Table 2

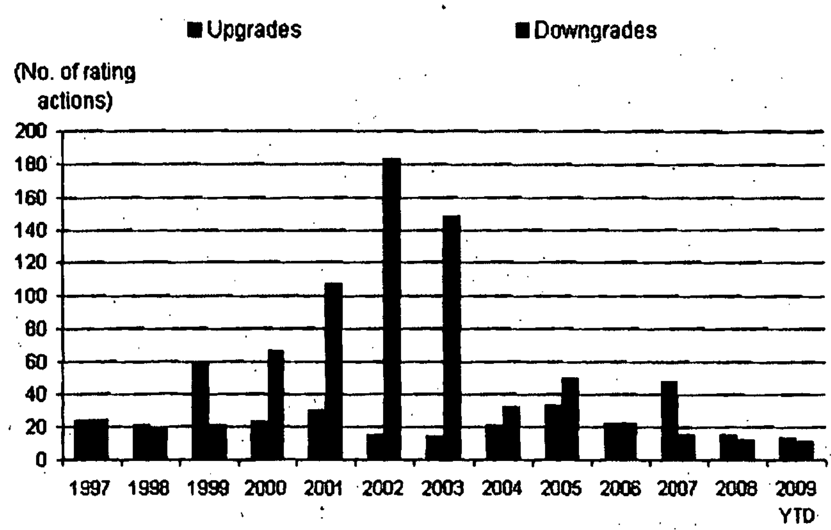
Recent Rating/Outlook/CreditWatch Actions* (cont.)				
Duquesne Light Holdings Inc.	BBB-/Stable/--	BBB-/Negative/--	Dec. 17, 2009	The outlook revision reflects the diminished possibility of a downgrade in light of the company's immediate and ongoing strengthening of its balance sheet. The ratings on DLH reflect the strength and cash flow stability of its utility subsidiary, Duquesne Light Co., and the riskier unregulated operations. Moderating the credit strengths are consolidated financial measures that have weakened following DLH's acquisition by an investor consortium and declining provider of last resort-related margins as a result of capacity payments to electricity generators in the PJM region.
PNM Resources Inc.	BB-/Stable/B-2	BB-/Negative/B-2	12/9/2009	The outlook revision reflects the diminished possibility of a downgrade in light of improved FFO resulting from rate increases in New Mexico and Texas, combined with less consolidated debt leverage resulting from the sale of natural gas operations and the application of proceeds toward repaying debt. Adjusted FFO to debt has improved to about 15% from below 10% earlier in the year, and is expected to remain above 12%. Incremental improvement in PNM's management of regulatory risk in New Mexico, which includes a reduction of wholesale exposure through the transfer of certain generating assets into rate base, a fuel and purchased power cost adjustment mechanism set annually, and new legislation allowing the use of a future test year (including a return on construction in progress), is expected to support credit quality by reducing cash flow volatility and rate lag.
Public Service Co. of New Mexico	BB-/Stable/B-2	BB-/Negative/B-2	12/9/2009	See PNM Resources Inc.
Texas-New Mexico Power Co.	BB-/Stable/--	BB-/Negative/--	12/9/2009	See PNM Resources,Inc.
Trans-Allegheny Interstate Line Company	BBB-/Stable/--	New	Nov. 23, 2009	On Nov. 23, 2009, Standard & Poor's Ratings Services assigned its 'BBB-' corporate credit rating to Trans-Allegheny Interstate Line Co. (TrAIL), a wholly-owned indirect subsidiary of Allegheny Energy. The outlook is stable. Currently, TrAIL has a $550 million credit facility that it's using to finance construction of the interstate transmission line. The ratings on TrAIL reflect the consolidated credit profile of Allegheny Energy, which incorporates the regulated cash flows of utility subsidiaries, Monongahela, Potomac Edison Co., and West Penn Power Co. (WPP), in conjunction with the higher business risk of unregulated generation subsidiary, Allegheny Energy Supply Co. LLC (AE Supply).

*Dates represent the period from Sept. 15, 2009 to Dec. 28, 2009 covered by this report card.

Rating Trends

Chart 3

U.S. Utility Upgrades Versus Downgrades*



*1997-2006 excludes midstream and pipeline companies. 2007 excludes midstream, pipeline, merchant power, gas, and water companies.

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Selected Articles

Table 3

Previously Published U.S. Electric Utilities Articles

Article title	Published date
A Power Surge For Global Solar Energy	Oct. 27, 2009
Improved Cost-Competitiveness To Increase Adoption Of Solar Energy In Retail Energy, Report Says	Oct. 27, 2009
Key Credit Factors: Methodology And Assumptions On Risks For Utility-Scale Solar Photovoltaic Projects	Oct. 27, 2009
Ratings Roundup: Three Upgrades, No Downgrades In U.S. Electric Utility Sector During Third-Quarter 2009	Oct. 6, 2009
Tracking The Economics Of Wholesale And Retail Solar Photovoltaic Generation	Oct. 27, 2009
U.S. Utility And Power Sector Refinancing Requirements Remain Manageable For The Next Few Years	Nov. 5, 2009

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Table 4

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Comments and ratings reflect available public data as of Dec. 28, 2009.

Con Edison

Hearing Exhibits

STATE OF NEW YORK
DEPT. OF PUBLIC SERVICE
DATE: 6/9/10
CASE NOS: 09-S-0794, 09-G-0795, and 09-S-0029
Ex. 302

The shrinking equity premium
Jeremy J Siegel
Journal of Portfolio Management; Fall 1999; 26, 1; ABI/INFORM Global
pg. 10

The Shrinking Equity Premium

Historical facts and future forecasts.

Jeremy J. Siegel

Few conundrums have caught the imagination of economists and practitioners as much as the "Equity Premium Puzzle," the title chosen by Rajnesh Mehra and Edward Prescott for their seminal 1985 article in the *Journal of Monetary Economics*. Mehra and Prescott show that the historical return on stocks has been too high in relation to the return on risk-free assets to be explained by the standard economic models of risk and return without invoking unreasonably high levels of risk aversion.[1] They calculate the margin by which stocks outperformed safe assets — the *equity premium* — to be in excess of 6 percentage points per year, and claim that the profession is at a loss to explain its magnitude.

There have been many attempts since to explain the size of the equity premium by variations of the standard finance model. I shall not enumerate them here, but refer readers to reviews by Abel [1991], Kocherlakota [1996], Cochrane [1997], and Siegel and Thaler [1997].

I review here the estimates of the equity premium derived from historical data, and offer some reasons why I believe that most of the historical data underestimate the real return on fixed-income assets and overestimate the expected return on equities. I shall also offer some reasons why, given the current high level of the stock market relative to corporate earnings, the forward-looking equity premium may be considerably lower than the historical average.

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REAL RETURNS ON "RISK-FREE" ASSETS

From 1889 through 1978, Mehra and Prescott estimate the real return on short-dated fixed-income assets (commercial paper until 1920 and Treasury bills thereafter) to have been 0.8%. In 1976 and again in 1982, Roger Ibbotson and Rex Sinquefield formally estimated the real risk-free rate to be even lower — at zero, based on historical data analyzed from 1926. This extremely low level of the short-term real rate is by itself puzzling, and has been termed the "real rate puzzle" by Weil [1989]. The essence of this puzzle is that, given the historical growth of per capita income, it is surprising that the demand to borrow against tomorrow's higher consumption has not resulted in higher borrowing rates.

The low measured level of the risk-free rate may in fact be in part an artifact of the time period examined. There is abundant evidence that the real rate both during the nineteenth century and after 1982 has been substantially higher. Exhibit 1, based on Siegel [1998], indicates that over the entire period from 1802 through 1998, the real compound annual return on Treasury bills (or equivalent safe assets) has been 2.9%, while the realized return on long-term government bonds has been 3.5%. Exhibit 2 presents the historical equity premium for selected time periods for both bonds and bills based on the same data.[2]

EXHIBIT 1
COMPOUND ANNUAL REAL RETURNS (%)
U.S. DATA, 1802-1998

	Stocks	Bonds	Bills	Gold	Inflation
1802-1998	7.0	3.5	2.9	–0.1	1.3
1802-1870	7.0	4.8	5.1	0.2	0.1
1871-1925	6.6	3.7	3.2	–0.8	0.6
1926-1998	7.4	2.2	0.7	0.2	3.1
1946-1998	7.8	1.3	0.6	–0.7	4.2

Source: Siegel [1998] updated.

The danger of using historical averages — even over long periods — to make forecasts is readily illustrated by noting Ibbotson and Sinquefield's long-term predictions made in 1976 and again in 1982 on the basis of their own analysis of the historical data. In 1976, they made predictions for the twenty-five-year period from

EXHIBIT 2
EQUITY PREMIUMS (%) — U.S. DATA, 1802-1998

	Equity Premium with Bonds		Equity Premium with Bills	
	Geometric	Arithmetic	Geometric	Arithmetic
1802-1998	3.5	4.7	5.1	5.5
1802-1870	2.2	3.2	1.9	2.9
1871-1925	2.9	4.0	3.4	4.6
1926-1998	5.2	6.7	6.7	8.6
1946-1998	6.5	7.3	7.2	8.6

Source: Siegel [1998] updated.

1976 through 2000, and in 1982 they made predictions for the twenty-year period from 1982 through 2001. Their forecasts are shown in Exhibit 3. Since we now have data for most of these forecast periods, it is of interest to assess their estimates.

The last two decades have been extremely good for financial assets, so it is not surprising that Ibbotson and Sinquefield underestimate all their real returns. But their most serious underestimation is for fixed-income assets, where they forecast the real bill rate to average essentially zero and the real return on bonds to be less than 2%. Given the standard deviation of estimates, realized annual real bond and bill returns have been 9.9% and 2.9%, respectively, significantly above their estimates. Since negative real returns on fixed-income assets persisted between the two surveys, Ibbotson and Sinquefield more seriously underestimate long-term real bill rates in their 1982 forecasts than they did in 1976.[3]

My purpose here is not to highlight errors in Ibbotson's and Sinquefield's past forecasts. Their analysis was state-of-the-art, and their data have rightly formed the benchmark for the risk and return estimates used by both professional and academic economists. I bring these forecasts to light to show that even the fifty-year history of financial returns available to economists at that time was insufficient to estimate future real fixed-income returns.

It is not well understood why the real rate of returns on fixed-income assets was so low during the 1926-1980 period. The bursts of unanticipated inflation following the end of World War II and during the 1970s certainly had a negative effect on the realized real returns from long-term bonds. Perhaps the shift from a gold standard to a paper monetary standard had a negative effect on these real returns until investors fully adjusted to the inflationary bias inherent in the new monetary standard.[4]

Whatever the reasons, the current yields on the Treasury inflation-protected securities, or TIPS, first issued in 1997 support the assertion that the future real returns on risk-free assets will be substantially above the level estimated over the Ibbotson-Sinquefield period. This is so even when the estimating period includes the higher real rates of the past two decades. In August 1999, the ten- and thirty-year TIPS bond yielded 4.0%, nearly twice the realized rate of return on long-dated government bonds over the past seventy-five years.[5]

The market projects real returns on risk-free assets to be substantially higher in the future than they have been over most of this century. It is also likely that the expected returns in the past are substantially greater than they have turned out ex post, especially for longer-dated securities. If one uses a 3.5% real return on fixed-income assets, the geometric equity premium for a 7.0% real stock return falls to 3.5%.

EXHIBIT 3
LONG-TERM FORECASTS OF REAL RETURNS — COMPOUND ANNUAL RATES OF RETURN

Forecast Period		Stocks	Bonds	Bills	Inflation
1976-2000	Forecast	6.3 (23.5)	1.5 (8.0)	0.4 (4.6)	6.4 (4.8)
	Actual*	11.0	5.3	2.1	4.8
1982-2001	Forecast	7.6 (21.9)	1.8 (8.3)	0.0 (4.4)	12.8 (5.1)
	Actual*	14.6	9.9	2.9	3.3

*Data through 1998.
Standard deviations of annual returns in parentheses.
Source: Ibbotson and Sinquefield [1976, 1982].

HISTORICAL EQUITY RETURNS AND SURVIVORSHIP BIAS

The real return on stocks, as I have emphasized [1998], has displayed a remarkable long-term stability. Over the entire 196-year period that I examine, the long-term after-inflation geometric annual rate of return on equity averages 7.0%. In the 1926-1998 period, the real return has been 7.4%, and since 1946 (when virtually all the thirteenfold increase in the consumer price index over the past two hundred years has taken place) the real return on equity has been 7.8%. The relative stability of long-term real equity returns is in marked contrast to the unstable real returns on fixed-income assets.

Some economists believe the 7% historical real return on equities very likely overstates the true expected return on stocks. They claim that using the ex post equity returns in the United States to represent returns expected by shareholders is misleading. This is because no investor in the nineteenth or early twentieth century could know for certain that the United States would be the most successful capitalist country in history and experience the highest equity returns.

This "survivorship bias" hypothesis, as it has been called, is examined by Jorion and Goetzmann [1999] in "Global Stock Markets in the Twentieth Century." They conclude that of thirty-nine equity markets that existed in 1921, none of them show as high a real capital appreciation as the United States, and most of them have had substantial disruptions in their operations or have disappeared altogether. They report that the median real capital appreciation of non-U.S. markets has been only 0.8% per year as opposed to 4.3% in the U.S.[6]

But this evidence may be misleading. Total returns of a portfolio, especially over long periods of time, are a very non-linear function of the returns of the individual components. Mathematically it can be shown that if individual stock returns are lognormal, the performance of the *median* stock is almost always worse than the market portfolio performance.[7]

So, it is not surprising that the median performance of individual countries will not match the "world portfolio" or the returns in the dominant market. Jorion and Goetzmann recognize this near the end of their study when they show that compound annual real return on a GDP-weighted portfolio of equities in all countries falls only 28 basis points short of the U.S. return. In fact, because of the real depreciation of the dollar over this time, the compound annual *dollar* return on a GDP-weighted world is actually 30 basis points *higher* than the return on U.S. equities.[8]

But examining international stock returns alone does not give us a better measure of the equity premium. The equity premium measures the *difference* between the returns on stocks and safe bonds. Although stock returns may be lower in foreign countries than the U.S., the real returns on foreign bonds are substantially lower. Almost all disrupted markets experienced severe inflation, in some instances wiping out the value of fixed-income assets. (One could say that the equity premium in Germany covering any period including the 1922-1923 hyperinflation is over 100%, since the real value of fixed-income assets fell to zero while equities did not.)

Even investors who purchased bonds that promised precious metals or foreign currency experienced significant defaults. It is my belief that if one uses a world portfolio of stocks and bonds, the equity *premium* will turn out higher, not lower, than found in the U.S.[9]

TRANSACTION COSTS AND DIVERSIFICATION

I believe that 7.0% per year does approximate the long-term real return on equity indexes. But the return on equity *indexes* does not necessarily represent the *realized* return to the equityholder. There are two reasons for this: transaction costs and the lack of diversification.[10]

Mutual funds and, more recently, low-cost "index funds" were not available to investors of the nineteenth or early twentieth century. Prior to 1975, brokerage commissions on buying and selling individual stocks were fixed by the New York Stock Exchange, and were substantially higher than today. This made the accumulation and maintenance of a fully diversified portfolio of stocks quite costly.

The advent of mutual funds has substantially lowered the cost of maintaining a diversified portfolio. And the cost of investing in mutual funds has declined over the last several decades. Rea and Reid [1998] report a decline of 76 basis points (from 225 to 149) in the average annual fee for equity mutual funds from 1980 to 1997 (see also Bogle [1999, p. 69]). Index funds with a cost of less than 20 basis points per year are now available to small investors.

Furthermore, the risk experienced by investors unable to fully diversify their portfolios made the risk-return trade-off less desirable than that calculated from stock indexes. On a risk-adjusted basis, a less-than-fully diversified portfolio has a lower expected return than the total market.

Given transaction costs and inadequate diversification, I assume that equity investors experienced real returns more in the neighborhood of 5% to 6% over most of the nineteenth and twentieth century rather than the 7% calculated from indexes. Assuming a 3.5% real return on bonds, the historical equity premium may be more like 1.5 to 2.5 percentage points, rather than the 6.0 percentage points recorded by Mehra and Prescott.

PROJECTING FUTURE EQUITY RETURNS

Future stock returns should not be viewed independently of current fundamentals, since the price of stocks is the present discounted value of all expected future cash flows. Earnings are the source of these cash flows, and the average price-to-earnings (P-E) ratio in the U.S. from 1871 through 1998 is 14 (see Shiller [1989] for an excellent source for this series).

Using data from August 13, 1999, the S&P 500 stock index is 1327, and the mean 1999 estimate for operating earnings of the S&P 500 stock index of fifteen analysts polled by Bloomberg News is $48.47.[11] This yields a current P-E ratio on the market of 27.4. But due to the increased number of write-offs and other special charges taken by management over the last several years, operating earnings have exceeded total earnings by 10% to 15%.[12] On the basis of reported earnings, which is what most historical series report (including Shiller's), the P-E ratio of the market is currently about 32.[13]

There are two long-term consequences of the high level of stock prices relative to fundamentals. Either 1) future stock returns are going to be lower than historical averages, or 2) earnings (and hence other fundamentals such as dividends or book value) are going to rise at a more rapid rate in the future. A third possibility, that P-E ratios will rise continually without bound, is ruled out since this would cause an unstable bubble in stock prices that must burst.

If future dividends grow no faster than they have in the past, forward-looking real stock returns will be lower than the 7% historical average. As is well known from the dividend discount model, the rate of return on stocks can be calculated by adding the current dividend yield to the expected rate of growth of future dividends. The current dividend yield on the S&P 500 index is 1.2%. Since 1871, the growth of real per share dividends on the index has been 1.3%, but since 1945, due in part to a higher reinvestment rate, growth has risen to 2.1%. If we assume future growth of real per share dividends to be close to the most recent average of 2.1%, we obtain a 3.3% real return on equities, less than one-half the historical average.

A second method of calculating future real returns yields a similar figure. If the rate of return on capital equals the return investors require on stocks, the *earnings yield*, or the reciprocal of the price-earnings ratio, equals the forward-looking real long-term return on equity (see Phillips [1999] for a more formal development of this proposition). Long-term data support this contention; a 14 price-to-earnings ratio corresponds to a 7.1% earnings yield, which approximates the long-term real return on equities. The current P-E ratio on the S&P 500 stock index is between 27 to 32, depending on whether total or operating earnings are considered. This indicates a current earnings yield, and hence a future long-term and real return, of between 3.1% to 3.7% on equities.

One way to explain these projected lower future equity returns is that investors are bidding up the price of stocks to higher levels as the favorable historical data about the risks and returns in the equity market become incorporated into investor decisions.[14] Lower transaction costs further enable investors to assemble diversified portfolios of stocks to take advantage of these returns. The desirability of stocks may be further reinforced by the perception that the business cycle has become less severe over time and has reduced the inherent risk in equities.[15]

If these factors are the cause of the current bull market, then the revaluation of equity prices is a one-time adjustment. This means that future expected equity returns should be lower, not higher, than in the past. During this period of upward price adjustment, however, equity returns will be higher than average, increasing the historical measured returns in the equity market.

This divergence between increased historical returns and lower future returns could set the stage for some significant investor disappointment, as survey evidence suggests that many investors expect future returns to be higher, not lower, than in the past (see "PaineWebber Index of Investor Optimism" [1999]).

SOURCES OF FASTER EARNINGS GROWTH

Although the increased recognition of the risks and returns to equity may be part of the explanation for the bull market in stocks, there must be other reasons. This is because the forward-looking rates of return we derive for equities fall below the current 4.0% yield on inflation-protected government bonds. Although one could debate whether in the long run stocks or *nominal* bonds are riskier in real terms, there should be no doubt that the inflation-protected bonds are safer than equities and should have a lower expected return.

Hence, some part of the current bull market in stocks must be due to the expectations that future earnings (and dividend) growth will be significantly above the historical average. Optimists frequently cite higher growth of real output and enhanced productivity, enabled by the technological and communications revolution, as the source of this higher growth. Yet the long-run relation between the growth of real output and *per share* earnings growth is quite weak on both theoretical and empirical grounds. Per share earnings growth has been primarily determined by the reinvestment rate of the firm, or the earnings yield minus the dividend yield, not the rate of output growth.[16]

The reason why output growth does not factor into per share earnings growth is that new shares must be issued (or debt floated) to cover the expansion of productive technology needed to increase output. Over the long run, the returns to technological progress have gone to workers in the form of higher real wages, while the return per unit of capital has remained essentially unchanged. Real output growth could spur growth in per share earnings only if it were "capital-enhancing," in the growth terminology, which is contrary to the labor-augmenting and wage-enhancing technological change that has marked the historical data (see Diamond [1999] for a discussion of growth and real return).

But there are factors that may contribute to higher future earnings growth of U.S. corporations, at least temporarily. The United States has emerged as the leader in the fastest-growing segments of the world economy: technology, communications, pharmaceuticals, and, most recently, the Internet and Internet technology. Furthermore, the penetration of U.S. brand names such as Coca-Cola, Procter & Gamble, Disney, Nike, and others into the global economy can lead to temporarily higher profit growth for U.S. firms.

Nonetheless, the level of corporate earnings would have to double to bring the P-E ratio down to the long-term average, or to increase by 50% to bring the P-E ratio down to 20. A 20 price-to-earnings yield corresponds to a 5% earnings yield or a 5% real return, a return that I believe approximates realized historical equity returns after transaction costs are subtracted. For per share earnings to temporarily grow to a level 50% above the long-term trend is clearly possible in a world economy where the U.S. plays a dominant role, but it is by no means certain.

CONCLUSION

The degree of the equity premium calculated from data estimated from 1926 is unlikely to persist in the future. The real return on fixed-income assets is likely to be significantly higher than that estimated on earlier data. This is confirmed by the yields available on Treasury inflation-linked securities, which currently exceed 4%. Furthermore, despite the acceleration in earnings growth, the return on equities is likely to fall from its historical level due to the very high level of equity prices relative to fundamentals.[17]

All of this makes it very surprising that Ivo Welch [1999] in a survey of over 200 academic economists finds that most estimate the equity premium at 5 to 6 percentage points over the next thirty years. Such a premium would require a 9% to 10% real return on stocks, given the current real yield on Treasury inflation-indexed securities. This means that real per share dividends would have to grow by nearly 8.0% to 9.0% per year, given the current 1.2% dividend yield, to prevent the P-E ratio from rising farther from its current record levels. This growth rate is more than six times the growth rate of real dividends since 1871 and more than triple their growth rate since the end of World War II.

Unless there is a substantial increase in the productivity of capital, dividend growth of this magnitude would mean an ever-increasing share of national income going to profits. This by itself might cause political ramifications that could be negative for shareholders.

ENDNOTES

This article is adapted from a paper delivered at the UCLA Conference, "The Equity Premium and Stock Market Valuations," and a Princeton Center for Economic Policy Studies Conference, "What's Up with the Stock Market?" both held in May 1999. The author thanks participants in these seminars and particularly Jay Ritter, Robert Shiller, and Peter L. Bernstein for their comments.

[1]A few economists believe these high levels of risk aversion are not unreasonable; see, e.g., Kandel and Stambaugh [1991].

[2]In the capital asset pricing model, equity risk premiums are derived from the *arithmetic* and not geometric returns. Compound annual geometric returns are almost universally used in characterizing long-term returns.

[3]Their wildly high 12.8% long-term inflation estimate in 1982 is derived by subtracting their low historical real yield from the high nominal bond rate. This overprediction has no effect on their estimated *real* returns.

[4]But real rates on *short-dated* bonds, for which unanticipated inflation should have been less important, were also extremely low between 1926 and 1980.

[5]I am very persuaded by the research of Campbell and Viceira [1998], who argue that in a multiperiod world the proper risk-free asset is an inflation-indexed annuity rather than the short-dated Treasury bill. This conclusion comes from intertemporal models where agents desire to hedge against unanticipated changes in the real rate of interest. The duration of such an indexed annuity is closely approximated by the ten-year inflation-indexed bonds.

[6]They are unable to construct dividend series for most foreign countries, but they make a not-unreasonable assumption that dividend yields in the U.S. were at least as high as abroad.

[7]Intuitively, the return of the winners more than compensates for the lower returns of the more numerous losers.

[8]Furthermore, the dollar return on the foreign portfolio is much better measured than the real return. These data are taken from Jorion and Goetzmann [1991], Tables VI and VII.

[9]To avoid the problems with default, gold is considered the "risk-free" alternative in many countries. But gold's long-term real returns are negative in the U.S. even before one considers storage and insurance costs. And precious metals are far from risk-free in real terms. The real return on gold since 1982 has been a negative 7% per year.

[10]I abstract from taxes, which reduce the return on both bonds and stocks.

[11]These data were taken from the Bloomberg terminal on August 16, 1999.

[12]From 1970 through 1989, operating earnings exceeded reported earnings by an average of 2.29%. Since 1990, the average has been 12.93%.

[13]There are other factors that distort reported earnings, some upward (underreporting option costs: see Murray, Smithers, and Emerson [1998]) and some downward (overexpensing R&D; see Nakamura [1999]). No clear bias is evident.

[14]This is particularly true on a long-term, after-inflation basis. See Siegel [1998, Chapter 2].

[15]Bernstein [1998] has emphasized the role of economic stability in stock valuation. Also see Zarnowitz [1999] and Romer [1999]. Other reasons given for the high price of equities rely on demographic factors, specifically the accumulations of "baby boomers." This should, however, reduce both stock and bond returns, yet we see real bond returns as high if not higher than historically.

[16]From 1871 to 1998, the growth of real per share earnings is only 1.7% per year, slightly less than obtained by subtracting the median dividend yield of 4.8% from the median earnings yield of 7.2%.

[17]This should not be construed as predicting that equity prices need fall significantly, or that the expected returns on equities are not higher, even at current levels, than those on fixed-income investments.

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Estimating the market risk premium ☆

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Abstract

This paper provides a method for estimating the market risk premium that accounts for shifts in investment opportunities by explicitly modeling the underlying process governing the level of market volatility. I find that approximately 50% of the measured risk premium is related to the risk of future changes in investment opportunities. Evidence of a structural shift in the underlying volatility process suggests that the simple historical average of excess market returns may substantially overstate the magnitude of the market risk premium for the period since the Great Depression.

JEL classification: G10; G31

Keywords: Risk premium; Asset pricing; Structural breaks; Markov-switching models

1. Introduction

The market risk premium is one of the most important numbers in finance. Unfortunately, estimating and understanding its value has proven difficult.

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Although a substantial body of research shows that expected returns vary over time, the static approach of estimating the risk premium as the simple average of historical excess stock returns remains the most commonly employed method in practice.[1] Merton (1980) suggests estimating the risk premium based on the theoretical relationship between expected returns and the contemporaneous variance of returns. Although this theoretical approach is appealing, empirical research has failed to document a significant positive relationship between expected returns and the level of market volatility.[2] Scruggs (1998) provides evidence suggesting the failure to find a positive relationship between excess returns and market volatility may result from not controlling for shifts in investment opportunities. Lettau and Ludvigson (2001) make a similar point, showing that rejections of the consumption capital asset pricing model may also be due to a failure to control for shifts in investment opportunities. In this paper, I develop a method for estimating the market risk premium based on the equilibrium relationship between volatility and expected returns when there are discrete shifts in investment opportunities—specifically, changes in the level of market volatility. I use this method to demonstrate the importance of accounting for the dynamic nature of market risk when estimating the risk premium from ex post market returns.

The volatility of market returns during the past century has varied significantly. Schwert (1989a, b) studies historical variations in market volatility and relates the fluctuations to changes in economic and financial market conditions. My results suggest that, as a result of changes in the level of market volatility, the simple historical average of excess market returns obscures significant variation in the market risk premium and that over half of the measured risk premium is associated with the risk of future changes in investment opportunities. My analysis also suggests that, as a result of a structural shift in the likelihood of future high-volatility periods, the simple historical average of excess market returns may substantially overstate the magnitude of the market risk premium for the period since the Great Depression.

In my model, market risk is characterized by periodic episodes of high market volatility followed by a return to a lower, more typical level. I assume that the evolution of these volatility states follows a Markov process, and I model the market risk premium as a function of the underlying process governing the evolution of the two volatility states.[3] The expression for the equilibrium risk premium in my model is a special case of the Merton (1973) intertemporal capital asset pricing model. Because individuals anticipate future changes in the volatility state and corresponding

[1] For examples of research showing that expected returns vary over time, see Fama and Schwert (1977), Shiller (1984), Campbell and Shiller (1988), Fama and French (1988, 1989), Campbell (1991), Hodrick (1992), and Lamont (1998). Bruner et al. (1998) survey a sample of 27 "highly regarded corporations" and find that the estimates of the risk premium are generally based on either the arithmetic or geometric average of historical excess market returns.

[2] See Campbell (1987), French et al. (1987), Baillie and DeGennaro (1990), Glosten et al. (1993).

[3] Many researchers, including Schwert (1989a), Turner et al. (1989), Cecchetti et al. (1990), Pagan and Schwert (1990), Hamilton and Susmel (1994), Hamilton and Lin (1996), Schaller and Van Norden (1997), and Kim et al. (2000) have used a two-state Markov-switching model to describe the time series properties of market returns.

changes in the level of stock prices, ex post measured returns are not equal to ex ante expected returns.[4] When individuals place a nonzero probability on the likelihood of a future change in volatility state, expected returns include the expected change in stock prices associated with a change in volatility state. While the economy remains in the low-volatility state, actual ex post returns are higher on average than expected returns. Conversely, while the economy remains in the high-volatility state, actual ex post returns will be lower on average than expected returns. Within each state, the difference between ex post returns and expected returns is similar to the peso-type problem discussed in Rietz (1988). My model generates periods of low-volatility and high ex post returns alternating with periods of high-volatility and low ex post returns, reconciling the empirical finding that returns are lower in periods of high volatility with the theoretical intuition that expected returns should be positively related to the level of market volatility.

My theoretical model maps directly into a standard empirical framework for estimating time variation in market volatility, providing a foundation for interpreting these earlier empirical results and a structural basis for estimating the market risk premium in a dynamic setting. Given the Markov structure of my model, its parameters can be estimated using the Hamilton (1989) Markov-switching model. Consistent with previous studies that use the Markov-switching model to describe the time series properties of stock market returns, my analysis shows that market returns can be described as having been drawn from two significantly different distributions: a low-volatility/high-return distribution, from which about 88% of the returns are drawn, and a high-volatility/low-return distribution, from which about 12% of the returns are drawn. In the low-volatility state, the annual standard deviation of returns is 13.0% and the mean annualized excess return is 12.4%. In contrast, the annual standard deviation of returns in the high-volatility state is 38.2% and the mean annualized excess return is -17.9%.[5]

My equilibrium expression for the risk premium allows the estimated moments of the two conditional return distributions to be mapped directly to preference parameters. Using this mapping, I decompose the unconditional risk premium into two state-dependent risk premia as well as into premia required for intrastate diffusion risk and interstate jump risk. My estimates for the annualized state-dependent risk premia in the low- and high-volatility states are 5.2% and 32.5%, respectively. Based on the estimated preference parameters, my analysis suggests that about 50% of the unconditional risk premium is related to the risk of future changes in the level of market volatility.

[4] The negative relationship between volatility and market prices, referred to as volatility-feedback, is examined in Malkiel (1979), Pindyck (1984), Poterba and Summers (1986), French et al. (1987), Campbell and Hentschel (1992), and Kim et al. (2000).

[5] When transitional months associated with changes in volatility states are excluded, the estimated standard deviation of returns in each volatility state remains essentially unchanged. The empirical method for identifying changes in volatility states tends to treat the jumps in stock prices associated with changes in volatility states as high-volatility returns, and the magnitude of the stock price changes during transitional months is comparable to the standard deviation of returns within the identified high-volatility periods.

Recent studies provide historical evidence of a structural shift in the market risk premium. Siegel (1992) documents that the market premium has not been constant over the past century and that excess stock returns during the mid-1900s are abnormally large. Pastor and Stambaugh (2001) use a Bayesian analysis to test for structural breaks in the distribution of historical returns and to relate those breaks to changes in the market risk premium. Fama and French (2002) provide evidence of a structural shift in the market risk premium by comparing the ex ante risk premium from a Gordon growth model with the ex post risk premium based on the historical average of excess market returns. Evidence of a structural shift in the volatility of market returns is also provided in earlier studies. Officer (1973) and Schwert (1989b) argue that market returns during the Great Depression era were unusually volatile, and Pagan and Schwert (1990) show that the volatility of market returns during the Great Depression was inconsistent with stationary models of conditional heteroskedastic returns. My model provides a structural basis for estimating the impact of such a structural shift on the market risk premium. Consistent with Pagan and Schwert (1990) and Pastor and Stambaugh (2001), I find evidence of a statistically significant shift in the underlying volatility process that governs the evolution of volatility states following the 1930s. Because of the structural shift in the Markov transition probabilities, the likelihood of entering into the high-volatility state falls from about 39% before 1940 to less than 5% after 1940. Given the lower likelihood of entering the high-volatility state, the risk premium falls from about 20.1% before 1940 to 7.1% after 1940.

Because of the structural shift in the underlying volatility process and the associated reduction in the market risk premium, ex post returns during the period following 1940 are not an unbiased estimate of ex ante expected returns. As investors learn that market risk has fallen because of the structural shift, stock prices will be bid up and ex post returns will be greater than ex ante expected returns. Elton (1999) stresses the importance of distinguishing between ex ante and ex post returns when average realized returns are used as a proxy for ex ante expected returns. Brown et al. (1995) make a related point, arguing that economies that survive ex post must have higher returns on average than the ex ante expected return of all economies. When I correct for this potential bias in my sample of ex post realized returns, my estimate of the market risk premium for the period after 1940 is 5.6%, suggesting that the simple historical average of excess market returns may substantially overstate the magnitude of the risk premium for the period since the Great Depression.

The remainder of the paper is structured as follows. Section 2 presents the analytical model of the risk premium with discrete volatility states. Section 3 describes the empirical framework used to identify and estimate the parameters of the model and reports the resulting decomposition of the unconditional risk premium. In Section 4, I test for a structural shift in the process governing the evolution of volatility states and show the impact on the market risk premium of such a shift. Section 5 summarizes the main findings of the paper.

2. A two-state model of the market risk premium

My analysis begins with the assumption that the variance of market returns follows a two-state Markov process. Defining $s_t \in (L, H)$ to represent the state of the economy at time t, the variance of returns at each instant is given by the equation

$$\sigma_t^2 = \begin{cases} \sigma_L^2, & \text{if } s_t = L, \\ \sigma_H^2, & \text{if } s_t = H, \end{cases} \tag{1}$$

where σ_L^2 is the variance of returns in the normal low-volatility state and σ_H^2 is the variance of returns in the abnormal high-volatility state. To focus on the risk of future changes in market volatility, I assume that investors know the current volatility state with certainty but face the possibility of a change in the volatility state at each point in time.[6] Because the variance process is Markov, the probability of a change in market volatility is a function of the current state only, such that

$$\pi_t = \begin{cases} \pi_L, & \text{if } s_t = L, \\ \pi_H, & \text{if } s_t = H. \end{cases} \tag{2}$$

In this environment, the risk premium must compensate investors for the current volatility of market returns as well as the risk associated with a change in volatility state.

I derive the expression for the equilibrium risk premium in a continuous-time, representative agent model in which preferences are described by power utility. The mathematical derivation of the equilibrium risk premium is provided in the appendix.[7] The equilibrium risk premium is given by the expression

$$\mathrm{E}[R_t] - R_t^{\mathrm{f}} = \gamma\sigma_t^2 + \pi_t J_t\left[1 - (1 + K_t^*)^{-\gamma}\right], \tag{3}$$

where $\mathrm{E}[R_t]$ is the expected return on the market at time t, R_t^{f} is the contemporaneous risk-free rate of return, γ is the coefficient of relative risk aversion, π_t is the instantaneous probability of a change in volatility state, J_t is the percentage change in wealth associated with a change in volatility state, and K_t^* is the percentage change in the optimal level of consumption resulting from a change in volatility state. Using Eq. (3), I decompose the risk premium into two components. The first term on the right-hand side of Eq. (3) is the component that accounts for current volatility risk, which I refer to as the intrastate risk premium. The second term is the component that accounts for changes in the level of market volatility, which I refer to as the interstate risk premium. Because there are only two volatility states, no uncertainty exists over the magnitude of the future change in volatility. Instead, uncertainty exists only over the time at which the level of volatility will change. Eq. (3) is a special case of Merton's (1973) intertemporal capital asset pricing

[6] Turner et al. (1989) study the inference problem faced by investors when the current state is not known and must, instead, be learned. My model is more in the spirit of the Merton (1980) model, in which agents have access to continuous return data over a discrete interval of time such that they are able to estimate the variance of the underlying data generating process to any degree of precision required.

[7] George Chacko provided helpful insights for formulating the state-dependent structure of the programming problem.

model in which changes in investment opportunities are restricted to unpredictable, state-dependent changes in the level of market volatility.[8]

In my formulation of the investor's problem, I allow for constraints on consumption that may limit the degree to which individuals are able to adjust their consumption when the economy switches volatility state. In the appendix, I show that the interstate component of the risk premium is a function of the optimal change in the level of consumption associated with the change in volatility state, even when the ability of investors to adjust their consumption is constrained. The intuition behind this result is that, around the optimum, the loss in utility from being constrained away from the optimum is equal to the loss in utility associated with the optimal change in consumption resulting from a change in volatility state. Assuming that the constraint binds only in the high-volatility state, the distortion in consumption is summarized by the value of the Lagrange multiplier λ_H and is given by the expression

$$\lambda_H = 1 - \left(\frac{1 + K_L^*}{1 + \tilde{K}_L}\right), \tag{4}$$

where $\tilde{K}_L$ is the actual change in consumption associated with a switch to the high-volatility state. Using Eq. (4) and the estimated value of K_L^*, the value of the Lagrange multiplier λ_H can be inferred from the actual change in consumption $\tilde{K}_L$ observed during periods when the economy enters the high-volatility state.

Because volatility levels are discrete, wealth and optimal consumption levels change in a discontinuous fashion when the economy changes state. However, given that there are only two volatility states, the wealth and consumption effects of a change in state are negated after every two changes in state, such that

$$W_t'' = (1 + J_t')(1 + J_t)W_t = W_t \tag{5}$$

and

$$C_t^{*''} = (1 + K_t^{*'})(1 + K_t^*)C_t^* = C_t^*, \tag{6}$$

where W_t'' and $C_t^{*''}$ are the wealth and optimal consumption levels after two state changes and J_t' and $K_t^{*'}$ are the changes in wealth and optimal consumption associated with switching out of the alternate volatility state. For this reason, the change in the levels of wealth and optimal consumption associated with the alternate volatility state can be written in terms of the changes associated with the current volatility state, such that

$$J_t' = \frac{1}{1 + J_t} - 1 \tag{7}$$

and

$$K_t^{*'} = \frac{1}{1 + K_t^*} - 1. \tag{8}$$

[8] Schwert (1989a, b) documents that changes in market volatility are correlated with changes in economic and financial market conditions.

From Eqs. (7) and (8), the magnitude of the jumps in wealth and consumption associated with changes in state are summarized by the two parameters J_t and K_t^*.

The percentage change in the optimal level of consumption K_t^* is determined by the change in the optimal consumption–wealth ratio together with the percentage change in wealth associated with a change in state J_t. The equilibrium consumption–wealth ratio in each state is given by the expression

$$\frac{C_t^*}{W_t} = \frac{\rho + (\gamma - 1)\mu_t - \frac{1}{2}\gamma(\gamma - 1)\sigma_t^2}{\gamma} + \frac{\pi_t}{\gamma}\left[1 - \left(\frac{1 + J_t}{1 + K_t^*}\right)^{\gamma}\right], \tag{9}$$

where C_t^* is optimal consumption at time t, W_t is wealth at time t, ρ is the investor's subjective discount rate, and μ_t is the expected return conditional on remaining in the current state. Consistent with my terminology for the two components of the risk premium, I refer to μ_t as the expected intrastate return. Because the optimal consumption–wealth ratio is itself a nonlinear function of K_t^*, when the model parameters are estimated, I solve numerically for the value of K_t^* that solves Eq. (9). In the appendix, I show that Eq. (9) collapses to the formula for the consumption–wealth ratio derived in Merton (1969) for the infinite horizon lifetime portfolio selection problem under uncertainty when a single volatility state is assumed.

Because wealth changes when the economy changes state, the expected return on the market is not equal to the expected intrastate return. The expected return on the market is given by the equation

$$\mathrm{E}[R_t] = \mu_t + \pi_t J_t. \tag{10}$$

When the economy is in the low-volatility state, investors expect a reduction in wealth when the economy enters the high-volatility state. For this reason, in the low-volatility state, the expected return on the market is less than the expected intrastate return. Similarly, when the economy is in the high-volatility state, investors expect an increase in wealth when the economy reenters the low-volatility state and the expected return on the market is greater than the expected intrastate return.

Fig. 1 depicts the distinction between state-dependent risk premia and expected intrastate excess returns. For each state, the slope of the line labeled "Expected market return" shows required returns and the slope of the line labeled "Expected intrastate return" shows expected returns conditional on the economy remaining in the current state. The vertical line segments at the boundary of low- and high-volatility states represent the jump in wealth associated with a change in volatility state. The figure is drawn such that expected intrastate returns are constant while required returns vary with changes in volatility state. Because of expected changes in wealth associated with changes in volatility state, expected intrastate returns vary by less than state-dependent expected returns. In the low-volatility state, expected intrastate returns are greater than required returns, and in the high-volatility state, expected intrastate returns are less than required returns. If the expected increase in wealth associated with a return to the low-volatility state is sufficiently large, then expected intrastate returns in the high-volatility state can be negative even though the risk premium is positive. My model provides a plausible explanation for reconciling the empirical observation that returns are lower in periods of high

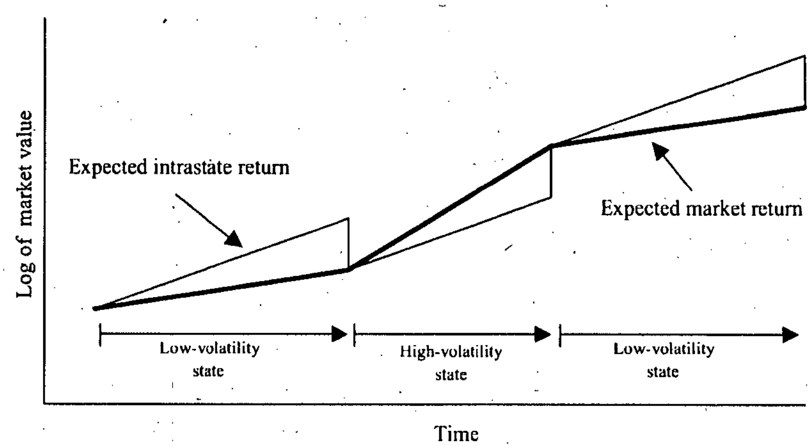

Fig. 1. Expected return on the market versus expected intrastate returns. The vertical axis depicts the log of market value and the horizontal axis represents time. The economy is initially in the low-volatility state, switches into the high-volatility state, and returns to the low-volatility state. The slope of the bold line labeled "Expected market return" is equal to the required return in each volatility state. The slope of the thin line labeled "Expected intrastate return" is equal to the expected return conditional on the economy remaining in each state. The vertical line segment at the boundary of low- and high-volatility states represents the jump in wealth associated with a change in state.

volatility with the theoretical intuition that expected returns should be positively related to the level of market volatility.

3. Model estimation

This section presents the results from estimating the theoretical model.

3.1. Data

The model described in Section 2 is estimated using data from the Center for Research in Security Prices (CRSP). I use monthly value-weighted returns including dividends for NYSE, Amex, and Nasdaq stocks (VWRETD) over the period from 1926 through 2000 as my proxy for market returns. Excess returns are calculated using the contemporaneous yield on one-month Treasury bills from the risk-free rate file provided with the CRSP government bond data.

Table 1 reports summary statistics for monthly excess returns. The average annualized excess return over the sample period is 8.3%, and the annualized standard deviation of returns is 19.0%. The largest and smallest one-month returns are 38.2% and −29.0%, respectively. The reported skewness measure is negative and statistically significant, indicating that large negative returns are more frequent than large positive returns. Finally, the reported measure of excess kurtosis indicates that large returns occur more frequently than would be the case if returns were normally

Table 1
Summary statistics for monthly excess returns, 1926–2000
Excess returns are constructed as the monthly value-weighted return including dividends for NYSE, Amex, and Nasdaq stocks in excess of the contemporaneous yield on one-month Treasury bills. Data were obtained from the Center for Research in Security Prices stock and government bond files. The first column reports the sample statistics, and the second column shows the associated p-value for a test that the true value of the statistic equals zero.

Statistic	Estimate	p-value
Mean (annualized)	8.3%	0.0039
Standard deviation (annualized)	19.0%	
Maximum	38.2%	
Minimum	−29.0%	
Skewness (ln returns)	−0.512	<0.0001
Excess kurtosis (ln returns)	7.043	<0.0001
Number of observations	900	

distributed. As Fama (1965) points out, time variation in market volatility will produce excess kurtosis in stock returns.

3.2. Methodology

To estimate the components of the market risk premium in each volatility state, I map the fundamental parameters of the model to the expected intrastate excess returns by combining Eqs. (3) and (10). This yields the expression

$$\mu_t - R_t^{\mathrm{f}} = \gamma\sigma_t^2 - \pi_t J_t (1 + K_t^*)^{-\gamma}. \tag{11}$$

Because the model is estimated using holding-period returns, the instantaneous transition probabilities π_t are converted to their discrete time equivalents. To do this, I write the instantaneous expected change in wealth associated with a change in volatility state in terms of the equivalent holding-period expected change in wealth, such that

$$\pi_t J_t = \pi_t' \ln(1 + J_t), \tag{12}$$

where π_t' is the discrete time transition probability. Eq. (12) requires that, over the expected duration of each volatility state, the continuously compounded expected change in wealth is equal to the actual change in wealth associated with a change in state.[9] Combining Eqs. (11) and (12) yields

$$\mu_t - R_t^{\mathrm{f}} = \gamma\sigma_t^2 - \pi_t' \ln(1 + J_t)(1 + K_t^*)^{-\gamma}. \tag{13}$$

Eq. (13) is the basis for my estimation method, which has three steps. In the first step, I use the Hamilton (1989) Markov-switching model to estimate the moments of the two state-dependent return distributions μ_t and σ_t as well as the transition

[9]The mathematical derivation of Eq. (11) comes from the requirement that $e^{(\pi_t J_t)D_t} - 1 = J_t$, where the expected duration of each volatility state D_t is given by the formula $D_t = 1/\pi_t'$.

probabilities π_t' that govern the dynamics of the underlying volatility process. In the second step, I use Eq. (13) together with Eqs. (7)–(9) to find the corresponding values of γ, J_t, and K_t^* that are consistent with the estimated moments of the two state-dependent return distributions.[10] Because there are only two free parameters, γ and J_L, available to match the two state-dependent means, μ_L and μ_H, the model is exactly identified. In the third step, I use the expression for the risk premium given by Eq. (3) together with the estimated model parameters to calculate the intrastate and interstate components of the risk premium in each volatility state.

3.3. Results

Table 2 presents the empirical results from my three-step method. Panel A provides the results from applying the Markov-switching model to my sample of returns. I assume that each monthly return is drawn from one of two state-dependent distributions and that returns are log-normally distributed in each state. Parameter estimates are obtained via maximum likelihood using the method described in Berndt et al. (1974). Standard errors are reported in parentheses. Panel B reports the estimated values of the preference parameters γ, J_t, and K_t^* that are consistent with the estimated time series model presented in Panel A. Finally, Panel C reports the implied decomposition of the market risk premium. Because of the nonlinear nature of the model, the standard errors of the coefficients reported in Panels B and C are simulated based on 500 random draws of the time series model parameters from a multivariate normal distribution with mean-vector and variance-covariance matrix equal to those reported in Panel A.

Panel A reports the time series model parameter estimates. The return distributions in the two volatility states are significantly different. The estimated annualized standard deviation of returns varies from 13.0% in the low-volatility state to approximately 38.2% in the high-volatility state. The annualized mean return in the low-volatility state is 12.4% and is significantly different from zero. The annualized mean return in the high-volatility state is -17.9% but is not significantly different from zero. The two volatility states are persistent. The point estimates of the transition probabilities π_L' and π_H' indicate a 0.017 and 0.119 probability of switching out of the low- and high-volatility states, respectively. Both estimated transition probabilities are significantly less than 0.5, indicating that both volatility states tend to persist over time. Based on the estimated transition probabilities, the expected durations of the low- and high-volatility states are approximately 59.2 and 8.4 months, respectively. These results are consistent with previous studies that use the Markov-switching model to describe the time series properties of returns, including Schwert (1989a), Turner et al. (1989), Pagan and Schwert (1990), and Schaller and Van Norden (1997).

[10] Eq. (9) also requires that the subjective discount rate ρ be specified. I set the value of ρ equal to the value estimated in Campbell and Cochrane (1999) of 0.1165. I also test a variety of alternative values for ρ and find that my results are not sensitive to the specific value of ρ chosen.

Table 2
Parameter estimates and implied risk premium decomposition
Estimates are based on 900 monthly excess returns from January 1926 through December 2000. Panel A reports the parameter estimates for the two-state Markov switching model based on Eq. (13). Panel B reports the estimated values of the preference parameters γ, J_t, and K_t^* from Eqs. (7)–(9) that are consistent with the estimated time series model. Panel C shows the implied decomposition of the market risk premium based on Equation (3) and the estimated model parameters. Standard errors are reported in parentheses. Because of the nonlinear nature of the model, the standard errors reported in Panels B and C are simulated.

Volatility state	Time series parameters			Preference parameters			Risk premium decomposition			
							State probability	State-dependent premium		
	$\mu_t - r_t$	σ_t	π_t	γ	J_t	K_t^*		Intrastate	Interstate	Total
	Panel A			*Panel B*				*Panel C*		
Low volatility	0.124	0.130	0.017	*1.129*	*−0.296*	−0.2488	0.876	0.019	0.033	0.052
($s_t = L$)	(0.017)	(0.004)	(0.007)	(0.565)	(0.088)	(0.108)	(0.037)	(0.010)	(0.011)	(0.016)
High volatility	−0.179	0.382	0.119	1.129	0.421	0.404	0.124	0.165	0.160	0.325
($s_t = H$)	(0.140)	(0.022)	(0.038)	(0.565)	(0.218)	(0.289)	(0.037)	(0.078)	(0.077)	(0.116)
Unconditional mean	0.086							0.037	0.049	0.086
	(0.023)							(0.018)	(0.016)	(0.023)
Log-likelihood value	1,491.0									
Number of observations	900									

Panel B reports the preference parameter estimates. The estimated values of the two free parameters γ and J_L are presented in italics. The other parameters are simultaneously determined using Eqs. (7)–(9) but are not independently estimated. The point estimate for γ equals 1.129 and is significantly different from zero at the 5% level based on a one-tailed test. The point estimate for the jump parameter J_L equals −29.6% and is significantly different from zero. The corresponding value of J_H is 42.1%. The implied values for the optimal percent change in consumption K_t^* in the low- and high-volatility states are −28.8% and 40.4%, respectively. Although the estimate of K_t^* for the low-volatility state is significant, given the high volatility of returns in the high-volatility state, the estimate of K_t^* for the high-volatility state is not significantly different from zero.

Panel C reports the implied decomposition of the market risk premium. The first column of the Panel C reports the unconditional probability of each volatility state based on the estimated transition probabilities presented in Panel A. The second and third columns of Panel C show the intrastate and interstate components of the two state-dependent risk premia. The fourth column of Panel C reports the state-dependent risk premium for each volatility state. For each component of the risk premium, the unconditional estimate is calculated as the probability weighted average of the two state-dependent estimates. The estimated values of the unconditional components of the risk premia are reported in the fourth row of the panel. Based on the estimated transition probabilities, the unconditional probability of the economy being in the low- and high-volatility states is 0.876 and 0.124, respectively. The point estimate of the risk premium in the low-volatility state is 5.2%. About 330 basis points, or 64% of the low-volatility state risk premium, are associated with the risk of a change in state. The point estimate of the risk premium in the high-volatility state is 32.5%. About 1,600 basis points, or 49% of the high-volatility state risk premium, are associated with the risk of a change in state. The unconditional risk premium is equal to 8.6%. About 490 basis points, or 57% of the unconditional risk premium, are associated with the risk of changes in state. These results suggest that more than half of the measured market risk premium is related to the risk of future changes in the level of market volatility.

3.4. Statistical tests

I perform a series of statistical tests of the estimated model reported in Table 2. My statistical analysis is presented in two parts: tests of the time series model and tests of the theoretical model. In my analysis of the time series model, I test whether the two volatility states are statistically different as well as whether the assumption of only two volatility states is reasonable. I also test the assumption that returns are independently, log-normally distributed within each state. In my analysis of the theoretical model, I use the low- and high-volatility episodes identified in the time series analysis to test the predictions of the theoretical model, including the statistical properties of returns in each identified state and the extent to which market prices jump when the economy switches between states.

The two volatility states are statistically different. I test the estimated model against the null hypothesis that both the mean and variance of returns is constant.

The likelihood ratio statistic for the test is 155.4 and the corresponding p-value is less than 0.0001, indicating that the null hypothesis can be rejected at any reasonable level of confidence. I also test the extent to which the explanatory power of the model is improved by the inclusion of a third volatility state. Although the inclusion of a third state increases the value of the estimated likelihood function, the increase is not statistically significant. The likelihood ratio statistic for a test of three states against a null hypothesis of two states is 8.82. The corresponding p-value of 0.1816 indicates that the null hypothesis of two states cannot be rejected at standard levels of significance.

The assumption that returns are independent within each volatility state is reasonable. I augment the time series model to allow for first-order serial correlation in returns within each volatility state. The point estimates for the serial correlation coefficients in the low- and high-volatility states are 0.28 and 1.26, respectively. Neither estimated coefficient is statistically significant. The likelihood ratio statistic for a test of the null hypothesis that both coefficients are zero is 0.82 and the corresponding p-value is 0.9915, indicating that the null hypothesis cannot be rejected at any reasonable level of confidence.

The assumption that returns are log-normally distributed within each volatility state is reasonable. Fig. 2 compares the cumulative distribution function (CDF) for the estimated model with the sampled cumulative distribution of returns. I also show the CDF for the assumption that the data are unconditionally log-normal. The top panel of the figure shows each of the cumulative distribution functions, and the bottom panel shows the difference between the estimated and sampled CDFs. To assess the reasonableness of the distributional assumptions, I perform a Kolmogorov-Smirnov test of the difference between the estimated and sample distributions.[11] Consistent with the two volatility states being statistically different, the null hypothesis that the data are unconditionally log-normal can be rejected at the 1% level. In contrast, the null hypothesis that the data are log-normally distributed within each volatility state cannot be rejected at the 5% level.

The results of these statistical tests of the estimated time series model suggest that a simple two-state model provides a reasonable description of monthly market returns. Based on the high-volatility periods identified by the two-state time series model, I perform statistical tests of the main predictions from the theoretical model. I define high-volatility periods as those months for which the implied probability of being in the high-volatility state is greater than 0.5. Based on this criteria, there are 21 high-volatility periods during the period from 1926 through 2000. Of the 900 months in the sample, 804 months are categorized as low volatility and 96 months are categorized as high volatility. Descriptive statistics for these low- and high-volatility periods are provided in Table 3.

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[11] The Kolmogorov-Smirnov (K-S) statistic for a test of the null hypothesis that the data are unconditionally log-normal is 0.0708. The critical value of the K-S statistic for a 1% test with 900 observations is 0.0543, indicating that the null hypothesis can be rejected. In contrast, the K-S statistic for a test of the null hypothesis that the data are log-normally distributed within each volatility state is 0.0211. The critical value of the K-S statistic for a 5% test with 900 observations is 0.0453, indicating that the null hypothesis cannot be rejected.

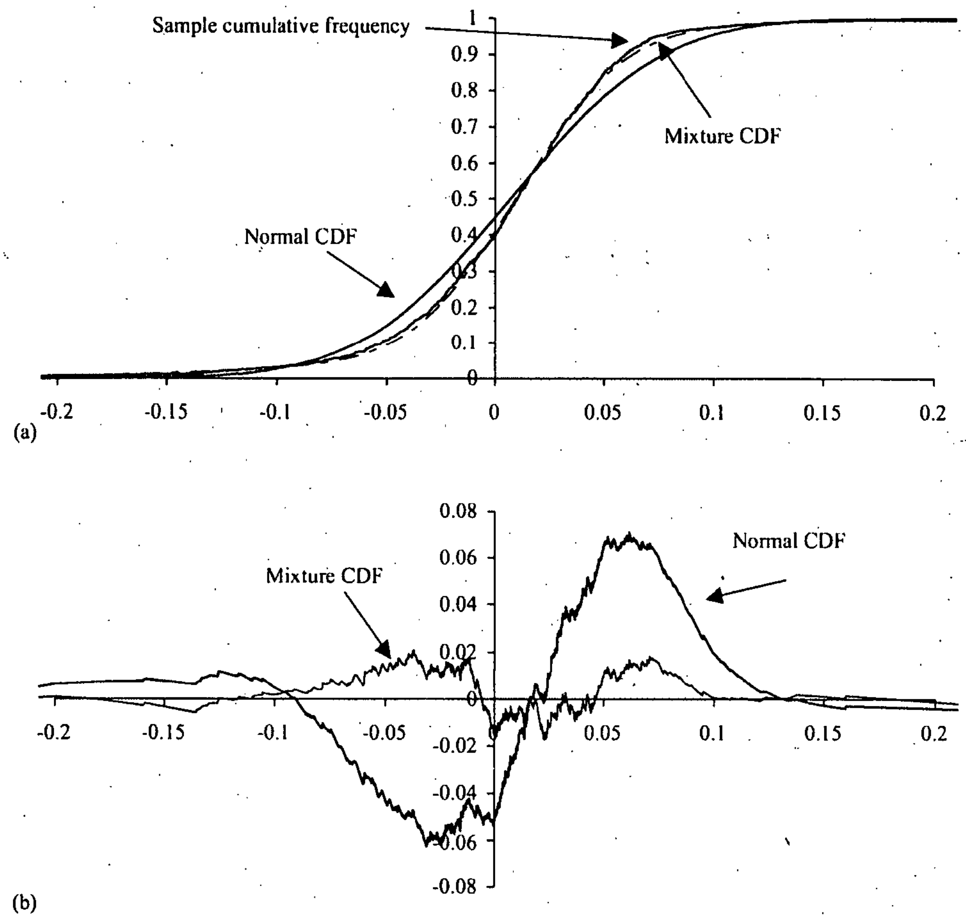

Fig. 2. Sample cumulative frequency distribution versus cumulative distribution functions (CDFs) for estimated mixture distribution and normal models. The mixture distribution is the implied distribution from the estimated two-state model presented in Table 2. The normal distribution is for the comparable static model with constant mean and variance. Panel A shows the cumulative distribution functions, and Panel B shows the corresponding errors between the actual and predicted CDFs.

The top panel of Table 3 groups returns into four categories: the first month of high-volatility periods, subsequent high-volatility months, the first month of low-volatility periods, and subsequent low-volatility months. For each category, I report the mean excess return and the associated p-value for a test of the null hypothesis that the true mean is zero. In addition, I report the standard deviation of returns, the average probability of being in the high-volatility state, and the number of observations for each category. The bottom panel of the table reports the results of hypothesis tests related to the predictions of the theoretical model.

Market returns are substantially more volatile during the identified high-volatility periods than low-volatility periods. Excluding the first month of each episode, the

Table 3

Statistical tests of categorized excess returns

Each monthly excess return is categorized as having been from one of two major categories: low- and high-volatility periods. A high-volatility period is defined as a continuous series of months for which the inferred probability of being in the high-volatility state is greater than 0.5. All other months are categorized as low volatility. Over the historical period, 21 high-volatility periods are identified. To test the predictions from the theoretical model regarding the transition between volatility states, returns are further categorized as having been from the first month or subsequent months of either a low- or high-volatility period. The top panel reports descriptive statistics for each category, and the bottom panel reports the results of a series of hypothesis tests.

Category	Monthly returns				
	Mean	*p*-value	Standard deviation	$Pr(s_t = H)$	*N* obs
Categorized returns					
All months	0.0069	0.0002	0.0549	0.1300	900
High-volatility periods					
First month	−0.1262	0.0000	0.0707	0.8844	21
Subsequent months	0.0114	0.4164	0.1212	0.8485	75
Low-volatility periods					
First month	0.0221	0.0004	0.0246	0.3694	22
Subsequent months	0.0096	0.0000	0.0379	0.0346	782
Hypothesis tests[a]	*t*-statistic	*p*-value			
First month of high-volatility periods equal to subsequent months of high-volatility periods	6.6075	<0.0001			
First month of low-volatility periods equal to subsequent months of low-volatility periods	2.3113	0.0301			
First month of high-volatility periods (ln returns) equal to negative of first month of low-volatility periods (ln returns)	6.5194	<0.0001			
Subsequent months of high-volatility periods equal to subsequent months of low-volatility periods	0.1295	0.8973			

[a] Based on the Smith-Satterhwaite test for difference in population means with unequal variances, Miller and Freund (1977).

annualized standard deviation of returns during the identified low- and high-volatility periods is 13.1% and 42.0%, respectively. Although the level of volatility in the two states is significantly different, the average excess return is not. Excluding the first month of each episode, the annualized average excess return during low- and high-volatility episodes is 13.7% and 11.5%, respectively. The *p*-value for a test of the null hypothesis that average excess returns in the low- and high-volatility periods are equal is 0.8973, indicating that the null hypothesis cannot be rejected at any reasonable level of confidence. This result is consistent with the time path of expected returns depicted by Fig. 1 in the theoretical discussion of the model. In addition, returns during the transition between volatility states are also generally consistent with those depicted in Fig. 1.

The average first month of low- and high-volatility episodes is significantly different from subsequent months. High-volatility periods start with a substantial loss in market value. The average excess return during the first month of the high-volatility periods equals −12.6% and is significantly different from zero. In contrast, the average excess return during subsequent high-volatility months is positive 1.1% but is not significantly different from zero. The *p*-value for a test of the null hypothesis that the mean of the first month of high-volatility periods equals the mean of subsequent high-volatility months is less than 0.0001, indicating that the null hypothesis can be rejected at any reasonable level of confidence. Low-volatility periods start with a significant increase in market value. The average excess return during the first month of the low-volatility periods is 2.2% and is significantly different from zero. The average excess return during subsequent low-volatility months equals 0.96% and is also significantly different from zero. Although the difference between the first-month and subsequent months of low-volatility periods is less pronounced than that of high-volatility periods, the average return during the first month of each low-volatility period is more than twice that of subsequent months and the difference in the mean returns is statistically significant. The *p*-value for a test of the null hypothesis that the mean of the first month of low-volatility periods equals the mean of subsequent low-volatility months is 0.0301, indicating that the null hypothesis can be rejected at the 5% level.

One aspect of the theoretical model is not supported by the data. Because the theoretical model assumes that there are only two states and that investors always correctly know the current state, the magnitude of the jump in log market value when the economy switches from the low-volatility state to the high-volatility state equals the magnitude of the jump in log market value when the economy returns to the low-volatility state. Although the point estimates of the average excess monthly returns low- and high-volatility periods are of the correct sign, the magnitude of the loss in market value when the economy enters the high-volatility state is significantly greater than the magnitude of the increase in market value when the economy returns to the low-volatility state. The *p*-value for a test of the null hypothesis that the magnitude of the mean excess log return during the first month of high-volatility periods is equal to the magnitude of the mean excess log return during the first month of low-volatility periods is less than 0.0001, indicating that the null hypothesis can be rejected at any reasonable level of confidence.

One explanation for the difference in first-month returns is that investors do not have perfect knowledge of the current state and so they must infer the volatility state from the returns they observe.[12] In this case, investors' ability to infer the current state is asymmetric. When the economy is in the low-volatility state, the standard deviation of returns is small and determining whether the economy has switched to

[12] Turner et al. (1989) explicitly incorporate learning into a Markov-switching model in which investors are uncertain of the true state.

the high-volatility state is easy. Large returns are unlikely to occur in the low-volatility state, so their occurrence quickly reveals to investors that the economy is in the high-volatility state. However, the inference problem is more difficult when the economy is in the high-volatility state. In the high-volatility state, small returns do not immediately reveal that the economy has switched states because a reasonable chance of getting a small return exists even though the standard deviation of returns is high. Instead, investors learn that the economy has returned to the low-volatility state over time by failing to observe enough large returns—or, in other words, by observing more small returns than are likely to occur in the high-volatility state. When investors have to learn whether the economy has switched states, the increase in market value associated with a return to the low-volatility state likely will occur over a longer period of time than the decrease in market value associated with a switch to the high-volatility state. In addition to the assumption that investors have perfect knowledge of the true volatility state, another important issue regarding the estimated model presented in Table 3 is whether the process governing the evolution of volatility states is constant over the estimation period.

Fig. 3 plots the historical returns on which the model is estimated along with the identified high-volatility periods represented by the shaded areas. Visual inspection of the figure suggests that the average duration of high-volatility periods is shorter during the later part of the sample than during the first part. The average duration of high-volatility periods is 7.2 months for the period from 1926 to 1940 versus only 2.6 months for the period after 1940. In addition, the average duration of low-volatility periods appears longer during the later part of the sample than during the first part of the sample. The average duration of low-volatility periods is only 11.3 months for the period from 1926 to 1940 versus 58.4 months for the period after 1940. The

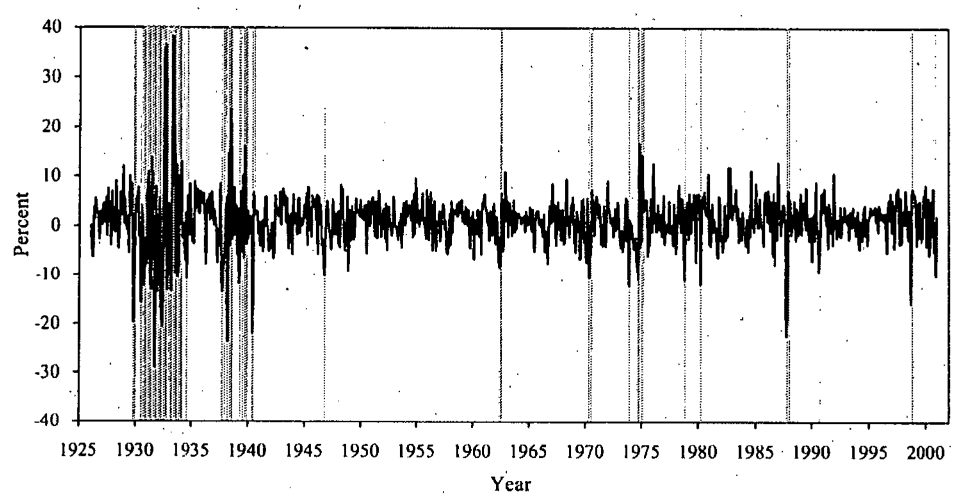

Fig. 3. Monthly excess returns and high-volatility state probability. The solid line plots the monthly excess returns for the period 1926 through 2000. The shaded areas correspond to the high-volatility episodes identified in Table 3. A high-volatility period is defined as a continuous series of months for which the inferred probability of being in the high-volatility state is greater than 0.5.

differences in the average durations of low- and high-volatility periods suggest that the transition probabilities governing the evolution of volatility states may not be constant over the historical period. A shift in the underlying volatility process is consistent with previous studies by Schwert (1989b), Pagan and Schwert (1990), and Pastor and Stambaugh (2001) that find evidence of structural shifts in the volatility of market returns. In my two-state model of the market risk premium, a shift in the transition probabilities governing the underlying volatility process would result in a change in the likelihood of the low- and high-volatility states and lead to a change in the unconditional market risk premium.

4. The effect of a structural shift in the volatility process

In this section of the paper, I augment the model to allow for a structural shift in the transition probabilities governing the evolution of the two volatility states. I assume there is a single structural break during the estimation period and test the estimated model against the null hypothesis of no structural break. To determine the most likely date for a structural shift in the volatility process, I estimate the augmented model for all possible annual breakpoints from 1927 through 1999 and select the breakpoint that maximizes the value of the estimated likelihood function. The analysis is then structured around the two subperiods defined by the most likely date for the structural shift in the volatility process.

Consistent with the approach presented in Section 3, the estimation method has three steps. In the first step, I estimate the time series model parameters allowing for a structural shift in the transition probabilities π_t and the means of the two state-dependent distributions μ_t.[13] I assume that the volatility of returns in each state remains constant over the estimation period. In the second step, I use Eq. (13) together with Eqs. (7)–(9) to find the corresponding values of γ, J_t, and K_t^* for each subperiod. I assume the value of γ is constant over the estimation period, but that the parameters J_t and K_t^* shift to correspond to the new transition probabilities. In the state-dependent model with a structural break, there are three free parameters, γ, $J_{L,\text{pre}}$, and $J_{L,\text{post}}$, available to match the four state-dependent means, $\mu_{L,\text{pre}}$, $\mu_{H,\text{pre}}$, $\mu_{L,\text{post}}$, and $\mu_{H,\text{post}}$. In contrast to the model presented in Section 3, the augmented model is no longer exactly identified. To find the values of the preference parameters that are consistent with the estimated moments of the two state-dependent distribution functions, I solve for the values of γ, $J_{L,\text{pre}}$, and $J_{L,\text{post}}$ that minimize the probability-weighted sum of the squared standardized errors over the entire estimation period. In the third step, I use the expression for the risk premium given by Eq. (3) together with the estimated model parameters to decompose the risk premium for each subperiod. These results are reported in Table 4.

[13] Diebold et al. (1994) discuss the estimation of time-varying transition probabilities in Markov-switching models.

Table 4

Parameter estimates and implied risk premium decomposition allowing for a structural shift in the underlying volatility process

Estimates are based on 900 monthly excess returns from January 1926 through December 2000. The most likely date for the structural shift in the volatility process is 1940. Panel A reports the parameter estimates for the augmented time series model based on Eq. (13). The augmented model allows for a shift in the transition probabilities π_t and the means μ_t of the two state-dependent distributions. The risk aversion coefficient γ and the standard deviation of returns within each state σ_t are assumed to remain constant, such that the intrastate risk premia are constant over the entire estimation period. For each of the two subperiods defined by the date for the structural shift, Panel B reports the estimated values of the preference parameters γ, J_t, and K_t^* from Eqs. (7)–(9) that are consistent with the estimated time series model. Panel C shows the implied decomposition of the market risk premium based on Eq. (3) and the estimated model parameters. Standard errors are reported in parentheses. Because of the nonlinear nature of the model, the standard errors reported in Panels B and C are simulated.

Volatility state	Time series parameters			Preference parameters			Risk premium decomposition: State probability	Risk premium decomposition: State-dependent risk		
	$\mu_t - r_t$	σ_t	π_t	γ	J_t	K_t^*		Intrastate	Interstate	Total
Pre-1940 (1926–1939)		*Panel A*			*Panel B*				*Panel C*	
Low volatility	0.243	0.127	0.033	1.703	−0.265	−0.289	0.611	0.028	0.097	0.124
($s_t = L$)	(0.052)	(0.004)	(0.029)	(0.762)	(0.133)	(0.151)	(0.075)	(0.011)	(0.053)	(0.057)
High volatility	−0.076	0.373	0.052	1.703	0.360	0.407	0.389	0.238	0.085	0.322
($s_t = H$)	(0.138)	(0.020)	(0.035)	(0.762)	(0.439)	(0.496)	(0.075)	(0.099)	(0.037)	(0.103)
Unconditional mean	0.119							0.109	0.092	0.201
	(0.0270)							(0.045)	(0.044)	(0.064)
Post-1940 (1940–2000)										
Low volatility	0.118	0.127	0.027	1.703	−0.175	−0.152	0.955	0.028	0.020	0.048
($s_t = L$)	(0.018)	(0.004)	(0.016)	(0.762)	(0.111)	(0.127)	(0.022)	(0.011)	(0.013)	(0.014)
High volatility	−0.574	0.373	0.571	1.703	0.213	0.179	0.045	0.238	0.322	0.560
($s_t = H$)	(0.487)	(0.020)	(0.158)	(0.762)	(0.268)	(0.361)	(0.022)	(0.099)	(0.294)	(0.273)
Unconditional mean	0.087							0.037	0.034	0.071
	(0.025)							(0.017)	(0.020)	(0.019)
Log-likelihood value	1,505.3									
Number of observations	900									

Panel A of Table 4 reports the results of the augmented time series model. After testing all possible annual breakpoints from 1927 to 1999, the date of the most likely breakpoint is 1940. The structural shift in the volatility process is statistically significant. The p-value for a likelihood ratio test of the null hypothesis of no structural shift is 0.0064, indicating that the null hypothesis can be rejected at standard levels of significance.[14] I also perform a test for structural change, which does not rely on the assumption that a structural shift has taken place. Based on the Andrews (1993) Lagrange multiplier test for regime changes, the null hypothesis that market returns during the 1930s were drawn from the same regime as the other returns can be rejected at the 1% level.[15] These results are consistent with results in Pagan and Schwert (1990) and Pastor and Stambaugh (2001) showing that the 1930s were a period of unusually high market volatility that cannot be explained by a single process over the complete historical period.

As a result of the structural shift in the volatility process, the expected duration of the high-volatility state falls dramatically after 1940. Before 1940, the point estimates of the transition probabilities π_t indicate that both volatility states are persistent. After 1940, however, only the low-volatility state is persistent. The expected duration of the low-volatility state increases marginally from 30.2 months for the period before 1940 to 37.2 months for the period after 1940. In contrast, the expected duration of the high-volatility state falls significantly from 19.2 months for the period before 1940 to only 1.8 months for the period after 1940.[16] The reduction in the length of time the economy is expected to remain in the high-volatility state dramatically reduces the unconditional probability of the economy being in the high-volatility state. As a result of the shift in the volatility process, the probability of the economy being in the high-volatility state falls from 38.9% for the period before 1940 to only 4.5% for the period after 1940.

Panel B reports the preference parameter estimates consistent with the augmented time series model. The point estimate of γ equals 1.703 and is larger than the estimate in the model with no structural shift. The point estimate of J_L equals −26.5% for the period before 1940 and −17.5% for the period after 1940. Because the higher discount rates associated with the high-volatility state are expected to be applied for a shorter period of time during the period after 1940, the point estimates for the expected change in market value when the economy enters the high-volatility state are consistent with the shortening of the expected duration of the high-volatility state.

[14]The likelihood ratio statistic for the null hypothesis of no structural shift equals 14.3 and is distributed as a chi-square with 4 degrees of freedom.

[15]The sup(LM) equals 29.62. The 1930s period corresponds to $\pi \in (0.0544, 0.1878)$ and a critical value of 22.54 for a 1% test.

[16]The reduction in the persistence of the high-volatility state is consistent with the results in Poterba and Summers (1986) showing that volatility is not persistent enough for volatility-feedback to be the sole cause of the changes in market value that are observed. However, my results suggest that volatility-feedback may have played a much larger role during the period before 1940.

Panel C reports the implied risk premium decomposition for the periods before and after the 1940 structural shift. Because of the dramatic reduction in the likelihood of being in the high-volatility state, the unconditional risk premium falls significantly after 1940. For the period before 1940, the point estimate of the unconditional risk premium is 20.1%. In contrast, for the period after 1940, the point estimate of the unconditional risk premium is only 7.1%. Although the magnitude of the individual components of the risk premium changes as a result of the structural shift, the proportion of the risk premium associated with the risk of future changes in volatility state remains relatively constant at about 45%.

Given the estimated reduction in the market risk premium, the average of ex post returns during the period following 1940 is likely to be a biased proxy of the ex ante expected return during the period since 1940. As investors learn that market risk has fallen because of the structural shift in the volatility process, stock prices will be bid up and ex post realized returns will be greater than ex ante expected returns. Assuming a real risk-free rate of 1%, a reduction in the market risk premium from 20% to 7% would cause the value of a perpetuity growing at a real rate of 2% per year to increase by approximately 213%. However, it is unlikely that investors would instantaneously realize that the transition probabilities governing the evolution of the two volatility states had changed. Given the expected duration of the low- and high-volatility periods, learning the values of the new transition probabilities would not be a trivial exercise and could easily take many years to uncover. For example, if this learning process took place over a period of 20 years, ex post returns would exceed ex ante expected returns during this period by approximately 5.9%. For this reason, I test for evidence of positive abnormal returns during the period following the 1940 structural shift in the underlying volatility process. Table 5 reports these results.

Table 5 presents actual excess returns for alternative subperiods from 1940 to 2000. I group the data by decade and report the average excess return for two periods: the decades immediately following the 1940 structural shift and the subsequent decades. The estimates in Table 5 show that the average excess return during the period from 1940 to 1959 is significantly greater than that during the subsequent 41-year period from 1960 through 2000. Consistent with the hypothesis of a structural shift in the volatility process following the 1930s, the p-value for a one-tailed test of the null hypothesis that the mean excess returns during these two periods are equal is 0.0458, indicating that the null hypothesis can be rejected at the 5% level. The magnitude of the excess return from 1940 to 1959 is also consistent with change in the market risk premium reported in Table 4. The average excess return during the 20-year period following the structural shift of 6.5% is comparable to the amortized percentage change in the value of a growing perpetuity implied by the reduction in the market risk premium of 5.9%. These results are consistent with the hypothesis that investors may have updated their beliefs regarding the level of market risk at some point during the period from 1940 to 1960. Given the evidence of abnormal returns after 1940, I re-estimate the model presented in Table 4 allowing for an abnormal return during the period following the structural shift.

Table 5
Analysis of excess returns during the period following the 1940 structural shift in the volatility process
Excess returns are grouped by decade into two subperiods following the structural shift: the period immediately following 1940 structural shift and the subsequent period. For each subperiod, the annualized mean excess return is reported along with the annualized standard deviation in returns and the difference in the means of the two subperiods. The last column reports the p-value for a one-tailed test of the null hypothesis of equal mean excess returns in the two subperiods.

Post-1940 subperiod	Mean	Standard deviation	Difference in means	p-value[a]
1: 1940–1949	10.0%	15.4%		
2: 1950–2000	8.2	14.5	1.8%	0.3662
1: 1940–1959	12.8	13.4		
2: 1960–2000	6.4	15.2	6.5	0.0458
1: 1940–1969	10.3	13.2		
2: 1970–2000	6.8	15.9	3.5	0.1775
1: 1940–1979	8.1	14.2		
2: 1980–2000	9.3	15.4	−1.2	0.6185
1: 1940–1989	8.2	14.7		
2: 1990–2000	9.9	14.2	−1.8	0.6438

[a] Based on Smith-Satterhwaite test for difference in population means with unequal variances, Miller and Freund (1977).

Table 6 reports the results from re-estimating the augmented model, allowing for abnormal returns during the 20-year period subsequent to the 1940 structural shift. The model is identical to that reported in Table 4 except for the inclusion of a dummy variable in the equations for the mean of each state-dependent distribution. The dummy variable equals one during the period from 1940 through 1959 and zero otherwise. The coefficient on the dummy variable provides an estimate of the mean abnormal return during the period following the structural shift. The point estimate of the average abnormal return during this period equals 5%, indicating that realized returns following the structural shift exceeded those required based on the underlying volatility process. The p-value for a one-tailed test that the estimated coefficient equals zero is 0.0941, indicating that the null hypothesis that there were no abnormal returns during this period can be rejected at the 10% level.

The estimated value of the market risk premium is substantially lower as a result of controlling for the presence of abnormal returns subsequent to the shift in the underlying volatility process. The point estimate of the unconditional risk premium for the period since 1940 is 5.6%, about 270 basis points lower than the historical average of excess market returns. Consistent with Brown et al. (1995) and Elton (1999), these results suggest that the simple historical average of excess market returns may substantially overstate the market risk premium for the period after the Great Depression. In addition, my results are consistent with the empirical finding in Fama and French (2002) that actual returns during the past 50 years have been much higher than expected. However, my method provides a structural basis for controlling for the extent of this bias and, as a result, provides an unbiased estimate of the market risk premium.

Table 6

Parameter estimates and implied risk premium decomposition allowing for a structural shift in the underlying volatility process and subsequent abnormal returns

Estimates are based on 900 monthly excess returns from January 1926 through December 2000. The date for the structural shift in the volatility process is 1940. The time series model adjusts for abnormal return during the 20-year period from 1940 through 1959. Panel A reports the parameter estimates for the augmented time series model based on Eq. (13). The augmented model allows for a shift in the transition probabilities π_t and the means μ_t of the two state-dependent distributions. The risk aversion parameter γ and the standard deviation of returns within each state σ_t are assumed to remain constant, such that the intrastate risk premia are constant over the entire estimation period. For each of the two subperiods defined by the date for the structural shift, Panel B reports the estimated values of the preference parameters γ, J_t , and K_t^* from Eqs. (7)–(9) that are consistent with the estimated time series model. Panel C shows the implied decomposition of the market risk premium based on Eq. (3) and the estimated model parameters. Simulated standard errors are reported in parentheses.

Volatility state	Time series parameters			Preference parameters			Risk premium decomposition			
							State probaility	State-dependent risk		
	$\mu_t - r_t$	σ_t	π_t	γ	J_t	K_t^*		Intrastate	Interstate	Total
Pre-1940 (1926–1939)		*Panel A*			*Panel B*				*Panel C*	
Low volatility	0.243	0.127	0.033	*1.491*	*−0.282*	−0.294	0.611	0.024	0.090	0.114
($s_t = L$)	(0.052)	(0.004)	(0.033)	(0.693)	(0.137)	(0.144)	(0.075)	(0.011)	(0.045)	(0.051)
High volatility	−0.075	0.375	0.052	1.491	0.393	0.416	0.389	0.209	0.084	0.293
($s_t = H$)	(0.138)	(0.020)	(0.038)	(0.693)	(0.365)	(0.460)	(0.075)	(0.096)	(0.042)	(0.107)
Unconditional mean	0.119							0.096	0.087	0.184
	(0.027)							(0.047)	(0.041)	(0.066)
Post-1940 (1940–2000)										
Low volatility	0.100	0.127	0.027	1.491	*−0.156*	−0.141	0.956	0.024	0.014	0.038
($s_t = L$)	(0.021)	(0.004)	(0.017)	(0.693)	(0.102)	(0.111)	(0.021)	(0.011)	(0.010)	(0.014)
High volatility	−0.576	0.375	0.579	1.491	0.184	0.164	0.044	0.209	0.237	0.447
($s_t = H$)	(0.492)	(0.020)	(0.157)	(0.693)	(0.186)	(0.214)	(0.021)	(0.096)	(0.261)	(0.267)
Unconditional mean	0.070							0.032	0.024	0.056
	(0.027)							(0.017)	(0.016)	(0.020)
Abnormal return: 1940–1959	0.050									
	(0.038)									
Log-likelihood value	1,506.3									
Number of observations	900									

5. Summary

This paper presents a method for estimating the market risk premium that incorporates shifts in investment opportunities and demonstrates the importance of accounting for the dynamic nature of market risk. Because of peso-type problems similar to that discussed in Rietz (1988), when investors anticipate changes in market value associated with future changes in the level of market risk, the ex post observed relationship between volatility and excess returns may severely distort the true ex ante relationship between risk and expected returns. My results suggest that the simple historical average of excess market volatility obscures significant variation in the market risk premium and that about half of the measured risk premium is associated with the risk of future changes in the level of market volatility.

The results presented in this paper also highlight the importance of distinguishing between ex post realized and ex ante expected returns as emphasized in Elton (1999). My analysis suggests that because of a structural shift in the volatility process underlying market returns and a reduction in the market risk premium, ex post returns during the period following the 1930s are not an unbiased estimate of ex ante expected returns. The bias in ex post returns is closely related to the survival bias discussed in Brown et al. (1995). My method provides a structural basis for controlling for the extent of this bias and allows for an unbiased estimate of the market risk premium. My corrected estimates suggest that the simple historical average of excess market returns substantially overstates the magnitude of the market risk premium for the period since the Great Depression.

Appendix A

Here, I derive the expression for the equilibrium risk premium given by Eq. (3) in Section 2. In the first section, I lay out the details of the investor's utility maximization problem and define the model parameters and assumptions. In the second section, I outline the steps involved in finding the equilibrium solution to this stochastic programming problem. And in the third section, I show that my solution collapses to the Merton (1969) solution to optimal lifetime portfolio selection under uncertainty when there are no changes in volatility states.

A.1. Model parameters and assumptions

I solve the utility maximization problem for a representative investor in an infinite horizon, continuous-time model with discrete volatility states. I assume that preferences are described by a power utility function parameterized by γ, the coefficient of relative risk aversion. I also assume that there are only two assets in which the investor can invest: a risk-free asset yielding a certain rate of return equal to r_t and a risky asset denoted S_t with an uncertain rate of return equal to dS_t/S_t. The standard deviation σ_t of the returns on the risky asset varies over time and is assumed to take on only two values, σ_L and σ_H. The simple average of the two volatility levels is denoted by the parameter $\bar{\sigma}$. Correspondingly, the expected drift in the price of the risky asset μ_t varies with state and takes on two values, μ_L and μ_H. The simple average of the two means is denoted by the parameter $\bar{\mu}$. In each volatility state, the probability that the economy will switch to the alternative volatility state is determined by the parameter π_t. Because the evolution of volatility states is assumed to follow a Markov process, π_t takes on two values, π_L and π_H. The simple average of the two values for π_t is denoted by the parameter $\bar{\pi}$. At each instant, the investor chooses an amount of consumption C_t and a fraction ω_t of his wealth W_t to invest in the risky asset. The investor's problem is given as

$$\max_{C_t,\omega_t} \quad \mathrm{E}_v \int_v^\infty \mathrm{e}^{-\rho t} \frac{C_t^{1-\gamma}}{1-\gamma} \, \mathrm{d}t, \tag{A.1}$$

$$\text{s.t. } \mathrm{d}W_t = \omega_t W_t \frac{\mathrm{d}S_t}{S_t} + (1-\omega_t) r_t W_t \, \mathrm{d}t - C_t \, \mathrm{d}t, \tag{A.2}$$

$$\mathrm{d}S_t = \mu_t S_t \, \mathrm{d}t + \sigma_t S_t \, \mathrm{d}Z + J_t S_t \, \mathrm{d}N(\pi_t), \tag{A.3}$$

$$\mathrm{d}\mu_t = 2(\bar{\mu} - \mu_t) \, \mathrm{d}N(\pi_t), \tag{A.4}$$

$$\mathrm{d}\sigma_t = 2(\bar{\sigma} - \sigma_t) \, \mathrm{d}N(\pi_t), \tag{A.5}$$

$$\mathrm{d}\pi_t = 2(\bar{\pi} - \pi_t) \, \mathrm{d}N(\pi_t), \tag{A.6}$$

$$\mathrm{d}J_t = 2(\bar{J} - J_t) \, \mathrm{d}N(\pi_t), \tag{A.7}$$

$$\mathrm{d}\hat{\lambda}_t = 2\left(\bar{\hat{\lambda}} - \hat{\lambda}_t\right) \mathrm{d}N(\pi_t), \tag{A.8}$$

and

$$C_t > \bar{C}_t, \tag{A.9}$$

where $\mathrm{d}Z$ is a standard Weiner process and $\mathrm{d}N(\pi_t)$ is a Poisson process that is equal to either zero or one. When $\mathrm{d}N(\pi_t) = 1$, Eqs. (A.4)–(A.6) cause the drift, volatility, and transition parameters to jump to the alternative state. Given the discrete jumps in these state variables, the equation describing the evolution of the stock price S_t includes the term $J_t S_t \, \mathrm{d}N(\pi_t)$, which allows the stock price to jump when the economy switches between volatility states. The parameter J_t is the magnitude of the jump in stock price that occurs when the economy switches state. The value of the jump parameter J_t takes on two values, J_L and J_H. The simple average of the two jump values is denoted by the parameter $\bar{J}$. Finally, Eqs. (A.8) and (A.9) allow for the possibility that consumption may be constrained in one of the volatility states. The value of the Lagrange multiplier associated with this constraint is given by the parameter $\hat{\lambda}_t$, which takes on two values, $\hat{\lambda}_L$ and $\hat{\lambda}_H$. The simple average of the two Lagrange multipliers is denoted by the parameter $\bar{\hat{\lambda}}$.

A.2. Derivation of the equilibrium solution

Given the problem described above, the indirect utility function at time v is defined as a function of the state variables at time v, such that

$$I_v = \max \mathrm{E}_v \int_v^{\infty} \mathrm{e}^{-\rho t} \frac{C_t^{1-\gamma}}{1-\gamma} \mathrm{d}t, \tag{A.10}$$

where $I_v = I(W_v, \mu_v, \sigma_v, \pi_v, J_v, \hat{\lambda}_v)$. From the principle of optimality,

$$\begin{aligned} 0 = & \frac{C_t^{1-\gamma}}{1-\gamma} - \rho I + [(\omega_t(\mu_t - r_t) + r_t)W_t - C_t]\frac{\partial I}{\partial W} \\ & + \frac{1}{2}\omega_t^2\sigma_t^2 W_t^2 \frac{\partial^2 I}{\partial W^2} + \pi_t \mathrm{E}_t[I_t' - I_t] + \hat{\lambda}_t C_t, \end{aligned} \tag{A.11}$$

where I_t' is the value of the indirect utility function subsequent to the next change of state and is equal to

$$I_t' = I\begin{pmatrix} W_t + \omega_t J_t W_t, \mu_t + 2(\bar{\mu} - \mu_t), \sigma_t + 2(\bar{\sigma} - \sigma_t), \\ \pi_t + 2(\bar{\pi} - \pi_t), J_t + 2(\bar{J} - J_t), \hat{\lambda}_t + 2(\bar{\hat{\lambda}} - \hat{\lambda}_t) \end{pmatrix}. \tag{A.12}$$

The first-order conditions for the investor's problem with respect to C_t and ω_t are given by the expressions

$$0 = C_t^{-\gamma} - \frac{\partial I}{\partial W} + \hat{\lambda}_t \tag{A.13}$$

and

$$0 = (\mu_t - r_t)W_t \frac{\partial I}{\partial W} + \omega_t \sigma_t^2 W_t^2 \frac{\partial^2 I}{\partial W^2} + \pi_t \mathrm{E}_t\left[J_t W_t \frac{\partial I'}{\partial W}\right]. \tag{A.14}$$

Defining $\hat{\lambda}_t$ in terms of the marginal utility of wealth, such that

$$\hat{\lambda}_t = \lambda_t \frac{\partial I}{\partial W}, \tag{A.15}$$

consumption at each instant is given by the expression

$$C_t = \left[(1 - \lambda_t)\frac{\partial I}{\partial W}\right]^{-1/\gamma}. \tag{A.16}$$

Because the net supply of the risk-free asset must equal zero in general equilibrium, the risk-free rate adjusts such that $\omega_t = 1$. Substituting Eq. (A.16) into Eq. (A.11), setting $\omega_t = 1$, and simplifying yields

$$\begin{aligned} 0 = & \frac{1}{1-\gamma}(1-\lambda_t)^{(\gamma-1)/\gamma}\left(\frac{\partial I}{\partial W}\right)^{(\gamma-1)/\gamma} - \rho I + \mu_t W_t \frac{\partial I}{\partial W} \\ & - (1-\lambda_t)^{(\gamma-1)/\gamma}\left(\frac{\partial I}{\partial W}\right)^{(\gamma-1)/\gamma} + \frac{1}{2}\sigma_t^2 W_t^2 \frac{\partial^2 I}{\partial W^2} + \pi_t \mathrm{E}_t[I_t' - I_t]. \end{aligned} \tag{A.17}$$

To solve Eq. (A.17), I guess the solution to be of the form

$$I_t = f_t \frac{W_t^{1-\gamma}}{1-\gamma}, \tag{A.18}$$

where $f_t = f(\mu_t, \sigma_t, \pi_t, J_t, \lambda_t)$. Because Eq. (A.18) must hold in each volatility state, the solution for the indirect utility function subsequent to the next change of state, I_t', is given by the expression

$$I_t' = f_t' \frac{(W_t')^{1-\gamma}}{1-\gamma}, \tag{A.19}$$

where f_t' and W_t' equal the values of f_t and W_t, respectively, in the subsequent volatility state. Given this solution, the first and second partial derivatives of I_t with respect to wealth are

$$\frac{\partial I}{\partial W} = f_t W_t^{-\gamma} \tag{A.20}$$

and

$$\frac{\partial^2 I}{\partial W^2} = -\gamma f_t W_t^{-(1+\gamma)}. \tag{A.21}$$

Substituting Eqs. (A.20) and (A.21) into Eq. (A.17), yields

$$\begin{aligned} 0 = &\frac{1}{1-\gamma}(1-\lambda_t)^{(\gamma-1)/\gamma}\left[f_t W_t^{-\gamma}\right]^{(\gamma-1)/\gamma} - \rho\left[f_t \frac{W_t^{1-\gamma}}{1-\gamma}\right] \\ &+ \mu_t f_t W_t^{1-\gamma} - (1-\lambda_t)^{(\gamma-1)/\gamma}\left[f_t W_t^{-\gamma}\right]^{(\gamma-1)/\gamma} \\ &+ \frac{1}{2}\sigma_t^2 W_t^2\left[-\gamma f_t W_t^{-(1+\gamma)}\right] + \pi_t \mathrm{E}_t\left[f_t' \frac{(W_t')^{1-\gamma}}{1-\gamma} - f_t \frac{W_t^{1-\gamma}}{1-\gamma}\right]. \end{aligned} \tag{A.22}$$

In general equilibrium, $\omega_t = 1$ such that all wealth is held in the form of the risky asset. For this reason, the expression Eq. (A.22) can be simplified by substituting the expression $W_t' = (1 + J_t)W_t$. This yields the expression

$$\begin{aligned} 0 = &f_t^{-1/\gamma}\gamma(1-\lambda_t)^{(\gamma-1)/\gamma} - \rho + (1-\gamma)\mu_t \\ &- \frac{1}{2}\gamma(1-\gamma)\sigma_t^2 + \pi_t \mathrm{E}_t\left[(1+\varepsilon_t)(1+J_t)^{1-\gamma} - 1\right], \end{aligned} \tag{A.23}$$

where $1 + \varepsilon_t = f_t'/f_t$. From Eqs. (A.16) and (A.20), $(1 + \varepsilon_t)$ is given by the expression

$$(1+\varepsilon_t) = \frac{(1-\lambda_t)(1+J_t)^\gamma}{(1-\lambda_t')(1+K_t)^\gamma}. \tag{A.24}$$

Substituting Eq. (A.24) into Eq. (A.23) and solving for $f(\mu_t, \sigma_t, \pi_t, J_t, \lambda_t)$ yields

$$\begin{aligned} f_t = &\left[\frac{\rho + (\gamma-1)\mu_t - \frac{1}{2}\gamma(\gamma-1)\sigma_t^2}{\gamma(1-\lambda_t)^{1-\gamma}}\right. \\ &\left. + \frac{\pi_t}{\gamma(1-\lambda_t)^{1-\gamma}}\left(1 - \frac{(1-\lambda_t)(1+J_t)^\gamma}{(1-\lambda_t')(1+K_t)^\gamma}\right)\right]^{-\gamma}, \end{aligned} \tag{A.25}$$

where K_t is the jump in consumption that is expected conditional on switching state. Because λ_t' can be expressed in terms of λ_t using Eqs. (A.8), (A.25) verifies that Eq. (A.18) is the solution to Eq. (A.17).

Using Eqs. (A.16), (A.20), and (A.25), the equilibrium consumption–wealth ratio in the model is given by

$$\frac{C_t}{W_t} = \frac{\rho + (\gamma - 1)\mu_t - \frac{1}{2}\gamma(\gamma - 1)\sigma_t^2}{\gamma(1 - \lambda_t)} + \frac{\pi_t}{\gamma(1 - \lambda_t)}\left(1 - \frac{(1 - \lambda_t)(1 + J_t)^\gamma}{(1 - \lambda_t')(1 + K_t)^\gamma}\right). \tag{A.26}$$

In Section A.3, I show that, when there are no changes in volatility states, the second term of Eq. (A.26) equals zero and the first term is equivalent to the Merton (1969) solution to the infinite horizon lifetime portfolio selection problem under uncertainty.

The expression for the equilibrium risk premium is found by taking the mathematical expectation of dS_t/S_t and substituting the equilibrium within-state excess return implied by the first-order condition for ω_t. From Eq. (A.3), the expected excess return on the risky asset is given by the expression

$$\mathrm{E}_t\left[\frac{dS_t}{S_t}\right] - r_t = \mu_t + \pi_t J_t - r_t. \tag{A.27}$$

The expression for the within-state excess return $\mu_t - r_t$ is derived by substituting Eqs. (A.20) and (A.21) into Eq. (A.14), setting $\omega_t = 1$, and simplifying, such that

$$\mu_t - r_t = \gamma\sigma_t^2 - \pi_t J_t (1 + \varepsilon_t)(1 + J_t)^{-\gamma}. \tag{A.28}$$

Combining Eqs. (A.27) and (A.28), substituting Eq. (A.24), and simplifying yields the expression for the equilibrium risk premium

$$\mathrm{E}_t\left[\frac{dS_t}{S_t}\right] - r_t = \gamma\sigma_t^2 + \pi_t J_t\left(1 - \frac{(1 - \lambda_t)}{(1 - \lambda_t')(1 + K_t)^\gamma}\right). \tag{A.29}$$

If the constraint on consumption does not bind in either state, then Eq. (A.29) can be simplified as

$$\mathrm{E}_t\left[\frac{dS_t}{S_t}\right] - r_t = \gamma\sigma_t^2 + \pi_t J_t[1 - (1 + K_t)^{-\gamma}]. \tag{A.30}$$

Eq. (A.30) is the expression for the market risk premium provided in the text as Eq. (3). Eq. (A.30) shows that the equilibrium risk premium in each state can be decomposed into two state-dependent risk premia, an intrastate risk premium and an interstate risk premium. The first term, $\gamma\sigma_t^2$, describes the required intrastate risk premium required to compensate for diffusion risk within the current state. The second term, $\pi_t J_t[1 - (1 + K_t)^{-\gamma}]$, describes the required interstate risk premium required to compensate for potential jump risk arising from a change in volatility state.

Eq. (A.29) can also be used to show that the equilibrium risk premium is invariant to the actual jumps in consumption that occur when the economy changes state. For example, if the constraint on consumption does not bind in either state, such that $\lambda_L = \lambda_H = 0$, then the risk premium in the low-volatility state is given by the expression

$$\mathrm{E}_t[R_L] - r_L = \gamma\sigma_L^2 + \pi_L J_L\left[1 - (1 + K_L^*)^{-\gamma}\right], \tag{A.31}$$

where K_L is the optimal change in the level of consumption when the economy switches from the low- to the high-volatility state. Alternatively, if consumption is unable to adjust when the economy enters the high-volatility state, then the constraint on consumption will bind in the high-volatility state, such that $\lambda_H > \lambda_L = 0$. In this case, the expression for the risk premium in the low-volatility state is given by the expression

$$\mathrm{E}_t[R_L] - r_L = \gamma\sigma_L^2 + \pi_L J_L\left[1 - (1 - \lambda_H)^{-1}(1 + \tilde{K}_L)^{-\gamma}\right], \tag{A.32}$$

where $\tilde{K}_L$ is the constrained change in the level of consumption when the economy switches from the low- to the high-volatility state. As a result of the constraint on consumption, the shadow price increases to reflect the fact that the actual level of consumption is no longer equal to the optimal level. The shadow price on the consumption constraint in the high-volatility state is given by the expression

$$\lambda_H = 1 - \left(\frac{1 + K_L^*}{1 + \tilde{K}_L}\right)^{\gamma}. \tag{A.33}$$

Eq. (A.33) is the expression for the Lagrange multiplier on the consumption constraint in the high-volatility state provided in the text as Eq. (4).

A.3. The special case of no changes in volatility state

This section shows that, when there are no changes in volatility state, my solution collapses to the Merton (1969) solution to the lifetime portfolio selection problem under uncertainty. Eqs. (A.26) and (A.30) summarize my solution to the investor's utility maximization problem when there are two discrete volatility states. Eq. (A.26) describes the optimal consumption–wealth ratio and Eq. (A.30) describes the equilibrium risk premium. If, instead, a single volatility state is assumed, then the dynamics associated with changes in volatility states can be turned off by setting $\pi_t = 0$ and $\lambda_t = 0$. By setting $\pi_t = 0$, only one volatility state is possible. With only one volatility state, there are no wealth jumps associated with changes in state and $\mathrm{E}_t[\mathrm{d}S_t/S_t] = \mu_t$. Also, because there are no jumps in wealth, there are no jumps in optimal consumption, so that $\lambda_t = 0$. Thus, for the special case of a single volatility state, Eqs. (A.26) and (A.30) can be rewritten as

$$\frac{C_t}{W_t} = \frac{\rho}{\gamma} + (\gamma - 1)\left[\frac{\mu_t}{\gamma} - \frac{\sigma_t^2}{2}\right] \tag{A.34}$$

and

$$\mu_t - r_t = \gamma\sigma_t^2. \tag{A.35}$$

Rearranging Eq. (A.34) yields

$$\frac{C_t}{W_t} = \frac{\rho}{\gamma} - (1 - \gamma)\left[\frac{\sigma_t^2}{2} + \frac{\mu_t - \gamma\sigma_t^2}{\gamma}\right]. \tag{A.36}$$

Using Eq. (A.35) to simplify the term $\mu_t - \gamma\sigma_t^2$, Eq. (A.36) can be rewritten as

$$\frac{C_t}{W_t} = \frac{\rho}{\gamma} - (1-\gamma)\left[\frac{\sigma_t^2}{2} + \frac{r_t}{\gamma}\right]. \tag{A.37}$$

Eq. (A.35) can also be used to express σ_t^2 in terms of excess returns, such that

$$\frac{C_t}{W_t} = \frac{\rho}{\gamma} - (1-\gamma)\left[\frac{\mu_t - r_t}{2\gamma} + \frac{r_t}{\gamma}\right]. \tag{A.38}$$

Finally, Eq. (A.35) can be used to rewrite the first term in brackets in a manner similar to that in Merton (1969)

$$\begin{aligned}\frac{C_t}{W_t} &= \frac{\rho}{\gamma} - (1-\gamma)\left[\frac{\mu_t - r_t}{2\gamma}\left(\frac{\mu_t - r_t}{\gamma\sigma_t^2}\right) + \frac{r_t}{\gamma}\right] \\ &= \frac{\rho}{\gamma} - (1-\gamma)\left[\frac{(\mu_t - r_t)^2}{2\gamma\sigma_t^2} + \frac{r_t}{\gamma}\right].\end{aligned} \tag{A.39}$$

Eq. (A.39) is equivalent to the Merton (1969) expression for the optimal consumption–wealth ratio in the infinite horizon lifetime portfolio selection problem.[17] This demonstrates that my model solution contains the Merton (1969) solution as a special case when there are no changes in volatility state.

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Assessing U.S. Vertically Integrated Utilities' Business Risk Drivers

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Table Of Contents

Assessing U.S. Vertically Integrated Utilities' Business Risk Drivers

The methodology that Standard & Poor's Ratings Services uses to rate vertically integrated electric, gas, and combination investor-owned utilities in the U.S. is based on the same precepts that we have used for many years, though the emphasis has changed as the utility industry has evolved. The fundamental methodology encompasses two basic components--business risk and financial risk--and their relationship. Where a utility presents a strong business risk profile, the financial profile can be less robust for any given rating. Likewise, where a utility's business risk profile is weaker, its financial performance must be stronger for any given rating. For combination utilities, the gas operations may have a stabilizing influence on credit quality, but since the electric business is typically significantly larger, it is the major credit driver. (For details on Standard & Poor's analytical approach to gas utilities, see "Key Credit Factors For Natural Gas Distributors" published Feb. 28, 2006.)

Often, an integrated utility is a part of a larger holding company structure that also owns other businesses, frequently unregulated electricity generation. This fact does not alter how we analyze the utility, but it may affect the ultimate rating outcome due to any credit drag that the unregulated activities may have on the utility. Such considerations include the freedom and practice of management with respect to shifting cash resources among subsidiaries and the presence of ring-fencing mechanisms that may protect the utility.

Five Factors Determine The Business Profile

Five basic characteristics define a vertically integrated utility's business profile:

- Regulation,
- Markets,
- Operations,
- Competitiveness, and
- Management.

Standard & Poor's is most concerned about how these elements contribute individually and in aggregate to the predictability and sustainability of financial performance, particularly cash flow generation relative to fixed obligations. While considerable attention has focused in recent years on companies in states that deregulated in the late 1990s and the early part of this decade and the related credit consequences of disaggregation and nonregulated generation, 27 states (plus four that formally reversed, suspended, or delayed restructuring) have retained the traditional regulated model. For utilities operating in those states, the quality of regulation and management loom considerably larger than markets, operations, and competitiveness in shaping overall financial performance. Policies and practices among state and federal regulatory bodies will be key credit determinants. Likewise, the quality of management, defined by its posture towards creditworthiness, strategic decisions, execution and consistency, and its ability to sustain a good working relationship with regulators, will be key. Importantly, however, it is virtually impossible to completely segregate each of these characteristics from the others; to some extent they are all interrelated.

On Standard & Poor's business profile scale (where '1' is excellent and '10' is vulnerable), vertically integrated utilities generally have satisfactory business profiles of '5' or '6'. (See tables 1 and 2 in the Appendix below for

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business profile benchmarks plus a list of utilities we rate and their business profile scores.) We view a company that owns regulated generation, transmission, and distribution operations, as positioned between companies with relatively low-risk transmission and distribution operations and companies with higher-risk diversified activities on the business profile spectrum. What typically distinguishes one vertically integrated utility's business profile score from another is the quality of regulation and management.

Regulation

Regulation is a critical aspect that underlies integrated utilities' creditworthiness. Decisions by state public service commissions can profoundly affect financial performance. Standard & Poor's assessment of the regulatory environments in which a utility operates is guided by certain principles, most prominently consistency and predictability, as well as efficiency and timeliness. For a regulatory scheme to be considered supportive of credit quality, commissions must limit uncertainty in the recovery of a utility's investment. They must also eliminate, or at least greatly reduce, the issue of rate-case lag, especially when a utility engages in a sizable capital expenditure program and incurs substantial deferrals of fuel costs.

Standard & Poor's evaluation encompasses the administrative, judicial, and legislative processes involved in state and federal regulation, and includes the political environment in which commissions render decisions. Regulation is assessed in terms of its ability to satisfy the particular needs of individual utilities. Rate-setting actions are reviewed case-by-case with regard to the potential effect on credit quality. As frequently postulated in prior years, our evaluation of regulation focuses on the willingness and ability of regulation to provide cash flow and earnings quality adequate to meet investment needs, earnings stability through timely recognition of volatile cost components such as fuel and satisfactory returns on invested capital and equity. Regulators' authorization of high rates of return is of little value unless returns are realistic and achievable. Allowing high returns based on noncash items does not benefit bondholders. A regulatory jurisdiction that permits incentives whereby utilities are allowed to earn a return based on their ability to sustain rates at competitive levels is viewed favorably. In addition to performance-based rewards or penalties, flexible plans could include market-based rates, price caps, index-based prices, and rates premised on the value of customer service. Also important is the ability to enter into long-term arrangements at negotiated rates without having to seek regulatory approval for each contract.

Because the bulk of a utility's operating expenses relate to fuel and purchased power, of primary importance to rating stability is the level of support that state regulators provide to utilities for fuel cost recovery, particularly as gas and coal costs have risen. Utilities that are operating under rate moratoriums, or without access to fuel and purchased-power adjustment clauses or with fixed-fuel mechanisms, or face significant regulatory lag, also are subject to reduced operating margins, increased cash flow volatility, and greater demand for working capital. Companies that are granted fuel true-ups may be required to spread recovery over many years to ease the pain for the consumer. Standard & Poor's notes that fuel-adjustment mechanisms have become more common in the industry, but not all are created equal. While some jurisdictions permit recovery on a dollar-for-dollar basis over a defined time period, certain jurisdictions, such as Washington State, impose a deadband in which the company absorbs all the risk and rewards of fuel costs above and below the established recovery rate. Beyond the deadband there is a sharing of risks and rewards with ratepayers. In Arizona, Arizona Public Service Co. has a 90/10 sharing mechanism between the company and ratepayers, respectively, for all costs passed through the power supply adjuster. The mechanism is triggered based on a date (once a year in February 2006) and not on a threshold level of deferrals. The annual adjustment is also subject to a lifetime cap of 4 mils per kilowatt-hour, which has led to power deferrals.

In addition to fuel cost recovery filings, regulators will have to address significant rate increase requests related to new generating capacity additions, environmental modifications, and reliability upgrades. Current cash recovery and/or return by means of construction work in progress support what would otherwise be a sometimes significant cash flow drain and reduces the utility's need to issue debt during construction.

Moreover, allowing rate recovery of projected costs with subsequent periodic updates for actual results reduces lags in cost recovery. Also supportive of credit quality is the ability of the utility, commission staff, consumer advocates, and other major interveners to reach a comprehensive settlement before construction of new base load capacity. Certain states, such as Indiana, Texas, Kansas, and Minnesota, have adopted environmental tracking mechanisms and other riders that allow companies to reflect in rates capital costs associated with environmental compliance equipment without having to file a formal rate case. In Florida, utilities may issue securitized debt to recover storm costs after the public service commission completes a prudency review. However, if the utilities do not choose securitization, then they may file a request with the regulatory commission to get a surcharge. In either situation, there will be some delay in recovering the costs, but the delay should be minimized compared with previous years.

Creditworthiness can also be enhanced when a company has the authority to timely recover unanticipated costs, such as those incurred for repairing storm damage, as in Florida and Mississippi. While the Alabama Public Service Commission does not currently employ a separate storm repair cost recovery mechanism to ensure rapid recovery of storm repair costs, it has shown a willingness to work with utilities to help them recover at least some of these costs on a timely basis and to start replenishing storm reserves. Finally, the greater the percentage of a utility's rates that are recovered through fixed charges rather than volume-based charges, the greater the support for credit quality.

For utilities that own a natural gas business, automatic and timely pass-through of commodity costs provides the strongest level of credit support. Lesser clauses, including mechanisms that require after-the-fact sign-off by regulators, introduce the potential for disallowance if the regulator deems gas to be purchased at imprudent cost levels.

Due to the extreme volatility and high gas prices over the past few heating seasons, more regulators have revised gas adjustment clauses to provide monthly gas adjustments rather than awaiting the end of the heating season to begin reimbursement. This expedited treatment helps the utility to reduce any regulatory lag to recover costs and streamlines working capital needs, which in turn should allow the firm to modestly temper rising gas bills to their customers.

Both regulators and natural gas companies are increasing customer-education programs on energy efficiency and conservation. Lawmakers, state regulators, and companies are in preliminary discussions to potentially restructure the current rate structures to encourage these goals of energy conservation and efficiency without hurting the company's bottom line and still allow utilities to achieve their approved regulated rate of return. In essence, "conservation tariffs" would aim to decouple earnings and rates of return from delivered volumes and should eliminate a current major disincentive for utilities to develop such conservation programs. This would also better align the interest of consumers with utility shareholders by implementing innovative rate designs that would encourage energy conservation and efficiency.

Key success factors include:

- Alternative ratemaking/flexibility,
- Attention to credit quality,

- Timely and consistent rate treatment,
- Support for fuel cost recovery,
- Support for a reasonable cash return on investment, and
- Support for rapid return on investment.

Markets

Assessing market dynamics begins with an economic and demographic evaluation of the service area in which a utility operates. Strength of long-term demand for energy is examined from a macroeconomic perspective, which enables Standard & Poor's to measure the affordability of rates and the staying power of demand. Distribution by classification according to total number of customers, revenues, and margins is closely scrutinized to assess the depth and diversity of the utility's customer mix. For example, heavy industrial concentration is viewed with some caution because the utility may be exposed to cyclical volatility and face competitive alternatives. A large residential component, on the other hand, produces a more stable and predictable revenue stream. The utility's largest customers are identified to determine their stability and importance to the bottom line because the loss of one large customer could adversely affect the utility's financial position. Moreover, large customers may turn to self-generation, potentially leading to less financial protection for the utility.

Standard & Poor's also analyzes any long-term consumption trends and the reasons behind them. Factors addressed include the market's size and growth rate, the franchise's strength, historical and projected growth rates, income levels and trends in population, employment, and per capita income. A utility with a healthy economy and customer base, as illustrated by diverse employment opportunities, average or above-average wealth and income statistics, and low unemployment, will be better able to support its operations.

For the gas business, Standard & Poor's also examines customer saturation. Firms that operate in service areas with low growth potential still can expand at healthy rates if a relatively low level of customer saturation permeates the service territory. For example, customers who convert to natural gas from other fuel sources (such as oil) provide growth opportunities to companies operating in low population growth service areas.

Despite the review of market characteristics, they are clearly a secondary consideration to regulation. In Nevada, for years the country's fastest growing state, Nevada Power Co. and Sierra Pacific Power Co. struggled to recover capital expenditures on a timely basis, and were accordingly rated as low investment-grade credits. In Florida, which has competed with Nevada for years in its pace of growth, the Florida Public Service Commission established polices of quick recovery of capital investments and, on a stand-alone basis, the state's utilities' credit metrics have remained strong.

Critical success factors include:

- A healthy and growing economy,
- Growth in population and number of customers,
- An attractive business environment, and
- An above-average residential base.

Operations

Standard & Poor's focuses on cost, reliability, safety, and quality of service when assessing a utility's operations. Management is always under pressure to optimize the use of resources, and if it is not cost-effective in meeting service standards and reliability, regulatory or competitive pressures are likely to increase. Consequently, Standard

& Poor's emphasizes areas that require heightened and ongoing management attention, in the absence of which political, regulatory, or competitive problems are likely to arise.

The status of utility plant investment is reviewed with regard to generating station availability, efficiency, and utilization, as well as for compliance with existing and potential environmental and other regulatory standards. The record of plant outages, system losses, equivalent availability, load factors, heat rates, and capacity factors are examined. Important considerations include the projected capital improvements and plant additions necessary to provide high-quality, reliable service. The general condition of the assets and how well such assets are maintained are also important considerations.

Emphasis is placed on reserve margins, fuel mix, fuel contract terms, purchased-power arrangements, and system operators. Moreover, the quality and concentration of capacity is just as important as the size of reserves. Standard & Poor's recognizes that reserve requirements differ among companies, depending upon individual operating and load characteristics.

Fuel diversity provides flexibility in a changing environment. Supply disruptions and price hikes can raise rates and ignite political and regulatory pressures that ultimately lead to erosion in financial performance. Thus, the ability to switch generating sources to take advantage of cheaper fuels is viewed favorably. Dependence on any single fuel, or asset concentration in one or two large generating stations, can cause significant swings in a company's financial performance. Similarly, utilities that rely on nuclear generation receive an elevated degree of attention due to the scale, technical complexity, and politically sensitive nature of nuclear facilities. Indeed, the sound operation of nuclear units can define a utility's operational risk profile and its ability to achieve projected financial results. Standard & Poor's seeks to distinguish between those operators that have exhibited sound and stable operational performance, and the likelihood that it will continue, and those whose nuclear operations are vulnerable to problems that may impair financial results.

But having a large concentration of capacity based on fossil fuels also imposes certain risks. Coal-fired capacity is burdened with increased environmental costs related to reducing sulfur dioxide, nitrogen oxide, mercury, and eventually carbon dioxide emissions. Gas-fired capacity presents its own challenges, particularly the extreme volatility and significant increase in gas prices over the past few years. Buying power may be a more appropriate option for a utility than new plant construction because the utility avoids construction costs and the financial risks posed by regulatory lag when seeking recovery of costs. Purchasing power may enhance supply flexibility, fuel resource diversity, and maximize load factors. Utilities that plan to meet demand projections with a portfolio of supply-side options also may be better able to adapt to future growth uncertainties. Despite these benefits, such a strategy does commit the utility to a fixed obligation, which Standard & Poor's captures analytically through certain adjustments to financial statements. We calculate the net present value of future annual capacity payments (discounted at the company's cost of debt) over the life of the contract. Standard & Poor's then applies a risk factor against this value and adds the result to the utility's balance sheet. The risk factor is largely a function of the strength of the regulatory recovery mechanisms established to address procurement costs.

Other operational characteristics that will support an above-average evaluation for vertically integrated companies are assets that are in good physical condition and are well maintained. In addition, capital expenditures for necessary system improvements must be at manageable levels, yet sufficient to provide for constant renewal and refurbishment of the system. Operating performance, reliability statistics (such as outage duration and frequency), and efficiency measures are expected to meet industry and regional averages. Having interconnections that provide access to low-cost and diverse power supply sources is viewed favorably, as is limited environmental exposure.

For a gas company, drawing from a single interstate pipeline or relying on a particular gas basin exposes it to event risk and negative supply shocks, respectively. The ability to access multiple sources of gas supply through multiple pipelines protects the utility from such disruptions. Adequate storage access not only helps supply incremental gas needed to meet peak demand, but also provides opportunities without purchased-gas adjustment clauses to arbitrage seasonal pricing fluctuations. Gas distributors benefit from storage if the cost of buying peak gas exceeds the cost of making off-season purchases and the associated carrying cost. Outdated systems requiring extensive maintenance and capital expenditures lower profitability and efficiency metrics. Newly installed systems mainly consisting of plastic pipe require limited expenditures over the long term compared with older, cast-iron systems that need replacing as they age. In addition, operational efficiencies can be obtained through the use of new technology.

Critical success factors include:

- Well-maintained assets,
- Solid plant performance,
- Fuel diversity,
- Adequate generating reserves, and
- Compliance with environmental standards.

Competitiveness

For vertically integrated utilities, competitive factors include percentage of firm wholesale revenues that are most vulnerable to competition, industrial load, and revenue concentrations, particularly in energy intensive industries; exposure of key customers to alternative suppliers; commercial concentrations; rates charged to various customer classes; rate design and flexibility; production costs, both marginal and fixed; the regional capacity situation; and transmission constraints. A regional focus is evident, but high costs and rates relative to national averages are also of significant concern because of the potential for electricity substitutes over time.

Electricity competes with other fuels--particularly natural gas--for certain segments of the market like space heating, water heating, and cooking. Thus, high electricity prices, which can be attributed to inefficient operations, are cause for concern if customers have access to alternative energy sources. Self-generation has been a risk, as large commercial and industrial customers may take advantage of cogeneration technologies to reduce their reliance on, and in some cases to disconnect from the system. In the future, technology could pose a greater threat. Bypass risk, too, may grow if distributed generation, microgeneration, and self-generation prove more economically attractive for smaller customers.

Due to their proximity to interstate gas pipelines, some large customers can directly tie into a transmission line and completely bypass gas distributors' services. Although such pipelines provide key sources of gas supply for these companies, it is important to recognize this bypass risk. Ideally located gas companies have adequate transmission access but have industrial customers far from interstate pipelines.

Critical success factors include:

- Low cost structure,
- Limited bypass risk, and
- Management's commitment to lowering costs.

Management

Evaluating management is of paramount importance to Standard & Poor's analysis because management decisions affect all areas of a company's operations and financial health. Although regulation, the economy, and other outside factors certainly influence results, the quality of management ultimately determines a company's success. Standard & Poor's private meetings with senior management significantly augment the public record in the effort to appraise management. Meetings are very useful for the candid interpretation of recent developments and, importantly, to provide executives with a forum for the presentation of goals, objectives, and strategies.

Management assessment is based on tenure, turnover, industry experience, financial track record, corporate governance, a grasp of industry issues, and knowledge of regulation, of customers, and their needs. Management's ability and willingness to develop workable strategies to address system needs, and to execute reasonable and effective long-term plans are assessed. Management quality is also indicated by thoughtful balancing of multiple--and often incompatible--priorities; a record of credibility; and effective communication with the public, regulatory bodies, and the financial community.

Standard & Poor's also focuses on management's ability to achieve cost-effective operations and commitment to maintaining credit quality. This can be assessed by evaluating accounting and financial practices, capitalization and common dividend objectives, and the company's philosophy regarding growth and risk-taking.

In addition, a company's accounting and financing practices are critical to Standard & Poor's analysis. For example, proactive management will likely adopt accounting practices that are more appropriate in a competitive environment such as higher depreciation rates for electric generation equipment.. Large, growing cost deferrals or regulatory assets are viewed more negatively. Management can enhance its financial condition by taking any number of discretionary actions, such as selling common equity, reducing the common dividend payout, and deleveraging. A utility's management will also be evaluated on cost-cutting ability and creativity in entering into strategic alliances that improve efficiency.

Strong corporate governance, reflected in active, independent board of directors that participate in determining and monitoring corporate controls, help to support management's credibility and corporate financial disclosure. If it is evident that a company's board is passive and does not exercise proper oversight, it weakens the checks and balances of the organization and may detract from credit quality. Included in Standard & Poor's review of corporate governance is the proportion of independent directors on the board, the breadth and depth of the directors' experience, the proportion of independent directors on the board's audit committee, and directors' compensation.

Some vertically integrated utilities have felt compelled to invest outside their traditional businesses to increase earnings, especially as stock prices have underperformed market indices. Participation in higher-risk, unregulated activities such as merchant generation, exploration and development, gathering and processing, or marketing and trading can significantly detract from the consolidated entity's credit profile. In this regard, credit ratings are not based on the regulated business only, but on the qualitative and quantitative fundamentals of the consolidated entity. Standard & Poor's considers the ratings of the regulated businesses as being less vulnerable to the negative credit influence of other affiliates and holding company activities, as relevant, where very strong structural and/or regulatory insulation exists, which tends to be more the exception than the rule.

Critical success factors include:

- Commitment to credit quality,

- Credibility,
- Strong corporate governance, and
- Conservative financial policies, especially regarding nonregulated activities, if relevant.

Effect On Ratings

In summary, Standard & Poor's examines the key business risk drivers for vertically integrated utilities--regulation, markets, operations, competitiveness, and management--in conjunction with financial measures when assigning credit ratings. The credit quality of most vertically integrated utilities is solidly investment grade. This is a primarily a function of the existence of regulation. As discussed above, the factors that further differentiate ratings among this sector include their markets, operational track record, competitive posture, and management's risk appetite. Vertically integrated utilities generally have satisfactory business risk profile scores, with only a few having strong or weak business positions.

Appendix

Table 1

Industry Benchmarks

Business Profile	AA		A		BBB		BB	
Adjusted FFO interest coverage (x)								
1	3.0	2.5	2.5	1.5	1.5	1.0	< 1.0	< 1.0
2	4.0	3.0	3.0	2.0	2.0	1.0	< 1.0	< 1.0
3	4.5	3.5	3.5	2.5	2.5	1.5	1.5	1.0
4	5.0	4.2	4.2	3.5	3.5	2.5	2.5	1.5
5	5.5	4.5	4.5	3.8	3.8	2.8	2.8	1.8
6	6.0	5.2	5.2	4.2	4.2	3.0	3.0	2.0
7	8.0	6.5	6.5	4.5	4.5	3.2	3.2	2.2
8	10.0	7.5	7.5	5.5	5.5	3.5	3.5	2.5
9	N/A	N/A	10.0	7.0	7.0	4.0	4.0	2.8
10	N/A	N/A	11.0	8.0	8.0	5.0	5.0	3.0
Adjusted FFO/average total debt (%)								
1	20.0	15.0	15.0	10.0	10.0	5.0	< 5.0	< 5.0
2	25.0	20.0	20.0	12.0	12.0	8.0	< 8.0	< 8.0
3	30.0	25.0	25.0	15.0	15.0	10.0	10.0	5.0
4	35.0	28.0	28.0	20.0	20.0	12.0	12.0	8.0
5	40.0	30.0	30.0	22.0	22.0	15.0	15.0	10.0
6	45.0	35.0	35.0	28.0	28.0	18.0	18.0	12.0
7	55.0	45.0	45.0	30.0	30.0	20.0	20.0	15.0
8	70.0	55.0	55.0	40.0	40.0	25.0	25.0	15.0
9	N/A	N/A	65.0	45.0	45.0	30.0	30.0	20.0
10	N/A	N/A	70.0	55.0	55.0	40.0	40.0	25.0
Adjusted total debt/total capital (%)								
1	48.0	55.0	55.0	60.0	60.0	70.0	> 70.0	> 70.0

Table 1

Industry Benchmarks(cont.)								
2	45.0	52.0	52.0	58.0	58.0	68.0	>68.0	>68.0
3	42.0	50.0	50.0	55.0	55.0	65.0	65.0	70.0
4	38.0	45.0	45.0	52.0	52.0	62.0	62.0	68.0
5	35.0	42.0	42.0	50.0	50.0	60.0	60.0	65.0
6	32.0	40.0	40.0	48.0	48.0	58.0	58.0	62.0
7	30.0	38.0	38.0	45.0	45.0	55.0	55.0	60.0
8	25.0	35.0	35.0	42.0	42.0	52.0	52.0	58.0
9	N/A	N/A	32.0	40.0	40.0	50.0	50.0	55.0
10	N/A	N/A	25.0	35.0	35.0	48.0	48.0	52.0

Note: Business profile scores are characterized from '1' (excellent) to '10' (weak). FFO--Funds from operations. N/A--Not applicable.

Table 2

Vertically Integrated Utilities		
Company	**Corporate credit rating**	**Business profile score**
Aquila Inc.	B/CW-Pos/B-2	6
AGL Resources Inc.	A-/Negative/A-2	4
Alabama Power Co.	A/Stable/A-1	4
ALLETE Inc.	BBB+/Stable/A-2	5
Ameren Corp.	BBB+/CW-Neg/A-2	6
Appalachian Power Co.	BBB/Stable/--	5
Arizona Public Service Co.	BBB-/Stable/A-3	6
Atmos Energy Corp.	BBB/Stable/A-2	4
Black Hills Power Inc.	BBB-/Negative/--	6
Central Illinois Light Co.	BBB+/CW-Neg/--	7
Central Vermont Public Service Corp.	BB+/Stable/--	6
CILCORP Inc.	BBB+/CW-Neg/--	7
Cincinnati Gas & Electric Co.	BBB/Positive/A-2	6
Cleco Power LLC	BBB/Negative/--	6
Cleveland Electric Illuminating Co.	BBB/Stable/--	6
Consolidated Natural Gas Co.	BBB/Stable/A-2	6
Consumers Energy Co.	BB/Stable/--	6
Dayton Power & Light Co.	BB+/Positive/--	5
Detroit Edison Co.	BBB/Stable/A-2	6
Duke Power Co. LLC	BBB/Positive/A-2	4
El Paso Electric Co.	BBB/Stable/--	6
Empire District Electric Co.	BBB-/Stable/A-3	6
Energy East Corp.	BBB+/Negative/A-2	3
Enogex Inc.	BBB+/Stable/--	7
Entergy Arkansas Inc.	BBB/Negative/--	5
Entergy Gulf States Inc.	BBB/Negative/--	6
Entergy Louisiana LLC	BBB/Negative/--	5
Entergy Mississippi Inc.	BBB/Negative/--	6

Table 2

Vertically Integrated Utilities(cont.)		
Entergy New Orleans Inc.	D/--/--	8
Equitable Resources Inc.	A-/CW-Neg/A-2	8
Florida Power & Light Co.	A/CW-Neg/A-1	4
Georgia Power Co.	A/Stable/A-1	4
Green Mountain Power Corp.	BBB/CW-Pos/--	5
Gulf Power Co.	A/Stable/--	4
Hawaiian Electric Co. Inc.	BBB+/Negative/A-2	5
IDACORP Inc.	BBB+/Negative/A-2	5
Idaho Power Co.	BBB+/Negative/A-2	5
Indiana Michigan Power Co.	BBB/Stable/--	6
Indianapolis Power & Light Co.	BB+/Positive/--	4
Interstate Power & Light Co.	BBB+/Stable/A-2	5
IPALCO Enterprises Inc.	BB+/Positive/--	4
Kansas City Power & Light Co.	BBB/Stable/A-2	6
Kansas Gas & Electric Co.	BB+/Positive/--	6
Kentucky Power Co.	BBB/Stable/--	5
Kentucky Utilities Co.	BBB+/Stable/A-2	5
Louisville Gas & Electric Co.	BBB+/Stable/--	5
Madison Gas & Electric Co.	AA-/Stable/A-1+	4
Michigan Consolidated Gas Co.	BBB/Stable/A-2	4
MidAmerican Energy Co.	A-/Stable/A-1	5
Mississippi Power Co.	A/Stable/A-1	4
Monongahela Power Co.	BB+/Positive/--	5
Montana-Dakota Utilities Co.	BBB+/Stable/--	6
National Fuel Gas Co.	BBB+/Stable/A-2	7
Nevada Power Co.	B+/Positive/--	6
New York State Electric & Gas Corp.	BBB+/Negative/A-2	3
NiSource	BBB/Stable/--	4
Northern Indiana Public Service Co.	BBB/Stable/--	5
Northern States Power Co.	BBB/Stable/A-2	5
Northern States Power Wisconsin	BBB+/Stable/--	4
Ohio Edison Co.	BBB/Stable/A-2	6
Oklahoma Gas & Electric Co.	BBB+/Stable/A-2	5
Pacific Gas & Electric Co.	BBB/Stable/A-2	5
PacifiCorp	A-/Stable/A-1	5
Pennsylvania Power Co.	BBB/Stable/--	6
Pinnacle West Capital Corp.	BBB-/Stable/A-3	6
PNM Resources Inc.	BBB/Negative/A-3	6
Portland General Electric Co.	BBB+/Negative/A-2	5
Progress Energy Carolinas Inc.	BBB/PositiveA-2	5
Progress Energy Florida Inc.	BBB/Positive/A-2	4
PSI Energy Inc.	BBB/Positive/A-2	4

Table 2

Vertically Integrated Utilities(cont.)		
Public Service Co. of Colorado	BBB/Stable/A-2	4
Public Service Co. of New Hampshire	BBB/Stable/--	5
Public Service Co. of New Mexico	BBB/Negative/A-3	6
Public Service Co. of Oklahoma	BBB/Stable/--	5
Puget Energy Inc.	BBB-/Stable/--	4
Puget Sound Energy Inc.	BBB-/Stable/A-3	4
Questar Market Resources Inc.	BBB+/Stable/---	8
Rochester Gas & Electric Corp.	BBB+/Negative/--	3
San Diego Gas & Electric Co.	A/Stable/A-1	5
Savannah Electric & Power Co.	A/Stable/--	4
SCANA Corp.	A-/Stable/--	4
Sierra Pacific Power Co.	B+/Positive/--	6
Sierra Pacific Resources	B+/Positive/B-2	6
South Carolina Electric & Gas Co.	A-/Stable/A-2	4
Southern California Edison Co.	BBB+/Stable/A-2	6
Southern Co.	A/Stable/A-1	4
Southern Indiana Gas & Electric Co.	A-/Stable/--	4
Southwestern Electric Power Co.	BBB/Stable/--	5
Southwestern Public Service Co.	BBB/Stable/A-2	5
System Energy Resources Inc.	BBB-/Negative/--	7
Tampa Electric Co.	BBB-/Stable/A-3	4
Toledo Edison Co.	BBB/Stable/--	6
Tucson Electric Power Co.	BB/Stable/B-2	6
TXU U.S. Holdings Co.	BBB-/Negative/--	8
Union Electric Co.	BBB+/CW-Neg/A-2	5
Union Light Heat & Power Co.	BBB/Positive/--	5
Vectren Utility Holdings Inc.	A-/Stable/A-2	3
Virginia Electric & Power Co.	BBB/Stable/A-2	5
Westar Energy Inc.	BB+/Positive/--	5
Wisconsin Electric Power Co.	A-/Negative/A-2	4
Wisconsin Energy Corp.	BBB+/Negative/A-2	5
Wisconsin Power & Light Co.	A-/Stable/A-2	4
Wisconsin Public Service Corp.	A+/CW-Neg/A-1	4
Xcel Energy Inc.	BBB/Stable/A-2	5

Con Edison

Hearing Exhibits

STATE OF NEW YORK
DEPT. OF PUBLIC SERVICE
DATE: 6/9/10
CASE NOS: 09-S-0794, 09-G-0795, and 09-S-0029
Ex. 305

STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

Case 09-S-0794 - 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.

Case 09-G-0795 - Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Consolidated Edison Company of New York, Inc. for Gas Service.

CASE 09-S-0029 - Proceeding on Motion of the Commission to Consider Steam Resource Plan and East River Repowering Project Cost Allocation Study, and Steam Energy Efficiency Programs for Consolidated Edison Company of New York, Inc.

ATTENTION

This exhibit is among those prefiled in the captioned cases by active parties that executed two joint proposals that were filed on May 18, 2010. Those that executed the joint proposals subsequently stipulated that they would not cross-examine the witnesses of each other given that they were supporting at that time the Commission's adoption of the terms of the joint proposals. In this context, the fact that these parties did not cross-examine the witnesses of each other does not mean and cannot reasonably be understood to mean that the information in this exhibit is uncontroverted among the parties that executed the joint proposals.

BEFORE THE
STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

In the Matter of

Consolidated Edison Company of New York, Inc.

Cases 09-S-0794 and 09-G-0795

MARCH 2010

Prepared Testimony of:
Staff Policy Panel

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Q. Would the members of the Staff Policy Panel please state your names, employer, and business addresses?

A. Robert Burke, Timothy Canty, Andrew Harvey, Marco Padula and Michael Salony. We are employed by the New York State Department of Public Service (DPS or the Department). Our business address is Three Empire State Plaza, Albany, New York 12223.

Q. Mr. Burke, what is your position in the Department?

A. I am a Supervisor Utility Accounting & Finance in the Office of Accounting and Finance. I joined the Department in 1974. The details of my background can be found in the Staff Accounting Panel testimony.

Q. Mr. Canty, what is your position in the Department?

A. I am a Public Utility Auditor III in the Office of Accounting and Finance. I joined the Department in 1988. The details of my background can be found in the Staff Accounting

Panel testimony.

Q. Mr. Harvey, what is your position in the Department?

A. I am a Principal Economist in the Office of Regulatory Economics. I joined the Department in 1974.

Q. Please summarize your educational and professional background.

A. I hold Bachelor of Arts and Master of Arts degrees in Economics from the State University of New York at Albany.

Q. Have you testified in any prior proceedings?

A. Yes. I have testified in about 50 proceedings before the New York State Board on Electric Generation Siting and the Environment and the New York State Public Service Commission (Commission) on a wide range of economic issues

Q. Mr. Padula, what is your position in the Department?

A. I am employed as a Utility Supervisor in the Rates and Tariffs Section of the Office of Electric, Gas and Water. I joined the Department in 1994.

Q. Mr. Padula, please briefly state your educational background and professional experience.

A. I received a Bachelor of Science Degree in Electrical Engineering from Northeastern University in 1990 and Master of Business Administration from Rensselaer Polytechnic Institute in 1998. From 1990 to 1994 I was employed by IBM as an Electrical Engineer responsible for the design and development of high performance power/thermal control systems for mainframe computers.

Q. Please briefly describe your current responsibilities with the Department.

A. My current responsibilities include electric and steam utility revenue allocation and rate design, computer simulation of electricity production, transmission and pricing, and wholesale electric market issues. I also serve as Staff co-leader on Con Edison electric and steam rate cases.

Q. Have you previously testified before the Commission?

A. Yes. I have testified in various electric, steam and gas proceedings on a wide range of utility ratemaking and policy issues.

Q. Mr. Salony, what is your position in the Department?

A. I am a utility supervisor in the Gas Rates Section of the Office of Electric, Gas & Water.

Q. Would you please state your educational background and professional experience?

A. I received a Bachelor of Science degree in Electrical Engineering from Pratt Institute in 1974. I joined the Department in May 1976. My responsibilities have included analysis of various rate and regulatory issues, including rate design, gas sales and revenue forecasts, operating and maintenance expenses, depreciation and rate base, and I have testified on these topics in several proceedings before the Commission.

Q. Panel, what is the purpose of your testimony?

A. We will discuss austerity, productivity, the Company's proposed multi-year plan, the Company's proposed Steam Revenue Adjustment Mechanism (SRAM), and Staff's proposal for a multi-year rate plan based on staged filings.

Q. Is the Panel sponsoring any Exhibits?

A. Yes, we are sponsoring two Exhibits. Exhibit___(SPP-1) contains responses to DPS Staff Information Requests (IR) that we refer to and have relied on in our testimony.

Exhibit ___ (SPP-2) contains historical and forecast data of the Gross City Product of New York City (GCPNYC), as calculated by the City of New York, Office of Management and Budget (CNYOMB).

Austerity Program

Q. The Commission Order in Case 09-M-0435, Proceeding on Motion of the Commission Regarding the Development of Utility Austerity Programs, issued December 22, 2009, page 3, states that the Commission will continue to seek austerity measures that can provide rate relief to utility customers and that, through 2010, it anticipates that all rate filings and all joint proposals submitted to the Commission will identify, for austerity purposes, discretionary spending cuts, correct?

A. Yes.

Q. Did Con Edison submit testimony addressing this directive in its rate case filing?

A. Con Edison filed its steam and gas rate requests on November 6, 2009, prior to the December 2009 Order. As such, the Company's rate filings do not explicitly identify any discretionary spending cuts for austerity purposes. Consequently, referring to the December 2009 Order, we requested, in Staff Information Request (IR) DPS-73 (Exhibit__(SPP-1)), that the Company identify, and quantify, all austerity related cost savings reflected in its steam and gas rate filings along with all necessary supporting workpapers. The Company's response to Staff's IR referenced its response to NYECC-23 (Exhibit__(SPP-1)).

Q. Did Con Edison's response to NYECC identify, and quantify, all austerity related cost savings reflected in their steam and gas rate filings?

A. No. The Company simply states in its response that its filings reflect ongoing efforts to provide service at the lowest reasonable cost consistent with its obligation to provide safe and adequate service. The response further states that several of the Company's witnesses describe these efforts and that the filings reflect its decision to defer, to the extent practicable, certain capital work in an effort to minimize the rate increase requests. For example, Con Edison states that it decided to defer capital spending on a Liquefied Natural Gas (LNG) liquefier project pending further evaluation of cost-effective alternatives and claims that it delayed certain supply main replacements and information technology (IT) related improvements to mitigate its rate request. Finally, the Company notes that it had previously implemented certain corporate-wide cost-savings measures as part of the response to the Commission's austerity related adjustment in Case 08-E-0539. Some of these corporate-wide measures are likely to be continued as part of the electric Joint Proposal pending before the Commission, and, in that event, Gas and/or Steam's allocated share of such corporate-wide costs would also be reduced.

Q. Does the Panel believe that very much of the austerity savings referred to in Con Edison's response to NYECC-23 are included in the Rate Year projections?

A. No we do not. Most of the Company's efforts to implement Austerity savings were put into action starting in July of 2009. Since the test year used in this case ended just before austerity measures were put into place, we do not believe that most austerity savings are included in the rate year forecast. In order for the savings to be included, they would need to be specifically identified as an adjustment to the test year, and we have not seen that.

Q. Is it the Panel's position that no austerity savings are included in the rate year forecast?

A. No, we believe there may be some austerity savings included in the rate year forecast, but we are not in a position to be able to identify and quantify all of them. This is precisely why we asked Con Edison to identify and quantify all austerity savings in DPS-73.

Q. Can you identify and quantify any austerity savings that are already included in Staff's rate year forecast.

A. Yes. We believe $475,000 in the gas filing and $150,000 in the steam filing are related to austerity savings. These austerity savings are related to our disallowance of specific program changes related to additional employees, and the canceled summer intern program which is included in our calculation of the labor escalation rate.

Q. Is the Panel recommending a certain amount of austerity savings be included in the rate year forecast?

A. Yes. As recently as December 2009, the

Commission made clear that it expects austerity measures to be included in all rate cases.

Q. How much austerity savings does the Panel believe should be included in the gas and steam revenue requirement?

A. The Commission in Case 08-E-0539, Con Edison - electric rates, included $60 million of austerity measures, which was equal to 3.6% of non-fuel operating and maintenance (O&M) costs. Con Edison recently filed a progress report on January 15, 2009, showing that it was able to achieve $47 million worth of austerity savings, or 74% of their target. The Company's achieved austerity savings equates to approximately 2.7% of non-fuel O&M savings. We believe this achieved-ratio of 2.7% of non-fuel O&M should be applied in the gas and steam cases as well, less any specifically identified and quantified measures that may be already included in the revenue requirement. In our adjustment, we have deducted austerity savings that we identified above.

Q. Does Con Edison plan to update its steam and gas rate year filings to identify austerity related cost savings?

A. The Company's intentions are unclear. Its response to NYECC-23 concerning its austerity efforts appear to leave open the possibility for an allocated share of corporate-wide cost reductions identified in the pending electric Joint Proposal. Accordingly, an update is possible.

Q. Do you have any comments regarding Con Edison's lack of any proposed steam or gas austerity program?

A. Yes. Since the economy in Con Edison's service territory is showing little sign of improvement, and to be responsive to the December 2009 Order to identify, for austerity purposes, discretionary spending cuts, we recommend that the Company's steam and gas revenue requirements reflect an austerity adjustment and that the Company's formal updates and rebuttal fully address this issue. We propose that the revenue requirements in these proceedings reflect an austerity target relying on the achieved austerity savings of the Company's electric division.

Q. How would you describe the New York City (NYC) economy?

A. The impact on NYC of prior national recessions, such as the recession that occurred during 1980-1982, pale in comparison with the present recession, which the National Bureau of Economic Research (NBER) declared began in December 2007. The basis for this conclusion can be found in Exhibit ___(SPP-2). Exhibit ___(SPP-2) contains historical data of the Gross City Product of New York City (GCPNYC) as calculated by The City of New York Office of Management and Budget (CNYOMB). This data shows the movement in the GCPNYC from 1980-2008 in both real (as defined in $2005) and nominal terms. It provides forecasts of GCPNYC in both real and nominal dollars for the years 2009-2014.

Q. Since 1980, what has been the trend for real

GCPNYC?

A. Despite the national recessions that occurred between 1980 and 1982, the NYC economy continued to experience growth in real GCPNYC of 4.1% in 1981, and 1.9% in 1982. Growth continued unabated until the recession from July 1990 to March 1991, which impacted the NYC economy negatively, with a reduction in real GCPNYC of -2.8% in 1991. Growth in real GCPNYC subsequently turned positive and accelerated during the 1990s, peaking in 2000 at 9.4%. The recession of 2001, along with the infamous September 11, 2001 terrorist attack, caused two years of sizable decreases in real GCPNYC of -4.7% in 2001 and -3.5% in 2002. Growth in GCPNYC then resumed in 2003 and continued through 2007. The national recession that began in December 2007, however, has precipitated a decline in real GCPNYC that has created staggering budgetary concerns for governments, businesses and households which continue to this day.

Q. Please explain.

A. Real GCPNYC plunged by -6.3% in 2008. CNYOMB foresees a further decrease in real GCPNYC of -3.5% in 2009. The envisioned recovery beginning in 2010 is seen as less than robust, with increases in real GCPNYC of 2.2% in 2010 and only 0.1% in 2011. Subsequent growth rates in real GCPNYC as forecast by CNYOMB still leave real GCPNYC in 2014 shy of levels that were experienced in 2007. This portends a sluggish recovery for the NYC economy that will further constrain government, business, and household budgets over the next few years.

Q. How is the present recession impacting NYC in comparison to the national economy?

A. Its impact on NYC is much more severe. The February 2010 Blue Chip Economic Indicators states that real United States Gross Domestic Product (USGDP) increased by 0.4% in 2008, decreased by -2.4% in 2009, and forecasts an increase of 3.0% in 2010, which is relatively better than described previously for NYC.

Q. Please contrast the experience of the unemployment rate for both the United States (U.S.) and NYC since the onset of this most recent recession.

A. The average annual unemployment rate in 2007 for NYC was 4.9% and 4.6% for the U.S. In 2008, the NYC unemployment rate increased to 5.5%, while it increased to 5.8% in the U.S. Since then, the NYC unemployment rate has more than doubled from its 2007 average, with the most recent NYC unemployment rate for December 2009 at 10.6%, while the same rate for the U.S. was 9.7%. The severity of this recession is clearly being acutely felt in NYC.

Q. What overarching economic uncertainties confront the national economy at this time?

A. With the Federal Funds rate close to 0%, the Federal Government is now primarily dependent on implementing fiscal policy to regenerate the economy back into a growth mode. Fiscal policy is inherently a slower policy tool than monetary policy. This makes forecasts of economic activity, as we go forward, fraught with uncertainty. Rising bankruptcies, continued home foreclosures, commercial real estate uncertainties, continued high unemployment, and lagging increases in wages and incomes all pose further challenges. Economists are uncertain whether this recession will look like the traditional "V" shape, where the economy exits the recession as rapidly as it entered, a "W" shape, where the economy demonstrates some recovery only to fall back into negative growth again (also known as a double-dip), or the dreaded "L" shape, where the economy falls into recession, and then remains in a sluggish growth mode for an extended period of time (e.g., Japan over the last 20 years). The cover story in the February 13, 2010 issue of *The Economist* entitled "New Dangers for the World Economy" puts this issue in context. In this lead editorial, it stated, "Optimism about a "V" shaped recovery is being replaced with pessimism about a double-dip recession, as fears grow that policymakers will be forced, or will mistakenly choose, to remove monetary and fiscal props too soon". Meanwhile, consumer confidence, as measured by the Reuters/University of Michigan preliminary index of consumer sentiment decreased to 73.7 in February 2010. The consensus forecast by economists, as determined by Bloomberg, had been 75 for February 2010. The index of expectations six months from now, which indicates the direction of consumer spending by this same survey decreased to 66.9 in February 2010 from 70.1 the prior month. The net effect of the confluence of these economic circumstances is that it may be a major challenge for the U.S. economy to experience sustained growth over the next few years.

Q. What overarching economic uncertainties confront the NYC economy at this time?

A. The challenges that confront the U.S. economy will continue to significantly impact NYC. Furthermore, the continued status of NYC as a global financial powerhouse, and its relative profitability, could be challenged, which could significantly contribute to the future economic vitality of NYC, New York State and the U.S. We are presently facing great uncertainty that suggests firms navigate cautiously and engage in cost savings wherever possible.

Q. Returning to your discussion of Con Edison's austerity program, what is the Panel's proposed adjustment related to austerity for the steam department?

A. We recommend a $5.065 million austerity adjustment for steam, which is equal to 2.7% of non-fuel O&M, less identified savings of $150,000 already in included in our Rate Year forecast discussed above.

Q. How much is the Panel's adjustment for the gas department related to austerity?

A. We recommend a $7.75 million austerity adjustment for gas, which is equal to 2.7% of non-fuel O&M, less identified savings of $475,000 already in included in our Rate Year forecast discussed above.

Productivity Adjustment

Q. Con Edison's Accounting Panel (AP), in deriving a labor factor used to escalate the historic test year labor expense for both steam and gas, assumed a 1% annual productivity adjustment. Are you proposing to modify the Company's assumed 1% annual productivity adjustment?

A. Yes. We recommend that the Company's proposed 1% productivity adjustment be increased to 2%, in part to reflect anticipated benefits of the recently completed Management Audit in Case 08-M-0152 (Comprehensive Management Audit of Consolidated Edison Company of New York, Inc.) into Staff's steam and gas revenue requirements for the rate year ending September 30, 2011. We also believe the Company can achieve additional efficiencies as a result of increased expenditures on its steam distribution system and steam production system. For example the Company's distribution system remote monitoring and system reinforcement projects should improve efficiencies by reducing manual patrols and inspections, and reducing leaks and repairs. On the production side, efficiencies should be gained as a result of the various control systems projects and the various water treatment upgrades. In addition, the Company has proposed, and Staff supports, steam customer service enhancements that should also result in efficiencies by providing customers the ability to pay their bills online, access key customer information and resolve billing-related problems and various enhanced computerized information systems on the gas system. These are just a few examples of projects and programs that could result in improved efficiencies and therefore, increasing the productivity adjustment to 2% will provide the necessary incentive for the Company to ultimately seek out and achieve those efficiencies.

Q. Do Con Edison's steam and gas rate requests for the rate year ending September 30, 2011, reflect any adjustments associated with the implementation of the management audit recommendations?

A. No. The Company states that it is simply too early in the implementation process to identify specific savings for the rate year. In addition, the Company states that numerous audit recommendations reflect ongoing Company initiatives. Realization of benefits beyond what the Company would be realizing absent audit recommendations is virtually impossible to identify or predict. To provide customers with a material share of benefits achieved from implementing audit recommendations during the term of a rate plan, the Company proposes to lower the sharing targets from 100 basis points above the allowed return on equity to 50 basis points starting in the second year of each plan. In addition, the sharing ratio would be changed from 50/50 (customer/Company) to 60/40 to give customers a material share of any savings.

Q. Is the Panel proposing to adjust Con Edison's rate filings to reflect Management Audit savings?

A. Yes. The Liberty Audit was approved by the Commission in August 2009. The Company has since submitted implementation plans in October 2009 and February 2010. Based on the February 2010 status report, approximately one-third of the recommendations have been implemented. By October 1, 2010, the start of the rate year, a substantial number of the recommendations should be completed. Given the fact that substantial progress has and will be made by the start of the rate year, it is reasonable to expect that savings from the management audit will occur in the rate year. Therefore, our recommended 2% productivity adjustment is a valid proxy adjustment to incorporate these savings.

Company's Proposal for a Multi-Year Rate Plan

Q. Did Con Edison propose a multi-year rate plan as an alternative to its one-year case for both its steam and gas operations?

A. Yes. Con Edison proposes a four-year rate plan for its steam business and a three-year rate plan for its gas business.

Q. Please briefly explain Con Edison's multi-year rate plan proposals.

A. The Company proposes that the rates set for the twelve months ended September 30, 2011 rate year become the base from which projections are made in order to establish rates for Rate Year 2 (RY2) through Rate Year 4 (RY4) for steam and for RY2 and Rate Year 3 (RY3) for gas. The Company notes that multi-year plans provide flexibility in phasing-in increases in base rates over the term of the rate plan in order to minimize bill impacts on customers and that prior Con Edison rate plans have included the use of levelized increases in conjunction with deferred accounting to handle revenue variations over the term of the plan.

Q. What are the projected increases in revenue requirement under Con Edison's four-year steam rate plan?

A. Based on its preliminary update filing, the projected steam revenue requirement increases in Rate Year 1 (RY1), RY2, RY3 and RY4 are $117 million, $15 million, $26 million and $16 million, respectively. In projecting these four increases, the Company factored in a stay-out premium of 60 basis points to increase its requested return on equity from 10.8% to 11.4%. As an alternative to the four annual increases, the Company proposes levelized annual increases of $59 million.

Q. What are the projected increases in revenue requirement under the Company's proposed three year gas rate plan?

A. Based on its preliminary update filing, the projected gas revenue requirement increases in RY1, RY2 and RY3 are $159 million, $57 million and $51 million respectively. In projecting these three increases, the Company factored in a stay-out premium of 50 basis points to increase the return on equity from 10.8% to 11.3%. As an alternative to the three annual increases, Con Edison proposes levelized annual increases of $108 million.

Q. What is driving the Company's projected increases in revenue requirements?

A. The primary causes of the Company's steam and gas rate increases in RY1 are attributable to carrying costs on capital additions, property tax expense, pension and Other Post Employment Benefits (OPEB) costs, and the cost of capital. An additional cause of the steam increase in RY1 is lower forecasted sales revenue. The major drivers of proposed steam and gas rate increases in RY2 and RY3 are carrying costs on capital additions (inclusive of depreciation expense and related income tax impacts) and property tax expense. In fact, these two items account for approximately 85% of the Company's projected steam revenue needs for RYs 2 through 4 and 94% of the Company's projected gas revenue needs for RY2 and RY3.

Q. Does Con Edison propose the use of various reconciliations, or true up, mechanisms?

A. Yes. The Company requests continuation of the same reconciliation mechanisms, with some modification, employed in currently effective rate orders. Specifically, Con Edison proposes that true-ups, for steam and gas, would be provided for pension and OPEB expense, interference costs (other than Company labor), property taxes, site investigation and remediation (SIR) program costs, and World Trade Center (WTC) costs and recoveries. Con Edison also proposes to continue to true-up and defer costs associated with new legislative and regulatory requirements. Further, it requests a new mechanism that would allow the Company to defer costs associated with abnormally high inflation levels that occur during the term of the rate plans.

Q. What modifications to the existing true-up mechanisms does Con Edison propose?

A. The Company proposes that a full reconciliation of property taxes be provided as opposed to the existing 90% / 10% (customer /Company) sharing of variations. Con Edison also proposes that the Commission eliminate the existing net plant reconciliation mechanisms for steam and gas that provides for the deferral of carrying costs for any shortfall in targeted net plant levels.

Q. As part of its multi-year rate proposals, did the Company recommend an excess earnings sharing mechanism?

A. Yes. Con Edison proposes to start sharing earnings with customers evenly (that is, 50/50) starting 100 basis points above the return on equity authorized in this case. Starting in RY2, in order to provide customers with a material share of benefits achieved from implementing Management Audit recommendations, the Company proposes to lower the sharing targets from 100 basis points above the allowed return on equity to 50 basis points starting in RY2. In addition, the sharing ratio would also be changed from 50/50 (customer/Company) to 60/40 to give customers a greater share of any savings to be achieved during the rate plan.

Q. What general comments do you have concerning the Company's proposed multi-year steam rate plan?

A. The Company's Steam Operations Panel proposes three very significant capital expenditure projects in the five year horizon that are not included in the Company's base rate increase request. Those projects relate to the Hudson Avenue Replacement Project and the Natural Gas Addition Projects at the Company's West 59th and East 74th stations. As detailed in Exhibit__(SOP-1.1), page 1, in total these projects will cost over $500 million over the next five years. Specifically, we are concerned with three issues: the potential rate impacts associated with these projects; the proposed cost recovery through the Company's FAC; and, the high level of uncertainty surrounding what Con Edison actually plans to do to replace the Hudson Avenue plant.

Q. Why are the potential rate impacts a concern?

A. Primarily because the Company has not included the costs of these projects in its requested RY1, RY2, RY3 and RY4 rate increases of $117 million, $15 million, $26 million and $16 million, respectively. As such, the revenue requirement increases are understated for all four rate years.

Q. Should the Commission adopt the Company's proposal to recover the costs of these major projects through the Steam Fuel Adjustment Clause (FAC)?

A. No. As Staff witness Jones and Randt discuss in their testimony, FAC recovery of the Natural Gas Conversion project costs should be rejected. Since the projects do not impact RY1, we have not included the cost of them in our revenue requirement. As Jones and Randt recommend, the Company would need to justify the need for these projects future staged filings as we describe later. Similarly, adopting the Company's proposal to recover the costs of the Hudson Avenue Replacement project, through the FAC should be rejected. The potential rate impact of this project is so significant that the Company should be required to provide quarterly updates to the Commission as to the status of this replacement project. As there is more certainty as to what is ultimately to be done at that plant, the Commission can decide on cost recovery as it renders its determinations on the annual staged filings we are proposing.

<u>Steam Revenue Adjustment Mechanism (SRAM)</u>

Q. Turning now to the Company's proposed Steam Revenue Adjustment Mechanism (SRAM). What is the Panel recommending?

A. We recommend that the SRAM not be adopted.

Q. What does Con Edison state as its reason for proposing the SRAM?

A. The Company, referencing the Commission's April 2007 Order in Case 03-E-0640 - Proceeding on Motion of the Commission to Investigate Potential Electric Delivery Rate Disincentives Against the Promotion of Energy Efficiency, Renewable Technologies and Distributed Generation, entitled <u>Order Requiring Proposals for Revenue Decoupling Mechanisms</u> (RDM Order), states that the principles contained in the RDM Order are also applicable to the steam business, providing a basis for requesting a steam RDM in this case. Further, the Company claims that because its steam customers have characteristics similar to its gas and electric customers, the it would be appropriate to require steam revenue decoupling so long as long as the Company is required to decouple gas and electric revenues.

Q. Did the Commission's RDM Order specifically address the steam business?

A. No, the Commission's RDM Order only addressed electric and gas service. The RDM Order did not address steam, nor did it address any other regulated utilities, such as water.

Q. Do you believe this omission from the RDM Order was intentional?

A. Yes. We do not believe that the exclusion of steam was an unintended oversight. Rather, we believe the Commission accurately identified that the implementation of revenue decoupling is specific to electric and gas services where there is an explicit interest in pursuing conservation programs, and that decoupling need not be extended to other utility services.

Q. Please describe the Company's proposed SRAM.

A. Company Witness Muccilo describes the SRAM as a revenue adjustment mechanism that would break the link between profits and sales; true-up revenues on a customer class basis and allow for interest on any over/under revenue collections at the other customer capital rate. Specifically, the Company proposes that the SRAM would true-up monthly revenues on a class specific basis and two classes would be excluded, Service Class 5 Negotiated Agreement Service and Service Class 6 Transportation Service.

Q. Since the proposed SRAM would not allow the Company to retain any incremental revenues associated with adding new customers, has the Company proposed another mechanism to provide it with an incentive to attract new load to the steam system?

A. On page 36 of Company Witness Muccilo's testimony, it merely suggests that a provision needs to be in place to adjust allowed revenues for unexpected and unavoidable factors that increase or decrease costs such as growth in customers, jobs and businesses above assumed levels. In addition, such provisions would adjust for variations in weather that may increase maintenance and inspection costs; and extreme storms and terrorist attacks. No further details on how these additional provisions would operate were provided.

Q. What is Staff's recommendation related to the Company's proposed SRAM and additional provisions?

A. We recommend that the Company's request for a revenue decoupling mechanism for its steam service be rejected by the Commission. Allowing the Company to retain all incremental revenues associated with load and customer growth provides it with an appropriate incentive and adequate financial resources to focus on the continued viability of the steam system. Conversely, holding the Company at risk for declining load growth provides an incentive for the Company to promote the expanded the most efficient use of its steam system for the benefit of all steam customers. In addition, the Company's proposal to use the SRAM as a revenue source to cover the effects of unexpected and unavoidable factors is not necessary. The Company continues to have the right to petition the Commission for deferral of extraordinary costs and the SRAM should not be created as a substitute for these purposes.

Q. According to the Company, what are some of the benefits of implementing an SRAM?

A. The Company claims that the SRAM would remove the financial disincentive the Company might otherwise have to promote the efficient use of energy and natural resources, allow existing customers to benefit from additional net revenues that new customers added to the system would bring, and assure adequate financial resources to allow the Company to build and strengthen the steam infrastructure and promote service reliability.

Q. Do you agree that implementation of the SRAM is the only way to provide such benefits?

A. No. As we previously stated, we believe that allowing Con Edison to implement the SRAM will remove the Company's incentive to increase the economic use of steam among its customers. Not allowing the SRAM to be implemented should further encourage the Company to promote the efficient use of steam so that this source of energy is competitive with others, such as natural gas. Under this scenario, we believe the Company is best positioned to acquire adequate financial resources to allow it to build and strengthen the steam infrastructure and promote service reliability.

Staff's Proposal for a Three-Year Rate Plan

Q. Did you explore the possibility of a multi-year rate plan as an alternative to a one-year case?

A. Yes. As an alternative to Staff's one-year case, we are proposing three-year rate plans for both Con Edison's steam and gas operations. The framework that we describe would also include any elements of a multi-year plan proposed by the Staff witnesses in these proceedings.

Q. Would you please explain your proposals?

A. In the last two Con Edison electric rate cases (Cases 08-E-0539 and 09-E-0428), carrying costs on capital additions, property taxes, pension and OPEB costs were primary drivers of the Company's proposed revenue increases. These are also major drivers of the Company's proposed steam and gas rate increases in these proceedings. Furthermore, Con Edison's steam and gas revenue requirement projections for their respective rate plans, (Exhibits __RM-2) February 2010 preliminary update Summary, show that increases in carrying costs on capital additions, pension and OPEB expense and property taxes account for approximately 81% ($46.5 million) of its purported steams needs and approximately 94% ($101 million) of its purported gas needs.

With this backdrop, we are proposing that the rates established for the rate year ending September 30, 2011, become the base from which the Commission provides for staged increases for the two subsequent rate years, limited to only four items: carrying costs on capital additions; pensions and OPEB; property tax expense; and, incremental costs, if any, related to new laws or regulations. There is little or no need for repeated full annual rate filings in the next two years involving these same cost drivers. Moreover, we are concerned that the public interest may not be served if Con Edison files annual rate cases for steam and gas that primarily raise these same cost drivers.

Q. Please continue explaining your proposal.

A. The Staff Accounting Panel notes that Staff is recommending a base rate increase of $73.265 million for steam and a base rate increase of $38.168 million for gas for the rate year ending September 30, 2010. There is no stay-out premium in the one-year case. With a three year rate plan, as discussed by Ms. Prylo, we recommend a stay-out premium of 13 basis points to increase the recommended return on equity (ROE) from 9.4% to 9.53%. Accordingly, if a multi-year plan was ordered by the Commission, the ROE increase would result in a Staff steam revenue requirement of $74.550 million and a Staff gas revenue requirement of $41.380 million for the rate year ending September 30, 2011. The increases in steam and gas revenue requirement for the rate years ended September 30, 2012 and September 30, 2013 would be determined in fully supported staged filings that Con Edison would be required to make related to: steam and gas capital additions, with cost recovery limited to Staff's recommended net plant forecast levels; pensions and OPEBs; property taxes; and, any incremental costs associated with any new laws and regulatory requirements. Since the recommended steam increase is so significant in the first rate year and because the economy in the Company's service territory is expected to continue to be relatively weak, we recommend that the Commission, if it were to adopt our multi-year proposal, consider authorizing the Company to recover a portion of the rate year revenue requirement in RYs 2 and 3. Should the gas delivery revenue increases be significant, we would also propose that the Commission consider allowing the Company to do the same in the gas proceeding. This would tend to levelize the increases in each of the three years considering that Con Edison's current projections indicate that the four categories for which staged increases would be permitted would result in steam rate increases in the range of $11 million in RY2 and $24 million in RY3. Current projections for gas indicate that the rate increases in RY2 would be in the range of $53 million and RY3 would be approximately $48 million.

Q. What are Staff's recommendations regarding the Company's proposed treatment and reconciliation of forecasted net plant as part of a multi-year rate plan?

A. The gas capital expenditures including gas interference, the associated gas plant and depreciation forecasts presented by the Staff Gas Construction Panel should be used as the basis for establishing the gas revenue requirements for RYs 1 through 3. Similarly, the steam production and distribution capital expenditures including interference, and the associated net plant and depreciation forecasts presented by Staff witness Cinadr and the Staff Steam Operations Panel should be used as the basis for establishing RYs 1 through 3 steam revenue requirements. Under our proposal, any gas and steam staged filings for these items would be capped at the forecasted allowed levels. The Company's proposal to eliminate the existing downward true up of gas and steam net plant should be rejected. Customers should be protected to the extent that Con Edison falls short of the allowed net plant levels for gas and steam capital work, including interference work related to municipal projects impacting Con Edison's gas and steam distribution systems. Therefore, the panel recommends that the carrying costs associated with any shortfall in net plant, be captured for the benefit of ratepayers annually and credited with interest to customers at the conclusion of the gas and steam rate plans. For steam, the downward net plant reconciliation should be applied separately to 1) distribution net plant, including interference and 2) production net plant. In addition, for gas and steam, the downward net plant reconciliation should be computed excluding the effects of the actual cost of removal to provide an incentive to the Company to keep those costs to a minimum. This approach was used by the Commission in the Company's recent electric rate case proceedings and, therefore, it is reasonable to do the same for gas and steam.

Q. What information would be included in the staged filings?

A. Con Edison would, among other things, present its forecast of pension and OPEB costs based on latest known actuarial information. Furthermore, the Company would be required to continue to demonstrate that it has taken action to control or reduce its pension and OPEB benefit plan costs. The staged filings would also include Con Edison's forecast of property tax expense based on latest known information. The Company would file a new property tax forecast for the upcoming rate year, by June 15th each year as part of its staged filings. That forecast will be permitted to be updated for latest known NYC tax rates until July 31st, or when NYC sets the final rate for the fiscal year, which ever is earlier. If NYC has not set a new rate by July 31st, the five year historical average for NYC tax rates should be used. In the event that the Company incurs incremental steam or gas costs resulting from changes to federal, State and or NYC changes in tax law (other than property taxes which are addressed separately) or other mandated law, rule or regulation, these costs may be reflected by Con Edison in the stage filing. Such costs should be fully documented and supported.

Q. Please explain your proposal regarding the remaining portion of Con Edison's steam and revenue requirements.

A. As noted above, approximately 74% ($11 million) and 93% ($24.4 million) of the Company's projected steam revenue requirement needs for RY2 and RY3 are driven by three items for which staged filings would be permitted under our proposal. Our staged filing proposal for gas would permit approximately 94% ($53 million) and 94% ($48 million) of the Company's projected revenue requirement needs for RY2 and RY3. The Company would be required to manage the remaining difference in its projected revenue requirements without incremental rate relief.

Q. Will Con Edison be allowed to reconcile, or true-up, any of its costs under the multi-year rate plans you propose?

A. Yes. For both steam and gas, our proposed rate plans provide for the reconciliation of pension and OPEB expense, site investigation & remediation (SIR) program costs, WTC costs and recoveries, and variable rate interest costs. Also, the downward-only reconciliation for infrastructure capital expenditures would continue as described earlier.

Q. How does your proposal address the sales forecast for RY2 and RY3?

A. Our proposal allows for the reconciliation of gas sales through the continuation of the RDM. The steam sales forecast for the RY2 and RY3 should assume the Company's proposed forecast but include the adjustment described by Staff witness Barney.

Q. How are existing regulatory deferrals amortized within your rate plan?

A. The regulatory deferrals subject to amortization are being reflected over the second and third rate years at the same levels as established in RY1.

Q. What are you proposing as the balance of regulatory deferrals increases or decreases during the rate plan period?

A. We propose that unless the cumulative changes in deferral balances provided for in the gas and steam plans reach $10 million, the Company would continue to defer the amounts until the end of the rate plans. If the balances exceed those amounts, Con Edison could request as part of its staged filings to recover from customers or refund to customers, as appropriate, the balance or a portion thereof.

Q. Do Staff's rate plans for gas and steam include a provision for excess earnings?

A. Yes. Our proposed rate plans include an earnings sharing mechanism because we believe that this virtually universal feature of multi-year rate plans, is a critical element. We believe that our earnings sharing mechanism will provide Con Edison with an incentive to minimize its costs and gain efficiencies. The sharing mechanism is balanced by protecting customers should forecasts implicit in a rate plan prove materially inaccurate with respect to items such as expenses, revenues from customer classes not subject to an RDM, or rate year capital structure.

Q. Please explain the design of your earnings sharing mechanisms for gas and steam.

A. Given the Staff Finance Panel's recommended ROE and its three-year stayout premium determination of 13 basis points, we recommend that an earning sharing threshold of 10.03% over the duration of the rate plans. Furthermore, the Commission should direct that, on an annual basis, Con Edison report the achieved earnings for both businesses and defer all earning in excess of that rate. Under our proposal, at the end of the three year rate plans, earnings above 10.03% will be shared 60/40 between the customer and Company.

Q. What is the basis for the sharing mechanism structure you recommend?

A. Our structure uses the sharing mechanism that Con Edison proposed for RY2 and RY3, but we propose that it be employed in all three years of the rate plans. We believe it is appropriate because it provides customers with a material share of benefits achieved from implementing management audit recommendations during the term of the rate plans.

Q. What incentives are included in your multi-year proposals?

A. We recommend that the existing Steam Safety Performance incentive mechanism as modified by the Staff Steam Operations Panel, and the existing gas Customer Service Performance incentive mechanism both continue for the duration of the three year rate plan and until modified by the Commission. We also recommend that the gas Safety Performance Incentives and Mechanisms proposed by the Gas Safety Panel be adopted to help ensure the continued safe and reliable operation of the gas distribution system. These too should continue for the duration of the three year rate plan and until modified by the Commission.

Q. When would the Company make its staged increase filings?

A. Under our proposal, the Commission would direct the Company to submit fully supported fillings for steam and gas, no later than June 15th for the rate year beginning October 1, 2011 and no later than June 15th for the rate year beginning October 1, 2012. However, the Company may update for property taxes until July 31, 2011 and July 31, 2012. We believe that this will provide sufficient time for Staff and other interested parties to examine the Company's filings and report recommendations to the Commission for its determination.

Q. What do you propose in the event Con Edison files for new rates during the term of the rate plans?

A. If Con Edison files for a steam and or gas rate increase to become effective before October 1, 2013, it should be required to refund the stayout premium of 13 basis points to customers starting from October 1, 2010 to the date new rates become effective. The Commission should establish regulatory mechanisms for the gas and steam businesses to recover these monies, should it be necessary

Q. Does this conclude your testimony at this time?

A. Yes it does.

Con Edison

Hearing Exhibits

STATE OF NEW YORK
DEPT. OF PUBLIC SERVICE
DATE: 6/9/10
CASE NOS: 09-S-0794, 09-G-0795, and 09-S-0029
Ex. 306

Consolidated Edison Company of New York, Inc.
Steam & Gas Rate Cases 09-S-0794 & 09-G-0795

Exhibit__(SPP-1)

Responses to Information Requests Relied Upon

Information Requests Relied Upon

Table of Contents

Company Name: Con Edison
Case Description: Con Edison Gas & Steam Rate Cases
Case: 09-G-0795-09-S-0794

Response to DPS Interrogatories - Set DPS11
Date of Response: 01/20/2010
Responding Witness: Muccilo

Question No. :73
Subject: Austerity Measures (steam and gas) - The Commission Order Approving Ratepayer Credits issued and effective December 22, 2009 states that through 2010, the Commission anticipates that all rate filings and all joint proposals submitted to the Commission will identify, for austerity purposes, discretionary spending cuts. Please identify and quantify all austerity spending cuts reflected in the Company's steam and gas rate filings. Please provide all necessary supporting workpapers.

Response:
See response to NYECC 23.

Company Name: Con Edison
Case Description: Con Edison Gas & Steam Rate Cases
Case: 09-G-0795-09-S-0794

Response to NYECC Interrogatories - Set NYECC2
Date of Response: 01/19/2010
Responding Witness: Accounting Panel

Question No. :23
Referencing the Commission's Order Approving Ratepayer Credits, Issued and Effective December 22, 2009, and the Commission's directive that ''though 2010, we anticipate that all rate filings and all joint proposals submitted to the Commission will identify, for austerity purposes, discretionary spending cuts" and that "[until the current economic downturn reverses, utilities should employ as many cost-cutting measures as possible." a. has Con Edison employed as many cost-cutting measures as possible in both its Steam and Gas Case filings? If not, please explain whether Con Edison plans to suggest additional cost cutting measures beyond any contained in its two rate case filings following the Commission's directive in this Order. b. the Commission's Order discusses some suggested cost-cutting measures, identify which of the following cost-cutting measures the Company has included in its filing and the effect of each on the proposed revenue requirement for each of the following costcutting measure taken by the Company: (i) limiting training of employees in only safety-related or legally-mandated areas; (ii) freezing of managerial salaries; (iii) foregoing of managerial bonuses; and (iv) l i t i n g travel.

Response:

a. has Con Edison employed as many cost-cutting measures as possible in both its Steam and Gas Case filings? If not, please explain whether Con Edison plans to suggest additional cost cutting measures beyond any contained in its two rate case filings following the Commission's directive in this Order.

Con Edison objects to this question as unduly vague as respects the qualifier "as many …. as possible." Notwithstanding, the Company responds as follows.

The Company's filing reflects the Company's ongoing efforts to provide service at the lowest reasonable cost consistent with the Company's obligation to provide safe and adequate service. Various Company witnesses describe these efforts in their testimony. In addition, the filing also reflects the Company's decision to defer, to the extent practicable, certain capital work in an effort to minimize the rate increase request. For example, in developing the gas capital budgets, the Company examined all capital programs and projects to determine areas in which projected work could be reduced or deferred. As a result, the Company decided to defer capital spending on the LNG liquefier project, pending further evaluation of cost-effective alternatives that meet the Company's requirements. In addition, we have delayed certain supply main replacements and IT related improvements, which would have increased the request by approximately $35M. We considered reducing the current mandate to replace 40 miles of leak-prone pipe annually, but decided for purposes of this filing that the Commission would want the Company to continue with this activity at the same level; the Company is open to considering a reduced level of activity for this program. The balance of the capital program was determined to be necessary to maintain the gas system for purposes of providing safe and reliable service to our customers.

Finally, the Company had previously implemented certain corporate-wide cost-cutting measures as part of the Company's response to the Commission's austerity imputation in Case 08-E-0539. Some of the corporate-wide measures are likely to be continued as part of its electric rate proceeding pending before the Commission and, in that event, Gas and/or Steam's allocated share of such corporate-wide costs would also be reduced.

b. the Commission's Order discusses some suggested cost-cutting measures, identify which of the following cost-cutting measures the Company has included in its filing and the effect of each on the proposed revenue requirement for each of the following cost cutting measure taken by the Company: (i) limiting training of employees in only safety-related or legally-mandated areas; (ii) freezing of managerial salaries; (iii) foregoing of managerial bonuses; and (iv) limiting travel.

The Company's Gas and Steam filings do not limit training to safety-related or legally-mandated areas, nor does the Company believe that to be a proper approach to developing a workforce capable of maintaining the high degree of service reliability that our stakeholders have come to expect. Nor would it be proper to eliminate training in other important areas of responsibility (e.g., financial reporting, compliance matters).

The Company's filings do not reflect freezing managerial salaries. The Company's testimony explains why the projected management salaries are a reasonable and necessary business expense. Note - the Company did elect to reduce certain managerial salaries in responding to the Commission's austerity directive in Case 08-E-0539. See also response to part "a" above.

As to forgoing managerial bonuses, per the Company's testimony, the Company has a management variable pay plan, not a bonus plan and the testimony explains why that program is a reasonable and necessary business expense.

Finally, the Company did limit travel as part of its response to the Commission's austerity directive in Case 08-E-0539. The Gas and Steam filings reflect what the Company believes to be a reasonable level of business travel based upon the extent of travel during the historic year and do not reflect an arbitrary reduction to that level. See also response to part "a" above.

Consolidated Edison Company of New York, Inc.
Steam & Gas Rate Cases 09-S-0794 & 09-G-0795

Exhibit__(SPP-2)

Historical and Forecast of the Gross City Product of New York City (GCPNYC)

Con Edison

Hearing Exhibits

STATE OF NEW YORK
DEPT. OF PUBLIC SERVICE
DATE: 6/9/09
CASE NOS: 09-S-0794, 09-G-0795, and 09-S-0029
Ex. 307

Exhibit ___

New York City Gross City Product in Nominal $ and Real ($2005)

	Nominal GCP ($bil)	% Chg	Real GCP (2005 $bil)	% Chg
1980	114.22		261.48	
1981	129.39	13.3%	272.20	4.1%
1982	139.56	7.9%	277.50	1.9%
1983	153.78	10.2%	290.11	4.5%
1984	168.37	9.5%	304.21	4.9%
1985	181.77	8.0%	318.22	4.6%
1986	197.60	8.7%	334.13	5.0%
1987	212.01	7.3%	343.69	2.9%
1988	226.50	6.8%	352.19	2.5%
1989	240.53	6.2%	357.69	1.6%
1990	252.20	4.9%	358.80	0.3%
1991	254.59	0.9%	348.76	-2.8%
1992	269.65	5.9%	358.85	2.9%
1993	282.38	4.7%	367.61	2.4%
1994	294.71	4.4%	376.56	2.4%
1995	307.55	4.4%	386.01	2.5%
1996	332.58	8.1%	409.68	6.1%
1997	357.17	7.4%	432.33	5.5%
1998	368.16	3.1%	440.28	1.8%
1999	405.24	10.1%	478.74	8.7%
2000	451.64	11.5%	523.76	9.4%
2001	439.14	-2.8%	499.30	-4.7%
2002	434.78	-1.0%	481.90	-3.5%
2003	460.81	6.0%	496.19	3.0%
2004	496.17	7.7%	515.34	3.9%
2005	545.52	9.9%	545.49	5.9%
2006	599.95	10.0%	578.12	6.0%
2007	641.82	7.0%	601.71	4.1%
2008	610.56	-4.9%	563.85	-6.3%
2009f	605.13	-0.9%	544.00	-3.5%
2010f	626.12	3.5%	555.86	2.2%
2011f	638.24	1.9%	556.18	0.1%
2012f	667.05	4.5%	571.71	2.8%
2013f	696.94	4.5%	585.90	2.5%
2014f	726.27	4.2%	598.23	2.1%

Actual (1980-2008) and Forecast (2009-2015) Data Provided by the City of New York, Office of Management and Budget.

Con Edison

Hearing Exhibits

STATE OF NEW YORK
DEPT. OF PUBLIC SERVICE
DATE: 6/9/09
CASE NOS: 09-S-0794, 09-G-0795, and 09-S-0029
Ex. 308

STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

Case 09-S-0794 - 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.

Case 09-G-0795 - Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Consolidated Edison Company of New York, Inc. for Gas Service.

CASE 09-S-0029 - Proceeding on Motion of the Commission to Consider Steam Resource Plan and East River Repowering Project Cost Allocation Study, and Steam Energy Efficiency Programs for Consolidated Edison Company of New York, Inc.

ATTENTION

This exhibit is among those prefiled in the captioned cases by active parties that executed two joint proposals that were filed on May 18, 2010. Those that executed the joint proposals subsequently stipulated that they would not cross-examine the witnesses of each other given that they were supporting at that time the Commission's adoption of the terms of the joint proposals. In this context, the fact that these parties did not cross-examine the witnesses of each other does not mean and cannot reasonably be understood to mean that the information in this exhibit is uncontroverted among the parties that executed the joint proposals.

BEFORE THE
STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

In the Matter of

Consolidated Edison Company of New York, Inc.

Cases 09-S-0794 and 09-G-0795

March 2010

Prepared Testimony of:

Henry Leak, III
Public Utility Auditor III
Office of Accounting and Finance
State of New York
Department of Public Service
Three Empire State Plaza
Albany, New York 12223-1350

Q. Please state your name and business address.

A. My name is Henry Leak, III. My business address is 3 Empire State Plaza, Albany, New York 12223.

Q. By whom and in what capacity are you employed?

A. I am employed by the New York State Department of Public Service (Department) as a Public Utility Auditor III. I work full-time as a project manager in the Management Audit Section in the Office of Accounting and Finance.

Q. Please describe your educational background.

A. I received a Bachelors of Science in Accounting from the State University of New York Albany in 1978.

Q. Please summarize your professional experience.

A. Prior to working for the Department, I performed financial audits while working as an auditor for then CPA firm, Peat Marwick and Mitchell from 1978 to 1981. I was hired as an Associate Utility Management Analyst in October 1981. I worked in the Utility Management Audit Section until 1985 when I transferred to the Operational Audit Section in the Office of Utility Efficiency and Productivity. I then transferred to the Office of Accounting and Finance in 1999.

In 2007, the Management Audit unit was formed and I transferred to the unit to assist in the re-initiation of the management audit program in New York State.

Q. Have you performed or supervised management and operations studies of New York State utilities?

A. Yes. While in the Utility Management Audit Section, I managed consultant-performed management and operations audits. I also worked on staff-performed audits in both the Utility Management Audit Section and the Operational Audit Section while assigned to the Office of Utility Efficiency and Productivity.

Q. Are you sponsoring any exhibits?

A. Yes, I am sponsoring one exhibit, Exhibit__(HYL-1).

Q. What is the purpose of your testimony in these proceedings?

A. I am informed by counsel that Section 66(19) of the Public Service Law (PSL) requires that "upon the application of a gas or electric corporation for a major change in rates as defined in subdivision twelve of this section, the commission shall review that corporation's compliance with the directions and recommendations made previously by the commission, as a result of the most recently completed management and operations audit. The commission shall incorporate the findings of such review in its opinion or order." The most recently completed management audit of Consolidated Edison of New York, Inc. (Con Edison or the Company) is the "Final Report, Management Audit of Consolidated Edison of New York, Inc.," dated June 16, 2009. The audit was performed by The Liberty Consulting Group. I will be testifying on Con Edison's compliance with the directions and recommendations made by the Commission in Case 08-M-0152 Comprehensive Management Audit of Consolidated Edison of New York, Inc, Order Directing the Submission of an Implementation Plan (Plan), issued August 20, 2009. The Commission's Order directed the submission of an implementation plan by Con Edison.

Q. What directions and recommendations did the Commission make in its August 20, 2009 Order?

A. In its Order, the Commission directed Con Edison to develop an Implementation Plan to fully address the findings and recommendations contained in the Liberty Audit Report within 45 days, but not later than October 5, 2009. The Implementation Plan should contain an overall characterization of the relative priorities for each of the recommendations, implementation action steps, schedules with specific milestones, risk/cost/benefit analyses, and the designation of executive officer accountability. In addition, Con Edison must: meet with Staff after the issuance of the Order to discuss the development of the implementation plan; as part of the implementation plan, develop and implement an outreach effort to interested parties and its various customer classes about what reliability means to each including how it is related to affordability of Con Edison's rates; address the extent to which implementation of certain recommendations will help the Company address issues raised in Cases 09-M-0243 (<u>Comprehensive Investigative Accounting Examination of Con Edison</u>) and 09-M-0114 (<u>Prudence of Certain Capital Program and</u>

Operation and Maintenance Expenditures by Con Edison) to avoid them in the future; provide written updates on the Company's progress at least every four months; and, file testimony and related documents to create a complete record to demonstrate the nature and extent of its achievement of the goals and objectives in its implementation plan in any rate proceeding filed on or after the date of the Order.

Q. What recommendations were made in the Liberty Audit Report?

A. The Liberty Audit Report contains 92 recommendations that are listed in Exhibit__(HYL-1).

Q. Can you summarize Liberty's report?

A. Liberty's report acknowledges that Con Edison operates in a complex and challenging business environment, where upgrading and maintaining its infrastructure is a costly proposition that puts upward pressure on customers' rates, thereby making it imperative that Con Edison perform efficiently and effectively. In addition, Liberty notes that outages, recent safety concerns about electrified facilities, gas and steam incidents and questions surrounding Con Edison's ability to adequately manage its construction program have drawn increased attention from the public, politicians and the investment community.

Liberty's report frames these dynamics as a three-level pyramid and believes that in order for Con Edison to ensure its future success, the Company must proactively and adroitly address matters in each level.

The more traditional management audit recommendations form the base of the pyramid. These are numerous, and while opinions may differ as to the resulting benefit and their manner of implementation there is general agreement among Con Edison, Liberty and Staff that they are necessary. Their implementation (along with all recommendations in the report) will be detailed in the Company's implementation plan. There is concern, however, that unless improvements in higher levels of the framework occur, that the benefits resulting from implementing these recommendations could be transitory and perhaps not fully realized.

The mid-level recommendations, while also typical of management audits, differ from those in the base level because of their widespread impact throughout the organization. The four recommendations that rise to this level are of paramount importance, and they are: 1) Con Edison needs to develop an integrated vision or plan for the electric system and link capital investment to economic or value driven parameters; 2) Con Edison needs to have a heighten involvement of its Board of Trustees in the planning and budget process; 3) Con Edison needs to develop a more holistic approach to cost management; and, 4) Con Edison needs to become less reliant on rate cases to manage its business. The consequences of not implementing these recommendations could potentially undermine the full achievement of the benefits from other recommendations.

These are management issues that require executive level attention in order to better ensure the success of Con Edison's construction and infrastructure management programs. Liberty also labeled these four items as "strawmen" and engaged Con Edison early in the audit for feedback. Liberty found different levels of acceptance, understanding and buy-in from Con Edison on these four key matters which in some ways lead to the final and most important top level of the pyramid.

Liberty labeled the issues rising to the top level as "barriers," and identified four broad categories of barriers: Cultural, Environmental, Financial, and Regulatory. These are somewhat atypical management audit findings, because rather than specific recommendations prone to objective measurement, they are more subjective, and are not so much recommendations as they are instead challenges (both internal and external) that Con Edison must overcome. Successful navigation by Con Edison of these barriers will increase the likelihood of ensuring that benefits resulting from implementing report recommendations are more than ephemeral and position Con Edison best for long-term success. Examples would include such items as being more adept at identifying root causes of problems, understanding the limits of the rate process as a solution to financial problems, and improving its creditability with stakeholders. Addressing the specific recommendations in the report with the backdrop of the barriers in mind is key to Con Edison's success in the future.

Q. Has Con Edison completed any of the directives or recommendations noted in the Commission's Order?

A. Yes. In its October 5, 2009 audit implementation filing, the Company indicated that it completed five (5) Liberty audit recommendations. In its February 5, 2010 audit implementation filing it indicated that it had completed an additional twenty-five audit recommendations for a total of thirty (30) recommendations. The completed recommendations are identified in Exhibit__(HYL-1).

Q. Has Staff confirmed that Con Edison has satisfactorily met the intent of Liberty's audit report for the completed recommendations?

A. No. Staff is in the process of finalizing the complete Department audit team that will be monitoring Con Edison's audit report implementation efforts to ensure compliance with the intent of each recommendation. In the ensuing months, Staff will meet with Company personnel to review various forms of documentation to understand the specifics regarding the Company's implementation efforts. Once it has been ascertained that the Company has satisfactorily met the intent of each recommendation, Staff will report this information to the Commission.

Q. Does this conclude your testimony at this time?

A. Yes.

Con Edison

Hearing Exhibits

STATE OF NEW YORK
DEPT. OF PUBLIC SERVICE
DATE: 6/9/10
CASE NOS: 09-S-0794, 09-G-0795, and 09-S-0029
Ex. 309

BEFORE THE
STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

In the Matter of

Consolidated Edison Company of New York, Inc.

Cases 09-S-0794 and 09-G-0795

March 2010

Prepared Exhibit of:

Henry Leak, III
Public Utility Auditor III
Office of Accounting and Finance
State of New York
Department of Public Service
Three Empire State Plaza
Albany, New York 12223-1350

Appendix B. Matrix of Recommendations

Team	CE No.	High Priority	Chapter Reference	Recommendation (w/referenced conclusions)	Start Date	Completion Date (Est.)	Completion Date (Act.)	Deliverable(s)	Summary of Cost, Benefit, and Risk Analysis	Assessment	Status
1 Electric Long Range Plan	1	H	III - Corporate Planning - 1	Improve the planning process. *(Conclusions 1, 2, 3, 4, 5)*	4/09	7/10		Updated Corporate Instructions on Standardized Business Plans and processes	Will seek to ensure the Company has capabilities to anticipate the future needs of our ever changing environment, using a standard integrated format for work plans and budgets across the business units. This will lead to greater efficiency in the planning process.	Accepted	In progress
	2		III - Corporate Planning - 2	Take the ERM process associated with operating risks to the next level. *(Conclusion 7)*	9/09	4/10		Summary of Process Improvements	Initial cost estimate of the vendor to work with Con Edison on ERM is $200K. Additional software may be $400K. Benefit of implementing this recommendation is expected to be improved prioritization of efforts to mitigate the major risks of the Company. In addition, the Company will benefit from a reduction in its risk profile. Additional benefits include increased ability to monitor NERC/FERC compliance, improved coordination of emergency management plans tied to risks, and improved tracking of EH&S risks.	Accepted	In progress
	3	H	III - Corporate Planning - 3	Define the role of the Strategic Planning Unit. *(Conclusion 6)*	3/09	12/09	12/09	Updated Corporate Policy Instruction that states the role of Strategic Planning.	The costs associated with implementing this recommendation consisted of benchmarking, research, analysis, and meetings with internal company officers. This equates to approximately $75,000 based on labor costs and subscriptions to research databases. The benefits of refining the role of Strategic Planning include an improved alignment of capital investment and operational spend with defined corporate priorities. The savings are expected to exceed the $75,000 cost incurred.	Accepted	Completed
	4		III - Corporate Planning - 4	Revisit the subjects investigated by the interdisciplinary teams. *(Conclusion 6)*	5/09	12/10		Document and refine the interdisciplinary team launch process.	Initial benefits include development of proactive strategies to address key implementation areas (e.g. achievement of renewable portfolio standards), development opportunities for employees, and cross-functional cooperation and thinking. Initial costs are project specific and primarily include full time staffing required on the team as well as targeted use of external services/products (e.g. research reports).	Accepted	In progress
	5	H	III - Corporate Planning - 5	Develop a comprehensive vision and 20-year master plan for the electric system. *(Conclusion 8, 9)*	3/09	12/10		A 20-year integrated plan for the electric system (Electric Long Range Plan or ELRP) that: o Defines the long-term vision and strategic goals of the electric system and clearly links programs and projects to the attainment of those measurable goals. o Evaluates customer bill and rate impact (affordability) and reliability in light of required system investment and various legislative, regulatory, and technology issues, and the impact of potential alternatives. o Develops the framework for more integrated transmission, substation, and distribution planning which incorporates innovative solutions to meet customer expectations. o Provides the linkage of our near-term plans and requests (i.e., rate case and other filings) to the 20-year integrated plan, by demonstrating that the near-term plans are the first steps in the longer program	Initial cost estimate of $2.2M (including internal and external labor). The ELRP is expected to provide a context for our programs, linking short term efforts with longer term system goals. Provide the framework for more integrated transmission, substation, and distribution planning which incorporates innovative solutions to meet customer expectations.	Accepted	In progress

21	H	VII - Load Forecasting - 8	Aggressively move forward with the major study planned by Market Research on efficiency potentials and include a special focus on efficiencies that can be targeted to specific networks. *(Conclusion 28)*	11/08	12/09	12/09	Energy efficiency market potential study with review and evaluation focusing on system and network needs	The major benefit of these studies is that we receive intelligence around the DSM opportunities. To the extent these opportunities materialize, the need for capital infrastructure spending is reduced. A risk of these studies is that the potential of DSM could be overstated and our actual electric energy and demand is higher than anticipated. Another risk is that these studies understate the potential and we build infrastructure ahead of need. The cost of the energy efficiency study was $825,000 and was funded in Case 07-E-0523 for the 2008 – 2009 rate year. All efficiency programs are subject to a Total Resource Cost test and the study helps us design better programs and address barriers to demand side management.	Accepted	Completed
22		VII - Load Forecasting - 9	Evaluate options to enable the consideration of current and future load curtailment initiatives, both at CECONY and NYISO, for dependable network demand reduction. *(Conclusion 29)*	6/09	12/11		Analysis of pilot results	Proposed pilot program cost is $22 million. Projected benefits of reducing energy consumption and demand, reducing environmental impact; and a reduction of capital infrastructure required to meet customer needs. Risk is that the programs do not deliver the full amount of DR, therefore maintaining the need for capital investment to meet customer needs or triggering the need to implement emergency measures to meet customer needs in the near term.	Accepted	In progress
34	H	VIII - System Planning - Electric - 11	Establish a base level of network reliability for new networks. *(Conclusion 24)*	9/09	12/09	12/09	Prepare white paper on ideal network reliability for new networks	Establishing a base level of network reliability allows Con Edison to identify the networks on which reliability funds should be targeted in order to provide an overall system improvement. In order to provide for system improvement but keep costs down, the Company has identified a number of programs which will address network deficiencies and increase network reliability. The effectiveness of each program on a specific network is evaluated in order to determine the effects of reliability spending. The most cost-beneficial solution that meets the reliability goal is selected.	Accepted	Completed
39	H	XI - Budgeting - 1	Strongly link CECONY's long-term electric plan with annual budgets, rate plans and 5-year capital plans. *(Conclusion 4)*	3/09	3/10		The ELRP, as discussed in recommendation 5, will link annual budgets, rate plans, and the 5-year capital plan to the attainment of longer term system performance goals.	The ELRP will provide the necessary long term vision and context needed to support the shorter term projects and programs in our annual budgets, rate plans and 5-year capital plans.	Accepted	In progress
42	H	XI - Budgeting - 4	Prioritize CECONY capital projects and allocate funding using long-term economic analysis metrics as a significant decision factor. *(Conclusion 8)*	3/09	12/10		The ELRP, as discussed in recommendation 5, will show the expected benefits of our electric projects and programs, as detailed in annual budgets, rate plans, and 5-year capital plans, in terms of cost, performance and risk over the long-term horizon. Projects and programs will be prioritized by customer needs, corporate strategic objectives, and management of operating risks.	Projects and programs will be prioritized by customer needs, corporate strategic objectives, and management of operating risks. This optimization of capital projects should provide context as we balance cost, performance, and risk of the many capital projects and programs	Accepted	In progress

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2 Board Leadership	6	H	IV - Corporate Oversight - 1	Revise Board Committee Structure to better coordinate functions and to focus on infrastructure planning, oversight, and performance measurement. *(Conclusions 1 and 8)*	8/09	5/10		Adopt revised Committee structure and 2010 calendar. Create a dashboard for each Committee and Board of key operating and performance metrics, risks and projects.	Initial benefits include increased Board engagement and oversight.	Accepted	In progress
	7	H	IV - Corporate Oversight - 2	Continue efforts to identify board candidates with energy utility experience. *(Conclusion 2)*	9/09	12/09	12/09	Review director search process with Executive Search Firm and Lead Director.	Such expertise enhances the Board focus on issues that directly impact the Company.	Accepted	Completed
	8	H	IV - Corporate Oversight - 3	Incorporate changes in management's form and schedule for infrastructure planning and budgeting into a more structured, resequenced, and more intensive regimen of board review. *(Conclusions 5 and 6)*	8/09	12/09	12/09	Revise management's form and schedule for infrastructure planning and budgeting Adopt revised Committee structure and 2010 calendar	Implementation allows for a more structured review of short and long-range system needs in advance of annual budgeting, and provides for planning and budget review by the committees and the Board.	Accepted	Completed
	43		XI - Budgeting - 5	Require changes in capital projects and programs of more than 20 percent from the annual budget to be approved by the board of trustees. *(Conclusion 6)*	8/09	11/10		Review results of revised Committee structure and budget process with Corporate Governance & Nominating Committee to determine whether to implement Conclusion 6 Draft delegation language to require approval by the Board or the Finance Committee, if required		Under review	In progress
	56	H	XII - Work Management - Resource Management - 4	Review the roles of management, the Board and/or its committees after serious events such as the 2008 electrical fatalities. *(Conclusion 6)*	8/09	12/09	12/09	Discuss roles and process with Board members	Benefits include enhancing the Board's role in the oversight of the Company's management of risks, including the oversight of risks that could lead to serious events.	Accepted	Completed

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3 Rate & Financial Strategy	41	H	XI - Budgeting - 3	Work toward the re-establishment of multi-year electric rate cases. *(Conclusion 3)*	8/09	5/10		Efforts to seek multi-year rate arrangements	A multi-year rate plan reduces the risks associated with the rate-making process by reducing the frequency of the rate cycle, and provides for additional flexibility with respect to managing the business. Risks inherent in a multi-year arrangement can be mitigated by the terms of the arrangement, including triggers to re-open issues and deferral of unexpected costs. On average, incremental non-staffing costs associated with electric rate case filings are between $1.2 and $1.6 million. The main components of these costs are for consultants and expert witnesses, public notice ads, travel expenses, and printing. Some of these costs (at least 20%), plus some staff positions, may be avoided in the longer term, to the extent that multi-year rate plans become the norm and the number of interim proceeding and collaboratives are not significant.	Accepted	In progress

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4 Work Management	32	H	VIII - System Planning - Electric - 9	Place all distribution tree trimming under a central corporate management function with accountability to corporate management. *(Conclusion 22)*	1/09	3/10		Consolidate all distribution line clearance activities under one management organization.	Qualitative benefits in the form of quality of workmanship, safety improvements, specification compliance and reliability improvements. Quantitative analysis will be provided in first quarter 2010.	Accepted	In progress
	33	H	VIII - System Planning - Electric - 10	Strengthen the distribution vegetation management inspection program with accountability. *(Conclusion 23)*	6/09	7/09	6/09	Implement Electric Operations Quality Assurance program that includes random field reviews of completed tree trimming work to ensure full compliance to the specification.	Qualitative benefits in the form of quality of workmanship, safety improvements, specification compliance and reliability improvements.	Accepted	Completed
	44	H	XI - Budgeting - 6	Establish formal informational feedback loops for project analysis and project prioritization. *(Conclusion 17)*	9/09	3/10		Update CI-291. Formalize process to evaluate merits of specific projects and overall portfolios.	Feedback loops may provide opportunities to evaluate and adjust specific projects and programs to ensure appropriate balance of cost and value. An annual review of the capital optimization portfolio will result in improved capital allocation decisions to achieve maximum value for set spend level.	Accepted	In progress
	51		XII - Work Management - Work Planning - 1	Establish fleet size criteria based on historical data on total vehicle usage hours versus total physical work performed in hours in the region for each vehicle class. *(Conclusion 6)*	4/09	6/10		Establish vehicle metrics in order to establish baseline of vehicle utilization. Define vehicle utilization policy and protocol. Create transparent business information for operating groups. (Due to limited availability of usage hours data, alternative metrics will be used as basis for evaluation),	We will seek to identify benefits of improved asset utilization, such benefits will be longer-term in nature. As metrics are established and asset utilization information clarified, forecasting and planning may more accurately correlate future components of the ELRP to the number and types of supporting assets. Capital assets may also be deferred through efficiencies.	Modified	In progress
	67	H	XII - Work Management - Performance Measurement - 5	Perform analysis on work items with unacceptable QA rejection rates to isolate performance problems. *(Conclusion 5)*	7/09	8/09	8/09	Significant and marked improvements have been demonstrated in 2007, 2008, and 2009 YTD Electric Operations QA performance. The alleged adverse trends cited in the Liberty audit report are due to changes in measuring techniques and personnel.	Qualitative benefits in the form of quality of workmanship and safety improvements.	Accepted	Completed
	71	H	XIII - Project Management - Electric - Electric Operations - 1	Implement a work management system in Electric Operations. *(Conclusion 1, 4, 5, 16)*	5/09	12/09	12/09	Development of business case, implementation plan, and change management communication plan.	The total cost of this project is estimated to be between $138 million and $174 million. The capital costs range between $119 million and $155 million; O&M costs account for $19 million. The total annual benefit which will be realized upon full implementation is between $45 million - $48 million.	Accepted	Completed
	72	H	XIII - Project Management - Electric - Electric Operations - 2	Design and implement written project and program management procedures and expectations, including definitions of roles, responsibilities and expectations, cost control plans, and scope control procedures. *(Conclusion 2, 7, 9. 13, 14, 15, 18)*	8/09	12/09	12/09	Develop a project management specification for Electric Operations.	Benefits which could be gained by formalizing the project management function include improved ownership/accountability of projects at a manageable level, improved focus on financials/schedule, better long term planning, and improved knowledge transfer. This equates to a potential efficiency improvement of $8.1 million on the total spending level if we achieve a 1% productivity improvement. The cost for implementing the program (staffing, software, certification and training) is $1.3 million.	Accepted	Completed

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5 Cost Management	9	H	IV - Corporate Oversight - 4	Increase emphasis on efficiency and effectiveness in operations auditing. *(Conclusion 10)*	6/09	12/09	12/09	Establish a new section in Auditing focused on construction projects, construction contractors and energy services; Obtain analytical audit extraction software; Integrate in the 2010 Audit Plan operations audits dealing with efficiency and effectiveness.	Approximately $550,000 will be expended annually to maintain the new Auditing section. An additional $150,000 (one time cost) has been expended to purchase the ACL analytical tool. The measures are also expected to help to deter and prevent recurrence of fraudulent activities in these areas. In addition to identifying inappropriate overcharges, the new group will work with Construction and other Corporate organizations to identify process improvements and controls and standardize policies and procedures to further reduce potential inappropriate charges and payments to contractors.	Accepted	Completed
	10	H	IV - Corporate Oversight - 5	Make consideration of Enterprise Risk Management a more structured part of audit planning. *(Conclusion 11)*	8/09	11/09	10/09	The 2010 Audit Plan will contain a cross reference to the applicable risk the audit will cover in the Enterprise Risk Management program.	There were no incremental costs expended to improve alignment between the annual Audit Plan and ERM Program. However, certain benefits, including proactive risk assessment and evaluation and reduction of risk exposure, are expected to be realized.	Accepted	Completed
	40	H	XI - Budgeting - 2	Establish consistent, company-wide economic value analysis methods and metrics for capital projects and programs. *(Conclusions 6 and 7)*	7/09	6/10		Implement portfolio management system to enable comparable analyses to determine prioritization of capital projects.	Cost of software is approximately $900,000. Benefits include portfolio alignment with corporate strategy and optimization goals.	Accepted	In progress
	45	H	XII - Work Management - Cost Management - 1	Implement a holistic approach to cost management that is designed and built around three key elements: (a) a guiding philosophy; (b) a formal, structured cost management plan; and (c) building blocks of comprehensive supporting capabilities *(Conclusions 4, 9)*	2/09	3/10		Formal Cost Management Program Document or Procedure	Con Edison is dedicating substantial resources to support its effort to enhance cost management practices. Consultant costs of $200,000 in addition to time of 20+ internal resources. Structured more proactive cost and budget variance analysis will result in more timely identification of cost containment and cost reduction opportunities. Benefits are associated with improved business processes, communication, consistency, and alignment. Risks are associated with continued use of technology platforms that adequately support the business's needs, however could be further improved.	Accepted	In progress
	46		XII - Work Management - Cost Management - 2	As skilled people represent the cornerstone of the holistic approach, expand the role of cost management professionals to encompass tasks and accountabilities important to holistic cost management. *(Conclusion 5)*	6/09	3/10		Evaluation of Roles and Responsibilities & revised Position Guides for Cost Management Personnel	Cost associated with developing formal training programs for cost management and line personnel. Developing a more highly skilled and trained cost management professional will result in savings through effective application of cost controls, reporting, analysis, and corrective action.	Accepted	In progress
	47	H	XII - Work Management - Cost Management - 3	Establish a cost support organization that is (a) placed consistent with the priority of cost management; (b) serves the cost management needs of all levels of management; (c) develops a force of skilled cost professionals and assures those skills are continuously improved; and (d) has overall accountability for the development and implementation of the cost management program. *(Conclusion 5)*	2/09	10/09	10/09	Recommendation for new organizational structure for Cost Management activities	The creation of a centralized Cost Management Director position who reports directly to the President of CECONY has led to a higher priority of cost, increased feedback and oversight. This new alignment ensures consistency of communication across all organizations and independence of cost management personnel. This organizational structure and enhanced role of Cost Management will be integrated with the broader organizational assessment of Con Edison.	Accepted	Completed
	48		XII - Work Management - Cost Management - 4	Provide training for managers, supervisors and cost support personnel in cost management techniques consistent with the holistic approach. *(Conclusions 1, 5, 6)*	6/09	3/10		Training and Curriculum for Cost Management and Line Personnel	As addressed in Recommendation 46.	Accepted	In progress
	49		XII - Work Management - Cost Management - 5	General Recommendation Implementation Guidance.	6/09	3/10		Formal Cost Management Program Document or Procedure	As addressed in Recommendation 45.	Accepted	In progress
	50		XII - Work Management - Cost Management - 6	Sample Cost Management Implementation Tactics.	2/09	3/10		Formal Cost Management Program Document or Procedure	As addressed in Recommendation 45.	Accepted	In progress
	52	H	XII - Work Management - Work Planning - 2	Perform in-depth reconciliation on cost estimates with substantial overrun to better understand the root causes of deviations. *(Conclusion 9)*	4/09	3/10		Analysis of projects with cost overruns and variance reporting templates	As addressed in Recommendation 45.	Accepted	In progress
	62	H	XII - Work Management - Resource Management - 10	Prepare an analysis of corporate overtime expenditures that includes root causes of the upward trends and strategies for attaining more economic levels. *(Conclusion 9)*	10/09	3/10		Analysis of overtime expenditures and guidance document as per Recommendation 61	As the policies and processes are further developed we will be better able to estimate dollar benefits related to these changes as a measure of effectiveness.	Accepted	In progress

65		XII - Work Management - Performance Measurement - 3	Implement a formal program for representatives from each region to share lessons learned in their respective fields. *(Conclusions 4, 9)*	10/09	3/10		Implementation of Lessons Learned discussions at Work Plan and other meetings	Sharing lessons learned will provide better information across business units to facilitate improved decision making in the future.	Accepted	In progress
68		XIII - Project Management - Electric - Central Operations - 1	Improve resource planning for design personnel and other essential project personnel. *(Conclusion 3)*	10/09	6/10		Staffing plan	Optimized design/engineering resources.	Accepted	In progress
69	H	XIII - Project Management - Electric - Central Operations - 2	Bring a corporate total holistic approach to cost management to the project and program management efforts. *(Conclusion 6)*	9/09	12/09	12/09	The Lessons Learned Template will be revised to include a cost management component to the process to be utilized in future projects.	The benefit of incorporating cost management practices into the lessons learned phase will be to provide better information for future decision making purposes. Cost of implementation is approximately $21,000 per project, implying break-even savings to justify implementation for a sample $15 million project of 0.14% of total project cost, and for projects with costs greater than $15 million, a potentially greater positive impact when compared to project cost. We expect a positive cost benefit for the Company and its customers.	Accepted	Completed
70		XIII - Project Management - Electric - Central Operations - 3	Strengthen Substation Operations program management processes by adding project management principles in a structured way. *(Conclusion 18)*	6/09	1/10		Program Management Teams will be developed identifying the key positions and associated roles and responsibilities . Current Working Estimates will be developed for each program and utilized for cost control.	Use of project management tools and principles for program management will allow for improved review and administration of these programs. It will also allow for improved cost control and containment. Increased focus on program management will positively impact schedule, quality, and cost criteria and general oversight of projects.	Accepted	In progress
73	H	XIII - Project Management - Electric - Electric Operations - 3	Implement a corporate total holistic approach to cost management. *(Conclusion 6)*	2/09	3/10		Formal Cost Management Program Document or Procedure	As addressed in Recommendation 45.	Accepted	In progress

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6 Load Forecasting	14		VII - Load Forecasting - 1	Analyze, and redirect as appropriate, the level of effort and sophistication applied to various load forecasting tasks and products, to better balance costs with product and user needs. *(Conclusion 2)*	6/09	1/10		Develop methods for shifting resources to higher value tasks and products.	Initial benefit could be the ability to shift the focus of Load Forecasting personnel to functions that support the needs of the longer term planning horizon anticipated in the Electric Long Range Plan.	Accepted	In progress
	16		VII - Load Forecasting - 3	Conduct an R&VF review of certain aspects of its approach to forecasting. *(Conclusions 9, 13, 14)*	7/09	6/10		Provide the changes to our current gas forecasting process, if it is determined that changes are needed.	Initial cost estimates show no significant incremental costs. Changes are expected to be implemented and maintained with existing staffing levels but additional modeling and software costs could be incurred. Potential benefit includes identifying alternative methods of forecasting from the benchmarking effort which may be incorporated in the Company's volume forecasting process.	Accepted	In progress
	17	H	VII - Load Forecasting - 4	Evaluate the factors responsible for consistently under-estimating 5 and 10 year peak load forecasts; assure that any bias is removed from future forecasts. *(Conclusion 14)*	7/09	12/09	11/09	Identify key factors causing the bias, and incorporate appropriate change(s) in revised forecasting process for electric long range plan.	There were no additional costs identified at this time to implement the recommendation, although consulting, modeling or software costs may be incurred in the future. A potential benefit from more accurate, but higher, longer term forecasts will be the identification of required capital expenditures sooner. A risk is that the implications of under and over forecasting can be significant.	Accepted	Completed
	18	H.	VII - Load Forecasting - 5	Expand load forecasting activities and capabilities to encompass analysis of uncertainties using sensitivity analyses, probabilistic tools or other applicable techniques. *(Conclusion 18)*	6/09	1/10		Incorporate sensitivity and probabilistic approaches as appropriate into future load forecasts.	A potential benefit will be the development of more robust electricity demand forecasts, or forecasts for different future scenarios. These enhanced forecasts could be used to develop plans for the Company's electric system for different peak demand conditions. Software package costs are initially estimated at $7,500 for software and license, $1,000/year for licenses and any associated training.	Accepted	In progress
	19		VII - Load Forecasting - 6	Develop an improved approach to the documentation, testing, and communication of forecast criteria and assumptions. *(Conclusion 19)*	1/09	12/09	11/09	Prepare a document identifying the key assumptions in the preparation of the long-term forecasts and for use in Electric Long Range Plan.	The cost to produce these documents was minimal. The benefit of having the documents is to provide greater awareness of the assumptions and drivers that both forecasting groups use to produce their respective forecasts. It will also ensure consistency when questions are posed about the forecasts since everyone will be able to reference the same information.	Accepted	Completed
	20	H	VII - Load Forecasting - 7	Examine and implement as appropriate the efficiencies and quality improvements that might result from utilization of CECONY's load research program, modified as cost-effective, to support load forecasting. *(Conclusion 26)*	6/09	9/10		Assess the use of load research data, and develop, test and implement appropriate findings in future summer appliance saturation surveys and load forecasts.	A potential benefit will be the development of more robust electricity demand forecasts, or forecasts for different future scenarios. These forecasts could be used to develop plans for the Company's electric system for different peak demand conditions.	Accepted	In progress
	23	H	VII - Load Forecasting - 10	Establish a structured approach to the consideration of long-term eventualities that might significantly impact load forecasts, such as changes in trends, new technologies and new policies. *(Conclusion 30)*	6/09	11/09	11/09	Develop a range of load forecasts that consider pertinent long-term eventualities, for use in the Electric Long Range Plan (ELRP).	Using demand sensitivities results in a robust planning process and improved capital budgeting. These sensitivities for long-term peak demand forecasts ensure that a range of possibilities for growth in the peak demand are considered and that take into account factors not in existence at the time the forecast is prepared.	Accepted	Completed
	79		XVI - Supply Procurement - Electric - 1	Consolidate duplicative Energy Management operations in the electric and gas hedging functions. *(Conclusion 2)*	8/09	4/10		Review gas and electric hedging group functions. Report findings and implement any changes to eliminate duplicative functions or consolidate.	Initial benefits suggest consolidation could result in improved performance and effectiveness of the hedging program.	Accepted	In progress
	80	H	XVI - Supply Procurement - Electric - 2	Develop a comprehensive portfolio management plan with quantified goals and objectives to optimize the electric resource portfolio and related hedging plans. *(Conclusions 3, 7, 14)*	2/09	6/10		Electricity Supply will develop and annually review and update a long term supply outlook.	Energy cost savings potential could be seen if the Company identifies improvements in its energy supply operations. In addition, more robust electricity supply outlook or forecasts could be used to develop plans for the Company's electric system for different future demand and supply conditions.	Accepted	In progress

	82		XVI - Supply Procurement - Electric - 4	Identify, analyze and document all reasonable alternatives to its existing sources for both capacity and energy. Alternatives that are superior to the status quo electric resources should be implemented. *(Conclusions 8, 9, 11)*	2/09	6/10		Electricity Supply will develop and annually review and update a long term supply outlook.	Energy cost savings potential could be seen if the Company identifies improvements in its energy supply operations. In addition, more robust electricity supply outlook or forecasts could be used to develop plans for the Company's electric system for different future demand and supply conditions.	Accepted	In progress

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7 Gas Main Replacement	35		IX - System Planning - Gas - 1	Maintain current information about CECONY's leak-prone pipe. *(Conclusion 6)*	4/09	2/10		Provide a final evaluation of the Company's cast iron and unprotected steel gas distribution system and develop the optimum annual replacement levels	Cost of study is $240,000. If necessary, additional capital required for main replacements would be required. Potential benefit to improve gas system performance by a reduction of incoming leaks in a measured fashion while avoiding a significant increase in customer rates. Risk that optimum level of main replacement may require re-prioritizing or deferring other capital work.	Accepted	In progress

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8 Gas Capacity Planning	15		VII - Load Forecasting - 2	Find a better way to forecast growth in the peak gas load. *(Conclusion 8)*	7/09	4/10		Revise gas demand growth forecast methodology and model.	A potential benefit will be the development of more robust natural gas demand forecasts, or forecasts for different future scenarios. These enhanced forecasts could be used to develop plans for the Company's natural gas system for different peak demand conditions.	Accepted	In progress
	86		XVII - Supply Procurement - Gas - 2	Provide for more regular examination of Gas Supply's award of supply contracts by Internal Auditing. *(Conclusions 7, 8)*	8/09	11/09	10/09	Schedule an audit of gas procurement in the 2010 Audit Plan	In 2008 we spent $1.5 billion for the procurement of natural gas for resale. By increasing the amount of review of these procurements in the annual plan, we increase the ability to ensure that the expenditures and the procurement decisions are made in compliance with all controls that have been put in place.	Accepted	Completed
	87		XVII - Supply Procurement - Gas - 3	Explore applying probability-of-occurrence analysis to its supply-capacity planning. *(Conclusion 13)*	8/09	4/10		Develop final conclusions and recommendations regarding application of applying probability-of-occurrence to the company's supply/capacity planning	A potential benefit will be the development of more robust natural gas supply forecasts and associated capacity requirements for different future scenarios.	Accepted	In progress

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9 Performance Measurement	11	H	V - Incentive Compensation - 1	Increase the amount of stretch and put more pay at risk as part of a broad revamping of incentive compensation. *(Conclusions 7, 9, and 10)*	1/09	7/11		Review management compensation plan and develop 2010 and 2011 performance measures linked to compensation		Accepted	In progress
	12	H	V - Incentive Compensation - 2	Before the study is done and implemented, reduce the emphasis on O&M expense and increase the weighting for capital expenditure performance and the operating performance measures. *(Conclusions 7 and 8)*	1/09	7/11		Introduce KPI measures for capital expenditure.		Accepted	In progress
	13		VI - Performance Measures - 1	Develop a corporate-wide management information system. *(Conclusions 2, 4, 5, 6, 7)*	10/09	1/11		Determine the approach and scope of work for augmenting the Corporate Performance Indicator/Key Performance Indicator reporting system. Execute the implementation plan.		Under review	In progress
	53	H	XII - Work Management - Resource Management - 1	Perform comprehensive resource analysis for all business units on a quarterly or semi-annual basis. *(Conclusions 3, 5, 9, 11)*	9/09	4/10		Establish schedules with operating groups to review short and long term resource requirements for workforce planning.		Accepted	In progress
	54		XII - Work Management - Resource Management - 2	Assess and monitor the productivity and cost impacts of carrying an extra trainee on some work crews on a continuous basis to achieve more efficient resource management. *(Conclusion 5)*	10/09	2/10		Determine annualized cost and productivity impact for use of extra trainee on a crew. Establish a uniform policy for determining the length of time for using the extra trainee on a crew.		Accepted	In progress
	55	H	XII - Work Management - Resource Management - 3	Conduct a root cause analysis of the upward trend in OSHA target rate in Gas Operations and prepare and implement a corrective action program. *(Conclusion 7)*	7/09	6/10		Determine the root cause of the upward trend in OSHA target rate in Gas Operations. Develop and implement a strategies to improve Gas Operations OSHA rate.	The cost of implementing corrective action program cannot be determined until the root cause and targeted corrective action(s) have been identified. Benefits of performing the root cause analysis and implementing a corrective action plan include: improved employee morale; reduction in lost time as a result of work place injuries; and lower worker's compensation payouts (insurance, medical, etc.)	Accepted	In progress
	57		XII - Work Management - Resource Management - 5	Increase efforts to segregate safety from contractual issues in management / bargaining unit dialog. *(Conclusion 6)*	8/09	4/10		Improved bargaining unit participation in safety programs, development of union /management safety committees that effectively separate safety from other contractual issues.		Accepted	In progress
	58	H	XII - Work Management - Resource Management - 6	Review safety targets with the objective of adapting "stretch," but attainable, levels that exceed historical averages. *(Conclusion 6)*	7/09	12/09	12/09	An established process to develop future goals that support the Company's commitment to safety excellence.	Safety is a top priority for the Company. The primary driver for improved safety performance is to ensure that our employees work safely and "go home the way they came to work." It also fosters a company culture that sustains our commitment to safety and health, contributes to injury reduction, and improves worker morale. In addition, financial benefits will be achieved. Achieving the new safety goal would improve productivity and reduce costs associated with injuries. In 2006, the total expenditures associated with workers compensation and medical costs were $6.8 million. Assuming we achieve this targeted level of improvement, the Company expects some reduction in these costs.	Accepted	Completed
	59	H	XII - Work Management - Resource Management - 7	Strengthen enforcement of contractor compliance with their safety programs. *(Conclusion 8)*	9/09	12/10		A completed evaluation of current efforts to ensure contractor compliance with safety requirements. Identification of opportunities to enhance those efforts.	By reinforcing our contractor's commitment to safety, there is the potential for reduced contract-worker injury.	Accepted	In progress
	60		XII - Work Management - Resource Management - 8	Establish a corporate philosophy, policies and supporting guidelines for the balancing of in-house and contractor resources. *(Conclusion 12)*	9/09	4/10		A single philosophy and written guidelines for balancing in-house and contractor resources.	An expected benefit is optimization of allocation between in-house and contractor resources.	Accepted	In progress
	61	H	XII - Work Management - Resource Management - 9	Establish a corporate philosophy, policies and supporting guidelines to provide managers and supervisors with a framework to manage overtime. *(Conclusion 9)*	9/09	3/10		Develop a guidance document for managing overtime	As the policies and processes are further developed we will be better able to estimate dollar benefits related to these changes as a measure of effectiveness. We foresee little risk to Public Safety, reliability or customer service if the proposed overtime controls are thoughtfully developed and applied.	Accepted	In progress
	63		XII - Work Management - Performance Measurement - 1	Advance the continuous improvement efforts under The Way We Work program. *(Conclusions 1, 2)*	9/09	2/10		Develop a plan to advance the continuous improvement efforts under the Way We Work Program		Accepted	In progress

64	H	XII - Work Management - Performance Measurement - 2	Include pertinent productivity improvement goals in future KPIs at various management levels. *(Conclusion 3)*	9/09	12/09	12/09	Provide a measurable Productivity initiative in the form of a department KPI at the VP level	The utilization of KPIs is expected to help facilitate achieving the 1-2% productivity improvement per year.	Accepted	Completed
66		XII - Work Management - Performance Measurement - 4	Participate more actively in external information sharing efforts. *(Conclusion 10)*	10/09	7/10		Evaluate the need for a central approach to involvement in benchmarking efforts. Develop a process for determining which efforts the Company should be involved in and who should be the proper representative. Determine how best to share throughout the company the information obtained from these efforts.		Accepted	In progress
81	H -	XVI - Supply Procurement - Electric - 3	Revise the performance measures (KPIs) for energy management to provide metrics and incentives that align with electric procurement objectives. *(Conclusion 4)*	5/10	11/10		KPI's reviewed as part of budget process.	Potential benefit is better alignment between procurement and the stated objections.	Accepted	Pending

Team	CE No.	High Priority	Chapter Reference	Recommendation (w/referenced conclusions)	Start Date	Completion Date (Est.)	Completion Date (Act.)	Deliverable(s)	Summary of Cost, Benefit, and Risk Analysis	Assessment	Status
10 Asset Optimization	24	H	VIII - System Planning - Electric - 1	Evaluate reliability programs to determine if they should be terminated earlier to release capital expenditures for more cost effective reliability programs. *(Conclusion 3)*	1/09	3/10		Efficient frontier curves for selected programs indicating cost and value. A recommendation on spend level.	Improved allocation of capital funds across various programs to strategically address reliability initiatives. The optimization of these programs will maintain or enhance reliability for less cost.	Accepted	In progress
	25		VIII - System Planning - Electric - 2	Analyze networks and the 138 kV system designed to N-1 standards to determine the extent that maintenance activities can be performed at load levels less than peak load; where appropriate, incorporate maintenance design requirements into relevant design standards *(Conclusion 6)*	8/09	2/10		Summary report of maintenance activities during specific load levels. Summary report on opportunities to add SCADA emergency ties on auto-loops.	After review there is a potential for improved opportunities to schedule work during non-peak periods without compromising reliability to customers. Improved reliability due to enhancements to selected auto-loops.	Accepted	In progress
	26		VIII - System Planning - Electric - 3	Clarify transmission planning criteria with regard to transfers used during second contingency analysis. *(Conclusion 8)*	6/09	11/09	11/09	Assessment of criteria	Improves operational clarity to stakeholders and maintains compliance with regulatory reliability performance criteria. There was minimal cost associated with performing the benchmarking effort and updating the document.	Accepted	Completed
	27		VIII - System Planning - Electric - 4	Perform a global review of all equipment ratings, input data, and time durations across the distribution and transmission areas to assure consistency and to justify and document differences. *(Conclusion 14)*	9/09	3/10		Report examining equipment ratings identifying modifications needed to promote consistency, and explaining rating differences where required.	Evaluation of current practices to ensure operational effectiveness.	Accepted	In progress
	28		VIII - System Planning - Electric - 5	Maintain the 2011 completion date for completion of network secondary topology updates and EPRI DEW software. *(Conclusion 16)*	7/07	12/11		Update load flow models to include customer secondary distributed load.	Potential reduction in capital expenditures on primary feeder and transformer reinforcement due to a more accurate load representation on specific assets. Model will support automated load distribution in place of the manual process currently used.	Modified	Reevaluating
	29	H	VIII - System Planning - Electric - 6	Perform a least cost system analysis that minimizes costs to customers with regard to implementation of 3G strategies. *(Conclusion 17)*	1/07	7/11		Assessment of 3G alternatives for load relief. Cost analysis for Flushing autoloop design. Risk assessment of network outage due to area station loss.	Substantiate cost savings associated with 3G designs. Increased utilization of assets; potential reliability improvements; improved operational flexibility.	Accepted	In progress
	30	H	VIII - System Planning - Electric - 7	Perform analyses to determine if peak demand can be reduced more economically than the addition of infrastructure. *(Conclusion 19)*	11/08	12/11		Summary report on opportunities to reduce peak and avoid capital expenditures	Proposed DR program cost is $22 million to be collected as a surcharge. Studies proposed in 12/08 filing to cost approximately $200k; program cost to be estimated after studies are completed. Studies for incremental voltage reduction to cost approximately $200k; program cost to be estimated after studies are completed. Potential for peak demand reduction programs to be cost effective compared to infrastructure investment.	Accepted	In progress
	31		VIII - System Planning - Electric - 8	Actively pursue the economic use of SCADA controlled network mid-point feeder sectionalizing switches or circuit breakers to reduce system investment. *(Conclusion 20)*	10/06	1/10		Issue of specifications for deployment of SCADA operated switches	A more cost-effective solution to improve the NRI (Network Reliability Index), and the potential for increased asset utilization with new design concepts. The potential for avoidance of capital expenditures for specific primary feeder and transformer reinforcement work activity. Remote diagnostics and switching capabilities avoid field visits. More timely response to feeder outages resulting in improved reliability for less cost than aggressive component replacement.	Accepted	In progress

Team	CE No.	High Priority	Chapter Reference	Recommendation (w/referenced conclusions)	Start Date	Completion Date (Est.)	Completion Date (Act.)	Deliverable(s)	Summary of Cost, Benefit, and Risk Analysis	Assessment	Status
11 Gas and Steam Planning	36	H	IX - System Planning - Gas - 2	Evaluate potential changes in the business environment for each of the businesses; for the GBU, Strategic Planning should advise Gas Engineering regarding potential demands on the gas transmission and distribution systems occasioned by those changes. *(Conclusion 16)*	9/09	7/10		Identification of major factors which could shift current energy utilization more towards higher gas consumption on the distribution and/or transmission systems. Development of the plan to address the effects of these factors and update the Gas System Long-Range Plan accordingly.	Potential for major system reinforcement to meet significant new load. Potential major design changes.	Accepted	In progress
	37		IX - System Planning - Gas - 3	Report to stakeholders and the NYPSC on any expansion of the transmission and distribution systems required to serve winter-period electric power generation. *(Conclusion 18)*	9/09	9/10		Identification of factors that will affect gas supplies to generators. Development of the plan to address the effects of these factors and update the Gas System Long-Range Plan accordingly.	Potential for major system reinforcement to meet an increased in electric generation may require re-prioritizing or deferring other capital work	Accepted	In progress
	38	H	X - System Planning - Steam - 1	Identify a Steam Master Plan and incorporate within it a greater emphasis on what is happening on and to its distribution system. *(Conclusion 4)*	8/09	4/10		The Steam Long Range Plan (SLRP) will detail short to long-term strategies with a greater emphasis on steam distribution.	The completion of the SLRP may provide benefits of an improved comprehensive planning process for Steam Operations and ultimately for Con Edison through integrated energy planning. Cost for this project will be evaluated in 4Q 2009. Risks include potentially accelerated capital work and potential major design changes.	Accepted	In progress
	74		XIV - Project Management - Gas - 1	Staff a project coordination/specialist group under the Chief Distribution Engineer to assist in the execution of distribution capital projects such as the main replacement program. *(Conclusion 1)*	8/09	12/09	12/09	The development and staffing of project managers/engineers to support the operations if cost beneficial. If it is determined to not be cost beneficial, then the implementation of project management principles to be utilized by construction managers.	The biggest benefit is expected to be improved cost control and program schedule accountability. This equates to an efficiency improvement of $700,000 on the total spending level for the replacement of leak-prone pipe if we achieve a 1% productivity improvement. The cost for implementing the program (software, training, and certification) is $25,000.	Accepted	Completed
	75	H	XIV - Project Management - Gas - 2	Improve and expand the current project scope documentation to add sections on risks and rewards and alternative methods. *(Conclusion 2)*	7/09	8/09	8/09	Improved budget justification and appropriation requests indicating more detailed risks, rewards and alternative methods	Improved decision making process.	Accepted	Completed
	76	H	XIV - Project Management - Gas - 3	Start benchmarking with other urban utilities and utilize what these other utilities are doing better to improve the CECONY program and project management of capital projects. *(Conclusion 3)*	8/09	11/09	11/09	Incorporate best practices from other urban utilities to improve on CECONY's existing program and project management of capital projects.	The cost of performing the benchmarking study was minimal. Doing the Conceptual Packages up front has no incremental cost. Therefore, implementation benefits may include all costs avoided as a result of doing Conceptual Packages prior to budgeting and detailed design. Conceptual Packages done up front should result in fewer design and construction changes, thereby providing a cost avoidance due to project changes in the detailed engineering phase of the project or in construction.	Accepted	Completed
	77		XV - Project Management - Steam - 1	Identify projects requiring the application of project management techniques through a more formal, structured process. *(Conclusion 1)*	9/09	4/10		The development of a departmental operation procedure that institutes a more formal, structured process for project management in Steam Operations.	The benefit of this project is to develop a more formal, structured process for project management in Steam Operations, particularly in Steam Distribution. Increased focus on project management can positively impact schedule, quality, and cost criteria and general oversight of projects. Without such an enhanced process, there would be a risk of sub-optimal management of major capital projects, which could result in additional costs.	Accepted	In progress
	78		XV - Project Management - Steam - 2	Train steam distribution operations personnel in work and project management techniques. *(Conclusion 3)*	9/09	6/10		The development of a successful training program on project management in Steam Operations. Evidence of training effectiveness will be demonstrated through pervasive the regular use of project management principles in the department.	The benefit of this project is the expansion of formal project management training for those individuals in Steam Operations responsible for project management, particularly Steam Distribution. The cost of implementation would include the costs associated with training of employees. Formal training will ensure consistency and priority for this initiative.	Accepted	In progress

Team	CE No.	High Priority	Chapter Reference	Recommendation (w/referenced conclusions)	Start Date	Completion Date (Est.)	Completion Date (Act.)	Deliverable(s)	Summary of Cost, Benefit, and Risk Analysis	Assessment	Status
12 Energy Supply	83	H	XVI - Supply Procurement - Electric - 5	Internal Auditing should schedule more frequent audits of electric procurement decisions, documentation for entering into electric supply contracts, and daily purchase decisions. *(Conclusion 17)*	8/09	11/09	10/09	Schedule an audit of electric procurement in the 2010 Audit Plan	In 2008 we spent $3.5 billion for the procurement of electric energy. By increasing the amount of review of these procurements in the annual plan we increase the ability to ensure that the expenditures and the procurement decisions are made in compliance with all controls that have been put in place.	Accepted	Completed
	84	H	XVI - Supply Procurement - Electric - 6	Document processes, procedures, and guidelines for electric supply and scheduling, and for the 20 percent purchase flexibility in electric hedging. *(Conclusion 20)*	1/09	9/09	9/09	New Physical Electricity Scheduling Manual and associated Process Guides. Guideline for 20 percent purchase flexibility.	Qualitative benefits include increased knowledge transfer, consistency in process, and flexibility and control of the hedging process.	Accepted	Completed
	85		XVII - Supply Procurement - Gas - 1	Make finding means for increasing interdepartmental coordination an Energy Management priority. *(Conclusion 3)*	8/09	12/09	12/09	Electricity Supply and Gas Supply will document actions they have identified that will improve coordination between the two departments.	Changes show alignment within Energy Management that reflects industry best practices and do not result in higher costs. To the extent that the results of the ongoing meetings and subsequent implementation of coordination improvements between the two groups results in hedging benefits or improvements, those reduced costs will be directly passed on to customers as they occur.	Accepted	Completed
	88	H	XVII - Supply Procurement - Gas - 4	Expand Gas Supply's range of potential capacity alternatives as it considers firm customers' peak-day requirements for supply. *(Conclusions 14, 15)*	10/09	12/09	12/09	Identify potential natural gas pipeline capacity alternatives and determine whether they are viable candidates for Gas Supply to include in the long term natural gas supply plan.	Offers for peaking supplies are evaluated and the least-cost supplies are selected based on established guidelines. Any cost benefits realized through these peaking supply arrangements would be passed along to the firm gas customers through the Monthly Gas Cost Factor.	Accepted	Completed
	89		XVII - Supply Procurement - Gas - 5	Conduct occasional Gas Supply tests to identify potential additional types of supply arrangements. *(Conclusion 18)*	9/09	12/09	12/09	Gas Supply will update their procurement guidelines to include a provision to encourage suppliers to propose alternative supply arrangements in future Requests-for Proposal.	These new supply points expand the range of suppliers that can participate in the Company's natural gas procurement activities. Any reductions in cost associated with new supply arrangements will be passed on to customers through the gas adjustment clause.	Accepted	Completed
	90		XVII - Supply Procurement - Gas - 6	Keep financial and credit information for gas suppliers current. *(Conclusion 21)*	9/09	9/09	9/09	Gas Supply will update their procurement guidelines to include a provision that they will request current credit information from the Energy Risk Management department for all active counterparties that will be invited to respond to future Requests-for Proposal.	Reduced risk of entering into transactions with counterparties whose credit rating is unacceptable to the Company	Accepted	Completed
	91		XVII - Supply Procurement - Gas - 7	Find specific, objective ways for Gas Supply to evaluate its own performance. *(Conclusion 28)*	8/09	1/10		Conduct benchmarking assessments with other utilities or utility organizations to identify best practices. Analyze information received and develop potential performance criteria. Propose and implement changes to performance criteria.	Implementing new best practices will improve Gas Supply's accountability.	Accepted	In progress
	92		XVII - Supply Procurement - Gas - 8	Solicit proposals for external asset management. *(Conclusions 29, 31)*	2/09	3/10		Conduct pilot in Summer 2010 Natural Gas Purchase Plan, for summer 2010 and Winter 2010/11.	Using an asset management agreement for certain Company storage contracts may provide financial benefits to customers, while retaining the reliability benefits of natural gas storage facilities.	Accepted	In progress

Con Edison

Hearing Exhibits

STATE OF NEW YORK
DEPT. OF PUBLIC SERVICE
DATE: 6/9/10
CASE NOS: 09-S-0794, 09-G-0795, and 09-S-0029
Ex. 310

STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

Case 09-S-0794 - 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.

Case 09-G-0795 - Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Consolidated Edison Company of New York, Inc. for Gas Service.

CASE 09-S-0029 - Proceeding on Motion of the Commission to Consider Steam Resource Plan and East River Repowering Project Cost Allocation Study, and Steam Energy Efficiency Programs for Consolidated Edison Company of New York, Inc.

ATTENTION

This exhibit is among those prefiled in the captioned cases by active parties that executed two joint proposals that were filed on May 18, 2010. Those that executed the joint proposals subsequently stipulated that they would not cross-examine the witnesses of each other given that they were supporting at that time the Commission's adoption of the terms of the joint proposals. In this context, the fact that these parties did not cross-examine the witnesses of each other does not mean and cannot reasonably be understood to mean that the information in this exhibit is uncontroverted among the parties that executed the joint proposals.

BEFORE THE
STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

In the Matter of

CONSOLIDATED EDISON COMPANY OF NEW YORK, INC.

Case 09-S-0794

MARCH 2010

Prepared Testimony of:

Nicola Jones
Utility Engineer 2
Office of Electric, Gas and Water

State of New York
Department of Public Service
90 Church Street
New York, New York 10007

Liliya A. Randt
Utility Engineer 2
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Q. Please state your names, titles and business addresses.

A. Nicola Jones, Utility Engineer 2, New York State Department of Public Service, 90 Church Street, New York, New York 10007 and Liliya A. Randt, Utility Engineer 2, New York State Department of Public Service (Department), Three Empire State Plaza, Albany, New York 12223.

Q. Ms. Jones please briefly state your educational background and professional experience.

A. I graduated from Rensselaer Polytechnic Institute with a Bachelor of Science Degree in Civil Engineering and a Bachelor of Science Degree in Management in 2003. I joined the Department in 2005. My responsibilities at the Department include: monitoring electric utility reliability; ensuring that utilities are adequately prepared to respond to emergencies by reviewing utilities' electric emergency plans and attending annual emergency drills; investigating the causes and response level of utilities after emergency events; evaluating the need for electric distribution projects; and monitoring utility compliance with electrical codes and with the Public Service Commission's (Commission) electric service and safety standards.

Q. Ms. Jones, have you previously testified before the Commission?

A. Yes. I testified in Case 07-E-0523 regarding Consolidated Edison Company of New York, Inc.'s (Con Edison or the Company) infrastructure investment and the reliability performance mechanism. I testified in Case 08-E-0539 regarding research and development, infrastructure investment, and the reliability performance mechanism. I also testified in Case 09-E-0428 regarding the reliability performance mechanism.

Q. Ms. Randt have you already discussed your educational background, professional and testimonial experience, and responsibilities?

A. Yes, that information is included in Staff Rate Panel testimony submitted in this proceeding.

Q. What is the purpose of the Panel's testimony?

A. The purpose of our testimony is to address the installation of a natural gas supply system and other equipment upgrades and purchases (gas addition project) at the West 59^{th} Street and East 74^{th} Street Steam Stations to allow dual-fuel firing capabilities of the respective existing steam boilers. It will also address the Company's proposal to recover the capital costs associated with these projects through the Steam Fuel Adjustment Clause (FAC).

Q. In your testimony, will you refer to, or otherwise rely upon, any information produced during the discovery phase of this proceeding?

A. Yes. We will refer to, and have relied upon, several Company responses to Staff Information Requests. They are attached as Exhibit___(JR-1)

Q. Are you sponsoring any other exhibits?

A. Yes. The Exhibit___(JR-2) shows the expected customer benefits for the West 59^{th} Street gas addition project.

Natural Gas Addition

Q. Did the Panel review the Company's plans for the gas addition projects at the West 59^{th} Street and East 74^{th} Street Generation Stations?

A. Yes.

Q. Please describe Con Edison's plans.

A. At the West 59th Street Generating Station, a natural gas supply system will be installed for the high pressure boilers and the existing natural gas supply system to the package boilers will be modified. The project is estimated to cost $29 million and be placed into service by December 2011 (Exhibit___(JR-1), DPS-55). At the East 74th Street Generating Station, for an estimated cost of $56 million, the Company plans to install a natural gas supply system for three high pressure boilers and six package boilers. The East 74th Street system is expected to go into service by November 2013 (Exhibit___(JR-1), DPS-192). The installation of a natural gas supply system at both generating stations will enable all of the existing boilers to use either natural gas or oil.

Q. Why does the Company claim it is necessary to proceed with these projects now?

A. According to Con Edison, the ability for the boilers to use two different types of fuel provides them with flexibility that can significantly enhance reliability in the event that either fuel supply may be disrupted. Also, the Company claims that the conversion to gas may be necessary in the future to comply with more stringent emissions regulations should they be enacted by the New York State Department of Environmental Conservation (NYSDEC). In addition, based on the Company's cost/benefit analysis, the gas addition project at West 59th Street and the East 74th Street Steam Station are projected to have an annual cost savings of approximately $8.7 million and $15 million, respectively, assuming the Company's current forecast of fuel prices.

Q. Please discuss the possible change to the emissions rules governed by NYSDEC.

A. A proposed regulation has been publicly issued by NYSDEC regarding "Subpart 227-2, Reasonably Available Control Technology (RACT) for Oxides of Nitrogen (NOx)," also referred to as NOx RACT. According to this notice, by July 1, 2012, very large boilers, large boilers, simple-cycle and combined-cycle cogeneration combustion turbines NOx per million Btu limits would be reduced. Other equipment also operated by Con Edison such as Liquefied Natural Gas flare and combustor may be added to the regulated items under NOx RACT, effective July 1, 2012. For example, for very large boilers with gas and oil burning capabilities that has a current emission limit of 0.25 pounds NOx per million Btu will have to comply with a reduced emission rate of 0.15 pounds NOx per million Btu. Comments regarding this proposed change must be submitted to NYSDEC by February 17, 2010.

Q. Can Con Edison currently meet the proposed emission rates?

A. No. The #6 fuel oil, currently used by its boilers, produces 0.29 pounds NOx per million Btu and natural gas produces 0.17 pounds NOx per million Btu (Exhibit___(JR-1), DPS-3). Through Con Edison's use of both fuels, in conjunction with various NOx reduction systems and equipment, Con Edison is able to stay below a daily system-wide average of 0.265 pounds NOx per million Btu (Exhibit___(JR-1), DPS-193). According to Con Edison, in order for it to meet the proposed NOx RACT emission rates, the use of #6 fuel oil at both the West 59th Street and the East 74th Street boilers would need to be reduced. By completing the gas addition projects at these steam generating stations, the Company can minimize the use of #6 fuel oil and maximize the use of natural gas.

Q. Please discuss the Company's cost/benefit analysis of the gas addition project at the West 59th Street Steam Generating Station.

A. According to Con Edison's cost/benefit analysis provided through discovery (Exhibit___(JR-1), DPS-3), the Company projects annual cost savings of approximately $8.7 million that is comprised of $8.2 million in fuel cost savings, a reduction of $480,000 in fuel delivery costs, $70,000 in reduced boiler washes and $6,000 in emissions reductions. By burning mostly natural gas, the Company expects to achieve $8.2 million in fuel cost savings based on the difference between the actual cost of natural gas and the actual cost of oil through August 31, 2009. The $480,000 in fuel delivery savings stems from using fewer barges to transport oil to the station. The $70,000 savings from reduced boiler washes represents a reduction of 1 boiler wash for each affected boiler per year. The Company's plans to use more natural gas and less oil will produce lower levels of NOx. The avoided tons of emissions have a NOx emission allowance market value of $6,000.

Q. Please discuss the Company's cost/benefit analysis of the gas addition project at the East 74th Street Generating Station.

A. According to Con Edison's cost/benefit analysis, the projected annual cost savings of approximately $15 million is comprised of fuel cost savings of $14.5 million, $220,000 from reduced boiler washes and $200,000 in emissions reductions. The methodology used to determine these savings is similar to what is applied to the West 59th Street Generating Station (Exhibit___(JR-1), DPS-3).

Q. Do you have any issues with these gas addition projects?

A. Yes. There are several uncertainties regarding these projects that need to be considered when evaluating the need and timing of them. For example, it is unknown at this time when NYSDEC's proposed NOx RACT regulation will actually go into effect and just how the NYSDEC will use comments received by February 17, 2010 (Exhibit___(JR-1), DPS-190). In addition, it is uncertain as to how amenable NYSDEC will be towards altering its proposed limits on emissions or the required compliance date.

Q. Please continue.

A. Con Edison's proposed budgets and projects are high-level and might change. Both gas addition projects are currently in the conceptual and planning phase (Exhibit___(JR-1), DPS-55). According to the Company, additional time is needed for Con Edison to evaluate the various compliance options available under the proposed NOx RACT regulations to determine how to comply with the requirements most economically (Exhibit___(JR-1), DPS-195). Funding, procurement, detailed engineering and design, and construction have not yet begun (Exhibit___(JR-1), DPS-55). In addition, the in-service date for 74^{th} Street gas addition project might change. Currently, it is scheduled for an in-service date of November 2013, after the proposed deadline of July 1, 2012, for NOx RACT. This was done because from engineering and project management perspectives, Con Edison would prefer to implement the 59^{th} Street and 74^{th} Street natural gas additions in series, rather than in parallel. If necessary, Con Edison plans to seek NYSDEC approval of the November 2013 in-service date for the 74th Street gas addition project. If NYSDEC does not defer the July 1, 2012 compliance date, Con Edison will have to adjust its implementation schedule at an unknown project cost (Exhibit___(JR-1), DPS-191).

Q. Please continue.

A. Furthermore, the cost/benefit analysis presented by the Company is based on the current and forecasted cost differential between natural gas and oil. While Con Edison has implemented measures to effectively manage the cost of fuel; there is no way to guarantee that the cost differential between natural gas and oil will remain the same in the future. The savings from the oil transportation, boiler washings and NOx allowance also has no guarantees. These savings are dependent on the needs of firm gas customers during the winter season. If there is a shortage in natural gas due to firm demand or a catastrophic event, Con Edison might have to increase its use of oil in its boilers to generate steam. This could reduce the savings associated with boiler washes, emission reduction, and barge transportation. Consequently, we are unable to rely solely on the cost/benefit analysis, and, therefore until NYSDEC finalizes its NOx RACT regulation, we are unable to determine if these projects are justified and reasonable at this time.

Q. What is your recommendation for these projects?

A. We recommend that after the rate year, if Con Edison determines and can justify that these projects are indeed necessary, then the Company could submit these projects as part of its next rate case or under its annual filing through Staff's Policy Panel proposed multi-year staged filing approach.

Q. Why should these projects be a part of a staged filing?

A. The proposed gas addition projects at West 59th Street and East 74th Street are not scheduled to go into service until December 2011 and November 2013, respectively; therefore, they do not impact the revenue requirement for the rate year. The annual staged filing will provide Con Edison the opportunity to re-assess its project scope and cost based on the actual NOx RACT regulation ultimately adopted; provide more transparency regarding the projects direction to the Commission; and ensure the proper revenue requirement will be reflected in rates.

Capital Costs Recovery

Q. Please describe how the Company is proposing to recover the capital costs associated with the gas addition projects at West 59th and East 74th

Street Steam Stations?

A. The Company is proposing to recover these capital costs through the steam FAC from the resulting fuel cost savings. The steam FAC would continue to reflect the costs of fuel as if oil were being burned in these two plants. The savings associated with purchasing and burning natural gas at these plants would be retained by the Company to offset the capital costs of installing the natural gas burning equipment.

After the capital costs are fully offset, the steam FAC would reflect the actual cost of fuel burned at the stations. Based on the Company's current projections of gas and oil prices, the Company estimates that it will be able to recoup the capital costs associated with adding the natural gas supply system to the West 59th Street station over a five to seven year time period. A similar payback period is projected for the East 74th Street station.

Q. Do you take an issue with the Company's cost recovery proposal?

A. Yes, we do. The Company proposes an accelerated recovery of the costs of these projects over five to seven years. This accelerated recovery through the steam FAC will benefit the Company while increasing the risk on the ratepayers and would result in intergenerational inequity.

Q. How will this accelerated recovery benefit the Company?

A. Accelerated cost recovery provides the Company its return on investment without having to wait the full life of the project. This reduces the risk of not having full recovery of the asset if for some reason the plant becomes stranded in the future.

Q. How does the proposed accelerated recovery result in intergenerational inequity?

A. Recovering the costs of these two projects over the proposed five to seven years instead of the normal thirty-six year life of the project results in current steam customers paying the full amount of the capital costs, but future customers would contribute nothing while receiving the expected benefits. Therefore, the recovery of these investments should be spread over the normal life of these projects to avoid intergenerational inequity.

Q. What increased risks on ratepayers does the Company's proposed cost recovery produce?

A. The Company proposes to keep the savings arising from the difference in the price of natural gas and #6 fuel oil to offset the capital costs of the projects. Steam customers would continue paying the fuel price as if the capital investment in gas burning facilities had not been made. Therefore, steam customers will be exposed to the risk of the fuel forecast and they would not see the immediate benefit of the project until the capital costs of installing the natural gas burning equipment are fully offset.

Q. What is Staff's proposal for the recovery of the capital costs associated with the gas addition projects at West 59th and East 74th Street?

A. If the Company includes these projects in its staged filings for Rate Year 2 (RY2) or Rate Year 3 (RY3), we recommend that recovery of the capital costs be accomplished in base rates over the normal life time of the projects.

Q. Have you performed an analysis that demonstrates why your proposed cost recovery is more beneficial to ratepayers than that proposed by the Company?

A. Yes. We compared the revenue requirement impact associated with including the capital cost of the West 59th Street gas addition projects in base rates with the expected annual benefits. In doing so, it clearly shows that our proposal would result in a benefit to ratepayers beginning on the day that the plant becomes used and useful, assuming the fuel price forecasts provided by the Company.

Q. Please continue.

A. According to responses to NYC-70, NYC-71 and NYC-75, included in Exhibit___(JR-1), the annual revenue requirement impact for West 59th Street in RY2, if it was included in base rates, would be approximately $4.8 million. Therefore the percentage increase in steam delivery rates associated with reflecting the cost of this project in base rates in RY2 would be approximately 0.7%. In RY3 the revenue requirement impact would be approximately $5.9 million or a 0.8% increase in steam delivery rates, respectively. Exhibit___(JR-2) shows the expected customer benefits for the West 59th Street project as described earlier. As shown, the RY2 revenue requirement amount of $4.8 million will be offset by the total expected annual savings of $8.7 million. Similarly, the RY3 revenue requirement amount of $5.9 million will be offset by the total expected annual savings of $8.7 million. Therefore, customers will see an immediate benefit of $3.9 million in RY2 followed by a $2.8 million benefit in RY3. The percentage decrease in steam delivery rates associated with these savings equates to approximately 0.6% in RY2 and 0.4% in RY3, compare to no change in the total bill under the Company's proposal.

Q. Does this conclude your testimony at this time?

A. Yes.

Con Edison

Hearing Exhibits

STATE OF NEW YORK
DEPT. OF PUBLIC SERVICE
DATE: 6/9/10
CASE NOS: 09-S-0794, 09-G-0795, and 09-S-0029
Ex. 311

BEFORE THE
STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

In the Matter of

CONSOLIDATED EDISON COMPANY OF NEW YORK, INC.

Case 09-S-0794

MARCH 2010

Prepared Unredacted Exhibits of:

Nicola Jones
Utility Engineer 2
Office of Electric, Gas and Water

State of New York
Department of Public Service
90 Church Street, 4^{th} Floor
New York, New York 10007

Liliya A. Randt
Utility Engineer 2
Office of Electric, Gas and Water

State of New York
Department of Public Service
Three Empire State Plaza
Albany, New York, 12223

Jones/Randt

Exhibit___ (JR-1)
(Unredacted)

List of Staff Information Requests

Staff Request	Exhibit Pages
3	1-68
55	69-79
190	80-86
191	87-106
192	107
193	108-109
195	110

Company Name: Con Edison
Case Description: Con Edison Gas & Steam Rate Cases
Case: 09-G-0795-09-S-0794

Response to DPS Interrogatories – Set DPS1
Date of Response: 12/21/2009
Responding Witness: Steam Ops Panel

Question No. :3
Subject: Capital Expenditures – 1. Referring to the Con Edison Steam Operations Panel testimony, page 15 lines 3-6, the Company stated: "The Company's recently updated 2009 peak demand forecast is lower than previous forecasts, due primarily to the lower than anticipated demand over the past 2008-2009 winter." a) Provide the Company's updated 2009 peak demand forecast. b) Provide the Company's most recent 10 year forecast. 2. Provide a spreadsheet (in Excel format) of forecasted demand and actual steam system peak demand for the last 30 years. 3. Provide copies of all internal company documents that describe the company's steam peak demand forecasting methodology. 4. Provide the cost/benefit analyses for the West 59th Street station as referred on page 18 line 16 of Steam Operations Panel testimony. 5. Provide the cost/benefit analyses and calculations of projected savings for East 74th street station gas addition projects as referred on page 19 lines 9-10 of Steam Operations Panel testimony. 6. For each of the West 59th Street and East 74th street gas addition projects provide: a) detailed cost breakdown, b) detailed calculation of projected costs with workpapers, c) detailed need analysis and justification. 7. Referring to the Con Edison Steam Operations Panel testimony, regarding the interference program on page 61 lines 11-13, the Company stated: "Based on an historical average, the Company projects an annual expenditure of $1 million annually for this program for the period 2010-2014." Provide the detailed calculation, including the historical average information that supports the $1 million funding request for each rate year.

Response:

CONFIDENTIAL RESPONSE

1. Referring to the Con Edison Steam Operations Panel testimony, page 15 lines 3-6, the Company stated: "The Company's recently updated 2009 peak demand forecast is lower than previous forecasts, due primarily to the lower than anticipated demand over the past 2008-2009 winter." a) Provide the Company's updated 2009 peak demand forecast. b) Provide the Company's most recent 10 year forecast.

   Response:
   Please see attached excel file, "2010-2019SDF.xls", first tab, for the latest 2009 and 10 year forecast. The latest 2009 forecast for winter 2009-10 is 9,480 Mlb. This

compares to the 2008 forecast of 10,170 Mlb for 2008-09 and 10,300 Mlb for 2009-10.

2. Provide a spreadsheet (in Excel format) of forecasted demand and actual steam system peak demand for the last 30 years.

   Response:

   Please see attached excel file, "2010-2019SDF.xls", second tab for historical actual and forecasted demand that is readily available to the Company. The Company objects to this request to the extent it seeks 30 years of historical data. Notwithstanding, and without waiving the Company's right to object to requests for historical data more than five years old, we have provided such information commencing with the winter period 1996/97, since the data starting with this period are readily available.

3. Provide copies of all internal company documents that describe the company's steam peak demand forecasting methodology.

   Response:
   Please see attached word file, "IRDPS1-3Steam Forecasting Manual (F).doc" for relevant documentation describing the company's steam peak demand forecasting methodology. Please note that this manual will be reviewed and updated as is necessary.

4. Provide the cost/benefit analyses for the West 59th Street station as referred on page 18 line 16 of Steam Operations Panel testimony.

   Response:
   Please see attached file entitled "Attachment 1 to DPS1-3 Part 4 59th Natural Gas Addition Cost Benefit Analysis Confidential". Please see Attachment 2 to DPS1-3 Part 4, which provides a worksheet containing the forecasts, assumptions, details, and analysis that determine the projected savings for the 59th Street Gas Addition Project.

5. Provide the cost/benefit analyses and calculations of projected savings for East 74th street station gas addition projects as referred on page 19 lines 9-10 of Steam Operations Panel testimony.

   Response:
   Please see attached file entitled "Attachment 1 to DPS1-3 Part 5 74th Natural Gas Addition Cost Benefit Analysis Confidential." Please see Attachment 2 to DPS1-3 Part 4, which provides a worksheet containing the forecasts, assumptions, details, and analysis that determine the projected savings for the 74th Street Gas Addition Project.

6. For each of the West 59th Street and East 74th Street gas addition projects provide: a) detailed cost breakdown, b) detailed calculation of projected costs with workpapers, c) detailed need analysis and justification.

   Response:
   a) & b) For the West 59th Street and East 74th Street Stations Gas Addition projects detailed cost estimates please see attached file entitled "Attachment 1 to DPS1-3 Part 6 Confidential."

   c) These projects are needed to comply with regulations that the DEC is committed to adopting that will require reductions in NOx emissions and NOx emission rates, i.e., adding gas firing to the stations will be needed to meet the draft NYS DEC NO_x-RACT regulations because the proposed lower emission limits cannot be met with oil. In addition, as explained in responses to 4 and 5 above, these projects are expected to result in significant cost savings to the customers, i.e., natural gas prices are expected to be lower than oil in the foreseeable future. They are also good for the environment, i.e., the air emissions will be significantly lower using natural gas rather than oil.

   Since the scope of these projects is significant and they will take several years to complete, especially in light of the long lead time required to purchase the equipment, it is appropriate to proceed with these projects now to reap the environmental and cost benefits as soon as possible.

7. Referring to the Con Edison Steam Operations Panel testimony, regarding the interference program on page 61 lines 11-13, the Company stated: "Based on an historical average, the Company projects an annual expenditure of $1 million annually for this program for the period 2010-2014." Provide the detailed calculation, including the historical average information that supports the $1 million funding request for each rate year.

   Response:

   To be provided.

Peak Steam Demand Forecast

Winter Period	Weather Adjusted Actual Demand (Mlbs/hr)	Forecasted Demand (Mlbs/hr)
2008/2009	9540	
2009/2010		9480
2010/2011		9560
2011/2012		9710
2012/2013		9830
2013/2014		9940
2014/2015		10040
2015/2016		10150
2016/2017		10290
2017/2018		10420
2018/2019		10540

Historical Steam Peak Information

Winter Period	Weather Adjusted Actual Steam Peak Load (Mlb/hr)	Winter Peak Demand Forecast (Mlb/hr)
1996/1997	11,775	11,790
1997/1998	11,935	11,880
1998/1999	11,900	11,970
1999/2000	11,920	11,940
2000/2001	11,130	10,980
2001/2002	10,610	10,700
2002/2003	10,490	10,540
2003/2004	10,380	10,430
2004/2005	10,365	10,340
2005/2006	10,310	10,490
2006/2007	10,190	10,330
2007/2008	10,160	10,310
2008/2009	9,540	10,170

Steam Peak Demand Forecasting Manual

Prepared by:

Demand Forecasting Section

Consolidated Edison
4 Irving Place
New York, New York 10003-3598

July 2008

Steam Peak Demand Forecasting

Table of Contents

1

DESCRIPTION OF THE STEAM SYSTEM

1.1 Description of the Steam System

Con Edison's steam system is the largest district steam system in the United States, larger than the next 9 largest combined. The Steam Distribution network consists of 104 miles of mains and service pipes extending from Battery Park north to 96th Street on the west side and 89th Street on the east side of Manhattan. It reliably serves approximately 1,800 customers with steam for space heating, air conditioning, production of domestic hot water and for various process uses. Steam air conditioning is used by more than 370 customers, displacing over 600,000 tons of electric chillers and avoiding an estimated 375 MW of peak electric load with concomitant savings in electric generation, transmission, and distribution resources.

Con Edison generates its own steam for large customer accounts including numerous commercial, residential and government buildings, many of the City's most famous landmarks. The forecasted 2007/2008 winter peak demand was 10,510 Mlbs/hr @ Temperature Variable (TV) of 6 degrees Fahrenheit (°F) using 2005/2006 winter experience. On February 11, 2008 at 9AM the 2007/2008 actual winter peak demand was 8,648 Mlbs/hr at a TV of 17.6°F. The forecasted 10-year compounded annual growth rate for the steam system is projected to be 0.47%. The peak demand is distributed throughout the Manhattan area as follows 50% Midtown, 25% Downtown, 15% Upper East Side and 10% Upper West Side.

2

STEAM PEAK DEMAND FORECAST METHODOLOGY

2.1 Steam Peak Demand Forecast Methodology

This section discusses the steam demand forecast used for the 2007-2026 time horizon. The forecast methodology starts with a determination of a design hour, winter-peak demand. Steam usage peaks in the winter because its largest service component is space heating. Projected new business hook-ups, for which the Company has received Service Information Requests (SIRs), and projected economic activity for residential and commercial customer segments are used to determine demand growth. Offsetting this demand growth is a forecast of lost business. Figure 1 illustrates the overall Demand Forecasting Methodology.

Steam Peak Demand Forecasting Support Function

The Peak Demand Forecasts serve primarily to support the following major activities:

1. Peak demand requirements at the design weather conditions for 10 winter seasons.
2. Demand versus temperature relationships for each winter in the forecast timeframe.
3. This information is also used by (1) Revenue & Volume Forecasting; (2) Steam Resource Planning; (3) Steam Operations Planning; and (4) the Steam Business Development Unit to determine the necessary supply, storage, and peak demand capacity.

This process involves analyzing the forecasted peak demand with the existing steam volumes forecast in order to ensure integrity and reliability of the steam requirements for Con Edison's service area.

Long-term Steam Peak Demand Forecast

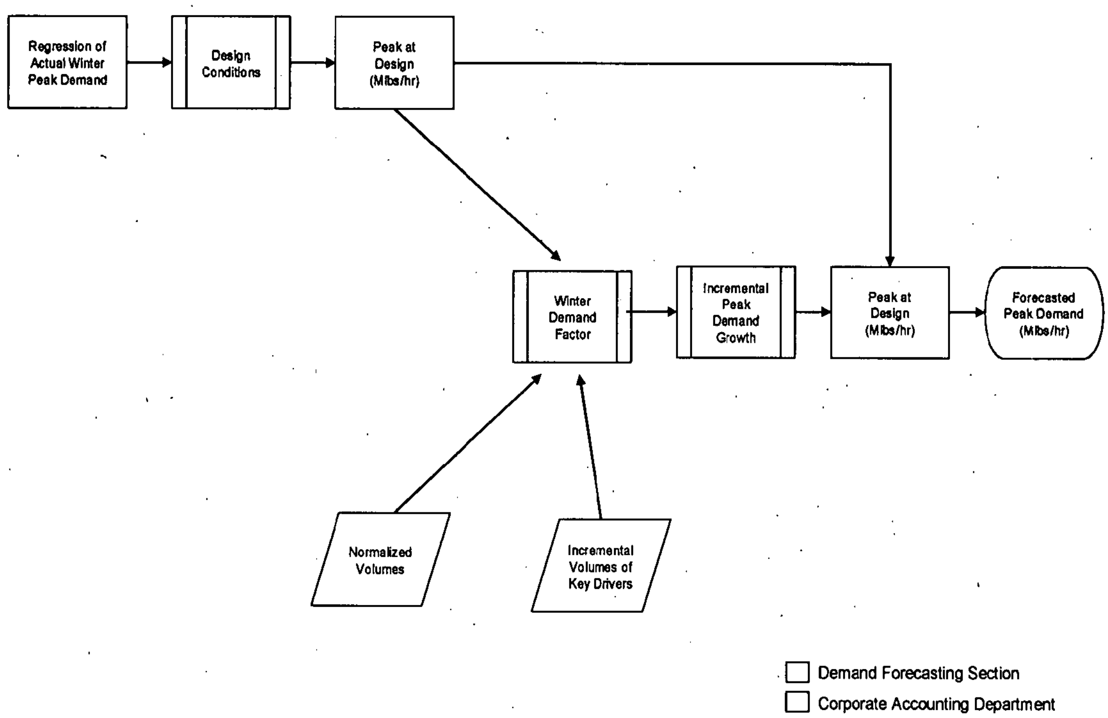
The Company develops its long-term steam peak demand forecasts for a ten-year time horizon using internally developed econometric models. The steam peak demand forecast begins by assessing the prior winter's actual peak demand and adjusting the forecasted peak demand to a design condition based on a one-in-three probability of being exceeded over 30 years through regression analysis.

The long-term steam peak demand forecast is developed by adding incremental volumes growth of key drivers such as new and lost business and vacant office space which are the same drivers used to develop the Annual Steam Volumes Forecast. The incremental volumes growth is converted to peak demand by using a winter demand factor discussed later in the manual. These key drivers are projected in terms of incremental peak demand growth and combined with the base steam peak demand at the design condition to determine the Long-term Steam Peak Demand Forecast. While ten-year forecast is the standard forecast time horizon, a twenty-year long-term forecast is also developed for the purposes of providing information for questions that arise about longer-term growth potential.

The Long-term Steam Peak Demand Forecast is developed during the fall to incorporate the past winter's results and to allow enough time prior to the start of the upcoming winter season each year. Also, while the past winter's results are available following the conclusion of the winter, the steam volumes forecast, upon which the incremental demand growth is derived, is not developed by the Corporate Accounting Department until early fall, shown in the yellow shaded area in Figure 1.

Figure 1

Flow Chart of Steam Demand Forecast Methodology



Temperature Variable

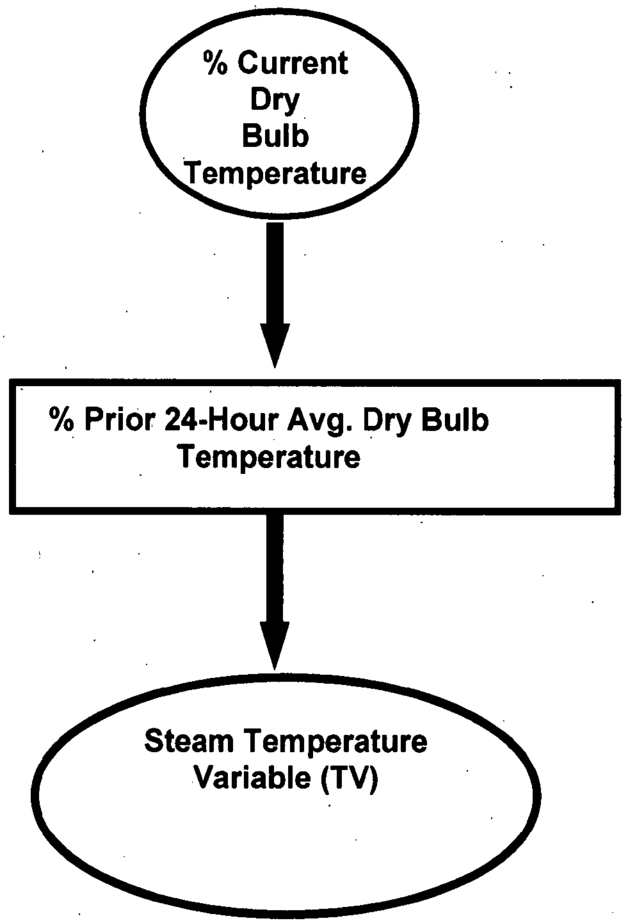
A Temperature Variable (TV) is used to calculate and forecast future steam demand, taking into account extreme cold weather conditions sustained over a 24 hour period that can be expected to occur in the New York metropolitan area where Con Edison's steam system is located. The TV is determined by a regression analysis using the prior winter's peak demand, the current hour's dry bulb temperature (the time when the peak demand actually occurred) and the prior 24-hour average dry bulb temperature shown in Figure 2 below.

The dry bulb temperature refers basically to the ambient air temperature. It is called dry bulb because it is measured with a standard thermometer whose bulb is not wet - if it were wet, the evaporation of moisture from its surface would affect the reading and give something closer to the wet bulb temperature. In weather data terms, dry bulb temperature refers to the outdoor air temperature.

This regression process also defines the percentage weight for the current hour's dry bulb temperature and the prior 24-hour average dry bulb temperature using the Central Park weather. Each winter experience provides the base starting point for the next ten year forecast. Regression analysis is used to determine the relationship between the steam peak demand and the TV based on daily information for the winter season spanning from November through March. For example, this past winter's TV was defined as 60% of the current hour's dry bulb temperature and 40% of the prior 24-hour average dry bulb temperature.

Figure 2

Winter Temperature Variable (TV) Calculation



Winter Steam Peak Demand at Design Condition

For planning purposes, the design weather condition used to calculate the Winter Peak Demand Forecast is a TV @ 6 ° F that is based on a one-in-three probability of being exceeded over 30 years (and using a rolling average) as shown in Figure 3 and Figure 4 below.

Figure 3

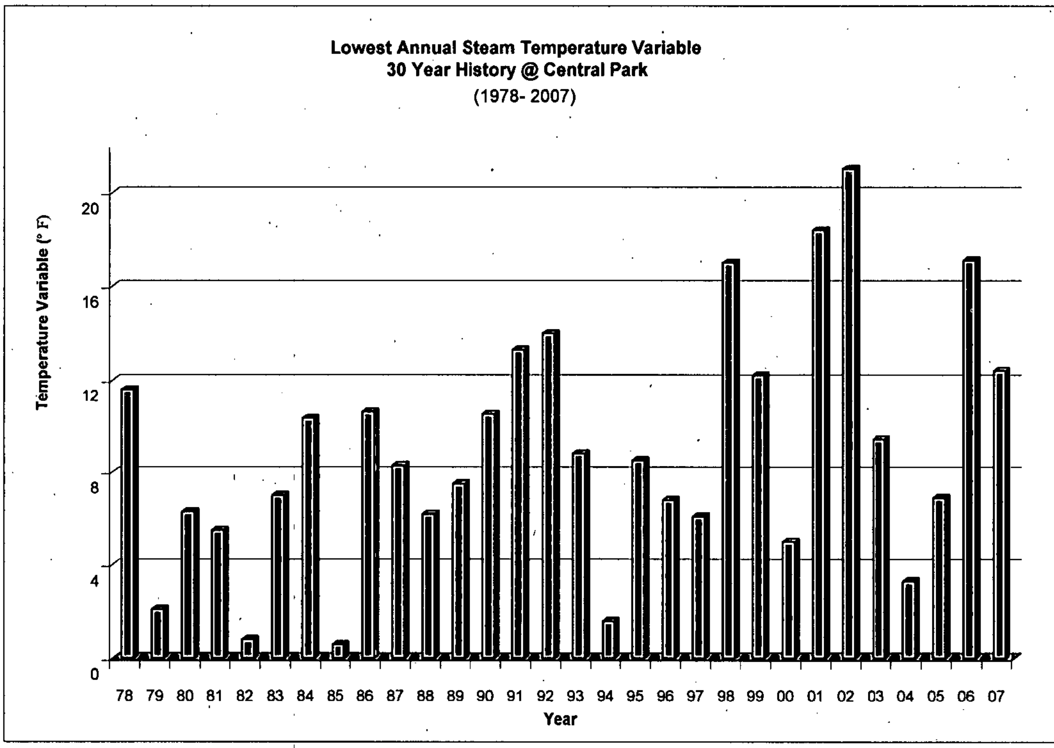
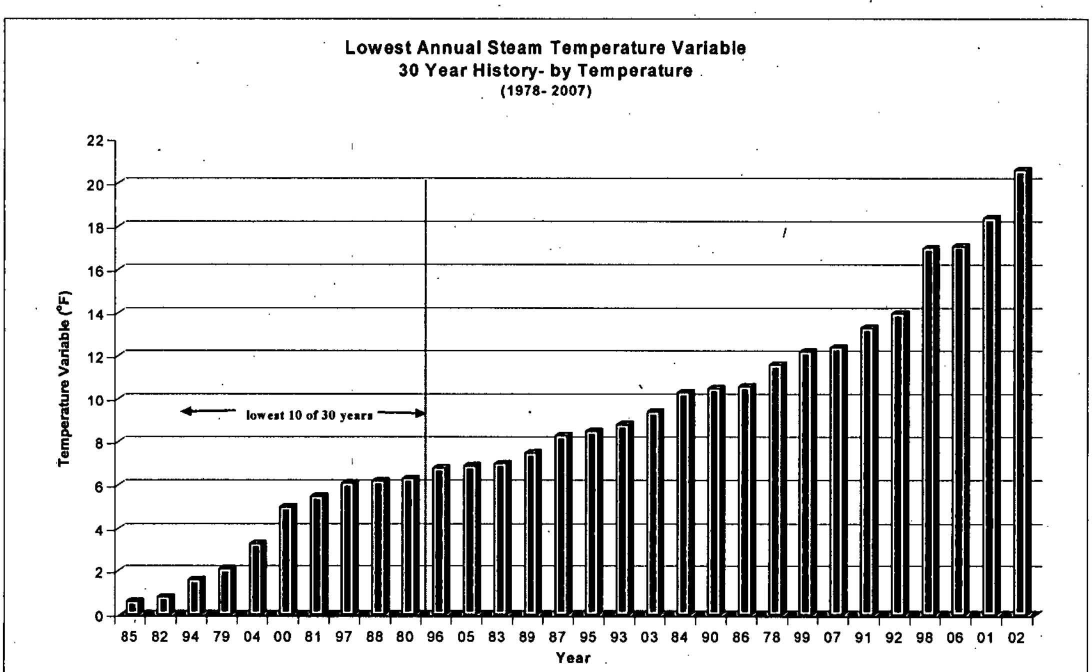


Figure 4

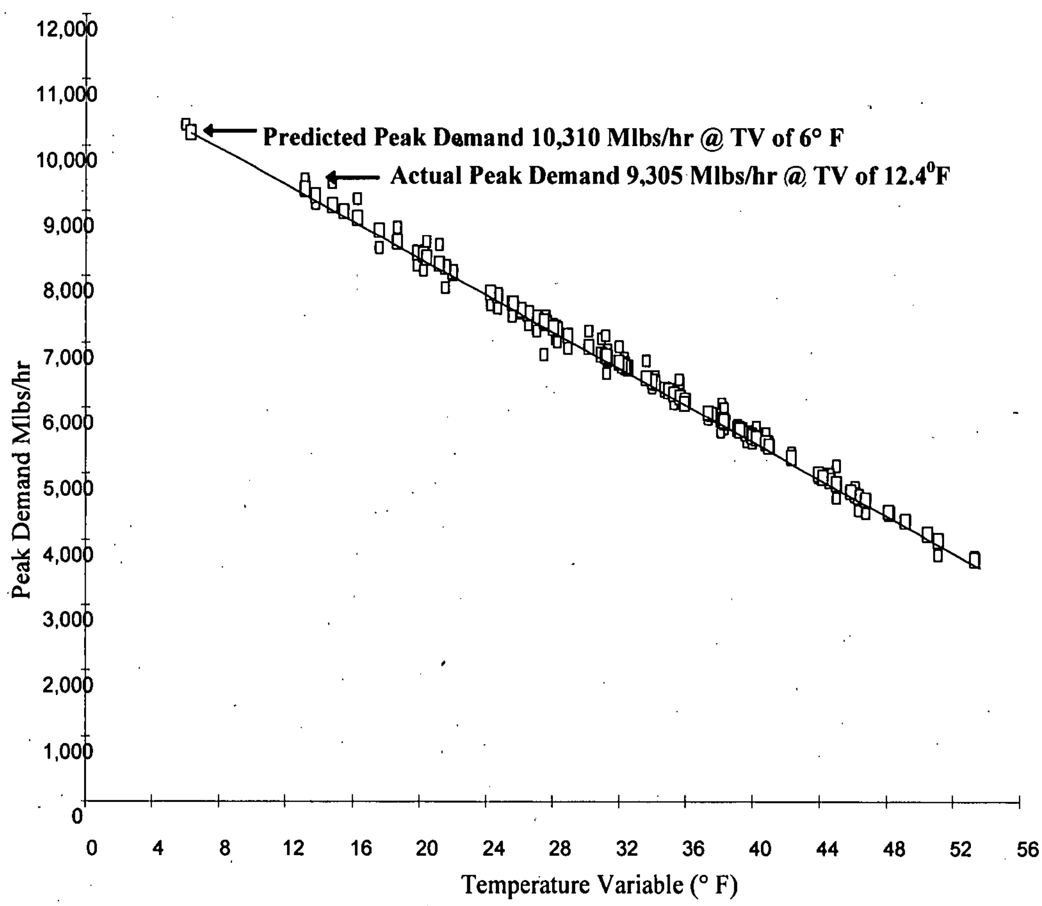


The winter peak demand forecasting process starts by correlating the prior winter's actual hourly peak demand with the actual current hour's dry bulb temperature and the prior 24-hour average dry bulb temperature. This regression analysis extrapolates the forecasted peak demand based on a design temperature variable as shown in Figure 5. In addition, the statistical technique of multiple regressions is used to find the best fit projection in forecasting future steam peak demand. A trend line is developed to help analyze the actual data and to make projections of future forecast as shown in Figure 5.

Figure 5

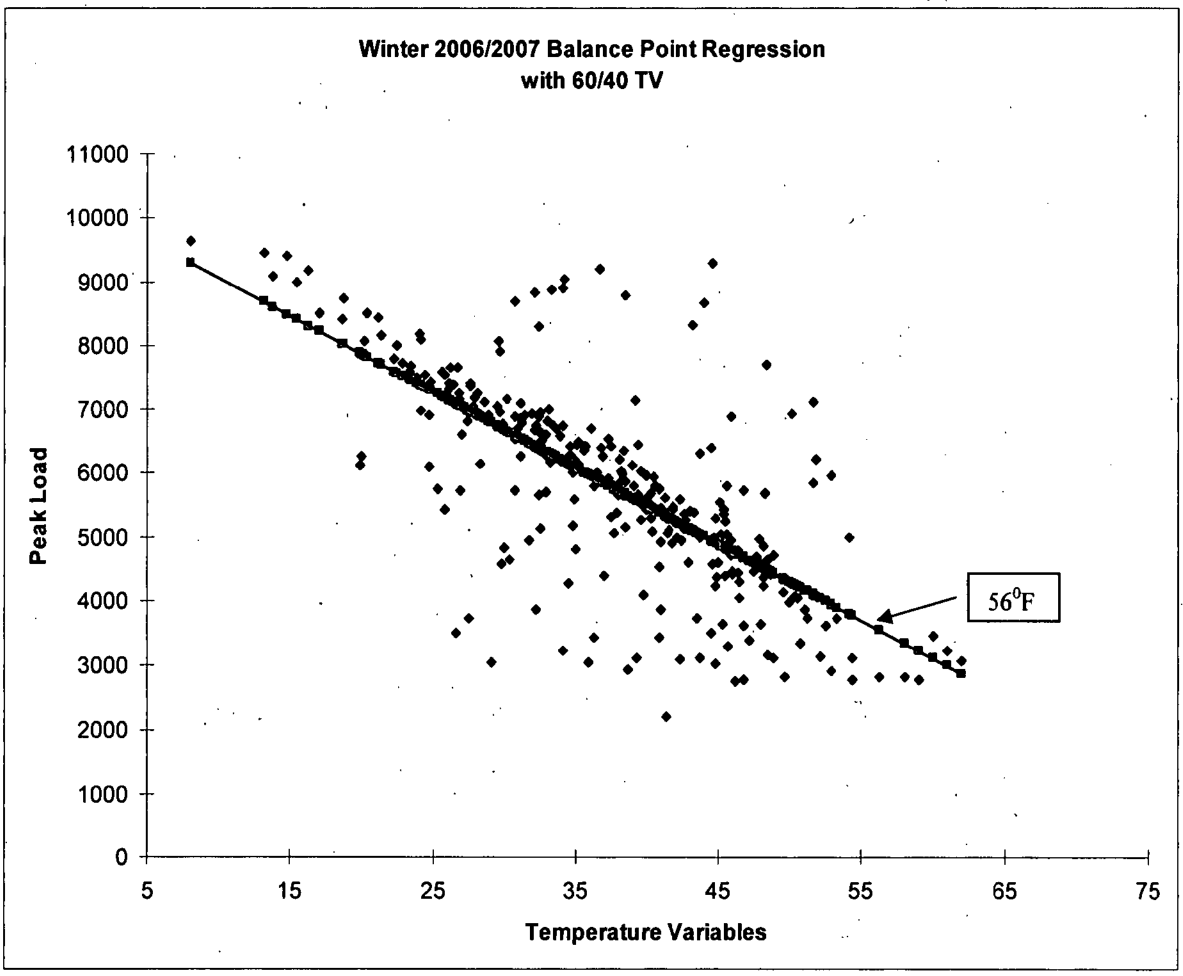
2006/2007 Winter Steam Peak Demand

vs. Temperature Variable



The winter period has been defined to be November-March for the steam system where temperatures typically range between 6° F and 56° F. This period also corresponds with the start of the commercial heating period and helps to incorporate as many cold weather days as possible into the regression analysis for the winter period. As Shown in Figure 6, the winter of 2006/2007 highlights that the majority of cold weather TVs are between 6° F and 56° F.

Figure 6



A Percentage Matrix of the peak demand for each hour is developed from 6° F to 50° F and used to estimate 24 hour demand shapes as shown in figure 7.

Figure 7

2006/2007 Winter Steam Peak Demand Hourly

Percentage Matrix

Hours	Demand @ 6ºF	Demand @ 15ºF	Demand @ 20ºF	Demand @ 30ºF	Demand @ 40ºF	Demand @ 50ºF
1AM	0.757592	0.644185	0.581181	0.455173	0.329166	0.203158
2AM	0.756290	0.641961	0.578445	0.451413	0.324381	0.197350
3AM	0.760518	0.643761	0.578896	0.449167	0.319437	0.189707
4AM	0.770973	0.652128	0.586103	0.454052	0.322002	0.189952
5AM	0.797428	0.676483	0.609291	0.474907	0.340523	0.206139
6AM	0.855124	0.734763	0.667896	0.534162	0.400428	0.266694
7AM	0.946803	0.825503	0.758113	0.623335	0.488557	0.353778
8AM	0.993971	0.871038	0.802741	0.666149	0.529556	0.392963
9AM	1.000000	0.874459	0.804714	0.665224	0.525735	0.386245
10AM	0.979237	0.854606	0.785367	0.646889	0.508411	0.369932
11AM	0.963550	0.839921	0.771237	0.633871	0.496505	0.359138
12PM	0.951349	0.830019	0.762614	0.627803	0.492993	0.358182
1PM	0.938361	0.819710	0.753793	0.621959	0.490125	0.358290
2PM	0.941047	0.820581	0.753655	0.619803	0.485951	0.352099
3PM	0.938456	0.817121	0.749713	0.614896	0.480079	0.345262
4PM	0.922325	0.801709	0.734700	0.600682	0.466665	0.332647
5PM	0.918050	0.795585	0.727549	0.591477	0.455405	0.319333
6PM	0.906473	0.784198	0.716268	0.580407	0.444546	0.308685
7PM	0.825507	0.714054	0.652136	0.528299	0.404463	0.280626
8PM	0.808945	0.697561	0.635681	0.511921	0.388162	0.264402
9PM	0.800723	0.689983	0.628461	0.505417	0.382372	0.259328
10PM	0.784834	0.675399	0.614602	0.493008	0.371414	0.249820
11PM	0.771681	0.662064	0.601165	0.479368	0.357571	0.235774
12AM	0.760646	0.649326	0.587481	0.463792	0.340103	0.216414

The steam peak demand is based on an hourly design and regression analysis is used to plot the steam demand shapes for each hour from 1AM- 12AM against the actual TVs from the prior year as shown in Figure 8 and Figure 9.

Figure 8

Winter 2006/2007 Hourly Demand Model

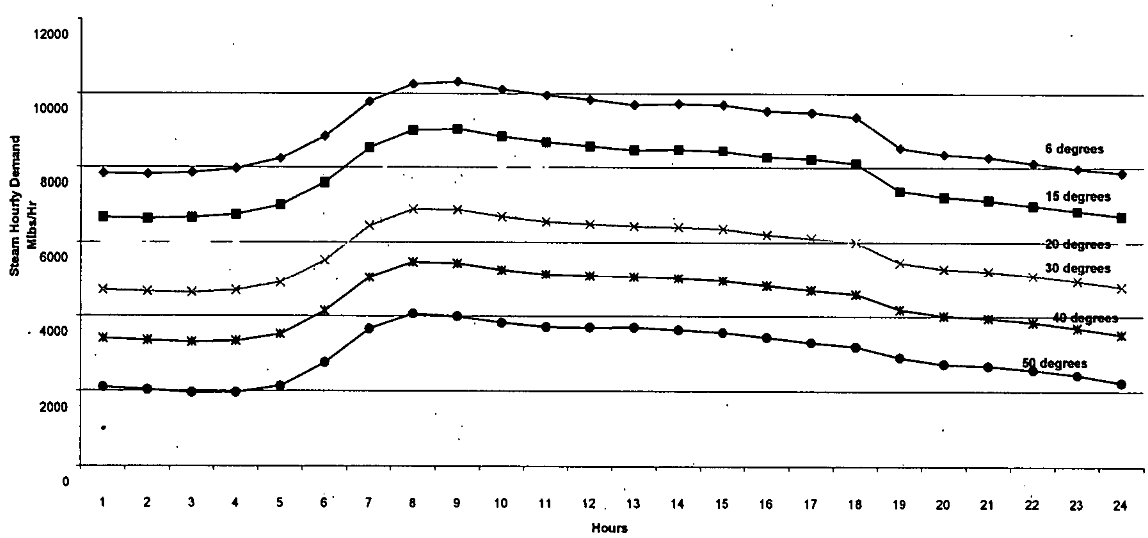
Weekday Heating Linear Regression

Hours	Intercept Coefficient	Slope Coefficient	Demand @ 6 °F	Demand @ 15 °F	Demand @ 20 °F	Demand @ 30 °F	Demand @ 40 °F	Demand @ 50 °F
1AM	8607	-130.17	7826	6654	6004	4702	3400	2099
2AM	8600	-131.22	7812	6631	5975	4663	3351	2039
3AM	8660	-134.01	7856	6650	5980	4640	3300	1960
4AM	8783	-136.41	7964	6736	6054	4690	3326	1962
5AM	9070	-138.82	8237	6988	6294	4906	3518	2129
6AM	9662	-138.15	8833	7590	6899	5518	4136	2755
7AM	10616	-139.23	9780	8527	7831	6439	5047	3655
8AM	11114	-141.10	10268	8998	8292	6881	5470	4059
9AM	11195	-144.09	10330	9033	8313	6872	5431	3990
10AM	10974	-143.05	10116	8828	8113	6682	5252	3821
11AM	10805	-141.90	9953	8676	7967	6548	5129	3710
12PM	10663	-139.26	9827	8574	7878	6485	5093	3700
1PM	10510	-136.18	9693	8468	7787	6425	5063	3701
2PM	10551	-138.27	9721	8477	7785	6403	5020	3637
3PM	10530	-139.27	9694	8441	7745	6352	4959	3567
4PM	10358	-138.44	9528	8282	7589	6205	4821	3436
5PM	10327	-140.56	9483	8218	7516	6110	4704	3299
6PM	10206	-140.34	9364	8101	7399	5996	4592	3189
7PM	9295	-127.92	8527	7376	6737	5457	4178	2899
8PM	9123	-127.84	8356	7206	6567	5288	4010	2731
9PM	9034	-127.10	8271	7128	6492	5221	3950	2679
10PM	8861	-125.61	8107	6977	6349	5093	3837	2581
11PM	8726	-125.82	7971	6839	6210	4952	3694	2436
12AM	8624	-127.77	7857	6708	6069	4791	3513	2236

Figure 9

Winter 2006/2007 Hourly Demand Model

Weekday Heating Linear Regression



The regression analysis determines the percentage ratio between the current dry bulb weather variable and the prior 24 hour dry bulb weather variable (i.e. 70%- 30%, 60%- 40%, etc.). The percentage ratios are then used to determine the TV by taking the percentage ratio of the current peak hour weather variable and the prior 24 hour weather variable coefficients as shown in Figure 8.

The Summary Output data in Figure 8 is the result of several consecutive regression analyses excluding data points substantially off the curve used to determine an acceptable statistical measured R-Square (i.e.85%-98%), the Standard Error, the Intercept and Coefficients. The 83 observations (data points) could not be shown in its entirety using this example.

A snap shot of the previous winters' statistical data and percentage ratios for the current weather variable and the prior 24 hour weather variable is shown in Figure 9.

For example, on Monday, February 5, 2007 at 9AM the steam peak demand for the 2006/2007 winter was 9,305 Mlbs/hr. The steam peak demand is also known as the integrated steam peak demand and it is recorded every hour on the hour ending (8AM – 9AM). A snapshot of the steam peak demand is taken in 15 minute intervals during each hour and the average peak demand within that hour determines the integrated steam peak demand.

Also, on Monday, February 5, 2007 at 9AM the current dry bulb weather variable was 9.0° F and the prior 24-hour average dry bulb weather variable was 17.4° F. Using 60% of the current dry bulb weather variable (.i.e. 9.0° F x 0.60 = 5.4° F) and 40% of the prior 24 hour dry bulb weather variable (17.4° F x 0.40 = 7.0° F), deriving a TV of 12.4° F (5.4° F + 7.0° F) for that hour.

Figure 10

Winter 2006/2007 Heating Demand Model

Weekday Linear Regression

Date	Day	Month	Peak Hr	Peak Demand-Mlbs/hr	Current Dry Bulb WV	*Prior 24 WV
17-Nov-05	Thu	Nov	9AM	4787	41.0	53.9
21-Nov-05	Mon	Nov	8AM	4416	47.0	50.0
2-Dec-05	Fri	Dec	8AM	5457	38.0	42.1
6-Dec-05	Tue	Dec	8AM	6703	30.0	33.3
13-Dec-05	Tue	Dec	9AM	8017	18.0	28.1
14-Dec-05	Wed	Dec	9AM	8413	16.0	20.0
19-Dec-05	Mon	Dec	9AM	6278	34.0	36.0
21-Dec-05	Wed	Dec	9AM	7155	26.0	28.6
28-Dec-05	Wed	Dec	9AM	5646	40.0	38.4
6-Jan-06	Fri	Jan	9AM	5597	39.0	43.4
10-Jan-06	Tue	Jan	9AM	5112	42.0	49.5
11-Jan-06	Wed	Jan	8AM	4985	45.0	44.1
17-Jan-06	Tue	Jan	3PM	7390	26.0	24.9
23-Jan-06	Mon	Jan	9AM	5791	38.0	38.9

WV= weather variable

*Prior 24 hour Dry Bulb weather Variable.

SUMMARY OUTPUT

Regression Statistics				
Multiple R	0.992027058	**Design @ 6**	**10,311**	**Mlbs/hr**
R Square	**0.984117684**	**Rounded**	**10,310**	**Mlbs/hr**
Adjusted R Square	0.983720626			
Standard Error	173.2659161			
Observations	**83**			

Analysis of Variance

	df	*SS*	*MS*	*F*	*Significance F*
Regression	2	148815949.1	74407975	2478.5244	1.08781E-72
Residual	80	2401686.216	30021.078		
Total	82	151217635.3			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*
Intercept	**11152.6606**	78.93029164	141.2976	9.845E-98	10995.58432	11309.737
Current WV	**-84.38412257**	4.338881911	-19.44836	4.672E-32	-93.0187726	-75.749473
Prior 24 Hr WV	**-55.94420305**	4.92436273	-11.3607	2.306E-18	-65.74399702	-46.144409
	-140.3283256	**60%**				
		40%				

Figure 11

WEEKDAY STEAM WINTER MODEL 2006/2007

	x	x^2	x^3	Linear	Forecasted Demand
	6	36	216		
x^3			-0.038451		
x^2		0.00605786	3.78936174		
x		-140.75378	-256.54087	-140.32833	
Intercept		11160.1455	12240.9693	11152.6606	
Mlbs/hr	@ 6	10,320	10,830	**10,310**	**10,330**
R^2		98.4%	98.5%	**98.4%**	
Current WV		**60%**			
Prior WV		**40%**			

WEEKDAY STEAM WINTER MODEL 2005/2006

	x	x^2	x^3	Linear	Forecasted Demand
	6	36	216		
x^3			-0.01		
x^2		-0.4276	0.5386		
x		-110.31	-138.75	-138.63	
Intercept		10778	11023	11197	
Mlbs/hr	@ 6	10,101	10,208	**10,365**	**10,490**
R^2		98.0%	98.0%	**97.8%**	
Current WV		**61%**			
Prior WV		**39%**			

WEEKDAY STEAM WINTER MODEL 2004/2004

	x	x^2	x^3	Linear	Forecasted Demand
	6	36	216		
x^3			-0.0479		
x^2		-0.6907	4.0583		
x		-91.23	-239.73	-137.17	
Intercept		10492	11939	11200	
Mlbs/hr	@ 6	9,920	10,636	**10,377**	**10,340**
R^2		97.3%	97.4%	**97.1%**	
Current WV		**63%**			
Prior WV		**37%**			

Overall Steam Winter Peak Demand Process

Step 1:

- Plot the actual peak demand from the prior year to predict what the upcoming year's peak demand would be at the design condition of 6° F.
- 2006/2007 Winter Steam Peak Demand Forecast was 10,310 Mlbs/hr at design of 6° F.
- The actual 2006/2007 Winter Steam Peak Demand was 9,305 Mlbs/hr at a TV of 12.4° F.

Step 2:

- Use of linear and polynomial regression analyses to produce the slope of a line or curve that best fits a set of data points. Based on a year's worth of peak demand data, for example, regression analysis projects the peak demand for the winter, summer, spring and fall of the following year and provides the slope, and y-intercept (the point where the line crosses the y-axis) of the line or curve that best fits the peak demand data. Following the line or curve forward in time, an estimate of future peak demand is determined.
- Multiple regressions to the second and third power are used to produce more realistic projections and to derive at the best fit curves.

Step 3:

- Review of known steam business activities such as new business projects, vacant office space, on-site generation losses, demolition and other lost business due to combine heat & power, price elasticity, and a reduction of volumes due to demand billing.
- Also, a review of other economic factors and trends are performed for such areas as:
  - Strong employment and population growth is forecasted in the Manhattan area over the next 20 years.
  - 2006/2007 Winter Steam Peak Demand Forecast is in-line with the prior years forecast.
  - Economic indicators show healthy growth over the next 20 years for new business in New York City.

The base starting point for the 10-Year Winter Steam Peak Demand Forecast for the 2006/2007 winter @ 6° F design was 10,310 Mlbs/hr as shown in Figure 10. This is also referred to as the Weather-Adjusted Winter Peak Demand Forecast.

Figure 12

10 Year Winter Steam Peak Demand Forecast

Units in Mlbs/hr	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
2005/2006	06/07	07/08	08/09	09/10	10/11	11/12	12/13	13/14	14/15	15/16
Winter @ Design	**10310**	10310	10310	10310	10310	10310	10310	10310	10310	10310
New Business										
Commercial	25	141	99	70	24	60	35	30	43	47
Residential	39	78	34	46	15	11	9	10	9	9
Vacant Space	17	22	29	31	31	29	33	30	33	30
Business Losses										
On-site Generation	-35	-35	-35	-35	-35	-35	-35	-35	-35	-35
Demolition & Other	-10	-10	-10	-10	-10	-10	-10	-10	-10	-10
Combine Heat & Power	-16	-16	-16	-16	-16	-16	-16	-16	-16	-16
Demand Billing	0	0	0	0	0	0	0	0	0	0
Price Elasticity	0	0	0	0	0	0	0	0	0	0
Total Increments	21	179	101	85	9	39	17	9	24	25
Cumulative Increments	21	200	301	387	396	434	451	460	484	509
Winter Forecast	10331	10510	10611	10697	10706	10744	10761	10770	10794	10819
Rounded	**10330**	**10510**	**10610**	**10700**	**10710**	**10740**	**10760**	**10770**	**10790**	**10820**

Below are some of the new commercial projects in 2008 and 2009:

Steam Business Development- New Commercial Projects

2008

Building Owner	Mlbs/hr
1) Goldman Sachs	56
2) Alexandria Realty East River Science Park	46
3) Time Equities (Hotel) 47-50 West Street	29
4) New York Law School 185 West Broadway	20
5) RFR Holdings 610 Lexington Ave	17
6) MSKCC-BIC 300 East 66th Street	17
Subtotal	**185**

2009

Building Owner	Mlbs/hr
1) Moynihan Station 372-78 9th Ave	75
2) John Jay College 899 10th Ave	27
3) MTA- Fulton Street Station 192 Broadway	18
Subtotal	**120**

3

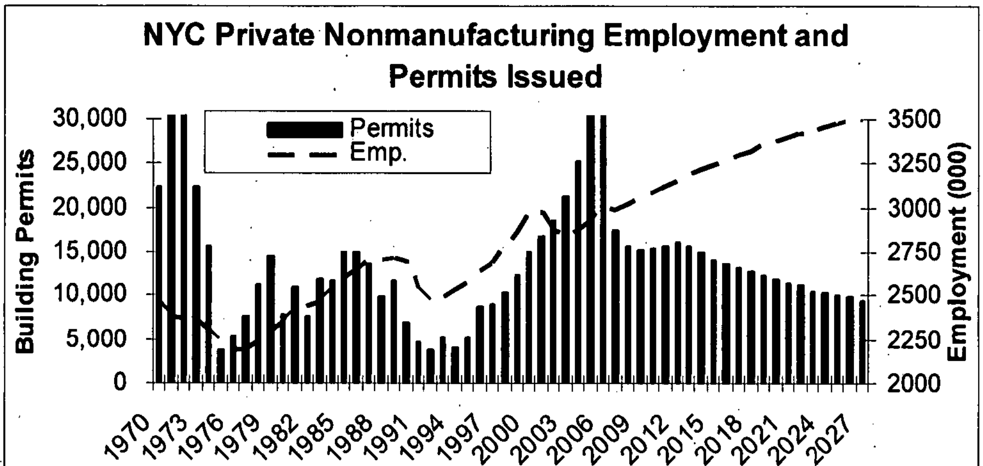
INCREMENTAL GROWTH

3.1 Economic Activity Considered in the Forecast

The analysis and diagrams below are examples of the information used to help develop the 10-Year Winter Steam Peak Demand Forecast shown in Figure 10 above. Some of this information may have changed by the time this manual is published.

New York City employment is the primary factor influencing the construction of new office space in Manhattan. Historically, office employment accounts for about 75% of private non-manufacturing (PNM) employment. PNM employment is cyclical but has trended upward since the mid-1970s (see Figure 11). Long-term growth averaged 1.0% per year over the 25 year period ending in 2006. Growth within that period has been significantly higher, particularly between 1994 and 2000 and in 2005 and 2006. Between 1996 and 2006, PNM employment grew by an average of 1.4% per year, the equivalent of an annual average of 380,000 jobs. This upward trend reflects the growth of the service sector in the economy of the city and the nation, and has occurred despite the downturn caused by the 2001 recession and the loss of jobs associated with 9/11. The forecasted compound annual rate of employment growth over the next 20 years is 0.8%. The New York City employment data is a subset of the vacant space used as a key driver for incremental volumes growth which increases the winter peak demand for steam.

Figure 13



Note: 1985 and 1986 permit data averaged to smooth spike in 1985 caused by rush by developers to obtain permits prior to change in regulations.

The level of new housing construction in New York City fluctuates with business cycles in the city's economy. Figure 11 shows forecasted construction of new housing in terms of housing permits issued and NYC employment, including historic data from 1970 and forecast projections until 2027. Also shown in Figure 11 is the surge in employment that took place in the late 1990s and from 2004 to 2006, which produced record high levels of permits for new construction. In 2005, the number of residential building permits issued in New York City reached a 32-year high. The data for the forecast in housing permits and PNM employment for New York City is from Moody's Economy.com (www.economy.com). The employment trend may have changed in the past year and it is being used to show what went into the incremental growth forecast for new business.

3.2 New Business - Residential

The Company forecasts the completion of new dwelling units based on a two-year lag of the housing-permits forecast. Relative to the historic highs reflected in the permit data, the rate of dwelling unit additions is expected to steadily decline over the forecast period 2008 - 2027. These statistics apply to all five boroughs of New York City. The demand forecast adjusts this based on data that shows that Manhattan accounts for about 26% of total New York City permits issued and the Con Edison steam service area is estimated at 80% of the Manhattan market. The average number of new dwelling units added in the steam service area over the 2008 - 2027 periods is forecasted at 3,300 per year. Market share for the Company's steam business is assumed to be 10% of the service area's new-dwelling-unit forecast. [1] New Residential Business construction data is a key driver for incremental volumes growth which increases the winter peak demand for steam.

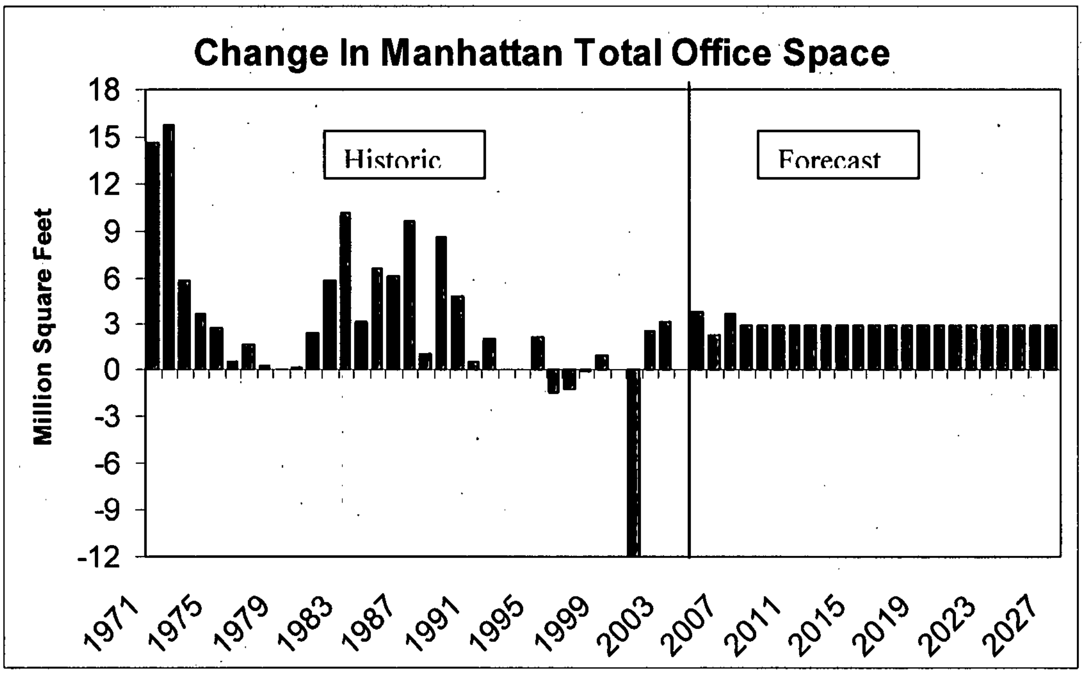
3.3 New Business – Commercial

The Manhattan Office Market

New office construction is generally driven by employment levels. Historically, new construction occurs in waves as seen in Figure 12. However, the forecasted year on year changes are based on long-term trends which level out the lumpiness in construction activity. And, the forecast assumes that the long-term trend in total office space is upward, consistent with the forecasted trend in employment. [2] The market share for targeted segments is higher. For example, the January 2007 Steam Strategic Plan cited an average capture rate of approximately 20% for residential buildings larger than 250,000 square feet near the steam system, over the last five years.

The Company's office-construction forecast is also shown in Figure 12. It assumes that New York City PNM employment will grow by an average of 0.8% per year between 2008 and 2027. This equates to a net new construction increase of 56.6 million square feet by 2027 in the steam service area, which includes 11.1 million square feet for World Trade Center (WTC) reconstruction, 3.6 million square feet for First Avenue properties (former site of the Waterside station), and 1.6 million square feet for major projects on the west side of Manhattan. For the years 2010 and beyond, the WTC is currently the only large-scale project requesting steam service. For most other future development, including the First Avenue properties, market share for the Company's steam business is assumed at 90%, which is based on the historical average share of new commercial business. [3] New Commercial Business construction data is a key driver for incremental volumes growth which increases the winter peak demand for steam.

Figure 14



3.4 Vacant Office Space

The winter peak demand forecast is subject to many uncertainties. The recent mortgage crisis is one example of an event that has the potential to change forecasted demand.

At this time, the Company is evaluating the impact on new office and residential construction and vacant Manhattan office space as a result of the mortgage crisis.

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[1] Steam Strategic plan stated: "The average over the last five years for residential buildings larger than 250,000 square feet, near the steam system, was approximately 20%."

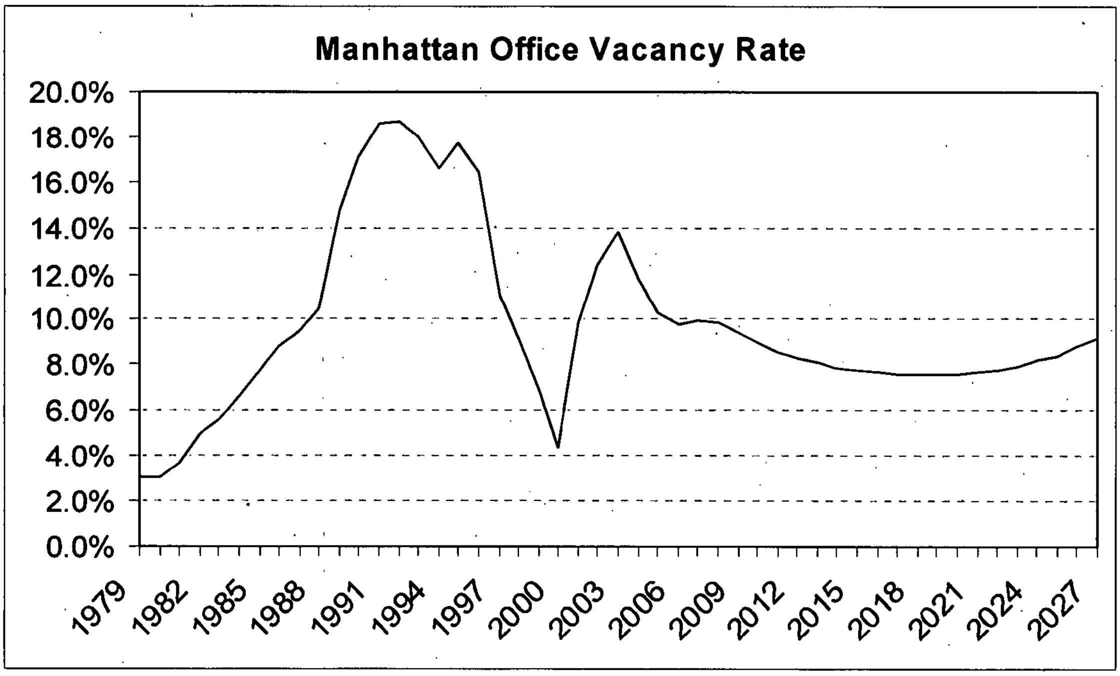
[2] The market share for targeted segments is higher. For example, the January 2007 Steam Strategic Plan cited an average capture rate of approximately 20% for residential buildings larger than 250,000 square feet near the steam system, over the last five years.

3 In the case of Hudson Yards, there are no active requests for steam service at this time and the forecast does not assume any new steam demand in the area on account of the economic and technical barriers to expanding service to the area.

Vacancy rates are forecasted to decline slowly over the 2008-2017 periods, dropping to a low of 7.6%, and rising gradually during 2021-2027 to 9.2% (Figure 13). Changes in vacancy rates are reflected in the steam forecast as increases or decreases in peak demand, as the occupancy of existing and new buildings increases or decreases.

Figure 15

Actual and Forecasted Manhattan Office Vacancy Rate



3.4 Summary of Key Drivers to Forecasted Net Increase in Peak Demand

3.4.1` New Business

The three main categories used to develop forecasted increases in peak demand are derived from economic activity discussed above for residential and commercial new construction along with changes in vacancy rates. Demand increases are based on the following three categories:

- New Commercial Office Space

- New Residential
- Utilization of Vacant Space

3.4.2 Lost Business

The anticipated growth from new customers is netted out against anticipated lost business. This is illustrated in the chart below. Lost business consists of the following main categories:

- Combined Heat and Power Installations
- Building Demolitions
- On-site Generation Losses
- Price Elasticity
- Demand Billing

3.5 Incremental Volumes Growth Converted to Steam Peak Demand

The Corporate Accounting Department provides the Winter Normalized Volumes for the key forecast drivers such as new business projects, vacant office space, on-site generation losses, demolition and other lost business due to combine heat & power, price elasticity, and a reduction in volumes due to demand billing.

The winter volumes growth drivers are converted into steam peak demand (Mlbs/hr) by using a winter demand factor as follows:

Step 1. Winter Volumes- MMlbs - The 5-year average volumes (in MMlbs) are broken out each month. For the Winter Steam Peak Demand (sometimes referred to as the Weather Adjusted Winter Steam Peak Demand) the winter months volumes (in MMlbs) are used (November – March)

Step 2. Average Winter Volumes - Mlbs/hr - Calculate the Average Winter Volumes converting that number into Mlbs/hr by taking the Winters Volumes (Step 1) divided by the number of days in the winter season (i.e. 154 days); divide by the numbers of hours in a day (24); multiple by 1000 for the conversion to demand per Mlbs/hr.

Step 3. Winter Peak Demand - Mlbs/hr – Multiple the Winter Steam Demand Factor (see below calculations for detail) by the Average Winter Volumes Demand (Step 2) to get the Winter Peak Demand- Mlbs/hr.

For example: 2006/2007 Winter Steam Demand Factor was 37.7%

Winter Normalized Volumes MMlbs	Winter Season Days	# of Hrs. in a Day	Avg. Hourly Demand
14401	154	24	3.89

The Average Winter Hourly Demand is calculated by taking the Winter Normalized Volumes in MMlbs of 14401 (provided by the Corporate Accounting Department) divided by the number of days in the winter season (154); divided by the number of hours in a day (24) gives you the Average Winter Hourly Demand (3.89).

Take the Average Winter Hourly Demand (3.89) divided by the Winter Steam Peak Demand in Mlbs/hr of 10,310 (developed by the Peak Demand Forecasting Section) multiplied by 1000 for the conversión to the Winter Steam Demand Factor in Mlbs/hr of 37.7%.

Figure 16 highlights the incremental volumes growth drivers that are converted to peak demand by using the Winter Steam Demand Factor (37.7%). The following is an example of how this is applied using the incremental 2007 Residential volumes growth:

1) Annual Steam Volumes-MMlbs— provided by Corporate Accounting = 87;

2) Winter Volumes-MMlbs are the volumes from November through March provided by Corporate Accounting = 55;

3) Average Volumes-Mlbs/hr derived by taking the Winter Volumes-MMlbs divided by the number of days in the Winter Season (154); divided by the number of hours in a Day (24); (55/155)/24 x 1000 = 15 Mlbs/hr;

4) Winter Peak Mlbs/hr derived by taking the Average Volume Mlbs/hr divided by Winter Demand Factor of 37.7%; (15/.377) = 39 Mlbs/hr.

Figure 16

10 Year Winter Steam Peak Demand Forecast

Key Incremental Growth Drivers

Commercial	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	Total
1) Annual Sales - MMlbs	61	257	208	140	42	136	22	27	18	18	928
2) Winter Sales - MMlbs	35	196	138	97	32	83	18	18	13	12	643
3) Average - Mlbs/hr	9	53	37	26	9	22	5	5	4	3	174
4) Winter Peak Mlbs/hr	25	141	99	70	24	60	13	13	10	9	461
5) Winter Peak -WTC	0	0	0	0	0	0	22	17	33	39	111
6) Winter Peak Mlbs/hr	**25**	**141**	**99**	**70**	**24**	**60**	**35**	**30**	**43**	**47**	572

Residential	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	Total
1) Annual Sales - MMlbs	87	159	72	92	29	24	21	22	21	21	548
2) Winter Sales - MMlbs	55	108	48	64	21	16	13	14	13	13	365
3) Average - Mlbs/hr	15	29	13	17	6	4	4	4	4	4	99
4) Winter Peak Mlbs/hr	**39**	**78**	**34**	**46**	**15**	**11**	**9**	**10**	**9**	**9**	262

Vacant Space	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	Total
1) Annual Sales – MMlbs	47	58	81	87	88	81	95	83	95	83	798
2) Winter Sales – MMlbs	24	31	40	43	43	40	46	42	46	42	397
3) Average - Mlbs/hr	6	8	11	12	12	11	12	11	12	11	107
4) Winter Peak Mlbs/hr	**17**	**22**	**29**	**31**	**31**	**29**	**33**	**30**	**33**	**30**	285

On-site Generation	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	Total
1) Annual Sales – MMlbs	-85	-85	-85	-85	-85	-85	-85	-85	-85	-85	-850
2) Winter Sales - MMlbs	-49	-49	-49	-49	-49	-49	-49	-49	-49	-49	-490
3) Average - Mlbs/hr	-13	-13	-13	-13	-13	-13	-13	-13	-13	-13	-130
4) Winter Peak Mlbs/hr	**-35**	**-35**	**-35**	**-35**	**-35**	**-35**	**-35**	**-35**	**-35**	**-35**	-350

Demolition & Other	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	Total
1) Annual Sales - MMlbs	-23	-23	-23	-23	-23	-23	-23	-23	-23	-23	-230
2) Winter Sales - MMlbs	-14	-14	-14	-14	-14	-14	-14	-14	-14	-14	-140
3) Average - Mlbs/hr	-4	-4	-4	-4	-4	-4	-4	-4	-4	-4	-40
4) Winter Peak Mlbs/hr	**-10**	**-10**	**-10**	**-10**	**-10**	**-10**	**-10**	**-10**	**-10**	**-10**	-100

Combine Heat & Power	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	Total
1) Annual Sales - MMlbs	-37	-37	-37	-37	-37	-37	-37	-37	-37	-37	-370
2) Winter Sales - MMlbs	-23	-23	-23	-23	-23	-23	-23	-23	-23	-23	-230
3) Average - Mlbs/hr	-6	-6	-6	-6	-6	-6	-6	-6	-6	-6	-60
4) Winter Peak Mlbs/hr	**-16**	**-16**	**-16**	**-16**	**-16**	**-16**	**-16**	**-16**	**-16**	**-16**	-160
Total Increments	**21**	**179**	**101**	**85**	**9**	**39**	**17**	**9**	**24**	**25**	

3.6 Net Increase in Demand

As indicated in Figure 17, although new business due to the aforementioned economic activity will result in substantial increases in steam load; these will be partially offset by lost business. The net increase between the first year of the forecast in 2008 and the last year in 2027 is 710 Mlb/hr of peak demand.

The overall peak demand forecast is shown in Figure 18. The first forecast year of 2007 shows a peak demand of 10,510 Mlbs/hr. This increases to 11,040 Mlbs/hr in 2027, the last year of the 20 year forecast period.

Figure 17

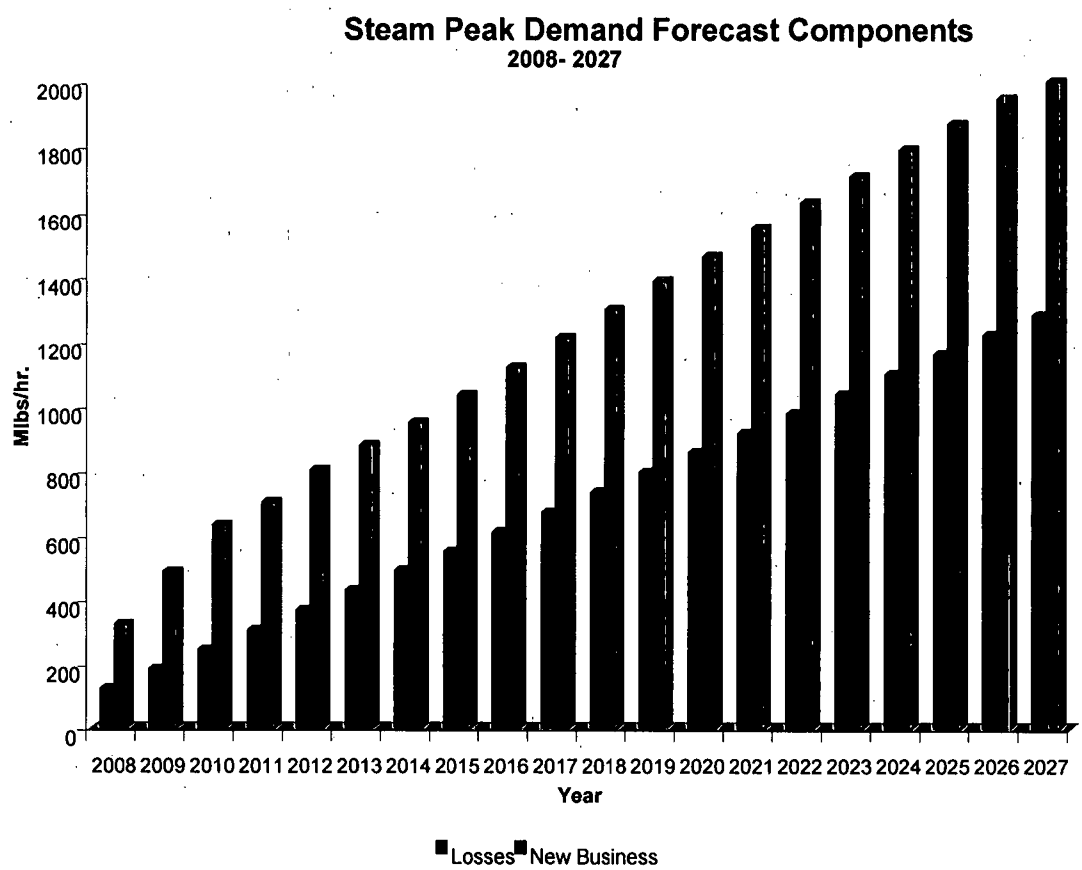
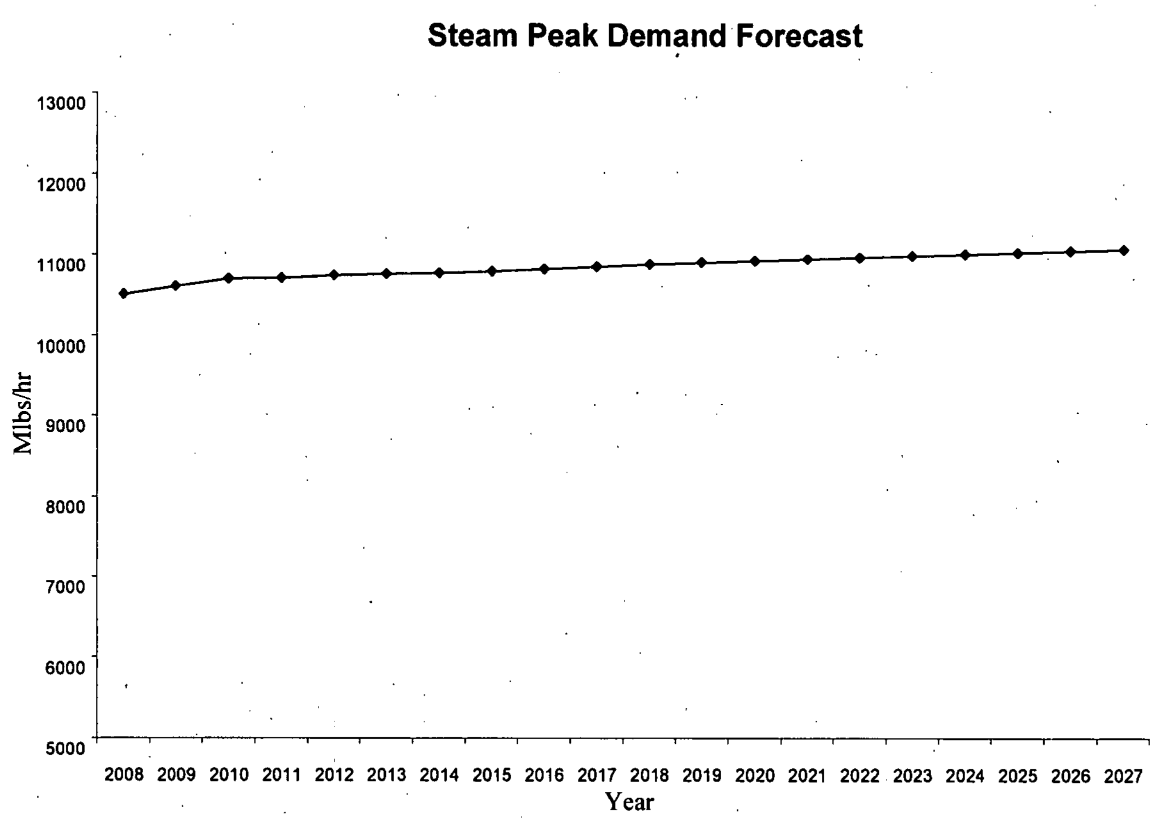


Figure 18



4

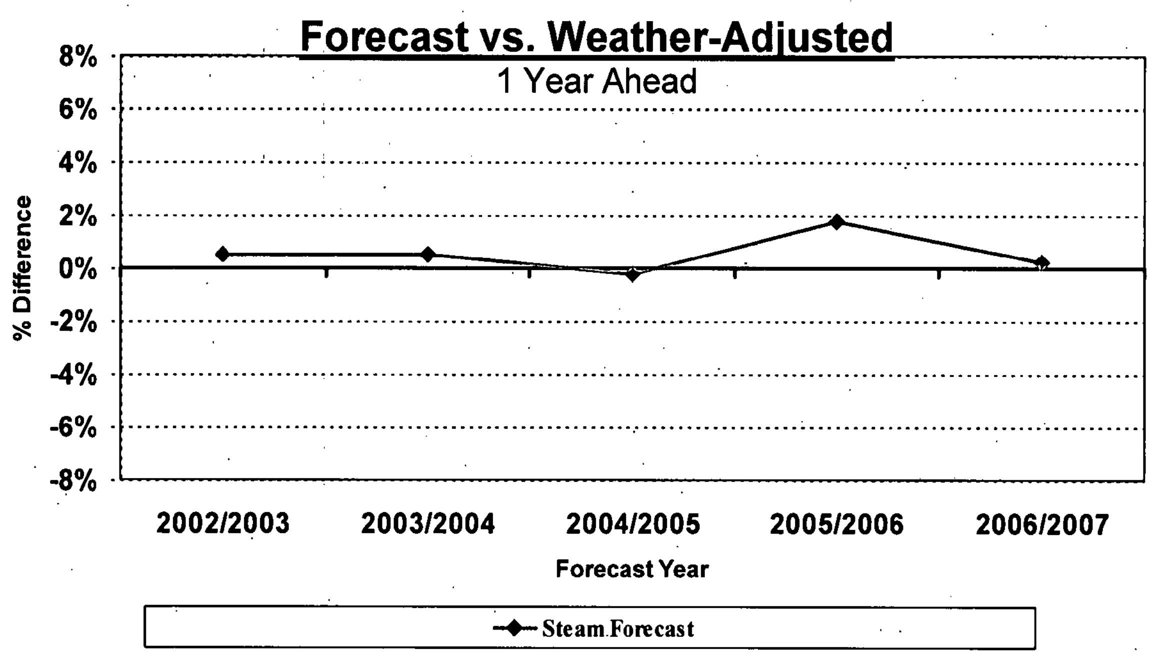
FORECAST ACCURACY

4.1 Forecast vs. Weather – Adjusted Forecast

The accuracy in our forecast versus the weather-adjusted demand from year to year is calculated and reported to senior management. The 1-Yr look ahead forecast accuracy is calculated by taking the prior year's Total Winter Steam Peak Demand Forecast (which includes the net incremental growth volumes factors) minus the current year's Winter Steam Peak Demand

Forecast @ 6° F design condition which also referred to as the Weather-Adjusted Winter Steam Peak Forecast. For example, the 2006/2007 Total Winter Steam Peak Demand Forecast was 10,330 Mlbs/hr minus the 2006/2007 Weather-Adjusted Winter Steam Peak Forecast of 10,310 Mlbs/hr divided by the 2006/2007 Weather-Adjusted Winter Steam Peak Forecast of 10,310 Mlbs/hr yields a forecast accuracy of 0.19 %. The last five years forecast accuracy for 1-Yr look ahead has been within 2% for the past five years as seen in Figure 19.

Figure 19



Note: Steam forecast years represent the winter ending year shown

4.2 In Summary

The Peak Demand Forecasting Section provides overall direction and develops short and long term forecasts of demand requirements for the Con Edison steam service area. The Steam Peak Demand Forecast is used by (1) Revenue & Volume Forecasting; (2) Steam Resource Planning; (3) Steam Operations Planning; and (4) Steam Business Development Unit.

These departments use the Steam Peak Demand Forecast to develop volumes forecast and to develop the Capacity, Demand, and Reserve Tables which are used to compare the amount of production resources to the peak demand and to calculate the reserve margin for a given forecast period.

Additionally, it is used to help determine the Loss of Load Expectation (LOLE) utilizing the Multi-Area Reliability Simulation (MARS) system for a given set of resources and demand assumptions. Further the Steam Peak Demand forecast is utilized to develop annual steam and electric production forecasts from steam only and steam-electric generating units using PROMOD simulations. These PROMOD simulations are used for studies, plans, budgets/cash flows, and rate cases.

The Steam Peak Demand Forecast provides the Forecasting and Planning groups information regarding estimated hourly demands (pounds per hour) and annual volumes (mlb per year) for all known future projects.

In addition, the Demand Forecasting Section provides to Revenue & Volume Forecasting the following economic forecasts: (1) US Gross Domestic Product, Local Private Non-Manufacturing employment, Local Residential Building Permits, Office Vacancy Rates, and Consumer Price Index; (2) Annual Winter Peak Demand forecast is utilized as an input to the Capacity, Demand and Reserve Table and to the MARS system. (3) Annual Winter Peak Demand forecast is utilized in steam system pressure and flow simulations using the STONER model. STONER model runs are used for studies and plans. (4) Interrelates with Forecasting and Planning Groups with on-going demand/volumes forecasts as new business opportunities arise.

Project Number: 22948-08
Station: 59th Street
Project Name: Natural Gas Conversion Accelerated (5 year project life)

Through use of the Consolidated Edison Cost/Benefit System, the resulting simple payback period for the given project is 4.66 years, followed by a discounted payback period of 5.62 years. In addition, a benefit/cost ratio of 2.99 and Internal Rate of Return (IRR) of 20.67% have been generated.

The results of the analysis completed on PN 22948-08 – 59th St, Natural Gas Conversion, are based on the following assumptions.

Capital Cost Assumptions:

- $29M Capital Expenditure – includes all internal building/system modifications and necessary street alterations for gas delivery
- Property tax of 5.4% on capital cost
- Standard 3% escalation
- 5 year accelerated project life

Associated O&M Assumptions:

- None

Benefit Assumptions:

- Energy Savings - $8.18M in annual fuel savings considering the price differential between #6 fuel oil and natural gas
- O&M Savings - $70k in annual savings related to boiler washes and work orders
- NOx and SO2 Savings - $6k in annual savings
- Barge Charter Savings - $480k in annual reduction costs

Unredacted

COST BENEFIT SYSTEM - (CBS)
SUMMARY

PROJECT DESCRIPTION: PN 22948-08 - 59th St, Natural Gas Conversion, 5 year Accelerated Recovery

REVENUE REQUIREMENT

	CURRENT $'S	P.W.
PROJECT COST:	$29,000,000.00	$29,000,000.00
SUM PW OF COSTS:		57,098,832.38
SUM PW OF BENEFITS:		178,250,404.33
NET PW OF RR:		121,151,571.95
BENEFIT/COST RATIO:		3.12
BREAK-EVEN YEAR:		7.54

CASHFLOW

	CURRENT $'S	P.W.
PROJECT COST:	$29,000,000.00	$29,000,000.00
PW OF NET CASH FLOWS:		97,674,681.70
NET PRESENT VALUE:		68,674,681.70
IRR (%):		20.67%
SIMPLE PAYBACK (YRS.):		4.66
DISCOUNTED PAYBACK (YRS.):		5.62
BENEFIT/COST RATIO:		2.99

COST OF CAPITAL

	%	COST	RETURN	AFTER TAX
DEBT	52.00	5.76	2.99	1.77
EQUITY	48.00	10.00	4.80	4.80
	100.00		7.79	6.57

12/11/2009

MAJOR ASSUMPTIONS:

	INV. 1	INV. 2	INV. 3
PROJECT LIFE - YRS.:	5	0	0
COST OF CAPITAL - %:	7.79	0.00	0.00
DISCOUNT RATE - %:	0.07	0.00	0.00
TAX LIFE - YRS.:	20	0	0
SALVAGE COST - %:	0.00	0.00	0.00
REMOVAL COST - %:	0.00	0.00	0.00
PROPERTY TAX - %:	0.00	0.00	0.00

Cost Assumptions:

Capital Costs:	$29M - Includes all internal building/system modifications and necessary street alterations for gas delivery
Property Tax:	5.4% of Capital
Escalation:	3%

Associated O&M Assumptions:

Property taxes have been added to overcome the program's default tax period reduction

Benefit Assumptions:

O&M:	$70k annual maintenance savings - reduced boiler washes and work orders
Energy:	$8,181,773 annual fuel savings by converting oil to natural gas
Barge Charters:	$483,500 annual barge charter reductions
Nox and SO2:	$6,270 annual emission reduction

Document References:

1) Gas RC (3).xls - Catuogno

COST BENEFIT SYSTEM - (CBS)
Unredacted
BENEFITS WORKSHEET
(1000-$)

					BENEFITS					REV. REQ. (INCL.. G.R.T)
				Barge						
YEAR	PER.	O&M	Energy	Charters	Emissions					
						TOTAL	FIT	NET		
1	0									
2	1	70000.00	8181773.00	483500.00	6270.00	8741543.00	-3584032.63	5157510.37		8998819.24
3	2	72100.00	8427226.19	498005.00	6458.10	9003789.29	-3691553.61	5312235.68		9268783.82
4	3	74263.00	8680042.98	512945.15	6651.84	9273902.97	-3802300.22	5471602.75		9546847.34
5	4	76490.89	8940444.26	528333.50	6851.40	9552120.06	-3916369.22	5635750.83		9833252.76
6	5	78785.62	9208657.59	544183.51	7056.94	9838683.66	-4033860.30	5804823.36		10128250.34
7	6	81149.19	9484917.32	560509.01	7268.65	10133844.17	-4154876.11	5978968.06		10432097.85
8	7	83583.66	9769464.84	577324.29	7486.71	10437859.49	-4279522.39	6158337.10		10745060.78
9	8	86091.17	10062548.79	594644.01	7711.31	10750995.28	-4407908.06	6343087.21		11067412.61
10	9	88673.91	10364425.25	612483.33	7942.65	11073525.14	-4540145.31	6533379.83		11399434.99
11	10	91334.12	10675358.01	630857.83	8180.93	11405730.89	-4676349.67	6729381.23		11741418.03
12	11	94074.15	10995618.75	649783.57	8426.36	11747902.82	-4816640.16	6931262.66		12093660.58
13	12	96896.37	11325487.31	669277.08	8679.15	12100339.90	-4961139.36	7139200.54		12456470.39
14	13	99803.26	11665251.93	689355.39	8939.52	12463350.10	-5109973.54	7353376.56		12830164.50
15	14	102797.36	12015209.49	710036.05	9207.71	12837250.60	-5263272.75	7573977.86		13215069.44
16	15	105881.28	12375665.77	731337.13	9483.94	13222368.12	-5421170.93	7801197.19		13611521.52
17	16	109057.72	12746935.74	753277.25	9768.46	13619039.16	-5583806.06	8035233.11		14019867.16
18	17	112329.45	13129343.82	775875.56	10061.51	14027610.34	-5751320.24	8276290.10		14440463.18
19	18	115699.33	13523224.13	799151.83	10363.35	14448438.65	-5923859.85	8524578.80		14873677.08
20	19	119170.31	13928920.85	823126.39	10674.26	14881891.81	-6101575.64	8780316.17		15319887.39
21	20	122745.42	14346788.48	847820.18	10994.48	15328348.56	-6284622.91	9043725.65		15779484.01
22	21	126427.79	14777192.13	873254.78	11324.32	15788199.02	-6473161.60	9315037.42		16252868.53
23	22	130220.62	15220507.90	899452.43	11664.05	16261844.99	-6667356.45	9594488.54		16740454.59
24	23	134127.24	15677123.14	926436.00	12013.97	16749700.34	-6867377.14	9882323.20		17242668.22
25	24	138151.06	16147436.83	954229.08	12374.39	17252191.35	-7073398.45	10178792.90		17759948.27
26	25	142295.59	16631859.93	982855.95	12745.62	17769757.09	-7285600.41	10484156.68		18292746.72
27	26	146564.46	17130815.73	1012341.63	13127.99	18302849.80	-7504168.42	10798681.38		18841529.12
28	27	150961.39	17644740.20	1042711.88	13521.83	18851935.30	-7729293.47	11122641.83		19406775.00
29	28	155490.23	18174082.41	1073993.23	13927.48	19417493.36	-7961172.28	11456321.08		19988978.25
30	29	160154.94	18719304.88	1106213.03	14345.31	20000018.16	-8200007.44	11800010.71		20588647.59
31	30	164959.59	19280884.03	1139399.42	14775.67	20600018.70	-8446007.67	12154011.03		21206307.02
32	31	169908.37	19859310.55	1173581.40	15218.94	21218019.26	-8699387.90	12518631.37		21842496.23
33	32	175005.62	20455089.87	1208788.85	15675.50	21854559.84	-8960369.54	12894190.31		22497771.12
34	33	180255.79	21068742.56	1245052.51	16145.77	22510196.64	-9229180.62	13281016.02		23172704.25
35	34	185663.47	21700804.84	1282404.09	16630.14	23185502.54	-9506056.04	13679446.50		23867885.38
36	35	191233.37	22351828.99	1320876.21	17129.05	23881067.61	-9791237.72	14089829.89		24583921.94
37	36	196970.37	23022383.85	1360502.50	17642.92	24597499.64	-10084974.85	14512524.79		25321439.60
38	37					0.00	0.00	0.00		0.00
39	38	0	0.00			0.00	0.00	0.00		0.00
40	39	0	0.00			0.00	0.00	0.00		0.00
41	40	0	0.00			0.00	0.00	0.00		0.00
42	41	0	0			0.00	0.00	0.00		0.00
43	42	0	0			0.00	0.00	0.00		0.00
44	43	0				0.00	0.00	0.00		0.00
45	44	0				0.00	0.00	0.00		0.00
46	45	0				0.00	0.00	0.00		0.00
47	46	0				0.00	0.00	0.00		0.00
48	47	0				0.00	0.00	0.00		0.00
49	48	0				0.00	0.00	0.00		0.00
50	49	0				0.00	0.00	0.00		0.00
51	50	0				0.00	0.00	0.00		0.00
52	51	0				0.00	0.00	0.00		0.00
53	52	0				0.00	0.00	0.00		0.00
54	53	0				0.00	0.00	0.00		0.00
55	54	0				0.00	0.00	0.00		0.00
56	55	0				0.00	0.00	0.00		0.00
57	56	0				0.00	0.00	0.00		0.00
58	57	0				0.00	0.00	0.00		0.00
59	58	0				0.00	0.00	0.00		0.00
60	59	0				0.00	0.00	0.00		0.00
61	60	0				0.00	0.00	0.00		0.00
62	61	0				0.00	0.00	0.00		0.00
63	62	0				0.00	0.00	0.00		0.00
64	63	0				0.00	0.00	0.00		0.00
65	64	0				0.00	0.00	0.00		0.00
66	65	0				0.00	0.00	0.00		0.00
67	66	0				0.00	0.00	0.00		0.00
68	67	0				0.00	0.00	0.00		0.00
69	68	0				0.00	0.00	0.00		0.00
70	69	0				0.00	0.00	0.00		0.00
71	70	0				0.00	0.00	0.00		0.00

COST BENEFIT SYSTEM - (CBS)
ASSOCIATED O WORKSHEET
(1000-$)

		Associated O&M							
							INVESTMENT 1		
		Property Taxes	O&M	Energy	Avail.	Reliability	AMOUNT	FIT	NET
YEAR									
1		1566000.00	0.00	0.00	0.00	0.00	1566000.00	-642060.00	923940.00
2	1	1566000.00	0.00	0.00	0.00	0.00	1566000.00	-642060.00	923940.00
3	2	1566000.00	0.00	0.00	0.00	0.00	1566000.00	-642060.00	923940.00
4	3	1566000.00	0.00	0.00	0.00	0.00	1566000.00	-642060.00	923940.00
5	4	1566000.00	0.00	0.00	0.00	0.00	1566000.00	-642060.00	923940.00
6	5	1566000.00	0.00	0.00	0.00	0.00	1566000.00	-642060.00	923940.00
7	6	1566000.00	0.00	0.00	0.00	0.00	1566000.00	-642060.00	923940.00
8	7	1566000.00	0.00	0.00	0.00	0.00	1566000.00	-642060.00	923940.00
9	8	1566000.00	0.00	0.00	0.00	0.00	1566000.00	-642060.00	923940.00
10	9	1566000.00	0.00	0.00	0.00	0.00	1566000.00	-642060.00	923940.00
11	10	1566000.00	0.00	0.00	0.00	0.00	1566000.00	-642060.00	923940.00
12	11	1566000.00	0.00	0.00	0.00	0.00	1566000.00	-642060.00	923940.00
13	12	1566000.00	0.00	0.00	0.00	0.00	1566000.00	-642060.00	923940.00
14	13	1566000.00	0.00	0.00	0.00	0.00	1566000.00	-642060.00	923940.00
15	14	1566000.00	0.00	0.00	0.00	0.00	1566000.00	-642060.00	923940.00
16	15	1566000.00	0.00	0.00	0.00	0.00	1566000.00	-642060.00	923940.00
17	16	1566000.00	0.00	0.00	0.00	0.00	1566000.00	-642060.00	923940.00
18	17	1566000.00	0.00	0.00	0.00	0.00	1566000.00	-642060.00	923940.00
19	18	1566000.00	0.00	0.00	0.00	0.00	1566000.00	-642060.00	923940.00
20	19	1566000.00	0.00	0.00	0.00	0.00	1566000.00	-642060.00	923940.00
21	20	1566000.00	0.00	0.00	0.00	0.00	1566000.00	-642060.00	923940.00
22	21	1566000.00	0.00	0.00	0.00	0.00	1566000.00	-642060.00	923940.00
23	22	1566000.00	0.00	0.00	0.00	0.00	1566000.00	-642060.00	923940.00
24	23	1566000.00	0.00	0.00	0.00	0.00	1566000.00	-642060.00	923940.00
25	24	1566000.00	0.00	0.00	0.00	0.00	1566000.00	-642060.00	923940.00
26	25	1566000.00	0.00	0.00	0.00	0.00	1566000.00	-642060.00	923940.00
27	26	1566000.00	0.00	0.00	0.00	0.00	1566000.00	-642060.00	923940.00
28	27	1566000.00	0.00	0.00	0.00	0.00	1566000.00	-642060.00	923940.00
29	28	1566000.00	0.00	0.00	0.00	0.00	1566000.00	-642060.00	923940.00
30	29	1566000.00	0.00	0.00	0.00	0.00	1566000.00	-642060.00	923940.00
31	30	1566000.00	0.00	0.00	0.00	0.00	1566000.00	-642060.00	923940.00
32	31	1566000.00	0.00	0.00	0.00	0.00	1566000.00	-642060.00	923940.00
33	32	1566000.00	0.00	0.00	0.00	0.00	1566000.00	-642060.00	923940.00
34	33	1566000.00	0.00	0.00	0.00	0.00	1566000.00	-642060.00	923940.00
35	34	1566000.00	0.00	0.00	0.00	0.00	1566000.00	-642060.00	923940.00
36	35	1566000.00	0.00	0.00	0.00	0.00	1566000.00	-642060.00	923940.00
37	36	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
38	37	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
39	38	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
40	39	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
41	40	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
42		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
43		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
44		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
45		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
46		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
47		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
48		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
49		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
50		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
51		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
52		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
53		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
54		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
55		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
56		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
57		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
58		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
59		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
60		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
61		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
62		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
63		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
64		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
65		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
66		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
67		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
68		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
69		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
70		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
71		0.00	0.00	0.00	0.00	0.00			
			0.00	0.00	0.00	0.00			

COST BENEFIT SYSTEM - (CBS)
REVENUE REQUIREMENT WORKSHEET
(1000-$)
]

				INVESTMENT 1				
		ANNUAL REVENUE REQUIREMENTS						
	BOOK	EQUITY	INTEREST		PROP.			TOTAL
YEAR	DEPR.	RETURN	RETURN	FIT	TAX	SUBTOTAL	G.R.T	REV REQ.
1	5800000	1299171	809979	902813.8	0.00	8811963.74	259348.8	9071312.57
2	5800000	1103613.9	688057.3	766918.1	0.00	8358589.23	246005.4	8604594.59
3	5800000	899704.24	560928.1	625218.2	0.00	7885850.54	232092	8117942.52
4	5800000	698768.06	435652.8	485584.6	0.00	7420005.41	218381.5	7638386.89
5	5800000	299506.69	186729.9	208131.8	0.00	6494368.40	191138.7	6685507.05
6	0	0	0	0	0.00	0.00	0	0.00
7	0	0	0	0	0.00	0.00	0	0.00
8	0	0	0	0	0.00	0.00	0	0.00
9	0	0	0	0	0.00	0.00	0	0.00
10	0	0	0	0	0.00	0.00	0	0.00
11	0	0	0	0	0.00	0.00	0	0.00
12	0	0	0	0	0.00	0.00	0	0.00
13	0	0	0	0	0.00	0.00	0	0.00
14	0	0	0	0	0.00	0.00	0	0.00
15	0	0	0	0	0.00	0.00	0	0.00
16	0	0	0	0	0.00	0.00	0	0.00
17	0	0	0	0	0.00	0.00	0	0.00
18	0	0	0	0	0.00	0.00	0	0.00
19	0	0	0	0	0.00	0.00	0	0.00
20	0	0	0	0	0.00	0.00	0	0.00
21	0	0	0	0	0.00	0.00	0	0.00
22	0	0	0	0	0.00	0.00	0	0.00
23	0	0	0	0	0.00	0.00	0	0.00
24	0	0	0	0	0.00	0.00	0	0.00
25	0	0	0	0	0.00	0.00	0	0.00
26	0	0	0	0	0.00	0.00	0	0.00
27	0	0	0	0	0.00	0.00	0	0.00
28	0	0	0	0	0.00	0.00	0	0.00
29	0	0	0	0	0.00	0.00	0	0.00
30	0	0	0	0	0.00	0.00	0	0.00
31	0	0	0	0	0.00	0.00	0	0.00
32	0	0	0	0	0.00	0.00	0	0.00
33	0	0	0	0	0.00	0.00	0	0.00
34	0	0	0	0	0.00	0.00	0	0.00
35	0	0	0	0	0.00	0.00	0	0.00
36	0	0	0	0	0.00	0.00	0	0.00
37	0	0	0	0	0.00	0.00	0	0.00
38	0	0	0	0	0.00	0.00	0	0.00
39	0	0	0	0	0.00	0.00	0	0.00
40	0	0	0	0	0.00	0.00	0	0.00
41	0	0	0	0	0.00	0.00	0	0.00
42	0	0	0	0	0.00	0.00	0	0.00
43	0	0	0	0	0.00	0.00	0	0.00
44	0	0	0	0	0.00	0.00	0	0.00
45	0	0	0	0	0.00	0.00	0	0.00
46	0	0	0	0	0.00	0.00	0	0.00
47	0	0	0	0	0.00	0.00	0	0.00
48	0	0	0	0	0.00	0.00	0	0.00
49	0	0	0	0	0.00	0.00	0	0.00
50	0	0	0	0	0.00	0.00	0	0.00
51	0	0	0	0	0.00	0.00	0	0.00
52	0	0	0	0	0.00	0.00	0	0.00
53	0	0	0	0	0.00	0.00	0	0.00
54	0	0	0	0	0.00	0.00	0	0.00
55	0	0	0	0	0.00	0.00	0	0.00
56	0	0	0	0	0.00	0.00	0	0.00
57	0	0	0	0	0.00	0.00	0	0.00
58	0	0	0	0	0.00	0.00	0	0.00
59	0	0	0	0	0.00	0.00	0	0.00
60	0	0	0	0	0.00	0.00	0	0.00
61	0	0	0	0	0.00	0.00	0	0.00
62	0	0	0	0	0.00	0.00	0	0.00
63	0	0	0	0	0.00	0.00	0	0.00
64	0	0	0	0	0.00	0.00	0	0.00
65	0	0	0	0	0.00	0.00	0	0.00
66	0	0	0	0	0.00	0.00	0	0.00
67	0	0	0	0	0.00	0.00	0	0.00
68	0	0	0	0	0.00	0.00	0	0.00
69	0	0	0	0	0.00	0.00	0	0.00
70	0	0	0	0	0.00	0.00	0	0.00

Unredacted Exhibit __ (JRS-) Page 48 of 110

59th Street

FORECAST OF FUEL PRICES

Assumptions:
Combined Oil/Gas Steam Rate = 1,400 lbs/MMbtu
Gas Steam Rate = 1,450 lbs/h
SSO = 2,100 MMlb/yr
Ignition Gas all year in Base Case
Oil Only in January but for Ignition Gas

Emission Rates
0.29 lb/MMbtu NOx for #6 Fuel Oil
0.17 lb/MMbtu NOx for Natural Gas
174 lb/MMbtu CO_2 for #6 Fuel Oil
117 lb/MMbtu CO_2 for Natural Gas
0.30 lb/MMbtu SO_2 for #6 Fuel Oil
0.0006 lb/MMbtu SO_2 for Natural Gas

NO SO2 Savings for 59th AX
NOX Savings of $120/ton During Ozone Season
PER AG of Corporate EHS

Maintenance Savings
1 Less Annual Boiler Wash $70K
Assumed other reduced PO Workorder costs Reduced
Are offset by work on incremental gas equipment

Barge Savings
$4,900/day for all year
$5,700/day for winter only

Year	Month	Natural Gas Prices: RC Fuel as of 8/09 Delivered Cost With Taxes ($/MMbtu)	0.3% Sulfur High Pour No. 6 Fuel Oil Prices: RC Fuel as of 8/09 Delivered No. 6 Oil Cost With Taxes ($/MMbtu)	59th Street Annex SSO (MMlb)	59th Street Annex Base	59th Street Annex Change	Fuel Savings	Base NOx (Tons)	Base SO2 (Tons)	Base CO2 (Tons)	Change NOx (Tons)	Change SO2 (Tons)	Change CO2 (Tons)	NOx Savings	Maintenance Savings	Barge Savings
2012	Jan	9.85	13.04	220	$3,690,418	$3,690,418		42	41	25,743	42	42	25,743	$0		
	Feb	9.26	13.06	350	$8,175,960	$4,698,450		68	65	40,954	43	0.2	29,689	$0		
	Mar	8.59	13.08	110	$1,931,345	$1,370,105		21	20	12,871	14	0.0	9,331	$0		
	Apr	8.04	13.09	150	$2,621,840	$1,748,700		29	28	17,552	18	0.1	12,724	$0		
	May	8.04	13.11	150	$2,625,338	$1,748,700		29	28	17,552	18	0.1	12,724	$1,254		
	Jun	8.44	13.13	150	$2,639,112	$1,835,700		29	28	17,552	18	0.1	12,724	$1,254		
	Jul	8.85	13.15	150	$2,653,140	$1,824,875		29	28	17,552	18	0.1	12,724	$1,254		
	Aug	8.86	13.16	150	$2,655,240	$1,827,060		29	28	17,552	18	0.1	12,724	$1,254		
	Sep	8.90	13.18	150	$2,659,944	$1,935,750		29	28	17,552	18	0.1	12,724	$1,254		
	Oct	9.17	13.20	150	$2,670,444	$1,994,475		29	28	17,552	18	0.1	12,724	$0		
	Nov	9.90	13.21	100	$1,793,792	$1,435,500		18	18	11,701	12	0.0	8,443	$0		
	Dec	10.99	13.23	270	$4,889,334	$4,302,585		52	50	31,593	33	0.1	22,903	$0		
				2,100	$37,223,704	$28,821,308	$8,402,396	448	388	245,725	274	43	185,214	$6,270	$70,000	$483,500
2013	Jan	9.40	13.25	220	$3,938,704	$3,938,704		42	41	25,743	42	42	25,743	$0		
	Feb	9.18	13.27	350	$8,261,600	$4,656,850		68	65	40,954	43	0.2	29,689	$0		
	Mar	8.55	13.29	110	$1,959,085	$1,363,725		21	20	12,871	14	0.0	9,331	$0		
	Apr	8.23	13.31	150	$2,667,084	$1,780,025		29	28	17,552	18	0.1	12,724	$0		
	May	8.21	13.33	150	$2,670,276	$1,765,675		29	28	17,552	18	0.1	12,724	$1,254		
	Jun	8.61	13.35	150	$2,684,052	$1,872,675		29	28	17,552	18	0.1	12,724	$1,254		
	Jul	9.08	13.37	150	$2,699,592	$1,974,900		29	28	17,552	18	0.1	12,724	$1,254		
	Aug	9.11	13.39	150	$2,704,044	$1,981,425		29	28	17,552	18	0.1	12,724	$1,254		
	Sep	9.15	13.42	150	$2,710,596	$1,990,125		29	28	17,552	18	0.1	12,724	$1,254		
	Oct	9.32	13.44	150	$2,718,578	$2,027,100		29	28	17,552	18	0.1	12,724	$0		
	Nov	10.27	13.46	100	$1,830,808	$1,489,150		19	18	11,701	12	0.0	8,483	$0		
	Dec	11.41	13.48	270	$5,001,545	$4,467,015		52	50	31,593	33	0.1	22,903	$0		
				2,100	$37,846,150	$29,339,360	$8,506,731	406	388	248,725	274	43	185,214	$6,270	$70,000	$483,500
2014	Jan	9.99	13.57	220	$4,047,243	$4,047,243		42	41	25,743	42	42	25,743	$0		
	Feb	9.63	13.60	350	$8,431,740	$4,897,375		68	65	40,954	43	0.2	29,689	$0		
	Mar	8.93	13.62	110	$2,018,609	$1,424,335		21	20	12,871	14	0.0	9,331	$0		
	Apr	8.57	13.64	150	$2,738,838	$1,863,975		29	28	17,552	18	0.1	12,724	$0		
	May	8.56	13.66	150	$2,740,080	$1,861,800		29	28	17,552	18	0.1	12,724	$1,254		
	Jun	8.98	13.68	150	$2,754,360	$1,953,150		29	28	17,552	18	0.1	12,724	$1,254		
	Jul	9.48	13.70	150	$2,770,656	$2,061,900		29	28	17,552	18	0.1	12,724	$1,254		
	Aug	9.49	13.72	150	$2,774,804	$2,064,075		29	28	17,552	18	0.1	12,724	$1,254		
	Sep	9.56	13.75	150	$2,781,912	$2,079,300		29	28	17,552	18	0.1	12,724	$1,254		
	Oct	9.77	13.77	150	$2,780,900	$2,124,975		29	28	17,552	18	0.1	12,724	$0		
	Nov	10.65	13.79	100	$1,877,848	$1,544,250		19	18	11,701	12	0.0	8,483	$0		
	Dec	11.70	13.81	270	$5,124,470	$4,580,550		52	50	31,593	33	0.1	22,903	$0		
				2,100	$38,841,258	$30,502,928	$8,338,330	405	388	345,725	274	43	185,214	$6,270	$70,000	$483,500
2015	Jan	10.58	13.92	220	$4,163,914	$4,163,914		42	41	25,743	42	42	25,743	$0		
	Feb	10.15	13.94	350	$8,607,748	$5,151,125		68	65	40,954	43	0.2	29,689	$0		
	Mar	9.54	13.96	110	$2,068,158	$1,521,630		21	20	12,871	14	0.0	9,331	$0		
	Apr	9.07	13.98	150	$2,812,068	$1,872,725		29	28	17,552	18	0.1	12,724	$0		
	May	9.06	14.00	150	$2,815,512	$1,970,550		29	28	17,552	18	0.1	12,724	$1,254		
	Jun	9.51	14.02	150	$2,830,548	$2,068,425		29	28	17,552	18	0.1	12,724	$1,254		
	Jul	10.04	14.04	150	$2,847,600	$2,183,700		29	28	17,552	18	0.1	12,724	$1,254		
	Aug	10.06	14.07	150	$2,853,848	$2,188,050		29	28	17,552	18	0.1	12,724	$1,254		
	Sep	10.12	14.10	150	$2,860,704	$2,201,100		29	28	17,552	18	0.1	12,724	$1,254		
	Oct	10.36	14.12	150	$2,870,448	$2,253,300		29	28	17,552	18	0.1	12,724	$0		
	Nov	11.60	14.14	100	$1,936,928	$1,682,000		19	18	11,701	12	0.0	8,483	$0		
	Dec	13.12	14.16	270	$5,305,306	$5,136,480		52	50	31,593	33	0.1	22,903	$0		
				2,100	$39,872,582	$32,402,999	$7,471,583	446	388	248,725	274	43	185,214	$6,270	$70,000	$483,500

59th Street

FORECAST OF FUEL PRICES

Assumptions:
Combined Oil/Gas Steam Rate - 1,400 btu/lb
Gas Steam Rate = 1,450 btu/lb
SSO = 2,100 MWh/yr
Ignition Gas all year in Base Case
Oil Only in January but for Ignition Gas

Emission Rates:
0.29 lb/MMbtu NOx for #6 Fuel Oil
0.17 lb/MMbtu NOx for Natural Gas
174 lb/MMbtu CO_2 for #6 Fuel Oil
117 lb/MMbtu CO_2 for Natural Gas
0.30 lb/MMbtu SO_2 for #6 Fuel Oil
0.0006 lb/MMbtu SO_2 for Natural Gas

NO SO2 Savings for 59th AX
NOX Savings of $120/ton During Ozone Season
PER AG of Corporate EHS

Maintenance Savings
1 Less Annual Boiler Wash $70K
Assumed other reduced PO Work Order and Failures
Are offset by work on incremental gas equipment

Steam Savings
$4,800/day for all year
$8,700/day for winter only

Year	Month	Natural Gas Prices RC Fuel as of 2/09 Delivered Cost With Taxes ($/MMbtu)	0.3% Sulfur High Pour No. 6 Fuel Oil Prices RC Fuel as of 2/09 Delivered No. 6 Oil Cost With Taxes ($/MMbtu)	59th Street Annex SSO (MWh)	59th Street Annex Base	59th Street Annex Change	Fuel Savings	Base NOx (Tons)	Base SO2 (Tons)	Base CO2 (Tons)	Change NOx (Tons)	Change SO2 (Tons)	Change CO2 (Tons)	NOx Savings	Maintenance Savings	Steam Savings
2012	Jan	9.85	13.04	220	$3,886,418	$3,886,418		42	41	25,743	42	42	25,743	$0		
	Feb	9.26	13.06	359	$6,170,980	$4,698,450		69	65	40,954	43	0.2	29,688	$0		
	Mar	8.59	13.08	110	$1,931,345	$1,370,105		21	20	12,871	14	0.0	8,331	$0		
	Apr	8.04	13.09	150	$2,621,640	$1,743,700		29	28	17,552	18	0.1	12,724	$0		
	May	8.04	13.11	150	$2,625,336	$1,743,700		29	28	17,552	18	0.1	12,724	$1,254		
	Jun	8.44	13.13	150	$2,638,112	$1,835,700		29	28	17,552	18	0.1	12,724	$1,254		
	Jul	8.85	13.15	150	$2,653,140	$1,924,875		29	28	17,552	18	0.1	12,724	$1,254		
	Aug	8.86	13.16	150	$2,666,240	$1,927,050		29	28	17,552	18	0.1	12,724	$1,254		
	Sep	8.90	13.18	150	$2,609,844	$1,935,750		29	28	17,552	18	0.1	12,724	$1,254		
	Oct	9.17	13.20	150	$2,678,444	$1,994,475		29	28	17,552	18	0.1	12,724	$0		
	Nov	9.90	13.21	100	$1,783,782	$1,435,500		19	18	11,701	12	0.0	8,463	$0		
	Dec	10.99	13.23	270	$4,830,334	$4,302,585		52	50	31,593	33	0.1	22,903	$0		
				2,100	$37,223,704	$28,821,300	$8,402,396	405	389	245,725	274	43	183,214	$6,270	$70,000	$483,000
2013	Jan	9.40	13.25	220	$3,836,704	$3,834,704		42	41	25,743	42	42	25,743	$0		
	Feb	9.18	13.27	359	$6,261,609	$4,654,800		69	65	40,954	43	0.2	29,688	$0		
	Mar	8.55	13.29	110	$1,959,065	$1,363,725		21	20	12,871	14	0.0	8,331	$0		
	Apr	8.23	13.31	150	$2,667,094	$1,790,025		29	28	17,552	18	0.1	12,724	$0		
	May	8.21	13.33	150	$2,670,276	$1,785,675		29	28	17,552	18	0.1	12,724	$1,254		
	Jun	8.61	13.35	150	$2,684,062	$1,872,675		29	28	17,552	18	0.1	12,724	$1,254		
	Jul	9.08	13.37	150	$2,698,582	$1,974,900		29	28	17,552	18	0.1	12,724	$1,254		
	Aug	9.11	13.39	150	$2,704,044	$1,981,425		29	28	17,552	18	0.1	12,724	$1,254		
	Sep	9.15	13.42	150	$2,710,886	$1,990,125		29	28	17,552	18	0.1	12,724	$1,254		
	Oct	9.32	13.44	150	$2,718,578	$2,027,100		29	28	17,552	18	0.1	12,724	$0		
	Nov	10.27	13.46	100	$1,830,800	$1,489,150		19	18	11,701	12	0.0	8,463	$0		
	Dec	11.41	13.48	270	$6,001,545	$4,467,015		52	50	31,593	33	0.1	22,903	$0		
				2,100	$37,848,160	$29,339,380	$8,508,781	405	389	245,725	274	43	183,214	$6,270	$70,000	$483,000
2014	Jan	9.99	13.57	220	$4,047,343	$4,047,343		42	41	25,743	42	42	25,743	$0		
	Feb	9.65	13.60	359	$6,631,740	$4,697,375		69	65	40,954	43	0.2	29,688	$0		
	Mar	8.93	13.62	110	$2,010,609	$1,424,335		21	20	12,871	14	0.0	8,331	$0		
	Apr	8.57	13.64	150	$2,736,636	$1,863,975		29	28	17,552	18	0.1	12,724	$0		
	May	8.56	13.66	150	$2,740,080	$1,861,800		29	28	17,552	18	0.1	12,724	$1,254		
	Jun	8.98	13.68	150	$2,754,360	$1,953,150		29	28	17,552	18	0.1	12,724	$1,254		
	Jul	9.48	13.70	150	$2,770,656	$2,061,900		29	28	17,552	18	0.1	12,724	$1,254		
	Aug	9.49	13.72	150	$2,774,604	$2,064,075		29	28	17,552	18	0.1	12,724	$1,254		
	Sep	9.56	13.75	150	$2,781,912	$2,079,300		29	28	17,552	18	0.1	12,724	$1,254		
	Oct	9.77	13.77	150	$2,780,900	$2,124,975		29	28	17,552	18	0.1	12,724	$0		
	Nov	10.65	13.79	100	$1,877,846	$1,544,250		19	18	11,701	12	0.0	8,463	$0		
	Dec	11.70	13.81	270	$6,124,470	$4,580,550		52	50	31,593	33	0.1	22,903	$0		
				2,100	$38,841,258	$30,502,928	$8,338,330	405	389	245,725	274	43	183,214	$6,270	$70,000	$483,000
2015	Jan	10.58	13.92	220	$4,163,914	$4,163,914		42	41	25,743	42	42	25,743	$0		
	Feb	10.15	13.94	359	$6,807,746	$5,151,125		69	65	40,954	43	0.2	29,688	$0		
	Mar	9.54	13.96	110	$2,066,168	$1,621,630		21	20	12,871	14	0.0	8,331	$0		
	Apr	9.07	13.98	150	$2,612,068	$1,972,725		29	28	17,552	18	0.1	12,724	$0		
	May	9.06	14.00	150	$2,615,517	$1,970,550		29	28	17,552	18	0.1	12,724	$1,254		
	Jun	9.51	14.02	150	$2,830,548	$2,068,425		29	28	17,552	18	0.1	12,724	$1,254		
	Jul	10.04	14.04	150	$2,847,600	$2,183,700		29	28	17,552	18	0.1	12,724	$1,254		
	Aug	10.06	14.07	150	$2,853,648	$2,188,050		29	28	17,552	18	0.1	12,724	$1,254		
	Sep	10.12	14.10	150	$2,860,704	$2,201,100		29	28	17,552	18	0.1	12,724	$1,254		
	Oct	10.36	14.12	150	$2,870,448	$2,253,300		29	28	17,552	18	0.1	12,724	$0		
	Nov	11.60	14.14	100	$1,938,928	$1,682,000		19	18	11,701	12	0.0	8,463	$0		
	Dec	13.12	14.16	270	$6,305,306	$5,136,480		52	50	31,593	33	0.1	22,903	$0		
				2,100	$39,872,983	$32,482,660	$7,470,583	405	389	245,725	274	43	183,214	$6,270	$70,000	$483,000

Project Number: 22945-08
Station: 74th Street
Project Name: Natural Gas Conversion Accelerated (5 year project life)

Through use of the Consolidated Edison Cost/Benefit System, the resulting simple payback period for the given project is 4.89 years, followed by a discounted payback period of 6.63 years. In addition, a benefit/cost ratio of 2.64 and Internal Rate of Return (IRR) of 18.49% have been generated.

The results of the analysis completed on PN 22945-08 – 74th St, Natural Gas Conversion, are based on the following assumptions.

Capital Cost Assumptions:

- $56M Capital Expenditure – includes all internal building/system modifications and necessary street alterations for gas delivery
- Property tax of 5.4% on capital cost
- Standard 3% escalation
- 5 year accelerated project life

Associated O&M Assumptions:

- None

Benefit Assumptions:

- Energy Savings - $14.48M in annual fuel savings considering the price differential between #6 fuel oil and natural gas
- O&M Savings - $220k in annual savings related to boiler washes and work orders
- NOx and SO2 Savings - $200k in annual savings

COST BENEFIT SYSTEM - (CBS)
SUMMARY

PROJECT DESCRIPTION: P/N 22945-08 - 74th Street, Natural Gas Conversion, 5 Year Accelerated Recovery

REVENUE REQUIREMENT

	CURRENT $'S	P.W.
PROJECT COST:	$56,000,000.00	$56,000,000.00
SUM PW OF COSTS:		110,259,814.29
SUM PW OF BENEFITS:		303,805,382.96
NET PW OF RR:		193,545,568.67
BENEFIT/COST RATIO:		2.76
BREAK-EVEN YEAR:		8.71

CASHFLOW

	CURRENT $'S	P.W.
PROJECT COST:	$56,000,000.00	$56,000,000.00
PW OF NET CASH FLOWS:		165,457,334.75
NET PRESENT VALUE:		109,457,334.75
IRR (%):		18.49%
SIMPLE PAYBACK (YRS.):		4.89
DISCOUNTED PAYBACK (YRS.):		6.63
BENEFIT/COST RATIO:		2.64

COST OF CAPITAL

	%	COST	RETURN	AFTER TAX
DEBT	52.00	5.76	2.99	1.77
EQUITY	48.00	10.00	4.80	4.80
	100.00		7.79	6.57

USER NAME:	Evan Yager	12/11/2009 8:47 AM

MAJOR ASSUMPTIONS:

	INV. 1	INV. 2	INV. 3
PROJECT LIFE - YRS.:	5	0	0
COST OF CAPITAL - %:	7.79	0.00	0.00
DISCOUNT RATE - %:	0.07	0.00	0.00
TAX LIFE - YRS.:	20	0	0
SALVAGE COST - %:	0.00	0.00	0.00
REMOVAL COST - %:	0.00	0.00	0.00
PROPERTY TAX - %:	0.00	0.00	0.00

Cost Assumptions:

Capital Costs:	$56M - Includes all internal building/system modifications and necessary street alternations for gas delivery
Property Tax:	5.4% of Capital
Escalation:	3%

Associated O&M Assumptions:

Property taxes have been added to overcome the program's default tax period reduction

Benefit Assumptions:

O&M:	$220k annual maintenance savings
Energy:	$14,478,833 - Average annual fuel savings considering price differential between #6 fuel oil and natural gas
Nox and SO2:	$200,027 annual emission reduction

Document References:

1) Gas RC (3).xls - Catuogno

COST BENEFIT SYSTEM - (CBS)
Unredacted
BENEFITS WORKSHEET
(1000-$)

		BENEFITS								REV. REQ. (INCL.. G.R.T)
YEAR	PER.	O&M	Energy	Nox and SO2		TOTAL	FIT	NET		
1	0									
2	1	220000.00	14478833.00	200027.00		14898860.00	-6108532.60	8790327.40		15337354.98
3	2	226600.00	14913197.99	206027.81		15345825.80	-6291788.58	9054037.22		15797475.63
4	3	233398.00	15360593.93	212208.64		15806200.57	-6480542.24	9325658.34		16271399.89
5	4	240399.94	15821411.75	218574.90		16280386.59	-6674958.50	9605428.09		16759541.89
6	5	247611.94	16296054.10	225132.15		16768798.19	-6875207.26	9893590.93		17262328.15
7	6	255040.30	16784935.72	231886.12		17271862.13	-7081463.48	10190398.66		17780197.99
8	7	262691.51	17288483.79	238842.70		17790018.00	-7293907.38	10496110.62		18313603.94
9	8	270572.25	17807138.31	246007.98		18323718.54	-7512724.60	10810993.94		18863012.05
10	9	278689.42	18341352.46	253388.22		18873430.09	-7738106.34	11135323.76		19428902.41
11	10	287050.10	18891593.03	260989.87		19439633.00	-7970249.53	11469383.47		20011769.49
12	11	295661.60	19458340.82	268819.56		20022821.99	-8209357.01	11813464.97		20612122.57
13	12	304531.45	20042091.05	276884.15		20623506.65	-8455637.73	12167868.92		21230486.25
14	13	313667.40	20643353.78	285190.67		21242211.85	-8709306.86	12532904.99		21867400.84
15	14	323077.42	21262654.39	293746.39		21879478.20	-8970586.06	12908892.14		22523422.86
16	15	332769.74	21900534.02	302558.78		22535862.55	-9239703.64	13296158.90		23199125.55
17	16	342752.83	22557550.04	311635.55		23211938.42	-9516894.75	13695043.67		23895099.31
18	17	353035.42	23234276.55	320984.61		23908296.58	-9802401.60	14105894.98		24611952.30
19	18	363626.48	23931304.84	330614.15		24625545.47	-10096473.64	14529071.83		25350310.86
20	19	374535.27	24649243.99	340532.58		25364311.84	-10399367.85	14964943.98		26110820.19
21	20	385771.33	25388721.31	350748.56		26125241.19	-10711348.89	15413892.30		26894144.79
22	21	397344.47	26150382.95	361271.01		26908998.43	-11032689.36	15876309.07		27700969.14
23	22	409264.81	26934894.43	372109.14		27716268.38	-11363670.04	16352598.35		28531998.21
24	23	421542.75	27742941.27	383272.42		28547756.43	-11704580.14	16843176.30		29387958.15
25	24	434189.03	28575229.51	394770.59		29404189.13	-12055717.54	17348471.59		30269596.91
26	25	447214.70	29432486.39	406613.71		30286314.80	-12417389.07	17868925.73		31177684.81
27	26	460631.14	30315460.98	418812.12		31194904.25	-12789910.74	18404993.50		32113015.36
28	27	474450.08	31224924.81	431376.48		32130751.37	-13173608.06	18957143.31		33076405.81
29	28	488683.58	32161672.56	444317.78		33094673.91	-13568816.30	19525857.61		34068697.99
30	29	503344.09	33126522.73	457647.31		34087514.13	-13975880.79	20111633.34		35090758.93
31	30	518444.41	34120318.42	471376.73		35110139.55	-14395157.22	20714982.34		36143481.69
32	31	533997.74	35143927.97	485518.03		36163443.74	-14827011.93	21336431.81		37227786.15
33	32	550017.68	36198245.81	500083.57		37248347.05	-15271822.29	21976524.76		38344619.73
34	33	566518.21	37284193.18	515086.08		38365797.47	-15729976.96	22635820.50		39494958.33
35	34	583513.75	38402718.98	530538.66		39516771.39	-16201876.27	23314895.12		40679807.07
36	35	601019.17	39554800.55	546454.82		40702274.53	-16687932.56	24014341.97		41900201.28
37	36	619049.74	40741444.56	562848.47		41923342.77	-17188570.53	24734772.23		43157207.33
38	37					0.00	0.00	0.00		0.00
39	38	0				0.00	0.00	0.00		0.00
40	39	0				0.00	0.00	0.00		0.00
41	40	0				0.00	0.00	0.00		0.00
42	41	0				0.00	0.00	0.00		0.00
43	42	0				0.00	0.00	0.00		0.00
44	43	0				0.00	0.00	0.00		0.00
45	44	0				0.00	0.00	0.00		0.00
46	45	0				0.00	0.00	0.00		0.00
47	46	0				0.00	0.00	0.00		0.00
48	47	0				0.00	0.00	0.00		0.00
49	48	0				0.00	0.00	0.00		0.00
50	49	0				0.00	0.00	0.00		0.00
51	50	0				0.00	0.00	0.00		0.00
52	51	0				0.00	0.00	0.00		0.00
53	52	0				0.00	0.00	0.00		0.00
54	53	0				0.00	0.00	0.00		0.00
55	54	0				0.00	0.00	0.00		0.00
56	55	0				0.00	0.00	0.00		0.00
57	56	0				0.00	0.00	0.00		0.00
58	57	0				0.00	0.00	0.00		0.00
59	58	0				0.00	0.00	0.00		0.00
60	59	0				0.00	0.00	0.00		0.00
61	60	0				0.00	0.00	0.00		0.00
62	61	0				0.00	0.00	0.00		0.00
63	62	0				0.00	0.00	0.00		0.00
64	63	0				0.00	0.00	0.00		0.00
65	64	0				0.00	0.00	0.00		0.00
66	65	0				0.00	0.00	0.00		0.00
67	66	0				0.00	0.00	0.00		0.00
68	67	0				0.00	0.00	0.00		0.00
69	68	0				0.00	0.00	0.00		0.00
70	69	0				0.00	0.00	0.00		0.00
71	70	0				0.00	0.00	0.00		0.00

COST BENEFIT SYSTEM - (CBS)
Unredacted
ASSOCIATED O WORKSHEET
(1000-$)

		Associated O&M					INVESTMENT 1		
YEAR		Property Taxes	O&M	Energy	Avail.	Reliability	AMOUNT	FIT	NET
1		3024000.00	0.00	0.00	0.00	0.00	3024000.00	-1239840.00	1784160.00
2	1	3024000.00	0.00	0.00	0.00	0.00	3024000.00	-1239840.00	1784160.00
3	2	3024000.00	0.00	0.00	0.00	0.00	3024000.00	-1239840.00	1784160.00
4	3	3024000.00	0.00	0.00	0.00	0.00	3024000.00	-1239840.00	1784160.00
5	4	3024000.00	0.00	0.00	0.00	0.00	3024000.00	-1239840.00	1784160.00
6	5	3024000.00	0.00	0.00	0.00	0.00	3024000.00	-1239840.00	1784160.00
7	6	3024000.00	0.00	0.00	0.00	0.00	3024000.00	-1239840.00	1784160.00
8	7	3024000.00	0.00	0.00	0.00	0.00	3024000.00	-1239840.00	1784160.00
9	8	3024000.00	0.00	0.00	0.00	0.00	3024000.00	-1239840.00	1784160.00
10	9	3024000.00	0.00	0.00	0.00	0.00	3024000.00	-1239840.00	1784160.00
11	10	3024000.00	0.00	0.00	0.00	0.00	3024000.00	-1239840.00	1784160.00
12	11	3024000.00	0.00	0.00	0.00	0.00	3024000.00	-1239840.00	1784160.00
13	12	3024000.00	0.00	0.00	0.00	0.00	3024000.00	-1239840.00	1784160.00
14	13	3024000.00	0.00	0.00	0.00	0.00	3024000.00	-1239840.00	1784160.00
15	14	3024000.00	0.00	0.00	0.00	0.00	3024000.00	-1239840.00	1784160.00
16	15	3024000.00	0.00	0.00	0.00	0.00	3024000.00	-1239840.00	1784160.00
17	16	3024000.00	0.00	0.00	0.00	0.00	3024000.00	-1239840.00	1784160.00
18	17	3024000.00	0.00	0.00	0.00	0.00	3024000.00	-1239840.00	1784160.00
19	18	3024000.00	0.00	0.00	0.00	0.00	3024000.00	-1239840.00	1784160.00
20	19	3024000.00	0.00	0.00	0.00	0.00	3024000.00	-1239840.00	1784160.00
21	20	3024000.00	0.00	0.00	0.00	0.00	3024000.00	-1239840.00	1784160.00
22	21	3024000.00	0.00	0.00	0.00	0.00	3024000.00	-1239840.00	1784160.00
23	22	3024000.00	0.00	0.00	0.00	0.00	3024000.00	-1239840.00	1784160.00
24	23	3024000.00	0.00	0.00	0.00	0.00	3024000.00	-1239840.00	1784160.00
25	24	3024000.00	0.00	0.00	0.00	0.00	3024000.00	-1239840.00	1784160.00
26	25	3024000.00	0.00	0.00	0.00	0.00	3024000.00	-1239840.00	1784160.00
27	26	3024000.00	0.00	0.00	0.00	0.00	3024000.00	-1239840.00	1784160.00
28	27	3024000.00	0.00	0.00	0.00	0.00	3024000.00	-1239840.00	1784160.00
29	28	3024000.00	0.00	0.00	0.00	0.00	3024000.00	-1239840.00	1784160.00
30	29	3024000.00	0.00	0.00	0.00	0.00	3024000.00	-1239840.00	1784160.00
31	30	3024000.00	0.00	0.00	0.00	0.00	3024000.00	-1239840.00	1784160.00
32	31	3024000.00	0.00	0.00	0.00	0.00	3024000.00	-1239840.00	1784160.00
33	32	3024000.00	0.00	0.00	0.00	0.00	3024000.00	-1239840.00	1784160.00
34	33	3024000.00	0.00	0.00	0.00	0.00	3024000.00	-1239840.00	1784160.00
35	34	3024000.00	0.00	0.00	0.00	0.00	3024000.00	-1239840.00	1784160.00
36	35	3024000.00	0.00	0.00	0.00	0.00	3024000.00	-1239840.00	1784160.00
37	36	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
38	37	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
39	38	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
40	39	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
41	40	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
42		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
43		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
44		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
45		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
46		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
47		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
48		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
49		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
50		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
51		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
52		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
53		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
54		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
55		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
56		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
57		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
58		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
59		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
60		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
61		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
62		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
63		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
64		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
65		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
66		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
67		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
68		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
69		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
70		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

COST BENEFIT SYSTEM - (CBS)

REVENUE REQUIREMENT WORKSHEET

(1000-$)

INVESTMENT 1

ANNUAL REVENUE REQUIREMENTS

YEAR	BOOK DEPR.	EQUITY RETURN	INTEREST RETURN	FIT	PROP. TAX	SUBTOTAL	G.R.T	TOTAL REV REQ.
1	11200000	2508744	1564097	1743364	0.00	17016205.82	500811.5	17517017.35
2	11200000	2131116	1328662	1480945	0.00	16140724.02	475044.8	16615768.85
3	11200000	1737360	1083172	1207318	0.00	15227849.31	448177.6	15676026.92
4	11200000	1349345	841260.5	937680.6	0.00	14328286.32	421702.2	14749988.49
5	11200000	578357.7	360582	401909.6	0.00	12540849.31	369095.3	12909944.63
6	0	0	0	0	0.00	0.00	0	0.00
7	0	0	0	0	0.00	0.00	0	0.00
8	0	0	0	0	0.00	0.00	0	0.00
9	0	0	0	0	0.00	0.00	0	0.00
10	0	0	0	0	0.00	0.00	0	0.00
11	0	0	0	0	0.00	0.00	0	0.00
12	0	0	0	0	0.00	0.00	0	0.00
13	0	0	0	0	0.00	0.00	0	0.00
14	0	0	0	0	0.00	0.00	0	0.00
15	0	0	0	0	0.00	0.00	0	0.00
16	0	0	0	0	0.00	0.00	0	0.00
17	0	0	0	0	0.00	0.00	0	0.00
18	0	0	0	0	0.00	0.00	0	0.00
19	0	0	0	0	0.00	0.00	0	0.00
20	0	0	0	0	0.00	0.00	0	0.00
21	0	0	0	0	0.00	0.00	0	0.00
22	0	0	0	0	0.00	0.00	0	0.00
23	0	0	0	0	0.00	0.00	0	0.00
24	0	0	0	0	0.00	0.00	0	0.00
25	0	0	0	0	0.00	0.00	0	0.00
26	0	0	0	0	0.00	0.00	0	0.00
27	0	0	0	0	0.00	0.00	0	0.00
28	0	0	0	0	0.00	0.00	0	0.00
29	0	0	0	0	0.00	0.00	0	0.00
30	0	0	0	0	0.00	0.00	0	0.00
31	0	0	0	0	0.00	0.00	0	0.00
32	0	0	0	0	0.00	0.00	0	0.00
33	0	0	0	0	0.00	0.00	0	0.00
34	0	0	0	0	0.00	0.00	0	0.00
35	0	0	0	0	0.00	0.00	0	0.00
36	0	0	0	0	0.00	0.00	0	0.00
37	0	0	0	0	0.00	0.00	0	0.00
38	0	0	0	0	0.00	0.00	0	0.00
39	0	0	0	0	0.00	0.00	0	0.00
40	0	0	0	0	0.00	0.00	0	0.00
41	0	0	0	0	0.00	0.00	0	0.00
42	0	0	0	0	0.00	0.00	0	0.00
43	0	0	0	0	0.00	0.00	0	0.00
44	0	0	0	0	0.00	0.00	0	0.00
45	0	0	0	0	0.00	0.00	0	0.00
46	0	0	0	0	0.00	0.00	0	0.00
47	0	0	0	0	0.00	0.00	0	0.00
48	0	0	0	0	0.00	0.00	0	0.00
49	0	0	0	0	0.00	0.00	0	0.00
50	0	0	0	0	0.00	0.00	0	0.00
51	0	0	0	0	0.00	0.00	0	0.00
52	0	0	0	0	0.00	0.00	0	0.00
53	0	0	0	0	0.00	0.00	0	0.00
54	0	0	0	0	0.00	0.00	0	0.00
55	0	0	0	0	0.00	0.00	0	0.00
56	0	0	0	0	0.00	0.00	0	0.00
57	0	0	0	0	0.00	0.00	0	0.00
58	0	0	0	0	0.00	0.00	0	0.00
59	0	0	0	0	0.00	0.00	0	0.00
60	0	0	0	0	0.00	0.00	0	0.00
61	0	0	0	0	0.00	0.00	0	0.00
62	0	0	0	0	0.00	0.00	0	0.00
63	0	0	0	0	0.00	0.00	0	0.00
64	0	0	0	0	0.00	0.00	0	0.00
65	0	0	0	0	0.00	0.00	0	0.00
66	0	0	0	0	0.00	0.00	0	0.00
67	0	0	0	0	0.00	0.00	0	0.00
68	0	0	0	0	0.00	0.00	0	0.00
69	0	0	0	0	0.00	0.00	0	0.00
70	0	0	0	0	0.00	0.00	0	0.00

Unredacted Exhibit (JR-1) Page 56 of 110

74th Street

FORECAST OF FUEL PRICES

Assumptions:
74th Street HP Oil Steam Rate = 1,400 btu/lb
74th Street PB Oil Steam Rate = 1,550 btu/lb
HP SEO = 2,300 MMlb/yr
Oil Only in January
74th Street HP Gas Steam Rate = 1,450 btu/lb
74th Street HP Gas Steam Rate = 1,600 btu/lb
PB SEO = 900 MMlb/yr

HP Emission Rates:
0.24 lb/MMbtu NOx for #6 Fuel Oil
0.17 lb/MMbtu NOx for Natural Gas
174 lb/MMbtu CO_2 for #6 Fuel Oil
117 lb/MMbtu CO_2 for Natural Gas
0.30 lb/MMbtu SO_2 for #6 Fuel Oil
0.0006 lb/MMbtu SO_2 for Natural Gas

PB Emission Rates:
0.32 lb/MMbtu NOx for #6 Fuel Oil
0.17 lb/MMbtu NOx for Natural Gas
174 lb/MMbtu CO_2 for #6 Fuel Oil
117 lb/MMbtu CO_2 for Natural Gas
0.30 lb/MMbtu SO_2 for #6 Fuel Oil
0.0006 lb/MMbtu SO_2 for Natural Gas

Maintenance Savings
1 Less Annual Boiler Wash $120K HP + $100K PBs
Assumed other reduced FO Work Order and Failures
Are offset by work on incremental gas equipment

SO2 Savings for 74th HP @ [illegible]/ton
74th HP Only NOx Savings of [illegible] during Ozone Season
PER ACI of Corporate EHS

Year	Month	Natural Gas Prices RC Fuel as of 8/09 Delivered Cost With Taxes ($/MMbtu)	0.3% Sulfur High Pour No. 6 Fuel Oil Prices RC Fuel as of 8/09 Delivered No. 6 Oil Cost With Taxes ($/MMbtu)	74th Street PB SEO (MMlb)	74th Street HP SEO (MMlb)	74th Street HP and PB Base	74th Street HP and PB Charge		Base NOx (Tons)	Base SO2 (Tons)	Base CO2 (Tons)	Charge NOx (Tons)	Charge SO2 (Tons)	Charge CO2 (Tons)	Maintenance Savings	HP NOx Gross Savings	HP NOx Annual Savings	HP SO2 Savings
2012	Jan	9.85	13.04	120	250	[illegible]	[illegible]		78	80	46,632	78	80	44,632		$0		
	Feb	9.26	13.06	120	360	[illegible]	[illegible]		103	104	60,039	61	0.2	40,365		$0		
	Mar	8.59	13.08	110	330	[illegible]	[illegible]		94	95	55,028	56	0.2	37,001		$0		
	Apr	8.04	13.09	30	130	[illegible]	[illegible]		35	34	19,884	20	0.1	13,367		$0		
	May	8.04	13.11	40	30	[illegible]	[illegible]		14	16	9,648	9	0.0	6,084		$363		
	Jun	8.44	13.13	60	160	[illegible]	[illegible]		47	48	27,579	20	0.1	18,545		$1,934		
	Jul	8.85	13.15	60	160	[illegible]	[illegible]		47	48	27,579	20	0.1	18,545		$1,934		
	Aug	8.86	13.16	60	160	[illegible]	[illegible]		47	48	27,579	20	0.1	18,545		$1,934		
	Sep	8.90	13.18	70	210	[illegible]	[illegible]		68	68	35,018	35	0.1	23,544		$2,539		
	Oct	9.17	13.20	40	50	[illegible]	[illegible]		19	20	11,484	12	0.0	7,722		$0		
	Nov	9.90	13.21	80	200	[illegible]	[illegible]		68	62	35,148	36	0.1	23,834		$0		
	Dec	10.99	13.23	110	260	[illegible]	[illegible]		79	80	46,502	47	0.2	31,268		$0		
				900	2,300	[illegible]	[illegible]	$14,846,130	683	692	409,808	437	82	285,254	$220,000	$8,706	$181,216	$40,000
2013	Jan	9.40	13.25	120	250	[illegible]	[illegible]		78	80	46,632	78	80	44,632		$0		
	Feb	9.18	13.27	130	360	[illegible]	[illegible]		103	104	60,039	61	0.2	40,365		$0		
	Mar	8.55	13.29	110	330	[illegible]	[illegible]		94	95	55,028	56	0.2	37,001		$0		
	Apr	8.23	13.31	30	130	[illegible]	[illegible]		35	34	19,884	20	0.1	13,367		$0		
	May	8.21	13.33	40	30	$1,396,320	$882,575		14	18	9,648	9	0.0	6,084		$363		
	Jun	8.61	13.35	60	160	$4,231,950	$2,824,080		47	48	27,579	20	0.1	18,545		$1,934		
	Jul	9.08	13.37	60	160	$4,210,296	$2,978,240		47	48	27,579	20	0.1	18,545		$1,934		
	Aug	9.11	13.39	60	160	$4,364,430	$2,988,030		47	48	27,579	20	0.1	18,545		$1,934		
	Sep	9.15	13.42	70	210	$5,481,580	$3,810,975		68	68	35,018	35	0.1	23,544		$2,539		
	Oct	9.32	13.44	40	50	$1,774,980	$1,272,180		19	20	11,484	12	0.0	7,722		$0		
	Nov	10.27	13.46	80	200	$5,437,840	$4,292,860		68	63	35,148	36	0.1	23,834		$0		
	Dec	11.48	13.48	110	260	$7,205,040	$6,309,730		79	80	46,502	47	0.2	31,268		$0		
				900	2,300	$63,625,180	$46,577,630	$18,067,570	683	692	409,808	437	82	285,254	$220,000	$8,706	$181,216	$40,000
2014	Jan	9.99	13.57	120	250	$7,773,520	$7,773,520		78	80	46,632	78	80	44,632		$0		
	Feb	9.65	13.60	120	360	$9,384,080	$6,890,100		103	104	60,039	61	0.2	40,365		$0		
	Mar	8.93	13.62	110	330	$8,614,650	$5,844,615		94	95	55,028	56	0.2	37,001		$0		
	Apr	8.57	13.64	30	130	$3,116,740	$2,826,805		35	34	19,884	20	0.1	13,367		$0		
	May	8.56	13.66	40	30	$1,498,640	$958,280		14	16	9,648	9	0.0	6,084		$363		
	Jun	8.98	13.68	60	160	$4,356,540	$3,945,444		47	48	27,579	20	0.1	18,545		$1,934		
	Jul	9.48	13.70	60	160	$4,342,900	$3,109,840		47	48	27,579	20	0.1	18,545		$1,934		
	Aug	9.49	13.72	60	160	$4,349,240	$3,112,720		47	48	27,579	20	0.1	18,545		$1,934		
	Sep	9.56	13.75	70	210	$5,534,375	$3,581,740		68	68	35,018	35	0.1	23,546		$2,539		
	Oct	9.77	13.77	40	50	$1,817,646	$1,353,603		19	20	11,484	13	0.0	7,722		$0		
	Nov	10.65	13.79	80	200	$5,571,160	$4,451,700		68	61	35,148	34	0.1	23,834		$0		
	Dec	11.70	13.81	110	260	$7,381,445	$6,470,100		79	80	46,502	47	0.2	31,268		$0		
				900	2,300	$63,148,970	$48,360,055	$14,782,815	683	692	409,808	437	82	285,254	$220,000	$8,706	$181,216	$40,000
2015	Jan	10.58	13.92	120	250	$7,441,120	$7,441,126		78	80	46,632	78	80	44,632		$0		
	Feb	10.15	13.94	120	360	$9,618,600	$7,317,100		103	104	60,039	81	0.2	40,365		$0		
	Mar	9.54	13.96	110	330	$8,829,700	$6,343,930		94	95	55,028	56	0.2	37,001		$0		
	Apr	9.07	13.98	30	130	$3,194,430	$2,145,055		35	34	19,884	20	0.1	13,367		$0		
	May	9.06	14.00	40	30	$1,656,040	$973,950		14	18	9,648	9	0.0	6,084		$363		
	Jun	9.51	14.02	60	160	$4,444,340	$3,139,286		47	48	27,579	28	0.1	18,545		$1,934		
	Jul	10.04	14.04	60	160	$4,450,680	$3,283,128		47	48	27,579	20	0.1	18,545		$1,934		
	Aug	10.06	14.07	60	160	$4,468,190	$3,299,680		47	48	27,579	20	0.1	18,545		$1,934		
	Sep	10.12	14.10	70	210	$5,675,250	$4,234,980		68	68	35,018	35	0.1	23,544		$2,539		
	Oct	10.36	14.12	40	50	$1,865,840	$1,434,160		19	20	11,484	12	0.0	7,722		$0		
	Nov	11.60	14.14	80	200	$5,712,560	$4,818,000		60	61	35,148	36	0.1	23,634		$0		
	Dec	13.12	14.16	110	260	$7,560,520	$7,255,860		79	80	46,502	47	0.2	31,268		$0		
				900	2,300	$64,754,154	$50,516,815	$15,310,715	683	692	409,808	437	82	285,254	$220,000	$8,706	$181,216	$40,000

74th Street

FORECAST OF FUEL PRICES

Assumptions:

[illegible]

HP Emission Rates:
0.24 lb/MMBtu NOx for #6 Fuel Oil
0.17 lb/MMBtu NOx for Natural Gas
174 lb/MMBtu CO_2 for #6 Fuel Oil
117 lb/MMBtu CO_2 for Natural Gas
0.30 lb/MMBtu SO_2 for #6 Fuel Oil
0.0006 lb/MMBtu SO_2 for Natural Gas

PB Emission Rates:
0.32 lb/MMBtu NOx for #6 Fuel Oil
0.17 lb/MMBtu NOx for Natural Gas
174 lb/MMBtu CO_2 for #6 Fuel Oil
117 lb/MMBtu CO_2 for Natural Gas
0.30 lb/MMBtu SO_2 for #6 Fuel Oil
0.0006 lb/MMBtu SO_2 for Natural Gas

Maintenance Savings:
[illegible]

Year	Month	Natural Gas Prices RC Fuel as of 6/09 Delivered Cost With Taxes ($/MMBtu)	0.3% Sulfur High Pour No. 6 Fuel Oil Prices RC Fuel as of 6/09 Delivered No. 6 Oil Cost With Taxes ($/MMBtu)
2012	Jan	9.83	13.04
	Feb	9.26	13.06
	Mar	8.59	13.08
	Apr	8.04	13.09
	May	8.04	13.11
	Jun	8.44	13.13
	Jul	8.05	13.15
	Aug	8.86	13.16
	Sep	8.90	13.18
	Oct	9.17	13.20
	Nov	9.90	13.21
	Dec	10.99	13.23
2013	Jan	9.40	13.25
	Feb	9.18	13.27
	Mar	8.55	13.29
	Apr	8.23	13.31
	May	8.31	13.33
	Jun	8.61	13.35
	Jul	9.08	13.37
	Aug	9.11	13.39
	Sep	9.15	13.42
	Oct	9.52	13.44
	Nov	10.27	13.46
	Dec	11.41	13.48
2014	Jan	9.99	13.57
	Feb	9.15	13.60
	Mar	8.83	13.62
	Apr	8.27	13.64
	May	8.56	13.66
	Jun	8.98	13.68
	Jul	9.48	13.70
	Aug	9.49	13.72
	Sep	9.56	13.75
	Oct	9.77	13.77
	Nov	10.65	13.79
	Dec	11.79	13.81
2015	Jan	10.53	13.92
	Feb	10.15	13.94
	Mar	9.54	13.96
	Apr	9.07	13.98
	May	9.06	14.00
	Jun	9.51	14.02
	Jul	10.04	14.04
	Aug	10.08	14.07
	Sep	10.12	14.10
	Oct	10.36	14.12
	Nov	11.48	14.14
	Dec	13.12	14.16

Year	Month	74th Street PB EFO (MWh)	74th Street HP EFO (MWh)	74th Street HP and PB Rev	74th Street HP and PB Change		Base NOx (Tons)	Base SO2 (Tons)	Base CO2 (Tons)	Change NOx (Tons)	Change SO2 (Tons)	Change CO2 (Tons)	Maintenance Savings	HP NOx Ozone Savings	HP NOx Annual Savings	HP SO2 Savings
2012	Jan–Dec	[illegible]	[illegible]	[illegible]	[illegible]		[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]		[illegible]		
	Total	990	2,300	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	$220,000	[illegible]	[illegible]	[illegible]
2013	Jan–Dec	[illegible]	[illegible]	[illegible]	[illegible]		[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]		[illegible]		
	Total	990	2,300	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	$220,000	[illegible]	[illegible]	[illegible]
2014	Jan–Dec	[illegible]	[illegible]	[illegible]	[illegible]		[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]		[illegible]		
	Total	990	2,300	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	$220,000	[illegible]	[illegible]	[illegible]
2015	Jan–Dec	[illegible]	[illegible]	[illegible]	[illegible]		[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]		[illegible]		
	Total	990	2,300	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	$220,000	[illegible]	[illegible]	[illegible]

PROJECT NO 22945-08
BUDGET NO . . .
ESTIMATE NO 22945-08-0409-09302
EST DATE 10/16/2009
PROJ ENG FA[illegible] WE[illegible]
PROJ EST BU[illegible]
LOCATION MANHATTAN

CONFIDENTIAL

CENTRAL ENGINEERING
ORDER OF MAGNITUDE ESTIMATE

FOR REVIEW AND COMMENT

APPROP.	START	/ /	COMPL.
ENG / DES.	START	/ /	COMPL.
PROCUR.	START	/ /	COMPL.
CONSTR.	START 12/01/2011		COMPL. 12/31/2012
PROJECT	IN SERVICE..		12/31/2012
OUTAGE	IS REQUIRED		

DESCRIPTION 74TH ST NATURAL GAS UPGRADE (REVISED 10/15/2009 TO INCORPORATE REVIEW COMMENTS)

ITEM	COMPANY MHRS	COMPANY LABOR $	COMPANY EQ / MAT $	CONTRACT MHRS	CONTRACT LABOR $	CONTRACT EQ / MAT $	TOTAL DIRECT	VAR ESCAL	OVERHEADS & AFDC	VAR CONTING	TOTAL
PURCHASED EQUIPMENT											
HP & PB BOILER BMS AND DCS EQUIPMENT			1,271,918				1,271,918	178,100	364,600	30%	2,359,018
INCLUDES BMS / DCS INSTALLER & COMMISSIONING			1,858,780				1,858,780	260,200	532,900	30%	3,447,480
FOB JOBSITE			150,000				150,000	21,000	43,000	30%	278,200
MAJOR MECHANICAL EQUIPMENT, INCLUDING:											
HP BOILER BURNERS			470,000				470,000	65,800	134,700	30%	871,700
PACKAGE BOILER BURNERS			960,000				960,000	134,400	275,100	30%	1,780,400
GAS TURBINE METERS			296,374				296,374	41,500	84,900	30%	549,574
STRAINERS, STRAIGHTENERS, VALVES			1,081,947				1,081,947	151,500	310,200	30%	2,006,747
FOB JOBSITE			100,000				100,000	14,000	26,800	30%	185,600
CONSTRUCTION CONTRACTS											
CIVIL (CONSTRUCT CLEAN ROOM)				30,670	3,419,360	1,023,745	4,443,105	622,000	1,486,500	30%	8,517,105
CIVIL (TRENCH FOR GAS MAIN TO CLEAN ROOM)				594	59,381	113,838	173,219	24,300	68,100	30%	332,319
COMPANY LABOR											
M&CS PIPE INSTALL	31,755	2,191,226	1,330,203				3,521,430	493,000	2,687,100	30%	8,712,030
M&CS WIRING FOR HVAC / LIGHTING / DETECTION	2,827	190,845	105,631				296,476	41,500	230,600	30%	739,176
BMS / DCS CONTROL EQUIPMENT CONDUIT & CABLI	17,300	1,167,735	464,138				1,631,873	228,500	1,350,100	30%	4,173,573
BMS / DCS CONTROL PIPING, VALVES, MOV	934	63,022	21,986				85,008	11,900	71,900	30%	219,408
IFGR SYSTEM INSTALL	8,775	592,313	1,392,000				1,984,313	277,800	1,071,700	30%	4,333,913
PM&I	4,800	403,200					403,200	56,400	412,400	30%	1,133,600
SO	2,400	164,400					164,400	23,000	168,200	30%	462,300
I&C COMMISSIONING	1,920	131,520					131,520	18,400	134,500	30%	369,720
EH&S TESTING / MONITORING	600	48,000					48,000	6,700	49,200	30%	135,100
IR / CCTN	3,840	307,200	360,000				667,200	93,400	434,700	30%	1,553,900
OTHER DIRECT COSTS											
PERMITS						20,000	20,000	2,800	6,800	30%	36,500
TESTS AND INSPECTIONS						20,000	20,000	2,800	6,800	30%	36,500
TRAFFIC / SECURITY						10,000	10,000	1,400	3,300	30%	19,100
ENGINEERING SERVICES						500,000	500,000	70,000	167,300	30%	958,500
GAS INTERCONNECT						8,333,332	8,333,332			20%	10,000,032
START UP AND TEST SUPPORT						1,500,000	1,500,000	210,000	501,900	30%	2,875,500
	75,151	5,259,461	9,882,977	31,264	3,478,741	11,520,916	30,122,095	3,050,400	10,615,300	12,303,200	56,090,995

Manzo 11/3/09

PROJECT NO 22945-08
BUDGET NO . . .
ESTIMATE NO 22945-08-0409-09002
EST DATE 10/16/2009
PROJ ENG FAIRWEATHER
PROJ EST BUERGER KB
LOCATION MANHATTAN

CENTRAL ENGINEERING
ORDER OF MAGNITUDE ESTIMATE

FOR REVIEW AND COMMENT

Exhibit ___ (JR-1)
Page 59 of 110

	START		COMPL.	
APPROP.	START		COMPL.	
ENG / DES.	START		COMPL.	
PROCUR.	START		COMPL.	
CONSTR.	START	12/01/2011	COMPL.	12/31/2012
PROJECT	IN SERVICE			12/31/2012
OUTAGE	IS REQUIRED			

DESCRIPTION 74TH ST NATURAL GAS UPGRADE (REVISED 10/15/2009 TO INCORPORATE REVIEW COMMENTS)

ITEM	COMPANY MHRS	COMPANY LABOR $	COMPANY EQ / MAT $	CONTRACT MHRS	CONTRACT LABOR $	CONTRACT EQ / MAT $	TOTAL DIRECT	VAR ESCAL	OVERHEADS & AFDC	VAR CONTING	TOTAL

TOTAL ADJ. - $ 56,090,995
SAY $ 56,100,000

ORDER OF MAGNITUDE TOTAL: $ 56,100,000 OOM RETIREMENT TOTAL: $ 186,000

OVERHEADS	CENTRAL ENG:	A & S:	P'ROLL TAX & PENS:		
	14.00%	2.60%	58.44%	TOTAL OH'S:	$ 9,750,000
	$ 3,477,600	$ 736,200	$ 5,536,200	2.71% AFDC:	$ 1,161,800

REMARKS

CENTRAL ENGINEERING	PROJECT MANAGER OR USER ORGANIZATION	CONSTRUCTION MANAGER
APPROVED BY Manzno DATE 11/3/09	APPROVED BY DATE	APPROVED BY DATE

PROJECT NO 22948-08
BUDGET NO . . .
ESTIMATE NO 22948-08-O409-09003-A1 R1
EST DATE 10/22/2009 (R1 11/4/09)
PROJ ENG LEARY
PROJ EST BUERGER
LOCATION MANHATTAN

CENTRAL ENGINEERING
ORDER OF MAGNITUDE ESTIMATE

FOR REVIEW AND COMMENT

APPROP.	START	/ /	COMPL.	/ /
ENG / DES.	START	/ /	COMPL.	/ /
PROCUR.	START		COMPL.	/ /
CONSTR.	START	12/03/2011	COMPL.	12/31/2012
PROJECT	IN SERVICE			12/31/2012
OUTAGE	IS REQUIRED			

Exhibit (JR-1) Page 60 of 110

DESCRIPTION 59TH ST NATURAL GAS UPGRADE (REVISED CLEAN ROOM LOCATION "A1" WITH VENT TO 58TH STREET) *** CORRECT PIPING AND METERS ***

ITEM	COMPANY MHRS	COMPANY LABOR $	COMPANY EQ / MAT $	CONTRACT MHRS	CONTRACT LABOR $	CONTRACT EQ / MAT $	TOTAL DIRECT	VAR ESCAL	OVERHEADS & AFDC	VAR CONTING	TOTAL
PURCHASED EQUIPMENT											
ANNEX & PACKAGE BOILER BMS / DCS EQUIPMENT			343,786				343,786	48,100	115,100	30%	659,086
BMS / DCS INSTALLER & COMMISSIONING			490,640				490,640	68,700	164,200	30%	940,640
FOB JOBSITE			22,000				22,000	3,100	7,300	30%	42,100
MAJOR MECHANICAL EQUIPMENT, INCLUDING:											
ANNEX BOILER BURNERS			340,000				340,000	47,600	113,800	30%	651,800
STRAINERS, STRAIGHTENERS, VALVES			409,183				409,183	57,300	136,900	30%	784,383
FOB JOBSITE			10,000				10,000	1,400	3,300	30%	19,100
CONSTRUCTION CONTRACTS											
CIVIL (CONSTRUCT CLEAN ROOM)				20,985	2,414,447	724,078	3,138,524	439,400	1,050,000	30%	6,016,324
COMPANY LABOR											
MECHANICAL INSTALLATION	19,663	1,333,623	946,181				2,279,804	319,200	1,881,100	30%	5,564,104
BMS / DCS CONTROL EQUIPMENT CONDUIT & CABLE	7,832	528,639	251,649				780,289	109,200	575,800	30%	1,904,889
BMS / DCS CONTROL PIPING, VALVES, MOV	77	3,611	3,283				6,894	1,000	4,300	30%	15,894
ELECTRICAL	1,316	96,993	41,720				138,713	19,400	113,100	30%	352,613
IFGR SYSTEM (LABOR & EQUIPMENT)	2,400	162,000	464,000				626,000	87,600	321,000	30%	1,345,000
PM&I	3,200	268,800					268,800	37,600	275,000	30%	756,800
SO	1,600	109,600					109,600	15,300	112,100	30%	308,100
I&C (COMMISSIONING)	1,920	131,520					131,520	18,400	134,500	30%	369,720
EH&S	400	32,000					32,000	4,500	32,800	30%	90,100
IR / CCTN	3,840	307,200	360,000				667,200	93,400	395,900	30%	1,503,500
OTHER DIRECT COSTS											
PERMITS / ENGINEERING SERVICES / TESTS						150,000	150,000	21,000	43,000	30%	278,200
GAS INTERCONNECT (ADDED $500K FOR 250 FT)						5,000,000	5,000,000			20%	6,000,000
START UP AND TEST SUPPORT						750,000	750,000	105,000	215,000	30%	1,391,000
	42,248	2,973,987	3,682,442	20,985	2,414,447	6,624,078	15,694,954	1,497,200	5,494,200	6,306,000	28,992,354

TOTAL ADJ. - $ 28,992,354
SAY $ 29,000,000

11/4/09

PROJECT NO 22948-08
BUDGET NO . . .
ESTIMATE NO 22948-08-O409-09003-A1 R1
EST DATE 10/22/2009 (R1 11/4/09)
PROJ ENG LEARY
PROJ EST BUERGER
LOCATION MANHATTAN

WJB

CENTRAL ENGINEERING
ORDER OF MAGNITUDE ESTIMATE

FOR REVIEW AND COMMENT

APPROP.	START	/ /	COMPL.	/ /
ENG / DES.	START	/ /	COMPL.	/ /
PROCUR.	START		COMPL.	/ /
CONSTR.	START	12/01/2011	COMPL.	12/31/2012
PROJECT	IN SERVICE....................................			12/31/2012
OUTAGE	IS REQUIRED			

DESCRIPTION 59TH ST NATURAL GAS UPGRADE (REVISED CLEAN ROOM LOCATION "A1" WITH VENT TO 58TH STREET) *** CORRECT PIPING AND METERS ***

ITEM	COMPANY MHRS	COMPANY LABOR $	COMPANY EQ / MAT $	CONTRACT MHRS	CONTRACT LABOR $	CONTRACT EQ / MAT $	TOTAL DIRECT	VAR ESCAL	OVERHEADS & AFDC	VAR CONTING	TOTAL

ORDER OF MAGNITUDE TOTAL: $ 29,000,000 OOM RETIREMENT TOTAL: $ 582,000

OVERHEADS	CENTRAL ENG:	A & S:	P'ROLL TAX & PENS:			
	14.00%	2.60%	58.44%		TOTAL OH'S:	$ 5,046,700
	$ 1,706,900	$ 361,200	$ 2,978,600	2.60%	AFDC:	$ 579,000

REMARKS

CENTRAL ENGINEERING	PROJECT MANAGER OR USER ORGANIZATION	CONSTRUCTION MANAGER
APPROVED BY ______ DATE 11/4/09	APPROVED BY ______ DATE	APPROVED BY ______ DATE
Manzno		

Company Name: Con Edison
Case Description: Con Edison Gas & Steam Rate Cases
Case: 09-G-0795-09-S-0794

Response to DPS Interrogatories – Set DPS1
Date of Response: 02/02/2010
Responding Witness: Steam Operations Panel

Question No. :3Rev2
Subject: Capital Expenditures – 1. Referring to the Con Edison Steam Operations Panel testimony, page 15 lines 3-6, the Company stated: "The Company's recently updated 2009 peak demand forecast is lower than previous forecasts, due primarily to the lower than anticipated demand over the past 2008-2009 winter." a) Provide the Company's updated 2009 peak demand forecast. b) Provide the Company's most recent 10 year forecast. 2. Provide a spreadsheet (in Excel format) of forecasted demand and actual steam system peak demand for the last 30 years. 3. Provide copies of all internal company documents that describe the company's steam peak demand forecasting methodology. 4. Provide the cost/benefit analyses for the West 59th Street station as referred on page 18 line 16 of Steam Operations Panel testimony. 5. Provide the cost/benefit analyses and calculations of projected savings for East 74th street station gas addition projects as referred on page 19 lines 9-10 of Steam Operations Panel testimony. 6. For each of the West 59th Street and East 74th street gas addition projects provide: a) detailed cost breakdown, b) detailed calculation of projected costs with workpapers, c) detailed need analysis and justification. 7. Referring to the Con Edison Steam Operations Panel testimony, regarding the interference program on page 61 lines 11-13, the Company stated: "Based on an historical average, the Company projects an annual expenditure of $1 million annually for this program for the period 2010-2014." Provide the detailed calculation, including the historical average information that supports the $1 million funding request for each rate year.

Response:
Please see attached excel file "Historical Peak Load.xls" which has been modified to include the Actual Steam Peak Load.

Historical Steam Peak Information

Winter Period	Weather Adjusted Actual Steam Peak Load (Mlb/hr)	Winter Peak Demand Forecast (Mlb/hr)	Actual Steam Peak Load (Mlb/hr)
1996/1997	11,775	11,790	9,672
1997/1998	11,935	11,880	8,511
1998/1999	11,900	11,970	9,751
1999/2000	11,920	11,940	10,850
2000/2001	11,130	10,980	9,220
2001/2002	10,610	10,700	7,783
2002/2003	10,490	10,540	9,701
2003/2004	10,380	10,430	10,063
2004/2005	10,365	10,340	9,639
2005/2006	10,310	10,490	8,413
2006/2007	10,190	10,330	9,305
2007/2008	10,160	10,310	8,648
2008/2009	9,540	10,170	8,593

Company Name: Con Edison
Case Description: Con Edison Gas & Steam Rate Cases
Case: 09-G-0795-09-S-0794

Response to DPS Interrogatories – Set DPS1
Date of Response: 12/23/2009
Responding Witness: Steam Operations Panel

Question No. :3R
Subject: Capital Expenditures – 1. Referring to the Con Edison Steam Operations Panel testimony, page 15 lines 3-6, the Company stated: "The Company's recently updated 2009 peak demand forecast is lower than previous forecasts, due primarily to the lower than anticipated demand over the past 2008-2009 winter." a) Provide the Company's updated 2009 peak demand forecast. b) Provide the Company's most recent 10 year forecast. 2. Provide a spreadsheet (in Excel format) of forecasted demand and actual steam system peak demand for the last 30 years. 3. Provide copies of all internal company documents that describe the company's steam peak demand forecasting methodology. 4. Provide the cost/benefit analyses for the West 59th Street station as referred on page 18 line 16 of Steam Operations Panel testimony. 5. Provide the cost/benefit analyses and calculations of projected savings for East 74th street station gas addition projects as referred on page 19 lines 9-10 of Steam Operations Panel testimony. 6. For each of the West 59th Street and East 74th street gas addition projects provide: a) detailed cost breakdown, b) detailed calculation of projected costs with workpapers, c) detailed need analysis and justification. 7. Referring to the Con Edison Steam Operations Panel testimony, regarding the interference program on page 61 lines 11-13, the Company stated: "Based on an historical average, the Company projects an annual expenditure of $1 million annually for this program for the period 2010-2014." Provide the detailed calculation, including the historical average information that supports the $1 million funding request for each rate year.

Response:

7. Referring to the Con Edison Steam Operations Panel testimony, regarding the interference program on page 61, lines 11-13, the Company stated: "Based on an historical average, the Company projects an annual expenditure of $1 million annually for this program for the period 2010-2014." Provide the detailed calculation, including the historical average information that supports the $1 million funding request for each rate year.

   Response:
   The Company has traditionally budgeted $1 million for steam capital interference projects. The budgets were based on steam infrastructure in direct interference with proposed City projects, which is work outside of the Company's control. As shown

on Attachment 1 of DPS1-2 Part 4.XLS, actual historical costs over the past 5 years were lower than what was budgeted. These lower expenditures were due to changes in City project plans and/or engineering changes that eliminated the direct steam interference condition. However for the forecast period 2010-2014, the best information available to the Company are forecasted City projects that may impact steam infrastructure, which are identified in the table below:

LOCATIONS	Estimated Footage to be Replaced
2010	
MANHATTAN WATER TUNNEL NO.3 VARIOUS LOCATIONS	35
1ST AVENUE - B/T 59TH STREET & 61ST STREET WATER MAIN SHAFT # 33B	25
REHAB OF PARK AVENUE VIADUCT - NORTHSIDE OF E42ND	25
WEST 30TH STREET WATER MAIN SHAFT #26B	25
20" WATER MAIN - EAST 59TH STREET B/T 5TH AVE & MADISON AVE AND 58TH STREET	25
Amount to be spent on main relocation:	$440,000
Amount to be spent on rebuilding manholes/relocating anchors, etc:	$560,000
2011	
1ST AVENUE - B/T 59TH STREET & 61ST STREET WATER MAIN SHAFT # 33B	25
REHAB OF PARK AVENUE VIADUCT - NORTHSIDE OF E42ND	25
WEST 30TH STREET WATER MAIN SHAFT. #26B	25
20" WATER MAIN - EAST 59TH STREET B/T 5TH AVE & MADISON AVE AND 58TH STREET	25
WATER MAIN CONNECTIONS TO SHAFT # 28B	25
Trunk Main Shaft 30B-GRAND ST. B/T BWAY & ESSEX	25
TRUNK MAIN SHAFT 32B 2ND AVE & E. 35TH ST	35
TRUNK MAIN SHAFT 27B	25
Amount to be spent on main relocation:	$840,000
Amount to be spent on rebuilding manholes/relocating anchors, etc:	$160,000
2012	
1ST AVENUE - B/T 59TH STREET & 61ST STREET WATER MAIN SHAFT # 33B	25
REHAB OF PARK AVENUE VIADUCT - NORTHSIDE OF E42ND	25
WEST 30TH STREET WATER MAIN SHAFT #26B	25
20" WATER MAIN - EAST 59TH STREET B/T 5TH AVE & MADISON AVE AND 58TH STREET	25
WATER MAIN CONNECTIONS TO SHAFT # 28B	25
Trunk Main Shaft 30B-GRAND ST. B/T BWAY & ESSEX	25
TRUNK MAIN SHAFT 32B 2ND AVE & E. 35TH ST	35
TRUNK MAIN SHAFT 27B	25
Amount to be spent on main relocation:	$840,000
Amount to be spent on rebuilding manholes/relocating anchors, etc:	$160,000

2013	
WATER MAIN CONNECTIONS TO SHAFT # 28B	25
Trunk Main Shaft 30B-GRAND ST. B/T BWAY & ESSEX	25
TRUNK MAIN SHAFT 27B	25
PARK AVE TUNNEL FROM E34th to E. 39th STREET	35
WEST 33rd STREET / AMTRACK 30TH STREET BRANCH	35
Amount to be spent on main relocation:	$580,000
Amount to be spent on rebuilding manholes/relocating anchors, etc:	$420,000
2014	
PARK AVE TUNNEL FROM E34th to E. 39th STREET	35
WEST 33rd STREET / AMTRACK 30TH STREET BRANCH	35
WEST 38TH STREET / AMTRACK 30TH STREET BRANCH	35
WEST 39TH STREET / AMTRACK 30TH STREET BRANCH	35
Amount to be spent on main relocation:	$560,000
Amount to be spent on rebuilding manholes/relocating anchors, etc:	$440,000

For illustrative purpose, the foregoing table demonstrates how replacement of footage and other associated work could amount to $1 million in expenditures per year.

Company Name: Con Edison
Case Description: Con Edison Gas & Steam Rate Cases
Case: 09-G-0795-09-S-0794

Response to DPS Interrogatories – Set DPS10
Date of Response: 01/27/2010
Responding Witness: steam Ops Panel

Question No. :55
Subject: Exhibit_(SOP-1.1) page 2. Proposed Cost Recovery through the FAC - Please provide all supporting documentation and calculations for each annual capital expenditure forecasted for the (1) Hudson Avenue replacement project, (2) the W 59th street gas addition and (3) the E 74th street gas addition projects shown in Exhibit_(SOP-1.2) page 2. Also provide as applicable for each project listed above: a) Copies of the company's internal construction schedule and monthly variance reports from the date that the project was started to the actual or forecasted in-service date; b) Copies of the company's Current Working Estimate (CWE) to date; c) Copies of the order of magnitude estimate; d) Identify the project manager for each project.

Response:

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1. The cash flow for Hudson Avenue Replacement Project consists of $12.0 million in 2010 for engineering, permitting, and relocation of existing equipment to prepare the site for the new facility. In 2011, $40.0 million will fund completion of engineering and procurement of long lead equipment, e.g., boilers. The $180.0 million in 2012, $200.0 million in 2013 will fund final payments of large equipment, construction and commissioning activities.
    a. The preliminary schedule is attached.
    b. The Current Work Estimates are typically prepared during construction to monitor the project's progress vs. actual expenditures. Since construction has not started, CWEs have not been prepared.
    c. The order of magnitude estimate is attached.
    d. A Project Manager will be assigned to the project at a later date.

2. The W59th Street gas addition project is currently in the conceptual and planning phase and funding, procurement, detailed engineering/design, and construction have not yet begun. Based on a preliminary high level schedule, the projected in-service date is December 2011. The cash flow for this project of $4.0 million in 2010 is earmarked for the purchasing of long lead equipment and the start of construction in November and December of that year. The balance of $25.0 million is to support the full construction and commissioning of the project in 2011.

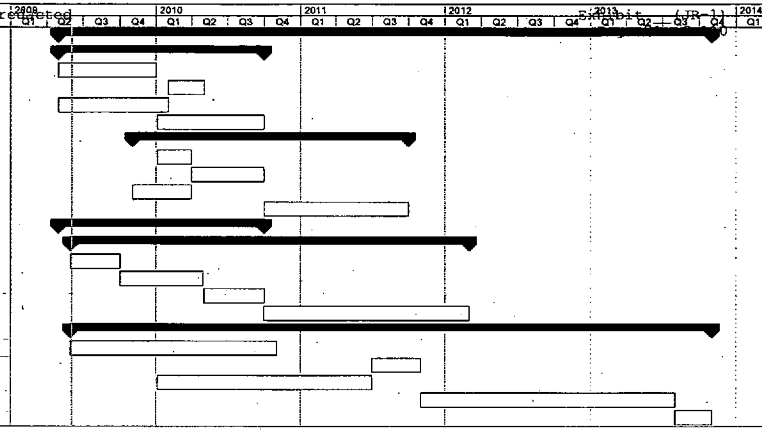
a. The preliminary high level schedule for the gas projects is attached. (See note below.)
b. The Current Work Estimates are typically prepared during construction to monitor the project progress vs. actual expenditures. Since construction has not started, CWEs have not been prepared.
c. The order of magnitude estimate is attached.
d. The Station's Project Manager will be assigned to this project.

The E74th Street gas addition project is currently in the conceptual and planning phase and funding, procurement, detailed engineering/design, and construction have not yet begun. The current planned in-service date is December 2013. The cash flow of $25.0 million in 2012 for this project is earmarked for the purchasing of long lead equipment and construction projected to start mid-2012. The balance of $31.0 is to fund the full construction and commissioning of the project in 2013.

a. The preliminary high level schedule for the project is attached. (See note below.)
b. The Current Work Estimates are typically prepared during construction to monitor the project progress vs. actual expenditures. Since construction has not started CWEs have not been prepared.
c. The order of magnitude estimate is attached.
d. The Station's Project Manager will be assigned to this project.

Note: As discussed above, the West 59th Street and 74th Street gas addition projects are currently planned to be in service 12/2011 and 12/2013, respectively. However, the attached preliminary schedule was prepared to recognize that the East 74th Street project in-service date may be required as early as 6/2012 to coincide with the new air emission rule proposed compliance date of 6/2012. The schedule and cash flow will be adjusted as needed to comply with the final rule requirements.

ID	Task Name	Duration	Start	Finish
1	**HA GENERATING STATION**	**1154 days**	**5/1/09**	**11/1/13**
2	**Relocations**	**356 days**	**5/1/09**	**9/30/10**
3	Funding	167 days	5/1/09	12/31/09
4	Procurement	65 days	2/1/10	5/3/10
5	Engineering	187 days	5/1/09	2/1/10
6	Construction	189 days	1/4/10	9/30/10
7	**Demolitions**	**483 days**	**11/2/09**	**9/30/11**
8	Funding	61 days	1/4/10	3/31/10
9	Procurement	128 days	4/1/10	9/30/10
10	Engineering	101 days	11/2/09	3/31/10
11	Construction	254 days	10/1/10	9/30/11
12	**SEQRA & Air Permit Activities**	**356 days**	**5/1/09**	**9/30/10**
14	**HARP Boiler Procurement**	**698 days**	**6/1/09**	**3/1/12**
15	Preparation of Boiler Specifications	87 days	6/1/09	10/1/09
16	Boiler Vendor Selection	144 days	10/1/09	4/30/10
17	Development & Approval of Boiler Vendor Drawings	107 days	5/3/10	10/1/10
18	Boiler Fabrication & Delivery	362 days	10/1/10	3/1/12
19	**HARP Facility Engineering & Construction (Install New Boilers)**	**1134 days**	**6/1/09**	**11/1/13**
20	Funding	357 days	6/1/09	11/1/10
21	Procurement	88 days	7/1/11	10/31/11
22	Engineering	378 days	1/4/10	6/30/11
23	Construction	457 days	11/1/11	8/1/13
24	Commissioning	67 days	8/1/13	11/1/13



Project: Harp Boiler Procurement
Date: 6/3/09

Task	Milestone	Rolled Up Task	Rolled Up Progress	External Tasks	Group By Summary
Progress	Summary	Rolled Up Milestone	Split	Project Summary	Deadline

PROJECT NO 22845-08
BUDGET NO . . .
ESTIMATE NO 22845-08-O401-09001 – Rev 2
EST DATE 8/24/2009
PROJ ENG R. FERRIS
PROJ EST BRIGGS / BUERGER
LOCATION BROOKLYN

CENTRAL ENGINEERING
ORDER OF MAGNITUDE ESTIMATE

FOR REVIEW AND COMMENT ONLY

Unredacted

	START		COMPL..	
APPROP.	START	/ /	COMPL..	/ /
ENG / DES.	START	/ /	COMPL..	/ /
PROCUR.	START	/ /	COMPL..	/ /
CONSTR.	START	09/01/2009	COMPL..	12/15/2013
PROJECT	IN SERVICE			12/15/2013
OUTAGE				

Exhibit __ (JR-1)
Page 72 of 110

DESCRIPTION HARP - INSTALL 4 PACKAGE BOILERS BASED ON PARSONS BRINCKERHOFF DIRECT COSTS (MODIFIED FOR DIRECT BILLING AND CON-ED ALLOWANCES)

ITEM	COMPANY MHRS	COMPANY LABOR $	COMPANY EQ / MAT $	CONTRACT MHRS	CONTRACT LABOR $	CONTRACT EQ / MAT $	TOTAL DIRECT	VAR ESCAL	OVERHEADS & AFDC	VAR CONTING	TOTAL
PURCHASED EQUIPMENT											
PACKAGE BOILERS EQUIPMENT / SYSTEM			37,000,000				37,000,000	3,330,000	7,384,600	20%	57,257,500
BALANCE OF PLANT EQUIPMENT			5,424,780				5,424,780	596,700	887,200	30%	8,981,280
WATER TREATMENT PLANT			9,474,000				9,474,000	1,042,100	1,549,300	30%	15,685,000
CONSTRUCTION CONTRACTS											
LABOR FOR PB EQUIPMENT					10,705,000		10,705,000	2,141,000	1,433,000	30%	18,562,700
LABOR FOR BOP EQUIPMENT					999,146		999,146	199,800	133,800	30%	1,732,546
LABOR FOR WT PLANT					2,854,000		2,854,000	570,800	382,100	30%	4,949,000
LABOR & MATERIAL FOR PIPING					5,912,000	3,694,000	9,606,000	1,921,200	1,285,900	30%	16,657,000
CIVIL STRUCTURAL ARCHITECTURAL					13,771,000	27,661,000	41,432,000	8,286,400	5,546,100	30%	71,843,900
ELECTRICAL SYSTEMS					6,534,000	7,828,000	14,362,000	2,872,400	1,922,600	30%	24,904,100
INSTRUMENTATION AND CONTROL SYSTEM					2,294,000	3,851,000	6,145,000	1,229,000	822,600	30%	10,655,600
ON SITE TRANSPORTATION, RIGGING, ERECTION						2,552,000	2,552,000	510,400	341,600	30%	4,425,200
GENERAL CONDITIONS					2,300,000	2,543,000	4,843,000	968,600	648,300	30%	8,397,900
CONTRACTORS ALLOWANCES						19,900,000	19,900,000	3,980,000	2,663,900	30%	34,507,100
SOIL REMEDIATION					2,000,000	1,500,000	3,500,000	385,000	711,400	30%	5,975,300
RELOCATIONS:											
RELOCATE FUEL OIL PIPING, KEROSENE					5,000,000	3,000,000	8,000,000	640,000	1,582,000	20%	12,266,400
FORWARDING PUMPS, OWS DISCHARGE,											
MAINTENANCE OFFICES, ELECTRICAL											
COMPANY LABOR											
CENTRAL ENGINEERING	47,040	5,174,400					5,174,400	724,400	1,080,100	20%	8,374,700
PM&I	36,400	6,370,015					6,370,015	891,800	1,329,700	20%	10,309,815
STATION SUPPORT	13,340	1,274,003					1,274,003	178,400	265,900	20%	2,082,003
TESTING & STARTUP	51,330	5,646,325					5,646,325	790,500	1,178,600	20%	9,138,525
OTHER DIRECT COSTS											
HA MASTER PLAN CONSULTANT					500,000		500,000		91,600	20%	709,900
PRELIMINARY DESIGN - SIGMA				13,500	2,000,000		2,000,000	160,000	395,500	20%	3,066,600
ENVIRONMENTAL ENGINEERING STUDIES				13,500	2,000,000		2,000,000	160,000	395,500	20%	3,066,600
PRELIMINARY RELOCATION ENGINEERING				1,800	250,000		250,000	20,000	49,400	20%	383,300
DETAILED DESIGN ENGINEERING					15,000,000		15,000,000	1,200,000	2,966,300	20%	22,999,600
TEST PITS					100,000		100,000	8,000	19,800	20%	153,400
SURVEY & TITLE SEARCH					50,000		50,000	4,000	9,900	20%	76,700
PUBLIC OUTREACH - COMMUNITY GOODWILL					1,500,000		1,500,000	120,000	296,600	20%	2,299,900
PERMITS - LEGAL SUPPORT					1,000,000		1,000,000	80,000	197,800	20%	1,533,400
CONSTRUCTION TECH SUPPORT					1,000,000		1,000,000	80,000	197,800	20%	1,533,400
INTERCONNECT PROJECTS											
STEAM					2,500,000		2,500,000	350,000	216,000	30%	3,985,800

PROJECT NO 22845-08
BUDGET NO . . .
ESTIMATE NO 22845-08-0401-09001 -- Rev 2
EST DATE 8/24/2009
PROJ ENG R. FERRIS
PROJ EST BRIGGS / BUERGER WJB/BIR
LOCATION BROOKLYN

CENTRAL ENGINEERING
ORDER OF MAGNITUDE ESTIMATE

FOR REVIEW AND COMMENT ONLY

Unredacted

	START		COMPL.	
APPROP.	START	/ /	COMPL.	/ /
ENG./DES.	START	/ /	COMPL.	/ /
PROCUR.	START	/ /	COMPL.	/ /
CONSTR.	START	09/01/2009	COMPL.	12/15/2013
PROJECT	IN SERVICE			12/15/2013
OUTAGE				

Exhibit (JR-1)
Page 73 of 110

DESCRIPTION HARP - INSTALL 4 PACKAGE BOILERS BASED ON PARSONS BRINCKERHOFF DIRECT COSTS (MODIFIED FOR DIRECT BILLING AND CON-ED ALLOWANCES)

ITEM	COMPANY			CONTRACT			TOTAL DIRECT	VAR ESCAL	OVERHEADS & AFDC	VAR CONTING	TOTAL
	MHRS	LABOR $	EQ / MAT $	MHRS	LABOR $	EQ / MAT $					
GAS					68,000,000		68,000,000	9,520,000		0%	77,520,000
ELECTRIC											
	148,111	18,464,743	51,898,780	28,800	146,269,146		289,161,669	42,960,500	35,984,900	75,907,100	444,014,169

TOTAL ADJ. - $ 444,014,169
SAY $ 444,020,000

ORDER OF MAGNITUDE TOTAL: $ 444,020,000

OVERHEADS	CENTRAL ENG:	0.00%	A & S:	4.00%	P'ROLL TAX & PENS:	0.00%	TOTAL OH'S:	$ 10,184,300
		$ -		$ 10,184,300		$ -	AFDC:	$ 25,800,600

REMARKS
7-23-09 version revised based upon internal comments received 8-19-09.

CENTRAL ENGINEERING	PROJECT MANAGER OR USER ORGANIZATION	CONSTRUCTION MANAGER
APPROVED BY	APPROVED BY	APPROVED BY
DATE	DATE	DATE

PROJECT NO 22845-08
BUDGET NO...
ESTIMATE NO 22845-08-0401-09001
EST DATE 7/22/2009

LOCATION BROOKLYN
DESCRIPTION HARP - INSTALL PACKAGE BOILERS

ESTIMATE RECAP

RECAP Rev 3

1 This OOM estimate is a combination of portions of a 2007-2008 Parsons Brinckerhoff estimate and the recent partial appropriation for long lead equipment for the installation of 4 Package Boilers at Hudson Ave. The Parsons estimate included escalation to 2009 $.

2 This estimate does **NOT** validate any data supplied by Parsons Brinckerhoff.

3 PB Power estimated $13M for demolition. This estimate does **NOT** include PB Power's $13M. Assume demolition to be funded under Retirement. **REVISED 8-19-09 See Note 8.**

4 This estimate includes Relocation dollars from the Partial Appropriation (relocate FO piping, kerosene forwarding pumps, OWS discharge, maintenance offices, some electrical). This is **NOT** the entire relocation scope. Additional relocations, as yet undefined, are possible. **REVISED 8-19-09 See Note 7.**

5 Spare parts are **NOT** included.

6 The PE cost for the Package Boilers = $40M based upon the Partial Appropriation.

7 Civil / Electrical / I&C comes from Table 2 - page 8 of the Sept 2008 PB report (in 2009$).

8 PB Power "Contractor Costs" is renamed "General Conditions".

9 PB Power "Contractors Soft Costs" is renamed "Contractors Allowances"

10 "Contractors Allowances" (old "Soft Costs") - removed profit - it is in the labor rates. Reduced Fees to $10M ; i.e. 10% mark-up on subcontractors.

11 Revised the gas and steam interconnects to $54M and $1M, respectively.
REVISED 8-19-09 see notes 2 & 3.

12 Note on Overhead Rates: **REVISED 8-19-09 see note 1.**
0% for Central Engineering
57.81% PT&P
6.88% AFDC for post partial items (i.e. 2 years construction = average of 1 years interest rate)
Revised escalation and contingency on the items in the partial to be consistent and to acknowledge work performed in early years.

RECAP Rev 4 8-20-2009 Based upon 8-19-09 mtg V. Mullin B. Manzino, R. ferris, B. Horowitz, W. Briggs

1 Revised Ohs to remove PT& P for Company Labor (included in the labor rate - direct charge).

2 Revised Gas to **$68M** (2009 loaded) escalated this to $2013. per e-mail 8-24-09, $54M HARP interconnect, $11M for reinforcemenst in Astoria, & 1/2 of new pipe at Transco gate south south of E 14th or $3M.

3 Revised Steam to $2.5M - 2009$ direct - per 8-19-09 mtg

4 Revised Outreach to **$1.5M** - 2009$ direct - per 8-19-09 mtg $2.5M reduced to $1.5M per 8-24-09 e-mail.

5 Added Permits and Legal - **$1M** - 2009$ direct per 8-19-09 mtg $2M reduced to $1M per 8-24-09 e-mail.

6 Added Construction Tech Support **$1M** - 2009$ direct per 8-19-09 mtg $2m reduced to $1M per 8-24-09 e-mail.

7 Revised Relocations to $8M - $2009 direct - per 8-19-09 mtg this is to include all costs.

8 Added Soil Remediation to $3.5M - $2009 direct - per 8-19-09 mtg; based upon TRC report that indicates approx. $7M for soil remediation – assumes 50% for Capital.

9 Revised General Conditions to be consistent with PB report.

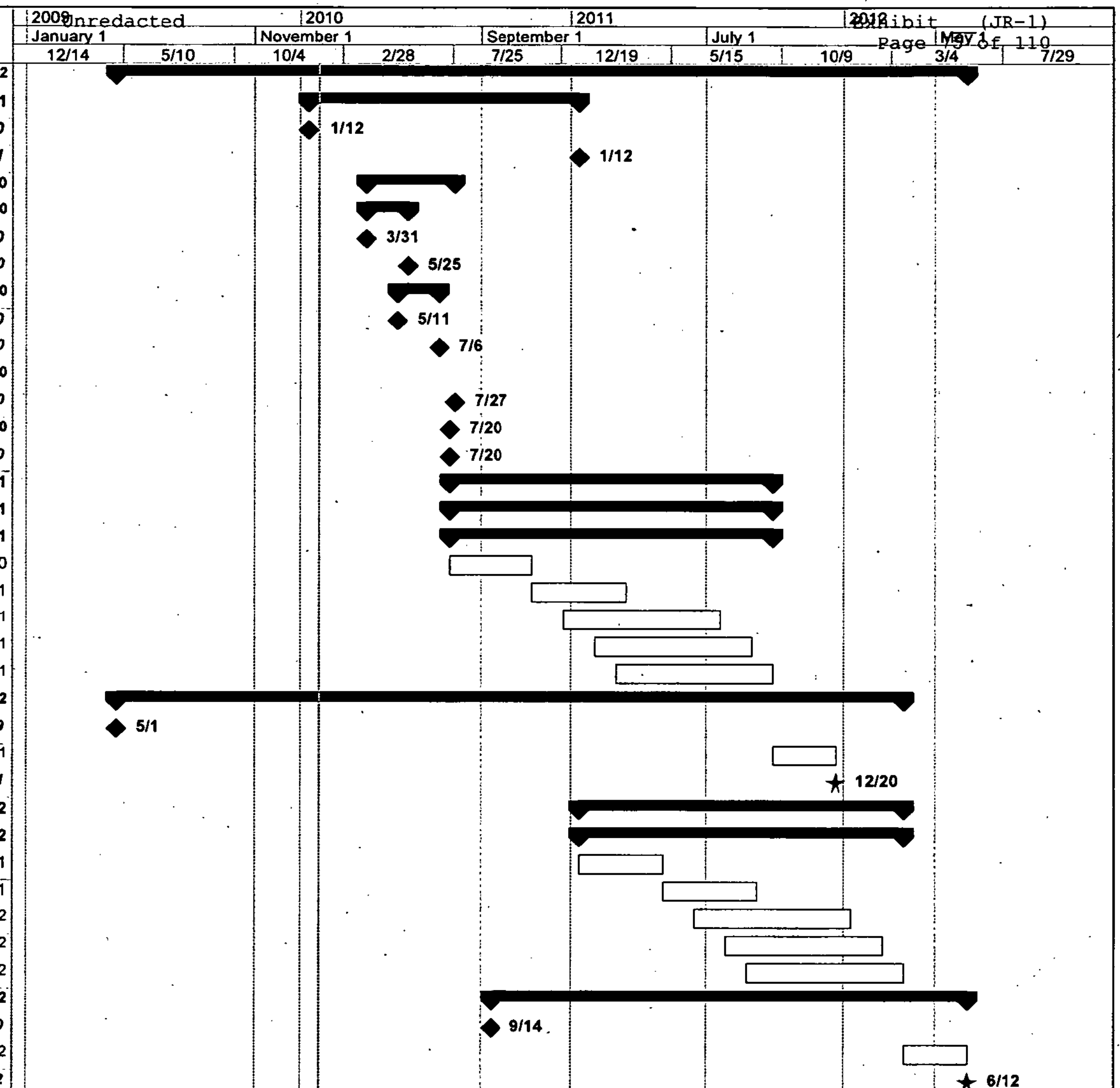
10 Adjusted escalation and AFDC based upon projected start & completion dates for all items.

11 Per e-mail 8-24-09 reduced Boiler package PE to $37M.

Unredacted

Exhibit __ (JR-1)
Page 74 of 110

ID	Task Name	Finish
1	**Gas Conversion**	6/12/12
2	**Funding**	1/12/11
3	***59th St. Appropriation***	1/12/10
4	***74th St. Appropriation***	1/12/11
5	**Engineering (59th St. and 74th St. in parallel)**	7/27/10
6	**Mechanical**	5/25/10
7	***Preliminary Mechanical Drawings Complete***	3/31/10
8	***Engineering Package Release***	5/25/10
9	**Electrical (Physical)**	7/6/10
10	***Preliminary Physical Drawings Complete***	5/11/10
11	***Engineering Package Release***	7/6/10
12	**Civil**	7/27/10
13	***Engineering Package Release***	7/27/10
14	**Electrical (Wiring)**	7/20/10
15	***Engineering Package Release***	7/20/10
16	**Construction**	9/27/11
17	**59th St.**	9/27/11
18	**Construction**	9/27/11
19	Contract Procurement	11/9/10
20	Civil Construction - Construction Management (CM)	3/15/11
21	Mechanical Construction - Construction Services (CS)	7/19/11
22	Electrical (Physical) Construction - Construction Services (CS)	8/30/11
23	Electrical (Wiring) Construction - Construction Services (CS)	9/27/11
24	**Start Up and Commissioning**	3/20/12
25	***Prepare Project Information Package (PIP)***	5/1/09
26	Testing & Commissioning	12/20/11
27	***System in Service***	12/20/11
28	**74th St.**	3/20/12
29	**Construction**	3/20/12
30	Contract Procurement	5/3/11
31	Civil Construction - Construction Management (CM)	9/6/11
32	Mechanical Construction - Construction Services (CS)	1/10/12
33	Electrical (Physical) Construction - Construction Services (CS)	2/21/12
34	Electrical (Wiring) Construction - Construction Services (CS)	3/20/12
35	**Start Up and Commissioning**	6/12/12
36	***Prepare Project Information Package (PIP)***	9/14/10
37	Testing & Commissioning	6/12/12
38	***System in Service***	6/12/12



Project: 21696-05 High Level--187
Date: 1/26/10

Task		Milestone		Rolled Up Task		Rolled Up Progress		External Tasks		Group By Summary
Progress		Summary		Rolled Up Milestone		Split		Project Summary		Deadline

PROJECT NO 22945-08
BUDGET NO . . .
ESTIMATE NO 22945-08-0409-09002
EST DATE 10/16/2009
PROJ ENG FA[illegible]
PROJ EST BU[illegible]
LOCATION MANHATTAN

CONFIDENTIAL

CENTRAL ENGINEERING
ORDER OF MAGNITUDE ESTIMATE

Unredacted

FOR REVIEW AND COMMENT

Exhibit ___ (JR-1)
Page 76 of 110

APPROP.	START	/ /	COMPL.
ENG / DES.	START	/ /	COMPL.
PROCUR.	START	/ /	COMPL.
CONSTR.	START	12/01/2011	COMPL. 12/31/2012
PROJECT OUTAGE	IN SERVICE IS REQUIRED		12/31/2012

DESCRIPTION 74TH ST NATURAL GAS UPGRADE (REVISED 10/15/2009 TO INCORPORATE REVIEW COMMENTS)

ITEM	COMPANY MHRS	COMPANY LABOR $	COMPANY EQ / MAT $	CONTRACT MHRS	CONTRACT LABOR $	CONTRACT EQ / MAT $	TOTAL DIRECT	VAR ESCAL	OVERHEADS & AFDC	VAR CONTING	TOTAL
PURCHASED EQUIPMENT											
HP & PB BOILER BMS AND DCS EQUIPMENT			1,271,918				1,271,918	178,100	364,600	30%	2,359,018
INCLUDES BMS / DCS INSTALLER & COMMISSIONING			1,858,780				1,858,780	260,200	532,900	30%	3,447,480
FOB JOBSITE			150,000				150,000	21,000	43,000	30%	278,200
MAJOR MECHANICAL EQUIPMENT, INCLUDING:											
HP BOILER BURNERS			470,000				470,000	65,800	134,700	30%	871,700
PACKAGE BOILER BURNERS			960,000				960,000	134,400	275,100	30%	1,780,400
GAS TURBINE METERS			296,374				296,374	41,500	84,900	30%	549,574
STRAINERS, STRAIGHTENERS, VALVES			1,081,947				1,081,947	151,500	310,200	30%	2,006,747
FOB JOBSITE			100,000				100,000	14,000	26,800	30%	185,600
CONSTRUCTION CONTRACTS											
CIVIL (CONSTRUCT CLEAN ROOM)				30,670	3,419,360	1,023,745	4,443,105	622,000	1,486,500	30%	8,517,105
CIVIL (TRENCH FOR GAS MAIN TO CLEAN ROOM)				594	59,381	113,838	173,219	24,300	68,100	30%	332,319
COMPANY LABOR											
M&CS PIPE INSTALL	31,765	2,191,226	1,330,203				3,521,430	493,000	2,687,100	30%	8,712,030
M&CS WIRING FOR HVAC / LIGHTING / DETECTION	2,827	190,845	105,631				296,476	41,500	230,600	30%	739,176
BMS / DCS CONTROL EQUIPMENT CONDUIT & CABLI	17,300	1,167,735	464,138				1,631,873	228,500	1,350,100	30%	4,173,573
BMS / DCS CONTROL PIPING, VALVES, MOV	934	63,022	21,986				85,008	11,900	71,900	30%	219,408
IFGR SYSTEM INSTALL	8,775	592,313	1,392,000				1,984,313	277,800	1,071,700	30%	4,333,913
PM&I	4,800	403,200					403,200	56,400	412,400	30%	1,133,600
SO	2,400	164,400					164,400	23,000	168,200	30%	462,300
I&C COMMISSIONING	1,920	131,520					131,520	18,400	134,500	30%	369,720
EH&S TESTING / MONITORING	600	48,000					48,000	6,700	49,200	30%	135,100
IR / CCTN	3,840	307,200	360,000				667,200	93,400	434,700	30%	1,553,900
OTHER DIRECT COSTS											
PERMITS						20,000	20,000	2,800	6,800	30%	38,500
TESTS AND INSPECTIONS						20,000	20,000	2,800	6,800	30%	38,500
TRAFFIC / SECURITY						10,000	10,000	1,400	3,300	30%	19,100
ENGINEERING SERVICES						500,000	500,000	70,000	167,300	30%	958,500
GAS INTERCONNECT						8,333,332	8,333,332			20%	10,000,032
START UP AND TEST SUPPORT						1,500,000	1,500,000	210,000	501,900	30%	2,875,500
	75,151	5,259,461	9,882,977	31,264	3,478,741	11,520,916	30,122,095	3,050,400	10,615,300	12,303,200	56,090,995

Manzo 11/3/09

PROJECT NO 22945-08
BUDGET NO . . .
ESTIMATE NO 22945-08-0409-09002
EST DATE 10/16/2009
PROJ ENG FAIRWEATHER
PROJ EST BUERGER KB
LOCATION MANHATTAN

CENTRAL ENGINEERING
ORDER OF MAGNITUDE ESTIMATE

FOR REVIEW AND COMMENT

Exhibit ___ (JR-1)
Page 27 of 110

APPROP.	START		COMPL.
ENG / DES.	START		COMPL.
PROCUR.	START		COMPL.
CONSTR.	START	12/01/2011	COMPL. 12/31/2012
PROJECT	IN SERVICE		12/31/2012
OUTAGE	IS REQUIRED		

DESCRIPTION 74TH ST NATURAL GAS UPGRADE (REVISED 10/15/2009 TO INCORPORATE REVIEW COMMENTS)

ITEM	COMPANY MHRS	COMPANY LABOR $	COMPANY EQ / MAT $	CONTRACT MHRS	CONTRACT LABOR $	CONTRACT EQ / MAT $	TOTAL DIRECT	VAR ESCAL	OVERHEADS & AFDC	VAR CONTING	TOTAL

TOTAL ADJ. - $ 56,090,995
SAY $ 56,100,000

ORDER OF MAGNITUDE TOTAL: $ 56,100,000 OOM RETIREMENT TOTAL: $ 186,000

OVERHEADS	CENTRAL ENG:	A & S:	P'ROLL TAX & PENS:		
	14.00%	2.60%	58.44%	TOTAL OH'S:	$ 9,750,000
	$ 3,477,600	$ 736,200	$ 5,536,200	2.71% AFDC:	$ 1,161,600

REMARKS

CENTRAL ENGINEERING
APPROVED BY [signature] DATE
Manzno 11/3/09

PROJECT MANAGER OR USER ORGANIZATION
APPROVED BY DATE

CONSTRUCTION MANAGER
APPROVED BY DATE

PROJECT NO 22948-08
BUDGET NO . . .
ESTIMATE NO 22948-08-O409-09003-A1 R1
EST DATE 10/22/2009 (R1 11/4/09)
PROJ ENG LEARY
PROJ EST BUERGER
LOCATION MANHATTAN

CENTRAL ENGINEERING
ORDER OF MAGNITUDE ESTIMATE

FOR REVIEW AND COMMENT

APPROP.	START	/ /	COMPL.	/ /
ENG / DES.	START	/ /	COMPL.	/ /
PROCUR.	START	/ /	COMPL.	/ /
CONSTR.	START	12/[illegible]	COMPL.	12/31/2012
PROJECT	IN SERVICE			12/31/2012
OUTAGE	IS REQUIRED			

Exhibit (JR-1)
Page 78 of 110

DESCRIPTION 69TH ST NATURAL GAS UPGRADE (REVISED CLEAN ROOM LOCATION "A1" WITH VENT TO 58TH STREET) *** CORRECT PIPING AND METERS ***

ITEM	COMPANY MHRS	COMPANY LABOR $	COMPANY EQ / MAT $	CONTRACT MHRS	CONTRACT LABOR $	CONTRACT EQ / MAT $	TOTAL DIRECT	VAR ESCAL	OVERHEADS & AFDC	VAR CONTING	TOTAL
PURCHASED EQUIPMENT											
ANNEX & PACKAGE BOILER BMS / DCS EQUIPMENT			343,786				343,786	48,100	115,100	30%	659,086
BMS / DCS INSTALLER & COMMISSIONING			490,640				490,640	68,700	164,200	30%	940,640
FOB JOBSITE			22,000				22,000	3,100	7,300	30%	42,100
MAJOR MECHANICAL EQUIPMENT, INCLUDING:											
ANNEX BOILER BURNERS			340,000				340,000	47,600	113,800	30%	651,800
STRAINERS, STRAIGHTENERS, VALVES			409,183				409,183	57,300	136,900	30%	784,383
FOB JOBSITE			10,000				10,000	1,400	3,300	30%	19,100
CONSTRUCTION CONTRACTS											
CIVIL (CONSTRUCT CLEAN ROOM)				20,985	2,414,447	724,078	3,138,524	439,400	1,050,000	30%	6,016,324
COMPANY LABOR											
MECHANICAL INSTALLATION	19,663	1,333,623	946,181				2,279,804	319,200	1,881,100	30%	5,564,104
BMS / DCS CONTROL EQUIPMENT CONDUIT & CABLE	7,832	528,639	251,649				780,289	109,200	575,800	30%	1,904,889
BMS / DCS CONTROL PIPING, VALVES, MOV	77	3,611	3,283				6,894	1,000	4,300	30%	15,894
ELECTRICAL	1,316	96,993	41,720				138,713	19,400	113,100	30%	352,613
IFGR SYSTEM (LABOR & EQUIPMENT)	2,400	162,000	464,000				626,000	87,600	321,000	30%	1,345,000
PM&I	3,200	268,800					268,800	37,600	275,000	30%	756,800
SO	1,600	109,600					109,600	15,300	112,100	30%	308,100
I&C (COMMISSIONING)	1,920	131,520					131,520	18,400	134,500	30%	369,720
EH&S	400	32,000					32,000	4,500	32,800	30%	90,100
IR / CCTN	3,840	307,200	360,000				667,200	93,400	395,900	30%	1,503,500
OTHER DIRECT COSTS											
PERMITS / ENGINEERING SERVICES / TESTS						150,000	150,000	21,000	43,000	30%	278,200
GAS INTERCONNECT (ADDED $500K FOR 250 FT)						5,000,000	5,000,000			20%	6,000,000
START UP AND TEST SUPPORT						750,000	750,000	105,000	215,000	30%	1,391,000
	42,248	2,973,987	3,682,442	20,985	2,414,447	6,624,078	15,694,954	1,497,200	5,494,200	6,306,000	28,992,354

TOTAL ADJ. - $ 28,992,354
SAY $ 29,000,000

11/4/09

PROJECT NO 22948-08
BUDGET NO . . .
ESTIMATE NO 22948-08-0409-09003-A1 R1
EST DATE 10/22/2009 (R1 11/4/09)
PROJ ENG LEARY
PROJ EST BUERGER
LOCATION MANHATTAN

NJB

CENTRAL ENGINEERING
ORDER OF MAGNITUDE ESTIMATE

FOR REVIEW AND COMMENT

APPROP.	START	/ /	COMPL.	/ /
ENG / DES.	START	/ /	COMPL.	/ /
PROCUR.	START		COMPL.	/ /
CONSTR.	START	12/01/2011	COMPL.	12/31/2012
PROJECT	IN SERVICE..			12/31/2012
OUTAGE	IS REQUIRED			

Exhibit (JR-1)
Page 79 of 116

DESCRIPTION 59TH ST NATURAL GAS UPGRADE (REVISED CLEAN ROOM LOCATION "A1" WITH VENT TO 58TH STREET) *** CORRECT PIPING AND METERS ***

ITEM	COMPANY MHRS	COMPANY LABOR $	COMPANY EQ / MAT $	CONTRACT MHRS	CONTRACT LABOR $	CONTRACT EQ / MAT $	TOTAL DIRECT	VAR ESCAL	OVERHEADS & AFDC	VAR CONTING	TOTAL

ORDER OF MAGNITUDE TOTAL: $ 29,000,000 OOM RETIREMENT TOTAL: $ 582,000

OVERHEADS	CENTRAL ENG:	A & S:	P'ROLL TAX & PENS:		
	14.00%	2.60%	58.44%	TOTAL OH'S:	$ 5,046,700
	$ 1,706,900	$ 381,200	$ 2,978,600	2.60% AFDC:	$ 579,000

REMARKS

CENTRAL ENGINEERING	PROJECT MANAGER OR USER ORGANIZATION	CONSTRUCTION MANAGER
APPROVED BY ___ DATE 11/4/09	APPROVED BY ___ DATE	APPROVED BY ___ DATE
Manzno		

Company Name: Con Edison
Case Description: Con Edison Gas & Steam Rate Cases
Case: 09-G-0795-09-S-0794

Response to DPS Interrogatories – Set DPS21
Date of Response: 02/17/2010
Responding Witness: Steam Ops Panel

Question No. :190
Subject: 59th & 74th Street Natural Gas Addition - Regarding Steam Operations Panel testimony, page 58, lines 17 to 22: "Third, the NYSDEC is evaluating changes to air emission regulations known as NOx RACT ("6 NYCRR Subpart 227-2 Reasonably Available Control Technology (RACT) For Oxides of Nitrogen (NOx)") and Clean Air Act, Section 185. The proposed regulatory requirements would significantly reduce the current air emission limits." 1. When will NYSDEC's proposed NOx RACT rulemaking be finalized and go into effect? 2. Has Con Edison met or does it plan to meet with NYSDEC regarding amendments to the emission regulations for NOx RACT and Clean Air Act, Section 185? Indicate when the meeting took place and what was discussed at the meeting. If the meeting is planed, explain what the Company plans on discussing and when the meeting will take place? 3. Did NYSDEC request input or comment from Con Edison prior to the notice of the proposed rule making? If so, what input or comment did Con Edison provide? 4. Provide a copy of all correspondence between Con Edison and NYSDEC regarding the proposed NOx RACT ruling and Clean Air Act, Section 185 over the past two years (January 2008 to January 2010). 5. Fully explain how the proposed changes to the Clean Air Act, Section 185 would or could impact Con Edison's steam generation process and forecasted capital projects for each of the next four calendar years (2010-2014)?

Response:

1. When will NYSDEC's proposed NOx RACT rulemaking be finalized and go into effect?

Response:
Con Edison has no specific knowledge of any DEC schedule for finalizing and implementing its proposed NOx RACT rulemaking, but it anticipates that the DEC will finalize this rulemaking by mid-year.

2. Has Con Edison met or does it plan to meet with NYSDEC regarding amendments to the emission regulations for NOx RACT and Clean Air Act, Section 185? Indicate when the meeting took place and what was discussed at the meeting. If the meeting is planned, explain what the Company plans on discussing and when the meeting will take place?

Response:
The DEC's proposed revisions to its NOx RACT regulations have been under discussion with the regulated community since early 2008. Con Edison staff participated in an industry outreach meeting, sponsored by DEC, on May 30, 2008. Con Edison staff also participated in the preparation of a letter addressing the proposed NOx RACT rulemaking by the Environmental Energy Alliance of New York (EEANY), dated June 27, 2008. Further, Con Edison staff met with DEC staff at DEC's Albany headquarters on November 13, 2008. At that meeting, DEC staff discussed possible compliance strategies for the Con Edison steam system in general terms, reflecting the early stage of the proposed rulemaking at that time.

Currently Con Edison has no meetings scheduled with DEC staff regarding the proposed NOx RACT rulemaking, but it plans to seek a meeting with DEC staff in the future. No agenda has yet been prepared for such a possible meeting.
Con Edison has not had extensive discussions with DEC staff regarding state implementation of the federal Clean Air Act Section 185 program. Through its participation in the "Clean Energy Group," a coalition of energy industry companies, Con Edison has provided input into the EPA's Clean Air Act Advisory Committee process. The Clean Air Act Advisory Committee was responsible for developing guidance to the states on incorporating Section 185 programs into their respective State Implementation Plans.

3. Did NYSDEC request input or comment from Con Edison prior to the notice of the proposed rule making? If so, what input or comment did Con Edison provide?

Response:
DEC invited Con Edison staff to its outreach session referenced in Response No. 190-2, above. As noted previously, Con Edison participated in the preparation of a consensus document with EEANY, which was sent to DEC on June 27, 2008.

4. Provide a copy of all correspondence between Con Edison and NYSDEC regarding the proposed NOx RACT ruling and Clean Air Act, Section 185 over the past two years (January 2008 to January 2010).

Response:
A copy of the June 27, 2008 letter from EEANY is attached.

5. Fully explain how the proposed changes to the Clean Air Act, Section 185 would or could impact Con Edison's steam generation process and forecasted capital projects for each of the next four calendar years (2010-2014)?

Response:

Federal law requires DEC to develop a program implementing Section 185 of the Clean Air Act. One option for DEC is to develop a fee program that would require all Clean Air Act "sources" to calculate a baseline emission rate using a two-year "look back". Sources that emit NOx in excess of 80 percent of that baseline will be required to pay a fee for each ton emitted each year over the 80 percent threshold. Another option for DEC would be to implement some of the flexible approaches that have been identified in EPA's recent guidance. Inasmuch as the nature of New York's Section 185 program has not yet been identified or determined, Con Edison has not yet developed strategies to comply with Section 185. We would note, however, that Con Edison's projects to reduce NOx emissions (capital projects that would add natural gas fuel capability at the 59th Street and 74th Street Generating Stations) would presumably reduce any compliance obligations Con Edison would have under New York's Section 185 program.

ENVIRONMENTAL ENERGY ALLIANCE OF NEW YORK

750 Broadway
Albany, New York 12207

June 27, 2008

Rob Sliwinski
Mike Jennings
NYS Department of Environmental Conservation
Division of Air Resources
625 Broadway
Albany, NY

Dear Rob and Mike:

Thank you for hosting the recent NOx RACT Stakeholder meeting. Subsequent to the meeting, the Alliance members had an opportunity to discuss your presentations. Members of the Generation Committee[1] are providing additional preliminary comments and questions that we hope are helpful as you proceed with development of a NOx RACT proposal.

The 20-state NOx RACT initiative. In view of the uncertainty associated with the states' draft agreement/MOU, Alliance members do not believe that New York should finalize a proposal that could prove to be inconsistent in terms of actual limits, timing or other considerations from what the other states approve. At the June 11, 2008 OTC Annual meeting, the presentation by Jeff Crawford (ME DEP) and discussions by other state representatives on current OTC initiatives and the next generation of EGU controls suggested the OTC, LADCO and VISTA states are only beginning to work on a regional or national proposal for additional EGU controls. At the meeting the OTC approved a "Charge to the Ozone Transport Commission Committees Concerning Implementation of the New Ozone National Ambient Air Quality Standard." In the charge the committees were directed to, "Provide recommendations for early emission reduction programs that can be instituted earlier than the mandated deadlines ..." The timeline for this process and for the committees to make their recommendations to the Commission itself for consideration and action is not defined. Based on past experience this could possibly take +/- a year. The next OTC meeting is not scheduled until November, 2008; therefore, it is unlikely that any proposals for additional EGU controls will be finalized until sometime in 2009. DEC's proposed timetable for finalizing the revised proposed NY RACT rule that was said to be based on the multistate effort is inconsistent with even an optimistic OTC timeline.

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[1] AES New York, Consolidated Edison Company of New York, Inc., Dynegy Northeast Generating, KeySpan/National Grid, NRG Energy, Rochester Gas & Electric Corporation, Selkirk Cogen Partners.

Need for background information. To allow sources to evaluate the proposal, the technical basis behind the proposed new emission limits, as well as the basis for the determination of the definition of RACT being technology costing up to $5,000 - $5,500 per ton NOx needs to be provided. Additionally we are interested in knowing what emission reductions compared with current emission are anticipated as a result of this rulemaking.

Need for additional modeling. Because the draft NOx RACT proposal goes beyond what is required by EPA, pursuant to ECL § 19-0303(4), NYSDEC must explain the environmental justification for the proposal and evaluate cost-effectiveness in comparison to alternatives. A modeling demonstration to support why the proposed NOx RACT levels are necessary from a public health and environmental perspective should be developed and provided for review. An assessment of the impacts on New York's electric system reliability and on the price of electricity is also needed.

Compliance date of June 2010. Alliance members offer the following preliminary list of reasons why the proposed compliance deadline is not achievable.

1. Capital projects currently take more than 24 to 36 months from inception to construction.
2. It is unclear that control equipment and construction resources will be available in that timeframe.
3. It should not be expected that large capital investment decisions be based on draft rules subject to significant change.
4. Permitting requirements will also likely add delays to the schedule.

Operating conditions that require startup and shutdown provisions.

1. Owing to thermal considerations, control equipment startup can lag hours behind boiler startup. This factor, coupled with severity of the proposed limits, could make it impossible to comply with the proposed 24 hr block limits during the ozone season.
2. The proposed emission rates are difficult to make for a unit on spinning reserve. At this operating condition (i.e., low load), NOx rates could be high as a result of the higher heat rate at lower efficiency.

Annual Tune Up. It is noteworthy that some EGU units have longer boiler maintenance cycles than one year, which should be accommodated in the draft rule. We request a definition of tune up, to accommodate maintenance outage schedules. In addition, the annual tune-up requirement will appear in the Title V permits so additional record keeping and documentation will be required.

Provisions for outages. Due to the stringency of the proposed limits, the Alliance believes that an identical exemption to the forced outages under the existing NOx RACT rule should be extended to planned outages.

Net Benefit Analysis. From your comments at the meeting, Alliance members understand that the collateral increases in other pollutants with the installation of NOx controls will be addressed in the regulatory impact analysis and should not affect the installation of NOx emission controls. However, in the advent of potentially more stringent state level NSR rules, unless the installation of such controls is expressly exempt from regulation, the lengthy review and permitting process associated with NSR could result in extending installation beyond the 24 to 36 months already anticipated.

System Wide Averaging. Even though system-wide averaging is now a viable option for compliance, the NOx limits proposed are so low that even with additional controls installed there may not be enough margin to cover a system. The High Electric Demand Day (HEDD) Memorandum of Understanding (MOU) was developed after nearly a year of a stakeholder process that included Ozone Transport Commission (OTC) staff, state environmental and utility regulators, EPA staff, EGU owners and operators and the independent regional systems operators. The stakeholders met to assess NOx emissions from electric generating units associated with HEDD during the ozone season and to address excess NOx emissions on those days in order to reduce ozone concentrations in the Northeast Corridor. As described in the MOU the goal was to "seek reductions in the most comprehensive, cost effective manner possible in order to maximize public health, environmental and economic benefits while ensuring an adequate electrical capacity and reliability for the region". The process culminated with specific state emission reduction targets and New York agreed to a 50.8 ton or 27% reduction in NOx emissions from the I-95 corridor on high energy demand days.

To further evaluate the proposed emission reduction levels, we examined historical emissions on August 2, 2006, an obvious HEDD. We note that the statewide emissions from the proposed NOx RACT limits would be reduced 111.5 tons. This reduction is well in excess of what is necessary to meet the MOU commitment. This estimate assumes that the units and system averaging plans operating that day could be reduced by the levels required but there was no evaluation of what was actually feasible or could be installed. The limits proposed would result in a reduction of 57.2 tons from units in NYC averaging plans and another 4.1 tons from other NYC units. Upstate there are additional reductions of 50.2 tons. In addition, those reductions do not account for future retirement commitments. The retirements of Poletti, Huntley 63-66, Russell and Lovett 4&5 will reduce NOx emissions by 58.6 tons. Although replacement power for those units will likely include sources with NOx emissions, any new replacement power will have much lower emission rates so those retirements will markedly decrease NOx emissions.

No Need for New NOx-RACT Limits during Non-Ozone Season: The ICI and EGU boilers in New York City may need to burn oil during the winter months in order to maintain fuel diversity and to mitigate possible gas supply shortages. During the non-ozone season when ozone is not a concern there is no need or justification to impose new limits. We propose that the existing NOx limits and rules may continue to be implemented with no revisions during the non-ozone season.

Apply New NOx Limits only During Peak Ozone Season and Exempt Shoulder Months: Some system averages, especially those in the downstate regions, rely on the operation of the low emitting steam units to create sufficient margin to allow for the operation of the higher emitting combustion turbines. During the shoulder months of May and September, it is not unusual to have numerous steam units off line, either for planned outages or low load demand. However, since a system contingency or an unexpected hot day could result in the need to run a significant number of combustion turbines, the various system averages are currently designed to ensure sufficient margin as well as with an understanding with the local Electric System Operators to assure that reliability needs will be met. For these reasons, we strongly suggest that the DEC apply lower limits during the June, July and August time frame only, when the air quality concerns are the greatest. The existing limits should then apply during May and September on a 24 hour basis and the new limits apply during June, July and August.

Thank you for the opportunity to provide input on this important rulemaking.

Sincerely,

John Holsapple
Principal

cc: Garry Brown
Paul DeCotis
Marcus Ferguson
Radmila Miletich

Company Name: Con Edison
Case Description: Con Edison Gas & Steam Rate Cases
Case: 09-G-0795-09-S-0794

Response to DPS Interrogatories – Set DPS21
Date of Response: 02/17/2010
Responding Witness: Steam Ops Panel

Question No. :191
Subject: 59th & 74th Street Natural Gas Addition - According to the NYSDEC proposed revision notice to Subpart 227-2, Reasonably Available Control Technology (RACT) for Oxides of Nitrogen, comments are to be submitted by February 17, 2010 and regulated entities must meet the new emission limits by July 1, 2012. 1. Why is the 74th Street natural gas addition scheduled for an in-service date of December, 2013 (based on the Company's response to DPS-55), after the July 1, 2012 deadline stated above? 2. What will be the change in project cost if the 74th Street natural gas addition had to be completed by July 1, 2012? 3. Has NYSDEC provided any input regarding what its next steps are after it has received comments that are due February 17, 2010? 4. When submitted, provide a copy of Con Edison's comments (due to NYSDEC on February 17, 2010).

Response:
1. Why is the 74th Street natural gas addition scheduled for an in-service date of December, 2013 (based on the Company's response to DPS-55), after the July 1, 2012 deadline stated above?

Response:
From engineering and project management perspectives, Con Edison would prefer to implement the 59th Street and 74th Street natural gas additions in series, rather than in parallel. We recognize that the DEC's proposed NOx RACT regulations have a compliance date of July 1, 2012. However, in comments it is submitting to the DEC on the proposed regulations, Con Edison contends that the proposed July 1, 2012 compliance date is impractical and infeasible for stationary sources in New York. Furthermore, if DEC decides to retain the proposed compliance date in any final rulemaking, Con Edison would likely seek DEC approval of its proposed in-service date for the 74th Street natural gas addition. If DEC does not defer the July 1, 2012 compliance date, Con Edison will have to adjust its implementation schedule. As indicated in response to Staff 192, Con Edison's current plan calls for implementation of the 74th Street gas addition on November 1, 2013. As further indicated in response to Staff 193 and 195, Con Edison has not yet determined how best to comply with the NOx RACT regulations.

2. What will be the change in project cost if the 74th Street natural gas addition had to be completed by July 1, 2012?

Response:
Con Edison has not calculated the cost for installing the 74th Street Generating Station natural gas addition concurrently with construction of the 59th Street natural gas addition.

3. Has NYSDEC provided any input regarding what its next steps are after it has received comments that are due February 17, 2010?

Response:
No.

4. When submitted, provide a copy of Con Edison's comments (due to NYSDEC on February 17, 2010).

Response:
Con Edison will provide the requested document when it is filed with NYSDEC.

Company Name: Con Edison
Case Description: Con Edison Gas & Steam Rate Cases
Case: 09-G-0795-09-S-0794

Response to DPS Interrogatories – Set DPS21
Date of Response: 02/19/2010
Responding Witness: Steam Ops Panel

Question No. :191R
Subject: 59th & 74th Street Natural Gas Addition - According to the NYSDEC proposed revision notice to Subpart 227-2, Reasonably Available Control Technology (RACT) for Oxides of Nitrogen, comments are to be submitted by February 17, 2010 and regulated entities must meet the new emission limits by July 1, 2012. 1. Why is the 74th Street natural gas addition scheduled for an in-service date of December, 2013 (based on the Company's response to DPS-55), after the July 1, 2012 deadline stated above? 2. What will be the change in project cost if the 74th Street natural gas addition had to be completed by July 1, 2012? 3. Has NYSDEC provided any input regarding what its next steps are after it has received comments that are due February 17, 2010? 4. When submitted, provide a copy of Con Edison's comments (due to NYSDEC on February 17, 2010).

Response:
See attached.

conEdison
a conEdison, inc. company

Randolph S. Price
Vice President
Environment, Health & Safety

February 17, 2010

<u>VIA OVERNIGHT MAIL AND E-MAIL</u>

Robert Stanton, P.E.
Mr. Mike Jennings
New York State Department of Environmental Conservation
Division of Air Resources
625 Broadway
Albany, NY 12233-3254

Re: <u>Proposed Revisions to 6 NYCRR Subpart 227-2</u>

Dear Messrs. Stanton and Jennings:

Consolidated Edison Company of New York, Inc. ("CECONY" or the "Company") welcomes the opportunity to provide comments to the New York State Department of Environmental Conservation (the "Department") on proposed revisions to Subpart 227-2 of the Department's regulations. These comments are filed in response to the public notices in the December 23, 2009 *New York State Register* and *Environmental Notice Bulletin.*

CECONY is a subsidiary of Consolidated Edison, Inc., one of the nation's largest investor-owned energy companies. The Company provides electric, gas and steam service to more than three million customers in New York City and Westchester County. Overall, CECONY serves a population of approximately nine million people throughout a service territory covering 660 square miles. CECONY's steam and electric generating systems and their reliable operation would be profoundly impacted by the proposed revisions to Subpart 227-2, "Reasonably Available Control Technology (RACT) for Major Facilities of Oxides of Nitrogen (NOx)", referred to here as "NOx RACT," under which, CECONY's fleet of 15 very large boilers, 20 large boilers, 8 simple-cycle and 2 combined-cycle cogeneration combustion turbines are, and Liquefied Natural Gas ("LNG") flare and combustor may be, regulated.

Consolidated Edison Company of New York, Inc.
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CECONY's detailed comments below address the following eight important issues: (i) concerns over the timing of these proposed revisions to Subpart 227-2 in light of the ongoing development of a successor regulatory program to the federal Clean Air Interstate Rule ("CAIR"); (ii) the need to recognize that the proposed regulatory compliance dates are unrealistic and unattainable given the significant delays in this rulemaking; (iii) the inadequacy of the stated methodology and basis for the Department's determination of the cost range for any reasonable control technologies; (iv) the need to develop a more detailed environmental assessment in support of the rulemaking's State Environmental Quality Review Act ("SEQRA") process; (v) concerns that the impact of increased compliance costs for CECONY may drive some of its steam customers to more polluting and less regulated technologies; (vi) the need to limit application of NOx RACT reductions to the ozone season, which is the principal driver of these regulations; (vii) the need to clarify the availability of certain rulemaking exemptions for emergency equipment that is not limited to power generation; and (viii) clarification that combined-cycle turbines can be included in a system averaging plan.

Issue 1: The revisions to the NOx RACT rules should be deferred pending EPA revisions to CAIR.

As discussed in detail below, CECONY believes that the Department's proposal should be deferred until EPA promulgates its CAIR replacement regulations. The Company believes that without the benefit of EPA's expected CAIR replacement regulations, Department efforts to revise its NOx RACT program could result in unnecessary and costly over-regulation that can be avoided if those revisions were deferred pending promulgation of EPA's CAIR replacement program.

In July and December 2008, the U.S. Court of Appeals for the District of Columbia Circuit issued two decisions remanding the federal CAIR program to EPA for further consideration and replacement. In reviewing the origin of the proposed revisions to Subpart 227-2, it is clear that the projected emissions reductions associated with the initial CAIR were a key element in the revision's drafting. For instance, a June 8, 2005 resolution of the member states in the Ozone Transport Commission ("OTC"), including New York, regarding development of a regional strategy for the integrated control of ozone precursors and other pollutants of concern from electrical generating units and other large sources made clear that the individual states needed to coordinate efforts to support the CAIR goal of reaching attainment of the eight-hour ozone standard. The Department itself acknowledged the importance of CAIR to the development of its own in-state program. In his July 29, 2008 testimony before the U.S. Senate Committee on the Environment and Public Works, Jared Snyder, the Department's Assistant Commissioner for Air Resources, Climate Change and Energy, noted that

> *"In New York, we are currently in the process of evaluating the changes that must be made in our current ozone and PM2.5 SIPs to take account of the court's decision. Our ozone SIP projects that we will be able to achieve compliance with the ozone standard by 2012, <u>but that assumes the reduction of emissions from out-of-state sources attributable to the implementation of CAIR</u>." [emphasis added]*

The changes needed to bring the sources associated with the revisions to Subpart 227-2 into regulatory compliance will be costly and may be disruptive to energy supplies. Accordingly, the Department should avoid actions that might result in the implementation of a compliance program that results in unnecessary overregulation pending completion of a federal CAIR replacement rule. This position is further reinforced by EPA testimony presented at a hearing before the Senate Committee on Environment and Public Works made in July 2009. At that hearing, Regina McCarthy, EPA's Assistant Administrator for the Office of Air and Radiation, stated:

> *"Working within the framework of the 2008 court decision that remanded CAIR, we are developing a new approach to reduce regional interstate transport of these long-distance pollutants while guaranteeing that each downwind nonattainment area is getting the reductions it is entitled to under the law." [emphasis added]*

When viewed against the backdrop of the Court of Appeals' decision, EPA's testimony suggests that New York will be able to rely on additional upwind reductions. Accordingly, the Department should not move forward with this rulemaking until the CAIR replacement rule is promulgated. Just as Assistant Commissioner Snyder is concerned that the State's actions may not be sufficient *without* CAIR, the regulated community and utility customers are concerned that, *with* a more-stringent CAIR replacement rule, the emission reductions brought about by the revisions to Subpart 227-2 will be too costly and more than necessary.

Assistant Administrator McCarthy's 2009 testimony further endorses this concern:

> *"[w]e must not pay any more than necessary to reach our environmental goals. This means looking for cost-effective ways to get reductions on the right geographic scales by using the right combination of emissions trading, performance standards and hybrid approaches as appropriate; providing industry with the kind of information they can rely on to plan for the future so we can keep the lights on and make smart investments; and avoid unnecessarily high or volatile energy costs for consumers."*

Implementing a revised Subpart 227-2 at this time – without benefit of the CAIR replacement rule – fails Ms. McCarthy's criteria on all counts. It is not cost-effective, it offers only limited flexibility, it fails to provide clear infrastructure investment guidance (because of a lack of clarity on CAIR) and it can lead to higher costs for consumers. For these reasons, promulgation of Subpart 227-2 should be deferred pending EPA's promulgation of a CAIR replacement rule.

Issue 2: The compliance dates outlined in proposed Subpart 227-2 are unrealistic, inconsistent and unattainable.

The Department is well aware that publication of its proposed revisions to Subpart 227-2 has been significantly delayed. The Department held stakeholder meetings in spring

2008 that outlined the general content of the revisions, and in its State Implementation Plan ("SIP") for Ozone Attainment Demonstration for [the] New York Metro Area, dated February 2008 (the "2008 Attainment Demonstration"), indicated its intent to complete the regulatory process and issue a final and effective revised Subpart 227-2 by no later than December 19, 2008. However, using the timeframes outlined for promulgation on page 9-1 of the 2008 Attainment Demonstration – from publication in the New York State Register to "Regulation Effective" – it would be no earlier than June 2010 before any proposed revisions to Subpart 227-2 can be finalized. Consequently, if the Department should decide to go forward with the promulgation of the currently proposed revisions, given the delays in their promulgation, a minimum of two years should be added to each compliance date in proposed Subpart 227-2 to allow for the delay in initial promulgation and to permit a complete review of the implications of the CAIR replacement rule when issued.

The Department has identified several compliance dates in proposed Subpart 227-2:

a) October 10, 2010 – the date by which an emission source retirement commitment must be captured within an enforceable permit;

b) January 1, 2011 – the date by which an emission source must either file a permit modification application or a demonstration indicating that the current emission level for a source is the RACT level; and

c) July 1, 2012 – the date by which an emission source must meet the new presumptive RACT limits or have an approved alternative RACT limit incorporated into an enforceable permit.

For owner/operators potentially subject to the rule, as proposed, it is equally important to identify the dates that are <u>not</u> listed in the proposed rule. For instance, as noted above, the Department's own documents suggest that the proposed revisions to Subpart 227-2 will not be finalized any earlier than June 1, 2010. Even if an owner had already concluded that the finalization of the rule would trigger a unit retirement, it is virtually impossible administratively to initiate and finalize a Title V permit modification within four months (e.g., by October 1, 2010). Furthermore, the Company, as a regulated utility, would require additional approvals from the Public Service Commission before it could commit to unit retirement. There is virtually no possibility that these administrative requirements and the required physical work could be completed in the time allotted by the proposed rule.

Similarly, presuming that the revisions to Subpart 227-2 are finalized by June 2010, the owner of an emission source must conduct a detailed engineering and economic analysis to determine a compliance strategy. A compliance strategy might include a series of emission sources, with a large number of variables driving a decision towards fuel-switching, system averaging, retirement or a demonstration of existing emissions as RACT. Proposed § 227-2.3(b) requires that every permit application must include documentation on emission limits, monitoring, recordkeeping, and a complete RACT analysis. Between June 2010 and January 2011, it is highly unlikely that a source owner with multiple units could complete all of the requisite analyses for submittal to the Department.

Moreover, although the text contained in proposed § 227-2.3(b), attempts to provide an opportunity for additional time to make a complete filing, that text, describing the threshold for such an extension, is unclear. The first statement in § 227-2.3(b) provides that:

> "By January 1, 2011 *(the RACT compliance date)* a facility must submit to the Department either a complete application for a permit *or* a RACT analysis that explains that the control technology the facility currently employs should still be considered RACT for that source." [emphasis added]

Stated another way, January 1 is the RACT compliance date, and an owner must file a complete application *or* a RACT analysis by that date. However, the next sentence in proposed § 227-3(b) states that to be complete, a permit application must include specific data *and* a RACT analysis. The section further goes on to state that "Facilities that submit a complete application but are unable to meet the RACT compliance date may request an extension...." Consequently, the first sentence in the section seems to state that a complete application is required by the RACT compliance date, but the third sentence indicates that an owner can get an extension if it has filed a complete application. But clearly, if an owner has filed a complete application, it has already met the RACT compliance date and would not need an extension. Accordingly, the Department needs to clarify the meaning of "RACT compliance date" as used in this section.

Continuing with the issue of schedule and compliance, and dates that are *not* set forth in the proposed rule, the Company notes that source owners are required to file applications by certain dates, and to meet new emission limits by specific dates, but that there are no specific requirements or dates (or time periods) certain for the Department to complete its own review and approve owner-submitted applications. The open-ended nature of Departmental approvals makes it even less likely that source owners could meet a new emission limit for any facility that required installation of controls or new infrastructure to support fuel-switching within the 18-month period between January 1, 2011 and July 1, 2012.

For a public utility such as CECONY, investing significant engineering resources towards the preparation of specifications for any control technology installation before the Department has approved an application (presumably to be filed by January 1, 2011) is problematic. Additionally, once approved, financial controls incumbent upon a regulated utility would require a specific budget for the work. Contractors to perform the requisite work would be solicited through public bid processes, and outages to perform the work would have to be scheduled so that electric and steam system reliability would not be compromised. Finally, the control technology (e.g., low NOx burners) would have to be installed and tested, and stack testing would be required to verify that the mandated emission reductions had been realized. Alternatively, if fuel-switching was the preferred compliance approach, additional time might be required to reinforce the natural gas system in the vicinity of the facilities that were principally using oil. Again, it seems implausible that all this work could be completed in the time allotted under proposed Subpart 227-2.

Further complicating the Department's ability to rapidly review and approve filings made by January 1, 2011, is the fact that the Department's administrative resources will likely be significantly strained by the large number of applications expected. The first table in the Regulatory Impact Statement section entitled "Costs" indicates that there are 85 very large boilers, 134 large boilers, and 354 mid-size boilers in the Department's database. Proposed §§ 227-2.3(a) and (b) taken together indicate that every source must file a complete application for either a new permit or a permit modification by January 1, 2011. Presuming that every one of the 573 sources noted by the Department submitted a timely application, we expect that the Department's processing resources would be severely taxed, and the likelihood of rapid review and approval of applications and RACT analyses would be substantially reduced. Given the number of applicants, particularly in light of recent State agency staff reductions, it is not inconceivable that the Department could consume the entire 18-month period (January 1, 2011 through July 1, 2012) in merely reviewing all of the applications and applicant responses to Department information requests.

As explained in Issue 1, above, the Company believes that the Department should defer implementation of any NOx RACT proposal. However, should the Department decide to proceed with the proposed Subpart 227-2 modifications, the Company recommends that the Department develop a more realistic and achievable approach to an implementation schedule.

First, two new definitions should be added to § 227-2.2 as follows (these two entries would be §§ 227-2.2 (6) and (7); with existing §§ 227-2.2(6) through (14) renumbered (8) through (16):

> *(6) "RACT filing date: a date two years after the promulgation of amendments to this Part. The promulgation date shall be the publication date of the State Register in which the modifications to this Part are published as final."*
>
> *(7) "RACT compliance date: a date two years after the RACT filing date. The Department may grant a one-year extension to the RACT compliance date for a source if the source owner has filed a complete application before the RACT filing date, and has requested an extension of the RACT compliance date from the Department. This request for extension is subject to Department review and approval. Once the extension is approved, the RACT compliance date shall be a date three years after the RACT filing date."*

Additionally, § 227-2.3(b) should be revised to state:

"By the RACT filing date, a facility must submit to the Department either a complete application for a permit or a RACT analysis that explains that the control technology the facility currently employs should still be considered RACT for that source. To be deemed complete, a permit application must include any new requirements (for example, emission limits, monitoring, and recordkeeping requirement) and an analysis that explains how the facility will comply with the provisions of this Subpart."

To make the revisions consistent, in any place within the proposed Subpart 227-2 where the date "January 1, 2011" appears, it should be replaced with the phrase "RACT filing date" and wherever the date "July 1, 2012" appears, it should be replaced with the phrase "RACT compliance date".

Finally, to be effective as a compliance tool, and to allow sources to take into consideration all of the economic and environmental factors that may stem from the Department's decision-making relative to the owners' RACT compliance filings, proposed § 227-2.5(d) should be revised as follows:

(c) 'Shutdown of an emission source.' An owner or operator of an existing emission source may opt to comply with this Subpart by shutting down the emission source. The intent to shut down must be recorded as part of a federally enforceable permit modification prior to the RACT compliance date, wherein the owner or operator commits to permanently shut down the emission source within 26 months of the RACT compliance date.

The proposed 26 month shutdown period is intended to mimic the time period associated with the dates currently proposed; i.e., between October 1, 2010 and December 31, 2012.

Issue 3: The Department has not provided a sufficient record for public review of the basis for its proposed control requirements in Section 227-2.4.

The Company believes that the Department's methodology for establishing its acceptable cost range per ton of NOx reduced is unclear and provides an insufficient basis for public review and comment. This is a critical aspect of the proposed rulemaking because the clear implication in setting a range is that per ton NOx reduction costs that exceed the Department's established cost range will not be considered reasonable and will not be required.

A key component in evaluating the Department's proposal in the revised Subpart 227-2 is understanding the basis for the link between the emission limits set forth in § 227-2.4 and the costs to achieve those limits. This link lies at the very heart of the definition of the term "reasonably available".[1] Towards that end, there are specific statements contained within the Regulatory Impact Statement describing the cost data that contributed to the Department's proposed NOx RACT emission limits. Specifically, the "Costs" section of

[1] A control technology is "reasonably available" if it is both technologically and economically feasible. *See* 6 NYCRR § 200.1(bq).

the Regulatory Impact Statement, page 11 of 26, includes a statement that "[T]he presumptive limits represent the level of NOx emissions that a typical source can achieve using available control technologies at a cost range of $5,000 to $5,500 per ton of NOx reduced," although there is nothing in the rulemaking record to support the Department's premise that a cost range of $5,000 to $5,500 per ton is economically feasible. Additionally, on page 13 of 26, there is a table entitled "Unit Costs for NOx Control Technologies for Very Large Boilers 2008 Costs." The paragraph that precedes that table states that the cost data comes from a February 28, 2007 Ozone Transport Commission (OTC) Technical Support Document, prepared by MACTEC; the MACTEC document can be located on the OTC website.

Page 4-22 of the MACTEC document, Section 4.6.4, deals with cost estimates for Industrial, Commercial and Institutional ("ICI") boiler controls, and it refers the reader to a reference by Bodnarik 2006. The Bodnarik work is actually listed in the reference section of the MACTEC document (page 5-1) as a presentation that Andrew Bodnarik made at the November 2, 2006 OTC Control Strategy / SAS Committee Meeting entitled "ICI Boiler NOx Control Cost Estimates from OTC Methodology"; this document was available by special request to technical staff at the OTC. However, none of the cost estimates shown in the table in the Regulatory Impact Statement match the data in Bodnarik's presentation or the Department's other cited sources.

Furthermore, putting the issue of cost aside, the Department's proposed emission limits are neither consistent with the information provided in the MACTEC document nor the justification provided in the Regulatory Impact Statement. For instance, the Regulatory Impact Statement indicates that the "limits for natural gas fired boilers are based on the application of low NOx burners" for both very large and large boilers. In all instances, the control efficiency for low NOx burners is shown as 50 percent. However, in the case of very large boilers, the Department proposes to reduce the presumptive NOx limit from 0.20 pounds NOx per million Btu to 0.08 pounds NOx per million Btu – a reduction of 60 percent. In the case of large boilers, the Department proposes to reduce the presumptive NOx limit from 0.20 pounds NOx per million Btu to 0.06 pounds NOx per million Btu – a reduction of 70 percent. Neither document provides a justification for these values.

The lack of foundation for the Department's proposed emission limits is further highlighted by their lack of consistency with the MACTEC document's recommendations. For instance, Table 4.4 of the MACTEC document, entitled "Addendum to OTC Resolution 06-02 Guidelines for ICI Boilers," presents four options for controlling NOx emissions for large boilers, and two options for controlling NOx emissions from very large boilers. The Department has not adopted any of the OTC Guidelines presented in the MACTEC report. Despite the Department's insistence in its Regulatory Impact Statement that it has drawn its proposed emission limits from the information provided by the MACTEC report, there is no clear "line of sight" between the two that allows an analysis of the Department's rationale for setting new limits. Accordingly, CECONY believes the finalization of Subpart 227-2 must also be deferred until the Department has revised the Regulatory Impact Statement to clearly set forth the underlying data which support the costs and bases for its emission targets, and justify the technological and economic feasibility of "reasonably available" control technologies. Such a revision would afford the public and the regulated community the ability to meaningfully examine the reasonableness of the Department's proposal and confirm or dispute the Department's rationale and calculations.

Issue 4: The Department's Negative Declaration is not supported by an adequate environmental assessment because it does not take into account the potentially adverse environmental impacts of the proposed revisions to Subpart 227-2.

The Department's December 23, 2009 announcement in the *Environmental Notice Bulletin* states that "Pursuant to Part 617 of the implementing regulations for the State Environmental Quality Review Act ('SEQRA'), NYS DEC has prepared a Negative Declaration stating that the proposed actions will not have a significant negative effect on the environment." Intuitively, a reduction in NOx emissions brought about by imposing more stringent standards would be considered a net benefit to the environment. However, it is possible that new NOx controls identified by the Department in the Regulatory Impact Statement (e.g., low NOx burners, flue gas recirculation, or selective catalytic reduction) may have other potentially adverse environmental impacts, which the Department has not evaluated in the environmental assessment upon which the Negative Declaration is based.

As examples, some control technologies lead to an increase in unit heat rate, which in turn leads to increased fuel consumption, and increased emissions of CO_2 and other pollutants. Further, selective catalytic reduction technology can lead to an increase in particulate matter emissions and require the shipment and storage of ammonia solutions within neighborhoods, as well as require the disposal of spent catalytic elements. To properly and comprehensively address SEQRA requirements and the Department's own Environmental Justice policy, the Department should evaluate and offer for public comment a detailed assessment of the potential environmental impacts resulting from implementation of the proposed revisions to Subpart 227-2, which, at the very least, should address the potential for significant adverse air quality, noise, traffic, waste disposal, and community impacts.

Issue 5: The proposed revisions to Subpart 227-2 may lead to increases in NOx emissions by driving steam customers to more polluting sources of energy.

Con Edison operates one of the largest steam distribution systems in the world. In general, the steam system provides space heating with a smaller emissions "footprint" (including NOx) than do unregulated sources. The Company's steam system, however, is not the only source of space heating in Manhattan below 96th Street. In fact, hundreds of buildings rely on small boilers that fall below the regulatory threshold of Subpart 227-2 and whose emissions are essentially unregulated. Even for those boilers that rise to the regulatory threshold of a "small boiler" under Subpart 227-2, there are no emission restrictions on those boilers other than to document annual tune-ups, regardless of the age and emission characteristics of these small boilers.

By proposing new control requirements on the boilers comprising the Company's steam system, the Department increases the cost of operating the steam system. These costs, in turn, are passed along to CECONY's steam customers. The Company's preliminary estimates suggest that its compliance with the proposed NOx RACT revisions could approach $90 million. These increased costs could well cause steam system customers to re-evaluate the costs and benefits of on-site boilers, and lead to an increase in the number of facilities that leave the steam system to install small on-site boilers. Consequently, without some consideration of the realistic cost increases likely to result from promulgation of a revised Subpart 227-2, the Department may actually be contributing to "NOx Creep" – inadvertent increases in NOx emissions within Manhattan caused by an increase in the number of unregulated boilers – rather than reducing the aggregate level of NOx emissions, which is the stated intent of this rulemaking proposal.

Issue 6: The Department provides no rationale for requiring sources to meet presumptive RACT limits on a year-round basis.

The Department's Regulatory Impact Statement (in the first paragraph under "Needs and Benefits") states that "ground level ozone or smog, which results from the mixing of VOCs and NOx on *hot sunny summer days*, can harm humans and plants." [emphasis added] The link of ozone with warm weather is reinforced by the Department's proposed language in § 227-2.5(a), which provides an incentive for emission sources to burn cleaner fuel "between May 1st and September 30th of each year."

The Department's Regulatory Impact Statement, however, provides no basis for driving expensive reductions in NOx emissions during the colder months of the year. As a consequence, the Department should limit the applicability of the proposed emission limits for each category listed in § 227-2.1(a) to the period between May 1and September 30. Accordingly, the text in §§ 227-2.4 (a)(1), (b)(1), and throughout § 227-2.4 should be revised to state:

> *(1) Emissions limits <u>applicable between May 1st and September 30th</u>:*

This issue is of particular importance to CECONY in light of its responsibility to maintain the reliability of its steam system. As temperatures decline during the winter months, steam output must be increased at the same time that residential and commercial demand on natural gas escalates rapidly. Since residential and commercial users have priority for natural gas during the winter, the Company is forced to burn oil to maintain system output. Under the current regulations, the non-ozone season NOx limits are obtainable while burning oil; furthermore, the current NOx limits do not lead to increases in ozone concentrations during the winter months. Attempting to apply lower NOx emission rates that may be relevant to ozone concentrations during the summer months to units that are operating at peak capacity in the winter months threatens the reliability of the steam system, compromises the integrity of the natural gas system, and yields no demonstrated benefit towards attainment with the ozone National Ambient Air Quality Standards.

The Company also recommends against the Department's proposed deletion of an exemption in § 227-2.4(e)(1). The proposed deletion eliminates the NOx RACT compliance exemption for simple cycle and regenerative combustion turbines that operate fewer than 500 hours during the non-ozone season. This exemption has no bearing on the ozone attainment status of the New York metropolitan area. But the elimination of this exemption will jeopardize the economic viability of these units, which can be critical for system reliability during portions of the year. The Company recommends that the existing wording of § 227-2.4(e)(1) be retained, which provides as follows:

> *(1) For simple cycle and regenerative turbines (With regard to peaking combustion turbines that operate fewer than 500 hours during the period of October 1 to April 30, the emission limits in subparagraphs (i) and (ii) are applicable only during the period May 1 through September 30.):*

In summary, the Company recommends that the current non-ozone season NOx RACT limits remain unchanged, and that the new emission limits ultimately adopted be applicable to the ozone season only.

Issue 7: Various exemptions found in proposed § 227-2.4 should be clarified in some cases and expanded in others.

CECONY has carefully reviewed proposed § 227-2.4 and has evaluated its potential impact on the day-to-day operations of the Company's steam, gas and electric systems. This review indicates that some of the proposed exemptions and definitions would benefit from modification to increase their effectiveness and meet the expressed intent of the Department. The three exemption cases discussed below make specific recommendations for modifying the language in the proposed rulemaking to streamline implementation and support the principal focus of the proposed revisions to § 227-2.4.

Case A: Proposed § 227-2.4(g) should also exempt safety- and emergency-related equipment associated with liquefied natural gas storage systems.

The Department has included a "catch-all" provision in § 227-2.4(g), requiring any combustion source not otherwise regulated and which has the potential to emit at least three pounds of NOx per hour and actual emissions of 15 pounds of NOx per day to file a case-by-case RACT determination. CECONY recommends that this provision should include an exemption for safety- and emergency-related equipment which does not meet the stated threshold under normal operating conditions.

CECONY owns and operates an LNG storage facility within the boundaries of its Astoria complex in Queens County. The safety provisions for LNG manufacturing and storage required by good engineering safety practice include a ground combustor and gas flare stack, so that excess natural gas can be safely discharged by controlled combustion during routine vent piping (safety-related) operations or during emergency releases of natural gas. For the ground combustor and flare stack, continuous pilot flame NOx emissions are de minimis, estimated at 0.015 and 0.088 lbs per hour, respectively, well below the NOx three pounds per hour and 15 lbs per day thresholds. Management of the LNG in the CECONY one billion cubic foot (vapor state equivalent) tank with the ground combustor and flare stack has the potential to yield more than three pounds of NOx per hour and would, if an abnormal condition were to evolve, emit more than 15 pounds of NOx in a 24-hour period. However, the ground combustor and the flare stack, operating as safety devices, have low annual NOx emissions. In addition, the flare stack has operated infrequently in emergency mode, but its maximum rated capacity is approximately 9,100 mmBtu/hr or over 600 pounds of NOx per hour. Consequently, based on the expected operation of this equipment at very low NOx annual emissions and infrequent operation in emergency mode, we believe that these are not the types of equipment that the Department is intending to regulate through its revision of the NOx RACT rules. Accordingly, CECONY proposes a new subparagraph (4) to § 227-2.4(g), as follows:

> *(4) combustion installations that are designed to operate as safety devices during normal operations or in an emergency, and that are associated with liquefied natural gas storage systems, are exempt from the requirements of this subdivision.*

Case B: The fuel switching compliance option in § 227-2.5(a) should have a fuel emergency adjustment to foster consistency with the system averaging plan compliance option in § 227-2.5(b).

The Department has wisely kept the fuel switching compliance option within its proposed revision of Subpart 227-2 (§ 227-2.5(a)), and CECONY appreciates that the fuel-switching option allows an individual facility to manage its NOx emissions with some flexibility and provides an incentive for sources to burn the cleanest possible fuel during the ozone season. However, as written, the fuel-switching compliance option presents a compliance risk for an owner/operator that the Department recognizes in its system averaging plan compliance option (§ 227-2.5(b)), but which it did not recognize in the fuel-switching option. Specifically, the system averaging compliance option has a provision that allows the weighted average permissible emission rate to be adjusted to account for an emission source or major electrical inter-tie (345 kV or greater) that is not in operation as a result of a forced outage. Under those circumstances, the adjusted emission rate is deemed to be in compliance for the period of the forced outage.

In contrast, § 227-2.5(a) – the fuel switching compliance option – indicates that an owner/operator may commit to burning a cleaner fuel during the ozone season provided that the fuel switching results in quantifiable annual NO_x emissions equal to or less than the NO_x emissions expected if the source complied with the presumptive RACT emission limits for its permitted fuel type. In CECONY's case, a commitment to burn a cleaner fuel would mean a commitment to burn a significantly higher percentage of natural gas in its dual fuel (gas and residual oil) steam plants. However, the Department should recognize that there are certain, limited times during the ozone season when utilities must burn oil to comply with the reliability rules of the New York State Reliability Council and the New York Independent System Operator ("NYISO") (such as NYISO Technical Bulletin No. 159). Just as the weighted average permissible emission rate is adjusted under § 227-2.5(b) because of a forced outage to allow a source to remain in compliance with its system-wide average, a plant operating under § 227-2.5(a) should also be considered to be in compliance with its commitment to burn cleaner fuel if it temporarily burns oil in compliance with NYISO's reliability rule. Therefore, CECONY recommends the following revised language for § 227-2.5(a):

(a) 'Fuel switching option.' The owner or operator of an emission source subject to this Subpart may commit to burning a cleaner fuel between May 1st and September 30th of each year. Fuel switching must result in quantifiable annual NO_x emissions equal to or less than the NO_x emissions expected if the emission source complied with the applicable presumptive RACT emission limits set forth in section 227-2.4 of this Subpart.

(1) An oil-burning emission source that commits to burn natural gas as a compliance option under this subpart, but which is subject to the requirement to burn oil by the terms of a NYISO reliability rule, shall be considered to be in compliance with its commitment to burn cleaner fuel during the period it is required to burn oil by such reliability rule.

Finally, to clarify use of the fuel-switching option, the Company recommends that a definition or explanation of the phrase "burning a cleaner fuel" be incorporated in the final regulation to indicate specifically whether the Department accepts mixed fuel burning (e.g., a mix of natural gas and residual oil) within the concept of "burning a cleaner fuel".

Case C: The Department should expand the applicability of the exemption found at § 227-2.4(f)(6)

The Department has wisely elected to exempt stationary internal combustion engines that are used for emergency purposes. These engines, which can be of significant size, do not incrementally contribute to NOx emissions on a Statewide basis, because they are rarely operated. Over many years, these units operate only when tested for reliability, and are limited by regulation to operate less than 500 hours of run time per year.

CECONY owns eight simple cycle and regenerative combustion turbines that similarly have limited annual operation, and which should be exempt from the provisions of § 227-2.4. Two units are used for natural gas compression (on an intermittent basis) and the remaining six are used to meet peak or emergency demands for electric energy. An additional subparagraph could be added to § 227-2.4(e)(1) to limit this exemption to units that are well-maintained and which operate only a specified maximum number of hours per year. Towards this end, the Company recommends the following text (added to § 227-2.4(e)(1)):

(iii) Notwithstanding the requirements of this subparagraph, sources that operate less than 250 hours per year and which meet the maintenance requirements

specified in 227-2.4(d) are exempt from the emission limits described in (i) and (ii), above.

Issue 8: The Department must clarify the language in § 227-2.5(b)(2) so that combined-cycle turbines can be included in a system averaging plan.

Most of the newer electric generating units installed in New York within the last ten years are combined-cycle combustion turbine installations. All of these units have state-of-the-art emission control equipment. As presently written, § 227-2.5(b)(2) appears to preclude incorporation of these units in a system averaging plan. The text of the proposed regulations states:

> "(2) All emission sources that participate in the system averaging plan *must be covered* by a *presumptive RACT emission* limit that is set forth in section 227-2.4 of this Subpart." [emphasis added]

A plain reading of § 227-2.4(e)(3) – "for all combustion turbines that operate after July 1, 2011, the owner or operator must submit a proposal for RACT to be implemented...." – is that there is no presumptive RACT emission limit for combined-cycle combustion turbines. In fact, the Regulatory Impact Statement (at page 17, bottom paragraph) states that the "proposed rule would require owners and/or operators of combined cycle combustion turbines to conduct a case-by-case RACT analysis." In the same paragraph, the Regulatory Impact Statement indicates that "the Department was not able to identify a presumptive NOx RACT emission limit for combined cycle combustion turbines."

Recent discussions between Company and Department staff indicate that the Department's view is that a combined cycle combustion turbine will be able to participate in a system averaging plan once the owner of that unit has demonstrated to the Department that the combined cycle combustion turbine in question cannot achieve any further reductions because it is already operating at the Lowest Achievable Emission Rate ("LAER").

Accordingly, in its response to public comments on the proposed rule, the Department should clarify this interpretation. One possible remedy would be to recast § 227-2.5(b)(2) as follows:

> *"(2) All emission sources that participate in the system averaging plan must be covered by a presumptive RACT emission limit that is set forth in section 227-2.4 of this Subpart, or be found by the Department, through the filing required in 227-2.4(e)(3), to be operating at the Lowest Achievable Emission Rate established by the Department."*

Again, the Company is pleased to have the opportunity to comment on this important rulemaking proposal. CECONY looks forward to the Department's response to its and other public comments and to working with the Department in developing a NOx RACT program that serves both the Department's goals and the Company's operating obligations as a regulated steam, electric and gas utility in New York State.

Sincerely,

Randolph Price

Randolph S. Price
Vice President
Environment, Health & Safety

Company Name: Con Edison
Case Description: Con Edison Gas & Steam Rate Cases
Case: 09-G-0795-09-S-0794

Response to DPS Interrogatories – Set DPS21
Date of Response: 02/17/2010
Responding Witness: Catuogno

Question No. :192
Subject: 74th Street Natural Gas Addition - Regarding John Catuogno's testimony on page 8, lines 8 to 12: "Accordingly, our PROMOD simulations have Boilers 114 and 115 at 59th Street Generating Station modeled to commence full gas firing starting November 1, 2011, and November 1, 2014 for all of the boilers at the 74th Street Generating Station." Why is November 1, 2014 used as the starting point for the PROMOD simulation if the 74th Street natural gas addition has an in-service date of December, 2013 as stated in Con Edison's response to DPS-55?

Response:
The November 1, 2014 was used as the starting point in PROMOD for the gas addition at the 74th Street Generating Station because this was the estimated in-service/operational date for this project at the time (around August 2009) the PROMOD runs were conducted for this Steam Filing.

Future PROMOD Runs will use November 1, 2013 as the in-service/operational dates for the gas addition at 74th Street.

Company Name: Con Edison
Case Description: Con Edison Gas & Steam Rate Cases
Case: 09-G-0795-09-S-0794

Response to DPS Interrogatories – Set DPS21
Date of Response: 02/17/2010
Responding Witness: Steam Ops Panel

Question No. :193
Subject: 59th & 74th Street Natural Gas Addition - What will be Con Edison's NOx emission rate (in lb/MMbtu as regulated by NOx RACT) for the following cases? 1. Do nothing approach where the system remains as it is today. 2. After December 2011, when 59th Street natural gas addition will be in-service. 3. After December 2013, when 59th and 74th Street natural gas addition will be in-service. 4. After May 2014, when 59th and 74th Street natural gas addition will be in-service and when the Hudson Avenue Replacement Project is complete and placed in-service.

Response:
Currently, Con Edison uses system-wide averaging, as defined in the existing regulations at 6 NYCRR §227-2.5(b), for calculating and reporting of NOx emission rates from its very large boilers (VLBs), its large boilers (LBs) and its simple cycle combustion turbines. System-wide heat input weighted average actual NOx emission rates in lb/MMBtu for the compliance period – either the 24-hour rolling average during the ozone season or the 30-day rolling average during the non-ozone season – are calculated from the sum of mass emissions (in pounds of NOx) divided by the sum of the heat inputs (in millions of Btus) for the averaged sources. The calculation utilizes source block hourly NOx emissions for the determination of mass emissions.

During the ozone season, the system-wide heat input weighted average actual NOx emission rates are determined on a 24-hour basis and include all of the VLBs, LBs, and SCCTs. During the non-ozone season, system-wide heat input weighted average actual NOx emission rates are calculated on a 30-day rolling average basis, excluding the peaking SCCTs that operate less than 500 hours during the non-ozone season (as authorized by current regulations at 6 NYCRR §227-2.4(e)(4)). The system-wide heat input weighted average allowable NOx emission rate for a compliance period is calculated in the same manner, except that the allowable NOx emission rate values are used in place of the actual NOx emission rates.

The current 6 NYCRR §227-2 rules authorize different emissions rates for each type of boiler, so that VLBs on gas and oil are authorized to emit 0.25 lb/MMBtu; LBs on gas and oil are authorized to emit 0.30 lb/MMBtu; and, peaking SCCTs burning gas and oil are authorized to emit 100 ppm NOx.

The Company calculates a system-wide average on a daily basis with a targeted goal of continuously staying below a system-wide average of 0.265 lb/MMBtu. This is a complex effort requiring Company personnel to manage multiple variables such as fuel, changing load, operational constraints, facility component outages, and cost. In light of these variables, a detailed response to sub-questions 2, 3 and 4 of this interrogatory cannot be developed. However, NOx emissions at each plant are expected to drop significantly if gas is used as the primary fuel at the 59th Street and 74th Street Generating Stations. The Company has not yet determined how these reduced NOx emissions could and would be used to satisfy the compliance options that might be contained in any final NOx RACT regulations.

Company Name: Con Edison
Case Description: Con Edison Gas & Steam Rate Cases
Case: 09-G-0795-09-S-0794

Response to DPS Interrogatories – Set DPS21
Date of Response: 02/17/2010
Responding Witness: Steam Ops Panel

Question No. :195
Subject: 59th & 74th Street Natural Gas Addition - According to the Company's response to DPS-3, there is an emission level of 0.17 lb/MMbtu NOx for natural gas and 0.29 lb/MMbtu NOx for #6 Fuel Oil. How will Con Edison be able to achieve the proposed NOx RACT rate of 0.15 lb/MMbtu with the use of natural gas and fuel oil? State which equipment and operational processes would be used along with the amount of expected reduction in lb/MMbtu NOx emission as a result of using each of these measures.

Response:
Con Edison is evaluating the various compliance options available under the proposed NOx RACT regulations to determine how to comply with the requirements of this program most economically. We would note that achieving the proposed NOx RACT rate of 0.15 lb/MMbtu is technically feasible using natural gas.

Con Edison

Hearing Exhibits

STATE OF NEW YORK
DEPT. OF PUBLIC SERVICE
DATE: 6/9/10
CASE NOS: 09-S-0794, 09-G-0795, and 09-S-0029
Ex. 312

Jones/Randt

Exhibit___ (JR-2)
(Unredacted)

West 59th Street Gas Addition Project

West 59th Street Natural Gas Addition Project Benefits

Rate Year	Annual Revenue Requrement Impact	Expected Annual Savings				Total expected Annual savings	Expected Customer Benefit
		O&M	Energy	Barge Charters	Emissions		
	(1)	(2)	(3)	(4)	(5)	(6)=(2)+(3)+(4)+(5)	(7)=(6)-(1)
RY2	**($4,800,000)**	**$70,000**	**$8,181,773**	**$483,500**	**$6,270**	**$8,741,543**	**$3,941,543**
RY3	**($5,900,000)**	**$70,000**	**$8,181,773**	**$483,500**	**$6,270**	**$8,741,543**	**$2,841,543**

Con Edison

Hearing Exhibits

STATE OF NEW YORK
DEPT. OF PUBLIC SERVICE
DATE: 6/9/10
CASE NOS: 09-S-0794, 09-G-0795, and 09-S-0029
Ex. 313

STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

Case 09-S-0794 - 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.

Case 09-G-0795 - Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Consolidated Edison Company of New York, Inc. for Gas Service.

CASE 09-S-0029 - Proceeding on Motion of the Commission to Consider Steam Resource Plan and East River Repowering Project Cost Allocation Study, and Steam Energy Efficiency Programs for Consolidated Edison Company of New York, Inc.

ATTENTION

This exhibit is among those prefiled in the captioned cases by active parties that executed two joint proposals that were filed on May 18, 2010. Those that executed the joint proposals subsequently stipulated that they would not cross-examine the witnesses of each other given that they were supporting at that time the Commission's adoption of the terms of the joint proposals. In this context, the fact that these parties did not cross-examine the witnesses of each other does not mean and cannot reasonably be understood to mean that the information in this exhibit is uncontroverted among the parties that executed the joint proposals.

BEFORE THE
STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

In the Matter of

CONSOLIDATED EDISON COMPANY OF NEW YORK, INC.

Case 09-S-0794

MARCH 2010

Prepared Testimony of Steam Research and Development Panel:

Nicola Jones
Utility Engineer 2
Office of Electric, Gas and Water

Joseph F. Klesin
Utility Supervisor
Office of Electric, Gas and Water

State of New York
Department of Public Service
90 Church Street, 4th Floor
New York, New York 10007

Q. Please state your names, titles, employer and business address.

A. Nicola Jones, Utility Engineer 2, and Joseph Klesin, Utility Supervisor. We are employed by the New York State Department of Public Service (Department) and our business address is 90 Church Street, New York, New York 10007.

Q. Ms. Jones have you already discussed your educational background, professional and testimonial experience, and responsibilities?

A. Yes, that information is included in Jones-Randt testimony submitted in this proceeding.

Q. Mr. Klesin have you already discussed your educational background, professional and testimonial experience, and responsibilities?

A. Yes, that information is included in Staff Steam Operations Panel testimony submitted in this proceeding.

Q. What is the purpose of the Panel's testimony?

A. To present our review of the Research and Development (R&D) portion of Con Edison's steam rate case filing as presented in the testimony of witness Edward Ecock.

Q. In your testimony, will you refer to, or otherwise rely upon, any information produced during the discovery phase of this proceeding?

A. Yes. We will refer to, and have relied upon, several Company responses to Staff Information Requests. They are attached as Exhibit___(SRDP-1)

Q. Did the Panel review all the projects and programs presented by the Company's witness, Edward Ecock?

A. Yes. We met with Edward Ecock and issued Information Requests regarding program and project descriptions, justifications and work schedules. We also reviewed the progress of on-going projects to determine its probability of success. Based on these reviews, we have concluded that each of the base programs are warranted and justified. In addition, we have requested and analyzed the Company's historic budgets and actual dollar amounts spent on each R&D project. That information was compared to the $2.492 million R&D operation and maintenance expenses that are being requested by the Company over the three-year rate period. This financial review generated concerns regarding the low level of actual R&D spending compared to R&D budgets approved and incorporated in rates.

Q. What is the basis for Staff's determination that the R&D projects are warranted and justified?

A. Con Edison's R&D projects aim to reduce operations and maintenance cost, maintain or improve reliability, reduce its negative impact on the environment and improve the safety of its steam system. The majority of these R&D projects are related to improving the reliability and safety of the steam system based on recommendations made by Staff in Case 07-S-0984 after the Steam Pipeline Rupture of July 18, 2007 at East 41 Street and Lexington Avenue in Manhattan. The new and on-going projects are feasible and, due to limited market potential for distributed steam equipment, there is a need for Con Edison to conduct much of its own R&D.

Q. What are the major projects included in the Company's rate year R&D program?

A. Of the 22 proposed R&D projects, Con Edison has five major projects with a forecasted funding level of $150,000 or higher over the three rate years. They are (Exhibit __(SRDP-1), DPS-35):

1. <u>EPRI Combustion Turbine, HRSG, and Steam & Water Chemistry Programs</u>. This program focuses on identifying advanced technologies for maintaining and possibly improving the reliability of combustion turbines, HRSGs and conventional steam generators. The Company proposes $115,000, $124,000 and $127,000 for the first (RY1), second (RY2), and third (RY3) rate years, respectively.
2. <u>Water Treatment Modeling</u>. This project focuses on developing a water treatment model that could be used to predict effects of various water treatment chemistries on the steam generating and distribution equipment. This model would assist operators with providing effective water treatment for equipments and to analyze effects of chemistry change on equipments. The Company proposes $50,000, $75,000 and $25,000 for RY1, RY2 and RY3, respectively.
3. <u>Development and Testing of a Predictive Water Hammer Model</u>. The Company plans to build upon the proof of concept and expand

the predictive water hammer model to include more variables and a larger part of the system. This model would help operators predict where potential water hammer conditions may occur, so that preventative action can be taken. The Company proposes $50,000, $75,000 and $175,000 for RY1, RY2 and RY3, respectively.

4. <u>Steam Condensate Detection and Monitoring in Steam Mains</u>. Con Edison will continue to work on the steam condensate detection breadboard and create a prototype for field testing. This system would be able to monitor and notify operators when condensation develops in steam mains. The Company proposes $30,000, $150,000 and $100,000 for RY1, RY2 and RY3, respectively.

5. <u>Demonstration of Remote Water Level Monitoring in Steam Manholes</u>. This project includes the advancement of the water level monitoring prototype into a commercially available product. This project would

improve upon the reliability of the existing float-type water level monitoring system used in the steam manholes. The Company forecasted $50,000, $50,000 and $100,000 for RY1, RY2 and RY3, respectively.

Q. What are your concerns regarding R&D historical spending levels?

A. In the rate year ending in 2008, of the Company's $723,000 budget, only about half or $354,000 was spent (Exhibit __(SRDP-1), DPS-37).

Q. Did Con Edison provide a reason for this level of spending?

A. Yes. In response to Staff Information Request, DPS-201, found in Exhibit __(SRDP-1), the Company's main reason for this level of spending was unforeseen project delays. For example, according to Con Edison, the Proof of Concept Demonstration of a Predictive Water Hammer Model needed to be deferred pending the outcome of a related study. This project is now scheduled to commence in March 2010. For the Demonstration of Ener-G-Rotor project, there was no spending in 2008 because a grant from NYSERDA was not secured by the vendor until mid 2009. The Ener-G-Rotor is now scheduled for field testing in June 2010.

Q. Are unforeseen project delays a common part of R&D?

A. Yes. Based on our past reviews of various R&D projects at the Department, unexpected delays are common and in some cases result in a company under-spending allocated funding.

Q. What is your recommendation for handling this budgeting concern?

A. We recommend that the Commission require a downward reconciliation on the Company's Steam R&D expenditures such that if, at the end of the rate year, Con Edison did not spend the projected amount, any unspent funds will be deferred for the benefit of steam ratepayers.

Q. Should the same mechanism apply if the Commission adopts Staff's proposed three year plan?

A. Yes. The same annual downward reconciliation should apply for each year of any multi-year plan that may ultimately be adopted.

Q. Why is this downward reconciliation beneficial to ratepayers and Con Edison?

A. Instituting a downward reconciliation limits the financial exposure to ratepayers. Having a downward reconciliation that goes into effect at the end of each rate year provides Con Edison the funding to proceed with these R&D projects without being limited by a specific adjustment level.

Q. Does this conclude your testimony at this time?

A. Yes.

Con Edison

Hearing Exhibits

STATE OF NEW YORK
DEPT. OF PUBLIC SERVICE
DATE: 6/9/09
CASE NOS: 09-S-0794, 09-G-0795, and 09-S-0029
Ex. 314

BEFORE THE
STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

In the Matter of

CONSOLIDATED EDISON COMPANY OF NEW YORK, INC.

Case 09-S-0794

MARCH 2010

Prepared Exhibit of Steam Research and Development Panel:

Nicola Jones
Utility Engineer 2
Office of Electric, Gas and Water

Joseph F. Klesin
Utility Supervisor
Office of Electric, Gas and Water

State of New York
Department of Public Service
90 Church Street, 4th Floor
New York, New York 10007

Exhibit___(SRDP-1)

List of Staff Information Requests

Staff Request	Exhibit page
35	1-4
36	5-7
37	8-36
201	37-51
202	52

Company Name: Con Edison
Case Description: Con Edison Gas & Steam Rate Cases
Case: 09-G-0795-09-S-0794

Response to DPS Interrogatories – Set DPS8
Date of Response: 01/07/2010
Responding Witness: Ecock

Question No. :35
Subject: Steam Research and Development - For all items listed under Steam Exhibit __(EE:1) for the forecasted three rate years (ending 9/30/11, 9/30/12 and 9/30/13), provide the following: a) a description of each program; b) an explanation as to why the program is needed by the Company; c) a tentative work schedule; and d) a description of the progress made under each existing program to date.

Response:

a) See Table 1 for program description.
b) See Table 1 for why program is needed.
c) See Table 2 for tentative work schedule.
d) See Table 2 for description of progress to date.

Table 1

Title	Project Description and Project Intent
EPRI GOBIG COST COMPETITIVENESS	This EPRI program targets gas and oil utilities that seek technologies to reduce NOx. This program is needed to help us identify advanced technologies to comply with NOx regulations.
EPRI COMBUSTION TURBINE, HRSG, AND STEAM & WATER CHEMISTRY PROGRAMS	This EPRI program conducts R&D to improve reliability of combustion turbines, HRSGs, and conventional steam generators. This program is needed to help identify advanced technologies for maintaining and possibly improving the reliability of our steam generating equipment.
PROOF OF CONCEPT DEMONSTRATION OF A PREDICTIVE WATER HAMMER MODEL	The intent of this project is to develop a conceptual engineering model to predict water hammer and conduct a small-scale demonstration. This project is needed to allow our operators to better predict potential water hammer conditions as they occur.
THERMOELECTRIC MODULES FOR STEAM MANHOLE INSTRUMENTATION - COMMERCIALIZATION	The intent of this project is to advance the prototype of these thermoelectric modules developed in Phase I into a commercially available product. This project is needed because these modules will be used to power the monitoring equipment in the manholes that would normally require elecric cable or batteries to be installed.
STEAM EXPO	The intent of this project is to conduct a brainstorming session with the Steam Business Unit, which is facilitated by an outside consultant. This project is needed to stay abreast of the problems in steam operations and to solicit ideas for improvements. Some of these ideas become R&D projects.
DEMO OF HIGH STRENGTH COATINGS FOR MAIN VALVES	The intent of this project is to demonstrate coatings for main steam valves in manholes that could withstand the high temperature and corrosive atmosphere. This project is need to reduce maintenance of the steam main valves and improve their reliability.
DEVELOPMENT AND TESTING OF A MANHOLE COVER MONITORING SYSTEM	The intent of this project is to perform a load test on new composite manhole covers with integrated telemetry systems. This project is needed to allow transmittal of data collected from new monitoring systems directly through the manhole cover itself thereby improving the capability to monitor the steam system better and respond quicker.
EXPLORATION AND DEVELOPMENT OF ADDITIONAL PIPE INSPECTION TECHNOLOGIES	The intent of this project is to find available, or develop new technologies that could inspect steam mains and provide a condition assessment. This project is needed to sustain the reliability of the steam system and help plan future maintenance.
EXPLORATION AND DEVELOPMENT OF MORE ACCURATE LEAK DETECTION TECHNOLOGIES	The intent of this project is to find available, or develop new technologies that could pinpoint steam leaks. This project is needed to help reduce erroneous excavations caused by current leak pinpointing methods that are not always accurate.
R&D OF TESTING PROTOCOLS FOR STEAM MAIN REPAIR LINERS	The intent of this project is to research liners that could be used to seal leaky flanges or repair steam mains using trenchless technologies. This project is needed because it is becoming more difficult to perform this work in Manhattan using the traditional excavation technique.
THERMAL POWERED STEAM VORTEX METERS PHASE III - COMMERCIALIZATION	The intent of this project is to advance the prototype of these thermal powered vortex meters developed in Phases I and II into a commercially available product. This project is needed to reduce the costs of installing electric cables to the new vortex meters.
DEMONSTRATION OF A TRANSIENT PRESSURE MONITOR	The intent of this project is to find available, or develop new devices that could monitor the steam system for pressure transients, or displacement, as a sign that pre-waterhammer conditions are developing. This project is needed to provide information to the operator that condensate is building up in the steam mains and corrective action is to be taken.
WATER TREATMENT MODELING	The intent of this project is to develop a water treatment model that could be used to predict effects of various water treatment chemistries on the steam generating and distribution equipment. This project is needed to assist the operators with providing effective water treatment for our equipment and to analyze effects of chemistry change on the equipment.
STEAM CONDENSATE FLOW BEHAVIOR TESTING IN STEAM MAIN MOCK-UP	The intent of this project is to create a physical flow model that could be used to determine the behavior of steam condensate in various steam main geometries. This project is needed to help understand the flow characteristics and flow direction of the condensate for input into the future engineering model for waterhammer prediction.
DEMONSTRATION OF IN-SITU CORROSION MONITORS	The intent of this project is to test the capabilities of an advanced type of corrosion monitoring device and ascertain the corrosion drivers. This project is needed to provide the operators with information to use in treating boiler water.
STEAM REMOTE MANHOLE TRAP MONITORING	The intent of this project is to enhance the data transmittal speed and mode of transmission for the monitoring information on the steam traps in the manholes. This project is needed to improve upon the steam trap data collection and transmission so that the operator can respond quicker to an off-design condition.
DEVELOPMENT AND TESTING OF A PREDICTIVE WATER HAMMER MODEL	The intent of this project is to build upon the proof of concept explored in Phase I and expand the engineering model for predicting water hammer to include more variables and a larger part of the system. This project is needed to help the operators predict where potential water hammer conditions may occur, so that they can take preventative action.
STEAM CONDENSATE DETECTION AND MONITORING IN STEAM MAINS - PHASE II	The intent of this project is to build upon the conceptual development work in Phase I and build a steam condensate detection breadboard for lab testing purposes prior to development of a prototype. This project is needed to monitor the steam mains for condensate development and to alarm the operator to take corrective action.
STEAM CONDENSATE DETECTION AND MONITORING IN STEAM MAINS - PHASE III	The intent of this project is to modify the breadboard built in Phase II and create a prototype for field testing. This project is needed to monitor the steam mains for condensate development and to alarm the operator so that he can take corrective action.
DEMONSTRATION OF REMOTE WATER LEVEL MONITORING IN STEAM MANHOLES (Phase II - Commercialization)	The intent of this project is to advance the prototype of the water level monitoring system developed in Phase I into a commercially available product. This project is needed to improve upon the reliability of the existing float-type water level monitoring system used in the steam manholes that will be subjected to frequent maintenace.
DEMONSTRATION OF ENER-G-ROTOR (Phase II - 50kW)	The intent of this project is to demonstrate a 50kW waste heat recovery device that will be used to convert waste steam condensate into electric power. This will be used as a showcase for our steam customers so that they may see additional benefits of using steam.
CO2 REDUCTION STUDIES	The intent of this project is to review and analyze CO2 reduction technologies that may be appropriate for our steam generation units. This project is needed to help us identify advanced technologies to comply with CO2 regulations.

Table 2

Title	Tentative Work Schedule	Description of Progress to Date
EPRI GOBIG COST COMPETITIVENESS	Ongoing. EPRI continues to seek out research opportunities for this small group of oil and gas users.	Still looking for research opportunities.
EPRI COMBUSTION TURBINE, HRSG, AND STEAM & WATER CHEMISTRY PROGRAMS	Ongoing. EPRI conducts two meetings per year to solicit research needs and develop priorities.	Several useful EPRI reports have come out of these programs since we joined.
PROOF OF CONCEPT DEMONSTRATION OF A PREDICTIVE WATER HAMMER MODEL	RFP to several vendors will be released in 1st quarter of 2010. Development will commence in mid 2010 and testing will be done in last quarter of 2010.	Draft RFP developed and list of vendors created.
THERMOELECTRIC MODULES FOR STEAM MANHOLE INSTRUMENTATION - COMMERCIALIZATION	First half of 2010 will be spent on contract arrangements with commercializer. Design and manufacuring of commercial units to begin in second half of 2010 and continue into 2011. Field testing of commercial units will commence in 2011.	Developer (Cooper Union) has been in contact with a commercializer.
STEAM EXPO	Workshop to be conducted in April, 2012. Planning activities will begin in April, 2011.	Planning activities will begin in April, 2011.
DEMO OF HIGH STRENGTH COATINGS FOR MAIN VALVES	A determination whether scope will include coatings or materials will be made in early 2010. Field demonstrations will commence in second half of 2010 and continue using different materials or coatings through 2013.	Purchased small double disc gate valves with upgraded materials. Field testing will commence in 1st quarter 2010.
DEVELOPMENT AND TESTING OF A MANHOLE COVER MONITORING SYSTEM	Load testing of cover will begin in 2nd quarter of 2010. Field testing with telemetrics will follow into late 2012.	Purchase order has been awarded. Prototype has been developed and is being tested in vendor's lab.
EXPLORATION AND DEVELOPMENT OF ADDITIONAL PIPE INSPECTION TECHNOLOGIES	An RFP will be issued in second quarter of 2010. We hope to have a device for testing in early 2011.	One inspection robot was identified but it requires shut down of steam main and resides in Europe. Alternatives are being sought.
EXPLORATION AND DEVELOPMENT OF MORE ACCURATE LEAK DETECTION TECHNOLOGIES	An RFP will be issued in second quarter of 2010. We hope to have a device for testing in early 2011.	A digital leak detector developed for the gas industry has demonstrated some success, but we have been unable to get a vendor to build a commercial unit and we have been using the prototype which is in need of parts. An alternative solution is is needed.
R&D OF TESTING PROTOCOLS FOR STEAM MAIN REPAIR LINERS	Finalize material selection in 4th quarter 2010, and begin lab tests in 2011.	A consultant was hired to research liners that would be suitable.
THERMAL POWERED STEAM VORTEX METERS PHASE III - COMMERCIALIZATION	First half of 2010 will be spent on contract arrangements with commercializer. Design and manufacuring of commercial units to begin in second half of 2010 and continue into 2011. Field testing of commercial units will commence in 2011.	Developer (Cooper Union) has been in contact with a commercializer.
DEMONSTRATION OF A TRANSIENT PRESSURE MONITOR	Research alternative sensing devices and select one for testing in 3rd quarter of 2010. Field testing will begin in late 2010 and continue into 2011.	Field tested one type of pressure sensing device in a steam manhole. Results were inconclusive.
WATER TREATMENT MODELING	An RFP will be issued in second quarter of 2010. Work should begin in 4th quarter of 2010 and continue into 2011. Model testing will continue thru end of 2012.	Vendor investigations have begun.
STEAM CONDENSATE FLOW BEHAVIOR TESTING IN STEAM MAIN MOCK-UP	A scope of work to test additional pipe geometries will be developed after the waterhammer model project gets underway in late 2010. The plexiglass model will be modified and testing will be done in 2011.	A plexiglass model has been constructed and initial testing has been completed.
DEMONSTRATION OF IN-SITU CORROSION MONITORS	Purchase of a second corrosion monitor will be done in 1st quarter of 2010. Installation of both monitors will be done in second quarter 2010, and field testing will follow into 2011 and early 2012.	One of two corrosion monitors has been purchased.
STEAM REMOTE MANHOLE TRAP MONITORING	Installation of additional SmartSynch RTUs will be completed in 1st quarter 2010. Field testing will continue through 2011.	Thermocouple and water level data are being monitored using hard-wired, second generation telemetry equipment. Faster data processing and transmission units (SmartSynch RTUs) are being purchased and installed.
DEVELOPMENT AND TESTING OF A PREDICTIVE WATER HAMMER MODEL	Scope of work from Phase I will be expanded in early 2011 after proof of concept demonstration is complete. The project will increase in scope and magnitude in phases during 2011-2013 to demonstrate validity of additional input variables and more complex system geometries.	Not started. Waiting on completion of Phase I.
STEAM CONDENSATE DETECTION AND MONITORING IN STEAM MAINS - PHASE II	Phase II will begin in 3rd quarter of 2010 and complete in 2nd quarter of 2011.	A conceptual study (Phase I) was awarded to NASA JPL in July, 2009 and will complete in June, 2010.
STEAM CONDENSATE DETECTION AND MONITORING IN STEAM MAINS - PHASE III	Phase III will begin in 3rd quarter of 2011 and complete in 2nd quarter of 2012. Testing of field ready prototypes will begin in 3rd quarter of 2012 and continue into 2013.	A conceptual study (Phase I) was awarded to NASA JPL in July, 2009 and will complete in June, 2010.
DEMONSTRATION OF REMOTE WATER LEVEL MONITORING IN STEAM MANHOLES (Phase II - Commercialization)	Phase I of study will be completed in 1st quarter of 2010. A prototype will be field tested into 2011. Commercialization efforts will begin after field testing is evaluated and deemed successful.	Purchase order was awarded to LC Pegasus in March, 2009.
DEMONSTRATION OF ENER-G-ROTOR (Phase II - 50kW)	The 50 kW prototype will be available in June 2010 from the vendor. If we are selected to be the demonstrator, then installation will be done in latter part of 2010 and testing will be done in early 2011.	A 5kW Ener-G-Rotor has been installed at Hudson Avenue Station and is scheduled for testing in early 2010.
CO2 REDUCTION STUDIES	An RFP will be issued in 3rd quarter of 2010. Depending on outcome of proposals, work will begin on one of the solicited proposals in early 2011.	Recently, we have reviewed 2 technologies that claim to aid in CO2 reduction. We have written support letters to NYSERDA for funding studies on these.

Company Name: Con Edison
Case Description: Con Edison Gas & Steam Rate Cases
Case: 09-G-0795-09-S-0794

Response to DPS Interrogatories – Set DPS8
Date of Response: 01/07/2010
Responding Witness: Ecock

Question No. :36
Subject: Steam Research and Development - For all items listed under Steam Exhibit __(EE;1) for the three rate years (ending 9/30/11, 9/30/12 and 9/30/13), provide the following: a) a cost/benefit analysis; and b) a description of what information was used to justify the requested funding for each program that does not have a correlating cost/benefit analysis.

Response:
Only six projects listed for the three rate years under Steam Exhibit EE-1 have reached the funding phase at this point, and consequently no cost benefit analyses have been performed for the remaining projects. See response to NYC 162(b). The six projects on the list that have been funded are:

a. EPRI GOBIG Competitiveness – No cost benefit analysis was performed as this is an EPRI collaborative program where our funds are leveraged with funds from other member utilities. This particular program is intended to develop and demonstrate NOx reduction technologies and its main benefit is to assist utilities in meeting regulatory standards on NOx emissions.
b. EPRI Combustion Turbine, HRSG, and Steam & Water Chemistry - No cost benefit analysis was performed as this is an EPRI collaborative program where our funds are leveraged with funds from other member utilities. This particular program is intended to research and develop technologies to improve the reliability of combustion turbines, conventional steam generators, and HRSGs and its main benefit is to increase reliability of these types of equipment.
c. R&D of Testing Protocols for Steam Main Repair Liners – No cost benefit analysis was performed. Per our R&D procedures, any project with a funding level less than $50,000 does not require a cost benefit analysis. In any event, the main benefit of this project is to improve the reliability of the steam system, and to reduce the cost of excavations.
d. Steam Condensate Flow Behavior Testing in Steam Main Mock Up - No cost benefit analysis was performed because the benefit of this project is public safety and this is not quantifiable. The goal of this project is to gain a better understanding of condensate flow behavior so that this information can be used to help predict potential water hammer conditions.

e. Demonstration of In-Situ Corrosion Monitors - No cost benefit analysis was performed. Per our R&D procedures, any project with a funding level less than $50,000 does not require a cost benefit analysis. In any event, the main benefit of this project is to improve the reliability of the steam system by monitoring corrosion in the steam mains and making repairs before leaks occur.
f. Steam Remote Manhole Trap Monitoring - No cost benefit analysis was performed because the benefit of this project is public safety and is not quantifiable. The goal of this project is to monitor the performance of steam traps in the manholes so that the operator can take action before a potential water hammer condition arises.

Company Name: Con Edison
Case Description: Con Edison Gas & Steam Rate Cases
Case: 09-G-0795-09-S-0794

Response to DPS Interrogatories – Set DPS8
Date of Response: 01/14/2010
Responding Witness: Ecock

Question No. :37
Subject: Steam Research and Development - For all items listed under Steam Exhibit __(EE;1) for the three rate years (ending 9/30/11, 9/30/12 and 9/30/13), provide the following in Excel: a) total funding allocated to each program as of the end of the 2008 rate year; b) total remaining funding estimated for this program as of the beginning of the 2009 rate year; c) a unit cost breakdown of how the requested funding listed was determined; d) justification and any documentation used to determine the requested funding level (beyond that provided in response to DPS-036); e) the budgeted funding and the spending to date for each of the past five rate years (including 2008 rate year); and f) state if the program has already been approved by Con Edison as an R&D program.

Response:
See Table 3 attached. Response per clarifications received from Staff.

Table 3

Title	Historical Year Ending 6/30/2009 ($ x 1000)	Rate Year Ending 9/30/2011	Variance	Rate Year Ending 9/30/2012	Variance	Rate Year Ending 9/30/2013	Variance	Response to Q37 (a) ($ x 1000)	Response to Q37 (b) ($ x 1000)	Response to Q37 (c)	Response to Q37 (d)	Response to Q37(e) ($ x 1000) RYE 2004		RYE 2005		RYE 2006		RYE 2007		RYE 2008		Response to Q37 (f)
												Budget	Spent	Budget	Spent	Budget	Spent	Budget	Spent	Budget	Spent	
BASE PROGRAM																						
ADMINISTRATION																						
SALARIES AND WAGES	$ 118	$ 119	$ 1	$ 124	$ 5	$ 129	$ 5	$ 109	$ 607	Note 1	Note 1	Note 5	Note 5	$ 99	$88	$ 94	$121	$116	$111	$114	$113	No
OTHER EXPENSES	16	15	(1)	15	-	16	1	9	67	Note 1	Note 1	Note 5	Note 5	10	11	10	14	11	12	17	16	No
PATENT SEARCHES IN CONNECTION WITH COMPANY R&D TECHNOLOGY APPLICATIONS	10	11	1	11	-	11	-	14	57	Note 1	Note 1	Note 5	Note 5	1	1	1	1	1	2	7	5	Yes
DEVELOPMENT OF R&D DEPARTMENT WEBSITE	-	5	5	-	(5)	-	-	$ -	5	Estimate	Note 4	-	-	-	-	-	-	5	5	-	-	Yes
INSTITUTIONAL																						
EPRI GOBIG COST COMPETITIVENESS	-	10	10	10	-	10	-	-	30	Estimate	Note 4	Note 5	Note 5	50	-	10	-	10	-	10	-	Yes
EPRI COMBUSTION TURBINE, HRSG, AND STEAM & WATER CHEMISTRY PROGRAMS	107	115	8	124	9	127	3	101	576	EPRI Quote	EPRI Quote	-	-	-	-	-	-	125	69	104	102	Yes
INTERNAL PROGRAM																						
PROOF OF CONCEPT DEMONSTRATION OF A PREDICTIVE WATER HAMMER MODEL	-	25	25	-	(25)	-	-	-	25	Note 2	Note 3	-	-	-	-	-	-	-	-	-	-	No
THERMOELECTRIC MODULES FOR STEAM MANHOLE INSTRUMENTATION - COMMERCIALIZATION	-	60	60	25	(35)	-	(25)	-	85	Note 2	Note 3	-	-	-	-	-	-	-	-	-	-	No
STEAM EXPO	-	-	-	25	25	-	(25)	-	25	Note 2	Note 3	-	-	-	-	-	-	-	-	-	-	No
DEMO OF HIGH STRENGTH COATINGS FOR MAIN VALVES	-	10	10	10	-	10	-	-	30	Note 2	Note 3	-	-	-	-	-	-	-	-	-	-	No
DEVELOPMENT AND TESTING OF A MANHOLE COVER MONITORING SYSTEM	-	10	10	10	-	10	-	-	20	Vendor Quote	RADPAR	-	-	-	-	-	-	-	-	-	-	Yes
EXPLORATION AND DEVELOPMENT OF ADDITIONAL PIPE INSPECTION TECHNOLOGIES	-	10	10	10	-	10	-	-	30	Note 2	Note 3	-	-	-	-	-	-	-	-	-	-	No
EXPLORATION AND DEVELOPMENT OF MORE	-	10	10	10	-	10	-	-	30	Note 2	Note 3	-	-	-	-	-	-	-	-	-	-	No
R&D OF TESTING PROTOCOLS FOR STEAM MAIN REPAIR LINERS	-	15	15	-	(15)	-		-	80	Note 2	RADPAR	-	-	-	-	-	-	-	15	-	-	Yes
THERMAL POWERED STEAM VORTEX METERS PHASE COMMERCIALIZATION	-	50	50	25	(25)	-	(25)		75	Note 2	Note 3	-	-	-	-	-	-	-	-	-	-	No
DEMONSTRATION OF A TRANSIENT PRESSURE MONITOR	-	20	20	-	(20)	-	-	-	20	Note 2	Note 3	-	-	-	-	-	-	-	-	-	-	No
WATER TREATMENT MODELING	-	50	50	75	25	25	(50)	-	150	Note 2	Note 3	-	-	-	-	-	-	-	-	-	-	No
STEAM CONDENSATE FLOW BEHAVIOR TESTING IN STEAM MAIN MOCK-UP	-	25	25	-	(25)	-	-	92	117	Note 2	Note 3	-	-	-	-	-	-	-	-	-	-	Yes
DEMONSTRATION OF IN-SITU CORROSION MONITORS	-	15	15	15	-	-	(15)	-	35	Vendor Quotes and estimated labor	RADPAR	-	-	-	-	-	-	-	-	-	17	Yes
STEAM REMOTE MANHOLE TRAP MONITORING	12	20	8	25	5	-	(25)	30	87	Vendor Quotes and estimated labor	RADPAR	-	-	-	-	-	-	-	-	116	129	Yes
DEVELOPMENT AND TESTING OF A PREDICTIVE WATER HAMMER MODEL	-	50	50	75	25	175	100	-	300	Note 2	Note 3	-	-	-	-	-	-	-	-	-	-	No
STEAM CONDENSATE DETECTION AND MONITORING IN STEAM MAINS - PHASE II	-	20	20	-	(20)	-	-	-	20	Note 2	Note 3	-	-	-	-	-	-	-	-	-	-	No
STEAM CONDENSATE DETECTION AND MONITORING IN STEAM MAINS - PHASE III	-	30	30	150	120	100	(50)	-	280	Note 2	Note 3	-	-	-	-	-	-	-	-	-	-	No
DEMONSTRATION OF REMOTE WATER LEVEL MONITORING IN STEAM MANHOLES (Phase II - Commercialization)	-	50	50	50	-	100	50	-	200	Note 2	Note 3	-	-	-	-	-	-	-	-	-	-	No
DEMONSTRATION OF ENER-G-ROTOR (Phase II - 50kW)	-	25	25	-	(25)	-	-	-	25	Note 2	Note 3	-	-	-	-	-	-	-	-	-	-	No
CO2 REDUCTION STUDIES	-	25	25	50	25	125	75	-	200	Note 2	Note 3	-	-	-	-	-	-	-	-	-	-	No

General Note for Q37(e): Budget figures are calendar dollars, not rate year dollars.
Note 1: Estimates are based on historical expenses.
Note 2: Estimates are based on typical research study costs using manpower rates and schedule durations.
Note 3: Funding requests have not been initiated yet. No documentation has been prepared.
Note 4: These are estimates with no documentation.
Note 5: Accounting system goes back to 1/1/04. Only partial data for RYE 2004 is available.

Table 3

Title	Response to Q37 (a)	Response to Q37 (b)	Response to Q37 (c)	Response to Q37 (d)	Response to Q37 (e) ($ x 1000) See General Note for Q37(e)										Response to Q37 (f)
	($ x 1000)	($ x 1000)			RYE 2004		RYE 2005		RYE 2006		RYE 2007		RYE 2008		
	See Note 1	See Note 2			Budget	Spent	Budget	Spent	Budget	Spent	Budget	Spent	Budget	Spent	
BASE PROGRAM															
ADMINISTRATION															
SALARIES AND WAGES	$ 601	$ 130	Note 3	Note 5	$ 99	$ 88	$ 94	$ 121	$ 116	$ 111	$ 114	$ 113	$ 138	$ 118	No
OTHER EXPENSES	70	10	Note 3	Note 5	10	11	10	14	11	12	17	16	14	12	No
PATENT SEARCHES IN CONNECTION WITH COMPANY R&D TECHNOLOGY APPLICATIONS	20	11	Note 3	Note 5	1	1	1	1	1	2	7	5	11	12	Yes
DEVELOPMENT OF R&D DEPARTMENT WEBSITE	5	-	Note 4	Note 7	-	-	-	-	5	5	-	-	-	-	Yes
INSTITUTIONAL															
EPRI GOBIG COST COMPETITIVENESS	25	10	Note 4	Note 7	50	-	10	-	10	-	10	-	10	-	Yes
EPRI COMBUSTION TURBINE, HRSG, AND STEAM & WATER CHEMISTRY PROGRAMS	410	110	EPRI Quote	EPRI Quote	-	-	-	-	125	69	104	102	120	108	Yes
INTERNAL PROGRAM															
PROOF OF CONCEPT DEMONSTRATION OF A PREDICTIVE WATER HAMMER MODEL	-	100	Note 4	Note 6	-	-	-	-	-	-	-	-	40	-	No
THERMOELECTRIC MODULES FOR STEAM MANHOLE INSTRUMENTATION - COMMERCIALIZATION	-	-	Note 4	Note 6	-	-	-	-	-	-	-	-	-	-	No
STEAM EXPO	-	-	Vendor Quote	Note 5	-	-	-	-	-	-	-	-	-	-	No
DEMO OF HIGH STRENGTH COATINGS FOR MAIN VALVES	-	-	Note 4	Note 6	-	-	-	-	-	-	-	-	-	-	No
DEVELOPMENT AND TESTING OF A MANHOLE COVER MONITORING SYSTEM	-	20	Vendor Quote	RADPAR (attached)	-	-	-	-	-	-	-	-	-	-	Yes
EXPLORATION AND DEVELOPMENT OF ADDITIONAL PIPE INSPECTION TECHNOLOGIES	-	-	Note 4	Note 6	-	-	-	-	-	-	-	-	25	-	No
EXPLORATION AND DEVELOPMENT OF MORE	-	-	Note 4	Note 6	-	-	-	-	-	-	-	-	-	-	No
R&D OF TESTING PROTOCOLS FOR STEAM MAIN REPAIR LINERS	15	80	Note 4	RADPAR (attached)	-	-	-	-	-	15	-	-	80	-	Yes
THERMAL POWERED STEAM VORTEX METERS PHASE - COMMERCIALIZATION	-	-	Note 4	Note 6	-	-	-	-	-	-	-	-	-	-	No
DEMONSTRATION OF A TRANSIENT PRESSURE MONITOR	-	-	Note 4	Note 6	-	-	-	-	-	-	-	-	10	-	No
WATER TREATMENT MODELING	-	125	Note 4	Note 6	-	-	-	-	-	-	-	-	50	-	No
STEAM CONDENSATE FLOW BEHAVIOR TESTING IN STEAM MAIN MOCK-UP	92	-	Vendor Quote and estimated labor	RADPAR (attached)	-	-	-	-	-	-	-	-	-	92	Yes
DEMONSTRATION OF IN-SITU CORROSION MONITORS	17	35	Vendor Quote and estimated labor	RADPAR (attached)	-	-	-	-	-	-	-	17	-	-	Yes
STEAM REMOTE MANHOLE TRAP MONITORING	142	100	Vendor Quote and estimated labor	RADPAR (attached)	-	-	-	-	-	-	116	129	125	12	Yes
DEVELOPMENT AND TESTING OF A PREDICTIVE WATER HAMMER MODEL	-	-	Note 4	Note 6	-	-	-	-	-	-	-	-	-	-	No
STEAM CONDENSATE DETECTION AND MONITORING IN STEAM MAINS - PHASE II	-	200	Note 4	Note 6	-	-	-	-	-	-	-	-	-	-	No
STEAM CONDENSATE DETECTION AND MONITORING IN STEAM MAINS - PHASE III	-	-	Note 4	Note 6	-	-	-	-	-	-	-	-	-	-	No
DEMONSTRATION OF REMOTE WATER LEVEL MONITORING IN STEAM MANHOLES (Phase II - Commercialization)	-	-	Note 4	Note 6	-	-	-	-	-	-	-	-	-	-	No
DEMONSTRATION OF ENER-G-ROTOR (Phase II - 50kW)	-	-	Note 4	Note 6	-	-	-	-	-	-	-	-	100	-	No
CO2 REDUCTION STUDIES	-	-	Note 4	Note 6	-	-	-	-	-	-	-	-	-	-	No

Note 1: Expenditures are from 1/1/04 to 9/30/09.
Note 2: Budget figures are 2010 calendar dollars, not 2009 rate year dollars.
Note 3: These administrative costs are proportionally shared based on commodity. For steam, the costs represent 5.65% of total R&D budget for this item.
Note 4: Estimates are based on $1000/man-day.
Note 5: Historical expenditures +/- adjustments are used to determine requested funding levels.
Note 6: Funding requests have not been initiated yet. No documentation has been prepared.
Note 7: These are estimates with no documentation.
General Note for Q37(e): Budgets are developed for upcoming calendar year, so "Budget" dollars are for calendar year (i.e. for RYE 2004, dollars are 2005 calendar year dollars 1/1/05 -12/31/05). "Spent" dollars are for rate year (i.e. for RYE 2004, dollars are for period 10/1/04 to 9/20/05).

Date: 07/22/09

CSN:	92055
CO Account:	3825
HO Account:	H0409
PSC:	761
FERC:	
Project Leader:	NG W.
Start Date:	07/21/09
End Date:	12/09
RateCase:	0.0.1

CC: John Amanna
Aromando J.
NG W.

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RESEARCH AND DEVELOPMENT PROJECT APPROPRIATION REQUEST

PROJECT TITLE	**SMALL-SCALE TESTING FOR THE BEHAVIORAL STUDY OF STEAM CONDENSATE AND STEAM TRAP OPERATION**	**INCREASED FUNDING REQUEST**	
		COST SEG. #	92055

SPONSORING ORGANIZATIONS		*Steam Distribution Engineering*		
PROJECT LEADER(S)	NAME	*Wilket (Jack) Ng*	LOCATION	*4 Irving Place, Rm 1328*
	TITLE	*Engineer*	PROJECT LEADER MANHOURS	
STEERING COMMITTEE	CHAIRMAN		MEMBERS	
PROJECT DURATION	Start Date	*July, 2009*	Completion Date	*December, 2009*
COSPONSOR(S)				
CONTRACTOR(S)	*Lucius Pitkin, Inc.*			

FUNDING		
PRIOR APPROPRIATION		
THIS APPROPRIATION	COMPANY LABOR	
	OTHER COSTS	*$105,000*
	TOTAL	*$105,000*
CON EDISON TOTAL		*$105,000*
COSPONSOR(S)		
PROJECT TOTAL		*$105,000*

EXPENDITURE PROJECTION		
PRIOR YEARS		
CURRENT YEAR	2009	*$105,000*
	2010	*$0*
PROJECT TOTAL		***$105,000***

AGREEMENT

For Projects less than $150,000*: As the sponsoring department, we agree to work with R&D to achieve a successful outcome to this research effort and to implement the results if they meet the project objectives and Corporate objectives. In addition, we agree to provide cost sharing, in the form of staff support, field testing, and unit installations. We also agree to review the need for this research periodically and inform R&D in a timely manner of any changes that are likely to affect the ultimate usefulness of the project results.*

For projects with costs estimated at $150,000 or more: *As the sponsoring department we agree to provide cost sharing in the form of staff support and/or other (O&M and/or Capital) funds. For these projects, a draft Implementation Plan for the products of this research and development - including preliminary schedules and budgets needs to be prepared and submitted with the RADPAR.*

For projects that successfully deliver a product or process, the sponsoring department shall update, finalize and undertake an Implementation Plan. The finalized plan shall include a schedule detailing the phases necessary to get the product incorporated into the company's operating practices. The finalized Implementation Plan may consider such factors as budgetary constraints (O&M and Capital), availability of human resources and any other factors that could affect the implementation costs and/or schedule. The finalized Implementation Plan needs to be approved by the sponsoring department at the Department Manager level or above, in accordance with Corporate Policy Statement 000-1and a copy submitted to R&D along with the project closing notice.

APPROVALS

SPONSORING ORGANIZATION - CENTRAL ENGINEERING

PROJECT MANAGER	See attached email *Wilket (Jack) Ng*	***DATE***
CHIEF ENGINEER	*Victor Mullen*	***DATE***

ENTERPRISE SHARED SERVICES - R&D

R & D MANAGER	Josephine G Aromando *Josephine G. Aromando*	7/22/09 ***DATE***
DIRECTOR	FMCoppersmith *Frederick M. Coppersmith*	7/21/09 ***DATE***

CON EDISON TOTAL APPROPRIATION REQUEST ***$105,000***

PROJECT TITLE

SMALL-SCALE TESTING FOR THE BEHAVIORAL STUDY OF STEAM CONDENSATE AND STEAM TRAP OPERATION

TECHNICAL PROBLEM

The steam distribution system consists of approximately 110 miles of piping that feed an estimated 1,800 customers in New York City. The system has critical components such as steam traps whose functions are important to the safe and efficient delivery of steam to these customers. As steam travels throughout the system, it begins to lose its energy as its heat transfers along the pipes, causing its own temperature to drop and for condensate to form. Condensate forms in areas where the piping is at low elevations but can also form higher than normal amounts during rain events, especially when rainwater enters steam manholes containing distribution components and associated piping. Steam traps located in those low points eliminate the condensate so that the potential for water hammer does not occur. While Steam Distribution has important operating procedures that prevent water hammer from occurring, there still needs to be a thorough understanding of the physics that take place when steam flows at certain temperatures and pressures. This knowledge will enable Engineering and Operations to make better business and operating decisions in designing and enhancing the steam system.

CORPORATE GOAL(S) SUPPORTED BY THIS PROJECT

Improve the quality of our normal operating practices and our readiness to deal with emergencies. Maintain the reliability of our generation, transmission, and our distribution systems and improve their integrity and efficiency.

PROJECT PLAN EXECUTIVE SUMMARY AND IMPLEMENTATION PLAN

This research effort, co-funded by both R&D and Engineering, will examine the behavior of condensate at different steam flows. R&D will fund the construction of the test apparatus and equipment; Engineering will fund the testing. A small-scale, 6" plexiglass piping with a slightly-sloped configuration will be built in the labs at Lucius Pitkin, Inc. (LPI). Both air and water at various points of entry along the piping are injected into the system during each test run. Laser sensors are installed at certain test point locations to tabulate the velocity of the water flow and of the air pressure with Labview software. Test runs will also be videotaped with specific attention to the direction and velocity of water flow as air pressure and water volume vary, particularly at fishmouth entrances into steam trap stations and at points along the main where service take-offs are located. LPI will work closely with Engineering to develop the test protocols and execute the procedures. The goal is to use the resulting data for later research using a large-scale version of the testing apparatus to be constructed on the premises of Hudson Avenue Station and conduct similar test scenarios using steam media.

JUSTIFICATION FOR CLASSIFICATION AS R&D

At this time, there is no documented evidence to show how condensate flow and direction as well as trap operation behaves at various steam pressures in the Con Edison steam system, particularly at fishmouth locations and at service take-offs.

ALTERNATIVES AND STEPS TAKEN TO ENSURE PROJECT DOES NOT DUPLICATE OTHER R&D

Although there have been other similar test set-ups built at other labs with air and water injection capabilities, those labs used steel pipes. Their objectives focused on studying re-designs of large capacity steam traps and their ability to handle excessive amounts of condensate at high velocity. Their studies did not examine the physics of flow behavior at tees or fishmouths.

EXPECTED BENEFITS AND TECHNOLOGY TRANSFER PLAN

A thorough understanding of how condensate behaves is critical to the way Engineering designs and enhances the steam system. This technical knowledge has the potential to lead to new or revised design and operating requirements that maintain the safety and integrity of the steam system so that pipe failures or incidents are avoided. Safety to the customers and preservation of public property and company assets are greatly increased.

Definition of Research, Development, and Demonstration

Research, development, and demonstration (RD&D) costs are expenditures incurred by the Company either directly or through another person or organization (such as a research institute, industry association, foundation, university, engineering company, or similar contractor) in pursuing research, R&D activities - including experiment, design, installation, construction or operation. Such costs should be reasonably related to existing or future Company business. R&D costs include but are not limited to: expenditures for the design, development, demonstration, or implementation of an experimental facility, plant process, product, formula, invention, system, or similar items, or the improvement of already existing items of a like nature; expenditures for the development or implementation of new or existing concepts until technically and commercially feasible operations are verified feasible; expenditures in connection with the proposed development or delivery of alternative sources of electricity; and expenditures for obtaining patents, such as an attorney's fees expended in making and perfecting a patent application. R&D costs also include expenditures for preliminary investigations, proof-of-concept studies, and detailed planning of specific projects (for securing for customers non-conventional electric, gas, or steam supplies) that rely on technology that has not been verified previously as being feasible.

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RESEARCH AND DEVELOPMENT PROJECT COST / BENEFIT ANALYSIS

PROJECT TITLE	SMALL-SCALE TESTING FOR THE BEHAVIORAL STUDY OF STEAM CONDENSATE AND STEAM TRAP OPERATION	COST SEQ. # 092055 PROJECT STATUS: [X] NEW [ ] COMPLETED [ ] REVISED (OR UPDATED)

APPLICATION OF RESULTS (CHECK ONE)

- [ ] ACTUAL PAST OR PRESENT USE
- [X] FIRM PLANS TO USE
- [ ] INDIRECT (BENEFIT)
- [ ] POTENTIAL / NEARTERM (< 2 YEARS)
- [ ] POTENTIAL / FUTURES (> 2YEARS)
- [ ] NOT APPLICABLE (WHY)

NATURE OF BENEFIT (CHECK ALL THAT APPLY)

- [X] COST AVOIDANCE
- [ ] COST SAVING
- [X] STRATEGIC ISSUE
- [X] OTHER PUBLIC SAFETY
- [ ] REGULATORY ISSUE
- [ ] REFERENCE / UPDATE
- [ ] JOINT OWNER / POWER POOL

BENEFIT DUE TO INCREASE / DECREASE IN:

- [X] CAPITAL COST
- [ ] CONSTRUCTION LEADTIME
- [X] EQUIPMENT LIFE
- [X] IMPROVED DISPATCH
- [ ] FUEL COST
- [ ] THEFT OF SERVICE
- [ ] EMISSIONS
- [X] QUALITY OF DECISION
- [X] QUALITY OF REGULATORY / LEGISLATION DECISIONS
- [X] O & M COST
- [X] RELIABILITY / AVAILABILITY / OUTAGES
- [ ] HEAT RATE
- [ ] SYSTEM LOSSES
- [X] LABOR PRODUCTIVITY
- [ ] ENVIRONMENTAL / FINANCIAL RISK
- [ ] OCCUPATIONAL HEALTH AND SAFETY
- [X] INFORMATION QUALITY AND AVAILABILITY
- [X] OTHER IMPROVED TECHNICAL KNOWLEDGE

BENEFIT TO COMPANY - QUALITATIVE OR QUANTITATIVE:

A thorough understanding of how condensate behaves is critical to the way Engineering designs and enhances the steam system. This technical knowledge has the potential to lead to new or revised design and operating requirements that maintain the safety and integrity of the steam system so that pipe failures or incidents are avoided. Safety to the customers and preservation of public property and company assets are greatly increased.

PROBABILITY THAT BENEFITS WILL BE REALIZED: [X] HIGH [ ] MED. [ ] LOW

BENEFITS **NOT QUANTIFIABLE BECAUSE**

Safety to the customers and preservation of public property and company assets are greatly increased.

PREPARED BY	Josephine G Aromando Josephine G. Aromando - Project Manager	7/22/09 DATE
APPROVED BY	Edward Ecock Edward Ecock - Department Manager	7/22/09 DATE
CONCURRED BY	FM Coppersmith Frederick M. Coppersmith - R&D Director	7/21/05 DATE

1-Jul-09

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RESEARCH AND DEVELOPMENT PROJECT COST / BENEFIT CALCULATION

PROJECT TITLE	SMALL-SCALE TESTING FOR THE BEHAVIORAL STUDY OF STEAM CONDENSATE AND STEAM TRAP OPERATION	COST SEG. # 0 92055

CALCULATIONS

R&D COST = $ 105,000

COST ANALYSIS

Analysis would not be quantifiable. The benefits would be to maintain public safety and preservation of property and assets.

Results from this small-scale testing will be used to conduct the next phase of testing, which will be to run similar condensate simulations in a large-scale test environment to be performed at Hudson Avenue Station. That next phase is anticipated to begin either in the 4th Quarter of 2009 or 1st Quarter of 2010.

	2009	2010	2011	2012	2013	2014	TOTAL
COST OF R&D	105,000						$105,000

	2009	2010	2011	2012	2013	2014	TOTAL
COST OF IMPLEMENTATION							$0

	LABOR	MATERIAL	OTHER ($)	TOTAL		
CURRENT COST / YEAR					INFLATION	2.80%
POTENTIAL ANNUAL SAVING (%)					DISCOUNT	8.32%
ESTIMATED SAVING					PRES VAL YR	2009
					INITIAL YEAR	2009

COST/BENEFIT ANALYSIS

CURRENT DOLLARS THROUGH	2009
CONSTANT DOLLARS AFTER	2009

YEAR	COST ($)	BENEFIT ($)	BENEFIT (%)	CUMULATIVE PRESENT VALUE COST	CUMULATIVE PRESENT VALUE BENEFIT	BENEFIT/COST RATIO
2009	105,000	0%	0%	105,000	0	0.0
2010			7%	105,000	0	0.0
2011			14%	105,000	0	0.0
2012			21%	105,000	0	0.0
2013			29%	105,000	0	0.0
2014			36%	105,000	0	0.0
2015			43%	105,000	0	0.0
2013			50%	105,000	0	0.0
2014			57%	105,000	0	0.0
2015			64%	105,000	0	0.0
2016			71%	105,000	0	0.0
2017			79%	105,000	0	0.0
2018			86%	105,000	0	0.0
2019			93%	105,000	0	0.0
2020			100%	105,000	0	0.0

Coppersmith, Fred

Exhibit__ (SRDP-1)
~~Page 17 of 52~~

92055

From: Aromando, Josephine
Sent: Tuesday, July 21, 2009 4:30 PM
To: Coppersmith, Fred
Cc: Ecock, Edward
Subject: RE: Draft R&D Appropriation for Lucius Pitkin's Condensate and Trap Behavior Tests

Fred,
This was a project that Engineering had taken the lead on as a result of this past February's water hammer incident up at 60th and 3rd. Before they even came to us for R&D support, they had already taken proactive steps to develop a course of action and plan that would mitigate water hammer.

Engineering has had a longstanding working partnership with Lucius Pitkin (LPI), especially during the water hammer incident of July, 2007. (It was LPI who had collaborated with ABS on the final reports that eventually were made public). They relied heavily on their expertise in root cause and failure analysis.

Steam has also maintained professional ties with the French steam utility, CPCU. As part of an information exchange, they and LPI met personally with CPCU to learn more about their own water hammer studies which included having to build similar test set-ups in their labs and performing flow studies. Engineering also obtained some video footage from a gas utility in the Netherlands that described their test set-ups for gas flow condensate.

As part of their plan and presentations to Lou Rana and Kevin Burke (of which Tom Esselmann of LPI was also invited to attend those meetings with them), they proposed to develop our own steam piping simulation with LPI as the principal investigators, similar to what was done at CPCU and in the Netherlands. These were approved by the executives and led to Engineering soliciting a proposal from LPI to develop a test system in their labs for the purpose of understanding how condensate flow behaves in the steam system when pressures are changed during each iteration and when elevation and pipe geometries are taken into account.

Engineering had asked if R&D could fund the testing equipment and construction while they would fund the actual test runs with LPI.

To summarize, this is a non-competitive procurement with LPI due to their water hammer technical and engineering experience from the July, 2007 incident that led to Engineering making the final decision to hire them for their testing services.

Please let me know if there are any other questions.

From: Coppersmith, Fred
Sent: Monday, July 20, 2009 4:38 PM
To: Aromando, Josephine
Cc: Ecock, Edward
Subject: FW: Draft R&D Appropriation for Lucius Pitkin's Condensate and Trap Behavior Tests

Is there a reason that this has to be a non-competitive procurement with Lucius Pitkin?

From: Aromando, Josephine
Sent: Monday, July 20, 2009 4:31 PM
To: Coppersmith, Fred
Subject: FW: Draft R&D Appropriation for Lucius Pitkin's Condensate and Trap Behavior Tests

Fred,
For your review and approval, attached is a RADPAR for $ 105K to fund the construction of a lab-setting test apparatus that will be used to simulate steam and condensate flow at various pressures. Air and water will be the media used to run the simulations; their variable parameters for each test simulation are the air pressure and the flow rate of the water. The purpose of the studies will be for Steam Distribution Engineering to better understand different types of flow characteristics, particularly those at service tees and at fishmouths to trap assemblies, and how they may lead to potential waterhammer conditions. Data from these test

simulations will be used in follow-on research work to be repeated on a larger-scale test set-up to be later constructed on the premises of the Hudson Avenue station, using actual steam and condensate.

Exhibit__ (SRDP-1)
Page 18 of 52

Below are the approvals from Vic Mullin of Civil-Mechanical Engineering and from Ed.

92055

Thanks,
Josephine

From: Ecock, Edward
Sent: Monday, July 20, 2009 2:02 PM
To: Aromando, Josephine
Cc: Ecock, Edward
Subject: FW: Draft R&D Appropriation for Lucius Pitkin's Condensate and Trap Behavior Tests

I approve. I edited the Cost Benefit calculation to remove the old savings figure.

From: Aromando, Josephine
Sent: Monday, July 20, 2009 10:40 AM
To: Ecock, Edward
Subject: FW: Draft R&D Appropriation for Lucius Pitkin's Condensate and Trap Behavior Tests

For your approval, below is Vic Mullin's concurrence for the $105,000 RADPAR to fund Lucius Pitkin's condensate flow and trap study.

From: Mullin, Victor
Sent: Monday, July 20, 2009 10:38 AM
To: Aromando, Josephine
Subject: RE: Draft R&D Appropriation for Lucius Pitkin's Condensate and Trap Behavior Tests

Approved

From: Aromando, Josephine
Sent: Monday, July 20, 2009 10:14 AM
To: Mullin, Victor
Subject: RE: Draft R&D Appropriation for Lucius Pitkin's Condensate and Trap Behavior Tests

Thanks, Vic. I assume then that you approve of the appropriation?

From: Mullin, Victor
Sent: Monday, July 20, 2009 10:13 AM
To: Aromando, Josephine
Subject: RE: Draft R&D Appropriation for Lucius Pitkin's Condensate and Trap Behavior Tests

Josephine
No additional comments
Thanks Vic Mullin

From: Aromando, Josephine
Sent: Thursday, July 02, 2009 4:50 PM
To: Ecock, Edward; Mullin, Victor; Ng, Wilket (Jack)
Cc: Somrah, Dowlatram
Subject: Draft R&D Appropriation for Lucius Pitkin's Condensate and Trap Behavior Tests

For your review, questions, comments, etc., please see the attached R&D appropriation for $ 105,000. The funding will solely support labor and materials for the construction of the testing apparatus at Lucius Pitkin for Engineering's condensate and trap behavior tests. Any revisions you wish for me to make, I will incorporate and re-send to Vic and Ed for their approval.

Thanks,

92055

Josephine Aromando
R&D
(212) 460-2504

From: Thomas C. Esselman [mailto:tesselman@luciuspitkin.com]
Sent: Tuesday, June 30, 2009 5:26 PM
To: Aromando, Josephine; Mullin, Victor
Subject: Revised Steam Test Proposal

Josephine and Vic,

Please find attached a revised proposal for the steam testing.

I have increased the cost of the construction of the condensate behavior test by $12,000 to reflect an increase in the actual time required to construct that test module. The total for construction is estimated to be $104,100. Let me know if this is OK. If necessary, we could use the earlier estimate that I had in the e-mails.

Tom

Date: 06/19/06

CSN:	92477
CO Account:	3825
HO Account:	H0409
PSC:	761
FERC:	
Project Leader:	AROMANDO J.
Start Date:	06/16/06
End Date:	09/06
RateCase:	0.0.1

CC: Richard Keary
Aromando J.

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RESEARCH AND DEVELOPMENT PROJECT APPROPRIATION REQUEST

June 16, 2006

Approved FMCoppersmith 6/19/06

TO: **Frederick M. Coppersmith**, Director
Research and Development

FROM: **Josephine Aromando,** Senior Engineer JA
Research and Development

SUBJECT: **Initiation of R&D Project of $50,000 or Less**

Agreement: As the sponsoring department, we agree to work with R&D to achieve a successful outcome to this research effort and to implement the results if they meet the project objectives and Corporate objectives. In addition, we agree to provide cost sharing, in the form of staff support, as detailed in the RADPAR. We also agree to review the need for this research periodically and inform R&D in a timely manner of any changes that are likely to affect the ultimate usefulness of the project results.

Project Title: ***Research and Development of Testing Protocols for Steam Main Repair Liner Materials***

CSN: 92477
(Assigned by R&D)

Technical Problem and Probable Application: Steam mains consist of steel which must withstand elevated temperatures and pressures to safely transport steam to its customers. When a steam main requires repair due to leaks or failures, the standard repair method for steam mains or its associated components such as valves or joints is to replace a failed section of steel pipe by welding a new section of same size pipe and material. This requires an extensive excavation of the roadway and asbestos abatement from the main for the crews to gain access and make their repairs. This results in a severe disruption to traffic flow, inconveniences the surrounding community, and increases O&M costs for street and service restoration.

Project Objective/Approach: This effort will evaluate potential materials that may be used as repair liners in the internal diameters of steam mains which could then be coupled later on with trenchless technology. At this time, Steam Distribution does not use trenchless technology for their repairs and there is also no known material or liner that could withstand the elevated temperatures and pressures in a steam distribution system. R&D will contract the services of a consultant who has expertise in materials and plastics to research if there are materials currently in development that could be tested for durability and steam applicability by a qualified laboratory. If such, this consultant will compile a technical report detailing what the materials are and make recommendations for the development of the sample material's test protocol. If the results show technical feasibility, a subsequent research phase may be followed through by testing the materials in the lab as per Steam's operating criteria.

Expected Benefits (quantify/qualify):

- Maintain the reliability of the steam distribution system
- Reduce the O&M expenditures associated with main repairs, steam outages, and street excavations and restoration

Expected Duration: Three months

Frequency of Review: Bi-weekly

Project Leader: Josephine Aromando

Appropriation Requested: $ 15,000

Original: $ 15,000
Total Appropriation: $ 15,000

Co-Sponsor(s):

Total Co-funding:

Recommended: Josephine Aromando (R&D Engineer) **Date**: 6/16/06

Approved: (R&D Department Manager) **Date**: 6/16/06

Aromando, Josephine

92477

From: Aromando, Josephine
Sent: Friday, June 16, 2006 4:21 PM
To: Coppersmith, Fred
Cc: Ecock, Edward
Subject: RADPAR for Research and Test Protocol Development of Steam Main Liners/Materials

Attachments: SmRADPAR_StmMainLiners.doc; SmRADPAR_StmMainLiners.doc

SmRADPAR_StmMainLiners.doc (17...

Fred,

Attached is a RADPAR for $15,000 for your review. (The signed hardcopy with mine and Ed's signatures are on your desk.)

Since Steam recently dealt with the leaks at Columbus Circle last spring and dealing with NYCDOT scrutiny, Steam Operations had requested our assistance in looking at different modes of repairing steam mains without the need to extensively excavate vast trenches in the streets of NYC and incurring restoration costs. We have been meeting monthly with our steam customers to explore working with other robotics welding companies (besides Honeybee). We are also exploring whether there are other materials in development in the plastics/composites industry that may be considered as repair liners or patches for repairing steam mains and which may potentially be installed using trenchless technology.

The attached $15K RADPAR is a request to provide funding towards consultants who will research the feasibility of such materials and who will then develop recommendations as to how the materials will be tested in a qualified lab as per Steam's operating criteria. These consultants will be required to have expert knowledge in high strength composite materials and/or liners, and familiarity with lab testing protocols to be able to complete the preliminary technical research and recommendations.

Should there be promising materials as possible steam main liners, the testing will follow through with additional requests for funding.

SmRADPAR_StmMainLiners.doc (17...

Thanks,
Josephine

Date: 10/02/07

CSN:	92618
CO Account:	3825
HO Account:	H0409
PSC:	761
FERC:	
Project Leader:	GUBERMAN K.
Start Date:	09/28/07
End Date:	09/08
RateCase:	0.0.1

CC: Richard Keary
Aromando J.
GUBERMAN K.

conEdison

RESEARCH AND DEVELOPMENT PROJECT APPROPRIATION REQUEST

September 20, 2007

Approved FmCoppersmith 9/20/07

TO: Frederick M. Coppersmith, **Director**
Enterprise Shared Services - Research and Development

FROM: Constantine Sanoulis, **Plant Manager**
Central Operations – Steam Business Unit, Hudson Avenue Station

SUBJECT: **Initiation of R&D Project of $50,000 or Less**

Agreement: As the sponsoring department, we agree to work with R&D to achieve a successful outcome to this research effort and to implement the results if they meet the project objectives and corporate objectives. In addition, we agree to provide cost sharing, in the form of staff support, as detailed in the RADPAR. We also agree to review the need for this research periodically and inform R&D in a timely manner of any changes that are likely to affect the ultimate usefulness of the project results.

Project Title: **Pre-Boiler Corrosion Monitoring and Control** (Assigned by R&D) CSN: 92618

Technical Problem and Probable Application:
Con Edison's steam system is the largest and one of the oldest steam energy networks in the world. It consists of five generation plants that supply steam through approximately 100 miles of pipe that extends from the southern tip of Manhattan to 96th Street, both to commercial and residential customers for heating, sterilization, air conditioning, and hot water. The operation and maintenance of the units that supply steam to the steam system in NYC involves many technical challenges and innovative solutions are needed to address them. Pre-boiler feed water piping corrosion is an issue of growing concern. The treated water produced by RO and Ion Exchange can be very aggressive towards steel pipe, resulting in corrosion. The quantification and monitoring of the severity of pre-boiler corrosion is important to the effective maintenance and reliability of Company boilers. As all steam produced by Company boilers is sent out as product there are limitations on the treatment option available to mitigate pre-boiler corrosion. In order to determine the potential risk pre-boiler corrosion presents and the need to evaluate additional treatment options, the problem must first be quantified. Honeywell's corrosion probe is a new measurement approach that enables corrosion data to be acquired and manipulates at the point of measurement and delivers trend-able data to a DCS or other user interface. The device also provides indication of the corrosion modality, detecting either localized or pitting corrosion. This data will aid in the selection of remedial treatment options and operational changes and allow for evaluation of their efficacy. This new technology has not been used at Con Edison and it's wide spread use can not be recommended until the capabilities of the device are ascertained.

Project Objective/Approach:
The goal of the project is to test the capabilities of the device, determine the pre-boiler corrosion at four locations, ascertain the criteria that impact the corrosion rate and evaluate corrective action efficacy. Hudson Ave.'s new feed water piping will act as a control to test the operation of the device. The three remaining locations will test the function of the device in different aqueous environment and water qualities. After the device is successfully tested, the corrosion rates and modality will be established under normal operating conditions. Next the impact of contaminants including oxygen concentration, TDS and pH will be tested. With this data optimal chemical treatment options and limits can be established. Finally the impact of these changes can be evaluated.

Expected Benefits (quantify/qualify):
The expected benefits of this project are improved unit reliability and reduced maintenance cost. The improved reliability will be accomplished by increasing knowledge of pre-boiler corrosion so that proactive steps can be taken. Reduced maintenance costs will be accomplished by optimizing chemical treatment limits so that pre-boiler corrosion is mitigated..

Expected Duration: One year. **Frequency of Review:** **Quarterly**

Project Leader: Keith Guberman

Appropriation Requested: $50,000

Approved electronically

Original:
Total Appropriation:
Total Spent To Date:

Co-Sponsor(s): **Total Cofunding:**

Recommended: See attached emails **Date:**

(R&D Engineer)

Approved: **Date:**

(R&D Department Head)

Coppersmith, Fred

From: Ecock, Edward
Sent: Friday, September 28, 2007 8:09 AM
To: Coppersmith, Fred; Kressner, Arthur; Aromando, Josephine
Cc: Ecock, Edward
Subject: RE: $50K RADPAR for Hudson Avenue Station's Pre-Boiler Corrosion Monitoring and Control

I spoke with Keith Guberman this morning about this. The corrosion monitor is a probe with a flat disk that is inserted into the pipe. The disk has three separate pieces of metal (coupons) that are attached to an electronics package which measures the electrical resistance of the metals and can, with the help of an algorithm, differentiate between general corrosion and corrosion pitting. The key to this is that it provides on-line monitoring and the coupons do not have to be removed until they are corroded away. This is new technology which the chemical industry is using, but to our knowledge, the utility industry has not used it. I think it is worthwhile to test it out.

From: Coppersmith, Fred
Sent: Tuesday, September 25, 2007 11:02 PM
To: Kressner, Arthur; Ecock, Edward; Aromando, Josephine
Subject: FW: $50K RADPAR for Hudson Avenue Station's Pre-Boiler Corrosion Monitoring and Control

let's dicuss this

thanks

From: Aromando, Josephine
Sent: Tue 9/25/2007 2:59 PM
To: Coppersmith, Fred
Subject: FW: $50K RADPAR for Hudson Avenue Station's Pre-Boiler Corrosion Monitoring and Control

Fred,

For your review and approval, please see attached RADPAR from Hudson Avenue below ($50K), approved both by Gus Sanoulis of Hudson Avenue Station and Ed.

Hudson Avenue Station wants to field-test the effectiveness of a corrosion monitoring probe that determines the severity of corrosion that may occur in pre-boiler feed water piping and which also identifies whether corrosion is localized or is pitted. Since steam requires as high a level of purity as possible for our steam customers, there are limitations in the choice of water treatment that may be applied. Thus, to fully understand the full scope of the corrosion problem, Hudson Avenue aims to quantify that severity by using the corrosion monitoring probe and building a database that will enable engineering and station personnel to make a thorough evaluation of the existing treatment methods and decide which method would be the most feasible for mitigating corrosion in pre-boiler feed water piping. The corrosion monitoring probe is not used as a standard tool here at Con Edison for detecting corrosion but if its field tests prove to be successful, the technology may be tried at the other steam stations.

Thanks
Josephine

From: Ecock, Edward
Sent: Tuesday, September 25, 2007 2:45 PM
To: Aromando, Josephine
Cc: Ecock, Edward
Subject: FW: $50K RADPAR for Hudson Avenue Station's Pre-Boiler Corrosion Monitoring and Control

I approve.

From: Aromando, Josephine
Sent: Tuesday, September 25, 2007 1:57 PM
To: Ecock, Edward
Subject: FW: $50K RADPAR for Hudson Avenue Station's Pre-Boiler Corrosion Monitoring and Control

Ed, for your review and approval, please see attached revised appropriation from Keith Guberman.

From: Sanoulis, Constantine
Sent: Tuesday, September 25, 2007 12:52 PM
To: Aromando, Josephine
Cc: Gajer, Alan; Guberman, Keith
Subject: FW: Pre-Boiler Corrosion Monitoring and Control

Approved.

From: Guberman, Keith
Sent: Tuesday, September 25, 2007 11:47 AM
To: Sanoulis, Constantine
Cc: Gajer, Alan; Aromando, Josephine
Subject: Pre-Boiler Corrosion Monitoring and Control

Gus,
Attached please find an updated write up on the Pre-Boiler Corrosion Monitoring and Control project for your review and approval. R&D requested more details of the testing and use of the device for R&D purposes. I made some changes and added the requested information.

Again an email approval to Josephine is suffecient.

Thank you,

Keith Guberman
Engineer
SBU
917-681-2594

<<Pre-Boiler Corrosion Monitoring and Control.doc>>

Research and Development
New Project Information

Date: 12/16/07

CSN:	92624
CO Account:	3825
HO Account:	H0409
PSC:	761
FERC:	
Project Leader:	DAVID LOW
Start Date:	02/15/06
End Date:	08/06
RateCase:	0.0.1

CC: Richard Keary
Aromando J.
DAVID LOW

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RESEARCH AND DEVELOPMENT PROJECT APPROPRIATION REQUEST

PROJECT TITLE	**STEAM REMOTE MANHOLE MONITORING SYSTEM (Steam REMMS)**	**INCREASED FUNDING REQUEST**	
		COST SEG. #	92624

SPONSORING ORGANIZATIONS	*Steam Distribution Engineering, Steam Distribution*				
PROJECT LEADER(S)	NAME	*David Low*		LOCATION	*4 Irving Place*
	TITLE	*Senior Engineer*		PROJECT LEADER MANHOURS	
STEERING COMMITTEE	CHAIRMAN		*Ramy Nahas*	MEMBERS	*Karen Oh, Candis Joseph, Pat Williams, Gerry Pilate, Renato Derech, Vin Badali*
PROJECT DURATION	Start Date		*October, 2007*	Completion Date	*October, 2008*
COSPONSOR(S)					
CONTRACTOR(S)	*Various*				

FUNDING		
PRIOR APPROPRIATION		
THIS APPROPRIATION	COMPANY LABOR	*$50,000*
	OTHER COSTS	*$100,000*
	TOTAL	*$150,000*
CON EDISON TOTAL		*$150,000*
COSPONSOR(S)		
PROJECT TOTAL		*$150,000*

EXPENDITURE PROJECTION		
PRIOR YEARS		#
CURRENT YEAR	2007	*$100,000*
	2008	*$50,000*
	2009	*$0*
		$0
PROJECT TOTAL		*$150,000*

AGREEMENT

***For Projects less than $150,000**: As the sponsoring department, we agree to work with R&D to achieve a successful outcome to this research effort and to implement the results if they meet the project objectives and Corporate objectives. In addition, we agree to provide cost sharing, in the form of staff support, field testing, and unit installations. We also agree to review the need for this research periodically and inform R&D in a timely manner of any changes that are likely to affect the ultimate usefulness of the project results.*

***For projects with costs estimated at $150,000 or more:** As the sponsoring department we agree to provide cost sharing in the form of staff support and/or other (O&M and/or Capital) funds. For these projects, a draft Implementation Plan for the products of this research and development - including preliminary schedules and budgets needs to be prepared and submitted with the RADPAR.*

For projects that successfully deliver a product or process, the sponsoring department shall update, finalize and undertake an Implementation Plan. The finalized plan shall include a schedule detailing the phases necessary to get the product incorporated into the company's operating practices. The finalized Implementation Plan may consider such factors as budgetary constraints (O&M and Capital), availability of human resources and any other factors that could affect the implementation costs and/or schedule. The finalized Implementation Plan needs to be approved by the sponsoring department at the Department Manager level or above, in accordance with Corporate Policy Statement 000-1and a copy submitted to R&D along with the project closing notice.

APPROVALS

SPONSORING ORGANIZATION - CENTRAL ENGINEERING		
PROJECT	David L. Low RN	10/12/07
MANAGER	David Low	DATE
CHIEF	Edward C. Foppiano	10/16/07
ENGINEER	Edward Foppiano	DATE

ENTERPRISE SHARED SERVICES - R&D		
R & D	Josephine G. Aromando	10/16/07
MANAGER	Josephine G. Aromando	DATE
	FM Coppersmith	10/16/07
DIRECTOR	Frederick M. Coppersmith	DATE

CON EDISON TOTAL APPROPRIATION REQUEST ***$150,000***

PROJECT TITLE

STEAM REMOTE MANHOLE MONITORING SYSTEM (Steam REMMS)

TECHNICAL PROBLEM

The steam distribution system consists of approximately 110 miles of piping that feed an estimated 1,800 customers in New York City. There are six thousand steam manholes that house vital components such as steam traps, main valves, and pumps. These system components require periodic maintenance and inspection so that they function properly and ensure that steam is delivered safely to the customers. A major detriment to their proper operation is when conditions arise where water infiltrates the manholes, either during a rainstorm or a water main break. This could lead to a potentially dangerous water hammer condition. At this time, due to the extreme temperatures and humidity in the manholes, there is no remote monitoring process in place for tracking steam trap functionality or water levels, nor for automatically alerting Steam Operations.

CORPORATE GOAL(S) SUPPORTED BY THIS PROJECT

Improve the quality of our normal operating practices and our readiness to deal with emergencies. Maintain the reliability of our generation, transmission, and our distribution systems and improve their integrity and efficiency.

PROJECT PLAN EXECUTIVE SUMMARY AND IMPLEMENTATION PLAN

This is a programmatic effort to research different technologies for remotely monitoring the conditions in a steam manhole. Immediate issues to address will be the steam heat and humidity in the manhole, management of data, and power requirements. Potential solutions that will be explored and tested will be to monitor traps and water levels using thermocouples, conductivity probes or other devices. Wireless technology will be explored by field-testing a number of communication modes using cellular phones or telephone lines in conjunction with data loggers, antennae, and the use of supplementing hardware to prove the concept of managing the data. Manhole structure design will also be considered as there may be a need to modify dimensions or a need to add a supplementary structure with a more favorable environment for the sensor electronics. In-house support from Van Nest Shops will also be tapped for their expertise in designing and constructing test set-ups for monitoring manhole trap operation and water levels. All of these issues will be addressed in this research effort.

JUSTIFICATION FOR CLASSIFICATION AS R&D

At this time, there is no remote monitoring process in place for tracking steam trap functionality or water levels, nor for automatically alerting Steam Operations. Additionally, there are no commercially available sensors that can survive temperatures above 180 degrees F for steam manhole monitoring applications. However, these high-temperature sensors may be developed over time.

ALTERNATIVES AND STEPS TAKEN TO ENSURE PROJECT DOES NOT DUPLICATE OTHER R&D

There have been previous R&D efforts for trap monitoring, but those were for steam customer meter rooms or for steam stations. There were also previous R&D efforts for water level monitoring in drip pots in gas distribution systems. However, this effort focuses on traps in steam manholes and adds on monitoring for water level which have not been explored before.

EXPECTED BENEFITS AND TECHNOLOGY TRANSFER PLAN

Remote monitoring of manhole conditions provides engineering and field personnel the ability to continuously track the operation of the steam system and react readily and quickly to potential emergencies. Efficient monitoring and quick responses to steam system conditions greatly enhance our existing maintenance and inspection programs for the steam manholes. They also ensure that the integrity of the system is intact and functioning properly so as to avoid potential pipe failures or incidents. Safety to the customers and preservation of public property and company assets are greatly increased.

Definition of Research, Development, and Demonstration

Research, development, and demonstration (RD&D) costs are expenditures incurred by the Company either directly or through another person or organization (such as a research institute, industry association, foundation, university, engineering company, or similar contractor) in pursuing research, R&D activities - including experiment, design, installation, construction or operation. Such costs should be reasonably related to existing or future Company business. R&D costs include but are not limited to: expenditures for the design, development, demonstration, or implementation of an experimental facility, plant process, product, formula, invention, system, or similar items, or the improvement of already existing items of a like nature; expenditures for the development or implementation of new or existing concepts until technically and commercially feasible operations are verified feasible; expenditures in connection with the proposed development or delivery of alternative sources of electricity; and expenditures for obtaining patents, such as an attorney's fees expended in making and perfecting a patent application. R&D costs also include expenditures for preliminary investigations, proof-of-concept studies, and detailed planning of specific projects (for securing for customers non-conventional electric, gas, or steam supplies) that rely on technology that has not been verified previously as being feasible.

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RESEARCH AND DEVELOPMENT PROJECT COST / BENEFIT ANALYSIS

PROJECT TITLE	STEAM REMOTE MANHOLE MONITORING SYSTEM (Steam REMMS)	COST SEQ. # 0 PROJECT STATUS: [X] NEW [ ] COMPLETED [ ] REVISED (OR UPDATED)

APPLICATION OF RESULTS (CHECK ONE)

[ ]	ACTUAL PAST OR PRESENT USE	[ ]	POTENTIAL / NEARTERM (< 2 YEARS)
[X]	FIRM PLANS TO USE	[ ]	POTENTIAL / FUTURES (> 2YEARS)
[ ]	INDIRECT (BENEFIT)	[ ]	NOT APPLICABLE (WHY)

NATURE OF BENEFIT (CHECK ALL THAT APPLY)

[X]	COST AVOIDANCE	[ ]	REGULATORY ISSUE
[X]	COST SAVING	[ ]	REFERENCE / UPDATE
[X]	STRATEGIC ISSUE	[ ]	JOINT OWNER / POWER POOL
[X]	OTHER PUBLIC SAFETY	[ ]	

BENEFIT DUE TO INCREASE / DECREASE IN:

[ ]	CAPITAL COST	[X]	O & M COST
[ ]	CONSTRUCTION LEADTIME	[X]	RELIABILITY / AVAILABILITY / OUTAGES
[X]	EQUIPMENT LIFE	[ ]	HEAT RATE
[X]	IMPROVED DISPATCH	[ ]	SYSTEM LOSSES
[ ]	FUEL COST	[X]	LABOR PRODUCTIVITY
[ ]	THEFT OF SERVICE	[ ]	ENVIRONMENTAL / FINANCIAL RISK
[ ]	EMISSIONS	[X]	OCCUPATIONAL HEALTH AND SAFETY
[X]	QUALITY OF DECISION	[X]	INFORMATION QUALITY AND AVAILABILITY
[ ]	QUALITY OF REGULATORY / LEGISLATION DECISIONS	[X]	OTHER PROCESS IMPROVEMENT

BENEFIT TO COMPANY - QUALITATIVE OR QUANTITATIVE:

Remote monitoring of manhole conditions provides engineering and field personnel the ability to continuously track the operation of the steam system and react readily and quickly to potential emergencies. Efficient monitoring and quick responses to steam system conditions greatly enhance our existing maintenance and inspection programs for the steam manholes. They also ensure that the integrity of the system is intact and functioning properly so as to avoid potential pipe failures or incidents.

PROBABILITY THAT BENEFITS WILL BE REALIZED: [X] HIGH [ ] MED. [ ] LOW

BENEFITS | **NOT QUANTIFIABLE BECAUSE**

Safety to the customers and preservation of public property and company assets are greatly increased.

PREPARED BY	Josephine G Aromando Josephine G. Aromando - Project Manager	10/16/07 DATE
APPROVED BY	Edward Ecock - Department Manager	10/16/07 DATE
CONCURRED BY	Frederick M. Coppersmith - R&D Director	10/16/07 DATE

 12-Oct-07

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RESEARCH AND DEVELOPMENT PROJECT COST / BENEFIT CALCULATION

PROJECT TITLE	STEAM REMOTE MANHOLE MONITORING SYSTEM (Steam REMMS)	COST SEG. # 0

CALCULATIONS

R&D COST = $150,000

COST ANALYSIS

Not quantifiable. Improvement to public safety and system reliability.

	2007	2008	2009	2010	2011	2012	TOTAL
COST OF R&D	100,000	50,000					$150,000

	2007	2008	2009	2010	2011	2012	TOTAL
COST OF IMPLEMENTATION							$0

	LABOR	MATERIAL	OTHER ($)	TOTAL		
CURRENT COST / YEAR					INFLATION	2.80%
POTENTIAL ANNUAL SAVING (%)					DISCOUNT	8.32%
ESTIMATED SAVING					PRES VAL YR	2007
					INITIAL YEAR	2007

COST/BENEFIT ANALYSIS

CURRENT DOLLARS THROUGH	2007
CONSTANT DOLLARS AFTER	2007

YEAR	COST ($)	BENEFIT ($)	BENEFIT (%)	CUMULATIVE PRESENT VALUE COST	CUMULATIVE PRESENT VALUE BENEFIT	BENEFIT/COST RATIO
2007			0%	0	0	#DIV/0!
2008				0	0	#DIV/0!
2009				0	0	#DIV/0!
2010				0	0	#DIV/0!
2011				0	0	#DIV/0!
2012				0	0	#DIV/0!
2013				0	0	#DIV/0!
2013				0	0	#DIV/0!
2014				0	0	#DIV/0!
2015				0	0	#DIV/0!
2016				0	0	#DIV/0!
2017				0	0	#DIV/0!
2018				0	0	#DIV/0!
2019				0	0	#DIV/0!
2020				0	0	#DIV/0!

Research and Development
New Project Information

Date: 02/05/09

CSN:	92646
CO Account:	3825
HO Account:	H0409
PSC:	761
FERC:	
Project Leader:	LOW D.
Start Date:	02/04/09
End Date:	08/09
RateCase:	0.0.1

CC: John Amanna
Aromando J.
LOW D.

conEdison

RESEARCH AND DEVELOPMENT PROJECT APPROPRIATION REQUEST

January 21, 2009

Approved
FMCoppersmith 2/4/09

TO: Frederick M. Coppersmith, Director
Research and Development

FROM: Victor Mullin, Chief Engineer
Civil-Mechanical Engineering

SUBJECT: **Initiation of R&D Project of $50,000 or Less**

Agreement: As the sponsoring department, we agree to work with R&D to achieve a successful outcome to this research effort and to implement the results if they meet the project objectives and Corporate objectives. In addition, we agree to provide cost sharing, in the form of staff support, as detailed in the RADPAR. We also agree to review the need for this research periodically and inform R&D in a timely manner of any changes that are likely to affect the ultimate usefulness of the project results.

Project Title: ***Phase I – Development & Load Testing of the Logicover™*** **CSN**: 92 646
(Assigned by R&D)

Technical Problem and Probable Application:

The majority of Steam Distribution Q-8-type, non-vented, round manhole covers in the steam system consist of cast iron and steel. Steam Distribution is looking to overcome two technical challenges with these covers. One issue is that cast iron and steel are both excellent thermal conductors and easily transfer steam heat from the manhole to the outer surface, thus presenting a potential safety hazard to the public when pedestrians or pets accidentally come into contact with these covers. Additionally, metal, non-vented covers impede wireless data transmission. Steam is actively investigating multiple types of communications technology that will enable them to monitor for certain manhole parameters, such as the state of the steam traps and rising and falling levels of water in the manhole, for example. There appears to be a manhole cover product that may address both issues offered by East Jordan Iron Works. They are offering to develop a cover, the Logicover™, which is made of composite material and which possesses a built-in telemetry and communications system that will allow for Steam to acquire manhole data and transmit through a wireless device using a radio, antenna, microprocessor, and sensors.

Project Objective/Approach:

Phase I will consist of the development of one prototype Logicover™ to be tested in a laboratory for its load-bearing capabilities under both ambient and elevated temperatures, as per Steam Distribution Engineering specifications. These first group of covers to be load-tested will not have the telemetry system in place. If necessary, East Jordan will re-design and re-fabricate one or two more versions of the Logicover™ accordingly if they fail the load-bearing lab tests. Successful load test results will then progress onto Phase II. The next test batch of covers will contain the telemetry modules as part of the cover unit. These will be installed at test manhole locations to be selected by Steam Distribution and evaluated for their ability to transmit manhole data and their ability to operate in the roadway or crosswalks safely.

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RESEARCH AND DEVELOPMENT PROJECT APPROPRIATION REQUEST

Expected Benefits (quantify/qualify):

- Composite manhole covers have the potential of protecting the public from accidental contact by retarding heat transfer and maintaining safe levels of temperature at the surface
- The ability to transmit vital data through composite covers will improve monitoring capabilities for Steam Distribution, enable personnel to track the system more efficiently and allow for rapid response

Expected Duration: Six months

Frequency of Review: Bi-Monthly

Project Team: David Low, Gregory Chu

Appropriation Requested: $35,000

Original	
Appropriation $	**$ 35,000**
Spent to Date	$0.00
Co-funding	$0.00

Recommended: see attached email
(R&D Engineer)

Date: 2/4/09

Approved:
(R&D Department Head)

Date: 2/4/09

Coppersmith, Fred

From: Aromando, Josephine
Sent: Wednesday, February 04, 2009 1:26 PM
To: Coppersmith, Fred
Subject: FW: SmRADPAR_SteamLogicover.doc

Attachments: SmRADPAR_SteamLogicover.doc

Fred,
For your review and approval, attached is the RADPAR for $ 35,000 for Steam Distribution Engineering to evaluate a composite hybrid manhole cover with monitoring telemetry hardware. Below are approvals from both Ed and Vic Mullin of Civil-Mechanical Engineering.

SmRADPAR_SteamLogicover.doc (1...

Thanks,
Josephine

From: Ecock, Edward
Sent: Wednesday, February 04, 2009 1:19 PM
To: Aromando, Josephine
Cc: Ecock, Edward
Subject: RE: SmRADPAR_SteamLogicover.doc

I approve.

From: Aromando, Josephine
Sent: Monday, February 02, 2009 9:59 AM
To: Ecock, Edward
Subject: FW: SmRADPAR_SteamLogicover.doc

Ed,
Attached is the $35,000 RADPAR for load testing the composite-telemetry Logicover® for your review and approval. I had attempted to approach Electric for their interest in possibly co-funding but they said they weren't interested.

In this first phase, East Jordan will provide one prototype cover to be load and thermal tested under Steam's direction. If the single cover passes the load and thermal tests, we move onto Phase II for field testing the cover with the communications telemetry installed beneath the cover. If the first cover fails the load and thermal tests, Steam will direct East Jordan to re-design their composite cover for a second round of testing.

Below is Dowlatram Somrah (Acting Section Manager) and Vic Mullin's approval.

Thanks,
Josephine

From: Mullin, Victor
Sent: Saturday, January 31, 2009 6:43 PM
To: Somrah, Dowlatram; Aromando, Josephine; Mullin, Victor
Subject: FW: SmRADPAR_SteamLogicover.doc

Approved

From: Somrah, Dowlatram

Sent: Friday, January 30, 2009 5:11 PM
To: Mullin, Victor
Cc: Aromando, Josephine
Subject: FW: SmRADPAR_SteamLogicover.doc

Vic,

I have review the RADPAR and approve. Your approval is key please review and indicate your decision.

From: Low, David Y.
Sent: Thursday, January 29, 2009 3:12 PM
To: Somrah, Dowlatram
Cc: Chu, Gregory K; Aromando, Josephine
Subject: SmRADPAR_SteamLogicover.doc

Greg Chu and I have reviewed the RADPAR and approve.

<< File: SmRADPAR_SteamLogicover.doc >>

David Y. Low, P.E.
Engineer - Consolidated Edison Company
Steam Distribution Engineering
Work - (212) 460-4989
Cell - (347) 386-5488
Fax - (212) 673-5458

Company Name: Con Edison
Case Description: Con Edison Gas & Steam Rate Cases
Case: 09-G-0795-09-S-0794

Response to DPS Interrogatories – Set DPS22
Date of Response: 02/16/2010
Responding Witness: Ecock

Question No. :201
Subject: Steam Research and Development - 1. Follow-up to the Company's response to DPS-37: Regarding the Steam Remote Manhole Trap Monitoring project, the RADPAR document provided illustrates no expenses after 2008. Provide the source of the cost estimate for the funding requests for rate year ending 9/30/11 and 9/30/12. 2. Follow-up to the Company's response to DPS-37(c): Provide the vendor quote for the Steam Expo. 3. Follow-up to the Company's response to DPS-37(e): For each item that was allocated a budget but had no actual expense, provide an explanation for why there was no spending. 4. Follow-up to the Company's response to DPS-37(f). For the items that did not receive approval: a. provide an explanation for why each item was not approved; and b. provide an explanation for why these items are included in the rate filing even though it did not receive approval.

Response:
1. The Steam Remote Manhole Monitoring System project was initiated in the last quarter of 2007 and it was originally expected to be completed in 2008. However, due to developmental work with the vendor that took longer than expected, the project continued into 2009. As the prototype was being field tested, it became clear that additional research was needed to develop and test faster data transmitters, and to develop wireless capability. The funding request for rate years ending 9/30/11 and 9/30/12 are labor estimates for periodic inspection of the new equipment being tested that is being purchased in 2010.
2. The estimate is based on a 2006 vendor quote for the Steam EXPO which is attached.
3. There are seven projects associated with the Company's response to DPS-37(e) where monies were budgeted but there was no actual expense. These are:
(a) EPRI GOBIG Cost Competiveness – This is a collaborative project to find NOx solutions for utilities burning oil and gas. There are a limited number of utilities that burn both of these fuels, and there have not been many candidate research projects offered by EPRI that could be funded by this small consortium. We continue to budget a small amount of money every year in the hope that projects will develop.
(b) Proof of Concept Demonstration of a Predictive Water Hammer Model – This project was deferred until the results of another study (to analyze the capabilities of existing Company systems for predicting water hammer) was completed. This project is now scheduled to commence with requests for proposals in March 2010.

(c) Exploration and Development of Additional Pipe Inspection Technologies – In preparing for the 2008 budget, one pipe inspection robot was brought to our attention that we thought could be used for our steam mains, so we allocated monies in the budget for testing it. As we learned more about the capabilities of the robot, we learned that it would not be useful for our system because it requires the steam main to be shut down, and requires introduction of water in the main to be used as a couplant for the transducers. Neither one of those requirements is acceptable, so we did not pursue the testing of this robot in 2008. We continue to search for technologies that could assist us in inspecting our steam mains.
(d) R&D of Testing Protocols for Steam Main Repair Liners - In 2007, the Company identified a need to conduct long-term research on alternate methods to repair or rehabilitate steam mains with little or no excavations. This need was due to new permit restrictions imposed by the NYCDOT. This proposed project would conduct a study on liners that have been successfully used in the water, sewer, and gas industries for repairing and rehabilitating pipes, to determine applicability for high temperature steam mains. Some initial investigations by a consultant were conducted in 2007 and some monies were spent. In June 2007, during the preparation of the 2008 budget, plans were made to conduct further studies and monies were allocated in the budget. After the steam event in July 2007, there were concerns with introducing any liner materials in steam mains that could exfoliate and potentially clog steam traps. Consequently, this project became a very low priority and no monies were spent in 2008. Because a need to develop alternate methods still exists, this project will recommence in 2010 but will focus on research for liner materials that can demonstrate long-term sustainability.
(e) Demonstration of a Transient Pressure Monitor – Field testing of one type of pressure sensor was conducted in 2006 and 2007 and the results were inconclusive. Monies were placed in the 2008 budget but there were no expenditures as research focus turned to was on other water hammer preventative measures such as predictive model study, steam trap monitoring, and water level monitoring.
(f) Water Treatment Modeling – In 2008, Company water specialists researched several vendors that could potentially develop models but initial findings were that these would be expensive. A request for proposal with a defined scope of work will be issued in the second quarter of 2010.
(g) Demonstration of Ener-G-Rotor – This is the Phase II project where a demonstration of a 50kW unit would be done. No monies were spent in 2008 because the vendor did not start developing the 50kW unit until it secured a grant from NYSERDA which did not occur until mid 2009. The 50kW unit is now scheduled for field testing in June, 2010.
4. See Attached Table 4. The rate filing is a forecast of expenditures on projects for future rate years. The filing is comprised of ongoing projects that have already received approval as well as future projects (or stages of projects) that will be submitted for approval prior to project initiation.

swing consulting, inc.
strategic exploration

279 Roslara Court
Bartlett, IL 60103
USA

Phone: 630-830-9070
Fax: 630-483-8117
Email: Sharon@swingconsulting.com
Website: www.swingconsulting.com

Budget Estimate for Services to Facilitate Steam Distribution R&D Brainstorming with ConEd Employees

Proposal Date:	June 15, 2006
PO #	TBD
Proposal #:	ConEd 2006.1
Date:	Workshop Date: October 2006
Customer ID:	ConEd Steam
Payment Terms:	Within 15 Days of periodic invoices as work progresses

Submitted to:

ConEd Steam Distribution
R&D Department
Josephine Aromando & Ed Ecock

Purpose:

To assist ConEdison's Steam Distribution R&D Department in facilitating a brainstorming workshop. The project's goal is to identify the technology and research needs of Steam Generation, Distribution and Marketing, define possible system, equipment or process development efforts that could address those needs, and structure future R&D programs. The focus of the effort is cost cutting, improving operating efficiency and the identification of potential new business opportunities.

Overview:

Swing Consulting will create a facilitation plan, and facilitate a one-day R&D Workshop for up to 45 participants from ConEd in NY October or November of 2006. A survey will be distributed via email to employees of ConEd for the purpose of identifying needs and gathering information for topics to be covered in the workshop. A structured brainstorming session will be facilitated with three groups focusing on different topic areas including Steam Generation, Steam Distribution and Steam Marketing. Each group will generate ideas for providing a listing of needs, technology, and research possibilities that can aid cost cutting, operational efficiency and potential new business opportunities. The participants will give input to the prioritization of the items. Swing Consulting will facilitate, graphically record the process and output of the meeting while it is happening, and develop a summary report after the meeting is completed that includes digital pictures of the charts of the final ideas and an overview of the process and methodology. The report will be delivered to Ed Ecock and Josephine Aromando for review and approval in an electronic format.

Services Provided:

- *Client interviews to determine facilitation plan*
  - Swing Consulting will meet with the client during one trip to NY prior to the workshop to agree upon expectations, trends, events and issues that can influence the meeting agenda and facilitation plan.

- *Survey design, launch and feedback*
  - The challenge questions for the workshop will be based on the results of a survey. Swing Consulting will design the on-line survey with up to 20 questions to be distributed to up to 300 participants.
  - The client will send an email invitation to the targeted group that includes a hot link to the survey. After the deadline for participants to complete the survey, a spreadsheet of the raw data would be made available to the client electronically.
  - Segmenting and sorting topics will be determined with the assistance of the client. The consultant would provide the actual responses, sorted by topic to the client, without summary comments.

- Topics of discussion for the workshop will then be agreed to and the agenda and process of the meeting determined.

- *Design and documentation of agreed-upon agenda*
  - We will design and document the final meeting agenda to meet the needs of the client organization. We assume the client will invite guests, distribute the agenda, and make meeting arrangements unless otherwise negotiated.
  - Appropriate representatives of ConEd and Swing Consulting will meet the day prior to the event at the event location to review meeting details and logistics.

- *Provide facilitators and graphic recorders, one pair per breakout group*
  - Swing Consulting will provide three facilitator/graphic recorder teams to guide the meeting process and drive toward agreed upon outcomes. The meeting process and outcomes will be recorded in words and pictures by three graphic recorders to cover plenary and breakout sessions. We recommend three facilitator/recorder pairs to work with groups of seven-fifteen participants. More teams can be added at your request to decrease the number of people in each group, but the overall project cost will increase.
  - Large chart paper will be attached to walls and windows for the purpose of recording. Special markers that will not bleed, tape and other consumable facilitation aids will be provided at cost. The client will provide flip charts and paper in their location.

- *Report*
  - o A report containing the output of the meeting will be delivered to ConEd at an agreed-upon time, depending on the final facilitation plan.
  - o Digital pictures of all charts will be provided on CD.

- *Expenses*
  - o Travel expenses for the consultant team and supplies for the meeting and any printing costs for reports will be billed at cost to the client.
  - o Coordination of and payment of the meeting room, food and beverage costs are the responsibility of the client.

- *Estimated Investment*
  - o Assuming the following parameters, the project cost to the client will be billed at $27,000 plus expenses.

    - Swing Consulting will design an Email-based survey for distribution by the client to as many as 300 people. Sorted data will be made available to the client electronically without summary comments. This will serve as the basis for the design of the challenge questions for the workshop.
    - One in-person meeting with Sharon Swing in NY to plan the survey, meeting agenda and agree upon desired outcomes and deliverables.
    - Three graphic recorder/facilitator pairs conducting a full day meeting in NY with 45 ConEd participants which will form three breakout groups for portions of the day, and meet collectively at the beginning and end of the meeting day.
    - Digital photographs will be taken of the charts produced in the meeting and will be delivered to the client on CD.
    - A meeting summary report will be delivered electronically to the client no later than 30 days after the event.

- o Expenses are estimated at $4,100, but will be billed as actual. These estimates include:
  - Airfare
  - Hotel
  - Ground travel
  - Meals
  - Incidental expenses

Research and Development
New Project Information

Date: 12/16/07

CSN:	92624
CO Account:	3825
HO Account:	H0409
PSC:	761
FERC:	
Project Leader:	DAVID LOW
Start Date:	02/15/06
End Date:	08/06
RateCase:	0.0.1

CC: Richard Keary
Aromando J.
DAVID LOW

conEdison

RESEARCH AND DEVELOPMENT PROJECT APPROPRIATION REQUEST

PROJECT TITLE	STEAM REMOTE MANHOLE MONITORING SYSTEM (Steam REMMS)	INCREASED FUNDING REQUEST	
		COST SEG. #	92624

SPONSORING ORGANIZATIONS	Steam Distribution Engineering, Steam Distribution				
PROJECT LEADER(S)	NAME	David Low		LOCATION	4 Irving Place
	TITLE	Senior Engineer		PROJECT LEADER MANHOURS	
STEERING COMMITTEE	CHAIRMAN		Ramy Nahas	MEMBERS	Karen Oh, Candis Joseph, Pat Williams, Gerry Pilate, Renato Derech, Vin Badali
PROJECT DURATION	Start Date		October, 2007	Completion Date	October, 2008
COSPONSOR(S)					
CONTRACTOR(S)	Various				

FUNDING		
PRIOR APPROPRIATION		
THIS APPROPRIATION	COMPANY LABOR	$50,000
	OTHER COSTS	$100,000
	TOTAL	$150,000
CON EDISON TOTAL		$150,000
COSPONSOR(S)		
PROJECT TOTAL		$150,000

EXPENDITURE PROJECTION		
PRIOR YEARS		#
CURRENT YEAR	2007	$100,000
	2008	$50,000
	2009	$0
		$0
PROJECT TOTAL		$150,000

AGREEMENT

***For Projects less than $150,000**: As the sponsoring department, we agree to work with R&D to achieve a successful outcome to this research effort and to implement the results if they meet the project objectives and Corporate objectives. In addition, we agree to provide cost sharing, in the form of staff support, field testing, and unit installations. We also agree to review the need for this research periodically and inform R&D in a timely manner of any changes that are likely to affect the ultimate usefulness of the project results.*
***For projects with costs estimated at $150,000 or more:** As the sponsoring department we agree to provide cost sharing in the form of staff support and/or other (O&M and/or Capital) funds. For these projects, a draft Implementation Plan for the products of this research and development - including preliminary schedules and budgets needs to be prepared and submitted with the RADPAR.*

For projects that successfully deliver a product or process, the sponsoring department shall update, finalize and undertake an Implementation Plan. The finalized plan shall include a schedule detailing the phases necessary to get the product incorporated into the company's operating practices. The finalized Implementation Plan may consider such factors as budgetary constraints (O&M and Capital), availability of human resources and any other factors that could affect the implementation costs and/or schedule. The finalized Implementation Plan needs to be approved by the sponsoring department at the Department Manager level or above, in accordance with Corporate Policy Statement 000-1and a copy submitted to R&D along with the project closing notice.

APPROVALS

SPONSORING ORGANIZATION - CENTRAL ENGINEERING			ENTERPRISE SHARED SERVICES - R&D		
PROJECT MANAGER	David Low (signed) RN	10/12/07	R & D MANAGER	Josephine G. Aromando (signed)	10/16/07
	David Low	DATE		Josephine G. Aromando	DATE
CHIEF ENGINEER	Edward C. Foppiano (signed)	10/16/07	DIRECTOR	Frederick M. Coppersmith (signed)	10/16/07
	Edward Foppiano	DATE		Frederick M. Coppersmith	DATE

CON EDISON TOTAL APPROPRIATION REQUEST $150,000

PROJECT TITLE

STEAM REMOTE MANHOLE MONITORING SYSTEM (Steam REMMS)

TECHNICAL PROBLEM

The steam distribution system consists of approximately 110 miles of piping that feed an estimated 1,800 customers in New York City. There are six thousand steam manholes that house vital components such as steam traps, main valves, and pumps. These system components require periodic maintenance and inspection so that they function properly and ensure that steam is delivered safely to the customers. A major detriment to their proper operation is when conditions arise where water infiltrates the manholes, either during a rainstorm or a water main break. This could lead to a potentially dangerous water hammer condition. At this time, due to the extreme temperatures and humidity in the manholes, there is no remote monitoring process in place for tracking steam trap functionality or water levels, nor for automatically alerting Steam Operations.

CORPORATE GOAL(S) SUPPORTED BY THIS PROJECT

Improve the quality of our normal operating practices and our readiness to deal with emergencies. Maintain the reliability of our generation, transmission, and our distribution systems and improve their integrity and efficiency.

PROJECT PLAN EXECUTIVE SUMMARY AND IMPLEMENTATION PLAN

This is a programmatic effort to research different technologies for remotely monitoring the conditions in a steam manhole. Immediate issues to address will be the steam heat and humidity in the manhole, management of data, and power requirements. Potential solutions that will be explored and tested will be to monitor traps and water levels using thermocouples, conductivity probes or other devices. Wireless technology will be explored by field-testing a number of communication modes using cellular phones or telephone lines in conjunction with data loggers, antennae, and the use of supplementing hardware to prove the concept of managing the data. Manhole structure design will also be considered as there may be a need to modify dimensions or a need to add a supplementary structure with a more favorable environment for the sensor electronics. In-house support from Van Nest Shops will also be tapped for their expertise in designing and constructing test set-ups for monitoring manhole trap operation and water levels. All of these issues will be addressed in this research effort.

JUSTIFICATION FOR CLASSIFICATION AS R&D

At this time, there is no remote monitoring process in place for tracking steam trap functionality or water levels, nor for automatically alerting Steam Operations. Additionally, there are no commercially available sensors that can survive temperatures above 180 degrees F for steam manhole monitoring applications. However, these high-temperature sensors may be developed over time.

ALTERNATIVES AND STEPS TAKEN TO ENSURE PROJECT DOES NOT DUPLICATE OTHER R&D

There have been previous R&D efforts for trap monitoring, but those were for steam customer meter rooms or for steam stations. There were also previous R&D efforts for water level monitoring in drip pots in gas distribution systems. However, this effort focuses on traps in steam manholes and adds on monitoring for water level which have not been explored before.

EXPECTED BENEFITS AND TECHNOLOGY TRANSFER PLAN

Remote monitoring of manhole conditions provides engineering and field personnel the ability to continuously track the operation of the steam system and react readily and quickly to potential emergencies. Efficient monitoring and quick responses to steam system conditions greatly enhance our existing maintenance and inspection programs for the steam manholes. They also ensure that the integrity of the system is intact and functioning properly so as to avoid potential pipe failures or incidents. Safety to the customers and preservation of public property and company assets are greatly increased.

Definition of Research, Development, and Demonstration

Research, development, and demonstration (RD&D) costs are expenditures incurred by the Company either directly or through another person or organization (such as a research institute, industry association, foundation, university, engineering company, or similar contractor) in pursuing research. R&D activities - including experiment, design, installation, construction or operation. Such costs should be reasonably related to existing or future Company business. R&D costs include but are not limited to: expenditures for the design, development, demonstration, or implementation of an experimental facility, plant process, product, formula, invention, system, or similar items, or the improvement of already existing items of a like nature; expenditures for the development or implementation of new or existing concepts until technically and commercially feasible operations are verified feasible; expenditures in connection with the proposed development or delivery of alternative sources of electricity; and expenditures for obtaining patents, such as an attorney's fees expended in making and perfecting a patent application. R&D costs also include expenditures for preliminary investigations, proof-of-concept studies, and detailed planning of specific projects (for securing for customers non-conventional electric, gas, or steam supplies) that rely on technology that has not been verified previously as being feasible.

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RESEARCH AND DEVELOPMENT PROJECT COST / BENEFIT ANALYSIS

PROJECT TITLE	STEAM REMOTE MANHOLE MONITORING SYSTEM (Steam REMMS)	COST SEQ. # 0 PROJECT STATUS: [X] NEW [ ] COMPLETED [ ] REVISED (OR UPDATED)

APPLICATION OF RESULTS (CHECK ONE)

- [ ] ACTUAL PAST OR PRESENT USE
- [X] FIRM PLANS TO USE
- [ ] INDIRECT (BENEFIT)
- [ ] POTENTIAL / NEARTERM (< 2 YEARS)
- [ ] POTENTIAL / FUTURES (> 2YEARS)
- [ ] NOT APPLICABLE (WHY)

NATURE OF BENEFIT (CHECK ALL THAT APPLY)

- [X] COST AVOIDANCE
- [X] COST SAVING
- [X] STRATEGIC ISSUE
- [X] OTHER PUBLIC SAFETY
- [ ] REGULATORY ISSUE
- [ ] REFERENCE / UPDATE
- [ ] JOINT OWNER / POWER POOL

BENEFIT DUE TO INCREASE / DECREASE IN:

- [ ] CAPITAL COST
- [ ] CONSTRUCTION LEADTIME
- [X] EQUIPMENT LIFE
- [X] IMPROVED DISPATCH
- [ ] FUEL COST
- [ ] THEFT OF SERVICE
- [ ] EMISSIONS
- [X] QUALITY OF DECISION
- [ ] QUALITY OF REGULATORY / LEGISLATION DECISIONS
- [X] O & M COST
- [X] RELIABILITY / AVAILABILITY / OUTAGES
- [ ] HEAT RATE
- [ ] SYSTEM LOSSES
- [X] LABOR PRODUCTIVITY
- [ ] ENVIRONMENTAL / FINANCIAL RISK
- [X] OCCUPATIONAL HEALTH AND SAFETY
- [X] INFORMATION QUALITY AND AVAILABILITY
- [X] OTHER: PROCESS IMPROVEMENT

BENEFIT TO COMPANY - QUALITATIVE OR QUANTITATIVE:

Remote monitoring of manhole conditions provides engineering and field personnel the ability to continuously track the operation of the steam system and react readily and quickly to potential emergencies. Efficient monitoring and quick responses to steam system conditions greatly enhance our existing maintenance and inspection programs for the steam manholes. They also ensure that the integrity of the system is intact and functioning properly so as to avoid potential pipe failures or incidents.

PROBABILITY THAT BENEFITS WILL BE REALIZED: [X] HIGH [ ] MED. [ ] LOW

BENEFITS NOT QUANTIFIABLE BECAUSE

Safety to the customers and preservation of public property and company assets are greatly increased.

PREPARED BY	Josephine G. Aromando (signature) Josephine G. Aromando - Project Manager	10/16/07 DATE
APPROVED BY	(signature) Edward Ecock - Department Manager	10/16/07 DATE
CONCURRED BY	(signature) Frederick M. Coppersmith - R&D Director	10/16/07 DATE

12-Oct-07

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RESEARCH AND DEVELOPMENT PROJECT COST / BENEFIT CALCULATION

PROJECT TITLE	STEAM REMOTE MANHOLE MONITORING SYSTEM (Steam REMMS)	COST SEG. # 0

CALCULATIONS

R&D COST = $150,000

COST ANALYSIS

Not quantifiable. Improvement to public safety and system reliability.

	2007	2008	2009	2010	2011	2012	TOTAL
COST OF R&D	100,000	50,000					$150,000

	2007	2008	2009	2010	2011	2012	TOTAL
COST OF IMPLEMENTATION							$0

	LABOR	MATERIAL	OTHER ($)	TOTAL		
CURRENT COST / YEAR					INFLATION	2.80%
POTENTIAL ANNUAL SAVING (%)					DISCOUNT	8.32%
ESTIMATED SAVING					PRES VAL YR	2007
					INITIAL YEAR	2007

COST/BENEFIT ANALYSIS

CURRENT DOLLARS THROUGH	2007
CONSTANT DOLLARS AFTER	2007

YEAR	COST ($)	BENEFIT ($)	BENEFIT (%)	CUMULATIVE PRESENT VALUE COST	CUMULATIVE PRESENT VALUE BENEFIT	BENEFIT/COST RATIO
2007			0%	0	0	#DIV/0!
2008				0	0	#DIV/0!
2009				0	0	#DIV/0!
2010				0	0	#DIV/0!
2011				0	0	#DIV/0!
2012				0	0	#DIV/0!
2013				0	0	#DIV/0!
2013				0	0	#DIV/0!
2014				0	0	#DIV/0!
2015				0	0	#DIV/0!
2016				0	0	#DIV/0!
2017				0	0	#DIV/0!
2018				0	0	#DIV/0!
2019				0	0	#DIV/0!
2020				0	0	#DIV/0!

Table 4

Title	Response to Q37 (f)	Response to Q201-(4a)
BASE PROGRAM		
ADMINISTRATION		
SALARIES AND WAGES	No*	Salaries and Wages do not get approved until the budget for the upcoming year is approved. *Note: the budget for 2010, which covers the first three months of rate year 1, has been approved.
OTHER EXPENSES	No*	Other Expenses do not get approved until the budget for the upcoming year is approved. *Note: the budget for 2010, which covers the first three months of rate year 1, has been approved.
PATENT SEARCHES IN CONNECTION WITH COMPANY R&D TECHNOLOGY APPLICATIONS	Yes	N/A
DEVELOPMENT OF R&D DEPARTMENT WEBSITE	Yes	N/A
INSTITUTIONAL		
EPRI GOBIG COST COMPETITIVENESS	Yes	N/A
EPRI COMBUSTION TURBINE, HRSG, AND STEAM & WATER CHEMISTRY PROGRAMS	Yes	N/A
INTERNAL PROGRAM		
PROOF OF CONCEPT DEMONSTRATION OF A PREDICTIVE WATER HAMMER MODEL	No	An appropriation request is submitted prior to project initiation. This project has not been initiated yet.
THERMOELECTRIC MODULES FOR STEAM MANHOLE INSTRUMENTATION - COMMERCIALIZATION	No	An appropriation request is submitted prior to project initiation. This project has not been initiated yet.
STEAM EXPO	No	An appropriation request is submitted prior to project initiation. This project has not been initiated yet.
DEMO OF HIGH STRENGTH COATINGS FOR MAIN VALVES	No	An appropriation request is submitted prior to project initiation. This project has not been initiated yet.
DEVELOPMENT AND TESTING OF A MANHOLE COVER MONITORING SYSTEM	Yes	N/A
EXPLORATION AND DEVELOPMENT OF ADDITIONAL PIPE INSPECTION TECHNOLOGIES	No	An appropriation request is submitted prior to project initiation. This project has not been initiated yet.
EXPLORATION AND DEVELOPMENT OF MORE ACCURATE LEAK DETECTION TECHNOLOGIES	No	An appropriation request is submitted prior to project initiation. This project has not been initiated yet.
R&D OF TESTING PROTOCOLS FOR STEAM MAIN REPAIR LINERS	Yes	N/A
THERMAL POWERED STEAM VORTEX METERS PHASE - COMMERCIALIZATION	No	An appropriation request is submitted prior to project initiation. This project has not been initiated yet.
DEMONSTRATION OF A TRANSIENT PRESSURE MONITOR	No	An appropriation request is submitted prior to project initiation. This project has not been initiated yet.
WATER TREATMENT MODELING	No	An appropriation request is submitted prior to project initiation. This project has not been initiated yet.
STEAM CONDENSATE FLOW BEHAVIOR TESTING IN STEAM MAIN MOCK-UP	Yes	N/A
DEMONSTRATION OF IN-SITU CORROSION MONITORS	Yes	N/A
STEAM REMOTE MANHOLE TRAP MONITORING	Yes	N/A
DEVELOPMENT AND TESTING OF A PREDICTIVE WATER HAMMER MODEL	No	An appropriation request is submitted prior to project initiation. This project has not been initiated yet.
STEAM CONDENSATE DETECTION AND MONITORING IN STEAM MAINS - PHASE II	No	An appropriation request is submitted prior to project initiation. This project has not been initiated yet.
STEAM CONDENSATE DETECTION AND MONITORING IN STEAM MAINS - PHASE III	No	An appropriation request is submitted prior to project initiation. This project has not been initiated yet.
DEMONSTRATION OF REMOTE WATER LEVEL MONITORING IN STEAM MANHOLES (Phase II - Commercialization)	No	An appropriation request is submitted prior to project initiation. This project has not been initiated yet.
DEMONSTRATION OF ENER-G-ROTOR (Phase II - 50kW)	No	An appropriation request is submitted prior to project initiation. This project has not been initiated yet.

Table 4

CO2 REDUCTION STUDIES	No	An appropriation request is submitted prior to project initiation. This project has not been initiated yet.

Company Name: Con Edison
Case Description: Con Edison Gas & Steam Rate Cases
Case: 09-G-0795-09-S-0794

Response to DPS Interrogatories – Set DPS22
Date of Response: 02/16/2010
Responding Witness: Ecock

Question No. :202
Subject: Steam Research and Development -Follow-up to the Company's response to DPS-35: For the Steam Expo, why is there a need to use an outside consultant to have a brainstorming session with the Steam Business Unit?

Response:
We have used this outside consultant for several prior brainstorming sessions and have found her services useful. The consultant is an expert in brainstorming techniques and has demonstrated her effectiveness in both drawing ideas from participants and getting the participants to prioritize these ideas. The consultant has been more effective in gathering and prioritizing suggestions to solve operating problems than similar in-house efforts conducted without the consultant.

Con Edison

Hearing Exhibits

STATE OF NEW YORK
DEPT. OF PUBLIC SERVICE
DATE: 6/9/09
CASE NOS: 09-S-0794, 09-G-0795, and 09-S-0029
Ex. 315

STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

Case 09-S-0794 - 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.

Case 09-G-0795 - Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Consolidated Edison Company of New York, Inc. for Gas Service.

CASE 09-S-0029 - Proceeding on Motion of the Commission to Consider Steam Resource Plan and East River Repowering Project Cost Allocation Study, and Steam Energy Efficiency Programs for Consolidated Edison Company of New York, Inc.

ATTENTION

This exhibit is among those prefiled in the captioned cases by active parties that executed two joint proposals that were filed on May 18, 2010. Those that executed the joint proposals subsequently stipulated that they would not cross-examine the witnesses of each other given that they were supporting at that time the Commission's adoption of the terms of the joint proposals. In this context, the fact that these parties did not cross-examine the witnesses of each other does not mean and cannot reasonably be understood to mean that the information in this exhibit is uncontroverted among the parties that executed the joint proposals.

BEFORE THE
STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

In the Matter of

CONSOLIDATED EDISON COMPANY of NEW YORK, INC.

Case 09-S-0794

MARCH 2010

Prepared Testimony of:

Matthew F. Cinadr
Power Systems Operations Specialist
Office of Electric, Gas, and Water
State of New York
Department of Public Service
Three Empire State Plaza
Albany, New York 12223-1350

Q. Please state your name, employer, and business address.

A. My name is Matthew F. Cinadr. I am employed by the New York State Department of Public Service (DPS or the Department). My business address is Three Empire State Plaza, Albany, NY 12223.

Q. What is your position in the Department?

A. I am employed as a Power Systems Operations Specialist in the Office of Electric, Gas, and Water in the Bulk Electric Systems Section.

Q. Please describe your experience regarding steam production and electric-generating facilities.

A. I have worked in the field of power systems and electric-generating facilities for over 30 years. I have testified in numerous administrative hearings before the Commission and provided reports on numerous issues such as capital expenditure additions, power plant performance, accidents, operations, and maintenance matters.

Q. Do you have additional information regarding your experience that you would like to present?

A. Yes, Exhibit__(MFC-5) provides more details on my experience.

Q. What will your testimony address?

A. My testimony will address my review of the Company's Capital spending and Operations and Maintenance (O&M) budget testimony for steam production. I will also present my findings and recommendations with respect to some of the ongoing challenges the Company faces in its steam production operations. Finally, my testimony addresses my recommendation for the Company to provide production plant performance data to the Commission on a regular basis

Q. Are you sponsoring any other exhibits?

A. Yes, exhibits Exhibit___(MFC-1) through Exhibit___(MFC-6). These Exhibits are aimed at presenting detailed levels of technical information used in my ongoing review and monitoring of the Company's planned and actual operations. Exhibit___(MFC-1) is a multipage document containing a reprint of an article that appeared in *Combined Cycle Journal*, First

Quarter of 2009, titled HRSG Assessments Identify Trends in Cycle Chemistry, Thermal Transient Performance by Dooley and Anderson. Exhibit___(MFC-2) is an article Flow-Accelerated Corrosion in Fossil and Combined Cycle /HRSG Plants by Dooley. Exhibit__(MFC-3) is an extract from an American Society of Mechanical Engineers library document titled an Overview of Gas Turbines. This extract discusses Gas Turbines and Heat Recovery Steam Generators and provides authoritative information on them. Exhibit___(MFC-4) is a reference to information obtained in response to DPS-53 on the Company's power plant performance. Exhibit___(MFC-5) is additional biographical information as noted above. Exhibit___(MFC-6) describes my recommended reporting requirements.

Production Capital Budget

Q. Please explain your overall approach for reviewing and analyzing the Company's proposed production capital budget.

A. In reviewing the Company's proposed production capital expenditures, I looked at the reasonableness of the proposed budget relative to recent historic budgets. I also looked at the necessity, timing, scheduling, and projected costs of specific programs and projects. In addition I reviewed the Company's formal budgeting methods, procedures, internal review and approval processes. After reviewing and studying the Company's testimony, exhibits and work papers, a series of informal information requests were issued. Further clarification on some requests was sought. Building on available information, initial conclusions were drawn and some formal requests were issued.

Q. What did you do to verify the reasonableness of your initial conclusions?

A. I visited the Company's facilities on numerous occasions during the discovery phase of this proceeding and in conjunction with my other case work and routine assignments. These visits build upon the many meetings and other site visits I have made over the last several years to the Company's East River, Hudson Avenue, 59th Street, 74th Street and other steam production plants. Most recently, over a two day period, I toured the Company's facilities at its 59th Street and 74th Street Plants. These inspection tours were done in conjunction with extensive discussions with plant managers, technical and operations managers, environmental, health and safety managers, engineering managers, and members of the Steam Operations and Corporate accounting and finance organizations. Numerous systems were inspected and both capital and O&M expenditures were discussed and evaluated at the facilities. For example, steam production sampling, steam purity and quality reporting were among the topics reviewed.

Q. Based on this review, what is your general conclusion related to the Company's proposed steam production capital projects for the next four years as presented in the Company's Exhibit__(SOP-1.1 page 1 of 2)?

A. The proposed budgets are extensive in that the projects and programs affect many areas of steam production across almost all the Company's facilities. I found the programs all contain the traditional engineering and operations and maintenance type of activities one would expect to find. Additionally, some of the Company's programs have elements and practices unique to Con Edison owing to the complexity, age, size, and location of the steam system. That said, the Company's overall production capital plans also include three other very significant projects; natural gas conversions at the 59th Street and 74th Street stations, and the Hudson Avenue Replacement project, as described in the Company's Exhibit___(SOP-1.1 page 2 of 2). My testimony only addresses those projects in Exhibit__(SOP-1.1 page 1 of 2).

Q. Please continue.

A. Based on my review, I have concluded that the Company's four-year budget is reasonable. The forecasted budget ranges from $55.7 million in

2010 to $25.4 million in 2013. Recent comparable historic budgets were approximately $52 million and $66 Million for 2008 and 2009 respectively. The increases are primarily driven by a subset of projects, some of which are the final completion of multi-year water treatment projects and other projects that will result in fuel efficiency savings for customers. For example, those projects related to the on-going West 59th street and 74th permanent demineralization systems, the recent East River 1 & 2 Water Treatment Upgrade and East River 1 & 2 Heat Recovery Steam Generator (HRSG) bottom blow down systems comprise the majority of the Company's forecasted expenditures in this case.

Q. Please explain how the information obtained during your site visits has affected your conclusions.

A. I'll use the East River station as an example. The station has undergone many changes and additions over the years. Currently, several large, related projects are being undertaken to study, modify, and improve this facility. For example, the Company has projected that cost reductions and operational efficiency improvements will be realized at Boilers 10 and 20 by implementing the Water Treatment Upgrade Project. These and other modifications permanently improve the facility and ease its operations in a cost-efficient manner. Certain boiler operations that are necessary to control steam purity are being improved, without them, operations can unnecessarily waste fuel. These and other Company operations are being addressed with cost-effective projects. The work proposed (Water Treatment Upgrade Project) is intended to increase throughput of the process and reduce operational problems inherent with the initial phase of the existing treatment system.

Q. Please continue.

A. In my review of the Company's projected capital projects, I found that many of the Company's projects and activities were familiar as part of my on-going, non-rate case, assignments, including from my work on Case 09-S-0029 in particular. I have been aware of on-going priority changes and emerging problems experienced by the Company’s steam production facilities that I review on an ongoing basis apart from the rate case schedule. In my opinion, Con Edison Managers have provided sufficient information to demonstrate that reasonable operations, engineering, capital planning and budgeting processes are in place and being used.

Steam Production Operations and Maintenance

Q. Please explain the scope of your review of the Company's steam production operations and maintenance programs?

A. My review was focused on the major items driving a need for the rate increase as detailed in the Company's Exhibit___(SOP-3 pages 1 through 5). My review was narrowed to the Steam Operations Production amounts cited at $3.644 million dollars. The trend in O&M as forecast is essentially flat, providing necessary funding for the Company given the associated operational, environmental, and health & safety issues.

Q. Please describe the extent of your review of these forecasted expenditures?

A. During recent site visits, Company representatives brought me to specific areas of the plant at which these activities are being undertaken. I observed the significant amount work in progress. This work is being accomplished, in many instances, while operations are on-going. A good example of some of the projects observed are those related to five-year building façade inspections, governed by New York City Local Law 11.

Q. Please continue.

A. The internal and external masonry repair projects, and similarly the steel and concrete projects, provide some good examples. I observed the serious approach to and extent of the work that has been completed and currently being undertaken by the Company.

Q. What is your overall opinion regarding the Company's forecast of rate year production O&M expenses?

A. It is my opinion that the Company has established reasonable forecasts of rate year steam production O&M expenses.

Reporting Requirements

Q. Do you have any recommendation in regard to reporting requirements?

A. Yes. I recommend that the Commission require Con Edison to submit reports to the Commission similar to those previously required in Section J of the Joint Proposal adopted in Case 05-S-1376. I have included a description of my recommended reporting requirements in Exhibit___(MFC-6). These reporting requirements, relate to the Company's production plant capital expenditures, production plant availability and O&M expenditures. In addition, these reports should include detailed North American Electric Reliability Corporation (NERC) Generating Availability Data System (GADS) power plant performance statistics. The Company's existing power plant performance reporting systems already collect the data that would be suitable for meeting the filing requirements. Routine reports are a valuable information source to Staff and the parties and could also streamline the discovery process in the future. Furthermore, the power plant performance data should be routinely provided with future steam rate case petitions to support and justify the Company's continued use of the fuel adjustment clause and provide assurance of the Company's continued reliability of service.

Steam Production Operations Concerns

Q. Have you regularly monitored and reviewed steam production operations issues with the Company?

A. Yes, I have.

Q. Do you understand the Company's recent Heat Recovery Steam Generator (HRSG) problems discussed in its Steam Operations Panel (SOP) testimony on page 57 line 1?

A. Yes, I have a general understanding of this problem at East River Re-powering plant (ERRP)?

Q. Briefly summarize some of your concerns as pertaining to the ERRP HRSG?

A. The units, Boiler 10 and Boiler 20, at East River are very large capacity steam generators. Each is capable of producing additional steam with supplemental firing in the HRSG. That is, added fuel is burned in the HRSG supplementing the exhaust heat captured from the operation of the gas turbines. Each large unit has, as expected, posed significant operational challenges with respect to low demand periods of operation. With the large capacity units on line, turn down has been a challenge (turn down refers to a unit's operating range, from minimum, to maximum capacity). Operation of the system is made all the more challenging when these sized units must be held online at low demand periods. The Company has successfully managed to work the scheduling and dispatch of these large units into its operational routines to address these challenges.

Q. What other operational concerns have you recently noted?

A. During routine meetings with the Company, reports were obtained related to a serious operational problem, which forced the units from service for a lengthy period of time in 2009. Eventually, design deficiencies within the HRSG economizer section caused incidents of boiler tube leaks. The economizer is a portion of the HRSG which preheats treated boiler water and is the initial path taken after the water leaves the deaerator, a tank like device which provides for control of the proper amount of oxygen in the water. It seems that an incipient design flaw, one causing problems plaguing the industry, was discovered by the company and promptly remedied within the water path or circuit. This design flaw caused improper distribution in the manifold or header feeding water into some of the HRSG economizer tubes.

Q. Please continue.

A. A certain number of the tubes were unintentionally provided with insufficient water flow and in such cases, rather than normally preheating the water, these sections when operated with low water flows, produced steam which led to a condition known as Flow Accelerated Corrosion (FAC). This operational problem in the economizer is called steaming because steam rather than hot water is produced. Some amount of steaming is always expected but, in this case, there was excessive steaming in what is designed to be a water only portion of the equipment.

Q. Please describe the FAC condition.

A. FAC is described in detail in Exhibit___(MFC-2). The essential problem at ERRP is that when steaming occurred, tubes intended to preheat water produced steam and, in this part of the equipment, excess steam works to remove the protective oxide coating intended to ensure the materials life and provide for reliable operation. Without the protective coating and with repeated exposure to steam, whatever protective oxide develops is washed away almost as quickly as it is developed within the boiler tubes.

Q. What were the consequences of the unknown FAC attacking the economizer?

A. Portions of the economizer sections were damaged beyond repair and lengthy and expensive modifications and repair projects were required.

Q. Have you reviewed the Company's actions in response to this forced outage?

A. Yes, the Company has explained in detail its method of evaluation and its projects to repair the damages. It thoroughly reported on its efforts to bring the units back in service as quickly as possible.

Q. What are your views of the Company's response to this forced outage?

A. The Company has very thoroughly responded and done a reasonable job of defining the problem, and proposing and implementing its solutions.

Q. Has the Company explained the steps being taken to ensure continued operation of the HRSG?

A. The Company has explained many details of its plans to monitor and inspect the HRSG to ensure that it is well aware of the conditions that might develop with respect to further instances of FAC.

Q. What conclusions have you reached with respect to the Company's planned actions on this matter?

A. While the Company has explained its actions and plans, after researching the issue, I have concluded that additional measures are needed and justified.

Q. Please explain?

A. In my research, I developed information as found and explained in Exhibit__(MFC-1). The text outlines a one-day HRSG assessment program. Leading experts in the field of HRSG and FAC have developed this program. A technical paper on FAC is found in Exhibit__(MFC-2). I recommend that the Company be required to work with Staff to develop plans to conduct a thorough assessment of the ERRP HRSGs. These assessment plans should be documented in a report to the Commission and be followed up with action plans based on the HRSG assessments.

Q. What other reasons justify your recommendations for the HRSG assessment?

A. The Company has experienced additional outages and tube-leaks in portions of the HRSG known as the super heater. This part of the HRSG adds more heat to the steam and is in the highest temperature region of the device. It seems that a number of internal tube support structures have been improperly welded, by the original equipment manufacturer, to the tubes and resulted in tube-leaks. This condition presently threatens the reliable operation of the HRSG. Multi-million dollar projects to replace these damaged portions of the HRSG are proposed and have been reviewed as part of the capitol spending plan I addressed earlier. Although the Company has taken every step possible to provide for continued reliable operations of the HRSG, the additional assessment to be conducted as recommended seems to be a reasonable step and one that will give additional assurance that every means possible is being taken to promote further reliable operations of the HRSG.

Q. Do you have any other recommendations?

A. No, this concludes my testimony.

Con Edison

Hearing Exhibits

STATE OF NEW YORK
DEPT. OF PUBLIC SERVICE
DATE: 6/9/10
CASE NOS: 09-S-0794, 09-G-0795, and 09-S-0029
Ex. 316

BEFORE THE
STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

In the Matter of

CONSOLIDATED EDISON COMPANY of NEW YORK, INC.

Case 09-S-0794

MARCH 2010

Prepared Exhibits of:

Matthew F. Cinadr
Power Systems Operations
Specialist
Office of Electric, Gas, and
Water
State of New York
Department of Public Service
Three Empire State Plaza
Albany, New York 12223-1350

Exhibit__(MFC-1)
Page 1 of 17

HRSG assessments identify trends in cycle chemistry, thermal transient performance

By **Barry Dooley,** Structural Integrity Associates, Charlotte, NC (bdooley@structint.com), and **Bob Anderson,** Competitive Power Resources, Palmetto, Fla (anderson@competitivepower.us)

This article compiles information from one-day assessments of heat-recovery steam generators (HSRGs) focusing on cycle chemistry and thermal transients. The primary goal of the work was to help operators become proactive in the identification of key drivers for cycle-chemistry- and thermal-transient-induced failure and damage mechanisms.

Regarding the former, the assessments addressed key factors for flow-accelerated corrosion (FAC), under-deposit corrosion (UDC), and pitting. For the latter, they addressed thermal fatigue and creep fatigue. In each area, the assessments provided a clear picture of exactly where the weaknesses in the approaches were. Based on their findings, the authors are not surprised that the current ranking order for HRSG tube failures essentially has remained static for the last 10 years.

The article also outlines successful approaches for optimizing (1) cycle chemistry to avoid FAC and UDC, (2) the operation of attemperating systems, and (3) the configuration of drain systems to avoid the thermal-transient-driven damage mechanisms. These important messages easily can be applied by operators to change the current mindset of "waiting for failure to occur."

The mechanisms that cause unreliability of HRSGs worldwide are mostly well-known. The leading HRSG tube failure (HTF) mechanism is flow-accelerated corrosion (FAC), followed by thermal fatigue. FAC involves the single- and two-phase variants[1] and is found predominantly in low-pressure (LP) economizers/preheaters and LP evaporators (tubes, headers, and risers). An increasing number of incidents is reported in intermediate-pressure (IP) circuits (tubes and risers)[1]. All HRSG components within the temperature range 100-2500C (212-4820F) are susceptible.

Thermal fatigue occurs in superheaters and reheaters, primarily at header/tube connections because of undrained condensate and attemperator overspray during startup[2]. Creep-fatigue examples are increasing at the same locations in HRSGs operating at steam temperatures above about 565C (1050F)—particularly in circuits containing dissimilar metals at the header/tube connections (T/P 91 and T/P 22)[3]. Thermal fatigue also is observed in LP economizer circuits because of steaming and quenching of the condensate inlet section during startup[4].

The third most important area of failure/damage involves the under-deposit corrosion (UDC) mechanisms in high-pressure (HP) evaporator tubing. As the name implies, this mechanism first requires a deposit on the inside surface of an HP evaporator tube and then some contaminant, or the use of an incorrect cycle-chemistry treatment, that is allowed to concentrate within the deposit and cause increased corrosion, loss of tube wall, and eventual failure.

The most important of these mechanisms, by far, is hydrogen damage which relates to the concentration of chloride (from contaminant ingress, such as condenser leakage) within and beneath the deposit. However, evaporator chemical treatments using acidic phosphates, phosphate blends, or excessive levels of sodium hydroxide also can concentrate and cause damage. Pitting tube failures can occur in any HRSG circuit as a result of repetitive inadequate, and in nearly all cases, non-existent shutdown procedures[5].

Over the last year the authors visited 11 combined-cycle plants around the world to conduct assessments of the cycle chemistry and thermal transient aspects of the HRSGs. A primary goal of these assessments has been to help the operators identify and address proactively previously undetected problems. This is based on the authors' strong implicit belief that the HRSG tube failures and damage mechanisms mentioned above are so well understood that the key drivers (or root causes) can clearly be identified and eliminated prior to inception of serious damage and failure.

These assessments have made it clear that there are common features associated with cycle chemistry operation and thermal transient drivers—most independent of the HRSG type or manufacturer. These repeating or continuing features rarely are identified by plant personnel, but if allowed to continue without remediation, eventually will lead to failure or damage[5]. There is very little variation in experience across the global HRSG fleet. In some respects, this is fortunate because it should allow operators to review the information presented here and commit to making the necessary changes knowing they can mitigate the drivers commonly present and active.

Exhibit__(MFC-1)
Page 2 of 17

Table 1: Demographics of combined-cycle units assessed

Plant	Capacity, MW/type	Gas turbine	Steam turbine	HRSG	Steam pressure/ temperature,psig/F	Operating hours/starts at assessment	Cooling water/ condenser tubing	Benchmark rating
A	535/2 x 1	GE 7FA Steam aug	GE D11	Vogt Duct burners SCR + CO	HP: 2100/1050 IP: 450/1050 LP: 70/. . .	14,000/570	ACC[2]	Above average
B	170/2 x 1	GE LM6000 Steam aug[1]	Nuovo Pignone	Nooter Duct burners SCR + CO	HP: 865/810 IP: None LP: 55/440	4000/300		Above average
C	85/3 x 1	GE LM2500[1]	GE DEX1.1	Zurn Duct burners SCR + CO	HP: 885/910 IP: 400/550 LP: . .	130,000/530-630	Wet tower	Average
D	525/2 x 1	GE 7FA	Toshiba	Vogt Duct burners SCR	HP: 1968/1056 IP: 477/1055 LP: 72/570	10,000/130	ACC[2]	Above average
E	540/2 x 1	Siemens W501FD2	Siemens HE	NEM	HP: 1726/1055 IP: 351/1055 LP: 55/. . .	4000/190	River/ stainless[3]	Average
F	380/1 x 1 Single shaft	Siemens V94.3A	Siemens	Nooter	HP: 1740/1050 IP: 333/1050 LP: 58/. . .	75,000/340	Seawater wet tower/ titanium	Average
G	380/1 x 1 Single shaft	Alstom GT26	Alstom	Alstom	HP: 1740/1050 IP: 398/1050 LP: 65/. . .	80,000/350	River/stainless[4]	Average
H	400/1 x 1 Single shaft	MHI M701F	MHI TC2F-30	NEM	HP: 1500/1040 IP: 493/1050 LP: 85/. . .	13,000/90	Wet tower/ stainless[5]	Above average
I	760/2 x 1	GE 9FA	GE	Nooter	HP: 1740/1050 IP: 334/1050 LP: 60/. . .	36,000/120	Seawater/ titanium	Average
J	286/1 x 1	Siemens V84.2	Siemens	ABB SCR + CO	HP: 962/932 IP: 128/479 LP: 60/. . .	72,000/300	Wet tower	Not done
K	90/2 x 1	GE MS6000	GE	Deltak	HP: 880/830 IP: 330/514 LP: 10/. . .	126,300/336	Wet tower	Not done

[1]Steam for NO_x control [2]Air-cooled condenser [3]10-20 ppm chlorides [4]200 ppm chlorides [5]River water, 15 ppm chlorides

Solutions to the cycle chemistry influenced areas are much more mature than those for the thermal transient issues. But both are now sufficiently established to allow operators to specify the necessary features to eliminate these drivers in new plant designs, and to take corrective action in existing plants. The authors already are implementing solutions for operators worldwide. One of the most important conclusions of this effort is that organizations should be proactive with plants that haven't already experienced failure. For HRSGs, it is never acceptable to sit back complacently because incipient damage hasn't yet manifested itself as failure.

Assessment process

Table 1 shows the diversity of plants assessed. They include units with equipment from seven HRSG, four gas turbine (GT), and six steam turbine manufacturers, and have a wide range of operating experience in terms of hours and starts. Cooling systems vary with the location and include use of river water, seawater, air-cooled condensers, and wet cooling towers.

The last column of the table provides an objective HRSG cycle chemistry and thermal transient benchmark rating that is independent of unit type and manufacturer. The benchmarking process was introduced in 2004 to permit ranking HRSGs on a worldwide basis[6]. A scorecard for use at your plant, presented in the sidebar, enables you to see how your facility stacks up against the units assessed for this article (p 118).

The assessment process is conducted during a one day visit by the authors to review the design, construction, operation, and cycle chemistry of the combined cycle and HRSG. On the cycle chemistry side, review and assessment of the following take place:

- Heat-balance diagrams for the plant.
- Arrangements of the HRSG tubing circuits.
- Cycle chemistry treatments for condensate and feedwater, and for each drum—including the actual chemicals used. Operating and shutdown conditions are included in the review.
- Installed online instrumentation and how close it comes the Structural Integrity's "Fundamental Level of Instruments," and whether they are alarmed in the control room. More detail on this later.
- Review of any HTF influenced by cycle chemistry.
- Close review of the FAC potential for the unit, which includes the materials identification and operating temperatures of the LP and IP circuits susceptible to FAC[1].
- The monitored total iron levels in the feedwater and drums.

On the thermal transient side, review and assessment of the following are conducted:

- Superheater and reheater: dimensions, materials and arrangement of tubes, headers, interconnecting pipes, attemperators, HP steam pipe, cold-reheat pipe, drains, and flash tank.

Exhibit __ (MFC-1)
Page 3 of 17

- LP economizer: dimensions, materials and arrangement of tubes, headers, interconnecting pipes, drains, and condensate pipe.
- For both lead and lag units in 2 × 1 plants: historical DCS plots of GT load, speed, and exhaust temperature, HP steam flow, HP drum pressure, HP superheater outlet temperature, attemperator inlet and outlet temperatures, HP spray-water valve position, and superheater drain valve positions for a typical cold start, hot start, and normal shutdown. Equivalent DCS points for the reheater system are also required for units with reheaters.
- For both lead and lag units in 2 × 1 plants: operating procedures used for cold starts, hot starts, and normal shutdowns.

Tube failure prevention program

It is very common for organizations to assume the cause of a unit's first tube failure is "a bad weld." Sometimes this may be true, but most often the actual root cause is an undetected cycle chemistry shortfall, design feature, or operating practice that has repeatedly inflicted corrosion, corrosion fatigue, or thermal-mechanical fatigue damage in the failed tube and its neighbors.

None of the plants assessed has a program or policies in place that ensure actual root cause will be determined when a failure occurs. Not surprisingly, 64% of the plants assessed already have experienced failures, or display obvious symptoms of severe thermal-transient damage in the superheater, reheater, or economizer (Table 2).

The only way to be sure that the corrective actions taken will prevent a tube failure from recurring is to remove the failure site, have the actual failure mechanism identified via a metallurgical laboratory analysis, then determine the root cause of the failure.

Taking the additional forced outage time to remove the failed section of tube is not a trivial matter. However, failing to do so is gambling with the unit's future reliability and maintenance costs. A tube failure prevention plan should be developed and implemented early in the unit's life—hopefully prior to any tube failure.

The time for plant mangers, asset managers, operations directors, general managers, and executives to objectively agree on the relative priorities of long-term unit reliability and maintenance cost versus short-term revenue and power production needs is before failures occur and the unit is operating well—not during the forced outage when the unavailability and lost-revenue meters are running.

Such a plan need not be complex, but should include the following key elements to be executed during each tube failure event:

- Prior agreement, throughout the management chain, that a material sample containing the failure site will be removed from the HRSG for metallurgical analysis.
- Root cause, as contrasted with apparent cause or failure mechanism, must be determined for each tube failure event.
- Each failure location within the HRSG must be precisely recorded using an unambiguous orientation scheme. Failure-site orientation (up/down, gas flow direction, etc) should be recorded and retained.
- A modest supply of spare HRSG tubing in appropriate sizes and materials, including a few bends, should be placed in inventory and kept in good condition.

HRSG cycle chemistry and thermal transient benchmarking scorecard

Answer the non-subjective questions below for your plant. Then do the math to see how it stacks up against the units assessed for this article.

Factor **Points**

1. How many HRSG tube failures have there been over the last three years?
- ☐ 0 0
- ☐ 1-2 1
- ☐ 3-5 2
- ☐ 5-10 3
- ☐ More than 10 4

Subtotal
(Points × Weighting of 3) =____

2. How many chemistry influenced failures have there been over the last three years (including FAC, corrosion fatigue, hydrogen damage, acid phosphate corrosion, caustic gauging, pitting)?
- ☐ 0 0
- ☐ 1-2 1
- ☐ 3-5 2
- ☐ 5-10 3
- ☐ More than 10 4

Subtotal
(Points × Weighting of 3) = ____

3. What percentage of the fundamental level of cycle chemistry instrumentation does the plant have (see Table 4 for details)?
- ☐ 100% 0
- ☐ 90-99% 1
- ☐ 70-89% 2
- ☐ Less than 70% 3

Subtotal
(Points × Weighting of 3) =____

4. Is a reducing agent (oxygen scavenger) used in the condensate and feedwater during operation or shutdown?
- ☐ Yes 1
- ☐ No 0

Subtotal
(Points × Weighting of 2) =____

5. What is the level of iron in feedwater during steady-state operation?
- ☐ Less than 5 ppb 0
- ☐ 5-10 ppb 1
- ☐ 11-20 ppb 2
- ☐ More than 20 ppb 3
- ☐ Don't know 3

Subtotal
(Points × Weighting of 2) = ____

6. What is the level of iron in the low-pressure drum during steady-state operation?
- ☐ Less than 5 ppb 0
- ☐ 5-10 ppb 1
- ☐ 11-20 ppb 2
- ☐ More than 20 ppb 3
- ☐ Don't know 3

Subtotal
(Points × Weighting of 2) = ____

7. Has temperature been monitored by specially installed thermocouples on low-pressure economizer, superheater, and reheater during startup, shutdown, and operation to identify damaging thermal transients?
- ☐ Yes, all three 0
- ☐ Yes, on two 1
- ☐ Yes, on one 2
- ☐ No 3

Subtotal
(Points × Weighting of 2) = ____

8. Does the plant have written action plans to address root causes of tube failures or potential tube failures?
- ☐ Yes 0
- ☐ No 1

Subtotal
(Points × Weighting of 1) = ____

9. Does the plant have written action plans to address damaged tubing or potential damage to tubing?
- ☐ Yes 0
- ☐ No 1

Subtotal
(Points × Weighting of 1) = ____

Grand total .... ____

Find your HRSG's cycle chemistry and thermal transient rating from the table below:

Less than 5 points	World class
6-10 points	Very good
11-25 points	Above average
26-40 points	Average
41-45 points	Below average
More than 45 points	Poor

Cycle chemistry, corrosion, FAC

There are several cycle chemistry issues important in preventing pressure-part failures in multiple-pressure combined-cycle systems. Among these, two major areas of concern that are influenced by the cycle chemistry treatment regime are FAC and UDC.

FAC. Both single- and two-phase FAC can occur equally in horizontal and vertical gas path (HGP and VGP) HRSG tubing, headers, risers, and the LP drum. During an assessment, it is important to recognize exactly which type of FAC can occur in each circuit because the potential solutions are different for each. A recent review of FAC in combined-cycle plants[1] included numerous examples of the different types of attack and morphologies common in HRSGs. Regions of concern include the following:

- Economizer/preheater tubes at inlet headers.
- Economizer/preheater tube bends in regions where steaming occurs.
- Vertical LP evaporator tubes on HGP units, especially in the bends near the outlet headers.
- LP evaporator inlet headers which have a tortuous fluid entry path and where orifices are installed.
- LP riser tubes/pipes to the LP drum.
- LP evaporator transition headers.
- IP economizer inlet headers.
- IP economizer outlet headers, especially in bends near the outlet headers in units prone to steaming.
- IP riser tubes/pipes to the IP drum.
- IP evaporator tubes on triple-pressure units that are operated at reduced pressure.
- LP drum internals.
- Horizontal LP evaporator tubes on VGP units, especially at tight hairpin bends.

UDC occurs exclusively in HP evaporator tubing. The three UDC mechanisms— hydrogen damage, acid phosphate corrosion, and caustic gouging—all require heavy deposits and a concentration mechanism within those deposits. For hydrogen damage, the concentrating medium is usually chloride, which enters the cycle through condenser leakage.

Acid phosphate corrosion relates to a plant using phosphate blends which have sodium to phosphate molar ratios below 3:1 and/or the use of congruent phosphate treatment using one or both of mono- or di-sodium phosphate.

Caustic gouging involves the concentration of either NaOH used above the required control level within caustic treatment or the ingress of NaOH from regeneration of ion-exchange resins.

Deposition and the UDC mechanisms occur in HP evaporator tubing in both vertical and horizontal HRSGs. On vertical tubing the deposition concentrates on the ID crown of the tube facing the GT. It nearly always is heaviest on the leading HP evaporator tubes in the circuit because these have the areas of maximum heat transfer. UDC mechanisms occur in exactly the same areas.

On horizontal tubing, both deposition and the UDC mechanisms occur on the ID crown facing towards or away from the GT. Damage usually occurs on the side facing away from the GT when poor circulation rates, steaming, or steam blanketing occur. These can lead to stratification of water and steam and subsequent

Table 2: Thermal transient factors considered for the HRSGs assessed

Thermal transient factors assessed	Plant										
	A	B	C	D	E	F	G	H	I	J	K
Tube failure root cause program in use?	No	No	No	No	No	No	No	No	No	No	No
Routine attemperator inspection program in use?	No	No	No	No	No	No	No	Yes	No	Yes	No
Symptoms of severe thermal transients in SH (bowed tubes, failed tubes, oxide spalling)?	Yes	Yes	No	No	No	No	No	No	Yes	Yes	Yes
Symptoms of severe thermal transients in RH (bowed tubes, failed tubes, oxide spalling)?	No	No RH	No RH	No	Yes	No	No	No	Yes	No RH	No RH
Symptoms of large thermal transients in economizer (stretched or failed tubes)?	No	Yes	No	No	Yes	No	Yes	No	No	No	No
Drain pipes too small?	Yes	—[1]	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
Blowdown vessel elevated above headers?	Yes	Yes	Yes	Yes	Yes	Yes	Yes	No	Yes	Yes	Yes
Drain pipes have continuous downward slope?	No	No	No	No	No	No	No	No	No	No	No
Drains from different pressure levels combined?	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
Drain operation based upon reliable condensate detection?	Press	Press	No	Tem P	Tem P	Tem P	Press	Press	Tem P	No	No
Drains located near SH/RH header ends?	No	No	No	No	No	No	No	No	No	No	No
Drains opened prior to purge?	Yes	Yes	Yes	No	No	No	No	No	Yes	Yes	Yes
Drains opened during purge?	Yes	No	Yes	No	No	No	No	No	Yes	Yes	Yes
Drain valves operate automatically?	No	No	No	Yes	Yes	Yes	Yes	Yes	No	No	No
Cold reheat piping sloped downhill in direction of steam flow?	No	No RH	No RH	Yes	Yes	Yes	No	Yes	Yes	No RH	No RH
Condensate migration evident from DCS data in SH?	Yes	No Plots	No	Yes	Yes	Yes	Yes	Yes	Yes	No Plots	No
Condensate migration evident from DCS data in RH?	Yes	No RH	No RH	No	Yes	Yes	No	Yes	No	No RH	No RH
Attemperator leakage/overspray can flow directly into heating coil?	Yes	Yes	Yes	Yes	Yes	Yes	No	No	Yes	Yes	Yes
Spray control valve integral with spray nozzle?	No	No	Yes	No	Yes	Yes	No	Yes	No	No	No
Simple feedback loop used for attemperator control?	Yes	No	No	Yes	No	No	No	No	Yes	No	No
Sufficient upstream or downstream straight pipe length?	Yes	Yes	No	Yes	Yes	Yes	Yes	Yes	Yes	No	Yes
Manual manipulation of outlet steam temperature setpoint?	Yes	No	No	No	No	No	No	No	Yes	No	No
Manual control of attemperator spray valve?	Yes	No	No	No	No	No	No	No	No	No	No
Intermittent attemperator operation?	No	No	No	No	No	No	No	Yes	Yes	No	No
Overspray conditions evident from DCS data in SH?	Yes	No Plots	No	Yes	No	No	No	No	No	No Plots	No
Overspray conditions evident from DCS data in RH?	Yes	No RH	No RH	No	No	No	No	No	No	No RH	No RH
Attemperator control instability evident from DCS data in SH?	No	No Plots	No	Yes	Yes	Yes	No	No	Yes	No Plots	No
Attemperator control instability evident from DCS data RH?	No	No RH	No	No	No	Yes	No	No	Yes	No RH	No RH
Outlet steam over-temperature conditions evident from DCS data in SH?	Yes	No Plots	No	Yes	No	No	No	No	No	No Plots	No
Outlet steam over-temperature conditions evident from DCS data in RH?	Yes	No RH	No RH	Yes	No	No	No	No	No	No RH	No RH
Economizer drains share second isolation valve?	Yes	Yes	No	Yes	Yes	Yes	No	No	Yes	No	No
Cross flow economizer inlet row with baffles in common headers?	Yes	No	No	Yes	Yes	No	No	Yes	No	No	Yes
Thermal deaerator or economizer recirculation used for startup?	No	No	Yes	Yes	Yes	Yes	Yes	Yes	No	Yes	Yes
Shutdown SH or RH temperature ramp rate limit established for headers?	No	Yes	No	No	Yes	No	Yes	Yes	No	Yes	Yes
Startup SH or RH temperature ramp rate limit established for outlet headers?	No	Yes	No	No	No	No	No	No	No	Yes	Yes
HP drum pressure ramp rate limit established for startup?	Yes	Yes	No	Yes	Yes	Yes	No	Yes	Yes	Yes	Yes
SH and RH steam cooled during shutdown?	No	Yes	No	No	Yes	No	Yes	No	No	Yes	Yes
Prudent SH or RH temperature ramp rate limit exceeded during shutdown?	Yes	No	No	Yes	No	Yes	No	Yes	Yes	No	No
Prudent SH or RH temperature ramp rate exceeded during startup?	No	No	No	Yes	Yes	Yes	Yes	No	Yes	No	No
Prudent HP pressure ramp rate exceeded during startup?	No	No	No	Yes	No	Yes	Yes	No	No	No	No
Use ETM on shutdown?	No	—[2]	—[2]	No	—[2]	—[2]	—[2]	—[2]	No	—[2]	—[2]
Use ETM during lag unit startup?	No	—[2]	—[2]	Yes	—[2]	—[2]	—[2]	—[2]	No	—[2]	—[2]

[1]No drain sizing calculations performed on this class of unit from which to determine if existing drains are adequate
[2]These factors are only applicable to units with the GE 7FA/9FA GT

The unit is subject to undesirable thermal transients due to this factor
Unit is not subject to undesirable thermal transients due to this factor
The unit may be subject to undesirable thermal transients due to this factor
The factor is not applicable to this unit

Table 3: Cycle chemistry factors considered

Plant	Reducing agent used?	Ammonia/amine	LP, IP, HP circuits independently fed?	Drum treatment	Iron in feedwater, ppb	Iron in steam drums, ppb	Fundamental instruments, %[2]	FAC inspections conducted?
A	Yes, carbohydrazide	Amine blend	No, LP drum feeds IP/HP feedpump	LP: None IP, HP: Phosphate blend	NM	NM	33	No
B	No, never	Ammonia	No, LP drum feeds HP feedpump	LP: None HP: Tri-sodium phosphate	< 5	LP: NM HP: 25-160	60	Yes
C	Yes, proprietary	Amine blend	No, LP drum feeds IP/HP feedpump	LP: None IP, HP: Congruent phosphate blend	NM	NM	0	No
D	No	Ammonia (pH 9.2-10.2)	No, LP drum feeds IP/HP feedpump	None	2-8	NM	85	No
E	No, after first two years	Ammonia (pH 9.3-9.4)	No, LP drum feeds IP/HP feedpump	LP: None IP, HP: Tri-sodium phosphate	5-6	NM	60	No
F	No, never	Ammonia	Yes, from deaerator	LP: NaOH (pH 9.5-9.7) IP, HP: None (pH 9.6-9.7)	10	LP: > 30 IP: 10 HP: 10	53	Yes, for preheater
G	No, removed after FAC attack	Ammonia (pH 9.6-9.8)	Yes, from deaerator	LP: NaOH (1 ppm) IP, HP: None	< 2	LP: 20-50 IP: 7-8 HP: < 5	58	Yes, on IP risers
H	No, never	Ammonia (pH 9.8)	Yes, after preheater	LP: NaOH IP, HP: None	About 10	LP: > 100 IP: < 10 HP: <5	81	No
I	No, after first two years	Ammonia (pH 9.8)	Yes, from deaerator	LP, IP, HP: Tri-sodium phosphate (pH 9.5-9.9)	< 1	NM	66	Yes, on economizer bends
J	Yes	NAv	No, LP feeds IP and HP feedpumps	IP, HP: Phosphate	—[1]	—[1]	—[1]	—[1]
K	NAv	Amine blend	No, LP drum feeds IP/HP feedpump	LP, IP, HP: Blend of mono-, di-, and tri-sodium phosphate	—[1]	—[1]	0	—[1]

NM= Not measured [1]Cycle chemistry assessment not conducted [2]Structural Integrity has identified the fundamental instruments, alarmed in the control room, necessary for identifying when contamination in the HP evaporator is serious (see Table 4). This column gives the percentage of those necessary instruments installed at each of the plants

heavy deposition in a band along the top of the tubing.

While the FAC and UDC mechanisms occur at opposite ends of the plant, they are linked by the corrosion products generated by the corrosion/FAC mechanisms in the LP sections of the HSRG. Corrosion products subsequently deposit in the HP evaporator tubing and form the basis of the under-deposit corrosion damage mechanisms. This link forms the main focus of the cycle chemistry assessments in the plants, which identify the precursors or active processes if left unaddressed, will eventually lead to failure/damage by one or both mechanisms. Acting proactively can mitigate the risk for both.

Analysis of Table 3, which presents the cycle chemistry treatments and key indicators for the diverse group of plants assessed, identifies the predominant factors for FAC and UDC.

Flow-accelerated corrosion

FAC is the leading cause of damage and failure in HRSGs. Its control in combined-cycle/HRSG plants usually requires a three-pronged approach that includes the following:

- Operating with an oxidizing chemistry. This requires an all-volatile treatment—oxidizing AVT(O)—or oxygenated treatment (OT) to control the single-phase component.
- Operating at elevated pH (at least 9.8) to control the two-phase component.
- Monitoring (specifically, analyzing the total iron concentration in the condensate, feedwater, and in each drum) to verify/confirm whether the treatment program is successful.

The 11 detailed assessments of the plants profiled in Tables 1-3 have revealed these important findings:

1. Reducing agents (oxygen scavengers) are used in 37% of the plants. This figure is reduced from previous surveys which indicated that about 50% of HRSGs were using reducing agents[5].
2. Of the plants assessed, 37% have the LP evaporator/drum independently fed and not feeding the IP and HP circuits. This affords operators the flexibility of addressing single- and two-phase FAC uniquely by increasing the pH and adding a solid alkali such as tri-sodium phosphate (TSP) or NaOH.
3. About 40% of the LP circuits add TSP or NaOH.
4. Four of the 11 plants assessed do not know the iron levels in the condensate/feedwater and eight do not know the levels in the LP drum. In many cases where iron levels are

Exhibit__ (MFC-1)
Page 7 of 17

measured, the organization uses a technique that is either only applicable for soluble iron or does not have sufficient low-level capability for total iron measurement.

5. Few plants (37%) have made any detailed NDE assessments of FAC in the lower-pressure circuits; those that had concentrated their assessments on individual circuits where failures or damage had been identified previously.

6. Many organizations, including those within these assessments, try to address both single- and two-phase FAC concurrently despite strong evidence that the optimum process is to address each individually[1]—this because they are controlled by different parts of the cycle-chemistry envelope.

Do plants have single-phase FAC under control? What indicators are used during the assessment for single-phase FAC?

To answer these questions requires giving proper attention to the following two factors:

- Ensure that a reducing agent is not used in the cycle during any period of operation or shutdown. It has been well established for about 20 years that single-phase FAC in HRSGs is controlled by the oxidizing-reducing potential (ORP) of the condensate and feedwater. In HRSGs, the potential always should be oxidizing; this means operating without a reducing agent[1].
- Identify whether sufficient oxidizing power is available to passivate all the single-phase locations. The indicators the authors look for are: (1) the actual level of oxygen at the condensate pump discharge (CPD) and in the feedwater at the feedpumps, and (2) the color of the LP and IP drums.

Many plants with HRSGs have excellent air in-leakage control, with only 5-10 ppb oxygen being identified at the CPD. The oxygen level would, of course, be much lower after a deaerator if one were installed ahead of the LP economizer/preheater, and in the feedwater if the feedpumps are fed by the LP drum (which may include an integral deaerator).

At some plants there clearly is inadequate passivation of the LP drum (and sometimes the IP drum as well). When there is inadequate passivation, the drum(s) will have a "patchy" red appearance and the grey/black magnetite showing through it usually is associated with low levels of oxygen (2-6 ppb). This means there is still magnetite exposure with incomplete conversion to red FeOOH and associated higher iron levels.

The level of low oxidizing power (low oxygen) may not be able to satisfactorily passivate all the single-phase flow locations in the economizer circuits as well as the LP and IP evaporator circuits and drums. The possibility of increasing the level of oxygen may require investigation—this to provide better single-phase protection while being cognizant of oxygen levels in other areas of the HRSG.

Possible methods include closing deaerator (if included in the cycle) vents or actually adding controlled amounts of oxygen at the deaerator outlet (boiler feedpump suction). However, if high levels of oxygen in the condensate occur intermittently, this would preclude closing of deaerator vents. In such situations, an aggressive air in-leakage solution is needed.

Best practice: Monitor iron to be sure that the level of oxygen in the LP drum is adequate to provide full single-phase FAC protection. Experts have determined the monitoring of total iron in the LP (and IP) drum(s) is the main indicator of the extent of passivation, with the target being total iron levels of less than 5 ppm. This is in agreement with the "Rule of 2 and 5" for corrosion products—that is, less than 2 ppm total iron in the condensate/feedwater and less than 5 ppm in each drum.

Do plants have two-phase FAC under control? What indicators are used during the assessment

Table 4: Fundamental instrumentation for a multi-pressure drum HRSG with condensate and feedwater on AVT(O) and evaporators operating with only tri-sodium phosphate additions

Parameter	Sample locations
Cation conductivity	Condensate pump discharge (CPD) Condensate polisher outlet—if installed (CPO) Feedwater/economizer inlet (EI) Each boiler drum/blowdown (BD) in multi-pressure systems High-pressure steam (HPSH) or reheat steam (RH)
Specific conductivity	Makeup (MU) Each boiler drum/blowdown (BD) in multi-pressure systems
pH	Each boiler drum/blowdown (BD) in multi-pressure systems
Sodium*	Condensate pump discharge (CPD) Condensate polisher outlet—if installed (CPO) or economizer inlet (EI) High-pressure steam (HPSH) or reheat steam (RH)
Dissolved oxygen	Condensate pump discharge (CPD) Feedwater/economizer inlet (EI)
Phosphate	Each boiler drum blowdown (BD) where phosphate is added

*Sodium may not be required on the CPD sample for units with air-cooled condensers

for two-phase FAC?

Two-phase FAC cannot be influenced by oxidizing power (oxygen level), so it is important to identify first the areas where two-phase steaming and streaming flows can occur; secondly, if pH can be increased locally in these areas. Once a plant is satisfied that the single-phase flow areas are adequately passivated—as indicated by the LP and IP drums having an even red surface color below the water level—the monitored total iron levels can be assessed in terms of two-phase FAC.

For the units investigated that exhibited two-phase FAC, total iron values in the LP and IP drums typically were greater than 20 ppb; one was as high as 100 ppb. The areas affected by two-phase FAC usually are the following:

- Preheater/LP economizer bends or areas where steaming occurs.
- LP evaporator bends near the outlet header where two-phase flow occurs.
- LP risers to the LP drum.
- IP economizer bends or areas where steaming occurs.
- IP risers to the IP drum.
- Hairpin bends in horizontal LP evaporator tubing in VGP units.
- LP drum internals.

Steaming easily can be identified in these areas by installing thermocouples at the appropriate locations. In only two of the units assessed had the HRSG manufacturer "armored" some of these areas with chromium-containing tubes and pipes (typically 1-1.25% Cr alloys); the usual areas are LP and IP evaporator outlet tubes with bends, and the risers.

In cases where the single-phase areas have been passivated by oxidizing treatments but monitored total iron levels remain high, two options are available with the potential to reduce and control the two-phase FAC chemically: (1) Increasing the pH of the condensate/feedwater in steps up to 9.8 with ammonia, and/or (2) Elevating the LP and IP drum pH to 9.8 by controlled additions of TSP or NaOH.

Another option, one related to (1), is to use an amine for increasing pH. But this requires very careful monitoring of steam to ensure that the steam turbine manufacturer's cation conductivity limits are maintained.

Also keep in mind that option (2) only can be adopted for the LP drum in cases where the IP and HP drums are not fed by the LP drum. Further, if option (2) is adopted using increased levels of NaOH in the LP and/or IP drums, you *must* monitor steam sodium (saturated and HP/IP); plus, the total carryover from the drums should be measured as discussed below. Whichever option is used, monitoring of total iron is the main indicator with the goal being to meet the "Rule of 2 and 5."

Be aware that optimized cycle chemistry treatments alone cannot always address the combination of single- and two-phase FAC in HRSG circuits. If after addressing single- and two-phase FAC separately and conducting the well understood sampling, chemistry, and monitoring steps suggested above, the iron levels do not approach the "Rule of 2 and 5," then the only options remaining are a combination of inspection/NDE and replacement of tubing/piping in the susceptible areas with that containing 1-1.25% Cr[1].

Under-deposit corrosion

One of the most important proactive items for plants is to ensure that the HP evaporator does not experience one of the under-deposit corrosion mechanisms—especially hydrogen damage. This takes on added importance when the plant is cooled by seawater or other sources with high levels of chloride (more than 10 ppm)—such as many river, reclaimed, or lake waters—and no condensate polisher in the cycle. In the assessment process, particular attention is given to the two key areas for hydrogen damage: (1) deposits in the HP evaporator, and (2) ingress of contaminant (chloride) into the HP evaporator under conditions when serious deposits are present and the HP evaporator chemistry treatment is inadequate.

The 11 detailed assessments conducted revealed the following with respect to UDC:

1. Only about one-third of the plants knows the iron levels in their HP evaporator/drum and, therefore, whether they meet the "Rule of 2 and 5."
2. None of the plants has taken HP evaporator tubing samples from the hottest row for analysis of internal deposits.
3. Most plants do not have an adequate level of "Fundamental Instruments" alarmed in the control room to alert operators when contamination in the HP evaporator is serious.

So, are plants proactively addressing the possibility of under-deposit corrosion? Are indicators being used to determine if a plant has adequate instrumentation coverage?

Obviously, no. None of the plants was trying to correlate the total iron level in its LP circuit to the level of deposit in the HP evaporator. None had taken HP tube samples for metallurgical examination and chemical analysis to assess the level of internal deposits, their morphology and their composition.

It was suggested at each plant that tube samples be taken from the lead (hottest) tube row of the HP evaporator section as near to the outlet of the circuit as possible. On units with vertical tubing (HGP) a secondary location is near the bottom of the lead tube row. If possible, samples should be taken from a tube adjacent to a side wall, or adjacent to the gap between side-by-side modules, where exhaust-gas bypassing results in greater heat transfer.

One of the authors has been developing a database of deposit analyses from a much wider suite of HRSGs worldwide to better understand how deposits in HP evaporator tubes are related to the operating cycle chemistry. Particular attention in developing this database has been given to these three aspects: (1) the "normal" deposit density (mg/cm^2), (2) optical metallography to determine the porosity and morphology of the deposits as well as the indigenously grown magnetite, and (3) elemental mapping across the deposits to determine if any reaction/corrosion products are being formed within or beneath the deposit.

This information will be published soon. But as expected for some time, it is already clear that deposits are minimized when optimum chemistry control is maintained. This is defined as chemistry that achieves the following objectives:

- Controls single-phase FAC in the condensate/feedwater and LP evaporator with an oxidizing treatment—AVT(O).
- Controls two-phase FAC in the same locations by using either TSP or NaOH in the LP drum, if allowed, as mentioned earlier (four of the units assessed, refer to Table 3).
- Adds nothing to the HP drum or a minimum amount of only TSP or NaOH.

It is also very clear that deposits are made worse (thicker) when an HRSG is operated outside of this envelope by the addition of reducing agents and amines in the condensate/feedwater, and mixtures of phosphates (other than TSP) and NaOH to the HP drum. It is important to know as early as possible—particularly in plants cooled by seawater—the deposition rate on the internal surfaces of HP evaporator tubes by sampling those tubes and analyzing their deposits. This helps to assess the risk of UDC in case of contaminant ingress and, more importantly, allows the HRSG to be cleaned at the optimum time.

Assessments focus on the fundamental level of instrumentation needed for every plant because of its importance in addressing the UDC mechanism. It refers to the minimum number and type of instruments required to identify cycle chemistry problems on a particular combined-cycle/HRSG unit. Table 4 shows an example of the fundamental level of instrumentation for a multi-pressure HRSG operating with an AVT(O) oxidizing treatment in the condensate and feedwater and only TSP being added to the drums.

It was quite alarming to record in Table 3 the relatively low level of needed instrumentation on some units. Remember that this instrumentation assures adequate, or increased, protection to the HRSG—especially the HP circuit—in the event of contaminant ingress. A key instrument for phosphate-treated units is a phosphate analyzer on the HP drum. It helps keep this circuit optimized continuously, as opposed to infrequently by grab sampling.

To clearly identify a specific contaminant-ingress situation it is imperative to have cation conductivity monitoring of the HP drum. Global experience confirms that relying solely on a pH monitor to record a pH depression in the HP drum to warn of a contaminant situation does not provide sufficient security when only small condenser "weepers" occur. In many cases, weepers go undetected; in others, operating decisions are made to continue operating the unit with ongoing contamination which has been "corrected" by chemical addition.

Best practice: Seawater-cooled plants without condensate polishing can lower their risk of UDC by installing more than the fundamental level of instrumentation—specifically, by addition of an online chloride analyzer on the HP drum for added security. None of the assessed plants has this feature.

Another item on instrumentation noted during the assessments is the disturbing trend of plants relying heavily on grab samples. It is increasingly common to see a large number of grab-sample analyses conducted every shift, every day, or every week or two by the operating or chemistry staff. Much better continuous control of cycle chemistry is possible by installing the fundamental instrumentation recommended by Structural Integrity—such as the example provided in Table 4. A further benefit of using online instrumentation: The time it took operators to take the grab samples can be used more productively.

Other important cycle chemistry items

Carryover from the HP, IP, and LP drums. As Table 3 illustrates, none of the organizations has comprehensive programs for monitoring carryover; in fact, the percentage of total carryover from any drum was not known by any organization. To protect the steam turbine, it is vital to know the amount of carryover from each drum.

Measurements should be made semiannually to ensure the integrity of steam separators and operational drum levels. The test is simple—one requiring concurrent sampling for sodium in the drum and in the saturated steam. Details of the process are provided in a recent IAPWS technical guidance document[7]. If TSP or NaOH is added to the drums then it shouldn't be necessary to add any more sodium to conduct the test.

Shutdown protection. Another item included in the assessment process is whether the plant protects its HRSG(s) and steam turbine during shutdown periods. Most of the units within the current assessment have facilities to nitrogen-blanket the HRSG(s) to prevent the initiation and growth of pits on internal surfaces. However, only one of the units has an operating dehumidified air system to protect the steam turbine during shutdown periods.

Most combined cycle/HRSG owner/operators should give serious consideration to installing dehumidified air for the LP steam turbine: This is the most effective method for preventing failures in the machine's phase transition zone (PTZ)[8]. This takes on added emphasis if the number of long shutdown periods (more than three days) is increasing year after year.

Thermal transients in HRSGs

Thermal transients are unavoidable if the HRSG is started and stopped, as it must be. This presents no problems provided:

- The OEM accurately anticipates the number and severity of thermal transients to which the HRSG will be exposed.
- The HRSG is competently designed and fabricated to withstand the anticipated transients.
- The OEM, EPC contractor, and/or owner/operator do not introduce features or operating procedures that result in significant unanticipated thermal transients.

HGP HRSGs are constructed with tubes arranged vertically in "harps." These harps are rigid structures requiring that adjacent tubes remain at similar temperatures to avoid severe thermal-mechanical fatigue damage and premature failure. Even with the use of advanced high-creep-strength materials, HRSGs operating at high pressure and temperature must be equipped with HP drum, HP superheater, and sometimes reheater outlet headers and piping, with sufficiently thick walls that require careful management of heat-up and cool-down rates to avoid internal cracking.

VGP HRSGs are arranged with banks of serpentine tubes, positioned horizontally, and supported along their length by tube-support plates. This tube arrangement is considered by some to be more flexible than the harp arrangement used in HGP HRSGs. While this may be true in some cases, VPG HRSGs are not immune to thermal-transient-induced tube failures. Discussion of these failures and their root causes are beyond the scope of this paper since the current assessments did not include any VGP units.

As with cycle chemistry, there are many thermal transient issues that must be managed effectively to avoid excessive thermal-mechanical fatigue damage. Among these, three stand out as having caused a large number of tube failures, or have a high potential to cause cracks in thick-walled components: (1) inadequate drainage of superheaters and reheaters, (2) interstage attemperator overspray, spraywater leakage, and erroneous operation, and (3) quenching of economizer/preheater inlet sections.

Table 2 shows the indicators of ineffective or incomplete drainage, damaging attemperator performance, LP economizer quench, and operating practices known to cause damaging thermal transients in thick-walled pressure parts for the plants assessed. Analysis of this table identifies several key factors that predominate in the three areas of concern.

Superheater, reheater drains

HP superheater and reheater drain-system designs and operating practices that do not remove all condensate prior to initiation of steam flow during cold, warm, and hot startups are unable to protect the superheater and reheater tube-to-header connections, header bores, and nozzle-to-header connections from severe thermal fatigue damage. Such damage has resulted in many premature tube failures, and can be expected to cause header bore cracking and/or nozzle-to-header weld failure.

A large quantity of condensate forms in the superheaters and reheaters during the prestart purge when these heat-transfer sections behave like large air-cooled condensers. It is critical to drain this condensate as fast as it forms; do not allow it to accumulate. For all types of startups, superheater tubes heat up to near exhaust-gas temperature during the time between GT light-off and when steam begins flowing though the tubes.

Undrained condensate will migrate selectively through some tubes as steam flow is initiated, quenching (and shrinking) them. Shrinkage of these tubes, relative to still hot neighboring tubes, results in a large bending stress at the tube-to-header connection and severe thermal fatigue damage. After shutdown, thick-walled headers and steam piping remain hot for long periods. During hot starts, condensate carried by steam flow will enter and quench the still-hot upper headers and steam piping. Cracks in the header bore and outlet nozzle-to-header welds may result from such quenching.

Analysis of data gathered during the 11 assessments reveals the following:

1. All but one of the plants assessed have drain pipes that are too small to remove the quantity of condensate formed during the purge cycle in the time available prior to substantial steam flow beginning. Detailed calculations to determine condensate formation rates in superheaters and reheaters under various startup conditions, and the drain pipe sizes required to remove that

amount of liquid, have been made over the years for several HRSG designs. The authors use this information in assessing drain-pipe size. As an example, each final superheater harp in a typical F-class HRSG requires the equivalent of three 2-in.-diam (5-cm) drain pipes to effectively remove the condensate.

2. Nearly all plants (91%) assessed have their flash tanks positioned at an elevation above the lower headers and none have drain pipes routed with a continuous downhill slope to the tank. During cold and warm starts from zero pressure it is impossible for condensate to flow uphill to the tank or through upwardly flowing sections of drain pipe. By the time sufficient pressure is generated to do so, and if cascading bypass valves are opened early to steam cool the reheater as they should be, steam flow has already moved the accumulated condensate through the superheater and reheater.

3. All plants have drain pipes from superheater or reheater sections that are interconnected and operate at different pressures[9]. This arrangement is ill-advised: When steam is flowing, the pressure in the primary superheater (the superheater upstream of the attemperator relative to steam flow) must be higher than that in the secondary superheater (the superheater downstream of the attemperator relative to steam flow).

If the drains from these sections are interconnected prior to entering the flash tank, condensate will flow from the primary superheater into the secondary superheater. While some condensate from the primary superheater may also flow to the flash tank (if its elevation is not too high) the secondary superheater will not drain and often has its condensate level rise.

Changes to the ASME Boiler & Pressure Vessel Code in 2007[11] mandate that interconnection of drains from superheaters or reheaters of different pressures must not be prevented from flowing, or back-flowing, because of backpressure in the common manifold, flash tank, etc. While useful for helping operators purchase new units with more effective drains, thoughtful attention to drain and flash tank arrangement is required if the desired results are to be realized.

4. None of the plants assessed are equipped with a reliable means of determining when condensate is actually present in the superheater/reheater and when drain valves should be open. Neither can they detect when the superheater/reheater has been successfully drained and drain valves should be closed. Plus, 55% of those assessed have no automatic means of drain operation.

At plants with some form of automation, half use thermocouples installed in drain pipes to determine when to close drain valves, and half close the valves at predetermined pressures. While these methods might work as intended during startups from one initial-pressure condition, neither can accomplish effective draining over the wide range of initial-pressure conditions from which a cycling HRSG must be started.

A significant challenge in effective drain control stems from needing very large drain pipes to remove condensate fast enough during starts initiated from zero pressure when only gravity head is available to move the water, and avoiding excessive release of steam through these large pipes during starts initiated from high pressure. For example, drain-pipe thermocouples might be effective during a startup from zero pressure, when it is possible to leave the drain valves open prior to and during the purge, then close them when the thermocouple detects superheated steam passing through the pipe. However, during a start from initial high pressure the drain valves can't be left open throughout the purge without risk of depressurizing the HP system (if the drain pipes are large enough to work at zero pressure).

Drain-pipe thermocouples are useless for controlling the drain valves during the critical pre-start and purge periods since condensate and steam are both at the prevailing saturation temperature. If the drain valves are not opened until the GT is fired and the drain-pipe thermocouple can be used, there is a good chance that the accumulated condensate will not have completely drained before steam flow commences. The preferred method of controlling drain valves during starts initiated from any pressure is through the use of a level detecting drain pot on each superheater and reheater section that operates at a different steam pressure[4,10].

5. None of the plants assessed has drains located near the ends of the superheater and reheater headers. When new, and when in the cold condition, most harps hang straight with their lower headers level. However, after years of operation lower headers may become tilted as harps are distorted. During hot starts, lower headers become "humped" because of the top-to-bottom temperature differential (condensate laying in the header cools the bottom, shrinking it, relative to the top)[4].

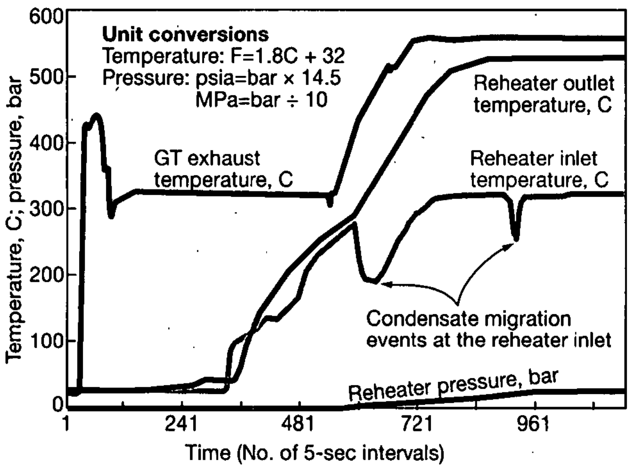
These conditions result in condensate being unable to reach a drain positioned in the center of the header. Such trapped condensate will migrate up adjacent tubes when steam flow commences, regardless of drain-pipe size and operating procedures. The addition of a drain near each end of the header prevents condensate from being trapped.

6. Six of the plants assessed open drains prior to initiating startup to assure superheaters and reheaters are dry. Of these six, five plants open the drains during the purge to drain condensate as it is forming. Waiting until the GT fires to open drain valves, as the other plants do, significantly increases the time required to remove all condensate and increases the risk that some condensate will remain when steam begins flowing.

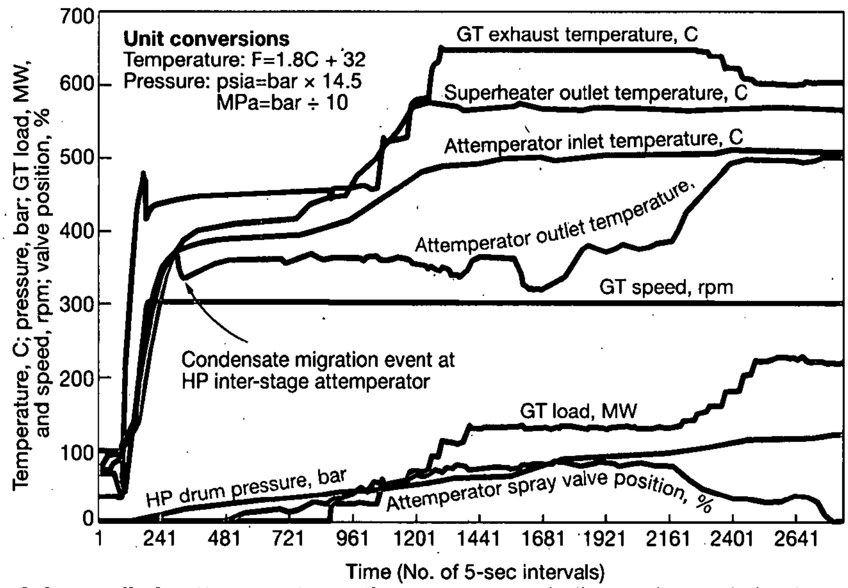
7. Of the plants assessed that have reheaters, 29% are equipped with cold-reheat piping that slopes uphill in the direction of steam flow from HP turbine to HRSG. This arrangement is conducive to having undrained condensate passing from the cold-reheat pipe into the primary reheater[4] as Fig 1 illustrates.

Are superheaters and reheaters being drained effectively?

Migration of undrained conden-



1. Cold-reheat pipe in this plant slopes upward from the steam turbine to the HRSG. Condensate formed in pipe during warming is swept into the reheater inlet, as indicated by the large drops in reheater inlet temperature



2. Large dip in attemperator outlet temperature indicates that undrained condensate was carried by steam flow from the primary to the secondary superheater. Only a large quantity of condensate would register like this on permanent plant instrumentation

sate normally cannot be monitored with the kind of instrumentation typically installed at combined-cycle plants. Permanent steam-temperature sensing elements are relatively slow to respond to sudden temperature changes. Small slugs of condensate pass these temperature elements too fast to register a change in temperature.

Unfortunately, such fast-moving slugs of condensate do cause significant changes in the temperature of the relatively thin-walled superheater and reheater tubes, and to the inner surfaces of hot headers. It is usually necessary to install several temporary tube-temperature thermocouples in the superheaters and reheaters to confirm the presence of condensate migration and quantify its severity[12]. Only very severe condensate migration events last long enough to register on the DCS steam-temperature instrumentation.

More than three-quarters of the plants assessed showed evidence of condensate migration on DCS plots of permanent thermocouples located near the attemperator. Figs 1 and 2 show two such DCS data plots. The dip in temperature at the attemperator outlet in Fig 2 indicates severe condensate migration between the primary and secondary HP superheaters. Likewise, the dip in temperature at the reheater inlet in Fig 1 indicates a large quantity of condensate passing from the cold-reheat pipe into the primary reheater.

Assessment: It's not necessary to install temporary tube-temperature thermocouples in these HRSGs to conclude that significant amounts of condensate remain in, and migrate through, the HP superheater and reheater during startups and that at least some of this condensate passes into the main-steam and hot-reheat piping.

Finally, seven of the plants assessed reported failures at superheater/reheater tube/header connections, stretched tubes caused by quenching, and/or spalling of external tube oxide from high strain at the tube/header connection.

Attemperation systems

The distribution of heat-transfer surface area among the primary and secondary superheaters and reheater, the type of GT, performance of the attemperator control system, quality of attemperator hardware installed, and the attemperator piping arrangement are all critical for obtaining acceptable attemperator performance[13].

The introduction of unvaporized spray water into downstream harps causes damaging thermal transients. This is called over spray and defined as an attemperator outlet steam temperature of less than 50 deg F (28 deg C) above the prevailing saturation temperature.

The 11 detailed assessments revealed the following:

1. Only 18% of the plants perform routine inspections or preventive maintenance on their attemperators. Desuperheaters are notoriously unreliable and subject to severe thermal transients. At least annually, remove/inspect/repair the spray nozzle, control valve, and block valve, and do a borescope inspection of the thermal liner and its attachment points.

2. Nine of the 11 plants assessed have attemperator piping arrangements that allow unvaporized, or leaking, spray water to flow directly into harps during low (or zero) steam-flow conditions. If this occurs while the harp is hot, severe thermal-mechanical fatigue damage, and sometimes immediate tube failure, results[13]. Changes to the ASME Boiler & Pressure Vessel Code in 2007[11] no longer permit undrained attemperator pipe arrangements[10]. Existing plants with such arrangements can benefit from the addition of a second spray-water block valve and tell-tail drain to reduce the risk of undetected block valve leakage.

3. Four plants assessed are equipped with spray-water control valves internal to the spray-nozzle assembly. This configuration has proven very unreliable in cycling service and is no longer offered by most HRSG OEMs.

4. Three plants use simple steam-outlet-temperature feedback loops for attemperator control. All have difficulty avoiding over-spray conditions and/or maintaining outlet steam temperature within design limits—or

manually control the attemperator setpoint in an attempt to compensate for the automatic control's inability to perform adequately[4].

Manual set-point manipulation and manual spray-valve positioning are dangerous workarounds. The thermodynamic complexity, the very long time delay for steam-temperature changes to register on DCS readouts, and the speed with which temperature changes occur place consistently safe manual attemperator control beyond the ability of even the best operator without creating over-spray conditions.

The preferred attemperator control scheme uses two cascaded controllers with real-time enthalpy calculations performed around the attemperator, and a feature to prevent spray down below 50 deg F (28 deg C) of superheat at the attemperator outlet. Plants equipped with GE 7FA/9FA GTs also find it useful to add an anticipatory feature by incorporating GT fuel demand or inlet-guide-vane position into the attemperator control scheme.

5. Two plants experienced attemperators coming into, and going out of, service multiple times during startup. Intermittent attemperator operation exposes attemperator hardware, piping, and superheaters/reheaters to avoidable and undesirable thermal transients. GT load and exhaust-temperature controls (ETM on GE 7FA/9FA units), and attemperator controls, should be coordinated to avoid the need for desuperheating until GT exhaust temperature can no longer be held below 950F (510C).

Once the attemperator is placed in service it should stay in service until no longer needed. New units should be designed to have desuperheaters remain in service continuously at minimum spray water flow to minimize thermal-fatigue damage to attemperator hardware.

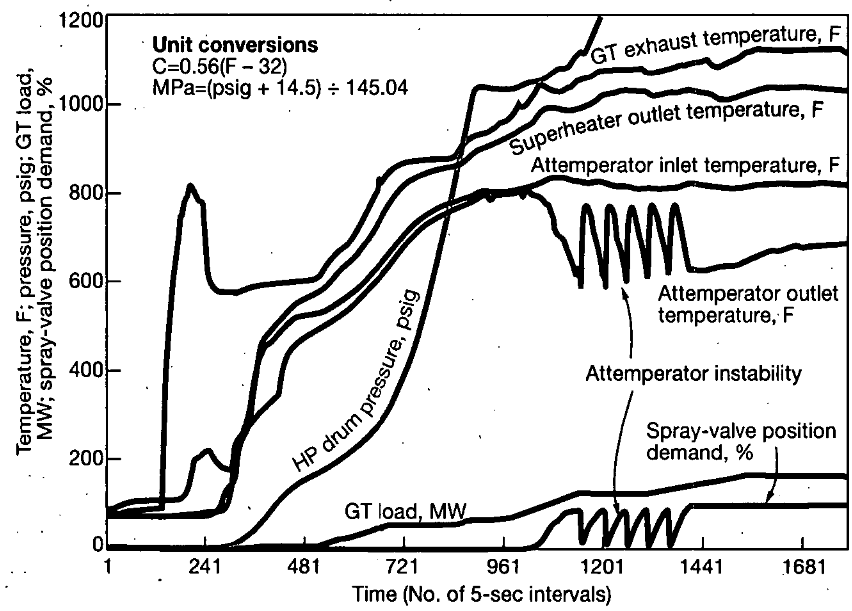
Special consideration for attemperation in plants equipped with GE 7FA/9FAs. HRSGs equipped with 7FA and 9FA GTs demand significantly more performance from their attemperator systems because of their unique exhaust-gas temperature (EGT) characteristic. At minimum GT load, EGT is about 950F (510C) unless the exhaust temperature matching (ETM) feature is engaged to lower it to 750F (399C).

In addition, when the GT load is increased above minimum load EGT rapidly increases to 1250F (677C) (called the isotherm) and remains there until GT load reaches about 60%. This rapid increase in EGT to such high temperature early in the startup process, when steam flow through the superheater is low, creates additional challenges for the attemperator's hardware and controls[4]. Table 5 shows the indicators for damaging attemperator performance, and operating practices known to cause damaging thermal transients unique to plants equipped with 7FA/9FAs.

Detailed assessments of the three 7FA/9FA plants have revealed the following:

1. High-quality attemperator equipment, well-tuned cascaded anticipatory attemperator controls, use of ETM during all startups, holding the GT at minimum load until more steam flow is available, and holding pressure steady while increasing GT load through the critical load range with EGT at the isotherm all may be required to (1) maintain stable, automatic attemperator control, (2) avoid over-spray conditions and (3) prevent over-temperature excursions at the superheater/reheater outlet.

Superheater arrangements with more than about 25% of the total surface area positioned downstream of the attemperator (in the secondary superheater) have greater difficulty avoiding overspray conditions with



3. This plant's attemperation system needs maintenance to reduce hunting. The unit is equipped with an integral spray valve/nozzle, which has a poor reputation for reliability in cycling service. It is likely that this hunting was caused by sticking of spray-valve trim

Table 5: Thermal transient factors unique to plants equipped with GE 7FA/9FA gas turbines

Thermal transient factors assessed	Plant A	Plant D	Plant I
Simple feedback loop used for attemperator control?	Yes	Yes	Yes
Manual control of attemperator spray valve?	Yes	No	No
Manual manipulation of outlet steam-temperature setpoint?	Yes	No	Yes
Overspray conditions evident from DCS data in SH?	Yes	Yes	No
Overspray conditions evident from DCS data in RH?	Yes	No	No
Outlet steam over-temperature conditions evident from DCS data in SH?	Yes	Yes	No
Outlet steam over-temperature conditions evident from DCS data in RH?	Yes	Yes	No
Attemperator control instability evident from DCS data in SH?	No	Yes	Yes
Attemperator control instability evident from DCS data in RH?	No	No	Yes
Intermittent attemperator operation?	No	No	Yes
Use ETM on shutdown?	No	No	No
Use ETM during lag unit startup?	No	Yes	No

The unit is subject to undesirable thermal transients because of this factor
Unit is not subject to undesirable thermal transients because of this factor

Exhibit_(MFC-1)
Page 14 of 17

GE units while at the same time preventing outlet steam temperature from exceeding design limits. As the proportion of total superheater surface located in the secondary superheater approaches 50%, it becomes unlikely that both over spray and over temperature can be avoided, even when all of the approaches listed above are used.

2. All of the 7FA/9FA plants assessed are equipped with simple steam-outlet-temperature feedback-loop attemperator controls. This single shortcoming is a significant contributor to poor attemperator performance experienced by this group of plants. Other 7FA/9FA plants, familiar to the authors but not included in these assessments, that are equipped with cascaded anticipatory control schemes deliver acceptable attemperator performance.

3. Two of the GE 7FA/9FA plants manually manipulate attemperator control setpoint or manually position the spray-water valve in an attempt to avoid excursions of steam outlet temperature above design limits. As previously noted, this is a dangerous practice and very likely to result in over-spray conditions.

Are attemperators being operated effectively? Here's what the assessment results say:

1. Twenty-two percent of the plants assessed experience over-spray conditions during startup as indicated in DCS plots. Not surprisingly, all of these plants are equipped with 7FA/9FAs.

2. Twenty-nine percent of the plants assessed experience an excursion of the HP or RH steam outlet temperature above design limits during startup. Again, all are the 7FA/9FA-equipped plants. Over-spray conditions inflict significantly more thermal-mechanical fatigue damage in the superheaters and reheaters than the creep damage caused by brief periods of over-temperature operation.

Optimize operating procedures, controls, and attemperator hardware to possibly avoid both of these undesirable consequences. However, when faced with the choice of over-spray versus limited over-temperature operation during startup, the priority should go to avoiding all over-spray events.

3. Four plants assessed experience attemperator control instability during startup. Two are equipped with integral spray-valve/nozzle assemblies. Regarding controls, two have simple controls (on the 7FA/9FAs), the other two more sophisticated controls—possibly pointing out the need for additional focus on spray-valve maintenance and control tuning. Fig 3 shows a DCS plot from one unit with significant control instability during a cold start.

Economizers

There have been many failures at tube/header connections in HRSGs attributed to "inlet quench." During startup, prior to initiation of feedwater flow, the LP economizer feedwater-inlet section heats up close to around 280F (138C)[4]. In plants not equipped with thermal deaerators, or other means of warming the incoming feedwater above ambient temperature, the LP inlet header and tubes adjacent to the inlet nozzle undergo a large quench when the feed valve is first opened. Since the flow rate often is very low during the initial feed, water only passes through the few tubes closest to the inlet nozzle—thereby creating large tube-to-tube temperature differences.

These very low flow rates (trickle feed) also can lead to flow instability and flow reversal in tubes near the gas-path walls and the gap between side-by-side modules where end tubes pick up more heat from bypassing

Exhibit__(MFC-1)
Page 15 of 17

exhaust gas[4]. LP economizers that incorporate bent tubes in the inlet pass, and "cross-flow" harps (baffles inside the headers force water to alternately flow up some tubes and down others as it progresses across the harp) generally suffer more from inlet quench than parallel-flow harps with straight tubes[9]. LP economizer harps with inlet nozzles located on the upper header experience more flow instability and flow reversal than ones with bottom-feed inlets, because down-flowing water has to overcome increasing buoyancy as it is heated.

The 11 detailed assessments revealed the following:

1. More than half (55%) of the plants have economizer drains arranged with a single small-bore inboard isolation valve for each harp and a common, larger downstream isolation valve. This arrangement promotes severe quenching in tubes located immediately above the drain connection in the hotter harps because of water bypassing through the drain pipe when more than one of the small-bore valves develop seat leakage[9]. This risk is avoided by the installation of tandem small-bore isolation valves for each harp.
2. Forty-five percent of the plants assessed have cross-flow economizer harps.
3. Nearly three-quarters (73%) of the plants use a thermal deaerator or LP economizer recirculation system during startup to minimize inlet quench. LP economizer recirculation systems generally are designed for increasing feedwater inlet temperature above the acid dewpoint during low-load operation and during oil firing. Some operators place these systems in service prior to startup to warm the water in a portion of the condensate piping, hopefully reducing the severity of inlet quench. The additional flow in the LP economizer created by recirculation also may reduce flow instability and flow reversal during trickle-feed conditions. Plant-specific pipe routing and recirculation-system flow capacity will determine how effective this practice is.

Are damaging economizer thermal transients being avoided?

Twenty-seven percent of the plants assessed report economizer tube/header connection failures, which are attributed to stretched tubes caused by quenching.

Thick-wall pressure parts

The HP steam drum, the hottest and thickest HP superheater headers, and the hottest and thickest reheater headers require care during startup and shutdown to avoid initiating thermal-mechanical fatigue cracks caused by overly aggressive heating and cooling rates[2].

1. Six plants assessed reported being given a maximum cool-down ramp rate for the critical superheater/reheater headers by the OEM, or had the unit evaluated to determine the maximum safe ramp rate for a normal shutdown. The others are "flying blind" on this potentially expensive issue. All other things being equal, cooling a thick-walled pressure part too quickly causes significantly more thermal-mechanical fatigue damage than does heating it too fast[2].
2. Twenty-seven percent of the plants assessed have been given a maximum heat-up ramp rate for the critical superheater/reheater headers by the OEM, or had the unit evaluated to determine the maximum safe ramp rate to be used during startup[2].
3. All but two of the plants have been given a maximum heat-up ramp rate for the HP drum by the OEM, or had the unit evaluated to determine the maximum safe ramp rate to be used during startup.

Exhibit_ (MFC-1)
Page 16 of 17

4. Five plants use shutdown procedures that steam-cool the superheaters and reheaters during normal shutdown[2]. Rapid unloading of the GT during normal unit shutdown leaves superheaters and reheaters near rated steam temperatures. After firing ceases and the GT is coasting down, or during a spin-cool, exhaust air temperature often falls below the prevailing saturation temperature inside superheater and reheater tubes.

When this occurs, condensate forms in the tubes and trickles into the lower headers. If the headers have been shut down hot, they undergo a severe quench. Slower unloading of the GT (at a rate that results in decreasing EGT at the maximum cooling rate determined safe for the critical superheater/reheater header) is suggested to avoid a damaging condensate quench after shutdown.

Recommendation: Unloading the GT (and using ETM on 7FA/9FAs) until outlet steam temperature is about 90 deg F (50 deg C) above the prevailing HP saturation temperature, then holding at that load for few minutes to let the header's through-wall temperature gradient equalize before shutting down the GT, will avoid the damaging condensate quench after shutdown.

5. None of the 7FA/9FA plants assessed use their ETM feature to control steam-temperature ramp rate during normal shutdown. The exhaust temperature characteristics of these GTs result in very aggressive steam-temperature ramp rates when shut down without using this feature.

6. One of the 7FA/9FAs uses its ETM feature to control exhaust temperature during startup of the "lag" HRSG in 2 × 1 plants. GE intended the ETM feature be used to match steam temperature from the "lead" HRSG to the steam turbine's requirements during startup of a cold steam turbine.

During cold starts, the lead HRSG typically is warmed up slowly and well within its HP drum and critical superheater/reheater-header temperature ramp rates. Failure to "voluntarily" use ETM for startup of the lag HRSG typically exposes the critical superheater/reheater headers to excessive heat-up ramp rates.

Are thick walled pressure parts being protected from excessive thermal-mechanical fatigue damage?

1. Five plants assessed routinely exceeded prudent temperature ramp rates for their critical superheater/reheater headers during both startup and shutdown. These plants are not likely to obtain design fatigue life from these expensive headers unless corrective actions are taken before too much damage is done.

2. Twenty-seven percent of the plants assessed routinely exceed prudent HP drum temperature ramp rates during startup. These plants are likely to find thermal-fatigue cracks in their HP drums before the HRSG reaches the end of its nominal design life if changes to operating procedures are not implemented to slow the startup-temperature ramp rate.

Concluding remarks. Assessments of 11 combined-cycle/HSRG plants around the world provide an indication of how proactively operators are addressing the known failure/damage HRSG tube failure (HTF) mechanisms, and the potential for damage in thick-section pressure vessels. The two most important aspects have been reviewed: cycle chemistry and thermal transients. In the former, the assessments have addressed the key factors for flow-accelerated corrosion, under-deposit corrosion, and pitting; in the latter, thermal fatigue and creep fatigue.

This effort offers a clear picture in each area of exactly where the weaknesses in the approaches are occurring, and it is not surprising that the current ranking order for HTF has remained virtually static for the last 10 years. Hopefully, the key messages presented in the article easily can be applied by operators to improve the current situation.

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Exhibit _(MFC-1)
Page 17 of 17

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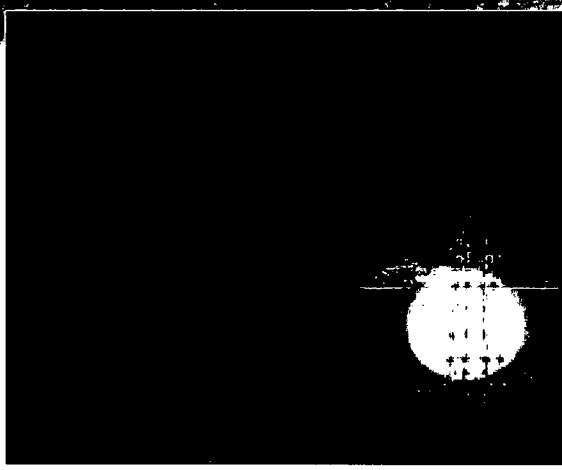

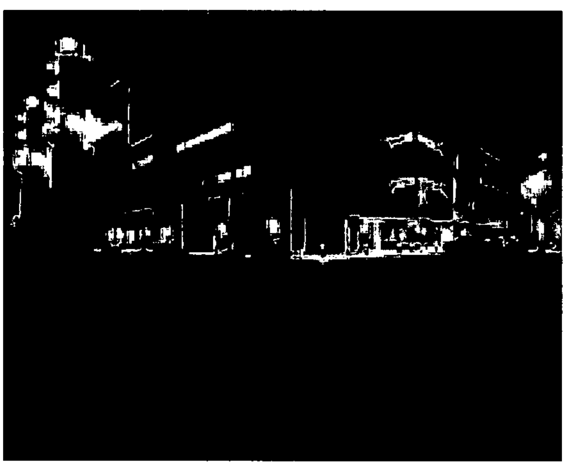

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Page 1 of 22

Flow-Accelerated Corrosion in Fossil and Combined Cycle/HRSG Plants

R. Barry Dooley

ABSTRACT

Flow-accelerated corrosion (FAC) has been researched for over 40 years at many locations around the world, and scientifically all the major influences are well recognized. However, the application of this science and understanding to fossil and combined cycle/HRSG plants has not been entirely satisfactory. Major failures are still occurring and the locations involved are basically the same as they were in the 1980s and 1990s. This paper reviews the mechanism of FAC with particular emphasis on fossil and combined cycle/HRSG plants. It includes discussion on a) typical locations of FAC, b) the single- and two-phase variants by describing their typical appearances in plant, c) oxides which grow in the areas of interest, d) the cycle chemistry alternatives and particularly the effect of potential (ORP) on the oxide forms, and e) the major influences on FAC of turbulence, geometry, mass transfer, and materials. Different approaches are needed within fossil and HRSG plants and these are delineated. The important differences between all-ferrous and mixed-metallurgy feedwater systems are emphasized. Overall, organizations should consolidate their inspection, predictive, and chemistry approaches into a company-wide, coördinated, multi-disciplinary FAC program.

INTRODUCTION

Although there had been a number of early references, it was thought that by the mid 1980s sufficient understanding of flow-accelerated corrosion (FAC) had been developed. Confidence was growing in the industry around the world that the parallel research work conducted in Germany, France and the UK throughout the 1970s for different facets of the nuclear and steam turbine industries had addressed the major concerns.

By the early 1960s, FAC, then called erosion-corrosion, had already been theoretically investigated by researchers [1,2]. It was demonstrated that the fundamental conditions for the development of FAC were processes occurring in the laminar boundary layer on the surface of the metal. The anodic iron dissolution in water results in the formation of Fe^{2+} ions and electrons reacting with a respective cathodic reaction. Normally iron dissolution was considered as a self-inhibiting process where the pH in the laminar boundary layer increases and, finally, $Fe(OH)_2$ precipitates after reaching its solubility limit. In this way, the iron dissolution is markedly impeded. Although a ferrous hydroxide layer already inhibits the iron dissolution to some extent, the optimum conditions are reached only after this layer is converted to a magnetite cover layer in a series of condensation reactions.

By the early 1980s there was thought to be consensus on the understanding of FAC along the following lines [3–8]. Magnetite is the oxide which grows on carbon steel surfaces in the feedwater up to about 280 to 300 °C (536 to 572 °F) under low oxygen (now defined as reducing) conditions. Under most operating scenarios with laminar flow (thicker fluid flow boundary layer) the oxide is protective where its growth is usually exactly balanced by its dissolution of mainly ferrous ions into the flowing water or steam/water mixture. Depending on the temperature its thickness may reach 15–25 μm but at temperatures below about 150 °C (302 °F) it can be very thin. Magnetite growth is controlled by the local cycle chemistries, which at that time were not defined as clearly as today. Wherever turbulent flow conditions exist as a result of local geometries, the dissolved ferrous ions are more rapidly removed from the surface. This process is balanced by an exact growth of more magnetite on the carbon steel surface. This faster oxide removal equates to a faster overall corrosion process (FAC) and thinner remaining magnetite on the surface (can be as thin as a few ångström, or equivalent to an interference film). FAC only occurs in water and water/steam mixtures and not in dry steam, and there is no mechanical damage to the metal as in liquid droplet erosion and cavitation. By the early 1980s the influences of the following factors on FAC had already been identified and, in some cases, quantified: pH, dissolved oxygen, reducing agent (earlier called oxygen scavenger), temperature, mass transfer, and alloying element composition.

Certainly this research had also identified a number of deficiencies in the state of knowledge, and it became clear that further research was needed into quantifying the effect of alloying elements and the influences of specific cycle chemistries with a concentration on the oxidizing environments, referred to then as the "oxygen effect". No serious damage had been reported during the 1970s, and perhaps the seriousness of the first major case of single-phase FAC at the Navajo fossil plant in Arizona in 1982 had not been identified or recognized.

This level of confidence was removed in 1986 when four workers were killed at the Surry nuclear plant. This event led to a coordinated effort to ensure that FAC was indeed understood at the power plant level, and to a large amount of research and organizational work to develop a coordinated approach of inspection and non-destructive evaluation (NDE). This eventually led to the development of a number of sophisticated FAC codes or models.

Unfortunately this increased research effort did not lead to a reduced amount of FAC being found in the nuclear and fossil industries. Once again the seriousness and complexity of FAC in high energy systems was not fully appreciated. Since 1986, there have been three more incidents where plant workers have unfortunately been killed as a result of single-phase FAC: Pleasant Prairie (1995), Mihama (2004) and most recently at Iatan (2007). Numerous incidents of two-phase FAC have also taken place.

During this time period a new generating source, the combined cycle/heat recovery steam generator (HRSG), has emerged into the generating industry in enormous numbers all around the world. Very quickly FAC became the number one availability problem in the HRSG with large numbers of single- and two-phase FAC failures occurring.

In a water constrained world an increasing number of both types of plant have been built with air-cooled condensers (ACC), which have experienced FAC and the associated generation of large amounts of corrosion products.

The primary purpose of this review is to indicate that the science of FAC is now much better understood and not a random situation or a mystery, and that this science can and should be easily applicable to all steam/electric generating plants. The paper deals primarily with FAC in conventional fossil plant feedwater systems, combined cycle/HRSG feedwater and evaporator systems, and air-cooled condensers. It will mention only briefly a few statistics from the nuclear industry where these can embellish or paint the same picture as in the conventional and combined cycle plants.

A Few Unofficial Statistics on FAC

No official FAC statistics are kept worldwide for fossil and combined cycle plants. However, EPRI has surveyed the attendees at cycle chemistry and boiler tube failure international conferences for the last 20 years [9,10]. A number of other organizations, such as the HRSG Users Groups, have paralleled these efforts [11]. About 70 % of fossil organizations report some recognition of FAC. The typical systems susceptible to FAC in fossil plants are shown in Table 1. Those occurring generally in single-phase flow areas are marked with an "S"; those in two-phase areas with a "T". Some of these general locations of course can have both.

Individual organizations have also reported similar compilations for many years [12,13]. These overall compilations such as in Table 1 are important to help determine the priorities for comprehensive inspection programs, discussed later.

In combined cycle plants, FAC has been the leading cause of HRSG tube failures (HTF) over the last 10 years and represents about 35–40 % of all HTFs. Both single- and two-phase FAC can occur in low pressure (LP) evaporator and economizer tubing but again there are no decent statistics which separate the two. Two-phase FAC has also been a problem in LP evaporator drum steam separation equipment [14].

Feedwater heater drains (S, T). Most prevalent area where about 60 % of organizations record problems
Piping around the boiler feed pump (S). Includes desuperheating supply piping
Piping to economizer inlet headers (S). Especially associated/near valves and supply Tees
Economizer inlet header tubes (S). Most frequent are usually those nearest to header supply
High pressure (HP) feedwater heater tube sheets fabricated in carbon steel (S)
Low pressure (LP) feedwater heater shells (T). Especially near cascading drain entries
Deaerator shells (T) near to fluid entry (HP cascading drains) piping
Reducers on either side of valves
Locations near to thermowells in piping
Turbine exhaust diffuser (T)
Air-cooled condenser (T)

Table 1:
Locations of FAC in conventional fossil plants.

Table 2 shows a listing of the major incidents of FAC, which were all single-phase. Although there were no fatalities, the initial major failure at the Navajo plant is included here for comparison. It is worth studying this table in detail because there are some very important commonalities across these plants which should help in the initial screening of conventional fossil plants in the future, and when designing/specifying new plants. First, it should be recognized that all of these failures, with the exception of Mihama, have occurred in systems where the feedwater heaters (LP and high pressure (HP)) are fabricated in stainless steel (usually 304) and that the oxygen levels were extremely low (typically less than 1 $\mu g \cdot kg^{-1}$ (ppb)) either because the air in-leakage into the condensate was under very good control or because the location of failure was after a deaerator. In each case a reducing agent (most often hydrazine) was injected at the start of the feedwater system. The low oxygen and the reducing agent ensured that the location of failure was under severe reducing potential conditions. It is also most significant that the pH control range for the feedwater was in the range from 8.75 to 9.3, with the actual most often operated value being 9.1 or less. The temperature range at the failure location has varied widely from 142 to 232 °C (287 to 450 °F), as has the pressure from 0.93 MPa to 20 MPa (134 to 2 900 psi). It is also interesting that most of the single-phase FAC failures at the economizer inlet header tubes (Table 1) were also in systems where the feedwater heaters were all stainless and the feedwater was running under severe reducing conditions as described above for the major incidents [15–17].

TYPICAL APPEARANCE AND LOCATIONS OF FAC

The last section provides some details on the locations of FAC in conventional and combined cycle/HRSG plants. Despite FAC having been well established by the early 1980s, there is still much confusion in the industry worldwide about the typical appearances of FAC in many of these locations. The reader is referenced to a number of key documents for a comprehensive coverage [24,25]. The selection made here by the author has concentrated on the most prevalent and on the major areas of uncertainty as ascertained by frequently asked questions (Appendix B) during FAC workshops, telephone enquiries and personal contacts at international meetings and conferences.

Single-Phase FAC in Conventional Plants

Photographs showing the most typical appearance of single-phase FAC are provided in Figures 1 and 2.

Figure 1 shows an FAC failure in a carbon steel economizer inlet header tube. The nipple weld is shown, and the damage starts between 2.5–5 cm (1–2 in) from the header bore. The surface looks like an orange peel, which is the typical appearance of single-phase FAC. There is no evidence of any mechanical (erosive) damage and the loss of wall thickness is purely a chemical dissolution phenomenon. In some areas where the FAC rate is not as fast, there is the appearance of distinct pit like features, but upon further investigation it is clear that these features have some directionality. Figure 1 also shows a reducer associated

		Navajo 2 [18]	Surry 2 [19]	Pleasant Prairie 1 [20,21]	Mihama 3 [22]	Iatan 1 [23]
Date (Fatalities)		11/1982 (0)	12/1986 (4)	2/1995 (2)	8/2004 (5)	5/2007 (2)
Location		90° bend between booster pump and HP BFP	90° bend following a Tee off main feedwater suction header	Feedwater pipe between isolation valve and economizer inlet	Feedwater piping between LP heaters and deaerator	Superheater attemperation line, from discharge of BFP
Temperature	°C (°F)	195 (382)	190 (374)	232 (450)	142 (287)	171 (340)
Pressure	MPa (psi)	4.14 (600)	2.55 (370)	13.8 (2 000)	0.93 (134)	20 (2 900)
Max fluid velocity	$m \cdot s^{-1}$ (ft/s)	7.3 (24)	5.3 (17.6)	6.1 (20)	2.2 (7.2)	
Range of pH (typical)		8.8–9.6 (9.0)	8.9–9.0	Average 8.75	8.6–9.3	8.9–9.1
Oxygen	$\mu g \cdot kg^{-1}$	< 1	4	< 1	< 5	< 5
N_2H_4		Yes	Yes	Yes	Yes	Carbohydrazide
Material		A105	A106 Gr B	A106 Gr C	JIS G3103 SB42	A106 Gr C
Feedwater Heaters		Stainless		Stainless	Copper containing alloys HP and LP	Stainless

Table 2:
Major single-phase FAC incidents in fossil and nuclear plants.

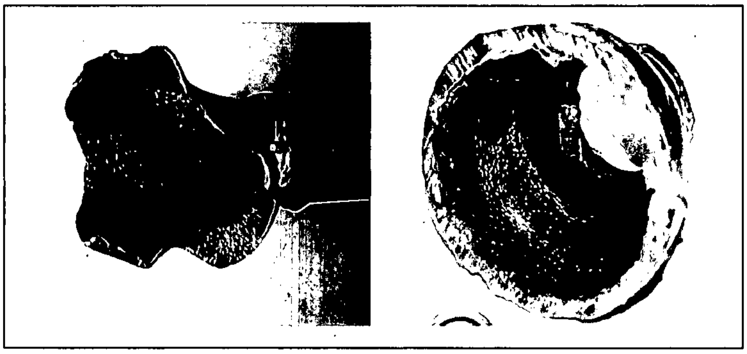

Figure 1:

Two examples of single-phase FAC.

Left: FAC failure in an economizer inlet header carbon steel tube (Source: T. Gilchrist, 1991).

Right: FAC in a reducer associated with a level control valve in an HP drain system (Source: T. Gilchrist, 2008).

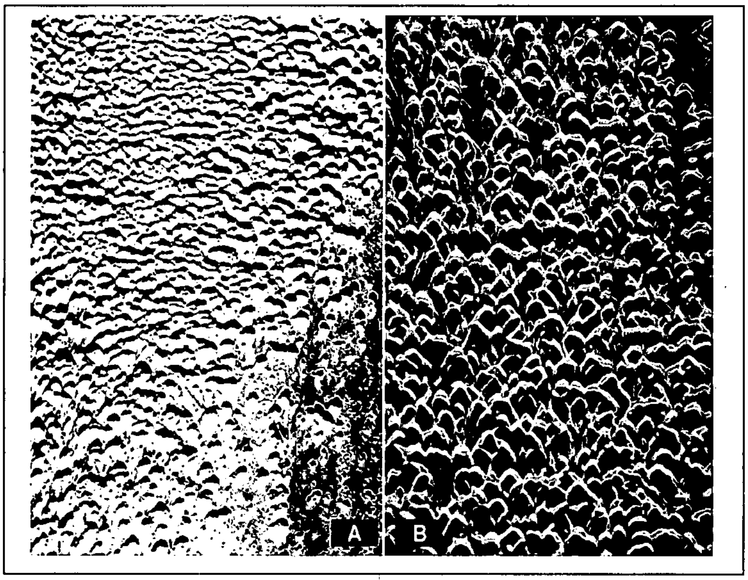

Figure 2:

Two views of the visual surface appearance of single-phase FAC.

A is a further detail from the economizer inlet header tube shown in Figure 1 (Source: T. Gilchrist, 1991).

Example B is a similar view from the FAC surface of an HRSG LP evaporator tube. In both cases the horseshoes or chevrons point in the direction of flow (bottom to top).

with a level control valve which shows all the same features. Figure 2 shows a detail of the visual appearance of FAC. Where the FAC is slower and very little wall loss has occurred (towards the lower right of Figure 2A) a series or "strings" of these "pit-like" features are clearly evident on the surface. These have been described variously to have a "chevron" or "horseshoe" appearance with the tip pointing in the direction of flow. These chevrons are due to the vectors of turbulent flow touching the surface of the component or surface oxide causing increased dissolution of the oxide at that point because the increased mass transfer assists the removal of the magnetite. As FAC becomes more severe (towards the middle of Figure 2A) then these chevrons overlap until, where the FAC is most severe (towards the top of Figure 2A), the surface takes on the continuous scalloped or orange peel appearance. In these areas there is very little oxide (magnetite) remaining on the surface and if a metallurgical cross-section is prepared, then the oxide is usually very thin (can be a few μm). Figure 2B shows almost exactly the same features of single-phase FAC on the surface of a low pressure (LP) HRSG evaporator tube to illustrate that the key features will be visible wherever single-phase FAC is occurring. Under higher magnification using a scanning microscope the typical scalloped appearance of FAC is always visible (an example is shown later in Figure 5D from an HRSG LP evaporator tube).

Two-Phase FAC in Conventional Plants

Some of the locations of two-phase FAC have been indicated in Table 1. There are two most predominant appearances of two-phase FAC. The first occurs in deaerators, where most of the surface is subjected to single-phase flow and is generally not subjected to FAC. For units operating under reducing feedwater conditions (AVT(R)), the protection is provided by magnetite and the surface will be mostly grey. For units operating with oxidizing feedwater (either AVT(O) or OT) the protection will be afforded by FeOOH and the surfaces will be mostly red. Two-phase FAC in deaerator vessels is primarily located near to piping which carries fluids into the deaerator. These might be the high pressure (HP) cascading drains for example. At each of these locations, there is a difference in temperature/pressure between the entering fluid and the bulk fluid in the deaerator, and thus the fluid flashes upon entry into the deaerator. This provides a local two-phase (turbulent) media which "sprays" against the deaerator surface. Figure 3 shows two typical areas adjacent to HP cascading drain entry points. The two-phase FAC is delineated by a surface which is usually black and shiny or even enamel-like. It often contains pit-like markings, which sometimes have the chevron/horseshoe directional appearance as seen with single-phase FAC. Two-phase FAC with these characteristics can be found in deaerators of units operat-

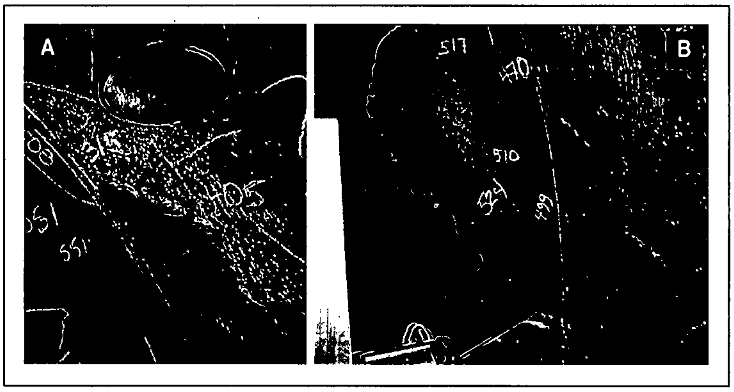

Figure 3:

Examples of severe two-phase FAC in deaerators.

Example A is located adjacent to an HP cascading drain entry (shown) into a deaerator.

Example B is directly in the path of the flashing steam from another drain entry. In both cases the two-phase FAC areas are easily seen by a black/shiny (enamel-like) appearance. In some very severe areas there are "pit-like" indications. Some of the areas have already been weld-overlaid with carbon steel material. The red coloration indicates where there is single-phase fluid because this is protected by the FeOOH covering.

ing under either oxidizing or reducing conditions; however, they are much more visible with units on oxidizing cycles, as the two-phase FAC appears as black or shiny black discontinuities immediately adjacent to the red surface protection, as shown particularly well in Figure 3B. The two-phase FAC areas are always black (very thin magnetite) because there is no oxidizing power in the two-phase media as it sprays against the surface because of the partitioning of any oxygen to the steam phase.

Both parts of Figure 3 show a typical weld overlay repair, which usually has been conducted with carbon steel material.

The second location is on the shells of low pressure feedwater heaters, usually the lowest LP heater. Figure 4A shows a nice example of two-phase FAC on a LP heater shell. The red areas (FeOOH) define the single-phase flow locations and indicate that the surface is protected from FAC. The black shiny areas define where the two-phase media is striking the surface as a result of flashing of a cascading LP heater drain entry into the vessel. No protection can be afforded in these areas because there is no oxidizing power of the liquid in the two-phase media, despite the unit operating with about 150 $\mu g \cdot kg^{-1}$ of oxygen on OT. Actually the grey magnetite can also be seen beneath the red FeOOH.

There is a very sharp boundary between the protected (single-phase) and the unprotected (two-phase) areas in this region. In Figure 4A it is highlighted because of the red/black boundary, but it can also be seen in units operating with reducing treatments where the two-phase media can be equally as severe for FAC. Figure 4B shows the boundary area in a unit operating on AVT(R), where in this case there is also some heavy deposition in the single-phase area.

Single- and Two-Phase FAC in Combined Cycle/HRSG Plants

In HRSGs there is one variant of single-phase FAC and a number of distinct variants of two-phase FAC depending on the level and type of turbulence, and on how the two-phase media "hits" the surface. FAC occurs equally in horizontal and vertical gas path units (HGP and VGP units) and is also common in LP drums. Overall some of the regions of concern are: a) economizer/preheater tubes at inlet headers, b) vertical LP evaporator tubes on HGP units, especially in the bends near the outlet headers, c) LP evaporator transition headers, d) IP evaporator tubes on triple-pressure units which are operated at reduced pressure, e) LP drum internals, and f) horizontal LP evaporator tubes on VGP units especially at tight hairpin bends [26].

Most of the LP evaporators in triple-pressure HRSGs operate at low pressures (0.4–0.5 MPa, 60–80 psi). Both single- and two-phase FAC can occur in these LP evaporator circuits and it is important to recognize exactly which type is occurring because the solutions are different for each type

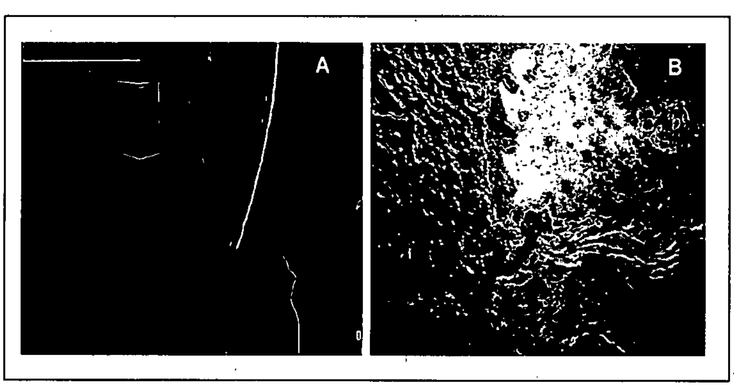

Figure 4:

Two examples of two-phase FAC on the shell side of the lowest LP heater.

Example A is on a unit operating on OT, where the red coloration delineates single-phase flow and is protected by the red FeOOH. The shiny black area is where two-phase FAC is taking place as a result of flashing of a cascaded drain entering the heater (Source: R. Brooker and D. Swainsbury 2002).

Example B shows the sharp demarcation between the area where two-phase FAC is taking place (right) and an area of heavy deposition in the single-phase area (left). This unit was operating on AVT(R).

[27]. Figure 5A is a common example of single-phase FAC in the bend of a vertical LP evaporator tube close to the upper outlet header of an HGP HRSG. Figure 5B is an example of two-phase FAC in a similar location. Figure 5C shows an example of two-phase FAC in a horizontal LP evaporator tube tight hairpin bend of a VGP HRSG.

In the cases of single-phase FAC, the damaged surface typically exhibits the same orange peel appearance with the chevron or horseshoes towards the extremities of the damage (slower FAC areas) (Figure 5A) as is seen in single-phase FAC in conventional plant feedwater systems (Figures 1 and 2). In cases where two-phase flow is turbulent the appearance of FAC depends on how the vectors of the flow touch the surface. Figure 5B seems to indicate a "swirly" turbulence created by the tube bend as it approaches the outlet header (to the right). Here the FAC is scalloped or wavy-like. Sometimes both types of FAC occur in the same tube region.

In the hairpin bends of LP evaporator tubing of VGP HRSGs the two-phase media is centrifugally forced to the outside of the bend and results in a smoother black/shiny FAC appearance. Such an example is shown in Figure 5C. This is very similar to the two-phase FAC in deaerators (Figure 3) and LP heater shells (Figure 4) of conventional plants. In all three cases of FAC in HRSGs the typical scalloped appearance of FAC is seen if these surfaces are viewed under the higher magnification of a scanning electron microscope (Figure 5D).

FAC in Air-Cooled Condensers

Air-cooled condensers (ACC) are becoming more common on fossil and combined cycle plants. As the two-phase mixture of water/steam of around 6–9 % moisture exits the steam turbine it is directed by a series of ducts into the air-cooled condenser. Measurements of the water droplets in this mixture have shown that the vast majority of them are less than 0.1 μm while a small number are up to 100 μm [28–30]. Many operators have recorded large amounts of corrosion products at the condensate pump discharge, sometimes over 100 $\mu g \cdot kg^{-1}$ of iron. High levels of iron in the condensate have increased pressure drop and fouled ion exchange resin in units equipped with condensate polishers, and can lead to deposition problems in boilers of conventional plants and evaporators of HRSGs. The problem is thought to be FAC in the ACC, but this area is only just starting to be addressed comprehensively [31,32]. Figure 6 provides a selection of photographs documenting the current understanding. Figure 6A shows a general view of a transfer duct and the entry into the A-frames running along the bottom of the ducting. This particular ducting is red colored because the unit is operating on oxygenated treatment (OT), however grey ducting has also been seen on units running with reducing treatments, AVT(R). Figure 6B shows a clearer detail of the entry into the A-frame tubes. Three distinct regions are usually visible: a) the red colored areas (FeOOH) represent generally protected surfaces, b) black/grey oxide which encompasses the whole entry area into the tubes, where there is turbulence as the two-phase media turns through 90° into the tubes, and c) white appearing areas, which are actually shiny metal. These white areas show up more clearly in Figure 6C together with the adjacent black areas, which are regions of heavy deposition of magnetite particles.

MECHANISM OF FAC IN FOSSIL AND COMBINED CYCLE/HRSG PLANTS

Since the early work in the 1970/80s much further work has been conducted on FAC worldwide. This together with the development of (unofficial) data bases of failures and damage in both types of plant has led to a much more comprehensive understanding of FAC, which is directly applicable to these fossil and combined cycle plants [10,15,16,33]. The basic process/mechanism remains as

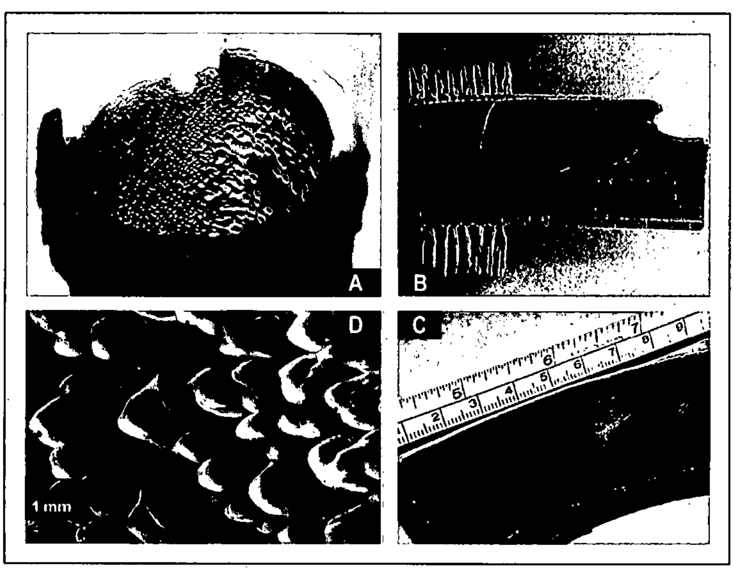

Figure 5:

Three examples of FAC in HRSG LP evaporator tubing.

A) shows single-phase FAC in a vertical tube (HGP),
B) shows an example of two-phase FAC in a vertical tube (HGP),
C) shows two-phase FAC in a tight hairpin bend of a horizontal tube (VGP), and
D) shows the surface of FAC damage on an HRSG LP evaporator taken with a scanning electron microscope showing the typical scalloped appearance always seen of FAC.
(Source: A and B are from Dooley et al. [27])

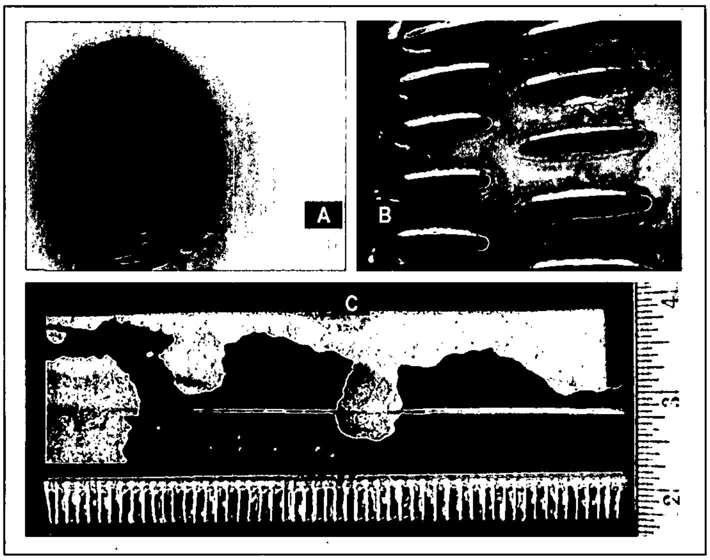

Figure 6:
FAC in air-cooled condensers.
A shows the general arrangement of the last section of transfer ducting from the steam turbine and the entry to the A-frame tubes running along the bottom of the duct.
B shows the entry to a set of A-frame tubes.
C shows a detail of the surface appearance near the top of an A-frame tube.

outlined in the opening section of this paper, where the normally semi-protective magnetite (Fe_3O_4) layer on carbon steel "dissolves" in a turbulent stream of flowing water (single-phase) or wet steam (two-phase). This process reduces the oxide layer thickness and leads to a rapid decrease in thickness of the base material until the pipe, tube or pressure vessel bursts. The FAC process can be very rapid and wall thinning rates higher than 3 mm per year (0.120 inch per year) have been measured [10,15]. The rate of metal loss depends in a very complex way on three main factors: the local cycle chemistry, the material composition, and the fluid hydrodynamics. The FAC mechanism is discussed here and first includes a description of the electrochemistry of the basic water chemistries which can be used in these plants, and then describes the formation and properties of the different oxides (Fe_3O_4, Fe_2O_3 and FeOOH) that can exist on the material surfaces as a function of the oxidizing-reducing potential (ORP). This then leads to how the chemistry, oxides, materials and hydrodynamic factors influence FAC.

Feedwater Chemistries

The feedwater chemistry is critical to overall corrosion, FAC and reliability of fossil and HRSG plants. Over the last 20 years three distinctly different feedwater treatments have been gradually consolidated [34–39]. These, based on the potential of the water, now form a critical part of providing optimized cycle chemistries for the complete cycle in fossil and combined cycle plants [40]:

- Reducing all-volatile treatment, AVT(R), which uses ammonia and a reducing agent in water where the oxygen level is < 10 $\mu g \cdot kg^{-1}$. Here the oxidizing-reducing potential, ORP, should be in the range –300 to –350 mV [Ag/AgCl/sat, KCl]. It should be noted that this range of ORP is not always achieved, because ORP is a careful balance between the levels of oxygen and reducing agent, and because ORP is a function of pH, temperature, materials, and the sensor characteristics [41]. Sometimes a reducing ORP can be as high as –80 to –100 mV.
- Oxidizing all-volatile treatment, AVT(O), where the reducing agent has been eliminated. No oxygen is added. The oxidizing power relies on the level of air inleakage, which should be optimized to give oxygen < 10 $\mu g \cdot kg^{-1}$ at the condensate pump discharge. Here the ORP will be around 0 mV but could be slightly positive or negative.
- Oxygenated treatment (OT), where oxygen and ammonia are added to the feedwater. Here the ORP can be as high as +100 to +150 mV.

Growth of Oxides in the Feedwater of Plants and in the LP HRSG Evaporator

In the feedwater system of conventional and HRSG plants, the fluid is essentially single-phase water. Here the overriding influence for corrosion and FAC is the feedwater oxidizing-reducing potential (ORP) or redox potential. For the carbon steel materials operating under reducing chemistry the reduced form of iron oxide, magnetite (Fe_3O_4), is formed, and its solubility is strongly controlled by the level of the reducing potential. Changing the treatment to oxidizing by eliminating the reducing agent and/or adding oxygen results in the formation of ferric oxide hydrate (FeOOH) [36]; the rate of the conversion depends on the oxidizing power. The formation of this cover oxide reduces the solubility of the surface oxide by at least two orders of magnitude in the temperature range up to just below 300 °C (572 °F). Thus the surface oxide has an enormous effect on both normal corrosion and FAC. However, as can be inferred from frequently asked questions (Appendix B), despite a vast amount of work by tens of researchers over the last 40 years, there is still a lack of understanding of how these oxides grow and the associated electrochemical processes. This section contains a short overview prior to discussion of the FAC mechanism. A full treatment in relation to FAC is provided in [24].

Under reducing feedwater conditions (AVT(R)), the protective oxide which forms on carbon steels in systems up to temperatures just below 300 °C (572 °F) consists almost exclusively of magnetite:

$$3Fe + 4H_2O \rightarrow Fe_3O_4 + 4H_2 \quad (1)$$

This reaction is considered the sum of two coupled processes. The first process really consists of three simultaneous reactions: a) a direct reaction (oxidation) occurs between iron and the reducing water to form soluble ferrous species and hydroxides, b) the ferrous species diffuse through the porous oxide, and c) the ferrous species dissolve by a reductive process that is promoted by the presence of hydrogen. In power plant terminology, reducing water is considered to contain less than 10 $\mu g \cdot kg^{-1}$ oxygen with a reducing agent being added [40,41]; this will give an ORP in the reducing range as defined above.

At the anodic site (carbon steel suface), an oxidation process occurs:

$$Fe \rightarrow Fe^{2+} \text{(solution)} + 2e^- \quad (2)$$

At the cathodic site, a reduction process occurs (hydrogen evolution):

$$2H^+ \text{(solution)} + 2e^- \rightarrow H_2 \text{(evolved from the surface)} \quad (3)$$

In reducing alkalized water, the cathodic reaction:

$$2H_2O + 2e^- \rightarrow 2OH^- + H_2 \quad (4)$$

Combining the anodic and cathodic reactions:

$$Fe + 2H_2O \rightarrow Fe(OH)_2 + H_2 \quad (5)$$

Both ferrous ions and ferrous hydroxide can be obtained according to an equilibrium reaction:

$$Fe^{2+} + 2OH^- \leftrightarrow Fe(OH)_2 \quad (6)$$

In the second process magnetite forms through the Schikorr reaction:

$$3Fe(OH)_2 \rightarrow Fe_3O_4 + H_2 + 2H_2O \quad (7)$$

A schematic showing the growth mechanism and morphology of Fe_3O_4 under AVT(R) conditions is shown in Figure 7 (top right). In single-phase flow at low velocities and/or in straight sections of pipe or tubing, the flow is laminar and essentially parallel to the surface of the metal. In this case the velocity varies from essentially zero in the fluid boundary layer near to the oxide/water surface to a

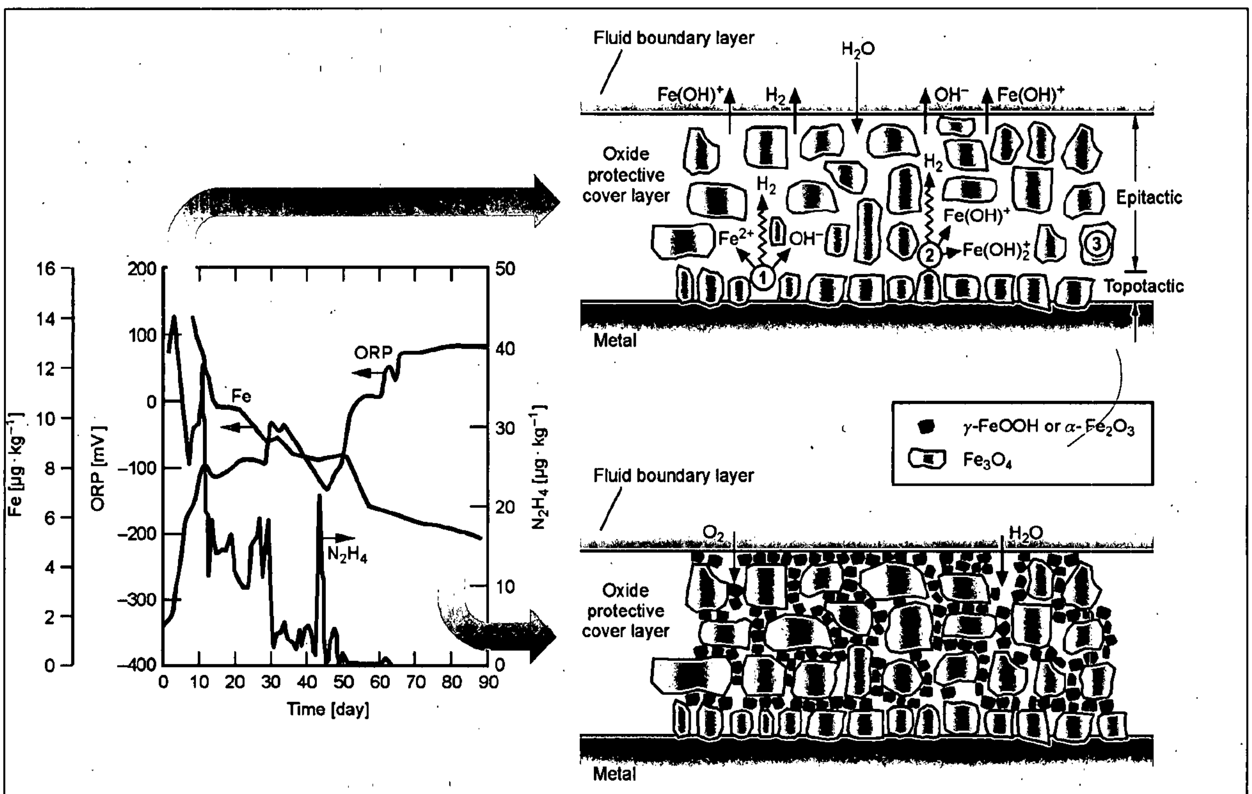

Figure 7:

Illustrating how the growth of oxides on carbon steel surfaces is controlled by the potential (ORP). The figure on the left shows how the amount of iron at the economizer inlet changes as a function of the ORP when the reducing agent is gradually eliminated to zero (Source: Platt, Vinnicombe [43]). The two drawings on the right illustrate schematically under laminar flow conditions (with a slow moving boundary layer or liquid) the growth of magnetite (top) under reducing conditions and the growth of a cover layer of FeOOH (bottom) on the magnetite under oxidizing conditions of AVT(O) or OT (Source: Dooley [36,44]).

maximum at the centerline of the pressure vessel/tube. Under such laminar flow conditions, the second process involves the transfer of the ferrous ions into the bulk water across a boundary layer. In two-phase laminar flow there is a slow moving layer of liquid along the surface of the oxide. The semi-protective magnetite which forms under either of these laminar flow conditions reaches an equilibrium condition where the oxide doesn't continue to increase in thickness and is usually limited to a thickness of no more than about < 20 μm depending on temperature. This is because the layer has lots of oxide hydrates and loose (non-protective) magnetite particles in the outer layers, and there are essentially equal amounts of dissolution of ferrous compounds into the flow and oxidation of iron at the metal/oxide interface. At temperatures below about 150 °C (302 °F), the magnetite formation is very slow [42]: in some cases it is difficult to detect a magnetite layer even after a hundred thousand hours of operation.

The formation of magnetite (Eq. (7)) is inhibited by increasing pH, which causes a reduction of the Fe^{2+} and $Fe(OH)^+$ ion concentrations corresponding to the solubility products of $Fe(OH)_2$. There have been many studies of the solubility of magnetite. Figure 8 shows one typical profile [45], which increases with increasing temperature to about 150 °C (302 °F), then decreases with a steep drop to 300 °C (572 °F), which can result in undesired magnetite deposits in this temperature range. To maintain the solubility of ferrous hydroxide ($Fe(OH)_2$) in the feedwater below or equal to that of magnetite at around 250 °C (482 °F) and to exclude the possibility of oversaturation, a minimum pH of at least 9.6 should be maintained [46]. A pH of 10 would be even better, but is limited in the cycle if the unit has a copper tubed condenser or condensate polisher operating in the hydrogen cycle. Here it is important to note that the growth of magnetite and FAC are directly related to the pH at the hot operating temperature, not the cold pH as usually measured in fossil and combined cycle plants following sample conditioning.

The growth and dissolution of magnetite into reducing feedwater is also a strong function of potential. As shown in Figure 7 (left), decreasing the ORP (more reducing) will lead to increasing amounts of iron in the water [43]. The cases where this iron is flushed away by the local turbulence is, of course, the reason why a semi-protective situation changes into single-phase FAC and the reason why all-ferrous feedwater systems should be operated on AVT(O) (no reducing agent) or OT to prevent the solubilization of the magnetite surface layers.

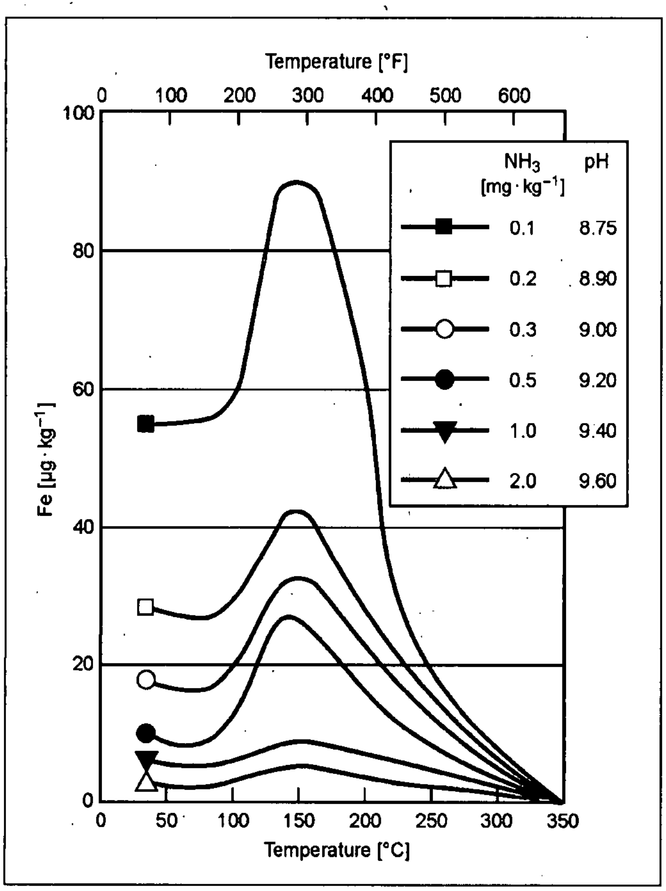

Figure 8:

Solubility of magnetite as a function of temperature at various ammonia concentrations (Source: Sturla [45]).

Elimination of a reducing agent (AVT(O)) and/or addition of oxygen (OT) raises the free corrosion potential of the steel by several hundred millivolts and the ORP of the fluid into the oxidizing regime. Under these conditions the protective cover layer pores in the magnetite become plugged with ferric oxide hydrate (FeOOH) or ferric oxide (Fe_2O_3) (see Figure 7 lower right) [15,36,47]. As a result, the Fe^{2+} ion diffusion from the steel surface through the pores of the protective magnetite cover layer to the oxide/water phase boundary is strongly inhibited. The few ferrous ions leaving the steel are oxidized either in the layer pores or right at the protective layer/water boundary. For this reason, the ferrous ion concentration in the feedwater should be very low (around 1 $\mu g \cdot kg^{-1}$) under AVT(O) conditions and below 1 $\mu g \cdot kg^{-1}$ for OT conditions. This has been confirmed on almost every unit on AVT(O) and/or OT; the conversion front from magnetite to FeOOH gradually progresses in the direction of flow as the local reducing conditions change to oxidizing. Additionally, the ferric ion concentration becomes almost undetectable [48]. Very few studies have been conducted on the solubility of ferric oxide/hydroxides. Sturla [49] conducted a theoretical study which is shown in Figure 9 and includes the calculated solubility of ferric oxide γ-Fe_2O_3, ferric oxide-hydrate γ-FeOOH, and ferric hydroxide. This figure also shows the solubility field of magnetite replotted from Figure 8 on the axis of Figure 9 so that a qualitative comparison can be made. This shows two features: first it illustrates at least two orders of magnitude lower solubility for the ferric

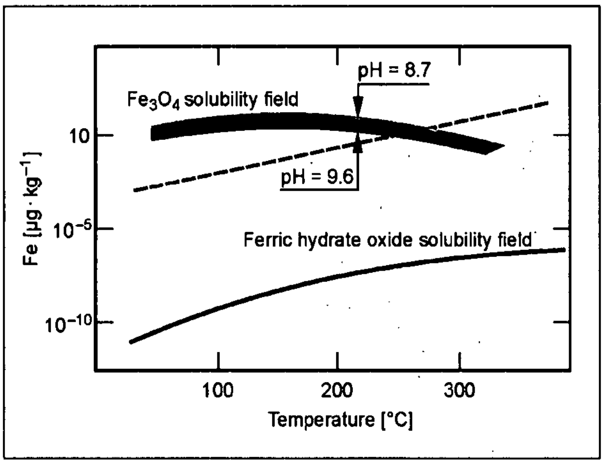

Figure 9:
Solubility of ferric hydrate-oxides at 0.5 ppm NH_4OH (data extracted from Sturla [49]). The Fe_3O_4 solubility curve has been replotted from Figure 8 to allow a qualitative comparison of the effects of changing the potential or pH.

oxide hydrates that form with oxidizing treatments (AVT(O) and OT) compared to magnetite at 150 °C (302 °F), and secondly it also shows the powerfulness of potential compared to changing the pH from 8.7 to 9.6.

The cover layer morphology is determined by the one or both of the reactions [50]:

$$2Fe_3O_4 + H_2O = 3Fe_2O_3 + 2H^+ + 2e^- \quad (8)$$

and

$$Fe_3O_4 + 2H_2O = 3FeOOH + H^+ + e^- \quad (9)$$

The formation of FeOOH is known to occur at elevated temperature (up to just below 300 °C, 572 °F), because the red FeOOH is found on economizer tubing just past the inlet header of conventional plants, but is not found on economizer outlet or water wall tubes which operate above 300 °C (572 °F). Also the use of oxidizing environments switches off active FAC of economizer inlet header tubes.

In summary, under the conditions where the ORP is oxidizing, FeOOH will form on magnetite and reduce the solubility of the surface oxide layers (Figure 9) by at least two orders of magnitude. Thus the oxidizing treatments (AVT(O) and OT) have the ability to reduce and even stop the active single-phase FAC mechanism up to just below 300 °C (572 °F) under exactly the same hydrodynamic (turbulent) conditions that existed previously with AVT(R) chemistry.

Flow-Accelerated Corrosion

The previous section has outlined the normal growth of Fe_3O_4 under laminar flow with reducing chemistry conditions, and how this growth is a balance between the cathodic hydrogen evolution reaction and the anodic dissolution of ferrous ions. FAC is simply an extension of this semi-protective process where the dissolution is accelerated by an increasing flow turbulence of water or water/steam mixture (decreasing boundary layer thickness) which causes an increased rate of ferrous species to become incorporated into the flow (increased mass transport). The FAC mechanism under reducing conditions is illustrated in Figure 10 and shows how some flow disturbance (bend, elbow, nozzle, valve, tee, reducer, etc.) introduces turbulence into the flow, which develops flow vectors against the oxide surface as suggested by the arrows.

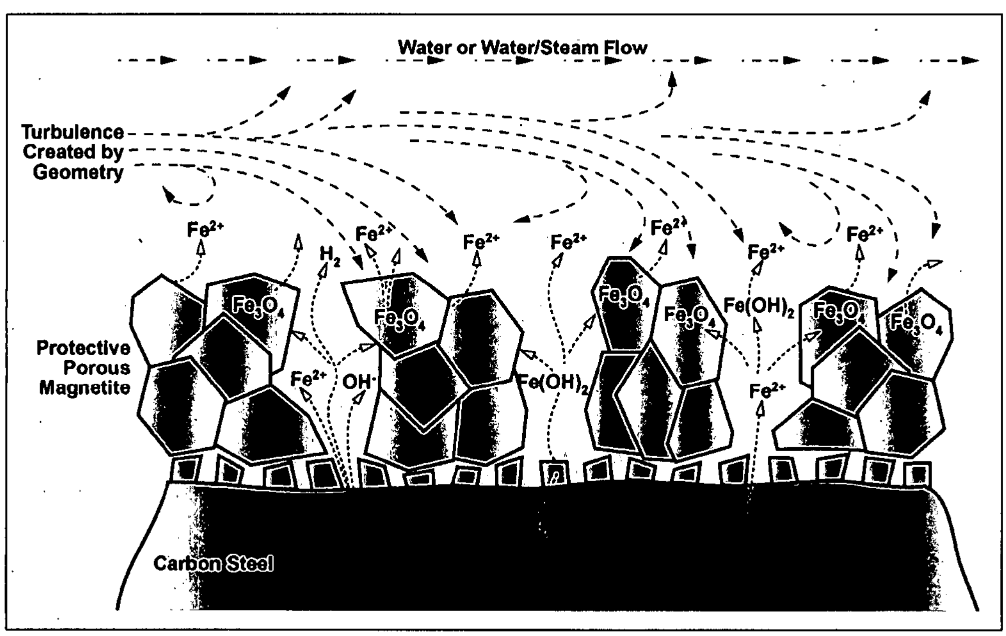

Figure 10:
Schematic of the mechanism of FAC.

This causes a reduction or removal (under severe conditions) of the slow moving boundary layer in single-phase flow and the liquid film in two-phase flow. In this case the anodic oxidation and growth of Fe_3O_4 cannot match the flow-accelerated dissolution or removal of the oxide (Fe_3O_4). At temperatures below about 150 °C (302 °F) with very thin magnetite layers and a thin laminar boundary layer due to the local flow conditions (turbulence), the ferrous ions are increasingly transported into the bulk flow; the solubility product of ferrous hydroxide cannot be reached and FAC occurs. This is probably the mechanism within an air-cooled condenser and on the LP heater shells. At higher temperatures, magnetite is formed markedly faster [42]. For this reason, the thin porous magnetite layers are found on the surface. This layer is not adequately resistant and cannot avoid the transport of ferrous ions into the bulk flow. With very high FAC rates the oxide can be as thin as an interference film and often is black/shiny or even has other colorations (green, yellow). The ultimate situation is that the corrosion (FAC) rate increases and the carbon steel component becomes locally thinner.

In these cases, the levels of iron oxide (particulate) measured in fossil plant and HRSG feedwater systems and in HRSG evaporator circuits can be extremely high (above 15–80 $\mu g \cdot kg^{-1}$), which is interesting because the mechanism of FAC relates to increased levels of "dissolution" of Fe_3O_4 from the surface of the oxide layer under turbulent flow reducing conditions. The level of dissolved Fe_3O_4 measured in the water of either type of plant, under severe FAC conditions, is always low (<< 5 % of the total iron) and not high enough to explain the rate based solely on dissolution. So under turbulent conditions with a vector of flow towards the oxide surface, "particles" of oxide must be removed from the surface by some assisted "exfoliation" or "spallation" mechanism. A similar mechanism has been discussed to explain FAC in a CANDU nuclear plant [51]. Other mechanisms have also been discussed which involve only dissolution of the ferrous ions from the magnetite on the surface and some saturation phenomena [48]. Clearly this level of fine tuning of the FAC mechanism still needs attention.

Influences on Single-Phase FAC

The mechanism of single-phase FAC is complex and influenced by three main factors: cycle chemistry, flow hydrodynamics and the material composition.

Cycle Chemistry All serious cases of FAC (Table 2) have been observed in systems with low oxygen levels (~1 $\mu g \cdot kg^{-1}$) and where a reducing agent has been added to the cycle. However, it has been found practically that it is not possible to assess the likelihood of FAC by separately monitoring the oxygen and/or the reducing agent.

The oxidizing-reducing potential (ORP) has been found to provide this indicator and is now recognized as the most important influence on single-phase FAC. It is important to note that in fossil and HRSG plants, the ORP is usually reported as a voltage versus that of a Ag/AgCl (sat. KCl) reference electrode. ORP reflects the balance between various conjugate redox systems and must not be confused with the corrosion potential [41]. However, it does provide a useful indicator of the corrosivity of the flowing water. ORP is sensitive to the materials of construction and to the temperature because of the effects of temperature on the redox reactions. ORP also changes with pH, partial pressure of oxygen in the flowing water, mass transport properties and flow rates; thus ORP cannot be compared from unit to unit.

As discussed above, not only does ORP control the surface oxide that forms in feedwater or evaporator water, AVT(R) or AVT(O) (or OT), but as the ORP becomes more reducing the greater is the possibility for FAC (Figure 7). Changing to AVT(O), by eliminating the reducing agent and/or adding oxygen (OT), essentially reduces the possibility of dissolution into the flowing water to very low values, even in areas where there was severe turbulence and FAC under AVT(R). With laminar flow the oxygen will diffuse across the boundary layer. But more importantly for FAC, under turbulent conditions the diffusion of oxygen to the surface will be faster [6] and thus the conversion of Fe_3O_4 to FeOOH will also occur faster. In most of the early research results [5] it was reported that oxygen inhibited FAC, but there has been much uncertainty in applying this information to fossil and combined cycle plants because the ORP was rarely measured or known in the early laboratory experiments. Simply eliminating the reducing agent will change the potential to oxidizing (AVT(O)) even with very low levels of oxygen (~1 $\mu g \cdot kg^{-1}$) and this will convert the surface layers to red FeOOH and reduce the dissolution of ferrous ions. This is in agreement with a number of the early studies even though the ORP was not measured [5,7]. Operating with higher levels of oxygen will speed up the conversion and protection afforded. It should also be reported that oxidizing conditions will exist even in systems with reducing agent additions if the oxygen levels are above about 10 $\mu g \cdot kg^{-1}$. Berge suggested that FAC was proportional to the hydrazine content to the one sixth power above about 60 $\mu g \cdot kg^{-1}$ but did not report on the oxygen levels or the ORP [52]. The basic message is that in both conventional and HRSG plants with all-ferrous feedwater systems the optimum cycle chemistry for FAC control is oxidizing (i.e., no addition of a reducing agent).

The pH is the second most important chemistry influence on FAC. Although it is the at-temperature pH that is important, it is very rarely measured in fossil and HRSG plants. At 204 °C (400 °F) Fe_3O_4 is about 10 times more soluble in reducing water at a pH of 8.7 compared to 9.6 (Figure 8) [17,53], and Figure 9 shows how much more powerful changing the potential to oxidizing is compared to changing the pH. Bates et al. found that there was a linear dependence of FAC on pH between 9.0 and 9.7 due primarily to the solubility change [7]. The pH locally at the site of active FAC will decrease as FAC proceeds [54].

Flow Hydrodynamics Clearly while FAC is controlled by the cycle chemistry, it is located by the complex interactions of the flow hydrodynamics, and specifically by the geometrical features which create turbulence in the flow and increase mass transport of the soluble ferrous species from the surface. It has not been found practical or economic however to change the flow hydrodynamic factors including the temperature of operation.

Flow Velocity FAC is not directly dependent on flow velocity, and recent computational analyses confirmed that the mean flow rate is not a good indicator of the FAC process [55]. Generally FAC shows a rather weak dependence on bulk velocity: Chexal [53] predicted only about a three times increase of the FAC rate when the flow rate is increased from 1.5 to 9 $m \cdot s^{-1}$ (5 to 30 ft/s), and Lister [51] suggested an exponent of about 1.5 for a CANDU outlet feeder coolant case. Also there isn't a threshold or critical velocity above which FAC begins to accelerate. Gabrielli [14] similarly discussed FAC failures in HRSG economizer tubing which had rather slow water flow (0.3 to 0.9 $m \cdot s^{-1}$ or 1 to 3 ft/s), but showed that the turbulence increased by a factor of two associated with a 17° bend compared to straight tubing. The turbulence was even greater for a tube with a 45° bend.

Temperature Some of the original experimental FAC studies by Keller [8] illustrated a strong dependence on temperature with a peak at about 140 °C (284 °F) for single-phase FAC. Numerous subsequent studies have generally shown similar peaks and temperature profiles. Two examples are shown in Figure 11, where the maximum in FAC rate is between 130 and 150 °C (266 and 302 °F) [4,56]. The temperature of the maximum FAC rate appears to increase with increasing flow rate or mass transfer. The observation of high FAC rates above 140–150 °C (284–302 °F) is consistent with the numerous examples of FAC in fossil plant feedwater systems (economizer inlet header piping and tubing). The lower FAC rates at temperatures above 200 °C (392 °F) reflect that temperature affects changes in other physical and chemical parameters which influence mass transfer (fluid density, viscosity, etc.). It will be noted in Table 2 that serious incidents of FAC have occurred across the temperature range from 142 to

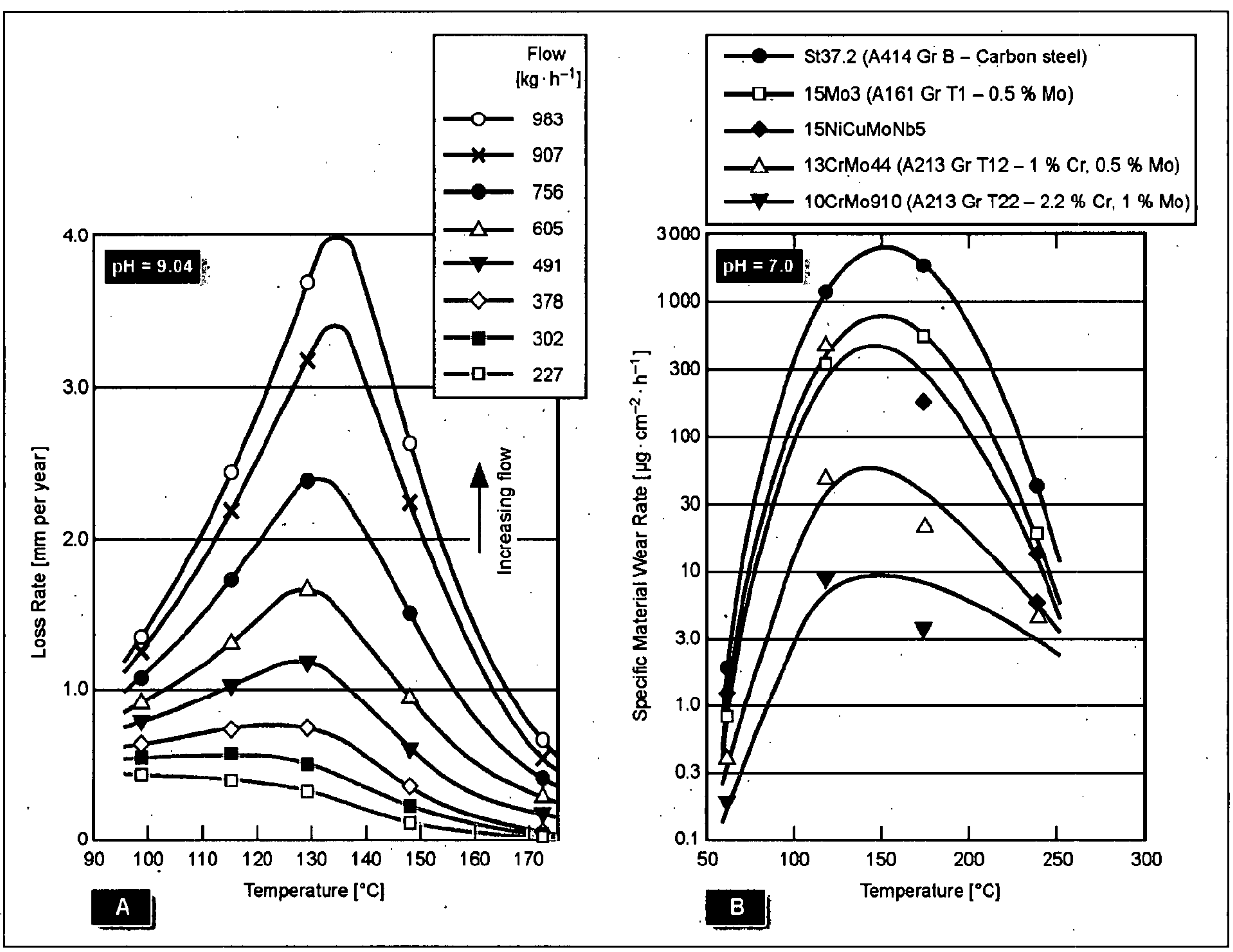

Figure 11:
Two examples of the temperature dependence of single-phase FAC under different flow and chemistry conditions. (Sources: A, Bignold and Woolsey [4], B, Heitman and Kastner [56]).

232 °C (287 to 450 °F) so changing the temperature does not appear to be a viable solution, and thus prioritization for inspections/NDE for FAC should also include the complete temperature range.

Geometry, Turbulence and Mass Transfer Geometries other than straight pipes or tubing affect mass transfer due to changes in local flow turbulence. FAC does not often occur in straight pipes or tubes, but is most often encountered at points of hydrodynamic disturbance. These include elbows, tight bends, reducer tees, locations downstream of flow control orifices and valves, and even fabrication discontinuities. The geometric enhancement of these features increases turbulence and mass transfer. Mass transfer has been expressed in terms of the correlation:

$$Sh = aRe^{x}Sc^{y} \qquad (10)$$

where the Sherwood number, Sh=Kd/D, the Reynolds number, Re=Vd/γ, the Schmidt number, Sc=γ/D, K is the mass transfer coefficient, D is the diffusion coefficient of the relevant species, d the characteristic dimension of the geometry, V is the flow velocity, and γ the kinematic viscosity [53,57]. Various workers over the last 30–40 years have investigated the effects of mass transfer on FAC. Laboratory studies were conducted. Bates [7] for instance showed a cubic relation at 150 °C (302 °F) between FAC of carbon steel and the mass transfer coefficient in PWR type water at a pH of 9.05 over a wide range of flow rates. Further studies [58] showed that the exponent was temperature dependent and decreased to around 1.0 at about 90 °C (194 °F).

There is extensive literature on the geometric factors as they are needed to prioritize inspection locations and for the various analytical models. The earliest work was conducted by Keller [8] for two-phase FAC in steam turbines, but it was quickly determined that these geometrical factors were not applicable to single-phase FAC [53]. This led to the generation of the factors in laboratory studies [57]. Chexal shows a very comprehensive set of geometric parameters which have been used within the Chec series of FAC codes [53]. A comparison of factors from five other authors has also been provided [24]. Usually everything is compared to a geometric factor for a straight section of piping being 1 (one). Larger values denote a greater propensity for flow disturbance and thus turbulence, which increases the mass transfer coefficients: 90° pipe elbows vary depending on the author but are usually around 3.5 to 4, reducers (similar to the one in Figure 1) vary from about 2 at the smaller end to about 2.5 at the larger, orifices and tees are around 5.

It is now possible to use computational fluid dynamics [14,55] to calculate increases in turbulence by geometrical factors as has already been mentioned.

Like with many of the factors which influence FAC, the geometrical factors and mass transfer do not provide unique suggestions for the locations of FAC. As an example, as FAC proceeds the surface becomes roughened (scalloped or orange peel appearance, Figures 1 and 2) and this surface will by itself increase the rate of mass transfer and thus FAC. So while such factors mentioned above provide a nice comparison of geometries, they may not be applicable as FAC progresses. Poulson [57] indeed found that the roughened surface becomes much more important than the original geometry. Bouchacourt's research [59,60] supported this and showed nicely how the surface roughness was caused by and increased FAC. This has a practical side when FAC in pressure vessels (deaerators or LP heater shells) is repaired by weld overlay with carbon steel instead of a 1.25 % Cr alloy. The roughness of the surface can actually make FAC return quicker.

Materials There are two distinct issues with respect to materials. The first relates to the plants that have mixed-metallurgy feedwater systems. The second addresses the material composition of the tube, pipe, or pressure vessel which is the subject of FAC.

Mixed-Metallurgy Feedwater Systems. The discussion to date in this review has concentrated on all-ferrous feedwater systems and has illustrated: a) that feedwater systems containing all stainless steel tubing are the most susceptible to FAC under reducing conditions, AVT(R), b) that optimization of the corrosion processes demands oxidizing conditions (AVT(O) or OT), and c) that these treatments have the ability to switch off FAC even in areas of turbulence. Mixed-metallurgy systems, where either all or some of the HP or LP feedwater tubing contains copper alloys, can only use AVT(R) feedwater chemistry with an optimum pH range of 9.1 to 9.3 [40,61]. This maintains a reducing environment under all operating regimes to protect the copper-based tubing (oxygen < 10 $\mu g \cdot kg^{-1}$ plus reducing agent). This means that the carbon steel interconnecting piping and the economizer inlet header tubing will also be exposed to the same reducing environment. Knowledge of the worldwide situation with FAC which collates into Tables 1 and 2 indicates that no serious FAC failures have occurred in fossil plants with mixed-metallurgy systems but that failures and wall loss due to FAC have occurred in these plants. This is thought to be because the copper alloys and oxides act as a catalyst for the reducing agent (hydrazine)/dissolved oxygen reaction in the feedwater. Because serious failures have occurred in nuclear plants with mixed-metallurgy systems (Table 2), the carbon steel components in mixed-metallurgy feedwater systems must be assessed within the same corporate FAC programs as used for the all-ferrous systems (Appendix A). Another aspect of copper-based feedwater heaters is that as they become old and fail they are gradually being replaced by materials other than copper. In many cases the feedwater system gradually changes from mixed-metallurgy to an all-ferrous system, and if the tubing has been changed to

Exhibit __ (MFC-2)
Page 14 of 22

stainless then this system now becomes very prone to FAC as mentioned above and shown by Table 2. Thus it is very important that as this change is made, the cycle chemistry is optimized in two areas to ensure that there is maximum protection against FAC. First the potential should be changed to oxidizing and secondly the pH should be raised into the range for all-ferrous systems (9.2–9.6) [40]. These changes may require that the feedwater system is chemically cleaned to remove any traces of copper that will have deposited throughout the feedwater system during the mixed-metallurgy reducing chemistry days.

Material Composition. Very extensive worldwide research over 25–30 years has shown that small additions of chromium to carbon steel will markedly reduce any FAC. Up to about 25 times improvement in FAC rates can be achieved by using 1.0 or 1.25 % chromium alloys. Similar results have been researched at many places. One of the clearest presentations of the effect is from work conducted by Ducreux in the early 1980s (Figure 12) at 180 °C (356 °F) in single-phase fluid at pH 9.0 under reducing conditions (NH_3 and N_2H_4) [62]. Work of Huijbregts [63] showed similar results of about a 50 % reduction in FAC with about 0.1 % Cr addition. Bouchacourt [60] showed that in compiling the data for different conditions in single- and two-phase FAC the improvements in FAC rates start at chromium levels above 0.04 %. In all discussions, the improved performance has usually been related to the presence of chromium building up gradually in the oxide film, which should reduce the solubility of the oxide. However, actual solubility data on oxides of this type is scarce, and it also needs to be recognized that the morphology of the oxide which forms on a ferritic steel containing chromium is different than the oxide which grows on carbon steel. On the former there is usually an inner layer of an iron/chromium spinel oxide. Many investigations of fossil plant FAC have also shown that FAC often doesn't occur in identical plant components when the chromium levels are slightly (maybe as small as 0.1 %) higher [12,20,21]. This of course has a major effect on the ability to rank components for inspection/NDE. The standard in the fossil and HRSG plants should be to make all materials replacements or repairs with at least 1.25 % Cr alloy. It is always better to make straight replacements with this alloy than to change the geometry, or to weld overlay an active FAC surface with a chromium containing alloy than use carbon steel, where the changes in surface roughness will increase the FAC rate.

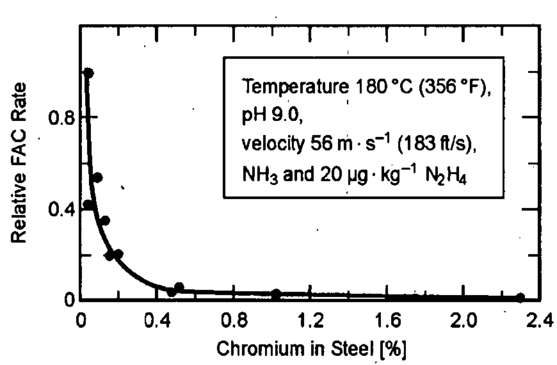

Figure 12:

The effect of chromium on the rate of single-phase FAC. (Source: J. Ducreux [62]).

Influences on Two-Phase FAC

As indicated in Tables 1 and 2, two-phase FAC occurs in both conventional plants (deaerators, LP heater shells, and heater drain lines), in HRSGs (LP evaporators and economizers, and LP evaporator drums), and in air-cooled condensers. Two-phase FAC occurs wherever the turbulent steam/water flow interfaces with the carbon steel surface (Figure 10). The slower moving layer of liquid along the surface under laminar two-phase conditions is broken up by the turbulence created by the local geometry in the same way as described for single-phase media. There are various appearances of two-phase FAC which are dependent on how the liquid droplets interface with the surface. Three obvious variants are: a) turbulent/swirling flow such as in a vertical HRSG LP evaporator tube (HGP) near an upper header (Figure 5B), where there are a series of gouges reflecting the swirling flow, b) a continuous stream of droplets being "forced" centrifugally to the outside of a tight (hairpin) bend in a horizontal HRSG LP evaporator tube (VGP) (Figure 5C), and c) areas where fluid flashes on entering pressure vessels operating at different temperature and pressure such as in deaerators (Figure 3) and LP heater shells (Figure 4). The first is similar to the "tiger striping" reported in nuclear plant two-phase areas [24]. The second two generally produce the same appearance, which in its most severe form is black and shiny. The two-phase FAC mechanism is controlled by the solubility of the reduced oxide (magnetite) and its mass transfer from the surface. Here there is also the thought that the final removal of particulate magnetite from the surface must relate to similar spalling reactions as discussed for single-phase FAC.

With regards to the temperature dependence of two-phase FAC, the bell-shaped profile is similar to that shown for single-phase FAC (Figure 11), but the peak is generally seen at higher temperatures of 175 to 180 °C (347 to 356 °F) [8,64].

With regards to the chemistry influences for two-phase FAC, the options are much narrower than for single-phase. Increasing the potential (ORP) or oxidizing power (AVT(O) or OT) cannot be adopted as a solution as with single-phase FAC because of the high partitioning of oxygen to the steam phase. It is clear that two-phase FAC occurs even in units operating with OT (Figures 3 and 4). To reduce two-phase FAC chemically, one option is to increase the pH locally at the FAC site. Ammonia used in fossil and HRSG plant feedwater does not perform well in these two-phase environments as its basicity decreases markedly with temperature and it partitions to steam, resulting in lower pH in the water adjacent to the surface. So basically in fossil plants, increasing the pH of the feedwater to address two-phase FAC will be limited by other factors in the plant (maybe condensate polishing, copper condensers, etc.) and thus solutions are usually materials related, with material or overlay containing at least 1.25 % Cr. For air-cooled condensers the current approach is to operate with higher pH in the range 9.6 to 9.8 [31]. Amines have better distribution properties and higher at-temperature pH for use in air-cooled condensers [32], but are usually not acceptable in fossil and combined cycle plants because of the thermal degradation, breakdown products and increased cation conductivity levels experienced in steam [65].

For HRSG LP evaporator circuits, the best option appears to be the use of a solid alkali, such as tri-sodium phosphate or NaOH, providing the HRSG circuitry and attemperation systems allow [26]. Worldwide, NaOH appears to provide the better protection. Chromium containing alloys can be used at "known" FAC sites again using at least 1.25 % Cr alloys, but it must be recognized that this only addresses FAC locally and not the root cause of the problem.

SUMMARIES AND SOLUTION APPROACHES FOR FAC

It should be clear that only a few of the various influences on FAC discussed in the last sections can realistically be changed to control/reduce FAC rates. The most important of these are: a) the optimum cycle chemistry for the particular plant and materials within the plant, and b) the materials of the tube, pipe, or pressure vessel that contain the turbulent flow. Both of these approaches ultimately reduce the solubility of the reduced form of iron oxide (magnetite) on the surface. New conventional and HRSG plants should be designed with the optimum chemistry and with materials resistant to FAC in the known locations.

Fluid Flow →

Flow Regime / Location and Conditions	A. Laminar Flow Boundary layer or slow moving liquid on the surface of the oxide.	B. Turbulent Flow Vector of flow against the surface, which reduces the slow moving liquid layer on surface	C. Laminar Flow Returns to A.
1. Areas with single-phase flow in units with reducing chemistries	Normal magnetite growth on surface. Semi-protective grey oxide dependent on the temperature. Small dissolution of Fe^{++} into flow	Increased dissolution of Fe^{++} and mass transfer. Chevron markings. With severe turbulence the surface becomes scalloped and black/shiny. FAC. Thinner magnetite.	Reestablishes conditions under 1A.
2. Areas with two-phase flow in units with reducing chemistries	As 1A.	Areas become black/shiny with some pits (maybe chevrons within black areas). FAC.	Reestablishes conditions under A. HRSG tubing and air-cooled condensers have deposition very close to FAC
3. Areas with single-phase flow in units with oxidizing chemistries	Surfaces become red. FeOOH forms on top of magnetite.	Surfaces become red. FeOOH forms on top of magnetite even in areas where FAC occurred under AVT(R).	Reestablishes conditions under 3A.
4. Areas with two-phase flow in units with oxidizing chemistries	Not many such locations (Straight sections of LP evaporator tubing and air-cooled condensers). Both can be red due to FeOOH	Areas will always be grey or black/shiny if turbulence is severe. FAC.	Reestablishes conditions under 4A.

Table 3:
Summary of FAC in conventional fossil and combined cycle plants.

Summary of the FAC Mechanism

The frequently asked questions (Appendix B) indicate that there remains some uncertainty about the various indicators of FAC, whether FAC is active or whether it has been slowed down or stopped by a change of chemistry, and what the various surface colors indicate. Table 3 provides an overview of the various flow regimes and the possible chemistries as a function of potential. The following two sections then summarize the key approaches for conventional fossil and combined cycle plants.

Summary for Conventional Fossil Plants

Based on the current understanding of the FAC mechanism, the various examples of FAC and reviews of hundreds of organizations' FAC programs around the world, the following conclusions can be drawn for control of FAC in fossil plants:

- Single-phase FAC can be controlled by the potential (ORP) of feedwater chemistry. FAC occurs under reducing conditions (low oxygen and a reducing agent) at locations where turbulence is generated by the system geometry.
- In all-ferrous feedwater systems (copper alloys may be in the condenser), an oxidizing feedwater treatment (AVT(O) or OT) will minimize corrosion, FAC and thus the transport of corrosion products to the boiler. The optimum pH range is 9.2 to 9.6.
- In mixed-metallurgy feedwater systems (copper alloys in the feedwater heaters and maybe also in the condenser) a reducing feedwater treatment (AVT(R)) will provide protection to the copper alloys. The interconnecting carbon steel components and pipework will also be operating under reducing conditions and may be subjected to FAC. Operating in the pH range of 9.1 to 9.3 will provide optimum protection for the copper alloys and will help to prevent dissolution of magnetite from the carbon steel components.
- It is important to change the feedwater chemistry when a change of feedwater heater tube material has been made. Probably the most common example is the change out of copper alloy tubed heaters to stainless. If this change (eventually) encompasses all the LP and HP heaters, then this markedly increases the risk of FAC and mandates an immediate change/optimization of the chemistry to oxidizing and an increase of the pH above that used in the mixed-metallurgy situation.
- For all types of feedwater systems, monitoring the iron (and copper) levels will indicate whether the feedwater chemistry is optimized and FAC is under control. For all-ferrous systems the iron levels should be approaching $2\ \mu g \cdot kg^{-1}$, and for those systems on OT it has been shown consistently worldwide that the iron can be less than $1\ \mu g \cdot kg^{-1}$. For mixed-metallurgy systems the copper levels should be approaching $2\ \mu g \cdot kg^{-1}$.
- Two-phase FAC regions (deaerators, LP heater shells) in the feedwater system generally require a materials solution using a 1.25 % Cr or higher alloy. This is applicable to rebuilding thickness with weld material or equipment replacement. Weld overlaying with carbon steel material will introduce surface roughness which has no better FAC resistance than the original pressure vessel material. Also it is always preferable to replace a component or part of a component in kind than to try to introduce a "better" flow hydrodynamic situation: the experience is also that these can have higher FAC rates than the original.
- FAC is most frequent in drain lines. Thinned or failed sections should always be replaced with at least a 1.25 % Cr alloy. The iron levels in the cascading HP and LP drain lines often provide a good indicator of the extent and activity of FAC.
- Air-cooled condensers are a special case within the fossil plant FAC envelope. Monitoring of the iron levels at the condensate pump discharge provides an important indicator of the extent and activity of FAC in the A-frame tubes. Worldwide experience indicates that initially the pH level around the cycle should be higher than the 9.2 to 9.6 range normally adequate for all-ferrous systems. Usually a pH of around 9.8 or higher will be required.
- All the activities of a comprehensive FAC program (Appendix A) involving prediction, inspection and a combination of Levels One and Two NDE techniques will also be required.

Summary for Combined Cycle/HRSG Plants

Based on the current understanding of the FAC mechanism, the various examples of FAC, and reviews of hundreds of organizations' FAC programs around the world, the following conclusions can be drawn for control of FAC in Combined Cycle/HRSG plants:

- The locations of single-phase FAC can be controlled by feedwater and evaporator chemistry. Multi-pressure HRSGs should operate only on an oxidizing cycle (AVT(O)) without any reducing agents. This decision should preferably be made during the specification/design stages of an HRSG, but if this stage has been missed, then the change should be made as early in the life of an HRSG as possible.
- Two-phase FAC of LP evaporator tubing can be addressed by LP evaporator chemistry by adding either tri-sodium phosphate or NaOH to the LP drum provided that the LP drum doesn't provide feed for upper pressure circuits or attemperation.
- Thus some two-phase FAC will need to be addressed by a materials solution. If obvious susceptible tube locations can be identified, then these should be replaced by a 1.25 % Cr or higher alloy. Steam separat-

ing equipment in the LP drum can also be designed or replaced with at least a 1.25 % Cr steel.

- Monitoring of iron in the feedwater and LP drum will identify whether FAC is active. Satisfying the "rule of 2 and 5", where the iron level is consistently less than 2 $\mu g \cdot kg^{-1}$ in the feedwater and less than 5 $\mu g \cdot kg^{-1}$ in each drum, will not only provide an indication that FAC is not active, but will also prevent excessive deposition of corrosion products in the HP evaporator tubing.
- Air-cooled condensers are a special case within the combined cycle/HRSG plant FAC envelope. Monitoring of the iron levels at the condensate pump discharge provides an important indicator of the extent and activity of FAC in the A-frame tubes. Worldwide experience indicates that initially the pH level around the cycle should be higher than the 9.2 to 9.6 normally adequate for all-ferrous systems. Usually a pH of around 9.8 or higher will be required.
- All the activities of a comprehensive FAC program (Appendix A) involving prediction, inspection and a combination of Levels One and Two NDE techniques will also be required.

CONCLUDING REMARKS

Flow-accelerated corrosion (FAC) has been researched for over 40 years, and scientifically all the major influences are well recognized. However, the application of this science and understanding to fossil and combined cycle/HRSG plants has not been entirely satisfactory. Major failures are still occurring and the locations involved are basically the same as they were in the 1980s and 1990s. This paper has attempted to delineate the different approaches needed within fossil and combined cycle plants for single- and two-phase FAC, and for cycle chemistries across the potential range from reducing to oxidizing. Because of the importance of FAC failures and the increased levels of corrosion products when the cycle chemistry is not optimized, it appears of paramount importance for organizations to consolidate their inspection, predictive, and chemistry approaches into a company-wide coordinated FAC program in the same way as many do for boiler tube failure reduction. Unfortunately such FAC programs are not too common across these industries. This becomes even more important if changes are made to a unit such as material components (feedwater heaters), piping, valves, tees, reducers and cycle chemistry. Each apparently small change can make a marked difference to FAC locally.

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APPENDIX A – OVERALL PROGRAMS FOR FAC

The complex interactions of the cycle chemistry and flow hydrodynamics control and locate FAC respectively. An overall comprehensive approach to identify and control FAC is required in steam generating plants. This Appendix provides a very brief overview of the parts required, and the two road maps for conventional (Figure A1) and combined cycle/HRSG plants (Figure A2) illustrate the process.

These road maps should make it crystal clear that optimizing the cycle chemistry and conducting NDE/inspections should never be separated. Only identifying the locations of FAC and addressing them (disposition and reassessment, repair, welding, weld overlay) does not address the root cause of the problem, which in most cases relates to the cycle chemistry. Only optimizing the cycle chemistry leaves possible FAC sites with reduced wall thickness. The following steps are briefly outlined, some are common to both plants, whereas some are unique.

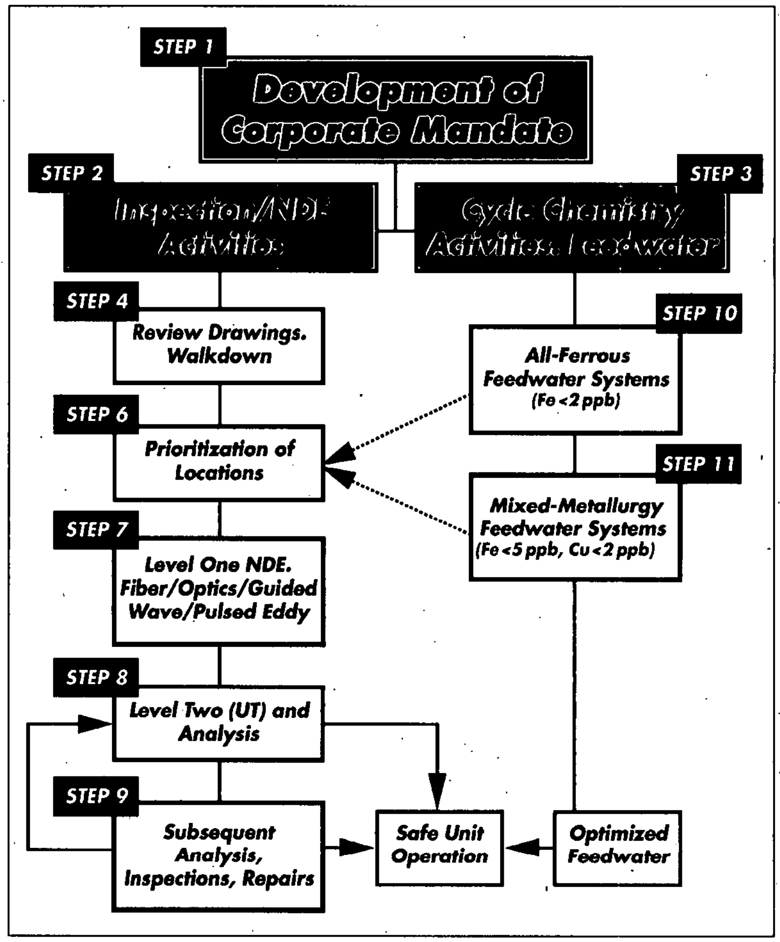

Figure A1:
Comprehensive FAC program for fossil plants (air-cooled condensers can be included).

NDE nondestructive evaluation
UT ultrasonic testing
1 ppb = 1 μg · kg^{-1}

Step 1
Development of a Corporate Mandate for FAC which is signed at the highest level in an organization. Such documents have been found in conventional plants to provide the ruggedness to a program and the support that the technical staff needs to conduct the whole program. They have yet to be applied to HRSGs. The overall approach must include an on-going benchmarking process so that feedback to the executive branch can be provided on how well the organization's FAC program is approaching world class.

Steps 2 and 3
Experience has shown that the cycle chemistry and the NDE/inspection need to be addressed in parallel chains of activities to comprehensively and safely address FAC.

Steps 4, 5 and 6
Identifying and prioritizing the locations of possible FAC damage is one of the critical processes and generally occurs slightly differently in the two types of plant. In conventional plants the prioritization can be accomplished by experience, walkdown and assessment of the heat balance diagram and drawings, or by the use of a predictive code. In combined cycle plants there are currently no specific predictive codes, and the prioritization is accomplished by the experience base in the industry and by the operating chemistry. The internal color (red or black) of the feedwater and LP evaporator pressure containment (Step 5 for HRSGs) also will play an important part in the process.

Step 7
Use of Level One NDE tools to locate damaged areas. In conventional plants this is often performed with pulsed eddy current, fiber optics or radiography. The guided wave ultrasonic testing technology is just emerging as a useful tool and may be able to fill an important Level One gap for the feedwater systems in fossil plants. In HRSGs there doesn't appear to be sufficient tubing and space to apply guided waves to tubing, but fiber optics and electromagnetic acoustic wave transducers (EMAT) appear useful Level One approaches in conjunction with the chemistry indicators ("Rule of 2 and 5").

Step 8
Once FAC damage has been located in Step 7, Level Two NDE is required to measure the wall loss and FAC rate. For conventional plants this involves UT with standardized protocols for grid layout and collection of the data at inter-

secting grid points or by recording the minimum values by scanning the grid. In HRSGs it usually involves UT scanning on tubes and headers.

Step 9
Analysis to determine reinspection intervals and disposition is required once the FAC rate is known. All repair aspects (weld overlay, replacement of equipment with similar geometry) should involve the use of 1.25 % Cr alloys. Any changes to the unit such as materials in feedwater heaters, piping/components, new equipment, or changes in cycle chemistry will need reassessment.

Step 10
Cycle Chemistry Optimization of All-Ferrous Feedwater Systems in Both Conventional and Combined Cycle/HRSG Plants This is accomplished by monitoring pH, dissolved oxygen, reducing agent and total iron. All-ferrous systems should not be treated with reducing all-volatile treatment (AVT(R)), which uses chemical reducing agents. Feedwater treatment of all-ferrous feedwater systems should use either oxidizing AVT (AVT (O)) or, where applicable in conventional plants, oxygenated treatment (OT). Total iron transport monitoring provides an overall indication of the activity of both single- and two-phase FAC. In conventional and combined cycle plants with all-ferrous feedwater systems, employing a properly selected and optimized feedwater treatment, it should be possible to attain iron concentrations consistently $< 2\ \mu g \cdot kg^{-1}$ in the final feedwater as measured at the economizer inlet or comparable sample point location.

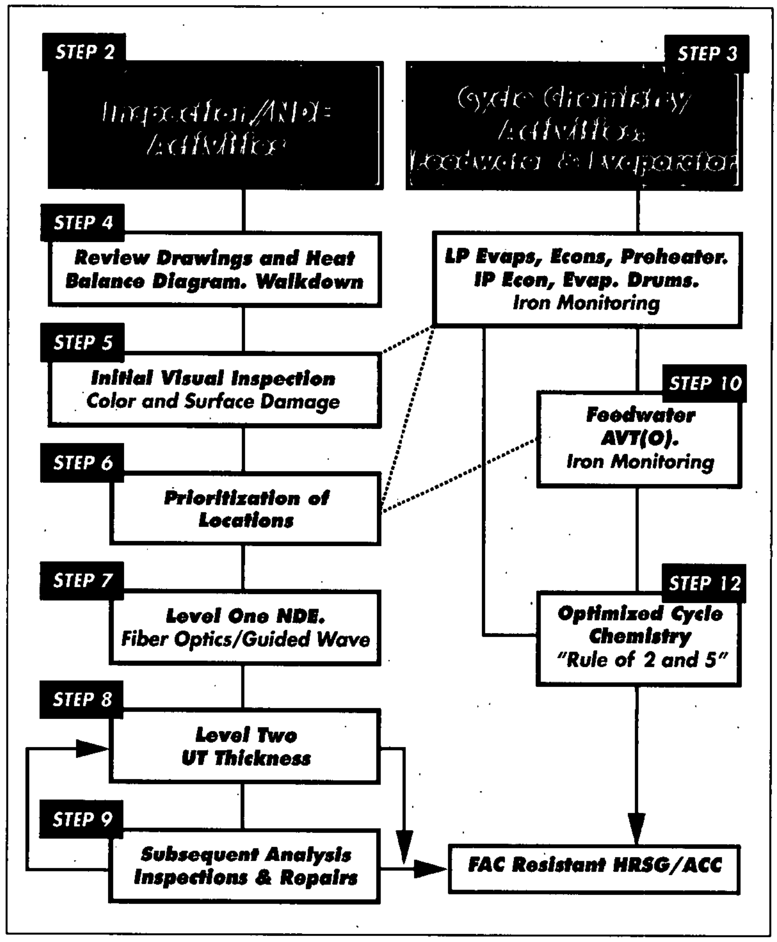

Figure A2:

Comprehensive FAC program for combined cycle/HRSG plants (air-cooled condensers can be included).

NDE	nondestructive evaluation
UT	ultrasonic testing
ACC	air-cooled condensers

Step 11
Cycle Chemistry Optimization of Mixed-Metallurgy Feedwater Systems in Conventional Fossil Plants
The monitoring in this step should add total copper to the parameters delineated in Step 10. This step is needed when the feedwater part of the plant contains copper alloys. In these cases it is necessary for the plant to use reducing agents and to operate with AVT(R). Monitoring of total iron will provide an indication of any FAC activity. The goal should be to attain $< 5\ \mu g \cdot kg^{-1}$ ($< 2\ \mu g \cdot kg^{-1}$ is preferred).

Step 12
Cycle Chemistry Optimization for Combined Cycle Plants
This step should ensure that both the feedwater and LP drum evaporator chemical treatments are optimized for FAC control. Further reductions in feedwater iron may be accomplished by increasing the pH control range above the normal range of 9.2–9.6. This will be particularly important if the combined cycle plant has an air-cooled condenser and will have a positive effect on the LP drum corrosion and FAC. If however the LP drum iron levels do not reach $< 5\ \mu g \cdot kg^{-1}$ by adjusting the feedwater pH, then consideration should be given to the addition of tri-sodium phosphate or NaOH to the LP drum if the LP drum does not provide feed for any upper pressure circuits or steam attemperation. The metric used to assess effective optimization of the feedwater and evaporator water is referred to as "The Rule of 2 and 5" with the final feedwater total iron $< 2\ \mu g \cdot kg^{-1}$ and all the drum evaporator circuits $< 5\ \mu g \cdot kg^{-1}$. In cycles that are unable to comply with this rule, despite successful optimization of the chemistry, it should be assumed that there is ongoing two-phase FAC that could not be arrested by any changes in the evaporator chemistry. This means that further action to evaluate and apply non-chemical solutions is needed (Steps 7–9).

APPENDIX B – FREQUENTLY ASKED QUESTIONS

During the second half of 2007 the author received many questions about FAC and its appearance, optimization of cycle chemistry in relation to FAC, prioritization of locations for inspection/NDE, and about developing comprehensive corporate-supported FAC programs. This appendix delineates the most frequently asked questions in no prioritized way. It was thought that these questions would stimulate others to develop optimum approaches and perhaps to prevent an FAC failure.

- What is the difference between single- and two-phase FAC?
- Do both types have chevrons (horseshoes)? Do they always point in the direction of flow?
- What does it mean if the chevrons are red colored, or if FAC damage is red colored?
- We only dose hydrazine. Is this OK?
- Is there a difference between FAC control in a mixed-metallurgy system and an all-ferrous system?
- What is the difference between having copper in the HP heaters as compared to the LP heaters?
- Is it necessary to change the feedwater chemistry from AVT(R) when initially/finally changing out copper feedwater heaters?
- What should we do on units where there are <u>now</u> no copper heaters?
- What is the optimum pH range for all-ferrous and mixed-metallurgy feedwater systems to control FAC?
- What should we do on "identical" units? Should we inspect the same areas?
- What is the critical level of chromium in a component above which we don't need to inspect?
- Should we concentrate our inspections at temperatures around 150 °C (300 °F)?
- We predict high FAC rates before and after the deaerator. Should we inspect both locations or put a higher priority on one location?
- We don't have time to inspect all the predicted highest priority areas. How do we choose which to inspect?
- The management has given us a small budget for inspection. How do we choose which areas to inspect?
- We have severe FAC which is red. Is this OK?
- We have severe FAC which has areas which look black, green, or yellow. Is this OK?
- Is there a critical fluid velocity we should look for?
- Which conventional fossil boiler components should we include in our FAC program?
- What does a management-supported FAC program look like?

THE AUTHOR

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Con Edison

Hearing Exhibits

STATE OF NEW YORK
DEPT. OF PUBLIC SERVICE
DATE: 6/9/10
CASE NOS: 09-S-0794, 09-G-0795, and 09-S-0029
Ex. 318

Exhibit_(MFC-3)
Page 1 of 8

point of the alloy can be achieved, thus providing a corresponding increase in high-temperature strength. The transverse creep and fatigue strength is increased, compared to equiaxed or DS structures. The advantage of single-crystal alloys compared to equiaxed and DS alloys in low-cycle fatigue (LCF) life is increased by about 10%.

Coatings

There are three basic types of coatings: thermal barrier coatings, diffusion coatings, and plasma sprayed coatings. The advancements in coating have also been essential in ensuring that the blade base metal is protected at these high temperatures. Coatings ensure that the life of the blades is extended and in many cases are used as sacrificial layers, which can be stripped and recoated. The life of a coating depends on composition, thickness, and the standard of evenness to which it has been deposited. The general type of coatings is little different from the coatings used 10–15 years ago. These include various types of diffusion coatings such as Aluminide Coatings originally developed nearly 40 years ago. The thickness required is between 25–75 μm thick. The new aluminide coatings with Platinum increase the oxidation resistance, and also the corrosion resistance. The thermal barrier coatings have an insulation layer of 100–300 μm thick, are based on ZrO2-Y2O3, and can reduce metal temperatures by 120–300 °F (50–150 °C). This type of coating is used in combustion cans, transition pieces, nozzle guide vanes, and also blade platforms.

The interesting point to note is that some of the major manufacturers are switching away from corrosion protection biased coatings towards coatings which are not only oxidation resistant, but also oxidation resistant at higher metal temperatures. Thermal barrier coatings are being used on the first few stages in all the advanced technology units. The use of internal coatings is getting popular due to the high temperature of the compressor discharge, which results in oxidation of the internal surfaces. Most of these coatings are aluminide type coatings. The choice is restricted due to access problems to slurry based, or gas phase/chemical vapor deposition. Care must be taken in production, otherwise internal passages may be blocked. The use of pyrometer technology on some of the advanced turbines has located blades with internal passages blocked causing these blades to operate at temperatures of 95–158 °F (35–70 °C).

Gas Turbine Heat Recovery

The waste heat recovery system is a critically important subsystem of a cogeneration system. In the past, it was viewed as a separate "add-on" item. This view

Exhibit _ (MFG-3)
Page 2 of 8

is being changed with the realization that good performance, both thermodynamically and in terms of reliability, grows out of designing the heat recovery system as an integral part of the overall system.

The gas turbine exhaust gases enter the Heat Recovery Steam Generating (HRSG), where the energy is transferred to the water to produce steam. There are many different configurations of the HRSG units. Most HRSG units are divided into the same amount of sections as the steam turbine. In most cases, each section of the HRSG has a Pre-heater, an Economizer and Feed-water, and then a Superheater. The steam entering the steam turbine is superheated.

The most common type of an HRSG in a large Combined Cycle Power plant is the drum type HRSG with forced circulation. These types of HRSGs are vertical; the exhaust gas flow is vertical with horizontal tube bundles suspended in the steel structure. The steel structure of the HRSG supports the drums. In a forced circulation HRSG, then the steam water mixture is circulated through evaporator tubes using a pump. These pumps increase the parasitic load and thus detract from the cycle efficiency. In this type of HRSG the heat transfer tubes are horizontal, suspended from un-cooled tube supports located in the hot gas path. Some vertical HRSGs are designed with evaporators, which operate without the use of circulation pumps.

The Once Through Steam Generators (OTSG) are finding quick acceptance due to the fact that they have smaller footprints, and can be installed in a much shorter time and at a lower price. The Once Through Steam Generators unlike other HRSGs do not have defined economizer, evaporator, or superheater sections. Figure 1-39 is the schematic of an OTSG system and a drum-type HRSG. The OTSG is basically one tube; water enters at one end and steam leaves at the other end, eliminating the drum and circulation pumps. The location of the water to steam interface is free to move, depending on the total heat input from the gas turbine, and flow rates and pressures of the Feedwater, in the tube bank. Unlike other HRSGs, the once-through units have no steam drums.

Some important points and observations relating to gas turbine waste heat recovery are:

Multipressure Steam Generators—These are becoming increasingly popular. With a single pressure boiler, there is a limit to the heat recovery because the exhaust gas temperature cannot be reduced below the steam saturation temperature. This problem is avoided by the use of multipressure levels.

Pinch Point—This is defined as the difference between the exhaust gas temperature leaving the evaporator section and the saturation temperature of the steam. Ideally, the lower the pinch point, the more heat recovered, but this calls for more surface area and, consequently, increases the backpressure and cost. Also, excessively low pinch points can mean inadequate steam production if the exhaust gas is low in energy (low mass flow or low exhaust gas temperature).

Exhibit_ (MFC-3)
Page 3 of 8

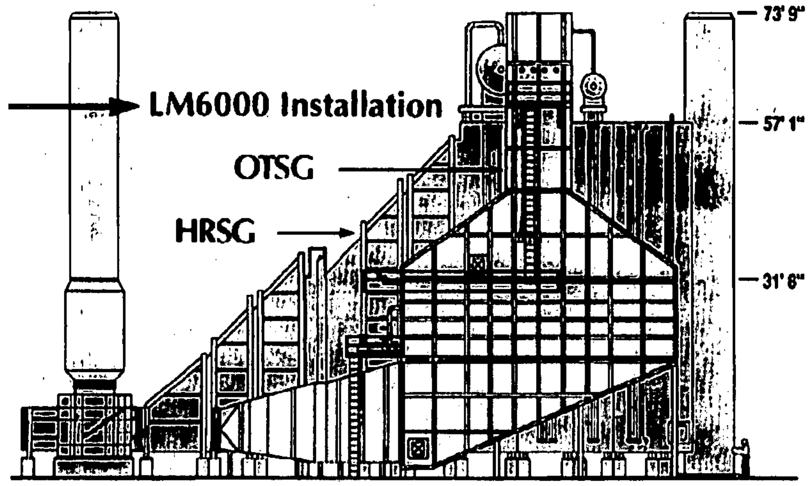

Figure 1-39. Comparison of a drum type HRSG to a once through steam generator. (Courtesy Innovative Steam Technologies.)

General guidelines call for a pinch point of 15–40 °F (8–22 °C). The final choice is obviously based on economic considerations.

Approach Temperature—This is defined as the difference between the saturation temperatures of the steam and the inlet water. Lowering the approach temperature can result in increased steam production, but at increased cost. Conservatively high-approach temperatures ensure that no steam generation takes place in the economizer. Typically, approach temperatures are in the 10–20 °F (5.5–11 °C) range. Figure 1-40 is the temperature energy diagram for a system and also indicates the approach and pinch points in the system.

Off-Design Performance—This is an important consideration for waste heat recovery boilers. Gas turbine performance is affected by load, ambient conditions, and gas turbine health (fouling, etc.). This can affect the exhaust gas temperature and the air flow rate. Adequate considerations must be given to bow steam flows (low pressure and high pressure) and superheat temperatures vary with changes in the gas turbine operation.

Evaporators—These usually utilize a fin-tube design. Spirally finned tubes of 1.25 in to 2 in outer diameter (OD) with three to six fins per inch are common. In the case of unfired designs, carbon steel construction can be used and boilers can run dry. As heavier fuels are used, a smaller number of fins per inch should be utilized to avoid fouling problems.

Forced Circulation System—Using forced circulation in a waste heat recovery system allows the use of smaller tube sizes with inherent increased heat transfer

Exhibit _ (MFC-3)
Page 4 of 8

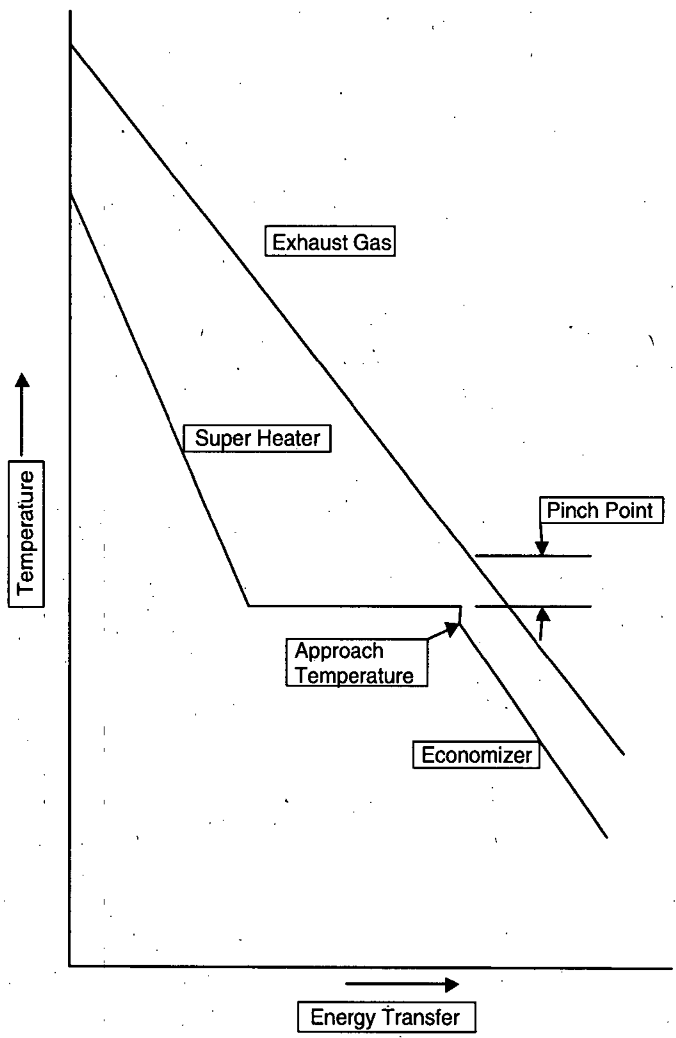

Figure 1-40. Energy transfer diagram in an HRSG of a combined cycle power plant.

Exhibit_(MFC-3)
Page 5 of 8

coefficients. Flow stability considerations must be addressed. The recirculating pump is a critical component from a reliability standpoint and standby (redundant) pumps must be considered. In any event, great care must go into preparing specifications for this pump.

Backpressure Considerations (Gas Side)—These are important, as excessively high backpressures create performance drops in gas turbines. Very low-pressure drops would require a very large heat exchanger and more expense. Typical pressure drops are 8–10 inches of water.

Supplementary Firing of Heat Recovery Systems

There are several reasons for supplementary firing of a wasteheat recovery unit. Probably the most common is to enable the system to track demand (i.e., produce more steam when the load swings upward, than the unfired unit can produce). This may enable the gas turbine to be sized to meet the base load demand with supplemental firing taking care of higher load swings. Figure 1-41 shows a schematic of a supplementary fired exhaust gas steam generator.

Raising the inlet temperature at the waste heat boiler allows a significant reduction in the heat transfer area and, consequently, the cost. Typically, as the gas turbine exhaust has ample oxygen, duct burners can be conveniently used.

An advantage of supplemental firing is the increase in heat recovery capability (recovery ratio). A 50% increase in heat input to the system increases the output 94%, with the recovery ratio increasing by 59%. Some important design guidelines to ensure success include:

- Special alloys may be needed in the superheater and evaporator to withstand the elevated temperatures.
- The inlet duct must be of sufficient length to ensure complete combustion and avoid direct flame contact on the heat transfer surfaces.
- If natural circulation is utilized, an adequate number of risers and feeders must be provided as the heat flux at entry is increased.
- Insulation thickness on the duct section must be increased.

Instrumentation and Controls

The advanced gas turbines are all digitally controlled and incorporate on-line condition monitoring. The addition of new on-line monitoring requires new and smart instrumentation. The use of pyrometers to sense blade metal temperatures are being introduced. The blade metal temperatures are the real concern, not the exit gas temperature. The use of dynamic pressure transducers for detection

Exhibit _(MFC-3)
Page 6 of 8

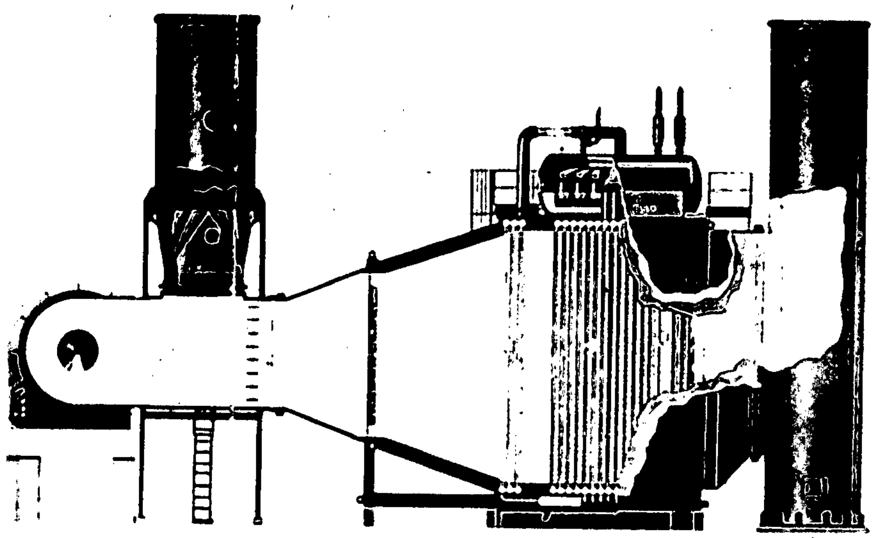

Figure 1-41. Supplementary fired exhaust gas steam generator.

of surge and other flow instabilities in the compressor and also in the combustion process especially in the new Low NO_X Combustors, are being introduced. Accelerometers are being introduced to detect high-frequency excitation of the blades. This prevents major failures in the new highly loaded gas turbines.

The use of pyrometers in control of the advanced gas turbines is being investigated. Presently, all turbines are controlled based on gassifier turbine exit temperatures, or power turbine exit temperatures. By using the blade metal temperatures of the first section of the turbine the gas turbine is being controlled at its most important parameter, the temperature of the first stage nozzles and blades. In this manner, the turbine is being operated at its real maximum capability.

The use of dynamic pressure transducers gives early warning of problems in the compressor. The very high pressure in most of the advanced gas turbines cause these compressors to have a very narrow operating range between surge and choke. Thus, these units are very susceptible to dirt and blade vane angles. The early warning provided by the use of dynamic pressure measurement at the compressor exit can save major problems encountered due to tip stall and surge phenomenon.

The use of dynamic pressure transducer in the combustor section, especially in the Low NO_X Combustors, ensures that each combustor can is burning evenly. This is achieved by controlling the flow in each combustor can till the spectrums obtained from each combustor can match. This technique has been used and found to be very effective and ensures smooth operation of the turbine.

Exhibit_(MFC-3)
Page 7 of 8

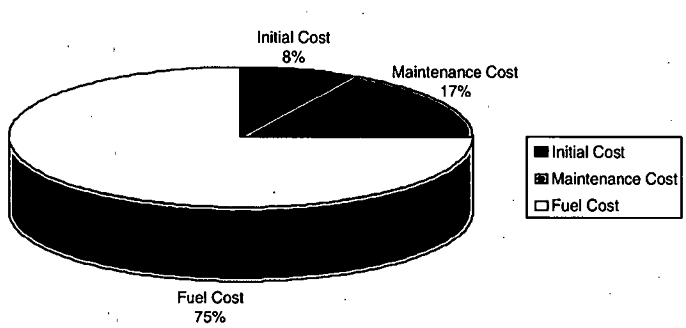

Figure 1-42. Plant life cycle cost for a combined cycle power plant.

Performance monitoring not only plays a major role in extending life, diagnosing problems, and increasing time between overhauls, but also can provide major savings on fuel consumption by ensuring that the turbine is being operated at its most efficient point. Performance monitoring requires an in-depth understanding of the equipment being measured. The development of algorithms for a complex train needs careful planning and understanding of the machinery and process characteristics. In most cases, help from the manufacturer of the machinery would be a great asset. For new equipment this requirement can and should be part of the bid requirements. For plants with already installed equipment a plant audit to determine the plant machinery status is the first step. Figure 1-42 shows the cost distribution over the life cycle of a gas turbine plant. It is interesting to note that the initial cost runs about 8% of the total life cycle cost, and the operational and maintenance cost is about 17%, and the fuel cost is abut 75%.

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Exhibit__(MFO-3)
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Hearing Exhibits

STATE OF NEW YORK
DEPT. OF PUBLIC SERVICE
DATE: 6/9/10
CASE NOS: 09-S-0794, 09-G-0795, and 09-S-0029
Ex. 319

Company Name: Con Edison
Case Description: Con Edison Gas & Steam Rate Cases
Case: 09-G-0795-09-S-0794

Response to DPS Interrogatories – Set DPS10
Date of Response: 01/28/2010
Responding Witness: steam Ops Panel

Question No. :53
Subject: East River Units 10 and 20 Heat Recovery Steam Generators (HRSGs):$6.5 million emergent projects, pages 56 and 57 of the Panel testimony. - 1. Please provide copies of all Incident Reports, of forced outages, unit de-ratings, and other operational events attributable to the HRSGs for both East River Units 10 and 20 from their in-service dates to present. 2. Please provide copies of at least five typical summary level reports used to monitor corrective actions taken and planned and HRSG operating performance to preclude recurrence of the flow accelerated corrosion noted in the testimony and/or other HRSG-related problems. 3. Please provide all reported NERC GADS (Generating Availability Data System) data summarized and demonstrating how the East River Units 10 and 20 HRSGs might be or have been individually tracked and evaluated and compared to peer group units for each of the categories on the attached (fn) extract from NERC GADS Data Reporting Instructions (DPS-053 HRSG.Excerpts.GADS_DRI_Complete_Set_Effective_January_2010.pdf). 4.Provide a summary list and accounting of all charges, invoices and other costs for each economizer repair. Include sufficient detail to identify costs for labor, materials, contractor costs, consultant fees and any other relevant cost categories.

Response:

Q. 1. Please provide copies of all Incident Reports, of forced outages, unit de-ratings, and other operational events attributable to the HRSGs for both East River Units 10 and 20 from their in-service dates to present.

A. Please see attached document entitled "Incident Report.PDF". The first eight pages of this document lists of the incidents. The applicable ER incident number is shown in the column entitled "INCIDENT NUMBER" The incident report corresponding to this number is provided in the remainder of the document in the order listed. Note that sometime in 2008 a new system was implemented. The new numbers have been noted in the right margin on the incident listing next to the old numbers. The new reports are provided in the order listed. Also, in some cases the incident number is repeated on the list but only one copy of the report was provided.

Q. 2. Please provide copies of at least five typical summary level reports used to monitor corrective actions taken and planned and HRSG operating performance to preclude recurrence of the flow accelerated corrosion noted in the testimony and/or other HRSG-related problems.

A. The HRSGs economizer repairs have been completed and the units returned to service. During operations the feedwater pH and dissolved oxygen levels are being monitored and recorded to ensure that the appropriate levels are maintained to mitigate recurrence of the flow accelerated corrosion. In addition, initial inspections, which include tube sampling, remote visual inspections, and ultrasonic thickness measurements, are scheduled for this upcoming spring outage season. All inspection reports and operating history data will be available for review at that time.

Q. 3. Please provide all reported NERC GADS (Generating Availability Data System) data summarized and demonstrating how the East River Units 10 and 20 HRSGs might be or have been individually tracked and evaluated and compared to peer group units for each of the categories on the attached (fn) extract from NERC GADS Data Reporting Instructions (DPS-053 HRSG.Excerpts.GADS_DRI_Complete_Set_Effective_January_2010.pdf)

A. The NERC code corresponding to the ER incidents is shown in "NERC CODE" column in the incident list included in the attached document entitled "Incident Report.PDF" The ER units performance data for the years 2005 -2009 is provided in the attached document entitled "ER Performance Data.PDF."

Q. 4.Provide a summary list and accounting of all charges, invoices and other costs for each economizer repair. Include sufficient detail to identify costs for labor, materials, contractor costs, consultant fees and any other relevant cost categories.

A. For a summary of the ER 10/20 HRSG Economizer Header replacement capital expenditure, please see attached spreadsheet.

HEAT RECOVERY STEAM GENERATOR (HRSG)
(Waste Heat Boiler)

<u>**HRSG Boiler Fuel Supply**</u>

Burners (Duct Burners)

0358	Oil burner piping and valves
0359	Gas burner piping and valves
0360	Duct burners
0361	Duct burner orfices
0370	Duct burner instruments and controls (except light-off)
0380	Light-off (igniter) systems (including fuel supply)
0385	Igniters
0410	Other duct burner problems

Oil and Gas Systems (except light-off)

0440	Fuel oil pumps (general)
0441	Fuel oil pumps (burner supply)
0442	Fuel oil pumps (forwarding/transfer)
0443	Fuel oil (burner supply) pump drives
0444	Fuel oil (forwarding/transfer) pump drives
0450	Fuel oil heaters
0460	Fuel oil atomizers
0470	Oil and gas fires
0480	Other oil and gas fuel supply problems (see codes 0360-0410 for burner problems)

Steam System Desuperheaters/Attemperators

See cause codes 6140 to 6154

<u>**HRSG Boiler Piping System**</u>

HRSG Startup Bypass

See cause codes 6160 to 6183

HRSG Main Steam

6110	HP steam piping up to turbine stop valves – Greater than 600 PSIG (see 0790 for piping supports)
6111	HP steam relief/safety valves
6112	Other HP steam valves (including vent and drain valves but not including the turbine stop valves)
6113	Other HP steam system problems
6120	IP steam piping up to turbine stop valves – Between 200 & 600 PSIG (see 0790 for piping supports)

<u>HRSG Boiler Piping System</u> (Continued)

6121	IP steam relief/safety valves
6122	Other IP steam valves (including vent and drain valves but not including the turbine stop valves)
6123	Other IP steam system problems
6130	LP steam piping up to turbine stop valves – Less than 200 PSIG (see 0790 for piping supports)
6131	LP steam relief/safety valves
6132	Other LP steam valves (including vent and drain valves but not including the turbine stop valves)
6133	Other LP steam system problems
6134	Other main steam valves (including vent and drain valves but not including the turbine stop valves)

HRSG Cold and Hot Reheat Steam

0540	Reheat steam piping up to turbine stop valves
0541	Cold reheat steam piping up to boiler
0550	Reheat steam relief/safety valves
0560	Other reheat steam valves (not including turbine stop or intercept valves)
0561	Other cold reheat steam valves (not including turbine stop or intercept valves)
0570	Other reheat steam problems

HRSG Desuperheaters/Attemperators

6140	HP Desuperheater/attemperator piping – Greater than 600 PSIG.
6141	HP Desuperheater/attemperator valves
6142	HP Desuperheater/attemperator spray nozzles
6143	HP Desuperheater/attemperator drums
6144	Other HP desuperheater/attemperator problems
6145	IP Desuperheater/attemperator piping – Between 200-600 PSIG
6146	IP Desuperheater/attemperator valves
6147	IP Desuperheater/attemperator spray nozzles
6148	IP Desuperheater/attemperator drums
6149	Other IP desuperheater/attemperator problems
6150	LP Desuperheater/attemperator piping – Less than 200 PSIG
6151	LP Desuperheater/attemperator valves
6152	LP Desuperheater/attemperator spray nozzles
6153	LP Desuperheater/attemperator drums
6154	Other LP desuperheater/attemperator problems

HRSG Startup Bypass

6160	HP Startup bypass system piping (including drain lines up to heaters or condenser)- Greater than 600 PSIG
6161	HP Startup bypass system valves
6162	HP Startup bypass tanks or flash tanks
6163	Other HP startup bypass system problems
6170	IP Startup bypass system piping (including drain lines up to heaters or condenser) – Between 200-600 PSIG

HRSG Boiler Piping System (Continued)

6171	IP Startup bypass system valves
6172	IP Startup bypass tanks or flash tanks
6173	Other IP startup bypass system problems
6180	LP Startup bypass system piping (including drain lines up to heaters or condenser) – Less than 200 PSIG
6181	LP Startup bypass system valves
6182	LP Startup bypass tanks or flash tanks
6183	Other LP startup bypass system problems

Feedwater and Blowdown

0670	Feedwater piping downstream of feedwater regulating valve
0680	Feedwater valves (not feedwater regulating valve)
0690	Other feedwater problems downstream of feedwater regulating valve (use codes 3401 to 3499 for remainder of feedwater system)
0700	Blowdown system valves
0710	Blowdown system piping
0720	Blowdown system controls / instrumentation
0730	Other blowdown system problems

Boiler Recirculation

0740	Boiler recirculation pumps
0741	Boiler recirculation pumps - motors
0750	Boiler recirculation piping including downcomers
0760	Boiler recirculation valves
0770	Other boiler recirculation problems

Miscellaneous (Piping)

0775	Economizer piping
0780	Headers between tube bundles
0782	Headers and caps
0790	Pipe hangers, brackets, supports (general)
0799	Other miscellaneous piping system problems

HRSG Boiler Internals and Structures

0800	Drums and drum internals (single drum only)
0801	HP Drum (including drum level trips not attributable to other causes)
0802	IP Drum (including drum level trips not attributable to other causes)
0803	LP Drum (including drum level trips not attributable to other causes)
0810	Boiler supports and structures (use code 1320 for tube supports)
0820	Casing
0830	Doors
0840	Refractory and insulation
0845	Windbox expansion joints
0847	Other expansion joints

<u>HRSG Boiler Internals and Structures</u> (Continued)

0848	Inlet panel
0850	Other internal or structural problems
0855	Drum relief/safety valves (Single drum only)
0856	HP Drum relief/safety valves
0857	IP Drum relief/safety valves
0858	LP Drum relief/safety valves
0859	Tube external fins/membranes

<u>HRSG Boiler Tube Leaks</u> (use code 0859 for tube/membrane failures)

6005	HP Evaporator tubes
6006	IP Evaporator tubes
6007	LP Evaporator tubes
6010	HP superheater
6011	HP reheater
6012	HP economizer
6020	IP superheater
6021	IP reheater
6022	IP economizer
6030	LP reheater
6031	LP superheater
6032	LP economizer
6090	Other HRSG tube Problems

<u>Miscellaneous HRSG Boiler Tube Problems</u>

1300	Water side fouling
1305	Fireside cleaning (which requires a full outage)
1310	Water side cleaning (acid cleaning)
1320	Tube supports/attachments
1330	Slag fall damage
1340	Tube modifications (including addition and removal of tubes)
1350	Other miscellaneous boiler tube problems

Air Supply

1400	Forced draft fans
1407	Forced draft fan lubrication system
1410	Forced draft fan motors
1411	Forced draft fan motors – variable speed
1412	Forced draft fan drives (other than motor)
1415	Forced draft fan controls
1420	Other forced draft fan problems
1430	Air supply ducts
1431	Air supply dampers from FD fan
1432	Air supply duct expansion joints
1440	Air supply dampers
1450	Other air supply problems

Miscellaneous (Boiler Air and Gas Systems)

1590	Stacks
1591	Stack damper and linkage
1592	Stack damper linkage motors
1599	Other miscellaneous boiler air and gas system problems

HRSG Boiler Control Systems (including instruments which input to the controls)

1700	Feedwater controls (report local controls — feedwater pump, feedwater regulator valve, etc., — with component or system)
1710	Combustion/steam condition controls (report local controls with component or system)
1720	Desuperheater/attemperator controls (not local controls)
1730	Boiler explosion or implosion
1740	Gage glasses
1750	Burner management system
1760	Feedwater instrumentation (not local controls)
1761	Combustion /Steam condition instrumentation (not local controls)
1762	Desuperheater/attemperator instrumentation (not local controls)
1799	Other boiler instrumentation and control problems

HRSG Boiler Overhaul and Inspections

1800	Major boiler overhaul (720 hours or more) (use for non-specific overhaul only; see page B-1)
1801	Minor boiler overhaul (less than 720 hours) (use for non-specific overhaul only; see page B-1)
1810	Other boiler inspections
1811	Boiler Inspections – problem identification/investigative
1812	Boiler Inspections – scheduled or routine
1820	Chemical cleaning/steam blows

HRSG Boiler Water Condition

1850	Boiler water condition (not feedwater water quality)

HRSG Boiler Design Limitations

1900	Improper balance between tube sections not due to fouling or plugging
1910	Inadequate air not due to equipment problems

Miscellaneous (Boiler) (use more specific codes X other slagging and fouling problems, other control problems, etc. X whenever possible. Describe miscellaneous problems in the verbal description.)

1980	Boiler safety valve test
6000	HRSG Boiler to gas turbine connecting equipment.
6100	Steam turbine to gas turbine coupling
1990	Boiler performance testing (use code 9999 for total unit performance testing)
1999	Boiler, miscellaneous

UnitName	MonthOrTotal	NetActualGeneration	SH	OH	AttemptedStarts	ActualStarts	StartingReliability	ForcedOutageRate	EFORd	EAF	NetCapacityFactor	Period
EAST RIVER 1	Dec-08	111271	714.52	0	2	2	100	0	1.08	95	80.84	Dec 2008 - Nov 2009
EAST RIVER 1	Jan-09	127990	744	0	0	0		0	0	100	92.99	Dec 2008 - Nov 2009
EAST RIVER 1	Feb-09	55377	332.2	306	2	2	100	47.95	47.95	49.43	44.54	Dec 2008 - Nov 2009
EAST RIVER 1	Mar-09	107557	689.9	53.1	1	1	100	7.15	7.15	92.85	78.14	Dec 2008 - Nov 2009
EAST RIVER 1	Apr-09	6285	44.63	0	0	0		0	0	6.2	4.72	Dec 2008 - Nov 2009
EAST RIVER 1	May-09	15464	111.75	0	1	1	100	0	0	15.02	14.14	Dec 2008 - Nov 2009
EAST RIVER 1	Jun-09	56982	441.75	201.63	2	2	100	31.34	31.34	61.35	53.84	Dec 2008 - Nov 2009
EAST RIVER 1	Jul-09	89308	702.08	0	1	1	100	0	0	94.37	81.66	Dec 2008 - Nov 2009
EAST RIVER 1	Aug-09	96248	744	0	0	0		0	0	100	88	Dec 2008 - Nov 2009
EAST RIVER 1	Sep-09	85624	720	0	0	0		0	0	100	80.9	Dec 2008 - Nov 2009
EAST RIVER 1	Oct-09	52090	432.68	0	0	0		0	0	58.16	37.79	Dec 2008 - Nov 2009
EAST RIVER 1	Nov-09	94152	646.33	0	2	1	50	0	0	99.03	70.68	Dec 2008 - Nov 2009
EAST RIVER 2	Dec-08	123426	744	0	0	0		0	0.05	99.95	89.67	Dec 2008 - Nov 2009
EAST RIVER 2	Jan-09	129610	744	0	0	0		0	0	100	94.17	Dec 2008 - Nov 2009
EAST RIVER 2	Feb-09	114554	672	0	0	0		0	0	100	92.14	Dec 2008 - Nov 2009
EAST RIVER 2	Mar-09	28211	168.75	63.4	0	0		27.31	27.31	22.71	20.5	Dec 2008 - Nov 2009
EAST RIVER 2	Apr-09	0	0	0	0	0			0	0	0	Dec 2008 - Nov 2009
EAST RIVER 2	May-09	5852	47.7	0	2	2	100	0	0	6.41	5.32	Dec 2008 - Nov 2009
EAST RIVER 2	Jun-09	54591	392.57	320.77	2	2	100	44.97	44.56	55.45	51.23	Dec 2008 - Nov 2009
EAST RIVER 2	Jul-09	93799	732.9	11.1	1	1	100	1.49	1.49	98.51	85.18	Dec 2008 - Nov 2009
EAST RIVER 2	Aug-09	97341	744	0	0	0		0	0	100	88.4	Dec 2008 - Nov 2009
EAST RIVER 2	Sep-09	76221	626.57	0	1	1	100	0	0	87.02	71.53	Dec 2008 - Nov 2009
EAST RIVER 2	Oct-09	70194	564.4	0	1	1	100	0	0	75.86	50.93	Dec 2008 - Nov 2009
EAST RIVER 2	Nov-09	104614	721	0	0	0		0	0	100	78.54	Dec 2008 - Nov 2009

NERC Data - 2008 from the NYISO

UnitName	MonthOrTotal	NetActualGeneration	SH	OH	AttemptedStarts	ActualStarts	StartingReliability	ForcedOutageRate	EFORd	EAF	NetCapacityFactor	Period
EAST RIVER 1	Jan-08	129124	744	0	0	0		0	0	100	93.81	Jan 2008 - Dec 2008
EAST RIVER 1	Feb-08	101137	601.12	0	3	3	100	0	0	86.65	78.55	Jan 2008 - Dec 2008
EAST RIVER 1	Mar-08	117907	694.22	0	1	1	100	0	0	93.43	85.66	Jan 2008 - Dec 2008
EAST RIVER 1	Apr-08	71181	454.97	0	0	0		0	0	63.19	53.51	Jan 2008 - Dec 2008
EAST RIVER 1	May-08	19627	173.2	11.03	6	6	100	5.99	5.99	23.28	17.95	Jan 2008 - Dec 2008
EAST RIVER 1	Jun-08	94777	720	0	0	0		0	0	100	89.55	Jan 2008 - Dec 2008
EAST RIVER 1	Jul-08	90636	701.5	39.68	1	1	100	5.35	5.34	94.67	82.87	Jan 2008 - Dec 2008
EAST RIVER 1	Aug-08	98428	744	0	0	0		0	0	100	90	Jan 2008 - Dec 2008
EAST RIVER 1	Sep-08	40834	322.15	0	3	2	66.67	0	0.12	44.69	38.58	Jan 2008 - Dec 2008
EAST RIVER 1	Oct-08	109165	737.03	0	1	1	100	0	0	99.06	79.21	Jan 2008 - Dec 2008
EAST RIVER 1	Nov-08	109762	721	0	0	0		0	0	100	82.4	Jan 2008 - Dec 2008
EAST RIVER 1	Dec-08	111271	714.52	0	2	2	100	0	1.08	95	80.84	Jan 2008 - Dec 2008
EAST RIVER 2	Jan-08	125401	744	0	0	0		0	0	100	91.11	Jan 2008 - Dec 2008
EAST RIVER 2	Feb-08	108355	696	0	0	0		0	0	100	84.15	Jan 2008 - Dec 2008
EAST RIVER 2	Mar-08	50102	326.97	0	0	0		0	0	44.01	36.4	Jan 2008 - Dec 2008
EAST RIVER 2	Apr-08	38056	236.53	0	5	5	100	0	0	32.85	28.61	Jan 2008 - Dec 2008
EAST RIVER 2	May-08	83249	740.87	0	0	0		0	0	99.58	75.6	Jan 2008 - Dec 2008
EAST RIVER 2	Jun-08	91651	692.53	0	1	1	100	0	0	97.22	86.01	Jan 2008 - Dec 2008
EAST RIVER 2	Jul-08	95895	734.73	9.27	1	1	100	1.25	1.25	98.75	87.09	Jan 2008 - Dec 2008
EAST RIVER 2	Aug-08	100200	744	0	0	0		0	0	100	91	Jan 2008 - Dec 2008
EAST RIVER 2	Sep-08	82763	617.45	0	0	0		0	0	85.76	77.67	Jan 2008 - Dec 2008
EAST RIVER 2	Oct-08	63271	450.28	0	1	1	100	0	0	60.52	45.91	Jan 2008 - Dec 2008
EAST RIVER 2	Nov-08	112467	721	0	0	0		0	0	100	84.43	Jan 2008 - Dec 2008
EAST RIVER 2	Dec-08	123426	744	0	0	0		0	0.05	99.95	89.67	Jan 2008 - Dec 2008

NERC Data - 2007 from the NYISO

UnitName	MonthOrTotal	NetActualGeneration	SH	OH	AttemptedStarts	ActualStarts	StartingReliability	ForcedOutageRate	EFORd	EAF	NetCapacityFactor	Period
EAST RIVER 1	Jan-07	122087	744	0	0	0		0	0	100	89.67	Jan 2007 - Dec 2007
EAST RIVER 1	Feb-07	104543	629.25	7.37	2	2	100	1.16	1.16	93.64	84.09	Jan 2007 - Dec 2007
EAST RIVER 1	Mar-07	120562	727.67	0	1	1	100	0	0	100	87.59	Jan 2007 - Dec 2007
EAST RIVER 1	Apr-07	53709	384.5	0	3	2	66.67	0	0	53.4	40.38	Jan 2007 - Dec 2007
EAST RIVER 1	May-07	94597	678.63	0	2	2	100	0	0	94.78	86.49	Jan 2007 - Dec 2007
EAST RIVER 1	Jun-07	67965	521.93	189.75	4	3	75	26.66	26.66	72.49	64.22	Jan 2007 - Dec 2007
EAST RIVER 1	Jul-07	55964	422.62	225.6	2	2	100	34.8	34.8	56.8	51.17	Jan 2007 - Dec 2007
EAST RIVER 1	Aug-07	101893	744	0	0	0		0	0	100	93.16	Jan 2007 - Dec 2007
EAST RIVER 1	Sep-07	44902	330.78	0	0	0		0	0	45.94	42.42	Jan 2007 - Dec 2007
EAST RIVER 1	Oct-07	75680	649.73	34.9	3	3	100	5.1	5.1	87.33	54.91	Jan 2007 - Dec 2007
EAST RIVER 1	Nov-07	116191	721	0	0	0		0	0	100	87.23	Jan 2007 - Dec 2007
EAST RIVER 1	Dec-07	126412	744	0	0	0		0	0	100	91.84	Jan 2007 - Dec 2007
EAST RIVER 2	Jan-07	115785	737.03	6.97	1	1	100	0.94	0.94	99.06	85.51	Jan 2007 - Dec 2007
EAST RIVER 2	Feb-07	105912	641.88	7.87	3	2	66.67	1.21	1.21	95.52	85.19	Jan 2007 - Dec 2007
EAST RIVER 2	Mar-07	119653	739.7	3.3	0	0		0.44	0.44	99.56	86.93	Jan 2007 - Dec 2007
EAST RIVER 2	Apr-07	74925	474.55	0	1	1	100	0	0	65.91	56.33	Jan 2007 - Dec 2007
EAST RIVER 2	May-07	88554	621.23	16.1	2	2	100	2.53	2.49	85.14	79.35	Jan 2007 - Dec 2007
EAST RIVER 2	Jun-07	87943	672.35	5.97	3	2	66.67	0.88	0.88	93.38	81.43	Jan 2007 - Dec 2007
EAST RIVER 2	Jul-07	93782	735.53	8.47	2	2	100	1.14	1.14	98.86	84.03	Jan 2007 - Dec 2007
EAST RIVER 2	Aug-07	97035	738.97	0	0	0		0	0	99.32	86.95	Jan 2007 - Dec 2007
EAST RIVER 2	Sep-07	62379	593.73	0	1	1	100	0	0	82.46	57.76	Jan 2007 - Dec 2007
EAST RIVER 2	Oct-07	54117	424.05	0	1	1	100	0	0	57	39.26	Jan 2007 - Dec 2007
EAST RIVER 2	Nov-07	113090	721	0	0	0		0	0	100	84.9	Jan 2007 - Dec 2007
EAST RIVER 2	Dec-07	122825	744	0	0	0		0	0	100	89.24	Jan 2007 - Dec 2007

PERFORMANCE SUMMARY
CONED, EAST RIVER 1
May 2006 - April 2007

Month	GAG	NAG	SH	OH	Starting Att	Starting Act	Starting Rel.	GHR	NHR	FOR	EFOR	EFORd	EAF	GCF	NCF
May 2006	0	103,584	737.85	6.15	2	2	100.00	0	0	0.27	0.27	0.27	99.17	0.00	96.68
June 2006	0	94,080	720.00	0.00	0	0	0.00	0	0	0.00	0.00	0.00	100.00	0.00	90.74
July 2006	0	100,863	744.00	0.00	0	0	0.00	0	0	0.00	0.00	0.00	100.00	0.00	94.14
August 2006	0	99,211	744.00	0.00	0	0	0.00	0	0	0.00	0.00	0.00	100.00	0.00	92.60
September 2006	0	91,392	720.00	0.00	0	0	0.00	0	0	0.00	0.00	0.00	100.00	0.00	88.15
October 2006	0	71,029	646.98	98.02	2	2	100.00	0	0	0.00	0.00	0.00	86.84	0.00	52.97
November 2006	0	49,339	312.95	407.05	7	4	57.14	0	0	0.00	0.00	0.00	43.47	0.00	38.07
December 2006	0	116,696	744.00	0.00	2	1	50.00	0	0	0.00	0.00	0.00	100.00	0.00	87.14
January 2007	0	122,087	744.00	0.00	0	0	0.00	0	0	0.00	0.00	0.00	100.00	0.00	89.67
February 2007	0	104,543	629.25	42.75	2	2	100.00	0	0	1.16	1.16	1.16	93.64	0.00	84.09
March 2007	0	120,562	743.00	0.00	1	1	100.00	0	0	0.00	0.00	0.00	100.00	0.00	87.59
April 2007	0	53,709	384.50	335.50	3	2	66.67	0	0	0.00	0.00	0.00	53.40	0.00	40.38
UNIT TOTAL	0	1127095	7870.53	889.47	19	14	73.68	0	0	0.12	0.12	0.12	89.85	0	77.33

Calculations done with NYISO conversion method of Outside Management Control events. Some events may be excluded from calculations.

PERFORMANCE SUMMARY
CONED, EAST RIVER 2
May 2006 - April 2007

Month	GAG	NAG	SH	OH	Starting Att	Starting Act	Starting Rel.	GHR	NHR	FOR	EFOR	EFORd	EAF	GCF	NCF
May 2006	0	60,072	440.55	303.45	10	6	60.00	0	0	0.67	0.67	0.67	59.21	0.00	56.07
June 2006	0	89,932	703.95	16.05	1	1	100.00	0	0	2.23	2.23	2.23	97.77	0.00	86.74
July 2006	0	92,644	676.37	4.63	2	2	100.00	0	0	0.00	0.00	0.00	99.38	0.00	86.47
August 2006	0	97,595	744.00	0.00	0	0	0.00	0	0	0.00	0.00	0.00	100.00	0.00	91.09
September 2006	0	86,976	689.25	30.75	0	0	0.00	0	0	0.00	0.00	0.00	95.73	0.00	83.89
October 2006	0	33,679	210.00	535.00	4	2	50.00	0	0	0.00	0.00	0.00	28.19	0.00	25.11
November 2006	0	77,833	720.00	0.00	0	0	0.00	0	0	0.00	0.00	0.00	100.00	0.00	60.06
December 2006	0	116,119	744.00	0.00	0	0	0.00	0	0	0.00	0.00	0.00	100.00	0.00	86.71
January 2007	0	115,785	737.03	6.97	1	1	100.00	0	0	0.94	0.94	0.94	99.06	0.00	85.51
February 2007	0	105,912	641.88	30.12	3	2	66.67	0	0	1.21	1.21	1.21	95.52	0.00	85.19
March 2007	0	119,653	739.70	3.30	0	0	0.00	0	0	0.44	0.44	0.44	99.56	0.00	86.93
April 2007	0	74,925	474.55	245.45	1	1	100.00	0	0	0.00	0.00	0.00	65.91	0.00	56.33
UNIT TOTAL	0	1071125	7521.28	1175.72	22	15	68.18	0	0	0.49	0.49	0.49	86.58	0	73.53

Calculations done with NYISO conversion method of Outside Management Control events. Some events may be excluded from calculations.

NERC PERFORMANCE REPORT VER.REL 2.8 PRODUCED 01/14/10 11:28
PERFORMANCE DATA YEAR-TO-DATE FOR ALL KNOWN NERC UNITS ENDING ----------- YEAR 2006 MONTH 12

STATION	UNIT	MO	GR MW-HRS	NET MW-HRS	ATT. ST.	ACT. ST.	FUEL1	QUANTITY1	HEAT CONT1	FUEL2	QUANTITY2	HEAT CONT2	GT SERV. HOURS
TOTAL FOR ELEC			2074430	1996646	26	16		0	0		0	0	0
TOTAL FOR BNY			2074430	1996646	26	16		0	0		0	0	0
ER	T-001	1	90377	90377	1	1	GG	0	0	DI	0	0	0
		2	100136	100136	1	1	GG	0	0	DI	0	0	0
		3	110906	110906	0	0	GG	0	0	KE	0	0	0
		4	71893	71893	0	0	GG	0	0	OO	0	0	0
		5	103584	103584	2	2	GG	0	0	OO	0	0	0
		6	94080	94080	0	0	GG	0	0	KE	0	0	0
		7	100863	100863	0	0	GG	0	0	OO	0	0	0
		8	99211	99211	0	0	GG	0	0	OO	0	0	0
		9	91392	91392	0	0	GG	0	0	OO	0	0	0
		10	71029	71029	2	2	GG	0	0	KE	0	0	0
		11	49339	49339	7	4	GG	0	0	KE	0	0	0
		12	116696	116696	2	1	GG	0	0	DI	0	0	0
TOTAL FOR T-001			1099506	1099506	15	11		0	0		0	0	0
	T-002	1	102102	98820	1	1	GG	0	0	DI	0	0	0
		2	96980	93897	1	1	GG	0	0	DI	0	0	0
		3	112293	108569	0	0	GG	0	0	KE	0	0	0
		4	55885	49271	0	0	GG	0	0	OO	0	0	0
		5	62409	60072	10	6	GG	0	0	OO	0	0	0
		6	93358	89932	1	1	GG	0	0	KE	0	0	0
		7	96060	92644	2	2	GG	0	0	OO	0	0	0
		8	101233	97595	0	0	GG	0	0	OO	0	0	0
		9	90319	86976	0	0	GG	0	0	OO	0	0	0
		10	34988	33679	4	2	GG	0	0	KE	0	0	0
		11	81297	77833	0	0	GG	0	0	KE	0	0	0
		12	119987	116119	0	0	GG	0	0	DI	0	0	0
TOTAL FOR T-002			1046911	1005407	19	13		0	0		0	0	0

NERC PERFORMANCE REPORT VER.REL 2.8 PRODUCED 01/14/10 11:27
PERFORMANCE DATA YEAR-TO-DATE FOR ALL KNOWN NERC UNITS ENDING ------------ YEAR 2005 MONTH 12

STATION	UNIT	MO	GR MW-HRS	NET MW-HRS	ATT. ST.	ACT. ST.	FUEL1	QUANTITY1	HEAT CONT1	FUEL2	QUANTITY2	HEAT CONT2	GT SERV. HOURS
TOTAL FOR ELEC			1814556	1744764	36	23		0	0		0	0	0
TOTAL FOR BNY			1814556	1744764	36	23		0	0		0	0	0
ER	T-001	4	24586	24586	9	5	GG	0	0	00	0	0	0
		5	57072	57072	3	3	GG	0	0	00	0	0	0
		6	70926	70926	8	8	GG	0	0	00	0	0	0
		7	84903	84903	2	2	GG	0	0	00	0	0	0
		8	78711	78711	1	1	GG	0	0	KE	0	0	0
		9	85246	85246	0	0	GG	0	0	00	0	0	0
		10	44133	44133	1	1	GG	0	0	KE	0	0	0
		11	107602	107602	0	0	GG	0	0	00	0	0	0
		12	125215	125215	0	0	GG	0	0	00	0	0	0
TOTAL FOR T-001			678394	678394	24	20		0	0		0	0	0
	T-002	4	36372	35105	6	5	GG	0	0	00	0	0	0
		5	57677	56030	2	2	GG	0	0	00	0	0	0
		6	57075	55091	8	7	GG	0	0	00	0	0	0
		7	89110	86141	2	2	GG	0	0	00	0	0	0
		8	90857	87743	0	0	GG	0	0	KE	0	0	0
		9	69950	68367	3	2	GG	0	0	00	0	0	0
		10	55080	53871	1	1	GG	0	0	KE	0	0	0
		11	73774	71526	2	2	GG	0	0	00	0	0	0
		12	114466	111151	1	1	GG	0	0	00	0	0	0
TOTAL FOR T-002			644361	625025	25	22		0	0		0	0	0

East River 10/20 HRSG Economizer Header Replacement Capital Expenditures

	Unit 10	Unit 20
Company Labor	367,152.11	925,934.95
Materials & Supplies	6,802.50	6,256.42
Accounts Payable		
Engineering Services	64,001.86	54,674.87
Building Mtce/Repair Equipment & Supplies	23,791.91	20,805.95
Plumbing Parts/Repair/Services	20,842.59	39,542.47
Misc Materials/Hardware/Parts & Supplies	109,947.08	98,849.46
Test & Inspection	1,692.96	10,436.60
Conv Plant Equipment/Parts & Services	690,177.74	1,806,090.29
Steam Plant Equipmen/Parts & Services	336,894.22	144,902.08
EDP Equipment, Incl Software	266.00	484.00
Tool Parts & Services	2,930.53	16,672.97
Reproduction/Photo Parts & Services	26,575.36	-
Office Supplies & Expenses	-	2,619.89
General Materials & Supplies	589.80	-
Contractor - Hired Vehicle	12,918.75	3,125.00
Freight	206.44	21,732.57
Rental Equipment - Other	16,330.00	17,155.28
Mtce & Inspection, Repair	3,501.80	-
Misc Studies & Activities	6,300.00	-
Other		
Accruals/Reversals - Net	88,867.27	60,177.42
Weekly Emp Exp	157.50	168.75
Transfers/Corrections	833,376.66	(847,392.17)
Indirects	766,922.55	988,313.48
	3,380,245.63	3,370,550.28

Con Edison

Hearing Exhibits

STATE OF NEW YORK
DEPT. OF PUBLIC SERVICE
DATE: 6/9/10
CASE NOS: 09-S-0794, 09-G-0795, and 09-S-0029
Ex. 320

Additional Details

Matthew F Cinadr's Engineering Experience

Q. Please state your professional qualifications, work experience, and educational background.

A. I received a bachelor's degree in mechanical engineering from Cleveland State University. After graduating, I began my engineering career as a field engineer with General Electric's Installation and Service Engineering Department. Various field assignments including the maintenance and installation of gas turbines and steam turbines in combined cycle configuration with heat recovery steam generators. This experience led to promotions to the Schenectady Large Steam Turbine Department and to the Apparatus Service Business Division where I was Manager of the Mechanical-Turbine Unit at the Charlotte, North Carolina Service Shop[1]. I left General Electric to

[1] While with General Electric I attended numerous professional and technical development workshops and

Exhibit _ (MFC-5)
Page 2 of 5

become the Manager of the Service Department for Stock Equipment Company. Power plant equipment startup and service was the main responsibility[2] for the 12 engineers in my department. In this capacity, I reported to the Manager of Engineering and thus became involved with design improvement projects and new project designs. I was promoted and joined Stock's Sales Department with responsibilities for a seven-state sales territory. I joined Stone & Webster's Operations Services Division and for over two years was responsible for a variety of tasks. As an engineer at Stone & Webster, I was responsible for evaluating, selecting, and applying standard engineering techniques, procedures, and criteria. I served as a Principal Engineer on a project for a 670 MW nuclear plant and was Division Specialist in coal handling. I joined the Department of Public Service, System Operations Section, in March 1982 and have been assigned and handled a variety of work related to the construction, operation and performance of generating

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seminars and completed a Management Development program at GE's 45-year-old corporate training facility in Crotonville, NY (recently renamed the John F. Welch Leadership Development Center at Crotonville).

[2] I developed Stock's first field engineering training program and was responsible for its use in training many new employees, service engineers and US and International sales engineering representative.

Exhibit_ (MFC-5)
Page 3 of 5

stations and the siting of new ones. Over the years I've investigated many boiler explosions and other accidents including the steam bubble condensation water hammer event at the Waterside Plant. I've also been assigned to several Management Audits of Con Ed and in one instance served as principal reporter on the Company's Power Generation Operations. Also important to mention is the role I played in my years working in Policy. During this time I was engaged in decisions and dealt directly with many key Company executives on matters surrounding the divestiture of its generators, formation of its subsidiaries and many other topics, including monitoring of the Company's responses to various legal matters.

Q. Have you previously submitted testimony before the Commission?

A. I have prepared numerous testimonies before and reports to the Public Service Commission for the Consolidated Edison Company of New York, Inc. (Con Edison) Rate Case 28211,04-E-0572, and 07-S-0315. Additionally, I've been assigned in the on-going Matter of Con Edison's Steam Planning Case, 07-S-0029 and many other Department activities involving Con Edison. I have prepared testimony in Rochester Gas and

Electric Corporation Rate Cases 28313 and 29426; Niagara Mohawk Power Corporation Rate Cases 29327 and 29728; Central Hudson Gas & Electric Corporation Case 29433.

Q. What are some of your duties and activities on which you are currently engaged?

A. My duties have required me to review every Article X application made downstate, in NYISO Zones J and K. My reviews have had a broad scope and generally covered all mechanical engineering aspects of project operations, and design. For example, I testified in Case

99-F-1314 "In the Matter of the Application of Consolidated Edison Company of New York, Inc. for a Certificate of Environmental Compatibility and Public Need to Re-power the East River Generating Station to Replace the Waterside Generating Station in Manhattan, New York County, New York". My current assignments include the ongoing work on the compliance[3] filing review in Case 00-F-2057 - Application by Besicorp-Empire Development Company, LLC for a Certificate of

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[3] This combined cycle plant is owned locally by a subsidiary of the international firm, GDF-Suez. It employs a gray water / evaporative cooling tower in its steam turbine cycle. First of its kind testing has been ordered in this case and is slated to be witnessed in 2010. Compliance reports will follow.

Environmental Compatibility and Public Need to construct and operate a 505 megawatt, combined cycle cogeneration plant in the City of Rensselaer, Rensselaer County.

Q. What other professional activities are you engaged in?

A I'm assigned to assist in the training of new engineers at the Department. I'm active in ASME and Professional Engineering activities and recently began presenting Engineering Topics in Continuing Professional Development programs as authorized by the New York State Education Department, Office of Professions, State Board of Engineering and Land Surveying.

Con Edison

Hearing Exhibits

STATE OF NEW YORK
DEPT. OF PUBLIC SERVICE
DATE: 6/9/09
CASE NOS: 09-S-0794, 09-G-0795, and 09-S-0029
Ex. 321

Recommended Reporting Requirements

1. <u>Production Plant Capital Expenditures</u>

The Company will, for informational purposes, file with the Commission and provide to Staff and other interested parties to this proceeding, by February 28 of each year, a comprehensive status report on its annual production capital expenditures. The report will, at a minimum:

i. identify each completed project, the date it was commenced and completed, and its total cost;
ii. for each ongoing project, provide its status, date of commencement, estimated date of completion, costs expended to date, and total project cost;
iii. for each project where the Company's expenditures have varied by more than 15 percent from the estimates contained in the Company's rate case filings, as updated during the course of the proceeding, provide a detailed explanation and justification for such variation; and
iv. for each new project (<u>i.e.</u>, those not previously identified by the Company in this proceeding), provide a detailed project description, justification of the need for the project, cash flow requirements from inception through completion, an explanation of how the cost figures were derived, and supporting work papers and other back up materials.

2. <u>Plant Availability and Performance Statistics</u>

The Company will file with the Commission an annual report on plant availability and performance statistics for each steam production unit for the winter and summer periods. This report will be filed within 60 days of the end of each calendar year.

3. <u>O&M Expenditures</u>

By February 28 of each year, the Company will file with the Commission its plans for each station that encompass major maintenance components (<u>i.e.</u>, corrective maintenance, major maintenance, overhauls, plant component upgrades, and plant inspection and repairs) for the current calendar year. These plans will include a description of the anticipated major activities and total planned expenditures in these categories. Copies of this filing will be provided to all interested parties. Starting in February 2007, where the Company's actual O&M expenditures for the previous year vary by more than 15 percent from the estimates provided for that year, the report will provide an explanation for such variation.

Con Edison

Hearing Exhibits

STATE OF NEW YORK
DEPT. OF PUBLIC SERVICE
DATE: 6/9/09
CASE NOS: 09-S-0794, 09-G-0795, and 09-S-0029
Ex. 322

STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

Case 09-S-0794 - 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.

Case 09-G-0795 - Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Consolidated Edison Company of New York, Inc. for Gas Service.

CASE 09-S-0029 - Proceeding on Motion of the Commission to Consider Steam Resource Plan and East River Repowering Project Cost Allocation Study, and Steam Energy Efficiency Programs for Consolidated Edison Company of New York, Inc.

ATTENTION

This exhibit is among those prefiled in the captioned cases by active parties that executed two joint proposals that were filed on May 18, 2010. Those that executed the joint proposals subsequently stipulated that they would not cross-examine the witnesses of each other given that they were supporting at that time the Commission's adoption of the terms of the joint proposals. In this context, the fact that these parties did not cross-examine the witnesses of each other does not mean and cannot reasonably be understood to mean that the information in this exhibit is uncontroverted among the parties that executed the joint proposals.

BEFORE THE
STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

In the Matter of

Consolidated Edison Company Of New York, Inc.

Case 09-S-0794

March 2010

Prepared Testimony of:

Staff Rate Panel

Richard F. George
Junior Engineer
Office of Electric, Gas and Water

Liliya A. Randt
Utility Engineer 2
Office of Electric, Gas and Water

State of New York
Department of Public Service
Three Empire State Plaza
Albany, New York, 12223-1350

Q. Please State your name, employer, and business address.

A. Richard F. George and Liliya A. Randt. We are employed by the New York State Department of Public Service (Department) and located at Three Empire State Plaza, Albany, New York 12223.

Q Mr. George, what is your position at the Department?

A. I am employed as a Junior Engineer in the Electric Rates Section of the Office of Electric, Gas and Water.

Q. Please state your educational background and professional experience.

A. I graduated magna cum laude from Rensselaer Polytechnic Institute with a Bachelor of Science degree in Civil Engineering in May 2008. I began my employment with the Department in May 2009.

Q. Please describe your duties with the Department.

A. My current duties include the review and evaluation of electric utility capital and Operations and Maintenance (O&M) budgets and the engineering analyses of electric utility rate, pricing and tariff proposals.

Q. Have you previously testified before the Commission?

A. Yes, I testified in the Consolidated Edison Company of New York, Inc.'s (Con Edison or the Company) electric rate case 09-E-0428 regarding the Company's Shared Services.

Q. Ms. Randt, what is your position in the Department?

A. I am employed as a Utility Engineer 2 in the Rates and Tariffs section of the Office of Electric, Gas and Water.

Q. Ms. Randt, please state your educational background and professional experience.

A. I graduated magna cum laude from the State University of New York, Institute of Technology at Utica with a Bachelor of Science degree in Mechanical Engineering Technology in May 2004. I also received a Master Degree in Civil Engineering from Poltava Technical University, Ukraine in 1997. I began my employment with the Department in April 2005 and currently hold the title of Utility Engineer 2. While with the Department, I have prepared, analyzed, and reviewed reports and studies involving operating revenues, sales forecasts, operation and maintenance expenses, embedded costs, revenue allocation, and rate design. My duties include engineering analyses of utility rate, pricing, and tariff proposals.

Q. Have you previously testified before the New York State Public Service Commission?

A. Yes, I testified in Consolidated Edison Company of New York, Inc.'s (Con Edison or the Company) steam rate cases (Cases 05-S-1376 and 07-S-1315) regarding the embedded cost of service study (ECOS), rate design and other revenue requirement issues. I testified in the Freeport Electric rate case (Case 06-E-0911) regarding capital expenditures, depreciation, and rate design. I testified in Orange and Rockland Utilities, Inc.'s electric rate cases (Cases 06-E-1433 and 07-E-0949) regarding the delivery revenue forecast, ECOS and rate design issues. I also testified in the three Con Edison electric rate proceedings, Cases 07-E-0523, 08-E-0539 and 09-E-0428 and steam Case 09-S-0029.

Q. What is the purpose of the Staff Rate Panel (SRP) testimony?

A. The purpose of our testimony is to address:

1. ECOS results presented in this case
2. Staff's Revenue allocation
3. Customer Charge rate design
4. Base cost of fuel
5. Recovery of expenses related to electric usage by steam operations
6. Proposed tariff changes
7. Customer Service Enhancements
8. The Company's Plant-in-Service forecast model
9. Revenue forecast associated with Staff's sales forecast adjustments

Q. In your testimony, will you refer to, or otherwise rely upon, any information produced during the discovery phase of this proceeding?

A. Yes, we will refer to, and have relied upon, several responses to Department of Public Service Staff (Staff) Information Requests (IR). These responses are included in Exhibit __ (SRP-1).

Q. Are you sponsoring any other exhibits?

A. Yes, we are sponsoring the following Exhibits: Exhibit___ (SRP-2) Revenue Allocation, which provides details of the revenue allocation of

Staff's proposed revenue requirement;

Exhibit__ (SRP-3) which contains estimated net plant additions for the rate year;

Exhibit__ (SRP-4) which contains the net revenue adjustment calculation based on staff sales forecast adjustments.

ECOS Study

Q. Did the Panel examine the ECOS study submitted by the Company?

A. Yes.

Q. Please briefly describe the purpose of an ECOS study.

A. An ECOS study reflects the cost of providing utility services to each customer class. It is based on an analysis of the rate base, operating expenses, and revenues for a prior calendar year period. There are two major steps in an ECOS study: functionalization and classification of costs to operating function, and allocation of these functionalized costs to customer classes. Functionalization and classification entail assigning costs either to production, distribution, customer accounting and customer service, with further division into sub-functions such as production demand, production energy-fuel, distribution demand, distribution customer and services. The second step is allocation of classified costs to customer classes based on selected characteristics such as class contribution to peak demand, steam sales, or the number of customers in a particular service class. The final output of the ECOS study is a summary of the individual class rates of return which indicates the level to which each class contributes to the total system rate of return.

Q. On what data was Con Edison's ECOS study based?

A. The costs allocated in this ECOS study include the booked 2008 data and the revenues reflect current rates effective October 1, 2009.

Q. Please explain the "tolerance band" that the Company applies to the results of the ECOS study.

A. Individual class revenue responsibilities have been measured with a +/-10% tolerance band around the total system average rate of return. Specific classes would be considered deficient or surplus if their computed return falls outside of this tolerance band.

Q. What are the results of the Company's ECOS study in this case?

A. The ECOS study indicates that all steam customer classes are within the +/-10% tolerance band.

Q. Does the Company propose any changes to the ECOS study from that submitted in the previous Steam filing?

A. Yes. The Company lowered the eligibility threshold for steam customers to take service under the SC 2 Rate II - Annual Power Service - Demand, and SC Rate II Demand - Apartment House Service Classes from the current level of 22,000 Mlbs to 14,000 Mlbs annually, which takes effect at the start of RY1 in this case, October 1, 2010.

Q. How did the Company reflect this future rate design change in the historic based ECOS?

A. The Company developed the ECOS allocating factors and revenues, as if those eligible customers had already been moved to the demand class.

Q. Does the Panel agree with this change?

A. Yes. We have reviewed the modification and find it to be reasonable.

Staff's Revenue Allocation

Q. Please describe how does the Company allocate the rate year increase in base rates?

A. The ECOS study reveals that all classes are within the +/-10% band and there are no deficiencies or surpluses, therefore the Company allocated the rate increase across the board using a uniform percentage for all customer classes.

Q. Has the panel prepared a revenue allocation?

A. Yes, we have performed a similar revenue allocation using the Company's ECOS and the same general approach as described above, but with Staff Accounting Panel proposed base rate increase of $73,216,000.

Q. Is Staff's revenue allocation provided herein as an Exhibit?

A. Yes, it is presented in Exhibit__ (SRP-2). The overall pure base rate change is 21.5%.

Rate Design

Q. Please summarize the Company's proposed rate design.

A. First the Company determined its proposed increase to the customer charge for each customer class. Then, the energy and demand charges in each class were increased to recover the balance of the revenue requirement for each class.

Q. Please explain the proposed customer charge increases for the steam customer classes.

A. The customer charge for the SC1 class, excluding the component relating to the fuel costs associated with steam fixed line losses, was increased by 1.1 times the class's overall pure base percentage increase. This moves the charge closer to the ECOS study customer charge while minimizing bill impacts to the SC1 low usage customers in recognition that the customer charge for the SC1 customer represents a significant portion of the customer's bill.

For the SC2 Non-Demand the customer charge was increased by 0.65 times the class's overall pure base percentage increase, because the current customer charge is slightly above the Company's cost to provide the service.

For the SC2 Demand class the customer charge was increased by 1.2 times the overall rate increase, since the current customer charge is close to the cost to provide the service.

For the SC3 non-demand class, the customer charge was increased by the percentage increase necessary to raise it to the level of the ECOS study customer charge.

For the SC3 demand class, the customer charge was increased by 1.5 times the class's overall pure base percentage increase to move it closer to the ECOS study's customer charge, while recognizing, that the customer charge does not represent a significant portion of the customer's bill for SC3 demand class.

Q. Does Staff agree with the proposed customer charge increases?

A. Yes. Based on our review of the Company workpapers we agree with the proposed increases to the customer charges. The Company's approach is reasonable for each class in that it recognizes both the impact on customer bills, and, at the same time, attempts to incorporate proper cost responsibility. By applying a greater increase to the customer charge, in certain instances, the resulting customer charge better reflects the level of customer related costs as identified in the ECOS. In addition, the proposed customer charges will ensure that greater levels of fixed costs are recovered from fixed rate components, and volumetric usage charges reflect primarily variable cost recovery.

Base Cost of Fuel

Q. Please summarize the Company's proposal regarding the revision to the base cost of fuel.

A. The Company proposes to revise the base cost of fuel at the conclusion of this proceeding. The current base cost of fuel is $8.049 per Mlb and that amount is included and recovered in base rates. Monthly variations between the base cost and actual cost is reconciled through the steam Fuel Adjustment clause (FAC). The Company proposes that the actual average cost of fuel in effect prior to the date new rates take effect, including any updated estimates of fuel costs provided during the course of this proceeding, be used as a guide in determining the level at which to set the base cost of fuel.

Q. Is the Company's proposal clear as to exactly how this calculation will be done?

A. No, therefore Staff recommends that the base cost of fuel be set at the conclusion of this proceeding based on using the average of the most recent (October 2010-Septemebr 2011) projected cost of fuel for the rate year and the average of the prior historic actual year (September 2009-August 2010). This approach is intended to have the base cost of fuel reflect equally the most recent actual costs and the Company's most current forecast of future costs of fuel.

Recovery of expenses related to electric usage by steam operations

Q. Please summarize the Company's proposal regarding the recovery of expenses related to electric usage by steam operations.

A. The cost of electricity used by steam operations for production is currently recovered through the steam base rates. The Company claims that these costs vary with the output of the plants and should be recovered in the same manner as fuel costs. The Company is proposing to recover these costs through the Fuel Adjustment Clause

(FAC).

Q. What level of costs does the Company project for the rate year?

A. The Company projects $13.0 million for the cost of electricity used by steam operations for production in the rate year.

Q. Do you agree with this level?

A. Yes, in its response to Staff IR DPS-115 (Exhibit__(SRP-1)), the Company provided workpapers showing electric usage of its steam only stations for production in the historic year and the forecasted amount for the rate year. The Company also provided the computation for the price per kWh of electricity used for Company purposes forecasted for the rate year. Based on Staff's review of these workpapers, these costs are reasonable and the calculations are complete and correct.

Q. What does Staff recommend regarding recovery of these costs?

A. Staff recommends denying the Company's proposal to move this cost recovery from base rates to the FAC.

Q. What is your basis for this recommendation?

A. Staff recommends keeping recovery of expenses related to electric usage by steam operations for production through base rates because the Company has some control over these costs. Staff's recommendation will provide the Company incentive to reduce its costs. Moving the recovery to the FAC would eliminate this incentive.

Q. If the Commission decides that the Company should recover these expenses through the FAC, what modifications to the Company's proposal would you recommend?

A. To address Staff's concern that the Company should have an incentive to reduce its electric usage by steam operations for production, we recommend first to establish an annual target ratio (kWh/Mlb) of electric usage for production to steam production by the Company.

Q. How would this target be determined?

A. The target ratio of kWh of electric usage for production to Mlb of steam production for any current calendar year would be determined using the average ratio of the prior three calendar years.

Q. How would this target be used to provide an incentive to the Company to reduce its electricity consumption for steam production?

A. At the end of each calendar year, the actual total steam production by the Company (Mlb) would be multiplied by the target ratio (kWh/Mlb) to obtain the target electricity usage for steam production (kWh). The expense of the difference between the cost of the target electricity usage for steam production and the actual cost of electricity usage for that year would be shared between the Company and the Customers, where the Customers receive 80% of the difference and the Company receives 20%. For example, if the amount of electricity used for steam production is lower than the target, meaning the Company was able to reduce its electric usage, the Company would be allowed to keep 20% of the benefit and the Customers would receive 80% of the benefit. Similarly, if the amount of electricity used for steam production is higher than the target, the Company would only be allowed to recover 80% of the increased costs and Customers would only be responsible for 20%. The actual sharing of costs or benefits from the prior year would be applied in the subsequent year through the FAC.

Q. Please provide examples on how the Company is able to control the amount of electricity used by its steam operations.

A. The Company is able to control its electricity usage by implementing energy efficient equipment and programs which promote the conservation of energy. For example the Company could utilize more efficient pumps, motors, fans, or lighting and create programs which promote employee energy conservation.

<u>Proposed Tariff Changes-Steam Operations Panel-Vincent Badali</u>

Q. Did Staff review the Company's various proposed tariff changes to its Steam Services as proposed by the Company's Steam Operations Panel and its witness Badali?

A. Yes, the proposed tariff changes include the implementation of demand billing for SC-2 and SC-3 customers with annual usage equal to or greater than 14,000 Mlb, lowering the threshold for the transfer of SC-2 and SC-3 customers from demand billing to non-demand billing from 14,000 Mlb to 12,000 Mlb, extending the period of accepting applications from SC-2 and SC-3 customers installing new or replacement air conditioning system under the current air-conditioning program, and new charges for temporary disconnection and reconnection of service performed by the Company at the customer's request.

Q. Do you agree with the Company's proposed Tariff changes?

A. Yes, in its response to Staff IR DPS-116 (Exhibit__ (SRP-1)), the Company provided workpapers supporting the proposed changes. Included in its response to DPS-116 were computations behind the proposal of lowering the threshold for the transfer of SC-2 and SC-3 customers from demand billing to non-demand billing from 14,000 Mlb to 12,000 Mlb. Also, the Company provided workpapers demonstrating how it arrived at the charges for temporary disconnection and reconnection. The changes are reasonable and the calculations are complete and correct based on review of the workpapers and contact with the Company.

Customer Service Enhancements

Q. Please summarize the Company's proposal regarding customer service enhancements.

A. Currently steam customers do not have the alternative of online payments that the Company's electric and gas customers have. The Company is proposing to modify its current customer service website to provide the customer with the ability to pay their bills online, access key customer information and resolve billing-related problems.

Q. What is the cost to perform and maintain these enhancements?

A. The Capital Costs are $200,000 and $100,000 in rate years 2010 and 2011 respectfully. The operating and maintenance costs are $100,000.

Q. Do you recommend the Company carry out these enhancements?

A. Yes, steam customers should have the expanded capabilities included in this proposal, which the Company's gas and electric customers already have. Based on review of the Company's workpapers provided in its response to DPS-117

(Exhibit__ SRP-1)) and contact with the Company these costs are reasonable.

Plant in Service Model

Q. Please explain the Plant-in-Service forecast model?

A. The Company provided a detailed Plant-in-Service model as part of its filing. The model included projections of the specific date when each individual capital project will go into service from July 2009 through 2014. The Plant-in-Service model arrives at the projected average net plant and estimated monthly balances that serve as a basis for the rate year projections.

Q. Have you developed adjustments to the Plant-in-Service model?

A. Yes. Staff witnesses examined the forecasted cost and projected in-service dates of each capital project proposed by Con Edison in this case. We were given specific adjustments to the capital expenditures from the Staff Steam Operations Panel. We incorporated those adjustments into the Plant-in-Service model. The average net plant in-service for the twelve months ending September 30, 2011 is $1.6

billion, as shown in Exhibit__ (SRP-3). We provided the average net plant and depreciation expense to the Staff Accounting Panel.

Revenue Forecast

Q. Have you reviewed the Company's rate year revenue forecast at current rate levels?

A. Yes. As reflected in the Company's Exhibit __ (FP-2), the Company forecasts $524,417,000 in steam revenues during the rate year based on its sales forecast of 23,175 MMlbs.

Q. Does Staff propose a different level of sales for the rate year?

A. Yes. Staff witness Barney proposes adjustments that increase the level of sales reflected in the Company's forecast by 44 MMlbs. This increased sales level increases the projected overall level of revenues that the Company will collect at current rates.

Q. Has Staff calculated a price out of witness Barney's adjusted sales forecast?

A. Yes, Staff calculated a price out of the rate year revenues at current rates based on Staff's forecasted sales level. We recommend that the rate year revenue requirement requested by the

Company be reduced by $1.1 million as a result of the sales adjustment.

Q. How did you then arrive at the rate year revenue requirement reduction associated with the increase in sales?

A. We calculated the corresponding increase in fuel and station electric costs associated with the increase in sales. This increase in cost was then subtracted from the increase in sales revenues to arrive at the net adjustment. The results of these calculations are shown in our Exhibit__ (SRP-4). This exhibit has been provided to the Staff Accounting Panel.

Q. Does this conclude your testimony at this time?

A. Yes.

Con Edison

Hearing Exhibits

STATE OF NEW YORK
DEPT. OF PUBLIC SERVICE
DATE: 6/9/10
CASE NOS: 09-S-0794, 09-G-0795, and 09-S-0029
Ex. 323

BEFORE THE
STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

In the Matter of

Consolidated Edison Company Of New York, Inc.

Case 09-S-0794

March 2010

Prepared Exhibit of:

Staff Rate Panel

Richard F. George
Junior Engineer
Office of Electric, Gas and
Water

Liliya A. Randt
Utility Engineer 2
Office of Electric, Gas and
Water

State of New York
Department of Public Service
Three Empire State Plaza
Albany, New York, 12223-1350

Company Name: Con Edison
Case Description: Con Edison Gas & Steam Rate Cases
Case: 09-G-0795-09-S-0794

Response to DPS Interrogatories – Set DPS14
Date of Response: 01/21/2010
Responding Witness: Muccilo

Question No. :115
Subject: Recovery of Electric Usage (Steam) – 1. Provide the historic and forecasted Electric Usage expenditures for the years of 2004 through 2009. 2. 2. The Company states on page 44, line 9-12, of Robert Muccilo's testimony that the Electric Usage expense for the rate year is approximately $13 million. Explain how the Company arrived at this value and provide any supporting detailed work papers that demonstrate calculation of such value.

Response:

Question:
1. Provide the historic and forecasted Electric Usage expenditures for the years of 2004 through 2009.

Response:
1. The information readily available for this request can be found in the Company's response to DPS 13, Question 111.

Question:
2. The Company states on page 44, line 9-12, of Robert Muccilo's testimony that the Electric Usage expense for the rate year is approximately $13 million. Explain how the Company arrived at this value and provide any supporting detailed work papers that demonstrate calculation of such value.

Response:
2. The $13.0 million is the rate year estimate and the calculation can be seen on the attached document, Attachment DPS Question 115 (2a). The historic year actual kWhs and charges for electricity used total the historic expense of $11.5 million. Based on the Company's estimated rate year usage (87,769,339 kWh) multiplied by the estimated rate year per kWh ($15.387) rate, the total estimated rate year cost would be $13.0 million. The increase of $1.5 million results in the Company's program change. The estimated rate year rate per kWhr of $15.387 is based on 12 months of actual costs incurred by the Company through May 31, 2009 divided by total kWhs used for the respective expense. Please see Attachment DPS Question 115 (2b) that details how the rate year rate per kWh was calculated.

Electric and Gas Used

Calculation of Program Change

Rate Adjustment - Program Change
Steam Only Stations
($000's)

	Historic Year Actual kWh (A)			Rate Year
	July - Dec 2008	Jan - June 2009	Total	kWh
59th Street - Live (B)	1,104,000	1,086,000	2,190,000	2,190,000
74th Street - Live	11,392,000	13,197,000	24,589,000	28,203,952
Hudson Avenue - Main	3,956,689	6,359,325	10,316,014	10,547,594
East River - South	5,022,000	7,698,000	12,720,000	11,274,159
59th St. - Pkg. Blrs.	3,576,000	3,822,000	7,398,000	6,537,658
74th St. - Pkg. Blrs.	3,474,000	4,428,000	7,902,000	7,953,690
Ravenswood	327,295	370,720	698,015	825,163
60th Street	7,422,000	8,508,000	15,930,000	17,237,123
Total	36,273,984	45,469,045	81,743,029	84,769,339
Historic Year Charge for Electricity Used				
2008 Rate - 13.717 cents/kWh	**$4,976**			
2009 Rate - 14.409 cents/kWh		**$6,552**	**$11,528**	
Rate Year Rate - 15.387 cents/kWh				**$13,043**
TOTAL ELECTRIC AND GAS USED PROGRAM CHANGE				**$1,515**

(A) Electricity usage is from the station's monthly Report of Steam Production and Report of Electric Production.
(B) 59th St. uses 6,000 kWh per day.

CONSOLIDATED EDISON COMPANY OF NEW YORK, INC.

COMPUTATION BASED ON TWELVE MONTHS ENDED MAY 31, 2009
AMOUNT TO BE CHARGED FOR ELECTRICITY USED FOR COMPANY PURPOSES DURING 2010

		Twelve Months Ended May 31 2009 Costs	Cost to Company Cents Per KWHR To Be Accounted For	
Production Expenses				
Fuel & Purchased Power		$3,513,552,669.30	13.758	(B)
Other Production Expenses		133,392,034.27	0.508	(C)
Total Production Expenses		3,646,944,703.57		
Transmission Expenses		181,457,745.62	0.306	(D)
Total Distribution Expenses		487,899,250.94		
Less:				
Customer Installations	$15,029,437.49			
Operation of Street Lighting and Signal Systems	1,749,745.12			
Supervision and Engineering applicable to above (2) items (A)	2,872,173.10			
Maintenance of Installations on Customers' Premises	8,645,863.45			
Maintenance of Street Lighting and Signal Systems	6,034,131.10			
Supervision and Engineering applicable to above (2) items (A)	945,821.21	35,277,171.47		
Total Distribution Expenses Included		452,622,079.47	0.763	(D)
Customer Accounts Expenses				
Meter Reading		31,009,730.90	0.052	(D)
Total Applicable Cost		$4,312,034,259.56		
Rate per KWHR - Company used Electricity			15.387	

	(B) Excl. NYPA , Retail Choice & MDA	(C) Excl. NYPA & Retail Choice Incl. MDA	(D) Incl. NYPA, Retail Choice & MDA
12 Months Ended May 31, 2009			
Total KWHRs Accounted for	25,538,262,381	26,249,904,500	59,282,990,698

(A) See page 2.
(B) Not Affected by NYPA, Retail Choice & MDA transfer; denominator is Company -only KWHRs.
(C) Not Affected by NYPA and Retail Choice transfer; denominator is Company-only KWHRs + KWHRs associated with MDA
(D) Transmission & Distribution Cost affected by All Sales including NYPA, Retail Choice and MDA

Company Name: Con Edison
Case Description: Con Edison Gas & Steam Rate Cases
Case: 09-G-0795-09-S-0794

Response to DPS Interrogatories – Set DPS14
Date of Response: 01/20/2010
Responding Witness: Badali

Question No. :116
Subject: Tariff Changes (Steam) – 1. The Company states on page 14, lines 13-15, of Vincent Badali's testimony that a customer will remain on the demand rate until their annual usage ending August drops below 12,000 Mlb. The Company also states on page 15, lines 13-16, that the average annual difference in usage for this group of customers, approximately 2,000 Mlb, represents a differential that is normal variation. a. Provide the detailed workpapers that demonstrate how the Company arrived at an average annual difference of 2,000 Mlb for this group of customers. b. The Company's previous threshold for SC-2 and SC-3 demand billing was 22,000 Mlb. Did the company provide a similar 2,000 Mlb differential when it implemented the previous threshold of 22,000 Mlb? If yes, provide the previously used differential quantity in Mlb and justification supporting such differential. 2. The Company states on page 16 of Mr. Badali's testimony that it is proposing to charge customers for each temporary disconnection and reconnection of service performed by the Company at the Customer's request. a. Provide the reason(s) why a customer would want the Company to perform the action of temporarily disconnecting or reconnecting to the steam system. b. Provide an explanation as to why the Company is proposing this new charge at this time. c. Provide detailed workpapers that demonstrate how the Company arrived at the charges for disconnection or reconnection stated on page 15, lines 19-21. d. Does the Company have similar charge(s) to gas and electric customers? If yes, provide the applicable charges to each respective customer?

Response:
Q1: The Company states on page 14, lines 13-15, of Vincent Badali's testimony that a customer will remain on the demand rate until their annual usage ending August drops below 12,000 Mlb. The Company also states on page 15, lines 13-16, that the average annual difference in usage for this group of customers, approximately 2,000 Mlb, represents a differential that is normal variation. a. Provide the detailed workpapers that demonstrate how the Company arrived at an average annual difference of 2,000 Mlb for this group of customers.

A1a. See attached work paper.

Q1b. The Company's previous threshold for SC-2 and SC-3 demand billing was 22,000 Mlb. Did the company provide a similar 2,000 Mlb differential when it implemented the previous threshold of 22,000 Mlb? If yes, provide the previously used differential quantity in Mlb and justification supporting such differential.

A1b: No.

Q2: The Company states on page 16 of Mr. Badali's testimony that it is proposing to charge customers for each temporary disconnection and reconnection of service performed by the Company at the Customer's request.

a. Provide the reason(s) why a customer would want the Company to perform the action of temporarily disconnecting or reconnecting to the steam system.

A2a: Customers request temporary disconnection and reconnection of steam service for several reasons, including performance of maintenance and repairs to their equipment and seasonal shutdown of service.

b. Provide an explanation as to why the Company is proposing this new charge at this time.

A2b: The Company is proposing this new charge at this time to better align customer responsibility for costs associated with these special services.

c. Provide detailed workpapers that demonstrate how the Company arrived at the charges for disconnection or reconnection stated on page 15, lines 19-21.

A2c: These charges are currently in place for disconnection and reconnection services (in excess of one time in twelve months) and reflect the cost of required resources to perform the work.

d. Does the Company have similar charge(s) to gas and electric customers? If yes, provide the applicable charges to each respective customer?

A2d: Yes. Electric and gas customers are charged for temporary disconnection and reconnection of service.

Per the Con Edison Electric Tariff, P.S.C. No. 9 Electricity, customers are charged for certain "Special Services at Stipulated Rates" that range from a minimum of $19.00 to a maximum of $1,003.00 (IV.1. A-E, leaves 81 - 81A). In addition to these services, Con Edison will perform certain "Special Services at Cost" (IV.2.A - P, leaves 82 - 83) upon request of a Customer, a Customer's agent, or the Department of Transportation (DOT). Cost to the company is defined in IV.3, leaf 83 "Definition Cost."

Per the Con Edison Gas Tariff, P.S.C. No. 9 Gas, customers are charged for certain "Special Services at Stipulated Rates" that range from a minimum of $15.00 to a maximum of $19.00 (IV.3.a - b, leaves 118 - 118.1). In addition to these services, Con Edison will perform certain "Special Services at Cost" (IV.1.A - H, leaves 116 -

117) upon request of a Customer. Cost to the company is defined in IV.2. A - G, leaf 117 "Definition Cost."

Steam Distribution
Temporary Disconnection/Reconnection of Service
Utility Service

	Straight Time	Overtime
Direct Labor and Excused Time	$ 32.26	$ 48.40
Excused time	4.64	4.64
Supervision and Clerical Support	24.09	24.09
Expenses	19.26	19.26
Fringe Benefits	24.27	24.27
Worker's Compensation / Public Liability	3.55	3.55
Administrative & Supervisory	1.34	1.34
Depreciation on Building	0.11	0.11
Depreciation on Vehicles	0.33	0.33
Return on Building	0.48	0.48
Return on Vehicles	0.39	0.39
Property Insurance	-	-
Property Taxes	0.19	0.19
Total labor rate per hour	110.92	127.05
Total labor rate for 2.5 hours	277.29	317.64
NYC Embargo Fee	30.00	30.00
Total cost	307.29	347.64
GRT	7.62	8.63
Total Charge	**$ 314.92**	**$ 356.26**

Steam Accounts that Qualified for Sample Billing in 2008 or 2009

Exhibit__ (SRP-1)
Page 8 of 13

Account Number	Service Address	2,009	2008	2009 Yes	2008 Yes	
[redacted]	[redacted]	13,065	15,774		Y	
[redacted]	[redacted]	11,988	18,070		Y	A/C Unit Upgraded For 2009
[redacted]	[redacted]	13,834	14,025		Y	[redacted]
[redacted]	[redacted]	13,062	14,645		Y	[redacted]
[redacted]	[redacted]	6,263	17,161		Y	[redacted]
[redacted]	[redacted]	11,350	20,532		Y	[redacted]
[redacted]	[redacted]	12,574	14,173		Y	[redacted]
[redacted]	[redacted]	13,887	15,385		Y	[redacted]
[redacted]	[redacted]	12,299	15,164		Y	[redacted]
[redacted]	[redacted]	12,989	18,794		Y	[redacted]
[redacted]	[redacted]	13,679	14,932		Y	[redacted]
[redacted]	[redacted]	13,895	15,774		Y	[redacted]
[redacted]	[redacted]	13,199	14,265		Y	[redacted]
[redacted]	[redacted]	12,418	14,721		Y	[redacted]
[redacted]	[redacted]	13,528	14,355		Y	[redacted]
[redacted]	[redacted]	13,167	14,974		Y	[redacted]
[redacted]	[redacted]	13,917	14,870		Y	[redacted]
[redacted]	[redacted]	12,565	14,487		Y	[redacted]
[redacted]	[redacted]	13,021	15,835		Y	[redacted]
[redacted]	[redacted]	9,852	14,219		Y	[redacted]
[redacted]	[redacted]	14,280	12,290	Y		[redacted]
[redacted]	[redacted]	14,230	13,877	Y		[redacted]
[redacted]	[redacted]	14,488	13,675	Y		[redacted]
[redacted]	[redacted]	15,357	13,671	Y		[redacted]
[redacted]	[redacted]	14,086	12,471	Y		[redacted]
[redacted]	[redacted]	14,875	13,568	Y		[redacted]
[redacted]	[redacted]	14,521	12,037	Y		[redacted]
[redacted]	[redacted]	14,358	11,839	Y		[redacted]
[redacted]	[redacted]	14,290	5,991	Y		[redacted]
[redacted]	[redacted]	14,633	12,021	Y		[redacted]
[redacted]	[redacted]	14,651	0	Y		[redacted]
[redacted]	[redacted]	14,907	10,069	Y		[redacted]
[redacted]	[redacted]	17,489	13,349	Y		[redacted]
[redacted]	[redacted]	17,447	2,319	Y		[redacted]
[redacted]	[redacted]	16,481	12,551	Y		[redacted]
[redacted]	[redacted]	17,321	13,237	Y		[redacted]
[redacted]	[redacted]	14,466	12,506	Y		[redacted]
[redacted]	[redacted]	14,250	13,356	Y		[redacted]
[redacted]	[redacted]	14,059	13,637	Y		[redacted]
[redacted]	[redacted]	14,436	11,251	Y		[redacted]
[redacted]	[redacted]	15,602	12,977	Y		[redacted]
[redacted]	[redacted]	14,165	13,992	Y		[redacted]
[redacted]	[redacted]	18,001	0	Y		[redacted]
[redacted]	[redacted]	14,114	12,555	Y		[redacted]
[redacted]	[redacted]	15,888	13,965	Y		[redacted]
[redacted]	[redacted]	15,039	13,618	Y		[redacted]
[redacted]	[redacted]	15,280	4,772	Y		[redacted]
Count	47					

Steam Accounts that Qualify for Sample Billing in 2008 or 2009					
whose Annual Sales Difference is Attributed to Normal Operating Conditions					
ACCT ID	Address	Sep07 Aug08 Sales	Sep08 Aug09 Sales	% Difference	M# Difference
[redacted]		15,774	13,065	17%	2,709
		12,290	14,280	16%	1,990
		13,877	14,230	3%	353
		14,025	13,834	1%	191
		13,675	14,488	6%	814
		13,671	15,357	12%	1,686
		12,471	14,086	13%	1,615
		14,645	13,062	11%	1,582
		13,568	14,875	10%	1,306
		12,037	14,521	21%	2,484
		11,839	14,358	21%	2,519
		12,021	14,633	22%	2,612
		14,173	12,574	11%	1,599
		15,385	13,887	10%	1,498
		10,069	14,907	48%	4,838
		15,164	12,299	19%	2,865
		18,794	12,989	31%	5,805
		14,932	13,679	8%	1,253
		13,349	17,489	31%	4,140
		15,774	13,895	12%	1,878
		14,265	13,199	7%	1,067
		12,551	16,481	31%	3,930
		13,237	17,321	31%	4,084
		12,506	14,466	16%	1,960
		14,721	12,416	16%	2,304
		13,356	14,250	7%	894
		13,637	14,059	3%	422
		11,251	14,436	28%	3,185
		14,355	13,524	6%	831
		14,974	13,167	12%	1,807
		12,977	15,602	20%	2,626
		13,992	14,165	1%	173
		12,555	14,114	12%	1,559
		13,965	15,888	14%	1,923
		14,870	13,917	6%	953
		13,618	15,039	10%	1,420
		14,487	12,565	13%	1,921
		15,835	13,021	18%	2,814
			Average	**15%**	**2,042**
Count	38				

Company Name: Con Edison
Case Description: Con Edison Gas & Steam Rate Cases
Case: 09-G-0795-09-S-0794

Response to DPS Interrogatories – Set DPS14
Date of Response: 01/20/2010
Responding Witness: Badali

Question No. :117
Subject: Customer Service Enhancements – 1. Provide detailed workpapers that demonstrate how the Company arrived at the operating and maintenance cost of $100,000 per year stated on page 18, lines 2-3 of Vincent Badali's testimony. 2. Provide detailed workpapers that demonstrate how the Company arrived at the capital expenditures of $200,000 in 2010 and $100,000 in 2011 as stated on page 17, lines 23-24 of Mr. Badali's testimony. 3. Provide an explanation as to the need for additional resources beyond what the Company currently has devoted to the customer service areas that will be served by the Company's proposal for expanded online billing information, self-service options and payment options. 4. Are the costs associated with the proposed customer service enhancements outlined in Mr. Badali's testimony, including an O&M cost of 100,000, incremental to the costs currently dedicated to provide these services to customers? 5. The Company states on page 17, lines 24-26, of Mr. Badali's testimony that the majority of costs will go towards replacement of obsolete servers. What are the current function(s) of the servers being replaced?

Response:
Q1: Provide detailed work-papers that demonstrate how the Company arrived at the operating and maintenance cost of $100,000 per year stated on page 18, lines 2-3 of Vincent Badali's testimony.

A1: See attached O&M worksheet.

Q2: Provide detailed work-papers that demonstrate how the Company arrived at the capital expenditures of $200,000 in 2010 and $100,000 in 2011 as stated on page 17, lines 23-24 of Mr. Badali's testimony.

A2: See attached Capital worksheet.

Q3: Provide an explanation as to the need for additional resources beyond what the Company currently has devoted to the customer service areas that will be served by the Company's proposal for expanded online billing information, self-service options and payment options.

A3: Today, the steam customer service system does not have any dedicated resources. With the implementation of the proposed enhancements to the system, which will include bill design enhancements, among other features, a dedicated resource is required.

Q4: Are the costs associated with the proposed customer service enhancements outlined in Mr. Badali's testimony, including an O&M cost of 100,000, incremental to the costs currently dedicated to provide these services to customers?

A4: Yes

Q5: The Company states on page 17, lines 24-26, of Mr. Badali's testimony that the majority of costs will go towards replacement of obsolete servers. What are the current function(s) of the servers being replaced?

A5: The existing servers support the current steam customer service website. New server capabilities are required to support the additional functions proposed.

Consolidated Edison Co. of New York, Inc.
2009 Steam Rate Case

Capital Worksheet

DRAFT - CONFIDENTIAL

SUBMITTING ORGANIZATION: Specialized Activities	Responsible Individual	Corporate Customer Group
PROGRAM NAME: Steam Customer Service Enhancements		
PROGRAM START DATE: 2010		

TYPE OF CHANGE	PLEASE CHECK ONE
PROGRAM/ PROJECT:	
VOLUME:	
NON-RECURRING: (Normalization)	

CAPITAL CALENDAR YEAR

AMOUNT (IN THOUSANDS OF DOLLARS)

THOUSANDS OF DOLLARS

ELEMENT OF EXPENSE	LENGTH OF PROGRAM	2010 Forecast	2010 Program Changes	2010 Revised Forecast	2011 Forecast	2011 Program Changes	2011 Revised Forecast	2012 Forecast	2012 Program Changes	2012 Revised Forecast	2013 Forecast	2013 Program Changes	2013 Revised Forecast
Professional Services		$40	$0	$40	$0	$0	$0	$0	$0	$0	$0	$0	$0
Servers		$90	$0	$90	$90	$0	$90	$0	$0	$0	$0	$0	$0
or Additional Web Page/Super User $9; UAT for Pa		$34	$0	$34	$0	$0	$0	$0	$0	$0	$0	$0	$0
Indirects		$22	$0	$22	$4	$0	$4	$0	$0	$0	$0	$0	$0
Contingency		$14	$0	$14	$6	$0	$6	$0	$0	$0	$0	$0	$0
TOTAL		$200	$0	$200	$100	$0	$100	$0	$0	$0	$0	$0	$0

UNITS OF PRODUCTION

UNITS OF PRODUCTION

WORK UNITS	LENGTH OF PROGRAM	2010 Forecast	2010 Program Changes	2010 Revised Forecast	2011 Forecast	2011 Program Changes	2011 Revised Forecast	2012 Forecast	2012 Program Changes	2012 Revised Forecast	2013 Forecast	2013 Program Changes	2013 Revised Forecast
		0	0	0	0	0	0	0	0	0	0	0	0
		0	0	0	0	0	0	0	0	0	0	0	0
		0	0	0	0	0	0	0	0	0	0	0	0
		0	0	0	0	0	0	0	0	0	0	0	0
		0	0	0	0	0	0	0	0	0	0	0	0
		0	0	0	0	0	0	0	0	0	0	0	0
TOTAL		0	0	0	0	0	0	0	0	0	0	0	0

AVERAGE HUMAN RESOURCES (MANAGEMENT & WEEKLY) (SEE NOTE BELOW)

JOB TITLE	2008 LABOR RATE	Quantity	2010 PROGRAM CHANGES	Quantity	2011 PROGRAM CHANGES	Quantity	2012 PROGRAM CHANGES	Quantity	2013 PROGRAM CHANGES
		0	$0		$0		$0		$0
			$0		$0		$0		$0
		0	$0		$0		$0		$0
		0	$0		$0		$0		$0
		0	$0		$0		$0		$0
		0	$0		$0		$0		$0
EQUIVALENT OVERTIME		0	$0		$0		$0		$0
TOTAL		0	$0	$0	$0	$0	$0	$0	$0

	Percent Allocation	2011	2012	2013
Clearing dollar % allocated to O&M per Authority Letter ——>		$0	$0	$0
Clearing dollars % allocated to Capital as per Authority Letter	100.00%	$0	$0	$0

NOTE:

Wkly. field employee @ Man-hour rate
Field Supervisors (included in man hour rate)
Clerical (included in man hour rate)
Wkly. employee (Basic Labor)
Management (Basic Labor)
Engineering support (Basic Labor rate)
Contractor oversight (Basic Labor rate)

SERVICE IMPACTED BY PROGRAM CHANGE	PLEASE CHECK ONE
ELECTRIC	
GAS	
STEAM	X
COMMON - ELECTRIC, GAS & STEAM	
COMMON - ELECTRIC & STEAM	
COMMON - GAS & STEAM	
CECONY & O&R	
CECONY, O&R & NON-UTILITY	

Exhibit __ (SRP-1)
Page 12 of 13

Consolidated Edison Co. of New York, Inc.
2009 Steam Rate Case

O&M Worksheet

DRAFT - CONFIDENTIAL

SUBMITTING ORGANIZATION:	Specialized Activities	Responsible Individual	Corporate Customer Group
PROGRAM NAME:	Steam Customer Service Enhancements		
PROGRAM START DATE:	2010		

TYPE OF CHANGE — PLEASE CHECK ONE

PROGRAM/ PROJECT:	
VOLUME:	
NON-RECURRING: (Normalization)	

O&M RATE YEAR

AMOUNT (IN THOUSANDS OF DOLLARS) — THOUSANDS OF DOLLARS

MAG	PSC	ELEMENT OF EXPENSE	LENGTH OF PROGRAM	Historical 6/30/09 HISTORICAL YEAR LEVEL OF SPENDING	Incremental RYE 9/30/11 PROGRAM CHANGES	RYE 2011 FIRST RATE YEAR LEVEL OF SPENDING	Incremental RYE 9/30/12 PROGRAM CHANGES	RYE 2012 SECOND RATE YEAR LEVEL OF SPENDING	Incremental RYE 9/30/13 PROGRAM CHANGES	RYE 2013 THIRD RATE YEAR LEVEL OF SPENDING
		Maintenance Support Staff		$0	$0	$100	$0	$100	$0	$100
				$0	$0	$0	$0	$0	$0	$0
				$0	$0	$0	$0	$0	$0	$0
				$0	$0	$0	$0	$0	$0	$0
				$0	$0	$0	$0	$0	$0	$0
		TOTAL		$0	$0	$100	$0	$100	$0	$100

UNITS OF PRODUCTION — UNITS OF PRODUCTION

MAG	PSC	WORK UNITS	LENGTH OF PROGRAM	Historical 6/30/09 HISTORICAL YEAR LEVEL OF WORK	Incremental RYE 9/30/11 PROGRAM CHANGES	RYE 2011 FIRST RATE YEAR LEVEL OF WORK	Incremental RYE 9/30/12 PROGRAM CHANGES	RYE 2012 SECOND RATE YEAR LEVEL OF WORK	Incremental RYE 9/30/13 PROGRAM CHANGES	RYE 2013 THIRD RATE YEAR LEVEL OF WORK
				0	0	0	0	0	0	0
				0	0	0	0	0	0	0
		TOTAL		0	0	0	0	0	0	0

AVERAGE HUMAN RESOURCES (MANAGEMENT & WEEKLY) (SEE NOTE BELOW)

JOB TITLE	2008 LABOR RATE	Quantity	2010 PROGRAM CHANGES	Quantity	2011 PROGRAM CHANGES	Quantity	2012 PROGRAM CHANGES	Quantity	2013 PROGRAM CHANGES
Senior Systems Analyst - Management				1	$100	1	$100	1	$100
			$0		$0		$0		$0
		0	$0		$0		$0		$0
		0	$0		$0		$0		$0
		0	$0		$0		$0		$0
		0	$0		$0		$0		$0
EQUIVALENT OVERTIME		0	$0		$0		$0		$0
TOTAL		0	$0	$1	$100	$1	$100	$1	$100
		Percent Allocation							
Clearing dollar % allocated to O&M per Authority Letter ——>					$0		$0		$0
Clearing dollars % allocated to Capital as per Authority Letter		100.00%			$0		$100		$100

NOTE:

Wkly. field employee @ Man-hour rate
Field Supervisors (included in man hour rate)
Clerical (included in man hour rate)
Wkly. employee (Basic Labor)
Management (Basic Labor)
Engineering support (Basic Labor rate)
Contractor oversight (Basic Labor rate)

SERVICE IMPACTED BY PROGRAM CHANGE	PLEASE CHECK ONE
ELECTRIC	
GAS	
STEAM	X
COMMON - ELECTRIC, GAS & STEAM	
COMMON - ELECTRIC & STEAM	
COMMON - GAS & STEAM	
CECONY & O&R	
CECONY, O&R & NON-UTILITY	

Exhibit __ (SRP-1)
Page 13 of 13

Con Edison

Hearing Exhibits

STATE OF NEW YORK
DEPT. OF PUBLIC SERVICE
DATE: 6/9/10
CASE NOS: 09-S-0794, 09-G-0795, and 09-S-0029
Ex. 324

Staff Steam Rate Panel
Class Allocation Exhibit

Development of Rate Year and Historical Year Base Rate Changes:

A =	$73,216,000	Staff's Proposed Rate Year Base Rate Increase incl. GRT
B =	2.16601%	Weighted Average Rate Year GRT
C = A/(1+B) =	$71,664,000	Proposed Base Rate Increase excl. GRT
D =	$333,312,946	Rate Year Pure Base Revenue at 10/1/09 Revenue Level
E = C/D =	21.500519%	Proposed Average Pure Base Rate % Increase
F =	23,087,828	Rate Year Sales (Mlbs)

SC1 Non-Dmd = 1.1 x Column 10
SC2 Non-Dmd = Column 10d
SC2 Dmd = Column 10d
SC3 Non-Dmd = Column 10e
SC3 Dmd = 1.5 x Column 10

Service Class	CECONY Rate Year 12 Mos 9/30/11 Sales Mlbs	CECONY Rate Year* 12 Mos 9/30/11 Pure Base Rev at 10/1/09 Rev Level Excl Base Cost of Fuel & Fixed Cost Chg	Historical Year 12 Mos 6/30/09 Sales Mlbs	Historical Year* 12 Mos 6/30/09 Base Rev at 10/1/09 Rev Level	Historical Year* 12 Mos 6/30/09 Pure Base Rev at 10/1/09 Rev Level Excl Base Cost of Fuel & Fixed Fuel Cost Chg	Historical Year Customer Charge Excl Fixed Fuel Cost Chg	Historical Year PBR W/O Customer Charge
	(1)	(2)	(3)	(4)	(4a)	(4b)	(4c)
1 Annual	580,000	$15,842,000	573,244	$73,045,044	$17,202,303	$4,585,879	$12,616,424
2 Non-Demand Summer	448,000	$6,971,000	413,308	$12,509,633	$6,773,643	$4,474,764	$2,298,879
2 Non-Demand Winter	1,739,000	$39,359,000	1,874,530	$58,131,106	$42,620,565	$6,682,882	$35,937,683
2 Non-Demand Annual	2,187,000	$46,330,000	2,287,838	$70,640,739	$51,394,207	$13,157,646	$38,236,561
4 Rate I Summer	29,297	$207,787	16,084	$506,672	$373,544	$56,796	$316,748
4 Rate I Winter	45,348	$622,096	26,127	$834,171	$570,205	$58,028	$562,177
4 Rate I Annual	74,645	$829,883	42,221	$1,340,843	$943,749	$114,824	$878,925
2 Non-Dmnd Ann & 4 Rate I Ann	2,261,645	$48,159,883	2,330,058	$71,981,581	$52,337,956	$13,272,470	$39,115,486
2 Demand Summer	5,774,000	$37,363,000	5,638,663	$82,793,188	$37,043,771	$8,225,985	$28,817,786
2 Demand Winter Shoulder	1,614,000	$29,988,000	2,111,042	$54,420,649	$37,710,981	$2,819,782	$34,890,388
2 Demand Winter Non-Shoulder	6,282,000	$108,434,000	6,510,567	$169,451,986	$115,795,846	$5,708,781	$110,087,187
2 Demand Winter Sub-Total	7,896,000	$138,422,000	8,621,609	$223,272,635	$153,506,109	$8,528,523	$144,977,586
2 Demand Annual	13,470,000	$175,796,000	14,260,272	$306,071,823	$190,549,880	$16,754,508	$173,795,372
4 Rate III Summer	106,620	$1,782,414	164,431	$3,017,771	$1,768,376	$189,414	$1,578,962
4 Rate III Winter	165,037	$3,225,463	220,268	$5,665,024	$3,803,041	$193,622	$3,609,519
4 Rate III Annual	271,657	$5,007,877	384,699	$8,682,795	$5,569,417	$382,936	$5,186,481
2 Dmnd Ann & 4 Rate III Ann	13,741,657	$180,802,877	14,644,971	$314,754,618	$196,119,297	$17,137,444	$178,981,853
3 Non-Demand Summer	670,783	$8,846,079	620,047	$14,029,554	$8,492,270	$4,025,410	$4,466,860
3 Non-Demand Winter	1,963,058	$32,234,359	2,136,913	$52,977,637	$35,216,994	$4,135,231	$31,081,763
3 Non-Demand Annual	2,633,834	$41,080,438	2,756,960	$67,007,195	$43,709,270	$8,160,647	$35,548,623
4 Rate II Summer	27,347	$138,867	1,870	$153,231	$137,394	$17,629	$119,765
4 Rate II Winter	42,329	$440,697	25,935	$688,126	$396,444	$18,012	$378,432
4 Rate II Annual	69,676	$579,564	27,805	$841,357	$533,838	$35,641	$498,197
3 Non-Dmnd Ann & 4 Rate II Ann	2,703,514	$41,660,002	2,784,466	$67,848,552	$44,243,108	$8,196,288	$36,046,820
3 Demand Summer	1,163,000	$8,077,000	1,242,976	$15,626,017	$8,459,937	$1,165,607	$7,294,325
3 Demand Winter Shoulder	808,000	$4,634,000	633,957	$14,137,033	$9,984,680	$381,965	$4,602,716
3 Demand Winter Non-Shoulder	2,029,000	$29,797,000	2,168,116	$46,863,298	$31,316,916	$808,921	$30,507,995
3 Demand Winter Sub-Total	2,838,000	$37,339,000	2,799,773	$61,000,913	$40,301,095	$1,190,886	$39,110,710
3 Demand Annual	3,821,000	$45,412,000	4,042,749	$91,625,930	$48,761,523	$2,356,493	$46,405,036
4 Rate IV Summer	11,779	$168,974	18,746	$307,276	$155,190	[illegible]	$146,481
4 Rate IV Winter	18,233	$290,212	11,670	$333,947	$238,795	[illegible]	$229,907
4 Rate IV Annual	30,012	$458,185	30,417	$641,223	$393,975	$17,597	$376,388
3 Dmnd Ann & 4 Rate IV Ann	3,851,012	$45,840,186	4,073,167	$92,267,053	$49,155,502	$2,374,090	$46,781,423
Sub-Total	23,087,828	$333,312,946	24,413,902	$559,898,844	$359,108,187	$45,506,181	$313,543,008
Contract (S)	30,217	$84,921	19,618	$228,088	$68,153		
Contract (W)	56,845	$344,641	95,079	$1,072,446	$323,325		
Total	23,174,890	$333,744,510	24,528,600	$561,195,367	$358,499,848		

Service Class	Ratio of Rate Year to Historical Year Pure Base Rev	Rate Year Deficiency / (Surplus) from ECOS	Rate Year Assigned Pure Base Rev at 10/1/09 Rev Level	Rate Year Proposed Base Rev Change	Rate Year Net Proposed Base Rev Change	Historical Year Net Proposed Base Rev Change	Historical Year Proposed % Pure Base Rate Change	Customer Charge at 10/1/09 Level Excl Fixed Fuel Cost Charge	Embedded Customer Cost Excl Fixed Customer Charge
	(5)=(2)/(4a)	(6)	(6a)=(2)+(6)	(7)=(6a)*E	(8)=(6)+(7)	(9)=(8)/(5)	(9a)=(9)/(4a)	(10a)	(10b)
1 Annual	0.9209232	$0	$15,842,000	$3,406,112	$3,406,112	$3,698,584	21.500517%	$740.60	$1,466.50
2 Non-Dmnd Ann & 4 Rate I Ann	0.8383814	$0	$48,159,383	$10,583,622	$10,583,625	$11,263,680	21.500514%	$3,139.02	$2,832.92
2 Dmnd Ann & 4 Rate III Ann	0.9219025	$0	$180,802,877	$38,873,550	$38,873,550	$42,166,659	21.500515%	$4,488.53	$4,703.95
3 Non-Dmnd Ann & 4 Rate II Ann	0.9418150	$0	$41,660,002	$8,957,116	$8,957,116	$9,512,496	21.500515%	$1,461.53	$2,310.56
3 Dmnd Ann & 4 Rate IV Ann	0.9327173	$0	$45,848,186	$9,857,526	$9,857,538	$10,568,686	21.500514%	$1,442.25	$3,982.94
Sub-Total	0.9291687	$0	$333,312,946	$71,664,001	$71,664,001	$77,210,105	21.500519%		

C = $71,664,000

Service Class	% Variation of Embedded Customer Charge (W/O Class Avg Increase) vs. Current Customer Charge	% Variation of Embedded Customer Charge (W Class Avg Increase) vs. Current Customer Charge	Proposed % Customer Charge Change	Historical Year Cust Charge Chg	Historical Year Net Proposed Base Rev Change W/O Cust Charge	Historical Year Proposed % Base Rev Change	Historical Year Total Proposed Base Rev Change	Historical Year Target Base Rev at Proposed 10/1/10 Rate Level	Historical Year Proposed % Base Rate Change
	(10c)=(10b-10a)/(10a)-1	(10d)=(10b*(1+10)-10a)/(10a)-1	(11)	(11a)=(4b)*(11)	(11b)=(9)-(11a)	(11c)=(11b)/(4c)	(12)=(11a)+(11b)	(13)=(4)+(12)	(13a)=(12)/(4)
1 Annual	98.019123%	148.083398%	23.690089%	$1,084,586	$2,613,898	20.718009%	$3,698,584	$76,743,628	5.06%
2 Non-Demand Annual				$1,414,481	$9,568,002	25.023174%	$10,982,483	$81,623,221	15.55%
4 Rate I Annual				$12,344	$268,853	[illegible]	$281,197	$1,622,040	20.97%
2 Non-Dmnd Ann & 4 Rate I Ann	(9.75145100%)	8.852451%	18.750257%	$1,426,825	$9,836,855	25.148237%	$11,263,680	$83,245,261	15.65%
2 Demand Annual				$4,548,809	$35,500,346	20.426529%	$40,088,155	$346,160,975	13.10%
4 Rate III Annual				$104,980	$1,972,623	[illegible]	$2,077,603	$10,760,296	23.93%
2 Dmnd Ann & 4 Rate III Ann	4.84486100%	27.188500%	27.188869%	$4,653,890	$37,472,969	20.936743%	$42,166,659	$356,921,277	13.40%
3 Non-Demand Annual				$4,740,672	$4,604,080	12.951438%	$9,344,737	$76,351,932	13.95%
4 Rate II Annual				$20,705	$147,056	29.517440%	$167,760	$1,009,117	19.94%
3 Non-Dmnd Ann & 4 Rate II Ann	[illegible]	[illegible]	[illegible]	$4,761,378	$4,751,120	13.180464%	$9,512,496	$77,361,048	14.02%
3 Demand Annual				$759,987	$9,697,992	[illegible]	$10,457,979	$92,063,809	12.41%
4 Rate IV Annual				$5,672	$105,036	27.900044%	$110,707	$751,930	17.26%
3 Dmnd Ann & 4 Rate IV Ann	174.77292500%	233.860817%	32.350771%	$765,659	$9,803,027	20.954957%	$10,568,686	$92,835,739	12.85%
Sub-Total				$12,732,136	$64,477,968	[illegible]	$77,210,105	$637,109,963	13.79%
Contract (S)								$236,070	0.00%
Contract (W)								$1,082,675	0.00%
Total							$77,210,105	$638,425,686	13.76%

Con Edison

Hearing Exhibits

STATE OF NEW YORK
DEPT. OF PUBLIC SERVICE
DATE: 6/9/10
CASE NOS: 09-S-0794, 09-G-0795, and 09-S-0029
Ex. 325

STEAM CASE 09-S-0794
STAFF ESTIMATED NET PLANT - STEAM **
TWELVE MONTH AVERAGE ENDING SEPTEMBER 30, 2011
($1000)

	BOOKCOST OF PLANT	ACCRUED DEPRECIATION	NET PLANT
SEPTEMBER 30, 2010 *	999,928	213,193	786,735
OCTOBER 31, 2010	2,005,106	429,454	1,575,652
NOVEMBER 30, 2010	2,016,302	432,538	1,583,764
DECEMBER 31, 2010	2,060,107	435,652	1,624,455
JANUARY 31, 2011	2,061,057	438,989	1,622,068
FEBRUARY 29, 2011	2,062,774	442,330	1,620,444
MARCH 31, 2011	2,064,819	445,675	1,619,145
APRIL 30, 2011	2,066,186	449,023	1,617,163
MAY 31, 2011	2,067,660	452,375	1,615,286
JUNE 30, 2011	2,072,071	455,728	1,616,343
JULY 31, 2011	2,073,469	458,051	1,615,417
AUGUST 31, 2011	2,076,401	460,377	1,616,023
SEPTEMBER 30, 2011 *	1,039,356	231,355	808,001
TOTAL	24,665,238	5,344,741	19,320,497
AVERAGE	$2,055,437	$445,395	$1,610,041

* ONE HALF OF ENDING BALANCE
**INCLUDES COMMON ALLOCATED

Con Edison

Hearing Exhibits

STATE OF NEW YORK
DEPT. OF PUBLIC SERVICE
DATE: 6/9/10
CASE NOS: 09-S-0794, 09-G-0795, and 09-S-0029
Ex. 326

Net Revenue Adjustment Calculation Based on Staff's Sales Forecast Adjustments

Staff Sales Forecast Adjustment: 44,000 Mlbs

Base Revenue (1)	**Base Cost Of Fuel** 8.049 $/Mlb (2)	**Station Electric Costs** 0.4723 $/Mlb (3)	**Net Revenue** $/Mlb (4=1-2-3)
$1,101,000	$354,156	$20,781	$726,063

Con Edison

Hearing Exhibits

STATE OF NEW YORK
DEPT. OF PUBLIC SERVICE
DATE: 6/9/10
CASE NOS: 09-S-0794, 09-G-0795, and 09-S-0029
Ex. 327

STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

Case 09-S-0794 -	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.
Case 09-G-0795 -	Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Consolidated Edison Company of New York, Inc. for Gas Service.
CASE 09-S-0029 -	Proceeding on Motion of the Commission to Consider Steam Resource Plan and East River Repowering Project Cost Allocation Study, and Steam Energy Efficiency Programs for Consolidated Edison Company of New York, Inc.

ATTENTION

This exhibit is among those prefiled in the captioned cases by active parties that executed two joint proposals that were filed on May 18, 2010. Those that executed the joint proposals subsequently stipulated that they would not cross-examine the witnesses of each other given that they were supporting at that time the Commission's adoption of the terms of the joint proposals. In this context, the fact that these parties did not cross-examine the witnesses of each other does not mean and cannot reasonably be understood to mean that the information in this exhibit is uncontroverted among the parties that executed the joint proposals.

BEFORE THE
STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

In the Matter of

CONSOLIDATED EDISON COMPANY OF NEW YORK, INC.

Case 09-S-0794

MARCH 2010

Prepared Testimony of:

Joseph F. Klesin
Utility Supervisor
Office of Electric, Gas and Water

Carlos Ortiz
Utility Engineer 3 (Safety)
Office of Electric, Gas and Water

Jeffrey Kline
Utility Engineer 3
Office of Electric, Gas and Water

Liliya Randt
Utility Engineer 2
Office of Electric, Gas and Water

State of New York
Department of Public Service
Three Empire State Plaza
Albany, New York 12223-1350

Q. Please state your names, titles and business addresses.

A. Joseph F. Klesin, Utility Supervisor, New York State Department of Public Service, 90 Church Street, New York, New York 10007 and Carlos Ortiz, Utility Engineer 3, New York State Department of Public Service, 90 Church Street, New York, New York 10007.

Q. Mr. Klesin, please state your education and experience.

A. I graduated from New York Institute of Technology (NYIT) in Old Westbury, NY in 1989 with a Bachelor of Technology Degree in Electro/Mechanical/Computer Technology. I joined the Department in 1990 and am currently the regional Supervisor of the Safety Section's NYC and Albany offices. I have oversight responsibility for two area supervisors and subordinate Staff and implementation responsibility for the New York Pipeline Safety Program in the Albany, New York City, Westchester and Long Island areas.
I am responsible for ensuring the organization, scheduling, coordination and direction of field

activities of the New York City and Albany area offices. The program involves comprehensive safety & reliability evaluations of eastern region utilities and covers all aspects of operations, maintenance and construction of jurisdictional natural gas, liquid petroleum, liquefied natural gas and steam pipelines. I am familiar with all NYS and federal gas, liquid and steam pipeline safety codes, including the overall operations of the major downstate gas utilities.

Q. Have you previously testified in a regulatory proceeding?

A. Yes, I have testified in five previous rate cases; three for Orange & Rockland Utilities in cases 99-G-1695, 02-G-1553, 08-G-1398 and two for Consolidated Edison of New York in cases 06-G-1332 and 07-S-1315. I have also pre-filed testimony in three other cases for the Keyspan Corporation; 06-M-0878, 06-G-1185 and 06-G-1186.

Q. Mr. Ortiz, please briefly state your educational background and professional experience.

A. I graduated from the New York Institute of Technology, Old Westbury, New York with a

Bachelor of Science Degree in Mechanical Engineering (Aerospace minor). I joined the Department in 1993. My responsibilities as a Utility Engineer 3 include: oversight responsibility of Staff comprised of Utility Engineers 1 and 2, and Junior Engineers all within the Safety Section; providing supervision and technical support required for the implementation of New York State, Federal, and National safety codes affecting gas and electric; provide Staff guidance and development and monitor completion of assigned work; responding to and investigating emergency events involving gas or electric facilities; monitoring gas projects both intra and interstate to ensure utility compliance with applicable safety standards.

Q. Mr. Ortiz, have you previously testified before the Commission?

A. Yes. I testified in Case's 02-G-1553, 05-G-1494, and 08-G-1398 all regarding Orange and Rockland Utilities, Inc. gas rate proceedings. Primary focus was on O&M, Capital Projects, and Performance Measures.

Q. Mr. Kline, what is your position with the Department of Public Service?

A. I am a Utility Engineer 3 assigned to the Office of Electric, Gas & Water, Steam, Electric, Gas Safety Section in the Albany Office.

Q. Mr. Kline, please state your education and experience.

A. I graduated in May 1986, from Western New England College, with a Bachelor of Science degree in Electrical Engineering. I have been employed by the Department of Public Service since November of 1994. Prior to that, I worked for the New York State Department of Transportation as a materials technician. I am responsible for the investigation and analysis of gas, liquid, and steam pipeline utility facilities, Company standard practices and records related to system design, construction, operation and maintenance. My duties also include ensuring compliance with the federal and state pipeline safety regulations that apply to gas, liquid, and steam utilities and pipeline operators. My other duties include engineering support for the Safety Section field Staff, reviewing possible violations relating to 16 NYCRR Part 753 (damage prevention), participating in rate proceedings and negotiations, reviewing proposed pipeline designs, processing petitions and waivers relating to code compliance matters, and reviewing proposed updates to utility operations and maintenance procedures. I have also participated in rotation programs within the Department which has given me to opportunity to work on gas rate matters.

Q. Have you previously testified in a regulatory proceeding?

A. Yes, in Case 07-S-1315, Consolidated Edison Company of New York, Inc. for Steam Service Rates, and in Case 08-G-1392, St. Lawrence Gas Company, Inc. Gas Service Rates.

Q. Ms. Randt have you already discussed your educational background, professional and testimonial experience, and responsibilities?

A. Yes, that information is included in the Staff Rate Panel testimony submitted in this proceeding.

Q. What is the purpose of the Panel's testimony?

A. The Staff Steam Operations Panel was primarily responsible for the review of the Company's Steam Operations Panel testimony as it relates to the steam distribution construction program and the operations and maintenance (O&M) budget. Our goal was to evaluate all capital projects for reasonableness of cost and the safety and reliability value provided to the steam distribution system. We compared both the proposed capital and O&M budgets to historic spending levels. Cost benefit analysis reviews were also utilized in considering if certain projects should be pursued and funded via potential future savings that would be realized by their implementation, whereas others were recommended for suspension due to their low priority under the current economic climate. We are also proposing to adjust the performance measures currently in place with new targets that reflect Con Edison's current level of performance. These performance measures are designed to encourage actions that improve public safety.

Q. Are you sponsoring any Exhibits?

A. Yes. Exhibit_(SSOP-1) contains responses to Staff Information Requests that we will refer to, or otherwise have relied upon in our testimony. Exhibit_(SSOP-2) details our proposed adjustments to the Company's steam distribution capital expenditures as described below. Exhibit_(SSOP-3) details the Company's 5-year projected project expenditures versus the Company's 5-year actual and average historical expenditures.

Steam Distribution Capital Programs

Q. Do you have any concerns with the Company's proposed Steam Distribution Construction program?

A. Yes. We have identified a number of distribution projects which warrant discussion.

Q. Which distribution projects will you elaborate on?

A. We will elaborate only on projects that we find are not fully supported and will recommend adjustments to the Company's steam distribution capital forecast commencing with the New Business capital project. This program includes the installation of piping and equipment to provide steam service to new steam customers. The Company budgeted $2.01 million in 2010 and $2.03 million in 2011 for this project. The Company is planning to have 11 new steam service connections for 2010, of them ten are new customers and one is an existing customer seeking to increase load (DPS-121). According to the Company's response to DPS-2 part 6, the Company is planning to install 630 units in 2010 and 2011 with average costs of $3,200 per foot.

Q. What is your proposed adjustment?

A. In IR DPS-121, Staff requested the complete cost breakdown for the installation of new service lines and upgrading of service lines in 2007, 2008, 2009. Based on the three years of historic actual costs for these projects, the average unit cost was $2,394 per foot. This is significantly lower than the $3,200 unit cost being proposed. Therefore, we applied the historic unit cost of $2,394 instead of the $3,200 per foot proposed by the Company. We recommend an adjustment of $502,000 in 2010 and $522,000 in 2011 based on the known historical costs associated with this project.

Q. Please discuss your next adjustment.

A. Our second adjustment is to the Interference program. This program consists of steam facility relocations due to interference with City of New York infrastructure projects. The Company divides this into two categories, Interference related to Lower Manhattan and Interference related to all other areas in Manhattan. The Company budgeted $1 million for 2010-2013 for Interference related to all areas other than Lower Manhattan. Based on the known historical spending for this project (DPS-2, part 6) Staff recommends a downward adjustment of $840,000 per calendar year for this budget item during 2010-2013.

Q. What is the Company's forecast for Lower Manhattan capital interference costs?

A. The Company's forecast for Lower Manhattan capital interference costs for calendar year 2010 through 2013 is $2.84 million, $4.29 million, $4.49 million and $3.32 million, respectively. That forecast is provided by the Company's Municipal Infrastructure Support Panel.

Q. Please discuss your concerns related to the Company's Lower Manhattan capital interference budget associated with the City's capital improvement projects.

A. Lower Manhattan capital interference costs are estimated based on a review of individual City projects for the Lower Manhattan area. In reviewing the reasonableness of the Company's forecast for calendar years 2010 through 2013, we began by comparing it to the Company's historic Lower Manhattan interference capital costs, as provided by the Company in its response to DPS-112. Comparing the Company's request with its historic actual 2009 costs revealed that the Company's requests for years 2010-2013 are approximately 162%, 296%, 314% and 206% more than its actual 2009 spending level. Comparing the Company's request with its highest historic actual annual costs, year 2006, for the previous five years, revealed the Company's requests for years 2010-2013 are approximately 79%, 171%, 174% and 110% more than its actual 2006 spending level. Based on these comparisons, we have concluded that the

Company's budget has not provided a clear indication of its actual expenditures.

Q. How does the panel propose to forecast Lower Manhattan interference capital expenses?

A. We believe a more reasonable approach is to base the 2010 through 2013 forecast upon the most recent actual spending levels. As such, we recommend that the forecast be based on a five-year average using the actual expenditures for 2005-2009. This results in our recommended annual capital budget of $1.420 million for Lower Manhattan interference.

Q. Has this approach been adopted in a previous Commission Order?

A. Yes, the Commission adopted this methodology for interference capital in its 2009 Rate Order (Case 08-E-0539). Staff also recommended a similar approach in the Company's pending Electric Rate Case 09-E-0428.

Q. What other programs would you like to speak to?

A. The Panel would like to address the Main Valve Replacement Program. In testimony provided by the Company's Steam Operations Panel, it is stated that the program is designed to replace main valves that are leaking, or inoperable. The Company is targeting 39 valves for replacement commencing in 2010 through 2014. The replacement targets: inoperable valves, 150# Class Darling Valves, internal (valve seat) leakage, and external leakage. Ten of the valves targeted for replacement are externally leaking valves as described in response to DPS-120, which are generally repaired and do not require replacement. Staff would not object to the replacement of inoperable valves, which may hinder an effective shutdown during an emergency. During non-emergency or planned work, which is routinely performed during off hours when steam demand is low, the impact of a leaking valve (internal or external) or inoperable valve would be minimal to the steam system or its customers. In such a case, the Company would select an alternate valve for operation. Therefore, Staff would allow for the replacement of 15 inoperable, as opposed to 29, during the calendar years 2010 through 2013. That equates to an adjustment of $1.4 million dollars over that period.

Q. Is there another program that you wish to speak to?

A. Yes. The Panel will now speak to the proposed Steam Pipeline Integrity Program. In Company testimony provided by the Steam Operations Panel and in Exhibit_ (SOP-2), page 11, a description of the program is provided along with estimated expenditures. The Company's response to DPS-122 also provided additional information regarding the program. Staff agrees that a well developed integrity program is an effective tool in identifying threats to the pipeline, associated risks, assessment methods, and remediation. Based on Company testimony, exhibits, and response to DPS-122, the Company has tracked steam leaks that were a result of internal corrosion since 2003. Other major threats not mentioned in the Pipeline Integrity Program are water condensate that could result from clogged steam traps, water impingement, and component failure (i.e. internally pressurized expansion joints). The mitigation of these threats is addressed through other proposed programs.

Q. Please continue.

A. The Company also describes lamination associated with a certain vintage pipe as being a threat. It appears that based on historical data, the Company as already identified pipe locations that have experienced internal corrosion as well as pipe that may be subject to lamination. Due to the operating environment and conditions of the steam system, an invasive inspection tool to assist in proactively identifying these threats, while the pipeline remains in service, is currently not available; therefore a shutdown would be required. And even then, the video camera inspection method proposed by the Company at this time may not provide quantified data necessary to warrant pipe replacement. While data gathering is the first step in the development of a sound pipeline integrity program, the Company did not demonstrate sufficiently that the proposed Steam Pipeline Integrity Program would be effective beyond the data gathering stage. Therefore, Staff does not support funding this program at this time and recommends an adjustment of $2.5 million dollars to the Company's 2010 through 2013 budget.

Q. Does the panel have any concern with respect to the Company's Flange Removal Program?

A. Yes. Con Edison currently maintains approximately 3,000 pairs of flanges throughout its steam distribution system and which are generally direct buried. These flanges have been identified as leak prone and as a result are targeted for removal. Historically, Con Edison annually replaced 65, 59 and 51 pairs in 2007, 2008 and 2009 respectively. Their proposal for this case is to target removal of 34 pairs in 2010 and 29 in each year thereafter at a cost of $86,000 per flange. However, as depicted in response to DPS-126, a percentage of these annual replacements occur during the course of other component repair and/or replacements such as valves, mainline leaks, interference work, etc., and which can result in substantial cost savings. For the three year period 2007 through 2009, an average of 25% of total flange replacements were carried out under these conditions, however the costs associated were not identified as a separate line item for accounting purposes.

Q. What is the panel proposing?

A. Based on the historical data and common practice by the Company to target flanges in conjunction with other work, Staff is proposing a reduction to the program budget equivalent to the cost of performing 25% fewer flanges in each rate year, rounded up to the nearest $100,000. This would equate to a negative adjustment of approximately $800,000 ($86,000 X (0.25 X 34) in 2010 and $700,000 ($86,000 X (0.25 x 29) in each year thereafter through 2013.

Q. Does the panel have any concerns with respect to the Company's Expansion Joint Replacement program?

A. Yes. These expansion joints are internally pressurized and pose potential risk should leaks develop. While Staff finds that the program is reasonable and warranted from a safety perspective, concerns similar to the Company's Flange Removal program apply in that a savings in costs associated with replacements are being realized due to integration with other work. Company response to DPS-123 depicts that historically, 9 joints were removed in 2007, 23 in 2008 and 23 in 2009. A total of 44% were removed in 2007 in conjunction with other system improvement, 22% in 2008 and 39% in 2009. The Company has proposed a replacement target of 20 per year at a cost of $100,000 per joint. Applying the same methodology as we did for the flange program, on average, approximately 35% of expansion joint replacement occurs as a result of other system improvement.

Q. What adjustment is the panel proposing to the Expansion Joint Replacement program?

A. Based on the historical data and common practice by the Company to target expansion joints in conjunction with other work, Staff is seeking a reduction to the program budget (not targets) equivalent to the cost to perform 35% fewer joints in each rate year, rounded upward to the nearest $100,000. This equates to a negative adjustment of approximately $700,000 ($100,000 X(0.35 X 20) for each of the proposed rate years. In addition, Staff notes that this adjustment brings the Company more in-line with its 5-year actual average expenditure of $1.325 million for this project line item.

Q. Does the panel have any concerns with respect to the Manhole Rebuild project?

A. Staff does not object to the Manhole Rebuild project as described, however, a review of the Company's 5-year actual average expenditure for this project noted $1.7 million dollars in expenditures for the period 2005 through 2009 as opposed to the requested $2.0 million the Company is seeking for each of the proposed rate years commencing in 2010. Based on the review, Staff proposes a negative adjustment of $300,000 per year for this program.

Q. Are there any other project related adjustments the panel is considering?

A. Yes. The Construction Management (CM) Mobile Office for Steam is a laptop application that will allow the Company to remotely update various job reports including Contractor Field Observation Reports. Staff inquired if a cost benefit analysis was performed for the project. The Company, in its response to DPS-172, stated that it estimates it would result in a productivity savings of 20 minutes per day per inspector and that the project has a 3.35 year payback period. Based on the Company's response, and the fact that the priority of this project is listed 25th of the 38 Distribution Programs submitted, Staff suggests that the project be suspended under the current economic climate or if pursued, to be funded via potential future savings that would be realized by its implementation. As a result Staff recommends a negative adjustment of $200,000 which is the total cost of the project as depicted under the Company's 2010 budget proposal.

Q. What comments do you have regarding the Steam Mapping Technology Upgrade - IT project and the GPS for Steam distribution project?

A. With regards to Steam Mapping, the Company's project description does not fully justify the need for an upgrade. Nor does the Company make a good argument for the need to have a mapping system in real world coordinates or the need for the spatial location of the steam system to be shared with other utilities in the Company. In addition, given the accuracies of current GPS systems, it is likely that numerous steam distribution components would fall within the same vicinity of each other and not likely to be easily assembled into a coherent system. This will likely cause errors to be introduced into the mapping system, if GPS data is solely relied on. The Company also notes reduced maintenance costs associated with the upgrades and Staff is of the opinion that these reductions could help fund the projects should they be pursued. As a result, Staff does not support these projects at this time, and recommends a negative adjustment of $500,000 for the Steam Mapping project in 2010 and 2011, followed by a negative adjustment of $200,000 for GPS in 2012 and 2013.

Q. What about the Meter Station Trap Remote Monitoring project?

A. This is a project proposed by the Company to remotely monitor Company traps at customer premises. Currently, the Company is in the midst of a remote monitoring installation program for its steam distribution system trap stations located outside customer premises as a result of Case 07-S-0984. One of Staff's recommendations there was for Con Edison to conduct feasibility analyses for remote monitoring systems to detect real-time water infiltration into subsurface structures containing steam pipeline facilities. Additionally, Con Edison must conduct feasibility analysis on systems to detect condensate levels within steam piping at specific locations identified based on history of excessive condensate formation requiring actions to alleviate potentially unsafe conditions. Subsequent to a period of R&D, the Company has since embarked on a remote monitoring program of 826 trap stations, where 85 recently became fully operational and are being monitored, while 107 locations are wired but awaiting trap station design replacements prior to implementation. The Company is ready to address the remaining 634 stations. At this time, meter station traps were not considered, and although timely detection of non-working traps at these locations is desirable, Staff recommends that this program be postponed, until such time that the Company's current street trap program, once fully operational, has been fully evaluated for its quality of operation and effectiveness. Staff finds that the forecast to install approximately 600 monitoring stations (approximately 75 per year) commencing in 2011 at a total cost of $2.3 million is premature and should be deferred. In the interim, the risk of non-detection of non-working meter station traps appears minimal due to their location within customer premises and their associated monthly inspection cycle.

Q. Do you take issue with the level of expenditures forecasted for the Remote Monitoring Project?

A. Yes. To begin, this is the Company's most costly project for the first two years of its five year budget. The Company forecasted $10 million, or approximately 25% of its total distribution capital budget, in 2010 and another $7.5 million, or approximately 22% of its total distribution capital budget, in 2011. Based on the historic actual expenditures related to this program, the Company spent $2.5 million on this program in 2008 and completed 63 units and an additional $6.2 million in 2009 and completed 125 units, while the budget in 2009 was $9.0

million.

Q. Is Staff concerned with the forecasted level of expenditures and the number of units planned for this project?

A. Yes. As the Commission indicated in its order related to the Lexington Ave steam incident investigation, it recommended that the Company explore the use of remote monitoring of its distribution system. Staff supports the Company's efforts in this regard but it is concerned that the Company is not focusing on the most critical high priority locations first while it continues to monitor the effectiveness and efficiency of remote monitoring technology and the potential roll out to all of its locations. For this reason, and to mitigate the rate impacts associated with this, the Company's most costly project, we recommend that this project be funded at $5 million per year, for three years. This level is more reflective of historic expenditure levels on this project than the levels proposed by the Company. In addition, the Company should be required to continue to report to the Commission on its efforts to implement this program and others related to the incident investigation and clearly identify the incremental cost savings associated with each.

Q. What about Remote Monitoring Phase II?

A. Staff finds that this project should be postponed until such time that current efforts under Phase I are fully evaluated. The Company has been continuously upgrading and improving the technology associated with trap station design and remote monitoring components. Although the Company has forecasted implementation commencing in 2012, Staff finds the endeavor is premature, especially if complete implementation of Phase I is not realized by 2011. The Company has argued, and Staff has agreed, that its implementation could reduce costs associated with labor intensive field inspections required during significant rain events as well as costs associated with anticipated maintenance of current monitoring equipment. The proposal apparently forecasts a significant $2.0 million annually requirement for anticipated future upgrades and enhancements that have yet to be proven, and therefore Staff recommends postponement of this project at this time. The projects listed priority and the current economic climate also factor in to Staff's recommendation. Should the Company wish to pursue the project Staff finds that it should be funded via cost benefit savings that will be realized during the course of its implementation.

Q. What about the Trap Combination Replacement program?

A. This program is basically a funding placeholder for replacement of newly designed trap stations that have recently been installed under the Steam Incident Recommendation and Action Plan on as need basis. Although the Company has historically replaced a percentage of stations for causal reasons, such as corrosion, Staff finds that the necessity to do so in the near future may prove to be non-existent due the fact that they involve fairly new installations. Staff recommends that this project be suspended until such time historical data accurately supports anticipated conditions and that a negative adjustment of $400,000 in 2012 and 2013 be applied.

Q. What about the Thermal Efficiency Improvement project?

A. This project is a process by which the Company plans on re-insulating direct buried steam main installations where the main housing has been compromised resulting in degradation of the original insulation. The Company details that it operates main installed at elevations below sea level and how thermal losses can be decreased in these areas. Notwithstanding the fact that insulation plays an important role in prevention of thermal losses and sub cooling of condensate which can lead to water hammer events, the cost associated with the Company's proposals basically equate to the cost of current steam main replacement at $4000/ft. Staff therefore questions the effectiveness of re-insulation which does not allow for full exposure of affected areas versus replacement/relocation of deep mains installed in contact with ground water or tidal prone areas. As required by the Commission, and so described in response to DPS-174, the Company will file an action plan in response to the ABS Thermal Efficiency and Losses Study within the next few months. The actual cost of each re-insulation project will be determined on a case by case basis. For these reasons, Staff finds that it is too early to commit funding for this project and therefore recommends adjustments of $500,000 for each of the calendar years 2012 and 2013.

Q. What about the Service Valve Replacement program?

A. The Company has forecasted an annual expenditure of $560,000 in RY3-RY5 to replace leak through, inoperable and or severely corroded service valves when exposed via excavation. Staff notes that this distribution project is a new line item with no historical data to support actual expenditures in this area. The project is also listed last on the Company's priority list of 38 distribution projects. The Company also notes that a cost savings in labor and lost revenue would be realized if the program was implemented. Staff recommends that the project be postponed under the current economic climate or if pursued, to be funded via potential future savings that would be realized by its implementation.

Q. Does this conclude the Panel's testimony with respect to Capital construction?

A. Yes.

Safety Performance Measures

Q. Does the Panel wish to comment on the Company's Steam Safety Performance Measures?

A. Yes. The Panel is recommending the continuance of the existing performance measures that were adopted as part of rate Case 07-S-1315.

Q. What were those Performance Measures?

A. 1) Emergency Response to Steam Leak/Vapor Calls, which evaluates the Company's response to steam leaks, vapor conditions and emergency calls generated by the public and non-Company personnel; and 2) Leak Management, which focuses on the reduction of active un-repaired steam leaks. Eliminating leaks help minimize the possibility of incidents involving uncontrolled vapor conditions. Elimination of leaks also reduces the amount of steam loss; aiding in the reduction of operating and maintenance costs. Reducing backlogs of un-repaired leaks immediately prior to peak summer and winter loads requires effort year-round and not only results in minimizing public hazards, but also mitigates excessive and prolonged system repairs that create increased risk to service reliability during peak demand periods.

Q. Are there specific targets associated with these performance measures?

A. Yes. The targets themselves were also established during the previous rate case, 07-S-01315. The targets are as follows:

Emergency Response to Steam Leak/Vapor Calls

For calendar years 2009 and 2010 the Company had to respond to 85% of all steam leak/vapor calls within 45 minutes, and 95% within 60 minutes.

Leak Management - Establishment

On February 13, 2009, representatives of Con Edison's Steam Distribution Department met with representatives of Staff and reviewed the Company's steam leak backlog for the calendar year 2008. The Company and Staff considered, among other relevant factors, the impact of not using leak sealant services on the Company's steam leak backlogs. After extensive discussions, the Company and Staff agreed on the following plan for managing the Company's steam leak backlog for the 2010 calendar year.

Leak Management - Target

Separate negative rate adjustments of 1.5 basis points will be applied to the benefit of customers if the June 2010 Average or the December 2010 Average is more than 24 (for a maximum of 3.0 basis points); provided, however, that if the June 2010 Average is more than 24 but the December 2010 Average is 24 or less, there will be no negative rate adjustment for exceeding 24 in June 2010 if the December 2010 Average is less than or equal to 24 minus the June 2010 overage. For example, if the June 2010 Average is 26, there would be no negative rate adjustment for exceeding 24 in June 2010 if the December 2010 average is 22 or less.

Additional Provisions

1. If the Company implements the use of leak sealant services in the future, then the steam leak backlog target of 24 for the calendar year

2010 will be re-evaluated by the Company and Staff.

2. The Company will report its performance under this mechanism to the Director of the Office of Electric, Gas & Water no later than 60 days following the end of the calendar year. If a performance metric is not met, the associated revenue adjustment could be excused if the Company can demonstrate to the Commission extenuating circumstances that prevented it from meeting such performance metric. The determination of whether such circumstances exist (e.g., extreme weather, DOT work embargos) will be made on a case-by-case basis and will be based upon the particular facts and circumstances presented.

3. This steam leak backlog management performance mechanism will continue in effect through the term of the current Steam Rate Plan and thereafter until modified or discontinued by the Commission.

Q. Is Staff proposing to keep the existing targets?

A. Based on data provided to Staff by the Company under Section K paragraph 4 of Attachment 1 of

Case 07-S-1315 as well in response to DPS-212, the following targets are now being proposed for Emergency Response for 2011, and for each subsequent year until the rate plan resulting from this proceeding is superseded:

a) Respond to 75% of all steam leaks, vapor and emergency calls within 30 minutes (new target).

b) Respond to 90% of all steam leaks, vapor and emergency call within 45 minutes (increase from 85% to 90%).

c) Respond to 95% of all steam leaks, vapor and emergency calls within 60 minutes (remain the same).

If Con Edison does not respond to steam leak/vapor calls from third parties within 30 minutes at the percentages set forth below for calendar years 2011 and subsequent years, the following negative rate adjustment will be applied to the benefit of customers for each calendar year that the performance measure is not attained, as directed by the Commission.

30 Minute Response Time

75% or more	No adjustment

More than 70% but less than 75%	1.5 basis points
70% or less	3.0 basis points
45 Minute Response Time	
90% or more	No Adjustments
More than 85% but less than 90%	1.5 basis points
85% or less	3.0 basis points
60 Minute Response Time	
95% or more	No adjustment
More than 90% but less than 95%	1.5 basis points
90% or less	3.0 basis points

Q. Are you proposing a change to the Leak Management target?

A. Yes. Staff proposes to maintain the current Leak Management target as described under **Leak Management - Target** and **Additional Provisions** above for calendar years 2010 and 2011. For subsequent years a new target of 22 should be imposed. Separate negative rate adjustments of 1.5 basis points should be applied to the benefit of customers if the June 2012 Average or the December 2012 Average is more than 22 (for a maximum of 3.0 basis points); provided, however, that if the June 2012 Average is more than 22 but the December 2012 Average is 22 or less, there will be no negative rate adjustment for exceeding 22 in June 2012 if the December 2012 Average is less than or equal to 22 minus the June 2012 overage. For example, if the June 2012 Average is 24 there would be no negative rate adjustment for exceeding 22 in June 2012 if the December 2012 average is 22 or less. The new target of 22 would continue to apply for each subsequent year until such time that it is modified by the Commission.

Q. Does this conclude your testimony?

A. Yes.

Con Edison

Hearing Exhibits

STATE OF NEW YORK
DEPT. OF PUBLIC SERVICE
DATE: 6/9/09
CASE NOS: 09-S-0794, 09-G-0795, and 09-S-0029
Ex. 328

BEFORE THE
STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

In the Matter of

CONSOLIDATED EDISON COMPANY OF NEW YORK, INC.

Case 09-S-0794

MARCH 2010

Prepared Exhibits of:

Joseph F. Klesin
Utility Supervisor
Office of Electric, Gas and Water

Carlos Ortiz
Utility Engineer 3 (Safety)
Office of Electric, Gas and Water

Jeffrey Kline
Utility Engineer 3
Office of Electric, Gas and Water

Liliya Randt
Utility Engineer 2
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State of New York
Department of Public Service
Three Empire State Plaza
Albany, New York 12223-1350

Staff Steam Operations Panel

Exhibit_(SSOP-1)

List of Staff Information Requests

Staff Request	Exhibit Pages
2	1-7
112	8, 9
120	10
121	11-14
122	15, 16
123	17, 18
124	19
125	20, 21
126	22
172	23
174	24
212	25

Exhibit_(SSOP-2)

Steam Distribution Programs/Project Budget Adjustments
(Page 26)

Exhibit_(SSOP-3)

Steam Distribution Programs/Project Cost Calculations
(Page 27)

Company Name: Con Edison
Case Description: Con Edison Gas & Steam Rate Cases
Case: 09-G-0795-09-S-0794

Response to DPS Interrogatories – Set DPS1
Date of Response: 12/21/2009
Responding Witness: Steam Ops Panel

Question No. :2
Subject: Capital Expenditures – 1. Provide a spreadsheet (in Excel format) of forecasted budgets and actual expenditures for all programs and underlying individual projects contained in the Company's steam production budget for 2005 through 2009 and actual amounts spent to date in similar format to that provided in Exhibit_(SOP-1.1) and Exhibit_(SOP-1.2). 2. Provide a priority ranking of each of the Capital Projects in the Company's Exhibit _ (SOP-1.2) and copies of all internal Company documents that described how the priority ranking is arrived at. 3. For each project in Exhibit_ (SOP-1.2) pages 3 of 88, provide an itemized breakdown (more detailed than what is provided in the white papers) and calculation of how the forecasted capital funding for each rate year was derived. 4. Provide a spreadsheet (in Excel format) of forecasted budgets and actual expenditures for all programs and underlying individual projects contained in the Company's steam production budget for 2005 through 2009 and actual amounts spent to date in similar format to that provided in Exhibit_(SOP-2). 5. Provide a priority ranking of each of the Capital Projects in the Company's Exhibit _ (SOP-2) and copies of all internal Company documents that described how the priority ranking is arrived at. 6. For each project in Exhibit__ (SOP-2) pages 2 of 39, provide an itemized breakdown (more detailed than what is provided in the white papers) and calculation of how the forecasted capital funding for each rate year was derived.

Response:

1. Provide a spreadsheet (in Excel format) of forecasted budgets and actual expenditures for all programs and underlying individual projects contained in the Company's steam production budget for 2005 through 2009 and actual amounts spent to date in similar format to that provided in Exhibit_(SOP-1.1) and Exhibit_(SOP-1.2).

   Response:
   Please see Attached Excel file "Attachment 1 to DPS1-2 Part 1.xls." The first tab of this file contains the summary for the five years through the 10 months ended October 2009 by functional programs. Additional tabs are provided showing the individual Steam Production capital projects for each year 2005 – 2009.

2. Provide a priority ranking of each of the Capital Projects in the Company's Exhibit _ (SOP-1.2) and copies of all internal Company documents that described how the priority ranking is arrived at.

   Response:
   For the priority ranking of each Capital Project in the Company's Exhibit (SOP-1.2) please see file "Attachment 1 to DPS1-2 Part 2". For a description of the Company's prioritization process, please see file "Attachment 2 to DPS1-2 Part 2".

3. For each project in Exhibit_ (SOP-1.2) pages 3 of 88, provide an itemized breakdown (more detailed than what is provided in the white papers) and calculation of how the forecasted capital funding for each rate year was derived.

   Response:
   An itemized breakdown for each project in Exhibit__ (SOP-1.2) is included in the attached file entitled "Attachment 1 to DPS1-2 Part 3." Please note that several factors were considered in the development of the forecasted capital expenditure for each year all of which are focused on the cost effective implementation of the projects needed to sustain the safe and reliable operation of the stations while minimizing the impact on the customers' rates.

   During the budget preparation process, the current capital plan is evaluated, new projects are identified, preliminary work scopes and cost estimates are prepared, and priorities are developed. Typically project cost estimates include material costs labor costs, Company overheads, contingency and escalation. Initially, the cost estimates are based on preliminary information and the contingency applied ranges from 25% to 30%. In addition, based on the project schedule, the outer year projects are escalated and allowable funds during construction ("AFDC") is applied to multi-year projects. As the project scope becomes more detailed, the contingency is reduced to 10% to 20%. The Company overheads consist of pension, payroll and taxes, engineering, project management and inspection, and administration and services expenses. Based on these factors, escalation, overhead and contingency may range from 25% to 50% of the projected total cost of the project.

   The yearly cash flows are derived via a series of meetings in which the aspects of the proposed projects are evaluated such as, the proposed scope of work, availability of long lead equipment, equipment and station outage durations, priorities, project synergy, etc. Typically, funding is allocated to complete the projects planned each year. However, in some cases funding is allocated over two or more years depending on the needs of the stations and the projects scope. For example, if a project includes long lead equipment, funding may be allocated in one year for procurement and in the subsequent year for installation. Another example is projects such as roof replacements which are extensive and are more properly scheduled and funded over several years.

4. Provide a spreadsheet (in Excel format) of forecasted budgets and actual expenditures for all programs and underlying individual projects contained in the Company's steam production budget for 2005 through 2009 and actual amounts spent to date in similar format to that provided in Exhibit_(SOP-2).

   Response:
   Please see Attached Excel file "Attachment 1 to DPS1-2 Part 4.xls." The first tab of this file contains the summary for the five years through the 10 months ended October 2009 by functional programs. Additional tabs are provided showing the individual Steam Distribution capital projects for each year 2005 – 2009.

5. Provide a priority ranking of each of the Capital Projects in the Company's Exhibit_ (SOP-2) and copies of all internal Company documents that described how the priority ranking is arrived at.

   Response:
   For the priority ranking of each Capital Project in the Company's Exhibit (SOP-2) please see file "Attachment 1 to DPS1-2 Part 5." For a description of the Company's prioritization process, please see file "Attachment 2 to DPS1-2 Part 2."

6. For each project in Exhibit__ (SOP-2) pages 2 of 39, provide an itemized breakdown (more detailed than what is provided in the white papers) and calculation of how the forecasted capital funding for each rate year was derived.

   Response:
   An itemized breakdown for each project in Ex__ (SOP-2) is included in the attached file entitled "Attachment 1 to DPS1-2 Part 6."

STEAM PRODUCTION HISTORICAL COSTS - ACTUAL/FORECAST 2005 - 10 MONTH ENDED OCTOBER 30, 2009
($ in thousands)

	2005		2006		2007		2008		10 Months ended October 2009	
Functional Category	Actual	Forecast	Actual	Forecast	Actual	Forecast	Actual	Forecast	Actual	Forecast
Capacity	202	-	563	-						
Reliability	23,771	18,850	34,408	35,633						
Regulatory	5,161	6,050	5,094	5,585						
Small Capital	3,207	3,020	2,535	2,630						
EH&S	2,804	4,680	2,178	2,261	1,501	650	3,448	600	2,150	2,831
Security					2,733	2,900	842	1,825	1,954	2,875
Control Systems					6,983	7,820	8,222	9,045	2,340	7,220
Boilers					4,449	3,150	4,705	3,505	6,912	4,689
Mechanical Equipment					18,579	16,855	26,474	27,200	46,109	33,868
Electric Equipment					881	2,110	8,010	2,700	(2,199)	2,707
Structures					4,880	5,030	1,640	2,795	358	1,342
Waterfront					3,950	8,300	1,361	3,000	465	-
Roofs					1,594	2,550	914	500	1,272	850
Total	35,145	32,600	44,778	46,109	45,550	49,365	55,616	51,170	59,361	56,382
Excludes East River Repowering Project	84,313	40,400	14,632	20,000	3,301	4,600				

NOTE: Revised Functional Categories in 2007.

STEAM DISTRIBUTION HISTORICAL COSTS - ACTUAL/FORECAST 2005 - 10 MONTH ENDED OCTOBER 30, 2009
($ in thousands)

	2005		2006		2007		2008		10 Months ended October 2009	
Functional Category	Actual	Forecast	Actual	Forecast	Actual	Forecast	Actual	Forecast	Actual	Forecast
New Business	3,543	2,680	1,133	1,440	774	2,200	2,322	2,650	679	2,118
Interference	-	500	957	1,000	(250)	1,000	27	1,000	53	810
System Reinforcement	14,476	8,875	14,823	10,535	21,418	15,210	25,666	18,750	19,322	26,087
Meter Installation	2,341	3,550	3,503	1,450	3,369	3,600	3,506	3,400	2,621	3,090
Meter Purchases	590	1,395	1,259	1,200	2,420	1,725	1,178	1,725	784	1,475
Total	20,950	17,000	21,675	15,625	27,731	23,735	32,699	27,525	23,459	33,580

NOTE: 2007 System Reinforcement includes $6.440 million related to the Steam Incident.

Steam Distribution Projects	
Priority	**Project**
1	Remote Monitoring
2	Improved Trap Stations (Debris Removal)
3	Infrastructure Condition Projects
4	Installation of High Capacity Traps
5	Pump Manhole Electrical Upgrade
6	Leaks
7	Expansion Joint Replacement
8	Flange Removal
9	Cooling Chamber Replacement
10	Manhole Rebuilds
11	Manhole Cover Replacement Program
12	New Business
13	Projected New Services and Various Meter Station Only
14	Anchor Replacement/Reinforcement
15	Demand Metering/Shuntflo Meter Conversions
16	Demand Metering/Meter Conversions
17	M Valve Conversion
18	Meter Downsizing Program
19	Various Locations - Load changes/upgrades/downsizing
20	Limitorque Angle Valve Replacement
21	Various Enhancement Reinforcements
22	New Business/load changes/upgrades
23	Steam Mapping Technology Upgrade - IT
24	SDS and Job Tracking Integration - IT
25	Mobile Office - IT
26	Main Valve Replacement
27	Water Hammer Prediction Model
28	Telemetry (per ABS Report)
29	Projected new interference projects
30	Operations Interface for Remote Metering - IT
31	Steam Meter Room Piping Automation - IT
32	Meter Station Trap Remote Monitoring
33	Steam Pipeline Integrity Model
34	GPS For Steam Distribution
35	Thermal Efficiency Improvement
36	Trap Combination Replacement Program
37	Remote Monitoring Phase II
38	Service Valve Replacement Program
	Total

ATTACHMENT 1 to DPS1-2 Part 6

Organization:
Steam Distribution

Project Name:
Steam Meter Room Piping Automation

A/P - PURCHASED EQUIPMENT	**$ 40,000**
A/P CONSTRUCTION CONTRACT/CONTRACTORS	**$ 120,000**
COMPANY LABOR	**$ 425,000**
MATERIAL AND SUPPLIES	**$ -**
OTHER DIRECT COSTS	**$ -**
ESCALATION, OVERHEADS AND CONTINGENCY	**$ 461,000**
TOTAL	$ 1,046,000
SAY	**$ 1,050,000**

Company Name: Con Edison
Case Description: Con Edison Gas & Steam Rate Cases
Case: 09-G-0795-09-S-0794

Response to DPS Interrogatories – Set DPS13
Date of Response: 01/20/2010
Responding Witness: Accounting Panel/MISP

Question No. :112
Subject: Capital and O&M Interference for Non-WTC and WTC (Steam) – 1. Provide the Company's approved steam capital interference for non-WTC work budgets and actual expenditures for the five years 2005 through 2009 with associated project detail including any normalizations for any special events such as the July 2007 Steam Explosion Incident. 2. Provide the Company's approved steam capital interference for WTC work budgets and actual expenditures for the five years 2005 through 2009 with associated project detail including any normalizations for any special events such as the July 2007 Steam Explosion Incident. 3. Provide the Company's approved steam O&M interference for non-WTC work budgets and actual expenditures for the five years 2005 through 2009 with the associated project detail including any normalizations for any special events such as the July 2007 Steam Explosion Incident. 4. Provide the Company's approved steam O&M interference for WTC work budgets and actual expenditures for the five years 2005 through 2009 with the associated project detail including any normalizations for any special events such as the July 2007 Steam Explosion Incident.

Response:

1. See Attached file for the Company's approved steam capital interference budgets and actual expenditures for Non-WTC work years 2005 – 2009.

2. See Attached file for the Company's approved steam capital interference budgets and actual expenditures for WTC work years 2005 – 2009.

3. See Attached file for the Company's approved steam O&M interference budgets and actual expenditures for Non-WTC work years 2005 – 2009.

4. See Attached file for the Company's approved steam O&M interference budgets and actual expenditures for WTC work years 2005 – 2009.

   - During the period of 2005 – 2007, the WTC expenditures were under the federal reimbursement criteria and did not have an official budget.

   - The Non WTC O&M expenditures are tracked by borough rather than by project.

Steam Interference Capital & O&M Expenditures
$ In Thousands

	2005		2006		2007		2008		2009	
	Actual	Budget	Actual	Budget	Actual	Budget	Actual	Budget	Actual	Budget
Capital Non WTC	-	500	957	1,000	(250)	1,000	27	1,000	52	1,000
Capital WTC	1,583	-	1,804	-	1,262	-	1,368	2,400	1,084	5,000
O&M Non WTC (excluding labor)	2,504	2,325	3,358	2,325	1,703	3,200	3,542	3,200	3,580	3,158
O&M WTC (excluding labor)	3,071	-	3,933	-	1,013	-	1,786	4,000	2,198	3,785

Company Name: Con Edison
Case Description: Con Edison Gas & Steam Rate Cases
Case: 09-G-0795-09-S-0794

Response to DPS Interrogatories – Set DPS15
Date of Response: 01/28/2010
Responding Witness: Steam Ops

Question No. :120
Subject: Main Valve Replacement Program (Steam) – 1. For the Main Valve Replacement Program, how many main valves are currently in the steam transmission/distribution pipeline system? 2. How many main valves are being targeted for replacement each year from 2010 through 2014? 3. How is the replacement selection made (Is it based on internal/external leakage and/or risk based or something else)? 4. How many main valves are currently leaking internally (valve seat issues)? How many are leaking externally? 5. How many main valves are targeted for replacement based on risk (if applicable)? Please provide risk score, ranking, and factors.

Response:

1. We have 43 main valves on the transmission system and 551 main valves on the distribution system, for a total of 594 main valves.

2. Two valves are targeted for 2010. Seven valves are targeted for 2011. Ten valves are targeted for each year from 2012 through 2014.

3. Priority 1 - Inoperable valves
   Priority 2 - 150# Class Darling valves
   Priority 3 – Internal (valve seat) leakage
   Priority 4 – External leakage

4. There are approximately 20 internal (valve seat) leaks associated with main valves. There are approximately 10 external leaks associated with main valves. When these leaks occur, they are generally packing or gasket leaks and are repaired without requiring valve replacement.

5. Targeted replacement is based on item 3 above.

Company Name: Con Edison
Case Description: Con Edison Gas & Steam Rate Cases
Case: 09-G-0795-09-S-0794

Response to DPS Interrogatories – Set DPS15
Date of Response: 01/28/2010
Responding Witness: Steam Ops

Question No. :121
Subject: New Business Program (Steam) - 1. Of the 11 proposed steam service connections for 2010, please provide the number of new steam services versus existing customers requiring additional load (upgrade). 2. For customers requiring additional load, does this entail the installation of a single larger diameter service line or the addition of parallel service line with the same or larger diameter? For new customer installations, does the design incorporate redundancy (parallel runs) commonly installed for system maintenance purposes? 3. Please provide the number of service lines installed and the number of service lines upgraded in 2007, 2008, and 2009. 4. Please provide the average length of the service lines installed in 2007, 2008, and 2009. 5. Please provide the complete cost breakdown for the installation of new service lines and upgrading of service lines in 2007, 2008, 2009. 6. Would new service lines be designed/installed with a larger size diameter in order to accommodate potential future steam load requirements?

Response:

1. Of the 11 proposed new steam service connections planned for 2010, 10 are new customers and one is an existing customer seeking to increase load.

2. For customers requiring additional load, the Company evaluates the maximum capacity of the existing service at an allowable pressure drop of 4 Psig. If the existing service capacity is lower than the requested increased load, the Company will replace the existing steam service with a larger diameter pipe.

   For new customer installations, the Company typically does not install parallel runs as redundancy for system maintenance purposes. This is not necessary due to the outages are short (several hours) in duration and the work is done in off-hours when the steam demand is low. However, the Company installs dual services across a main valve for large customers, 6" and larger service, and twin services, fed from two different mains, for hospitals.

3. The number of service lines installed was:
   - 2007 – 8 new services

- 2008 – 11 new services
- 2009 – 9 new services

There were no service lines upgraded in these 3 years.

4. The average length of the service lines was:
   - 2007 – 52 ft
   - 2008 – 44 ft
   - 2009 – 122 ft

5. Exhibit A is the cost breakdown for installing the new services. There were no service lines being upgraded in 2007, 2008 and 2009.

6. The new service lines are designed with a Pressure Drop allowable of 2 Psig, instead of 4 Psig as required for the existing services. The delta of 2 Psig is to accommodate potential future load increases.

Exhibit A - 2007 to 2009 New Business Services

	Service Information					Actual Costs					
Item	Address	Load Typ	Size (in)	Length (ft)	Work Order	Construction Contracts ($)	Company Labor ($)	Material & Supplies ($)	Other Direct Costs ($)	Indiect Costs ($)	Total ($)
2009 New Services											
1	Customer A	New	8	260	19283	508,322	52,531	26,733	71	166,268	753,924
2	Customer B	New	6	70	11802	64,871	0	0	0	15,134	80,005
3	Customer C	New	4	283	68871	364,357	11,240	7,070	0	109,549	492,216
4	Customer D	New	3	34	68971	51,403	8,039	4,227	0	19,621	83,289
5	Customer E	New	4	80	28380	102,605	16,266	8,423	3,591	40,250	171,136
6	Customer F	New	6	32	16730	67,554	2,396	15	0	19,025	88,990
7	Customer G	New	6	39	16289	175,645	19,732	9,937	0	58,940	264,254
8	Customer H	New	6	191	13525	218,318	20,087	12,248	0	72,982	323,635
9	Customer I	New	4	107	13535	151,000	32,629	4,270	5,187	61,692	254,777
	Average Length			**122**							
2008 New Services											
1	Customer A	New	6	30	26517	30,818	6,071	8,107	0	9,078	54,074
2	Customer B	New	6	15	26521	33,743	10,908	7,571	0	12,923	65,146
3	Customer C	New	3	45	10688	72,297	8,217	3,645	0	21,494	105,653
4	Customer D	New	3	60	10685	62,005	29,358	4,723	0	28,493	124,579
5	Customer E	New	8	110	10695	293,768	473	0	0	77,074	371,315
6	Customer F	New	4	29	12369	42,784	7,508	2,822	0	13,499	66,613
7	Customer G	New	6	46	17342	86,563	23,026	11,385	0	28,354	149,328
8	Customer H	New	4	40	17248	63,270	19,414	8,187	0	28,031	118,903
9	Customer I	New	4	45	18640	74,189	12,678	1,079	0	28,112	116,058
10	Customer J	New	3	39	18676	80,734	6,329	8,869	0	26,889	122,821
11	Customer K	New	3	30	22627	40,651	23,147	9,000	0	23,857	96,656
	Average Length			**44**							

2007 New Services

1	Customer A	New	8	25	14830	72,659	15,967	25,771	0	34,148	148,545
2	Customer B	New	4	52	11442	71,111	7,930	4,546	0	27,549	111,135
3	Customer C	New	6	45	14833	94,236	11,935	11,300	(68,000)	32,817	82,287
4	Customer D	New	3	63	16719	55,002	5,501	5,897	0	19,805	86,205
5	Customer E	New	4	40	26508	32,029	7,998	851	0	9,337	50,215
6	Customer F	New	4	40	16110	78,635	11,438	8,000	1,421	29,764	129,257
7	Customer G	New	8	34	16196	51,818	22,638	9,017	0	26,573	110,047
8	Customer H	New	4	120	25960	65,834	17,581	18,755	0	36,947	139,117
	Average Length			**52**							

Company Name: Con Edison
Case Description: Con Edison Gas & Steam Rate Cases
Case: 09-G-0795-09-S-0794

Response to DPS Interrogatories – Set DPS15
Date of Response: 01/28/2010
Responding Witness: Steam Ops

<u>Question No.</u> :122
Subject: Steam Pipeline Integrity Program (Steam) - 1. For the Steam Pipeline Integrity Program, please describe the process that will be used to identify and prioritize replacement areas associated with internal corrosion. 2. How many leaks have been attributed to internal corrosion in 2007, 2008, and 2009? 3. What was the cost associated with these replacements in 2007, 2008, and 2009? 4. Does a list with priority locations exist? Is so, please provide the locations and schedule for replacement.

<u>Response</u>:

1. Currently, the failures associated with internal corrosion are tracked on our mapping system - Steam Operations Mapping Information System (SOMIS). SOMIS is utilized to assist in identifying piping segments with the highest incidences of failure. The program will review the areas with the highest concentration of internal corrosion, geographic location and customer impact. A statistical analysis will be performed utilizing the history, environmental conditions and characteristics of the pipes found with leaks to provide guidance for prioritizing the locations for inspections and possible replacements.

2. The numbers of leaks attributed to internal corrosion are:
    - 2007 – 6 leaks
    - 2008 – 11 leaks
    - 2009 – 15 leaks

3. The costs associated with the replacements:
    - 2007 – $455,769
    - 2008 – $1,679,984
    - 2009 – $1,487,537

4. The Company does not have a list with priority locations. Although the prone areas are known, the piping is inaccessible for inspection. The Company fixes the leak as the leak emerges. Where possible, an attempt is made to video inspect the piping; however, this is not always feasible due to

operating conditions from leak –through valves and outage restraints for customer impact.

Company Name: Con Edison
Case Description: Con Edison Gas & Steam Rate Cases
Case: 09-G-0795-09-S-0794

Response to DPS Interrogatories – Set DPS15
Date of Response: 01/29/2010
Responding Witness: Steam Ops

Question No. :123
Subject: Expansion Joint Replacement Program (Steam) - 1. For the Expansion Joint Replacement Program, how are internally pressurized expansion joints selected for replacement? Leakage and/or risk based? 2. If a risk assessment is performed, please provide the ranking and scores associated with those expansion joints targeted for replacement in 2010 along with the risk factors that are considered. 3. Please provide the number of internally expansion joints replaced in 2007, 2008, 2009 due to leakage versus risk selection (if applicable). 4. How much was expended in 2007, 2008, and 2009 to replace the targeted expansion joints? 5. Of the total replacements in 2007, 2008, and 2009 what percentage was completed in conjunction with other targeted work (i.e.: city/state interference work, mainline leak repairs, mainline valve replacements, etc) 6. Please provide a complete breakdown of the costs associated with a typical expansion joint replacement.

Response:

1. Under the Expansion Joint Replacement Program, the internally pressurized expansion joints are targeted for removal due to leakage, risks and opportunity. Opportunities arise in areas where the City plans to do major street reconstruction and resurfacing projects, and in the vicinity of other leaking component works. Joints are selected based on risk, such as location on mains adjoining the transmission mains, low points, and in sensitive areas, for example, in front of schools.

2. There is no formal risk assessment performed for the expansion joints targeted for replacement in 2010. The list of expansion joint replacement for 2010 was established based on City's Reconstruction Projects scheduled in 2010.

3. The number of internally pressurized expansion joints replaced in 2007, 2008 and 2009 were:
    - 2007 – total 9 expansion joints (5 leaking at weld end; 4 non-leaking removed with other components)
    - 2008 – total 23 expansion joints (17 leaking at weld end; 5 non-leaking removed with other components; and an additional non-leaking joint removed with an interference project)

- 2009 – total 23 expansion joints (13 non-leaking removed based unknown material composition; 9 non-leaking removed in conjunction with other work; and an additional non-leaking joint removed with an interference project)

4. The annual expenditures for the Expansion Joint Program for 2007, 2008 and 2009 were:
   - 2007 - $760,000
   - 2008 - $2.7 million
   - 2009 - $1.5 million

5. The Company's records indicate that an internally pressurized joint has been removed due to leakage, under an interference project, or with other system improvement work. It does not provide any breakdowns on joints replaced with mainline leak repairs, mainline valve replacements, etc. The percentage of the internally pressurized joints replaced under other programs was:
   - 2007 – 44% removed with other system improvement
   - 2008 – 22% removed with other system improvement; 4% removed with an interference project
   - 2009 – 39% removed with other system improvement; 4% removed with an interference project

6. For a typical expansion joint replacement, the cost breakdowns are as follows:
   - Construction Contract – $45,000
   - Company Labor – $10,000
   - Materials & Supplies – $13,000
   - Other Direct Costs – $12,000
   - Indirect Costs – $20,000
   - The total cost of a typical expansion joint replacement is approximately $100,000 per expansion joint

Company Name: Con Edison
Case Description: Con Edison Gas & Steam Rate Cases
Case: 09-G-0795-09-S-0794

Response to DPS Interrogatories – Set DPS15
Date of Response: 01/29/2010
Responding Witness: Steam Ops

Question No. :124
Subject: Pump Manhole Electrical Upgrade (Steam) - 1. For the Pump Manhole Electrical Upgrade Project, are the pumps themselves affected by the harsh environment or is just the wiring and the conduit leading to the pumps? 2. Can the wiring and conduit be replaced and existing pumps reused?

Response:

1. The pumps are very much affected by the harsh environment. The very hot water is close to boiling temperature at 212°F and the higher ambient air temperature greatly shorten the operating life of our pumps. The pump manholes were constructed and installed in areas where there is a history of known groundwater or tidal water infiltration into steam structures. The water in the structures absorbs the radiant heat and creates a very hot and humid atmosphere for these pumps to operate in. In addition, street level dirt and road salts settle in these manholes and contribute to accelerated corrosion of any electrical components in the structure. Controls and wiring for the pumps need to be upgraded to conform to current electrical standards and to provide better protection for the equipment.

2. The wiring and conduit will be replaced to bring the installation up to current electrical standards and codes. While some existing pumps could be reused, we have found that they would continue to fail. Therefore, the existing pumps will be replaced with new high temperature pumps that are specially designed to withstand the harsh environment of the steam manholes.

Company Name: Con Edison
Case Description: Con Edison Gas & Steam Rate Cases
Case: 09-G-0795-09-S-0794

Response to DPS Interrogatories – Set DPS15
Date of Response: 02/01/2010
Responding Witness: Steam Ops

Question No. :125
Subject: Flange Removal Program - 1. For the Flange Removal Program, please provide the total number of flanges currently in the steam pipeline system. 2. Are all flanges required to be replaced? How many are currently leaking? 4. Is there a risk based approached used to select replacement? If so please provide the risk score, ranking, and risk factors. 5. Shouldn't those flanges replaced as a result of City/State construction projects be captured under the "Interference Program?" If not, please explain. 6. How may are targeted for replacement due to leakage and/or risk (if applicable) in 2010? 7. Please provide the number of flanges removed in 2007, 2008, and 2009, and the total cost expended in each of the years. 8. How many flanges removed in 2007, 2008, and 2009 was a result of leakage? 9. Of the total flange replacements in 2007, 2008, and 2009 what percentage was completed in conjunction with other targeted work (i.e.: city/state interference work, mainline leak repairs, mainline valve replacements, etc) 10. Please provide a complete breakdown of the costs associated with a typical flange replacement.

Response:

1. Currently, there are approximately 3,000 pairs of flanges in the Steam system.

2. All flanges are not required to be replaced. However, flanges are prone to leak. It is our goal to eliminate the leak prone equipment. Therefore, when exposed, flanges are removed or sleeved if congested subsurface conditions render the removal impractical.

3. Currently, one pair of flanges is leaking.

4. The flange replacement is not based on risk assessment. The flanges are removed due to leakage or where other maintenance activities are occurring or are scheduled.

5. The flanges replaced as a result of City construction projects had been captured under the "Interference Program."

6. A total of 34 pairs of flanges are targeted to be replaced in 2010.

7. The numbers of flanges removed in 2007, 2008 and 2009 are indicated below. Although the replacement costs associated with the leaking flanges are known, the costs of non-leaking flange removals associated with other component repairs and interference projects have not been identified as a separate line item for accounting purpose.

    - 2007 – total 65 pairs;
        - 46 leaking pairs were removed and their costs were $3,185K.
        - 19 non-leaking pairs were removed with other component repairs.
    - 2008 – total 59 pairs;
        - 46 leaking pairs were removed and their costs were $4,160K.
        - 13 non-leaking pairs were removed with other component repairs and interference projects.
    - 2009 – total 51 pairs;
        - 38 leaking pairs were removed and their costs were $4,200K.
        - 13 non-leaking pairs were removed with other component repairs.

8. The number of flanges removed in 2007, 2008 and 2009 as a result of leakage were:
    - 2007 – 46 pairs
    - 2008 – 46 pairs
    - 2009 – 38 pairs

9. The percentage of total flange replacements with other component repairs / replacements and interference work were:
    - 2007 – 29%
    - 2008 – 22%
    - 2009 – 25%

10. For a typical flange replacement, the cost breakdowns are:
    - Construction Contracts - $27,520
    - Company Labor - $13,760
    - Materials & Supplies - $2,580
    - Other Direct Costs - $20,640
    - Indirect Costs - $21,500
    - Total average cost for a typical flange replacement - $86,000

Company Name: Con Edison
Case Description: Con Edison Gas & Steam Rate Cases
Case: 09-G-0795-09-S-0794

Response to DPS Interrogatories – Set DPS15
Date of Response: 02/01/2010
Responding Witness: Steam Ops

Question No. :126
Subject: Interference Program - 1. Concerning Interference, please provide the actual expenditures for interference work in years 2007, 2008, and 2009. 2. Please provide the number of main line valves, flanges, internally pressurized expansion joints, and leaks replaced or eliminated as a result of interference work in 2007, 2008, and 2009 respectively.

Response:

1. See response to Staff 1-2.

2. Main Valve Replacement or elimination with the interference work:
   - 2007 – 1 Main Valve
   - 2008 – None
   - 2009 - None

   Flanges replaced / eliminated with the interference projects.
   - 2007 – None
   - 2008 – 3 pairs
   - 2009 - None

   Internally pressurized joints replaced / eliminated:
   - 2007 – None
   - 2008 – 1 expansion joint
   - 2009 – 1 expansion joint

   Leaks that may have been addressed in connection with interference projects are not separately identified.

Company Name: Con Edison
Case Description: Con Edison Gas & Steam Rate Cases
Case: 09-G-0795-09-S-0794

Response to DPS Interrogatories – Set DPS18
Date of Response: 02/05/2010
Responding Witness: Steam Operations Panel

Question No. :172
Subject: System Mobile Office for Steam - 1. What offset in productivity is gained should this project be implemented? Has the Company performed a cost benefit analysis for this project? If so, what was the result?

Response:
It is estimated that there would be a productivity savings of 20 minutes per day per inspector. Yes, a cost benefit analysis was performed and the project has a 3.35 year payback period.

Company Name: Con Edison
Case Description: Con Edison Gas & Steam Rate Cases
Case: 09-G-0795-09-S-0794

Response to DPS Interrogatories – Set DPS18
Date of Response: 02/04/2010
Responding Witness: Steam Operations Panel

Question No. :174
Subject: Thermal Efficiency Improvement (Re-insulation) - 1. Has the Company performed a cost benefit analysis for this program, as it appears to equate to the $/ft of listed main replacement projects? If so, what was the result?

Response:
This capital budget allowance is to cover any insulation that is damaged and discovered when we open up pipe housings or structures. Re-insulation occurs on an unscheduled basis and the cost is dependant upon the scope of each job.

We also direct you to the recent ABS Thermal Efficiency and Losses: Review and Action Plan Study that was conducted and submitted to PSC Staff back in mid 2009. The independent consultant estimated that utilizing pumpable insulation can cost $900/ft or more.

There are several factors to be considered when using this type of insulation and it needs to be considered on a case by case basis. The Company has looked at the Priority Locations and employing pumpable insulation. Our preliminary findings showed a simple payback of 9 years, which is unacceptable. The Company intends to file is response to the ABS Thermal Efficiency and Losses: Review and Action Plan within the next few months.

Company Name: Con Edison
Case Description: Con Edison Gas & Steam Rate Cases
Case: 09-G-0795-09-S-0794

Response to DPS Interrogatories – Set DPS26
Date of Response: 02/19/2010
Responding Witness: Steam Ops

Question No. :212
Subject: Steam Leak/Vapor Calls Response Data - 1. Provide 2008 and 2009 year end response time percentages for minutes 28, 29, 30, 31, and 32 respectively.

Response:
For 2008, the data is not available. Before 2009, the Company did not differentiate between types of calls received from the public and does not have the breakdown for steam leak/vapor call response time.

For 2009, the year end response time data requested is as follows:

Minutes	Percentage
0 - 28	59.42%
0 - 29	62.62%
0 - 30	68.05%
0 - 31	70.29%
0 - 32	73.16%

Con Edison

Hearing Exhibits

STATE OF NEW YORK
DEPT. OF PUBLIC SERVICE
DATE: 6/9/09
CASE NOS: 09-S-0794, 09-G-0795, and 09-S-0029
Ex. 329

STAFF OPERATIONS PANEL
2010-2013 STEAM DISTRIBUTION PROGRAMS/PROJECTS BUDGET ADJUSTMENTS
For Consolidated Edison Steam Rate Case 09-S-0794
Budget ($1,000)

Priority	Functional Category / Projects	2010			2011			2012			2013		
		Con Edison	Staff	Adjustment	Con Edison	Staff	Adjustment	Con Edison	Staff	Adjustment	Con Edison	Staff	Adjustment
1	Remote Monitoring	10,000	5,000	-5,000	7,500	5,000	-2,500	0	5,000	5,000	-		
2	Trap Station Improvement Program	3,200	3,200	0	2,035	2,035	0	-			-		
3	Infrastructure Condition Project	1,500	1,500	0	1,500	1,500	0						
4	Installation of High Capacity Traps	800	800	0	640	640	0	-			-		
5	Pump Manhole Electrical Upgrade	1,000	1,000	0	500	500	0	500	500	0	500	500	0
6	Leaks/Upgrades	3,000	3,000	0	2,850	2,850	0	2,800	2,800	0	2,800	2,800	0
7	Expansion Joint Replacement	2,000	1,300	-700	2,000	1,300	-700	2,000	1,300	-700	2,000	1,300	-700
8	Flange Removal	3,000	2,200	-800	2,500	1,800	-700	2,500	1,800	-700	2,500	1,800	-700
9	Cooling Chamber Replacement	1,500	1,500	0	1,000	1,000	0	1,000	1,000	0	1,000	1,000	0
10	Manhole Rebuild	2,000	1,700	-300	2,000	1,700	-300	2,000	1,700	-300	2,000	1,700	-300
11	Manhole Cover Replacement Program	250	250	0	-			-			-		
12	New Business	2,010	1,508	-502	2,030	1,508	-522	2,500	1,867	-633	2,500	1,867	-633
13	New Business	375	375	0	375	375	0	375	375	0	375	375	0
14	Anchor Replacement Program	500	500	0	500	500	0	500	500	0	500	500	0
15	Demand Meter /Shuntflo Meter Conversion	2,450	2,450	0	1,950	1,950	0	1,300	1,300	0	1,300	1,300	0
16	Demand Meter /Shuntflo Meter Conversion	1,050	1,050	0	800	800	0	920	920	0	920	920	0
17	M-Valve Conversion	500	500	0	500	500	0	500	500	0	500	500	0
18	Meter Downsizing Program	300	300	0	300	300	0	300	300	0	300	300	0
19	Various Locations - Load	150	150	0	150	150	0	150	150	0	150	150	0
20	Limitorque Angle Valve Replacement	100	100	0	100	100	0	100	100	0	100	100	0
21	Various Enhancement Reinforcements	995	995	0	200	200	0	200	200	0	200	200	0
23	Steam Mapping Technology Upgrade	500	0	-500	500	0	-500	-			-		
24	SDS and Job Tracking Integration	370	0	-370	180	0	-180	-			-		
25	CM Mobile Office for Steam	200	0	-200	-			-			-		
26	Main Valve Replacement	200	100	-100	700	350	-350	1,000	500	-500	1,000	500	-500
27	Water hammer Prediction Model	300	300	0	300	300	0	300	300	0	300	300	
28	Telemetry	300	300	0	300	300	0	300	300	0	300	300	
29	Interference	1,000	160	-840	1,000	160	-840	1,000	160	-840	1,000	160	-840
30	Operations Interface To Remote Metering	500	500	0	150	150	0	-			-		
31	Steam Meter Room Piping Automation	350	350	0	350	350	0	350	350	0	-		
32	Meter Station Trap Remote Monitoring	-			500	0	-500	600	0	-600	600	0	-600
33	Steam Pipeline Integrity Program	-			500	0	-500	1,000	0	-1,000	1,000	0	-1,000
34	GPS for Steam Distribution	-			-			200	0	-200	200	0	-200
35	Thermal Efficiency Improvement	-			-			500	0	-500	500	0	-500
36	Trap Combination Replacement Program	-			-			400	0	-400	400	0	-400
37	Remote Monitoring Phase II	-			-			2,000	0	-2,000	2,000	0	-2,000
38	Service Valve Replacement Program	-			-			560	0	-560	560	0	-560
	Total	40,400	31,088	-9,312	33,910	26,318	-7,592	25,855	21,922	-3,933	25,505	16,572	-8,933

Con Edison

Hearing Exhibits

STATE OF NEW YORK
DEPT. OF PUBLIC SERVICE
DATE: 6/9/10
CASE NOS: 09-S-0794, 09-G-0795, and 09-S-0029
Ex. 330

STEAM DISTRIBUTION PROGRAMS/PROJECTS COST CALCULATION -2010 TO 2014

Priority	Functional Category / Projects	2005 Actual	2006 Actual	2007 Actual	2008 Actual	2009(10month) Actual	Average	2010 Forecast	2011 Forecast	2012 Forecast	2013 Forecast	2014 Forecast	Total Forecast ($1,000)
1	Remote Monitoring				2525	4,286		10,000	7,500	-	-	-	17,500
2	Trap Station Improvement Program				1109			3,200	2,035	-	-	-	5,235
3	Infrastructure Condition Project					348		1,500	1,500				3,000
4	Installation of High Capacity Traps					144		800	640	-	-	-	1,440
5	Pump Manhole Electrical Upgrade			119	644	1,417	727	1,000	500	500	500	500	3,000
6	Leaks/Upgrades	9780	8408	2998	3358	3,186	5,546	3,000	2,850	2,800	2,800	2,800	14,250
7	Expansion Joint Replacement	483	903	760	2701	1,780	1,325	2,000	2,000	2,000	2,000	2,000	10,000
8	Flange Removal	1574	3051	3185	4160	3,944	3,183	3,000	2,500	2,500	2,500	2,500	13,000
9	Cooling Chamber Replacement			518	1495	1,163	1,059	1,500	1,000	1,000	1,000	1,000	5,500
10	Manhole Rebuild	1629	1364	926	2702	2,011	1,726	2,000	2,000	2,000	2,000	2,000	10,000
11	Manhole Cover Replacement Program		112	2136	4838	(253)	1,708	250	-	-	-	-	250
12	New Business	3543	1133	774	2322	815	1,717	2,010	2,030	2,500	2,500	2,500	11,540
13	New Business							375	375	375	375	375	1,875
14	Anchor Replacement Program					847	847	500	500	500	500	500	2,500
15	Demand Meter /Shuntflo Meter Conversion	1421	2870	1274	2264	2,454	2,057	2,450	1,950	1,300	1,300	1,300	8,300
16	Demand Meter /Shuntflo Meter Conversion	590	1259	2420	1178	941	1,278	1,050	800	920	920	920	4,610
17	M-Valve Conversion	698		1090	604	486	720	500	500	500	500	500	2,500
18	Meter Downsizing Program							300	300	300	300	300	1,500
19	Various Locations - Load	222	633	1005	638	205	541	150	150	150	150	150	750
20	Limitorque Angle Valve Replacement							100	100	100	100	100	500
21	Various Enhancement Reinforcements							995	200	200	200	200	1,795
23	Steam Mapping Technology Upgrade							500	500	-	-	-	1,000
24	SDS and Job Tracking Integration							370	180	-	-	-	550
25	CM Mobile Office for Steam							200	-	-	-	-	200
26	Main Valve Replacement							200	700	1,000	1,000	1,000	3,900
27	Water hammer Prediction Model							300	300	300	300	300	1,500
28	Telemetry	654	251	111	58	34	222	300	300	300	300	300	1,500
29	Interference	0	957	-250	27	64	160	1,000	1,000	1,000	1,000	1,000	5,000
30	Operations Interface To Remote Metering							500	150	-	-	-	650
31	Steam Meter Room Piping Automation							350	350	350	-	-	1,050
32	Meter Station Trap Remote Monitoring							-	500	600	600	600	2,300
33	Steam Pipeline Integrity Program							-	500	1,000	1,000	1,000	3,500
34	GPS for Steam Distribution							-	-	200	200	200	600
35	Thermal Efficiency Improvement							-	-	500	500	500	1,500
36	Trap Combination Replacement Program			1386	1190	3,478	2,018	-	-	400	400	400	1,200
37	Remote Monitoring Phase II							-	-	2,000	2,000	2,000	6,000
38	Service Valve Replacement Program							-	-	560	560	560	1,680
	Other	356	734	9,279	886	802	2,411						
	Total	**20,950**	**21,675**	**27,731**	**32,699**	**28,151**		**36,210**	**29,755**	**17,970**	**17,970**	**17,970**	

Con Edison

Hearing Exhibits

STATE OF NEW YORK
DEPT. OF PUBLIC SERVICE
DATE: 6/9/10
CASE NOS: 09-S-0794, 09-G-0795, and 09-S-0029
Ex. 331

STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

Case 09-S-0794 - 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.

Case 09-G-0795 - Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Consolidated Edison Company of New York, Inc. for Gas Service.

CASE 09-S-0029 - Proceeding on Motion of the Commission to Consider Steam Resource Plan and East River Repowering Project Cost Allocation Study, and Steam Energy Efficiency Programs for Consolidated Edison Company of New York, Inc.

ATTENTION

This exhibit is among those prefiled in the captioned cases by active parties that executed two joint proposals that were filed on May 18, 2010. Those that executed the joint proposals subsequently stipulated that they would not cross-examine the witnesses of each other given that they were supporting at that time the Commission's adoption of the terms of the joint proposals. In this context, the fact that these parties did not cross-examine the witnesses of each other does not mean and cannot reasonably be understood to mean that the information in this exhibit is uncontroverted among the parties that executed the joint proposals.

BEFORE THE
STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

In the Matter of

CONSOLIDATED EDISON COMPANY OF NEW YORK, INC.

Case No. 09-S-0794

MARCH 2010

Prepared Testimony of:

FREDERICK W. BARNEY
Econometrician 1
Office of Regulatory Economics
State of New York
Department of Public Service
Three Empire State Plaza
Albany, New York 12223-1350

Q. Please state your name, employer, and business address.

A. My name is Frederick William Barney. I am employed by the New York State Department of Public Service (Department). My business address is Three Empire Plaza, Albany, New York 12223-1350.

Q. Mr. Barney, what is your position in the department?

A. I am employed as an Econometrician I in the Office of Regulatory Economics.

Q. Please describe your educational background and professional experience.

A. I received a Bachelor of Science degree in Economics from the College of Education of Wayne State University in Detroit, Michigan in 1967. I earned a Master of Science degree in Economics from Wayne State in 1971. I also earned a Masters of Science degree in Statistics from Virginia Tech in Blacksburg in 1983. I have completed 30 semester hours in Ph.D level statistics at the University of Michigan in Ann Arbor. Before I joined the Department in 1992, I held various jobs teaching economics and statistics. I was also economics department head at Walsh College in Michigan.

Q. Please briefly describe your current responsibilities with the Department.

A. My responsibilities include forecasting sales for rate cases, survey sampling, and statistical evaluation of retail and wholesale service quality.

Q. Have you previously testified before the New York Public Service Commission (Commission)?

A. Yes. I have testified before the Commission on sales forecasting issues.

Q. What is the purpose of your testimony?

A. To provide an adjustment to Consolidated Edison Company of New York, Inc.'s (Con Edison or the Company) forecast of steam sales.

Q. What is the nature of your proposed adjustment?

A. I recommend that what has been referred to as the Company's price elasticity adjustment or conservation adjustment be computed as was done in the Company's response to DPS-142. This information request response is contained in Exhibit__(FWB-1). Using this alternative computation amounts to a change of the Company's price elasticity related decrement in sales from 355 MMlbs to 311 MMlbs. Alternatively expressed, this change would add 44 MMlbs to the Company's steam sales forecast.

Q. Why do you recommend that the price elasticity estimate produced in response to information request DPS-142 be accepted by the Commission?

A. I offer two reasons. The first reason is the Company's Steam Forecasting Panel's computation of the elasticity adjustment was a linear approximation to the constant elasticity demand curve estimated by the Company's consultant in the last rate case and used to produce the price elasticity coefficients which were relied upon by the Steam Forecasting Panel in making their elasticity estimates. The effect of the Steam Forecasting Panel's straight line approximation to the curvilinear demand curve estimated by the Company's consultant is to overstate the estimated elasticity adjustment.

Q. Is this adjustment substantial?

A. Yes, this difference in approach results in over a 12% difference in the magnitude of the estimated price elasticity effect. Thus, it has material benefit to ratepayers while allowing the Company to receive a price elasticity adjustment consistent with their chosen elasticity model.

Q. Would you please state your second reason for rejecting the Company's 355 MMlbs price elasticity adjustment figure?

A. The Company's objection to the use of the 311 MMlb figure is based on assertion involving considerations not incorporated into their consultant's model. The Company's response to DPS-142 indicates that the 355 MMlb figure reflects "customer decisions in a more dynamic fashion". However, the company's consultant could have estimated its price elasticity model with a dynamic specification and chose not to do so. What I am recommending is the result of the direct computations of the Company's steam elasticity model coefficients as opposed to the linear approximation to the model's implied elasticities as was used in the Company's elasticity adjustment.

Q. What is the result of rejecting the Company's price elasticity adjustment on the forecast of steam sales?

A. The Ccompany's forecast of normalized sales is 23,175 MMlbs. The forecast becomes 23,219 MMlbs with the alternative price elasticity computation I propose.

Q. Have you provided this sales forecast adjustment to the Staff Rate Panel?

A. Yes.

Q. Does this conclude your testimony at this time?

A. Yes.

Con Edison

Hearing Exhibits

STATE OF NEW YORK
DEPT. OF PUBLIC SERVICE
DATE: 6/9/10
CASE NOS: 09-S-0794, 09-G-0795, and 09-S-0029
Ex. 332

BEFORE THE
STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

In the Matter of

Consolidated Edison Company of New York

Case 09-S-0794

March 2010

Prepared Exhibit of:

Frederick W. Barney
Econometrician I
Office of Regulatory Economics
State of New York
Department of Public Service
Three Empire State Plaza
Albany, New York 12223-1350

Company Name: Con Edison
Case Description: Con Edison Gas & Steam Rate Cases
Case: 09-G-0795-09-S-0794

Response to DPS Interrogatories – Set DPS17
Date of Response: 02/01/2010
Responding Witness: Muccilo/Steam Forecasting Panel

Question No. :142
Referencing page 35, lines 18-21 of your testimony, in relevant part, you state: "SRAM should afford the Company sufficient revenues to cover the incremental customer growth above forecast levels." 1. To what extent does your projection differ from the Forecasting Panel's forecast of customer growth used in its sales forecast? 2. Your testimony implies that you foresee a net growth in the customer base. Please explain if this is what your testimony intended. For the Steam Forecasting Panel, 3 Regarding the electronic spread sheet file "DPS-009 Q14.xls" associated with the construction of Exhibit_ (FP-1) that was provided in response to Staff DPS-9, question 14, by how much would the cumulative MMlb impact associated with the price elastic response of steam customers change if the reduction factor used [for example, see the column labeled "(C9)" on spreadsheet tab 13d] were based upon a constant elasticity formulation instead of a linear elasticity formulation. Confirm that a constant elasticity formulation would better reflect the logarithmic specification of conservation elasticity models estimated by the Brattle Group in the last rate case.

Response:

1. I do not have a projection that differs from that reflected by the Forecasting Panel.

2. See response to part 1.

3. See attached file "DPS17 Q142 Price Elasticity". The "constant" elasticity formulation would change line 17 of Exhibit __ (FP-1) from (355) MMlbs to (311) MMlbs. In regard to the requested confirmation: no such confirmation can be provided. The Brattle Group conservation models employ a double-log specification to estimate conservation elasticities by using a dataset consisting of winter months for the period of 1999 to 2006. Due to the double-log specification, the coefficients of the price terms are readily interpreted as elasticities. Once these elasticities are estimated, it is possible to obtain a percentage change in consumption due to a given percentage change in prices. In that sense, the "constant elasticity formulation" and "linear elasticity formulation" approaches are both consistent with the Brattle Models. However, if the intent is to reflect the customer decisions in a more dynamic fashion, then the "linear elasticity formulation" would more readily accommodate this pursuit.

Price Elasticity Impact for SC1 - MMlbs
Price Elasticity Factor -0.11

	(C1)	(C2)	(C3)	(C4)	(C5)	(C6)	(C7)	(C8)	(C9)	(C10)	(C11)	(C12)
			(C2/C1)-1			C1*100/C4	C2*100/C5	(C7/C6)-1	If C8>0,C8*(-0.11)		C10*C9	
	Avg Winter Season Price* Prior $/Mlbs	Current $/Mlbs	Variance%	Prior GDP	Current GDP	Adjusted Price Prior $/Mlbs	Adjusted Price Current $/Mlbs	Adjusted Variance%	Reduction Factor%	Sales Forecast w/o Price MMlbs	Price Impact Incremental MMlbs	**Price Impact Cumulative MMlbs**
Nov-09	$41.57	$42.38	1.95%	124.0	125.7	$33.52	$33.72	0.60%	-0.07%	37	0	**0**
Dec-09	$41.57	$42.38	1.95%	124.0	125.7	$33.52	$33.72	0.60%	-0.07%	87	1	**1**
Jan-10	$41.57	$42.38	1.95%	124.0	125.7	$33.52	$33.72	0.60%	-0.07%	106	0	**0**
Feb-10	$41.57	$42.38	1.95%	124.0	125.7	$33.52	$33.72	0.60%	-0.07%	119	0	**0**
Mar-10	$41.57	$42.38	1.95%	124.0	125.7	$33.52	$33.72	0.60%	-0.07%	106	0	**0**
Apr-10	$41.57	$42.38	1.95%	124.0	125.7	$33.52	$33.72	0.60%	-0.07%	26	0	**0**
Nov-10	$42.38	$49.32	16.40%	125.7	127.8	$33.72	$38.59	14.44%	-1.59%	37	(1)	**(1)**
Dec-10	$42.38	$49.32	16.40%	125.7	127.8	$33.72	$38.59	14.44%	-1.59%	83	(1)	**0**
Jan-11	$42.38	$49.32	16.40%	125.7	127.8	$33.72	$38.59	14.44%	-1.59%	107	(2)	**(2)**
Feb-11	$42.38	$49.32	16.40%	125.7	127.8	$33.72	$38.59	14.44%	-1.59%	115	(2)	**(2)**
Mar-11	$42.38	$49.32	16.40%	125.7	127.8	$33.72	$38.59	14.44%	-1.59%	103	(2)	**(2)**
Apr-11	$42.38	$49.32	16.40%	125.7	127.8	$33.72	$38.59	14.44%	-1.59%	26	0	**0**
Nov-11	$49.32	$53.07	7.60%	127.8	130.1	$38.59	$40.79	5.70%	-0.63%	38	0	**(1)**
Dec-11	$49.32	$53.07	7.60%	127.8	130.1	$38.59	$40.79	5.70%	-0.63%	78	0	**0**
Jan-12	$49.32	$53.07	7.60%	127.8	130.1	$38.59	$40.79	5.70%	-0.63%	107	(1)	**(3)**
Feb-12	$49.32	$53.07	7.60%	127.8	130.1	$38.59	$40.79	5.70%	-0.63%	112	(1)	**(3)**
Mar-12	$49.32	$53.07	7.60%	127.8	130.1	$38.59	$40.79	5.70%	-0.63%	101	(1)	**(3)**
Apr-12	$49.32	$53.07	7.60%	127.8	130.1	$38.59	$40.79	5.70%	-0.63%	26	0	**0**
Nov-12	$53.07	$56.19	5.90%	130.1	132.9	$40.79	$42.28	3.65%	-0.40%	40	0	**(1)**
Dec-12	$53.07	$56.19	5.90%	130.1	132.9	$40.79	$42.28	3.65%	-0.40%	70	0	**0**
Jan-13	$53.07	$56.19	5.90%	130.1	132.9	$40.79	$42.28	3.65%	-0.40%	107	0	**(3)**
Feb-13	$53.07	$56.19	5.90%	130.1	132.9	$40.79	$42.28	3.65%	-0.40%	106	0	**(3)**
Mar-13	$53.07	$56.19	5.90%	130.1	132.9	$40.79	$42.28	3.65%	-0.40%	99	0	**(3)**
Apr-13	$53.07	$56.19	5.90%	130.1	132.9	$40.79	$42.28	3.65%	-0.40%	27	0	**0**
Nov-13	$56.19	$59.26	5.50%	132.9	135.8	$42.28	$43.64	3.22%	-0.35%	40	0	**(1)**
Dec-13	$56.19	$59.26	5.50%	132.9	135.8	$42.28	$43.64	3.22%	-0.35%	66	0	**0**
Jan-14	$56.19	$59.26	5.50%	132.9	135.8	$42.28	$43.64	3.22%	-0.35%	108	0	**(3)**
Feb-14	$56.19	$59.26	5.50%	132.9	135.8	$42.28	$43.64	3.22%	-0.35%	101	0	**(3)**
Mar-14	$56.19	$59.26	5.50%	132.9	135.8	$42.28	$43.64	3.22%	-0.35%	97	0	**(3)**
Apr-14	$56.19	$59.26	5.50%	132.9	135.8	$42.28	$43.64	3.22%	-0.35%	26	0	**0**

* Average winter price from November through April calculated by taking total bill including all taxes except sales tax divided by sales. Season price reflects one month lag.

Rate Year 1	**(7)**
Rate Year 2	**(10)**
Rate Year 3	**(10)**
Rate Year 4	**(10)**

Price Elasticity Impact for SC2 Non-Demand - MMlbs

Price Elasticity Factor -0.15

	(C1)	(C2)	(C3) (C2/C1)-1	(C4)	(C5)	(C6) C1*100/C4	(C7) C2*100/C5	(C8) (C7/C6)-1	(C9) If C8>0,C8*(-0.15)	(C10)	(C11) C10*C9	(C12)
	Avg Winter Season Price* Prior $/Mlbs	Current $/Mlbs	Variance%	Prior GDP	Current GDP	Adjusted Price Prior $/Mlbs	Adjusted Price Current $/Mlbs	Adjusted Variance%	Reduction Factor%	Sales Forecast w/o Price MMlbs	Price Impact Incremental MMlbs	**Price Impact Cumulative MMlbs**
Nov-09	$36.49	$34.74	-4.80%	124.0	125.7	$29.43	$27.64	-6.08%	0.00%	318	0	**0**
Dec-09	$36.49	$34.74	-4.80%	124.0	125.7	$29.43	$27.64	-6.08%	0.00%	363	0	**0**
Jan-10	$36.49	$34.74	-4.80%	124.0	125.7	$29.43	$27.64	-6.08%	0.00%	710	0	**0**
Feb-10	$36.49	$34.74	-4.80%	124.0	125.7	$29.43	$27.64	-6.08%	0.00%	551	0	**0**
Mar-10	$36.49	$34.74	-4.80%	124.0	125.7	$29.43	$27.64	-6.08%	0.00%	471	0	**0**
Apr-10	$36.49	$34.74	-4.80%	124.0	125.7	$29.43	$27.64	-6.08%	0.00%	280	0	**0**
Nov-10	$34.74	$40.56	16.80%	125.7	127.8	$27.64	$31.74	14.83%	-2.22%	240	(5)	**(5)**
Dec-10	$34.74	$40.56	16.80%	125.7	127.8	$27.64	$31.74	14.83%	-2.22%	183	(4)	**(4)**
Jan-11	$34.74	$40.56	16.80%	125.7	127.8	$27.64	$31.74	14.83%	-2.22%	525	(12)	**(12)**
Feb-11	$34.74	$40.56	16.80%	125.7	127.8	$27.64	$31.74	14.83%	-2.22%	331	(7)	**(7)**
Mar-11	$34.74	$40.56	16.80%	125.7	127.8	$27.64	$31.74	14.83%	-2.22%	298	(7)	**(7)**
Apr-11	$34.74	$40.56	16.80%	125.7	127.8	$27.64	$31.74	14.83%	-2.22%	184	(4)	**(4)**
Nov-11	$40.56	$43.41	7.00%	127.8	130.1	$31.74	$33.37	5.14%	-0.77%	256	(2)	**(7)**
Dec-11	$40.56	$43.41	7.00%	127.8	130.1	$31.74	$33.37	5.14%	-0.77%	173	(1)	**(5)**
Jan-12	$40.56	$43.41	7.00%	127.8	130.1	$31.74	$33.37	5.14%	-0.77%	554	(4)	**(16)**
Feb-12	$40.56	$43.41	7.00%	127.8	130.1	$31.74	$33.37	5.14%	-0.77%	343	(3)	**(10)**
Mar-12	$40.56	$43.41	7.00%	127.8	130.1	$31.74	$33.37	5.14%	-0.77%	304	(2)	**(9)**
Apr-12	$40.56	$43.41	7.00%	127.8	130.1	$31.74	$33.37	5.14%	-0.77%	194	(1)	**(5)**
Nov-12	$43.41	$45.83	5.60%	130.1	132.9	$33.37	$34.48	3.33%	-0.50%	278	(1)	**(8)**
Dec-12	$43.41	$45.83	5.60%	130.1	132.9	$33.37	$34.48	3.33%	-0.50%	144	(1)	**(6)**
Jan-13	$43.41	$45.83	5.60%	130.1	132.9	$33.37	$34.48	3.33%	-0.50%	574	(3)	**(19)**
Feb-13	$43.41	$45.83	5.60%	130.1	132.9	$33.37	$34.48	3.33%	-0.50%	328	(2)	**(12)**
Mar-13	$43.41	$45.83	5.60%	130.1	132.9	$33.37	$34.48	3.33%	-0.50%	306	(2)	**(11)**
Apr-13	$43.41	$45.83	5.60%	130.1	132.9	$33.37	$34.48	3.33%	-0.50%	202	(1)	**(6)**
Nov-13	$45.83	$47.88	4.50%	132.9	135.8	$34.48	$35.26	2.26%	-0.34%	283	(1)	**(9)**
Dec-13	$45.83	$47.88	4.50%	132.9	135.8	$34.48	$35.26	2.26%	-0.34%	132	0	**(6)**
Jan-14	$45.83	$47.88	4.50%	132.9	135.8	$34.48	$35.26	2.26%	-0.34%	588	(2)	**(21)**
Feb-14	$45.83	$47.88	4.50%	132.9	135.8	$34.48	$35.26	2.26%	-0.34%	310	(1)	**(13)**
Mar-14	$45.83	$47.88	4.50%	132.9	135.8	$34.48	$35.26	2.26%	-0.34%	306	(1)	**(12)**
Apr-14	$45.83	$47.88	4.50%	132.9	135.8	$34.48	$35.26	2.26%	-0.34%	201	(1)	**(7)**

* Average winter price from November through April calculated by taking total bill including all taxes except sales tax divided by sales. Season price reflects one month lag.

Rate Year 1	**(39)**
Rate Year 2	**(52)**
Rate Year 3	**(62)**
Rate Year 4	**(68)**

Price Elasticity Impact for SC2 Demand - MMlbs
Price Elasticity Factor -0.15

	(C1)	(C2)	(C3)	(C4)	(C5)	(C6)	(C7)	(C8)	(C9)	(C10)	(C11)	(C12)
			(C2/C1)-1			C1*100/C4	C2*100/C5	(C7/C6)-1	If C8>0,C8*(-0.15)		C10*C9	
	Avg Winter Season Price*					Adjusted Price	Adjusted Price			Sales Forecast	Price Impact	**Price Impact**
	Prior	Current		Prior	Current	Prior	Current	Adjusted	Reduction	w/o Price	Incremental	**Cumulative**
	$/Mlbs	$/Mlbs	Variance%	GDP	GDP	$/Mlbs	$/Mlbs	Variance%	Factor%	MMlbs	MMlbs	**MMlbs**
Nov-09	$31.65	$29.16	-7.87%	124.0	125.7	$25.52	$23.20	-9.09%	0.00%	562	0	**0**
Dec-09	$31.65	$29.16	-7.87%	124.0	125.7	$25.52	$23.20	-9.09%	0.00%	1,223	0	**0**
Jan-10	$31.65	$29.16	-7.87%	124.0	125.7	$25.52	$23.20	-9.09%	0.00%	1,167	0	**0**
Feb-10	$31.65	$29.16	-7.87%	124.0	125.7	$25.52	$23.20	-9.09%	0.00%	1,471	0	**0**
Mar-10	$31.65	$29.16	-7.87%	124.0	125.7	$25.52	$23.20	-9.09%	0.00%	1,082	0	**0**
Apr-10	$31.65	$29.16	-7.87%	124.0	125.7	$25.52	$23.20	-9.09%	0.00%	700	0	**0**
Nov-10	$29.16	$34.60	18.70%	125.7	127.8	$23.20	$27.07	16.68%	-2.50%	673	(17)	**(17)**
Dec-10	$29.16	$34.60	18.70%	125.7	127.8	$23.20	$27.07	16.68%	-2.50%	1,360	(34)	**(34)**
Jan-11	$29.16	$34.60	18.70%	125.7	127.8	$23.20	$27.07	16.68%	-2.50%	1,432	(36)	**(36)**
Feb-11	$29.16	$34.60	18.70%	125.7	127.8	$23.20	$27.07	16.68%	-2.50%	1,684	(42)	**(42)**
Mar-11	$29.16	$34.60	18.70%	125.7	127.8	$23.20	$27.07	16.68%	-2.50%	1,273	(32)	**(32)**
Apr-11	$29.16	$34.60	18.70%	125.7	127.8	$23.20	$27.07	16.68%	-2.50%	811	(20)	**(20)**
Nov-11	$34.60	$37.71	9.00%	127.8	130.1	$27.07	$28.99	7.09%	-1.06%	707	(7)	**(24)**
Dec-11	$34.60	$37.71	9.00%	127.8	130.1	$27.07	$28.99	7.09%	-1.06%	1,322	(14)	**(48)**
Jan-12	$34.60	$37.71	9.00%	127.8	130.1	$27.07	$28.99	7.09%	-1.06%	1,487	(16)	**(52)**
Feb-12	$34.60	$37.71	9.00%	127.8	130.1	$27.07	$28.99	7.09%	-1.06%	1,714	(18)	**(60)**
Mar-12	$34.60	$37.71	9.00%	127.8	130.1	$27.07	$28.99	7.09%	-1.06%	1,296	(14)	**(46)**
Apr-12	$34.60	$37.71	9.00%	127.8	130.1	$27.07	$28.99	7.09%	-1.06%	831	(9)	**(29)**
Nov-12	$37.71	$39.83	5.60%	130.1	132.9	$28.99	$29.97	3.38%	-0.51%	773	(4)	**(28)**
Dec-12	$37.71	$39.83	5.60%	130.1	132.9	$28.99	$29.97	3.38%	-0.51%	1,276	(7)	**(55)**
Jan-13	$37.71	$39.83	5.60%	130.1	132.9	$28.99	$29.97	3.38%	-0.51%	1,548	(8)	**(60)**
Feb-13	$37.71	$39.83	5.60%	130.1	132.9	$28.99	$29.97	3.38%	-0.51%	1,709	(9)	**(69)**
Mar-13	$37.71	$39.83	5.60%	130.1	132.9	$28.99	$29.97	3.38%	-0.51%	1,323	(7)	**(53)**
Apr-13	$37.71	$39.83	5.60%	130.1	132.9	$28.99	$29.97	3.38%	-0.51%	860	(4)	**(33)**
Nov-13	$39.83	$41.76	4.80%	132.9	135.8	$29.97	$30.75	2.60%	-0.39%	797	(3)	**(31)**
Dec-13	$39.83	$41.76	4.80%	132.9	135.8	$29.97	$30.75	2.60%	-0.39%	1,281	(5)	**(60)**
Jan-14	$39.83	$41.76	4.80%	132.9	135.8	$29.97	$30.75	2.60%	-0.39%	1,610	(6)	**(66)**
Feb-14	$39.83	$41.76	4.80%	132.9	135.8	$29.97	$30.75	2.60%	-0.39%	1,700	(7)	**(76)**
Mar-14	$39.83	$41.76	4.80%	132.9	135.8	$29.97	$30.75	2.60%	-0.39%	1,345	(5)	**(58)**
Apr-14	$39.83	$41.76	4.80%	132.9	135.8	$29.97	$30.75	2.60%	-0.39%	874	(3)	**(36)**

* Average winter price from November through April calculated by taking total bill including all taxes except sales tax divided by sales. Season price reflects one month lag.

Rate Year 1	**(181)**
Rate Year 2	**(259)**
Rate Year 3	**(298)**
Rate Year 4	**(327)**

Price Elasticity Impact for SC3 Non-Demand - MMlbs
Price Elasticity Factor -0.11

	(C1)	(C2)	(C3)	(C4)	(C5)	(C6)	(C7)	(C8)	(C9)	(C10)	(C11)	(C12)
			(C2/C1)-1			C1*100/C4	C2*100/C5	(C7/C6)-1	If C8>0,C8*(-0.11)		C10*C9	
	Avg Winter Season Price* Prior $/Mlbs	Current $/Mlbs	Variance%	Prior GDP	Current GDP	Adjusted Price Prior $/Mlbs	Adjusted Price Current $/Mlbs	Adjusted Variance%	Reduction Factor%	Sales Forecast w/o Price MMlbs	Price Impact Incremental MMlbs	**Price Impact Cumulative MMlbs**
Nov-09	$31.58	$28.78	-8.87%	124.0	125.7	$25.47	$22.90	-10.09%	0.00%	312	0	**0**
Dec-09	$31.58	$28.78	-8.87%	124.0	125.7	$25.47	$22.90	-10.09%	0.00%	462	0	**0**
Jan-10	$31.58	$28.78	-8.87%	124.0	125.7	$25.47	$22.90	-10.09%	0.00%	583	0	**0**
Feb-10	$31.58	$28.78	-8.87%	124.0	125.7	$25.47	$22.90	-10.09%	0.00%	548	0	**0**
Mar-10	$31.58	$28.78	-8.87%	124.0	125.7	$25.47	$22.90	-10.09%	0.00%	467	0	**0**
Apr-10	$31.58	$28.78	-8.87%	124.0	125.7	$25.47	$22.90	-10.09%	0.00%	308	0	**0**
Nov-10	$28.78	$34.23	18.90%	125.7	127.8	$22.90	$26.78	16.94%	-1.86%	234	(4)	**(4)**
Dec-10	$28.78	$34.23	18.90%	125.7	127.8	$22.90	$26.78	16.94%	-1.86%	299	(6)	**(6)**
Jan-11	$28.78	$34.23	18.90%	125.7	127.8	$22.90	$26.78	16.94%	-1.86%	425	(8)	**(8)**
Feb-11	$28.78	$34.23	18.90%	125.7	127.8	$22.90	$26.78	16.94%	-1.86%	381	(7)	**(7)**
Mar-11	$28.78	$34.23	18.90%	125.7	127.8	$22.90	$26.78	16.94%	-1.86%	326	(6)	**(6)**
Apr-11	$28.78	$34.23	18.90%	125.7	127.8	$22.90	$26.78	16.94%	-1.86%	213	(4)	**(4)**
Nov-11	$34.23	$37.10	8.40%	127.8	130.1	$26.78	$28.52	6.50%	-0.72%	245	(2)	**(6)**
Dec-11	$34.23	$37.10	8.40%	127.8	130.1	$26.78	$28.52	6.50%	-0.72%	273	(2)	**(8)**
Jan-12	$34.23	$37.10	8.40%	127.8	130.1	$26.78	$28.52	6.50%	-0.72%	433	(3)	**(11)**
Feb-12	$34.23	$37.10	8.40%	127.8	130.1	$26.78	$28.52	6.50%	-0.72%	377	(3)	**(10)**
Mar-12	$34.23	$37.10	8.40%	127.8	130.1	$26.78	$28.52	6.50%	-0.72%	322	(2)	**(8)**
Apr-12	$34.23	$37.10	8.40%	127.8	130.1	$26.78	$28.52	6.50%	-0.72%	213	(2)	**(6)**
Nov-12	$37.10	$38.91	4.90%	130.1	132.9	$28.52	$29.28	2.66%	-0.29%	263	(1)	**(7)**
Dec-12	$37.10	$38.91	4.90%	130.1	132.9	$28.52	$29.28	2.66%	-0.29%	237	(1)	**(9)**
Jan-13	$37.10	$38.91	4.90%	130.1	132.9	$28.52	$29.28	2.66%	-0.29%	440	(1)	**(12)**
Feb-13	$37.10	$38.91	4.90%	130.1	132.9	$28.52	$29.28	2.66%	-0.29%	355	(1)	**(11)**
Mar-13	$37.10	$38.91	4.90%	130.1	132.9	$28.52	$29.28	2.66%	-0.29%	317	(1)	**(9)**
Apr-13	$37.10	$38.91	4.90%	130.1	132.9	$28.52	$29.28	2.66%	-0.29%	215	(1)	**(7)**
Nov-13	$38.91	$40.78	4.80%	132.9	135.8	$29.28	$30.03	2.56%	-0.28%	264	(1)	**(8)**
Dec-13	$38.91	$40.78	4.80%	132.9	135.8	$29.28	$30.03	2.56%	-0.28%	220	(1)	**(10)**
Jan-14	$38.91	$40.78	4.80%	132.9	135.8	$29.28	$30.03	2.56%	-0.28%	449	(1)	**(13)**
Feb-14	$38.91	$40.78	4.80%	132.9	135.8	$29.28	$30.03	2.56%	-0.28%	335	(1)	**(12)**
Mar-14	$38.91	$40.78	4.80%	132.9	135.8	$29.28	$30.03	2.56%	-0.28%	313	(1)	**(10)**
Apr-14	$38.91	$40.78	4.80%	132.9	135.8	$29.28	$30.03	2.56%	-0.28%	213	(1)	**(8)**

* Average winter price from November through April calculated by taking total bill including all taxes except sales tax divided by sales. Season price reflects one month lag.

Rate Year 1	**(35)**
Rate Year 2	**(49)**
Rate Year 3	**(55)**
Rate Year 4	**(61)**

Price Elasticity Impact for SC3 Demand - MMlbs

Price Elasticity Factor -0.11

	(C1)	(C2)	(C3)	(C4)	(C5)	(C6)	(C7)	(C8)	(C9)	(C10)	(C11)	(C12)
			(C2/C1)-1			C1*100/C4	C2*100/C5	(C7/C6)-1	If C8>0,C8*(-0.11)		C10*C9	
	Avg Winter Season Price*					Adjusted Price	Adjusted Price			Sales Forecast	Price Impact	**Price Impact**
	Prior	Current		Prior	Current	Prior	Current	Adjusted	Reduction	w/o Price	Incremental	**Cumulative**
	$/Mlbs	$/Mlbs	Variance%	GDP	GDP	$/Mlbs	$/Mlbs	Variance%	Factor%	MMlbs	MMlbs	**MMlbs**
Nov-09	$29.26	$25.39	-13.23%	124.0	125.7	$23.60	$20.20	-14.41%	0.00%	147	0	**0**
Dec-09	$29.26	$25.39	-13.23%	124.0	125.7	$23.60	$20.20	-14.41%	0.00%	305	0	**0**
Jan-10	$29.26	$25.39	-13.23%	124.0	125.7	$23.60	$20.20	-14.41%	0.00%	301	0	**0**
Feb-10	$29.26	$25.39	-13.23%	124.0	125.7	$23.60	$20.20	-14.41%	0.00%	345	0	**0**
Mar-10	$29.26	$25.39	-13.23%	124.0	125.7	$23.60	$20.20	-14.41%	0.00%	271	0	**0**
Apr-10	$29.26	$25.39	-13.23%	124.0	125.7	$23.60	$20.20	-14.41%	0.00%	198	0	**0**
Nov-10	$25.39	$30.72	21.00%	125.7	127.8	$20.20	$24.04	19.01%	-2.09%	240	(5)	**(5)**
Dec-10	$25.39	$30.72	21.00%	125.7	127.8	$20.20	$24.04	19.01%	-2.09%	439	(9)	**(9)**
Jan-11	$25.39	$30.72	21.00%	125.7	127.8	$20.20	$24.04	19.01%	-2.09%	482	(10)	**(10)**
Feb-11	$25.39	$30.72	21.00%	125.7	127.8	$20.20	$24.04	19.01%	-2.09%	497	(10)	**(10)**
Mar-11	$25.39	$30.72	21.00%	125.7	127.8	$20.20	$24.04	19.01%	-2.09%	412	(9)	**(9)**
Apr-11	$25.39	$30.72	21.00%	125.7	127.8	$20.20	$24.04	19.01%	-2.09%	294	(6)	**(6)**
Nov-11	$30.72	$33.78	10.00%	127.8	130.1	$24.04	$25.96	7.99%	-0.88%	248	(2)	**(7)**
Dec-11	$30.72	$33.78	10.00%	127.8	130.1	$24.04	$25.96	7.99%	-0.88%	432	(4)	**(13)**
Jan-12	$30.72	$33.78	10.00%	127.8	130.1	$24.04	$25.96	7.99%	-0.88%	498	(4)	**(14)**
Feb-12	$30.72	$33.78	10.00%	127.8	130.1	$24.04	$25.96	7.99%	-0.88%	504	(4)	**(14)**
Mar-12	$30.72	$33.78	10.00%	127.8	130.1	$24.04	$25.96	7.99%	-0.88%	417	(4)	**(13)**
Apr-12	$30.72	$33.78	10.00%	127.8	130.1	$24.04	$25.96	7.99%	-0.88%	297	(3)	**(9)**
Nov-12	$33.78	$35.69	5.70%	130.1	132.9	$25.96	$26.85	3.43%	-0.38%	264	(1)	**(8)**
Dec-12	$33.78	$35.69	5.70%	130.1	132.9	$25.96	$26.85	3.43%	-0.38%	419	(2)	**(15)**
Jan-13	$33.78	$35.69	5.70%	130.1	132.9	$25.96	$26.85	3.43%	-0.38%	510	(2)	**(16)**
Feb-13	$33.78	$35.69	5.70%	130.1	132.9	$25.96	$26.85	3.43%	-0.38%	501	(2)	**(16)**
Mar-13	$33.78	$35.69	5.70%	130.1	132.9	$25.96	$26.85	3.43%	-0.38%	422	(2)	**(15)**
Apr-13	$33.78	$35.69	5.70%	130.1	132.9	$25.96	$26.85	3.43%	-0.38%	303	(1)	**(10)**
Nov-13	$35.69	$37.41	4.80%	132.9	135.8	$26.85	$27.55	2.61%	-0.29%	268	(1)	**(9)**
Dec-13	$35.69	$37.41	4.80%	132.9	135.8	$26.85	$27.55	2.61%	-0.29%	415	(1)	**(16)**
Jan-14	$35.69	$37.41	4.80%	132.9	135.8	$26.85	$27.55	2.61%	-0.29%	523	(2)	**(18)**
Feb-14	$35.69	$37.41	4.80%	132.9	135.8	$26.85	$27.55	2.61%	-0.29%	497	(1)	**(17)**
Mar-14	$35.69	$37.41	4.80%	132.9	135.8	$26.85	$27.55	2.61%	-0.29%	426	(1)	**(16)**
Apr-14	$35.69	$37.41	4.80%	132.9	135.8	$26.85	$27.55	2.61%	-0.29%	305	(1)	**(11)**

* Average winter price from November through April calculated by taking total bill including all taxes except sales tax divided by sales. Season price reflects one month lag.

Rate Year 1	**(49)**
Rate Year 2	**(70)**
Rate Year 3	**(80)**
Rate Year 4	**(87)**

Total Price Elasticity Impact Summary - MMlbs

	Price Impact Incremental MMlbs	Price Impact Cumulative MMlbs
Nov-09	0	0
Dec-09	1	1
Jan-10	0	0
Feb-10	0	0
Mar-10	0	0
Apr-10	0	0
Nov-10	(32)	(32)
Dec-10	(54)	(53)
Jan-11	(68)	(68)
Feb-11	(68)	(68)
Mar-11	(56)	(56)
Apr-11	(34)	(34)
Nov-11	(13)	(45)
Dec-11	(21)	(74)
Jan-12	(28)	(96)
Feb-12	(29)	(97)
Mar-12	(23)	(79)
Apr-12	(15)	(49)
Nov-12	(7)	(52)
Dec-12	(11)	(85)
Jan-13	(14)	(110)
Feb-13	(14)	(111)
Mar-13	(12)	(91)
Apr-13	(7)	(56)
Nov-13	(6)	(58)
Dec-13	(7)	(92)
Jan-14	(11)	(121)
Feb-14	(10)	(121)
Mar-14	(8)	(99)
Apr-14	(6)	(62)

	Price Impact Cumulative MMlbs
Rate Year 1	**(311)**
Rate Year 2	**(440)**
Rate Year 3	**(505)**
Rate Year 4	**(553)**

GDP Deflator-2000=100

Forecast Prepared June 2009

	2004	2005	2006	2007	2008	Forecast 2009	2010	2011	2012	2013	2014	2015
Mar. 31	108.2	111.8	115.5	118.9	121.6	124.2	125.7	127.8	130.3	133.1	136.1	139.2
Jun. 30	109.2	112.4	116.3	119.5	122.0	124.4	126.2	128.3	130.8	133.7	136.6	139.7
Sep. 30	109.8	113.5	117.1	120.0	123.1	124.8	126.7	128.9	131.3	134.2	137.1	140.3
Dec. 31	110.7	114.5	117.7	120.8	123.3	125.3	127.2	129.4	131.8	134.7	137.7	140.9
Average	109.5	113.0	116.7	119.8	122.5	124.7	126.5	128.6	131.0	133.9	136.9	140.0
Season Average					124.0	125.7	127.8	130.1	132.9	135.8	138.9	140.9
Annual Average Year-over-year % change	2.9%	3.3%	3.2%	2.7%	2.2%	1.8%	1.4%	1.7%	1.9%	2.2%	2.2%	2.3%

Average 12 months Ending Dec. 31, 2005	(Actual)	=	113.0
Average 12 months Ending Dec. 31, 2006	(Actual)	=	116.7
Average 12 months Ending Dec. 31, 2007	(Actual)	=	119.8
Average 12 months Ending Dec. 31, 2008	(Actual)	=	122.5
Average 12 months Ending Dec. 31, 2009	(Actual)	=	124.7
Average 12 months Ending Dec. 31, 2010	(Forecast)	=	126.5
Average 12 months Ending Dec. 31, 2011	(Forecast)	=	128.6

Escalation rate for the 24 Months Ending 12/31/09 over 12/31/07 - Rate Year 1	=	**1.040**
	or	**4.0%**
Rate Year 2 (increase over Rate Year 1	=	**1.014**
	or	**1.4%**
Rate Year 3 (increase over Rate Year 2	=	**1.017**
	or	**1.7%**

Notes: Actual GDP deflator from press release by U.S. Department of Commerce Bureau of Economic Analysis as of 6/25/09.
Quarterly Forecasts for 2009 and 2010 from Blue Chip dated June 10, 2009.
Annual Forecasts for 2011 on are from ***Blue Chip*** dated March 10, 2008.
The quarterly values for 2011 on are extrapolated by applying the year-over-year rate to the prior year's corresponding quarter.

Con Edison

Hearing Exhibits

STATE OF NEW YORK
DEPT. OF PUBLIC SERVICE
DATE: 6/9/10
CASE NOS: 09-S-0794, 09-G-0795, and 09-S-0029
Ex. 333

BEFORE THE
STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

In the Matter of

CONSOLIDATED EDISON COMPANY of NEW YORK, INC.

Case 09-S-0029/Case 09-S-0794

March 2010

Prepared Supplemental Staff
ERRP Allocation Panel
Exhibits of:

Marco L. Padula
Utility Supervisor
Office of Electric, Gas and Water

Liliya A. Randt
Utility Engineer 2
Office of Electric, Gas and Water

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Comparison of Fuel Cost Allocation Methodologies Using Year 2008 Actual Data								
Method	**Method Description**	**Steam System Fuel Cost $/Mlb**	**ER 1, 2 Net Electric Fuel Cost* $1,000**	**Cost Shift from Electric to Steam $1,000**	**Steam Price % Increase from Cost Shift to Steam Total Bill**	**Steam Price % Increase from Cost Shift to Steam Delivery Only**	**Electric Price % Savings from Cost Shift to Steam Total Bill**	**Steam Fuel Cost from ERRP $/Mlb**
		(1)	(2)	(3)	(4)	(5)	(6)	(7)
Current	Charge GT fuel to electric, HRSG fuel to steam.	$12.22	$62,499	NA	N/A	N/A	NA	0.51
Above Market	Current method modified: transfer GT fuel costs above electric revenue to steam.	$14.86	$0	$62,499	8.07%	15.65%	0.62%	6.96
Proportional Method used from 1975 to 1978	**Electric and steam customers share fuel savings** arising from cogeneration process on equal percent savings basis. (Using 2008 Market Heat Rate.)	$16.95	-$49,583	$112,082	14.48%	28.06%	1.12%	12.08
Steam priced as byproduct used pre-1975 method and post-1978	**Steam customers receive entire fuel savings** arising from cogeneration; electric is charged fuel cost based on proxy generator. (Using 2008 Market Heat Rate)	$14.10	$18,022	$44,477	5.75%	11.14%	0.44%	5.10

* Electric fuel cost = cost of fuel charged to electric net of electric revenue.

Comparison of Fuel Cost Allocation Methodologies Using Year 2008 Actual Data

Method	Method Description	Steam System Fuel Cost $/Mlb	ER 1, 2 Net Electric Fuel Cost* $1,000	Cost Shift from Electric to Steam $1,000	Steam Price % Increase from Cost Shift to Steam Total Bill	Steam Price % Increase from Cost Shift to Steam Delivery Only	Electric Price % Savings from Cost Shift to Steam Total Bill	Steam Fuel Cost from ERRP $/Mlb
		(1)	(2)	(3)	(4)	(5)	(6)	(7)
Economic Allocation, Steam Floor	Economic Allocation Method, steam allocation based upon steam price floor			$41,775	5.40%	10.46%	0.42%	4.65
Economic Allocation, Steam Ceiling	Economic Allocation Method, steam allocation based on steam stand-alone cost ceiling			$134,759	17.41%	33.74%	1.35%	15.00
Economic Allocation using elasticities	Economic Allocation Method, common costs allocated assuming steam is 4.19 times more price elastic than electric			$118,163	15.27%	29.58%	1.18%	13.15
Market Price Benefit of avoiding 350MW	Benefit of avoiding 350 MW of electric summer cooling capacity ($51.9M capacity cost + $0 energy congestion cost)** Market Price impacts			($51,900)	-6.71%	-12.99%	-0.52%	($2.19)
T&D Benefit of avoiding 350MW	Benefit of T&D investments avoided by 350 MW of unecessary electric summer cooling capacity **			($87,600)	-11.32%	-21.93%	-0.88%	($3.70)
Environmental benefit	Benefit of reduced polution associated with steam cooling ***			($7,500)	-0.97%	-1.88%	-0.08%	($0.77)

** Benefit of 350 MW reduction allocated over steam system total MMLBs, *** Benefit of reduced polution allcoated over ERRP MMLBs

Con Edison

Hearing Exhibits

STATE OF NEW YORK
DEPT. OF PUBLIC SERVICE
DATE: 6/9/10
CASE NOS: 09-S-0794, 09-G-0795, and 09-S-0029
Ex. 334

Ten Year Bill Impacts of Staff's Proposed $73 million Revenue Increase in Rate Year 1 and Potential Changes to the Current ERRP Fuel Allocation

Case 1: Assumes New Hudson Ave Boilers in 2014 and No Change to Current ERRP Fuel Allocation									
	2011	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
Total Bill Increase	13%	4%	2%	10%	2%	2%	1%	2%	2%
Cumulative Bill Increase		18%	20%	33%	35%	37%	38%	41%	43%
Case 2: Assumes New Hudson Ave Boilers in 2014 and $42 Million ERRP Fuel Allocation to Steam									
	2011	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
Total Bill Increase	19%	4%	2%	10%	1%	2%	1%	2%	2%
Cumulative Bill Increase		24%	26%	39%	41%	43%	44%	47%	49%
Case 3: Assumes New Hudson Ave Boilers in 2014 and $135 Million ERRP Fuel Allocation to Steam									
	2011	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
Total Bill Increase	33%	4%	2%	9%	1%	1%	1%	1%	1%
Cumulative Bill Increase		37%	40%	52%	54%	56%	58%	60%	62%

Con Edison

Hearing Exhibits

STATE OF NEW YORK
DEPT. OF PUBLIC SERVICE
DATE: 6/9/09
CASE NOS: 09-S-0794, 09-G-0795, and 09-S-0029
Ex. 335

Development of Long Term Steam Price Elasticity for use in Economic ERRP Allocation Methodology

Staff's proposed economic allocation method requires a long term price elasticity estimate for steam as an input. Since the steam provided at ERRP is used by all steam customer classes, the price elasticity coefficient must be representative of steam customers in aggregate. Staff used demand curve information for SC1, SC2 and SC3 customers from the February 8, 2010 Report Regarding Steam Price Elasticity and Long Term Steam Revenue Requirement Forecast (Steam Elasticity Report). Staff has aggregated the price and quantity data points from these three customer classes to produce an overall steam demand curve. Staff used a regression analysis to estimate a representative price elasticity over the entire range of these data points. The regression equation specified the log of the aggregate quantity of MMlbs (lnmmlbs) to be a function of the log of the price ratio for each of the aggregate data pairs (lnprice). The constant elasticity coefficient estimated from this model specification is -0.191.

Analysis of Combined SC1, SC2, SC3 Customer Price Sensitivity

	Service Class	Customers (demand plus non demand)	Customers Likely to Switch	Avg Steam to Gas Price Ratio	Likely Remaining Customers	% increase in price ratio	% likely change in customers	likely price elasticity for switching	Reduction in MMlbs from Customers that Switch	Conservation Elasticity Response from Likely Remaining Customers	Combined Elastic Response (in MMlbs) from Conservation and from Customer Switching	likely remaining MMlbs (demand plus non demand)	% increase in price ratio	% change in MMlbs	likely price elasticity for MMlbs	log of price ratio (lnprice)	log of remaining MMlbs (lnmmlbs)
Brattle Logistic Switching Model Baseline	1,2 & 3	2179	0	1.000	2179	0						23,174	0			0	4.365001
Case A Total 5 Years Logistic Switching Model	1,2 & 3	2179	18	1.278	2161	27.8%	-0.8%	-0.0297	-157.84	(640)	-798.00	22,376	27.8%	-3.4%	-0.1237	0.106657	4.349782
Case B Total 5 Years Logistic Switching Model	1,2 & 3	2179	21	1.340	2158	34.0%	-1.0%	-0.0284	-185.12	(833)	-1018.00	22,156	34.0%	-4.4%	-0.1294	0.126948	4.345491
Case C Total 5 Years Logistic Switching Model	1,2 & 3	2179	25	1.446	2154	44.6%	-1.1%	-0.0257	-224.07	(1,058)	-1282.00	21,892	44.6%	-5.5%	-0.1241	0.160095	4.340285
Case A Total 7 Years Logistic Switching Model	1,2 & 3	2179	19	1.317	2160	31.7%	-0.9%	-0.0275	-158.85	(731)	-890.00	22,284	31.7%	-3.8%	-0.1212	0.119578	4.347993
Case B Total 7 Years Logistic Switching Model	1,2 & 3	2179	23	1.380	2156	38.0%	-1.1%	-0.0278	-197.80	(909)	-1107.00	22,067	38.0%	-4.8%	-0.1257	0.139869	4.343743
Case C Total 7 Years Logistic Switching Model	1,2 & 3	2179	28	1.489	2151	48.9%	-1.3%	-0.0263	-237.77	(1,113)	-1351.00	21,823	48.9%	-5.8%	-0.1191	0.173017	4.338914
Case C2 Total 5 Years Logistic Switching Model	1,2 & 3	2179	32	1.573	2147	57.3%	-1.5%	-0.0256	-276.72				57.3%			na	na
Case C2 Total 7 Years Logistic Switching Model	1,2 & 3	2179	34	1.605	2145	60.5%	-1.6%	-0.0258	-302.99				60.5%			na	na
RAM Model Case A Total 5 Years	1,2 & 3	2179	6	1.278	2173	27.8%	-0.3%	-0.0099	-397	(660)	-1057.07	22,117	27.8%	-4.6%	-0.1639	0.106657	4.344725
RAM Model Case B Total 5 Years	1,2 & 3	2179	8	1.340	2171	34.0%	-0.4%	-0.0108	-445	(843)	-1288.15	21,886	34.0%	-5.6%	-0.1637	0.126948	4.340163
RAM Model Case C Total 5 Years	1,2 & 3	2179	12	1.446	2167	44.6%	-0.6%	-0.0124	-645	(1,020)	-1664.72	21,509	44.6%	-7.2%	-0.1612	0.160095	4.332626
CPROM Model Case A Total 5 Years	1,2 & 3	2179	68	1.278	2111	27.8%	-3.1%	-0.1121	-302	-1033	-1335	21,839	27.8%	-5.8%	-0.2069	0.106657	4.339233
CPROM Model Case B Total 5 Years	1,2 & 3	2179	72	1.340	2107	34.0%	-3.3%	-0.0973	-339	-1268	-1607	21,567	34.0%	-6.9%	-0.2042	0.126948	4.33379
CPROM Model Case C Total 5 Years	1,2 & 3	2179	73	1.446	2106	44.6%	-3.4%	-0.0752	-344	-1480	-1824	21,350	44.6%	-7.9%	-0.1766	0.160095	4.329398
CPROM Model Case A Total 7 Years	1,2 & 3	2179	88	1.317	2091	31.7%	-4.0%	-0.1274	-389	-908	-1297	21,877	31.7%	-5.6%	-0.1766	0.119578	4.339988
CPROM Model Case B Total 7 Years	1,2 & 3	2179	94	1.380	2085	38.0%	-4.3%	-0.1135	-441	-1193	-1634	21,540	38.0%	-7.1%	-0.1856	0.139869	4.333246
CPROM Model Case C Total 7 Years	1,2 & 3	2179	94	1.489	2085	48.9%	-4.3%	-0.0881	-445	-1389	-1834	21,340	48.9%	-7.9%	-0.1617	0.173017	4.329194
CPROM Model Case A Total 9 Years	1,2 & 3	2179	106	1.370	2073	37.0%	-4.9%	-0.1314	-468	-901	-1369	21,805	37.0%	-5.9%	-0.1596	0.136778	4.338556
CPROM Model Case B Total 9 Years	1,2 & 3	2179	113	1.436	2066	43.6%	-5.2%	-0.1190	-536	-1178	-1714	21,460	43.6%	-7.4%	-0.1697	0.157069	4.33163
CPROM Model Case C Total 9 Years	1,2 & 3	2179	115	1.550	2064	55.0%	-5.3%	-0.0960	-538	-1362	-1900	21,274	55.0%	-8.2%	-0.1492	0.190217	4.327849
RAM Model Case C2 Total 5 Years	1,2 & 3	2179	20	1.573	2159	57.3%	-0.9%	-0.0160	-882				57.3%			na	na
	-		min	1.2784	2,064	27.8%	-5.3%	-0.1314	-882	-1480	-1900	21,274	27.8%	-8.2%	-0.2069	0.106657	4.327849
			max	1.6046	2,173	60.5%	-0.3%	-0.0099	-158	-640	-798	22,376	60.5%	-3.4%	-0.1191	0.205367	4.349782

Regression of log of MMlbs on log of price ratio

constant elasticity regression coefficient -0.19142

SUMMARY OUTPUT

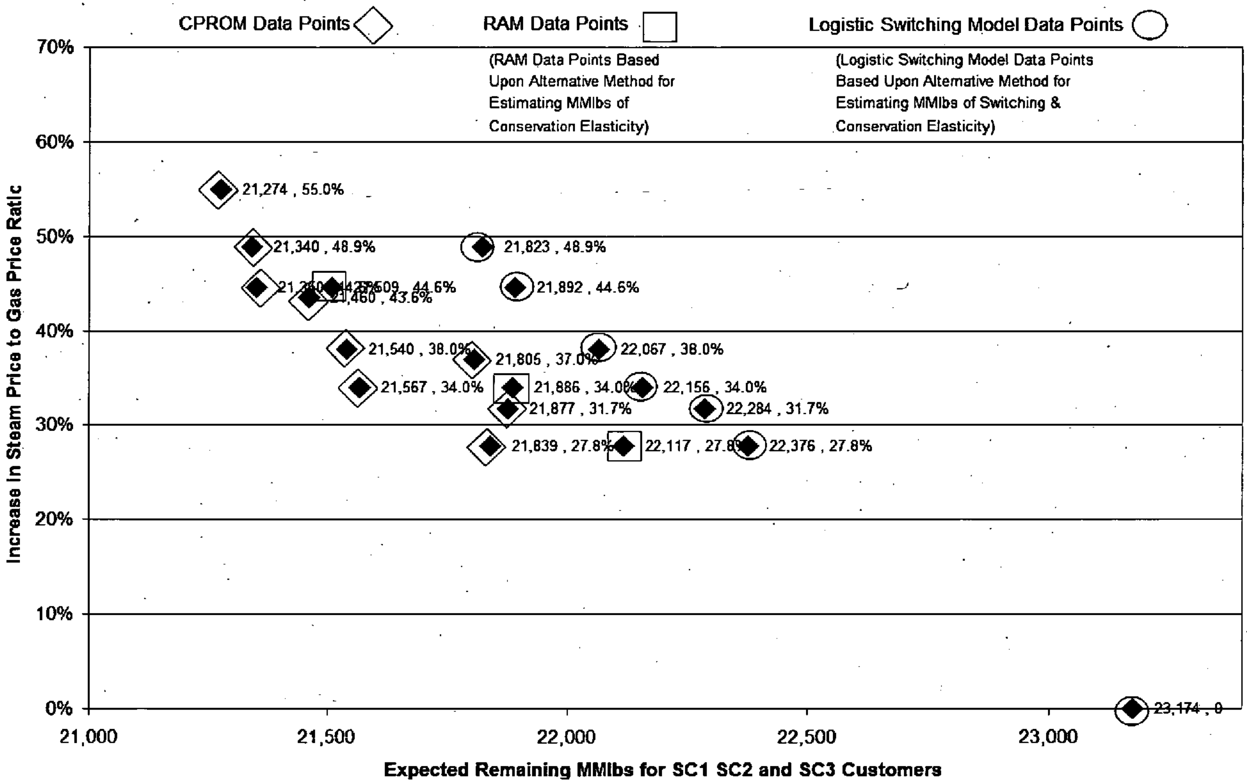
Regression Statistics	
Multiple R	0.868941
R Square	0.755058
Adjusted R Square	0.74065
Standard Error	0.00455
Observations	19

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	0.0010849	0.00108	52.40421	1.3843E-06
Residual	17	0.0003519	2.1E-05		
Total	18	0.0014368			

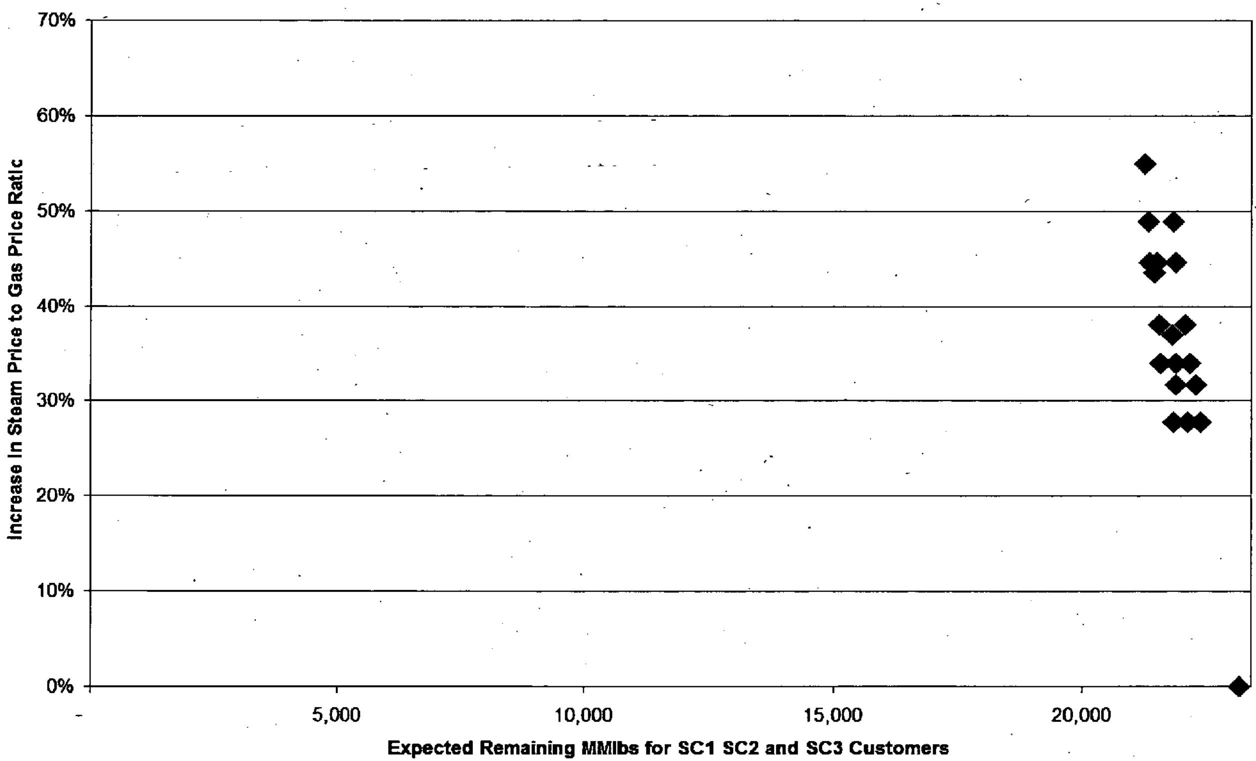
	Coefficient	*Standard Err*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*
Intercept	4.365049	0.0036727	1188.53	2.91E-43	4.35729989	4.37279713
X Variable 1	-0.19142	0.0264428	-7.23908	1.38E-06	-0.24721052	-0.1356318

Combined SC1, SC2 & SC3 Demand Curve (MMlbs)



Exhibit_(SEAP-9)
Page 3 of 4

Combined SC1, SC2 & SC3 Demand Curve (MMlbs) : Alternative Scale



Con Edison

Hearing Exhibits

STATE OF NEW YORK
DEPT. OF PUBLIC SERVICE
DATE: 6/9/09
CASE NOS: 09-S-0794, 09-G-0795, and 09-S-0029
Ex. 336

Development of Long Term Electric Price Elasticity for use in Economic ERRP Allocation Methodology

Staff's proposed economic allocation method for ERRP requires the comparison of long run steam and long run electric elasticities. The following electricity price elasticity estimates can be found in the EPRI and RAND studies that were distributed on September 29, 2009 to the members of the Steam Price Elasticity Working Group (PEWG) per the discussion during the PEWG's conference call on September 24, 2009.

Regional Differences in the Price-Elasticity of Demand for Energy, by Mark A. Bernstein and James Griffin, The RAND Corporation, Santa Monica, CA, 2005

Price Elasticity of Demand for Electricity: A Primer and Synthesis, by Bernard Neenan and Jiyong Eom, Electric Power Research Institute (EPRI), Palo Alto, CA, January 2008

Long Term Elasticity	Source
-0.9	Residential Electricity, (2008 EPRI Study, p. 20)
-1.1	Commercial Electricity, (2008 EPRI Study, p. 20)
-1.2	Industrial Electricity, (2008 EPRI Study, p. 20)
0 to -2.0	Residential Electric Customers, Taylor (1975) (see 2005 Rand Study, p. 11)
-1.36	Commercial Electric Customers, Taylor (1975) (see 2005 Rand Study, p. 11)
-0.7	Residential Electric Customers, Bohi and Zimmerman (1984), (see 2005 Rand Study, p. 11)
-0.24	Maddala et al. (1997), (see 2005 Rand Study, p. 13)

The mid point of the -0.24 to -1.36 range for these long term electric price elasticities is -0.8.