City, especially if a new stack is required. This should be addressed when upgrades are considered.

4.1.5 Hudson Avenue Station Assessment

4.1.5.1 Performance Issues

The gross and net capacities of the boilers are shown on Exhibit 4-3.

Exhibit 4-3 Hudson Avenue Boiler Capacities

Boiler	Gross Design Steam Capacity (lb/hr)	Net Steam Capacity (lb/hr)
71	[REDACTED]	400,000
72	[REDACTED]	400,000
81	[REDACTED]	400,000
82	[REDACTED]	400,000

The boilers are presently operating somewhat near their original design efficiency. The continuing monitoring of the exhaust gas temperatures and cleaning the boilers, if possible, when the temperatures exceed preset limits helps to keep the boilers operating near their design efficiency.

The boilers are being operated below the original design pressure. This reduced pressure operation should help to extend the life of the pressure parts. However, the continuing blistering of furnace tubes, the thinning of generating bank tubes, and the need to plug economizer tubes could seriously impact the operation of these boilers.

While the Annex Unit 10/100 turbine/boiler was operational (see a brief history of Unit 10/100 in Section 4.1.5.3), much of the steam demand from the station was supplied by the Unit. With the retirement of this Unit in 2004, more demand is placed on the 4 low pressure boilers, which is likely to cause more pressure part failures than in the recent past. The continued long term operation of these boilers without significant pressure part replacement (possibly including the drums) is seriously in question.

4.1.5.2 Operation and Maintenance Considerations and Issues

Accessibility to plant equipment due to building spalling is an issue in the Boiler Building. This has been mitigated mostly by the use of netting and scaffolding, but the building issues should be addressed directly, and not just partially mitigated.

The Nos. 71, 72, 81, and 82 boilers have had many issues and over time have degraded significantly. This is to be expected, but useful life of the boilers for an additional twenty years is questionable. Of the four boilers, No. 82 has operational restrictions due to lack of a superheater and No. 71 is the worst as far as issues noted. Significant maintenance will be needed to keep these units running fairly efficiently and reliably.

There is currently a capital improvement project to replace the feedwater and deaerator systems with a new system. Current Boiler Feed Pumps are variable speed and provide a large amount of flexibility with their support. The new system does not incorporate any spare BFPs for the projected steam sendout of 1.6 million lb/hr, so this could be an issue with respect to reliability.

The plant currently uses CC910 fuel additive to the fuel oil to help with O_2 levels and opacity. This has been ongoing for 1 year and has met with some success.

4.1.5.3 Site Specific Considerations, Issues, and Constraints

The largest indoor areas include the remaining boiler building area where other boilers had previously existed as well as the Turbine Building. The Boiler Building spalling issues would be an increased cost for installation in that area compared to the Turbine Building. The Turbine Building ceiling would need repair and/or replacement if additional units were desired to be placed there. There are some outside areas to note for potential repowering options. The area bordering Plymouth Street (called the Annex Yard) has some area, but has direct exposure to the surrounding areas that are residential. There is a small area located east of the demineralization trailer station in the Frequency House and SH Yard that has room for additions.

ID Fans currently have pole changer issues and would need some upgrades to improve the reliability of the units. The electrical system is old and unused truck switches are abundant throughout the plant. Any replacement of these switches

should be well planned due to the fact that each switch powers more than one load. This would need to be studied for any upgrades as far as which loads are available to be taken out of service for any upgrades.

A separate trip was made to determine the structural integrity of the existing LP boiler house building to support new equipment. Based upon the site visit it was determined that supporting the new equipment proposed in the re-powering configuration will require major renovation and replacement of the structures and because of the unknowns (hidden structures, absence of original calculations and design basis), WorleyParsons is of the opinion that an alternate siting of new equipment will be a better choice.

Unit 10/100, located at the Hudson Avenue Generating Station in Brooklyn, is a steam-electric topping unit that was originally retired from service in 1997. This Unit was originally commissioned in the early 1950s. The unit consists of a boiler and topping turbine which had the capability to simultaneously deliver steam to the Company's steam system as well as provide in-City electric supply.

In late 2000, Con Edison identified Unit 10/100 as having the potential to provide near-term help in ensuring a reliable electric supply to the NYC area in the summer of 2001. Unit 10/100 was placed back in service in July 2001 and was permitted under the Station's Title V Air Permit for a limited 39 month period. The Unit supplied approximately 65 MW of electric capacity and approximately 1,100,000 lb/hr of steam capacity. Unit 10/100 was again retired from service on October 1, 2004 in accordance with conditions of the Station's Title V air permit and the shutdown plan approved by the New York State Department of Environmental Conservation ("DEC").

Following permitting as a new emission source, and the rehabilitation of major plant systems, Unit 10/100 could be operated as a base load electric and steam generating unit. Putting the 10/100 Unit in service would require an extensive examination of the electrical systems prior to restart. [REDACTED].

Even though Con Edison personnel have indicated that the public sentiment may not be favorable to restarting Unit 10/100, the condition of the Unit is good, especially in comparison to boilers #71, 72, 81, and 82. [REDACTED].

If Unit 10/100 is to be placed in service, it would be treated as a new unit from a regulatory view point. This would require a modified Title V Permit along with the unit meeting current regulations (NSPS, MACT, and others).

One of the issues with operation of the #71, 72, 81, & 82 boilers is that the units share FD Fans and a common plenum. This is not as much an issue for continued operation, but is important to note for any re-powering options.

There are underground intake and discharge tunnels from the river. These tunnels would require some evaluation for both continued use as well as location as they would be important for locating new foundations for re-powering options.

There is only a small natural gas line to the Hudson Avenue Station. The addition of gas powered equipment would require installation of an appropriate sized gas line to the plant boundary as well as internal fuel piping to the new equipment.

4.1.6 Current and Forecast Steam Production

Based upon WorleyParsons' review of the Con Edison's Steam Business Development Plan, dated August 26, 2005, provided by Con Edison, Con Edison's current net steam supply capacity is approximately 12.8 million pounds per hour (MMPPH). This includes approximately 900 thousand pounds per hour supply from the Brooklyn Navy Yard Cogeneration facility. The four facilities under WorleyParsons scope of work, namely the 59th Street, 74th Street, Hudson Avenue, and Ravenswood (A-House) Stations, contribute about 5.4 MMPPH, which is approximately 42% of the total supply capacity. A summary of steam sendout data from various Stations is shown in Exhibit 4-4.

It is also noted from the review that the recorded actual 2004-05 winter peak steam demand is 9.7 MMPPH (not weather normalized to the design temperature) and the 2005-2006 winter peak projection is 10.4 MMPPH (at design temperature). The current supply capacity has a margin of about 23% over the projected 2006 peak demand.

WorleyParsons has received historic and the future 20 year projected steam send out data from Con Edison for the four facilities studied, and the results are shown in Exhibit 4-5 and Exhibit 4-6 for the Hudson Avenue, 59th Street, and 74th Street Stations and in Appendix G for the Ravenswood Station.

The following summarizes the results of WorleyParsons findings and observations.

a) Historical Data (2000 – 2004). Reference Exhibit 4-5.

- Average Annual Send Out for the three stations being examined is approximately 12,900 million pounds, with the highest recorded in 2004 of about 14,300 million pounds. The 2000 – 2003 total annual Send Out is rather steady varying between 12,270 – 12,860 million pounds.
- Maximum Send Out occurs typically in January while the minimum Send Out is typically in May.

b) Future Projection Data (20 year 2006 – 2025). Reference Exhibit 4-6.

- [REDACTED].

Exhibit 4-4 Steam Sendout Data from Various Stations

Item	Station	Steam flow (kpph)	
A. Facilities in WorleyParsons Study Scope			**Remarks**
1	59th Street Station	1,331	Mid & Uptown facilities
2	74th Street Station	1,960	Mid & Uptown facilities
3	Hudson Avenue	1,600	Downtown & lower Manhattan
4	Ravenswood	500	Mid & Uptown facilities
	Total Steam Produced	**5,391**	
B. Other ConEd Facilities			
1	60th Street Station	762	Mid & Uptown facilities
2	ERRP	3,200	288 MW Cogen
3	East River 6 & 7	1,890	300 MW
4	East River South Steam	650	On No #6 Oil
5	Brooklyn Navy Yard	918	267 MW Cogen
	Total Steam Produced	**7,420**	
C.	**Sum Total of A & B**	**12,811**	

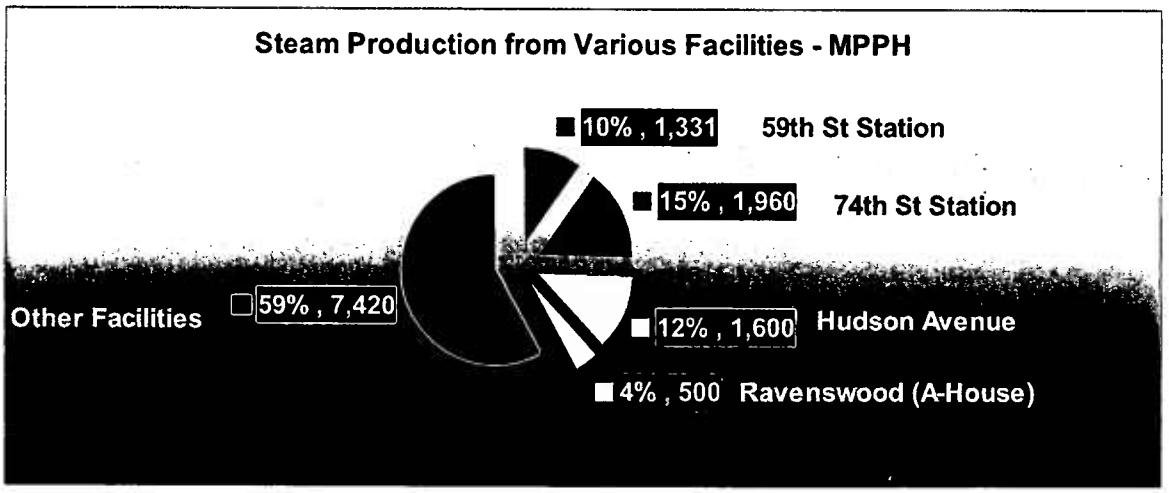


Exhibit 4-5 Summary of Historical Steam Sendout Data from Selected Stations

Item	Description	Yr - 2000	Yr - 2001	Yr - 2002	Yr - 2003	Yr - 2004	5 Year Average
1	**Total Annual Steam Send Out[1]**	**12,277,493**	**11,858,048**	**11,393,398**	**12,253,621**	**13,197,018**	**12,195,916**
a.	- Hudson Avenue Station[2]	4,105,860	4,322,271	3,725,252	3,536,457	3,923,171	3,922,602
b.	- 59th Street Station	3,168,909	2,767,042	2,946,346	3,986,442	3,622,894	3,298,327
c.	- 74th Street Station	5,002,724	4,768,735	4,721,800	4,730,722	5,650,953	4,974,987
2	**Monthly Avg Steam Send Out[1]**	**1,023,124**	**988,171**	**949,450**	**1,021,135**	**1,099,752**	**1,016,326**
a.	- Hudson Avenue Station[2]	342,155	360,189	310,438	294,705	326,931	326,884
b.	- 59th Street Station	264,076	230,587	245,529	332,204	301,908	274,861
c.	- 74th Street Station	416,894	397,395	393,483	394,227	470,913	414,582
3	**Package Boiler Contribution[3]**						
	- Hudson Avenue Station	N.A	N.A	N.A	N.A	N.A	
	- 59th Street Station	31%	34%	35%	29%	26%	31%
	- 74th Street Station	17%	18%	21%	25%	18%	20%
4	**Maximum Send Out Month**	**January**	**January**	**December**	**January**	**January**	**1,421,371**
5	**Minimum Send Out Month**	**May**	**May**	**May**	**June**	**May**	**555,596**
6	**Seasonal Average Send Out**						
a.	- Winter (December - February)	1,527,997	1,409,513	1,188,645	1,737,574	1,960,293	1,564,804
b.	- Spring (March - May)	704,532	979,671	815,401	888,748	1,015,403	880,751
c.	- Summer (June - August)	941,414	1,075,228	1,188,460	872,847	953,483	1,006,287
d.	- Fall (September - November)	918,758	696,720	966,061	788,063	862,176	846,356

Notes

1. All Steam Flow data are in 1000 pounds, net Send out 2. Boiler #10 & STG 100 in Hudson Avenue Plant were operational in years 2001 - 2004
3. Percentage of Total Steam Send Out

Exhibit 4-6 Summary of Projected Steam Sendout Data from Selected Stations

[REDACTED]

- [REDACTED].

- [REDACTED].

Con Edison also provided WorleyParsons with hourly steam production data from Steam MIMIC for the Hudson Avenue, 59th Street, and 74th Street Stations for periods of operation during the years 2004 and 2005. WorleyParsons used the hourly profile data to develop an estimated hourly profile for the years 2006 through 2025 which matched the annual forecasts provided by Con Edison for those facilities. WorleyParsons also developed load duration curves based on the profile to be used in estimating the performance of the repowering options evaluated. The profiles for the three facilities (Hudson Avenue, 59th Street, and 74th Street Stations) are shown in Exhibit 4-7.

Exhibit 4-7 Steam Sendout Load Duration Curves Used as Basis for Evaluations

[REDACTED]

4.1.7 Current and Projected Cost of Operation

The current and projected costs of operation of the existing facilities are presented along with projected costs of operations of repowering options evaluated in later sections of this report.

4.1.8 Recommendations for Reductions in Steam Production Costs

WorleyParsons recommends the replacement of the boilers at Hudson Avenue with new boilers or other systems to ensure that new systems can be placed in service before the older boilers become inoperable and/or not cost effective to operate. Currently installed air compressors for the Package Boilers are not considered reliable by Boiler Operators. WorleyParsons recommends replacement of the air compressors for the Package Boilers to improve reliability and potentially reduce costs. [Note: subsequent to the site visit by WorleyParsons engineers, Con Edison replaced the air compressors.] Except for the promising new Options considered in the latter sections of this report, WorleyParsons was unable to identify any other areas that appear to have the potential to reduce the steam production costs at these facilities other than continuation of the Con Edison planned maintenance programs as described to us and reviewed in documents provided by Con Edison.

4.2 FEASIBILITY OF RE-POWERING CON EDISON PLANTS

4.2.1 Hudson Avenue Station

4.2.1.1 Re-Powering Options Considered

The major site specific issues at the Hudson Avenue station that were considered in determining options to be considered are as follows:

- Existing LP boilers are aged and not suitable for 20 years operation without replacement.
- Existing boiler house building and structures are not considered suitable for repowering installation.
- Demolition of existing buildings / structures / equipment are required for new repowering options.
- There is no existing natural gas supply to support operation of any large gas fired facility.
- Electrical reinforcements are required for cogeneration and combined cycle repowering options.
- Relocation of existing equipment / utilities are required for all installation of all repowering options.

As Hudson Avenue has the greatest potential for re-powering compared to the other two sites, a large number of Options were evaluated at this site to satisfy the projected

steam supply needs while maximizing the simultaneous electric power generation. The following summarizes the various Options:

- 14 Options Evaluated
  - 4 Cogeneration Options (CG-1 through CG-4)
  - 6 Combined Cycle Options(CC-1 through CC-6)
  - 3 Boiler / Steam turbine Options (BP-1, 1A and BP-3)
  - 1 Boiler Only Option (BP-2)
- Initial cogen and combined cycle options (CG-1 through CG-4 and CC-1 through CC-4 - a total of 8) were sized to match steam generation from the HRSG as close as possible to the projected average annual steam sendout from the plant with or without supplemental firing in the HRSG while staying within the normal operating limits of various equipment.
- 2 additional combined cycle options (CC-5 & CC-6) were added to the initial list as requested by the Core Team. These combined cycle plants are sized to maximize electric power generation while satisfying the annual average send out requirements from the facility. The additional steam generated in these options will be used to generate electricity.
  - 1 on 1 combined cycle option (CC-5) generating about 258 MWe (Net) with average steam send out / 335 MWe (Net) in full condensing mode at ISO with natural gas firing.
  - 2 on 1 combined cycle option (CC-6) generating about 480 MWe (Net) with average steam sendout/ 521 MWe (Net) in full condensing mode at ISO with natural gas firing.
- Two (BP-1 and 1A) of the 3 Boiler / Steam Turbine Options include resurrection of the retired Unit 10/100 (~62 MW net with natural gas firing) with partial or full capacity dump condenser. The other boiler / turbine option (BP-3) is to include a small new back pressure steam turbine (~16 MW net with natural gas firing) with dump condenser sized to meet the annual average hourly steam send out and balance of steam supplied by new steam only boilers.
- The Boiler only option essentially replaces the current steam generation mode with new steam boilers with no on-site power generation.

The tables in Exhibit 4-8 through Exhibit 4-10 summarize the salient features of various Cogen, Combined Cycle, and Boiler options, respectively. Exhibit 4-11 identifies some of the key pros and cons of the types of systems utilized in the options.

Exhibit 4-8 Summary of Features of Cogeneration Options Evaluated for Hudson Avenue Station

	CG1	CG2	CG3	CG4
CT Type	Seimens 501D5A	GE7EA	GE LM6000	Siemens GTX100
No. of CTs / HRSGs	1	1	1	1
Dump Condenser	yes	yes	no	yes
No. LP Boilers	3	3	4	4
Peak Design SSO Capacity, Mlb/hr	1,600	1,600	1,600	1,600
Net Electric Capacity, MWe (ISO)	117	84	42	43
20-year Avg Annual SSO, MMlb	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]

Note: The Electric Capacity Data are with CTs operating on natural gas fuel

Exhibit 4-9 Summary of Features of Combined Cycle Options Evaluated for Hudson Avenue Station

	CC1	CC2	CC3	CC4	CC5	CC6
CT Type	Seimens 501D5A	GE7EA	GE LM6000	Siemens GTX100	Siemens 501FD	GE 7FA
No. of CTs / HRSGs	1	1	1	1	1	2
No. Extraction / Condensing Steam Turbines	1	1	1	1	1	1
No. LP Boilers	3	3	4	4	3	0
Peak Design SSO Capacity, Mlb/hr	1,600	1,600	1,600	1,600	1,600	1,600
CT Electric Capacity, MWe (ISO) Gross, Ea.	120	86	43	45	198	174
Net Electric Capacity, MWe (ISO) based on Annual Avg Extraction flow from STG	146	104	43	48	258	479
20-year Avg, Annual SSO, MMlb	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]

Note: The Electric Capacity Data are with CTs operating on natural gas fuel

Exhibit 4-10 Summary of Features of Boiler Options Evaluated for Hudson Avenue Station

	BP1	BP2	BP3	BP1A
No. HP Boilers	1 (Existing 10/100)	N.A	1	1 (Existing 10/100)
HP Boiler Net Capacity, Mlb/hr	1,320		330	1,320
No. LP Boilers	2	4	4	2
Total Net LP Boiler Capacity, Mlb/hr	408	1,600	1,300	408
No. BP Steam Turbines	1	N.A	1	1
Dump Condenser	Yes (partial capacity)	No	Yes (full capacity)	Yes (full capacity)
Peak SSO Capacity, Mlb/hr	1,600	1,600	1,600	1,600
Net Electric Capacity, MWe (ISO) based on Annual Avg Extraction flow from STG	12	N.A	14	62
20-year Avg, Annual SSO, MMlb	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]

Exhibit 4-11 Pros and Cons of Options

	Pros	Cons
Cogeneration Relative to Combined Cycle	♦ Lower capital cost ♦ Smaller footprint for same steam sendout capacity ♦ Lower maintenance costs	♦ Lower electric generation capacity ♦ Lower electric generation efficiency ♦ Require dumping of steam for some options that cannot be effectively used ♦ No flexibility to increase/optimize electric generation versus steam sendout
Cogeneration Relative to Boiler Only Options	♦ Electric generation capability ♦ Higher overall energy efficiency	♦ Larger space requirement ♦ Higher capital cost ♦ More complex operation ♦ Higher maintenance costs ♦ Electric market risk
Cogeneration Relative to Unit 10/100 Boiler/ST Option	♦ Higher average electric generation capability ♦ Higher energy efficiency	♦ Higher capital cost ♦ Demolition/remediation required ♦ Higher maintenance costs
Large Cogeneration Relative to Small Cogeneration	♦ Higher electric generation capacity ♦ Higher efficiency ♦ Fewer package boilers for peak loads	♦ Higher capital cost ♦ Larger space requirement ♦ Higher maintenance costs
Combined Cycle Relative to Boiler Only Options	♦ Electric generation capability ♦ Higher overall energy efficiency ♦ Provides flexibility of generation of both electric and steam to maximize revenue	♦ Larger space requirement ♦ Higher capital cost ♦ More complex operation ♦ Higher maintenance costs ♦ Electric market risk
Combined Cycle Relative to Unit 10/100 Boiler/ST Option	♦ Higher electric generation capacity ♦ Higher energy efficiency	♦ Higher capital cost ♦ Demolition/remediation required ♦ Higher maintenance costs
Large Combined Cycle Relative to Small Combined Cycle	♦ Higher electric generation capacity ♦ Higher efficiency ♦ Fewer package boilers for peak loads ♦ Lower overall cost of steam	♦ Higher capital cost ♦ Larger space requirement ♦ Higher maintenance costs

4.2.1.2 Conceptual Description of Re-Powered Facilities

The conceptual description of the Re-powering options considered for the Hudson Avenue Station are presented below. The summary performance data for various options and typical schematics of the Cogeneration and Combined Cycle Options are shown in Exhibit 4-12, Exhibit 4-13, and Exhibit 4-14, respectively, that follow the descriptions. Conceptual layouts of the promising options are shown in Section 4.2.1.7.

- **CG-1:** This Cogen plant option will utilize one (1) dual fuel (natural gas with back up low sulfur No 2 fuel oil) fired Siemens SGT6 – 3000E (501D5) gas turbine, one (1) two pressure supplementally fired Heat recovery Steam Generator (HRSG), and three (3) package boilers to supplement the peak steam demand. Steam will be sent out directly from the HRSG at the operating condition of 350 psia/455F. The gas turbine will be provided with a dry low NOx combustion system and will use water injection for NOx control during oil firing. The supplemental firing in the HRSG is by natural gas (firm gas supply) only. The package boilers will also be designed for dual fuel operation and be provided with emission control equipment (Low NOx burner, SCR and CO catalyst). The configuration will include a dump condenser to sustain base load power generation during low steam demand period. The facility will include other equipment such as gas compressors, water treatment plant, transformers, electrical switchgears etc as required to support the operation of the plant. The gas turbine systems are provided with evaporative cooler and fuel gas heater to improve upon the overall performance.
- **CG-2:** This Cogen plant option is similar to the CG-1 Option except that it utilizes a General Electric's (GE) 7EA gas turbine.
- **CG-3:** This Cogen plant option is similar to the CG-1 Option except that it utilizes a General Electric's (GE) LM6000 aeroderivative type gas turbine, four (4) package boilers and does not require any dump condenser as the minimum steam demand from the facility matches very well with the base load operation the gas turbine without any supplemental firing in the HRSG. The steam production from the cogen facility with supplemental fired HRSG matches very well with the average annual hourly send out requirements.
- **CG-4:** This Cogen plant option is similar to the CG-1 Option except that it utilizes a Siemens SGT 800 (GTX 100) gas turbine and four (4) package boilers. Similar to the CG-3 option, the steam production from the cogen facility with supplemental fired HRSG matches very well with the average annual hourly send out requirements
- **CC-1:** This Combined Cycle plant option will utilize one (1) dual fuel (natural gas with back up low sulfur fuel oil) fired Siemens SGT6 – 3000E (501D5) gas turbine (Same as that of CG-1), one (1) two pressure supplementally fired Heat recovery Steam Generator (HRSG), a condensing / controlled extraction steam turbine exhausting to an air cooled condenser and three (3) package boilers to supplement the peak steam demand. Steam will be generated at higher pressure and temperature (1500 psia/950°F) and will be sent to the steam turbine first. Steam sendout will be supplied from the controlled extraction to maximize electrical generation while matching the steam demand at a pressure

of 350 psia/455F. The plant is designed to run the gas turbine in base load to maximize the overall plant efficiency and any steam in excess of the send out requirements will be expanded through the back end of the turbine to provide additional electrical output. A steam turbine bypass system will also be provided to maximize steam send out flow when needed (at the sacrifice of electricity production) or to supply steam to the send out header during steam turbine outage condition. The gas turbine design and the other plant equipment are similar to the CG-1 option except that the capacity and ratings of the equipment are different due to different operating conditions. The maximum steam send out from the steam turbine extraction without any supplemental firing in the HRSG matches well with the annual average hourly send out requirements.

- **CC-2:** This CC plant option is similar to the CC-1 Option except that it utilizes a General Electric's (GE) 7EA gas turbine.
- **CC-3:** This CC plant option is similar to the CC-1 Option except that it utilizes a General Electric's (GE) LM6000 aeroderivative type gas turbine, four (4) package boilers.
- **CC-4:** This CC plant option is similar to the CC-1 Option except that it utilizes a Siemens SGT 800 (GTX 100) gas turbine and four (4) package boilers.
- **CC-5:** This CC plant option is similar to the CC-1 Option except that it utilizes a Siemens SGT6 5000F (501F) gas turbine and three (3) package boilers. The gas turbine produces about 198 MW compared to 120 MW for CC-1 and is more efficient. The gas turbine is dual fuel fired and is provided with water injection for NOx control, evaporative cooler and performance heater.
- **CC-6**: This CC plant option is similar to CC-1 option except that it utilizes 2 x General Electric 7FA gas turbines with two supplementally fired HRSGs, one large steam turbine with controlled extraction but no package boilers. This option produces the maximum electric output and can meet the peak send out requirements without any supplemental package boiler. The gas turbine produces about 175 MW each compared to 120 MW for CC-1 and is more efficient. The gas turbines are dual fuel fired and are provided with water injection for NOx control, evaporative coolers and performance heaters.
- **BP-1:** This option includes resurrecting the existing retired Unit 10/100 (~62 MW net) with a partial capacity dump condenser. The boiler will be converted to natural gas firing with low sulfur No 2 oil as back up and will be fitted with emission control equipment (LNB, SCR and CO Catalyst). The back pressure steam turbine will be refurbished and will operate to match the steam send out requirements. However when the steam send out requirements is below about the current minimum operating limits of 350 Mlb/hr, the dump condenser will be placed in operation to maintain stable operation of the unit. As this is a back pressure turbine, the electrical output will vary based upon the steam send out and will remain constant (~ 12.4 MW net) when it reaches the lower operating limit noted above. This option will also include two package boilers to supplement the peak steam sendout requirements. A separate LP deaerator and a condensate preheater as shown on the heat balance diagram will be provided to maintain the same condensate conditions as shown on the current heat balances. A steam turbine bypass system will also be provided to maximize steam sendout flow when needed (at the sacrifice of electricity

production) or to supply steam to the sendout header during steam turbine outage condition.

- **BP-1A:** This option is same as that of BP-1 Option except that it includes a full capacity dump condenser so that the steam turbine can be run base loaded (~62 MW net) irrespective of the steam sendout requirements.
- **BP-2:** This option replicates the current operation by replacing the existing LP boilers with four (4) new dual fuel (natural gas with low sulfur no 2 oil back up) boilers. The new boilers will be fitted with emission control features. There is no electric power generation with this option. The steam conditions are 350 psia/455°F, the same as that of the cogen options.
- **BP-3:** This option utilizes one(1) high pressure boiler with a small backpressure steam turbine (~14 MWe net) sized to supply the annual average hourly steam sendout requirements and four (4) low pressure boilers to supplement the peak steam demand. The HP steam conditions are 1500 psia / 950F. the same as that of the CC plant. The LP steam conditions are 350 psia / 455F, same as that of the cogen plant. All boilers are dual fuel fired design and will be fitted with emission control devices as in the BP-2 option. The steam turbine will be fitted with a dump condenser to support base load operation of the steam turbine when the demand falls below the average annual hourly sendout requirements of 328 Mlb/hr. A steam turbine bypass system will also be provided to maximize steam sendout or to supply steam to the header during steam turbine outage condition.

Equipment Availability

- Gas Turbines : Gas turbines are highly reliable machines for power generation and have been used both for base loaded and peaking duty applications. The availability data of the gas turbines are provided by the gas turbine OEMs based upon their fleet operating experience and also independently published by various organizations such ad NERC (North American Electric Reliability Council) or ORAP (Operating Reliability Analysis Program) data marketed by SPS. Based upon the survey of the above data, WorleyParsons has used the following availability data of the gas turbines in the economic model and screening of various options.

  Mature Gas Turbine Units (501D5, GE 7EA, GTX 100): 94%

  Aeroderivative Machines (LM 6000) : 95%

  "F" Class machines (501F and 7FA) : 92%

- Boilers and Steam Turbines: The availability of these machines is assumed to be 95% based upon industry accepted practice.

Equipment Degradation

Gas Turbines: Gas turbines experience non-recoverable performance degradation due to aging until a major overhaul takes place. The degradation occurs due to changes in the gas turbine operational characteristics primarily from fouling of blades and also due to changes in operational clearances between various components. Similar degradation occurs for other equipment as well except that the impacts are much greater for gas turbines.

The degradation reduces the electric output and the efficiency of the equipment. For the performance modeling of various Options for future years, WorleyParsons have considered the following degradation factors for various equipment.

- Cogeneration Options (CG-1 through CG-4): Net Output & Net Electric Generation are reduced by 0.32% and Gas turbine Fuel Consumption is reduced by 0.17% - per year every year from the previous year starting after the first year of operation.
- Combined Cycle Options: Net Output & Net Electric Generation are reduced by 0.26% and Gas turbine Fuel Consumption is reduced by 0.17% per year every year starting after the first year of operation.

HRSG and Boiler Fuel Consumption: Fuel Consumption is increased by 0.08% per year every year starting after the first year of operation

Exhibit 4-12 Hudson Avenue Options Screening Model

CONCEPTUAL DATA FOR REALTIVE COMPARISON ONLY[1]

A. Combined Gas & Oil Firing - Steam Send Out Based Upon Projected Demand, Gas Firing for 335 Days and Oil Firing for 30 Days[3 &18]

ITEM	DESCRIPTION	Current Operation	STEAM GENERATION AND RE-POWERING OPTIONS: Cogeneration Options with Supp Fired HRSGs				Combined Cycle Options with Supp Fired HRSGs						Boiler Repowering Options			
A.	Option Description	Based on 2005 Operation on Oil	Option - CG1: Cogen Plant with Siemens 501D5A with full capacity Dump Cond & New LP Blrs	Option - CG2: Cogen Plant with GE 7EA with full capacity Dump Cond & New LP Blrs	Option - CG3: Cogen Plant with GE LM 6000 with New LP Blrs	Option - CG4: Cogen Plant with Siemens GTX 100 with Dump Cond & New LP Blrs	Option - CC1: CC Plant with Siemens 501D5A & New LP Blrs	Option - CC2: CC Plant with GE 7EA & New LP Blrs	Option - CC3: CC Plant with GE LM 6000 & New LP Blrs	Option - CC4: CC Plant with Siemens GTX 100 & New LP Blrs	Option - CC5: CC Plant with Siemens 501FD - 335 MW & New LP Boilers	Option - CC6: CC Plant with 2xGE 7FA - 500 MW(12)	Option - BP1: Exis 10/100 Boiler & STG Plant - Gas Fuel, partial capacity Dump Condenser & New LP Blrs(13)	Option - BP1A: Exis 10/100 Boiler & STG Plant - Gas Fuel, Full capacity Dump Condenser & New LP Blrs(13)	Option - BP2: New LP Boiler Plant - Stm Only	Option - BP3: 1 New HP Boiler Plant & back pressure STG with full capacity Dump Condenser Plus 4 LP boilers
B.	New Configuration Description															
1.	Number of Gas turbines/HRSGs	N.A.	1	1	1	1	1	1	1	1	1	2				
2.	Number of Steam Turbine	N.A.					1	1	1	1	1	1	1	1		1
3.	Number of New HP Boilers															1
4.	Capacity of New HP Boiler, Mlb/hr															360
5.	Number of New LP Boilers	N.A.	3	3	4	4	3	3	4	4	3	0	2	2	4	4
6.	LP Boiler Capacity each, Mlb/hr[20]	N.A.	255	345	385	385	350	420	410	410	260	0	245	245	480	390
C.	Net Steam Generation[21]															
1.	Design Capacity Regmnt, Mlb/hr								1,600							
2.	Annual Average Send Out, MMlb								[REDACTED]							
3.	Annual Avg Hourly Send out, Mlb/hr								[REDACTED]							
4.	Design Cogen / CC /Boiler Plant Steam Export Capacity, Mlb/hr															
a	With full SF in HRSGs / HP Boiler Plant		946	742	316	320	724	580	243	249	963	1,600	1,007	1,007	0	328
b.	No SF in HRSGs/HP Blrs no dumping		540	429	132	187	369	295	75	120	537	1,150				
c.	STG Bypass Condition		N.A.	N.A.	N.A.	N.A.	Not Considered due to significant loss in Annual Electric revenue during bypass operation					1,600	1,195	1,195		Not Considered
5.	Design Net LP Boiler Send Out Capacity, Mlb/hr[22]	1,600	650	866	1,281	1,279	875	1,040	1,357	1,282	642	0	405	405	1,600	1,600
6.	Maximum possible steam send out wth all equipment operating simultaneously in the repowered configurations with Steam turbine Operational, Mlb/hr		1,612	1,607	1,603	1,604	1,600	1,610	1,610	1,605	1,608	1,600	1,416	1,416	1,600	1,628
7.	Maximum possible steam send out wth all equipment operating simultaneously in the repowered configurations & steam turbine bypassed, Mlb/hr		1,612	1,607	1,603	1,604	1,825	1,794	1,686	1,698	2,118	2,610	1,603	1,603	1,600	1,729
8.	Design Average Annual Send out, Mlb/hr															
a	Cogen Plant in partial SF & CC Plant in Intermediate Export mode[24]		595	563	197	254	520	405	170	182	699	1,267				
b.	HP Boiler plant on partial capacity												568	568		
c.	No SF in HRSGs/HP Blrs wth dumping		243	215	133	149	200	173	75	120	244	354	190	190		195
9.	Design Annual Stm Production Capability, MMlb															
a	With Suppl Firing in HRSGs / Boiler Plant		7,870	6,177	2,833	2,867	6,023	4,660	2,022	1,905	7,933	13,316				
b	Without Suppl Firing in HRSGs		4,498	3,573	1,097	1,560	3,074	2,372	624	1,031	4,472	9,570				
D.	Cogen/CC/Boiler Plant Annual Operation and Steam Generation Profile based on 335 days operation on Gas															
1.	Gas Turbine[23] / Boiler Operating hours	N.A.	[ALL DATA REDACTED]													
2.	Operating Hours- HRSG with full SF & Max Ext/ HP Blrs at full capacity w/o bypass															
3.	Oper Hours - HP Boilers at partial export capacity before dumping															
4.	Oper Hours - HRSG for part SF(CG) /intermediaste Export (CC) / HP Blrs in dumping mode[24]															
5.	HRSG - Oper Hours no Supp Firing															
6.	Boiler Plant Full STG Bypass Oper Hours															
7.	CC/Cogen Plant [25]															
a.	Export Steam with full SF, MMlb															
b.	Export Steam with Partial SF /Int Exp, MMlb															
c.	Export Steam W/O Supp Firing, MMlb															
8	HP Boiler Steam, MMlb															
a.	Export Stm with Full Capacity															
b.	Export Steam with partial capacity															
c.	Export Steam during dumping															
d.	Export Steam during full Bypass Operation															
9.	LP Boiler Steam, MMlb[20]															
10.	Total Annual Steam Check, MMlb															
E.	Electrical Output[21], kW															
1.	Gas Turbine	Not Applicable	119,766	86,213	42,934	44,626	119,793	86,269	43,171	44,783	187,708	349,466				
2.	Steam Turbine - CC (SF, max Extraction)		0	0	0	0	44,811	34,468	13,214	14,368	69,048	105,490				
3.	Steam Turbine -CC (No SF,Ext)/ HP Blrs		0	0	0	0	15,206	10,799	1,690	4,799	36,512	59,963	66,600	66,600		15,630
4.	Cogen Net Output - ISO		117,879	87,189	39,947	45,179										
5.	CC Plant Net Output[22]						159,143	116,916	54,277	57,171	257,710	441,330				
a.	Net Elec with Full SF & Max Extr - ISO						176,063	130,257	59,278	61,714	294,421	472,867				
b.	Net Output with partial SF,Ant exp-Ext, ISO						145,556	103,889	42,824	47,750	257,839	480,010				
c.	Net Output with Avg demand/Max Extr -w/o SF mode ISO for Energy Sale															
6.	HP Boiler Plant Net Output												62,100	62,100		14,000
a.	Net Output, Full Cap Operation												29,456			
b.	Net Output, Partial Cap Operation												12,400			14,000
c.	Net Output during dumping												62,100	62,100		14,000
7.	Maximum Net Output (in full condensing mode-CC) at ISO		117,879	87,189	41,902	46,179	178,439	134,421	60,902	64,845	334,969	540,838	62,100	62,100		14,000
8.	Net Plant Output for Capacity Payment [9]		117,475	84,649	41,741	43,627	154,744	114,055	56,583	56,193	252,530	479,994	12,400	62,100		14,000
F.	Annual Fuel (MMBtu - HHV), Electricity (MWh), Water Consumption (M Gal) and Electricity Generation(MWh)															
1.	Gas Turbine Fuel - Gas	Not Applicable	[ALL DATA REDACTED]													
2.	Gas Turbine Fuel - Oil															
3.	HRSG Fuel for Full Supp Firing - Gas only															
4.	HRSG Fuel for Partial SF (CG) / Int Exp (CC) - Gas Only															
5.	HP Boiler Fuel - Gas															
6.	HP Boiler Fuel - Oil															
7.	LP Boiler Fuel - Gas															
8.	LP Boiler Fuel - Oil															
9.	Total Fuel Consumption - Oil															
10.	Total Fuel Consumption - Gas															
11.	Water Consumption[17]															
12.	Elec Consumption - Stm only Plants															
13.	Net Elec Generation - Power Plants[9]															

Exhibit 4-12 (cont'd) Hudson Avenue Options Screening Model

CONCEPTUAL DATA FOR REALTIVE COMPARISON ONLY[1]

A. Combined Gas & Oil Firing - Steam Send Out Based Upon Projected Demand, Gas Firing for 335 Days and Oil Firing for 30 Days[3 &18]

ITEM	DESCRIPTION	Current Operation	STEAM GENERATION AND RE-POWERING OPTIONS													
			Cogeneration Options with Supp Fired HRSGs				Combined Cycle Options with Supp Fired HRSGs						Boiler Repowering Options			
			Option - CG1	Option - CG2	Option - CG3	Option - CG4	Option - CC1	Option - CC2	Option - CC3	Option - CC4	Option - CC5	Option - CC6	Option - BP1	Option - BP1A	Option - BP2	Option - BP3
A.	Option Description	Based on 2005 Operation on Oil	Cogen Plant with Siemens 501D5A with	Cogen Plant with GE 7EA with full	Cogen Plant with GE LM 6000 with	Cogen Plant with Siemens GTX 100	CC Plant with Siemens 501D5A &	CC Plant with GE 7EA & New LP	CC Plant with GE LM 6000 & New LP Blrs	CC Plant with Siemens GTX 100 &	CC Plant with Siemens 501FD - 335	CC Plant with 2xGE 7FA - 500 MW(12)	Exis 10/100 Boiler & STG Plant - Gas Fuel,	Exis 10/100 Boiler & STG Plant - Gas Fuel,	New LP Boiler Plant - Stm Only	1 New HP Boiler Plant & back pressure STG with
G.	**Total NPV of Plant Cost - US Dollars**	**See Economic Model for Details**														
1.	Existing Plant Maintenance Cost															
2.	EPC Cost															
a.	Cogen / CC Unit and accessories															
b.	HP and LP Boiler Plant															
c.	Demin Plant															
d.	Other BOP															
3.	Demolition /Relocation/ Remediation Costs															
a.	Demolition Costs															
b.	Relocation Costs															
c.	Remediation Costs															
4.	Permitting/Prelim Engineering															
5	Gas Piping Interconnect Costs															
6.	Electrical Reinforcement/Interconnect Costs															
7.	Contingency															
8.	Owner"s other Costs[4]															
9.	**Total Plant Cost (TPC)**															
H.	**Total NPV of Annual Costs**	**See Economic Model for Details**														
1.	Fuel Cost															
2.	Fixed Charges on TPC (Debt Services)															
3.	Water & Chemical Costs															
4.	Electricity Purchase Cost															
5.	O&M Costs of existing plant[15]															
6.	Non Fuel O&M Costs															
7.	Property Taxes & ICICP															
8.	ICICP Credit															
9.	**Total Annual Cost**															
I.	**Total NPV of Steam Generation Costs ($/1000 lbs) based upon Electric Revenue Offset**	**SEE Economic Model for Details**														
1.	Revenue from Energy															
2.	Revenue from Capacity Payment[6]															
3	Total Revenue from Electricity															
4.	Cost Attributed to Steam															
5	**Steam Generation Cost W/O Emission Credits**															
6	Emission Credits on Annual Costs[7]															
a.	Nox															
b.	SO_2															
c.	PM_{10}															
d.	PM															
e.	VOC															
f.	CO															
g.	Total Credits															
7.	Cost Attributed to Steam with Emission Credits															
8.	**Steam Gen Cost with Emission Credits**															
J.	**Annual Emmissions (TPY)[9]**	[ALL DATA REDACTED]														
1.	NO_x															
2.	SO_2															
3.	PM_{10}															
4.	PM															
5.	VOC															
6.	CO															
K.	**Site Specific Constraints**															
1.	Layout Constraints															
2.	Stack Issues															

Notes

1. The costs and performance data presented herein are based on conceptual level studies. All costs are total NPV based on costs in years 2006 through 2025. All performances are at 59F/60% RH Ambient & Sea Level (ISO) operation and include applicable degrada
2. [REDACTED]
3. All performances except for the Current Operation are based upon firing natural gas & low sulfur oil. Low sulfur oil will be fired in gas turbine & boilers only. The HRSGs will be firing Gas only. The plant will be designed for dual fuel firing (natural use extraction turbine with condenser. Exist Boiler plant (BP-1) uses existing back pressure turbine. New Boiler Plant (BP-3) also uses back pressure turbine with STG throttle conditions of 1500 psia/950F
4. This includes AFDUC & Owner's supervision costs, developmental fees, O&M Training.
5. The LP Boilers will be operating to generate steam when the gas turbines/HP Boilers are unavailable and when the demand exceeds the steam generation from the HRSG (with full supplemental firing) or from the HP Boilers .
6. The total capacity of the LP boilers plus the capacity of the HRSGs in suppl firing mode or HP boiler meets the maximum send out requirements of the facility. Includes steam required for Deaerators.
7. Emissions are Based upon AP - 42 Data except for existing which is based upon 5 year average data. All new technologies include required emission controls.
8. For the CC and BP-1 Options, this is based upon the weighted average of the net output during various modes of operation. For the CG, BP - 1A and BP Options this is based on full net power generation
9. The Net Energy Generation for the CC Options are based upon actual steam send out during the particular mode of operation. Steam in excess of demand is sent to condenser. For the CG (1,2 & 4), Boiler 1 and BP-3 Options with dump condensers, this is based For BP-1A Option, the steam turbine is run base loaded and dump excess steam to dump condenser. As the minimum steam send out (150Mlb/hr) from the facility is more than the generation from the CG-3 option in unfired mode, no dump condenser is provided for
10. For CC 1, 2 5& 6, the average extraction from the STG is based upon the total steam send out W/O supplemental firing in the HRSG divided by the operating hours in this mode. For CC-3 & 4, the max extraction is dictated by the minimum cooling flow requirem For CC Options, this assumes full duct firing in the intermediate export case and sending additional steam to condenser.
11. Deleted
12. Although this configuration can produce more than 1,600 Mlb/hr steam in supplemental firing or in bypass mode with both units running, the analysis has been done based on 1,600 Mlb/hr max production as applicable
13. [REDACTED]
14. For CG Options, this includes partial SF. For CC Options, this includes max SF and additional steam going to Cond. For BP-1 Option, this is based upon dumping steam below the minimum load on the boiler/STG as shown on heat balance diagram.
15. For the CC-6 Option this represents both units available for 84% of the time and one unit available for 16% of the time with an equivalent availability of 92% on two unit basis.
16. This includes O&M Costs of the existing facility for 5 years until the new system is in place and also the maintenance cost of the remainder of the existing facility for the remaining 14 years
17. This includes 2% blowdown requirements for all HRSGs/ Boilers and also the water injection in gas turbine during oil firing case.
18. Oil firing applicable for Gas Turbines and Boilers only. Supplemental firing in HRSG is by Gas only. LP & HP Boiler efficiency assumed to increase by 4.25% with oil firing

Legends

CG: Cogeneration
CC: Combined Cycle
HP: High Pressure
LP: Low Pressure
SF: Supplemental Firing

Exhibit 4-13 Schematic Flow Diagram of Typical Cogeneration Option at Hudson Avenue

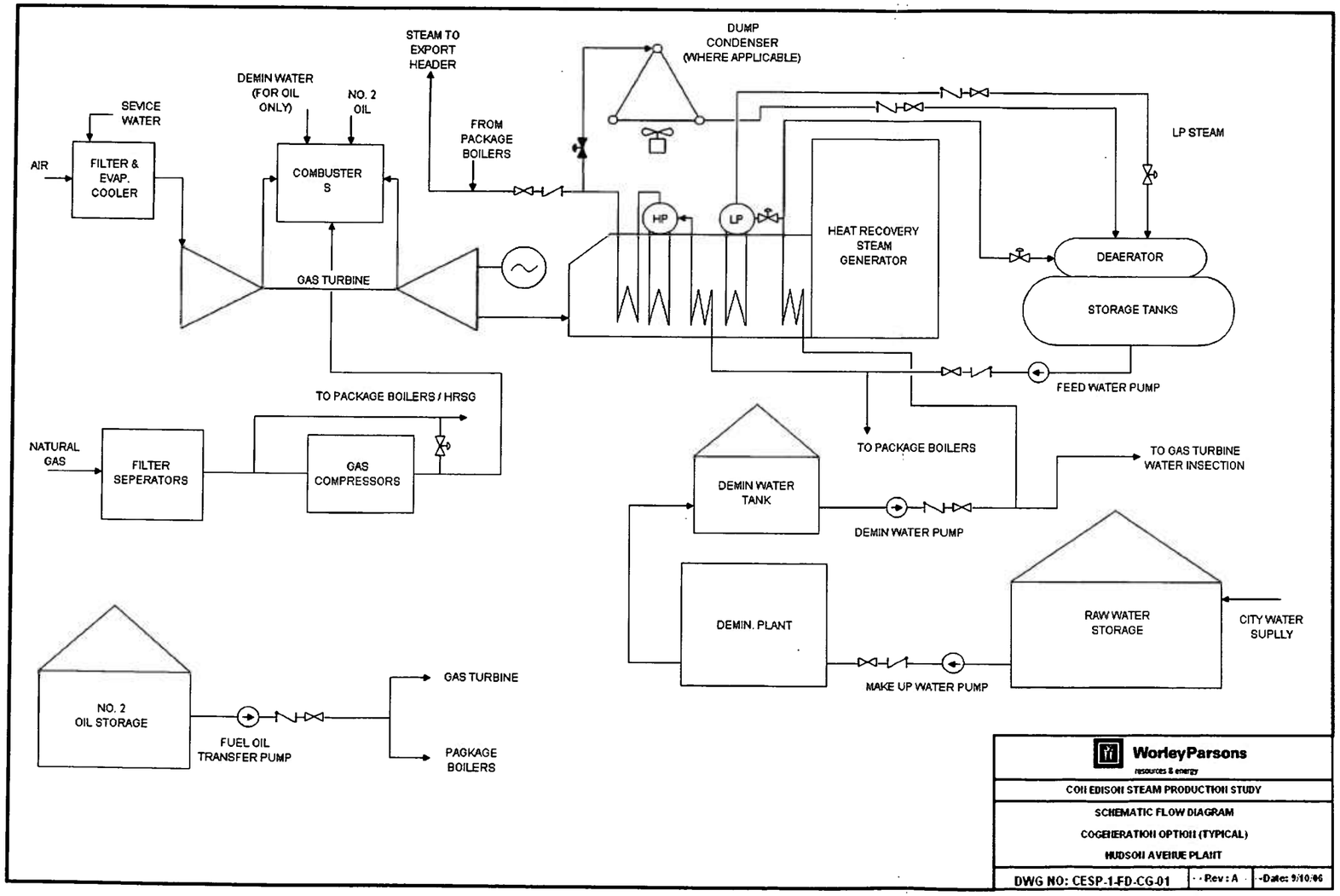
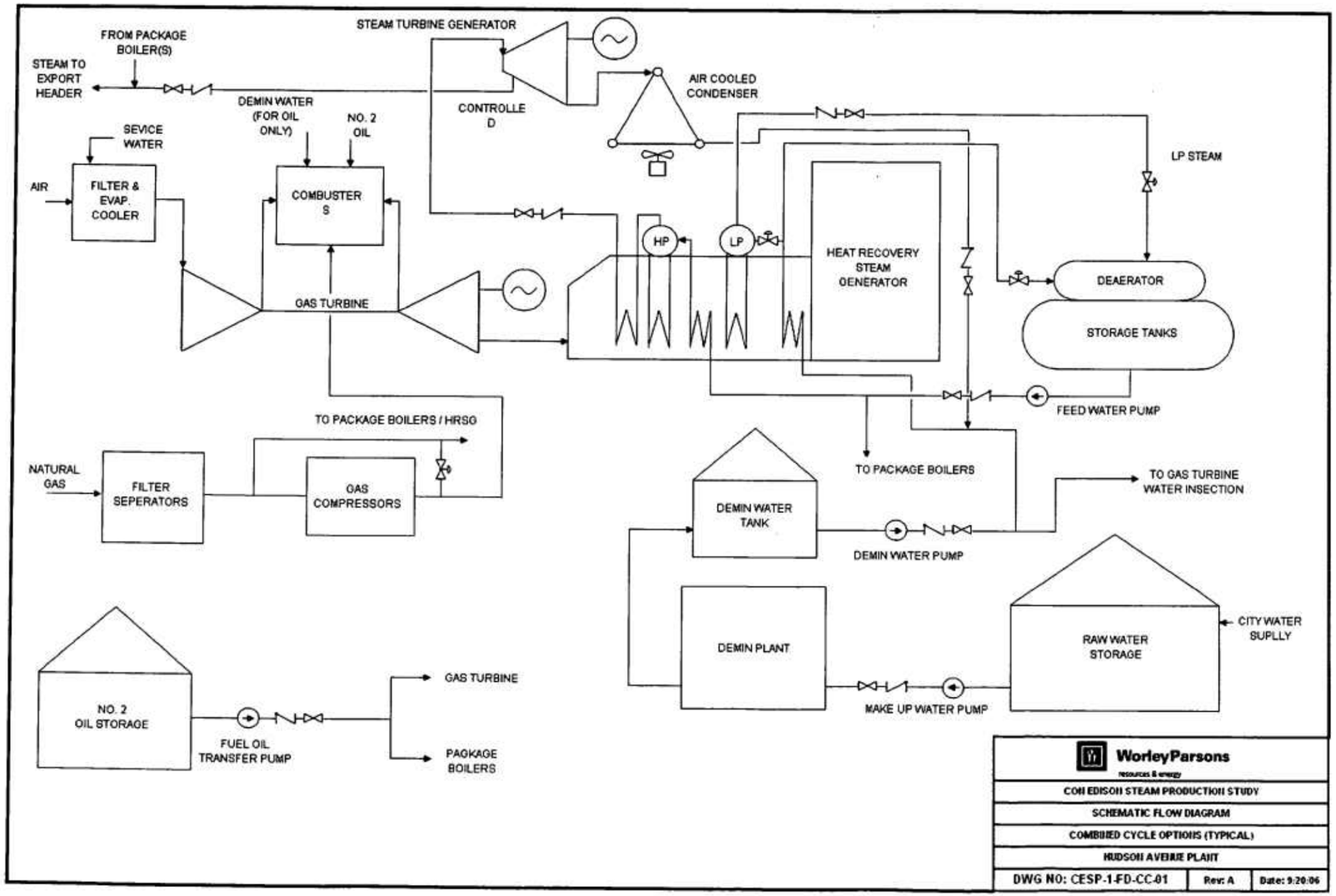


Exhibit 4-14 Schematic Flow Diagram of Typical Combined Cycle Option at Hudson Avenue



4.2.1.3 Projected Cost of Operation

The cost of steam production was evaluated for the potential repowering options identified by WorleyParsons for the Hudson Avenue Station over the 20 year study period. Since it was WorleyParsons opinion that the existing boilers at Hudson Avenue would not operate reliably for 20 years, and that the condition of the boilers was such that rebuild seemed impractical, WorleyParsons evaluated an option of replacing the boilers with new ones for comparison with cogeneration options. WorleyParsons estimated the total plant capital costs, total annual production costs, the total annual production costs per thousand pounds of annual steam sendout for each of the options for each of the years from 2006 to 2025. WorleyParsons also calculated the NPV of the total annual production costs, and a Figure of Merit for comparison of the operations defined by the net present value of the total annual costs divided by a discounted annual steam sendout (export), as described in the economic criteria for the study in Section 3.3.

The projected costs of operation for the options evaluated for the Hudson Avenue Station are summarized in Exhibit 4-15 through Exhibit 4-21. These data are based on the CERA 2005 Rearview Mirror fuel and electricity price scenario. The following information is provided in each of the Exhibits:

- Exhibit 4-15 - NPV of the total plant cost for each option over 20 year study period.
- Exhibit 4-16 – NPV of total annual costs, including the contributions of capital, fixed O&M, variable fuel, and non-fuel variable costs; taxes, and tax credits over 20 year study period.
- Exhibit 4-17 – NPV of cost of steam production including the impact of electric energy and capacity revenues (credits) and NYISO Tariff (blackstart revenue), but not including emission reduction credits, over 20 year study period.
- Exhibit 4-18 – NPV of cost of steam production including emission reduction and other credits over 20 year study period.
- Exhibit 4-19 – Unit NPV of cost of steam production (NPV of cost of production divided by discounted steam sendout over 20 year study period), excluding emission reduction credits.
- Exhibit 4-20 - Unit NPV of cost of steam production, including emission reduction credits.
- Exhibit 4-21 – Breakdown of the NPV costs over the 20 year study period by cost category.

Summaries of the estimated capital and operating costs and credits by year in current year dollars are provided for each option in the Appendix A. The summaries include the NPV of total plant cost, annual operating costs, and total annual costs and cumulative NPV of total annual costs by year.

Exhibit 4-15 NPV of Total Plant Cost for Hudson Avenue Repowering Options from 2006 to 2025

[REDACTED]

Exhibit 4-16 NPV of Total Annual Costs Excluding Credits for Hudson Avenue Repowering Options from 2006 to 2025 Based on CERA 2005 Rearview Mirror Price Projections

[REDACTED]

Exhibit 4-17 NPV of Cost of Steam Production Excluding Emission Reduction Credits for Hudson Avenue Repowering Options 2006 to 2025 Based on CERA 2005 Rearview Mirror Price Projections

[REDACTED]

Exhibit 4-18 NPV of Cost of Steam Production Including All Credits for Hudson Avenue Repowering Options 2006 to 2025 Based on CERA 2005 Rearview Mirror Price Projections

[REDACTED]

Exhibit 4-19 Unit NPV of Cost of Steam Production Excluding Emission Credits for Hudson Avenue Repowering Options 2006 to 2025 Based on CERA 2005 Rearview Mirror Price Projections

[REDACTED]

Exhibit 4-20 Unit NPV of Cost of Steam Production Including All Credits for Hudson Avenue Repowering Options 2006 to 2025 Based on CERA 2005 Rearview Mirror Price Projections

[REDACTED]

Exhibit 4-21 Summary of Breakdown of NPV of Cost of Steam Production for Hudson Avenue Options by Cost Category

Option Sheet Number ->		0	1	2	3	4	5	6	7	8	9	10	11	12	13	14
0																
	Hudson Avenue		Cogeneration Options with Supp Fired HRSGs				Combined Cycle Options with Supp Fired HRSGs						Boiler Repowering Options			
ITEM	DESCRIPTION	Base	CG1	CG2	CG3	CG4	CC1	CC2	CC3	CC4	CC5	CC6	BP1	BP2	BP3	BP1A
A.	Option Description	Based on 2005 Operation on Oil	Cogen Plant with Siemens 501D5A with full capacity Dump Cond & New LP Gas Blrs	Cogen Plant with GE 7EA with full capacity Dump Cond & New LP Gas Blrs	Cogen Plant with GE LM 6000 with New LP Gas Blrs	Cogen Plant with Siemens GTX 100 with Dump Cond & New LP Gas Blrs	CC Plant with Siemens 501D5A & New LP Gas Blrs	CC Plant with GE 7EA & New LP Gas Blrs	CC Plant with GE LM 6000 & New LP Gas Blrs	CC Plant with Siemens GTX 100 & New LP Gas Blrs	CC Plant with Siemens 501FD - 395 MW & New LP Gas Boilers	CC Plant with 2xGE 7FA - 500 MW(12)	Existing 10/100 Boiler & STG Plant - Gas Fuel, partial capacity Dump Condenser & New LP Gas Blrs(13)	New LP Boiler Plant - Stm Only, Gas Fired	1 New HP Boiler Plant & back pressure STG with full capacity Dump Condenser Plus 4 LP boilers, Gas Fired	Existing 10/100 Boiler & STG Plant - Gas Fuel, Full capacity Dump Condenser & New LP Gas Blrs(13)
		NPV	NPV	NPV	NPV	NPV	NPV	NPV	NPV	NPV	NPV	NPV	NPV	NPV	NPV	NPV
C	Total 20 Year Steam Send Out, MMlb															
E	Total 20 Year Net Elec Generation															
G.	Total NPV of Plant Cost - US Dollars															
1.	Existing Plant Maintenance Cost															
2.	EPC Cost															
a.	Cogen / CC Unit and accessories															
b.	HP and LP Boiler Plant															
c.	Demin Plant															
d.	Other BOP															
3.	Demolition /Relocation/ Remediation Costs															
a.	Demolition Costs - loaded															
b.	Relocation Cos															
c.	Remediation Costs															
4.	Permitting/Prelim Engineering															
5.	Gas Piping Interconnect Costs - loaded															
6.	Electrical Reinforcement/Interconnect Costs - loaded															
7.	Contingency															
8.	Owner's other Costs(4)															
0	Capitalized Property Tax During Construction															
9.	Total Plant Cost (TPC)															
H.	Total NPV of Annual Costs															
1.	Fuel Cost															
2	Fixed Charges on TPC (Debt Services)															
3.	Water & Chemical Costs															
4.	Electricity Purchase Cost															
5.	O&M Costs of existing plant(16)															
6.	Non Fuel O&M Costs															
7	Property Tax															
8.	ICIP Credit															
9.	Total Annual Cost															
I.	Steam Generation Costs based upon Electric Revenue Offset - NPV															
1.	Revenue from Energy															
2.	Revenue from Capacity Payment(8)															
3.	NY ISO Black Start and System Restoration Tariff															
4	Total Revenue from Electricity															
5a	Cost Attributed to Steam w/o Emission Credits - NPV ($)															
6d	Cost of Steam w/o Emission Credits ($/1000lb) - NPV															
8	Emission Credits on Annual Costs(7)															
a.	NOx															
b.	SO2															
c.	PM10															
c.	VOC															
e.	Total Credits															
9a	Cost Attributed to Steam with Emission Credits - NPV ($)															
10d	Cost of Steam with Emission Credits ($/1000lb) - NPV															
J.	Total 20 Year Emissions (tons/20 years)															
1.	NOx	13,705														
2.	SO2	14,077														
3.	PM10	1,335														
4.	PM	1,689														
5.	VOC	239														
6.	CO	1,595														
J.	Total Annual Emissions (tons/yr)															
1.	NOx	685														
2.	SO2	704														
3.	PM10	67														
4.	PM	84														
5.	VOC	12														
6.	CO	80														

[ALL DATA REDACTED]

[REDACTED

4.2.1.4 Fuel and Electricity Price Sensitivity Analysis

WorleyParsons evaluated the repowering options for Hudson Avenue Station initially using CERA 2005 Rearview Mirror price projections, the results of which were shown in Exhibit 4-15 through Exhibit 4-20. Subsequently, the repowering options were evaluated using the CERA 2005 Shades of Green price projections. The major difference in prices between the two scenarios is that the fuel and electric energy prices beyond the year 2010 are significantly higher in the SOG scenario than in the Rearview Mirror. The Shades of Green scenario prices are [REDACTED] than the Rearview Mirror scenario prices beyond 2010.

The Unit NPVs of cost of steam production for the options using the Shades of Green scenario are shown in Exhibit 4-22. [REDACTED].

Exhibit 4-22 Unit NPV of Cost of Steam Production for Hudson Avenue Repowering Options Based on CERA 2005 Shades of Green Fuel and Electricity Price Scenario

[REDACTED]

4.2.1.5 Environmental and Other Permitting Requirements

The expected emissions from the repowering options are presented in Exhibit 4-23 in comparison with the applicable NSPS, NESHAP, and PSD/NSR requirements. The expected emissions are based on the projected annual steam sendout for the Hudson Avenue Station provided by Con Edison for the study. The emission control equipment and their expected efficiencies for the new turbine and boiler options that were used to adjust the expected emissions to meet environmental regulations are shown in Exhibit 4-24. The NSPS and NESHAP requirements are on a pound emission/MMBtu of fuel input basis. The PSD/NSR limits, the annual emissions that would trigger PSD/NSR, are on a tons per year basis and combine the existing average annual emissions from the Hudson Avenue Station contained in the 2003 and 2004 Emission Statements (based on CEMS, stack testing, and AP-42 emission factors) and the significant net emission rates presented in Exhibit 3-5.

For the Hudson Avenue Plant options, all the existing units are being retired regardless of whether the repowering option is a cogeneration option, combined cycle option, or a boiler only option. At a minimum, the turbines or boilers will have to meet NSPS and NESHAP. The potential annual emissions for each turbine and boiler option are based on the new natural gas fired turbine or boiler operating at 100 percent capacity factor for 8040 hours per year with the new turbine or boiler operating on No. 2 oil for 720 hours per year (30-days per year). For the options, PSD/NSR permitting is based on comparing the Future Potential emissions from the option versus Past Actual emissions from existing sources being retired.

Exhibit 4-23 Emission Requirements and Expected Emissions For Hudson Avenue Steam Production Options

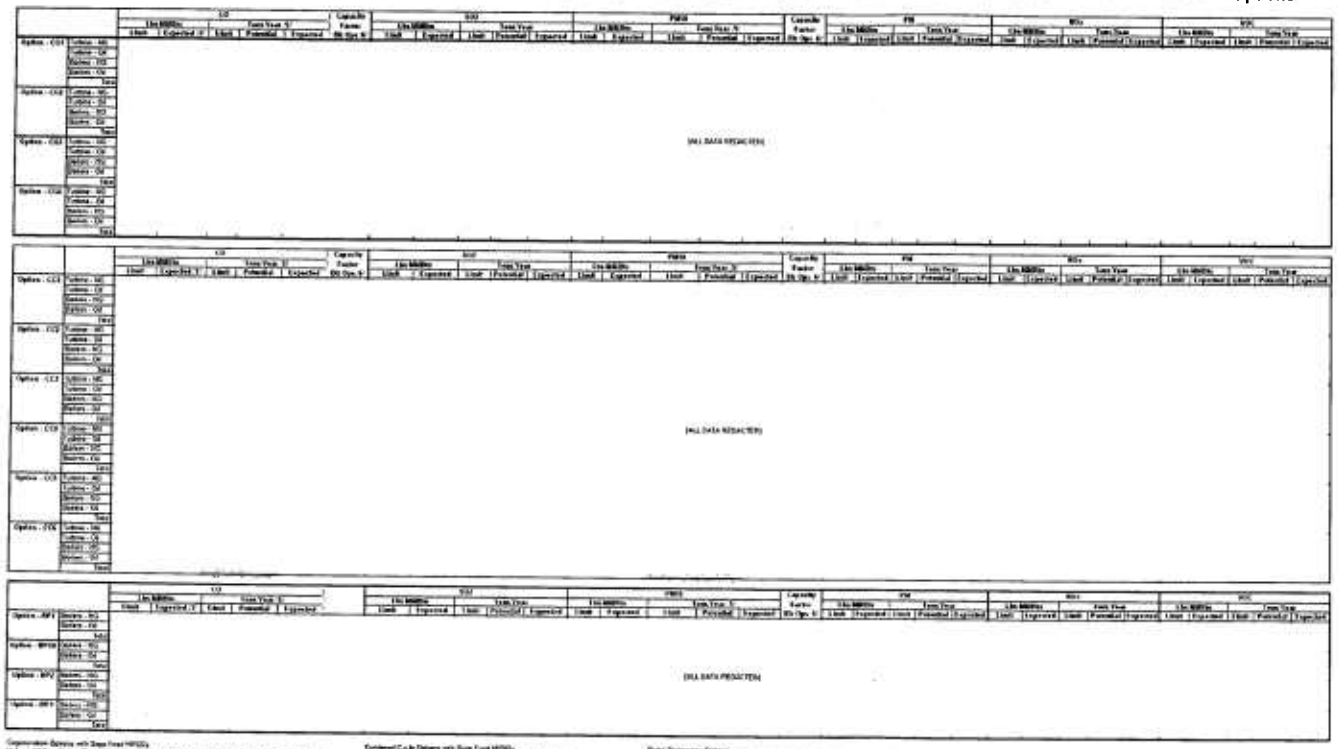


Exhibit 4-24 Efficiencies of Emissions Controls Technologies Considered

Control Technology	Natural Gas-Fired	No. 2 Oil-Fired
Cogeneration		
SCR	90%	90%
Oxidation Catalyst - CO	80%	80%
Oxidation Catalyst - VOC	50%	50%
Boiler		
SCR	90%	75%
Oxidation Catalyst - CO	80%	80%
Oxidation Catalyst - VOC	50%	50%

As shown in Exhibit 4-23, it appears that the CO and PM10 annual emission increase would exceed PSD/NSR regulatory requirements for all cogeneration and combined cycle options, and PM10 for boiler repowering option BP3, based on 100% capacity factor for 8,760 hours per year. Capacity factors that would result in emissions being below PSD/NSR requirements are also provided in the Exhibit. The expected annual emissions for each option are based on a new cogeneration or boiler system meeting the expected annual steam production of about [REDACTED] of steam, or about [REDACTED] annual capacity factor. As is evidenced by the expected emissions shown in the Exhibit, the expected annual capacity factor based on the projected annual steam sendout rate is well below those required to meet the PSD/NSR regulatory requirements.

Summary charts comparing the expected emissions from the repowering options and the emissions that would be expected from the existing boilers at the Hudson Avenue Station with the annual steam sendout projection used in the study are shown in Exhibit 4-25 through Exhibit 4-30. The representative emissions factors used for the existing boilers were five-year averages based on the emissions in the 2000 through 2004 Emission Statements for the Station. As apparent in Exhibit 4-23, with the exception of option CC-6 for PM10 and CO all of the repowering options are below the PSD/NSR applicability thresholds using the expected emissions from the existing boilers at the projected annual steam sendout.

Exhibit 4-25 Expected Annual NOx Emission from Hudson Avenue Repowering Options

[REDACTED]

Exhibit 4-26 Expected Annual SO_2 Emission from Hudson Avenue Repowering Options

[REDACTED]

Exhibit 4-27 Expected Annual PM10 Emission from Hudson Avenue Repowering Options

[REDACTED]

Exhibit 4-28 Expected Annual PM Emission from Hudson Avenue Repowering Options

[REDACTED]

Exhibit 4-29 Expected Annual VOC Emission from Hudson Avenue Repowering Options

[REDACTED]

Exhibit 4-30 Expected Annual CO Emission from Hudson Avenue Repowering Options

[REDACTED]

4.2.1.6 Rationale for Options Rejected / Selected as Promising Options

The existing Boiler plants at the Hudson Avenue Station are not suitable for long term steam production and need to be replaced by suitable re-powering options. Although most of the Options are within the acceptable range of the accuracy level of the study, WorleyParsons recommends the following three Options be considered for further evaluation:

- BP-1: Retrofitting Existing Unit 10/100 with Dump Condenser Option – this option has [REDACTED] and will provide for some electric power generation.
- BP-2: New Boiler only Option. – this option has [REDACTED] and does not rely on revenues from sale of electric power to achieve its [REDACTED] NPV.
- CG-1: Cogen Option with 501D5 Gas Turbine – this option also has [REDACTED] NPV(very close to option BP-2) and provides for electric power generation in NY City; however, it does rely on revenues from the sale of electric power and is, thus, dependent on the electric energy and capacity prices projected to achieve its [REDACTED].

4.2.1.7 Conceptual Description of Options Selected as Promising

4.2.1.7.1 RETROFITTING BOILER 10/100 (BP-1)

Overview

In this option the retired unit 10/100 will be refurbished, including addition of natural gas-fired burners, and placed in service to supply steam to the process. Upon refurbishment, this unit is expected to operate satisfactorily for the 20 year period considered in this study. As the maximum generation capacity of this unit is less than the projected steam demand, two package boilers of 245,000 lb/hr (245 MPPH) gross capacity will be installed to supplement the peak sendout requirements. All boilers will be firing natural gas as primary fuel with No. 2 oil back up and will be provided with SCR and CO catalysis for emission controls. A new small capacity dump condenser sized to condense about 350 MPPH of steam is proposed to allow power generation during lower steam demand periods.

The heat balances for this Option for the Base Load, Minimum Load, and for the Turbine Bypass cases are shown on Exhibit 4-31 through Exhibit 4-33. The heat balances are based on the design send out pressure of 295 psia. If the send out pressure is increased to 415 psia, the net steam send out is expected to be about 5% less than that shown on the respective heat balance diagrams.

Layout

There are no major issues with this option. The new SCR and CO catalyst modules fit in the footprint of the Annex Building. The two new Package Boilers fit across John Street next to the Switch House with the Dump Condenser on a steel structure over the package boilers. A conceptual layout is shown in the Exhibit 4-34 (Plan View) and Exhibit 4-35 (Elevation View).

Exhibit 4-31 Heat Balance for 10/100 Boiler Retrofit Case at Base Load

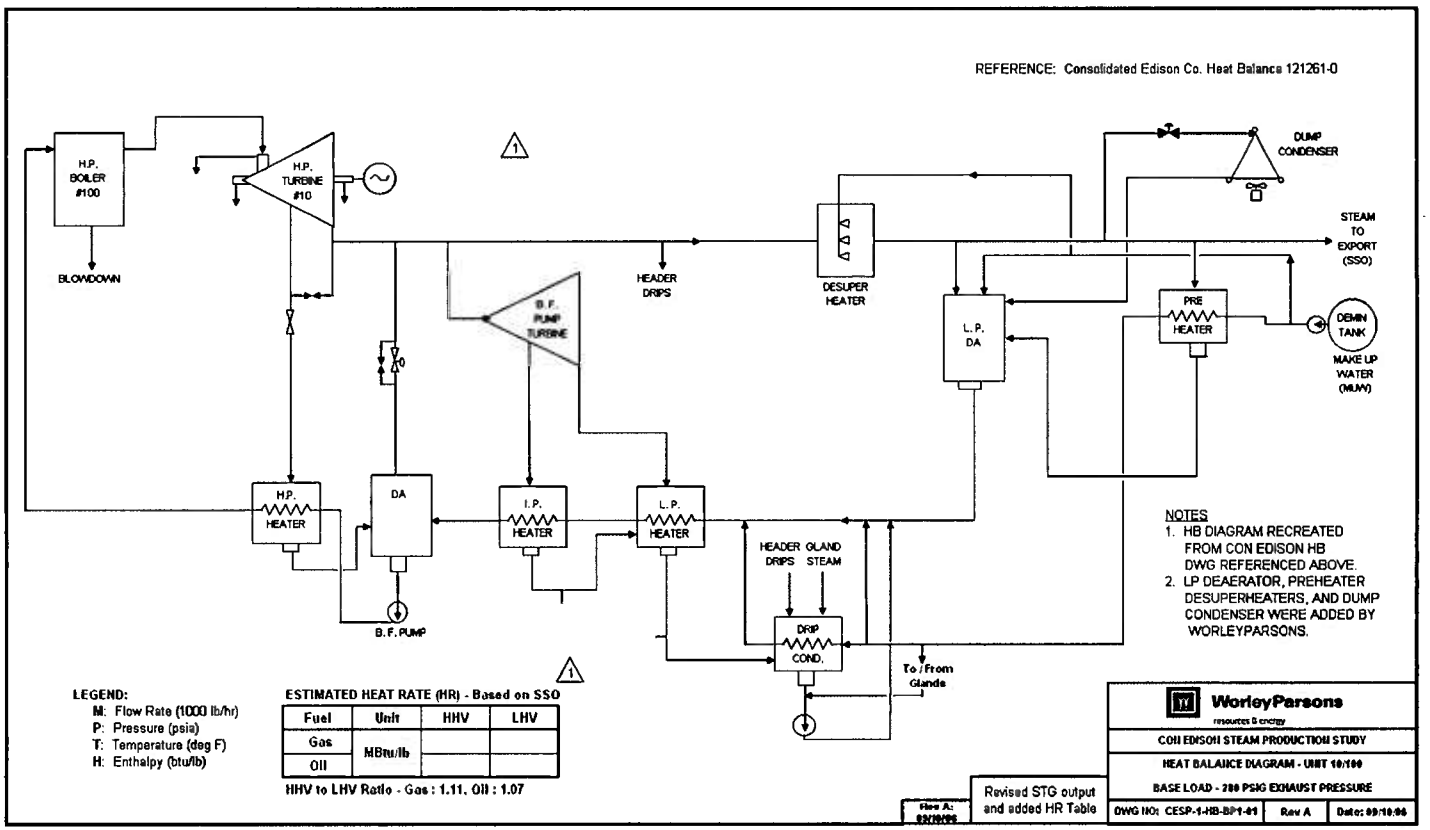


Exhibit 4-32 Heat Balance for 10/100 Boiler Retrofit Case at Minimum Load

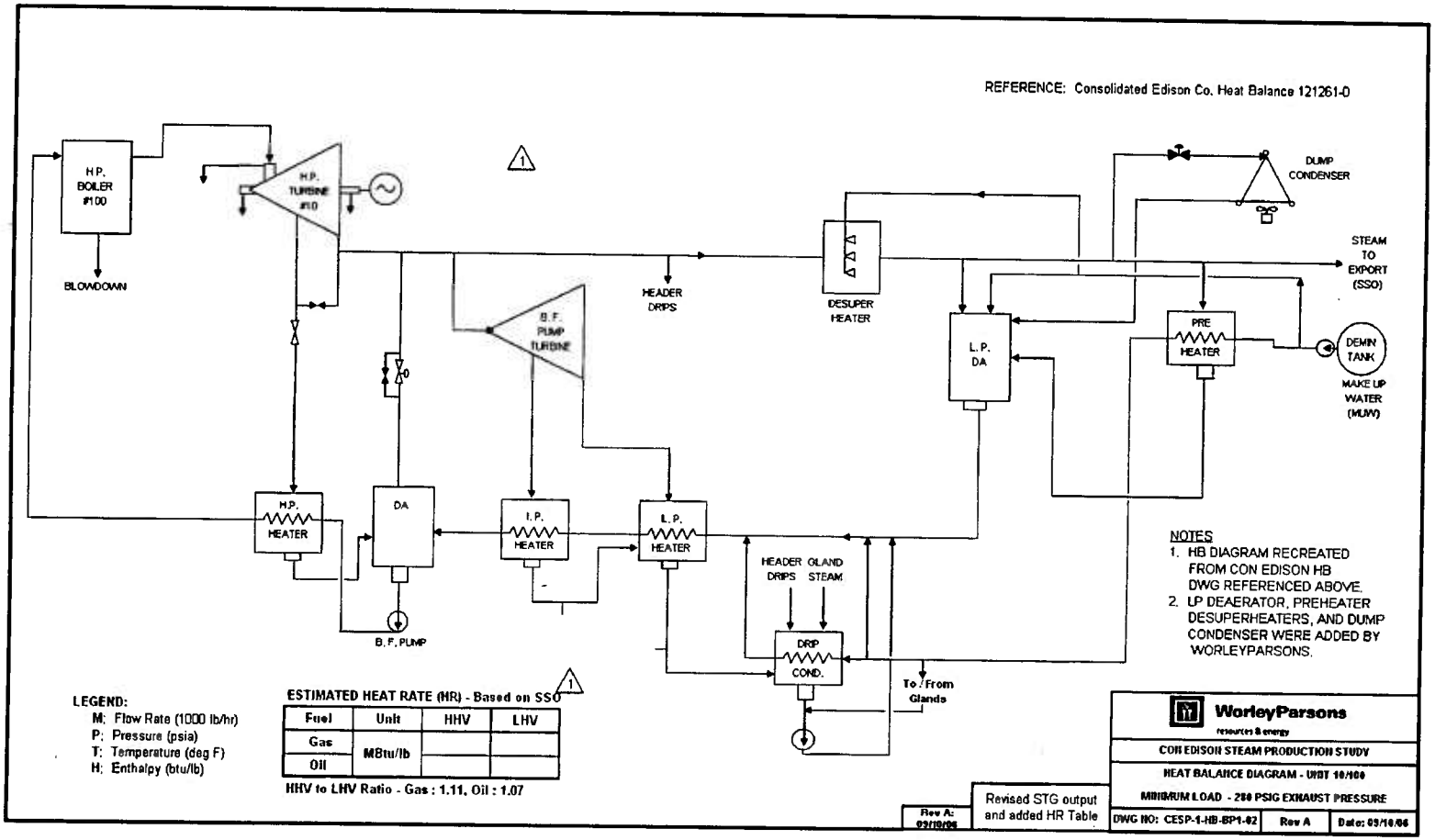


Exhibit 4-33 Heat Balance for 10/100 Boiler Retrofit Case- Turbine Bypass Case

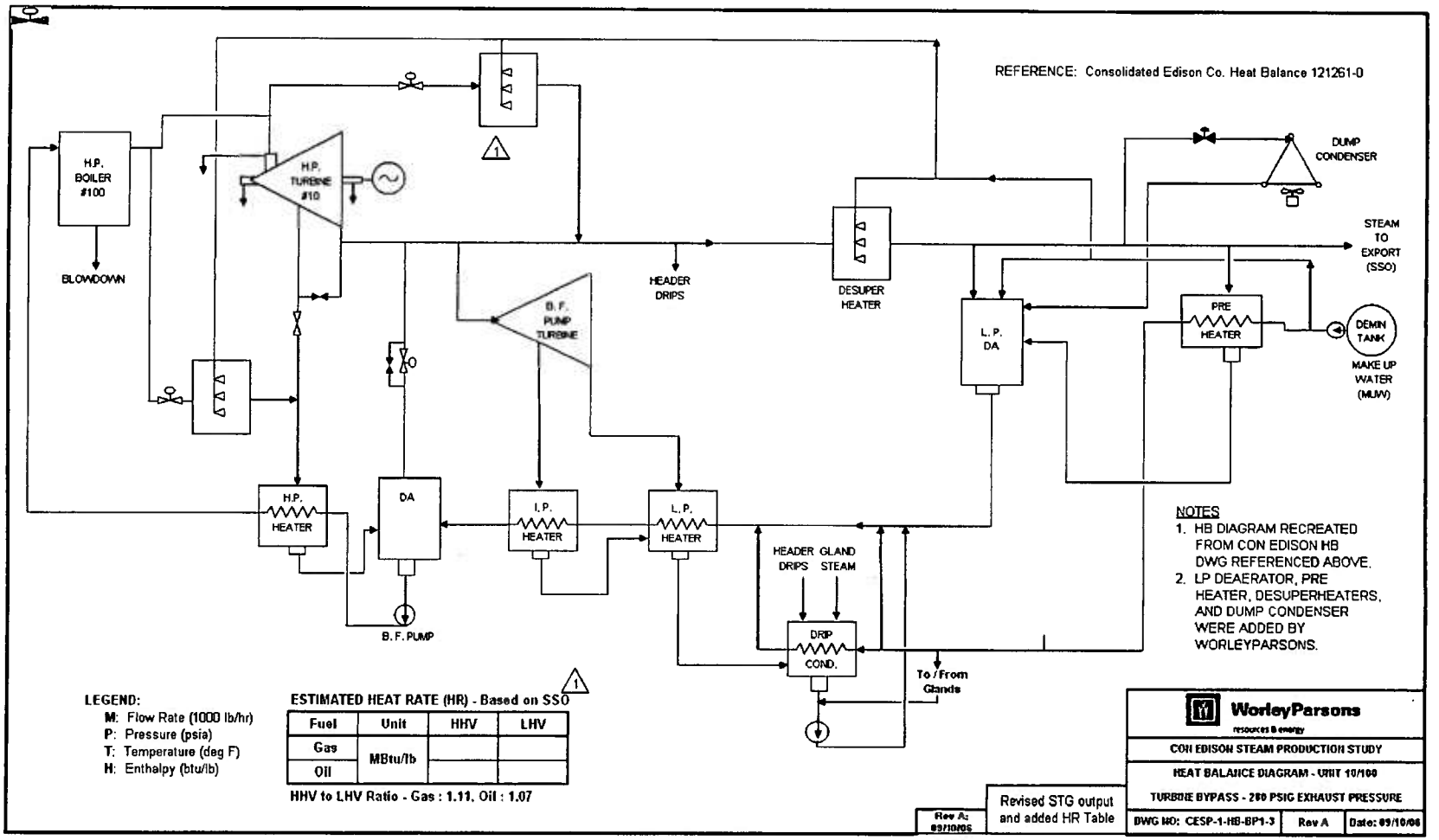
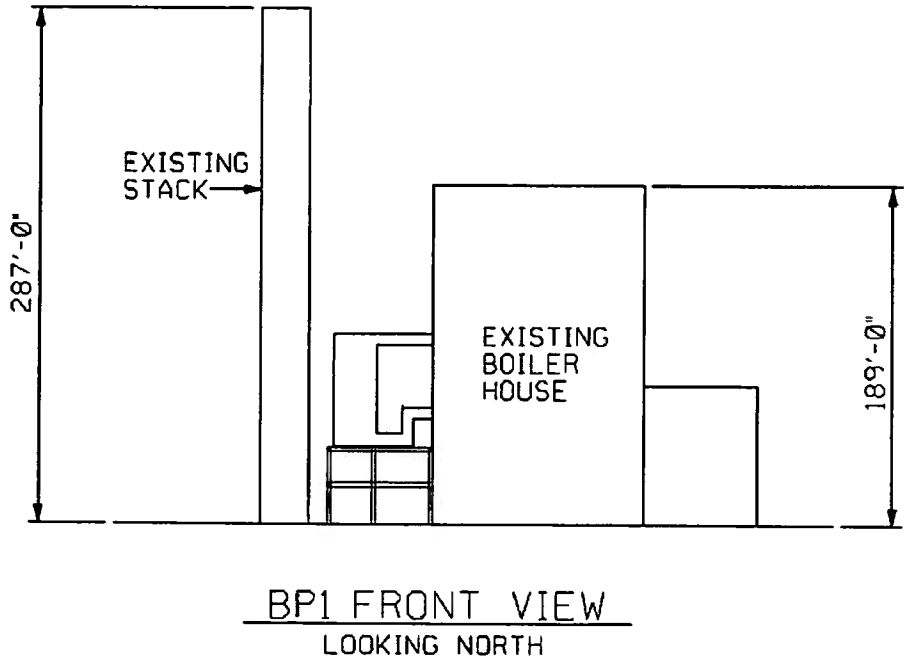


Exhibit 4-34 Conceptual Layout of 10/100 Boiler Retrofit Option (Plan View)

[REDACTED]

Exhibit 4-35 Conceptual Layout of 10/100 Boiler Retrofit Option (Elevation View)



Major Equipment and Systems

The following highlights the major equipment and systems to be included in this Option

Package Boilers

Two (2) new gas/oil fired package boilers each with a gross steaming capacity of 245,000 PPH each will be provided to supply the peak steam demand. The boilers will be connected to the existing stack.

The package boilers will be of water tube design, bottom supported, modular section construction and be provided with low NOx combustion system, SCR and CO Catalyst module, dual fuel train, FD fan, superheater, and economizer.

LP Deaerator and Condensate Preheater

A new LP Deaerator and new Condensate Preheater will be provided to meet the condensate return conditions as shown on the existing 10/100 Heat Balance diagrams. The steam required for the LP deaerator and Condensate preheater will be taken from the steam send out header,

Dump Condenser

Provide a new Dump Condenser of about 310 million Btu/hr capacity connected in parallel to the steam supply header to export. The dump condenser is a pressurized steam to air heat exchanger and will condense any steam in excess of the minimum

steam sendout requirements while the Unit 10/100 is operating at minimum load. The dump condenser will drain the water to the new LP deaerator by static pressure differences.

Steam and Feed water System

Existing steam and feed water system shall be reused. The steam turbine will be provided with a bypass system with desuperheaters to maximize steam production if needed at the cost of lower electricity production or to supply steam during steam turbine outage condition .Desuperheaters will also be provided at the steam turbine exhaust to condition the steam conditions to suit the steam send out requirements.

Water Treatment System

A new water treatment system will be provided. The water treatment plant will consist of a conventional cation/anion demineralization water treatment system followed by an Electrodeionization (EDI) plant for producing higher quality water required for the operation of the high pressure boiler and steam turbine. City water is supplied to a raw water tank. The raw water pumps take suction from this raw water tank and supply the water to the demineralizer plant. The treated water is then pumped to the treated water storage tank for use in the boilers.

Fuel Gas system

A new fuel gas system will be provided that will be used as a primary fuel for the boilers. It is assumed that the fuel gas will be available at a minimum pressure of 50 psig at the plant boundary and will be distributed to the boilers. No gas compressor is required.

Fuel Oil

The existing No#6 fuel oil storage tanks will be refurbished to store No#2 oil. Fuel oil will be fed from the existing storage tanks to each Boiler. Re-circulated fuel oil is returned to the storage tank.

Waste Water

Waste water from the water treatment equipment and the cooled blowdown from the boilers are directed to floor sumps. The sumps are pumped to the waste water disposal facility in the plant.

4.2.1.7.2 BOILER ONLY OPTION (BP-2)

Overview

In this option four new package boilers, each of a gross capacity of 480 MPPH, will be provided. All boilers will be firing natural gas as primary fuel with No. 2 fuel oil back up and will be provided with SCR and CO catalyst for emission controls. This Option replaces the current operation and does not have any provision of power generation. The performance data of the boilers have been obtained from the Vendor and been referenced on the screening model. The heat and mass balances for this Option are provided in Appendix B.

Layout

There are no major layout issues with this configuration. The four new Boilers fit in the Maintenance Area along with the Control Room, the Water Treatment Room, the new Raw Water Tank, and the new Treated Water Tank. A conceptual equipment layout is shown in Exhibit 4-36 (Plan View) and Exhibit 4-37 (Elevation View).

Major Equipment and Systems

Package Boilers

Four (4) new gas/oil fired package boilers each with a gross steaming capacity of 480,000 PPH will be provided to supply the peak steam demand. The boilers will be provided with a common stack. The package boilers will be of water tube design, bottom supported, modular section construction and be provided with low NOx combustion system, SCR and CO Catalyst module, dual fuel train, FD fan, superheater, and economizer.

Deaerator

One(1) new common deaerator will be provided for the package boilers. The deaerator will be combined spray and tray type and will be designed to operate at a pressure of about 36 psia with a design pressure of 50 psig. Steam required for the deaerator will be tapped off from the common header.

Steam system

The steam outlet from the various steam sources are fed into a single manifold. Before the manifold reaches the Head House, the steam is divided into 2 separate lines, one for Grand Street and one for Water Street.

Boiler Feed Water

The feed water from the deaerator will be pumped to the boiler economizer by feed water pumps. The new feed water pumps will be horizontal split, centrifugal type. A common feed water pumping system consisting of 3x50% capacity pumps to cater to the peak supply requirements will be provided.

Water Treatment System

The new water treatment plant will consist of a conventional cation/anion demineralization water treatment system designed to produce make up water suitable for the operation of the boilers. City water is supplied to a raw water tank. The raw water pumps take suction from this raw water tank and supply the water to the demineralizer plant. The treated water this then pumped to the treated water storage tank for use in the boilers.

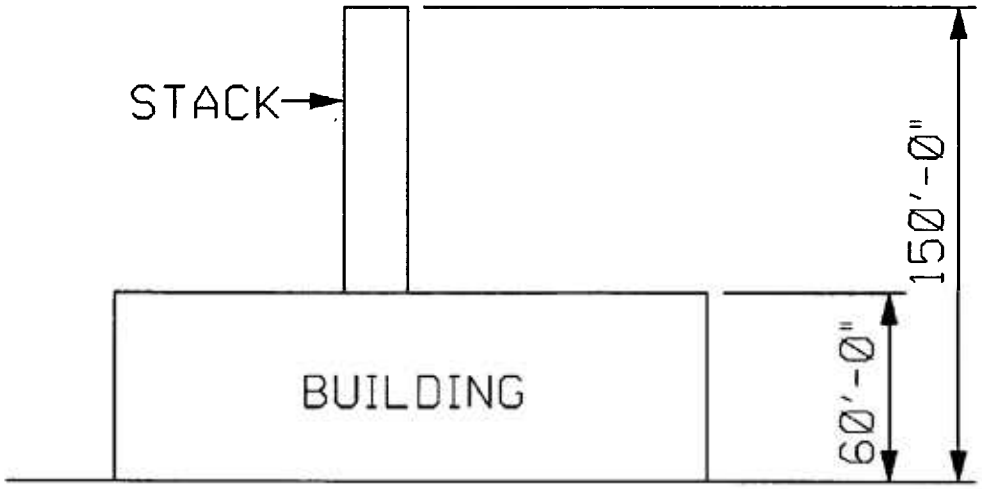
Fuel Gas system

A new fuel gas system will provide natural gas as primary fuel for the boilers. It is assumed that the fuel gas will be available at a minimum pressure of 50 psig at the plant boundary and will be distributed to the boilers. No gas compressor is required.

Exhibit 4-36 Conceptual Layout of BP-2 Boiler Only Retrofit Option – Plan View

[REDACTED]

Exhibit 4-37 Conceptual Layout of BP-2 Boiler Only Option Retrofit Option – Elevation View



BP2 FRONT VIEW
LOOKING NORTH

Fuel Oil

The existing No. 6 fuel oil storage tanks will be refurbished to store No. 2 oil. Fuel oil will be fed from the existing storage tanks to each Boiler. Re-circulated fuel oil is returned to the storage tank.

Waste Water

Waste water from the water treatment equipment and the cooled blowdown from the boilers are directed to floor sumps. The sumps are pumped to the waste water disposal facility in the plant.

4.2.1.7.3 COGEN OPTION (CG-1)

Overview

In this option one new Siemens make 501D5 Gas turbine along with supplementally fired HRSG will be provided to supply steam. As the maximum steam generation with supplementally fired HRSG is less than the maximum send out requirements, three new LP Boilers each of a gross capacity of 265 MPPH will be provided. The Gas turbine and all new boilers will be firing natural gas as primary fuel with No. 2 oil back

up. The HRSG will be designed to fire only natural gas (firm supply). Both the HRSG and the boilers will be provided with SCR and CO catalysis for emission controls.

The heat balances for this Option for the various operating conditions are shown in Exhibit 4-38 through Exhibit 4-40.

Layout

There are no major issues with the layout. The gas turbine with HRSG, the 3 new Package Boilers, the new Stack, and the Control Room fit in the footprint of the Annex Building with a 20 foot setback from Plymouth Street. The Gas Compressor Room, the Water Treatment Room, the new Raw Water Tank, and the new Treated Water Tank fit across John Street next to the Electrical Building. A conceptual layout of the CG-1 option is shown in Exhibit 4-41 (Plan View) and Exhibit 4-42 (Elevation View).

Major Equipment and Systems

Gas Turbine

The cogeneration plant will be based on one Siemens 501D5 gas turbine generators . The gas turbine generators will include pulse jet type inlet air filtration systems; inlet silencers; evaporative cooling; lube oil systems including fin-fan coolers; hydraulic control oil systems and fin-fan coolers; starting systems; acoustical enclosures including heating and ventilation; and control systems including supervisory, fire protection, and fuel systems. The gas turbine will be provided with Dry Low NOx Combustor (DLN) capable of firing either natural gas or diesel oil. The gas turbine is capable of producing 25 ppmvd NOx @15% O_2 during gas firing without any diluent injection and 42 ppmvd NOx @15% O_2 during oil firing with water injection. Fuel gas will be heated to 280F using water from HRSG economizer to improve upon the gas turbine efficiency.

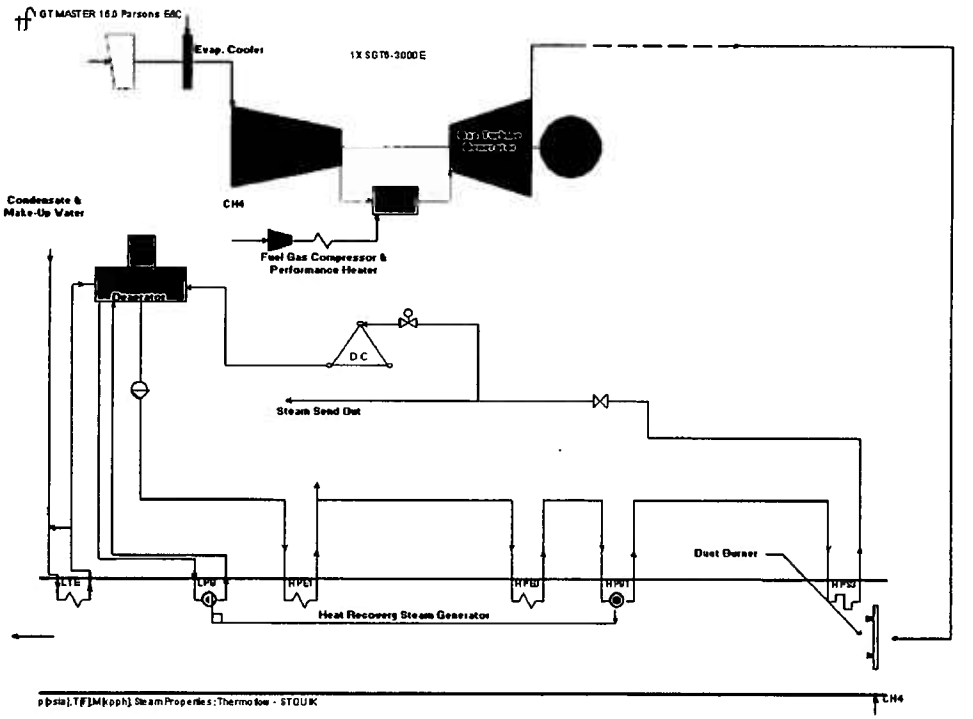
The generators will be provided with the gas turbine package. The generators will be 3-phase, 60 hertz, 13.8 kV, totally enclosed, water/air-cooled (TEWAC), complete with excitation system, cooling, and protective relaying constructed to meet ANSI and NEMA standards for turbine-driven synchronous generators.

The gas turbine produces about 120 MW at 59F and about 112 MW at 90F ambient temperature.

Heat Recovery Steam Generator

The new Heat Recovery Steam Generator (HRSG) will be a 2-pressure level, non-reheat, supplementally fired, natural circulation-type with horizontal gas turbine exhaust flow through vertical tube heat transfer sections. The high-pressure (HP) steam will be sent directly to the export header while the low pressure steam will be used to heat and deaerate the incoming make up water.

Exhibit 4-38 Heat Balance for CG-1 Option at 59°F Ambient Temperature – Natural Gas-Fired



CONCEPTUAL DESIGN

NOTES

1. None

WorleyParsons resources & energy		
Con Edison Steam Production Option Study Hudson Avenue Plant		
Preliminary Heat Balance - Cogeneration Plant Option CG1: CG Plant with 501DSA & LP Gas Boilers Gas, 59°F/60% R.H, Fired HRSG (NG)		
DWG No: CESP-1-HB-CG1-02	Rev A	Date: 7/10/2006

Exhibit 4-39 Heat Balance for CG-1 Option at 59°F Ambient Temperature – Oil-Fired

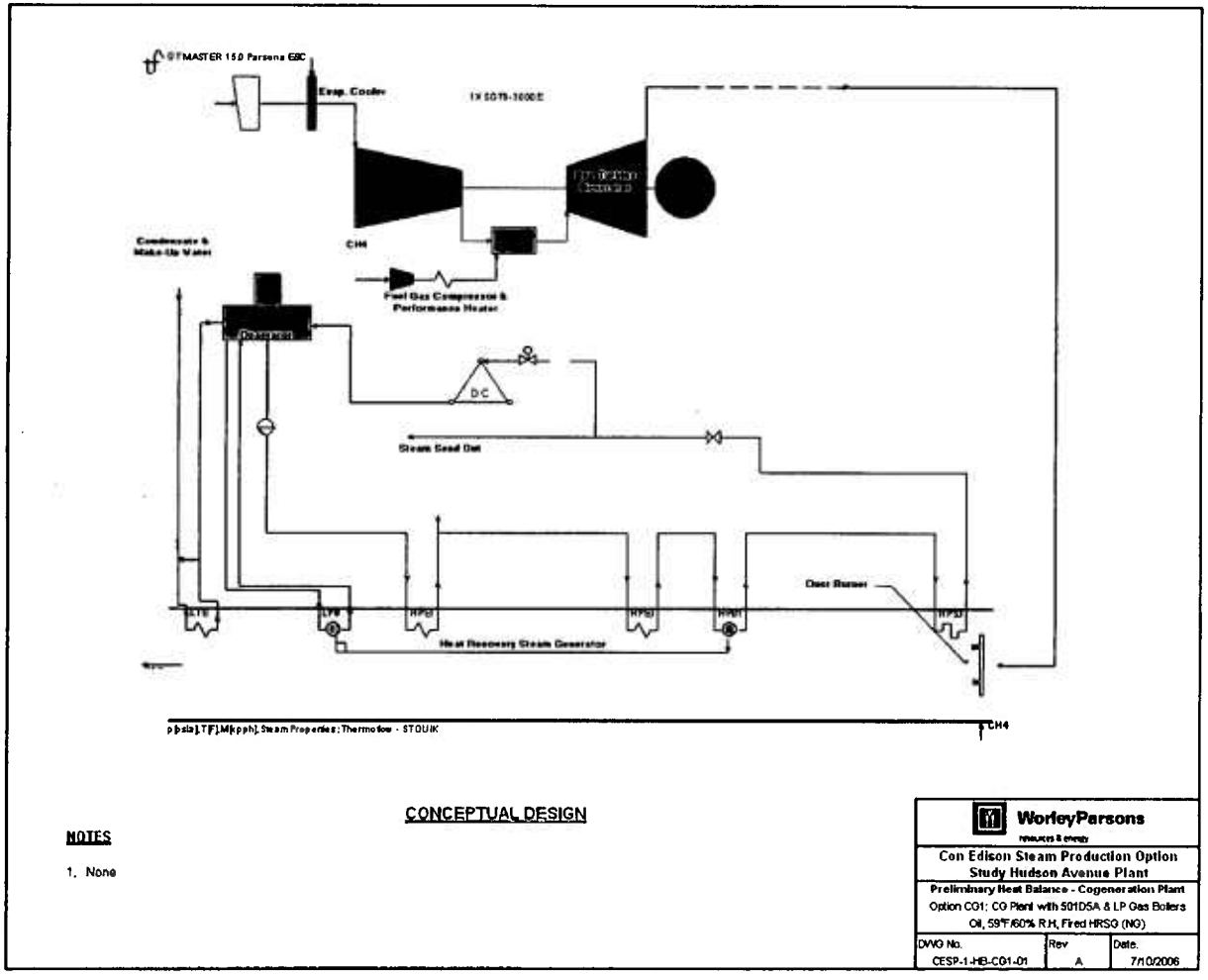
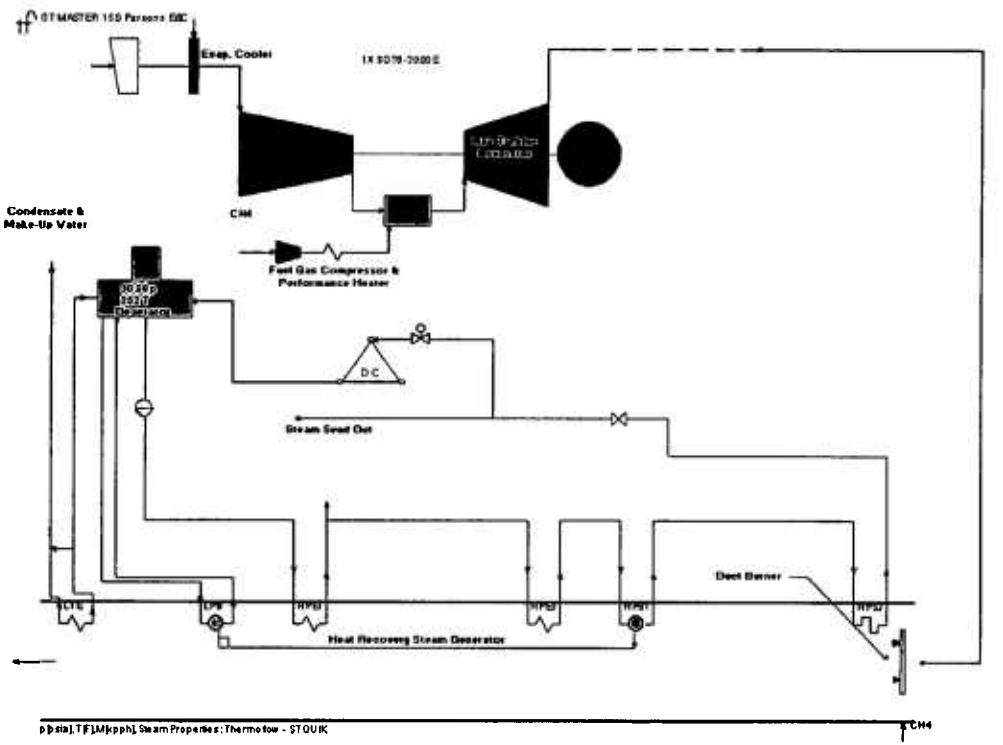


Exhibit 4-40 Heat Balance for CG-1 Option at 90°F Ambient Temperature – Natural Gas-Fired



CONCEPTUAL DESIGN

NOTES

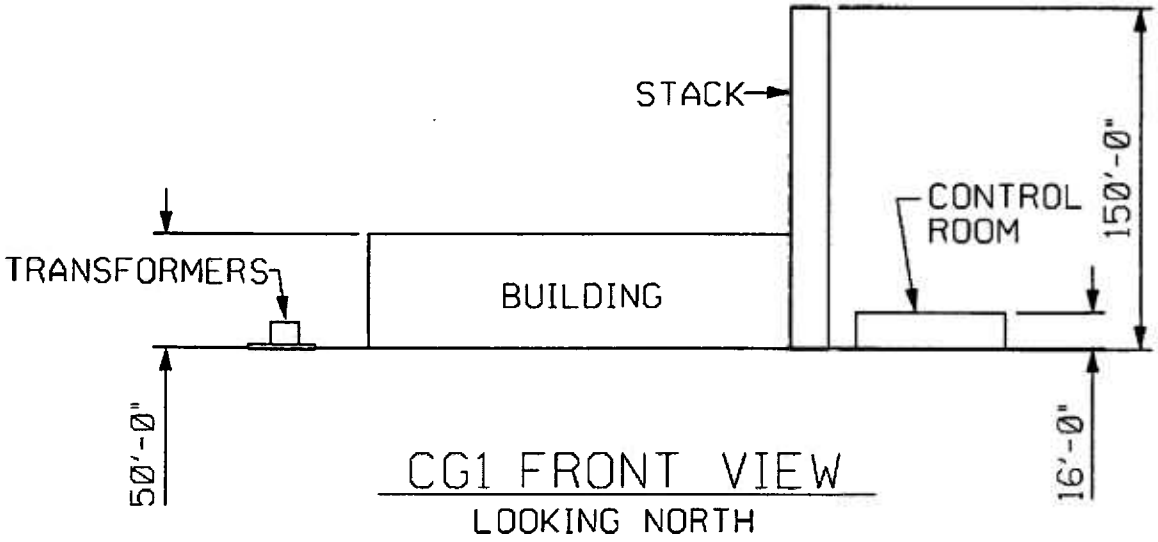
1. None

WorleyParsons resources & energy		
Con Edison Steam Production Option Study Hudson Avenue Plant		
Preliminary Heat Balance - Cogeneration Plant Option CG1: CG Plant with 501D5A & LP Gas Boilers Gas, 90F/35% R.H, Fired HRSG (NG)		
DWG No. CESP-1-HB-CG1-03	Rev A	Date. 7/10/2006

Exhibit 4-41 Conceptual Layout of Cogeneration Option CG-1

[REDACTED]

Exhibit 4-42 Conceptual Layout of Cogeneration Option CG-1



The HRSG net steam sent out capacities of the HRSG at 59F are as follows:

- Without any supplemental firing: 543,000 / 516,000 PPH with gas / oil firing in gas turbine respectively
- With supplemental firing: 950,000 /902,000 PPH with gas / oil firing in gas turbine respectively

The steam send out is at 350 psia and 455F. If the send out pressure is increased to 415 psia, the net steam send out is expected to be no more than 5% less than that shown on the respective heat balance diagrams.

The HRSG will be designed for indoor operation and set on a concrete foundation. The HRSG will have:

- Natural circulation
- Drum-type unit
- Two pressure level steam generation
- Vertical-tubed sections
- Extended surface, finned tubes
- Internally insulated
- Full draining capability

- Stainless steel floor liner
- SCR catalyst with provision to add 10% more catalyst in future
- CO Catalyst Module
- Sparging system to keep the HRSG warm after shutdown

The HRSG will be provided with a self-supporting stack equipped with ports for emissions sampling. Platforms, ladders, and personnel protection will be provided to permit access to the emissions sampling ports. Aircraft warning lights, as required by the applicable local, state, and federal authorities, will be incorporated into the design. Personnel protection will be provided as required.

Boiler water chemistry will be controlled by both continuous blowdown and the addition of chemicals into the HRSG drums. Blowdown systems will be included for the HRSG steam drums to remove dissolved solids. The HRSG will be provided with a continuous blowdown tank that will receive cascaded blowdown from the steam drums.

Package Boilers

Three new gas/oil fired package boilers each with a gross steaming capacity of 265,000 PPH will be provided to supplement the peak steam demand. The boilers will be provided with a common stack. The package boilers will be of water tube design, bottom supported, modular section construction and will be provided with low NOx combustion system, SCR and CO Catalyst module, dual fuel train, FD fan, superheater, and economizer.

Dump Condenser

A new, full capacity dump condenser will be provided to facilitate full power generation during low or no steam demand periods. The capacity of the dump condenser is estimated to be 441 million Btu/hr corresponding to full steam dumping with no supplemental firing in the HRSG. The dump condenser is a pressurized steam-to-air heat exchanger and will condense any steam in excess of the minimum steam demand while the Cogen unit is operating at minimum load. The dump condenser will be located outdoor on the roof and will drain the water to the new deaerator by static pressure differences.

Deaerator System

One (1) new, separate deaerator will be provided for the package boilers. The HRSGs will have their own deaerator at the top of the LP drum. The deaerator for the package boilers will be combined spray and tray type and will be designed to operate at a pressure of about 36 psia with a design pressure of 50 psig. Steam required for the deaerator will be tapped off the common header.

Steam System

The steam outlet from the various steam sources (HRSG, and Boilers) are fed into a single manifold. Before the manifold reaches the Head House, the steam is divided into 2 separate lines, one for Grand Street and one for Water Street.

Boiler Feedwater

The feed water from the deaerator will be pumped to the boiler economizer by feed water pumps. The new feed water pumps will be horizontal split, centrifugal type. A common feed water pumping system consisting of 3x50% capacity pumps to cater to the peak supply requirements will be provided.

Fuel Gas System

A new fuel gas system will be brought at the site to support the operation of the Cogen plant. It is expected that the pressure of the gas at the plant boundary will not be sufficient to support the requirements of the gas turbine. Therefore two (2) X 100% capacity gas compressors will be provided to boost the pressure of the incoming gas stream.

In order to comply with the specific fuel quality requirements of the gas turbine, a new fuel gas treatment system consisting of fuel gas filter separator will precede the gas compressors. The treated gas will be supplied to the boilers and HRSG and gas turbine. It is anticipated that only the gas required for the gas turbines will be required to pass through the gas compressors.

The maximum gas requirements for the plant is estimated as 3,275 MMBH (with margin included). The fuel gas required for HRSG supplemental firing will be firm gas supply. The maximum firm gas requirements is estimated to be 600 MMBH (with margin included).

Fuel Oil System

The existing No#6 fuel oil storage tanks will be refurbished to store No. 2 oil. Fuel oil will be fed from the existing storage tanks to the gas turbine and package boilers. Re-circulated fuel oil is returned to the storage tank.

Water Treatment System

The new water treatment plant will consist of a conventional cation/anion demineralization water treatment system designed to produce make up water suitable for the operation of the boilers. City water is supplied to a raw water tank. The raw water pumps take suction from this raw water tank and supply the water to the demineralizer plant. The treated water is then pumped to the treated water storage tank for use in the HRSG/Boilers. A slip stream of the deionized water will be passed through an Electrodeionization (EDI) plant for producing higher quality water required for water injection during oil firing as well as for gas turbine water wash system.

Waste Water

Waste water from the water treatment equipment and the cooled blowdown from the boilers are directed to floor sumps. The sumps are pumped to the waste water disposal facility in the plant.

4.2.1.8 Combined Cycle Option (CC-1)

Overview

Although the Combined Cycle options are not the most cost effective means of steam production for the Hudson Avenue Station, the following descriptions are being provided for Option CC-1 as an example of the Combined Cycle options evaluated.

In this option one new Siemens make 501D5 Gas turbine along with supplementally fired HRSG and an extraction /condensing type steam turbine will be provided for producing power and to supply steam. As the maximum steam generation with supplementally fired HRSG is less than the maximum demand, three new LP Boilers each of a gross capacity of 350 MPPH each will be provided. The Gas turbine and all new boilers will be firing natural gas as primary fuel with No. 2 oil back up. The HRSG will be designed to fire only natural gas (firm supply). Both the HRSG and the boilers will be provided with SCR and CO catalysis for emission controls.

A heat balance for this Option with natural gas firing at 59°F ambient temperature is shown in Exhibit 4-43.

Layout

There are no major layout issues with this option. The Combustion Turbine with HRSG, the 3 new Package Boilers, the new Stack, and the Control Room fit in the footprint of the Annex Building with a 20 foot setback from John Street. The Gas Compressor Room, the Water Treatment Room, the new Raw Water Tank, and the new Treated Water Tank fit across John Street next to the Electrical Building.

Major Equipment and Systems

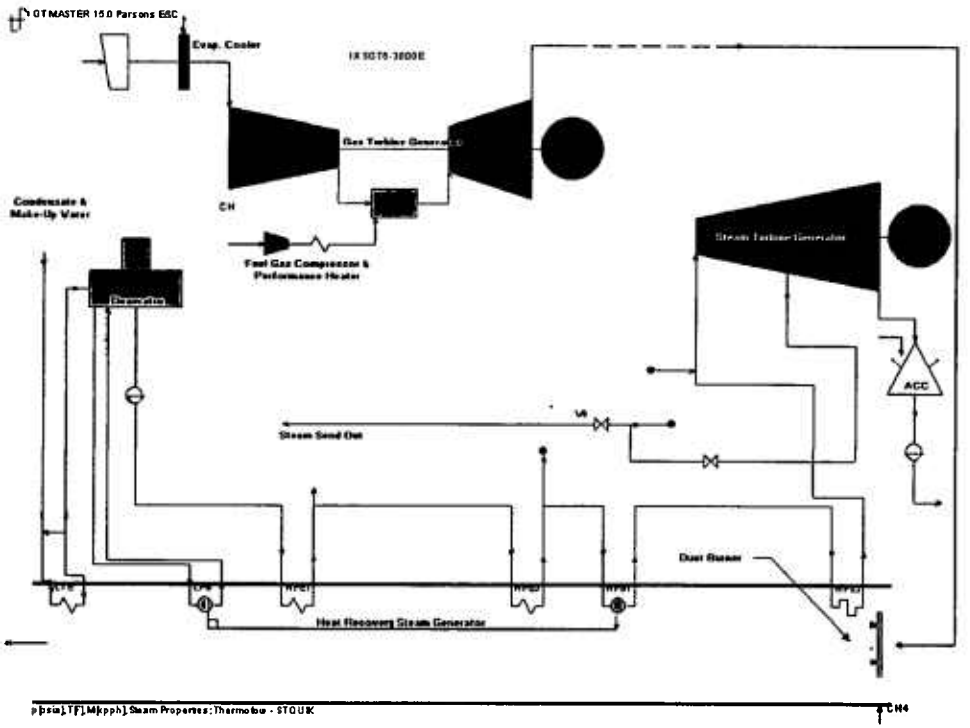
Gas Turbine

The gas turbine for this Option is the same as in Option CG-1.

Heat Recovery Steam Generator

The Heat Recovery Steam Generator (HRSG) is similar to the Cogen Option (CG-1) except that it will generate high pressure steam at about 1,500 psia/950°F. The high pressure steam will be sent to the steam turbine generator and the low pressure steam will be used in the deaerator.

Exhibit 4-43 Heat Balance for Combined Cycle Option CC-1 at 59°F – Natural Gas-Fired



CONCEPTUAL DESIGN

NOTES

1. None

WorleyParsons resources & energy		
Con Edison Steam Production Option Study Hudson Avenue Plant		
Preliminary Heat Balance - Combined Cycle Plant Option CC1: CC Plant with 501DSA & LP Gas Boilers Gas, 59°F/60% R H, Fired HRSG (NG)		
DWG No: CESP-1-HB-CC1-02	Rev A	Date 7/10/2006

The net steam sendout capacities of the HRSG at 59F are as follows:

- Without any supplemental firing: 370,000 / 362,400 PPH with gas / oil firing in gas turbine respectively
- With supplemental firing: 725,000 /710,000 PPH with gas / oil firing in gas turbine respectively

The steam conditions at HRSG outlet is at 1570 psia and 962F.

The other features of the HRSG is similar to that of the Cogen Option.

Steam Turbine/Generator (STG)

The steam turbine generator will be a controlled extraction / condensing, multi-stage, non-reheat, axial exhaust-type design. The steam turbine will receive main steam from the HRSGs. The steam for export will be taken from a controlled extraction point of the turbine. The turbine generator will be complete with stop and throttle valves, hydraulic control oil system including cooling, lube oil system including cooling, exhaust hood spray system, and gland seal system including condenser with exhausters, and turning gear. The steam turbine will be exhausting to an air cooled condenser.

The generator will be provided with the turbine package. The generator will be 15 kV, 3-phase, 60 hertz, totally enclosed, water/air-cooled (TEWAC), complete with excitation system, cooling, and protective relaying constructed to meet ANSI and NEMA standards for turbine-driven synchronous generators.

The steam turbine will be provided with a bypass system with desuperheaters to maximize steam production if needed at the cost of lower electricity production or to supply steam during steam turbine outage condition. The design shall incorporate features to ensure minimum cooling flow through the back end under all operating conditions.

Air Cooled Condenser

The steam turbine will be exhausting to a new air cooled condenser located on the roof of the turbine hall. The air cooled condenser is similar in construction as that of the dump condenser except that it handles steam under vacuum. The ACC will be provided with two speed fans and acoustic shroud. The condensate from the ACC will be collected in a condensate collection tank and will be pumped to the deaerator.

Package Boilers

Three new gas/oil fired package boilers each with a gross steaming capacity of 350 MPPH at 350 psia and 455 F will be provided to supplement the peak steam demand. The boilers will be provided with a common stack.

The package boiler design and construction features are the same as that of the Cogen Option.

Balance of Plant Systems

The other systems in this Option are similar to the Cogen option except that all water required for the cycle make up will pass through the EDI system to comply with the steam purity requirements of the steam turbine and the equipment ratings and capacities will be different to suit the CC plant operation.

4.2.1.9 Project Schedule for Promising Concepts

A conceptual project schedule for each of the three options selected as promising (BP-1, BP-2, and CG-1) is shown in Exhibit 4-44, Exhibit 4-45, and Exhibit 4-46. The schedules are based upon a turnkey EPC Contracting approach. In order to be consistent with the Cost Analysis and Financial Model, the completion schedule is taken as 72 months for all options starting January 2006. This includes 36 months for front end engineering; permitting and award of the EPC Contract; and an additional 36 months for detail engineering, procurement, construction, interconnections, start up, testing, and commercial operation. The schedule of specific milestone event / activity is calculated backwards from the 72 month overall schedule duration before commercial operation.

In all the promising option cases, WorleyParsons believes that there may be potential opportunities to advance the overall project schedule and provide steam or power earlier than the projected seventy-two months schedule by expediting the purchase and delivery of major equipment. Con Edison may also consider buying major pieces of equipment in advance and issue that to the EPC Contractor for installation.

Specific issues related to the promising options are summarized below.

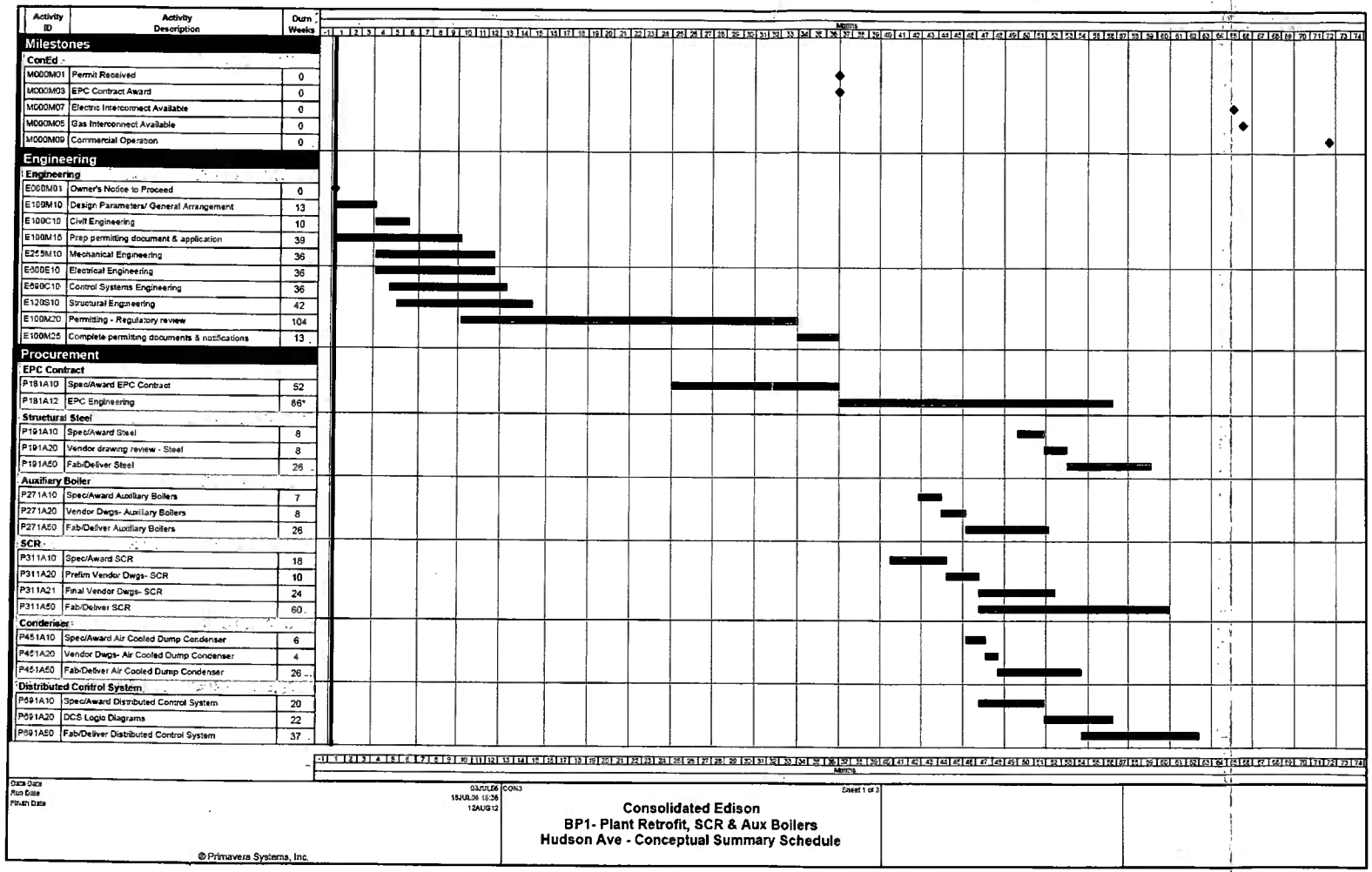
- BP-1:Retrofitting Existing Unit 10/100 with Dump Condenser Option :
  - The plan for the BP-1 option after the Regulatory Permitting and award of an EPC contract is to mobilize to the site commencing sixteen (16) months later.
  - The twenty (20) month construction and startup schedule includes restoration and modifications of the existing unit 10/100, converting it into gas firing with oil back up, the installation of new emission control equipment, two auxiliary boilers with emission control equipment, one dump condenser, tying into the existing stack, conversion of the fuel source for the boiler from oil, to gas with oil backup, along with all other equipment and systems required to support the operation of this configuration option.
  - The critical path for the BP-1 option begins with the receipt of permits and award of the EPC contract, and continues through the engineering, procurement, delivery, restoration of the existing units, installation, and startup of the SCR and ductwork.
- BP-2: New Boiler only Option:
  - The plan for the BP-2 option after the Regulatory Permitting and award of an EPC contract is to mobilize to the site commencing six (6) months later.

- The thirty (30) month construction and startup schedule includes relocation / demolition of existing equipment, the installation of four auxiliary boilers with emission control equipment, a new stack along with all other equipment and systems required to support the operation of this configuration option.
- The critical path for the BP-2 option begins with the receipt of permits and award of the EPC contract, and continues through the engineering, procurement, delivery, installation, and startup of the boilers and associated systems.

◆ CG -1: Cogen Plant with 501D5 Gas Turbine Option:

- The plan for the CG-1 option after the Regulatory Permitting and award of an EPC contract is to mobilize to the site commencing nine (9) months later.
- The thirty (27) month construction and startup schedule includes relocation / demolition of existing equipment, the installation of three auxiliary boilers with emission control equipment, dump condenser, gas compressors, new stacks along with all other equipment and systems required to support the operation of this configuration option.
- The critical path for the CG-1 option begins with the receipt of permits and award of the EPC contract, and continues through the engineering, procurement, delivery, installation, and startup of the Gas turbine and HRSG.

Exhibit 4-44 Conceptual Project Schedule for BP-1 Option at Hudson Avenue Station (Page 1 of 3)



Activity ID	Activity Description	Dur'n Weeks
Milestones		
ConEd		
M000M01	Permit Received	0
M000M03	EPC Contract Award	0
M000M07	Electric Interconnect Available	0
M000M05	Gas Interconnect Available	0
M000M09	Commercial Operation	0
Engineering		
Engineering		
E000M01	Owner's Notice to Proceed	0
E100M10	Design Parameters/ General Arrangement	13
E100C10	Civil Engineering	10
E100M15	Prep permitting document & application	39
E255M10	Mechanical Engineering	36
E600E10	Electrical Engineering	36
E690C10	Control Systems Engineering	36
E120S10	Structural Engineering	42
E100M20	Permitting - Regulatory review	104
E100M25	Complete permitting documents & notifications	13
Procurement		
EPC Contract		
P181A10	Spec/Award EPC Contract	52
P181A12	EPC Engineering	66*
Structural Steel		
P191A10	Spec/Award Steel	8
P191A20	Vendor drawing review - Steel	8
P191A50	Fab/Deliver Steel	26
Auxiliary Boiler		
P271A10	Spec/Award Auxiliary Boilers	7
P271A20	Vendor Dwgs- Auxiliary Boilers	8
P271A50	Fab/Deliver Auxiliary Boilers	26
SCR		
P311A10	Spec/Award SCR	18
P311A20	Prelim Vendor Dwgs- SCR	10
P311A21	Final Vendor Dwgs- SCR	24
P311A50	Fab/Deliver SCR	60
Condenser		
P451A10	Spec/Award Air Cooled Dump Condenser	6
P451A20	Vendor Dwgs- Air Cooled Dump Condenser	4
P451A50	Fab/Deliver Air Cooled Dump Condenser	26
Distributed Control System		
P591A10	Spec/Award Distributed Control System	20
P591A20	DCS Logic Diagrams	22
P591A50	Fab/Deliver Distributed Control System	37

Months

Data Date 03JUL06
Run Date 19JUL06 16:26
Finish Date 12AUG12

CON3

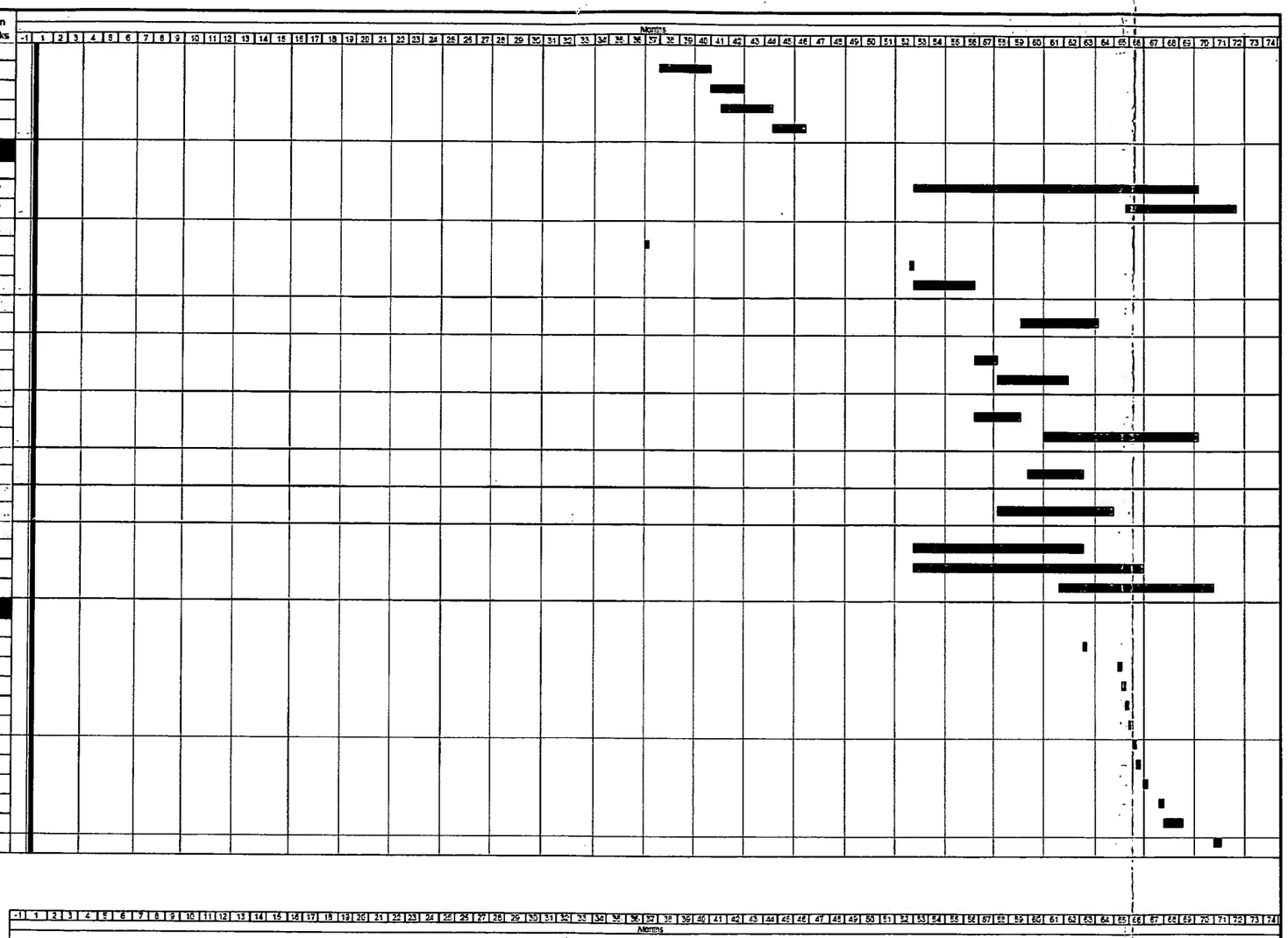
Sheet 1 of 3

Consolidated Edison
BP1- Plant Retrofit, SCR & Aux Boilers
Hudson Ave - Conceptual Summary Schedule

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Exhibit 4-44 (cont'd) Conceptual Project Schedule for BP-1 Option at Hudson Avenue Station (Page 2 of 3)

Activity ID	Activity Description	Durn Weeks
Boiler & Turbine Restoration		
P710A10	Boiler 10 Restoration/ Mods/ Gas Conversion Engr	13
P710A20	Select Boiler 10 Restoration vendor	9
P711A10	Turbine 100 Modifications Engineering	13
P711A20	Select Turbine 100 Modifications vendor	9
Construction		
Construction		
C000C1H	Site Construction	74*
C000C2H	Plant & Unit Startup	29*
Site Preparation and Improvement		
C050C10	Permits Approved	1
C100C10	Mobilize to Site	1
C100C11	Site Prep/ Demolition/ Relocation	16
Structural Steel		
C191C10	Erect Structural Steel	20
Auxiliary Boiler		
C258C10	FRP Auxiliary Boiler & Concenser Foundations	6
C258C20	Auxiliary Boiler Installation	18
SCR		
C311C10	FRP SCR & Ductwork Foundations	12
C311C20	SCR & Ductwork Installation	40
Condenser		
C451C20	Dump Condenser Installation	14
Piping		
C191C40	Pipe Installation	30
Boiler & Turbine Restoration		
C711A30	Install Turbine 100 Modifications	44
C710A30	Install Boiler 10 Modifications	60
C690C60	Restore BOP Systems & Controls	40
Unit Startup		
Startup and Commissioning		
S258S30	Steam Blow Aux Steam	1
S670S10	Energize Switchyard	1
S616S10	Backfeed and Soak Transformers	1
S258S10	Chemical Clean Aux Boilers	1
S258S20	Hydro Test Aux Boilers	1
S258S40	First Fire on Gas Aux Boilers	1
S311S10	Lube Oil Flush 100 Turbine	1
S211S10	Chemical Clean 10 Boiler	1
S2100	100 Turbine on Turning Gear	1
S441S30	10 Boiler Steam Blow & Restoration	5
S311S30	First Fire on Gas / Initial Sync 10/100	2



Data Date
Run Date 03JUL06
Finish Date 15JUL06 15:26
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CON3

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Consolidated Edison
BP1- Plant Retrofit, SCR & Aux Boilers
Hudson Ave - Conceptual Summary Schedule

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Exhibit 4-44 (cont'd) Conceptual Project Schedule for BP-1 Option at Hudson Avenue Station (Page 3 of 3)

Activity ID	Activity Description	Dura Weeks
Plant Startup		
Startup and Commissioning		
A2150	Aux Boiler Perf. Reliability & Operability Tests	3
A2151	15/100 Perf. Reliability & Operability Tests	3
A2160	Commercial Operation	1
A2170	Punchlist Items	8
A2180	Final Completion	1

Months

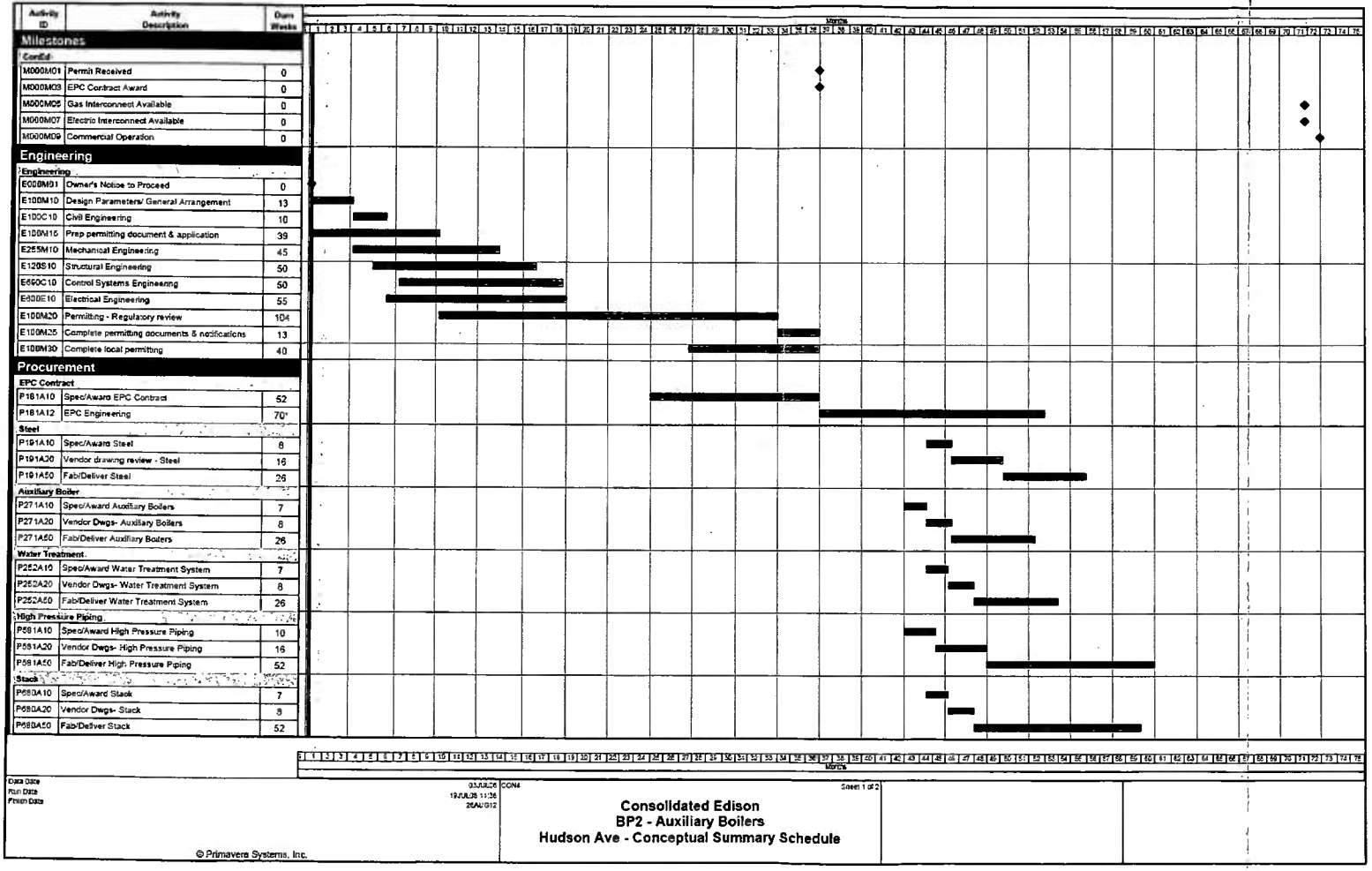
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Run Date 15JUL06 16:26
Finish Date 15AUG12

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CON9 Sheet 3 of 3

Consolidated Edison
BP1- Plant Retrofit, SCR & Aux Boilers
Hudson Ave - Conceptual Summary Schedule

Exhibit 4-45 Conceptual Project Schedule for BP-2 Option at Hudson Avenue Station (Page 1 of 2)



Activity ID	Activity Description	Dura Weeks
Milestones		
Conf'd:		
M000M01	Permit Received	0
M000M03	EPC Contract Award	0
M000M05	Gas Interconnect Available	0
M000M07	Electric Interconnect Available	0
M000M09	Commercial Operation	0
Engineering		
Engineering:		
E000M01	Owner's Notice to Proceed	0
E100M10	Design Parameters/ General Arrangement	13
E100C10	Civil Engineering	10
E100M15	Prep permitting document & application	39
E255M10	Mechanical Engineering	45
E120S10	Structural Engineering	50
E660C10	Control Systems Engineering	50
E600E10	Electrical Engineering	55
E100M20	Permitting - Regulatory review	104
E100M25	Complete permitting documents & notifications	13
E100M30	Complete local permitting	40
Procurement		
EPC Contract:		
P161A10	Spec/Award EPC Contract	52
P161A12	EPC Engineering	70*
Steel:		
P191A10	Spec/Award Steel	8
P191A20	Vendor drawing review - Steel	16
P191A50	Fab/Deliver Steel	26
Auxiliary Boiler:		
P271A10	Spec/Award Auxiliary Boilers	7
P271A20	Vendor Dwgs- Auxiliary Boilers	8
P271A50	Fab/Deliver Auxiliary Boilers	26
Water Treatment:		
P252A10	Spec/Award Water Treatment System	7
P252A20	Vendor Dwgs- Water Treatment System	8
P252A50	Fab/Deliver Water Treatment System	26
High Pressure Piping:		
P581A10	Spec/Award High Pressure Piping	10
P581A20	Vendor Dwgs- High Pressure Piping	16
P581A50	Fab/Deliver High Pressure Piping	52
Stack:		
P680A10	Spec/Award Stack	7
P680A20	Vendor Dwgs- Stack	8
P680A50	Fab/Deliver Stack	52

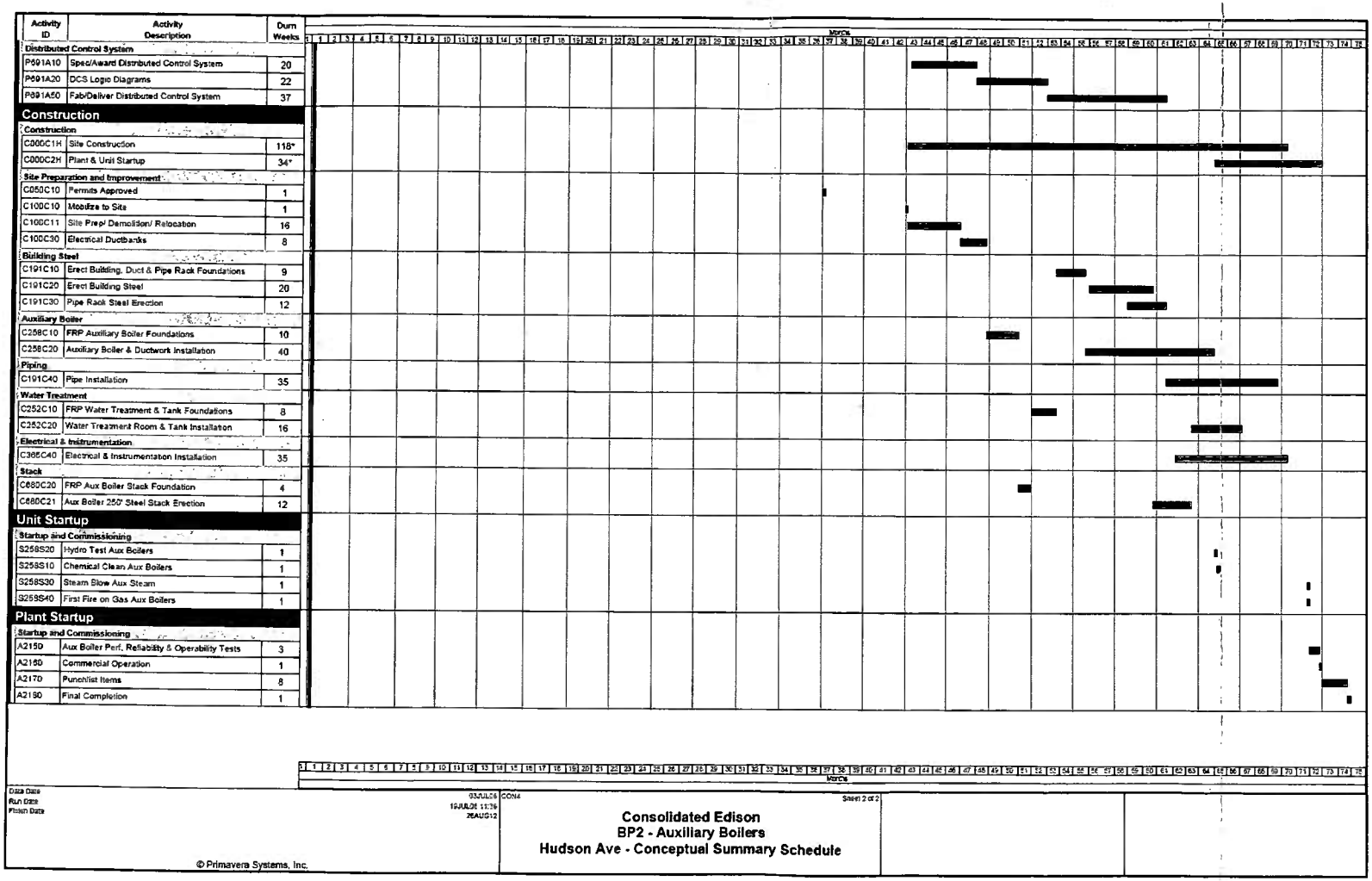
Months

Data Date 03JUL06
Run Date 19JUL06 11:36
Finish Date 26AUG12
CON4
Sheet 1 of 2

Consolidated Edison
BP2 - Auxiliary Boilers
Hudson Ave - Conceptual Summary Schedule

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Exhibit 4-45 (cont'd) Conceptual Project Schedule for BP-2 Option at Hudson Avenue Station (Page 2 of 2)



Activity ID	Activity Description	Dur Weeks
Distributed Control System		
P691A10	Spec/Award Distributed Control System	20
P691A20	DCS Logic Diagrams	22
P691A50	Fab/Deliver Distributed Control System	37
Construction		
Construction		
C000C1H	Site Construction	118*
C000C2H	Plant & Unit Startup	34*
Site Preparation and Improvement		
C050C10	Permits Approved	1
C100C10	Mobilize to Site	1
C100C11	Site Prep/ Demolition/ Relocation	16
C100C30	Electrical Ductbanks	8
Building Steel		
C191C10	Erect Building, Duct & Pipe Rack Foundations	9
C191C20	Erect Building Steel	20
C191C30	Pipe Rack Steel Erection	12
Auxiliary Boiler		
C258C10	FRP Auxiliary Boiler Foundations	10
C258C20	Auxiliary Boiler & Ductwork Installation	40
Piping		
C191C40	Pipe Installation	35
Water Treatment		
C252C10	FRP Water Treatment & Tank Foundations	8
C252C20	Water Treatment Room & Tank Installation	16
Electrical & Instrumentation		
C365C40	Electrical & Instrumentation Installation	35
Stack		
C680C20	FRP Aux Boiler Stack Foundation	4
C680C21	Aux Boiler 250' Steel Stack Erection	12
Unit Startup		
Startup and Commissioning		
S258S20	Hydro Test Aux Boilers	1
S258S10	Chemical Clean Aux Boilers	1
S258S30	Steam Blow Aux Steam	1
S258S40	First Fire on Gas Aux Boilers	1
Plant Startup		
Startup and Commissioning		
A215D	Aux Boiler Perf, Reliability & Operability Tests	3
A215D	Commercial Operation	1
A217D	Punchlist Items	8
A219D	Final Completion	1

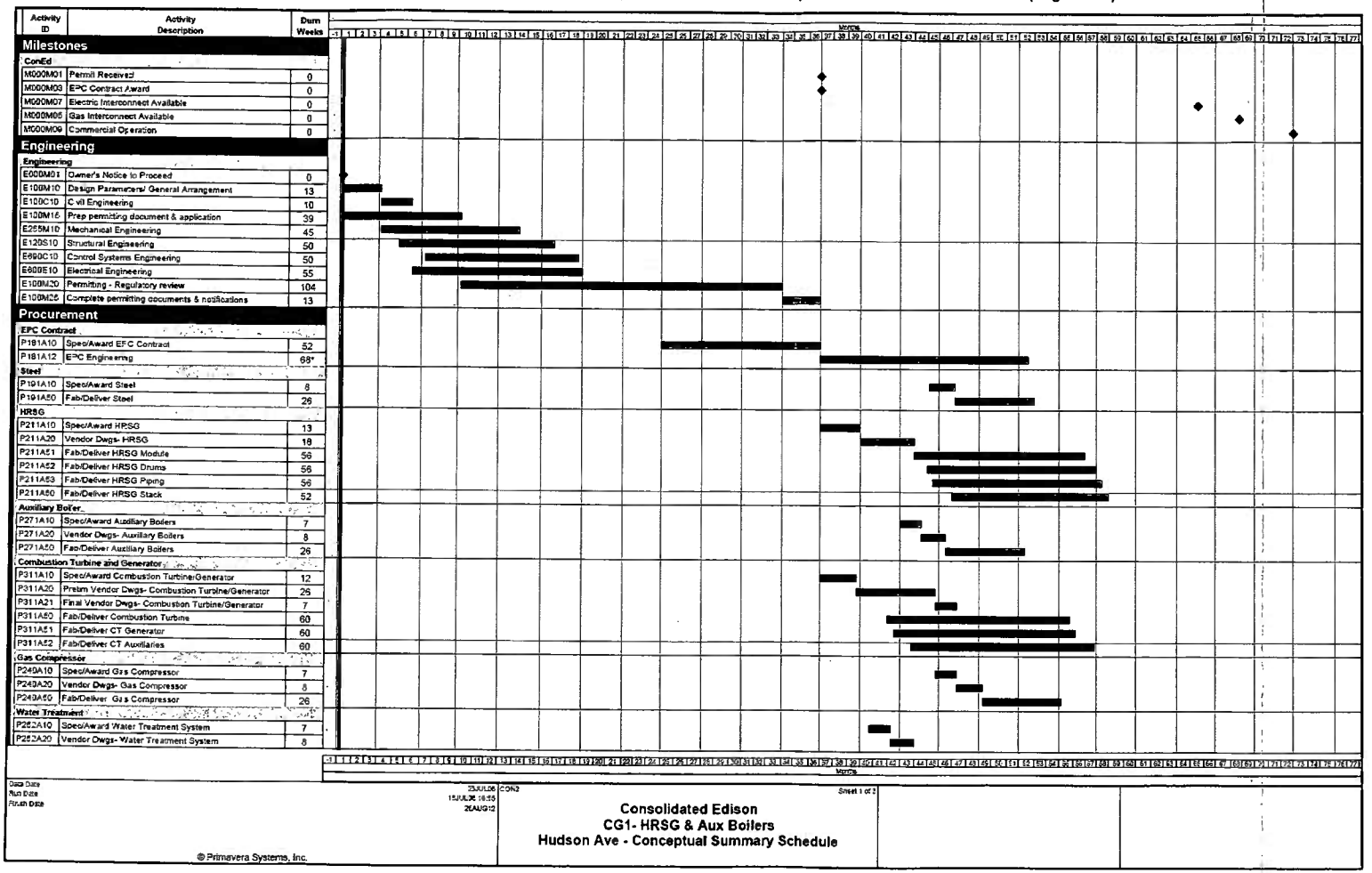
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CON4 Sheet 2 of 2

Consolidated Edison
BP2 - Auxiliary Boilers
Hudson Ave - Conceptual Summary Schedule

Exhibit 4-46 Conceptual Project Schedule for CG-1 Option at Hudson Avenue Station (Page 1 of 3)



Activity ID	Activity Description	Dur Weeks
Milestones		
ConEd		
M000M01	Permit Received	0
M000M03	EPC Contract Award	0
M000M07	Electric Interconnect Available	0
M000M05	Gas Interconnect Available	0
M000M09	Commercial Operation	0
Engineering		
Engineering		
E000M01	Owner's Notice to Proceed	0
E100M10	Design Parameters/ General Arrangement	13
E100C10	Civil Engineering	10
E100M15	Prep permitting document & application	39
E255M10	Mechanical Engineering	45
E120S10	Structural Engineering	50
E600C10	Control Systems Engineering	50
E600E10	Electrical Engineering	55
E100M20	Permitting - Regulatory review	104
E100M25	Complete permitting documents & notifications	13
Procurement		
EPC Contract		
P181A10	Spec/Award EFC Contract	52
P181A12	EPC Engineering	68*
Steel		
P191A10	Spec/Award Steel	8
P191A50	Fab/Deliver Steel	26
HRSG		
P211A10	Spec/Award HRSG	13
P211A20	Vendor Dwgs- HRSG	18
P211A51	Fab/Deliver HRSG Module	56
P211A52	Fab/Deliver HRSG Drums	56
P211A53	Fab/Deliver HRSG Piping	56
P211A50	Fab/Deliver HRSG Stack	52
Auxiliary Boiler		
P271A10	Spec/Award Auxiliary Boilers	7
P271A20	Vendor Dwgs- Auxiliary Boilers	8
P271A50	Fab/Deliver Auxiliary Boilers	26
Combustion Turbine and Generator		
P311A10	Spec/Award Combustion Turbine/Generator	12
P311A20	Prelim Vendor Dwgs- Combustion Turbine/Generator	26
P311A21	Final Vendor Dwgs- Combustion Turbine/Generator	7
P311A50	Fab/Deliver Combustion Turbine	60
P311A51	Fab/Deliver CT Generator	60
P311A52	Fab/Deliver CT Auxiliaries	60
Gas Compressor		
P240A10	Spec/Award Gas Compressor	7
P240A20	Vendor Dwgs- Gas Compressor	8
P240A50	Fab/Deliver Gas Compressor	26
Water Treatment		
P252A10	Spec/Award Water Treatment System	7
P252A20	Vendor Dwgs- Water Treatment System	8

Months

Data Date
Run Date 15JUL06 16:55
Finish Date 26AUG12

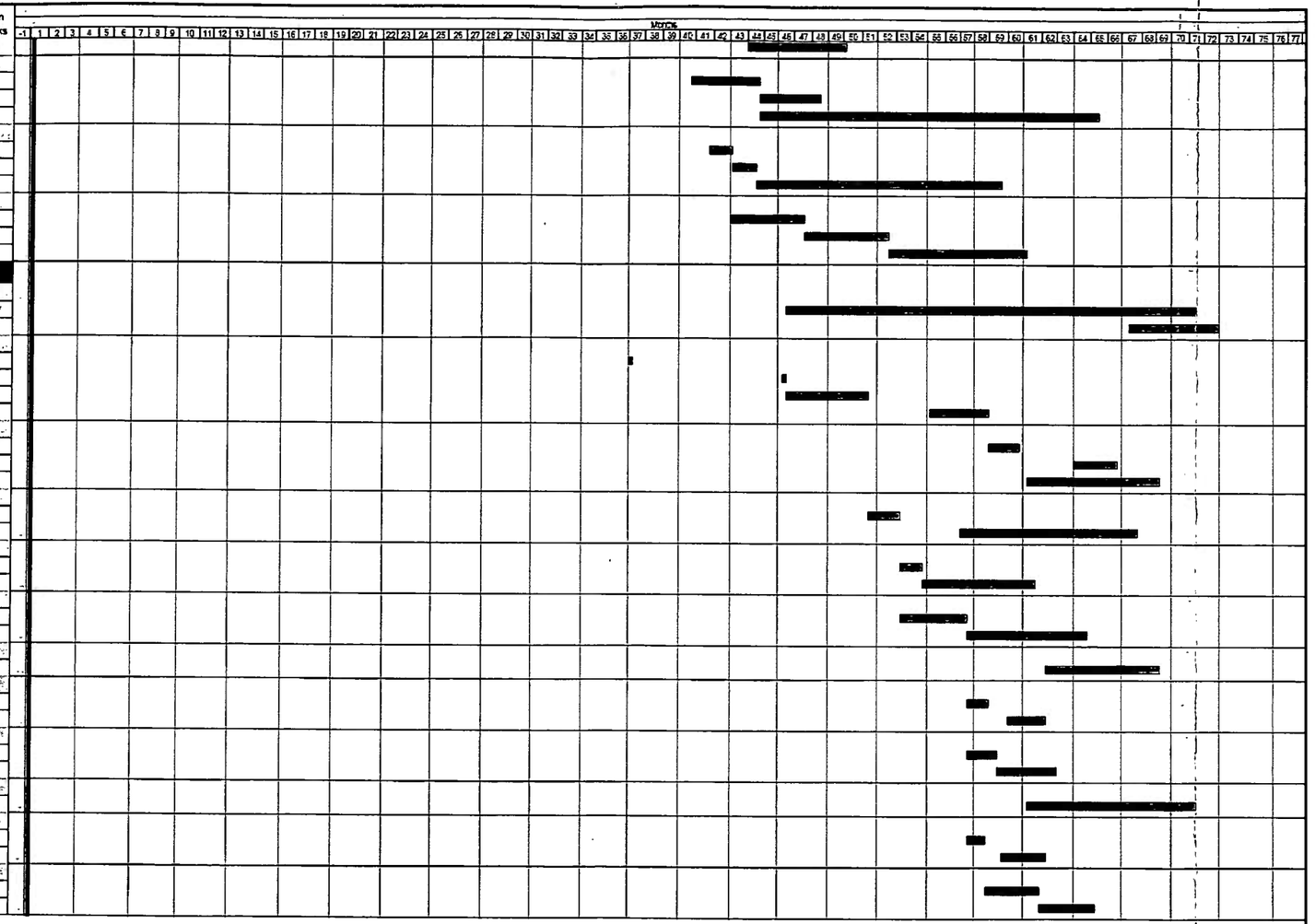
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Consolidated Edison
CG1- HRSG & Aux Boilers
Hudson Ave - Conceptual Summary Schedule

Exhibit 4-46 (cont'd) Conceptual Project Schedule for CG-1 Option at Hudson Avenue Station (Page 2 of 3)

Activity ID	Activity Description	Dur Weeks
P252A50	Fab/Deliver Water Treatment System	26
High Pressure Piping		
P581A10	Spec/Award High Pressure Piping	18
P581A20	Vendor Dwgs- High Pressure Piping	16
P581A50	Fab/Deliver High Pressure Piping	90
Generator Stepup Transformers		
P618A10	Spec/Award Step-Up Transformers	6
P618A20	Vendor Dwgs- Step-Up Transformers	6
P618A50	Fab/Deliver Step-Up Transformers	65
Distributed Control System		
P691A10	Spec/Award Distributed Control System	20
P691A20	DCS Logic Diagrams	22
P691A50	Fab/Deliver Distributed Control System	37
Construction		
Construction		
C000C1H	Site Construction	109*
C000C2H	Plant & Unit Startup	24*
Site Preparation and Improvement		
C050C10	Permits Approved	1
C100C10	Mobilize to Site	1
C100C11	Site Prep/ Demolition/ Relocation	22
C100C30	Electrical Ductbanks	16
Building Steel		
C191C10	Erect Building, Duct & Pipe Rack Foundations	8
C191C30	Pipe Rack Steel Erection	12
C191C20	Erect Building Steel	35
HRSG		
C211C10	FRP HRSG Foundation	8
C211C11	HRSG Erection	47
Auxiliary Boiler		
C258C10	FRP Auxiliary Boiler Foundations	6
C258C20	Auxiliary Boiler Installation	30
Combustion Turbine and Generator		
C311C10	FRP CTG Foundation	18
C311C20	CTG Erection	32
Piping		
C191C40	Pipe Installation	30
Gas Compressor		
C240C10	FRP Gas Compressor Foundations	6
C240C20	Gas Compressor Installation	10
Water Treatment		
C252C10	FRP Water Treatment & Tank Foundations	8
C252C20	Water Treatment Room & Tank Installation	16
Electrical & Instrumentation		
C365C40	Electrical & Instrumentation Installation	45
Transformers		
C660C10	FRP Stepup Transformer Foundations	5
C660C20	Stepup Transformer Installation	12
Switchyard		
C670C10	FRP Switchyard Foundations	14
C670C20	Switchyard Installation	15



Data Date 03JUL06
Run Date 15JUL06 16:55
Finish Date 26AUG12

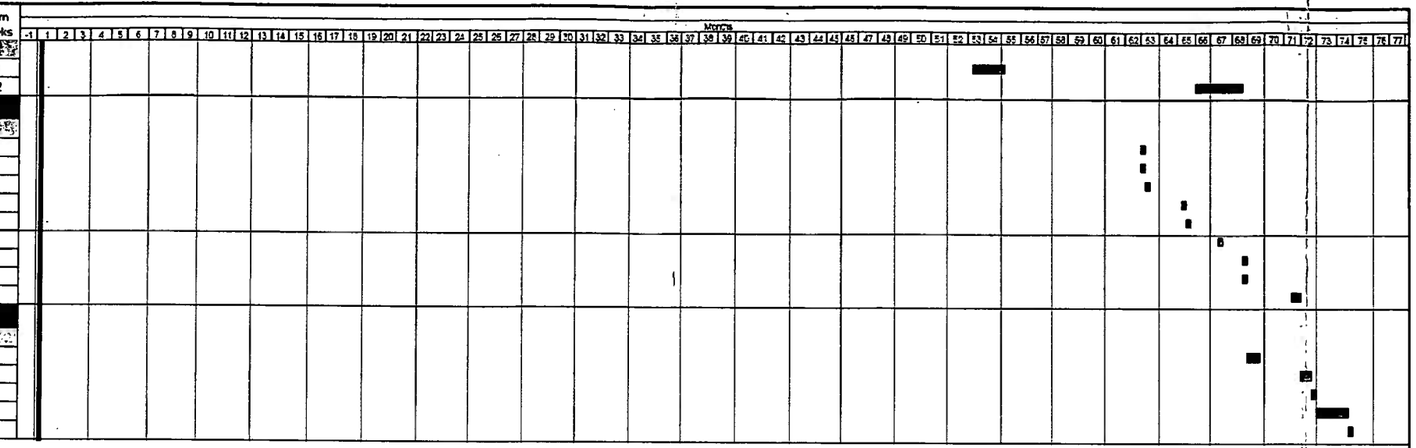
CON2 Sheet 2 of 3

Consolidated Edison
CG1- HRSG & Aux Boilers
Hudson Ave - Conceptual Summary Schedule

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Exhibit 4-46 (cont'd) Conceptual Project Schedule for CG-1-Option-at-Hudson-Avenue Station (Page 3 of 3)

Activity ID	Activity Description	Dum Weeks
Stack		
C680C10	FRP HRSG Stack Foundation	8
C680C11	HRSG 250' Steel Stack Erection	12
Unit Startup		
Startup and Commissioning		
S258S20	Hydro Test Aux Boilers	1
S311S10	Lube Oil Flush CTG	1
S258S10	Chemical Clean Aux Boilers	1
S670S10	Energize Switchyard	1
S618S10	Backfeed and Soak Transformers	1
S211S10	Chemical Clean HRSG	1
S258S30	Steam Blow Aux Steam	1
S258S40	First Fire on Gas Aux Boilers	1
S311S30	First Fire/Initial Sync CTG	2
Plant Startup		
Startup and Commissioning		
A2150	Aux Boiler Perf, Reliability & Operability Tests	3
A2151	Unit Perf, Reliability and Operability Tests	3
A2180	Commercial Operation	1
A2170	Punchlist Items	8
A2190	Final Completion	1



Data Date 03JUL06
Run Date 15JUL06 16:55
Finish Date 26AUG12
CON2
Sheet 3 of 3

Consolidated Edison
CG1- HRSG & Aux Boilers
Hudson Ave - Conceptual Summary Schedule

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4.2.2 59th Street Station

4.2.2.1 Re-Powering Options Considered

The major site specific issues at the 59th Street Station that were considered in determining options to be considered are as follows:

- The site has limited available space for addition of new equipment associated with larger gas turbine options similar to those considered for the Hudson Avenue Station.
- There is no space other than the roof to locate any Air Cooled Condenser (ACC) /Dump Condenser (DC) required for the CC plant or large cogen plant.
- The roof needs to be replaced to locate any ACC / DC. Being located in the heart of the city, the site may have problems related to aesthetics and noise associated with addition of such equipment on the power house building roof
- Available head room below the existing crane rail poses restrictions to include larger size HRSG.
- The available gas supply at the station is limited to about 700 MSCFH which can support only smaller size gas turbines without capacity augmentation.
- Delivery of large pieces of equipment would likely require the temporary closing of the West Side Highway. Also, temporary closings of some local streets (12th Ave. in particular) are likely.

The Repowering Options for this site were established taking into considerations the major site constraints noted above. The following describes the salient features of the Options:

- Evaluate re-powering options in cogen mode only with smaller size gas turbines (GTX 100 & LM 6000). These gas turbines fit well within the current available gas supply and within the available space at this facility.
- No boilers will be added to the facility as the condition of existing boilers are in good shape and are expected to provide reliable future operation with the current planned upgrades & maintenance program.
- Because of the addition of Cogen facility, two of the package boilers can be retired without impacting the maximum net send out from this plant.

4.2.2.2 Conceptual Description of Re-Powered Facilities

The conceptual description of the Re-powering options considered for the 59th street is similar to that provided for options CG-3 and CG-4 for the Hudson Avenue Station evaluation except that there is be no dump condenser. The summary performance data for various options are presented in Exhibit 4-47. A conceptual layout of the cogeneration facility evaluated for 59th Street Station is shown in Exhibit 4-48.

Exhibit 4-47 59th Street Station Evaluation Screening Model Performance Data

CONCEPTUAL DATA FOR RELATIVE COMPARISION ONLY[1]

A. Combined Gas & Oil Firing - Steam Send Out Based Upon Projected Demand, Gas Firing for 335 Days and Oil Firing for 30 Days[3 &18]

ITEM	DESCRIPTION	Current Operation	RE-POWERING OPTIONS	
			Cogeneration Options	
			Option - CG1	Option - CG2
A.	Option Description	Based on 2005 Oil / Gas Fired Operation	Cogen Plant with GE LM 6000 Gas Turbine	Cogen Plant with Siemens GTX 100 Gas Turbine
B.	**New Configuration Description**			
1.	Number of Gas turbines/HRSGs	N.A.	1	1
2.	Number of Steam Turbine	N.A.		
3.	Number of new HP Boilers		N.A.	
4.	Capacity of HP Boiler, Mlb/hr		N.A.	
5.	Number of New LP Boilers	N.A.	N.A.	
6.	New LP Boiler Capacity each, Mlb/hr[8]	N.A	N.A.	
C.	**Net Steam Generation[2]**			
1.	Design Capacity Reqmnt, Mlb/hr	1,331		
2.	Annual Average Send Out, MMlb	[REDACTED]		
3.	Annual Avg Hourly Send out, Mlb/hr	[REDACTED]		
4.	Cogen Plant Steam Export Capacity, Mlb/hr			
a.	With full SF in HRSGs		316	320
b.	No SF in HRSGs		132	187
5.	Net Boiler Send Out Capacity, Mlb/hr[6]	1,331	1,015	1,011
6.	Design Average Annual Send out, Mlb/hr			
a.	Cogen Plant in partial firing [14]		215	267
b.	No SF in HRSGs		24	72
7.	Design Annual Stm Production Capability in CC & Cogen Plant, MMlb			
a.	With Suppl Firing in HRSGs		0	0
b.	Without Suppl Firing in HRSGs		0	0
D.	**Cogen/CC/Boiler Plant operation and Annual Steam Generation Profile.**			
1.	Gas Turbine[15] Operating hours	N.A.	[ALL DATA REDACTED]	
2.	Operating Hours- HRSG with full SF			
3.	Oper Hours - HRSG for part SF mode[14]			
4.	HRSG - Oper Hours no Supp Firing			
5.	Cogen Plant			
a.	Export Steam with full SF, MMlb			
b.	Export Steam with Partial SF /Int Exp, MMlb			
c.	Export Steam W/O Supp Firing, MMlb			
6.	Steam from Existing Boilers, MMlb[5]			
7.	**Total Annual Steam Check, MMlb**			
E.	**Electrical Output[3], kW**			
1.	Gas Turbine	Not Applicable	42,934	44,419
2.	Cogen Net Output - ISO		41,740	43,627
F.	**Annual Fuel (MMBtu - HHV), Electricity (MWh), Water Consumption (M Gal) and Electricity Generation(MWh)**			
1.	Gas Turbine Fuel - Gas	[ALL DATA REDACTED]		
2.	Gas Turbine Fuel - Oil			
3.	HRSG Fuel for Full Supp Firing - Gas Only			
4.	HRSG Fuel for Partial Suppl Firing - Gas Only			
5.	Boiler Fuel - Gas[5]			
6.	Boiler Fuel - Oil[5]			
7.	Total Fuel Consumption - Oil			
8.	Total Fuel Consumption - Gas			
9.	Total of all Fuels			
10.	Water Consumption[17]			
11.	Net Elec Generation - Power Plants[9]			

Exhibit 4-47 (cont'd) 59th Street Station Evaluation Screening Model Performance Data

CONCEPTUAL DATA FOR RELATIVE COMPARISION ONLY[1]

A. Combined Gas & Oil Firing - Steam Send Out Based Upon Projected Demand, Gas

ITEM	DESCRIPTION	Current Operation	RE-POWERING OPTIONS Cogeneration Options	
			Option - CG1	Option - CG2
A.	Option Description	Based on 2005 Oil / Gas Fired Operation	Cogen Plant with GE LM 6000 Gas Turbine	Cogen Plant with Siemens GTX 100 Gas Turbine
G.	**Total NPV of Plant Cost - US Dollars**			
1.	Existing Plant Maintenance Cost	See Economic Model for details		
2.	EPC Cost			
a.	Cogen / CC Unit and accessories			
b.	Boiler Plant			
c.	Demin Plant			
d.	Other BOP			
3.	Demolition /Relocation/ Remediation Costs			
a.	Demolition Costs			
b.	Relocation Costs			
c.	Remediation Costs			
4.	Permitting/Prelim Engineering			
5.	Gas Piping Interconnect Costa			
6.	Elctrical Reinforcement/Interconnect Costs			
7.	Contingency			
8.	Owner"s other Costs[4]			
9.	**Total Plant Cost (TPC)**			
H.	**Total NPV of Annual Costs**	See Economic Model for details		
1.	Fuel Cost			
2.	Fixed Charges on TPC (Debt Services)			
3.	Water & Chemical Costs			
4.	Electrcity Purchase Cost			
5.	O&M Costs of existing plant[10]			
6.	Non Fuel O&M Costs			
7.	Property Taxes & ICICP			
8.	ICICP Credit			
9.	**Total Annual Cost**			
I.	**Total NPV of Steam Generation Costs ($/1000 lbs) based upon Electric Revenue Offset**	See Economic Model for details		
1.	Revenue from Energy			
2.	Revenue from Capacity Payment[8]			
3.	Total Revenue from Electricity			
4.	Cost Attributed to Steam			
5.	**Steam Generation Cost W/O Emission Credits**			
6	Emission Credits on Annual Costs[7]			
a.	Nox			
b.	SO_2			
c.	PM_{10}			
d.	PM			
e.	VOC			
f.	CO			
g.	Total Credits			
7.	Cost Attributed to Steam with Emission Credits			
8.	**Steam Gen Cost with Emission Credits**			

Exhibit 4-47 (cont'd) 59th Street Station Evaluation Screening Model Performance Data

CONCEPTUAL DATA FOR RELATIVE COMPARISION ONLY(1)

A. Combined Gas & Oil Firing - Steam Send Out Based Upon Projected Demand, Gas

ITEM	DESCRIPTION	Current Operation	RE-POWERING OPTIONS Cogeneration Options	
			Option - CG1	Option - CG2
A.	Option Description	Based on 2005 Oil / Gas Fired Operation	Cogen Plant with GE LM 6000 Gas Turbine	Cogen Plant with Siemens GTX 100 Gas Turbine
J.	Annual Emmissions (TPY)(7)	[ALL DATA REDACTED]		
1.	NOx			
2.	SO_2			
3.	PM_{10}			
4.	PM			
5.	VOC			
6.	CO			
K.	Site Specific Constraints			
1.	Layout Constraints	Although there are site specific constraints, both options considered in the screening model can be fitted in the existing site with different level of difficulties.		
2.	Stack Draft Issues	Not an issue at this site for the Options included in this analysis		

Notes

1. The costs and performance data presented herein are based on conceptual level studies. All costs are total NPV based on costs in years 2006 through 2025. All performances are at 59F/60% RH Ambient & Sea Level (ISO) operation and include applicable degrada
2. [REDACTED]
3. All performances except for the Current Operation are based upon natural gas & Low Sulfur fuel. The plant will be designed for dual fuel firing (natural gas and low sulfur No#2 oil) for all new Options. Supplemental Firing in HRSGs to 1500F max flue gas temp.
4. This includes AFDUC & Owner's supervis on costs, developmental fees, O&M Training.
5. These are for existing boilers only. Currently the existing boilers run on 58% Oil & 42% on gas. After cogen system implementation, the existing boilers will run on oil only.
6. Deleted
7. Emissions are Based upon AP - 42 Data. The current emission reflects the existing emission control systems in place and uses the weighted average emission from gas & oil firing. All new technologies include required emission controls.
8. This is based upon the weighted average of the net output during various modes of Operation.
9 - 13. Deleted
14. For CG Options, this includes partial SF.
15. Deleted
16. This includes O&M Costs of the existing facility for 6 years until the new system is in place and also the maintenance cost of the remainder of the existing facility for the remaining 14 years
17. This includes 2% blowdown requirements for all HRSGs/ Boilers and also the water injection in gas turbine during oil firing case.
18. Oil firing applicable for Gas Turbines and Boilers only. Supplemental firing in HRSG is by Gas only.

Exhibit 4-48 Conceptual Layout of 59th Street Station Cogeneration Option

[REDACTED]

4.2.2.3 Projected Cost of Operation

The cost of steam production was evaluated for the existing system and potential repowering options identified by WorleyParsons for the 59th Street Station over the 20 year study period. WorleyParsons estimated the total plant capital costs, total annual production costs, the total annual production costs per thousand pounds of annual steam sendout for each of the options for each of the years from 2006 to 2025. WorleyParsons also calculated the NPV of the total annual production costs, and a Figure of Merit for comparison of the operations defined by the net present value of the total annual costs divided by a discounted annual steam sendout (export), as described in the economic criteria for the study in Section 3.3.

The projected costs of operation for the existing system and options evaluated for the 59th Street Station are summarized in Exhibit 4-49 through Exhibit 4-55. These data are based on the CERA 2005 Rearview Mirror fuel and electricity price scenario. The following information is provided in each of the Exhibits:

- Exhibit 4-49 - NPV of the total plant cost for each option over 20 year study period.
- Exhibit 4-50 - NPV of total annual costs, including the contributions of capital, fixed O&M, variable fuel, and non-fuel variable costs; taxes, and tax credits over 20 year study period.
- Exhibit 4-51 – NPV of cost of steam production including the impact of electric energy and capacity revenues (credits) and NYISO Tariff (blackstart revenue), but not including emission reduction credits, over 20 year study period.
- Exhibit 4-52 – NPV of cost of steam production including emission reduction and other credits over 20 year study period.
- Exhibit 4-53 – Unit NPV of cost of steam production (NPV of cost of production divided by discounted steam sendout over 20 year study period, excluding emission reduction credits.
- Exhibit 4-54 - Unit NPV of cost of steam production, including emission reduction credits.
- Exhibit 4-55 – Breakdown of the NPV costs over the 20 year study period by cost category.

Summaries of the estimated capital and operating costs and credits by year in current year dollars are provided for each option in the Appendix A. The summaries include the NPV of total plant cost, annual operating costs, and total annual costs and cumulative NPV of total annual costs by year.

As can be seen in Exhibit 4-52 and Exhibit 4-54, the NPV and Unit NPV of the estimated cost of steam production for the existing system over the study period from 2006 to 2025 are significantly less ([REDACTED) for the existing system than for either of the cogeneration options evaluated.

Exhibit 4-49 NPV of Total Plant Cost for 59th Street Repowering Options from 2006 to 2025

[REDACTED]

Exhibit 4-50 NPV of Total Annual Costs Excluding Credits for 59 Street Repowering Options from 2006 to 2025 Based on CERA 2005 Rearview Mirror Price Projections

[REDACTED]

Exhibit 4-51 NPV of Cost of Steam Production Excluding Emission Reduction Credits for 59th Street Repowering Options 2006 to 2025 Based on CERA 2005 Rearview Mirror Price Projections

[REDACTED]

Exhibit 4-52 NPV of Cost of Steam Production Including All Credits for 59th Street Repowering Options 2006 to 2025 Based on CERA 2005 Rearview Mirror Price Projections

[REDACTED]

Exhibit 4-53 Unit NPV of Cost of Steam Production Excluding Emission Credits for 59th Street Repowering Options 2006 to 2025 Based on CERA 2005 Rearview Mirror Price Projections

[REDACTED]

Exhibit 4-54 Unit NPV of Cost of Steam Production Including All Credits for 59th Street Repowering Options 2006 to 2025 Based on CERA 2005 Rearview Mirror Price Projections

[REDACTED]

Exhibit 4-55 Summary of Breakdown of NPV of Cost of Steam Production for 59th Street Options by Cost Category

Option Sheet Number ->			1	2
STEAM GENERATION AND RE-POWERING OPTIONS				
	59th Street		Cogeneration Options	
ITEM	DESCRIPTION	Base	CG1	CG2
A.	Option Description	Based on 2005 Oil / Gas Fired Operation	Cogen Plant with GE LM 6000 Gas Turbine	Cogen Plant with Siemens GTX 100 Gas Turbine
		NPV	NPV	NPV
C	Total 20 Year Steam Send Out, MMlb			
E	Total 20 Year Net Elec Generation			
G.	Total NPV of Plant Cost - US Dollars			
1.	Existing Plant Maintenance Cost			
2.	EPC Cost			
a.	Cogen / CC Unit and accessories			
b.	HP and LP Boiler Plant			
c.	Demin Plant			
d.	Other BOP			
3.	Demolition /Relocation/ Remediation Costs			
a.	Demolition Costs - loaded			
b.	Relocation Cos			
c.	Remediation Costs			
4.	Permitting/Prelim Engineering			
5.	Gas Piping Interconnect Costs - loaded			
6.	Electrical Reinforcement/Interconnect Costs - loaded			
7.	Contingency			
8.	Owner's other Costs(4)			
	Capitalized Property Tax During Construction			
9.	Total Plant Cost (TPC)			
H.	Total NPV of Annual Costs			
1.	Fuel Cost			
2	Fixed Charges on TPC (Debt Services)			
3.	Water & Chemical Costs			
4.	Electricity Purchase Cost			
5.	O&M Costs of existing plant(16)			
6.	Non Fuel O&M Costs			
7	Property Tax			
8.	ICIP Credit			
9.	Total Annual Cost			
I.	Steam Generation Costs based upon Electric Revenue	[ALL DATA REDACTED]		
1.	Revenue from Energy			
2.	Revenue from Capacity Payment(8)			
3.	NY ISO Black Start and System Restoration Tariff			
4	Total Revenue from Electricity			
5a	Cost Attributed to Steam w/o Emission Credits - NPV			
6d	Cost of Steam w/o Emission Credits ($/1000lb) - NPV			
8	Emission Credits on Annual Costs(7)			
a.	NOx			
b.	SO2			
c.	PM10			
d.	VOC			
e.	Total Credits			
9a	Cost Attributed to Steam with Emission Credits - NPV			
10d	Cost of Steam with Emission Credits ($/1000lb) - NPV			
J.	Total 20 Year Emissions (tons/20 years)			
1.	NOx			
2.	SO2			
3.	PM10			
4.	PM			
5.	VOC			
6.	CO			
J.	Total Annual Emissions (tons/yr)			
1.	NOx			
2.	SO2			
3.	PM10			
4.	PM			
5.	VOC			
6.	CO			

O refer to notes on InputFromScreeningModel sheet

4.2.2.4 Fuel and Electricity Price Sensitivity Analysis

WorleyParsons evaluated the existing system and the repowering options for 59th Street Station initially using CERA 2005 Rearview Mirror price projections, as was shown in Exhibit 4-49 through Exhibit 4-54. Subsequently, the options were evaluated using the CERA 2005 Shades of Green price projections. The major difference in prices between the two scenarios is that the fuel and electric energy prices beyond the year 2010 are significantly higher in the Shades of Green Scenario than in the Rearview Mirror. The Shades of Green Scenario prices are [REDACTED] than the Rearview Mirror scenario prices beyond 2010.

The Unit NPV of cost of steam production for the options using the Shades of Green Scenario are shown in Exhibit 4-56. The difference in the estimated Unit NPV of cost of steam production for the options between the Rearview Mirror scenario and Shades of Green scenario is only [REDACTED].

Exhibit 4-56 NPV of Cost of Steam Production for 59th Street Options Based on CERA 2005 Shades of Green Fuel and Electricity Price Scenario

[REDACTED]

4.2.2.5 Environmental and Other Permitting Requirements

The expected emissions from the repowering options are presented in Exhibit 4-57 in comparison with the applicable NSPS, NESHAP, and PSD/NSR requirements. The expected emissions are based on the projected annual steam sendout for 59th Street Station provided by Con Edison for the study. The emission control equipment and their expected efficiencies for the new turbine options that were used to adjust the expected emissions are shown in Exhibit 4-58. The NSPS and NESHAP requirements are on a lb emission/MMBtu of fuel input basis. The PSD/NSR limits, the annual emissions that would trigger PSD/NSR, are on a tons per year basis and combine the existing average annual emissions from the 59th Street Station contained in the 2003 and 2004 Emission Statements (based on CEMS, stack testing, and AP-42 emission factors) and the significant net emission rates presented in Exhibit 3-5.

For the 59th Street Station options, at a minimum the cogeneration options will have to meet NSPS and NESHAP. The potential annual emissions for each cogeneration option are based on the new natural gas fired turbine or boiler operating at 100 percent capacity factor for 8040 hours per year with the new turbine or boiler operating on No. 2 oil for 720 hours per year (30-days per year). For the options, PSD/NSR permitting is based on comparing the future potential to emit (PTE) emissions from the option versus past actual emissions from existing sources being retired. As shown in the Exhibit 4-57, it appears that no annual emission increase would exceed PSD/NSR regulatory requirements for all cogeneration options.

Summary charts comparing the expected emissions from the repowering options and the emissions that would be expected from the existing boilers at the 59th Street Station with the annual steam sendout projection used in the study are shown in Exhibit 4-59 through Exhibit 4-64. The representative emissions factors used for the existing boilers were five-year averages based on the emissions in the 2000 through 2004 Emission Statements for the Station.

WorleyParsons reviewed the maintenance capital projections by Con Edison for future boiler repairs/maintenance. These data appear to be less than half of what would be expected for replacement boilers. Therefore, based on this information and WorleyParsons' understanding of current environmental regulations, it is WorleyParsons opinion that NSPS would not be triggered requiring conversion of the existing boilers at the 59th Street Station to natural gas. Therefore, the cost of such conversion was not included in the estimated steam production cost for continued use of the existing boilers.

Exhibit 4-57 Emission Requirements and Expected Emissions For 59th Street Station Steam Production Options

		CO				SO2				PM10				PM				NOx /2/				VOC /3/			
		Lbs/MMBtu		Tons/Year /5/		Lbs/MMBtu		Tons/Year		Lbs/MMBtu		Tons/Year /5/		Lbs/MMBtu		Tons/Year		Lbs/MMBtu		Tons/Year		Lbs/MMBtu		Tons/Year	
		Limit	Expected /1/	Limit	Potential	Limit	Expected	Limit	Potential	Limit	Expected	Limit	Potential	Limit	Expected	Limit	Potential	Limit	Expected	Limit	Potential	Limit	Expected	Limit	Potential
Option - CG1	Cogen - NG																								
	Cogen - Oil																								
	Total																								
Option - CG2	Cogen - NG																								
	Cogen - Oil																								
	Total																								

[ALL DATA REDACTED]

Cogeneration Options with Supp Fired HRSGs
Option - CG1 Cogen Plant with GE LM 6000 Combustion Turbine
Option - CG2 Cogen Plant with Siemens GTX 100 Combustion Turbine

Emission comparison based on current actual emissions to future potential emissions (i.e., 8,760 hours/year at 100% capacity factor) and AP-42 emission factors.
Tons/Year Limit includes Significant Net Emission Increase requirement added to the 2003 and 2004 59th Street Station Emission Statement values.
These are for existing boilers only. Currently the existing boilers run on 58% Oil & 42% on gas. After cogen system implementation, the existing boilers will run on oil only.
Emissions are Based upon AP-42 Data. The current emission reflects the existing emission control systems in place and uses the weighted average emission from gas & oil firing. All new technologies include required emission controls.

/1/ Expected emission based on oxidation catalysts: 80% reduction firing natural gas and 80% reduction firing No. 2 oil.
/2/ Expected emission based on selective catalytic reduction: 90% reduction firing natural gas and 70% reduction firing No. 2 oil.
/3/ Expected emission based on oxidation catalysts: 50% reduction firing natural gas and no reduction firing No. 2 oil.
/4/ Based on NSPS limit of 15 ppmvd corrected to 15% oxygen firing natural gas and 42 ppmvd corrected to 15% oxygen firing distillate oil.
/5/ Combustion turbines will need to meet a formaldehyde emission of 91 ppbvd at 15% oxygen (CT MACT).

Exhibit 4-58 Efficiencies of Emission Controls Technologies Used in 59th Street Station Repowering Options

Control Technology	Natural Gas-Fired	No. 2 Oil-Fired
Turbine		
SCR	90%	90%
Oxidation Catalyst - CO	80%	80%
Oxidation Catalyst - VOC	50%	50%

Exhibit 4-59 Expected Annual NOx Emission from 59th Street Station Repowering Options

[REDACTED]

Exhibit 4-60 Expected Annual SO_2 Emission from 59th Street Station Repowering Options

[REDACTED]

Exhibit 4-61 Expected Annual PM10 Emission from 59th Street Station Repowering Options

[REDACTED]

Exhibit 4-62 Expected Annual PM Emission from 59th Street Station Repowering Options

[REDACTED]

Exhibit 4-63 Expected Annual VOC Emission from 59th Street Station Repowering Options

[REDACTED]

Exhibit 4-64 Expected Annual CO Emission from 59th Street Station Repowering Options

[REDACTED]

4.2.2.6 Rationale for Options Rejected / Selected as Promising Options

The cogeneration option was rejected primarily because the NPV of the 20 year costs, including credit for revenue from electric energy sales, is higher than the NPV of the costs to continue operation of the existing system. WorleyParsons recommends that the existing system be maintained and operated over the next twenty years as compared to repowering with a cogeneration system.

4.2.3 74th Street Stations

4.2.3.1 Re-Powering Options Considered

The major site specific issues at the 74th Street Station that were considered in determining options to be considered are as follows:

- The site has limited available space for addition of new equipment.
- Currently there is no gas supply available at the station.
- The existing stack has a draft problem and severely restricts the operation of the Boilers while the existing gas turbines are operating.
- There is no space other than the roof to locate any Air Cooled Condenser (ACC) /Dump Condenser (DC) required for the CC plant or a cogen plant.

- The roof needs to be modified and reinforced to locate any ACC / DC. Being located in the heart of the city, the site may have problems related to aesthetics and noise issues associated with addition of such equipment on the power house building roof.
- Available head room below the existing crane rail is only 43'. This poses a challenge to the installation of any HRSG associated with medium or large gas turbine (similar to other plants) without custom design and /or major modifications to the building and roof structures.
- Delivery of large pieces of equipment would likely require the temporary closing of the FDR Drive. Also, temporary closings off the Eastern end of 74th and/or 75th Streets would likely be needed

Due to the site specific constraints (stack draft issue, no gas supply, limited head room, major building/structure modification requirements) as noted earlier, and also based upon the results of the analysis done on other sites, WorleyParsons considers that a Re-powering option with gas turbine will not reduce the steam generation cost. Also, the condition of existing boilers are in good shape and are expected to provide reliable future operation with the current planned upgrades & maintenance program; therefore, WorleyParsons considers that continued operation of the existing steam generation facilities at the plant will result in a lower cost of steam production than repowering with new boilers or cogeneration systems.

4.2.3.2 Conceptual Description of Re-Powered Facilities

In WorleyParsons opinion, there does not appear to be a viable repowering option for this facility. The operating parameters for the current plant upon which the estimate of the projected cost of operation is based are shown on Exhibit 4-65.

4.2.3.3 Projected Cost of Operation

The cost of steam production was evaluated for the existing system at the 74th Street Station over the 20 year study period based on estimates of the maintenance capital requirements and operating and maintenance costs. WorleyParsons estimated the total plant capital costs, total annual production costs, the total annual production costs per thousand pounds of annual steam sendout for each of the options for each of the years from 2006 to 2025. WorleyParsons also calculated the NPV of the total annual production costs, and the net present value of the total annual costs divided by a discounted annual steam sendout (export), as described in the economic criteria for the study in Section 3.3.

The projected cost of operation for the existing system at the 74th Street Station is summarized in These data are based on the CERA Rearview Mirror fuel and electricity price scenario. The following information is provided in each of the Exhibits:

- NPV of the total plant cost for each option over 20 year study period.
- NPV of total annual costs, including the contributions of capital, fixed O&M, variable fuel, and non-fuel variable costs; taxes, and tax credits over 20 year study period.

- NPV of cost of steam production including the impact of electric energy and capacity revenues (credits) and NYISO Tariff (blackstart revenue), but not including emission reduction credits, over 20 year study period.
- NPV of cost of steam production including emission reduction and other credits over 20 year study period.
- Unit NPV cost of steam production (NPV of cost of production divided by discounted steam sendout over 20 year study period, excluding emission reduction credits.
- Unit NPV cost of steam production (NPV of cost of production divided by discounted steam sendout over 20 year study period, including emission reduction credits.
- Breakdown of the NPV costs over the 20 year study period by cost category.

A summary of the estimated capital and operating costs and credits by year in current year dollars are provided in the Appendix A. The summary includes the NPV of total plant cost, annual operating costs, and total annual costs and cumulative NPV of total annual costs by year.

4.2.3.4 Environmental and Other Permitting Requirements

WorleyParsons does not envision any new environmental regulations in the foreseeable future that would require major modifications to the facility.

Exhibit 4-65 Operating Parameters for 74th Street Station Evaluation

CONCEPTUAL DATA FOR RELATIVE COMPARISION ONLY[1]

A. Steam Send Out Based Upon Projected Demand

ITEM	DESCRIPTION	Current Operation
A.	**Option Description**	**Based on 2005 Oil / Gas Fired Operation**
B.	**New Configuration Description**	
1.	Number of Gas turbines/HRSGs	N.A.
2.	Number of Steam Turbine	N.A.
3.	Number of new HP Boilers	
4.	Capacity of HP Boiler, Mlb/hr	
5.	Number of New LP Boilers	N.A.
6.	New LP Boiler Capacity each, Mlb/hr[9]	N.A.
C.	**Net Steam Generation[2]**	
1.	Design Capacity Reqmnt, Mlb/hr	1,960
2.	Annual Average Send Out, MMlb	[REDACTED]
3.	Annual Avg Hourly Send out, Mlb/hr	[REDACTED]
4.	Cogen Plant Steam Export Capacity, Mlb/hr	
a.	With SF in HRSGs	
b.	No SF in HRSGs	
5.	Net Boiler Send Out Capacity, Mlb/hr[5]	1,960
6.	Average Annual Send out, Mlb/hr	
a.	Cogen Plant in partial firing [14]	
b.	No SF in HRSGs	
7.	Annual Stm Production Capability, MMlb	
a.	With Suppl Firing in HRSGs	
b.	Without Suppl Firing in HRSGs	
D.	**Cogen/CC/Boiler Plant operation and Annual Steam Generation Profile.**	
1.	Gas Turbine[15] Operating hours	N.A.
2.	Operating Hours- HRSG with full SF	
3.	Oper Hours - HRSG for part SF mode[14]	
4.	HRSG - Oper Hours no Supp Firing	
5.	Cogen Plant	
a.	Export Steam with full SF, MMlb	
b.	Export Steam with Partial SF /Int Exp, MMlb	
c.	Export Steam W/O Supp Firing, MMlb	
6.	Steam from Existing Boilers, MMlb[3]	
7.	**Total Annual Steam Check, MMlb**	
E.	**Electrical Output[3], kW**	
1.	Gas Turbine	Not Applicable
2.	Cogen Net Output - ISO	
F.	**Annual Fuel (MMBtu - HHV), Electricity (MWh) Consumption and Electricity Generation(MWh)**	
1.	Gas Turbine Fuel	
2.	HRSG Fuel for Full Supp Firing	
3.	HRSG Fuel for Partial SF	
4.	Boiler Fuel[6]	[REDACTED]
5.	Total Fuel Consumption	[REDACTED]
6.	Net Elec Generation - Power Plants[9]	
G.	**Total NPV of Plant Cost - US Dollars**	**See Economic Model for Details**
1.	Existing Plant Maintenance Cost	
2.	EPC Cost	
a.	Cogen / CC Unit and accessories	
b.	Boiler Plant	
c.	Demin Plant	
d.	Other BOP	
3.	Demolition /Relocation/ Remediation Costs	
a.	Demolition Costs	
b.	Relocation Costs	
c.	Remediation Costs	
4.	Permitting/Prelim Engineering	
5.	Gas Piping Interconnect Costs	
6.	Elctrical Reinforcement/Interconnect Costs	
7.	Contingency	
8.	Owner's other Costs[4]	
9.	**Total Plant Cost (TPC)**	

Exhibit 4-65 (cont'd) Operating Parameters for 74th Street Station Evaluation

CONCEPTUAL DATA FOR RELATIVE COMPARISION ONLY(1)

A. Steam Send Out Based Upon Projected Demand

ITEM	DESCRIPTION	Current Operation
A.	Option Description	Based on 2005 Oil / Gas Fired Operation
H.	Total NPV of Annual Costs	See Economic Model for Details
1.	Fuel Cost	
2.	Fixed Charges on TPC (Debt Services)	
3.	Water & Chemical Costs	
4.	Electricity Purchase Cost	
5.	O&M Costs of existing plant(15)	
6.	Non Fuel O&M Costs	
7.	Property Taxes & ICICP	
8.	ICICP Credit	
9.	Total Annual Cost	
I.	Total NPV of Steam Generation Costs ($/1000 lbs) based upon Electric Revenue Offset	See Economic Model for Details
1.	Revenue from Energy	
2.	Revenue from Capacity Payment(3)	
3.	Total Revenue from Electricity	
4.	Cost Attributed to Steam	
5.	Steam Generation Cost W/O Emission Credits	
6	Emission Credits on Annual Costs(7)	
a.	Nox	
b.	SO_2	
c.	PM_{10}	
d.	PM	
e.	VOC	
f.	CO	
g.	Total Credits	
7.	Cost Attributed to Steam with Emission Credits	
8.	Steam Gen Cost with Emission Credits	
J.	Annual Emmissions (TPY)(7)	
1.	NOx	
2.	SO_2	
3.	PM_{10}	[REDACTED]
4.	PM	
5.	VOC	
6.	CO	
K.	Site Specific Constraints	
1.	Layout Constraints	Yes
2.	Stack Draft Issues	Yes

Notes

1. The costs and performance data presented herein are based on conceptual level studies. All costs are total NPV based on costs in years 2006 through 2025. All performances are at 59F/60% RH Ambient & Sea Level (ISO) operation and include applicable degrada
2. Deleted
3. Deleted
4. Deleted
5. Deleted
6. Deleted
7. The current emission reflects the existing emission control systems in place and uses the average emission factors from 2000-2004 Data
8. Deleted

9 - 13 Deleted

14. Deleted
15. Deleted
16. Deleted

Legends

CG: Cogeneration
CC: Combined Cycle
HP: High Pressure
LP: Low Pressure
SF: Supplemental Firing

Exhibit 4-66 NPV of Total Plant Cost for 74th Street Station from 2006 to 2025

[REDACTED]

Exhibit 4-67 NPV of Total Annual Costs for 74th Street Station from 2006 to 2025 Based on CERA 2005 Rearview Mirror Price Projections

[REDACTED]

Exhibit 4-68 NPV of Cost of Steam Production for 74th Street Station 2006 to 2025 Based on CERA 2005 Rearview Mirror Price Projections

[REDACTED]

Exhibit 4-69 Unit NPV of Cost of Steam Production for 74th Street Station 2006 to 2025 Based on CERA 2005 Rearview Mirror Price Projections

[REDACTED]

Exhibit 4-70 Summary of Breakdown of NPV of Cost of Steam Production for 74th Street Station by Cost Category

74th Street		
ITEM	DESCRIPTION	Base
A.	Option Description	Based on 2005 Operation on Oil NPV
C E	[REDACTED]	
G.	**Total NPV of Plant Cost - US Dollars**	[ALL DATA REDACTED]
1.	Existing Plant Maintenance Cost	
2.	EPC Cost	
a.	Cogen / CC Unit and accessories	
b.	HP and LP Boiler Plant	
c.	Demin Plant	
d.	Other BOP	
3.	Demolition /Relocation/ Remediation Costs	
a.	Demolition Costs - loaded	
b.	Relocation Cos	
c.	Remediation Costs	
4.	Permitting/Prelim Engineering	
5.	Gas Piping Interconnect Costs - loaded	
6.	Electrical Reinforcement/Interconnect Costs - loaded	
7.	Contingency	
8.	Owner's other Costs(4)	
	Capitalized Property Tax During Construction	
9.	**Total Plant Cost (TPC)**	
H.	**Total NPV of Annual Costs**	
1.	Fuel Cost	
2	Fixed Charges on TPC (Debt Services)	
3.	Water & Chemical Costs	
4.	Electricity Purchase Cost	
5.	O&M Costs of existing plant(16)	
6.	Non Fuel O&M Costs	
7	Property Tax	
8.	ICIP Credit	
9.	**Total Annual Cost**	

74th street		
ITEM	DESCRIPTION	Base
A.	Option Description	Based on 2005 Operation on Oil NPV
I.	**Steam Generation Costs based upon Electric Revenue Offset - NPV**	[ALL DATA REDACTED]
1.	Revenue from Energy	
2.	Revenue from Capacity Payment(8)	
3.	NY ISO Black Start and System Restoration Tariff	
4	Total Revenue from Electricity	
5a	**Cost Attributed to Steam w/o Emission Credits - NPV ($)**	
6d	**Cost of Steam w/o Emission Credits ($/1000lb) - NPV**	
8	Emission Credits on Annual Costs(7)	
a.	NOx	
b.	SO2	
c.	PM10	
d.	VOC	
e.	Total Credits	
9a	**Cost Attributed to Steam with Emission Credits - NPV ($)**	
10d	**Cost of Steam with Emission Credits ($/1000lb) - NPV**	
J.	**Total 20 Year Emissions (tons/20 years)**	
1.	NOx	
2.	SO2	
3.	PM10	
4.	PM	
5.	VOC	
6.	CO	
J.	**Total Annual Emissions (tons/yr)**	
1.	NOx	
2.	SO2	
3.	PM10	
4.	PM	
5.	VOC	
6.	CO	

(0 refer to notes on InputFromScreeningModel sheet

5.0 ASSESSMENT OF ALTERNATIVE STEAM SUPPLIES

WorleyParsons Scope of Work included the assessment of alternative steam supply from three facilities; namely, KeySpan Ravenswood, LLC Ravenswood Unit 40 combined cycle power generating plant, Brooklyn Navy Yard Cogeneration Partners' (BNYCP) cogeneration facility, and TransGas Energy's (TGE) proposed combined cycle power generating plant. WorleyParsons initially sent an Alternative Facilities Data/Information Request (DIR) document to the owner's of the facilities and then followed up with visits to the facilities and discussions with the owner's. A copy of the Alternative Facilities DIR is included in Appendix C. The following sections summarize the activities and results of the assessment.

5.1 KEYSPAN RAVENSWOOD, LLC

KeySpan Ravenswood, LLC (KeySpan) responded to WorleyParsons' request for information with a completed spreadsheet with the technical data requested by WorleyParsons and a Term Sheet with a non-binding indicative offer for steam capacity and energy sales to Con Edison. A copy of the technical data spreadsheet and Term sheet are included in Appendix E. WorleyParsons had a follow-up meeting with KeySpan in New York City to discuss the information provided and request additional information, including clarification of the emissions from the combined cycle plant and system operations. As a result of the meeting, KeySpan provided additional emissions data, as shown in Appendix E.

One of the conditions of KeySpan's indicative price offer contained in the Term Sheet was that [REDACTED].

WorleyParsons requested a revised indicative price offer from KeySpan with whatever charges to Con Edison would be required to satisfy the full Con Edison dispatch control criteria in the alternative steam supplier operating and technical (O&T) requirements for the study as provided by Con Edison (included in Appendix D). The O&T requirements include a condition that Con Edison will have full steam dispatch control between zero and maximum steam offered, and Con Edison will not guarantee a minimum steam dispatch. KeySpan responded with indicative price offers for two additional options that meet the full dispatch criteria: [REDACTED]

. Copies of the Term Sheets with indicative price and conditions are included in the Appendix E.

All of the indicative price offers contained a cost of energy and a capacity charge schedule by year. The offers provided formulas for determining the energy price as a

function of steam sendout, fuel consumption, fuel price, steam variable operating and maintenance (VOM) cost, electric power generation, and electric VOM cost. The indicative price in the steam only option was also dependent on hourly Vernon Switchyard NYISO LBMP.

Based on the indicative price offers provided by KeySpan and an hourly steam dispatch profile provided by Con Edison, WorleyParsons estimated the cost of KeySpan supplied steam to Con Edison over 20 years for each option. The steam dispatch profile was the same as that used for the Con Edison Ravenswood Steam Generating Station evaluation. WorleyParsons also estimated the impact of KeySpan's Unit 40 supplying steam to Con Edison on City-wide (NYISO Zone J) emissions. The emissions analysis accounts for the changes in emissions from KeySpan's Unit 40 resulting from providing steam to Con Edison, and the change in emissions from an electric power generating station in Zone J that would make up for the electric energy displaced by KeySpan Unit 40 to produce steam for Con Edison. Additionally, since the interconnection proposed for the KeySpan steam supply with the Con Edison steam network is the Ravenswood Steam Generating Station head house, it is assumed that the Ravenswood Steam Generating Station would be retired upon availability of steam from the KeySpan Unit 40; therefore, the City-wide emissions impact evaluation accounted for the reduction in emissions resulting from the retirement of Con Edison's Ravenswood Steam Generating Station.

The following sections present results of activities that were performed with respect to the KeySpan steam supply option.

5.1.1 Review of Investment Grade Studies Provided By Owner

KeySpan did not provide any investment grade studies. KeySpan did provide preliminary performance information and Term Sheets with indicative price offers.

5.1.2 Description of Plant Systems

KeySpan proposes to supply steam to the Con Edison system from KeySpan's Unit 40 combined cycle power generation system. The existing system consists of a GE7FA combustion turbine/generator (CT/G), HRSG, and condensing steam turbine/generator (ST/G). The system is equipped with selective catalytic reduction NOx emissions control and catalytic CO emission control. The Unit utilizes an air-cooled steam condenser. The HRSG does not currently have supplemental firing capability. The Unit's current net electric power generation capacity is about 249 MWe at full load at ISO conditions when using natural gas as the fuel. About 173 MWe is produced by the combustion turbine, about 84 MWe from the steam turbine, and the auxiliary power requirements total about 8 MWe. The facility has 30-day interruptible natural gas supply, and has No. 1 oil (kerosene) storage as a back-up for natural gas supply interruption. The facility is permitted to operate on oil for up to 30 days per year.

KeySpan proposes to modify the facility with the equipment/systems necessary to provide a peak winter steam sendout to Con Edison of [REDACTED]r and peak summer sendout of [REDACTED]. The modifications proposed by KeySpan include the following:

- Addition of supplemental firing capability in the HRSG – [REDACTED].

- Addition of reboilers to generate steam for Con Edison using the steam generated by the HRSG as the heat source.
- Addition of water treatment required to treat the city water that KeySpan would use as the water source for generation of the steam for Con Edison.
- Addition of the piping and other components necessary to transport the steam from Unit 40 to the Ravenswood steam plant (A-House) headhouse and connect the steam piping to the Con Edison steam line at the headhouse.

Conceptual Piping and Instrument Diagrams (P&IDs) of the proposed system and a conceptual heat balance diagram of the reboiler system at maximum export steam condition provided by KeySpan are shown in Appendix E. Conceptual layouts of the facility showing the proposed location for the reboilers and supporting equipment provided by KeySpan are also shown in Appendix E.

[REDACTED].

Exhibit 5-1 Proposed KeySpan System Estimated Performance Summary

Steam Sendout to Con Edison, lb/hr	**[REDACTED]**	**[REDACTED]**	**[REDACTED]**
CT/G Power Output, MWe	[REDACTED]	[REDACTED]	[REDACTED]
ST/G Power Output, MWe	[REDACTED]	[REDACTED]	[REDACTED]
Auxiliary Power Requirement, MWe	[REDACTED]	[REDACTED]	[REDACTED]
Net Power Output, MWe	[REDACTED]	[REDACTED]	[REDACTED]
Combined Cycle Heat Rate (LHV), Btu/kW-hr	[REDACTED]	[REDACTED]	[REDACTED]
HRSG Heat Rate, MMBtu/Mlb steam			[REDACTED]

5.1.3 Cost of Steam

As discussed previously, term sheets with indicative price offers were provided by KeySpan for three options:

- [REDACTED]
- [REDACTED]
- [REDACTED]

The term sheets contain formulas for estimating the energy price as a function of steam sendout, fuel consumption, fuel price, steam VOM cost, electric power generation, electric variable operating cost, and price of electricity. WorleyParsons utilized the price and system performance data provided by KeySpan to estimate the price that Con Edison would have to pay to KeySpan annually for steam for the years 2012 (the assumed start date of purchase of steam from KeySpan) through 2025 for each option. The 2012 start date was used for all Con Edison facility repowering options. In order to facilitate comparison of the KeySpan alternative options to other repowering options, WorleyParsons then evaluated the net steam cost for the KeySpan steam supply option including the following contributions:

- Price paid to KeySpan for steam
- Cost of steam production at the Ravenswood Steam Plant from 2006 through 2011 using the same steam dispatch profile as used for the evaluation of the price of steam from KeySpan
- Cost for piping modifications at 71st Street and 74th Street required to distribute a maximum of [REDACTED] lb/hr steam from KeySpan
- Cost for demolition of the Ravenswood Steam Plant after 2011.
- Revenue to Con Edison from sale of electric power generated by KeySpan Unit 40 for KeySpan indicative price options based on sale of electricity to the NYISO.

All costs were evaluated on an annual basis and net present value (NPV) of net costs over the 20-year study period.

Sections 5.1.3.1 and 5.1.3.2 summarize the results of the cost of steam evaluations for the two KeySpan alternative options [REDACTED]

. The basis and assumptions upon which the results are based are provided in Section 5.1.6.

5.1.3.1 [REDACTED] Option

In this option, Con Edison would purchase steam and all of the electric power generated by KeySpan Unit 40. Con Edison would pay for the fuel, a variable operating and maintenance charge for electric and steam, and a capacity charge to KeySpan. Additionally, Con Edison would be responsible for all Energy Management, including NYISO bidding and fuel supply. Although the Term Sheet for this option

provided by KeySpan includes the same condition as the [REDACTED] option concerning adjustment to be made to variable pricing during hours that electric LBMP is below variable electric generation costs, KeySpan informed WorleyParsons during follow-up discussions that the condition was inadvertently included in the Term Sheet for [REDACTED] option. Therefore, this condition was excluded in the evaluation of this option. The fuel price, electricity price, and economic factors (escalation, NPV discount rate, steam discount rate) used in this evaluation were consistent with those used for all the options in this study.

A summary of the estimated cost of steam production for the KeySpan steam and electric supply alternative resulting from WorleyParsons evaluation is presented in Exhibit 5-2 for the [REDACTED] option. The costs include the following:

- KeySpan charges for steam;
- Cost of steam production at Con Edison's Ravenswood Steam Plant for the period from 2006 through 2011 (including the cost of piping modifications at the 71st Street and 74th Street steam interconnections and cost of demolition of the Ravenswood Plant after 2011) until the KeySpan facility is ready to dispatch steam to Con Edison;
- Firm gas supply reinforcements; and
- Credit for the potential revenue from the sale of electricity to the NYISO by Con Edison.

Exhibit 5-2 Summary of Net Cost of Steam from KeySpan to Con Edison for Steam and 100% Electric Purchase Option Based on CERA 2005 Rearview Mirror Price Projections

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
KeySpan Steam Price Summary																				
Energy Charges, Current $																				
Capacity and Other Fixed Charges, Current $																				
Total Price of Steam, Current $																				
Annual Steam Sendout, Mlb																				
Total Price/Steam Sendout, Current $/Mlb																				
NPV of Total Steam Price, $																				
Discounted Steam Sendout, Mlb																				
NPV of Total Steam Price/Discounted Steam Sendout, $/Mlb																				
Firm Gas Reinforcements and Steam Piping Modifications																				
[REDACTED]										[ALL DATA REDACTED]										
Ravenswood Cost of Operation Summary																				
Annual Cost, Current $ (Note 1)																				
Steam Sendout, Mlb																				
Annual Cost/Steam Sendout, Mlb																				
Net Cost of Steam for KeySpan Alternative Summary																				
Total Annual Cost, Current $																				
Steam Sendout, Mlb																				
Total Annual Cost/Steam Sendout, $/Mlb																				
NPV of Total Annual Cost of Steam, $ (Note 3)																				
Discounted Steam Sendout, Mlb (Note 4)																				
NPV of Total Annual Cost of Steam/Steam Sendout, $/Mlb																				

Note 1: Assumes shutdown of Ravenswood boilers at the end of 2011 followed by demolition and remediation. After 2013, annual costs represent depreciation on remaining net plant value.
Note 2: Based on nominal discount factor of 0.0687
Note 3: Based on nominal discount factor of 0.0376

5.1.3.2 [REDACTED] Option

In this option, Con Edison would purchase [REDACTED]

. Con Edison would pay for the fuel, a variable operating and maintenance charge for electric and steam, and a capacity charge to KeySpan. Additionally, in any hour in which the electric VOM is greater than the LBMP, then Con Edison will pay the difference between the electric VOM and LBMP for the amount of electric power that Con Edison does not take.

A summary of the estimated cost of steam production for the KeySpan steam [REDACTED] alternative resulting from WorleyParsons evaluation is presented in Exhibit 5-3 for the [REDACTED] option. The evaluation includes:

- KeySpan charges for steam;
- Cost of steam production at Con Edison's Ravenswood Steam Plant for the period from 2006 through 2011 (including the cost of piping modifications at the 71st Street and 74th Street steam interconnections and cost of demolition of the Ravenswood Plant after 2011) until the KeySpan facility is ready to dispatch steam to Con Edison;
- Firm gas supply reinforcements; and
- [REDACTED]

5.1.3.3 Comparison of KeySpan Alternatives with Ravenswood Repowering Option

A comparison of the estimated cost of steam production associated with the [REDACTED] KeySpan Alternative options to the estimated cost of steam production from the Con Edison Ravenswood Steam Generating Station for the four boiler replacement option (Option NB-4 previously discussed) is presented in Exhibit 5-4. A direct comparison can be made because both alternatives have the capability of supplying up to [REDACTED] of steam to the Con Edison steam system, and both alternatives interconnect with the steam network from the Ravenswood Steam Generating Station headhouse. [REDACTED].

5.1.4 Delivery Terms

KeySpan would deliver steam meeting the steam condition and quality specifications provided in the DIR and operating and technical requirements as specified by Con Edison for the study for steam supply to the Con Edison steam network.

Exhibit 5-3 Summary of Net Cost of Steam from KeySpan to Con Edison for Steam and 70 MWe Purchase Option Based on CERA 2005 Rearview Mirror Price Projections

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
KeySpan Steam Price Summary																				
Energy Charges, Current $																				
Capacity and Other Fixed Charges, Current $																				
Cost Adjustment for Electric Revenue Lower Than Variable Electric Cost, $ (Note 1)																				
Total Price of Steam, Current $																				
Annual Steam Sendout, Mlb																				
Total Price/Steam Sendout, Current $/Mlb																				
NPV of Total Steam Price, $																				
Discounted Steam Sendout, Mlb																				
NPV of Total Steam Price/Discounted Steam Sendout, $/Mlb																				
Firm Gas Reinforcements and Steam Piping Modifications																				
[REDACTED]										[ALL DATA REDACTED]										
Ravenswood Cost of Operation Summary																				
Annual Cost, Current $ (Note 2)																				
Steam Sendout, Mlb																				
Annual Cost/Steam Sendout, Mlb																				
Net Cost of Steam for KeySpan Alternative Summary																				
Total Annual Cost, Current $																				
Steam Sendout, Mlb																				
Total Annual Cost/Steam Sendout, $/Mlb																				
NPV of Total Annual Cost of Steam, $ (Note 3)																				
Discounted Steam Sendout, Mlb (Note 4)																				
NPV of Total Annual Cost of Steam/Steam Sendout, $/Mlb																				

Note 1: Based on hourly comparison of revenue from sale of electricity with variable electric production cost
Note 2: Assumes shutdown of Ravenswood boilers at the end of 2011 followed by demolition and remediation. After 2013, annual costs represent depreciation on remaining net plant value.
Note 3: Based on nominal discount factor of 0.0687
Note 4: Based on nominal discount factor of 0.0376

Exhibit 5-4 Comparison of Unit NPV of Steam Production Cost for KeySpan Alternative Options with Ravenswood Steam Generating Station Repowering Options Based on CERA 2005 Rearview Mirror Price Projections

[REDACTED]

5.1.5 Maximum and Minimum Capacity, Turndown and Cycling Limitations (if any), availability, and Steam Conditions at Delivery Point.

The maximum steam sendout capacity proposed by KeySpan is [REDACTED] during the summer months and [REDACTED] during the winter months. The minimum steam sendout capability is zero. KeySpan estimates a system availability of [REDACTED] in the winter and [REDACTED] in the summer. The steam conditions at the point of delivery (Ravenswood Steam Plant (A-House) steam headhouse) are estimated to be [REDACTED] and [REDACTED].

5.1.6 Price Basis and Assumptions

The basis for the price evaluation was the indicative price offer Term Sheets provided to WorleyParsons by KeySpan. The rates provided were adjusted for inflation as discussed in Section 5.1.11. To evaluate the impact of the NYISO LBMP on the steam price, WorleyParsons estimated hourly electric energy prices based on the CERA 2005 Rearview Mirror Scenario monthly average on-peak and off-peak electric energy price projections and 2005 Ravenswood_4 LBMP hourly data obtained from the NYISO website.

To evaluate the impact of the LBMP on steam price for the [REDACTED] , for each hour of each year being evaluated, the estimated LBMP (electric energy price) was multiplied by the KeySpan electric power generation estimated based on the steam dispatch profile provided by Con Edison and the estimated performance characteristics of KeySpan Unit 40 to estimate the revenue from sale of electricity. This value was

then compared to the variable electric generation costs estimated based on the fuel consumption and electric VOM rates provided by KeySpan. In any hour for which the revenue was less than the variable electric generation costs, the positive difference was added to the estimated price of steam based on the energy rates, in accordance with the condition identified by KeySpan. The same approach was used to evaluate the impact of the LBMP on steam price for the [REDACTED].

The fuel price forecast used for the evaluation was the same as that used for the evaluation of other options in the study (CERA 2005 Rearview Mirror price projections). The CERA projected natural gas price is at the City gate. KeySpan provided WorleyParsons with an estimate of the transportation cost as a formula consisting of a demand charge and energy charge (refer to Item 5 in the information provided to WorleyParsons by KeySpan in the Appendix E). WorleyParsons estimated the cost of firm natural gas supply for the HRSG (it was assumed that the HRSG could not burn oil) based on rates provided to WorleyParsons by Con Edison.

As discussed previously, Con Edison provided an hourly steam dispatch profile for the evaluation. The load duration curve presented in Exhibit 5-5 was derived from the profile data. It should be noted that there are only [REDACTED] when the steam sendout is greater than [REDACTED]. Based on the performance characteristics provided by KeySpan, for steam sendouts at or under [REDACTED], no supplemental firing of the HRSG is required. For steam sendouts above [REDACTED], supplemental firing of the HRSG is required. Therefore, an increase in the number of hours of operation at steam sendouts above [REDACTED] could significantly impact the unit cost of steam relative to that estimated in this evaluation based on the steam dispatch schedule provided.

5.1.7 Value of Cogenerated Electric Products and Fuel Price.

The indicative price offer from KeySpan for the cogenerated electric and steam products is provided in the Appendix E. The fuel and electricity prices that WorleyParsons used for the evaluation were based on monthly price projections for years 2006 through 2020 provided by CERA. WorleyParsons extrapolated the CERA price projections to estimate prices for 2020 through 2025. The hourly electric energy prices used for evaluating the impact of LBMP on steam price were based on the CERA monthly price projections and hourly NYISO 2005 LBMP (Ravenswood_4).

Exhibit 5-5 Load Duration Curve Developed from Steam Dispatch Profile for KeySpan Evaluation

[REDACTED]

5.1.8 Interconnection Requirements

Steam supplied by the KeySpan Unit 40 plant would interconnect with the Con Edison steam system at Con Edison's Ravenswood Steam Plant headhouse. The maximum steam dispatch offered by KeySpan is [REDACTED]. It is WorleyParsons understanding based on discussions with Con Edison that the steam tunnel from the headhouse to the 71st Street interconnection can handle the [REDACTED] of steam flow; however, due to restrictions at the 71st Street interconnection, the maximum capacity at the interconnection is currently 860,000 lb/hr. It is WorleyParsons understanding based on discussions with Con Edison that reinforcement at the 71st Street interconnection and enhancements at 74th Street would be required to distribute the [REDACTED] of steam. Con Edison provided an estimated cost for the reinforcement and enhancement, and these costs to Con Edison were included in the KeySpan Option evaluation.

5.1.9 Assessment of Environmental Impacts of Steam Sale

WorleyParsons estimated the impact of the KeySpan steam supply alternative on annual air emissions City-wide (Zone J). The evaluation included the increase in emissions from the KeySpan Unit 40 associated with providing steam to Con Edison, and the increase in emissions from other electric power generators who would produce the power displaced by KeySpan Unit 40 when supplying steam to Con Edison, and the reduction in emissions associated with retirement of Con Edison's Ravenswood Steam Generation Station.

The approach that WorleyParsons took in selecting the alternative electric power generating facilities to produce the power displaced by KeySpan Unit 40 and evaluating the increase in emissions are as follows:

- A power generator stacking database provided by CERA that contained information on power generating units in Zone J by month for each year between 2006 and 2020 that included type of unit, type fuel, the dispatch and fuel cost, estimated NOx and SO_2 emissions on a lb/MMBtu basis, unit heat rate, capacity, and electric energy generated (MW-hrs) was used to select a unit for generation of the electric power displaced by the KeySpan Unit 40 supplying steam to Con Edison.
- CERA 2005 Rearview Mirror Scenario monthly fuel and electric energy price projections were used to determine the marginal heat rate for selecting the power generator.
- The emissions factors from the selected electric power generator in the CERA database were used when available and deemed reasonable; otherwise, emissions factors from the EPA AP-42 were used.

The type of power generators selected based on the above is as follows:

- During the summer, the power generating unit is a natural gas-fired steam boiler/turbine unit with average heat rate of about 9,360 Btu/kW-hr.
- During the winter, the power generated is from a combination of natural gas-fired combined cycle (NGCC) units and low-sulfur (0.3% sulfur), #6 fuel oil-fired (residual oil-fired) steam boiler/turbine units, with 50% of the energy being produced from each type system. The average heat rate used for the NGCC is about 7,100 Btu/kW-hr, and the average heat rate used for the residual oil-fired steam unit is about 9,400 Btu/kW-hr.

Estimated emissions for KeySpan Unit 40 when burning natural gas and oil were provided by KeySpan. The estimated emissions factors used in the evaluation for KeySpan Unit 40 and the electric power generators replacing displaced power are summarized in Exhibit 5-6. The estimated emissions used for the Ravenswood Steam Plant were those estimated by WorleyParsons for Ravenswood with four new natural gas-fired boilers with SCR and CO and VOC catalysts for emissions controls, based on the results of WorleyParsons evaluation of the Ravenswood Steam Plant performed in this study.

The steam dispatch profile used for the KeySpan (and Ravenswood Steam Plant) alternative was kept the same for all of the KeySpan offer options. Therefore, the impact on emissions of the KeySpan steam supply alternative is the same regardless of the option.

The estimated impact of the KeySpan alternative on City-wide emissions resulting from WorleyParsons' evaluation is summarized in the charts in Exhibit 5-7 and Exhibit 5-8. Exhibit 5-7 shows the overall estimated net impact and Exhibit 5-8 shows the contribution by entity to the overall impact.

Exhibit 5-6 Estimated Emissions Factors Used in the KeySpan Alternative Evaluation

	KeySpan Unit 40				Electric Power Generator					
	Natural Gas-Fired		Oil-Fired		Steam Unit				Combined Cycle	
	Duct Burner Off	Duct Burner On	Duct Burner Off	Duct Burner On	Natural Gas-Fired		Residual Oil-Fired		Natural Gas-Fired	
	lb/MMBtu	lb/MMBtu	lb/MMBtu	lb/MMBtu	lb/MMBtu	lb/MW-hr	lb/MMBtu	lb/MW-hr	lb/MMBtu	lb/MW-hr
NOx	[ALL DATA REDACTED]				0.1590	1.4882	0.1623	1.53	0.0150	0.1065
SO2					0.0006	0.0055	0.3140	2.95	0.0034	0.0241
VOC					0.0054	0.0505	0.0051	0.0476	0.0021	0.0149
CO					0.0824	0.7708	0.0333	0.3133	0.0150	0.1065
PM10					0.0075	0.0697	0.0278	0.2610	0.0066	0.0469

Exhibit 5-7 Estimated Net Impact on Air Emissions City-Wide of KeySpan Alternative

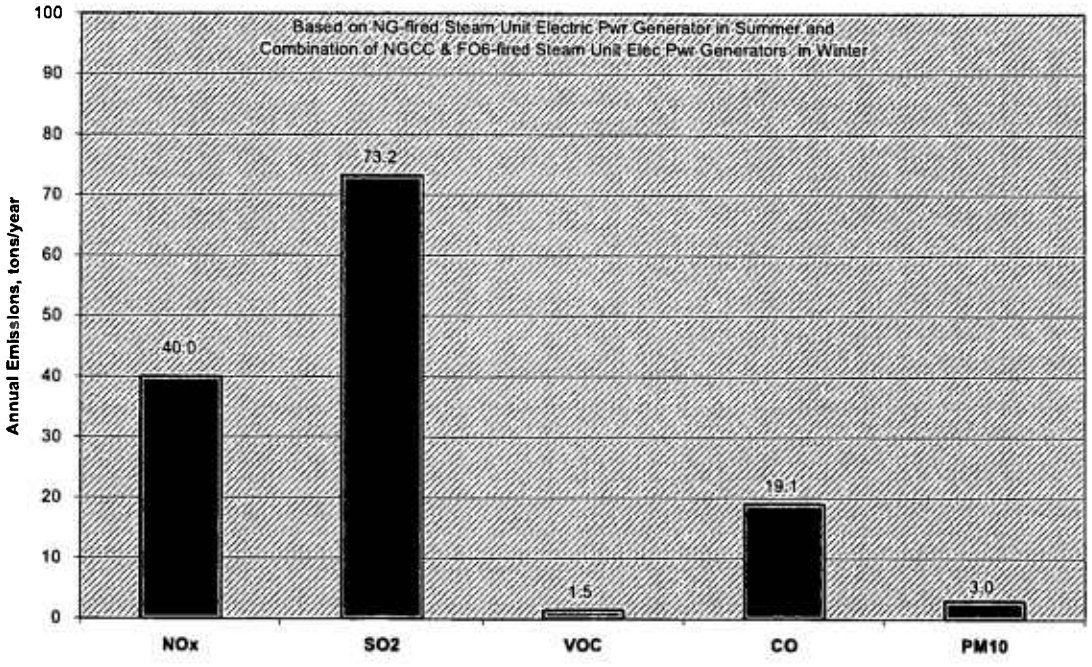


Exhibit 5-8 Contribution of Entities to Estimated Net Impact on Air Emissions of KeySpan Alternative

[REDACTED]

5.1.10 Estimated Date of Steam Delivery

WorleyParsons used an estimated date of delivery of steam by KeySpan Unit 40 to the Con Edison system of January 1, 2012, based on an allowance of 1 year beginning in 2008 for contract negotiation, one year for permitting activities, and up to 2 years for installation of new equipment required at KeySpan Unit 40 and Con Edison steam system reinforcements. This is also consistent with the start date of other options being evaluated as part of this study.

5.1.11 Adjustments to Owner-Supplied Information

WorleyParsons used the indicative offer Term Sheets provided by KeySpan as the basis for the evaluation. The VOM rates provided were assumed to be in December 2005 dollars. WorleyParsons adjusted the rates by an inflation rate of 3% per year (consistent with the inflation rate used for evaluation of other options in this study) to estimate the rates in current year dollars. Based on discussions with KeySpan, WorleyParsons understood that the capacity charges were provided by KeySpan in current year dollars. WorleyParsons assumed Year 1 to be 2006 and adjusted the capacity charges using the 3% inflation factor to reflect Year 1 being 2012. KeySpan did not provide WorleyParsons with oil-fired system performance information for ISO conditions. WorleyParsons utilized natural gas-fired performance information provided

by KeySpan along with WorleyParsons experience database with respect to natural gas and oil fired combined cycle performance to estimate the performance of the KeySpan Unit 40 on oil (for the 30-day oil-fired period) for the evaluation. The natural gas-fired heat rate used was the target heat rate (guarantee heat rate) provided by KeySpan in their indicative offeres. The oil-fired performance characteristics estimated by WorleyParsons for the evaluation are compared with the natural gas-fired performance characteristics estimated by KeySpan in Exhibit 5-9.

Exhibit 5-9 Estimated Performance Characteristics of KeySpan Unit 40 at ISO Conditions

	Natural Gas-Fired[1]	Distillate Oil-Fired[2]
Steam Sendout to Con Edison, lb/hr	[ALL DATA REDACTED]	
CT/G Power Output, MWe		
ST/G Power Output, MWe		
Auxiliary Power Requirement, MWe		
Net Power Output, MWe		
Combined Cycle Heat Rate (HHV), Btu/kW-hr		
HRSG Heat Rate, MMBtu/Mlb steam		

Note 1: Provided by KeySpan
Note 2: Estimated by WorleyParsons

5.1.12 Environmental and Other Permitting Requirements

It is WorleyParsons understanding based on discussions with KeySpan that when the existing facility was permitted, it was done so with the expectation that Unit 40 would eventually supply steam to Con Edison. The estimated increase in emissions associated with supplying steam to Con Edison, based on the dispatch profile provided by Con Edison for the study, is less than 2 tons/year for NOx, SO_2, PM10, VOC, and CO.

5.2 TRANSGAS ENERGY

WorleyParsons requested the information identified in WorleyParsons' scope of work from TransGas Energy (TGE), via Alternative Facilities Data/Information Request (DIR) document, with respect to a TGE cogeneration facility providing steam to the Con Edison steam system. TGE responded with a completed spreadsheet with the technical data requested by WorleyParsons and a copy of a summary of results of an assessment previously performed by TGE of the benefits to New York City of a TGE proposed 824 MW electric power and steam cogeneration facility in New York City, providing steam to the Con Edison steam system. A copy of the summary document is included in the Appendix F.

WorleyParsons then had a follow-up meeting with TGE in New York City to discuss the information provided and request additional information required to complete

WorleyParsons' task with respect to evaluating the TGE supply option. The additional information requested included TGE's proposed price of steam to Con Edison as a function of steam sendout (to meet Con Edison's requirement for control over dispatchability from zero to maximum proposed steam sendout), and price of fuel and electricity in order for WorleyParsons to evaluate the cost of TGE supplied steam to Con Edison over the next 20 years using CERA projected fuel and electricity prices.

In response to WorleyParsons' request for additional information, TGE provided a matrix of indicative steam price as a function of natural gas price and combined electricity energy and capacity price for one TGE supplied steam sendout, that is, 2 million lb/hr. This information, however, was not in compliance with Con Edison's O&T requirements. In a telephone conversation with WorleyParsons, TGE presented their position with respect to providing indicative pricing for only 2 million lb/hr of steam sendout. WorleyParsons' understanding of TGE's position (which WorleyParsons did not evaluate) based on the conversation is as follows:

- The TGE price for steam will represent the lowest cost of steam for the Con Edison system, and, therefore, the TGE steam should have dispatch priority over all other steam generating facilities;
- The location of the proposed TGE facility and the location selected for interconnection of TGE supplied steam with the Con Edison system is such that the 2 million lb/hr of steam supplied by TGE could be utilized in the Con Edison system all the time.
- Providing pricing information at other steam sendout rates would require TGE to perform extensive additional technical and economic analyses, at a significant cost to TGE.

Upon further request by WorleyParsons for price data that would include all charges that would be incurred for steam sendouts from zero to the maximum proposed, in accordance with the operating and technical (O&T) requirements of the study provided to WorleyParsons by the Core Task Force, TGE provided a single value of indicative price of steam for an average steam dispatch rate of 1.5 million lb/hr at a specific fuel price and electricity price (the full response by TGE explaining TGE's position on the subject is included in Appendix F). This response was still not in compliance with Con Edison's O&T requirements, and there was insufficient information with respect to how the price for 1.5 million lb/hr of steam would vary with fuel and energy price for WorleyParsons to evaluate the cost of TGE supplying steam at this rate using data (CERA electricity and fuel price projections and steam supply capacity factors) consistent with evaluations of Con Edison repowering options and other steam supply alternatives in this study.

Based on the technical, price, and economic data that TGE provided to WorleyParsons for the 2 million lb/hr steam supply, WorleyParsons estimated the cost of TGE steam to Con Edison over 20 years and the net present value of the cost of steam, using CERA projections for fuel and electricity prices, as best possible with the data provided. A major difference between the TGE alternative and other alternatives evaluated by WorleyParsons as a part of this study is that the quantity of steam supply by the other alternatives evaluated is the same as that currently being supplied by the particular facility being evaluated; whereas, the quantity of steam supply proposed by TGE (2

million lb/hr) requires an evaluation of the Con Edison steam distribution network to determine if reinforcements and/or enhancements are necessary to distribute the steam to end-users and the potential costs of reinforcements. Additionally, WorleyParsons did not evaluate whether the steam system can be operated and dispatched to permit the baseload delivery of 2 million lb/hr on a 24/7 basis. Such evaluations were beyond WorleyParsons scope of work for the study, and, therefore, steam distribution network reinforcement costs, if necessary, are not included in WorleyParsons evaluation of the cost of TGE steam supply. Additionally, the costs associated with the retirement of any existing Con Edison steam generating stations that may be afforded by supply of steam by TGE were not included since the analysis required to determine what facilities, if any, could be retired was also beyond WorleyParsons scope of work. Accordingly, a comparison between the TGE Alternative and the other alternatives considered in this study would not be meaningful.

WorleyParsons also evaluated the impact of the TGE supply of steam alternative on emissions, including the change in the proposed TGE facility emissions associated with supplying steam to Con Edison and the change in emissions of other electric power generating facilities in New York City that would be associated with generating electric power that would be displaced by TGE exporting steam.

A complete discussion of WorleyParsons' partial evaluation of the TGE supply of steam alternative, and the assumptions upon which the evaluation was based, are contained in Appendix F.

5.3 BROOKLYN NAVY YARD COGENERATION FACILITY

WorleyParsons requested the information identified in WorleyParsons' scope of work from Brooklyn Navy Yard Cogeneration Partners (BNYCP), via Alternative Facilities Data/Information Request (DIR) document, with respect to the potential for the BNYCP cogeneration facility providing additional steam to the Con Edison steam system. The BNYCP facility currently sells up to 918,000 lb/hr of steam to Con Edison. WorleyParsons visited the BNYCP facility to discuss the information required for the study. BNYCP indicated that it is unlikely that the existing facility could provide additional steam to Con Edison. BNYCP also indicated that the current facility could not be expanded to provide additional steam, but the potential exists within the Brooklyn Navy Yard to increase steam capacity. However, BNYCP said that they did not have the resources at this time to provide the information required by WorleyParsons for the evaluation. As a result, WorleyParsons did not proceed with an evaluation of the BNYCP steam supply alternative.

6.0 EVALUATION OF CUSTOMER-SUPPLIED STEAM

6.1 ESTABLISH DESIGN AND OPERATING CRITERIA

WorleyParsons in consultation with the Core Task Force Members postulated two representative customer supplied steam facilities and the underlying assumptions regarding the options. One facility is a boiler facility and the other is a combined heat and power facility.

WorleyParsons consulted with representatives of the [REDACTED], a company that provides building developers in New York City with combined heat and power to satisfy a portion of the buildings energy needs.

WorleyParsons discussed with the representative of the [REDACTED] a planned cogeneration system for the [REDACTED]. Based on the discussions, it is WorleyParsons understanding that the cogeneration system for this facility will consist of a 5.5 MWe gas turbine combined cycle system with backpressure steam turbine. The combustion turbine will produce about 4.5 MWe and the steam turbine about 1 MWe. The steam turbine exhaust, about 25,000 lb/hr of steam, will be used to provide energy to absorption chillers. The electrical power generated will be used to satisfy a portion of the building's electrical energy needs. The building has an area of about [REDACTED]. WorleyParsons performed a preliminary evaluation of the space required for installation of the system, and estimated the plan area to be in the range from 8,000 ft^2 to 10,000 ft^2. The representative indicated that there is a Con Edison steam line in close proximity to the building. The representative also indicated that it would be preferable in his opinion to eliminate the steam turbine if steam could be exported to the Con Edison steam system. This would reduce the capital cost investment.

WorleyParsons discussed with the representative from the [REDACTED] a planned replacement of an existing cogeneration system with two 6.5 MWe Solar gas turbines combined with a 2.4 MWe back pressure steam turbine. All of the electric power and steam produced would be used to meet the energy needs of [REDACTED]. The representative indicated that the approximate 10,000 ft^2 that is available will just meet the requirements of the combined cycle system. The representative indicated that there is insufficient space to install a larger system in order to provide steam to the Con Edison steam system. Additionally, he indicated that the nearest Con Edison steam interconnection point was over a mile in distance, which would likely make it uneconomical to provide steam to the Con Edison system.

At the recommendation of the Core Task Force Members, WorleyParsons contacted a representative of the [REDACTED]. The representative referred WorleyParsons to a representative from [REDACTED]. As a result of

discussions with the representative of the [REDACTED], several technical and economic factors relevant to the study were identified. These include:

- Building electric demand does not vary much from season to season except that during summer months, the consumption may go up by about 5%.
- The peak electric demand of a Class A building in New York City is on the order of 5 to 10 watts per square foot (a little less for Class B buildings). The higher consumption rate is associated with buildings with large data centers, which many buildings now have.
- Electric consumption during peak hours is 2 to 4 times that during non-peak hours.
- An average might be about 5 Watts/ft^2 during peak and 1 to 1.5 Watts/ft^2 during off-peak (peak hours on the Con Edison system are from 8 am to 10 pm). From 8 am to about 6 pm the building consumption would be about 5 Watts/ft^2, then it would ramp down basically linearly reaching about 1 to 1.5 Watts/ft^2 at 10 pm and remain their until about 8 am. For a 2 million ft^2 building, the estimated average peak demand is 10 MW.
- Steam is used for chillers in summer and for heating in winter. There is not much steam consumption in the spring and fall seasons. However, spring and fall will have the greatest variation in steam consumption.
- Building steam demand in the summer is the most consistent.
- Steam demand in the summer during peak hours is about 3 to 4 times the peak demand in the winter.
- Example of a winter building steam profile for a 1 million ft^2 Class A building is:
    1. 10pm to 5am: 1,000 to 2,000 lb/hr
    2. 5 am to 8am: ramp up to 9,000 to 12,000 lb/hr
    3. 8am to 10am: ramp down to about 6,000 lb/hr
    4. 10am to 6pm: 6,000 lb/hr
    5. 6pm to 10pm:ramp down to 1,000 lb/hr

    Note: For the 2 million ft^2 building being considered for this study, the steam consumption data noted above are to be doubled.
- Example of a summer building steam demand profile for a 1 million ft^2 Class A building is:
    1. Peak at 24,000 lb/hr (temperature normalized)
    2. Minimum at 14,000 pph
    3. Daily average during 6am to 6pm: 18,000 to 20,000 pph.

    Note: For the 2 million ft^2 building being considered for this study, the steam consumption data noted above are to be doubled.
- A diesel generator for back up or black start cannot be permitted for buildings in New York City because they are typically very dirty (high particulate emitters).

- When designing a cogeneration system to only meet the electrical needs of the building, a reciprocating engine cogen system may be more suitable than gas turbine cogen system because of the frequent cycling that may be required to meet the varying building electric demand. However, if designing to generate more steam than the building requires in order to export steam, a gas turbine cogen system is likely to be the better choice because of the higher steam generation per electric power generation capability of the gas turbine system.
- There is typically no space for large backup fuel oil storage capacity; therefore, uninterruptible natural gas supply will be required to meet Con Edison's condition for uninterruptible fuel supply.
- Typical economic/financial factors for a commercial building project in Manhattan may be
    - 60%/40% debt-to-equity capitalization (higher than industrial because of the few completed projects);
    - 8% loan interest with a period up to 20 years;
    - Return on equity requirement of about 20%.
    - Construction financing (AFUDC) would probably be on the order of 7 to 7.5%.
    - Engineering and project management about 15% to 20% of project cost.
- Economic/financial factors would be slightly different for academic application.
    - Debt-to-equity capitalization would probably be about 50/50.
    - Loan interest rates right now would be on the order of 7% to 8%.
    - Construction financing could be about 6% to 6.5%.
    - Return on Equity requirement of about 15% would be reasonable.
    - Engineering and project management would be about the same percentage of project cost as for a commercial project.

Based on the results of discussions with representatives of the commercial and academic sectors, WorleyParsons developed the criteria identified in the following sections for the customer supplied steam evaluations.

6.1.1 Combined Heat and Power (Cogen) Option

The following criteria were established for the combined heat and power option:

- The cogen system will be designed for an annual average electric demand of 8.5MW and an annual average steam demand of about 25,000 lb/hr for the facility.
- The cogen system will consist of a gas fired combustion turbine and supplementally-fired HRSG for producing with a total steam generation capacity of about 100,000 lb/hr.

- A backup 25,000 lb/hr net capacity gas fired package boiler will be incorporated to provide steam for the building usage only when the cogen system is out of service.
- Space requirement based on system requirements
- Uninterruptible (firm) natural gas supply will be provided to the cogeneration system from Con Edison gas supply system. No oil back up is provided..
- Electrical backup will be via purchase of electricity from the local utility provider.
- An air-cooled dump condenser will be included to allow for the cogen system to follow the building electrical load demand and still satisfy the Con Edison requirement for full steam dispatch control from zero to maximum offered.
- Must meet Con Edison steam condition and quality criteria
- Cost and economic factors will include the following:

1. Commercial application:
    a. Capitalization: 60% debt / 40% equity
    b. Loan interest rate: 8%
    c. Return on Equity: 20%
    d. Inflation Rate: 3%
    e. NPV Discount Factor (Present Worth Factor): Weight cost of capital (10.88%)
    f. Steam sendout discount rate: 7.65% (calculated)
    g. Property taxes: 5.4%
    h. Federal and State Income Taxes: 40%
    i. Depreciation per year: 3.33%
    j. Carrying charge: 21.4%
    k. Forgone revenue of cogeneration space based on $50 per sq. ft.
2. Academic
    a. Capitalization: 50% debt/ 50% equity
    b. Return on Equity: 15%
    c. NPV Discount Factor: Weighted cost of capital (9.9%)
    d. Steam sendout discount rate: 6.7% (calculated)
    e. Other factors same as for Commercial application
3. Other

a. Fuel cost is based on Con Edison's firm gas supply rate (SC-12 and SC-2 Rate II) for both CG-1 and BP-1 Options. Fuel cost adjustment per CERA 2005 Rearview mirror scenario.

b. Avoided cost of steam (that would have to be purchased if not self-generating) calculated in accordance with Con Edison's SC-2 rate for both the CG-1 and BP-1 Option.

c. Avoided cost of electricity: This applies for the Cogen option only and has been applied at the Con Edison's Large Customer (SC-9) rate.

d. Electric Purchase Cost:

   i. Cogen (CG-1) Option – Con Edison's Stand-by rate.

   ii. Boiler (BP-1) Option – Con Edison's Large Customer (SC-9) rate.

6.1.2 Boiler Option

The following criteria were established for the Boiler Option:

- Building steam and electric demand the same as for combined heat and power (Cogen) option
- Maximum steam generation capacity of about 100,000 lb/hr provided by 2 -50% capacity natural gas-fired boilers
- Space requirement based on system requirements
- Other criteria the same as for combined heat and power option

6.2 CONCEPTUAL DESIGN OF FACILITIES

6.2.1 Combined Heat and Power Option

Overview

In this option one new Solar Mars Gas turbine of 10 MW nominal capacity along with a supplementally fired HRSG will be provided to supply steam. A standby package boiler of 25,000 PPH net capacity will also be provided to supply steam for the facility's average internal consumption when the gas turbine is out of service. The Gas turbine, HRSG and the package boiler will be firing natural gas only. The gas turbine will be following the building electricity demand profile which is estimated to be about 8,500 kW on average. The facility will have a maximum average net steam export capacity of 68,000 PPH with full supplemental firing in the HRSG and about 14,000 PPH with no supplemental firing. The HRSG and package boiler will be provided with SCR and CO catalyst for emission controls. In this option, the facility will be buying its electrical requirements from the utility only when the gas turbine is out of service. A dump condenser will be provided to allow the gas turbine operation to match the building electric demand irrespective of Con Edison's steam supply requirements.

The heat balances for this option are included in Appendix B.

Layout

A conceptual layout of the facility is shown in drawing CESP-1-DW-001 in Exhibit 6-1. It includes the gas turbine, HRSG, one package boiler, chillers, water treatment plant, control room and other auxiliary facilities. Based upon discussions with Pace, it is our understanding that no oil storage will be allowed in the facility. Therefore, the plant shall be designed with firm gas supply.

Major Equipment and Systems

Gas Turbine

The cogeneration plant will be based on one Solar Mars gas turbine generators . The gas turbine generators will include pulse jet type inlet air filtration systems; inlet silencers; evaporative cooling; lube oil systems including fin-fan coolers; hydraulic control oil systems and fin-fan coolers; starting systems; acoustical enclosures including heating and ventilation; and control systems including supervisory, fire protection, and fuel systems. The gas turbine will be provided with Dry Low NOx Combustor (DLN) capable of firing natural gas. Fuel gas will be heated to 168F using water from HRSG economizer to improve upon the gas turbine efficiency.

The generators will be provided with the gas turbine package. The generators will be 3-phase, 60 hertz, 13.8 kV, drip proof generator complete with excitation system, cooling, and protective relaying constructed to meet ANSI and NEMA standards for turbine-driven synchronous generators.

The gas turbine produces about 10,500 kW net at 59F ambient temperature.

Heat Recovery Steam Generator

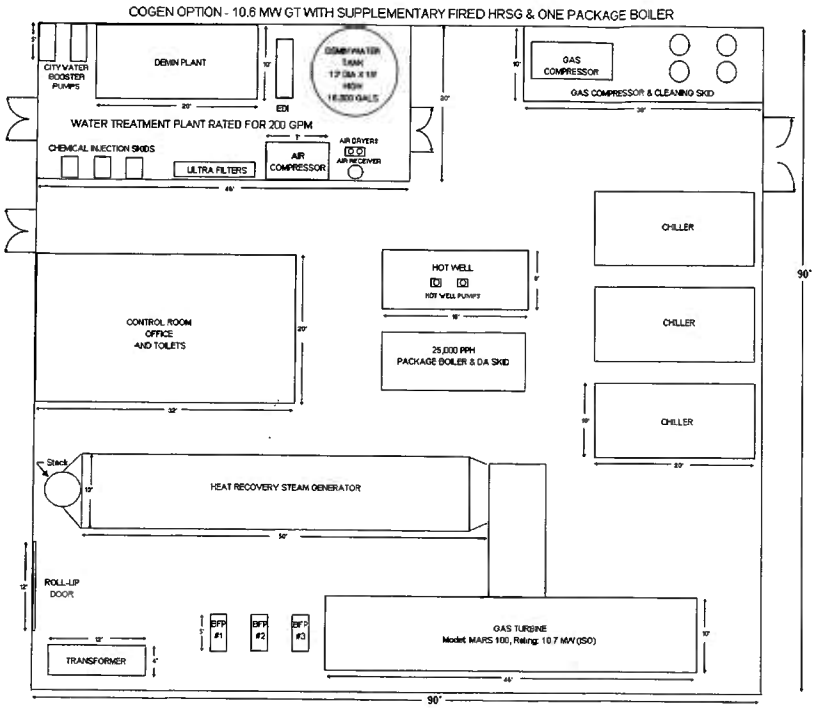
The Heat Recovery Steam Generator (HRSG) will be a 2-pressure level, non-reheat, supplementally fired, natural circulation-type with horizontal gas turbine exhaust flow through vertical tube heat transfer sections. The high-pressure (HP) steam will be sent directly to the export header while the low pressure steam will be used to heat and deaerate the incoming make up water.

The HRSG net steam sent out capacities of the HRSG at 59F are as follows:

- Without any supplemental firing: 48,800 PPH at base load of 10,500 kW, and 38,600 PPH at the average operating load of 8,500 kW.
- With supplemental firing: 104,000 PPH at base load and 92,500 PPH the average operating load

The steam conditions at HRSG outlet is at 430 psia and 474F

Exhibit 6-1 Conceptual Layout of Cogeneration Option for Customer Supplied Steam



CONCEPTUAL DESIGN

NOTES

1. Building and facility average internal consumption: Steam 25,000 PPH, Electric 6,450 kW.
2. A dump condenser will be provided to dump any excess steam while the gas turbine satisfies the building electrical load. The dump condenser will be located outdoor.

WorleyParsons		
Con Edison Steam Production Option Study		
Customer Sell Back (CSB) Option Equipment Layout - Cogen Option (CG-1) 68,000 PPH Design Steam Sendout		
DWG No: CESP-1-DW-001	Rev B	Date 9/30/2006

The HRSG will be designed for indoor operation and set on a concrete foundation. The HRSG will have:

- Natural circulation
- Drum-type unit
- Two pressure level steam generation
- Vertical-tubed sections
- Extended surface, finned tubes
- Internally insulated
- Full draining capability
- Stainless steel floor liner
- SCR catalyst with provision to add 10% more catalyst in future
- CO Catalyst Module
- Sparging system to keep the HRSG warm after shutdown

Each HRSG will be provided with a self-supporting stack equipped with ports for emissions sampling. Platforms, ladders, and personnel protection will be provided to permit access to the emissions sampling ports.

Boiler water chemistry will be controlled by both continuous blowdown and the addition of chemicals into the HRSG drums. Blowdown systems will be included for the HRSG steam drums to remove dissolved solids. The HRSG will be provided with a continuous blowdown tank that will receive cascaded blowdown from the steam drums.

Package Boilers

One (1) new gas/oil fired package boilers each with a net steaming capacity of 25,000 PPH will be provided to supply the building internal consumption when the gas turbine is out. The boiler will be connected to the HRSG stack. Since the package boiler will be designed to supply steam for internal usage only, the steam condition of the package boiler will be about 150 psig, saturated.

The package boilers will be of water tube design, bottom supported, modular section construction and be provided with low NOx combustion system, SCR and CO Catalyst module, single fuel train, FD fan, superheater, and economizer.

Dump Condenser

A partial capacity dump condenser will be provided to facilitate full power generation during low or no steam demand periods. The capacity of the dump condenser is estimated to be 20 MMBH corresponding to dumping of about 24,000 PPH of when the gas turbine is running at base load with unfired HRSG and steam is supplied for internal consumption only. The dump condenser is a pressurized steam-to-air heat exchanger and will condense any steam in excess of the minimum steam demand while the Cogen unit is operating at minimum load. The dump condenser will be

located outdoor and will drain the water to the new deaerator by static pressure differences.

Deaerator

A deaerator will be provided for the HRSG and will be located on the top of the LP drum. The deaerator will be combined spray and tray type and will be designed to operate at a pressure of about 30 psia with a design pressure of 50 psig. Steam required for the deaerator will be tapped off from the common header.

The package boiler will be provided with a separate deaerator. The design of the deaerator will be same as that of the HRSG deaerator except that the operating pressure will be about 20 psia.

Steam system

The steam outlet from the various steam sources (HRSG, and Boilers) are feed into a single manifold before connecting to Con Edison system.

Boiler Feed Water

The feed water from the deaerators will be pumped to the boiler / HRSG economizer by feed water pumps. The feed water pumps will be horizontal split, centrifugal type. A common feed water pumping system consisting of 3x50% capacity pumps to cater to the peak supply requirements will be provided.

Fuel Gas System

A new fuel gas system will be brought at the site to support the operation of the Cogen plant. It is expected that the pressure of the gas at the plant boundary will not be sufficient to support the requirements of the gas turbine. Therefore two (2) X 100% capacity gas compressors will be provided to boost the pressure of the incoming gas stream.

In order to comply with the specific fuel quality requirements of the gas turbine, a fuel gas treatment system consisting of fuel gas filter separator will precede the gas compressors. The treated gas will be supplied to the boilers and HRSG and gas turbine. It is anticipated that only the gas required for the gas turbines will be required to pass through the gas compressors.

Water Treatment System

The water treatment plant will consist of a conventional cation/anion demineralization water treatment system designed to produce make up water suitable for the operation of the boilers. City water is supplied to a raw water tank. The raw water pumps take suction from this raw water tank and supply the water to the demineralizer plant. The treated water this then pumped to the treated water storage tank for use in the boilers.

Fuel Oil

Fuel oil will not be used.

Waste Water

Waste water from the water treatment equipment and the cooled blowdown from the boilers are directed to floor sumps. The water will be conditioned to meet the city specification before discharging to the sewer system.

6.2.2 Steam Only Boiler Option

Overview

In this option two (2) new package boilers each of a gross capacity of 60,000 PPH (about 51,000 PPH Net) will be provided. The facility average internal usage for cooling and heating is estimated as 25,000 PPH. Therefore, the facility will have a net export capacity of 77,000 PPH max. All boilers will be firing natural gas only and will be provided with SCR and CO catalyst for emission controls. In this option, the facility will be buying its electrical requirements from the utility. The minimum design steam supply to Con Edison system will be 25,000 PPH when one boiler is out of service.

The heat balances for this option are included in Appendix B.

Layout

A conceptual layout of the facility is shown in drawing CESP-1-DW-002 in Exhibit 6-2. It includes two 50% capacity boilers, chillers, water treatment plant, control room and other auxiliary facilities. Based upon discussions with Pace, it is our understanding that no oil storage will be allowed in the facility. Therefore, the plant shall be designed with firm gas supply.

Major Equipment and Systems

Package Boilers

Two (2) new gas fired package boilers each with a gross steaming capacity of 60,000 PPH will be provided to supply the peak steam demand. The boilers will be provided with a common stack.

The package boilers will be of water tube design, bottom supported, modular section construction and be provided with low NOx combustion system, SCR and CO Catalyst module, single fuel train, FD fan, superheater, and economizer.

Deaerator

One(1) common deaerator will be provided for the package boilers. The deaerator will be combined spray and tray type and will be designed to operate at a pressure of about 35 psia with a design pressure of 50 psig. Steam required for the deaerator will be tapped off from the common header.

Steam system

The steam outlet from the various steam sources are feed into a single manifold before connecting to the Con Edison system.

Boiler Feed Water

The feed water from the deaerator will be pumped to the boiler economizer by feed water pumps. The feed water pumps will be horizontal split, centrifugal type. A common feed water pumping system consisting of 2x50% capacity pumps to cater to the peak supply requirements will be provided.

Water Treatment System

The water treatment plant will consist of a conventional cation/anion demineralization water treatment system designed to produce make up water suitable for the operation of the boilers. City water is supplied to a raw water tank. The raw water pumps take suction from this raw water tank and supply the water to the demineralizer plant. The treated water this then pumped to the treated water storage tank for use in the boilers.

Fuel Gas system

A new fuel gas system (firm supply) will be provided for the boilers. It is assume that the fuel gas will be available at a minimum pressure of 50 psig at the plant boundary and will be distributed to the boilers. No gas compressor is required.

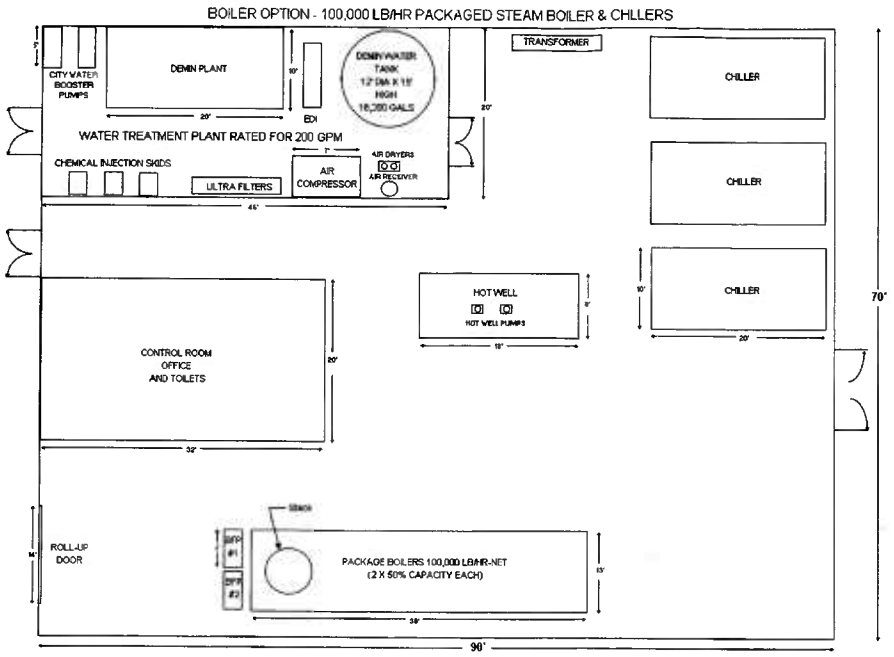
Fuel Oil

Fuel oil will not be used

Waste Water

Waste water from the water treatment equipment and the cooled blowdown from the boilers are directed to floor sumps. The water will be conditioned to meet the city specification before discharging to the sewer system.

Exhibit 6-2 Conceptual Layout of Boiler Option for Customer Supplied Steam



CONCEPTUAL DESIGN

NOTES

1. Building and facility average internal consumption: Steam 25,000 PPH, Electric 8,440 kW.

WorleyParsons		
Con Edison Steam Production Option Study		
Customer Sell Back (CSB) Option Equipment Layout - Boiler Option (BP-1) 77,000 PPH Design Steam Sendout		
DWG No: CESP-1-DW-002	Rev B	Date: 9/30/2006

6.3 ENVIRONMENTAL AND REGULATORY REQUIREMENTS

The system must meet all federal, state, and local regulatory requirements. It is anticipated that the system can be designed to meet noise and visual requirements. Diesel generators will not be permitted because of the particulate emission levels. There are no other issues that WorleyParsons foresees at this time that would prevent permitting of cogeneration or boiler systems for customer supply of steam to Con Edison.

6.4 RANGE OF STEAM COSTS

The NPV of estimated total annual cost of steam production, and NPV of estimated total annual cost of steam production per thousand pounds of discounted steam sendout evaluated over the 20 year study period as a function of annual steam sendout capacity factor are shown in Exhibit 6-3 and Exhibit 6-4 for the Commercial cogeneration and boiler options and Exhibit 6-5 and Exhibit 6-6 for the two Academic options. The discounted steam sendout over the 20 year study period was calculated using the same methodology as for other options evaluated in this study to provide a Figure of Merit for option comparison. The steam production cost for the years 2006 through 2011 until the customer steam supply starts (assumed to be in 2012) was estimated using the average of the estimated unit cost of steam production for Con Edison's Hudson Avenue, 59th Street, and 74th Street Stations.

Currently, Con Edison steam generation stations operate at annual capacity factor of 27%. If the customer supplied steam facilities operate at similar capacity factors, the cost of steam appears to be significantly higher than those at the Con Edison stations. If higher capacity factors can be accommodated by the Con Edison steam system because of the very small capacity of what would be considered typical of a customer supplied steam system, then the unit cost of steam from these facilities could be substantially reduced, as shown in Exhibit 6-4 and Exhibit 6-6.

A breakdown of the NPV of each capital and annual operating cost category is shown for 25% capacity factor in Exhibit 6-7. The capital and annual operating costs estimated for the four options upon which the NPVs are based are provided in Appendix A.

Exhibit 6-3 NPV of Net Cost of Steam Production for Commercial Customer Supplied Steam Options Versus Steam Sendout Capacity Factor Based on CERA 2005 Rearview Mirror Price Projections

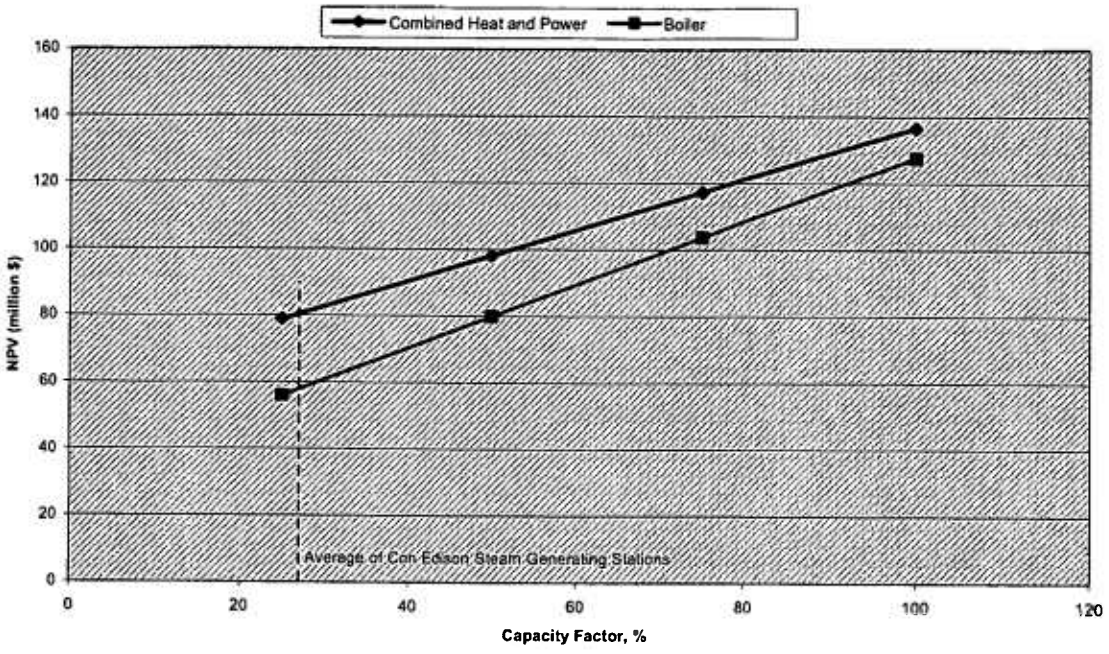


Exhibit 6-4 NPV of Net Cost of Steam Production per Mlb Discounted Steam Sendout for Commercial Customer Supplied Steam Options Versus Annual Steam Sendout Capacity Factor Based on CERA 2005 Rearview Mirror Price Projections

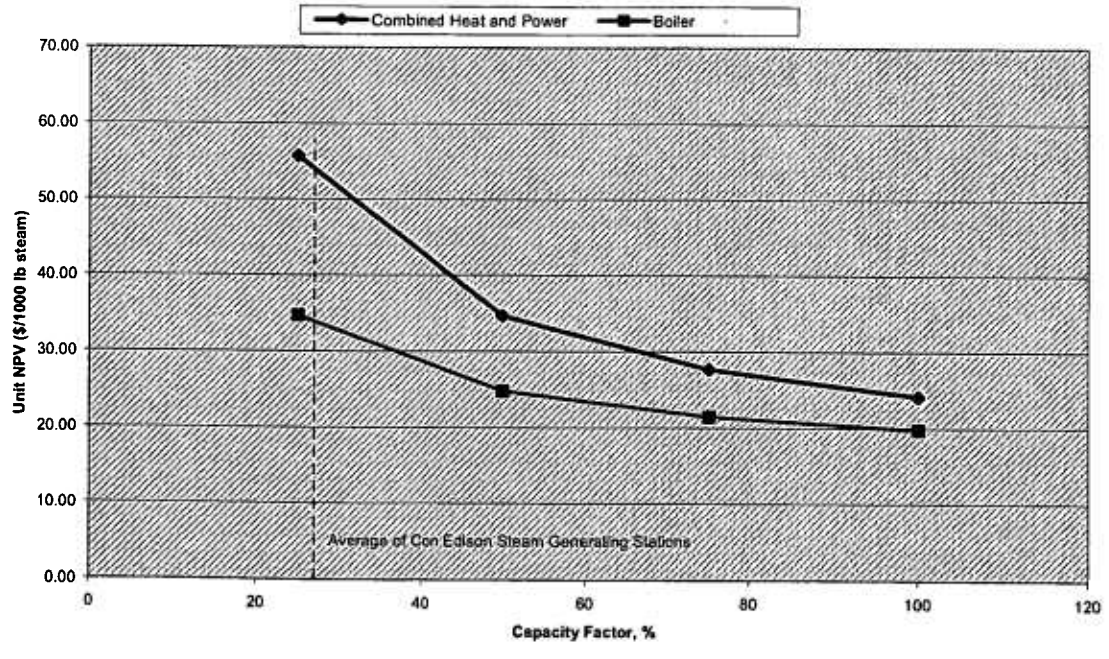


Exhibit 6-5 NPV of Net Cost of Steam Production for Academic Customer Supplied Steam Options Versus Steam Sendout Capacity Factor Based on CERA 2005 Rearview Mirror Price Projections

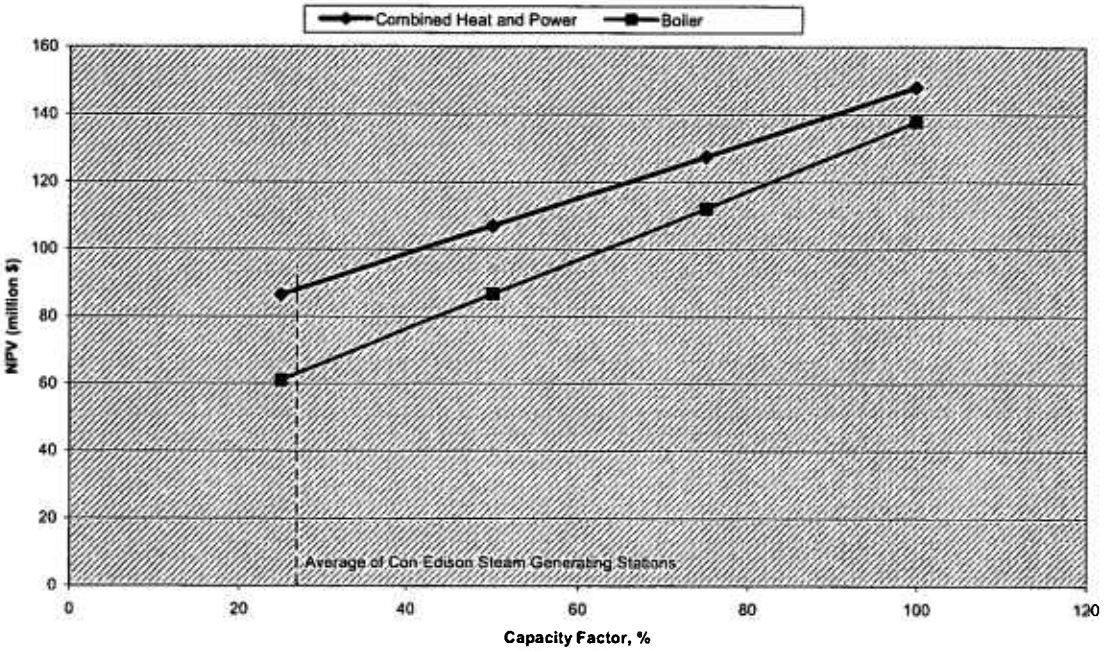


Exhibit 6-6 NPV of Net Cost of Steam Production per Mlb Discounted Steam Sendout for Academic Customer Supplied Steam Options Versus Annual Steam Sendout Capacity Factor Based on CERA 2005 Rearview Mirror Price Projections

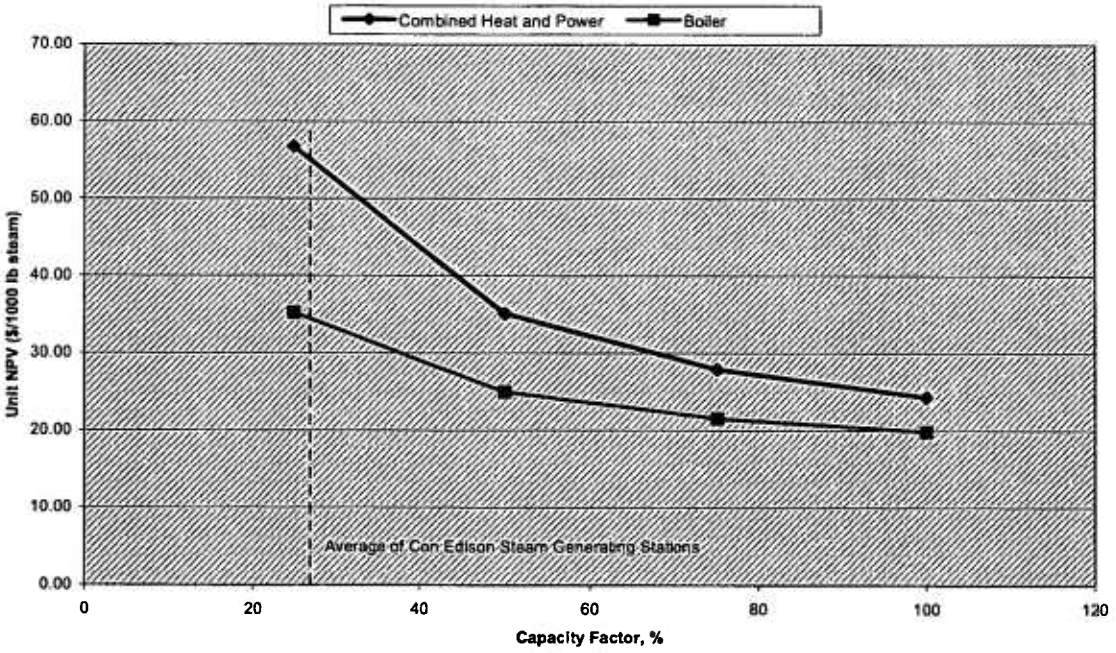


Exhibit 6-7 NPV of Estimated Capital and Annual Operating Cost Categories for Customer Supplied Steam Options at 25% Annual Capacity Factor

Option Sheet Number ->		1	2	1	2
STEAM GENERATION AND RE-POWERING OPTIONS		Commercial Case	Commercial Case	Academic Case	Academic Case
	Customer Supplied Steam	Cogeneration Options with Supp Fired HRSGs	Boiler Only Option (BP-1)	Cogeneration Options with Supp Fired HRSGs	Boiler Only Option (BP-1)
ITEM	DESCRIPTION	CG1	BP1	CG1	BP1
A.	Option Description	One (1) Solar Mars 100 Gas Turbine with Supp Fired HRSG, partial capacity Dump Condenser plus 1 package boiler - Gas fired	Two (2) package boilers, gas Fired	One (1) Solar Mars 100 Gas Turbine with Supp Fired HRSG, partial capacity Dump Condenser plus 1 package boiler - Gas fired	Two (2) package boilers, gas Fired
25%	= STEAM SEND OUT CAPACITY FACTOR	NPV	NPV	NPV	NPV
C	**Total 20 Year Steam Send Out, MMlb**	2,809	3,203	2,809	3,203
E	**Total 20 Year Net Elec Generation**	116,008		116,008	
G.	**Total NPV of Plant Cost - US Dollars**				
1.	Existing Plant Maintenance Cost				
2.	EPC Cost				
a.	Cogen / CC Unit and accessories	$36,181,392		$37,873,826	
b.	Boiler Plant		$16,709,615		$17,491,230
c.	Demin Plant	$1,453,055		$1,521,024	
d.	Other BOP	$636,298		$666,062	
3.	Demolition /Relocation/ Remediation Costs				
a.	Demolition Costs - loaded				
b.	Relocation Cos				
c.	Remediation Costs				
4.	Permitting/Prelim Engineering	$7,830,283	$3,132,113	$8,002,881	$3,201,152
5.	Gas Piping Interconnect Costs - loaded				
6.	Electrical Reinforcement/Interconnect Costs - loaded				
7.	Contingency	included in above	included in above	included in above	included in above
8.	Owner's other Costs(4)	included in above	included in above	included in above	included in above
	Capitalized Property Tax During Construction	$4,785,412	$2,042,738	$5,092,230	$2,173,709
9.	**Total Plant Cost (TPC)**	**$50,886,441**	**$21,884,466**	**$53,156,023**	**$22,866,092**
H.	**Total NPV of Annual Costs**				
1.	Fuel Cost	$36,243,041	$21,679,621	$40,468,704	$24,215,351
2	Fixed Charges on TPC (Debt Services)	$57,811,890	$24,923,891	$63,993,420	$27,588,876
3.	Water & Chemical Costs	$1,140,249	$1,181,998	$1,272,846	$1,319,450
4.	Electricity Purchase Cost	$8,195,769	$1,246,707	$9,139,959	$1,392,354
	Steam Purchase Cost	$11,474,015	$13,083,538	$11,804,578	$13,460,471
5.	O&M Costs of existing plant(16)				
6.	Non Fuel O&M Costs	$2,574,674	$1,795,186	$2,874,078	$2,003,944
	Foregone Rent	$2,125,878	$1,653,461	$2,373,092	$1,845,738
7	Property Tax	$21,398,337	$9,237,148	$23,886,701	$10,311,315
8.	ICIP Credit				
9.	**Total Annual Cost**	**$140,963,853**	**$74,801,549**	**$155,813,376**	**$82,137,498**
I.	**Steam Generation Costs ($) based upon Avoided Cost Offset**				
1.	Avoided Cost of Electricity Purchase(8)	$43,287,415		$48,322,228	
2.	Avoided Cost of Steam Purchase(9)	$18,796,538	$18,796,538	$20,978,618	$20,978,618
3.	-				
4	Total Avoided Costs	$62,083,953	$18,796,538	$69,300,845	$20,978,618
5a	**Cost Attributed to Steam w/o Emission Credits - NPV**	**$78,879,900**	**$56,005,012**	**$86,512,531**	**$61,158,881**
6d	**Cost of Steam w/o Emission Credits ($/1000lb) - NPV**	**$55.72**	**$34.70**	**$56.79**	**$35.21**
8	Emission Credits on Annual Costs(7)				
a.	NOx				
b.	SO2				
c.	PM10				
d.	VOC				
e.	Total Credits				
9a	**Cost Attributed to Steam with Emission Credits - NPV**	**$78,879,900**	**$56,005,012**	**$86,512,531**	**$61,158,881**
10d	**Cost of Steam with Emission Credits ($/1000lb) - NPV**	**$55.72**	**$34.70**	**$56.79**	**$35.21**
J.	**Total 20 Year Emissions (tons/20 years)**				
1.	NOx	198	71	198	71
2.	SO2	21	2	21	2
3.	PM10	42	28	42	28
4.	PM	12	7	12	7
5.	VOC	7	10	7	10
6.	CO	104	63	104	63
J.	**Total Annual Emissions (tons/yr)**				
1.	NOx	14	5	14	5
2.	SO2	1	0	1	0
3.	PM10	3	2	3	2
4.	PM	1	1	1	1
5.	VOC	1	1	1	1
6.	CO	7	4	7	4

() refer to notes on InputFromScreeningModel sheet

7.0 EVALUATION OF IMPACT OF ALTERNATIVE STEAM SUPPLIES ON PRODUCTION COSTS AND EMISSIONS AT ELECTRIC AND STEAM FACILITIES CITYWIDE

The impact of the electric power generating repowering options at Hudson Avenue and the KeySpan steam supply alternative on steam and electric production costs City-wide due to variable fuel and emission costs was evaluated by WorleyParsons. The variable operating costs considered were fuel and emissions costs assuming that other variable operating costs are constant in accordance with WorleyParsons Scope of Work. The evaluations did not include other annual costs. Evaluations were not performed for the other steam supply alternatives for the following reasons:

- The repowering options for the 59th Street Station were not evaluated because none were considered by WorleyParsons to be promising options base on the results of the cost evaluation of those options discussed in Section 4.2.2.
- Results of WorleyParsons assessment of the 74th Street Station indicated that repowering options at the 74th Street Station would not reduce the cost of steam production at the 74th Street Station, as discussed in Section 4.2.3.
- The customer supplied steam options were not evaluated because the cost of steam production from these options at a capacity factor typical of the other steam supply options did not appear to be economically attractive with other options, as shown in Section 6.0.
- The TransGas Energy alternative was not evaluated because the conditions of steam supply provided by TGE did not meet the operating and technical requirements established for the study, as discussed in Section 5.2.
- The BNYCP alternative was not evaluated since BNYCP indicated that they did not have the resources available to support the study, as discussed in Section 5.3.

Results of the evaluation of the impact of Hudson Avenue Station repowering options on steam and electric production costs City-wide are presented in Section 7.1.1, and for the KeySpan alternative in Section 7.2.1.

The impact of repowering options at the Hudson Avenue Station and the KeySpan alternative on emissions City-wide was also evaluated by WorleyParsons. The evaluation of the Hudson Avenue Station options is discussed in Section 7.1.2. The evaluation of the impact of the KeySpan steam supply alternative on emissions discussed in Section 5.1.9 considered the impact on City-wide emissions since it took into consideration the incremental emissions associated with an electric power generator that would make up the power displaced by KeySpan providing steam to Con Edison and the emissions at the Ravenswood Steam Plant. Therefore, the results of the evaluation are not repeated in this section.

7.1 RE-POWERING AT CON EDISON FACILITIES

7.1.1 Impact on Production Costs

The impact of the electric power generating repowering options evaluated for Hudson Avenue on production costs City-wide (Zone J) due to variable fuel and emissions operating costs was evaluated by WorleyParsons. Since, in WorleyParsons opinion, the existing boilers at Hudson Avenue would not operate reliably over the 20 year study period, the boiler only repowering option (BP-2) was used as the base for this evaluation. The evaluation considered the following:

- The difference in the total annual variable operating cost (fuel and emissions) for each of the options relative to that for option BP-2.
- The savings in annual fuel consumption and cost for an electric power generator (within Zone J) associated with the portion of the electric energy displaced by the repowering option - The basis for selection of the electric generating facility (unit) in Zone J for the evaluation was the highest dispatch cost (fuel cost), baseloaded unit in a database provided by CERA. A baseloaded unit rather than a peaking unit was selected since the displaced electric energy used is on an average annual basis.
- The savings associated with emissions reductions at the electric power generating facility where a portion of the electrical energy produced would be displaced by the repowering option. The cost values of the emission reduction credits were the same as used in the evaluation of all repowering options in this study as identified in Section 3.3.
- The CERA 2005 Rearview Mirror Scenario fuel and electric energy price projections were used as a basis for the evaluation.

The estimated impact on City-wide electric and steam production costs of the Hudson Avenue repowering options resulting from this evaluation are summarized in Exhibit 7-1 through Exhibit 7-4.

Exhibit 7-1 shows the estimated impact on net present value of production costs over the 20 year period of the study, and Exhibit 7-2 shows the contributions of the repowering options fuel cost, net emissions cost, and electric generator fuel cost savings. Exhibit 7-3 and Exhibit 7-4 show the estimated impact on net present value of production costs divided by the discounted steam export by the repowering options, using the methodology described in Section 3.3 for the discount factor.

As mentioned previously, the evaluation was performed considering fuel and emissions costs only and did not include other variable or fixed operating costs, and did not include the contribution of capital cost. Inclusion of the contribution of capital costs to annual costs would significantly impact the results of the evaluation due to the high cost of the cogeneration and combined cycle repowering options relative to the boiler only option.

Exhibit 7-1 Impact of Repowering Options on NPV of Production Costs City-Wide Due to Variable Fuel and Emissions Operating Costs Based on CERA 2005 Rearview Mirror Price Projections

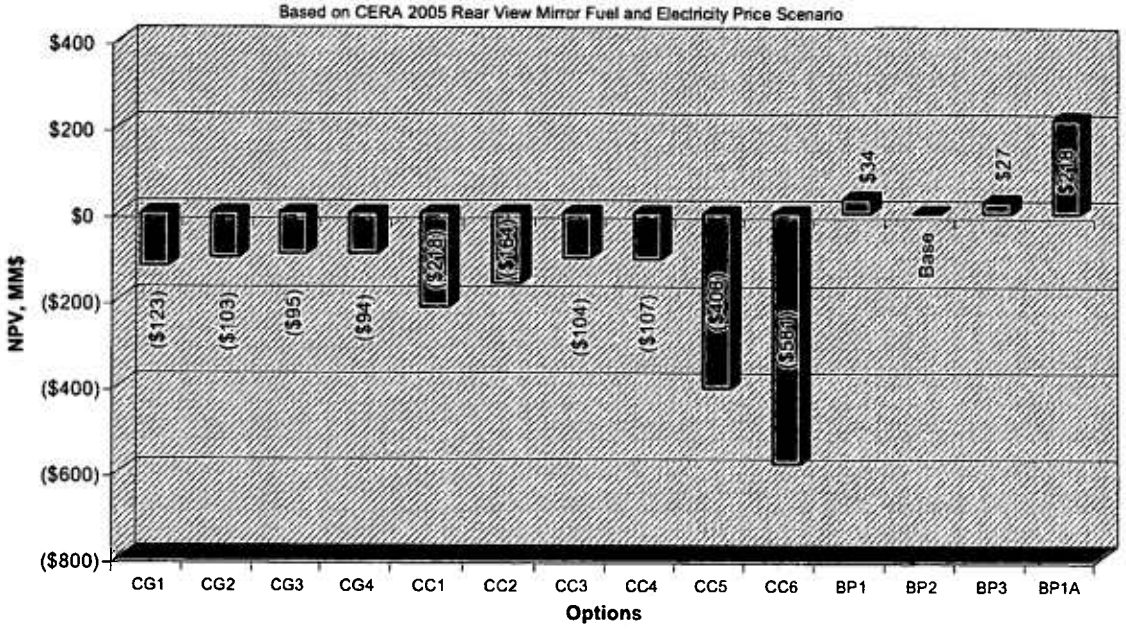


Exhibit 7-2 Impact of Repowering Options on NPV of Production Costs City-Wide Due to Variable Fuel and Emissions Operating Costs Based on CERA 2005 Rearview Mirror Price Projections

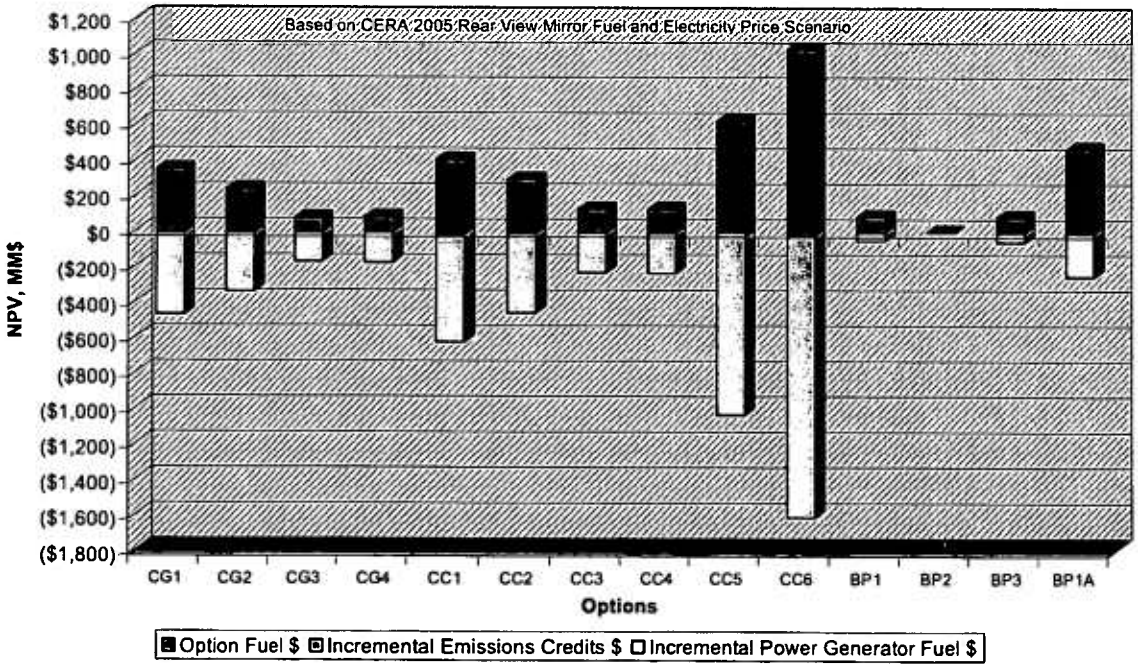


Exhibit 7-3 Impact of Repowering Options on Unit NPV of Production Costs City-Wide Due to Variable Fuel and Emissions Operating Costs Based on CERA 2005 Rearview Mirror Price Projections

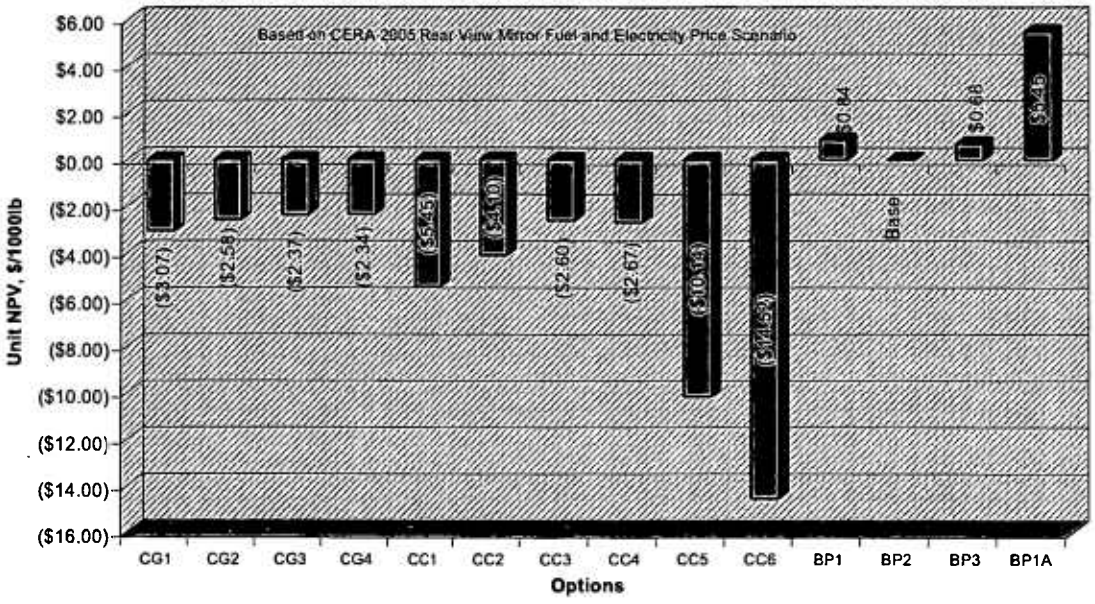
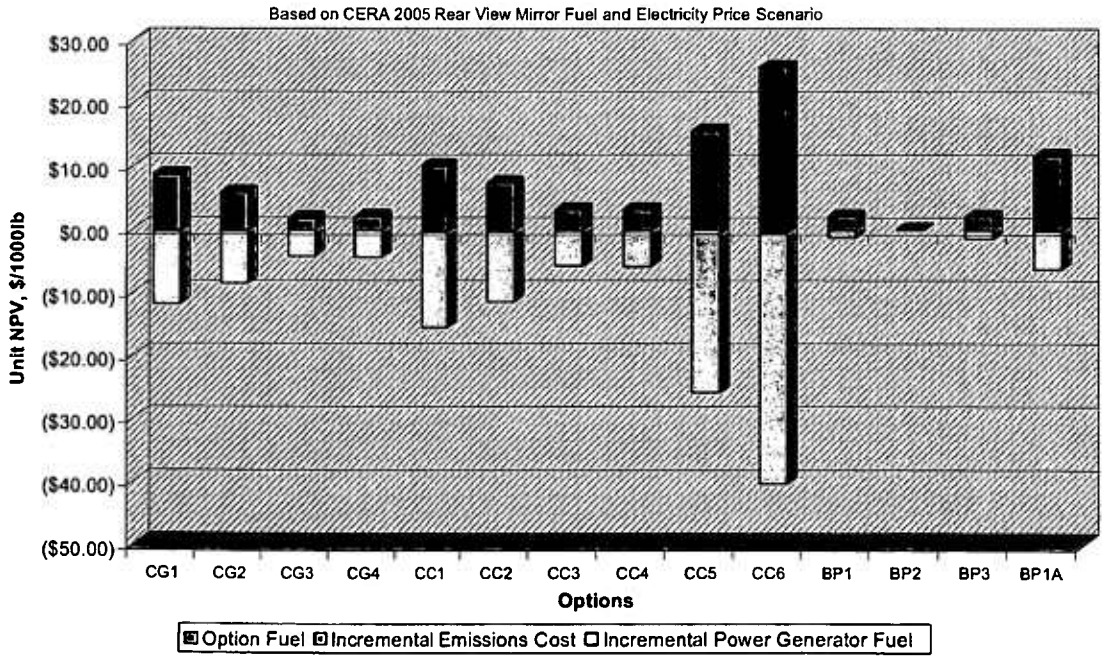


Exhibit 7-4 Impact of Repowering Options on Unit NPV of Production Costs City-Wide Due to Variable Fuel and Emissions Operating Costs Based on CERA 2005 Rearview Mirror Price Projections



7.1.2 Impact on Emissions

The impact of the repowering options on annual air emissions (NOx, SO_2, PM, VOC, and CO) City-wide was evaluated by WorleyParsons, again relative to the emissions associated with option BP-2. The results are shown in Exhibit 7-5 through Exhibit 7-9. Estimates of the emissions for the electric power generator whose energy generation would be displaced by the cogeneration repowering options were based on NOx and SO_2 emissions factors provided in the CERA dispatch database and EPA AP-42 emissions factors for PM, VOC, and CO for a residual-fired boiler. The electric power generator selected from the CERA database generates power using a residual-fired steam boiler/turbine system.

Exhibit 7-5 Impact of Hudson Avenue Repowering Options on Annual NOx Emissions City-Wide

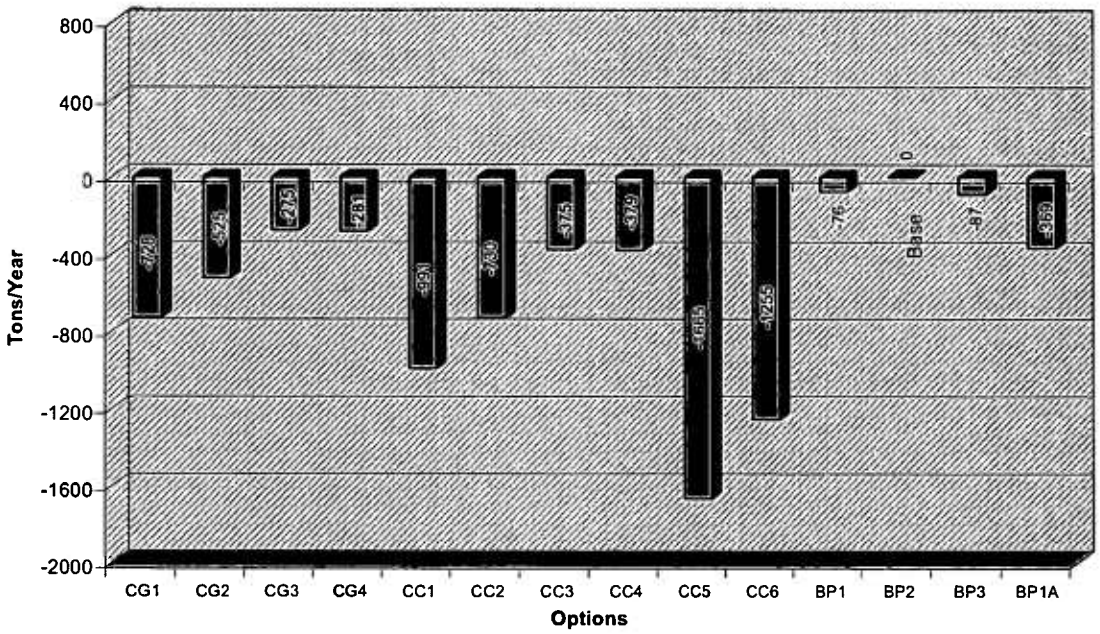


Exhibit 7-6 Impact of Hudson Avenue Repowering Options on Annual SO2 Emissions City-Wide

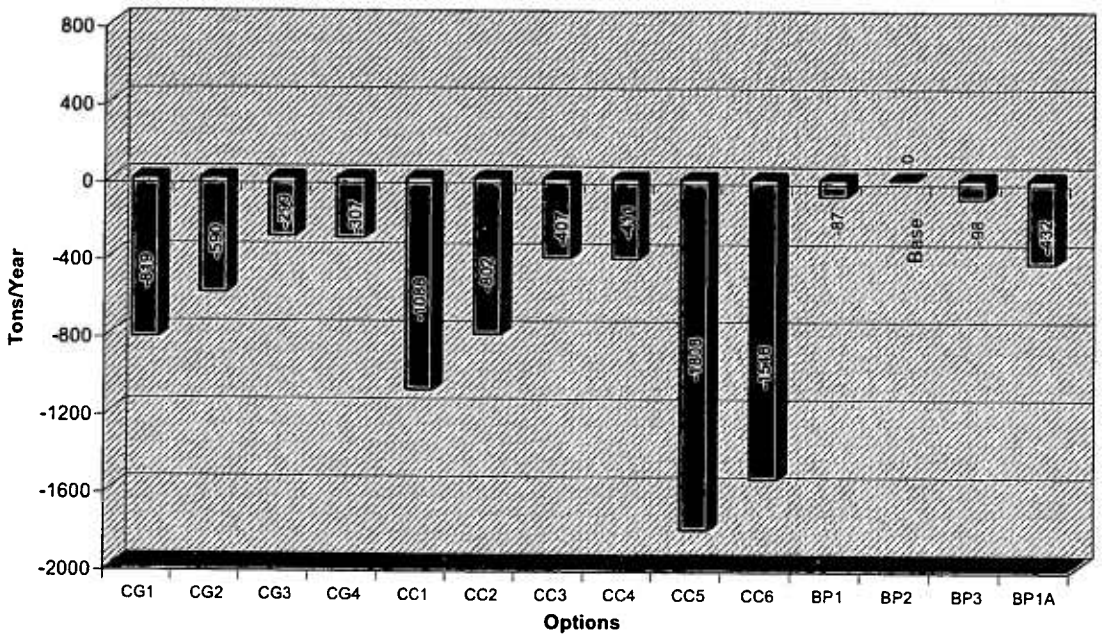


Exhibit 7-7 Impact of Hudson Avenue Repowering Options on Annual PM10 Emissions City-Wide

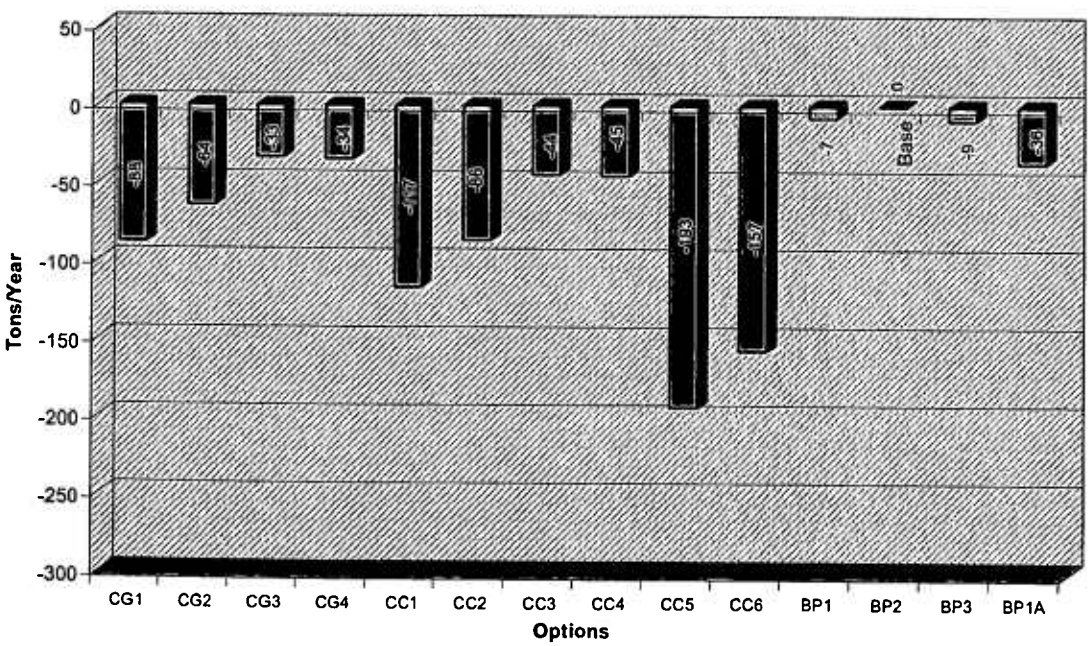


Exhibit 7-8 Impact of Hudson Avenue Repowering Options on Annual VOC Emissions City-Wide

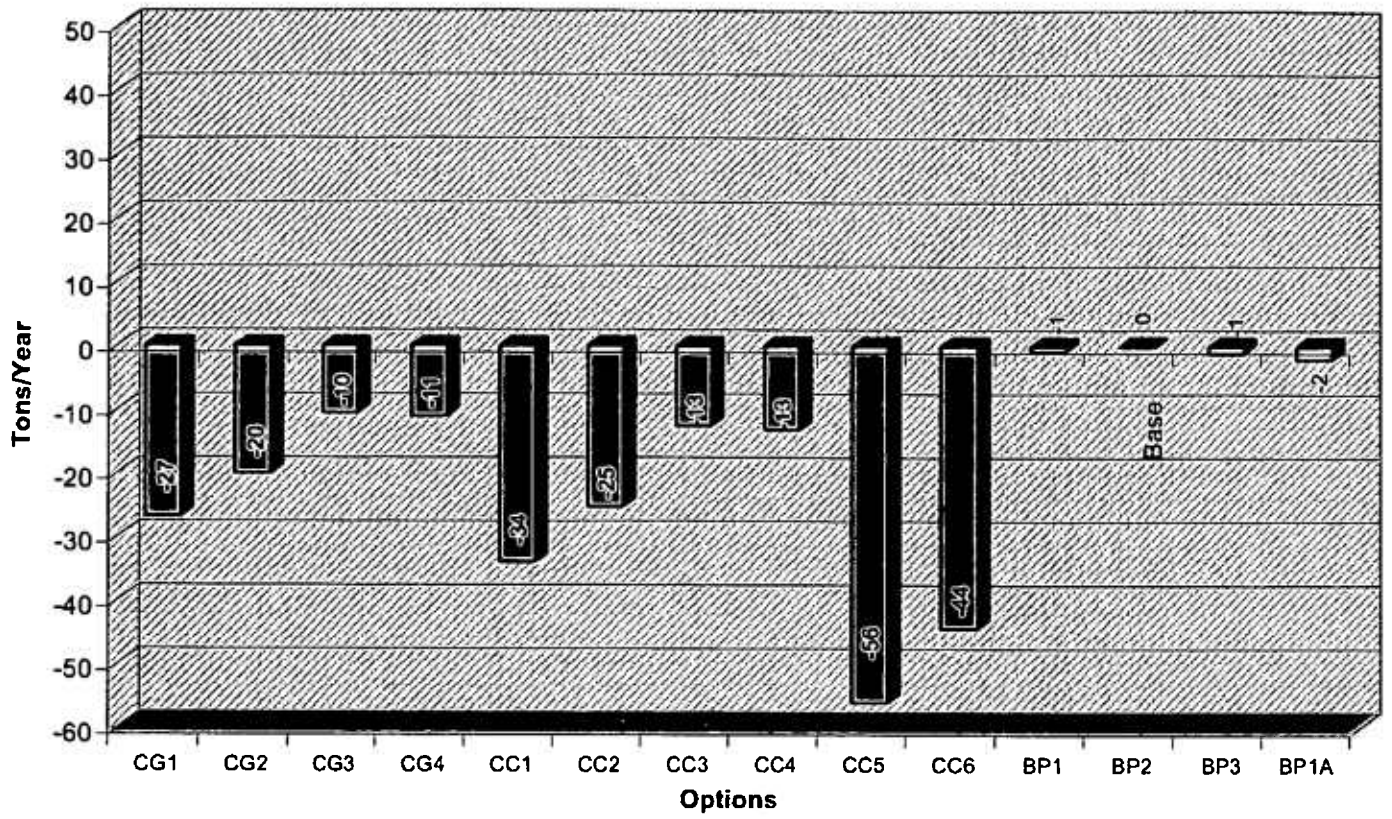
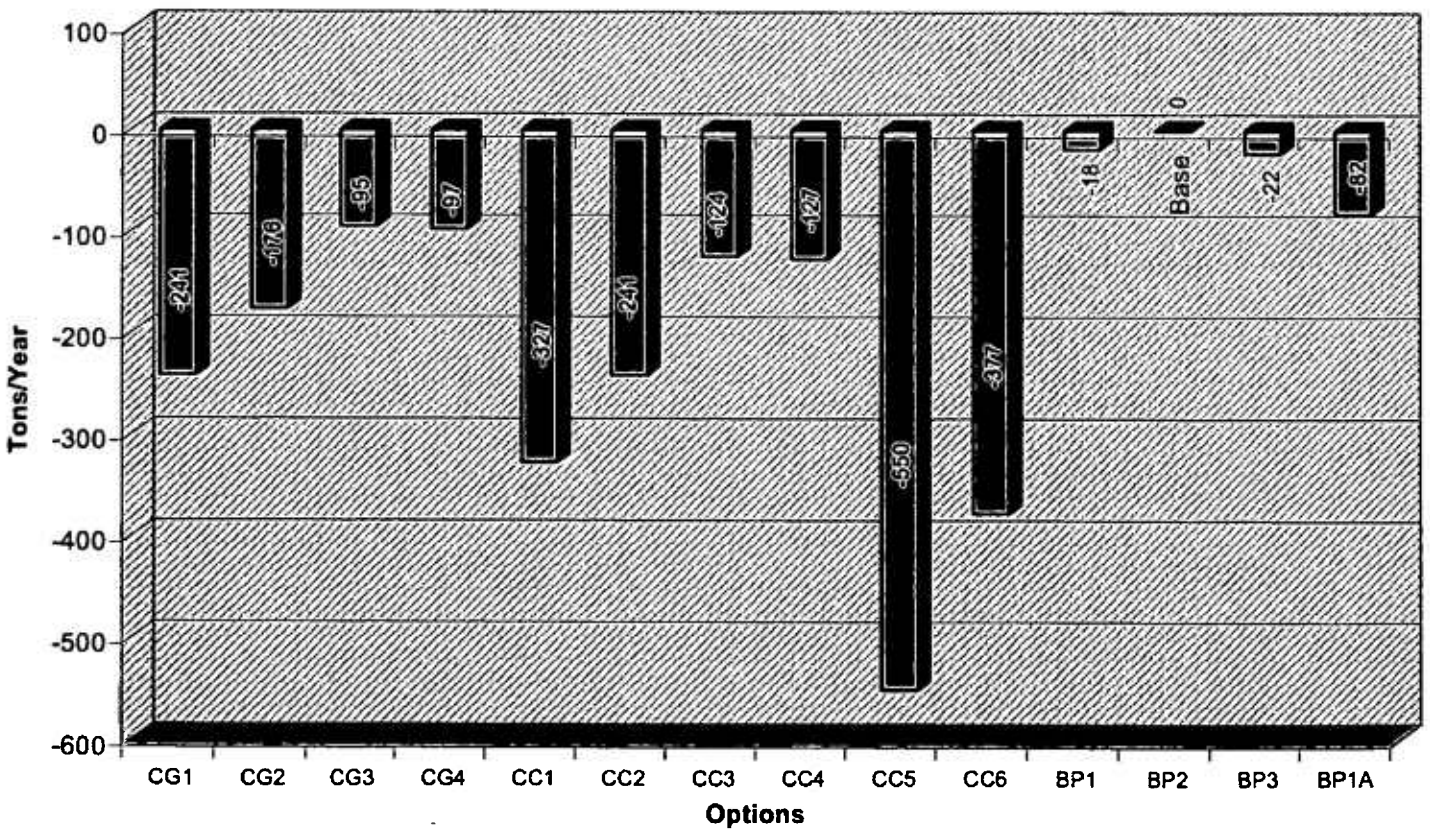


Exhibit 7-9 Impact of Hudson Avenue Repowering Options on Annual CO Emissions City-Wide



7.2 ALTERNATIVE (MERCHANT) SUPPLIES OF STEAM

7.2.1 Impact on Production Costs

The estimated impact of the KeySpan steam supply alternative on electric and steam production costs City-wide due to variable fuel and emission costs is summarized in Exhibit 7-10. The basis for the evaluation, that is the alternative to KeySpan steam supply, was continued operation of Con Edison's Ravenswood Steam Plant with four new, natural gas boilers (with oil backup) as described for the Ravenswood Steam Plant evaluation in the Appendix G. The evaluation of the impact considered the following:

- For the KeySpan alternative, the fuel cost for operation of the Ravenswood Steam Plant with its existing boilers for the first six years (2006 through 2011) while the KeySpan permitting, engineering and design, procurement, and installation activities required to provide steam to Con Edison are completed;
- Cost of fuel for KeySpan Unit 40 operation and steam supply from 2012 to 2025;
- Fuel cost for an electric power generated that would generate electric energy displaced by KeySpan Unit 40 for the production of steam for Con Edison - the methodology for selection of the power generating unit was as described for the KeySpan alternative in Section 5.0;
- Net incremental emissions cost/credit considering the increase in emissions from KeySpan Unit 40 to produce steam for Con Edison, increase in emissions from the electric power generator making up for the electric energy displaced by KeySpan Unit 40, and the reduction in emissions from retirement of the Ravenswood Steam Plant after 2011.
- Fuel cost for operation of the Ravenswood Steam Generating Station as an alternative to KeySpan steam supply.

As with the Hudson Avenue evaluations, this evaluation is based on variable fuel and emission costs only and does not include other annual costs.

Exhibit 7-10 Impact of KeySpan Option on Electric and Steam Production Costs City-Wide Due to Variable Fuel and Emissions Operating Costs Based on CERA 2005 Rearview Mirror Price Projections

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Ravenswood 6 yr. Operation																				
Fuel cost																				
KeySpan Energy Unit 40 Operation																				
KeySpan Unit 40 without Steam Sendout Fuel Cost																				
KeySpan Unit 40 with Steam Sendout Fuel Cost																				
Incremental Fuel Cost (with Steam Sendout - without Steam Sendout)																				
Electric Power Generator Replacing Displaced Power (Note 1)																				
MW-hr Generated																				
Incremental Power Generator Fuel Cost, $ (Note 1)																				
Ravenswood Steam Plant																				
Ravenswood Fuel Cost, Four New Boilers Option (Natural Gas Fired)																				
Net Incremental Emissions Credit/Cost (Note 1)																				
NOx (Note 2)																				
VOC (Note 3)																				
Total																				
Net Impact of KeySpan Alternative on City-Wide Production Cost																				
Net Incremental Production Cost, $																				
NPV of Net Incremental Production Cost, $																				
Steam Sendout																				
Discounted Steam Sendout, MMlb																				
NPVDiscounted Steam Sendout, $/Mlb																				
Note 1: Based on CERA energy price projections, natural gas-fired steam unit generating displaced electric power in summer, combination natural gas-fired combined cycle unit and #6 fuel oil (FO6)-fired steam unit generating power in winter.																				
Note 2: Based on $1,600/ton/year NOx allowance and $643/ton/year SO2 allowance costs and net emissions change for KeySpan Unit 40 and electric power generators.																				

[ALL DATA REDACTED]

8.0 CONCLUSIONS AND RECOMMENDATIONS

WorleyParsons has performed an evaluation of the feasibility of alternative steam supplies as part of Phase 1 of a steam production cost study of long-term steam production options in support of Con Edison and the Steam Business Development Task Force. The alternatives included repowering options at four Con Edison steam plants, supply of steam by Alternative Merchant Facilities, and supply of steam by Commercial and Academic customers.

The four Con Edison steam plants are the Hudson Avenue Station, 59th Street Station, 74th Street Station, and Ravenswood Steam Generating Station. WorleyParsons performed an assessment of the existing systems at the facilities and identified repowering options for those facilities for evaluation with respect to their potential to reduce the cost of steam production at the facilities. The options for the Hudson Avenue, 59th Street, and 74th Street Stations included combustion turbine, combustion turbine combined cycle, and steam boiler/steam turbine cogeneration systems, and boiler only systems. The options for the Ravenswood Steam Generating Station included rebuilding of one, two, three, or all four of the existing boilers and replacement of one, two, three, or all four of the existing boilers with new boilers.

The Alternative Merchant Facilities included the KeySpan Ravenswood LLC's Ravenswood Unit 40 combined cycle power system and the TransGas proposed combined cycle cogeneration system. The Customer steam suppliers were proxy-facilities representing commercial and academic owned facilities with either a boiler or a cogeneration system.

WorleyParsons developed criteria for the evaluations and capital and annual cost estimates for the options over a twenty year period from 2006 to 2025 based on inputs from Con Edison. WorleyParsons also evaluated the Net Present Value (NPV) of total annual costs for the options and a Unit NPV of net cost of steam production per thousand pounds of discounted annual steam production as a Figure of Merit for selecting promising options.

Key conclusions from the Phase 1 study are as follows:

- Hudson Avenue Station:
  - In WorleyParsons opinion, the existing operating boilers at the Station will not provide reliable service for 20 years and need to be replaced, and it would not be economical to continue use of the building housing the boilers for 20 years.
  - [REDACTED].
  - [REDACTED].
  - [REDACTED].

- Options BP-1, BP-2, and CG-1 would all result in significant emission reductions relative to the existing boilers at the projected annual steam sendout provided by Con Edison for the study.
- The Unit NPV of the cost of steam production for all the combustion turbine cogeneration and combined cycle options, except for CC5 and CC6, are within [REDACTED] of each other based on the CERA 2005 Rearview Mirror Scenario projections. Option CC5 is also within about [REDACTED] of all the cogen and combined cycle options based on the Shades of Green price projections. The Unit NPV for options CC5 and CC6 are [REDACTED] than that of option BP-1, respectively, based on the Rearview Mirror Scenario projections and about [REDACTED], respectively, based on the Shades of Green price projections.

♦ 59th Street

- In WorleyParsons opinion, with the present operation of the boilers and the ongoing capital replacement and maintenance program, these boiler systems should provide satisfactory operation over the 20 year study period.
- The NPV and Unit NPV of the cost of steam production over the 20 year study period for the existing system are less ([REDACTED]) than the cogeneration repowering options evaluated based on both the CERA 2005 Rearview Mirror Scenario and Shades of Green Scenario price projections.

♦ 74th Street Station

- In WorleyParsons opinion, site specific constraints inhibit the repowering of this facility.
- With the present operation of the boilers and the ongoing capital replacement and maintenance program, the existing boiler systems should provide satisfactory operation over the 20 year study period.

♦ KeySpan Steam Supply Alternative

- The Unit NPV of projected nte cost of steam projection for the [REDACTED] KeySpan Option is estimated to be about [REDACTED] that estimated for Ravenswood [REDACTED] Option [REDACTED], and the [REDACTED] Option is about [REDACTED] the Ravenswood Steam Generating Station [REDACTED] Option.

♦ Customer Supplied Steam

- The cost of steam production estimated for the customer supplied steam options based on economic factors applicable to both commercial interests and academic interests do not appear to be competitive at the capacity factors typical of Con Edison steam generating stations (Currently, Con Edison steam production facilities operate at an average annual capacity factor of 27%).

Based on the above conclusions, WorleyParsons recommends the following:

- **Hudson Avenue Plant**: Options BP-1, BP-2 and CG-1 be further evaluated. These options [REDACTED], and represent one each of a boiler/steam turbine cogeneration system, boiler only system, and .combustion turbine cogeneration system.
- **59th Street Plant**: Maintain current operation with planned future upgrades and modifications.
- **74th Street Plant**: Maintain current operation with planned future upgrades and modifications.
- **Alternative Facility:** Consider the KeySpan [REDACTED] Option as a potential alternative to Ravenswood plant repowering.

A

WorleyParsons

resources & energy

Long Term Con Edison Steam Production Options Study - Phase 1

Final Report Appendix A

Study Cost Estimate Data

Prepared for

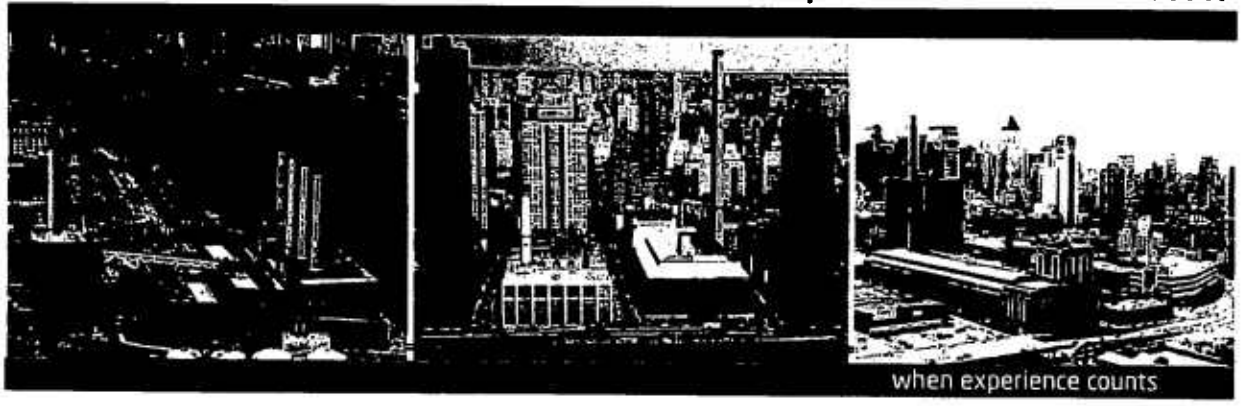
Consolidated Edison Company of New York, Inc.

in conjunction with the

Steam Business Development Core Task Force

October 2006

Report No. 53780001-CED-FR-01-R



NOTICE

This report reflects the work performed by WorleyParsons, using technical and financial inputs provided by Consolidated Edison and others, relating to the existing condition, environment, energy demands, and other data from selected Consolidated Edison Steam Generating Stations and other steam and power generating facilities. The report is based also on information, facts, assumptions and representations provided by Con Edison and others, which have not been independently verified by WorleyParsons, and is provided solely for information purposes, and there is no representation or warranty, expressed or implied, regarding for the fairness, accuracy or completeness of the information. The information also represents WorleyParsons understanding of an approach to potential feasible Projects that will provide the most economic solution; however, every possible combination or scenario has not been considered, and no liability, howsoever arising, is or will be accepted by WorleyParsons for the fairness, accuracy or completeness of the information contained in, or any omissions from, the report, or any other information supplied or made available regarding the Project, in writing or orally, in connection with any decisions to be taken by Consolidated Edison with respect to a proposed Project, or for the consequences of any reliance upon, or other use of, any such information or the report. WorleyParsons does not take direct responsibility for decisions which are based on the findings and results presented herein. Consolidated Edison, or any other third person is responsible for making its own decisions, and we cannot predict the actions of third parties whose actions may be required to execute projects discussed herein.

APPENDIX A - COST ESTIMATES FOR STUDY OPTIONS

CONCEPTUAL PLANT CAPITAL COST DETAILS FOR CASES

Exhibit A-0 Plant Capital Cost Detail for Options

CONCEPTUAL COST ESTIMATE DETAILS FOR HUDSON AVENUE CASES

Exhibit A-1 Conceptual Cost Estimates for Hudson Avenue Repowering Option CG-1
Exhibit A-2 Conceptual Cost Estimates for Hudson Avenue Repowering Option CG-2
Exhibit A-3 Conceptual Cost Estimates for Hudson Avenue Repowering Option CG-3
Exhibit A-4 Conceptual Cost Estimates for Hudson Avenue Repowering Option CG-4
Exhibit A-5 Conceptual Cost Estimates for Hudson Avenue Repowering Option CC-1
Exhibit A-6 Conceptual Cost Estimates for Hudson Avenue Repowering Option CC-2
Exhibit A-7 Conceptual Cost Estimates for Hudson Avenue Repowering Option CC-3
Exhibit A-8 Conceptual Cost Estimates for Hudson Avenue Repowering Option CC-4
Exhibit A-9 Conceptual Cost Estimates for Hudson Avenue Repowering Option CC-5
Exhibit A-10 Conceptual Cost Estimates for Hudson Avenue Repowering Option CC-6
Exhibit A-11 Conceptual Cost Estimates for Hudson Avenue Repowering Option BP-1
Exhibit A-12 Conceptual Cost Estimates for Hudson Avenue Repowering Option BP-2
Exhibit A-13 Conceptual Cost Estimates for Hudson Avenue Repowering Option BP-3
Exhibit A-14 Conceptual Cost Estimates for Hudson Avenue Repowering Option BP-1A

Exhibit A-0 Plant Capital Cost Detail for Options

REDACTED

Exhibit A-0 Plant Capital Cost Detail for Options (continued)

REDACTED

Exhibit A-1 Conceptual Cost Estimates for Hudson Avenue Repowering Option CG-1

REDACTED

Exhibit A-1 Conceptual Cost Estimates for Hudson Avenue Repowering Option CG-1 (continued)

REDACTED

Exhibit A-2 Conceptual Cost Estimates for Hudson Avenue Repowering Option CG-2

REDACTED

Exhibit A-2 Conceptual Cost Estimates for Hudson Avenue Repowering Option CG-2 (continued)

REDACTED

Exhibit A-3 Conceptual Cost Estimates for Hudson Avenue Repowering Option CG-3

REDACTED

Exhibit A-3 Conceptual Cost Estimates for Hudson Avenue Repowering Option CG-3 (continued)

REDACTED

Exhibit A-4 Conceptual Cost Estimates for Hudson Avenue Repowering Option CG-4

REDACTED

Exhibit A-4 Conceptual Cost Estimates for Hudson Avenue Repowering Option CG-4 (continued)

REDACTED

Exhibit A-5 Conceptual Cost Estimates for Hudson Avenue Repowering Option CC-1

REDACTED

Exhibit A-5 Conceptual Cost Estimates for Hudson Avenue Repowering Option CC-1 (continued)

REDACTED

Exhibit A-6 Conceptual Cost Estimates for Hudson Avenue Repowering Option CC-2

REDACTED

Exhibit A-6 Conceptual Cost Estimates for Hudson Avenue Repowering Option CC-2 (continued)

REDACTED

Exhibit A-7 Conceptual Cost Estimates for Hudson Avenue Repowering Option CC-3

REDACTED

Exhibit A-7 Conceptual Cost Estimates for Hudson Avenue Repowering Option CC-3 (continued)

REDACTED

Exhibit A-8 Conceptual Cost Estimates for Hudson Avenue Repowering Option CC-4

REDACTED

Exhibit A-8 Conceptual Cost Estimates for Hudson Avenue Repowering Option CC-4 (continued)

REDACTED

Exhibit A-9 Conceptual Cost Estimates for Hudson Avenue Repowering Option CC-5

REDACTED

Exhibit A-9 Conceptual Cost Estimates for Hudson Avenue Repowering Option CC-5 (continued)

REDACTED

Exhibit A-10 Conceptual Cost Estimates for Hudson Avenue Repowering Option CC-6

REDACTED

Exhibit A-10 Conceptual Cost Estimates for Hudson Avenue Repowering Option CC-6 (continued)

REDACTED

Exhibit A-11 Conceptual Cost Estimates for Hudson Avenue Repowering Option BP-1

REDACTED

Exhibit A-11 Conceptual Cost Estimates for Hudson Avenue Repowering Option BP-1 (continued)

REDACTED

Exhibit A-12 Conceptual Cost Estimates for Hudson Avenue Repowering Option BP-2

REDACTED

Exhibit A-12 Conceptual Cost Estimates for Hudson Avenue Repowering Option BP-2 (continued)

REDACTED

Exhibit A-13 Conceptual Cost Estimates for Hudson Avenue Repowering Option BP-3

REDACTED

Exhibit A-13 Conceptual Cost Estimates for Hudson Avenue Repowering Option BP-3 (continued)

REDACTED

Exhibit A-14 Conceptual Cost Estimates for Hudson Avenue Repowering Option BP-1A

REDACTED

Exhibit A-14 Conceptual Cost Estimates for Hudson Avenue Repowering Option BP-1A (continued)

REDACTED

CONCEPTUAL COST ESTIMATE DETAILS FOR 74TH STREET CASE

Exhibit A-15 Conceptual Cost Estimates for 74th Street Existing Facility

Exhibit A-15 Conceptual Cost Estimates for 74th Street Existing Facility

REDACTED

Exhibit A-15 Conceptual Cost Estimates for 74th Street Existing Facility (continued)

REDACTED

CONCEPTUAL COST ESTIMATE DETAILS FOR 59TH STREET CASES

Exhibit A-16 Conceptual Cost Estimates for 59th Street Existing Facility

Exhibit A-17 Conceptual Cost Estimates for 59th Street Repowering Option CG-1

Exhibit A-18 Conceptual Cost Estimates for 59th Street Repowering Option CG-2

Exhibit A16 Conceptual Cost Estimates for 59th Street Existing Facility

REDACTED

Exhibit A16 Conceptual Cost Estimates for 59th Street Existing Facility (continued)

REDACTED

Exhibit A-17 Conceptual Cost Estimates for 59th Street Repowering Option CG-1

REDACTED

Exhibit A-17 Conceptual Cost Estimates for 59th Street Repowering Option CG-1 (continued)

REDACTED

Exhibit A-18 Conceptual Cost Estimates for 59th Street Repowering Option CG-2

REDACTED

Exhibit A-18 Conceptual Cost Estimates for 59th Street Repowering Option CG-2 (continued)

REDACTED

CONCEPTUAL COST ESTIMATE DETAILS FOR CUSTOMER SUPPLIED CASES

Exhibit A-19 Conceptual Cost Estimates for Commercial Customer Supplied Steam Option CG-1

Exhibit A-20 Conceptual Cost Estimates for Commercial Customer Supplied Steam Option BP-1

Exhibit A-21 Conceptual Cost Estimates for Academic Customer Supplied Steam Option CG-1

Exhibit A-22 Conceptual Cost Estimates for Academic Customer Supplied Steam Option BP-1

Exhibit A - 19 Conceptual Cost Estimates for Commercial Customer Supplied Steam Option CG-1

4	CERA 2005 Pricing senerio = Rear View Mirror	Items	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025		
CONCEPTUAL DATA(1)		General Inflation:	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	20yr Total or NPV	
Commercial Case		Compounded:	1.00	1.03	1.06	1.09	1.13	1.16	1.19	1.23	1.27	1.30	1.34	1.38	1.43	1.47	1.51	1.56	1.60	1.65	1.70	1.75		
ITEM	DESCRIPTION	STEAM GENERATION AND RE-POWERING OPTIONS	Cost Values in Current (Nominal) Dollars unless noted otherwise.																					
	Customer Supplied Steam	Cogeneration Options with Supp Fired HRSGs																						
100%	= STEAM SEND OUT CAPACITY FACTOR	Option - CG1	Base	Base	Base	Base	Base	Base	Option - CG1	Option - CG1	Option - CG1	Option - CG1	Option - CG1	Option - CG1	Option - CG1	Option - CG1	Option - CG1	Option - CG1	Option - CG1	Option - CG1	Option - CG1	Option - CG1		
A.	Option Description	One (1) GE 7FA Gas Turbine with Supp Fired HRSG, partial capacity Dump Condenser plus 1 package boiler - Gas																						
B.	New Configuration Description																							
1.	Facility Area Size for Foregone Rent, Sq Ft	8100																						
2.	Average Steam Consumption , Mlb/hr	25																						
3.	Average Elec. Requirement (W/O Stm Export), kW	8460																						
4.	Number of Gas turbines/HRSGs	1																						
5.	Gas Turbine Rating at ISO, KW	10700																						
6.	Number of Steam Turbine	N.A.																						
7.	Number of New HP Boilers	N.A.																						
8.	Capacity of New HP Boiler, Mlb/hr	N.A.																						
9.	Number of New LP Boilers(6)	1																						
10.	LP Boiler Capacity each, Mlb/hr(6)	30																						
C.	Net Steam Generation(2)																							
1.	Design Send Out Capacity, Mlb/hr	88																						
2.	Annual Average Send Out Capacity, MMlb	582																						
3.	Annual Avg. Hourly Send out Capacity, Mlb/hr	64																						
4.	Cogen Plant Steam Generation Capacity, Mlb/hr																							
a.	With SF in HRSGs, Base Load	104																						
b.	No SF in HRSG, Base Load	49																						
c.	With SF in HRSGs, Operating Load	93																						
d.	No SF in HRSG, Operating Load	39																						
5.	Net New Package Boiler Capacity, Mlb/hr	25																						
6.	Annual Net Stm Send Out Capability, MMlb																							
a.	With Suppl Firing in HRSGs /Boilers	582																						
b.	Without Suppl Firing in HRSGs	114																						
D.	Cogen/CC/Boiler Plant operation and Annual Steam Ge																							
1.	Gas Turbine / Boiler Operating hours	8,322																						
2.	Operating Hours- HRSG with full SF	8,322							8,322	8,322	8,322	8,322	8,322	8,322	8,322	8,322	8,322	8,322	8,322	8,322	8,322	8,322	116,508	Total over 20 years
3.	Oper Hours - HRSG for part SF mode																							
4.	HRSG - Oper Hours no Supp Firing																							
5.	Cogen Plant																							
a.	Net Export Steam with full SF, MMlb	582																						
b.	Net Export Steam with Partial SF /Int Exp, MMlb								562	562	562	562	562	562	562	562	562	562	562	562	562	562	7,865	Total over 20 years
c.	Export Steam W/O Supp Firing, MMlb																							Total over 20 years
6.	Steam from Package Boilers, MMlb(4)																							Total over 20 years
a.	Export Steam																							Total over 20 years
b.	Internal Steam Usage(7)	11							11	11	11	11	11	11	11	11	11	11	11	11	11	11	153	Total over 20 years
7.	Annual Building Internal Consumption, MMLb	219							219	219	219	219	219	219	219	219	219	219	219	219	219	219	3,065	Total over 20 years
10.	Total Annual Steam Export, MMlb	562	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	561,821	561,821	561,821	561,821	561,821	561,821	561,821	561,821	561,821	561,821	561,821	561,821	561,821	561,821	11,236	Total over 20 years
E.	Electrical Output(3), kW																							
1.	Gas Turbine	8,884							8,584	8,656	8,629	8,601	8,573	8,546	8,519	8,491	8,464	8,437	8,410	8,383	8,356	8,330	119,079	Total over 20 years
2	Net Plant Output Capacity	8,460							8,460	8,433	8,406	8,379	8,352	8,326	8,299	8,272	8,246	8,219	8,193	8,167	8,141	8,115	116,088	Total over 20 years
F.	Annual Fuel (MMBtu - HHV), Electricity (MWh), Water C																							
1.	Gas Turbine Fuel - Gas	888,384							888,384	888,887	885,414	883,943	882,474	881,008	859,544	858,083	856,624	855,168	853,714	852,263	850,814	849,367	12,023,865	Total over 20 years
2.	Gas Turbine Fuel - Oil																							Total over 20 years
3.	HRSG Fuel for Full Supp Firing - Gas only	528,962																						Total over 20 years
4.	HRSG Fuel for Partial SF (CG) / Int Exp (CC) - Gas Only								528,962	529,386	529,809	530,233	530,657	531,082	531,506	531,932	532,357	532,783	533,209	533,636	534,063	534,490	7,444,105	Total over 20 years
5.	HP Boiler Fuel - Gas																							Total over 20 years
6.	HP Boiler Fuel - Oil																							Total over 20 years
7.	Pkg Boiler Fuel - Gas	14,265							14,265	14,276	14,288	14,299	14,311	14,322	14,334	14,345	14,356	14,368	14,379	14,391	14,402	14,414	200,750	Total over 20 years
8.	Pkg Boiler Fuel - Oil																							Total over 20 years
9.	Total Fuel Consumption - Oil																							Total over 20 years
10.	Total Fuel Consumption - Gas	1,411,591							1,411,591	1,410,549	1,408,511	1,408,475	1,407,442	1,406,411	1,405,384	1,404,359	1,403,338	1,402,319	1,401,303	1,400,289	1,399,279	1,398,271	19,668,520	Total over 20 years
11.	Total Water Consumption (1000 gal)	68,794							68,794	68,794	68,794	68,794	68,794	68,794	68,794	68,794	68,794	68,794	68,794	68,794	68,794	68,794	963,117	Total over 20 years
12.	Total Electric Import, (MWh)(5)	3,705							3,705	3,705	3,705	3,705	3,705	3,705	3,705	3,705	3,705	3,705	3,705	3,705	3,705	3,705	51,877	Total over 20 years
13.	Annual Net Plant Output Capacity (MWh)	70,404							70,404	70,179	69,954	69,730	69,507	69,285	69,063	68,842	68,622	68,402	68,183	67,965	67,748	67,531	965,416	Total over 20 years

Exhibit A - 19 Conceptual Cost Estimates for Commercial Customer Supplied Steam Option CG-1

4	CERA 2005 Pricing senario = Rear View Mirror	Items	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025		
CONCEPTUAL DATA[1]		General Inflation:	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%		
Commercial Case		Compounded:	1.00	1.03	1.06	1.09	1.13	1.16	1.19	1.23	1.27	1.30	1.34	1.38	1.43	1.47	1.51	1.56	1.60	1.65	1.70	1.75		
ITEM	DESCRIPTION	STEAM GENERATION AND RE-POWERING OPTIONS	Cost Values in Current (Nominal) Dollars unless noted otherwise.																					
	Customer Supplied Steam	Cogeneration Options with Supp Fired HRSGs																						
100%	= STEAM SEND OUT CAPACITY FACTOR	Option - CG1	Base	Base	Base	Base	Base	Base	Option - CG1	Option - CG1	Option - CG1	Option - CG1	Option - CG1	Option - CG1	Option - CG1	Option - CG1	Option - CG1	Option - CG1	Option - CG1	Option - CG1	Option - CG1	Option - CG1		
A.	Option Description	Gas Turbine with Supp Fired HRSG, partial capacity Dump Condenser plus 1 package boiler - Gas																						
Q.	Total Plant Cost - 2006 US Dollars	2006 $																						
1.	Existing Plant Maintenance Cost																							
2.	EPC Cost																							
a	Cogen / CC Unit and accessories	$34,686,000				$11,218,683	$26,840,700	$23,682,781																
b	Boiler Plant																						$36,181,392	
	HP and LP Boiler Plant - Loaded																							
c	Demin Plant	$1,393,000				$450,546	$1,077,930	$951,107																
d	Other BOP																						$1,453,055	
	Black Start	$305,000				$98,648	$236,015	$208,247																
	Dump Condenser	$305,000				$98,648	$236,015	$208,247															$318,149	
	SCR																						$318,149	
	Steam Piping (above grnd), excl york line replacement																							
	Gas Boiler Enclosures																							
	Other HP Boiler - BP Turbine																							
3.	Demolition /Relocation/ Remediation Costs																							
a	Demolition Costs - loaded																							
b	Relocation Costs - Unloaded																							
	Relocation Costs - loaded																							
c	Remediation Costs																							
4.	Permitting/Prelim Engineering	$5,000,000	$2,466,577	$2,725,568	$3,006,203	$614,876	$660,992	$710,566																
5.	Gas Piping Interconnect Costs - loaded																						$7,830,283	
6.	Electrical Reinforcement/Interconnect Costs - loaded																							
7.	Contingency																							
8.	Owner's other Costs(4)		included in above	included in above	included in above	included in above	included in above	included in above	included in above	included in above	included in above	included in above	included in above	included in above	included in above	included in above	included in above	included in above	included in above	included in above	included in above	included in above	included in above	
	Capitalized Property Tax During Construction		included in above	included in above	included in above	included in above	included in above	included in above	included in above	included in above	included in above	included in above	included in above	included in above	included in above	included in above	included in above	included in above	included in above	included in above	included in above	included in above	included in above	
9	Total Plant Cost (TPC)	$41,689,000	$2,466,577	$2,725,568	$3,006,203	$12,481,401	$29,051,652	$25,760,948	$9,860,340														$46,785,412	
H.	Annual Costs								$9,860,340														$50,886,441	
1.	Fuel Cost																							
2a	Depreciation								$12,650,781	$13,113,864	$13,605,807	$14,620,106	$13,550,713	$14,160,679	$14,673,230	$15,283,504	$16,425,078	$16,861,632	$17,580,430	$18,282,218	$18,987,112	$19,886,229	$58,193,155	
2b	Equity Return								$2,845,090	$2,845,090	$2,845,090	$2,845,090	$2,845,090	$2,845,090	$2,845,090	$2,845,090	$2,845,090	$2,845,090	$2,845,090	$2,845,090	$2,845,090	$2,845,090	$10,767,355	
2c	Interest on Debt								$6,600,608	$6,373,001	$6,145,394	$5,917,786	$5,690,179	$5,462,572	$5,234,965	$5,007,358	$4,779,751	$4,552,143	$4,324,536	$4,096,929	$3,869,322	$3,641,715	$20,758,353	
2d	Federal & State Income Tax								$3,980,365	$3,823,800	$3,687,236	$3,550,672	$3,414,108	$3,277,543	$3,140,979	$3,004,415	$2,867,850	$2,731,286	$2,594,722	$2,458,157	$2,321,593	$2,185,029	$12,455,612	
3.	Water & Chemical Costs								$4,400,405	$4,248,887	$4,096,929	$3,945,181	$3,793,453	$3,641,715	$3,489,977	$3,338,238	$3,186,500	$3,034,762	$2,883,024	$2,731,286	$2,579,548	$2,427,810	$13,839,589	
4.	Electricity Purchase Cost								$1,037,528	$1,068,653	$1,100,713	$1,133,734	$1,167,746	$1,202,779	$1,238,862	$1,276,028	$1,314,309	$1,353,738	$1,394,350	$1,436,181	$1,479,266	$1,523,644	$4,560,995	
	Steam Purchase Cost		[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	$1,933,385	$1,978,820	$2,031,851	$2,063,315	$2,105,302	$2,155,813	$2,205,722	$2,258,059	$2,322,477	$2,377,525	$2,430,093	$2,482,345	$2,534,278	$2,585,889	$8,190,769	
5.	O&M Costs of existing plant(16)																						$45,896,058	
6.	Non Fuel O&M Costs	$490,500																						
	Foregone Rent								$585,683	$603,253	$621,351	$639,991	$659,191	$678,967	$699,336	$720,316	$741,925	$764,183	$787,109	$810,722	$835,043	$860,095	$2,574,674	
7a	Property Tax eligible ICIP		$133,195	$288,787	$469,672	$1,220,255	$3,022,549	$4,725,881	$483,591	$498,099	$513,042	$528,433	$544,288	$560,615	$577,433	$594,756	$612,599	$630,977	$649,905	$669,403	$689,485	$710,170	$2,125,878	
7b	Property Tax Not eligible ICIP								$4,687,658	$5,013,688	$5,184,098	$5,319,021	$5,478,592	$5,642,950	$5,812,238	$5,986,605	$6,166,203	$6,351,189	$6,541,725	$6,737,977	$6,940,116	$7,148,320	$27,251,761	
7c	Property Tax on New but not completed Project credit		($133,195)	($288,787)	($469,672)	($1,220,255)	($3,022,549)	($4,725,881)																
8	ICIP Credit																						($5,853,424)	
9	Total Annual Cost		[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]																
I.	Steam Generation Costs ($) based upon Avoided Cost Offset								$39,374,093	$39,568,935	$40,031,510	$40,583,342	$39,228,859	$39,628,671	$39,917,831	$40,264,369	$41,261,781	$41,522,526	$42,030,965	$42,550,308	$43,080,853	$43,622,989	$198,758,757	
1.	Avoided Cost of Electricity Purchase(5)																							
2.	Avoided Cost of Steam Purchase(9)								$9,839,388	$10,157,858	$10,598,743	$11,003,121	$10,842,787	$11,207,484	$11,549,187	$11,924,333	$12,511,196	$12,922,052	$13,332,466	$13,744,466	$14,156,338	$14,574,122	$43,287,415	
3.	-								$4,341,748	$4,407,048	$4,568,446	$4,841,427	$4,741,181	$4,828,189	$5,019,303	$5,187,486	$5,408,884	$5,558,394	$5,735,739	$5,915,812	$6,098,695	$6,284,472	$18,796,538	
4	Total Avoided Costs																							
5a	Cost Attributed to Steam		[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	$14,181,115	$14,559,906	$15,167,189	$15,844,548	$15,583,948	$16,035,653	$16,566,490	$17,111,819	$17,920,080	$18,480,446	$19,068,145	$19,680,278	$20,257,031	$20,858,594	$62,083,053	
5b	Steam Generation Cost w/o Emission Credits ($/1000lb)		[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	$25,192,978	$25,007,028	$24,864,321	$24,738,793	$23,644,711	$23,593,019	$23,349,341	$23,182,552	$23,341,701	$23,042,080	$22,962,840	$22,890,030	$22,823,822	$22,764,395	$136,672,805		
6a	Cost Attributed to Steam w/o Emission Credits - NPV ($)		[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	$44.84	$44.51	$44.26	$44.03	$42.09	$41.99	$41.56	$41.25	$41.55	$41.01	$40.87	$40.74	$40.62	$40.52		
6b	Cumulative NPV of Cost Attributed to Steam w/o Emission Credits ($)		[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	$12,226,638	$10,945,519	$9,815,166	$8,807,372	$7,591,858	$6,831,964	$6,097,935	$5,460,298	$4,958,317	$4,414,385	$3,967,535	$3,566,880	$3,207,578	$2,885,305	$136,672,805	Total over 20 years
6c	NPV of Steam Product (MMlb)		[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	$56,122,695	$69,068,213	$78,883,379	$87,690,751	$95,282,619	$102,114,572	$108,212,508	$113,672,804	$118,831,120	$123,045,505	$127,013,042	$130,579,921	$133,787,499	$136,672,805		
6d	Cost of Steam w/o Emission Credits ($/1000lb) - NPV		[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	335	312	289	269	250	232	215	200	186	173	160	149	138	129	5,662	Total over 20 years
7	Cumulative NPV of Cost of Steam w/o Emission Credits ($/1000lb)		[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	36.46	35.14	33.92	32.77	30.40	29.45	28.30	27.25	26.67	25.56	24.73	23.93	23.17	22.43	24.14	
8	Emission Credits on Annual Costs(7)								$19.83	$21.11	$22.15	$22.90	$23.38	$23.68	$23.80	$24.05	$24.15	$24.18	$24.31	$24.20	$24.18	$24.14		
a	NOx																							
b	SO2																							
c	PM10																							
d	VOC																							
e	Total Credits																							
9a	Cost Attributed to Steam with Emission Credits ($)		[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	$25,192,978	$25,007,028	$24,864,321	$24,738,793	$23,644,711	$23,593,019	$23,349,341	$23,182,552	$23,341,701	$23,042,080	$22,962,840	$22,890,030	$22,823,822	$22,764,395	$136,672,805		
9b	Steam Generation Cost with Emission Credits ($/1000lb)		[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	$44.84	$44.51	$44.26	$44.03	$42.09	$41.99	$41.56	$41.25	$41.55	$41.01	$40.87	$40.74	$40.62	$40.52		
9c	Cost Attributed to Steam with Emission Credits - NPV ($)		[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	$12,226,638	$10,945,519	$9,815,166	$8,807,372	$7,591,858	$6,831,964	$6,097,935	$5,460,298	$4,958,317	$4,414,385	$3,967,535	$3,566,880	$3,207,578	$2,885,305	$136,672,805	Total over 20 years
10b	Cumulative NPV of Cost Attributed to Steam with Emission Credits ($)		[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	$56,122,695	$69,068,213	$78,883,379	$87,690,751	$95,282,619	$102,114,572	$108,212,508	$113,672,804	$118,831,120	$123,045,505	$127,013,042	$130,579,921	$133,787,499	$136,672,805		
10c	NPV of Steam Product (MMlb)		[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	335	312	289	269	250	232	215	200	186	173	160	149	138	129	5,662	Total over 20 years
10d	Cost of Steam with Emission Credits ($/1000lb) - NPV		[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	36.46	35.14	33.92	32.77	30.40	29.45	28.30	27.28	26.67	25.56	24.73	23.93	23.17	22.43	24.14	
11	Cumulative NPV of Cost of Steam with Emission Credits ($/1000lb)		[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	$19.83	$21.11	$22.15	$22.90	$23.38	$23.68	$23.80	$24.05	$24.15	$24.18	$24.31	$24.20	$24.18	$24.14		
J.	Annual Emissions (TPY)(7)																							
1.	NOx	19																						
2.	SO2	2							19	19	19	19	19	19	19	19	19	19	19	19	19	19	264	Total over 20 years
3.	PM10	5							2	2	2	2	2	2	2	2	2	2	2	2	2	2	23	Total over 20 years
4.	PM	1							5	5	5	5	5	5	5	5	5	5	5	5	5	5	63	Total over 20 years
5.	VOC	1							1	1	1	1	1	1	1	1	1	1	1	1	1	1	19	Total over 20 years
6.	CO	12							1	1	1	1	1	1	1	1	1	1	1	1	1	1	17	Total over 20 years
									12	12	12	12	12	12	12	12	12	12	12	12	11	11	162	Total over 20 years
K.	Site Specific Constraints																							
1.	Layout Constraints																							
2.	Stack Issues																							
	Years to project completion	6																						

(1) refer to notes on Input From Screening Model on "WithProjectedSendOut-GandO" sheet
All costs in first data column are unloaded and 2006 $ unless otherwise noted

Exhibit A - 20 Conceptual Cost Estimates for Commercial Customer Supplied Steam Option BP-1

4	CERA 2005 Pricing senerio = Rear View Mirror	Items	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025		
CONCEPTUAL DATA[1]		General Inflation:	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	20yr Total or NPV	
Commercial Case		Compounded:	1.00	1.03	1.06	1.09	1.13	1.16	1.19	1.23	1.27	1.30	1.34	1.38	1.43	1.47	1.51	1.56	1.60	1.65	1.70	1.75		
ITEM	DESCRIPTION	STEAM GENERATION AND RE-POWERING OPTIONS	Cost Values in Current (Nominal) Dollars unless noted otherwise.																					
	Customer Supplied Steam	Boiler Only Option (BP-1)																						
100%	= STEAM SEND OUT CAPACITY FACTOR	Option - BP1	Base	Base	Base	Base	Base	Base	Option - BP1	Option - BP1	Option - BP1	Option - BP1	Option - BP1	Option - BP1	Option - BP1	Option - BP1	Option - BP1	Option - BP1	Option - BP1	Option - BP1	Option - BP1	Option - BP1		
A.	Option Description	Two (2) package boilers, gas Fired																						
B.	New Configuration Description																							
1.	Facility Area Size for Foregone Rent, Sq Ft	6300																						
2.	Average Steam Consumption , Mlb/hr	25																						
3.	Average Elec. Requirement (W/O Stm Export), kW	8440																						
4.	Number of Gas turbines/HRSGs	1																						
5.	Gas Turbine Rating at ISO, KW	N.A.																						
6.	Number of Steam Turbine	N.A.																						
7.	Number of New HP Boilers	N.A.																						
8.	Capacity of New HP Boiler, Mlb/hr	N.A.																						
9.	Number of New LP Boilers(6)	2																						
10.	LP Boiler Capacity each, Mlb/hr(6)	80																						
C.	Net Steam Generation(2)																							
1.	Design Send Out Capacity, Mlb/hr	77																						
2.	Annual Average Send Out Capacity, MMlb	641																						
3.	Annual Avg Hourly Send out Capacity, Mlb/hr	73																						
4.	Cogen Plant Steam Generation Capacity, Mlb/hr																							
a.	With SF in HRSGs, Base Load																							
b.	No SF in HRSG, Base Load																							
c.	With SF in HRSGs, Operating Load																							
d.	No SF in HRSG, Operating Load																							
5.	Net New Package Boiler Capacity, Mlb/hr	102																						
6.	Annual Net Stm Send Out Capability, MMlb	-																						
a.	With Suppl Firing in HRSGs /Boilers	824																						
b.	Without Suppl Firing in HRSGs																							
D.	Cogen/CC/Boiler Plant operation and Annual Steam G																							
1.	Gas Turbine / Boiler Operating hours	8,760																						
2.	Operating Hours- HRSG with full SF	-																						
3.	Oper Hours - HRSG for part SF mode																							
4.	HRSG - Oper Hours no Supp Firing																							
5.	Cogen Plant	-																						
a.	Net Export Steam with full SF, MMlb																							
b.	Net Export Steam with Partial SF /Int Exp, MMlb																							Total over 20 years
c.	Export Steam W/O Supp Firing, MMlb																							Total over 20 years
6.	Steam from Package Boilers, MMlb(4)																							Total over 20 years
a.	Export Steam	641																						Total over 20 years
b.	Internal Steam Usage(7)	219							641	641	641	641	641	641	641	641	641	641	641	641	641	641	8,969	Total over 20 years
7.	Annual Building Internal Consumption, MMLb	219							219	219	219	219	219	219	219	219	219	219	219	219	219	219	3,066	Total over 20 years
10.	Total Annual Steam Export, MMlb	641	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	219	219	219	219	219	219	219	219	219	219	219	219	219	219	3,066	Total over 20 years
E.	Electrical Output(3), kW								640.63	640.63	640.63	640.63	640.63	640.63	640.63	640.63	640.63	640.63	640.63	640.63	640.63	640.63	12,813	Total over 20 years
1.	Gas Turbine	N.A.																						
2.	Net Plant Output Capacity	N.A.																						Total over 20 years
F.	Annual Fuel (MMBtu - HHV), Electricity (MWh), Water								N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.			Total over 20 years
1.	Gas Turbine Fuel - Gas																							
2.	Gas Turbine Fuel - Oil																							Total over 20 years
3.	HRSG Fuel for Full Supp Firing - Gas only																							Total over 20 years
4.	HRSG Fuel for Partial SF (CG) / Int Exp (CC) - Gas Only																							Total over 20 years
5.	HP Boiler Fuel - Gas																							Total over 20 years
6.	HP Boiler Fuel - Oil																							Total over 20 years
7.	Pkg Boiler Fuel - Gas	1,223,706																						Total over 20 years
8.	Pkg Boiler Fuel - Oil								1,223,706	1,224,685	1,225,665	1,226,645	1,227,627	1,228,609	1,229,592	1,230,575	1,231,560	1,232,545	1,233,531	1,234,518	1,235,506	1,236,494	17,221,259	Total over 20 years
9.	Total Fuel Consumption - Oil																							Total over 20 years
10.	Total Fuel Consumption - Gas	1,223,706																						Total over 20 years
11.	Total Water Consumption (1000 gal)	78,444							1,223,706	1,224,685	1,225,665	1,226,645	1,227,627	1,228,609	1,229,592	1,230,575	1,231,560	1,232,545	1,233,531	1,234,518	1,235,506	1,236,494	17,221,259	Total over 20 years
12.	Total Electric Import, (MWh)(5)	4,430							78,444	78,444	78,444	78,444	78,444	78,444	78,444	78,444	78,444	78,444	78,444	78,444	78,444	78,444	1,098,219	Total over 20 years
13.	Annual Net Plant Output Capacity (MWh)	N.A.							4,430	4,430	4,430	4,430	4,430	4,430	4,430	4,430	4,430	4,430	4,430	4,430	4,430	4,430	62,014	Total over 20 years
																								Total over 20 years

Exhibit A - 20 Conceptual Cost Estimates for Commercial Customer Supplied Steam Option BP-1

4	CERA 2005 Pricing senario = Rear View Mirror	Items	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025		
CONCEPTUAL DATA[1]		General Inflation:	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	20yr Total or NPV	
Commercial Case		Compounded:	1.00	1.03	1.06	1.09	1.13	1.16	1.19	1.23	1.27	1.30	1.34	1.38	1.43	1.47	1.51	1.56	1.60	1.65	1.70	1.75		
ITEM	DESCRIPTION	STEAM GENERATION AND RE-POWERING OPTIONS	Cost Values in Current (Nominal) Dollars unless noted otherwise.																					
	Customer Supplied Steam	Boiler Only Option (BP-1)																						
100%	= STEAM SEND OUT CAPACITY FACTOR	Option - BP1	Base		Base	Base	Base	Base	Option - BP1	Option - BP1	Option - BP1	Option - BP1	Option - BP1	Option - BP1	Option - BP1	Option - BP1	Option - BP1	Option - BP1	Option - BP1	Option - BP1	Option - BP1	Option - BP1		
A.	Option Description	Two (2) package boilers, gas Fired																						
G.	Total Plant Cost - 2004 US Dollars	2006 $																						
1.	Existing Plant Maintenance Cost																							
2.	EPC Cost																							
a.	Cogen / QC Unit and accessories																							
b.	Boiler Plant	$16,019,000				$5,181,113	$12,395,813	$10,937,354																
	HP and LP Boiler Plant - Loaded																						$16,709,615	
c.	Demin Plant	incl w/b																						
d.	Other BOP																							
	Black Start																							
	Dump Condenser																							
	SCR																							
	Steam Piping (above grnd), excl york line replacement																							
	Gas Boiler Enclosures																							
	Other HP Boiler + BP Turbine																							
3.	Demolition /Relocation/ Remediation Costs																							
a.	Demolition Costs - loaded																							
b.	Relocation Costs - Unloaded																							
	Relocation Costs - loaded																							
c.	Remediation Costs																							
4.	Permitting/Prelim Engineering	$2,000,000	$986,631	$1,090,227	$1,202,481	$245,950	$264,397	$284,225															$3,132,113	
5.	Gas Piping Interconnect Costs - loaded																							
6.	Electrical Reinforcement/Interconnect Costs - loaded																							
7.	Contingency		included in above	included in above	included in above	included in above	included in above	included in above	included in above	included in above	included in above	included in above	included in above	included in above	included in above	included in above	included in above	included in above	included in above	included in above	included in above	included in above		
8.	Owner's other Costs(4)		included in above	included in above	included in above	included in above	included in above	included in above	included in above	included in above	included in above	included in above	included in above	included in above	included in above	included in above	included in above	included in above	included in above	included in above	included in above	included in above		
	Capitalized Property Tax During Construction								$4,209,061															
9	Total Plant Cost (TPC)	$16,019,000	$986,631	$1,090,227	$1,202,481	$5,427,064	$12,660,210	$11,221,621	$4,209,061														$3,132,113	
H.	Annual Costs																						$21,884,496	
1.	Fuel Cost																							
2a	Depreciation								$10,975,514	$11,386,870	$12,023,274	$12,733,517	$11,802,859	$12,371,249	$12,836,594	$13,375,584	$14,415,434	$14,838,746	$15,476,535	$16,118,847	$16,785,709	$17,417,508	$49,120,076	
2b	Equity Return								$1,226,576	$1,226,576	$1,226,576	$1,226,576	$1,226,576	$1,226,576	$1,226,576	$1,226,576	$1,226,576	$1,226,576	$1,226,576	$1,226,576	$1,226,576	$1,226,576	$4,837,718	
2c	Interest on Debt							($0)	$2,845,657	$2,747,531	$2,649,405	$2,551,279	$2,453,153	$2,355,027	$2,256,901	$2,158,775	$2,060,648	$1,962,522	$1,864,396	$1,766,270	$1,668,144	$1,570,018	$3,949,783	
2d	Federal & State Income Tax							($0)	$1,707,394	$1,648,519	$1,589,643	$1,530,767	$1,471,892	$1,413,016	$1,354,140	$1,295,265	$1,236,389	$1,177,513	$1,118,638	$1,059,762	$1,000,886	$942,011	$3,389,870	
3.	Water & Chemical Costs							($0)	$1,697,105	$1,631,688	$1,756,270	$1,700,853	$1,635,435	$1,570,018	$1,504,600	$1,439,183	$1,373,766	$1,308,348	$1,242,931	$1,177,513	$1,112,096	$1,046,679	$5,966,522	
4.	Electricity Purchase Cost								$1,075,516	$1,107,781	$1,141,015	$1,175,245	$1,210,502	$1,246,817	$1,284,222	$1,322,749	$1,362,431	$1,403,304	$1,445,403	$1,488,765	$1,533,428	$1,579,431	$4,727,902	
	Steam Purchase Cost		[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	$668,314	$629,800	$559,795	$687,333	$879,046	$704,260	$728,149	$754,327	$794,326	$823,169	$852,156	$881,429	$910,993	$940,858	$2,724,141	
5.	O&M Costs of existing plant(15)																						$52,334,152	
6.	Non Fuel O&M Costs	$342,000																						
	Foregone Rent								$408,366	$420,617	$433,235	$446,232	$459,619	$473,408	$487,610	$502,239	$517,306	$532,825	$548,810	$565,274	$582,232	$599,699	$1,795,186	
7a.	Property Tax eligible ICIP		$53,278	$115,515	$187,869	$513,741	$1,298,609	$2,040,049	$376,126	$387,410	$399,033	$411,004	$423,334	$436,034	$449,115	$462,588	$476,466	$490,760	$505,483	$520,647	$536,266	$552,354	$1,653,461	
7b	Property Tax Not eligible ICIP								$2,101,251	$2,164,289	$2,229,217	$2,296,094	$2,364,976	$2,435,926	$2,509,004	$2,584,274	$2,661,802	$2,741,656	$2,823,906	$2,908,623	$2,995,881	$3,085,758	$11,729,490	
7c	Property Tax on New but not completed Project credit																							
8.	ICIP Credit		($53,278)	($115,515)	($187,869)	($513,741)	($1,298,609)	($2,040,049)															($2,492,342)	
9.	Total Annual Cost		[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	$23,221,820	$23,550,881	$24,117,464	$24,758,901	$23,727,393	$24,232,331	$24,639,012	$25,121,559	$26,125,144	$26,505,421	$27,104,835	$27,713,706	$28,332,303	$28,960,893	$146,516,048	
I.	Steam Generation Costs ($) based upon Avoided Cost Offset																							
1.	Avoided Cost of Electricity Purchase(6)																							
2.	Avoided Cost of Steam Purchase(6)																							
3.	-								$4,341,748	$4,407,048	$4,568,446	$4,841,427	$4,741,181	$4,828,189	$5,019,303	$5,187,466	$5,408,884	$5,556,394	$5,735,739	$5,915,812	$6,098,695	$6,284,472	$18,796,538	
4	Total Avoided Costs																							
5a	Cost Attributed to Steam		[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	$4,341,748	$4,407,048	$4,568,446	$4,841,427	$4,741,181	$4,828,189	$5,019,303	$5,187,466	$5,408,884	$5,556,394	$5,735,739	$5,915,812	$6,098,695	$6,284,472	$18,796,538	
5b	Steam Generation Cost w/o Emission Credits ($/1000lb)		[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	$18,880,073	$19,143,833	$19,549,017	$19,917,473	$18,986,212	$19,404,142	$19,619,709	$19,934,073	$20,716,260	$20,947,027	$21,369,095	$21,797,895	$22,233,808	$22,676,421	$127,719,509	
6a	Cost Attributed to Steam w/o Emission Credits - NPV ($)		[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	$29.47	$29.88	$30.52	$31.09	$29.64	$30.29	$30.63	$31.12	$32.34	$32.70	$33.36	$34.03	$34.71	$35.40		
6b	Cumulative NPV of Cost Attributed to Steam w/o Emission Credits ($)		[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	$9,162,862	$8,379,211	$7,716,955	$7,090,912	$6,096,112	$5,618,959	$5,123,901	$4,695,167	$4,400,612	$4,013,016	$3,692,168	$3,396,606	$3,124,832	$2,874,155	$127,719,509	Total over 20 years
6c	NPV of Steam Product (MMlb)		[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	$61,497,013	$59,878,225	$77,595,180	$84,684,092	$90,780,204	$96,399,162	$101,523,063	$106,218,230	$110,618,642	$114,631,658	$118,324,026	$121,720,722	$124,845,554	$127,719,509		
6d	Cost of Steam w/o Emission Credits ($/1000lb) - NPV		[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	382	355	330	307	285	264	246	228	212	197	183	170	158	147	6,457	Total over 20 years
7	Cumulative NPV of Cost of Steam w/o Emission Credits ($/1000lb)		[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	23.96	23.59	23.39	23.13	21.41	21.24	20.85	20.57	20.76	20.38	20.18	19.99	19.79	19.60	19.78	
8	Emission Credits on Annual Costs(7)		[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	$18.22	$18.73	$19.11	$19.39	$19.51	$19.61	$19.67	$19.71	$19.74	$19.77	$19.78	$19.78	$19.78	$19.78		
a.	NOx																							
b.	SO2																							
c.	PM10																							
d.	VOC																							
e.	Total Credits																							
9a	Cost Attributed to Steam with Emission Credits ($)		[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	$18,880,073	$19,143,833	$19,549,017	$19,917,473	$18,986,212	$19,404,142	$19,619,709	$19,934,073	$20,716,260	$20,947,027	$21,369,095	$21,797,895	$22,233,808	$22,676,421	$127,719,509	
9b	Steam Generation Cost with Emission Credits ($/1000lb)		[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	$29.47	$29.88	$30.52	$31.09	$29.64	$30.29	$30.63	$31.12	$32.34	$32.70	$33.36	$34.03	$34.71	$35.40		
9c	Cost Attributed to Steam with Emission Credits - NPV ($)		[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	$9,162,862	$8,379,211	$7,716,955	$7,090,912	$6,096,112	$5,618,959	$5,123,901	$4,695,167	$4,400,612	$4,013,016	$3,692,168	$3,396,606	$3,124,832	$2,874,155	$127,719,509	Total over 20 years
10b	Cumulative NPV of Cost Attributed to Steam with Emission Credits ($)		[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	$61,497,013	$59,878,225	$77,595,180	$84,684,092	$90,780,204	$96,399,162	$101,523,063	$106,218,230	$110,618,642	$114,631,658	$118,324,026	$121,720,722	$124,845,554	$127,719,509		
10c	NPV of Steam Product (MMlb)		[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	382	355	330	307	285	264	246	228	212	197	183	170	158	147	6,457	Total over 20 years
10d	Cost of Steam with Emission Credits ($/1000lb) - NPV		[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	23.96	23.59	23.39	23.13	21.41	21.24	20.85	20.57	20.76	20.38	20.18	19.99	19.79	19.60	19.78	
11	Cumulative NPV of Cost of Steam with Emission Credits ($/1000lb)		[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	$18.22	$18.73	$19.11	$19.39	$19.51	$19.61	$19.67	$19.71	$19.74	$19.77	$19.78	$19.78	$19.78	$19.78		
J.	Annual Emissions (TPY)(7)																							
1.	NOx	11							11	11	11	11	11	11	11	11	11	11	11	11	12	12	160	Total over 20 years
2.	SO2	0							0	0	0	0	0	0	0	0	0	0	0	0	0	0	5	Total over 20 years
3.	PM10	5							5	5	5	5	5	5	5	5	5	5	5	5	5	5	84	Total over 20 years
4.	PM	1							1	1	1	1	1	1	1	1	1	1	1	1	1	1	16	Total over 20 years
5.	VOC	2							2	2	2	2	2	2	2	2	2	2	2	2	2	2	23	Total over 20 years
6.	CO	10							10	10	10	10	10	10	10	10	10	10	10	10	10	10	142	Total over 20 years
K.	Site Specific Constraints																							
1.	Layout Constraints																							
2.	Stack Issues																							
	Years to project completion	6																						

(1) refer to notes on input From Screening Model on "WithProjectedSendOut-GandO" sheet
All costs in first data column are unloaded and 2006 $ unless otherwise noted

Exhibit A - 21 Conceptual Cost Estimates for Academic Customer Supplied Steam Option CG-1

4	CERA 2005 Pricing scenario = Rear View Mirror	Items	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025		
CONCEPTUAL DATA[1]		General Inflation:	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	20yr Total or NPV	
Academic Case		Compounded:	1.00	1.03	1.06	1.09	1.13	1.16	1.19	1.23	1.27	1.30	1.34	1.38	1.43	1.47	1.51	1.56	1.60	1.65	1.70	1.75		
ITEM	DESCRIPTION	STEAM GENERATION AND R5-POWERING OPTIONS	Cost Values in Current (Nominal) Dollars unless noted otherwise.																					
	Customer Supplied Steam	Cogeneration options with Supp Fired HRSGs																						
100%	= STEAM SEND OUT CAPACITY FACTOR	Option - CG1	Base	Base	Base	Base	Base	Base	Option - CG1	Option - CG1	Option - CG1	Option - CG1	Option - CG1	Option - CG1	Option - CG1	Option - CG1	Option - CG1	Option - CG1	Option - CG1	Option - CG1	Option - CG1	Option - CG1		
A.	Option Description	Gas Turbine with Supp Fired HRSG, partial capacity Dump Condenser plus 1 package boiler - Gas																						
B.	New Configuration Description																							
1.	Facility Area Site for Foregone Rent, Sq Ft	8100																						
2.	Average Steam Consumption , Mlb/hr	25																						
3.	Average Elec. Requirement (W/O Stm Export), kW	8460																						
4.	Number of Gas turbines/HRSGs	1																						
5.	Gas Turbine Rating at ISO, KW	10700																						
6.	Number of Steam Turbine	N.A.																						
7.	Number of New HP Boilers	N.A.																						
8.	Capacity of New HP Boiler, Mlb/hr	N.A.																						
9.	Number of New LP Boilers(6)	1																						
10.	LP Boiler Capacity each, Mlb/hr(6)	30																						
C.	Net Steam Generation(2)																							
1.	Design Send Out Capacity, Mlb/hr	68																						
2.	Annual Average Send Out Capacity, MMlb	562																						
3.	Annual Avg Hourly Send out Capacity, Mlb/hr	64																						
4.	Cogen Plant Steam Generation Capacity, Mlb/hr																							
a.	With SF in HRSGs, Base Load	104																						
b.	No SF in HRSG, Base Load	49																						
c.	With SF in HRSGs, Operating Load	93																						
d.	No SF in HRSG, Operating Load	39																						
5.	Net New Package Boiler Capacity, Mlb/hr	25																						
6.	Annual Net Stm Send Out Capability, MMlb																							
a.	With Suppl Firing in HRSGs /Boilers	562																						
b.	Without Suppl Firing in HRSGs	114																						
D.	Cogen/CC/Boiler Plant operation and Annual Steam Ge																							
1.	Gas Turbine / Boiler Operating hours	8,322							8,322	8,322	8,322	8,322	8,322	8,322	8,322	8,322	8,322	8,322	8,322	8,322	8,322	8,322	116,508	Total over 20 years
2.	Operating Hours HRSG with full SF	8,322																						
3.	Oper Hours - HRSG for part SF mode																							
4.	HRSG - Oper Hours no Supp Firing																							
5.	Cogen Plant																							
a.	Net Export Steam with full SF, MMlb	562																						
b.	Net Export Steam with Partial SF /Int Exp, MMlb								562	562	562	562	562	562	562	562	562	562	562	562	562	562	7,865	Total over 20 years
c.	Export Steam W/O Supp Firing, MMlb																							Total over 20 years
6.	Steam from Package Boilers, MMlb(4)																							Total over 20 years
a.	Export Steam																							Total over 20 years
b.	Internal Steam Usage(7)	11							11	11	11	11	11	11	11	11	11	11	11	11	11	11	153	Total over 20 years
7.	Annual Building Internal Consumption, MMLb	219							219	219	219	219	219	219	219	219	219	219	219	219	219	219	3,066	Total over 20 years
10.	Total Annual Steam Export, MMlb	562	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	561.82	561.82	561.82	561.82	561.82	561.82	561.82	561.82	561.82	561.82	561.82	561.82	561.82	561.82	11,236	Total over 20 years
E.	Electrical Output(3), kW																							
1.	Gas Turbine	8,884							8,684	8,656	8,629	8,601	8,573	8,546	8,519	8,491	8,464	8,437	8,410	8,383	8,356	8,330	119,079	Total over 20 years
2.	Net Plant Output Capacity	8,460							8,460	8,433	8,406	8,379	8,352	8,326	8,299	8,272	8,246	8,219	8,193	8,167	8,141	8,115	116,008	Total over 20 years
1.	Gas Turbine Fuel - Gas	868,384							868,384	868,837	865,414	863,943	862,474	861,008	859,544	858,083	856,624	855,168	853,714	852,263	850,814	849,367	12,023,865	Total over 20 years
2.	Gas Turbine Fuel - Oil																							Total over 20 years
3.	HRSG Fuel for Full Supp Firing - Gas only	528,962							528,962	529,386	529,809	530,233	530,657	531,082	531,506	531,932	532,357	532,783	533,209	533,636	534,063	534,490	7,444,105	Total over 20 years
4.	HRSG Fuel for Partial SF (CG) /Int Exp (CC) - Gas Only																							Total over 20 years
5.	HP Boiler Fuel - Gas																							Total over 20 years
6.	HP Boiler Fuel - Oil																							Total over 20 years
7.	Pkg Boiler Fuel - Gas	14,265							14,265	14,276	14,288	14,299	14,311	14,322	14,334	14,345	14,356	14,368	14,379	14,391	14,402	14,414	200,750	Total over 20 years
8.	Pkg Boiler Fuel - Oil																							Total over 20 years
9.	Total Fuel Consumption - Oil																							Total over 20 years
10.	Total Fuel Consumption - Gas	1,411,591							1,411,591	1,410,549	1,409,511	1,408,475	1,407,442	1,406,411	1,405,384	1,404,359	1,403,338	1,402,319	1,401,303	1,400,289	1,399,279	1,398,271	19,668,520	Total over 20 years
11.	Total Water Consumption (1000 gal)	68,794							68,794	68,794	68,794	68,794	68,794	68,794	68,794	68,794	68,794	68,794	68,794	68,794	68,794	68,794	963,117	Total over 20 years
12.	Total Electric Import, (MWh)(5)	3,705							3,705	3,705	3,705	3,705	3,705	3,705	3,705	3,705	3,705	3,705	3,705	3,705	3,705	3,705	51,877	Total over 20 years
13.	Annual Net Plant Output Capacity (MWh)	70,404							70,404	70,179	69,954	69,730	69,507	69,285	69,063	68,842	68,622	68,402	68,183	67,965	67,748	67,531	965,416	Total over 20 years

Exhibit A - 21 Conceptual Cost Estimates for Academic Customer Supplied Steam Option CG-1

4	CERA 2005 Pricing senario = Rear View Mirror	Items	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025		
CONCEPTUAL DATA[1]		General Inflation:	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	20yr Total or NPV	
Academic Case		Compounded:	1.00	1.03	1.06	1.09	1.13	1.16	1.19	1.23	1.27	1.30	1.34	1.38	1.43	1.47	1.51	1.56	1.60	1.65	1.70	1.75		
ITEM	DESCRIPTION	STEAM GEKERATION AND RE-POWERING OPTIONS																						
	Customer Supplied Steam	Cogeneration Options with Supp Fired HRSGs	Cost Values in Current (Nominal) Dollars unless noted otherwise.																					
100%	= STEAM SEND OUT CAPACITY FACTOR	Option - CG1	Base	Base	Base	Base	Base	Base	Option - CG1	Option - CG1	Option - CG1	Option - CG1	Option - CG1	Option - CG1	Option - CG1	Option - CG1	Option - CG1	Option - CG1	Option - CG1	Option - CG1	Option - CG1	Option - CG1		
A.	Option Description	Gas Turbine with Supp Fired HRSG, partial capacity Dump Condenser plus 1 package boiler - Gas																						
G.	Total Plant Cost - 2006 US Dollars	2006 $																						
1.	Existing Plant Maintenance Cost																							
2.	EPC Cost																							
a.	Cogen / CC Unit and accessories	$34,686,000				$11,218,683	$26,840,700	$23,682,781																
b.	Boiler Plant																						$37,873,825	
	HP and LP Boiler Plant - Loaded																							
c.	Demin Plant	$1,393,000				$450,546	$1,077,030	$951,107															$1,521,024	
d.	Other BOP																							
	Black Start	$305,000				$98,648	$236,015	$208,247															$333,031	
	Dump Condenser	$305,000				$98,648	$236,015	$208,247															$333,031	
	SCR																							
	Steam Piping (above grnd), excl york line replacement																							
	Gas Boiler Enclosures																							
	Other HP Boiler + BP Turbine																							
3.	Demolition /Relocation/ Remediation Costs																							
a.	Demolition Costs - loaded																							
b.	Relocation Costs - Unloaded																							
	Relocation Costs - loaded																							
c.	Remediation Costs																							
4.	Permitting/Prelim Engineering	$5,000,000	$2,466,577	$2,725,568	$3,006,203	$614,878	$660,992	$710,566															$8,002,881	
5.	Gas Piping Interconnect Costs - loaded																							
6.	Electrical Reinforcement/Interconnect Costs - loaded																							
7.	Contingency																							
8.	Owner's other Costs(4)		included in above	included in above	included in above	included in above	included in above	included in above	included in above	included in above	included in above	included in above	included in above	included in above	included in above	included in above	included in above	included in above	included in above	included in above	included in above	included in above	included in above	
	Capitalized Property Tax During Construction		included in above	included in above	included in above	included in above	included in above	included in above	included in above	included in above	included in above	included in above	included in above	included in above	included in above	included in above	included in above	included in above	included in above	included in above	included in above	included in above	included in above	
9	Total Plant Cost (TPC)	$41,689,000	$2,466,577	$2,725,568	$3,006,203	$12,481,401	$29,051,652	$25,760,948	$9,860,340														$52,092,230	
H.	Annual Costs								$9,860,340														$53,156,023	
1.	Fuel Cost																							
2a	Depreciation								$12,659,781	$13,113,864	$13,825,807	$14,820,108	$13,530,713	$14,160,629	$14,673,230	$15,263,504	$16,425,078	$16,881,632	$17,580,430	$18,282,218	$18,987,112	$19,695,229	$82,752,275	
2b	Equity Return								$2,845,089	$2,845,090	$2,845,090	$2,845,090	$2,845,090	$2,845,090	$2,845,090	$2,845,090	$2,845,090	$2,845,090	$2,845,090	$2,845,090	$2,845,090	$2,845,090	$11,960,598	
2c	Interest on Debt								$6,600,608	$8,373,001	$6,145,394	$5,917,766	$5,690,179	$5,462,572	$5,234,965	$5,007,358	$4,779,751	$4,552,143	$4,324,536	$4,096,929	$3,869,322	$3,641,715	$22,965,656	
2d	Federal & State Income Tax								$3,960,365	$3,823,800	$3,687,236	$3,550,672	$3,414,108	$3,277,543	$3,140,979	$3,004,415	$2,867,850	$2,731,286	$2,594,722	$2,458,157	$2,321,593	$2,185,029	$13,773,394	
3.	Water & Chemical Costs								$4,400,405	$4,248,667	$4,096,929	$3,945,191	$3,793,453	$3,641,715	$3,489,977	$3,338,239	$3,186,500	$3,034,762	$2,883,024	$2,731,286	$2,579,548	$2,427,810	$15,303,771	
4.	Electricity Purchase Cost								$1,037,524	$1,068,653	$1,100,713	$1,133,734	$1,167,746	$1,202,779	$1,238,862	$1,276,028	$1,314,309	$1,353,738	$1,394,350	$1,436,181	$1,479,266	$1,523,644	$9,091,383	
	Steam Purchase Cost		[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	$1,933,385	$1,976,820	$2,031,851	$2,083,315	$2,105,302	$2,155,813	$2,205,722	$2,256,059	$2,322,477	$2,377,525	$2,430,093	$2,482,345	$2,534,278	$2,585,889	$9,139,959	
5.	O&M Costs of existing plant(16)																						$47,218,311	
6.	Non Fuel O&M Costs	$490,500																						
	Foregone Rent								$585,683	$603,253	$621,351	$639,991	$659,191	$678,967	$699,336	$720,316	$741,925	$764,183	$787,109	$810,722	$835,043	$860,095	$2,874,078	
7a	Property Tax eligible ICIP		$133,195	$288,787	$469,672	$1,220,255	$3,022,549	$4,725,881	$483,591	$498,099	$513,042	$528,433	$544,286	$560,615	$577,433	$594,756	$612,599	$630,977	$649,906	$669,403	$689,485	$710,170	$2,373,092	
7b	Property Tax Not eligible ICIP								$4,867,658	$5,013,688	$5,164,098	$5,319,021	$5,478,592	$5,642,950	$5,812,238	$5,986,605	$6,166,203	$6,351,189	$6,541,725	$6,737,977	$6,940,116	$7,148,320	$30,004,877	
7c	Property Tax on New but not completed Project credit		($133,195)	($288,787)	($469,672)	($1,220,255)	($3,022,549)	($4,725,881)																
8.	ICIP Credit																						($6,118,176)	
9	Total Annual Cost		[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	$39,374,663	$39,566,935	$49,031,510	$40,583,342	$39,228,859	$39,625,871	$39,917,831	$40,294,369	$41,261,781	$41,522,526	$42,030,985	$42,550,308	$43,080,853	$43,622,959	$217,329,218	
I.	Steam Generation Costs ($) based upon Avoided Cost Offset																							
1.	Avoided Cost of Electricity Purchase(8)								$9,839,368	$10,152,858	$10,598,743	$11,003,121	$10,842,787	$11,207,454	$11,548,187	$11,924,331	$12,511,186	$12,922,052	$13,332,406	$13,744,466	$14,158,336	$14,574,122	$48,322,228	
2.	Avoided Cost of Steam Purchase(8)								$4,341,748	$4,407,048	$4,566,446	$4,841,427	$4,741,181	$4,828,169	$5,019,303	$5,187,486	$5,408,584	$5,558,394	$5,735,739	$5,915,812	$6,098,695	$6,284,472	$20,978,618	
3.	-																							
4	Total Avoided Costs																							
5a	Cost Attributed to Steam		[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	$14,181,115	$14,559,906	$15,167,189	$15,844,548	$15,583,968	$16,035,653	$16,568,490	$17,111,817	$17,920,080	$18,480,446	$19,068,145	$19,660,278	$20,257,031	$20,858,584	$69,300,845	
5b	Steam Generation Cost w/o Emission Credits ($/1000lb)		[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	$25,192,978	$25,007,028	$24,864,321	$24,738,793	$23,644,711	$23,593,019	$23,349,341	$23,182,552	$23,341,701	$23,042,080	$22,962,840	$22,890,030	$22,823,822	$22,784,395	$148,029,373	
6a	Cost Attributed to Steam w/o Emission Credits - NPV ($)		[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	$44.84	$44.51	$44.26	$44.03	$42.09	$41.99	$41.56	$41.26	$41.55	$41.01	$40.87	$40.74	$40.62	$40.52		
6b	Cumulative NPV of Cost Attributed to Steam w/o Emission Credits ($)		[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	$13,010,550	$11,751,155	$10,631,569	$9,625,019	$8,370,654	$7,599,958	$6,843,915	$6,182,919	$5,664,572	$5,088,135	$4,613,864	$4,184,927	$3,796,927	$3,445,897	$148,029,373	Total over 20 years
6c	NPV of Steam Product (Mlb)		[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	$60,228,881	$71,980,016	$82,611,585	$92,236,604	$100,607,258	$108,207,216	$115,051,132	$121,234,051	$126,898,623	$131,986,758	$136,600,622	$140,785,549	$144,582,476	$148,028,373	$148,028,373	
6d	Cost of Steam w/o Emission Credits ($/1000lb) - NPV		[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	357	334	313	294	275	258	242	227	212	199	187	175	164	154	6,084	Total over 20 years
7	Cumulative NPV of Cost of Steam w/o Emission Credits ($/1000lb)		[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	36.45	35.14	33.92	32.77	30.40	29.45	28.30	27.28	26.87	25.56	24.73	23.93	23.17	22.43	24.29	
8	Emission Credits on Annual Costs(7)		[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	$19.65	$21.21	$22.28	$23.05	$23.52	$23.86	$24.09	$24.23	$24.33	$24.38	$24.39	$24.37	$24.34	$24.29		
a.	NOx																							
b.	SO2																							
c.	PM10																							
d	VOC																							
e.	Total Credits																							
9a	Cost Attributed to Steam with Emission Credits ($)																							
9b	Steam Generation Cost with Emission Credits ($/1000lb)		[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	$25,192,978	$25,007,028	$24,864,321	$24,738,793	$23,644,711	$23,593,019	$23,349,341	$23,182,552	$23,341,701	$23,042,080	$22,962,840	$22,890,030	$22,823,822	$22,784,395	$148,029,373	
9c	Cost Attributed to Steam with Emission Credits - NPV ($)		[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	$44.84	$44.51	$44.26	$44.03	$42.09	$41.99	$41.56	$41.26	$41.55	$41.01	$40.87	$40.74	$40.62	$40.52		
10b	Cumulative NPV of Cost Attributed to Steam with Emission Credits ($)		[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	$13,010,550	$11,751,155	$10,631,569	$9,625,019	$8,370,654	$7,599,958	$6,843,915	$6,182,919	$5,664,572	$5,088,135	$4,613,864	$4,184,927	$3,796,927	$3,445,897	$148,029,373	Total over 20 years
10c	NPV of Steam Product (Mlb)		[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	$60,228,881	$71,980,016	$82,611,585	$92,236,604	$100,607,258	$108,207,216	$115,051,132	$121,234,051	$126,898,623	$131,986,758	$136,600,622	$140,785,549	$144,582,476	$148,028,373		
10d	Cost of Steam with Emission Credits ($/1000lb) - NPV		[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	357	334	313	294	275	258	242	227	212	199	187	175	164	154	6,084	Total over 20 years
11	Cumulative NPV of Cost of Steam with Emission Credits ($/1000lb)		[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	36.45	35.14	33.92	32.77	30.40	29.45	28.30	27.28	26.87	25.56	24.73	23.93	23.17	22.43	24.29	
J.	Annual Emissions (TPY)(7)																							
1.	NOx	19																						
2.	SO2	2							19	19	19	19	19	19	19	19	19	19	19	19	19	19	284	Total over 20 years
3.	PM10	2							2	2	2	2	2	2	2	2	2	2	2	2	2	2	23	Total over 20 years
4	PM	1							5	5	5	5	5	5	5	5	5	5	5	5	5	5	58	Total over 20 years
5.	VOC	1							1	1	1	1	1	1	1	1	1	1	1	1	1	1	19	Total over 20 years
6.	CO	12							1	1	1	1	1	1	1	1	1	1	1	1	1	1	17	Total over 20 years
									12	12	12	12	12	12	12	12	12	12	12	12	11	11	162	Total over 20 years
K.	Site Specific Constraints																							
1.	Layout Constraints																							
2.	Stack Issues																							
	Years to project completion	6																						

(1) refer to notes on Input From Screening Model on "WithProjectedSendOut-GandO" sheet
All costs in first data column are unescaled and 2006 $ unless otherwise noted

Exhibit A - 22 Conceptual Cost Estimates for Academic Customer Supplied Steam Option BP-1

4	CERA 2005 Pricing senario = Rear View Mirror	Items	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025		
CONCEPTUAL DATA[1]		General Inflation:	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	20yr Total or NPV	
Academic Case		Compounded:	1.00	1.03	1.06	1.09	1.13	1.16	1.19	1.23	1.27	1.30	1.34	1.38	1.43	1.47	1.51	1.58	1.60	1.65	1.70	1.75		
ITEM	DESCRIPTION	STEAM GENERATION AND RE-POWERING OPTIONS	Cost Values in Current (Nominal) Dollars unless noted otherwise.																					
	Customer Supplied Steam	Boiler Only Option (BP-1)																						
100%	= STEAM SEND OUT CAPACITY FACTOR	Option - BP1	Base	Base	Base	Base	Base	Base	Option - BP1	Option - BP1	Option - BP1	Option - BP1	Option - BP1	Option - BP1	Option - BP1	Option - BP1	Option - BP1	Option - BP1	Option - BP1	Option - BP1	Option - BP1	Option - BP1		
A.	Option Description	Two (2) package boilers, gas Fired																						
B.	New Configuration Description																							
1.	Facility Area Size for Forsgone Rent, Sq Ft	6300																						
2.	Average Steam Consumption , Mlb/hr	25																						
3.	Average Elec. Equirement (W/O Stm Export), kW	8440																						
4.	Number of Gas turbines/HRSGs	1																						
5.	Gas Turbine Rating at ISO, KW	N.A.																						
6.	Number of Steam Turbine	N.A.																						
7.	Number of New HP Boilers	N.A.																						
8.	Capacity of New HP Boiler, Mlb/hr	N.A.																						
9.	Number of New LP Boilers(6)	2																						
10.	LP Boiler Capacity each, Mlb/hr(6)	80																						
C.	Net Steam Generation(2)																							
1.	Design Send Out Capacity, Mlb/hr	77																						
2.	Annual Average Send Out Capacity, MMlb	641																						
3.	Annual Avg Hourly Send out Capacity, Mlb/hr	73																						
4.	Cogen Plant Steam Generation Capacity, Mlb/hr																							
a.	With SF in HRSGs, Base Load																							
b.	No SF in HRSG, Base Load																							
c.	With SF in HRSGs, Operating Load																							
d.	No SF in HRSG, Operating Load																							
5.	Net New Package Boiler Capacity, Mlb/hr	102																						
6.	Annual Net Stm Send Out Capability, MMlb																							
a.	With Suppl Firing in HRSGs /Boilers	624																						
b.	Without Suppl Firing in HRSGs																							
D.	Cogen/CC/Boiler Plant operation and Annual Steam G																							
1.	Gas Turbine / Boiler Operating hours	8,760																						
2.	Operating Hours- HRSG with full SF																							
3.	Oper Hours - HRSG for part SF mode																							
4.	HRSG - Oper Hours no Supp Firing																							
5.	Cogen Plant																							
a.	Net Export Steam with full SF, MMlb																							
b.	Net Export Steam with Partial SF /Int Exp, MMlb																							Total over 25
c.	Export Steam W/O Supp Firing, MMlb																							Total over 25
6.	Steam from Package Boilers, MMlb(4)																							Total over 25
a.	Export Steam	641							641	641	641	641	641	641	641	641	641	641	641	641	641	641		Total over 25
b.	Internal Steam Usage(7)	219							219	219	219	219	219	219	219	219	219	219	219	219	219	219	8,969	Total over 25
7.	Annual Building Internal Consumption, MMLb	219							219	219	219	219	219	219	219	219	219	219	219	219	219	219	3,066	Total over 25
10.	Total Annual Steam Export, MMlb	641	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	640.63	640.63	640.63	640.63	640.63	640.63	640.63	640.63	640.63	640.63	640.63	640.63	640.63	640.63	3,066	Total over 25
E.	Electrical Output(3), kW																						12,813	Total over 25
1.	Gas Turbine	N.A.																						
2.	Net Plant Output Capacity	N.A.																						Total over 25
F.	Annual Fuel (MMBtu - HHV), Electricity (MWh), Water								N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.		Total over 25
1.	Gas Turbine Fuel - Gas																							
2.	Gas Turbine Fuel - Oil																							Total over 25
3.	HRSG Fuel for Full Supp Firing - Gas only																							Total over 25
4.	HRSG Fuel for Partial SF (CG) / Int Exp (CC) - Gas Only																							Total over 25
5.	HP Boiler Fuel - Gas																							Total over 25
6.	HP Boiler Fuel - Oil																							Total over 25
7.	Pkg Boiler Fuel - Gas	1,223,706																						Total over 25
8.	Pkg Boiler Fuel - Oil								1,223,706	1,224,685	1,225,665	1,226,645	1,227,627	1,228,609	1,229,592	1,230,575	1,231,560	1,232,545	1,233,531	1,234,518	1,235,506	1,236,494	17,221,259	Total over 25
9.	Total Fuel Consumption - Oil																							Total over 25
10.	Total Fuel Consumption - Gas	1,223,706																						Total over 25
11.	Total Water Consumption (1000 gal)	78,444							1,223,706	1,224,685	1,225,665	1,226,645	1,227,627	1,228,609	1,229,592	1,230,575	1,231,560	1,232,545	1,233,531	1,234,518	1,235,506	1,236,494	17,221,259	Total over 25
12.	Total Electric Import, (MWh)(5)	4,430							78,444	78,444	78,444	78,444	78,444	78,444	78,444	78,444	78,444	78,444	78,444	78,444	78,444	78,444	1,098,219	Total over 25
13.	Annual Net Plant Output Capacity (MWh)	N A							4,430	4,430	4,430	4,430	4,430	4,430	4,430	4,430	4,430	4,430	4,430	4,430	4,430	4,430	82,014	Total over 25
																								Total over 25

Exhibit A - 22 Conceptual Cost Estimates for Academic Customer Supplied Steam Option BP-1

4	CERA 2005 Pricing senario = Rear View Mirror	Items	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	20yr Total or NPV	
CONCEPTUAL DATA[1]		General Inflation:	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%		
Academic Case		Compounded:	1.00	1.03	1.06	1.09	1.13	1.16	1.19	1.23	1.27	1.30	1.34	1.38	1.43	1.47	1.51	1.56	1.60	1.65	1.70	1.75		
ITEM	DESCRIPTION	STEAM GENERATION AND RE-POWERING OPTIONS	Cost Values in Current (Nominal) Dollars unless noted otherwise.																					
	Customer Supplied Steam	Boiler Only Option (BP-1)																						
100%	= STEAM SEND OUT CAPACITY FACTOR	Option - BP1	Base	Base	Base	Base	Base	Base	Option - BP1	Option - BP1	Option - BP1	Option - BP1	Option - BP1	Option - BP1	Option - BP1	Option - BP1	Option - BP1	Option - BP1	Option - BP1	Option - BP1	Option - BP1	Option - BP1		
A.	Option Description	Two (2) package boilers, gas Fired																						
G.	Total Plant Cost - 2004 US Dollars	2008 $																						
1.	Existing Plant Maintenance Cost																							
2.	EPC Cost																							
a.	Cogen / CC Unit and accessories																							
b.	Boiler Plant	$16,019,000				$5,181,113	$12,395,813	$10,937,394																
	HP and LP Boiler Plant - Loaded																						$17,491,230	
c.	Demin Plant	incl w/1b																						
d.	Other BOP																							
	Black Start																							
	Dump Condenser																							
	SCR																							
	Steam Piping (above grnd), excl york line replacement																							
	Gas Boiler Enclosures																							
	Other HP Boiler + BP Turbine																							
3.	Demolition /Relocation/ Remediation Costs																							
a.	Demolition Costs - loaded																							
b.	Relocation Costs - Unloaded																							
	Relocation Costs - loaded																							
c.	Remediation Costs																							
4.	Permitting/Prelim Engineering	$2,000,000	$988,631	$1,090,227	$1,202,481	$245,950	$264,307	$264,226															$3,201,152	
5.	Gas Piping Interconnect Costs - loaded																							
6.	Electrical Reinforcement/Interconnect Costs - loaded																							
7.	Contingency		included in above	included in above	included in above	included in above	included in above	included in above	included in above	included in above	included in above	included in above	included in above	included in above	included in above	included in above	included in above	included in above	included in above	included in above	included in above	included in above		
8.	Owner's other Costs(4)		included in above	included in above	included in above	included in above	included in above	included in above	included in above	included in above	included in above	included in above	included in above	included in above	included in above	included in above	included in above	included in above	included in above	included in above	included in above	included in above		
	Capitalized Property Tax During Construction								included in above	included in above	included in above	included in above	included in above	included in above	included in above	included in above	included in above	included in above	included in above	included in above	included in above	included in above		
9.	Total Plant Cost (TPC)	$18,019,000	$988,631	$1,090,227	$1,202,481	$5,427,064	$12,660,210	$11,221,621	$4,209,061														$3,173,709	
H.	Annual Costs								$4,209,061														$22,868,092	
1.	Fuel Cost																							
2a	Depreciation								$10,975,614	$11,368,670	$12,023,274	$12,733,517	$11,802,859	$12,371,249	$12,838,694	$13,375,564	$14,415,434	$14,838,746	$15,476,535	$16,118,847	$16,765,799	$17,417,505	$54,865,388	
2b	Equity Return								$1,226,576	$1,226,576	$1,226,576	$1,226,576	$1,226,576	$1,226,576	$1,226,576	$1,226,576	$1,226,576	$1,226,576	$1,226,576	$1,226,576	$1,226,576	$1,226,576	$5,156,459	
2c	Interest on Debt								$2,845,657	$2,747,531	$2,649,405	$2,551,279	$2,453,153	$2,355,027	$2,256,901	$2,158,775	$2,060,648	$1,962,522	$1,864,396	$1,766,270	$1,668,144	$1,570,018	$9,996,554	
2d	Federal & State Income Tax								$1,707,394	$1,648,519	$1,589,643	$1,530,767	$1,471,892	$1,413,016	$1,354,140	$1,295,265	$1,236,389	$1,177,513	$1,118,638	$1,059,762	$1,000,886	$942,011	$5,937,993	
3.	Water & Chemical Costs								$1,897,105	$1,831,648	$1,766,270	$1,700,853	$1,635,435	$1,570,018	$1,504,600	$1,439,183	$1,373,768	$1,308,348	$1,242,931	$1,177,513	$1,112,096	$1,046,679	$6,597,769	
4.	Electricity Purchase Cost								$1,675,516	$1,167,761	$1,141,015	$1,210,502	$1,246,817	$1,284,222	$1,322,749	$1,362,431	$1,403,304	$1,445,403	$1,488,765	$1,533,428	$1,579,431	$5,277,800		
a.	Steam Purchase Cost		[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	$808,314	$829,800	$659,795	$687,333	$679,048	$704,260	$728,149	$754,327	$794,328	$823,169	$852,158	$881,429	$910,993	$940,858	$3,042,359	
5.	O&M Costs of existing plant(16)																						$53,841,884	
6.	Non Fuel O&M Costs	$342,000																						
	Foregone Rent								$408,356	$420,617	$433,235	$446,232	$459,619	$473,408	$487,610	$502,239	$517,306	$532,825	$548,810	$565,274	$582,232	$599,699	$2,003,944	
7a	Property Tax eligible ICIP		$53,278	$115,515	$187,869	$513,741	$1,298,609	$2,040,049	$376,126	$387,410	$399,033	$411,004	$423,334	$436,034	$449,115	$462,588	$476,466	$490,760	$505,483	$520,647	$536,266	$552,354	$1,845,738	
7b	Property Tax Not eligible ICIP								$2,101,251	$2,164,289	$2,229,217	$2,296,094	$2,364,976	$2,435,926	$2,509,004	$2,584,274	$2,661,802	$2,741,656	$2,823,906	$2,908,623	$2,995,881	$3,085,758	$12,917,005	
7c	Property Tax on New but not completed Project credit																							
8.	ICIP Credit		($53,278)	($115,515)	($187,869)	($513,741)	($1,298,609)	($2,040,049)															($2,605,889)	
9.	Total Annual Cost		[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	$23,221,820	$23,550,881	$24,117,464	$24,758,901	$23,727,393	$24,232,331	$24,639,012	$25,121,559	$26,125,144	$26,505,421	$27,104,835	$27,713,708	$28,332,303	$28,960,893	$158,777,312	
I.	Steam Generation Costs ($) based upon Avoided Cost Offset																							
1.	Avoided Cost of Electricity Purchase(8)																							
2.	Avoided Cost of Steam Purchase(9)																							
3.									$4,341,748	$4,407,048	$4,566,446	$4,841,427	$4,741,181	$4,828,189	$5,019,303	$5,187,488	$5,408,884	$5,558,394	$5,735,739	$5,915,812	$6,098,695	$6,284,472	$20,978,618	
4	Total Avoided Costs								$4,341,748	$4,407,048	$4,566,446	$4,841,427	$4,741,181	$4,828,189	$5,019,303	$5,187,488	$5,408,884	$5,558,394	$5,735,739	$5,915,812	$6,098,695	$6,284,472	$20,978,618	
5a	Cost Attributed to Steam		[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	$18,880,073	$19,143,833	$19,549,017	$19,917,473	$18,985,212	$19,404,142	$19,619,709	$19,934,073	$20,716,280	$20,947,027	$21,369,095	$21,797,895	$22,233,808	$22,678,421	$137,798,695	
5b	Steam Generation Cost w/o Emission Credits ($/1000lb)		[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	$29.47	$29.88	$30.52	$31.09	$29.64	$30.29	$30.63	$31.12	$32.34	$32.70	$33.36	$34.03	$34.71	$35.40		
6a	Cost Attributed to Steam w/o Emission Credits - NPV ($)		[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	$9,750,341	$8,995,957	$8,358,834	$7,749,208	$6,721,462	$6,250,606	$5,750,724	$5,318,531	$5,027,429	$4,625,507	$4,293,537	$3,985,255	$3,698,740	$3,432,580	$137,798,695	Total over 20
6b	Cumulative NPV of Cost Attributed to Steam w/o Emission Credits ($)		[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	$63,592,225	$72,588,182	$80,947,016	$88,696,224	$95,417,685	$101,668,291	$107,419,016	$112,735,547	$117,762,976	$122,388,483	$126,682,020	$130,667,275	$134,366,015	$137,798,595		
6c	NPV of Steam Product (MMb)		[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	407	381	357	335	314	294	276	258	242	227	213	199	187	175	6,849	Total over 20
6d	Cost of Steam w/o Emission Credits ($/1000lb) - NPV		[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	23.98	23.59	23.38	23.13	21.41	21.24	20.85	20.57	20.76	20.38	20.18	19.99	19.79	19.60	19.83	Total over 20
7	Cumulative NPV of Cost of Steam w/o Emission Credits ($/1000lb)		[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	$18.23	$18.75	$19.15	$19.44	$19.57	$19.68	$19.72	$19.76	$19.80	$19.82	$19.83	$19.84	$19.84	$19.83		
8	Emission Credits on Annual Costs(7)																							
a.	NOx																							
b.	SO2																							
c.	PM10																							
d.	VOC																							
e.	Total Credits																							
9a	Cost Attributed to Steam with Emission Credits ($)		[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	$18,880,073	$19,143,833	$19,549,017	$19,917,473	$18,985,212	$19,404,142	$19,619,709	$19,934,073	$20,716,280	$20,947,027	$21,369,095	$21,797,895	$22,233,808	$22,678,421	$137,798,695	
9b	Steam Generation Cost with Emission Credits ($/1000lb)		[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	$29.47	$29.88	$30.52	$31.09	$29.64	$30.29	$30.63	$31.12	$32.34	$32.70	$33.36	$34.03	$34.71	$35.40		
9c	Cost Attributed to Steam with Emission Credits - NPV ($)		[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	$9,750,341	$8,995,957	$8,358,834	$7,749,208	$6,721,462	$6,250,606	$5,750,724	$5,318,531	$5,027,429	$4,625,507	$4,293,537	$3,985,255	$3,698,740	$3,432,580	$137,798,695	Total over 20
10b	Cumulative NPV of Cost Attributed to Steam with Emission Credits ($)		[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	$63,592,225	$72,588,182	$80,947,016	$88,696,224	$95,417,685	$101,668,291	$107,419,016	$112,735,547	$117,762,976	$122,388,483	$126,682,020	$130,667,275	$134,366,015	$137,798,595		
10c	NPV of Steam Product (MMb)		[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	407	381	357	335	314	294	276	258	242	227	213	199	187	175	6,849	Total over 20
10d	Cost of Steam with Emission Credits ($/1000lb) - NPV		[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	23.96	23.59	23.38	23.13	21.41	21.24	20.85	20.57	20.76	20.38	20.18	19.99	19.79	19.60	19.83	
11	Cumulative NPV of Cost of Steam with Emission Credits ($/1000lb)		[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	$18.23	$18.75	$19.15	$19.44	$19.57	$19.68	$19.72	$19.76	$19.80	$19.82	$19.83	$19.84	$19.84	$19.83		
J.	Annual Emissions (TPY)(7)																							
1.	NOx	11							11	11	11	11	11	11	11	11	11	11	11	11	12	12	160	Total over 20
2.	SO2	0							0	0	0	0	0	0	0	0	0	0	0	0	0	0	5	Total over 20
3.	PM10	5							5	5	5	5	5	5	5	5	5	5	5	5	5	5	64	Total over 20
4.	PM	1							1	1	1	1	1	1	1	1	1	1	1	1	1	1	16	Total over 20
5.	VOC	2							2	2	2	2	2	2	2	2	2	2	2	2	2	2	23	Total over 20
6.	CO	10							10	10	10	10	10	10	10	10	10	10	10	10	10	10	142	Total over 20
K.	Site Specific Constraints																							
1.	Layout Constraints																							
2.	Stack Issues																							
	Years to project completion	6																						
(1) refer to notes on Input From Screening Model on "WithProjectedSendOutSandO" sheet																								
All costs on first data column are unloaded and 2008 $ unless otherwise noted																								

CONCEPTUAL COST ESTIMATE DETAILS FOR KEYSPAN ENERGY SUPPLIED CASES

Exhibit A-23 Conceptual Cost Estimates for KeySpan Energy Supplied Steam Option KS

Exhibit A-23 Conceptual Cost Estimates for KeySpan Energy Supplied Steam Option KS

REDACTED

Exhibit A-23 Conceptual Cost Estimates for KeySpan Energy Supplied Steam Option KS (continued)

REDACTED

Exhibit A-23 Conceptual Cost Estimates for KeySpan Energy Supplied Steam Gas Piping

REDACTED

CONCEPTUAL COST ESTIMATE DETAILS FOR RAVENSWOOD CASES

Exhibit A-24 Conceptual Cost Estimates for Ravenswood Boiler Rebuilding Option RB1
Exhibit A-25 Conceptual Cost Estimates for Ravenswood Boiler Rebuilding Option RB2
Exhibit A-26 Conceptual Cost Estimates for Ravenswood Boiler Rebuilding Option RB3
Exhibit A-27 Conceptual Cost Estimates for Ravenswood Boiler Rebuilding Option RB4
Exhibit A-28 Conceptual Cost Estimates for Ravenswood Boiler Replacement Option NB1
Exhibit A-29 Conceptual Cost Estimates for Ravenswood Boiler Replacement Option NB2
Exhibit A-30 Conceptual Cost Estimates for Ravenswood Boiler Replacement Option NB3
Exhibit A-31 Conceptual Cost Estimates for Ravenswood Boiler Replacement Option NB4

Exhibit A-24 Conceptual Cost Estimates for Ravenswood Boiler Rebuilding Option RB1

REDACTED

Exhibit A-24 Conceptual Cost Estimates for Ravenswood Boiler Rebuilding Option RB1 (continued)

REDACTED

Exhibit A-25 Conceptual Cost Estimates for Ravenswood Boiler Rebuilding Option RB2

REDACTED

Exhibit A-25 Conceptual Cost Estimates for Ravenswood Boiler Rebuilding Option RB2 (continued)

REDACTED

Exhibit A-26 Conceptual Cost Estimates for Ravenswood Boiler Rebuilding Option RB3

REDACTED

Exhibit A-26 Conceptual Cost Estimates for Ravenswood Boiler Rebuilding Option RB3 (continued)

REDACTED

Exhibit A-27 Conceptual Cost Estimates for Ravenswood Boiler Rebuilding Option RB4

REDACTED

Exhibit A-27 Conceptual Cost Estimates for Ravenswood Boiler Rebuilding Option RB4 (continued)

REDACTED

Exhibit A-28 Conceptual Cost Estimates for Ravenswood Boiler Replacement Option NB1

REDACTED

Exhibit A-28 Conceptual Cost Estimates for Ravenswood Boiler Replacement Option NB1 (continued)

REDACTED

Exhibit A-29 Conceptual Cost Estimates for Ravenswood Boiler Replacement Option NB2

REDACTED

Exhibit A-29 Conceptual Cost Estimates for Ravenswood Boiler Replacement Option NB2 (continued)

REDACTED

Exhibit A-30 Conceptual Cost Estimates for Ravenswood Boiler Replacement Option NB3

REDACTED

Exhibit A-30 Conceptual Cost Estimates for Ravenswood Boiler Replacement Option NB3 (continued)

REDACTED

Exhibit A-31 Conceptual Cost Estimates for Ravenswood Boiler Replacement Option NB4

REDACTED

Exhibit A-31 Conceptual Cost Estimates for Ravenswood Boiler Replacement Option NB4 (continued)

REDACTED

B

WorleyParsons

resources & energy

Long Term Con Edison Steam Production Options Study - Phase 1

Final Report Appendix B

Heat Balance Data

Prepared for

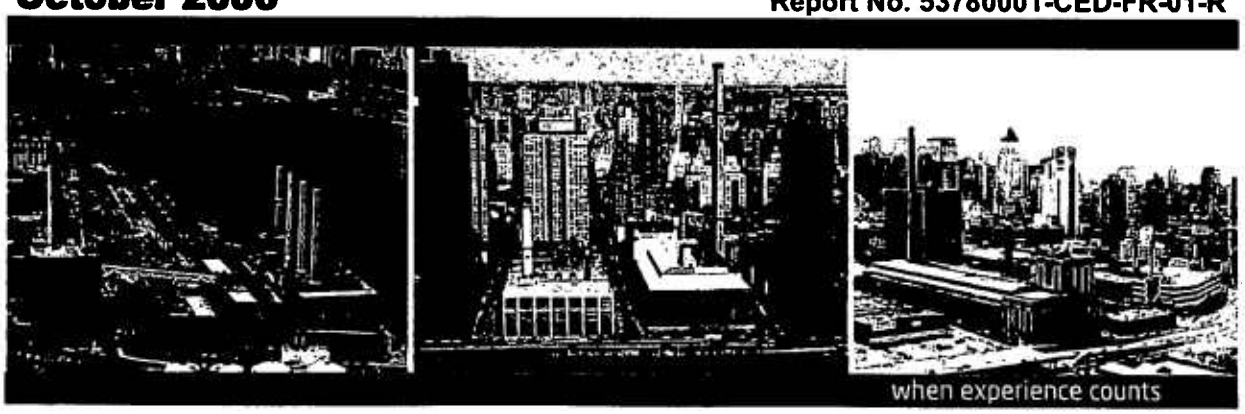
Consolidated Edison Company of New York, Inc.

in conjunction with the

Steam Business Development Core Task Force

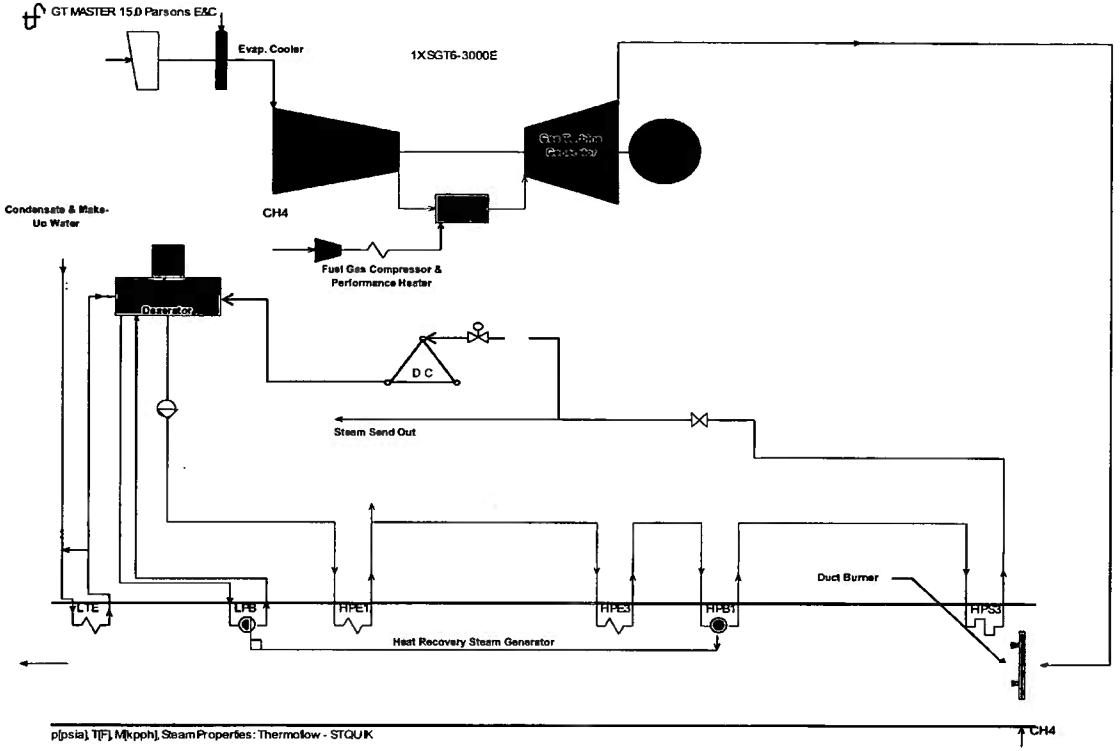
October 2006

Report No. 53780001-CED-FR-01-R



HEAT AND MATERIAL BALANCES FOR HUDSON AVENUE CO-GENERATION CASES

Drawing #	Description
CESP-1-HB-CG1-01	Cogen Plant with Siemens 501D5A with full capacity Dump Condenser and New LP Gas Boilers
CESP-1-HB-CG1-02	Cogen Plant with Siemens 501D5A with full capacity Dump Condenser and New LP Gas Boilers
CESP-1-HB-CG1-03	Cogen Plant with Siemens 501D5A with full capacity Dump Condenser and New LP Gas Boilers
CESP-1-HB-CG1-04	Cogen Plant with Siemens 501D5A with full capacity Dump Condenser and New LP Gas Boilers
CESP-1-HB-CG2-01	Cogen Plant with GE 7EA with full capacity Dump Condenser and New LP Gas Boilers
CESP-1-HB-CG2-02	Cogen Plant with GE 7EA with full capacity Dump Condenser and New LP Gas Boilers
CESP-1-HB-CG2-03	Cogen Plant with GE 7EA with full capacity Dump Condenser and New LP Gas Boilers
CESP-1-HB-CG2-04	Cogen Plant with GE 7EA with full capacity Dump Condenser and New LP Gas Boilers
CESP-1-HB-CG3-01	Cogen Plant with GE LM6000 with New LP Gas Boilers
CESP-1-HB-CG3-02	Cogen Plant with GE LM6000 with New LP Gas Boilers
CESP-1-HB-CG3-03	Cogen Plant with GE LM6000 with New LP Gas Boilers
CESP-1-HB-CG3-04	Cogen Plant with GE LM6000 with New LP Gas Boilers
CESP-1-HB-CG4-01	Cogen Plant with Siements GTX100 with Dump Condenser & New LP Gas Boilers
CESP-1-HB-CG4-02	Cogen Plant with Siements GTX100 with Dump Condenser & New LP Gas Boilers
CESP-1-HB-CG4-03	Cogen Plant with Siements GTX100 with Dump Condenser & New LP Gas Boilers
CESP-1-HB-CG4-04	Cogen Plant with Siements GTX100 with Dump Condenser & New LP Gas Boilers

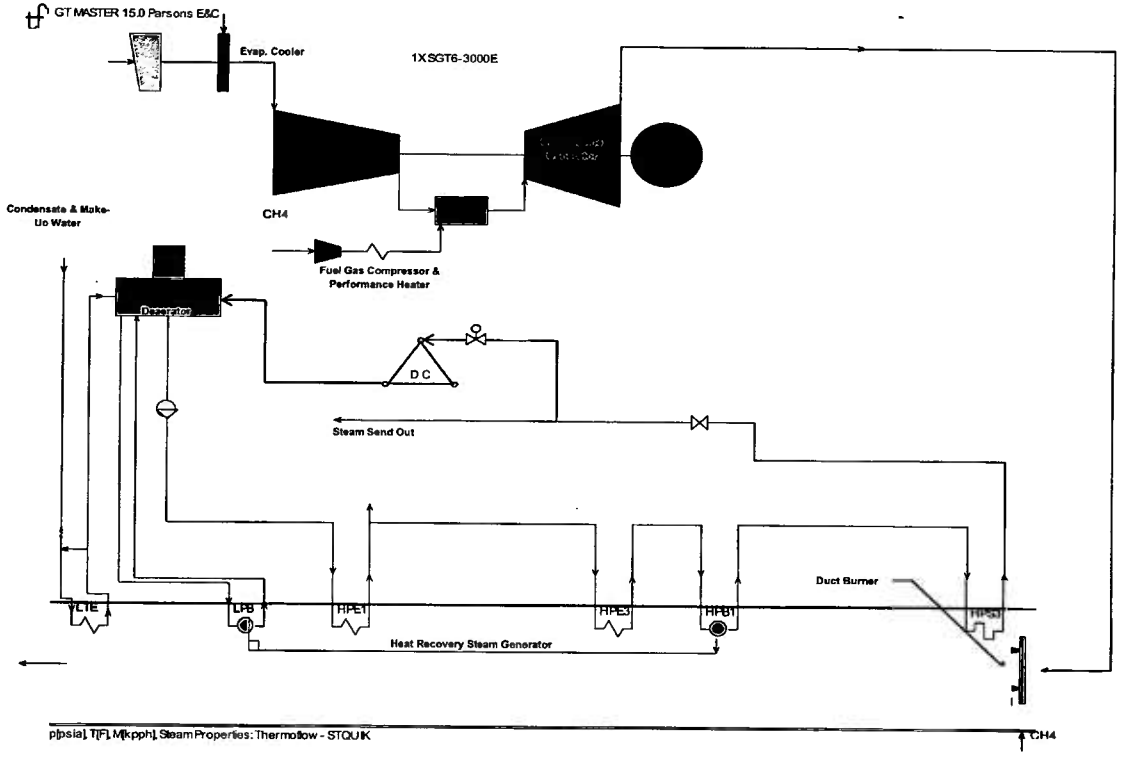


CONCEPTUAL DESIGN

NOTES

1. None

WorleyParsons		
Con Edison Steam Production Option Study Hudson Avenue Plant		
Preliminary Heat Balance - Cogeneration Plant Option CG1: CG Plant with 501D5A & LP Gas Boilers Oil, 59°F/60% R.H, Fired HRSG (NG)		
DWG No: CESP-1-HB-CG1-01	Rev A	Date: 7/10/2006

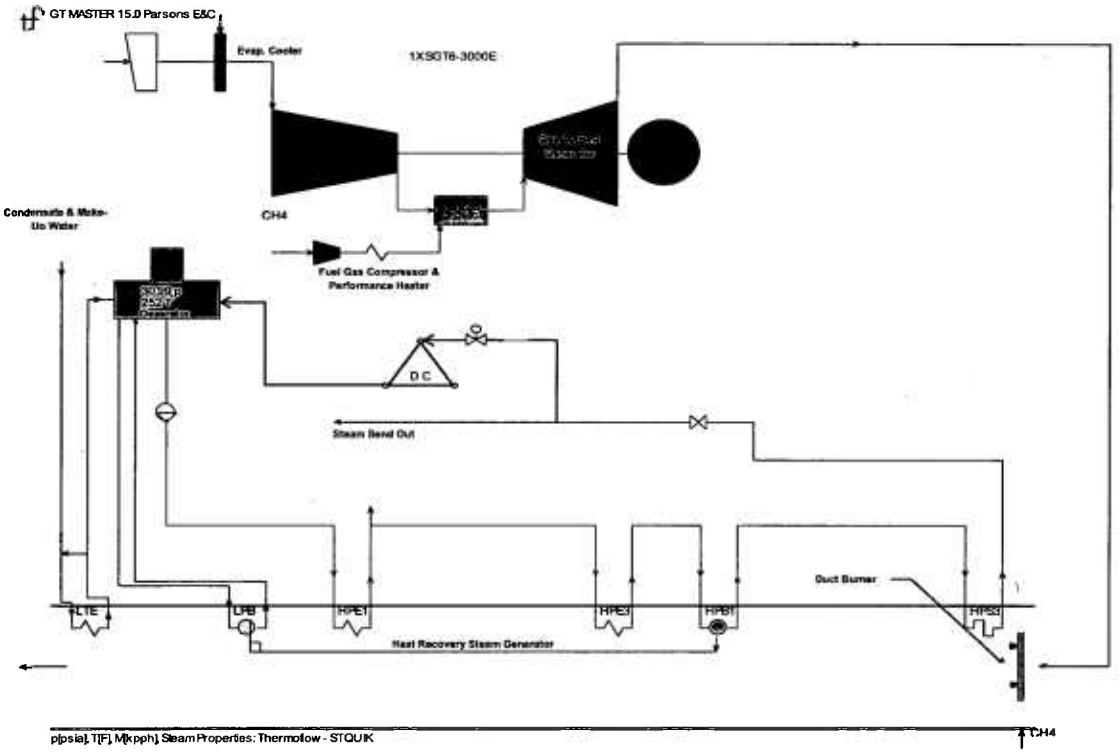


CONCEPTUAL DESIGN

NOTES

1. None

WorleyParsons resources & energy		
Con Edison Steam Production Option Study Hudson Avenue Plant		
Preliminary Heat Balance - Cogeneration Plant Option CG1: CG Plant with 501D5A & LP Gas Boilers Gas, 59°F/60% R.H, Fired HRSG (NG)		
DWG No: CESP-1-HB-CG1-02	Rev A	Date: 7/10/2006

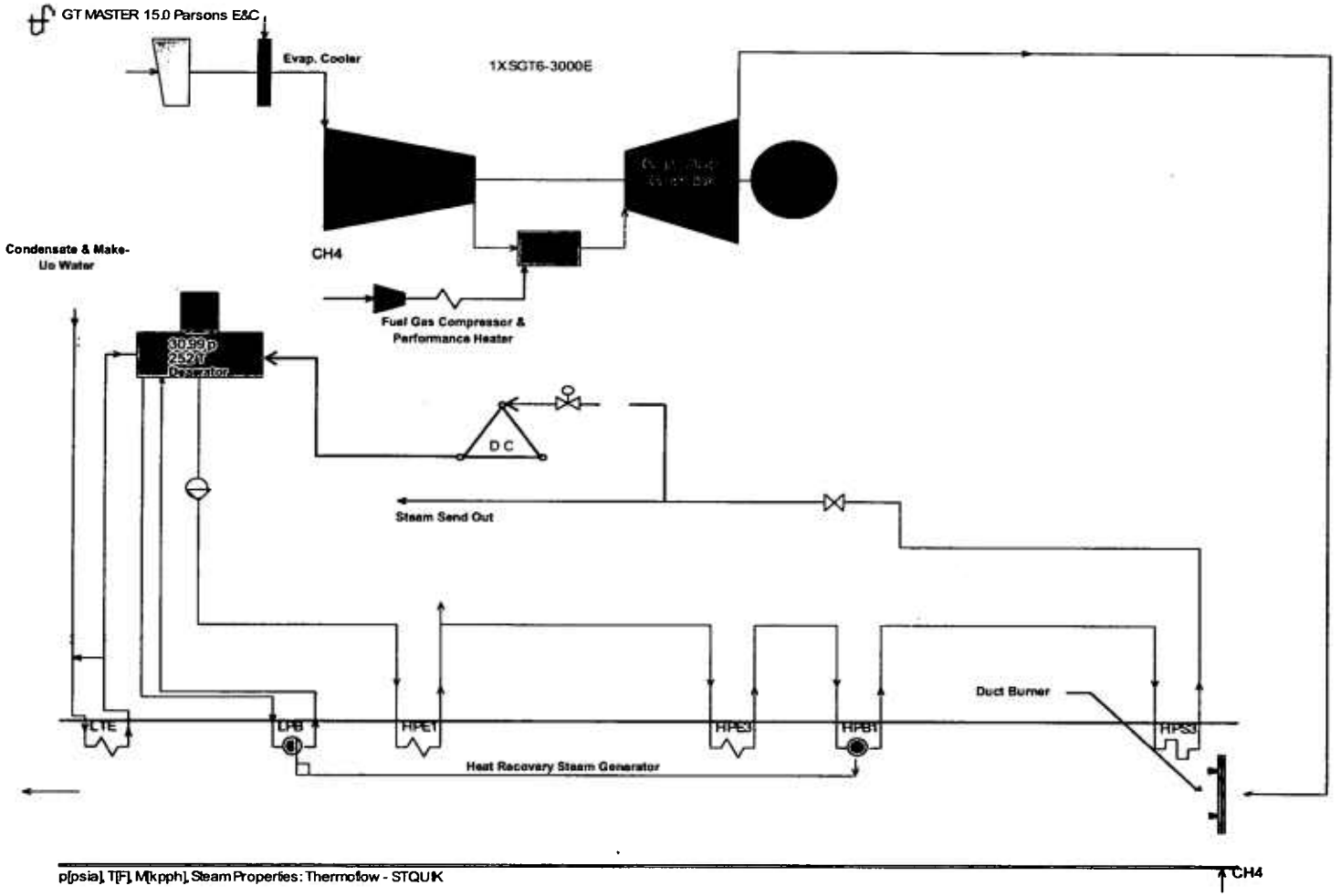


CONCEPTUAL DESIGN

NOTES

1. None

WorleyParsons		
Con Edison Steam Production Option Study Hudson Avenue Plant		
Preliminary Heat Balance - Cogeneration Plant Option CG1: CG Plant with 501D5A & LP Gas Boilers Gas, 90F/35% R.H, Fired HRSG (NG)		
DWG No: CESP-1-HB-CG1-03	Rev A	Date: 7/10/2006

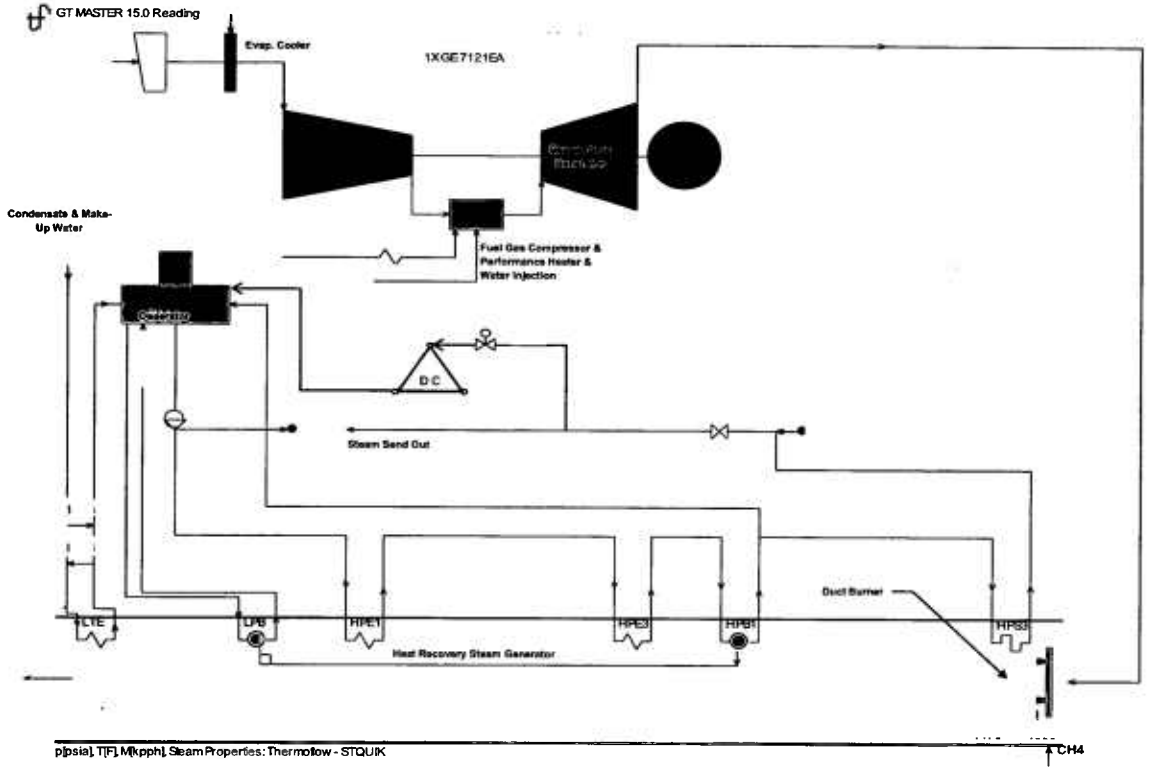


CONCEPTUAL DESIGN

NOTES

1. None

WorleyParsons		
Con Edison Steam Production Option Study Hudson Avenue Plant		
Preliminary Heat Balance - Cogeneration Plant Option CG1: CG Plant with 501D5A & LP Gas Boilers Gas, 59°F/60% R.H, Unfired HRSG		
DWG No: CESP-1-HB-CG1-04	Rev A	Date: 7/10/2006

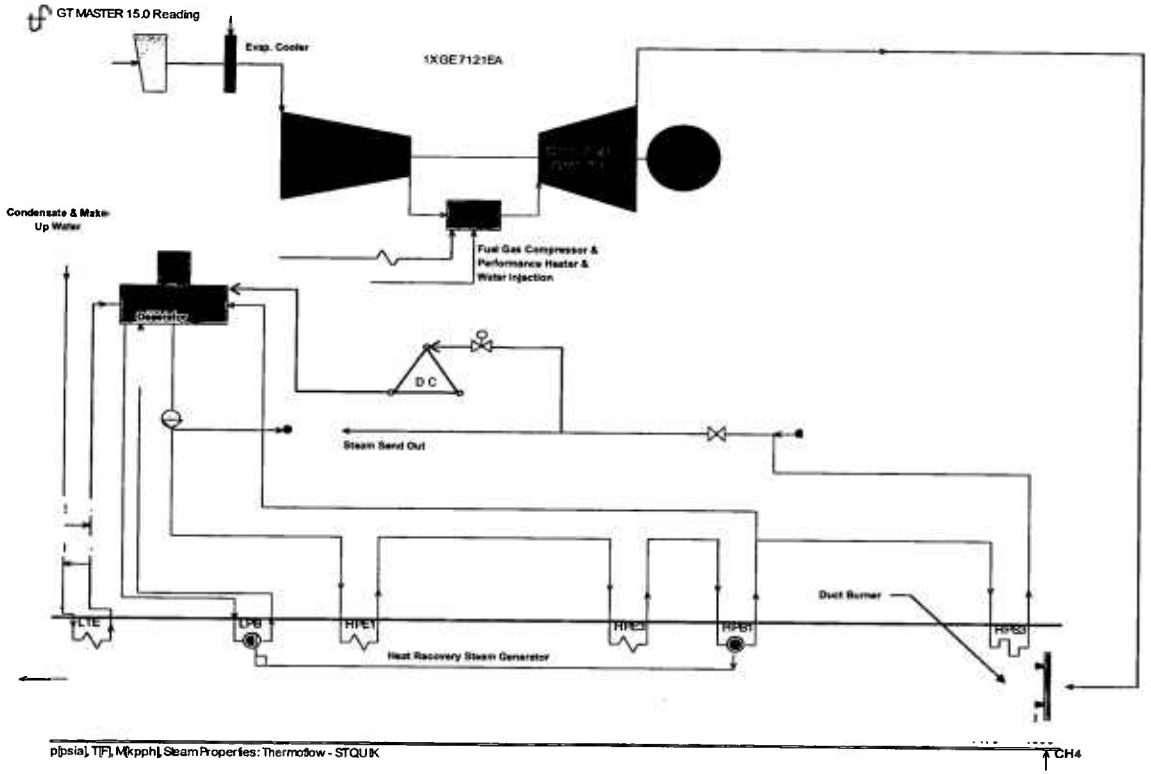


CONCEPTUAL DESIGN

NOTES

1. None

WorleyParsons		
Con Edison Steam Production Option Study Hudson Avenue Plant		
Preliminary Heat Balance - Cogeneration Plant Option CG2: CG Plant with GE 7EA & LP Gas Boilers Oil, 59°F/60% R.H, Fired HRSG (NG)		
DWG No: CESP-1-HB-CG2-01	Rev A	Date: 7/10/2006

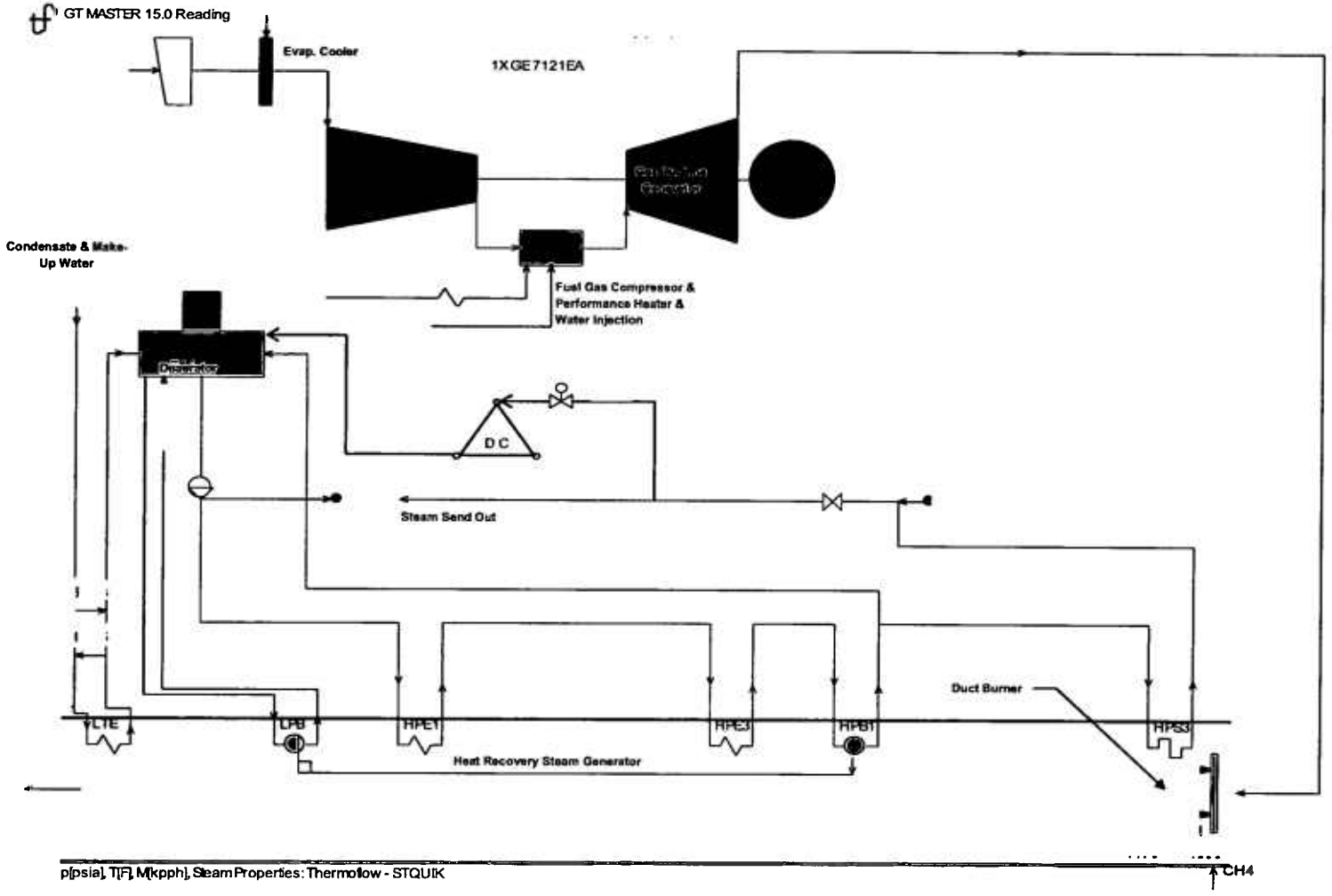


CONCEPTUAL DESIGN

NOTES

1. None

WorleyParsons		
Con Edison Steam Production Option Study Hudson Avenue Plant		
Preliminary Heat Balance - Cogeneration Plant Option CG2: CG Plant with GE 7EA & LP Gas Boilers Gas, 59°F/60% R.H, Fired HRSG (NG)		
DWG No: CESP-1-HB-CG2-02	Rev A	Date: 7/10/2006

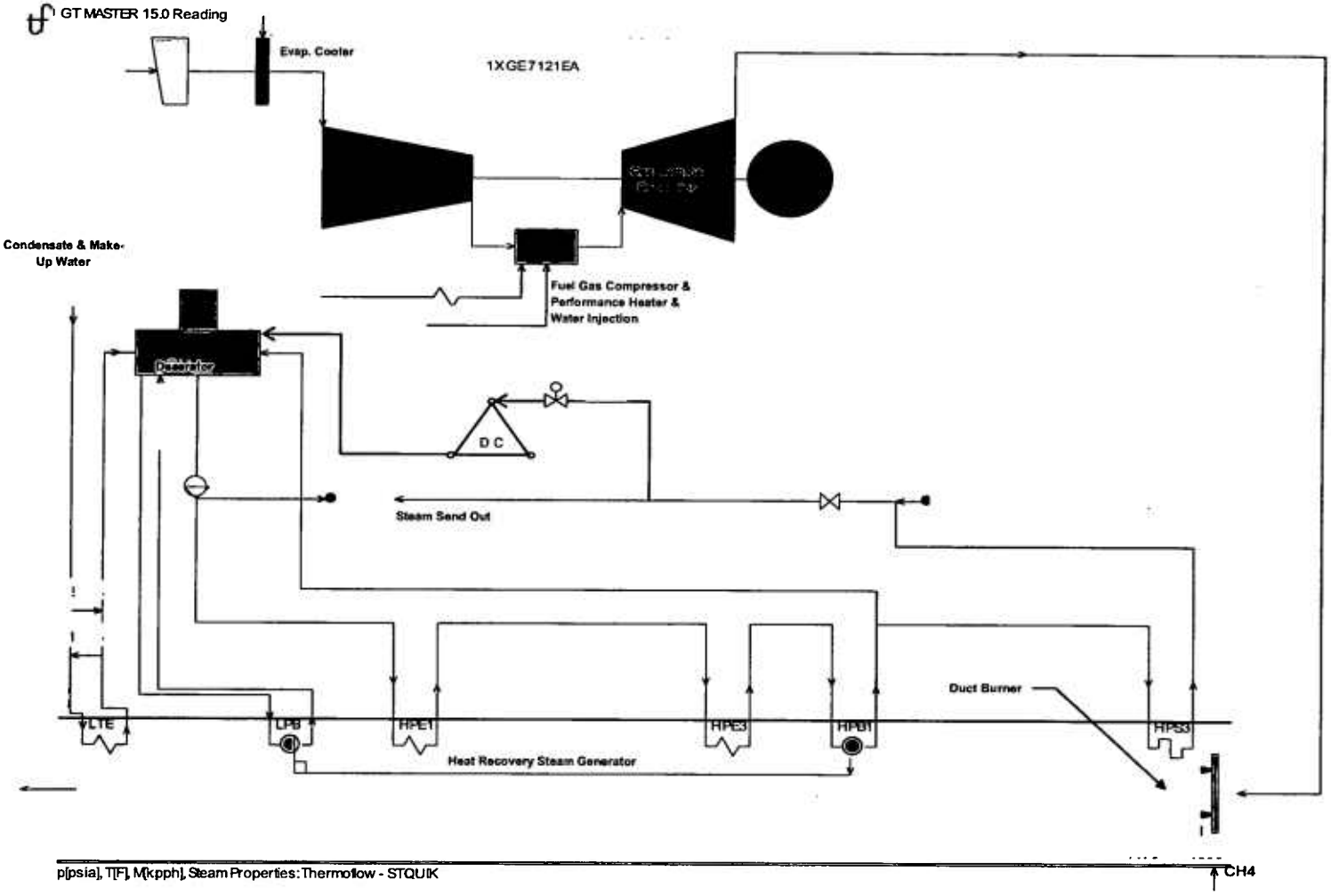


CONCEPTUAL DESIGN

NOTES

1. None

WorleyParsons		
Con Edison Steam Production Option Study Hudson Avenue Plant		
Preliminary Heat Balance - Cogeneration Plant Option CG2: CG Plant with GE 7EA & LP Gas Boilers Gas, 90°F/35% R.H, Fired HRSG (NG)		
DWG No: CESP-1-HB-CG2-03	Rev A	Date: 7/10/2006

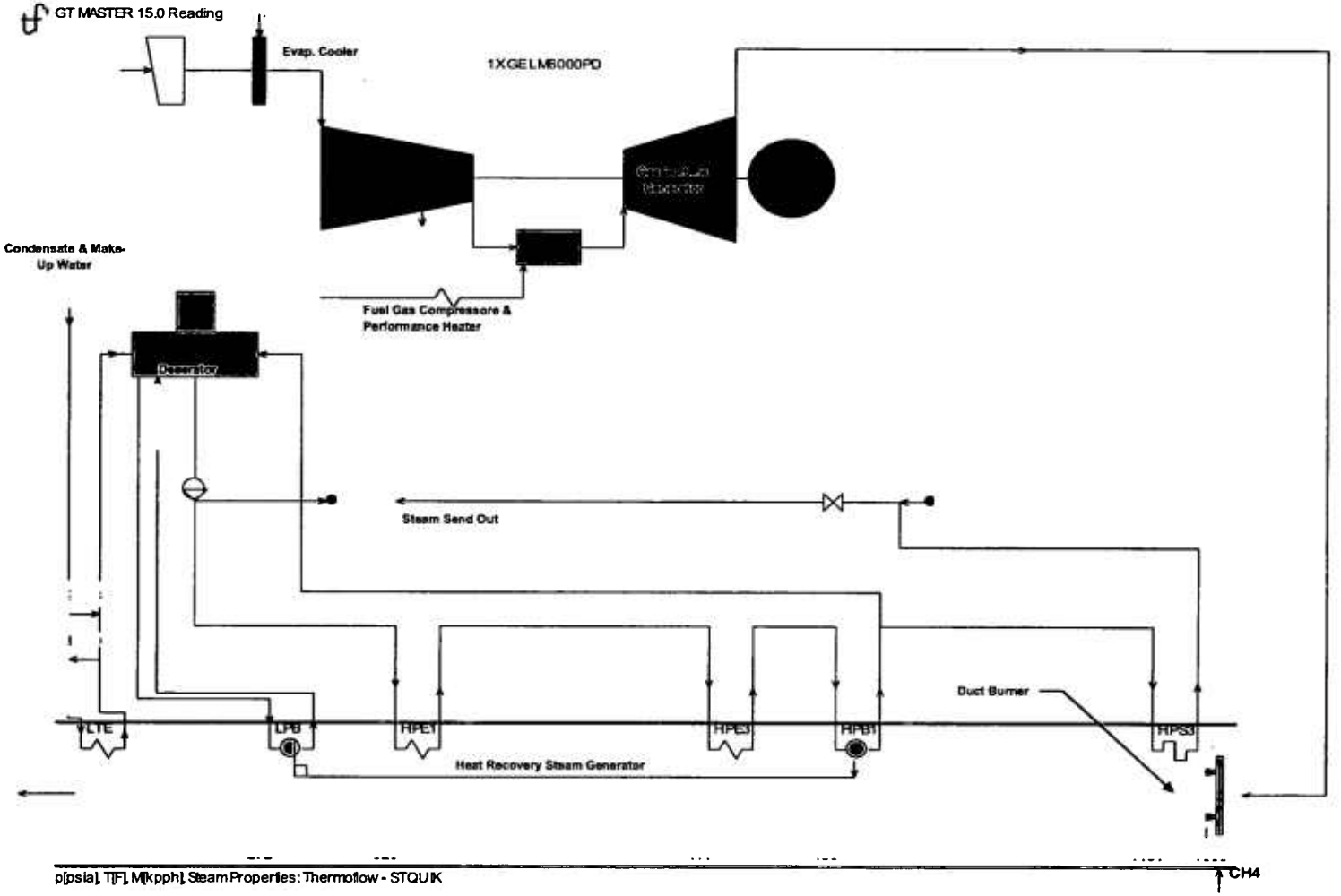


CONCEPTUAL DESIGN

NOTES

1. None

WorleyParsons		
Con Edison Steam Production Option Study Hudson Avenue Plant		
Preliminary Heat Balance - Cogeneration Plant Option CG2: CG Plant with GE 7EA & LP Gas Boilers Gas, 59°F/60% R.H, Unfired HRSG		
DWG No: CESP-1-HB-CG2-04	Rev A	Date: 7/10/2006

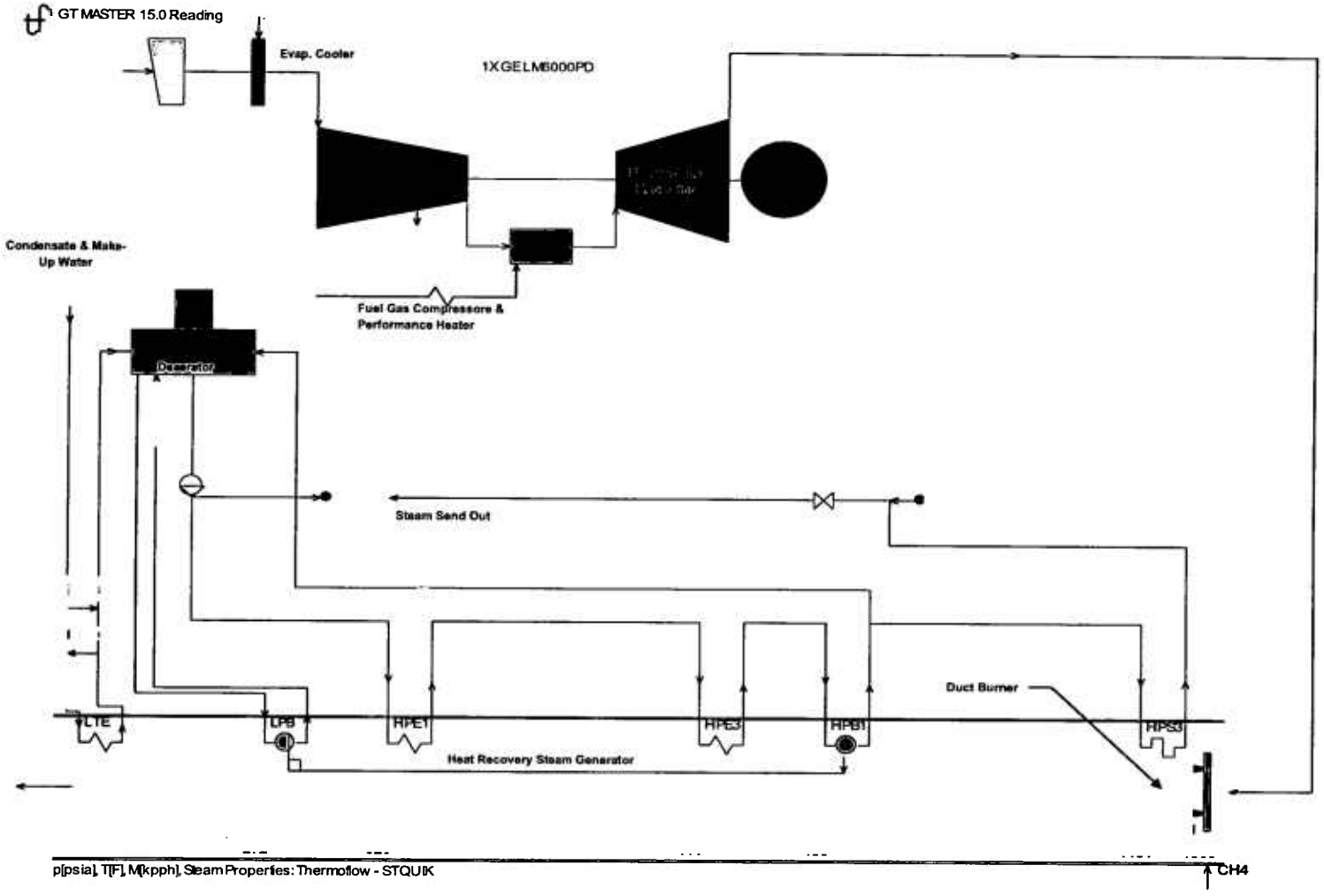


CONCEPTUAL DESIGN

NOTES

1. Heat Balance applies to 59th Street Plant Option CG1.

WorleyParsons		
Con Edison Steam Production Option Study Hudson Avenue Plant		
Preliminary Heat Balance - Cogeneration Plant Option CG3: CG Plant with LM6000 & LP Gas Boilers Oil, 59°F/60% R.H, Fired HRSG (NG)		
DWG No: CESP-1-HB-CG3-01	Rev A	Date: 7/10/2006

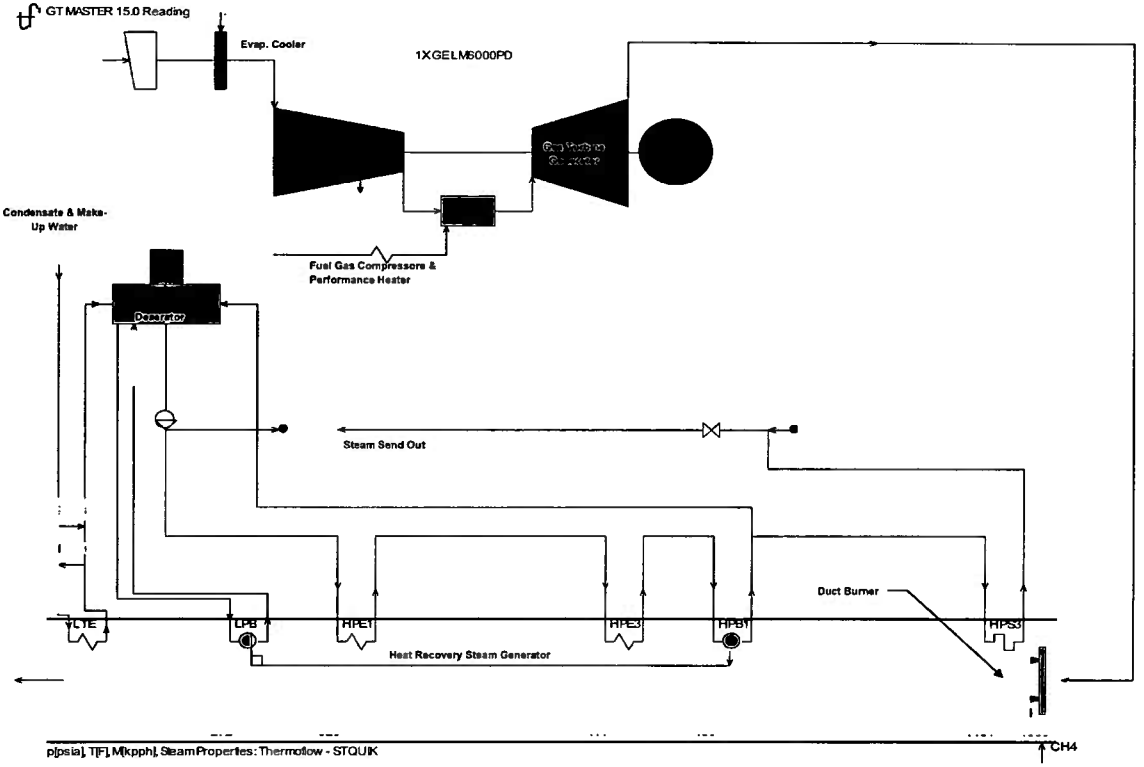


CONCEPTUAL DESIGN

NOTES

1. Heat Balance applies to 59th Street Plant Option CG1.

WorleyParsons		
Con Edison Steam Production Option Study Hudson Avenue Plant		
Preliminary Heat Balance - Cogeneration Plant Option CG3: CG Plant with LM6000 & LP Gas Boilers Gas, 59°F/60% R.H, Fired HRSG (NG)		
DWG No: CESP-1-HB-CG3-02	Rev A	Date: 7/10/2006

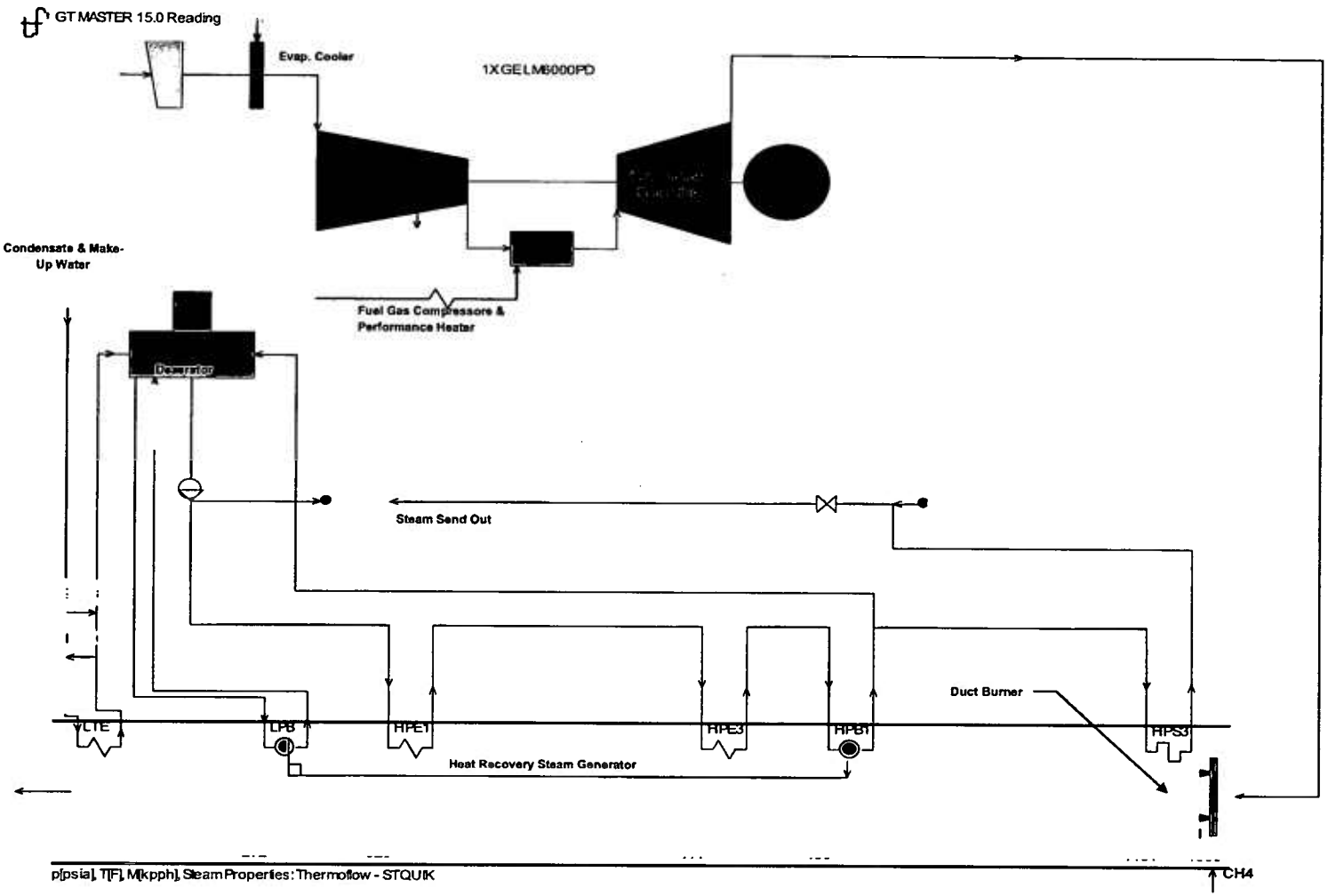


CONCEPTUAL DESIGN

NOTES

1. Heat Balance applies to 59th Street Plant Option CG1.

WorleyParsons		
Con Edison Steam Production Option Study Hudson Avenue Plant		
Preliminary Heat Balance - Cogeneration Plant Option CG3: CG Plant with LM6000 & LP Gas Boilers Gas, 90°F/35% R.H, Fired HRSG (NG)		
DWG No: CESP-1-HB-CG3-03	Rev A	Date: 7/10/2006

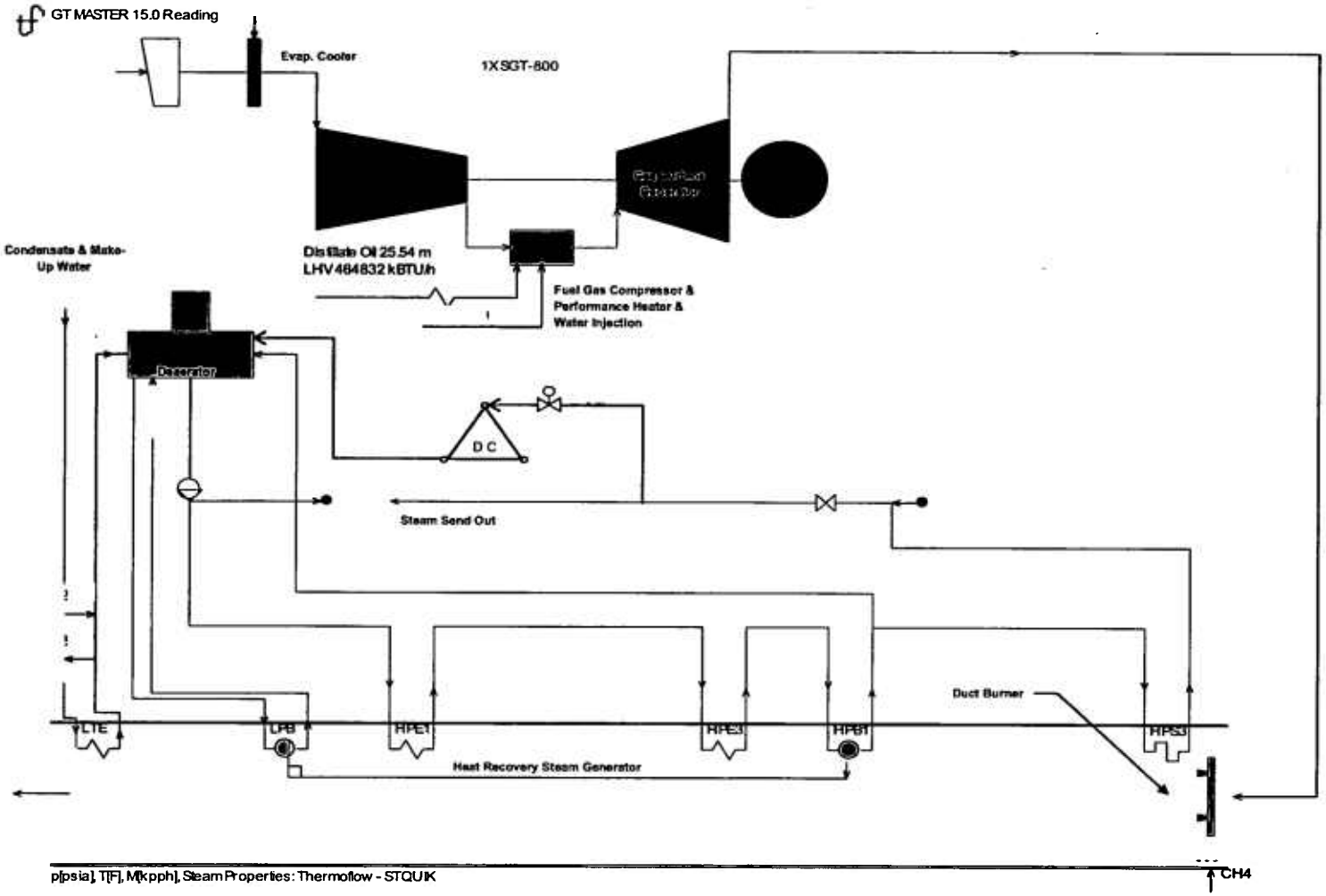


CONCEPTUAL DESIGN

NOTES

1. Heat Balance applies to 59th Street Plant Option CG1.

WorleyParsons		
Con Edison Steam Production Option Study Hudson Avenue Plant		
Preliminary Heat Balance - Cogeneration Plant Option CG3: CG Plant with LM6000 & LP Gas Boilers Gas, 59°F/60% R.H, Unfired HRSG		
DWG No: CESP-1-HB-CG3-04	Rev A	Date: 7/10/2006

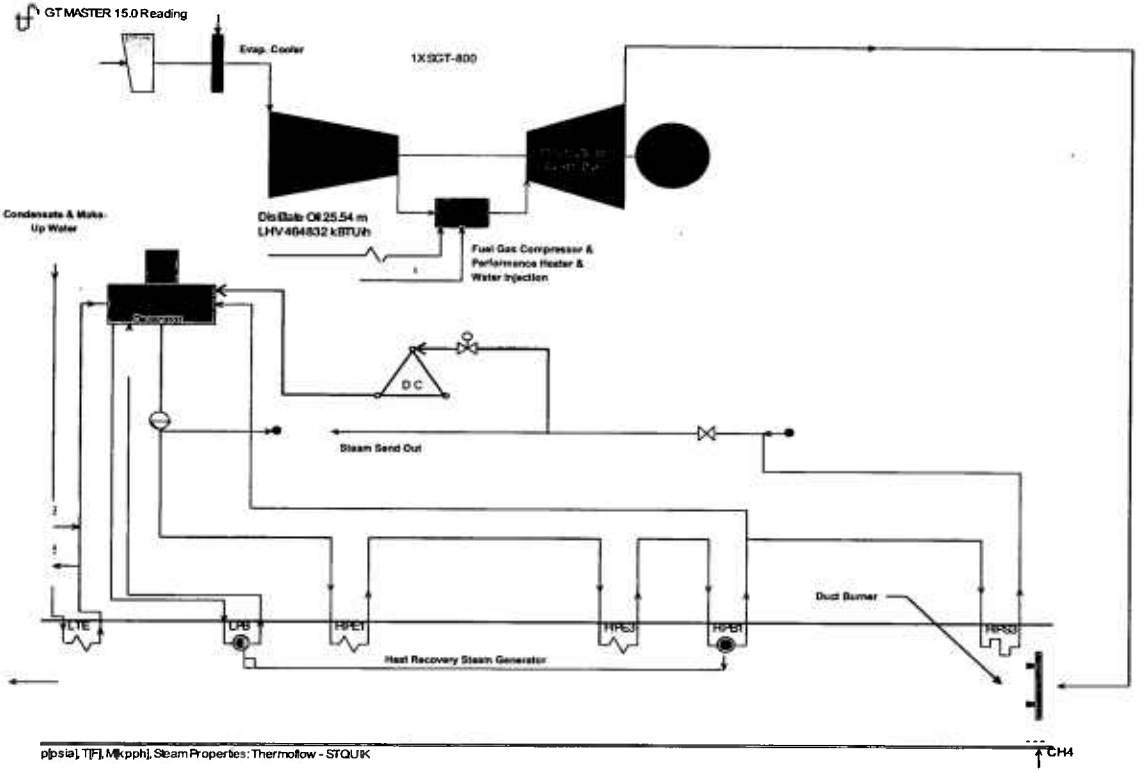


CONCEPTUAL DESIGN

NOTES

1. Heat Balance applies to 59th Street Plant Option CG-2 Except that 59th Street Plant will not have any dump condenser.

WorleyParsons		
Con Edison Steam Production Option Study Hudson Avenue Plant		
Preliminary Heat Balance - Cogeneration Plant Option CG4: CG Plant with GTX100 & LP Gas Boilers Oil, 59°F/60% R.H, Fired HRSG (NG)		
DWG No: CESP-1-HB-CG4-01	Rev A	Date: 7/10/2006

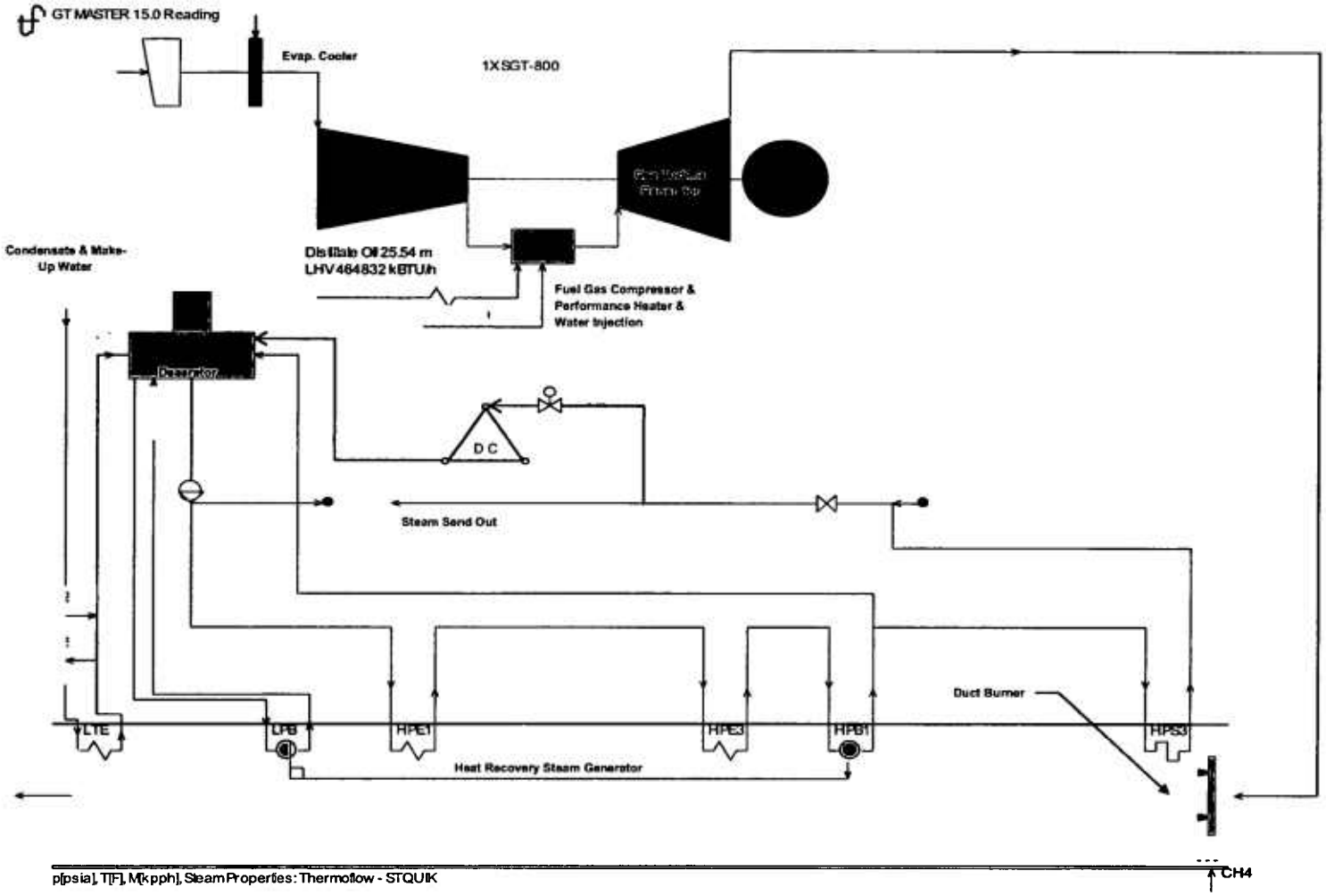


CONCEPTUAL DESIGN

NOTES

1. Heat Balance applies to 59th Street Plant Option CG-2 Except that 59th Street Plant will not have any dump condenser.

WorleyParsons		
Con Edison Steam Production Option Study Hudson Avenue Plant		
Preliminary Heat Balance - Cogeneration Plant Option CG4: CG Plant with GTX100 & LP Gas Boilers Gas, 59°F/60% R.H, Fired HRSG (NG)		
DWG No: CESP-1-HB-CG4-02	Rev A	Date: 7/10/2006

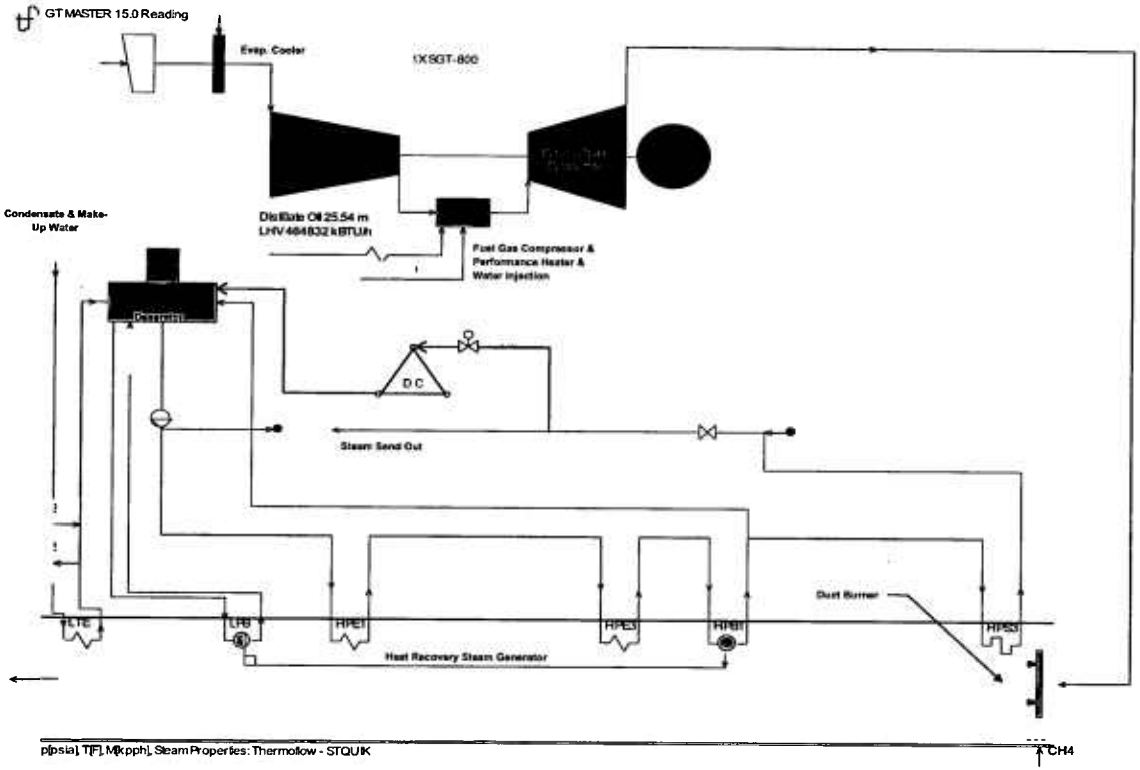


CONCEPTUAL DESIGN

NOTES

1. Heat Balance applies to 59th Street Plant Option CG-2 Except that 59th Street Plant will not have any dump condenser.

WorleyParsons		
Con Edison Steam Production Option Study Hudson Avenue Plant		
Preliminary Heat Balance - Cogeneration Plant Option CG4: CG Plant with GTX100 & LP Gas Boilers Gas, 90°F/35% R.H, Fired HRSG (NG)		
DWG No: CESP-1-HB-CG4-03	Rev A	Date: 7/10/2006



CONCEPTUAL DESIGN

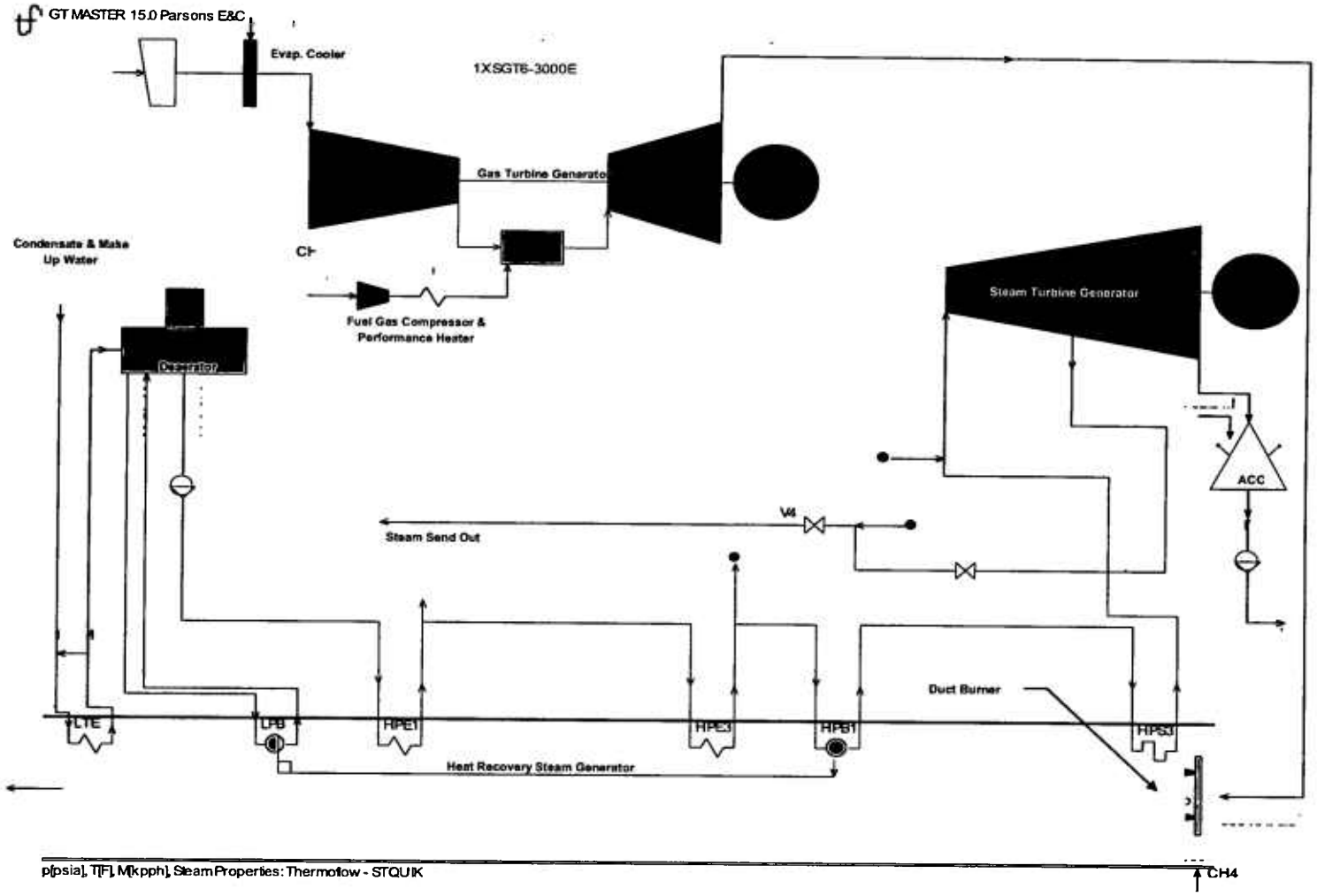
NOTES

1. Heat Balance applies to 59th Street Plant Option CG-2 Except that 59th Street Plant will not have any dump condenser.

WorleyParsons		
Con Edison Steam Production Option Study Hudson Avenue Plant		
Preliminary Heat Balance - Cogeneration Plant Option CG4: CG Plant with GTX100 & LP Gas Boilers Gas, 59°F/60% R.H, Unfired HRSG		
DWG No: CESP-1-HB-CG4-04	Rev A	Date: 7/10/2006

HEAT AND MATERIAL BALANCES FOR HUDSON AVENUE COMBINED CYCLE CASES

Drawing #	Description
CESP-1-HB-CC1-01	CC Plant with Siemens 501D5A & New LP Gas Boilers
CESP-1-HB-CC1-02	CC Plant with Siemens 501D5A & New LP Gas Boilers
CESP-1-HB-CC1-03	CC Plant with Siemens 501D5A & New LP Gas Boilers
CESP-1-HB-CC1-04	CC Plant with Siemens 501D5A & New LP Gas Boilers
CESP-1-HB-CC2-01	CC Plant with GE 7EA & New LP Gas Boilers
CESP-1-HB-CC2-02	CC Plant with GE 7EA & New LP Gas Boilers
CESP-1-HB-CC2-03	CC Plant with GE 7EA & New LP Gas Boilers
CESP-1-HB-CC2-04	CC Plant with GE 7EA & New LP Gas Boilers
CESP-1-HB-CC3-01	CC Plant with GE LM6000 & New LP Gas Boilers
CESP-1-HB-CC3-02	CC Plant with GE LM6000 & New LP Gas Boilers
CESP-1-HB-CC3-03	CC Plant with GE LM6000 & New LP Gas Boilers
CESP-1-HB-CC3-04	CC Plant with GE LM6000 & New LP Gas Boilers
CESP-1-HB-CC4-01	CC Plant with GTX100 & New LP Gas Boilers
CESP-1-HB-CC4-02	CC Plant with GTX100 & New LP Gas Boilers
CESP-1-HB-CC4-03	CC Plant with GTX100 & New LP Gas Boilers
CESP-1-HB-CC4-04	CC Plant with GTX100 & New LP Gas Boilers
CESP-1-HB-CC5-01	CC Plant with Siemens 501FD - 335 MW & New LP Gas Boilers
CESP-1-HB-CC5-02	CC Plant with Siemens 501FD - 335 MW & New LP Gas Boilers
CESP-1-HB-CC5-03	CC Plant with Siemens 501FD - 335 MW & New LP Gas Boilers
CESP-1-HB-CC5-04	CC Plant with Siemens 501FD - 335 MW & New LP Gas Boilers
CESP-1-HB-CC6-01	CC Plant with 2xGE 7FA - 500 MW(12)
CESP-1-HB-CC6-02	CC Plant with 2xGE 7FA - 500 MW(12)
CESP-1-HB-CC6-03	CC Plant with 2xGE 7FA - 500 MW(12)
CESP-1-HB-CC6-04	CC Plant with 2xGE 7FA - 500 MW(12)

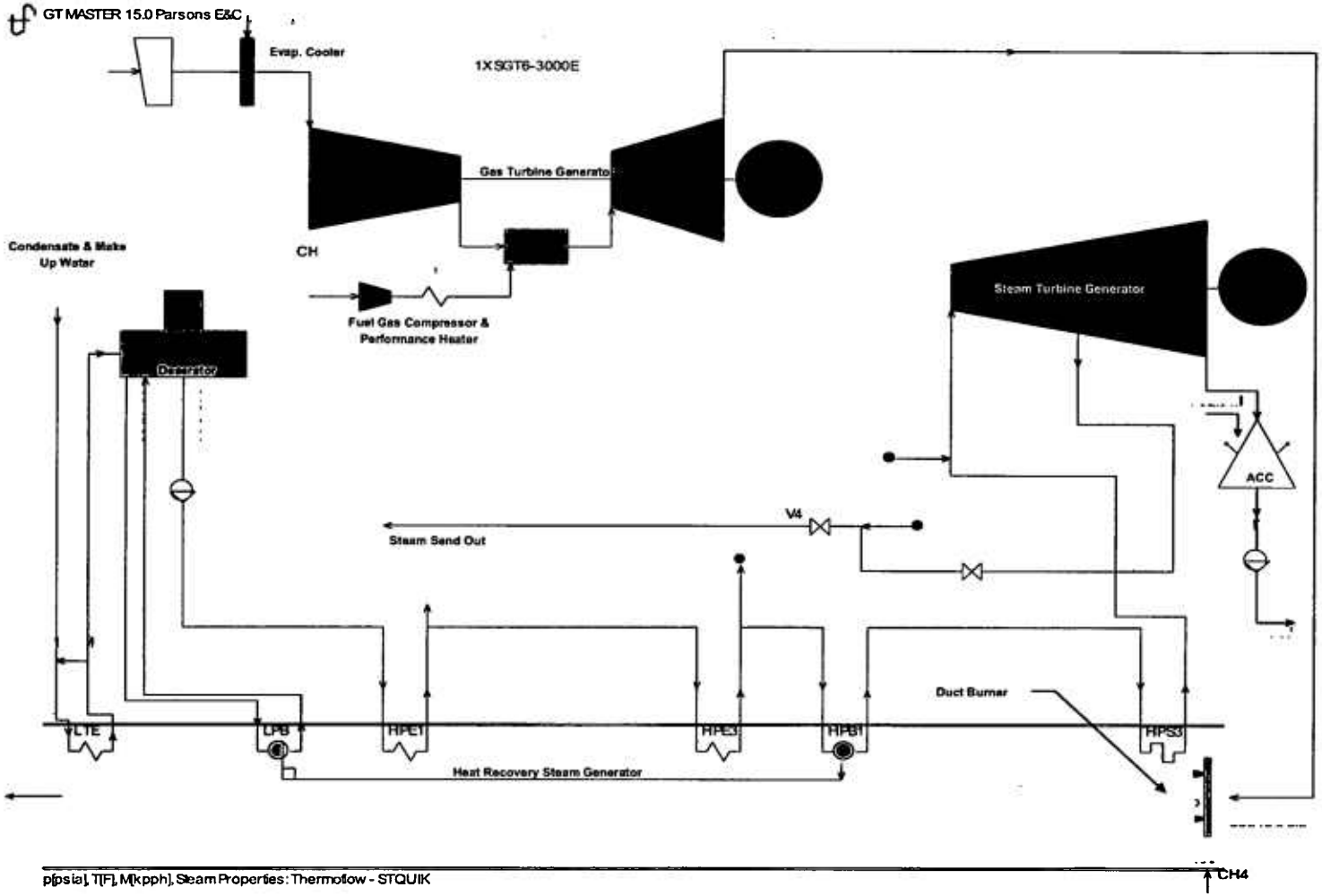


CONCEPTUAL DESIGN

NOTES

1. None

WorleyParsons		
Con Edison Steam Production Option Study Hudson Avenue Plant		
Preliminary Heat Balance - Combined Cycle Plant Option CC1: CC Plant with 501D5A & LP Gas Boilers Oil, 59°F/60% R.H, Fired HRSG (NG)		
DWG No: CESP-1-HB-CC1-01	Rev A	Date: 7/10/2006

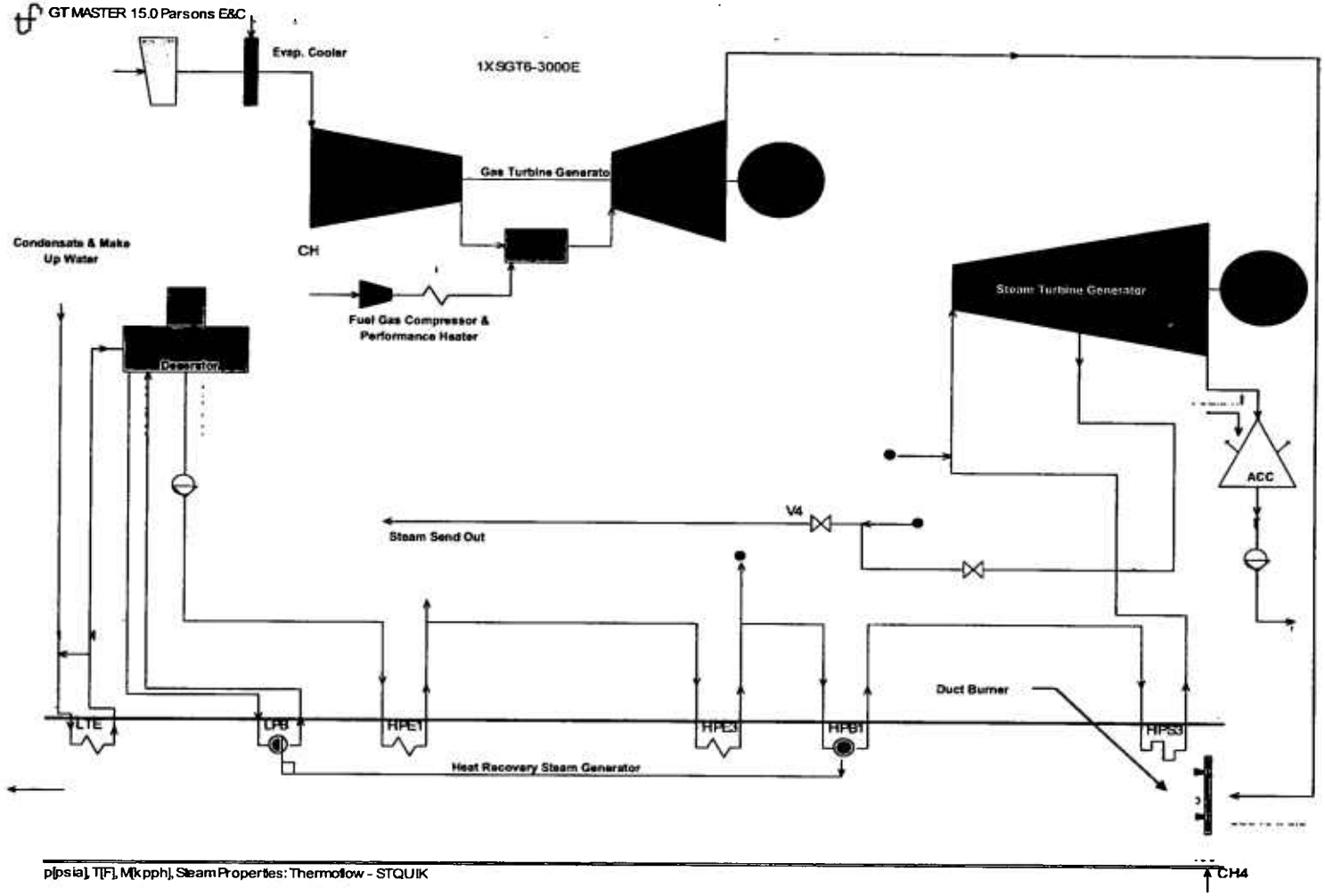


CONCEPTUAL DESIGN

NOTES

1. None

WorleyParsons		
Con Edison Steam Production Option Study Hudson Avenue Plant		
Preliminary Heat Balance - Combined Cycle Plant Option CC1: CC Plant with 501D5A & LP Gas Boilers Gas, 59°F/60% R.H, Fired HRSG (NG)		
DWG No: CESP-1-HB-CC1-02	Rev A	Date: 7/10/2006

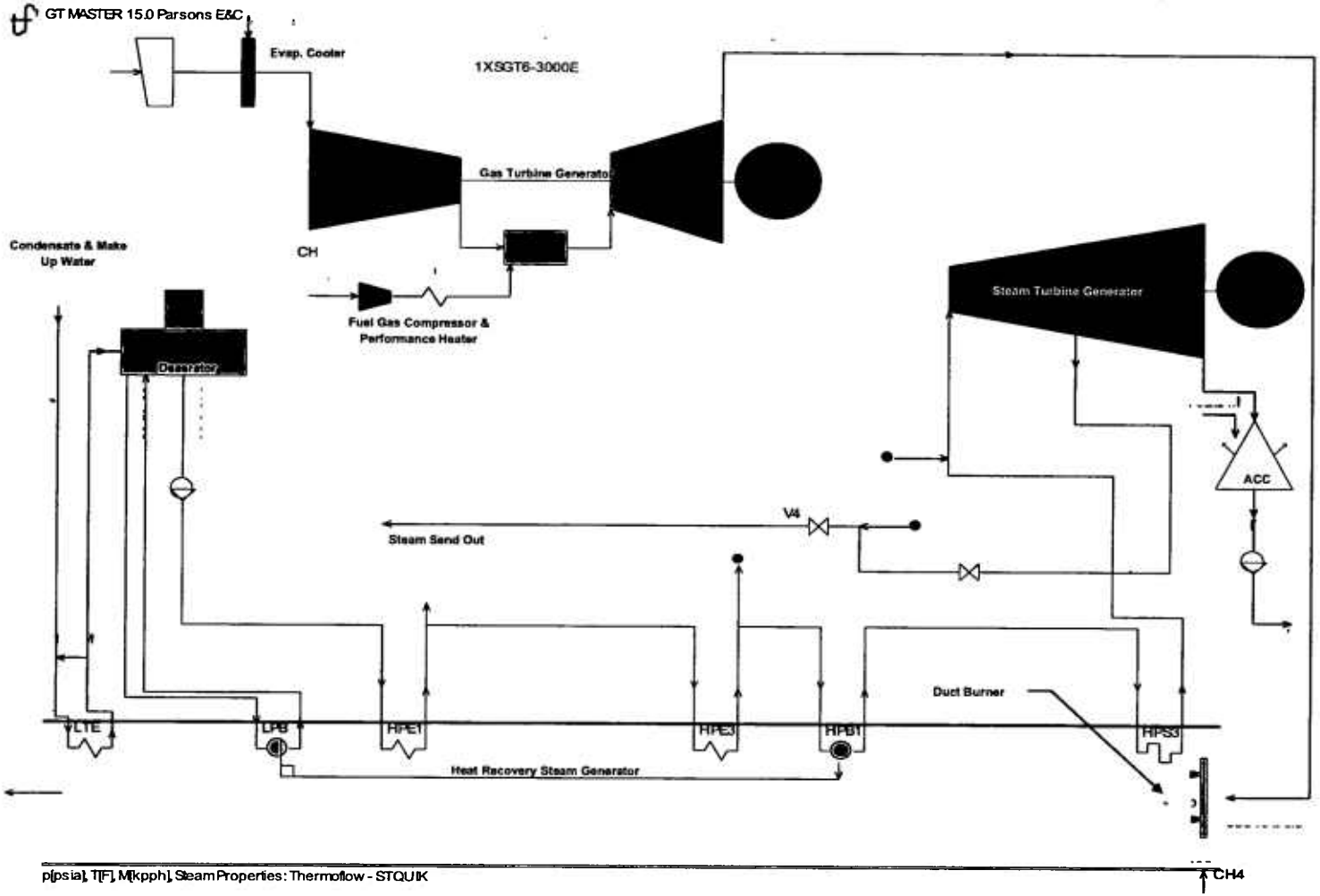


CONCEPTUAL DESIGN

NOTES

1. None

WorleyParsons resources & energy		
Con Edison Steam Production Option Study Hudson Avenue Plant		
Preliminary Heat Balance - Combined Cycle Plant Option CC1: CC Plant with 501D5A & LP Gas Boilers Gas, 90°F/35% R.H, Fired HRSG (NG)		
DWG No: CESP-1-HB-CC1-03	Rev A	Date: 7/10/2006

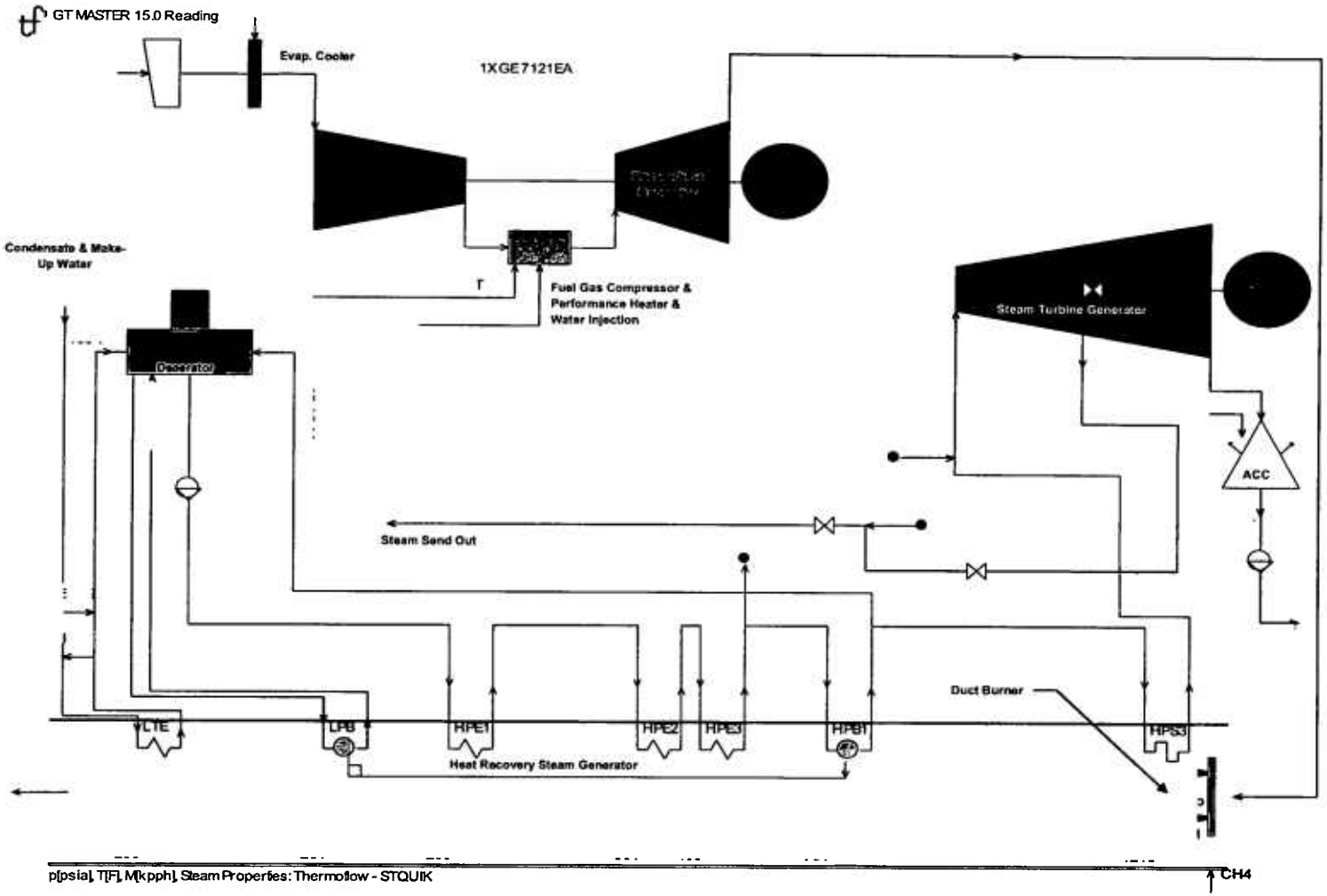


CONCEPTUAL DESIGN

NOTES

1. None

WorleyParsons		
Con Edison Steam Production Option Study Hudson Avenue Plant		
Preliminary Heat Balance - Combined Cycle Plant Option CC1: CC Plant with 501D5A & LP Gas Boilers Gas, 59°F/60% R.H, Unfired HRSG		
DWG No: CESP-1-HB-CC1-04	Rev A	Date: 7/10/2006

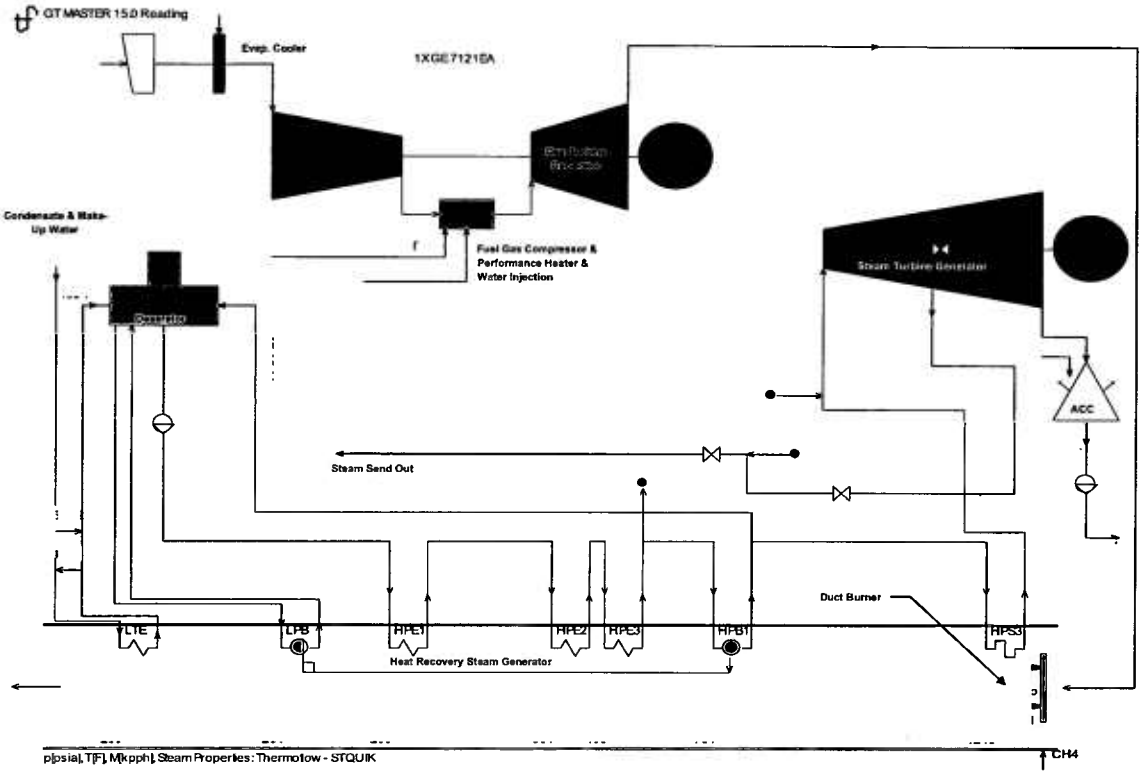


CONCEPTUAL DESIGN

NOTES

1. None

WorleyParsons		
Con Edison Steam Production Option Study Hudson Avenue Plant		
Preliminary Heat Balance - Combined Cycle Plant Option CC2: CC Plant with GE 7EA & LP Gas Boilers Oil, 59°F/60% R.H, Fired HRSG (NG)		
DWG No: CESP-1-HB-CC2-01	Rev A	Date: 7/10/2006

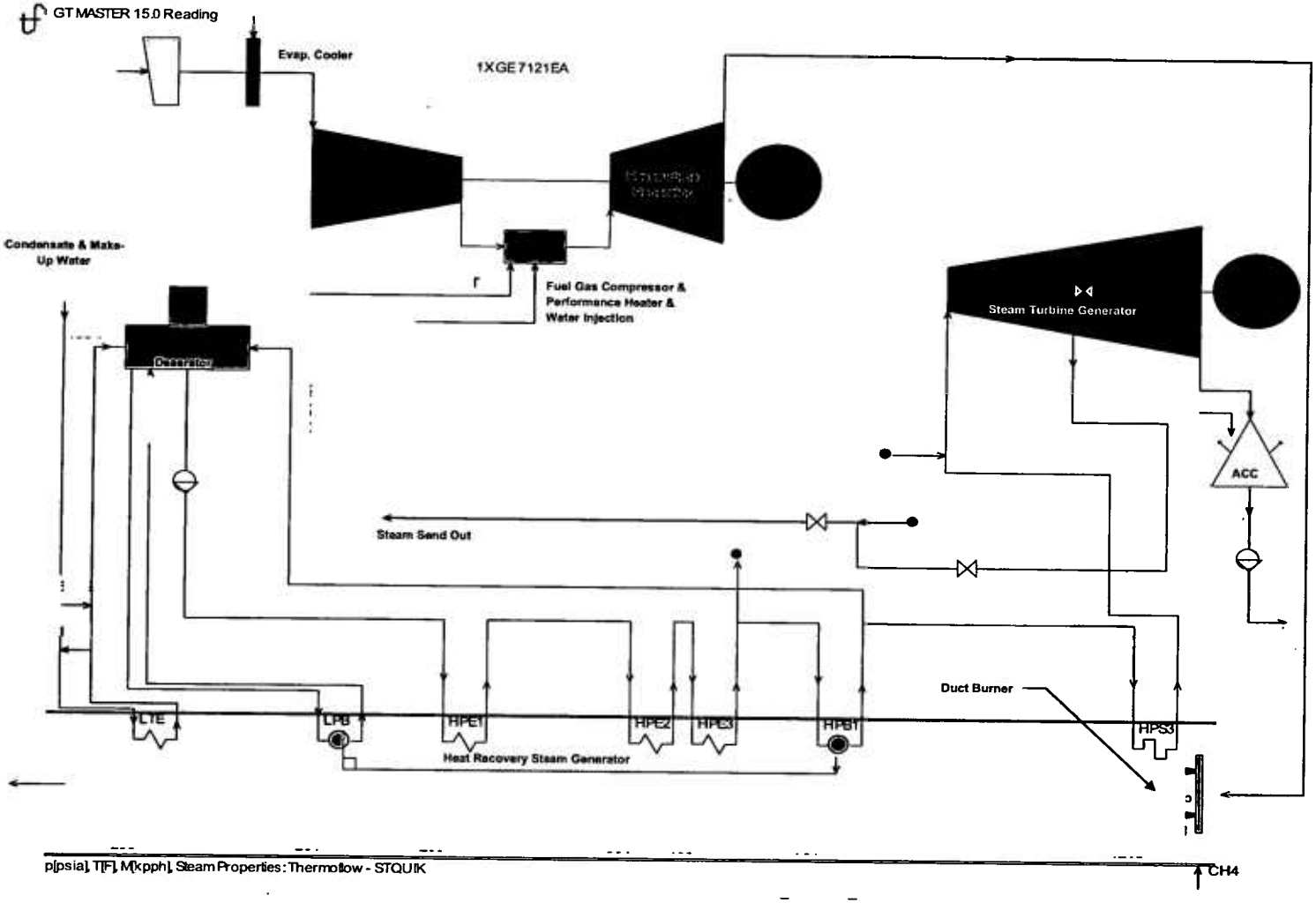


CONCEPTUAL DESIGN

NOTES

1. None

WorleyParsons		
Con Edison Steam Production Option Study Hudson Avenue Plant		
Preliminary Heat Balance - Combined Cycle Plant Option CC2: CC Plant with GE 7EA & LP Gas Boilers Gas, 59°F/60% R.H, Fired HRSG (NG)		
DWG No: CESP-1-HB-CC2-02	Rev A	Date: 7/10/2006

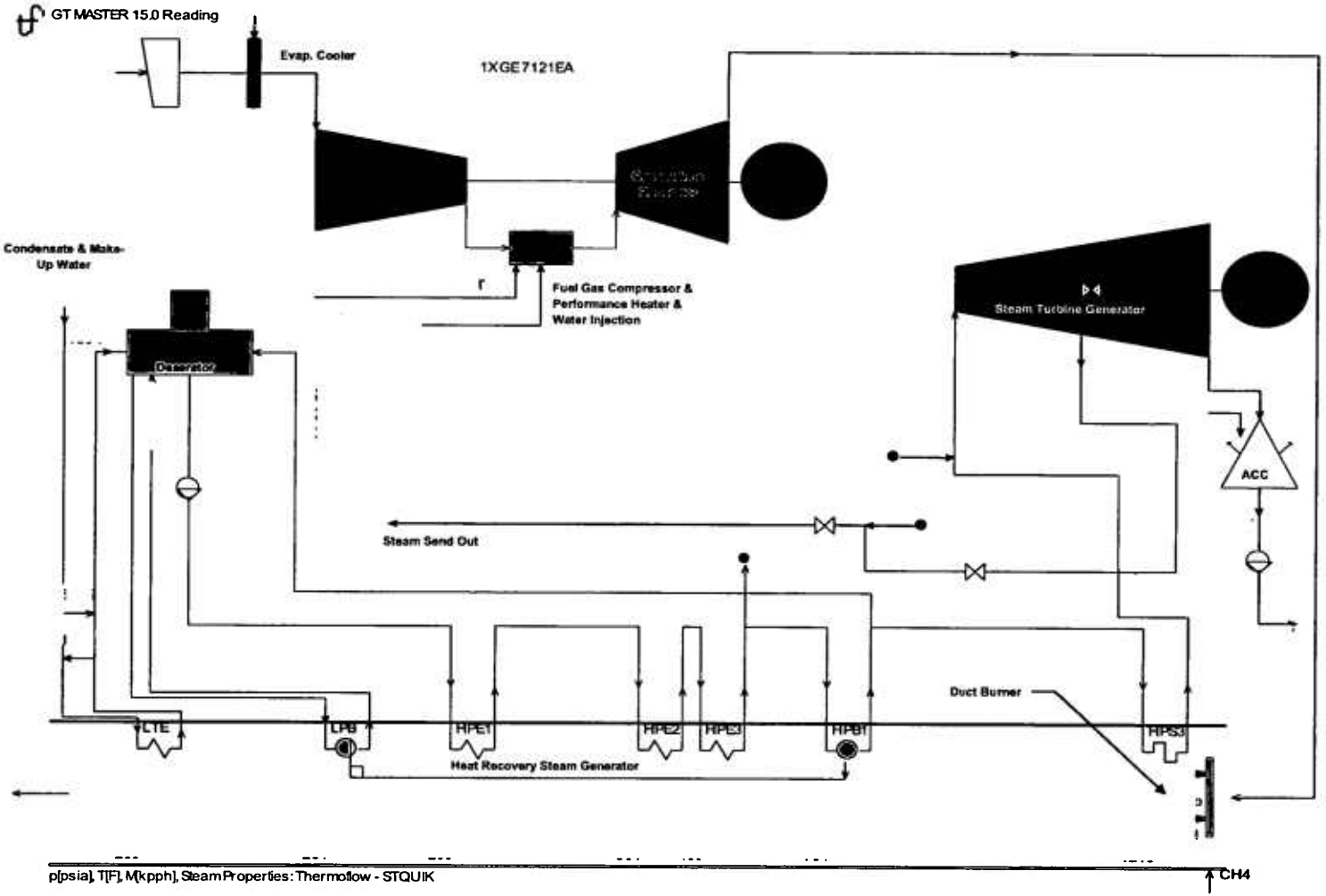


CONCEPTUAL DESIGN

NOTES

1. None

WorleyParsons		
Con Edison Steam Production Option Study Hudson Avenue Plant		
Preliminary Heat Balance - Combined Cycle Plant Option CC2: CC Plant with GE 7EA & LP Gas Boilers Gas, 90°F/35% R.H, Fired HRSG (NG)		
DWG No: CESP-1-HB-CC2-03	Rev A	Date: 7/10/2006

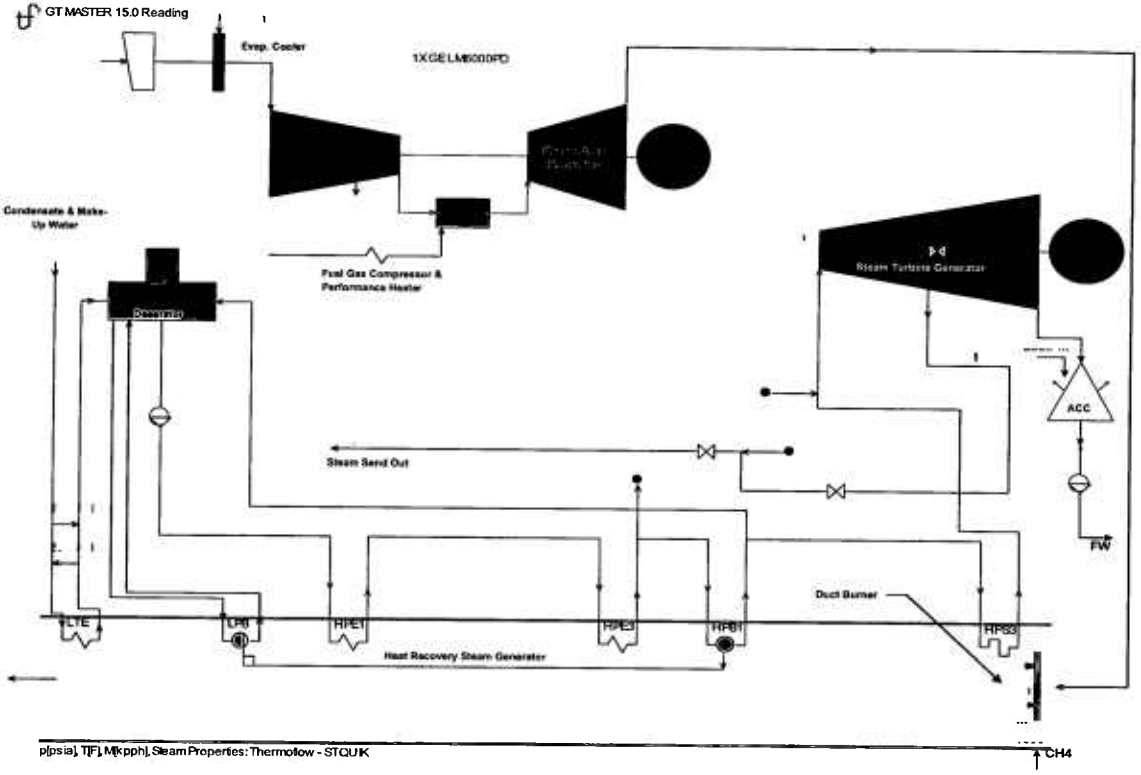


CONCEPTUAL DESIGN

NOTES

1. None

WorleyParsons		
Con Edison Steam Production Option Study Hudson Avenue Plant		
Preliminary Heat Balance - Combined Cycle Plant Option CC2: CC Plant with GE 7EA & LP Gas Boilers Gas, 59°F/60% R.H, Unfired HRSG		
DWG No: CESP-1-HB-CC2-04	Rev A	Date: 7/10/2006

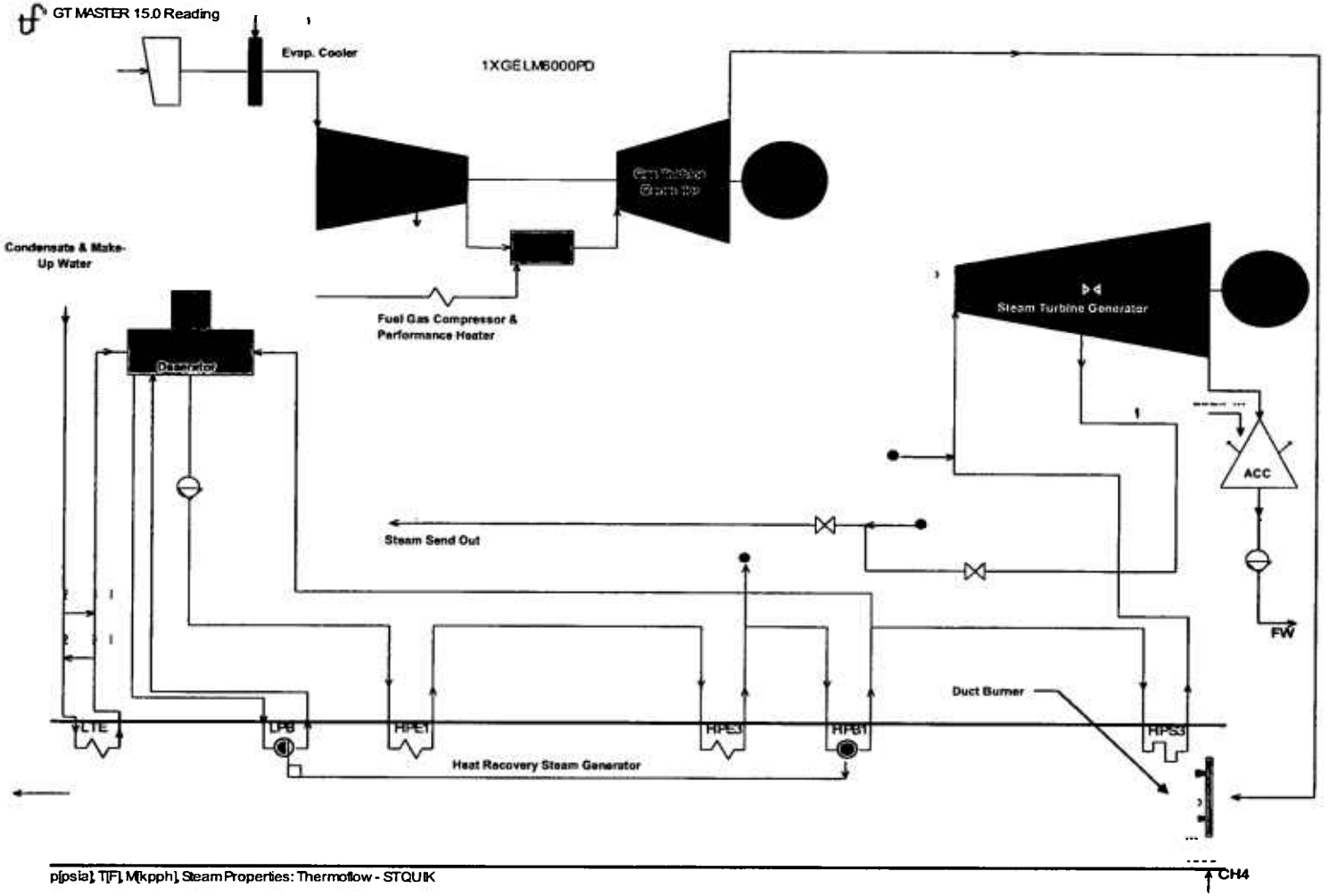


CONCEPTUAL DESIGN

NOTES

1. None

WorleyParsons		
Con Edison Steam Production Option Study Hudson Avenue Plant		
Preliminary Heat Balance - Combined Cycle Plant Option CC3: CC Plant with LM6000 & LP Gas Boilers Oil, 59°F/60% R.H, Fired HRSG (NG)		
DWG No: CESP-1-HB-CC3-01	Rev A	Date: 7/10/2006

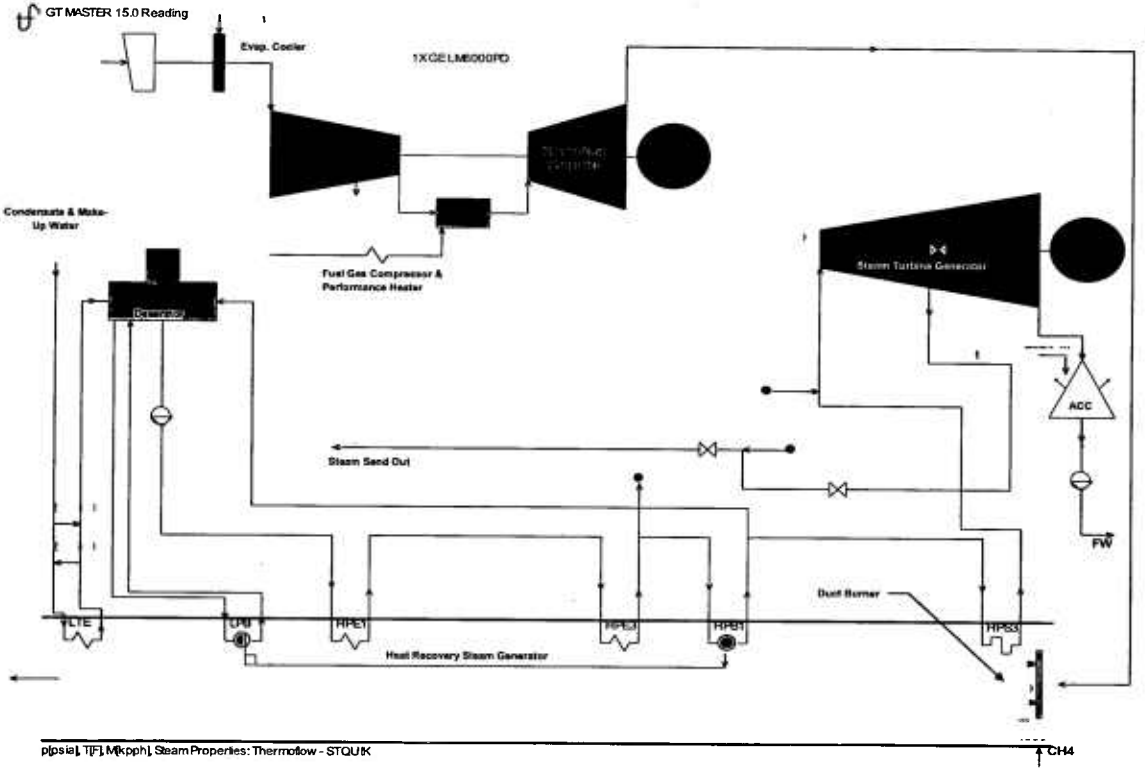


CONCEPTUAL DESIGN

NOTES

1. None

WorleyParsons		
Con Edison Steam Production Option Study Hudson Avenue Plant		
Preliminary Heat Balance - Combined Cycle Plant Option CC3: CC Plant with LM6000 & LP Gas Boilers Gas, 59°F/60% R.H, Fired HRSG (NG)		
DWG No: CESP-1-HB-CC3-02	Rev A	Date: 7/10/2006

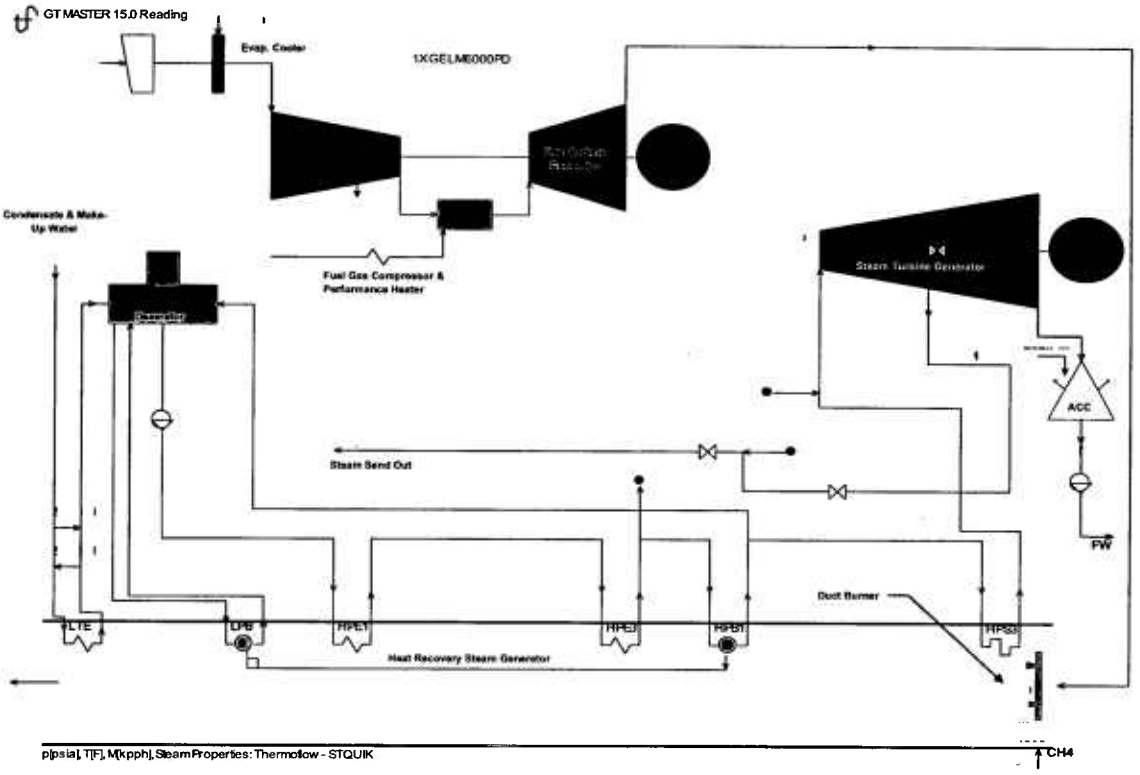


CONCEPTUAL DESIGN

NOTES

1. None

WorleyParsons		
Con Edison Steam Production Option Study Hudson Avenue Plant		
Preliminary Heat Balance - Combined Cycle Plant Option CC3: CC Plant with LM6000 & LP Gas Boilers Gas, 90°F/35% R.H, Fired HRSG (NG)		
DWG No: CESP-1-HB-CC3-03	Rev A	Date: 7/10/2006

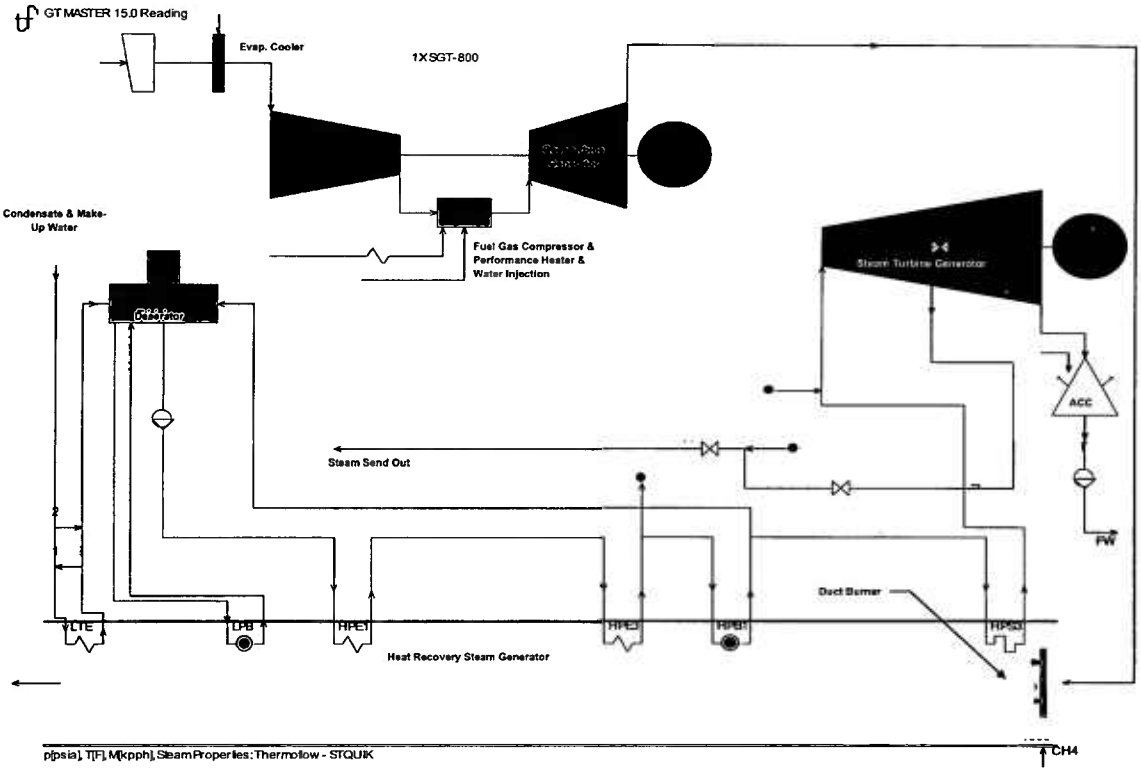


CONCEPTUAL DESIGN

NOTES

1. None

WorleyParsons		
Con Edison Steam Production Option Study Hudson Avenue Plant		
Preliminary Heat Balance - Combined Cycle Plant Option CC3: CC Plant with LM6000 & LP Gas Boilers Gas, 59°F/60% R.H, Unfired HRSG		
DWG No: CESP-1-HB-CC3-04	Rev A	Date: 7/10/2006

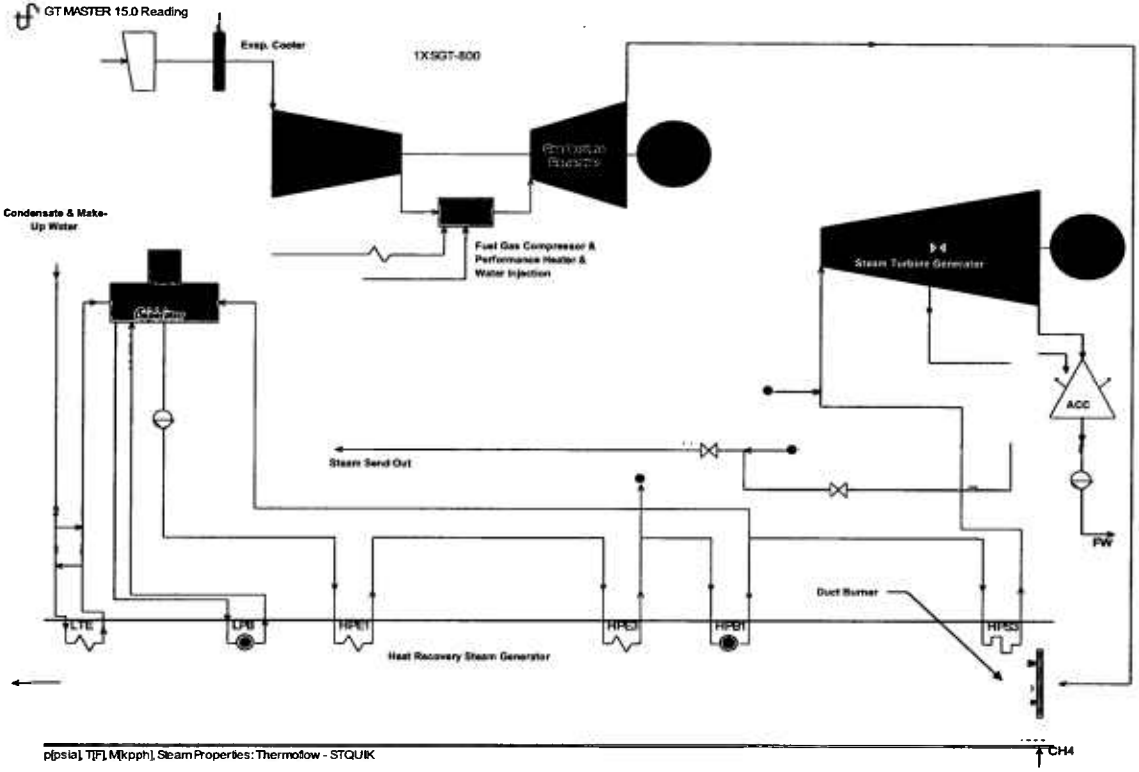


CONCEPTUAL DESIGN

NOTES

1. None

WorleyParsons		
Con Edison Steam Production Option Study Hudson Avenue Plant		
Preliminary Heat Balance - Combined Cycle Plant Option CC4: CC Plant with GTX100 & LP Gas Boilers Oil, 59°F/60% R.H, Fired HRSG (NG)		
DWG No: CESP-1-HB-CC4-01	Rev A	Date: 7/10/2006

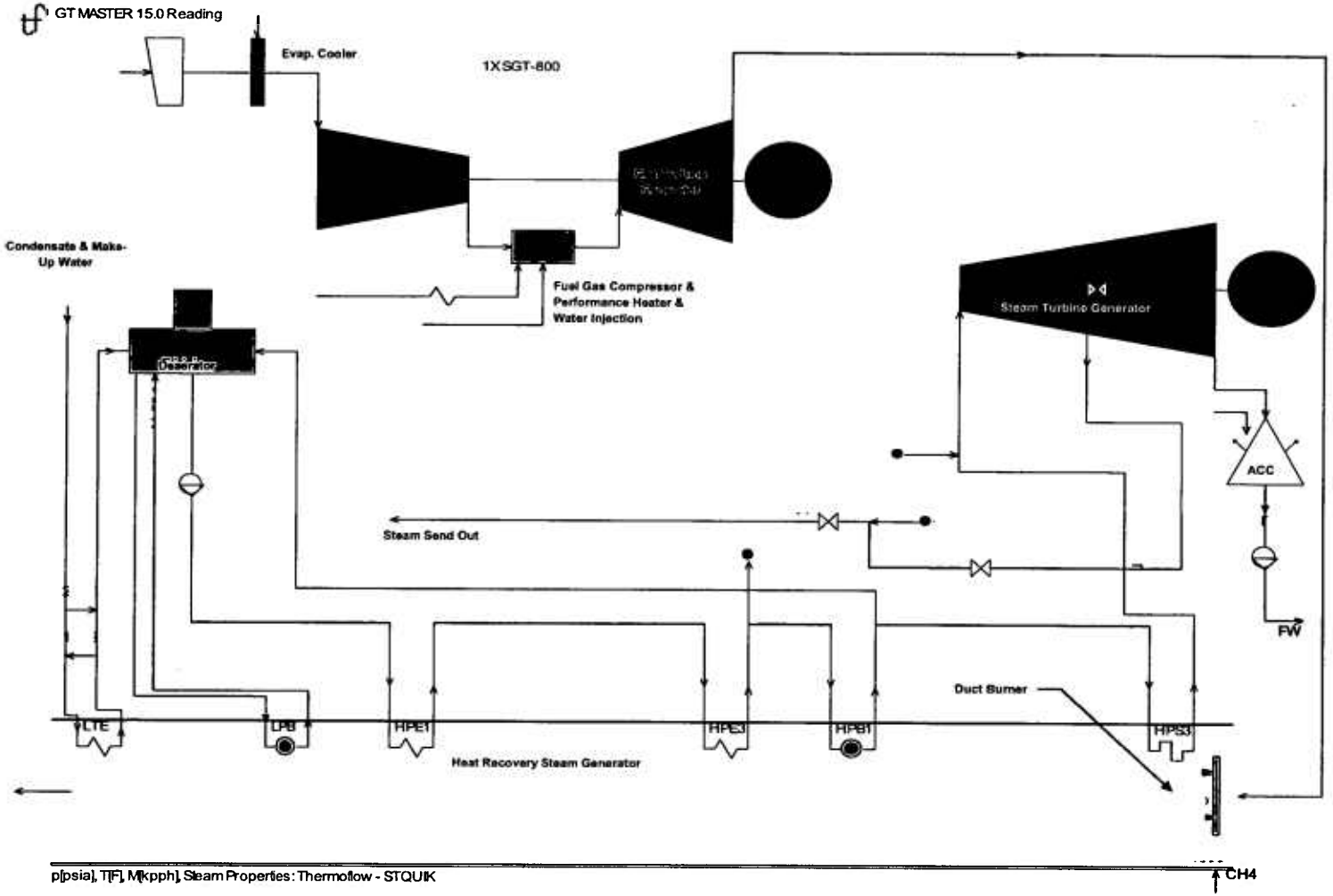


CONCEPTUAL DESIGN

NOTES

1. None

WorleyParsons		
Con Edison Steam Production Option Study Hudson Avenue Plant		
Preliminary Heat Balance - Combined Cycle Plant Option CC4: CC Plant with GTX100 & LP Gas Boilers Gas, 59°F/60% R.H, Fired HRSG (NG)		
DWG No: CESP-1-HB-CC4-02	Rev A	Date: 7/10/2006

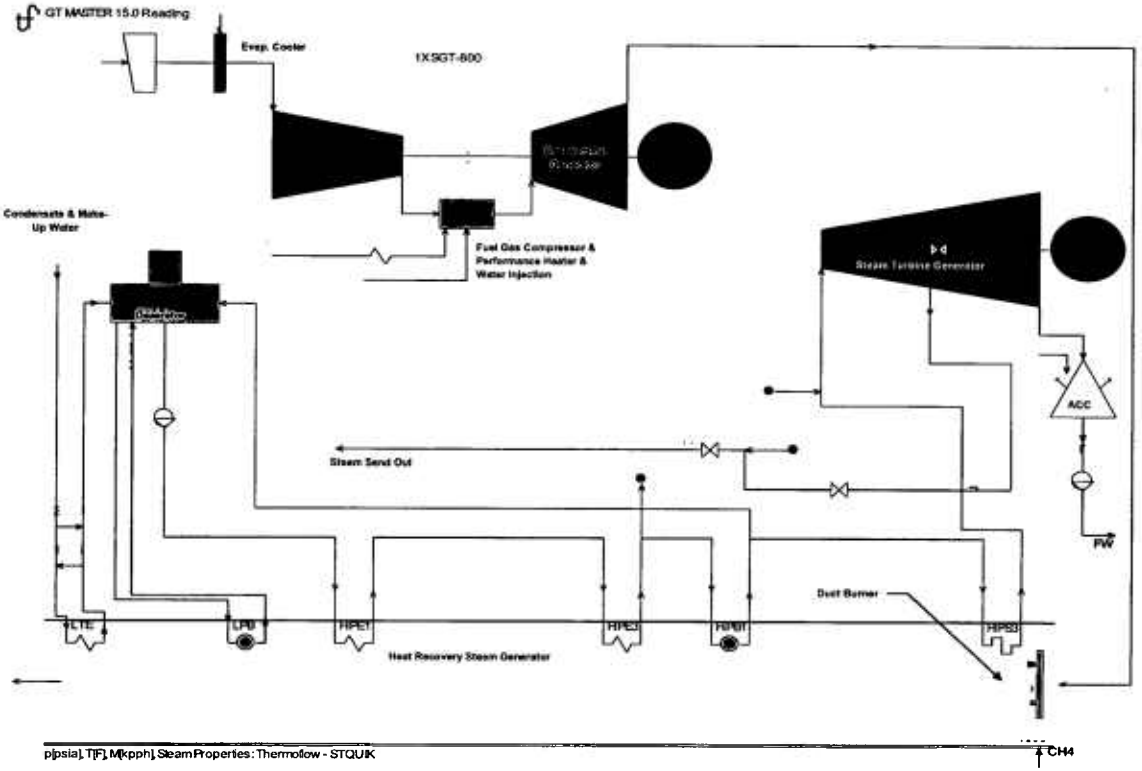


CONCEPTUAL DESIGN

NOTES

1. None

WorleyParsons resources & energy		
Con Edison Steam Production Option Study Hudson Avenue Plant		
Preliminary Heat Balance - Combined Cycle Plant Option CC4: CC Plant with GTX100 & LP Gas Boilers Gas, 90°F/35% R.H, Fired HRSG (NG)		
DWG No: CESP-1-HB-CC4-03	Rev A	Date: 7/10/2006

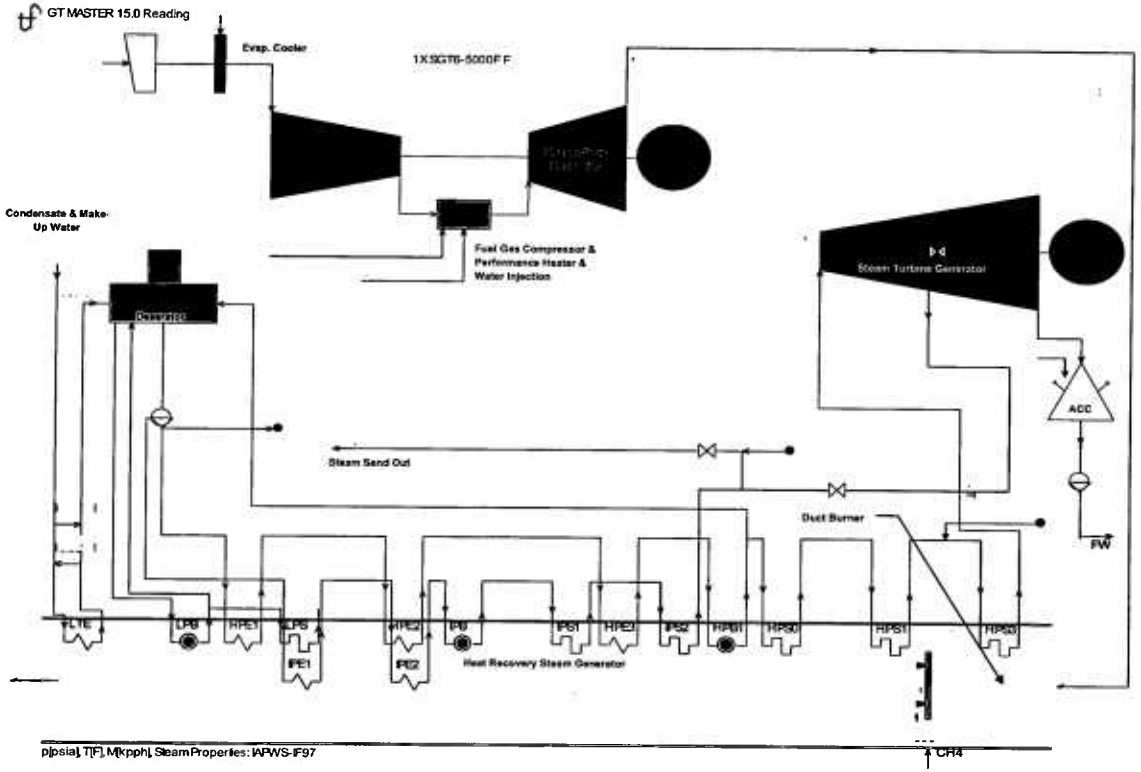


CONCEPTUAL DESIGN

NOTES

1. None

WorleyParsons		
Con Edison Steam Production Option Study Hudson Avenue Plant		
Preliminary Heat Balance - Combined Cycle Plant Option CC4: CC Plant with GTX100 & LP Gas Boilers Gas, 59°F/60% R.H, Unfired HRSG		
DWG No: CESP-1-HB-CC4-04	Rev A	Date: 7/10/2006

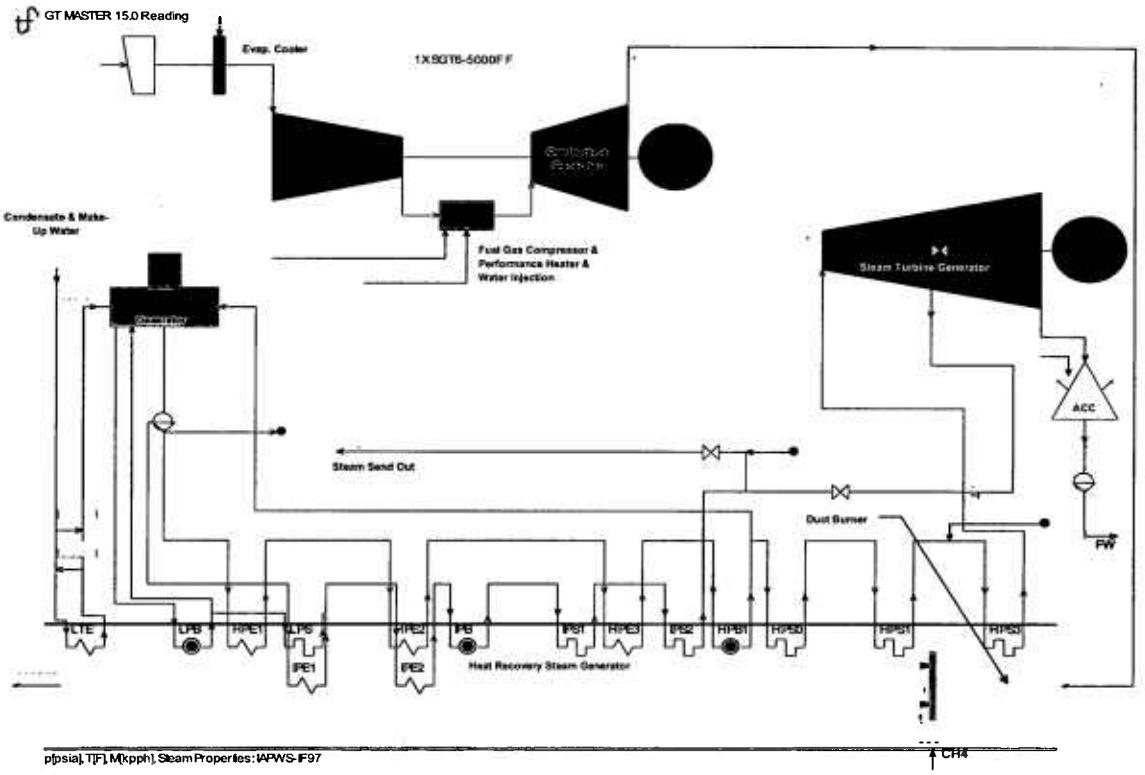


CONCEPTUAL DESIGN

NOTES

1. None

WorleyParsons		
Con Edison Steam Production Option Study Hudson Avenue Plant		
Preliminary Heat Balance - Combined Cycle Plant Option CC5: CC Plant with 501FD & LP Gas Boilers Oil, 59°F/60% R.H, Fired HRSG (NG)		
DWG No: CESP-1-HB-CC5-01	Rev A	Date: 7/10/2006

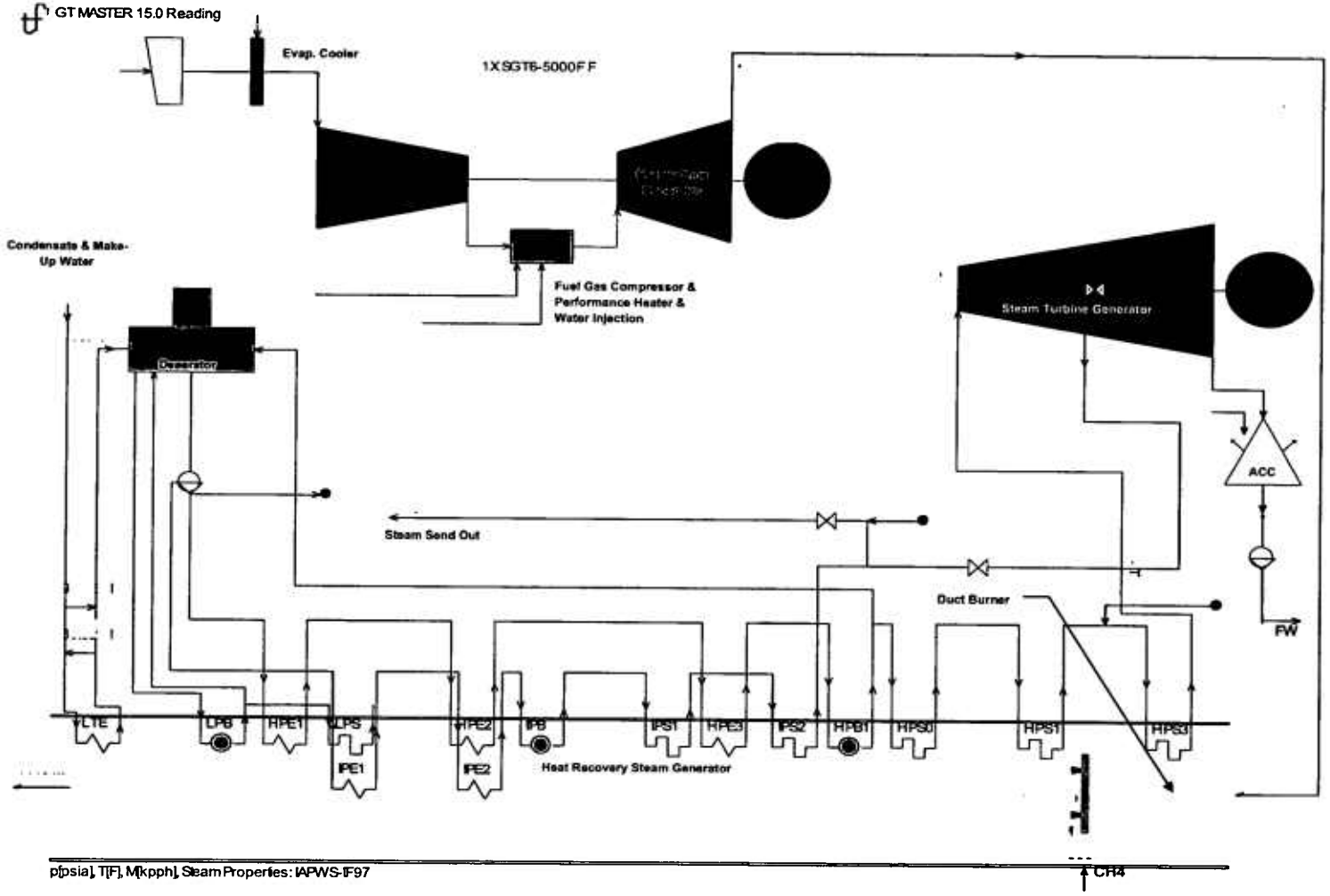


CONCEPTUAL DESIGN

NOTES

1. None

WorleyParsons		
Con Edison Steam Production Option Study Hudson Avenue Plant		
Preliminary Heat Balance - Combined Cycle Plant Option CC5: CC Plant with 501FD & LP Gas Boilers Gas, 59°F/60% R.H, Fired HRSG		
DWG No: CESP-1-HB-CC5-02	Rev A	Date: 7/10/2006

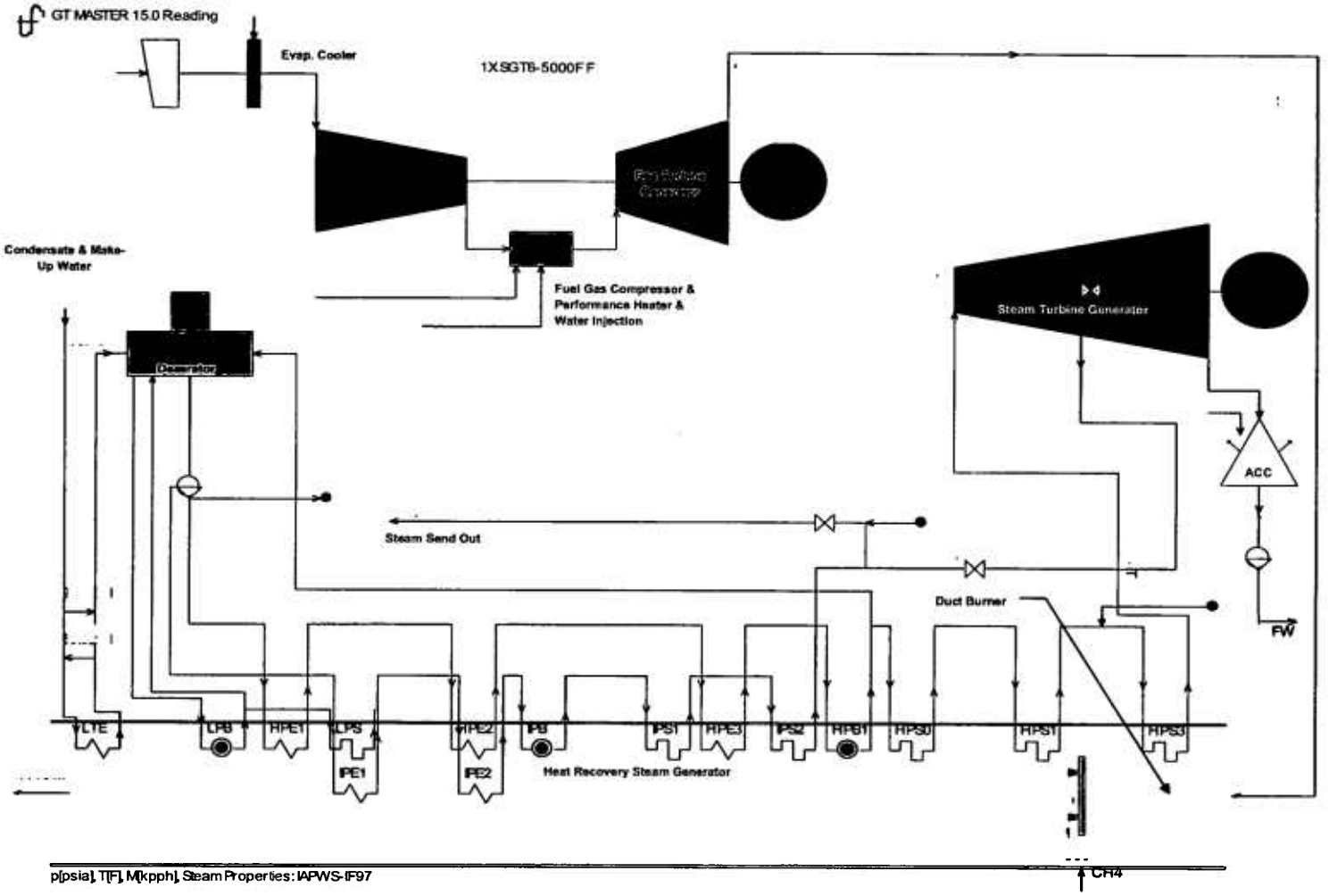


CONCEPTUAL DESIGN

NOTES

1. None

WorleyParsons		
Con Edison Steam Production Option Study Hudson Avenue Plant		
Preliminary Heat Balance - Combined Cycle Plant Option CC5: CC Plant with 501FD & LP Gas Boilers Gas, 90°F/35% R.H, Fired HRSG (NG)		
DWG No: CESP-1-HB-CC5-03	Rev A	Date: 7/10/2006

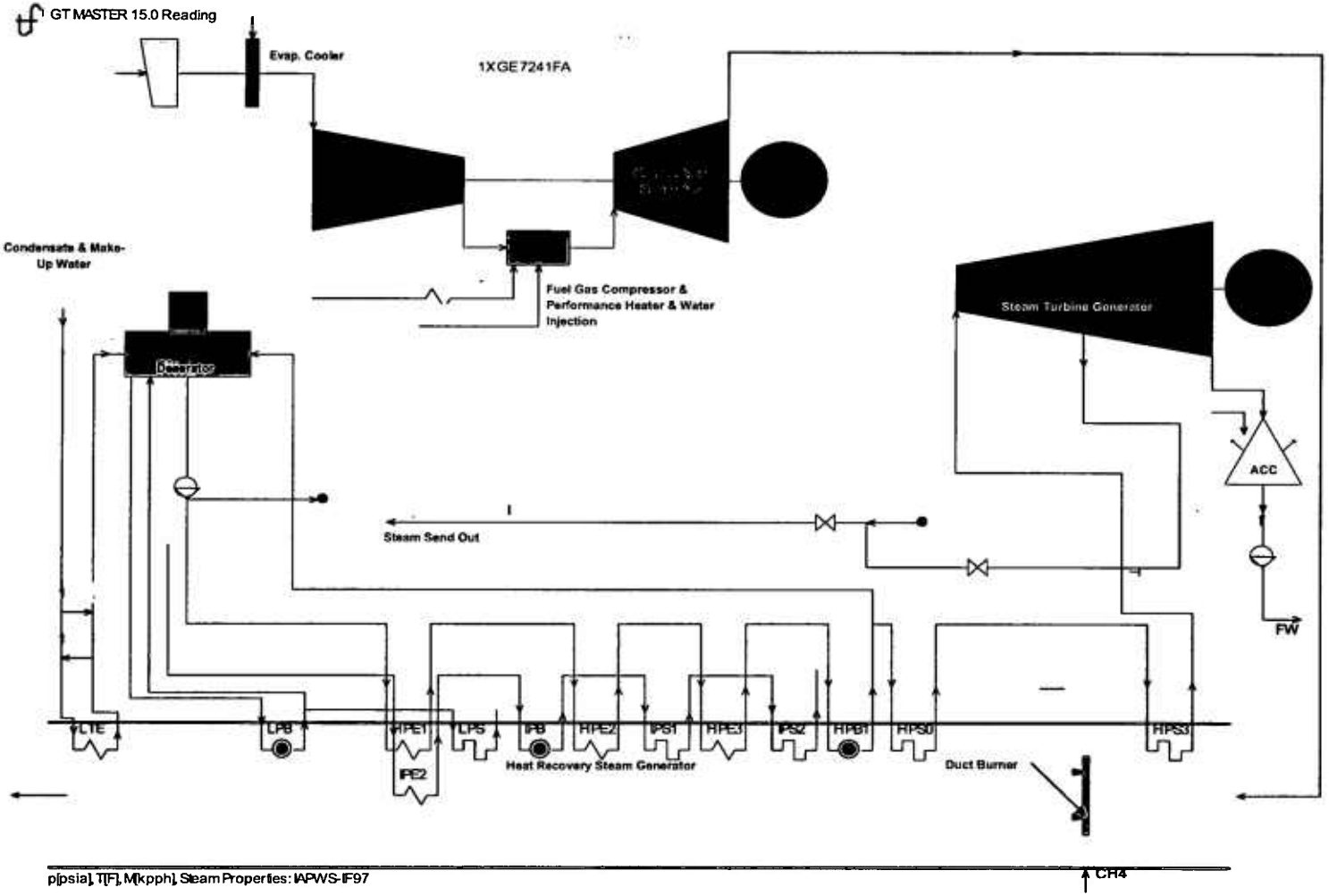


CONCEPTUAL DESIGN

NOTES

1. None

WorleyParsons		
Con Edison Steam Production Option Study Hudson Avenue Plant		
Preliminary Heat Balance - Combined Cycle Plant Option CC5: CC Plant with 501FD & LP Gas Boilers Gas, 59°F/60% R.H, Unfired HRSG		
DWG No: CESP-1-HB-CC5-04	Rev A	Date: 7/10/2006

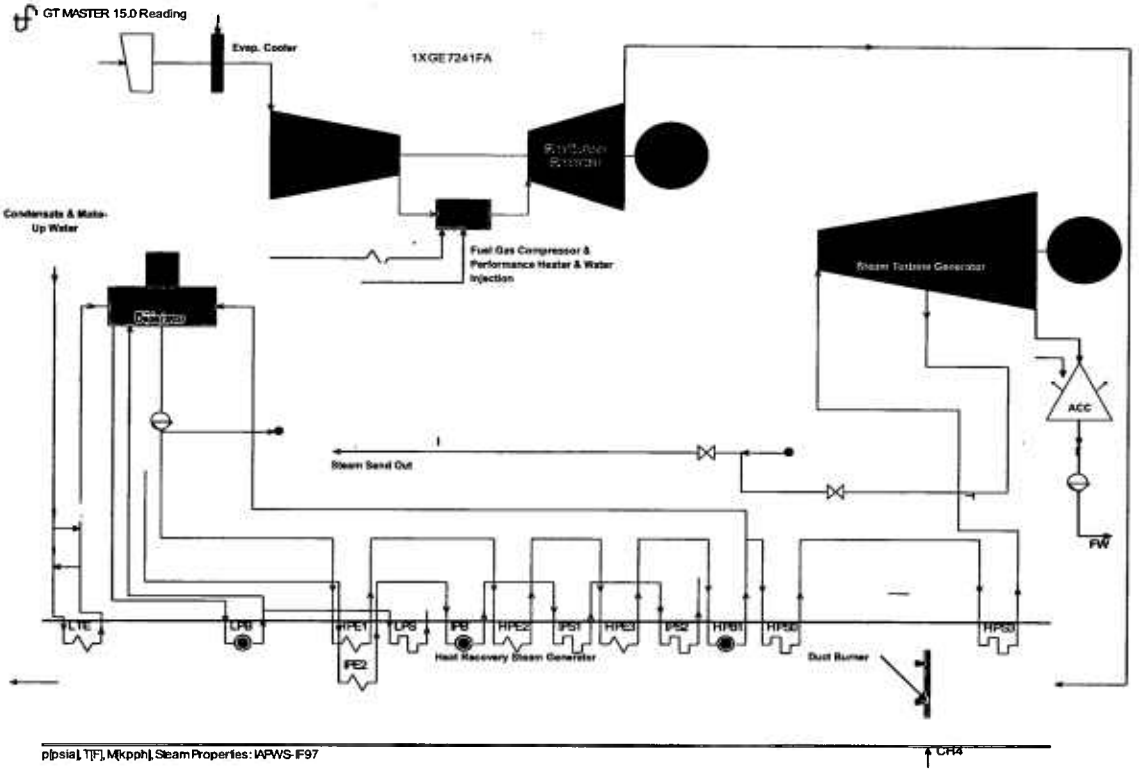


CONCEPTUAL DESIGN

NOTES

1. None

WorleyParsons		
Con Edison Steam Production Option Study Hudson Avenue Plant		
Preliminary Heat Balance - Combined Cycle Plant Option CC6: CC Plant with GE 7FA & LP Gas Boilers Oil, 59°F/60% R.H, Fired HRSG (NG)		
DWG No: CESP-1-HB-CC6-01	Rev A	Date: 7/10/2006

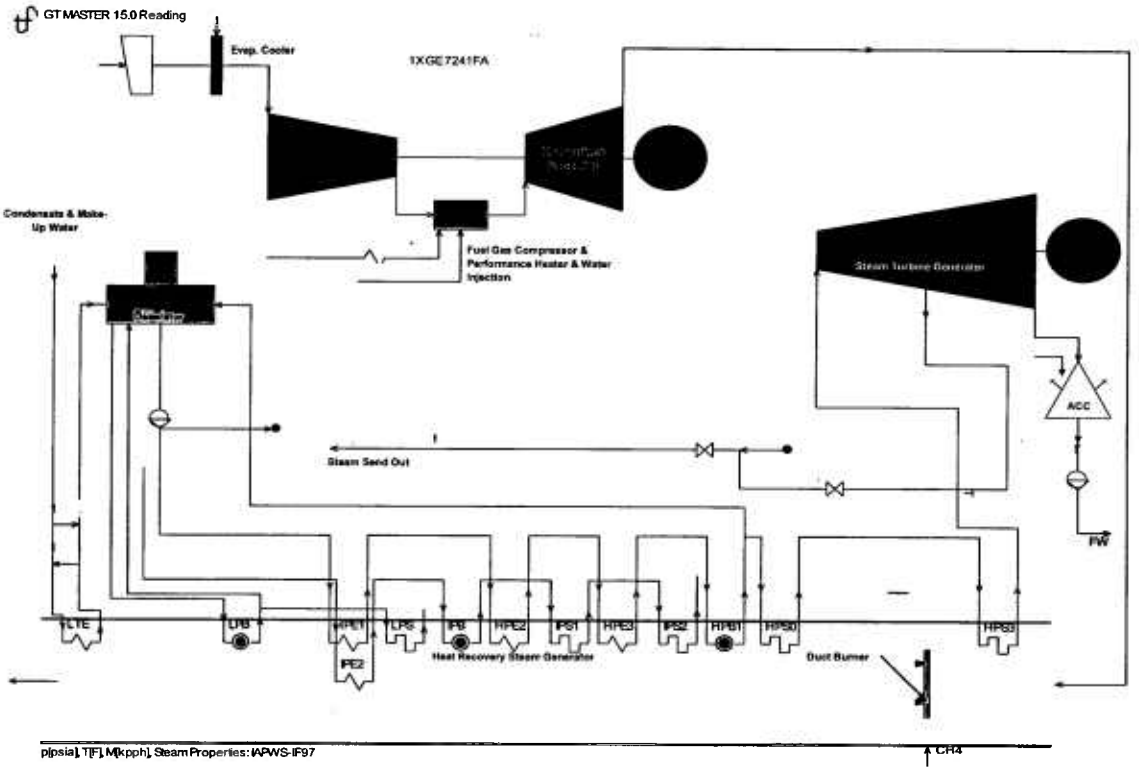


CONCEPTUAL DESIGN

NOTES

1. None

WorleyParsons		
Con Edison Steam Production Option Study Hudson Avenue Plant		
Preliminary Heat Balance - Combined Cycle Plant Option CC6: CC Plant with GE 7FA & LP Gas Boilers Gas, 59°F/60% R.H, Fired HRSG (NG)		
DWG No: CESP-1-HB-CC6-02	Rev A	Date: 7/10/2006

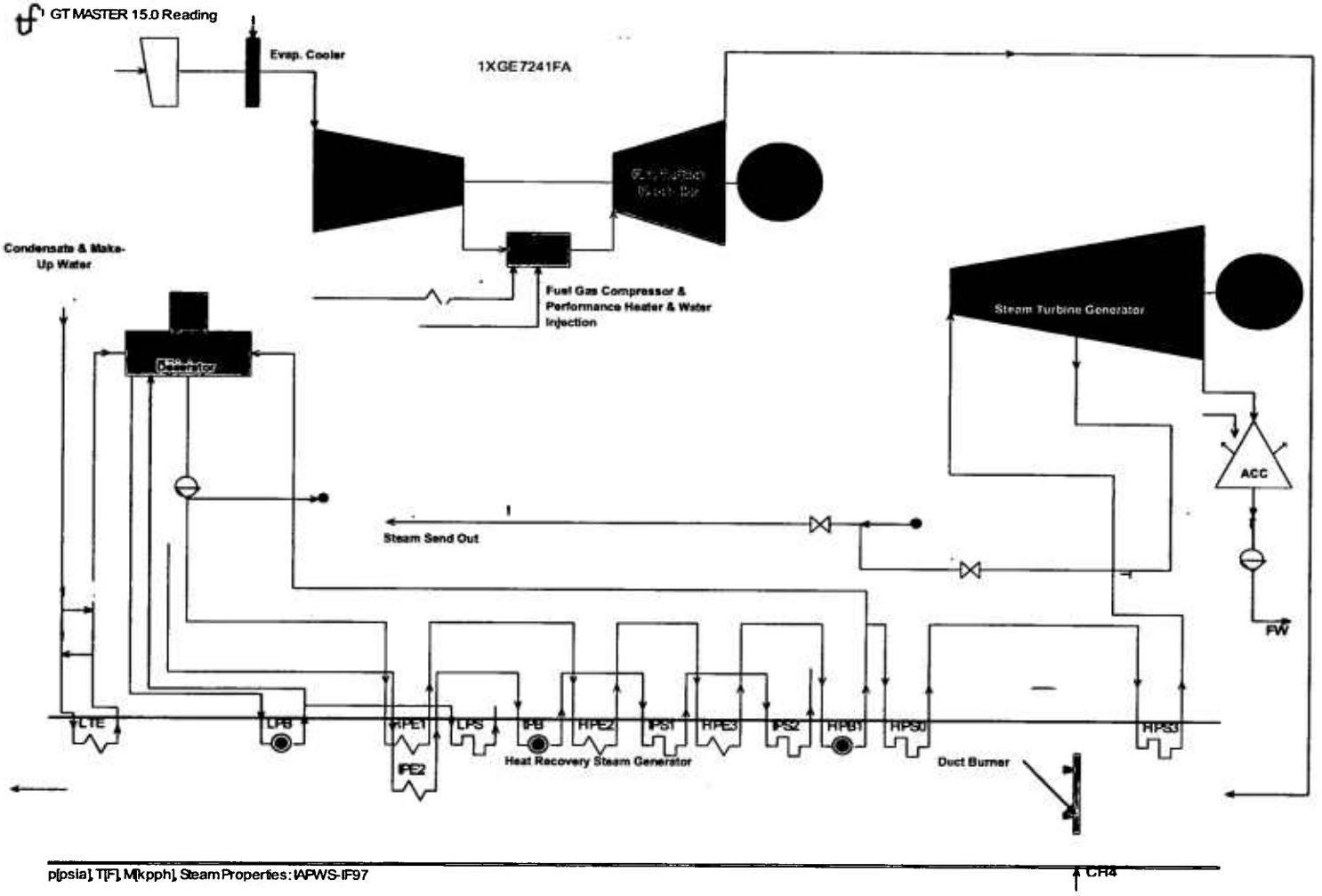


CONCEPTUAL DESIGN

NOTES

1. None

WorleyParsons		
Con Edison Steam Production Option Study Hudson Avenue Plant		
Preliminary Heat Balance - Combined Cycle Plant Option CC6: CC Plant with GE 7FA & LP Gas Boilers Gas, 90°F/35% R.H, Fired HRSG (NG)		
DWG No: CESP-1-HB-CC6-03	Rev A	Date: 7/10/2006



CONCEPTUAL DESIGN

NOTES

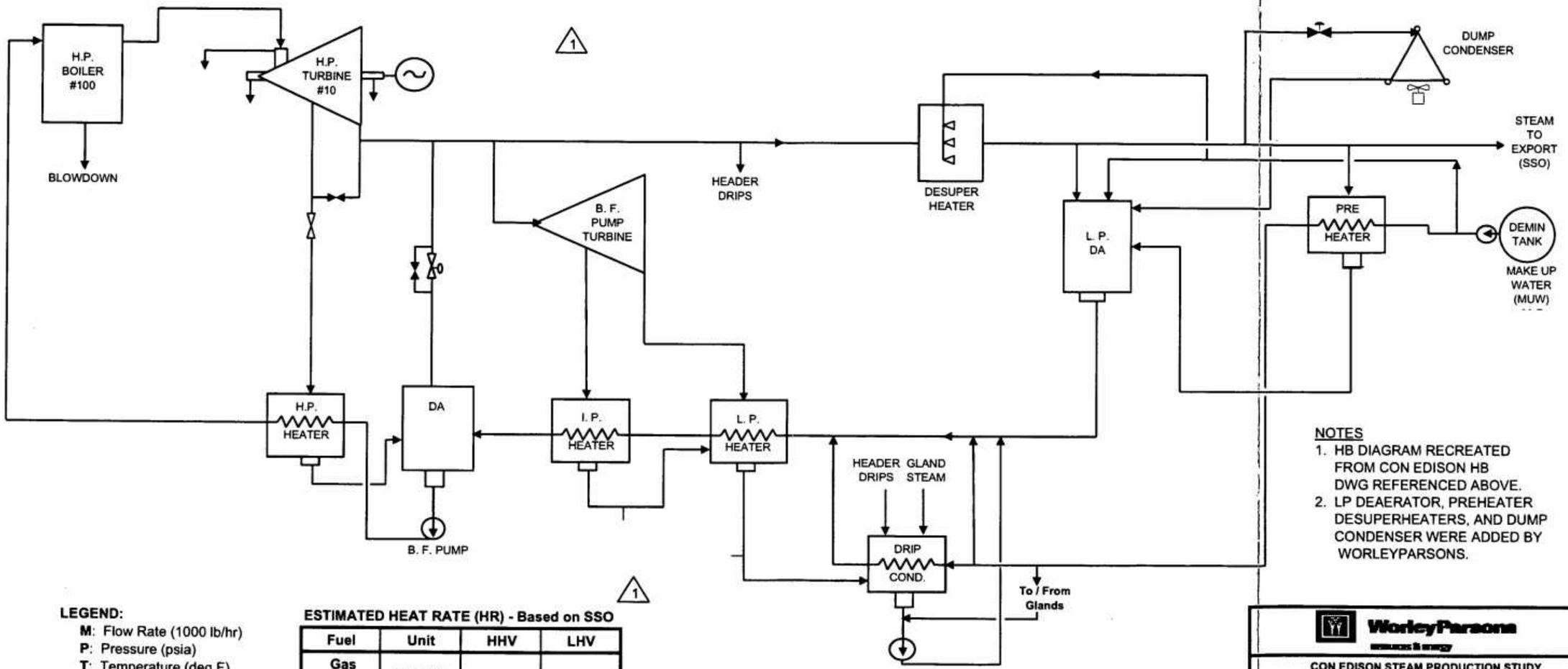
1. None

WorleyParsons		
Con Edison Steam Production Option Study Hudson Avenue Plant		
Preliminary Heat Balance - Combined Cycle Plant Option CC6: CC Plant with GE 7FA & LP Gas Boilers Gas, 59°F/60% R.H, Unfired HRSG		
DWG No: CESP-1-HB-CC6-04	Rev A	Date: 7/10/2006

HEAT AND MATERIAL BALANCES FOR HUDSON AVENUE BOILER CASES

Drawing #	Description
CESP-1-HB-BP1-01	Unit 10/100 – Base Load - 280 PSIG Exhaust Pressure
CESP-1-HB-BP1-02	Unit 10/100 – Minimum Load - 280 PSIG Exhaust Pressure
CESP-1-HB-BP1-03	Unit 10/100 – Turbine Bypass - 280 PSIG Exhaust Pressure
CESP-1-HB-BP3-01	1 New HP Boiler Plant & back pressure STG with full capacity Dump Condenser Plus 4 LP Gas Boilers
CESP-1-HB-PB-01	New Package Boilers – Hudson Avenue, A House and CSB Facilities

REFERENCE: Consolidated Edison Co. Heat Balance 121261-0



NOTES
1. HB DIAGRAM RECREATED FROM CON EDISON HB DWG REFERENCED ABOVE.
2. LP DEAERATOR, PREHEATER DESUPERHEATERS, AND DUMP CONDENSER WERE ADDED BY WORLEYPARSONS.

LEGEND:
- **M**: Flow Rate (1000 lb/hr)
- **P**: Pressure (psia)
- **T**: Temperature (deg F)
- **H**: Enthalpy (btu/lb)

ESTIMATED HEAT RATE (HR) - Based on SSO

Fuel	Unit	HHV	LHV
Gas	MBtu/lb		
Oil			

HHV to LHV Ratio - Gas : 1.11, Oil : 1.07

Rev		
Rev A: 09/10/06	Revised STG output and added HR Table	

WorleyParsons

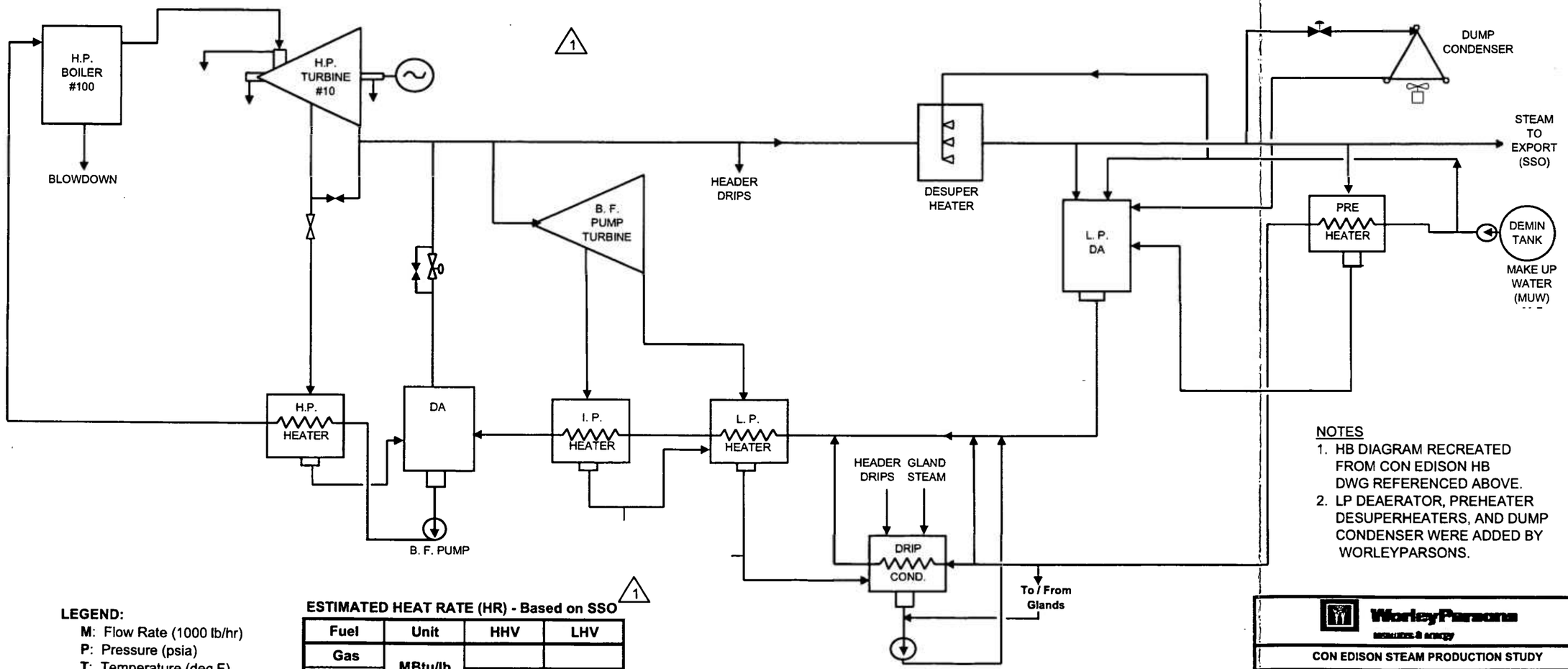
CON EDISON STEAM PRODUCTION STUDY

HEAT BALANCE DIAGRAM - UNIT 10/100

BASE LOAD - 280 PSIG EXHAUST PRESSURE

DWG NO: CESP-1-HB-BP1-01	Rev A	Date: 09/10/06

REFERENCE: Consolidated Edison Co. Heat Balance 121261-0



LEGEND:

- **M**: Flow Rate (1000 lb/hr)
- **P**: Pressure (psia)
- **T**: Temperature (deg F)
- **H**: Enthalpy (btu/lb)

ESTIMATED HEAT RATE (HR) - Based on SSO 1

Fuel	Unit	HHV	LHV
Gas	MBtu/lb		
Oil			

HHV to LHV Ratio - Gas : 1.11, Oil : 1.07

NOTES

1. HB DIAGRAM RECREATED FROM CON EDISON HB DWG REFERENCED ABOVE.
2. LP DEAERATOR, PREHEATER DESUPERHEATERS, AND DUMP CONDENSER WERE ADDED BY WORLEYPARSONS.

Rev	Date	Description
A	09/10/06	Revised STG output and added HR Table

WorleyParsons resources & energy

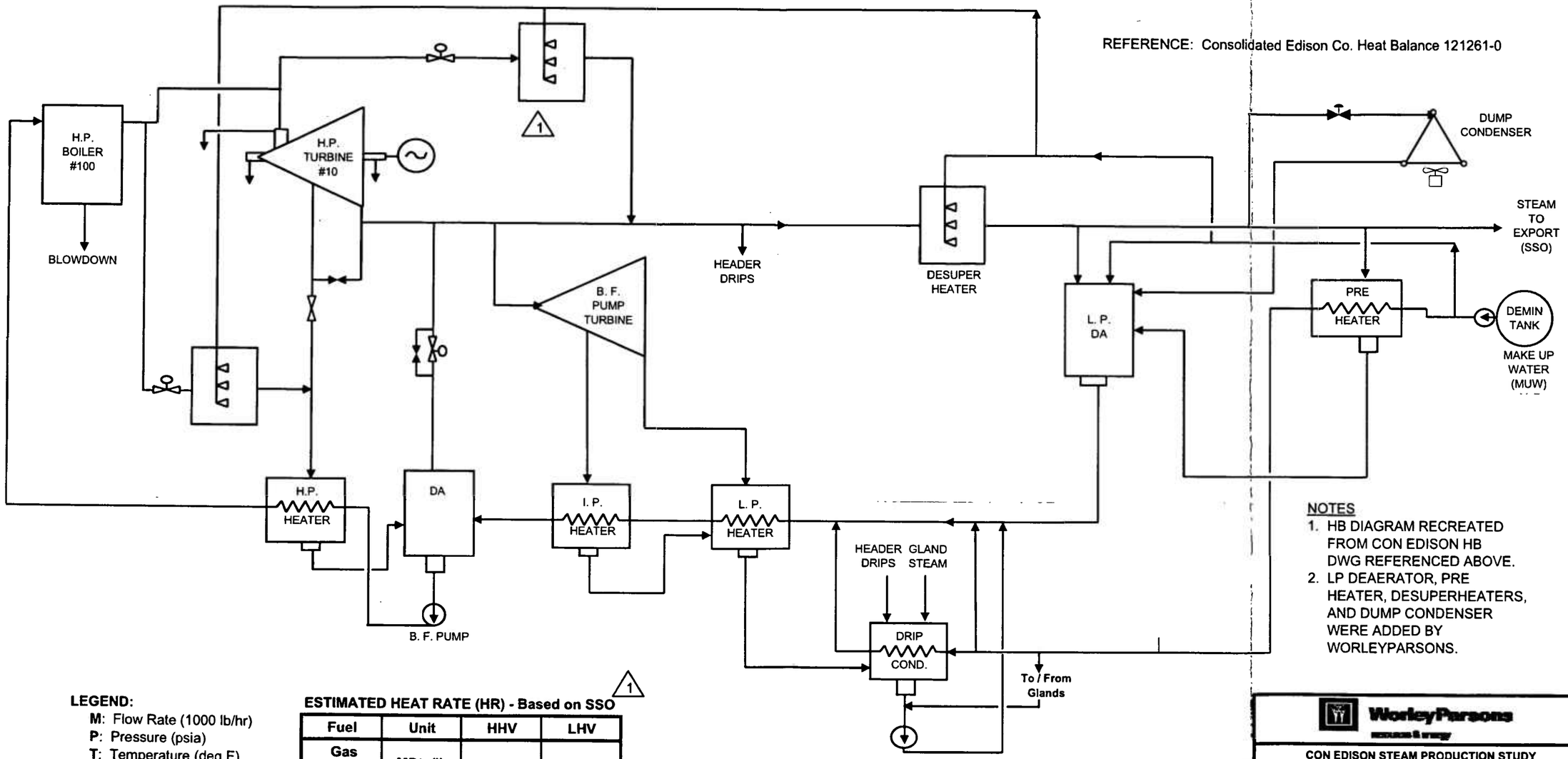
CON EDISON STEAM PRODUCTION STUDY

HEAT BALANCE DIAGRAM - UNIT 10/100

MINIMUM LOAD - 280 PSIG EXHAUST PRESSURE

DWG NO: CESP-1-HB-BP1-02 | Rev A | Date: 09/10/06

REFERENCE: Consolidated Edison Co. Heat Balance 121261-0



LEGEND:

- **M**: Flow Rate (1000 lb/hr)
- **P**: Pressure (psia)
- **T**: Temperature (deg F)
- **H**: Enthalpy (btu/lb)

ESTIMATED HEAT RATE (HR) - Based on SSO 1

Fuel	Unit	HHV	LHV
Gas	MBtu/lb		
Oil			

HHV to LHV Ratio - Gas : 1.11, Oil : 1.07

NOTES

1. HB DIAGRAM RECREATED FROM CON EDISON HB DWG REFERENCED ABOVE.
2. LP DEAERATOR, PRE HEATER, DESUPERHEATERS, AND DUMP CONDENSER WERE ADDED BY WORLEYPARSONS.

Rev		
Rev A: 09/10/06	Revised STG output and added HR Table	

WorleyParsons

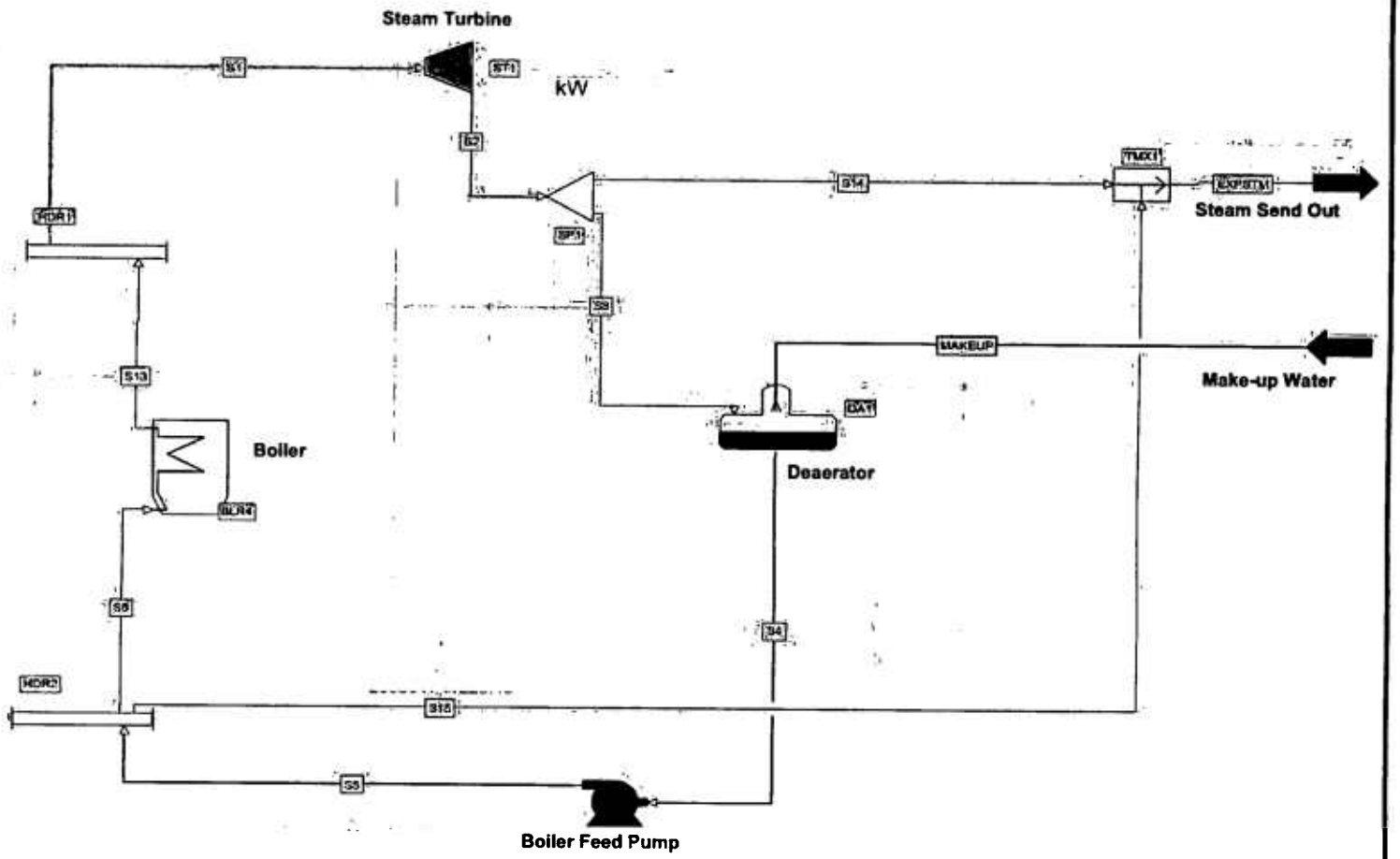
CON EDISON STEAM PRODUCTION STUDY

HEAT BALANCE DIAGRAM - UNIT 10/100

TURBINE BYPASS - 280 PSIG EXHAUST PRESSURE

DWG NO: CESP-1-HB-BP1-3	Rev A	Date: 09/10/06

MODEL:	CONED
CASE:	CONED
POWER:	
HR:	
EFF:	



CONCEPTUAL DESIGN

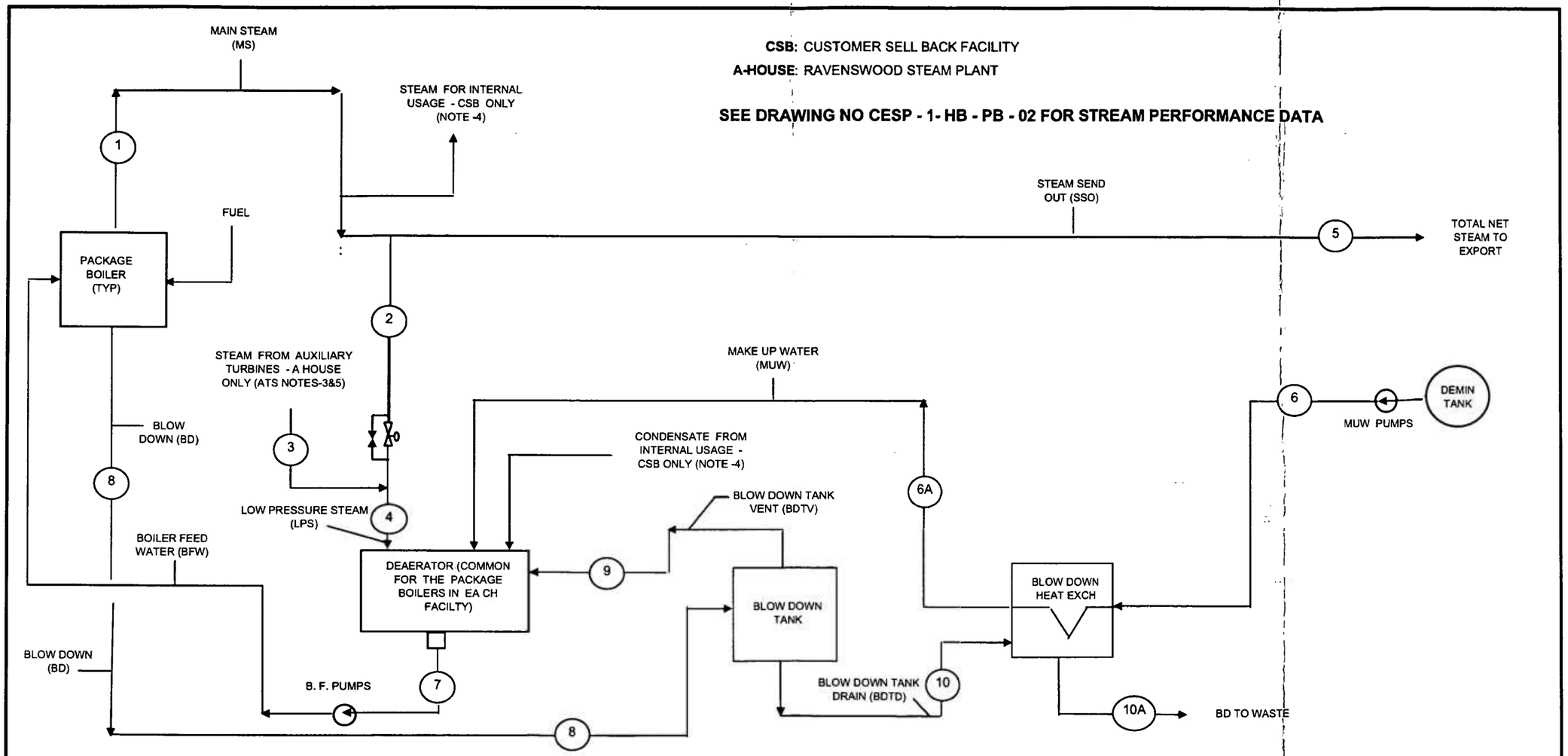
NOTES
1. None

WorleyParsons

Con Edison Steam Production Option Study
Hudson Avenue Plant

Preliminary Heat Balance - Cogeneration Plant
OPTION BP3: 1HP Boiler Plant & Back Pressure STG
59°F/60% R.H; Gas/Oil Fired

DWG No:	Rev	Date:
CESP-1-HB-BP3-01	A	7/10/2006



NOTES

1. REFER TO THE TABLE IN DRAWING CESP-1-HB-PB-02 FOR PERFORMANCE DATA OF INDIVIDUAL NEW PACKAGE BOILERS (PB). DEAERATOR IS COMMON FOR ALL NEW PACKAGE BOILERS FOR EACH OPTION.
2. REFER TO THE REPORT AND SCREENING MODEL FOR DESCRIPTION OF OPTIONS, NO OF BOILERS & TOTAL NET STEAM SENDOUT QUANTITIES.
3. THIS APPLIES FOR RAVENSWOOD PLANT (A HOUSE) ONLY. AUX. TURBINES ARE FOR FEED / MU WATER PUMPS AND FAN DRIVES. SEE NOTE 5.
4. THIS IS FOR CSB ONLY AND IS FOR BUILLDING HVAC APPLICATION. THE STEAM SENDOUT (SSO) FLOW IS NET OF INTERNAL USAGE. THE AVERAGE INTERNAL USAGE IS 25,000 PPH WITH 100% CONDENSATE RETURNED.
5. RAVENSWOOD STEAM PLANT (A HOUSE) HEAT BALANCE DATA IS BASED ON WEI DRAWING 109.11 - HB1 DATED 03/16/06
6. BOILER EFFICIENCY (BASED ON RENTECH DATA) - GAS FIRING -:82.5%, (HHV), OIL FIRING -:87.3% (HHV). HHV to LHV Rato - Gas: 1.11, OIL: 1.07

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CON EDISON STEAM PRODUCTION STUDY		
HEAT BALANCE DIAGRAM - NEW PACKAGE BOILERS BASE LOAD OPERATION - 59 F DB / 60% RH		
DWG NO: CESP-1-HB-PB-01	PRELIM	Date: 09/10/06

STREAM NO.	PARA-METER	PACKAGE BOILERS FOR HUDSON AVENUE PLANT OPTIONS[3]										A House[2]	CSB FACILITY[3]		REMARKS
		CG -1	CG - 2	CG - 3 and 4	CC - 1	CC - 2	CC - 3 and 4	CC - 5	CC - 6	BP - 1 and 1A	BP - 2	BP - 3	NB -1 Thru 4	CG -1	BP - 1	
1 (MS)	M P T H	REDACTED											REDACTED	26,805 165 366 1,196	60,000 445 479 1,224	For CSB CG-1 Option, this is for Internal HVAC usage only during Cogen Outage
2 (LPS)	M P T H	REDACTED											REDACTED	1,805 150 366 1,195	9,010 430 475 1,223	
3 (LPS for A House Aux Turb)	M P T H	REDACTED											REDACTED	Not Applicable	Not Applicable	
4 (LPS to DA)	M P T H	REDACTED											REDACTED	1,805 20 228 1,156	9,010 36 372 1,223	For both CSB Options, Condensate from HVAC is returned to DA at 120 Btu/lb
5 (SSO)	M P T H	REDACTED											REDACTED	25,000 150 366 1,195	38,490 430 475 1,223	For CSB CG-1 Option, this is for Internal HVAC usage only. No Steam to export
6 (MUW)[4]	M P T H	REDACTED											REDACTED	626 85 60 0	39,609 100 60 0	
7 (BFW)	M P T H	REDACTED											REDACTED	27,431 20 228 196	61,401 0 0 0	
8 (BD)	M P T H	REDACTED											REDACTED	626 20 366 196	1,401 445 455 436	
9 (BDTV)	M P T H	REDACTED											REDACTED	126 23 236 1,159	282 0 0 0	
10 (BDTD)[4]	M P T H	REDACTED											REDACTED	500 23 236 204	1,119 0 0 0	
HR - HHV (LHV)[5]	Gas	REDACTED											REDACTED	1.303 (1.174)	1.424 (1.282)	Heat Rate for CSB -BP1 Option is net of internal HVAC heat consumption
	OIL	REDACTED											REDACTED	N.A	N.A	

NOTES

1. See Drawing No CESP - 1- HB - PB - 01 for Stream Reference Data and Various Notes
2. A- House is Ravenswood Steam Plant. 3. Assumed Heat loss in steam piping from Blr to SSO = 0.5Btu/lb
4. Temperature Downstream of the Blow Down Heat Exchanger

	HA Plant	A House	CSB (CG-1)	CSB (BP-1)
Stream 6A (MUW)	REDACTED	REDACTED	108.2	
Stream 10A (BDTD)	REDACTED	REDACTED	100	100

5. Heat Rate is based on Net SSO except for CSB CG-1 Option where it is based on internal usage.

Legend:

M: Flow (Pounds Per Hour)
P: Pressure (Psia)
T: Temperature (^{0}F)
H: Enthalpy (Btu/lb)
HR: Heat Rate (1000Btu/lb of steam)

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CON EDISON STEAM PRODUCTION STUDY

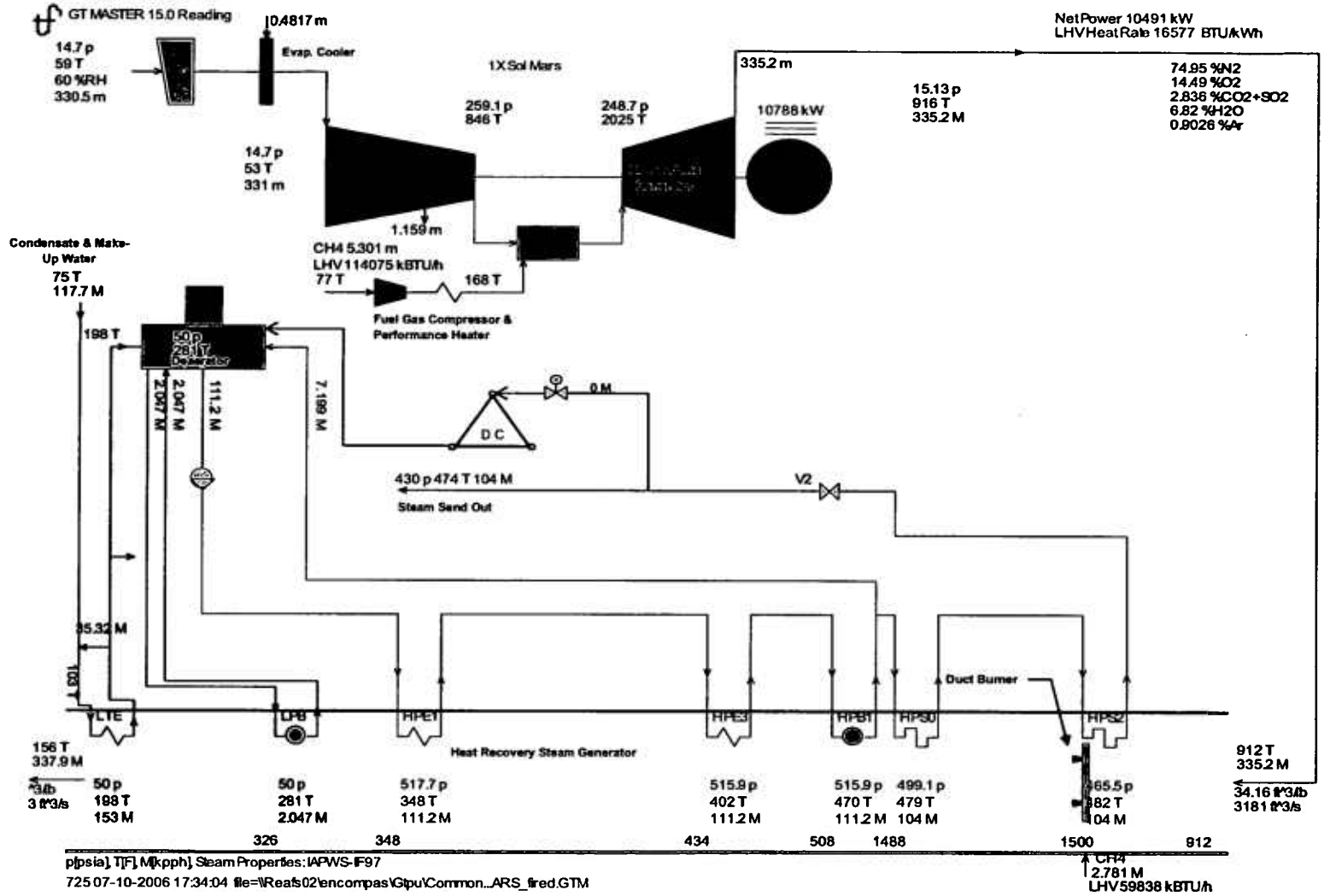
HEAT BALANCE STREAM DATA - NEW PACKAGE BOILERS

BASE LOAD OPERATION - 59F DB / 60 RH

DWG NO: CESP-1-HB-PB-02	PRELIM	Date: 09/10/06

HEAT AND MATERIAL BALANCES FOR CUSTOMER SELL BACK CO-GENERATION CASES

Drawing #	Description
CESP-1-HB-CF1-01	CG Plant with Solar Mars - 100% Load
CESP-1-HB-CF1-02	CG Plant with Solar Mars - 100% Load
CESP-1-HB-CF1-03	CG Plant with Solar Mars - 80% Load
CESP-1-HB-CF1-04	CG Plant with Solar Mars - 80% Load

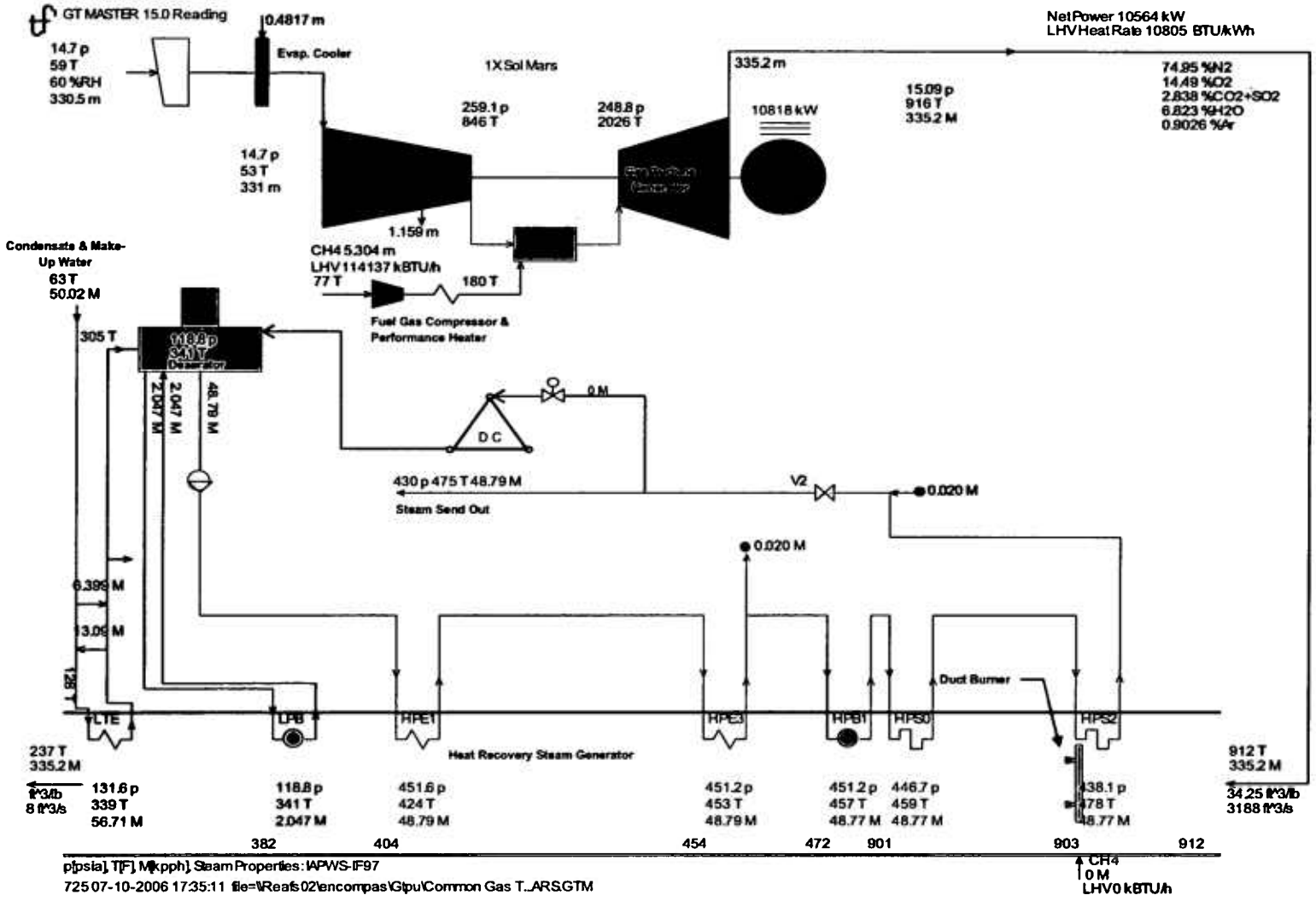


CONCEPTUAL DESIGN

NOTES

1. None

Worley Parsons		
Con Edison Steam Production Option Study Customer Sell Back		
Preliminary Heat Balance - Cogeneration Plant CF Plant - Solar Mars 100% Load 59°F, 60% R.H, Fired HRSG		
DWG No: CESP-1-HB-CF1-01	Rev A	Date: 7/10/2006

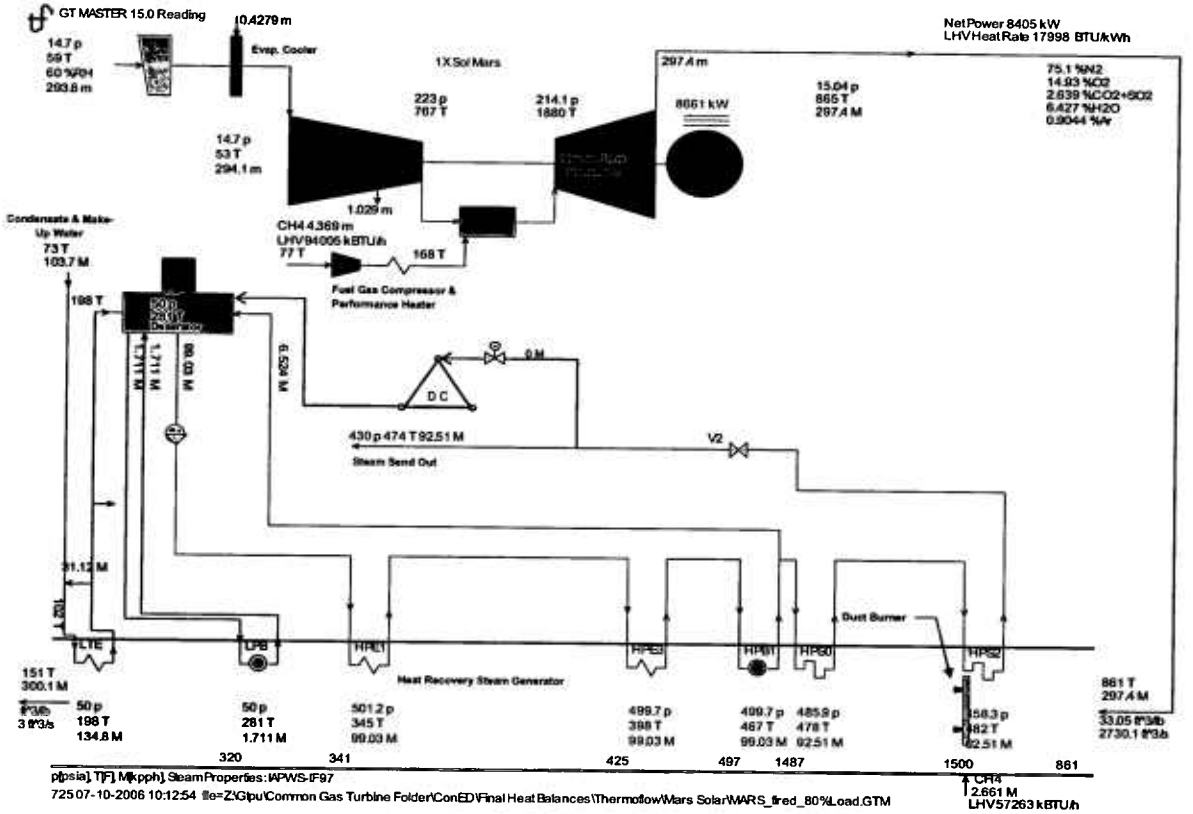


CONCEPTUAL DESIGN

NOTES

1. None

Worley Parsons		
Con Edison Steam Production Option Study Customer Sell Back		
Preliminary Heat Balance - Cogeneration Plant CF Plant - Solar Mars 100% Load 59°F, 60% R.H, Unfired HRSG		
DWG No: CESP-1-HB-CF1-02	Rev A	Date: 7/10/2006

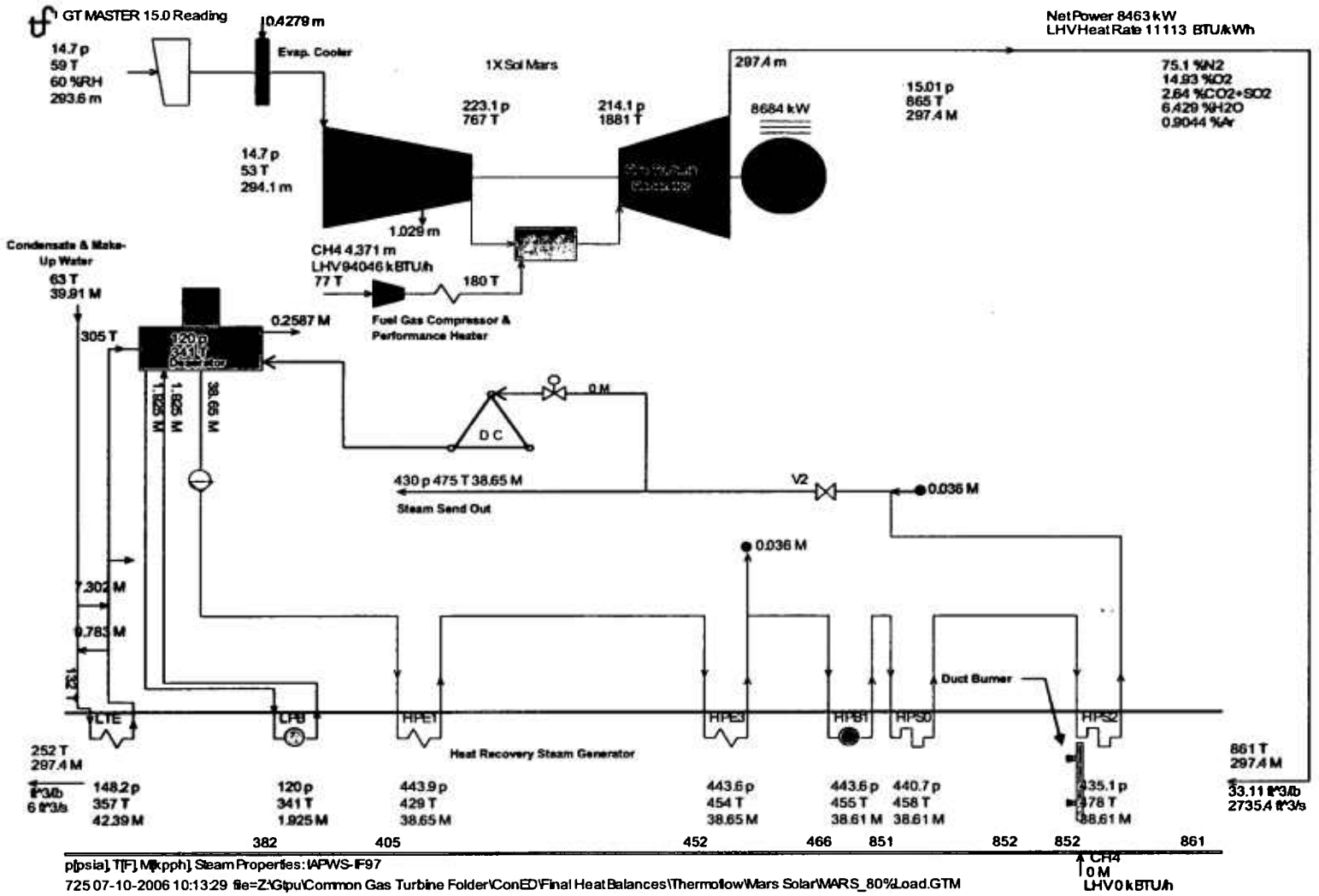


CONCEPTUAL DESIGN

NOTES

1. None

WorleyParsons		
Con Edison Steam Production Option Study Customer Sell Back		
Preliminary Heat Balance - Cogeneration Plant CF Plant - Solar Mars 80% Load 59°F, 60% R.H, Fired HRSG		
DWG No: CESP-1-HB-CF1-03	Rev A	Date: 7/10/2006



CONCEPTUAL DESIGN

NOTES

1. None

WorleyParsons		
Con Edison Steam Production Option Study Customer Sell Back		
Preliminary Heat Balance - Cogeneration Plant CF Plant - Solar Mars 80% Load 59°F, 60% R.H, Unfired HRSG		
DWG No: CESP-1-HB-CF1-04	Rev A	Date: 7/10/2006

C

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Long Term Con Edison Steam Production Options Study - Phase 1

Final Report Appendix C

Alternative Facilities Data/Information Request Document

Prepared for

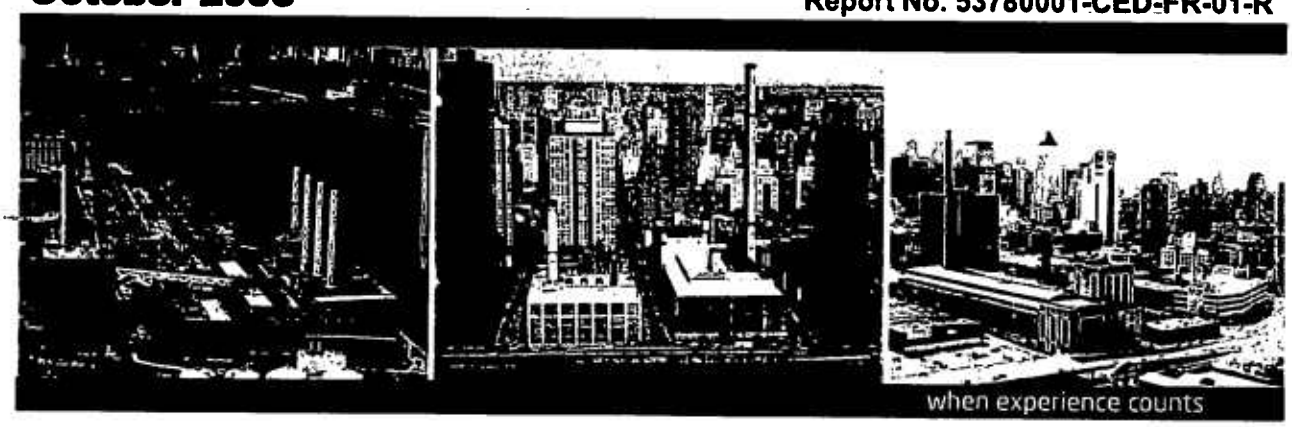
Consolidated Edison Company of New York, Inc.

In conjunction with the

Steam Business Development Core Task Force

October 2006

Report No. 53780001-CED-FR-01-R



Report No. 53780001-CED-DIR-02

Con Edison Steam Production Options Study
Phase 1

ALTERNATIVE FACILITIES DATA / INFORMATION REQUEST (DIR)

Prepared for:

TransGas Energy
KeySpan Corporation
Brooklyn Navy Yard Cogeneration Partners

January 18, 2006

Prepared by



WorleyParsons
resources & energy

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1. Introduction 1
2. WorleyParsons' Scope of Work 2
3. Requested Data/Information 4
4. Con Edison Steam Specifications/Constraints 6

Attachment – Alternative Facility Data Input Form (transmitted as separate file)

1. INTRODUCTION

WorleyParsons Group, Inc. is performing a study of long-term steam production options for the New York City Con Edison district steam system. The options include the potential for merchant steam production by three facilities: the proposed TransGas Energy Facility in Brooklyn, KeySpan's Ravenswood Unit 4, and Brooklyn Navy Yard Cogeneration Partners Plant. WorleyParsons' scope of work (detailed in Section 2) includes evaluating the impact of merchant steam supply on steam production costs and benefits to air emissions Citywide through displacement of existing electric and steam generating facilities. WorleyParsons' evaluation will be based on information obtained from the potential merchant steam suppliers, and, therefore, the quality of the evaluation is dependent on the quality of this information.

In accordance with WorleyParsons Scope of Work, WorleyParsons will disclose cost information for any of the specific plants it investigates to the Con Edison Long-term Steam Production Study Core Task Force members only; however, if asked by the Core Task Force Members, WorleyParsons will produce a range of alternative plant costs to be used for discussions by the Working Group.

This Data/Information Request Document describes the following:

- WorleyParsons; Scope of Work with respect to the investigation of potential steam supply from alternative facilities (Section 2);
- Data/information required and requested from the owners/developers of the merchant production facilities to perform our evaluation in accordance with the project scope of work (Section 3); and
- The Con Edison steam specifications that must be satisfied by facilities providing steam to the Con Edison system (Section 4).

WorleyParsons requests that the owners/developers of the potential merchant facilities provide the data/information requested in this document by end of business on Friday, January 27, 2006. The data/information should be transmitted to Mr. Mike Bartone by email at leonard.bartone@worleyparsons.com, or by postal service to the following address:

Mr. Mike Bartone
WorleyParsons Group, Inc.
2675 Morgantown Road
Reading, PA 19607-9656 US

After WorleyParsons reviews the responses, we will request a separate meeting with the representative(s) of each facility to discuss the responses and, if necessary, request additional data/information.

2. WORLEYPARSONS' SCOPE OF WORK

The following is WorleyParsons' scope of work with respect to the investigation of the potential cost of steam from Alternative Facilities:

WorleyParsons will seek information (including investment grade studies) from the owners\developers of the following facilities regarding possible supply of steam to the Con Edison steam system:

- The proposed TransGas Energy Facility in Brooklyn;
- KeySpan's Ravenswood Unit 4
- Brooklyn Navy Yard Cogeneration Partners Plant (in excess of that currently supplied).

WorleyParsons will ask the owners/developers to first sign a Memorandum of Understanding ("MOU"), provided by the Working Group Chair, and proceed to gather data only from those owners/developers who sign.

If TransGas Energy signs the MOU and Con Edison authorizes Advantica Stoner to provide WorleyParsons with the information it previously developed on behalf of TransGas Energy concerning simulations of the Con Edison steam system, WorleyParsons will also be provided Con Edison's evaluation of the study.

WorleyParsons will seek to obtain from the owners/developers who sign an MOU the following information:

- the potential cost of steam;
- the conditions under which steam could be made available for sale to Con Edison, including commercial conditions such as term of contract and escalation indices;
- a description of the plant systems that would be used to produce the steam;
- how the steam would be delivered to the Con Edison system;
- the steam conditions at the point of delivery and their expected variation;
- the required steam system reinforcements and interconnection requirements;
- the capacities available for sale (minimum\maximums);
- any constraints or restrictions on steam availability;
- the basis upon which the owner would arrive at the price for steam, including the owners assumptions regarding fuel and power costs, and breakdown of the steam cost in terms of the fuel, assumption regarding annual volume of steam sales, a variable non-fuel costs, a fixed costs, and capital recovery cost; and

- the environmental impacts that the sale of steam to Con Edison would have on the specific facility's environmental profile as well as any benefits to air emissions Citywide through the displacement of existing electric and steam generating facilities.

WorleyParsons will prepare a data and information request document for completion by the owners/developers, and then meet with and interview the owners/developers to assure a thorough understanding of the information provided.

WorleyParsons will review the information provided by the owner and make a determination as to the time frame required to implement the delivery of steam from each plant.

WorleyParsons will review the data for reasonableness and adjust it where necessary to 1) to make it consistent with the assumptions established in this study; and 2) to provide an independent assessment based on WorleyParsons' judgment and experience. Upon the request of the Developer/Owner of any alternative that has executed the MOU and supplied the requested data to WorleyParsons, WorleyParsons will discuss said adjustments with the Developer/Owner and, upon request of the Developer/Owner, with the Working Group. WorleyParsons will provide the Core Task Force Members with our assessment of any uncertainties associated with the information provided by owners, and, as may be directed by the Core Members, a similar assessment for Working Group members.

WorleyParsons will exclude from consideration any alternative that cannot meet the steam operational and other technical requirements (e.g., temperature, pressure, purity, and dispatchability) provided by Con Edison. WorleyParsons will discuss the potential exclusion of an alternative with the Working Group. WorleyParsons will not disclose cost information for any of the specific plants it investigated to the Non-Core Members, but, if asked by the Core Task Force Members, will produce a range of cost projections for Con Edison plant costs and alternative plant costs to be used for discussions by the Working Group.

3. REQUESTED DATA/INFORMATION

The owners/developers of the proposed TransGas Energy facility, KeySpan's Ravenwood Unit #4, and Brooklyn Navy Yard Cogeneration Partners Plant are requested to provide WorleyParsons with the following data/information:

1. Time frame required to implement the delivery of steam to Con Edison
2. Selling price of steam to Con Edison from start of delivery through year 2025
   a. Price per thousand pounds of steam delivered
   b. Price escalation indices
   c. Basis for arriving at price, including
      i. Fuel and power cost assumptions
      ii. Annual volume of steam sales
      iii. Variable non-fuel costs
      iv. Fixed costs
      v. Capital recovery costs
      vi. Value of cogenerated electric products
3. Conditions under which steam could be made available for sale to Con Edison, including commercial conditions such as term of contract
4. Steam capacities available for sale through Year 2025
   a. Maximum capacity
   b. Minimum capacity
   c. Turndown and cycling limitations (if any)
5. Steam conditions at point of delivery to Con Edison and expected variation
   a. Temperature
   b. Pressure
   c. Purity specifications (if other than Con Edison specifications in Section 0)
6. Any constraints or restrictions on steam availability
7. Location of the steam interconnection point with the Con Edison steam system
8. Description of existing steam production systems that would be used to supply steamto Con Edison, including
   a. Type of steam generating equipment (CT combined cycle, CT cogeneration, boiler) and manufacturer and model of major components (CT and boiler)

b. Water treatment system

c. Minimum and maximum steam production capacity

d. Minimum and maximum electric power production capacity (if any)

e. Fuel consumption (by type) at minimum, maximum, and total annual steam supply condition

f. NO_x, SO_2, CO, PM_{10} , $PM_{2.5}$, and VOC emissions per million Btu of fuel input (by fuel type) at minimum, maximum, and total annual steam supply condition.

9. Description of modifications in faciilty's systems/operations that will be required to produce steam for Con Edison, including:

   a. Water treatment system to meet Con Edison steam quality criteria

   b. Features provided to maintain the pressure & temperature at the interconnection point

   c. Features provided to protect ConEdison's system from overpressure & temperature

   d. Reduction in electric power production (if any)

   e. Steam system reinforcements and interconnection requirements

10. Impacts that the sale of steam to Con Edison would have on the facility's environmental profile and emissions

11. Other benefits that sale of steam to Con Edison would have on facility, Con Edison, or New York City (e.g., if gray water source is used for any operations that would result in net reduction in city water usage by displacement of Con Edison steam production)

12. Copies of any investment grade studies performed related to supply of steam to the Con Edison steam system.

An Excel workbook with a format for entering most of the data is being transmitted with this information/data request document, and WorleyParsons requests that facilities use the workbook for providing the associated data. However, data in other formats (Microsoft Word, Excel, and/or Adobe pdf) will be accepted if it is more convenient. WorleyParsons requests that information/data not covered in the provided Excel workbook be provided in Microsoft Word, Excel, and/or Adobe pdf format.

4. CON EDISON STEAM SPECIFICATIONS/CONSTRAINTS

The specifications provided herein are preliminary specifications for steam production study purposes only. A detailed Operating Procedure, Testing Procedure, Water Chemistry Limitations, and Action Sequence for Determining Source of Steam Impurities would also be required with the Steam Specification.

4.1. STEAM CONDITIONS AT INTERCONNECTION WITH CON EDISON SYSTEM

The steam delivered shall have the pressure and temperature specified by the Buyer's Energy Dispatcher. Generally, the pressure in a Con Edison Transmission Main is in the range from 125 psig to 400 psig, and in a Distribution Main is in the range from 125 psig to 200 psig. Therefore, the design pressure for the steam supplied from the merchant steam production facility must be greater than 400 psig if interconnecting with a Transmission Main and 200 psig if interconnecting with a Distribution Main. The amount of superheat required depends on the location of the interconnection, and could be as high as 25°F above saturation temperature for both Mains. Water used for desuperheating the steam must be free of all contaminants and must not include any additives.

4.2. CON EDISON STEAM PURITY SPECIFICATIONS:

Con Edison (Buyer) is committed to delivering its steam customers a steam product that is clean and meets FDA purity requirements. The Steam produced by the seller shall have make-up water treatment consisting of a water treatment process of at least a Cation/Anion Train Demineralization system or a Reverse Osmosis/ Electrodionization system that produces effluent not exceeding 1μS/cm. Either system shall produce make-up water supplied to the steam generator that is less than 1 ppm of inorganic carbon and less than 10 ppb of dissolved oxygen. Desuperheating water shall have oxygen levels lower than 10 ppb of dissolved O2. When this steam is condensed, it is clear, colorless, odorless and has pH between 5.5 and 8.5 pH units. The steam delivered to the Buyer under this specification must meet the limits shown in Exhibit 4-1 at all times. Failure to meet any of these limits shall be cause for the Buyer to reject any steam from the Seller until the parameter(s) are found to be in conformance:

All criteria contained herein are continuous and instantaneous requirements and are not averaged over any time period.

Continuous monitoring is required of steam conductivity, sodium ion concentration, and pH. These 3 signals must be made available to Con Edison at all times and must be recorded.

Exhibit 4-1 Specifications for Steam Supplied to Con Edison Steam System

Parameter	Upper Limit in Condensed Steam Sample
Total Dissolved Solids	<1.0 ppm
Sodium ion	<0.010 ppm
Calcium ion	<0.10 ppm
Magnesium ion	<0.10 ppm
Sulfate/Sulfite ions	<0.10 ppm
Phosphate ion	<0.10 ppm
Ammonia	0.00 ppm
Chloride ion	0.10 ppm
Silica	<0.020 ppm = 20.0 ppb
Dissolved Iron	None
Dissolved Copper	None
Organics (TOC)	<0.10 ppm = 100.0 ppb
Color	None allowed
Moisture	0.0% - As measured by a throttling calorimeter. Steam Quality shall be 100%.
Odor	None allowed
PH	5.5-8.5
Specific Conductivity	3.0 µS/cm

The Seller shall be required to monitor the pH readings from drip pots located at the generating facility as well as on the send out main, prior to the Delivery Point, which shall be defined in the contract and is normally the point at which the Seller's steam main interconnects with the Buyer's steam system.

Hydrazine, cyclohexylamine, and morpholine, and any other chemical whose reaction or decomposition products include ammonia must not be used for the condensate, feedwater system, boiler water treatment, or steam systems.

All chemical(s) used for boiler water treatment shall conform to the regulations contained in the Code of Federal Regulations, Food and Drugs, Title 21, Part 173, Section 310, Boiler Water Additives, including the special requirements for steam used in milk production. All treatment chemicals must be FDA approved.

All steam samples are taken from the horizontal center of the main using an isokinetic probe described in ASTM 1066. Whenever the limits outlined above are exceeded, corrective action must be taken immediately, and a log entry made stating the time, duration, magnitude of the excursion, and the suspected reason for the excursion. No steam is to be sent out if the limitations are exceeded. If the steam conductivity equals or exceeds the limit for more than 15 minutes, the Buyer must be notified. The steam conductivity shall be continuously recorded and supplied to Buyer with an audible alarm signaling exceedence of the limit. Seller shall have a corrective action procedure for steam conductivity excursions. The steam sample system pressure gauges must be calibrated every six months; a calibration sticker with the date of calibration must be placed on the gauge, and a file shall be maintained of "before and after" calibration readings. Seller shall prepare and submit to Buyer, on a monthly basis, a report of the hourly readings of the following parameters: (a) for the steam sendout: conductivity and sodium (ppb); (b) for desuperheating water: conductivity, sodium (ppb), and dissolved oxygen (ppb). Seller will grant access to Buyer to the steam sample location for the purpose of taking grab samples for either routine analyses or for trouble shooting purposes. Seller will notify Buyer in advance concerning any significant changes in boiler configuration or boiler chemistry. Nothing stated herein relieves the Seller from operating and maintaining the Plant in accordance with Prudent Steam Utility Practices.

4.3. OTHER CONSTRAINTS

The Con Edison steam system will not return condensate to the merchant production facilities.

D

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Long Term Con Edison Steam Production Options Study - Phase 1

Final Report Appendix D

Study Operating & Technical Requirements for Alternative Steam Suppliers

Prepared for

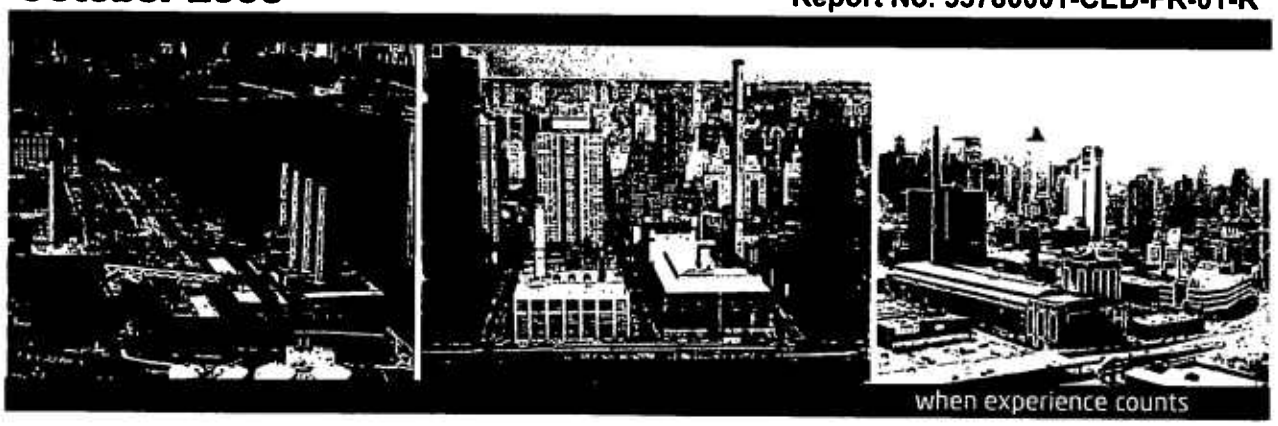
Consolidated Edison Company of New York, Inc.

in conjunction with the

Steam Business Development Core Task Force

October 2006

Report No. 53780001-CED-FR-01-R



Alternative Steam Supplier
Operating and Technical Requirements for Purposes of the Steam Production Cost Study[1]

1. Alternative Steam Supplier (Supplier) shall specify net winter and summer steam capacity (Mlb/hr) offered

2. Con Edison shall have full dispatch control of the steam sendout
   a. Con Edison shall provide a preliminary hourly schedule for each day in advance, however Con Edison shall have the right to modify the schedule thereafter in real time based on actual system requirements
   b. Supplier must be able to vary steam production as required between zero and the applicable seasonal steam capacity. Con Edison will not guarantee minimum hourly or annual steam purchase volume
   c. Steam dispatch shall take precedence over electric dispatch
   d. Steam supply must have black start capability.

3. Supplier shall notify Con Edison of preferred maintenance outage schedule one year in advance
   a. Final maintenance outage schedule shall be subject to Con Edison approval
   b. Maintenance outages shall only be approved for the Spring and Fall periods

4. Supplier will comply with Con Edison's steam quality specifications, previously provided; Supplier shall test, operate, and maintain its facility in accordance with Prudent Steam and Electric Utility Practice

5. Supplier shall provide a non-interruptible fuel supply for the production of steam
   a. Supplier shall be responsible for all gas system reinforcement and/or delivery costs
   b. Oil supply and storage capability must be sufficient to cover any gas interruptions

6. Supplier's interconnection to the Con Edison steam system must meet the following criteria:
   a. System pressures and flow must not be degraded or adversely impacted on a prospectively modeled basis as compared to current system conditions
   b. Interconnection is adequately sized to permit Supplier's full capacity to be delivered while maintaining pressure at the delivery point within allowable limits
   c. Supplier shall provide for Con Edison steam system reinforcements necessary to meet the above criteria
   d. Interconnection design must meet Con Edison's engineering specifications

[1] This document provides operating and technical requirements for the purposes of this study only.

E

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Long Term Con Edison Steam Production Options Study - Phase 1

Final Report Appendix E

KeySpan Ravenswood, LLC Steam Supply Alternative Information

Prepared for

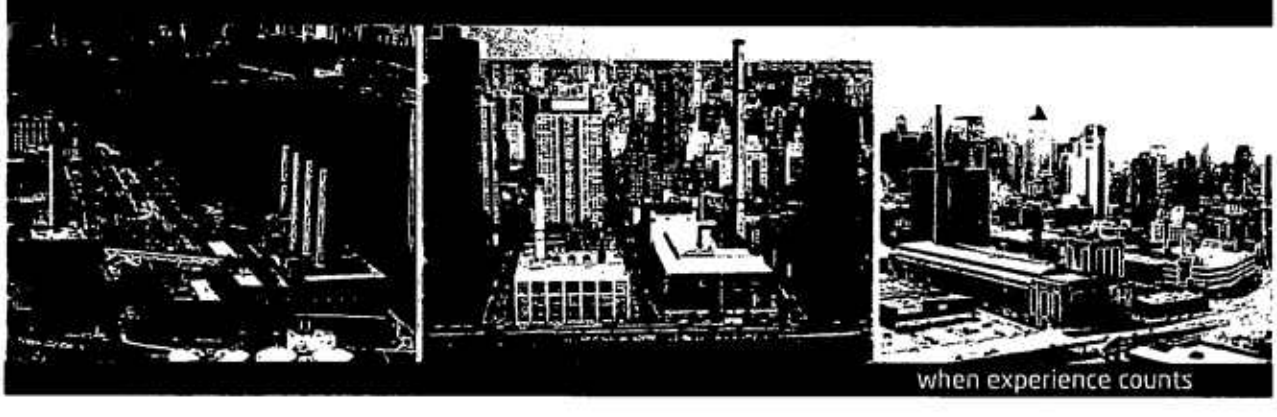
Consolidated Edison Company of New York, Inc.

In conjunction with the

Steam Business Development Core Task Force

October 2006

Report No. 53780001-CED-FR-01-R



NOTICE

This report reflects the work performed by WorleyParsons, using technical and financial inputs provided by Consolidated Edison and others, relating to the existing condition, environment, energy demands, and other data from selected Consolidated Edison Steam Generating Stations and other steam and power generating facilities. The report is based also on information, facts, assumptions and representations provided by Con Edison and others, which have not been independently verified by WorleyParsons, and is provided solely for information purposes, and there is no representation or warranty, expressed or implied, regarding for the fairness, accuracy or completeness of the information. The information also represents WorleyParsons understanding of an approach to potential feasible Projects that will provide the most economic solution; however, every possible combination or scenario has not been considered, and no liability, howsoever arising, is or will be accepted by WorleyParsons for the fairness, accuracy or completeness of the information contained in, or any omissions from, the report, or any other information supplied or made available regarding the Project, in writing or orally, in connection with any decisions to be taken by Consolidated Edison with respect to a proposed Project, or for the consequences of any reliance upon, or other use of, any such information or the report. WorleyParsons does not take direct responsibility for decisions which are based on the findings and results presented herein. Consolidated Edison, or any other third person is responsible for making its own decisions, and we cannot predict the actions of third parties whose actions may be required to execute projects discussed herein.

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Terminology

ACC	Air Cooled Condenser
ADI	Applicability Determination Index
AFUDC	Allowance for Funds During Construction
ANSI	American National Standards Institute
BACT	Best Available Control Technology
bar	0.98692 atmospheres
BFW	Boiler Feedwater
BMS	Burner Management System
BNYCP	Brooklyn Navy Yard Cogeneration Partners
BOOS	Burners Out of Service
BOP	Balance of Plant
Btu	British thermal unit
CAMPD	Compliance Assessment Media Programs Division
CC	Combined Cycle
CEMS	Continuous Emissions Monitoring System
CERA	Cambridge Energy Research Associates
CO	Carbon Monoxide
CO_2	Carbon Dioxide
COE	U.S. Army Corps of Engineers
CT	Combustion Turbine
DC	Dump Condenser
DEC	Department of Environmental Conservation
DLN	Dry Low NOx Combustor
EPA	Environmental Protection Agency (United States)
EPC	Engineer Procure Construct
EPCM	Engineer Procure Construct Manage
ERRP	East River Repowering Project
FD	Forced Draft
°F	Degrees Fahrenheit
ft	Foot or Feet
h, hr	Hour
HHV	Higher Heating Value
HP	High Pressure (Steam)
HRSG	Heat Recovery Steam Generator
ID	Induced Draft (Fan)
ISO	International Standards Organization
I&C	Instrumentation and Control
KPPH, klb/hr	Thousand lb/hr
kW	Kilowatts
LAER	Lowest Achievable Emission Rate
lb	Pound
LEA	Low Excess Air
LHV	Lower Heating Value
LNB	Low NOx Burner
LP	Low Pressure (Steam)
LBMP	Locational Based Marginal Price
MACT	Maximum Available Control Technology
Mlb/hr, MPH	Thousand lb/hr
MOU	Memorandum of Understanding
MMBH, MMBtu/hr	Million Btu/hr
MMlb/hr, MMPPH	Million lb/h
MM	Million
MMSCFD	Million Standard Cubic Feet per Day
MP	Medium Pressure (Steam)
MW	Megawatts
MWH	Megawatt-Hours
NEMA	National Electrical Manufacturers Association
NESHAP	National Emission Standards for Hazardous Air Pollutants
NGCC	Natural Gas-Fired Combined Cycle
NOx	Nitrogen Oxide
NPV	Net Present Value
NSPS	New Source Performance Standards

NSR	New Source Review
NYISO	New York Independent System Operator
OECA	Office of Enforcement and Compliance Assurances
OEM	Original Equipment Manufacturer
O&M	Operation & Maintenance
O&T	Operating & Technical
OTR	Ozone Transport Region
PFD	Process Flow Diagram
PM	Particulate Matter
PM2.5	Particulate Matter Less Than 2.5 microns
PM10	Particulate Matter Less Than 10 microns
PPH, pph	lbs/hr
PSC	Public Service Commission
PSD	Prevention of Significant Deterioration
psi	lb/square inch (14.696 psi = 1 atm)
Q	Heat
RACT	Reasonably Available Control Technology
RVM	Rear View Mirror
S	Sulfur Content of Fuel
SCFD	Standard Cubic Feet per Day
SCR	Selective Catalytic Reduction
SO_2	Sulfur Dioxide
SPDES	State Pollutant Discharge Elimination System
T&D	Transmission & Distribution (Electrical)
SOG	Shades of Green
ST	Steam Turbine
t	Ton (2000 lbs)
TCLP	Toxicity Characteristic Leaching Procedure
TGE	TransGas Energy
t/h	Tonne/hour
ton	Short Ton, (2000 lbs)
tpd	Ton per Day
US, U.S.	United States
USD, US$	the United States Dollar
VOC	Volatile Organic Compounds
VSD	Variable Speed Drive
y, yr	Year

E.1 INTRODUCTION

[REDACTED]

E.2 KEYSPAN DATA INFORMATION SHEETS

[REDACTED]

Exhibit E.1 KeySpan Data Information Sheet 1

[REDACTED]

Exhibit E.2 KeySpan Data Information Sheet 2

[REDACTED]

E.3 KEYSPAN INDICATIVE OFFER TERM SHEETS

[REDACTED]

Exhibit E.3 KeySpan [REDACTED] Term Sheet

[REDACTED]

Exhibit E.3 continued

[REDACTED]

Exhibit E.3 continued

[REDACTED]

Exhibit E.4 KeySpan [REDACTED] Term Sheet

[REDACTED]

Exhibit E.4 Continued

[REDACTED]

Exhibit E.4 Continued

[REDACTED]

Exhibit E.5 KeySpan [REDACTED] Term Sheet

[REDACTED]

Exhibit E.5 continued

[REDACTED]

Exhibit E.5 continued

[REDACTED]

E.4 KEYSPAN RESPONSES TO ADDITIONAL REQUESTS

[REDACTED]

Exhibit E.6 KeySpan Response to WorleyParsons' Request for Additional Information

[REDACTED]

Exhibit E.6 continued

[REDACTED]

Exhibit E.6 continued

[REDACTED]

Exhibit E.7 KeySpan Response to WorleyParsons Request for Clarification

[REDACTED]

Exhibit E.7 continued

[REDACTED]

E.5 KEYSPAN CONCEPTUAL LAYOUTS AND P&IDS

[REDACTED]

Exhibit E.8 KeySpan Conceptual Layout of Proposed System for Steam Supply to Con Edison

[REDACTED]

Exhibit E.8 continued

[REDACTED]

Exhibit E.9 KeySpan Conceptual P&IDs of Proposed System for Steam Supply to Con Edison

[REDACTED]

Exhibit E.9 continued

[REDACTED]

Exhibit E.9 continued

[REDACTED]

Exhibit E.9 continued

[REDACTED]

E.6 EVALUATION OF KEYSPAN [REDACTED] OPTION

KeySpan Ravenswood, LLC (KeySpan) responded to WorleyParsons' initial request for information with a Term Sheet with a non-binding indicative price offer for steam only sales to Con Edison, as shown in Exhibit E.3. [REDACTED].

In response to a request by WorleyParsons, KeySpan responded with indicative price offers for two additional options [REDACTED]. This section of the Appendix describes the results of WorleyParsons' evaluation of the first option, [REDACTED, in order to fully document WorleyParsons' work during the Study.

The [REDACTED] offer contained three significant conditions, [REDACTED], as follows:

- For steam sendout greater than [REDACTED], the energy price is the greater of fuel cost plus steam VOM cost and Vernon Switchyard NYISO LBMP (Locational Based Marginal Pricing) in $/MWh times [REDACTED], on an hourly basis.
- In any hour in which the electric VOM is greater than the LBMP, then Con Edison will pay the difference between the electric VOM and LBMP.
- Con Edison shall reimburse KeySpan for the incremental lost electric revenue resulting directly from Con Edison's real-time steam dispatch modifications.

WorleyParsons used the CERA 2005 Rearview Mirror Scenario electricity price projections as a basis for estimating the impact of the first two bulleted conditions on the price of steam from KeySpan. WorleyParsons did not include the impact of the third bulleted condition above in the evaluation. To do so would require an analysis of the probability of real-time dispatch modification and the conditions under which it may occur dependent on the time of year and time of day.

The evaluation assumed 30 days of combustion turbine distillate oil firing in the month of January, with natural gas firing of the HRSG. The natural gas prices were based on CERA 2005 Rearview Mirror Scenario projections; interruptible gas transport cost for natural gas supplied to the combustion turbine based on information provided by KeySpan; and firm gas transport cost, provided by Con Edison, for the amount of fuel required for supplemental firing of the HRSG based on the maximum fuel consumption of the HRSG. As discussed in Section 5.1 of the report, WorleyParsons used KeySpan estimates for the performance of the Ravenswood Combined Cycle Unit 40 when firing on natural gas. WorleyParsons estimated the system performance when the

combustion turbine is fired on distillate oil at ISO conditions based on information provided by KeySpan and WorleyParsons experience database with respect to natural gas-fired and oil-fired combustion turbine combined cycle systems.

In addition to the KeySpan price of steam, the evaluation included the cost of firm gas supply reinforcements, the cost of steam production at Con Edison's Ravenswood Steam Generating Station for the period from 2006 through 2011 until the KeySpan facility is ready to dispatch steam to Con Edison, the cost of piping modifications at the 71st Street and 74th Street steam interconnections, and the cost of demolition of the Ravenswood Steam Generation Station after 2011.

A summary of the estimated cost of steam production for the KeySpan steam supply alternative resulting from WorleyParsons evaluation is presented in Exhibit E.10 for the [REDACTED] option. The table shows the annual cost (in current dollars), the annual steam dispatched, the annual cost per thousand pounds of steam dispatched, the NPV of the annual costs over the study period, the discounted steam dispatched over the study period based on the method of discounting approved for the study, and the NPV of the annual costs divided by the discounted steam dispatched.

[REDACTED].

Exhibit E.10 Summary of Net Cost of Steam from KeySpan to Con Edison for [REDACTED] Option Based on CERA 2005 Rearview Mirror Scenario Price Projections

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
KeySpan Steam Price Summary																				
Energy Charges, Current $																				
Capacity and Other Fixed Charges, Current $																				
Cost Adjustment for Electric Revenue Lower Than Variable Electric Cost, $ (Note 1)																				
Total Price of Steam, Current $ (Note 2)																				
Annual Steam Sendout, Mlb																				
Total Price/Steam Sendout, Current $/Mlb																				
NPV of Total Steam Price, $																				
Discounted Steam Sendout, Mlb																				
NPV of Total Steam Price/Discounted Steam Sendout, $/Mlb																				
Firm Gas Reinforcements and Steam Piping Modifications																				
Ravenswood Cost of Operation Summary																				
Annual Cost, Current $ (Note 3)																				
Steam Sendout, Mlb																				
Annual Cost/Steam Sendout, Mlb																				
Net Cost of Steam for KeySpan Alternative Summary																				
Total Annual Cost, Current $																				
Steam Sendout, Mlb																				
Total Annual Cost/Steam Sendout, $/Mlb																				
NPV of Total Annual Cost of Steam, $ (Note 4)																				
Discounted Steam Sendout, Mlb (Note 5)																				
NPV of Total Annual Cost of Steam/Steam Sendout, $/Mlb																				

[ALL DATA REDACTED]

Note 1: Based on hourly comparison of revenue from sale of electricity with variable electric production cost
Note 2: Does not include impact of any real-time mofidication to steam dispatch schedule by Con Edison that may occcur
Note 3: Assumes shutdown of Ravenswood boilers at the end of 2011 followed by demolition and remediation. After 2013, annual costs represent depreciation on remaining net plant value.
Note 4: Based on nominal discount factor of 0.0687
Note 5: Based on nominal discount factor of 0.0376

F

WorleyParsons

resources & energy

Long Term Con Edison Steam Production Options Study - Phase 1

Final Report Appendix F

TransGas Energy Steam Supply Alternative Information and Evaluation

Prepared for

Consolidated Edison Company of New York, Inc.

In conjunction with the

Steam Business Development Core Task Force

October 2006

Report No. 53780001-CED-FR-01-R



NOTICE

This report reflects the work performed by WorleyParsons, using technical and financial inputs provided by Consolidated Edison and others, relating to the existing condition, environment, energy demands, and other data from selected Consolidated Edison Steam Generating Stations and other steam and power generating facilities. The report is based also on information, facts, assumptions and representations provided by Con Edison and others, which have not been independently verified by WorleyParsons, and is provided solely for information purposes, and there is no representation or warranty, expressed or implied, regarding for the fairness, accuracy or completeness of the information. The information also represents WorleyParsons understanding of an approach to potential feasible Projects that will provide the most economic solution; however, every possible combination or scenario has not been considered, and no liability, howsoever arising, is or will be accepted by WorleyParsons for the fairness, accuracy or completeness of the information contained in, or any omissions from, the report, or any other information supplied or made available regarding the Project, in writing or orally, in connection with any decisions to be taken by Consolidated Edison with respect to a proposed Project, or for the consequences of any reliance upon, or other use of, any such information or the report. WorleyParsons does not take direct responsibility for decisions which are based on the findings and results presented herein. Consolidated Edison, or any other third person is responsible for making its own decisions, and we cannot predict the actions of third parties whose actions may be required to execute projects discussed herein.

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Terminology

ACC	Air Cooled Condenser
ADI	Applicability Determination Index
AFUDC	Allowance for Funds During Construction
ANSI	American National Standards Institute
BACT	Best Available Control Technology
bar	0.98692 atmospheres
BFW	Boiler Feedwater
BMS	Burner Management System
BNYCP	Brooklyn Navy Yard Cogeneration Partners
BOOS	Burners Out of Service
BOP	Balance of Plant
Btu	British thermal unit
CAMPD	Compliance Assessment Media Programs Division
CC	Combined Cycle
CEMS	Continuous Emissions Monitoring System
CERA	Cambridge Energy Research Associates
CO	Carbon Monoxide
CO_2	Carbon Dioxide
COE	U.S. Army Corps of Engineers
CT	Combustion Turbine
DC	Dump Condenser
DEC	Department of Environmental Conservation
DLN	Dry Low NOx Combustor
EPA	Environmental Protection Agency (United States)
EPC	Engineer Procure Construct
EPCM	Engineer Procure Construct Manage
ERRP	East River Repowering Project
FD	Forced Draft
°F	Degrees Fahrenheit
ft	Foot or Feet
h, hr	Hour
HHV	Higher Heating Value
HP	High Pressure (Steam)
HRSG	Heat Recovery Steam Generator
ID	Induced Draft (Fan)
ISO	International Standards Organization
I&C	Instrumentation and Control
KPPH, klb/hr	Thousand lb/hr
kW	Kilowatts
LAER	Lowest Achievable Emission Rate
lb	Pound
LEA	Low Excess Air
LHV	Lower Heating Value
LNB	Low NOx Burner
LP	Low Pressure (Steam)
LBMP	Locational Based Marginal Price
MACT	Maximum Available Control Technology
Mlb/hr, MPH	Thousand lb/hr
MOU	Memorandum of Understanding
MMBH, MMBtu/hr	Million Btu/hr
MMlb/hr, MMPPH	Million lb/h
MM	Million
MMSCFD	Million Standard Cubic Feet per Day
MP	Medium Pressure (Steam)
MW	Megawatts
MWH	Megawatt-Hours
NEMA	National Electrical Manufacturers Association
NESHAP	National Emission Standards for Hazardous Air Pollutants
NGCC	Natural Gas-Fired Combined Cycle
NOx	Nitrogen Oxide
NPV	Net Present Value

NSPS	New Source Performance Standards
NSR	New Source Review
NYISO	New York Independent System Operator
OECA	Office of Enforcement and Compliance Assurances
OEM	Original Equipment Manufacturer
O&M	Operation & Maintenance
O&T	Operating & Technical
OTR	Ozone Transport Region
PFD	Process Flow Diagram
PM	Particulate Matter
PM2.5	Particulate Matter Less Than 2.5 microns
PM10	Particulate Matter Less Than 10 microns
PPH, pph	lbs/hr
PSC	Public Service Commission
PSD	Prevention of Significant Deterioration
psi	lb/square inch (14.696 psi = 1 atm)
Q	Heat
RACT	Reasonably Available Control Technology
RVM	Rear View Mirror
S	Sulfur Content of Fuel
SCFD	Standard Cubic Feet per Day
SCR	Selective Catalytic Reduction
SO_2	Sulfur Dioxide
SPDES	State Pollutant Discharge Elimination System
T&D	Transmission & Distribution (Electrical)
SOG	Shades of Green
ST	Steam Turbine
t	Ton (2000 lbs)
TCLP	Toxicity Characteristic Leaching Procedure
TGE	TransGas Energy
t/h	Tonne/hour
ton	Short Ton, (2000 lbs)
tpd	Ton per Day
US, U.S.	United States
USD, US$	the United States Dollar
VOC	Volatile Organic Compounds
VSD	Variable Speed Drive
y, yr	Year

F.1 INTRODUCTION

WorleyParsons requested the information identified in WorleyParsons' scope of work from TransGas Energy (TGE), via Alternative Facilities Data/Information Request (DIR) document, with respect to a TGE cogeneration facility providing steam to the Con Edison steam system. TGE responded with a completed spreadsheet with the technical data requested by WorleyParsons and a copy of a summary of results of an assessment previously performed by TGE of the benefits to New York City of a TGE proposed 824 MW electric power and steam cogeneration facility in New York City, providing steam to the Con Edison steam system. A copy of the summary document is included in Section F2.11.

WorleyParsons then had a follow-up meeting with TGE in New York City to discuss the information provided and request additional information required to complete WorleyParsons' task with respect to evaluating the TGE supply option. The additional information requested included TGE's proposed price of steam to Con Edison as a function of steam sendout (to meet Con Edison's requirement for full dispatch control of steam sendout from zero to maximum proposed), and price of fuel and electricity in order for WorleyParsons to evaluate the cost of TGE supplied steam to Con Edison over the next 20 years using CERA projected fuel and electricity prices.

In response to WorleyParsons' request for additional information, TGE provided a matrix of indicative steam price as a function of natural gas price and combined electricity energy and capacity price for one TGE supplied steam sendout, that is, 2 million lb/hr. In a telephone conversation with WorleyParsons, TGE presented their position with respect to providing indicative pricing for only 2 million lb/hr of steam sendout. WorleyParsons' understanding of TGE's position based on the conversation is as follows:

- The TGE price for steam will represent the lowest cost of steam for the Con Edison system, and, therefore, the TGE steam should have dispatch priority over all other steam generating facilities;
- The location of the proposed TGE facility and the location selected for interconnection of TGE supplied steam with the Con Edison system is such that the 2 million lb/hr of steam supplied by TGE could be utilized in the Con Edison system all the time.
- Providing pricing information at other steam sendout rates would require TGE to perform extensive additional technical and economic analyses, at a significant cost to TGE.

However, it was beyond the scope of this study for WorleyParsons to investigate these positions.

Upon further request by WorleyParsons for price data that would include all charges that would be incurred for steam sendouts from zero to the maximum proposed, in

accordance with the operating and technical (O&T) requirements of the study provided to WorleyParsons by the Core Task Force, TGE provided a single value of indicative price of steam for an average steam dispatch rate of 1.5 million lb/hr at a specific fuel price and electricity price (the full response by TGE explaining TGE's position on the subject is included in Section F2.12). However, there was insufficient information with respect to how the price for 1.5 million lb/hr of steam would vary with fuel and energy price for WorleyParsons to evaluate the cost of TGE supplying steam at this rate using data (CERA electricity and fuel price projections and steam supply capacity factors) consistent with evaluations of Con Edison repowering options and other steam supply alternatives in this study.

Based on the technical, price, and economic data that TGE provided to WorleyParsons for the 2 million lb/hr steam supply, WorleyParsons estimated the cost of TGE steam to Con Edison over 20 years and the net present value of the cost of steam, using CERA projections for fuel and electricity prices, as best possible with the data provided. A major difference between the TGE alternative and other alternatives evaluated by WorleyParsons as a part of this study is that the quantity of steam supply by the other alternatives evaluated is the same as that currently being supplied by the particular facility being evaluated; whereas, the quantity of steam supply proposed by TGE (2 million lb/hr) requires an evaluation of the entire Con Edison steam distribution network to determine if reinforcements and/or enhancements are necessary to distribute the steam to end-users and the potential costs of reinforcements/enhancements. Such an evaluation is beyond WorleyParsons current scope of work for the study, and, therefore, such reinforcement/enhancement costs, if necessary, are not included in WorleyParsons evaluation of the cost of TGE steam supply. Additionally, the costs associated with the retirement of any existing Con Edison steam generating stations that may be afforded by supply of steam by TGE were not included since the analysis required to determine what facilities, if any, could be retired is also beyond WorleyParsons scope of work.

WorleyParsons also evaluated the impact of the TGE supply of steam alternative on emissions, including the change in the proposed TGE facility emissions associated with supplying steam to Con Edison and the change in emissions of other electric power generating facilities in New York City that would be associated with generating electric power that would be displaced by TGE exporting steam.

The results of WorleyParsons evaluation of the TGE supply of steam alternative, and the assumptions upon which the evaluation was based, are discussed in this Appendix.

F.2 REVIEW OF INVESTMENT GRADE STUDIES PROVIDED BY OWNER

TransGas Energy (TGE) provided WorleyParsons with a copy of a summary of results of an assessment of the benefits to New York City of a TGE proposed [REDACTED] MW electric power and steam cogeneration facility in New York City, providing steam to the Con Edison steam system. A copy of the document is included in F2.11.

The summary included a narrative description of needs for the facility and site, how the steam supply would be interconnected to the Con Edison steam system, and an illustrative cost evaluation that showed [REDACTED]. The summary document identified the site of the proposed TGE facility as "across the East River for the central distribution hub for the Con Edison steam distribution system in Manhattan – the East River Station complex and nearby First Avenue steam lines." It indicated that a tunnel, 10 to 13 feet in diameter, beneath the East River would transport the steam distribution piping from the TGE facility to an interconnection point with Con Edison in the vicinity of the East River Generating Station or First Avenue in Manhattan.

The document also included an illustrative cost comparison between the proposed TGE facility and Con Edison's Hudson Avenue Station repowered with a cogeneration system. However, data from the comparison was not used by WorleyParsons because TGE provided WorleyParsons with other data to be used in the study.

F2.1 DESCRIPTION OF PLANT SYSTEMS

The following description is a summary of WorleyParsons understanding of the proposed TGE facility based on written and verbal communications with TGE personnel. The proposed TGE plant is a combustion turbine combined cycle plant consisting of 4 Siemens-Westinghouse W501Fcombustion turbines and 2 Siemens-Westinghouse 160,000 kWe extraction steam turbines. The combined cycle power output is about 1,111 MWe with no export steam and 843.5 MWe with the full 2 million lb/hr of export steam from the combined cycle system. The proposed heat recovery steam generators (HRSG) in the combined cycle do not have duct firing capability. TGE indicates that duct firing could be added if additional steam capacity from the system is desired. The proposed facility also contains 2 auxiliary boilers with a total of 1 million lb/hr steam capacity. TGE indicates that their minimum steam sendout capability is 125,000 lb/hr based on operation of 1 auxiliary boiler at 25% capacity.

The entire proposed facility has black start capability and would have 30 days of on-site oil storage for oil backup of the primary natural gas fuel, satisfying the Con Edison requirements for black start capability and firm fuel supply.

The proposed facility would use sewage plant grey water for cooling. TGE indicates that the current proposal is based on the use of city water as feedwater to the steam

generation system, but that the facility might be able to use water from the MTA that is currently pumped to prevent flooding of the subway system. The proposed facility would contain all the water treatment required to meet the Con Edison steam quality condition criteria.

The proposed system technical information sheet provided by TGE to WorleyParsons in response to WorleyParsons request for information is shown in Exhibit 2-1.

Exhibit 2-1 Proposed System Information Sheet Provided by TransGas Energy

[REDACTED]

F2.2 COST OF STEAM

TGE provided a matrix of their proposed price of steam (2005 dollars) as a function of fuel (natural gas) price and electricity price (combined energy and capacity) for a constant steam sendout of 2 million lb/hr, as shown in Exhibit 2-2. TGE stated that the price includes the capital and operating costs of the TGE facility, capital cost for the steam tunnel to transport steam from the TGE facility to point of interconnection with the Con Edison steam system, and interconnection costs. TGE stated that the price is based on that required to meet a goal of [REDACTED] rate of return on equity, and where the revenue from electricity sales was sufficiently high that no revenue from steam sales is required to obtain an [REDACTED] rate of return, then a sale price of zero was identified in the matrix. However, TGE indicated that this does not mean that there would be no charge to Con Edison for the steam.

From the data provided by TGE, WorleyParsons estimated the price of steam over the next 20 years (2006 to 2025) and the net present value (NPV) of the price of steam for the TGE Alternative based on the following assumptions:

- Fuel and electricity prices provided by CERA for their Rear View Mirror Scenario.
- A natural gas local delivery charge (LDC) of about $0.12/MMBtu for 30-day interruptible gas supply in 2006 dollars based on the formula used for the Hudson Avenue repowering option evaluations.
- Constant steam sendout rate of 2 million lb/hr (provided by TGE)
- Constant net electric power generation of [REDACTED] kWe (provided by TGE)
- TGE system availability of [REDACTED].
- Annual inflation rate of 3% applied to the TGE indicative price and natural gas LDC, consistent with other facility repowering evaluations.
- Sales tax of 4% on CERA natural gas price and LDC, consistent with other facility repowering evaluations.
- The same NPV discounting factor that was used for the Con Edison repowering alternatives (0.0687)
- The same steam discount factor that was used for the Con Edison repowering alternatives (0.0376)
- Linear interpolation of indicative steam price for fuel and electricity prices between those provided by TGE.
- TGE facility supply of steam beginning in 2012, consistent with Con Edison repowering alternatives.
- Steam production cost from Con Edison steam generating facilities for the six years preceding TGE steam supply (2006 through 2011) based on the weighted

average of the cost of steam production from the existing systems at Con Edison's Hudson Avenue, 59th Street, and 74th Street stations.

WorleyParsons did not address whether the steam system can be operated and dispatched to permit the base load delivery of 2 million lb/hr of steam on a 24/7 basis. Even if this were possible, the evaluation did not include the following:

- Costs of reinforcements and enhancements to the Con Edison steam distribution network to enable distribution of 2 million lb/hr of steam to end users since evaluation of the entire steam network was not in WorleyParsons' scope of work.
- Costs associated with retirement of Con Edison facilities that may be afforded by the production of steam by the TGE facility since a more extensive evaluation of the entire Con Edison steam system than included in WorleyParsons' scope of work would be required to identify the stations that could be retired, if any, and associated costs.

Exhibit 2-2 Indicative Price Data Provided by TGE for Constant Steam Sendout of 2 million lb/hr

[REDACTED]

The estimated cost of steam for the TGE Alternative based on the TGE provided data and the above assumptions is shown in Exhibit 2-3 in current year dollars for the years 2006 through 2025. The NPV of the cost of steam over the 20 year evaluation period is estimated to be about [REDACTED]. The discounted steam flow over the 20 years is about 226 billion pounds, calculated in accordance with the method approved for this study and described in Section 3.3 of the Final Report. The Unit NPV of the steam cost (NPV/Discounted Steam Exported) is thus estimated to be [REDACTED].

The evaluations for the other steam supply alternatives (repowering options at Con Edison facilities and KeySpan Alternatives) were based on a capacity factor of about [REDACTED].

Exhibit 2-3 Estimated Net Present Value of Steam for the TGE Alternative

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
TransGas Steam Price Summary																				
Adjusted TGE Indicative Steam Price, $/Mlb (Note 1)																				
Annual Steam Sendout, Mlb									[ALL DATA REDACTED]											
Annual Steam Charge, $																				
NPV of Total Steam Price, $																				
Discounted Steam Sendout, Mlb																				
NPV of Total Steam Price/Discounted Steam Sendout, $/Mlb																				
Cost of Steam Production from Existing Facilities																				
Average Unit Cost of Steam Production, Current $/Mlb (Note 2)									[ALL DATA REDACTED]											
Annual Steam Sendout, Mlb																				
Annual Cost of Steam Production, Current $																				
Other Costs																				
Steam network reinforcements, demolition/remediation of existing facilities, etc. (if ar	Unknown - not within scope of study																			
Net Cost of Steam for TransGas Alternative Summary (Note 4)																				
Total Annual Cost, Current $																				
Steam Sendout, Mlb									[ALL DATA REDACTED]											
Total Annual Cost/Steam Sendout, $/Mlb																				
NPV of Total Annual Cost of Steam, $ (Note 5)																				
Discounted Steam Sendout, Mlb (Note 6)																				
NPV of Total Annual Cost of Steam/Steam Sendout, $/Mlb																				

Note 1: Adjusted from 2005 dollars to current dollars based on 3% annual inflation
Note 2: [REDACTED]
Note 3: Does not include costs of steam reinforcements required of Con Edison steam network to enable distribution of steam from proposed interconnection of TGE facility and steam network.
Note 4: Excluding Other Costs
Note 5: Based on nominal discount factor of 0.0687
Note 6: Based on nominal discount factor of 0.0376

F2.3 DELIVERY TERMS

The basis for the TGE proposal is delivery of an average 2 million lb/hr of steam at all times to an interconnect point with Con Edison in the vicinity of the East River Generating Station or First Avenue in Manhattan.

F2.4 MAXIMUM AND MINIMUM CAPACITY, TURNDOWN AND CYCLING LIMITATIONS (IF ANY), AVAILABILITY, AND STEAM CONDITIONS AT DELIVERY POINT.

The maximum steam sendout capacity proposed by TGE is 3 million lb/hr, 2 million lb/hr from the combustion turbine combined cycle system and 1 million lb/hr from the auxiliary boilers. The minimum steam sendout capacity of the proposed facility is 125,000 lb/hr assuming 25% turndown from one auxiliary boiler. The steam conditions at delivery point were identified by TGE as [REDACTED], meeting the quality criteria of Con Edison.

F2.5 PRICE BASIS AND ASSUMPTIONS

The basis for the indicative price matrix provided by TGE and used in the study evaluation was delivery of an average of 2 million lb/hr of steam and assumptions previously discussed.

F2.6 VALUE OF COGENERATED ELECTRIC PRODUCTS AND FUEL PRICE.

TGE provided a schedule (matrix) of indicative steam price as a function of fuel price and electricity price (combined energy and capacity) for an average steam sendout of 2 million lb/hr which WorleyParsons used in the evaluations presented herein. TGE also provided a single indicative steam price of [REDACTED] per thousand pounds of exported steam (2005 dollars) based on a natural gas price of [REDACTED] and combined electricity price of [REDACTED] for an average steam sendout of 1.5 million lb/hr.. However, there was insufficient data/information with which to adjust the price for the natural gas and energy price projections upon which this study was based (CERA price projections). Therefore, the indicative steam price for 1.5 million lb/hr steam sendout was not used in the evaluations presented herein.

F2.7 INTERCONNECTION REQUIREMENTS

The TGE proposal is based on a steam interconnection point with Con Edison in the vicinity of the East River Generating Station or First Avenue in Manhattan. TGE indicated that their proposal includes the cost for interconnection with the Con Edison system; however, it does not include Con Edison steam system reinforcement costs.

F2.8 ASSESSMENT OF ENVIRONMENTAL IMPACT OF STEAM SALE

In the context of this study, the environmental impacts of steam sale by TGE to Con Edison are assessed by comparing the TGE facility air emissions assuming that no steam is exported to Con Edison with the combined emissions of the TGE facility with steam export to Con Edison and the incremental emissions of another NYISO Zone J power generating facility that must make up the electrical energy displaced from the TGE facility to allow for steam export. Since the TGE facility would be a new, large, primarily natural gas-fired combined cycle plant, it would be expected that its emissions per unit of fuel input would be less than or equal to existing facilities. If the facility making up the displace power is a boiler facility versus a combined cycle facility, then the emissions could be significant, especially if the other facility is an oil-fired unit.

The approach that WorleyParsons took in selecting the alternative electric power generating facilities to produce the power displaced by the TGE facility and evaluating the increase in emissions were the same as described for the KeySpan Alternative, as follows:

- A power generator stacking database provided by CERA that contained information on power generating units in Zone J by month for each year between 2006 and 2020 that included type of unit, type fuel, the dispatch and fuel cost, estimated NOx and SO_2 emissions on a lb/MMBtu basis, unit heat rate, capacity, and MW-hrs generated was used to select a unit for generation of the electric power displaced by the TGE facility.
- CERA Rear View Mirror Scenario monthly fuel and electric energy price projections were used to determine the marginal heat rate for selecting the power generator.
- The emissions factors from the selected electric power generator in the CERA database were used when available and deemed reasonable; otherwise, emissions factors from the EPA AP-42 were used.

The types of power generators selected based on the above approach were the same as for the KeySpan Alternative evaluation, as follows:

- During the summer, the power generating unit is a natural gas-fired steam boiler/turbine unit with average heat rate of about 9,360 Btu/kW-hr.
- During the winter, a combination of natural gas-fired combined cycle (NGCC) units and low-sulfur (0.3% sulfur), #6 fuel oil-fired (residual oil-fired) steam boiler/turbine unit, with 50% of the energy being produced from each type system. The average heat rate for the NGCC is about 7,100 Btu/kW-hr, and the average heat rate for the residual oil-fired steam unit is about 9,400 Btu/kW-hr.

The estimated emissions factors and performance estimates used for the TGE facility were provided by TGE.

Results of the assessment of the impact of the TGE alternative on emissions are shown in Exhibit 2-4. Also shown are the emissions factors upon which the assessment was based for the TGE facility and the alternative power generators. Also shown in the Exhibit for comparison purposes are the estimated emissions from a

residual oil-fired boiler generating 2 million lb/hr of steam based on emissions factors of boilers at Con Edison's Hudson Avenue Station.

Exhibit 2-4 Estimated Incremental Emissions for TGE Provided Steam[f]

			NOx	SO2	VOC	CO	PM
TGE Emissions Factor, lb/MMBtu[a]			[DATA REDACTED]				
Alt. Pwr Gen. Plant Avg. Annual Emissions Factor, lb/MMBtu[b]			0.123825	0.079644	0.004488	0.004488	0.012318
Residual Oil-fired Steam Generating Station Emissions Factors, lb/Mlb steam[c]			[DATA REDACTED]				
	Power, kW	Fuel Input, MMBtu/hr	Estimated Emissions, lb/hr				
			NOx	SO2	VOC	CO	PM
TGE Emission Without Steam Export	[DATA REDACTED]						
TGE Emission With 2 MMlb/hr Steam Export							
Alt. Power Generating Facility	267,560	2356	292	188	11	11	29
			NOx	SO2	VOC	CO	PM
Incremental Increase in Emissions for TransGas Alternative, lb/hr[d]			[DATA REDACTED]				
Emissions from Residual-Oil-Fired Boiler Generating 2 million lb/hr Steam, tons/year			[DATA REDACTED]				

[a] Based on data provided by TGE.

[b] Based on natural gas-fired steam unit in summer and combination natural gas-fired combined cycle and #6 fuel oil-fired steam unit in winter.

[c] Based on Hudson Avenue Station 5-year average emissions factors.

[d] Includes only TGE facility and power generating facility making up for displaced electric power, does not include reduction in emissions resulting from steam reduction at Con Edison steam generating facility.

[b] Based on natural gas-fired steam unit in summer and combination natural gas-fired combined cycle and #6 fuel oil-fired steam unit in winter.

F2.9 ESTIMATED DATE OF STEAM DELIVERY

The estimated date of steam delivery used for the evaluation was the beginning of year 2012.

F2.10 ADJUSTMENTS TO OWNER-SUPPLIED INFORMATION

The indicative price data as a function of fuel price and electricity price provided by TGE for an average steam sendout of 2 million lb/hr was adjusted from 2005 dollars to current year dollars for years 2006 through 2025 using an annual inflation rate of 3%. The annual cost of steam was then estimated for each year using the CERA provided electricity price and natural gas fuel price, and adjusting the CERA fuel cost by the addition of an estimate of LDC.

F2.11 TRANSGAS ENERGY ASSESSMENT PROVIDED BY OWNER

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Via Overnight Delivery

February 3, 2006

Leonard M. Bartone, Jr., P.E.
WorleyParsons Group, Inc.
2675 Morgantown Rd.
Reading, PA 19607-9656

Re: Con Edison Stream Production Options Study Phase 1 – Alternative Facilities Data/Information Request, dated January 18, 2006.

Dear Mr. Bartone:

Pursuant to the request made in the captioned document, attached is information/data being submitted on behalf of TransGas Energy Systems LLC ("TransGas") for consideration in the Steam Production Options Study Phase I. On several occasions, you and I had discussed the schedule for the submission of the data and agreed that providing as much as is available by the end of this week would be acceptable notwithstanding the deadline contained in the captioned document. We also discussed setting up a meeting during the week of February 13, 2006 as both WorleyParsons and TransGas are unavailable in New York City during the week of February 6th, although TransGas is available at its out-of-state location that week.

Enclosed you will find the information/data sheet WorleyParsons requested TransGas to complete, an illustrative comparison of a TransGas proposal to a possible Hudson Avenue Repowering and a number of excerpts from regulatory and judicial filings made by TransGas summarizing the benefits of a cogeneration facility.

With respect to the information/data sheet, there were some lines that could not be completed at this time, but TransGas would be pleased to discuss them with you at our upcoming meeting, to be scheduled. The illustrative comparison that TransGas has provided demonstrates that if a proposed TransGas cogeneration plant and a possible Hudson Avenue Repowering were to sell electricity at the same price, the

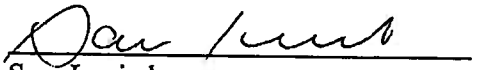
TransGas proposal could supply steam at a much lower cost. We would be happy to supply further backup data for this comparison as well as discuss it with you in more detail when we meet.

As to the benefits of the TransGas plant, the summary excerpts attached are drawn from much larger filings copies of which can also be supplied. In the instance of benefits such as emission reductions, they are the results of MAPS simulations that were run on similar, but not precisely the same, plant configurations. The same holds true for electric cost reductions that would occur through economic displacement throughout the City and State. The magnitude of the reductions is expected to be the same, however. As the TransGas plant confirmation would include auxiliary steam boilers and blackstart capability, it would provide reliability redundancy for the steam system that would be quite valuable. In this regard, one of the attached excerpts describes the four-day shutdown of the steam system that occurred on August 14, 2003 as a result of the electric blackout. TransGas' blackstart capability could restart its auxiliary boilers and keep steam flowing in Con Edison's steam mains, helping to keep them warm and avoiding the possibility of a steam main freeze, with a possible loss of heat and potable water to 2200 buildings in NYC, if such an outage occurred during the winter. Other benefits discussed in the excerpts include the much greater In-City electric capacity that a TransGas plant would provide versus a Hudson Avenue Repowering, the use of grey water for producing steam that could displace Con Edison's reliance on potable NYC water, the construction of a new steam tunnel that could house multiple utility services and the fact that the TransGas location would allow service to both the uptown and downtown steam districts in Manhattan.

Feel free to contact the undersigned should you have any questions about the attached information. We stand ready to work with WorleyParsons to answer any inquiries you might have.

Very truly yours,

READ AND LANIADO, LLP
Attorneys for TransGas Energy
Systems LLC

By: 
Sam Laniado

Enclosures
cc: Adam Victor

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EXHIBIT 1

Brief Summary of Cogeneration Project Benefits: TRANSGAS

The Property was selected because it lies in an area currently zoned for heavy industry (M3-1), its proximity to existing gas, electric and oil lines and its proximity to Manhattan to which the Project will provide steam via a tunnel beneath the East River.

WHEREAS, it has been determined that the Project will provide the following public uses:

1. The Project will help satisfy the forecasted need for additional generation to serve growing loads in the City of New York and greater Metropolitan Area.
2. The Project will remediate a highly contaminated site.
3. The Project will displace older, less controlled power plants, thereby reducing emissions of nitrogen oxides, sulfur oxides and carbon dioxide in the City of New York, New York State, and in the locality in which the Project is located.
4. The Project will reduce market concentration of generation in NYC, thereby contributing to the development of a more competitive electric market and preventing the exercise of market power that could cause excessive electric rate pricing to consumers on their electric bills.
5. The Project will reduce energy and capacity costs by tens of millions of dollars in the New York State and New York City regions resulting in savings to consumers.
6. The Project is consistent with the objectives of the New York State Energy Plan in that it promotes electric competition between suppliers, relieves transmission congestion, employs cogeneration technology and reduces greenhouse gas emissions.
7. By using North American natural gas, the Project will reduce crude oil imports by hundreds of millions of gallons each year.
8. The Project will create jobs, increase earnings and foster economic development as follows.

   i. Project Construction

      (a) Infusion into the local economy for onsite payroll and non-payroll of $250 million.

      (b) About 1,375 on-site annual construction jobs – or 620 total jobs lasting several years – are created as a result of the $250 million infusion.

(c) Temporary employment in the local area is expected to increase by 1,048 jobs.

(d) Economic output will increase by $430 million.

(e) Earnings in the local area are expected to increase by $171 million.

ii. Projection Operation

(a) 40 permanent jobs.

(b) Local, non-fuel, operation and maintenance annual expenditures of $10 million.

(c) Annual payroll for the 40 permanent jobs is estimated at $2.5 million.

(d) Output in the local area is estimated to increase $16.5 million per year.

(e) Earnings in the area are estimated to increase $4.35 million annually.

(f) 60 new permanent positions are expected to be created in the region.

iii. Approximate economic Benefits of Energy Cost Savings

- 896 permanent new jobs in NYC;
- $67 million per year in economic growth in NYC;
- $59 million per year in increased earnings in NYC.

9. The Project will provide new waterfront access and advance one or more policies of NYC's New Waterfront Revitalization Program.

10. The Project will benefit the electric system serving New York City and the State of New York in the following ways:

(a) The Project will provide blackstart capability that will help NYC recover from electric and steam outages.

(b) The Project will provide in-City reactive power to help support voltage on the electric system.

(c) The Project will reduce congestion on the transmission lines serving NYC from the north, thereby reducing electric prices.

(d) The Project will reduce transmission losses, thereby improving efficiency, lowering costs and reducing air pollution by the amount of the saved losses.

(e) By siting new generation away from the generation complex at Powell Cove, Queens, near LaGuardia Airport, the Project reduces the vulnerability of the NYC electric system to a catastrophic outage.

11. The Project will reduce potable water consumption in NYC by one billion gallons per year by using non-potable water to produce steam, thereby allowing Con Edison to terminate its use of potable water.

12. By selling steam to Con Edison at discounts to Con Edison's avoided costs, the Project can save ratepayers on their steam bills.

EXHIBIT 2

ELECTRIC NEED AND
Steam Blackstart Capability

The Need for the Facility and the Site

New York City needs additional electricity. Year after year, studies conducted by the New York Independent System Operator ("NYISO") show that, due to economic growth, environmental regulations and the retirement of existing generating facilities, the City's electric generation and import capabilities may be insufficient in coming years to meet the expected increased demand.[9] The NYISO issued the Power Alert Study in 2003 and then Power Trends in 2005. Both studies show that New York State and the City need additional power as early as 2008. (Tr. 1240-1243) (Reproduced in Appendix § 4) The most recent study conducted by the NYISO was the Reliability Needs Assessment ("RNA"). (A copy of the RNA is included in Appendix § 10) This RNA also indicates that New York City's forecasted electric system does not meet reliability criteria due to continued increases in demand for electricity as early as 2008-2009 without compensating capacity additions. The demand for electricity in southeastern New York has grown in excess of two percent per year, totaling approximately 5,000 MW, with only approximately 1250 MW of net new generation having been added in over the last ten years. The TransGas facility was conceived, *inter alia,* to help satisfy this increased demand for reliable electricity and, due to the expiration of Article X, remains the only Article X project that could be certified in the near future.[10]

The record also shows that the Facility is consistent with the objectives of the 2002 New York State Energy Plan in that it promotes electric competition between suppliers, relieves transmission congestion, employs cogeneration technology and reduces greenhouse gas emissions. (Exh. E, Article X App., Vol. 1,

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[9] *See e.g.,* POWER TRENDS 2005, New York Independent System Operator, *available at* http://www.nyiso.org/public/webdocs/newsroom/whats_new/ptrends2005.pdf .

[10] POWER TRENDS 2005, *supra,* note 8.

§ 1.3.2 (Reproduced in Appendix § 11). Because it is highly efficient and will produce power economically, the Project would displace older, less controlled power plants, thereby reducing emissions of nitrogen oxides, sulfur oxides and carbon dioxide in the City of New York, New York State, and in the local Greenpoint/Williamsburg community. On a larger scale, by using North American natural gas, the Project will reduce crude oil imports by hundreds of millions of gallons each year. (Exh. E, Article X App., Vol. 1, § 1.2.11) (Reproduced in Appendix § 11) (Exh. E, Tr. 1258, 1261) (Reproduced in Appendix § 4); (Exh. E, Article X Amendment § 16.3) (Reproduced in Appendix § 12).

The Facility promises unique reliability benefits to both the City's electric and steam systems. In addition to the myriad electric reliability benefits that an In-City generator provides, such as less reliance on vulnerable overhead transmission lines, TransGas is the only new plant equipped with blackstart capability. Blackstart capability allows a generating facility to restart on its own without receiving electricity from another generating facility. As such, TransGas could help Consolidated Edison Company of New York, Inc. restart the electric and steam systems more quickly from a blackout, such as that occurred on August 14, 2003. (Exh. E, Article X App., Vol. 1, § 1.2.1) (Reproduced in Appendix § 11); (Exh. E, Tr. 400) (Reproduced in Appendix § 4).

Following the electric blackout on August 14, 2003, the steam system in New York City went down, lost all pressure and needed at least four days to recover. Rather than mere inconvenience, the consequences to New Yorkers could have been far worse if the steam system was lost during a winter month, and buildings, heating pipes and potable water pipes could not be kept warm. With its blackstart capability, TransGas could start its auxiliary boilers quickly and

continue to provide steam to Con Edison's mains at pressure. (Exh. E, Tr. 400, 1243) (Reproduced in Appendix § 4).[11]

As demonstrated in TransGas' Article X application, the construction and operation of the TransGas facility will create economic benefits for the local community as well. (Exh. E, Article X App., Vol. 1, §§ 12.3-12.7) (Reproduced in Appendix § 13). As a result of its construction, payroll and non-payroll expenditures will inject an additional $250,000,000 into the local economy, with secondary impacts producing another $180,000,000 in economic output. Construction will create 1,668 direct and indirect temporary jobs. As a result of Facility operation, output in the local area is estimated to increase $16.5 million per year. Annual payroll for the 40 permanent jobs is estimated at $2.5 million. Earnings in the area are estimated to increase $4.35 million annually and, as a result of the 40 new TransGas jobs, 60 new positions are expected to be created in the region. Since the property would remain in private ownership under TransGas' proposal, it would remain taxable, producing millions of dollars to the City, which would benefit its economy. This benefit would be lost should the City take the property in condemnation.

Evidence in the record in the Article X proceeding shows that projected energy cost savings will also create statewide economic benefits. (Exh. E, Article X App., Vol. 1, § 12.4.3) (Reproduced in Appendix § 13). According to the 2002 New York State Energy Plan, electricity cost savings of $100 million per year would stimulate approximately 1600 jobs in New York State, increase the gross

[11] *See also,* Excerpts from Initial Report of the New York State Department of Public Service on the August 14, 2003 Blackout, dated February 2004. The Examiners took official notice of this Report in the RD (p. 124). (Reproduced in Appendix § 3).

output of goods and services in the State by $199 million and increase personal income by $105 million over a ten-year period.

The Project will reduce market concentration of generation in NYC, thereby contributing to the development of a more competitive electric market and preventing the exercise of market power that could cause excessive electric rate pricing to consumers on their electric bills. The Project will also reduce energy and capacity costs by tens of millions of dollars in the New York State and New York City regions resulting in savings to consumers. (Exh. E, Article X App., Vol. 1, § 12.4.3) (Reproduced in Appendix § 13).

Suitable sites in New York City for such a facility are scarce, especially to connect to Con Edison's Manhattan steam system. (Exh. E, Tr. 1428). (Reproduced in Appendix § 4) Tens of alternate sites were examined by parties in the proceeding, including seven different data bases compiled by different entities over the past decade. (Exh. E, Tr. 1398) (Reproduced in Appendix § 4). TransGas evaluated, *inter alia,* alternatives to the site, project size, fuel and generating technologies. (Exh. E, Vol. 6, Att. Y-4) (Reproduced in Appendix § 14). The current site of the Bayside Fuel Oil Depot, the Property, was selected as the preferable site. The Property was ideal for the TransGas project because of its current zoning for heavy industry (M3-1), its proximity to existing gas, electric and oil lines and its proximity to Manhattan to which the Project will provide steam via a tunnel beneath the East River. When TransGas acquired the option to purchase the Property, the zoning for the Property was M3 (heavy industry) which authorizes the construction of generating facilities as of right.

The draft Williamsburg 197-A Plan, prepared in accordance with Section 197-A of the New York City Charter, was approved by the City Council in December 2001. In the City's discussion of the Williamsburg Plan (CB 5), the

EXHIBIT 3

STEAM Interconnection with Con Edison

TGE would supply this steam to Con Edison at an interconnection point in the vicinity of the East River Generating Station or First Avenue in Manhattan, across the East River from the Project site. TGE has proposed to Con Edison a concept for a Steam Sales Agreement that would provide the terms for supply, interconnection, pricing and other terms and conditions typical of an energy sales agreement. TGE envisions selling Con Edison steam at prices that would provide cost savings to Con Edison and its ratepayers. TGE's supply of steam would be highly reliable to meet or exceed Con Edison's requirements, which could facilitate the displacement of equivalent steam generating capacity on the steam system. TGE's hourly deliveries would be fully dispatchable by Con Edison. There would be no minimum take of steam by Con Edison.

There have been more than six meetings with Con Edison on the steam supply issue alone, with numerous other phone contacts. The meetings have been held on a confidential basis and have only been attended by Con Edison and TGE representatives. There is no formal agreement, but issues such as supply, price, interconnection and basic supply terms have been discussed. Con Edison recently authorized the consulting firm it has retained in the past for modelling its steam system to conduct certain system simulations as a contractor for TGE, employing the Con Edison proprietary steam system data base. The purpose of the simulations is to determine a preferred configuration for interconnecting TGE's steam supply to the Con Edison steam system. That modeling is ongoing. Meetings with Con Edison will be resumed after the results of those simulations are available.

3.7.2 Steam Tunnel Description

The site of TGE's proposed Project is located across the East River from the central distribution hub for the Consolidated Edison Company of New York, Inc., steam distribution system in Manhattan – the East River Station complex and nearby First Avenue steam lines. The tunnel diameter will be 10 to 13 feet, depending upon detailed design considerations. The tunnel will be approximately 6,600 feet long. The primary purpose of the tunnel is to deliver steam to the Con Edison system. Space can also be reserved in the tunnel for an additional electric, communication or water line, as a way of offering additional linkages to city infrastructure and to help recover tunneling costs. By allowing for the potential cross-river connection of compatible non-steam utilities, the tunnel would be a considerable enhancement to New York City's infrastructure overall. An added benefit of the tunnel is that it will be installed more than 80 feet below the project depth of the East River Federal Navigation Channel, and more than 70 feet below the lowest river bottom elevations along the route. The steam tunnel will not affect the present or future course, location, or capacity of the East River or its federal navigation channel. A detailed description of the steam tunnel is presented in Section 6.6.

EXHIBIT 4

EMISSION REDUCTIONS AND COST REDUCTIONS

- TGE contracts with the distributor of the steam, presumably Con Edison, but it could be another entity, to supply the steam for the initiatives.

These initiatives would help build steam load and reduce summertime electric load. It would enhance the vitality of the steam system in New York City. These goals have been endorsed by the New York State Public Service Commission in the recently-decided Con Edison steam rate case.

16.3 Multi-Area Production Simulation (MAPS) Analysis

In its September 15, 2004 Order, the Board requested that TGE update its MAPS analyses as follows:

> New MAPS analyses reflecting updated fuel costs[1] and assuming the operation of each alternative plant. Analyses purporting to attribute net emissions reductions to operation of the proposed facility shall include scenarios assuming implementation of the federal Environmental Protection Agency's proposed Clean Air Interstate Rule.[2]

This section of the Amendment gives the results of the updated MAPS analysis. The MAPS database employed in the Article X proceeding, as modified in October and November 2003 for the submission of rebuttal and rejoinder testimony, was modified to incorporate the updated fuel prices supplied by the DPS staff. These fuel prices were employed for MAPS simulations used in the New York State Public Service Commission's Retail Renewable Portfolio Standard proceeding.

The emissions were also reduced to account for the assumed implementation of the federal EPA's proposed Clean Air Act Interstate Rule. The EPA's proposed "Interstate Air Quality Rule" (IAQR) will cap statewide emissions of sulfur dioxide (SO_2) and oxides of nitrogen (NO_X) for 28 States and the District of Columbia in 2010. Each state will be able to choose to either require utilities to participate in an interstate "cap and trade" system or they can choose their own emissions cap methodologies. The EPA's IAQR statewide caps were compared to the statewide emissions as modeled in the original Article X application. A summary of the percent reductions required by each state to meet the 2010 IAQR cap is shown in Table 16-4 below.

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[1] See PSC Case 03-E-0188, Retail Renewable Portfolio Standard, Recommended Decision (issued June 3, 2004), pp. 39-41.
[2] 69 Fed. Reg. 32684 (June 10, 2004) and 69 Fed. Reg. 4966 (January 30, 2004); see TR. 1381-1383.

Table 16-4: Emission Reductions Required to Meet Proposed 2010 IAQR		
State	**SO_2 Reduction (%)**	**NO_X Reduction (%)**
Connecticut	29.2751	0
Delaware	28.4651	51.8187
Maine	4.8317	0
Maryland	72.1499	75.6506
Massachusetts	0	0
New Hampshire	0	0
New Jersey	59.1492	73.8605
New York	6.4133	0
Pennsylvania	75.5808	51.1412
Rhode Island	0	0
Vermont	0	0
Virginia	0	0

As requested in the Order, various scenarios were examined at two different locations in addition to the base case, which assumed no new TransGas generation. Table 16-5 shows the net electric capacity for each scenario, the energy output of the plant and the average annual capacity factor. As can be seen, even though Case 1 had reduced capacity due to the increased steam extraction, it had the most energy production due to its significantly improved heat rate.

- Case 1 – 1100 MW Combined Cycle Cogeneration-Bayside
- Case 2 – 1100 MW Combined Cycle Cogeneration-ExxonMobil
- Case 3 – 1100 MW Combined Cycle-ExxonMobil
- Case 4 – 500 MW Combined Cycle-ExxonMobil
- Case 5 – 776 MW Combined Cycle Cogeneration w/ Topping Turbines – Bayside
- Case 6 – 1079 MW Combined Cycle Electric Only-Bayside
- Case 7 - 1050 MW Proposed Underground Design-Bayside

Table 16-5: Energy and Capacity for Each Scenario			
Unit Name	**Energy (GWH)**	**Winter Capacity (MW)**	**Capacity Factor (%)**
Case 1	6,751	917	84.0
Case 2	6,514	1,011	73.5
Case 3	4,233	1,034	46.7
Case 4	2,241	517	49.5
Case 5	6,514	1,011	73.5%
Case 6	4,233	1,034	46.7%
Case 7	6,514	1,011	73.5%

The annual and seasonal New York emissions are shown in Table 16-6. The reductions from the base case are shown in Table 16-7. The largest reduction in emissions from electricity production comes from Case 1. The emissions reductions reflect the reductions assumed for the recently promulgated New York State NO_x and SO_x reductions as these were incorporated in the database used for the MAPS runs in rebuttal and rejoinder testimony last fall. They also reflect an adjustment for the assumed implementation of the IAQR, as requested in the Siting Board Order dated September 15, 2004.

Table 16-6: NYISO Emissions (000's tons)				
	Annual SO_2	Annual NO_x	5 Month NO_x	Annual CO_2
No TGE	164.3	60.7	24.6	58,267.3
Case 1	158.9	58.1	23.5	56,480.2
Case 2	160.1	58.3	23.5	57,534.9
Case 3	159.7	58.2	23.5	57,641.0
Case 4	161.9	59.3	24.0	57,913.9
Case 5	160.1	58.3	23.5	57,534.9
Case 6	159.7	58.2	23.5	57,641.0
Case 7	160.1	58.3	23.5	57,534.9

Table 16-7: NYISO Emission Reductions (000's tons)				
	Annual SO_2	Annual NO_x	5 Month NO_x	Annual CO_2
Case 1	5.4	2.6	1.1	1,787.1
Case 2	4.3	2.4	1.1	732.4
Case 3	4.7	2.5	1.1	626.3
Case 4	2.4	1.4	0.6	353.4
Case 5	4.3	2.4	1.1	732.4
Case 6	4.7	2.5	1.1	626.3
Case 7	4.3	2.4	1.1	732.4

Based on information developed by TRC Environmental Corporation, the total SO_2 emissions in New York State, in the base case, and with TGE, were reduced by 6.4133% to reflect the reduction in total New York State SO_2 emissions assuming the implementation of the proposed IAQR. NO_2 emissions were not reduced because they were already below the proposed allocations for New York State in the proposed IAQR.

The total savings in operations costs is shown in Table 16-8. These reflect reductions in fuel, variable O&M and start-up costs in the NYISO region.

Table 16-8: NYISO Variable Costs		
Scenario	**Total Variable Cost ($000)**	**Total Savings ($000)**
No TGE	4,571,863	--
Case 1	4,422,654	149,208
Case 2	4,527,715	44,148
Case 3	4,546,222	25,641
Case 4	4,554,368	17,494
Case 5	4,527,715	44,148
Case 6	4,546,222	25,641
Case 7	4,527,715	44,148

In the LBMP market as operated in the NYISO the reduction in the cost of operation is only part of the story. The Load Serving Entities (LSEs) will purchase energy at the marginal cost of operation, not the average cost, so the load payments have to be examined as well. Table 16-9 shows the load payments for just the NYISO for each of the scenarios examined and the

corresponding reductions. Table 16-10 shows the same values for just the Con Edison service territory. As might be expected, the bulk of the savings in all of the cases occurs in the region where the plant is located.

Table 16-9: NYISO Load Payments

Scenario	Load Payments ($000)	Load Payment Reduction ($000)
No TGE	6,922,687	--
Case 1	6,761,625	161,063
Case 2	6,817,685	105,003
Case 3	6,823,479	99,208
Case 4	6,869,972	52,715
Case 5	6,817,685	105,003
Case 6	6,823,479	99,208
Case 7	6,817,685	105,003

Table 16-10: Con Edison Load Payments

Scenario	Load Payments ($000)	Load Payment Reduction ($000)
No TGE	2,635,336	--
Case 1	2,534,031	101,305
Case 2	2,556,317	79,018
Case 3	2,560,740	74,596
Case 4	2,594,655	40,681
Case 5	2,556,317	79,018
Case 6	2,560,740	74,596
Case 7	2,556,317	79,018

EXHIBIT 5

Increased Jobs And Economic Development

12.3.2 Construction Expenditures

Stipulation 7, Clause 3(b) calls for an estimate of the annual payroll for each year of Project construction and an estimate of the direct non-payroll expenditures that will likely be made for the Project during its construction period.

For purposes of determining socioeconomic effects from construction, two types of expenditures need to be considered – those made outside the region and those made inside it. The former carries no secondary economic benefits to the region, while the latter does. Thus, estimates of economic impact are based only on the latter type of expenditure.

A calculation of estimated on-site payroll expenditures to construct the Project is approximately $100 million, as detailed in Table 12-7. The local purchase and/or contracting for construction materials, including tunneling materials and lining, supplies, and services purchased or contracted locally will have another significant direct and positive socioeconomic impact on the community. These estimated non-payroll local expenditures include the cost of labor benefits, fees to incumbent utilities for infrastructure interconnections, overhead, taxes, disposal fees for soil and hazardous materials, local transport and logistics costs, permit fees, purchase of local supplies, services and consumables – approximately $150 million in all. Consequently, the direct infusion of funds into the local economy is expected to be approximately $250 million.

12.3.3 Secondary Economic Impact Due to Project Construction

This section addresses Stipulation 7, Clause 3(i), which requires an assessment of potential indirect employment and economic impacts associated with the construction of the plant. The stipulation requires that an input-output multiplier be used.

Assuming the direct economic impact estimates noted above, regional input-output models can be used to estimate the indirect/induced impact. The New York State Department of Economic Development (DED, or Empire State Development) provided multiplier data based on the IMPLAN input-output model in order to estimate secondary impacts that are specific both to certain types of industries and to geography – New York City.

The estimated primary investment (calculated above) is approximately $100 million in on-site payroll expenditures and an estimated $150 million in other local investments. Thus, an approximately $250 million investment in the local economy is anticipated. An estimated 620 jobs (many lasting approximately two years) will be created. Secondary effects are estimated for: (1) overall economic output; (2) change in earnings; and (3) employment levels.

The DED economic output multiplier for industrial construction in New York is 1.72. Thus, economic output in the area will increase by $430 million ($250 million x 1.72), of which $180 million is secondary impact.

The regional multiplier for changes in earnings due to industrial construction payroll in the local area, as provided by DED, is 1.71. Thus, earnings in the area can be estimated to increase by $171 million ($100 million x 1.71) of which $100 million is primary payroll and $71 million is secondary earnings impact.

The DED employment multiplier for construction is 1.69 jobs for every new industrial construction job. Thus, on the basis of 620 on-site construction jobs directly associated with the Project, employment in the area is expected to temporarily increase by an additional 1,048 jobs (620 x 1.69).

12.4 Economic Effects of Project Operation

12.4.1 On-Site Operations Employment and Payroll

Stipulation 7, Clause 3(c) requires an estimate of the number of jobs and the on-site payroll, by discipline, during a typical year once the Project is complete, and an estimation of other expenditures likely to be made in the vicinity of the Project during a typical year of operation.

The Project is expected to provide an estimated 40 permanent power plant operator jobs. According to the Bureau of Labor Statistics employment and wage data for 2000 (cited in reference to Table 12-7 above), the annual wage for a power plant operator in the New York City metropolitan area is $61,360. On that basis, the annual on-site payroll is expected to be approximately $2.5 million per year. In addition, local non-fuel annual O&M expenditures are expected to be another $10 million. These expenditures do not include the wages for the operating staff, but do include contracted services, such as security, maintenance of plant and steam operations, and janitorial support, and the costs of chemicals, water supply and treatment, routine inspection and repairs, and forced-outage inspection and repairs.

12.4.2 Secondary Economic Impact Due to Project Operations

This section addresses Stipulation 7, Clause 3(i), which requires an assessment of potential indirect employment and economic impacts associated with the operation of the plant. The stipulation requires that an input-output multiplier be used.

DED's multiplier database has also been used to estimate secondary impacts of Project operation for a typical operating year. Total expenditures in the study area are estimated to be $12.5 million [$2.5 million (payroll) + $10 million (services and supplies)]. The regional output multiplier for electrical services in the study area is 1.32. Thus, output in the area is estimated to increase by $16.5 million per year ($12.5 million x 1.32), of which $4.0 million is secondary impact.

The regional multiplier for changes in earnings associated with utility services payroll is 1.74. Thus, earnings in the area can be estimated to increase by $4.35 million per year, of which $2.5 million is direct payroll and $1.85 million is secondary earnings impact.

The regional employment multiplier is 2.5 jobs for every new job in the electrical industry. Thus, a reasonable estimated employment increase is 100 permanent new jobs, of which 40 jobs are directly generated by TGE and 60 additional jobs are created.

12.4.3 Economic Impact of Energy Cost Savings

The analysis above does not include the economic benefits associated with energy cost savings for individuals and businesses. As detailed in Section 1, the Project is expected to reduce wholesale power costs by an estimated $122 to $198 million in New York State, of which $80 to $110 million will be realized within the Con Edison service area. Translating the Con Edison service area to its New York City component, 90 percent of the savings – $72 to $99 million – will be realized in New York City. According to the 2002 New York State Energy Plan (See Attachment V, State Energy Plan, 2-24), an electricity cost savings of $100 million per year would stimulate approximately 1,600~~1,584~~ jobs in New York, increase the gross output of goods ands services in the state by about $199~~$118~~ million, and increase personal income by about $105~~$104~~ million over a ten-year period. The economic benefits would be sustained because the incremental business profits and consumer purchasing power would carry over into the next year, and increase consumer spending and business investment. Thus, the Project's energy cost savings would be responsible for creating, over time:

- 1,152 to 1,584 permanent new jobs in New York City
- $86 to 118 million per year in economic growth in New York City
- $76 to 104 million per year in increased earnings in New York City.

In conclusion, energy cost savings are important economic drivers. The increase in economic output, personal income, and employment level due to energy price reductions is expected to be much greater than (and is in addition to) the economic benefits of this power plant's construction and operation. This Project is proposed in an area in which potential energy cost savings are high, and the Project will contribute to economic benefits for the region by enhancing the supply of competitive electric generation.

EXHIBIT 6

WATER CONSERVATION BENEFIT

ONE BILLION GALLON PER YEAR SAVINGS

To reduce current water supply demands on the NYC municipal distribution system, process makeup water for the Facility will primarily be satisfied through reuse of dewatering effluent currently pumped from the Brooklyn/Queens Aquifer by the Metropolitan Transportation Authority (MTA) New York City Transit. Dewatering is required by the MTA to control the inflow of groundwater into subway tunnels and underground stations. In Brooklyn, MTA dewatering effluent is discharged to either the East River (a part of New York Harbor) or Sheepshead Bay (a part of Jamaica Bay), depending on station/tunnel location. Under the proposed plan, rather than discharging this groundwater into the East River or Sheepshead Bay it would be used to satisfy more than 90 percent of the Facility's average annual process makeup water requirements for both electrical generation and steam export. Supplemental and backup water for the Facility will be obtained from the municipal distribution system. Indeed, this concept would *reduce* potable water withdrawals compared to present, because potable water that is currently used to produce steam will be displaced by non-potable dewatering effluent. Thus, municipal water demands from upstate reservoir supplies on a system wide basis will decline.

EXHIBIT 7

Table 16-8: NYISO Variable Costs		
Scenario	Total Variable Cost ($000)	Total Savings ($000)
No TGE	4,571,863	--
Case 1	4,422,654	149,208
Case 2	4,527,715	44,148
Case 3	4,546,222	25,641
Case 4	4,554,368	17,494

16.4 Electric Transmission System Benefits

The September 15, 2004 Order required the Applicant to submit:

> Documentation to support claimed benefits such as voltage support, congestion relief, and line loss reductions, including a thorough analysis of technological alternatives that could achieve comparable benefits.

This section of the Amendment demonstrates that constructing and operating the proposed Facility at the Bayside site will benefit New York State and the New York City metropolitan area by: 1) adding reactive power and voltage support capability; 2) reducing transmission line losses throughout New York State; and 3) reducing congestion at the transmission interfaces throughout the Hudson Valley in upstate New York. In addition, an evaluation of technological alternatives that could achieve comparable benefits is provided. The reasonable alternatives examined were not found to deliver comparable benefits.

16.4.1 Reactive Power and Voltage Support

Transmission and distribution of electrical power requires both real and reactive power. Whereas real power (MWs) is necessary to perform work (for running motors, lighting, heating, etc.) reactive power is also an essential part to support the voltage. Any deficiency in reactive power will result in reduced import capability at best and/or low and depressed voltages. A major shortfall would cause a blackout. A very good non-technical description on reactive power and its importance to electric power system operation as well as comments by various industry experts may be found in a New York Times newspaper article[3] (see Attachment B at the end of this section). Following the August 14, 2003 blackout, the North American Electric Reliability Council (NERC) advised all control areas and reliability coordinators to "ensure sufficient voltage support for reliable operations," followed by a list of seven specific actions related

[3] "Elusive Force May Lie A Root of Blackout", by Richard Perez-Pena and Eric Lipton, The New York Times, Tuesday, September 23, 2003, pA20.

thereto.[4] The consequences of not paying sufficient attention to reactive power and voltage support for reliable operation is underscored by the following quote directly from the referenced document:

> FirstEnergy and ECAR failed to assess and understand the inadequacies of [FirstEnergy's] system, particularly with respect to voltage instability and the vulnerability of the Cleveland-Akron area, and [FirstEnergy] did not operate its system with appropriate voltage criteria and remedial measures. [FirstEnergy] did not monitor and manage reactive reserves for various contingency conditions as required by NERC Policy 2, Section B, Requirement 2.[5]

With an electric power system that imports a fairly large amount of power from outside, such as the system serving the New York City Metropolitan area, providing sufficient reactive support, by having sufficient generating supply in New York City, is a very important engineering consideration. Another key aspect of reactive power is that it needs to be as local as possible. In other words, in an alternating current system such as the Eastern Interconnection, it is not possible to depend on the reactive power support from remote locations using transmission lines. Thus, any addition to the reactive capability and the reserve margins within New York City, by locating new generation within the City, is beneficial and contributes to the reliability and economic operation of the electric power system.

Table 16-9 indicates the reactive power capability of the six generators at the proposed TGE Facility:

Table 16-9: TGE Reactive Power Ratings

Generator ID	Reactive Power Ratings (MVAR)	
	Maximum	Minimum
TGECT1	104	-75
TGECT2	104	-75
TGECT3	104	-75
TGECT4	104	-75
TGEST1	75	-56
TGEST2	75	-56
Total	**566**	**-412**

Source: Attachment-3 to September 5,2003 TGE Response to DPS-ECS-3, dated August 25, 2003.

[4] "Near-Term Actions to Assure Reliable Operations", North American Electric Reliability Council, dated October 15, 2003. (Attachment B).

[5] U.S.-Canada Power System Outage Task Force, Final Report on the August 14,2003 Blackout in the United States and Canada: Causes and Recommendations, P17, Column #2.

The positive MVAR (maximum) indicates reactive support from the generators to the system. The negative MVAR (minimum) indicates that the generator can also absorb reactive power during minimum load conditions. In a system with large amount of underground cable such as New York City, a large amount of reactive power is generated during low load conditions. This excessive amount of reactive power, if left uncontrolled/unabsorbed, can cause unacceptable high voltages in the system. The negative MVAR of the generators indicates the extent to which these generator units can absorb the reactive power. Further, the generators provide a continuous (called dynamic control) control of voltage (and consequently reactive power). Thus generators can quickly respond to system contingencies and quickly provide the reactive support (or absorption as the case may be) and control the voltages to the set points by the operators. Transmission lines proposed to deliver energy to New York City cannot absorb reactive power or provide continuous voltage control, nor quickly respond to system contingencies involving high voltages.

16.4.2 Transmission Line Loss Reductions

Losses and congestion are fundamental aspects of operating an electric system. Accounting for the cost of losses and congestion is the basis for Locational Based Marginal Prices (LBMP). LBMP is the cornerstone of the NYISO, PJM and ISO-NE deregulated energy markets.

The NYISO Technical Bulletin #62 (TB 62) on LBMP – "Meaning and Myths" – describes the significance of losses in the following manner:

> Losses are due to the electrical resistance (otherwise, known as impedance) in transmission lines and transformers. Losses incurred are low for generation that is close to load centers compared to generation in regions furthest from the loads. If there were no constraints in New York then the congestion component would equal zero and price differentials would be due entirely to the cost of losses. Generation that is close to load centers is most valuable at these times as the losses incurred in getting the energy to the customers is very low and in some instances the incremental energy will reduce total system losses. Generation in regions furthest from the loads is worth the least as the losses incurred getting the energy to the loads are large. With no congestion, if the LBMPs were $40/MWh in the West and $50/MWh in New York City, then a New York City Zone generator bid of $50 would be considered equivalent to $40 generator bid in the West Zone. This would account for the $10/MWh cost in losses to transport the energy from the West. (NYISO Technical Bulletin #62, page 1.)

The load center for New York is generally New York City and Long Island areas. As noted in TB 62, generation that is close to a load center results in fewer losses than generation that is located further from the load center. The proposed TransGas Facility will be located in New York City in the biggest load center for the NYISO. As such, when it displaces generation that is outside the load center it also reduces the losses that otherwise would be incurred in delivering the energy from generators that are located further from New York City.

It is possible to estimate the amount of losses that are saved as a result of adding the proposed TransGas Facility by using a combination of information on the marginal losses within the NYISO and the MAPS modeling results.

The estimate of marginal losses is included in the NYISO's LBMP values. The NYISO calculates an LBMP for each generator and for each of the NYISO load zones. The generator specific LBMPs are used for payments to generators, The zonal LBMPs are used for charging loads for the energy they consume. The load zones within the NYISO have been defined on the basis of transmission interfaces that are within the NYISO. Figure 16-1 shows the NYISO Zones and the transmission interfaces that connect the Zones.

TB 62 describes the meaning of LBMP as follows:

> In mathematical terms locational prices are calculated using the following equation:
>
> $Pi = Pref + LI\ Pref + \Sigma j\ \Sigma k\ SPjk\ SFjki = \mathbf{Energy + Losses + Congestion}$
> where,
> Pi = Locational price at Bus i;
> Li = Marginal loss factor at Bus i;
> Pref = Locational price of energy at the reference bus;
> SPjk = Shadow price of constraint j in contingency k; and
> SFjki; = Shift factor for real load at Bus i on constraint j, in contingency k.
>
> This equation separates the locational price into the price of energy at a reference bus (Pref), the cost of losses relative to the reference bus (LI Pref) and the cost of congestion, also relative to the reference bus ($\Sigma j\ \Sigma k\ SPjk\ SFjki$).
>
> As the first term of the equation shows, the locational price of energy at the reference bus is used in calculating the LBMP for all other locations across the state. The loss and congestion components at the reference bus, by definition, are zero. At other buses, the transmission grid determines the losses, and transmission constraints determine congestion values. TB62, page 1.)

Using LBMP data, it is possible to estimate the loss component from any generator or zone in the NYISO relative to the reference bus. The reference bus for the NYISO is the Marcy South bus. Table 16-10 shows the average marginal loss component for each Zone's Day Ahead Market LBMP for the period September 2003 through August 2004. The table also shows the marginal loss from the Zone to New York City Zone (Zone J).

Table 16-10: NYISO Marginal Losses

New York ISO Zone		Marginal Losses Relative to Proxy Bus (%)	Marginal Losses Relative to NYC Zone (%)
A	West	9.1	17.5
B	Genese	3.6	11.9
C	Central	3.1	11.4
D	North	1.6	9.9
E	Mohawk Valley	-0.4	7.9
F	Capital	-4.7	3.6
G	Hudson Valley	-5.2	3.2
H	Millwood	-5.6	2.7
I	Dunwoodie	-7.1	1.2
J	NYC	-8.3	0.0
K	Long Island	-8.7	-0.3

The MAPS model is able to produce the energy flows across each of the interfaces between the zones. Using the MAPS data presented in this Amendment on energy flows between the zones, and the marginal loss values between the zones, it is possible to estimate the savings in losses associated with adding the proposed TransGas Facility. This analysis is presented in Table 16-11 for the proposed Facility located at the Bayside site.

Table 16-11: Losses Across NYISO Interfaces (Case 1)				
Interface		Loss (%)	Change In Flow Due To Addition of TransGas (MWh)	Change in System Losses (MWh)
Dysinger East	[Zone A --> Zone B]	5.6	42,406	2,359
West Central	[Zone B --> Zone C]	0.5	5,362	27
Volney East	[Zone C --> Zone E]	3.5	-595,483	-20,646
Moses South	[Zone D --> Zone E]	2.0	-94,992	-1,887
Total East	[Zone E --> Zone F]	4.3	-828,128	-35,558
UPNY/SENY	[Zone F --> Zone G]	0.5	-1,995,595	-9,666
UPNY/Con-ED	[Zone G --> Zone H]	0.4	-2,852,970	-12,626
Millwood South	[Zone H --> Zone I]	1.5	-2,852,687	-42,819
Dunwoodie South	[Zone I --> Zone J]	1.2	-2,225,365	-27,175
Con-Ed/Lilco	[Zone J --> Zone K]	0.3	69,865	231
			Total Loss Savings (MWh)	**147,760**

The final step is to combine the loss savings with an approximation of the reference bus energy price. The MAPS runs show a price of approximately $35/MWh for the area of Marcy South. This results in an annual savings to the statewide electric system of approximately $5.2 million due to operation of the proposed TransGas Facility.

16.4.3 Congestion Reductions

As noted above, congestion is also a critical determinant of the LBMP for a location. Congestion occurs any time that transmission limits prohibit the loads being served by the least expensive generators in the NYISO (adjusted for loss impacts). The NYISO describes it as follows:

> A constraint occurs when the energy flow on a transmission line is limited due to the generation dispatch pattern or the possible re-routing of energy due to a contingency. When a constrainit occurs, energy to serve the load must come from other locations that are not binding. The cost of congestion is determined by the shadow price of the constraint and the real power shift factor on the constraint to serve load. Shadow prices and shift factors are incremental shifts of costs or power for constraints caused by contingencies. (NYISO TB 62, pages 1-2.)

Congestion can result from persistent factors such as an inability to deliver all the economic energy across an interface. It can also result from reduced transfer capability that results from transmission outages. Congestion has been a prevalent factor for the NYISO. (See NYISO, Power Alert III, pages 29-31). However it is not possible to estimate congestion by looking at historic data because the level of congestion is highly dependent upon the level of loads and the generators that are available to meet the loads. Load is expected to grow significantly between now and 2008 and the generation that will be available in 2008 is significantly different from the generation that has been available since the NYISO began operating.

It is possible to get a rough idea of the reduction in congestion by adding the proposed TransGas Facility from the MAPS model results. Adding generation close to the load center reduces the need to import energy to the load center and therefore can reduce the frequency of the transmission interface binding. MAPS can accurately model the congestion that is caused by transmission limits on the interfaces because it explicitly models the interfaces. The MAPS runs modeled interface flows for the four Hudson Valley interfaces (UPNY/SENY, UPNY/Con Edison, Millwood South, and Dunwoodie South) as presented in Figures 16-2 to 16-3, respectively, for the Facility operating at the Bayside site. Each of the figures shows the 2000 hours with the heaviest utilization of the interface.[6] As the figures show, the loading of each interface is significantly reduced by the operation of the proposed TransGas Facility. The UPNY-SENY interface is the most binding with the flat portion at the top of the figure showing cases where the interface was constrained and therefore would not allow all the economic energy to flow. With the addition of the proposed TransGas Facility, the number of hours that UPNY-SENY is constrained, and therefore being congested, is reduced from 646 hours to 424 hours. Consequently, the addition of the proposed TransGas Facility would reduce the hours of congestion for the UPNY-SENY interface by roughly one-third.

MAPS cannot accurately capture the congestion that will result from random transmission line outages. With the proposed TransGas Facility, the system would be less likely to become congested due to a transmission problem because there would not be as much demand for the transmission capability, given the reduction in flows with the proposed TransGas Facility operating.

The cost savings associated with reducing the congestion as a result of adding the proposed TransGas Facility is incorporated into the MAPS results of zonal price reductions and in the total production costs savings.

[6] Each hour that is modeled in MAPS represents two hours of actual operation.

EXHIBIT 8

CAPACITY COST SAVINGS

Q. Have you provided an updated estimate of the installed capacity market savings?

A. Yes. Our estimate builds upon the analysis presented by Dr. Carl Pechman in his testimony. We make five changes to Dr. Pechman's analysis. First, we have adjusted the values of both the existing demand curve and the savings to account for how the savings change as the New York City capacity requirement grows from its current level to the level that is consistent with the 2008 forecast peak load.

Second, we only show results for between 0% and 50% of the capacity being under long term bilateral contracts.

Third, we use the NYISO's year two installed capacity demand curve to estimate the installed capacity market savings.

Fourth, we include savings associated with the winter capability period.

Fifth, we represent the curve in terms if Installed Capacity rather than Unforced Capacity to avoid the confusion of having to convert both prices and quantities from Installed Capacity values to Unforced Capacity values.

Q. What are the results of your analysis?

A. Exhibit ___ MY-1 presents the estimate of the summer and winter capability period savings associated with adding TGE as a function of the amount of capacity under long term contract and the amount that the capacity in the market exceeds the minimum in-City installed capacity requirement. The winter capacity savings are based upon the assumption that the aggregate winter ratings of the in-City units (with the exception of TGE) are approximately 750 MW more than the units aggregate summer ratings.

Q. How does this translate to a savings estimate in this case?

A. The addition of the three units that are currently under construction (Poletti – 500 MWs, East River Repower- 122 net MWs, and Keyspan Ravenswood 250 MWs) will add approximately 872 MW of new summer capacity. The capacity requirement is also growing from current levels. As noted above, current New York City minimum installed

capacity requirement is slightly over 8800 MW. Current installed capacity markets for New York City have essentially been clearing at the minimum requirement.

Schlissel-Keith projected the 2008 New York City peak loads at 11,935 MW. This translates to a minimum installed capacity requirement of almost 9,550 MW in 2008 assuming that the in-City requirement remains at 80% of the in-City peak load.

Consequently, forecast peak load growth between now and 2008 absorbs all but 122 MWs of the capacity that results from adding the Poletti Repowering, East River Repowering, and the Keyspan Ravenswood plants that are currently under construction. If we conservatively look at the savings based upon having 200 more MW than the minimum requirement from these units, and TGE is the only additional unit built and all capacity is valued based upon the demand curve then the addition of TGE will save approximately $458 million in Summer capacity costs and $355 million in winter capacity costs for a total savings of $813 million. If 40% of the in-City capacity is under long term contracts then the savings will be $271 million in Summer capacity costs and $216 million in winter capacity costs for a total savings of $487 million.

Q. **How will the capacity market savings change if the transmission line to Bergen 2 were completed and Bergen 2 became an in-City capacity resource, the SCS Astoria Energy capacity that was under contract was completed or the Reliant Astoria Repowering was completed?**

A. Each of these changes individually would add between 500 to 600 MW of additional capacity to the City. This would reduce the capacity market benefit provided by adding TGE but would still result in a capacity market benefit. If we assume 600 MW of additional capacity from these sources then the in-City capacity exceeds the minimum requirement by 800 MW before the addition of TGE. In this case the addition of TGE will save approximately $418 million in Summer capacity costs and $82 million in winter capacity costs for a total savings of $500 million. If 40% of the in-City capacity is under long term contracts then the savings will be $264 million in Summer capacity costs and $52 million in winter capacity costs for a total savings of $316 million.

Q. **What happens if two of these units are added between now and 2008 for a total additional capacity of 1200 MW?**

A. If we assume 1200 MW of additional capacity from these sources then the in-City capacity exceeds the minimum requirement by 1400 MW before the addition of TGE. In this case the addition of TGE will save approximately $153 million in Summer capacity costs and $0 million in winter capacity costs for a total savings of $153 million. If 40% of the in-City capacity is under long term contracts then the savings will be $100 million in Summer capacity costs and $0 million in winter capacity costs for a total savings of $100 million.

Q. **Would the capacity market savings change significantly if there were higher growth in peak loads than Con Edison is currently predicting?**

A. Yes.

Q. **Is there any reason to believe that the current forecast may understate load growth?**

A. Yes. The 11,935 MW forecast for 2008 New York City peak load is only 915 MW higher than the 11,020 MW forecast for summer 2003. This represents a load growth of only 1.6% per year. Con Edison's growth in energy demand for the last ten years has averaged over 2%/year. Peak load growth has been growing at an even faster rate. In early 2000, the NYISO forecast the in-City temperature adjusted peak load for summer 2000 at 10,340 MW.[1] In early 2003, the forecast for the summer 2003 in-City temperature adjusted peak load was 11,020 MW. This translates to a 2.15%/year growth in in-City peak load.

Q. **Has Con Edison noted the robust growth in peak demand?**

A. Yes. Con Edison commented on it in their 2002 annual report as follows:

> In the summer of 2002, with the weather warmer than usual, Con Edison of New York experienced five of the ten highest summer peak load days in our history. The high loads came even at a time of relatively slow economic growth, and

[1] The forecast is based upon the transmission owners own forecasts of the temperature adjusted peak loads.

reflected increased reliance on appliances such as computers and air conditioners. Record electric demand continued into the winter.

(Con Edison 2002 Annual Report, Page 9.)

While the summer 2002 loads were impacted by the high temperatures that summer, the NYISO forecast for 2003 is based upon temperature adjusted conditions. The Con Edison report is also significant because the load growth was during a period of relatively slow economic growth. It now appears that the economy is picking up. Therefore, recent electricity load growth may well understate future load growth unless consumers' appetites for appliances such as computers and air conditioners abates significantly.

Q. **What impact would higher load growth have on the capacity savings?**

A. A 2.15% peak load growth would result in a New York City peak load in 2008 of approximately 12,250 MW rather than the 11,935 MW that is included in the Schlissel-Keith testimony. Under the higher, recent, load growth assumptions, the installed capacity requirement in 2008 would be 9,800 MW rather than the 9,550 presented above.

Q. **How significant is the additional 250 MW for capacity market savings?**

A. The exact impact will depend upon the amount of capacity in the market but the approximate increase in savings will be somewhere above $50 million/year in addition to capacity savings based upon original load growth.

RELIABILITY BENEFITS

Q. **At p. 45 of the Schlissel-Keith direct testimony, they state that "there is no evidence to support the claim that the transmission system is unreliable or less reliable." Does TGE's Article X Application or your direct testimony make that claim?**

A. No they do not. The Panel does not provide any citations to the representations they attribute to TGE. This point is important because the Panel proceeds to establish a straw argument and then purports to knock it down. The Panel does not address NYC's reliance on the more vulnerable imports that is discussed in the Younger direct testimony

F2.12 TGE RESPONSE TO REQUEST FOR INFO AFTER WORLEYPARSONS' MARCH 31, 2006, PROJECT REVIEW MEETING WITH THE CORE TASK FORCE

[REDACTED]

G

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Long Term Con Edison Steam Production Options Study - Phase 1

Final Report Appendix G

Ravenswood Steam Plant Evaluation

Prepared for

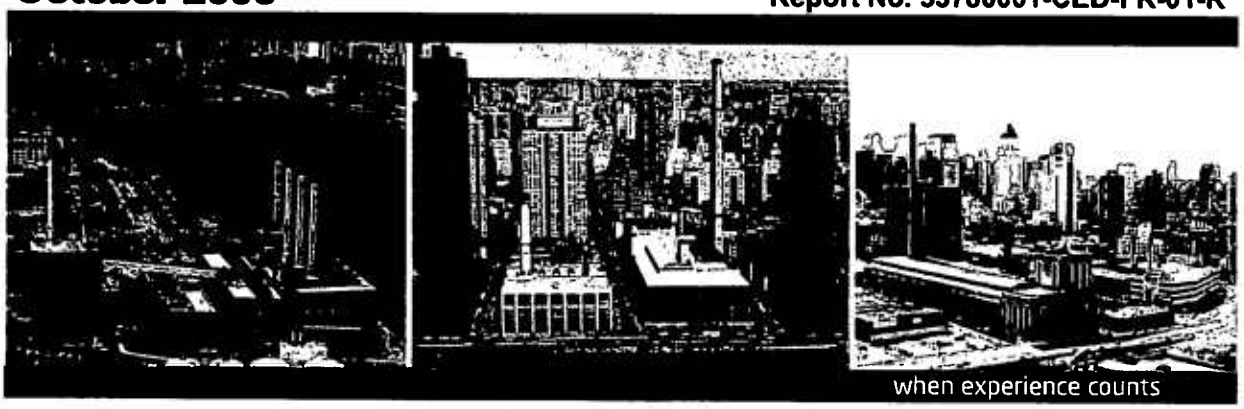
Consolidated Edison Company of New York, Inc.

in conjunction with the

Steam Business Development Core Task Force

October 2006

Report No. 53780001-CED-FR-01-R



NOTICE

This report reflects the work performed by WorleyParsons, using technical and financial inputs provided by Consolidated Edison and others, relating to the existing condition, environment, energy demands, and other data from selected Consolidated Edison Steam Generating Stations and other steam and power generating facilities. The report is based also on information, facts, assumptions and representations provided by Con Edison and others, which have not been independently verified by WorleyParsons, and is provided solely for information purposes, and there is no representation or warranty, expressed or implied, regarding for the fairness, accuracy or completeness of the information. The information also represents WorleyParsons understanding of an approach to potential feasible Projects that will provide the most economic solution; however, every possible combination or scenario has not been considered, and no liability, howsoever arising, is or will be accepted by WorleyParsons for the fairness, accuracy or completeness of the information contained in, or any omissions from, the report, or any other information supplied or made available regarding the Project, in writing or orally, in connection with any decisions to be taken by Consolidated Edison with respect to a proposed Project, or for the consequences of any reliance upon, or other use of, any such information or the report. WorleyParsons does not take direct responsibility for decisions which are based on the findings and results presented herein. Consolidated Edison, or any other third person is responsible for making its own decisions, and we cannot predict the actions of third parties whose actions may be required to execute projects discussed herein.

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Terminology

ADI	Applicability Determination Index
AFUDC	allowance for funds during construction
BACT	best available control technology
bar	0.98692 atmospheres
BFW	boiler feedwater
BOP	balance of plant
Btu	British thermal unit
CAMPD	Compliance Assessment Media Programs Division
CERA	Cambridge Energy Research Associates
CO_2	carbon dioxide
EPA	Environmental Protection Agency (United States)
EPC	engineer procure construct
EPCM	engineer procure construct manage
ERRP	East River Repowering Project
°F	degrees Fahrenheit
ft	foot or feet
h, hr	hour
HHV	higher heating value
HP	high pressure (steam)
HRSG	heat recovery steam generator
ID	induced draft (fan)
I&C	Instrumentation and Control
KPPH, klb/hr	thousand lb/h
kW	kilowatts
LAER	lowest achievable emission rate
lb	pound
LP	low pressure (steam)
MACT	maximum available control technology
Mlb/hr, MPH	thousand lb/hr
MOU	memorandum of understanding
MMBH	million Btu/hr
MMlb/hr, MMPPH	million lb/h
MM	million
MMSCFD	million standard cubic feet per day
MP	Medium pressure (steam)
MW	megawatts
MWH	megawatt-hours
NESHAP	National Emission Standards for Hazardous Air Pollutants
NSPS	new source performance standards
NSR	new source review
OECA	Office of Enforcement and Compliance Assurances
OEM	original equipment manufacturer
O&M	operation & maintenance
OTR	ozone transport region
PFD	process flow diagram
PSD	prevention of significant deterioration
psi	lb/square inch (14.696 psi = 1 atm)
Q	heat
RACT	reasonably available control technology
S	Sulfur content of fuel
SCFD	standard cubic feet per day
SPDES	State Pollutant Discharge Elimination System
T&D	transmission & distribution (electrical)
ST	steam turbine
t	ton (2000 lbs)
TCLP	toxicity characteristic leaching procedure
t/h	tonne/hour
ton	short ton, (2000 lbs)
tpd	ton per day
US, U.S.	United States
USD, US$	the United States Dollar
VSD	variable speed drive
y, yr	year
ZnO	zinc oxide

G1.0 EXECUTIVE SUMMARY

WorleyParsons Group, Inc. performed an evaluation of the Con Edison Ravenswood Steam Plant (A House) as part of the Phase 1 Steam Production Cost Study of long-term steam production options in support of Con Edison and the Steam Business Development Task Force. The objective of the Ravenswood evaluation was to estimate the cost of steam production for eight boiler rebuild and replacement options as follows:

- Rebuild one, two, three, or all four of the existing boilers (4 options)
- Replace one, two, three, or four of the boilers with new boilers of the same design capacity as the existing boilers (4 options)

In both cases, the existing boilers that are not rebuilt or replaced will be retired in place.

The tasks for accomplishing the objective included the following:

- Assess the condition and operation of the existing facility based on information collected from Con Edison during a facility tour and meetings with Con Edison engineering and plant personnel.
- Evaluate the necessity for conversion of the boilers for the rebuild options to natural gas fired considering applicable environmental regulations.
- Determine if residual oil or distillate oil must be used as backup fuel for natural gas-fired applications considering applicable environmental regulations.
- Estimate the cost of steam production for each of the four (4) rebuild and four (4) replacement options over the 20 year study period;
- Estimate the impact of the rebuild/replacement options on emissions;

This report describes the activities and results of the evaluation.

The key results of the study are summarized as follows:

- [REDACTED]

- For all options, natural gas is used as the primary fuel for the boilers because the expected emissions with residual oil as the primary fuel would exceed applicable environmental regulatory requirements.
- Residual oil (0.3% sulfur No. 6 oil) can be used as the back-up fuel based on 30 days per year operation for all options at the projected [REDACTED] annual steam sendout capacity factor provided by Con Edison for the study. For the four (4) boiler replacement option, the plant would have to operate at an annual

steam sendout capacity factor of [REDACTED] or lower to not trigger Prevention of Significant Deterioration/New Source Review (PSD/NSR) which would prohibit the use of residual oil as the back-up fuel because of the resulting increase in annual PM10 emissions.

G2.0 ECONOMIC AND ENVIRONMENTAL CRITERIA

G2.1 FUEL AND POWER PRICE ASSUMPTIONS

The fuel and electricity price assumptions for the Ravenswood Steam Plant evaluation are the same as described for the evaluation of the other Phase 1 study options. The prices used in this evaluation were based on the CERA Rear View Mirror Scenario.

G2.2 ENVIRONMENTAL FRAMEWORK

The environmental framework for the Ravenswood Steam Plant evaluation was the same as for the evaluation of Repowering options for the other Con Edison steam generation facilities in the Phase 1 study. However, the specific environmental regulatory requirements of NSPS, NESHAP, and PSD/NSR as they apply to the Ravenswood Steam Plant were used considering the location of the plant and the actual emissions of the existing boilers as provided in Emissions Statements by Con Edison.

G2.3 FINANCIAL ASSUMPTIONS

The economic and financial assumptions used for the evaluation of the Ravenswood Steam Plant were the same as used for the evaluation of the repowering options at the other Con Edison steam generation facilities.

G2.4 CAPITAL COST DEVELOPMENT

The capital costs for the rebuild and replacement options were estimated by WorleyParsons considering inputs provided by Con Edison. The methodology of developing capital costs for the evaluations was similar to that described for the evaluation of repowering options for the other Con Edison steam generating facilities in the Phase 1 study.

Estimates of capital costs associated with continued operation of the facility and rebuilding of the boilers for a continued operational period of 20 years were developed by WorleyParsons based on the tour of the Ravenswood Steam Plant, discussions with Con Edison engineering and plant personnel, and documentation provided by Con Edison with respect to results of equipment condition assessments. The boiler rebuilds would basically include a complete retubing, refractory repair, and casing repair. Capital cost estimates for boiler rebuilds were based upon a survey of boiler repair companies, WorleyParsons partnership in Tennessee that performs boiler repair work for TVA, as well as one of WorleyParsons maintenance managers at an operating

facility. The rebuild cost estimate developed by WorleyParsons was then compared to estimates provided by Con Edison, and the overall costs were found to be within about 10%. WorleyParsons' estimates were based upon a walkdown of the Ravenswood Steam Plant and no dismantling or internal inspections were performed. The accuracy of the estimates is plus or minus 30%.

A review was conducted of the Con Edison provided estimated Ravenswood O&M Costs and Capital Improvement Costs. The O&M Costs at the Ravenswood Facility are based upon Con Edison having a contract in place with KeySpan, who provides operators whenever there is a need. It is WorleyParsons understanding that the contract value is approximately $4 million/year of which approximately $1 million is given back to Con Edison's Maintenance Services Department, who is contracted for A-House Maintenance. Based upon these data and the cost for O&M for other facilities of similar size, this is very consistent with O&M Costs. WorleyParsons comparisons are based on known O&M contracts with third party operators and their approximate costs. An [REDACTED] annual cost was [REDACTED] to account non-fuel consumables costs.

G3.0 ASSESSMENT OF RAVENSWOOD STEAM PLANT

This section describes the methodology and basis for the study, including preliminary findings of the plant visits.

G3.1 METHODOLOGY

In order to assess the physical conditions and identify the operational issues of the existing equipment at the Ravenswood facility, WorleyParsons took the following approach:

- Met with the Core Task Force to discuss and finalize the scope.
- Met with Con Edison personnel and reviewed the information provided by Con Edison
- Toured the Ravenswood Plant including a physical walkdown and meetings with the Operating/ Maintenance Personnel and Technical/Engineering Personnel to discuss site specific issues; and
- Interviewed Con Edison corporate and plant personnel, including Engineering, Environmental, and Financial disciplines to have a better understanding of the current and future modes of operations of these facilities.

The results of the assessment are presented in the following sections. However; it is noted that WorleyParsons' assessment is solely based on the review of the documents, physical walk down of the facilities, and various interviews as noted above. It did not include any independent verification of the conditions of the existing equipment and facilities.

G3.2 DOCUMENTS/DATA REVIEWED

The following documents / data provided by Con Edison were reviewed as part of the assessment of the existing plants and operations:

- Steam Sendout Data from 2003.
- Projected Steam Dispatch Profile and Capacity Factor for the eight options.
- Condition Assessment Report of existing Boilers

- Tube Failure Report of the existing Boilers
- Waldron Study Report for replacing existing boilers[1]
- Future Capital & O&M Cost projection, cash Flow and Tax data
- Black Start Procedure
- A-House Performance Test Data
- Existing Boiler Performance Data
- Existing and Replacement steam turbine drive data sheets

G3.3 RAVENSWOOD STATION ASSESSMENT

G3.3.1.1 Performance Issues

The design gross and net capacity of the Boilers and the Plant are shown in Exhibit 3-1.

Exhibit 3-1 Ravenswood Plant Boiler Capacities

Description	Value (lb/hr)
Gross Capacity, Each	[REDACTED]
Auxiliary Steam Consumption	[REDACTED]
Net Send Out Capacity, Each	244,000
Net Design Facility Send Out	976,000

The boilers have suffered measurable performance degradation over the years. Factors contributing to the performance degradation include fouling in the tubes from water chemistry problems; air-in leakage; draft; fan problems due to deteriorated exterior brick, refractory, insulation, and casing; and interior tile/refractory baffle walls.

is due to the fouling in the tubes from water chemistry problems. Boiler no #3 has been shut down since 2001 due to various maintenance issues.

Presently, the boilers are operating below their original design efficiency. Based upon the recent performance test data, the efficiencies of Boilers 1, 2 & 4 are noted to be 73%, 78.5% and 77.7%, respectively, compared to the original design efficiency of about 80.7%.

All boilers are currently operating about 20% to 30% below their design capacities due to the tube fouling problems, with Boiler #1 suffering the maximum derating. The boilers needs either rebuilding or replacement to provide reliable efficient steam supply over the future years.

---

[1] Ravenswood Steam Plant Study, Final Report. Prepared by Waldron Engineering for Con Edison. May 2006.

G3.3.1.2 Operation and Maintenance Considerations and Issues

- The Boiler house is very compact and does not have much room for equipment additions and major maintenance.
- Fuel is supplied by KeySpan from a stationed barge adjacent to the site.
- The water for the boiler make-up comes from an open pond that receives water from the city water system. The water off-take from the pond is such that currently the plant can make use of only about one-third of the total pond storage capacity of about 750,000 gallons. This needs to be changed to have access to the currently unused water storage.
- There is currently no water treatment system at the site, and the only chemistry control is by chemical addition and blow down from the boiler drums. The untreated water has caused numerous tube plugging and consequently derating of the boilers and requires periodic cleaning.
- Boiler #3 has not been operated since 2001 due to problems holding water.
- Boiler steam carryover does not appear to be a problem.

G3.3.1.3 Site Specific Considerations, Issues, and Constraints

- Boilers #1, #3, and #4 were originally built in 1947, Boiler #2 was installed in 1962. They are field erected boilers with wide space tubes enclosed by brick walls with a steel plate casing. Boilers are balanced draft with single FD and single ID fan per boiler. Fans are steam turbine driven.
- There are two stacks, one for Boilers #1 and #3, and one for Boilers #2 and #4.
- There are 6 burners per boiler on the front wall firing low sulfur #6 oil with Class 1 gas fired igniters. The igniters are fired continuously and have a heat input equivalent to about 10% steaming capacity of the boilers. New burners would be required for conversion to natural gas as the primary fuel.
- There are three (3) new steam turbine driven boiler feed pumps. Plant personnel are of the opinion that the three (3) new feed pumps can support a design steam send out rate of [REDACTED]. WorleyParsons agrees with this assessment based on the review of the boiler feed pump performance data sheets.
- Plant is "Black Start" capable by back feeding steam from the steam main to the turbine drives. Minimum steam pressure required for "Black Start" is 100 psig.
- A new deaerator was installed in 2005.

- There is a 20" main carrying the steam to the Head House and over to Manhattan. Steam flow rate through this main is limited to 860,000 lb/hr maximum due to piping restrictions at 71st Street and at the 74th Street Generating Station in Manhattan.

- There is still some asbestos in the Ravenswood A-House. The facility operating/maintenance personnel estimate that the A-House is 80% asbestos free.

- Rebuild according to Con Edison would mean:
  - Replace all pressure parts except for the drums, wind box burners, and ducts;
  - Replace feed water piping.

- According to Con Edison the main steam piping is in good shape and does not need to be replaced.

- The existing A-House Building was built in the late 1940s. Drawings for the building are dated 1947. The main portion of the A-House is concrete frame construction with metal siding (reported to have been replaced in 1999). The fan rooms on the north and south ends of the building and the pump room on the east side are one-story steel frame construction. The roof structure is steel trusses with a concrete roof deck and a rubber roof with a stone protective covering. It was reported that the roof will be replaced in 2006 with construction to begin later in June. The steel chimneys are on the centerline of the building on the north and south ends outside the fan rooms

- Roof plan area of the main boiler house is approximately 90'-1"(east-west) x 96'-10 ½". Centerline of column dimensions are approximately 86'-10" x 93'-9". The six roof trusses span east west on 18'-9" centers creating 5 bays. The end roof bays are braced bays and the center bay trusses support the deaerator. It appears that the roof over the 2nd and 4th bays could be removed for construction access.

- The intermediate columns on the north and south ends do not appear to be supporting the end roof trusses. These columns do not end on truss panel points and there is a gap between the truss and the column over at least part of the area of the column. This indicates that the intermediate columns can be removed if necessary to install equipment without disrupting the building structural

- The internal steel structure in the building is independent of the building structure and consists of platforming and pipe supports. It appears logical to demolish this steel and construct new platforming and pipe support structure in the appropriate locations for the new boilers rather than trying to reuse the existing structure

- There is adequate room to the north and south of the boiler house to perform minor assembly tasks on the new boilers. The new package boilers would be

shop fabricated to the maximum extent possible based on vendor design, but some minor site assembly may be required. Any assembly required would be performed outside of the boiler house while the existing boilers are demolished and then skidded into place. Platforming and piping would then be installed. Units 3 & 4 boilers could be assembled immediately outside of their final location. Because the control room is just to the south of the Unit 2 boiler, the new Unit 2 boiler would have to be assembled to the north of the boiler house while both the Units 1 & 2 boilers were demolished. It would then be skidded through the Unit 1 position along the length of the boiler house to its final location at the south end of the house. Unit 1 would then be installed in its location.

- The above construction method would require the removal of the associated fan and fan pedestal. The pedestal would have to be reconstructed and the fan reinstalled. The Unit 2 fan and pedestal would not have to be removed.

- It is likely that all the boilers and most piping are contaminated with asbestos. Based on the age of the units, asbestos is likely in the boiler refractory and much of the piping insulation is not labeled as asbestos free.

G3.3.2 Current and Forecast Steam Production

Based upon the data provided by Con Edison, the steam sendout from this plant over the last three years are summarized below:

Year	Annual Steam Send Out Mlb
2005	994,236
2004	1,091,293
2003	1,186,607

Based upon the above data, there has been about 16% reduction in the total steam sendout in the last two years. The average hourly steam sendout is about 113,500 pph based upon 2005 sendout data, with an annual capacity factor of about 20%.

For the various repowering Options, Con Edison contemplates a maximum net sendout of 976,000 PPH. Based upon the projected demand profile provided by Con Edison, the projected annual capacity factor is about [REDACTED]. Based upon the discussions with Con Edison, the same capacity factor will be used for all repowering Options.

G4.0 REPOWERING EVALUATION

G4.1 RE-POWERING OPTIONS CONSIDERED

Based upon the scope of works a total of eight (8) re-powering Options consisting of four(4) rebuilt and four (4) Replacement Boiler options were considered.

- **Rebuild Boiler cases :**
  - RB1: Rebuild One (1) Boiler and retire others in place
  - RB2: Rebuild Two (2) Boilers and retire others in place
  - RB3: Rebuild Three (3) Boilers and retire other in place
  - RB4: Rebuild all Four (4) Boilers
- **New Replacement Boiler cases :**
  - NB1: Replace one (1) boiler with a new one and retire others in place
  - NB2: Replace two (2) boilers with new ones and retire others in place
  - NB3: Replace three (3) boilers with new ones and retire the other in place
  - NB4: Replace all four (4) boilers with new ones.

G4.2 CONCEPTUAL DESCRIPTION OF RE-POWERED FACILITIES

The conceptual descriptions of the Re-powering options considered for the Ravenswood Plant are presented below. The summary performance data for various options are presented in Exhibit 4-1, Option Screening Model Table.

Heat balance data from a Waldron report provided by Con Edison were used as a basis for determining the performance of the new boiler cases. WorleyParsons has reviewed the heat balance for steam distribution and felt comfortable using the data for the analysis. Vendor provided boiler efficiency data was used to determine fuel consumption of the new boilers. The heat balance diagram for a new package boiler is shown in Exhibit 4-2, and the expected performance is shown in Exhibit 4-3 under the column heading "A-House NB1 thru 4".

For the rebuild boiler cases, the fuel consumption was calculated based on the assumption that the boilers can be brought back to the original design efficiency of about 80.7%. after rebuilt.

For all these Options, steam generation interruptions shall be minimized.

Exhibit 4-1 Options Screening Model Table Summarizing Performance Data for Ravenswood Steam Plant Repowering Options Evaluation

CONCEPTUAL DATA FOR REALATIVE COMPARISON ONLY[1]

Steam Send Out Based Upon Projected Demand

ITEM	DESCRIPTION	STEAM GENERATION OPTIONS								
		Current Operation	Rebuild Boiler Options[1,2,5]				New Boiler Options[1,2,5]			
			Option - RB1	Option - RB2	Option - RB3	Option - RB4	Option - NB1	Option - NB2	Option - NB3	Option - NB4
A.	Option Description	Based on 2008 Operation on Gas and Oil	Rebuild One (1) Boiler and Retire Three (3) in Place, Gas & No #6 Oil	Rebuild Two (2) Boilers and Retire Two (2) in Place, Gas & No #6 Oil	Rebuild Three (3) Boilers and Retire One (1) in Place, Gas & No #6 Oil	Rebuild All Four (4) Boilers, Gas & No #6 Oil	Install One (1) New Boiler and Retire Three (3) Existing Boilers in Place, Gas & No #6 Oil	Install Two (2) New Boilers and Retire Two (2) Existing Boilers in Place, Gas & No #6 Oil	Install Three (3) New Boilers and Retire One (1) Existing Boiler in Place, Gas & No #6 Oil	Install Four (4) New Boilers, Gas & No #6 Oil
B.	New Configuration Description									
1.	Number of Boilers in Service	3	1	2	3	4	1	2	3	4
2.	Boiler Gross Capacity each, MW/hr	265	265	670	855	1,140	265	670	855	1,140
3	Number of Boilers in Service on Gas		1	2	3	4	1	2	3	4
4.	Number of Boilers in Service on No#6 Oil		1	2	3	4	1	2	3	4
5	Number of Boilers in Service on No # 2Oil		0	0	0	0	0	0	0	0
C.	Net Steam Generation[2,3]									
1	Design Max Capacity MW/hr	795								
2	Annual Average Steam Gen, MMlb									
a	With Gas Firing									
b	With No#6 Oil Firing									
c	With No#2 Oil Firing									
d	Total Steam on all fuels	5524								
3	Annual Avg Hourly Send out, MW/hr	631								
4.	Maximum possible steam send out with all equipment operating simultaneously, MM lbs									
a	With Gas Firing		244	488	732	976	244	488	732	976
b	With No#6 Oil Firing		244	488	732	976	244	488	732	976
c	With No#2 Oil Firing		0	0	0	0	0	0	0	0
7.	Total Max Annual Send Out, MMlb									
a	With Gas Firing									
b	With No#6 Oil Firing									
c	With No#2 Oil Firing									
d	Total Max Steam on all fuels									
D.	Annual Fuel Balance - MMA, Electricity MWhr, Water Consumption MGal and Electricity Consumption/hr									
1	Fuel Consumption Consumption									
a	Natural Gas									
b	No #6 Oil									
c	No # 2 Oil									
d	Total Fuel Consumption									
2	Water Consumption[3]									
3	Elec Consumption[3]									
E.	Total NPV of Plant Cost - US Dollars									
1	EPC Cost									
a	Boiler Plant									
b	Demin Plant									
c	Other BOP									
d	Total EPC Cost									
2	Demolition /Relocation/ Remediation Costs									
a	Demolition Costs									
b	Relocation Costs									
c	Remediation Costs									
d	Total Demolition/Relocation/Remediation Costs									
3	Permitting/Public Engineering									
4	Gas Piping Interconnect Costs									
5	Electrical Reinforcement/Interconnect Costs									
6	Contingency									
7	Owner's other Costs[4]									
8	Total Plant Cost (TPC)									
F.	Total NPV of Annual Costs									
1	Fuel Cost									
2	Fixed Charges on TPC (Debt Services)									
3	Water & Chemical Costs									
4	Electricity Purchase Cost									
5	O&M Costs of existing plant									
6	Non Fuel O&M Costs									
7	Property Taxes & ICAP									
8	ICAP Credit									
9	Total Annual Cost									
G.	Total NPV of Steam Generation Costs (1,000 lbs) based upon Electric Revenue Offset									
1	Steam Generation Cost W/O Emission Credits									
2	Emission Credits on Annual Costs[5]									
a	Nox									
b	SO_2									
c	PM_{10}									
d	$PM_{2.5}$									
e	VOC									
f	CO									
3	Total Credits									
4	Cost Attributed to Steam with Emission Credits									
5	Steam Gen Cost with Emission Credits									
H.	Annual Emissions (TPY)[5]									
1.	NOx									
2.	SO_2									
3	PM_{10}									
4.	$PM_{2.5}$									
5.	VOC									
6.	CO									
K.	Site Specific Constraints									
1.	Layout Constraints									
2.	Stack Issues									

[ALL DATA REDACTED]

See Economic Analysis Model for Details

See Economic Analysis Model for Details

See Economic Analysis Model for Details

[ALL DATA REDACTED]

See Report
None at this site

Notes:

1. The costs and performance data presented herein are based on conceptual level studies. All costs are total NPV based on costs in years 2008 through 2025. All performances are at 69F,60% RH Ambient & Gas Load (ISO) operation and unit-life applicable degradation factors for future years. See Report for additional details.
2. [REDACTED]
3. [REDACTED]
4. [REDACTED]
5. Emissions Factors are Based upon AP - 42 Data. For description of the emission control technologies for the Rebuilt and New boiler cases see Report.
6. Electric consumption is based upon lighting, ventilation and minor equipment loads. All major equipment major equipment (FD/ID fans, Boiler Feed Pumps and Service Water Pumps) are steam turbine driven.

Exhibit 4-2 Conceptual Process Flow Diagram for Package Boilers

[REDACTED]

Exhibit 4-3 Conceptual Package Boiler Performance

[REDACTED]

A new demineralized water treatment system consisting of cation/anion exchangers will be provided. This also includes adding a raw water tank and a treated water tank.

All boilers are natural gas-fired with 0.3% sulfur No. #6 oil (residual oil) as a back up. Results of the evaluation of the expected emissions from the repowering options, considering the requirements of NSPS, NESHAP, and PSD/NSR, as discussed in Section G4.2.3, show that both the rebuilt and replacement boilers must use natural gas as the primary fuel. The results of the evaluation also show that residual oil can be used as the backup fuel for 30 days operation based on the projected annual steam sendout provided by Con Edison for the study. Therefore, the existing residual oil barge storage can be used for the backup fuel for the Ravenswood Steam Plant repowering options. The use of distillate oil as backup fuel would require a new storage tank or other storage facility sized for a maximum 30 days per year usage.

Boilers will be provided with emission control features to comply with various regulatory requirements.

The availability of the boilers is assumed to be 95% based upon industry accepted practice.

G4.2.1 Projected Cost of Steam Production

The projected costs of operation of the repowering options evaluated are summarized in Exhibit 4-4 through Exhibit 4-7. These data are based on the CERA Rear View Mirror (RVM) fuel and electricity price projection scenario. Breakdowns of projected capital costs, annual costs, and cost of steam production by category and by year for each option are shown in Section G7.0 of this Appendix. Exhibit 4-4 shows the net present value (NPV) of total plant costs over the 20 year study period for each option. [REDACTED].

Exhibit 4-5 shows the NPV of total annual costs, excluding emission reduction credits (ERCs). Exhibit 4-6 shows the NPV of total annual costs including emission reduction credits, or the NPV of net cost of steam production.

The ERCs are based on the difference between the expected annual emissions from the options at the projected annual steam sendout (representing a capacity factor of about [REDACTED]), provided by Con Edison, and the current annual emissions of the existing generating station based on emissions statements provided by Con Edison. [REDACTED]..

Exhibit 4-4 NPV of Total Plant Costs for Ravenswood Repowering Options 2006 to 2025

[REDACTED]

Exhibit 4-5 NPV of Total Annual Costs for Ravenswood Repowering Options for 2006 to 2025 Based on CERA RVM Price Scenario

[REDACTED]

Exhibit 4-6 NPV of Steam Production Costs for Ravenswood Repowering Options Including All Credits for 2006 to 2025 Based on CERA RVM Price Scenario

[REDACTED]

Exhibit 4-7 Unit NPV of Steam Production Costs for Ravenswood Repowering Options Including All Credits for 2006 to 2025 Based on CERA RVM Price Scenario

[REDACTED]

Exhibit 4-7 shows the Unit NPV of net cost of steam production; that is, the NPV of net cost of steam production divided by the discounted annual steam sendout over the study period base on the method of discounting approved for the study. This parameter (Unit NPV) is being used as the basis for comparison of alternatives, with the most promising option being that with the lowest Unit NPV. As can be seen in Exhibit 4-7, the four (4) replacement boiler option (NB4) has the lowest Unit NPV.

G4.2.2 Fuel and Electricity Cost Sensitivity Analysis

A sensitivity analysis of the cost of steam production to fuel and electricity price for the options was performed by evaluating the options using the CERA Shades of Green pricing scenario. The results of the evaluation are shown in Exhibit 4-8 and Exhibit 4-9. [REDACTED] has the lowest Unit NPV of cost of steam production using the CERA Shades of Green fuel and electricity pricing scenario also.

Exhibit 4-8 NPV of Steam Production Costs for Ravenswood Repowering Options Including Emissions Credits for 2006 to 2025 Based on CERA Shades of Green Price Scenario

[REDACTED]

Exhibit 4-9 Unit NPV of Steam Production Costs for Ravenswood Repowering Options Including Emissions Credits for 2006 to 2025 Based on CERA Shades of Green Price Scenario

[REDACTED]

G4.2.3 Environmental and Other Permitting Requirements

Exhibit 4-10 and Exhibit 4-11 present new source performance standards (NSPS) and national emission standards for hazardous air pollutants (NESHAP) emission limits in pounds per million Btu heat input (lbs/MMBtu) for liquid and gaseous fuel fired combustion units under the boiler rebuild options (Exhibit 4-10) and the new boiler replacement options (Exhibit 4-11). Also included in this exhibit are the expected emissions in lbs/MMBtu (HHV) for the rebuilt boilers and the new replacement boilers. These emissions are based primarily from AP-42 emission factors.

The NSPS limit for NOx emission rate is different for the natural gas-fired low heat release rate ((i.e., 70,000 Btu/hour-ft^3 or less) boilers than the natural gas-fired high heat release rate boilers. The limit for low heat release rate boilers is 0.1 lb/MMBtu, and the limit for high heat release rate boilers is 0.2 lb/MMBtu. The existing boilers are low heat release rate boilers. New replacement boilers could be either low or high heat release rate design depending on the selected vendor's standard design philosophy. Therefore, the more restrictive limit is shown in Exhibit 4-11. The emissions rates for the new boilers are expected to be less than the NSPS emission rate limit for low heat release rate boilers.

NESHAP regulations for Industrial Boilers include a particulate emission limit of 0.03 lbs/MMBtu with no exceptions for burning very low sulfur oil. The estimated particulate emissions when firing No. 6 oil is 0.0398 lbs/MMBtu. An exception under NESHAP regulations requires that, for all options, natural gas be the primary fuel and that No. 6 oil only be fired during curtailment of natural gas supplies.

Exhibit 4-10 Emissions Requirements and Expected Emissions for Boiler Rebuild Options at Ravenswood Steam Plant

Exhibit 4-8 Emission Requirements and Expected Emissions for Boiler Rebuild Options at Ravenswood Steam Plant

		CO				SO2				PM10				PM				NOx				VOC			
		Lbs/MMBtu		Tons/Year		Lbs/MMBtu		Tons/Year		Lbs/MMBtu		Tons/Year		Lbs/MMBtu		Tons/Year		Lbs/MMBtu		Tons/Year		Lbs/MMBtu		Tons/Year	
		Limit	Expected	Limit	Expected	Limit	Expected	Limit	Expected	Limit	Expected	Limit	Expected	Limit	Expected	Limit	Expected	Limit	Expected	Limit	Expected	Limit	Expected	Limit	Expected
Option - RB1	Natural Gas																								
	No. 6 Oil																								
Option - RB2	Natural Gas	[ALL DATA REDACTED]				[ALL DATA REDACTED]				[ALL DATA REDACTED]				[ALL DATA REDACTED]				[ALL DATA REDACTED]				[ALL DATA REDACTED]			
	No. 6 Oil																								
Option - RB3	Natural Gas																								
	No. 6 Oil																								
Option - RB4	Natural Gas																								
	No. 6 Oil																								

Rebuild Option - RB1 – One boiler rebuilt (assuming lowest "paired" emissions, which includes emissions from one boiler)
Rebuild Option - RB2 – Two boilers rebuilt (assuming highest "paired" emissions, which includes emissions from two boilers)
Rebuild Option - RB3 – Three boilers rebuilt (assuming all "paired" emissions, which includes emissions from three boilers)
Rebuild Option - RB4 – Four boilers rebuilt (Non-operating Boiler 3 actual emissions assumed at zero)

Emission comparison based on current actual emissions to future actual emissions ([REDACTED]).
Tons/Year Limit includes Significant Net Emission Increase requirement

/1/ Based on MACT limit of 400 ppmvd corrected to 3% oxygen
/2/ NSPS limit includes an exception for low sulfur oil (0.3% S).
/3/ MACT limit of 0.03 lbs/MMBtu allows firing of No. 6 oil only during gas curtailment (natural gas primary fuel with No. 6 oil backup)
/4/ NSPS limit of 0.20 lbs/MMBtu requires additional 25% reduction in NOx emissions beyond LNB for No. 6 oil firing. This is accomplished with SCR.

Exhibit 4-11 Emissions Requirements and Expected Emissions for Boiler Replacement Options at Ravenswood Steam Plant

		CO					SO2					PM10					PM					NOx					VOC				
		Lbs/MMBtu		Tons/Year			Lbs/MMBtu		Tons/Year			Lbs/MMBtu		Tons/Year /7/			Lbs/MMBtu		Tons/Year			Lbs/MMBtu		Tons/Year			Lbs/MMBtu		Tons/Year		
		Limit	Expected /1/	Limit	Potential	Expected	Limit	Expected	Limit	Potential	Expected	Limit	Expected	Limit	Potential	Expected	Limit	Expected	Limit	Potential	Expected	Limit	Expected /5/	Limit	Potential	Expected	Limit	Expected /6/	Limit	Potential	Expected
Option - NB1	Natural Gas																														
	No. 6 Oil																														
Option - NB2	Natural Gas		[ALL DATA REDACTED]					[ALL DATA REDACTED]					[ALL DATA REDACTED]					[ALL DATA REDACTED]					[ALL DATA REDACTED]					[ALL DATA REDACTED]			
	No. 6 Oil																														
Option - NB3	Natural Gas																														
	No. 6 Oil																														
Option - NB4	Natural Gas																														
	No. 6 Oil																														

Rebuild Option 1 – One new boiler (existing A-House Boilers shutdown and/or removed)
Rebuild Option 2 – Two new boilers (existing A-House Boilers shutdown and/or removed)
Rebuild Option 3 – Three new boilers (existing A-House Boilers shutdown and/or removed)
Rebuild Option 4 – Four new boilers (existing A-House Boilers shutdown and/or removed)

Emission comparison based on current actual emissions to future potential emissions (i.e., 8,760 hours/year at 100% capacity factor).
Tons/Year Limit includes Significant Net Emission Increase requirement

/1/ Expected emission based on oxidation catalysts: 80% reduction firing natural gas and 50% reduction firing No. 6 oil.
/2/ Based on MACT limit of 400 ppmvd corrected to 3% oxygen
/3/ NSPS limit includes an exception for low sulfur oil (0.3% S).
/4/ MACT limit of 0.03 lbs/MMBtu allows firing of No. 6 oil only during gas curtailment (natural gas primary fuel with No. 6 oil backup)
/5/ Expected emission based on selective catalytic reduction: 70% reduction firing natural gas and 35% reduction firing No. 6 oil.
/6/ Expected emission based on oxidation catalysts: 50% reduction firing natural gas and 25% reduction firing No. 6 oil.
/7/ PM10 emissions for the four replacement boilers would result in NSR applicability. ~80% capacity factor for all four replacement boilers or one boiler with ~40% capacity factor and others at 100% capacity factor would result in emissions below NSR applicability requirements.

The only additional control for the rebuild option is for NOx emissions when firing No. 6 oil to meet the 0.20 lbs/MMBtu NSPS limit [40CFR60.44b(l)(2)]. This requires a reduction beyond AP-42 estimated emissions using only low NOx burners (LNB). Therefore, SCR is added to the rebuild options with a NOx removal efficiency of 25% with oil firing (50% with natural gas firing) to meet the NSPS emission requirement. The emission control equipment and their expected efficiencies for the new boiler replacement options are shown in Exhibit 4-12. The SCR efficiency was based on that required to meet the PSD/NSR limits for NOx based on potential emissions.

Exhibit 4-12 Emission Control Equipment Efficiencies

Control Technology	Natural Gas-Fired	No. 6 Oil-Fired
SCR	70%	35%
Oxidation Catalyst - CO	80%	50%
Oxidation Catalyst - VOC	50%	25%

The tons per year emission limit shown in Exhibit 4-10 and Exhibit 4-11 are the annual emission increases that would trigger PSD/NSR for the rebuild and new boiler options. This limit combines the existing average annual emissions from the A-House contained in the 2004 and 2005 Emission Statements (which are based on AP-42 emission factors except for NOx which is based on CEMS data and particulates which are based on a stack test) and the PSD/NSR Applicability Thresholds presented in Exhibit 4-13:

For the rebuild options, PSD/NSR permitting is based on comparing the future projected actual emissions from the option versus past actual emissions from existing sources being retired. For the new boiler replacement options, PSD/NSR permitting is based on comparing the future potential to emit (PTE) emissions from the option versus past actual emissions from existing sources being retired. Since the annual emissions are based on a "paired" unit basis, the one unit rebuild option is compared to the paired units with the lower annual emission (this assumes only one boiler is operating). The two unit rebuild option is compared to the paired units with the higher annual emission (this assumes both boilers are operating). With the three unit rebuild option, emissions are compared to the total actual emissions from the A-House (this assumes three boilers are operating). With the four unit rebuild option and the new boiler replacement options, the emissions are compared to the total emissions from the A-House.

REBUILD OPTION

The estimated cost to rebuild an existing boiler is on the order of about [REDACTED]. The cost of a new replacement boiler would have to exceed about [REDACTED] to prevent the rebuilding of an existing boiler from being "reconstructed" and becoming affected facilities under NSPS. The estimated cost for a new replacement boiler is less than [REDACTED]; therefore, the rebuilding of the existing boilers will result in the boilers being "reconstructed."

Since the rebuild options are not expected to result in an increase in fuel firing rate, heat input, nor emissions, there would be no increase in hourly emissions to result in any increase in annual emission rates. So New Source Review would not be expected to be triggered by any of the boiler rebuild options for the operating boilers.

NEW BOILER REPLACEMENT OPTION

For the new boiler replacement options all the existing units are being retired and/or replaced as noted earlier regardless of the number of boilers being replaced. At a minimum, the replacement boilers will have to meet NSPS and NESHAP. The potential annual emissions for each replacement option are based on the new boiler(s) firing natural gas operating at 100 percent capacity factor for 8040 hours per year and operating on No. 6 oil (0.3% sulfur) for 720 hours per year (30-days per year). The expected annual emissions for each replacement option are based on a new boiler to meet the expected annual steam production at a capacity factor of about [REDACTED].

As shown in the Exhibit 4-11, the PM10 annual emission increase would trigger PSD/NSR for the four new boiler replacement option at 100% annual capacity factor. A 90% annual capacity factor for the four replacement (new) boilers option would result in emissions being below PSD/NSR requirements with an estimated annual steam sendout of 7,500 million pounds. This is significantly greater than the annual capacity factor used as a basis for the option evaluations [REDACTED].

G4.2.4 Schedule

The project schedule is based upon a turnkey EPC Contracting approach. The schedule assumes staggered operation of the units as shown in Exhibit 4-14 and Exhibit 4-15. This approach will also allow keeping only one stack operational for up to two boiler rebuild/replacement options. It is assumed that the permitting effort will take about a year in support of the above operation schedule.

G4.2.5 Rationale for Options Rejected / Selected as Promising Options

Based upon the results of the economic model, the [REDACTED] option with [REDACTED] provides the lowest Unit NPV of the steam production cost. Therefore, a more detailed description of the [REDACTED] option is provided in the following section.

G4.2.6 Conceptual Description of [REDACTED]

G4.2.6.1 Overview

[REDACTED]

G4.2.6.2 Layout

[REDACTED]

G4.2.6.3 Major Equipment and Systems

[REDACTED]

G6.0 CONCLUSIONS AND RECOMMENDATIONS

WorleyParsons has performed an evaluation of the feasibility of rebuilding or replacing the boilers at Con Edison's Ravenswood Steam Plant (A-House) as part of Phase 1 of a steam production cost study of long-term steam production options in support of Con Edison and the Steam Business Development Task Force. Eight options for the Ravenswood Steam Plant were evaluated as follows:

- Rebuild one, two, three, or four of the existing boilers (4 options)
- Replace one, two, three, or four of the boilers with new boilers of the same design capacity as the existing boilers (4 options)

WorleyParsons developed estimates of the capital costs, annual operating and maintenance costs, net annual cost of steam production (total annual cost including emission reduction credits), and the net present value (NPV) of the cost of steam production over a 20-year period from 2006 to 2025. WorleyParsons also calculated a Unit NPV, as described in Section 3 of the Final Report, to be used as a Figure of Merit for comparing the options. The economic, financial, and environmental criteria used for the evaluations were the same as those used for the evaluation of repowering options at other Con Edison steam generating stations and other alternative steam supply options.

The results of the evaluation indicate that of the eight options evaluated for the Ravenswood Steam Plant, the [REDACTED] has the lowest Unit NPV of estimated cost of steam production.

Exhibit G7-1 Conceptual Cost Estimates for Ravenswood Boiler Rebuilding Option RB1

REDACTED

Exhibit G7-2 Conceptual Cost Estimates for Ravenswood Boiler Rebuilding Option RB2

REDACTED

Exhibit G7-3 Conceptual Cost Estimates for Ravenswood Boiler Rebuilding Option RB3

REDACTED

Exhibit G7-4 Conceptual Cost Estimates for Ravenswood Boiler Rebuilding Option RB4

REDACTED

Exhibit G7-5 Conceptual Cost Estimates for Ravenswood Boiler Replacement Option NB1

REDACTED

Exhibit G7-6 Conceptual Cost Estimates for Ravenswood Boiler Replacement Option NB2

REDACTED

Exhibit G7-7 Conceptual Cost Estimates for Ravenswood Boiler Replacement Option NB3

REDACTED

Exhibit G7-8 Conceptual Cost Estimates for Ravenswood Boiler Replacement Option NB4

REDACTED