CALIFORNIA COGENERATION COUNCIL
A Combined Heat and Power Association

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April 27, 2005

Honorable John L. Geeseman,
Commissioner and Presiding Member, IEPR Committee
and
Honorable James D. Boyd,
Commissioner and Associate Member, IEPR Committee
California Energy Commission
1516 Ninth Street,
Sacramento CA 95814-5512

Re: 2005 Energy Report – CHP Workshop April 28, 2005
Docket No. 04-IEP-1E and 04-DIST-GEN-1

Dear Commissioners:

Attached is a copy of the Comments of the **California Cogeneration Council (CCC)** for the 2005 Energy Report - CHP Workshop to be held tomorrow, April 28th. We have filed the original and requisite copies with the Docket Office and will bring additional copies for participants at the Workshop.

These comments address our perspective on: (1) the role of CHP in California's resource mix; (2) the benefits of CHP for California; (3) threats to California's existing CHP resources; (4) barriers to CHP in the State and (5) policies to promote additional CHP in California. CCC has also reviewed the draft consultant report to the CEC "Assessment of California CHP Market and Policy Options for Increased Penetration" and our comments thereon are integrated into the sections outlined above.

We appreciate the convening of this Workshop to discuss the State's policy on cogeneration, and look forward to participating tomorrow and as you proceed with the development of the 2005 IEPR Update. Please feel free to contact me at any time if you have questions or seek additional information. Our technical consultant, Tom Beach of Crossborder Energy, is also available to provide support as requested (510-649-9790).

Sincerely,

Maureen Lennon

CC: Mark Rawson, CEC
Dockets Unit, CEC

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BEFORE THE
ENERGY RESOURCES CONSERVATION
AND DEVELOPMENT COMMISSION
OF THE STATE OF CALIFORNIA

In the Matter of:	)	
	)	Docket No. 04-IEP-1E,
Exploring Issues Associated with	)	Preparation
Implementation and Distribution Planning	)	04-DIST-GEN-1
of Distributed Generation	)	
	)	

Comments of the California Cogeneration Council for the 2005 Energy Report – Committee Workshop on Combined Heat & Power, April 28, 2005

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On behalf of
CALIFORNIA COGENERATION COUNCIL

April 27, 2005

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	)	

Comments of the California Cogeneration Council

for the Committee Workshop on

Combined Heat & Power and Distributed Generation

The California Cogeneration Council (CCC) is pleased to present these comments on the important role that distributed combined heat & power (CHP)[1] facilities can play in California's energy future. The CCC hopes that the Commission's upcoming Integrated Energy Policy Report (IEPR) will highlight the many benefits of CHP for California. The Commission also should:

- encourage the adoption of a **CHP Development Goal** – a goal of expanding the state's CHP resources by 25% by 2010;

- recommend that the California Public Utilities Commission (CPUC) require the state's investor-owned utilities to offer **new long-term contracts to CHP projects** in their service territories, at long-run avoided cost prices; and

- clarify that **existing and new CHP are included as part of the state's "distributed generation" resources** in the second element of the "loading order" of the state's Energy Action Plan.

The CCC is an *ad hoc* association of natural gas-fired CHP facilities located throughout California, in the service territories of all three of California's major investor-owned electric

[1] The CCC uses the terms "CHP" and "cogeneration" synonymously throughout these comments.

utilities (IOUs) – Pacific Gas & Electric Company (PG&E), Southern California Edison Company (Edison), and San Diego Gas & Electric Company (SDG&E). CCC member facilities are certified as qualifying facilities (QFs) pursuant to the Public Utility Regulatory Policies Act of 1978 (PURPA). CCC members have sold their power to the IOUs for many years, pursuant to contract terms and avoided cost prices established by this Commission.

In aggregate, CCC members' 32 different CHP projects in California sell almost 2,700 megawatts (MWs) of generation into the California grid. They also provide on-site power and useful thermal energy to their host commercial and industrial facilities. **Attachment 1** provides a map with a list of current CCC members and the location of their projects throughout California. It is important to note that, with a few exceptions, CCC member projects are located in or near the major electric load centers in the state. The CCC represent a significant share of the distributed CHP projects now operating in California.

1. The Role of CHP in California's Resource Mix

Gas-fired cogeneration projects under long-term contracts to the state's three investor-owned utilities (Pacific Gas & Electric, Southern California Edison, and San Diego Gas & Electric–the "IOUs") provide more than 6,000 megawatts of electric generating capacity on the grid operated by the California Independent System Operator (CAISO). As shown in **Figure 1**, this amounts to 12% of the total "native" generation located within the CAISO system.[2] Cogeneration is the third-largest source of power in the state, trailing only conventional thermal plants and hydroelectric facilities. Since cogeneration projects tend to operate as baseload resources, they produce an even larger share – about 17% – of the IOUs' annual energy requirements. In addition, before cogenerators sell their surplus power to the IOUs, they serve on-site manufacturing, agricultural, or other commercial loads; statewide, such self-generation serves about 4% of California's electricity requirements.[3]

California has significant potential for new distributed CHP projects. The draft assessment of the CHP market in California that the Commission released in conjunction with this workshop (the "Draft CHP Assessment") indicates that the state could develop an additional 2,000 to 7,300 MW of CHP capacity, with the upper end of the range possible with supportive state policies.[4] Another recent study performed for the U.S. Combined Heat & Power

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[2] CAISO, "2002 - 2003 Winter Assessment" (October 7, 2002), at 12.

[3] California Energy Commission, "Staff's Statewide Outlook for California Net Electricity for Generation Load: 1980 - 2007." This data is available at www.energy.ca.gov/ electricity/STATEWIDE_CONSUMPTION.PDF.

[4] "Assessment of California CHP Market and Policy Options for Increased Penetration," draft consultant report to the CEC (April 2005, Publication No. CEC-500-2005-060-D, hereafter, the "Draft CHP Assessment"), at page ix.

Association estimates that California has the technical potential for an additional 13,000 MW of cogeneration, with a realistic expectation that 5,000 MW of this potential could be developed.[5] Development of 5,000 MW of new CHP projects would increase the state's installed CHP capacity by over 50%,[6] and would reduce the state's demand for natural gas by 9%.[7]

The CCC believes that the CEC's CHP market assessments may have missed the potential for existing CHP projects to repower and expand their current facilities. For example, in **Attachment 3**, the CCC presents publicly-available information on one significant QF cogeneration repowering project in California – Delta Power's recent turbine replacement project at its Carson Cogeneration facility. Delta replaced the existing IM5000 turbine with an LM6000PC turbine. This project resulted in a 20% increase in capacity (8 MW), a 3% improvement in efficiency, and improvements in air emission control equipment that allowed the plant to meet newer, more stringent emission requirements. The fact is that, today, there are numerous existing cogeneration projects that are interested in upgrading their existing turbines. California has a large fleet of mid-size cogeneration projects in the same size range as the Carson project – almost 3,000 MW of facilities between 30 MW and 120 MW. A 15% to 20% increase in the capacity of these projects through repowering similar to the Carson example would add 400 to 600 MW to the state's grid.

2. High Oil & Gas Prices: Deja Vu All Over Again

Today, world crude oil prices exceed $50 per barrel and gasoline prices are pushing $3 per gallon. In this environment, we are often reminded that, adjusted for inflation, today's crude oil and gasoline prices are approaching the record levels set in the early 1980s.[8] It is important to

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[5] Energy and Environmental Analysis, "Natural Gas Impacts of Increased CHP" (October 2003). This study is **Attachment 2** to these comments.

[6] *Ibid*, at page ES-2, Table ES-1. Energy Information Administration data and the Draft CHP Assessment show that California has more than 9,000 MW of existing CHP. This is greater than the 6,400 MW of capacity that cogeneration QFs sell to the IOUs, due to the facts that many CHP units sell or use all of their power on-site and that municipal utilities like the Sacramento Municipal Utility District also have cogeneration resources in their service territories.

[7] *Ibid.*, at page ES-2, Table ES-2.

[8] See http://www.energy.ca.gov/gasoline/statistics/gasoline_cpi_adjusted.html. Inflation-adjusted gasoline prices exceeded $2.00 per gallon from 1980 to 1982, with a peak price of $2.99 per gallon in March 1982. http://www.energy.ca.gov/gasoline/retail_gasoline_prices.html shows that recent gasoline prices exceeded $2.00 per gallon starting in February 2004, and have climbed to over $2.50 per gallon as of April 2005. For similar information on current and historical crude oil prices, showing the return to $50 per barrel prices, see the respective CEC and EIA weblinks: http://www.energy.ca.gov/gasoline/statistics/us_gas+oilprices_1918-1999.html and

remember how California and the nation reacted to the first major "energy crisis" – when oil prices first spiked in the 1970s. Indeed, in the early 1980s CHP development was a key element of the California's response to seemingly limited and increasingly expensive fossil fuel resources – the same concerns that are again current today. As we shall see below, there is no reason that CHP cannot be part of the solution to California's present energy circumstances, as well.

In 1973, world oil prices skyrocketed during the Arab oil embargo. In the following years OPEC exercised its market power to keep oil prices high. In the electric industry, high oil prices hit ratepayers hard, particularly in states such as California where the utilities burned fuel oil in a substantial amount of their generating capacity. The traditional alternatives to oil seemed increasingly suspect. Natural gas resources were in short supply, and gas was widely perceived to be a declining resource.[9] The electric utilities responded to the crisis by seeking to build ever-larger central station coal and nuclear power plants. Their plans foundered on safety concerns and environmental opposition, as exemplified by the 1979 Three Mile Island accident and the California utilities' aborted efforts to build huge coal-fired power plants both inside and outside of California. Perhaps even more important, the utility-owned nuclear plants that were built encountered extraordinary construction cost overruns.

The nation needed a new approach to meeting its energy needs. That new paradigm emerged in PURPA, enacted in 1978 as part of a broad national energy plan. PURPA sought to reduce the country's dependence on oil through the development of new resources for electric generation, including renewable resources (solar, wind, biomass, geothermal, and small hydro) and the more efficient use of oil and gas in CHP projects. To make certain that qualifying cogeneration facilities advanced PURPA's goals, CHP QFs were required to meet certain operating and efficiency standards.[10]

In fostering these new generation resources, PURPA embodied a completely new approach to the development of electric generation–a change that was as important as the new technologies that PURPA encouraged. In essence, PURPA moved beyond the electric utilities' traditional role as the sole builders of new electric generation and fostered a new industry in the independent development, ownership, and operation of such plants. PURPA broke down the barriers to entry that the utilities had erected through their refusal to negotiate with, buy power from, interconnect with, or provide reasonable back-up services to independent power

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http://tonto.eia.doe.gov/oog/info/twip/twip_crude.html.

[9] In fact, to conserve what were thought to be limited natural gas supplies, in 1978 Congress passed the Power Plant and Industrial Fuel Use Act, which limited the use of natural gas in new power plant and industrial boilers. This act was repealed in 1987 when it became clear that natural gas supplies were not dwindling.

[10] *See* 18 CFR § 292.205.

producers.[11] PURPA's key reforms included a requirement that the utilities must purchase the power output of qualifying cogeneration and other small power production facilities (so-called "QFs") at the purchasing utility's **avoided cost** – that is, at the cost that the utilities would have incurred themselves to produce or purchase the same energy and capacity. The CPUC-approved avoided costs included fixed capacity payments over the term of the contract; these payments were based on the levelized cost of the utility's <u>cheapest</u> source of capacity at that time–a combustion turbine.[12] Energy payments reflected the utility's operating costs that it avoided through its QF purchases (principally the costs of additional gas- or oil-fired thermal generation).

By the end of 1982, the key elements of PURPA had been implemented in California, including "standard offer" contracts with avoided cost prices that the CPUC required the IOUs to make available to viable CHP projects and other QFs. At the same time, industrial and institutional customers with large energy requirements were considering cogeneration as a means to reduce their rapidly increasing electricity and natural gas costs. Most of the state's existing CHP projects were developed and built between 1982 and 1990, under 20- to 30-year contracts which provided for the sale of excess electricity to the local utility. These long-term power purchase contracts enabled cogeneration plants to make firm commitments to supply power and steam to their host industrial and institutional facilities. Unlike the utilities, the developers of CHP projects bore all of the permitting, financing, and construction risks associated with the timely completion of these plants. Also unlike utility plants, ratepayers pay for power from CHP plants only if the power is actually produced and delivered to the purchasing utility.

3. The Benefits of CHP for California

California derives substantial benefits from its indigenous CHP resources, beyond the electric capacity and energy that these projects sell to the utilities. Many of these benefits can be quantified, as the CCC discusses below.

a. Efficiency

As it has since the 1980s, CHP technology continues to represent a clean, efficient use of natural gas to produce two types of useful energy. The FERC efficiency standards for cogeneration QFs ensure that such projects produce, sequentially, significant amounts of both

[11] In California, this Commission found that the utilities had erected barriers to QF development, including to the development of cogeneration projects. *See* D. 91109 and D. 91107. In response, the Commission took the further step of developing "standard offer" power purchase contracts, available to any QF, that governed the terms of QF power sales to the utilities. *See* D. 82-01-103 and D. 82-12-120.

[12] *See* D. 82-12-055, at 200.

power and useful thermal energy.[13] Cogeneration reduces natural gas use by 20% to 40%, compared to the separate production of the same amounts of thermal and electric energy. The efficiency with which cogenerators use natural gas supplies is particularly important given the surge in natural gas prices since 2003 and the increasing concerns over the adequacy of the North American gas supply. Based on Energy Information Administration data, I estimate that cogeneration reduces California's natural gas demand by about 527 MMcf/d (192 million MMBtu per year), compared to the demand for gas if the same amount of electric and thermal energy were produced separately.[14] These gas savings represent about 10% of the state's overall gas demand,[15] and alone are enough to generate more than 26,000 GWh of electricity each year in 3,400 MW of new combined-cycle generating plants. This is enough electricity to power over 4 million homes in California. Viewed from another perspective, the annual gas savings from existing cogeneration facilities in California are almost 100 times the first-year gas savings expected from the aggressive new natural gas efficiency programs that the CPUC approved in 2004.[16]

The natural gas savings from cogeneration benefits all gas consumers, by reducing the price of gas across the entire market. A recent study by the Lawrence Berkeley National Laboratory examined a wide range of studies on the natural gas consumer benefits resulting from renewable electric generation and energy efficiency programs.[17] LBNL concluded that the regional benefits for gas consumers from renewable energy and energy efficiency in California are roughly $5 per MWh of renewable energy production and $1 per MMBtu of conserved natural gas. Based on the latter figure and the 192 million MMBtu per year in gas savings from CHP projects in California, the state's cogeneration facilities produce $192 million per year in

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[13] *See* 18 CFR §292.205.

[14] This calculation is based on a three-year (2002 - 2004) average of annual gas use for cogeneration in California, as reported to EIA, and assumes that cogeneration reduces natural gas use by 30% compared to the separate production of steam and power. An example of the efficiency benefits of CHP is provided in the study "Natural Gas Impacts of CHP," by Joel Bluestein, Energy & Environmental Analysis, Inc on behalf of USCHPA (October 2003). See http://uschpa.admgt.com/CHP_GasOct03.pdf. EIA data on cogeneration fuel use may be found at the weblink: http://www.eia.doe.gov/cneaf/electricity/page/eia906_920.html.

[15] The *2004 California Gas Report*, at page 9, projects the state's gas demand in 2004 to be 5,338 MMcf/d, including both loads served by California gas utilities and loads in the state served directly from interstate or private pipelines..

[16] Attachment 9 to D.04-09-060 cites natural gas savings of 2.1 million MMBtu per year. See http://www.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/40212.htm

[17] R. Wiser, M. Bolinger, M. St. Clair, "Easing the Natural Gas Crisis: Reducing Natural Gas Prices through Increased Deployment of Renewable Energy and Energy Efficiency" (LBNL-56756, January 2005), available at http://eetd.lbl.gov/EA/EMP.

lower natural gas bills for all California gas consumers.

b. Environmental

Cogenerators provide significant environmental benefits. The air emissions from producing power and steam sequentially are much lower than if both forms of energy were produced separately. The efficiency of cogeneration projects conserves natural gas and results in a substantial reduction in net carbon emissions, compared to the separate production of the useful thermal and electric output. The CPUC recently approved a range of $8 to $25 per ton for the cost of carbon dioxide (CO_2) emissions, for use in future evaluations of electric utility procurement options.[18] Accordingly, these values can be used to quantify the environmental benefits of the state's cogeneration resources, compared to the separate, less efficient production of their electric and thermal output. Based on 192 million MMBtu per year in conserved natural gas from cogeneration facilities in California, the annual carbon benefits from cogeneration range from $100 to $330 million.[19]

c. Economic benefits

Cogenerators are an in-state resource whose combined production of thermal and electric energy supports important segments of the California economy. CHP projects reduce the cost of energy to industry in California, thus helping to maintain the competitiveness of the state's economy in regional, national, and global markets. Cogeneration is used in most of the state's oil refineries, and is widespread in the petroleum production, mining, paper products, and food processing industries. In 2003, these five industries together employed 290,000 Californians. In addition, many large institutions – universities, hospitals, and prisons – also have CHP facilities to serve on-site demand for both thermal and electric energy.

A simple example illustrates the importance of cogeneration to the California economy. According to the Commission, Californians consumed 16 billion gallons of gasoline in 2003 (or 2 billion MMBtu at 125,000 Btu per gallon).[20] Virtually every refinery in the state uses CHP to save energy in the process of refining crude oil into gasoline and other petroleum products. The petroleum industry reports that refining a barrel of crude oil into gasoline and other petroleum

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[18] *See* D. 04-12-050, at 156.

[19] These benefits include both the reduced CO_2 emissions from not burning the conserved natural gas and the reduced methane emissions from reduced losses of methane to the atmosphere during the production, processing, and transportation of natural gas.

[20] According to monthly CEC data (see http://www.boe.ca.gov/sptaxprog/spftrpts.htm), Californians purchased 15.9 billion gallons of gasoline in 2004. See also page 10 of http://www.energy.ca.gov/papers/2004-02-09_PEREZ_NASEO.PDF for a graph of California demand for gasoline.

products requires energy equal to about 10% of the energy in that barrel of crude. Assuming that cogeneration results in a 30% savings in the amount of energy used to refine a gallon of gasoline, cogeneration saves 60 million MMBtu per year in the production of gasoline alone. Given natural gas prices of $6.50 per MMBtu, cogeneration reduces the cost of producing the state's gasoline by $390 million per year, or about 2.4 cents per gallon. These are the economic benefits of CHP in just one sector of one industry – CHP undoubtedly provides hundreds of millions of dollars of economic benefits in other industries as well.

d. Reliability

Most cogeneration projects in California have operated reliably for many years under standard offer QF contracts. The IOUs have many years of performance data for such projects. These are resources that are ready, willing, and able to supply power to California. In fact, the Commission's *2003 Integrated Energy Policy Report* recently observed that, during the 2000 - 2001 energy crisis,

> *. . . despite not being paid for generation as a result of the adverse financial condition of the IOUs, cogeneration and renewable facility operators maintained relatively high levels of availability and were largely responsible for keeping the lights on during the darkest days of the crisis.*[21]

e. Distributed and deliverable generation

QFs represent the bulk of the state's distributed generation. Cogeneration QFs are widely distributed geographically, and many are located in or near load centers. As a result, they increase the stability and reliability of the state's electric grid. The CPUC recently has placed increased emphasis on the **deliverability** of electric resources, and has charged the IOUs to assume greater responsibility for ensuring that they have adequate supplies of local generation dedicated to serve the loads in their service territories. In this regard, the focus of the Commission's concern has been to ensure that there is adequate local generation to serve Edison's Los Angeles Basin loads, because the ISO has experienced constraints moving out-of-basin generation into Edison's load center under high demand conditions.[22] The CCC notes that cogeneration QFs are a vital component of the in-basin resources dedicated to serving Edison's loads: there are 2,060 MWs of cogeneration QF resources under contract to Edison in the Los Angeles Basin. Similarly, the CCC estimates that 1,425 MWs of PG&E's and 240 MW of SDG&E's CHP resources are

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[21] CEC, *2003 Integrated Energy Policy Report* (December 2003), at 7; hereafter, the *2003 IEPR.*

[22] *See* D. 04-07-028, issued in R. 04-04-003 on July 8, 2004.

located in the major load centers of these utilities.[23]

Because they provide reliable, local generation in the load center, cogeneration QFs avoid the need for the ISO to contract for additional Reliability Must-Run (RMR) generation.[24] But for QF production, the ISO would need to purchase more RMR capacity in certain areas of its grid. As a result, QFs allow the ISO to avoid the need for the capacity payments associated with additional RMR generation. In 2005, the IOUs expect to spend $573 million to contract for 9,468 MWs of RMR generation, for an average cost of $60.50 per kW of RMR generation. Assuming that the 3,725 MWs of QF generation in the load centers of the three IOUs allow them to avoid additional RMR purchases, QFs allow the IOUs to avoid $225 million in annual RMR costs.

f. Resource diversity

QFs have greatly increased the diversity of the state's electric supply. QFs avoided the construction of additional central station coal and nuclear power plants, similar to the Diablo Canyon and SONGS plants that were built in the 1980s. Such central station plants were very expensive and produced substantial above-market costs. Although California ratepayers did incur above-market costs for QF generation developed during the 1980s, these above-market costs were principally the result of the ten years of fixed energy prices paid to renewable QFs under Interim Standard Offer No. 4 (ISO4). Cogeneration QFs were allowed to elect energy payments based a maximum of 20% on the high ISO4 fixed prices, and very few elected to do so.

g. Lack of market power

Furthermore, the small size, diverse ownership, and geographic dispersion of QF facilities

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[23] Based on the CEC's 2004 database of generation facilities in California, which is available at www.energy.ca.gov/database/index.html#powerplants. The Los Angeles Basin is defined as the counties of Los Angeles, Orange, San Bernardino, Riverside, and Ventura. PG&E's cogeneration QFs that avoid RMR costs are assumed to be located in Alameda, Contra Costa, Fresno, Santa Clara, San Joaquin, and San Mateo counties. SDG&E's cogeneration QFs that avoid RMR costs are those located in San Diego County.

[24] The ISO calculates its need for RMR power assuming that all QFs in a particular area are operating at firm contract capacity or, for as-available QFs, at historical output levels. Furthermore, the ISO treats the generation of small QFs (many of whom have SO1 / SO3 contracts with as-available capacity payments) as a reduction in the nearest load. As a result, the ISO does not consider QFs to be eligible for RMR contracts, unless the QF can show that it is not contractually obligated to be on-line absent an RMR agreement. For example, *see* the ISO's *"Request for Proposals to Provide 2004 Local Area Reliability Service to California ISO,"* California ISO, May 21, 2003, at 2. This document is available on the ISO's website at www.caiso.com/docs/09003a6080/22/45/09003a608022450d.pdf.

means that QF power does not present the same market power concerns as large merchant generators. The CPUC regulates the short-run avoided cost prices paid to QFs in California, and is working to develop long-run avoided cost prices that could be applied to purchases of QF power under new long-term standard offer contracts.

h. Conclusion on the benefits of CHP

The benefits of California's existing CHP resources are substantial; together, the magnitude of just the benefits that I have quantified above exceed $1 billion per year. Importantly, these benefits are **not** included in the avoided cost prices for the energy and capacity that CHP projects sell to the IOUs, and the CCC does not recommend that they be included. However, the clear conclusion that the Commission should draw from these significant benefits is that utility purchases of power from CHP facilities is a bargain at avoided cost prices. These benefits are the reason that state policy has long supported the development of cogeneration projects in California. For example, Public Utilities Code Section 372 provides:

> *. . . It is the policy of the state to encourage and support the development of cogeneration as an efficient, environmentally beneficial, competitive energy resource that will enhance the reliability of local generation supply, and promote local business growth.*

4. Threats to California's CHP Resources

State energy policy should focus on preserving the state's substantial existing CHP resources, as well as on promoting **new** CHP development. The long-term survival of existing CHP projects is by no means assured. The amount of QF generation under contract to the IOUs has begun to decrease, principally due to the fact that some QF projects – for example, projects developed in the early 1980s that signed 20-year power purchase contracts – are reaching the end of the terms of their original contracts with the IOUs. Most of the QF projects with 20-year contracts are CHP facilities. QF contract terminations will increase in the coming years, as more QFs reach the end of their original contracts.[25] The IOUs' contracted QF capacity will begin to decline more sharply after this year, as a result of the termination of the large cohort of QF contracts with 20-year terms for projects that began operations between 1985 and 1990.

In formulating the state's energy plan, the Commission should be aware of the escalating trend of contract terminations involving CHP QFs. California needs to retain these indigenous, efficient, and reliable generation supplies. Recent CEC data shows that southern California's electric reserve margin will fall well below 7% this summer in a 1-in-10 hot summer; by 2008

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[25] *See* D. 04-01-050, table at 136. This order notes that "by 2008, expired QF contract capacity is expected to exceed 1,000 MW and approach 1,800 MW by 2010," and that "SCE is projected to lose most of its QF capacity during this time period."

northern California will face the same situation.[26] In such forecasts, the state appears to be planning to continue to rely on generation at current levels from existing QFs. However, if California is to retain the full benefits of its QF resources, this Commission and the IOUs must act to offer viable procurement options to cogeneration QFs

5. Barriers to CHP in California

The CCC strongly agrees with the CEC's Draft CHP Assessment that a principal barrier to increased use of CHP in California is the lack of a long-term means for CHP projects to market their power at the wholesale level.[27] This is the critical issue, in the CCC's view, for both existing and new CHP projects. The CCC also is concerned with the increasing complexity of the energy market and regulatory structures in California

a. Lack of a long-term market for CHP power

Cogeneration QFs do not have realistic options for selling their output, except for a QF contract with their serving utility. The utilities have argued that community choice aggregation, direct access, and bilateral wholesale market sales provide options for the sale of CHP power. However, today these other options provide little opportunity for most cogeneration QFs:

- **Community choice aggregation.** The CPUC is still developing the rules for community choice aggregation; although there is interest in this option, it is not yet a real opportunity.

- **Direct access.** The direct access market is beginning to constrict, due to the deteriorating economics of direct access service. The state has yet to act to re-open that option for customers that now take bundled utility service.

- **Wholesale market.** The bilateral wholesale market today is a small economy-energy market, has volatile prices, lacks transparency on a day-ahead basis, and often does not respond directly to natural gas price changes. There a very few, if any, gas-fired CHP QFs whose original IOU contracts have expired and who are operating in California today on the basis of sales of excess power into the bilateral wholesale market, without a contract with an IOU.

Cogeneration QFs whose contracts have terminated or expired have either shut down or have signed Standard Offer No. 1 contracts under the provisions of recent CPUC orders that

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[26] *See* the CEC/CPUC/CAISO "California's Electricity Situation: Summer 2005" (February 22, 2005), at slides 16 and 17. This analysis is available on the CEC website, at http://www.energy.ca.gov/electricity/2005_summer_forecast/2005-02-22_SENATE_PRESENTATION.PDF.

[27] *See* Draft CHP Assessment, at xv.

require to IOUs to make SO1 contracts available with short-run avoided cost prices and terms of up to five years.[28] Even more important, the availability of long-term contracts is vital if existing CHP projects are to make new capital investments in upgrading or repowering their facilities.

The utilities continue to argue that QFs should be limited to the option of bidding their power into the IOUs' procurement solicitations. The reality is that most cogeneration QFs are unlikely to be able to win a contract in a utility's solicitation if that is their only option.[29] The utilities' resource plans state that their primary need is for firm, dispatchable resources. CHP projects certainly can provide firm capacity during summer peak periods; however, most cogeneration projects also need to operate during most or all other hours in order to be a reliable provider of thermal energy. Thus, CHP projects have difficulty providing purely dispatchable power. However, unless a CHP project can provide dispatchable power, it is unlikely to be selected as a winner in an IOU solicitation. A cogenerator thus is faced with either: (1) having to arrange to sell its power on a short-term basis during the hours when it is not dispatched by the utility or (2) operating its generating facility as a dispatchable peaker, while installing steam boilers to produce the required thermal energy. With respect to the first option, many CHP projects do not have the ability or expertise to market their power on a short-term basis. The Draft CHP assessment concludes that the difficulties in "scheduling hour-by-hour exports with the CAISO, and finding an electricity buyer" are key impediments to developing the potential 5,200 MW of new large CHP projects in California.[30] The second option fails to capture for California the efficiency benefits of cogeneration.

The utilities have complained that new contracts to purchase baseload CHP generation will force them to purchase power that they do not need in off-peak, low-demand hours. In the CCC's view, this issue is best handled through the price that CHP projects are paid for their power sales. If the price is set correctly to reflect the utility's avoided cost during off-peak hours, then ratepayers are indifferent financially to the purchase of CHP power at those times.

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[28] *See* D. 02-08-071, D. 03-12-062, or D. 04-01-050.

[29] In fact, many of the procurement solicitations that the IOUs have conducted since 2002 have included 25 MW minimum size requirements for bidders, which eliminates most QFs from even participating. For example, Edison issued Request for Offers (RFOs) in September 2002, May 2003, April 2004, and recently released a new draft RFO. All of these RFOs imposed a 25 MW minimum on the amount of capacity that a bidder could provide. 79% of the QFs under contract to Edison today have a contract capacity less than 25 MW. As a result, almost four-fifths of Edison's QFs would not even qualify to bid in response to the RFOs that Edison has issued over the past three years. Edison's July 9, 2004 Resource Plan "encourages" cogeneration QFs to bid into all-source solicitations for which many would not even qualify!

[30] Draft CHP Assessment, at xv to xvii and 6-1.

b. Complexity of California's energy markets & regulations

The CCC is not surprised that the Draft CHP Assessment finds "the hassle factor" to be a significant issue for potential CHP customers.[31] It is a significant hurdle for many businesses to devote money and management attention to energy issues that are beyond the organization's core competency; this barrier is heightened by the complexity of the "hybrid" structure of the California market and the increasingly number of regulations with which generators must contend. The CCC notes below just a few of the ways in which this increased complexity can impede CHP development:

- **Dealing with the CAISO.** In the 1980s, CHP projects only had to deal with their serving IOU on interconnection, scheduling, and operational issues. Today, the CAISO's operation of most of the state's bulk power facilities has introduced another layer of potential complexity into these issues. Unfortunately, the CAISO's institutional focus has been on the large merchant generators, power marketers, the California utilities, and other interconnected utility systems. The CAISO has not devoted significant attention to streamlining its regulations or procedures to accommodate large numbers of small, distributed generators. The CCC does not fault the CAISO for this lack of attention to small generators, given the difficult times in which the CAISO has had to function since 1998. The CCC also believes that the IOUs could function as the interface between CHP projects and the CAISO - for example, by acting as the scheduling coordinator (SC) for CHP projects that sell excess power to the IOUs. Although the IOUs have served as SCs for their QF resources since 1998, the utilities have been reluctant to serve as SCs for QFs with new contracts.

- **Exit fees.** New CHP projects that serve on-site loads are subject to the payment of certain "exit fees" related to cost incurred during the 2000 - 2001 energy crisis. A limited number of exemptions are available for the largest component of these exit fees, the costs of the long-term Department of Water Resources (DWR) contracts. A project's ability to obtain such exemptions has added another layer of risk and complexity to CHP project development in the state.

- **Implementation of new standby rate policies.** During the energy crisis, the CPUC began a process to review its policies concerning the design of utility standby rates, in an effort to promote distributed generation. The CPUC issued an order in July 2001 that set forth new standby rate policies (D. 01-07-027), and directed the IOUs to file applications with new standby rates. However, rather than processing those applications, the CPUC has left the implementation of new standby rates to subsequent utility general rate cases, which has resulted in the staggered, piecemeal implementation of the new policies. PG&E's standby rates have yet to be revised, almost four years after D. 01-07-027.

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[31] *Ibid*, at Table 4-2, page 4-5.

c. Examples of missed opportunities

The CCC presents in **Attachment 4** two examples of opportunities that have been missed to increase the CHP capacity of CCC member companies. These examples emphasize the important need to develop a long-term contract for sales of excess CHP electric production to the California utilities.

6. Policies to Promote CHP in California

The CCC recommends that the Commission's IEPR should endorse the following policies to promote the retention of California's existing CHP capacity and the development of the state's significant potential for new CHP projects.

- **New Long-term IOU Contracts for CHP QFs.** The Commission should encourage the CPUC to require the utilities to offer CHP projects new standard contracts to provide long-term, firm baseload capacity to the IOUs at long-run avoided cost prices, for terms of 10, 15, or 20 years. These contract terms are identical to those approved for RPS contracts for new renewable generation, and reflect the fact that many cogeneration facilities appear to have useful lives well beyond their initial 20-year QF contracts. Most important, the state appears to need firm baseload power in the years after 2008. New long-term contracts are absolutely required if existing CHP facilities are to make new investments to prolong their useful lives, to meet new environmental standards, or to repower to produce additional energy.[32] The CPUC should require the IOUs to offer new long-term firm-capacity contracts to CHP projects so long as the amount of cogeneration resources under contract to the IOU is equal to or less than 125% of the amount of cogeneration QFs under contract to the IOU on January 1, 2003.

- **Place CHP in the Second Element of California's "Loading Order."** The Commission should support a policy that distributed CHP resources are encompassed within the second element in the "loading order" in California's Energy Action Plan – "renewable energy resources and distributed generation."[33] The utilities should be required to procure power from CHP projects in preference to other gas-fired or fossil-fueled generation purchased through the utilities' all-source procurement procedures.

- **A CHP Development Goal.** California should adopt a policy to ensure that the utilities retain the existing level of cogeneration resources now dedicated to their systems, and to

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[32] For example, Delta Power's Carson repowering project was able to justify its $11.5 million upgrade due to the 17 years that remain on its 30-year power purchase contract with Edison. Without the assurance of the long remaining term of its Edison contract, Delta would not have been able to undertake this investment.

[33] *See* the Energy Action Plan (adopted in April / May 2003), at 4.

set a goal to expand these levels by 25 percent by 2010, in order to preserve and to grow the benefits of these important distributed generation resources. This is a modest goal in light of federal initiatives designed to double the level of CHP resources nationally by 2010,[34] and the much greater potential for CHP development set forth in the Draft CHP Assessment and other studies.

7. Conclusion

The CCC urges the Commission to recognize the many benefits of California's CHP resources. These comments have attempted to focus on the benefits of the state's existing CHP resources; the Draft CHP assessment is an excellent effort to understand the benefits of new CHP development. In order to secure those benefits, the CCC urges the Commission to incorporate the recommendations presented above into its IEPR. The CCC appreciates the opportunity to present these comments.

Respectfully submitted,

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On behalf of
CALIFORNIA COGENERATION COUNCIL

April 27, 2005

[34] The U.S. Department of Energy's Office of Energy Efficiency and Renewable Energy ("EERE") has been working on a number of fronts to support increased use of CHP technologies. In December 1998, the Assistant Secretary for Energy Efficiency and Renewable Energy issued a "CHP Challenge" calling on industry and government to work together to double the capacity of CHP in the U.S. by 2010. More recently, the "National CHP Roadmap: Doubling Combined Heat and Power Capacity in the United States by 2010" was published in March 2001 by the United States Combined Heat and Power Association, in cooperation with the U.S. Department of Energy and the U.S. Environmental Protection Agency. The goal is to double the amount of CHP capacity in the U.S., by 2010, as compared to 1998 levels. This means adding approximately 46 GW of new CHP installations. *See* http://uschpa.admgt.com/fed_inits.htm.

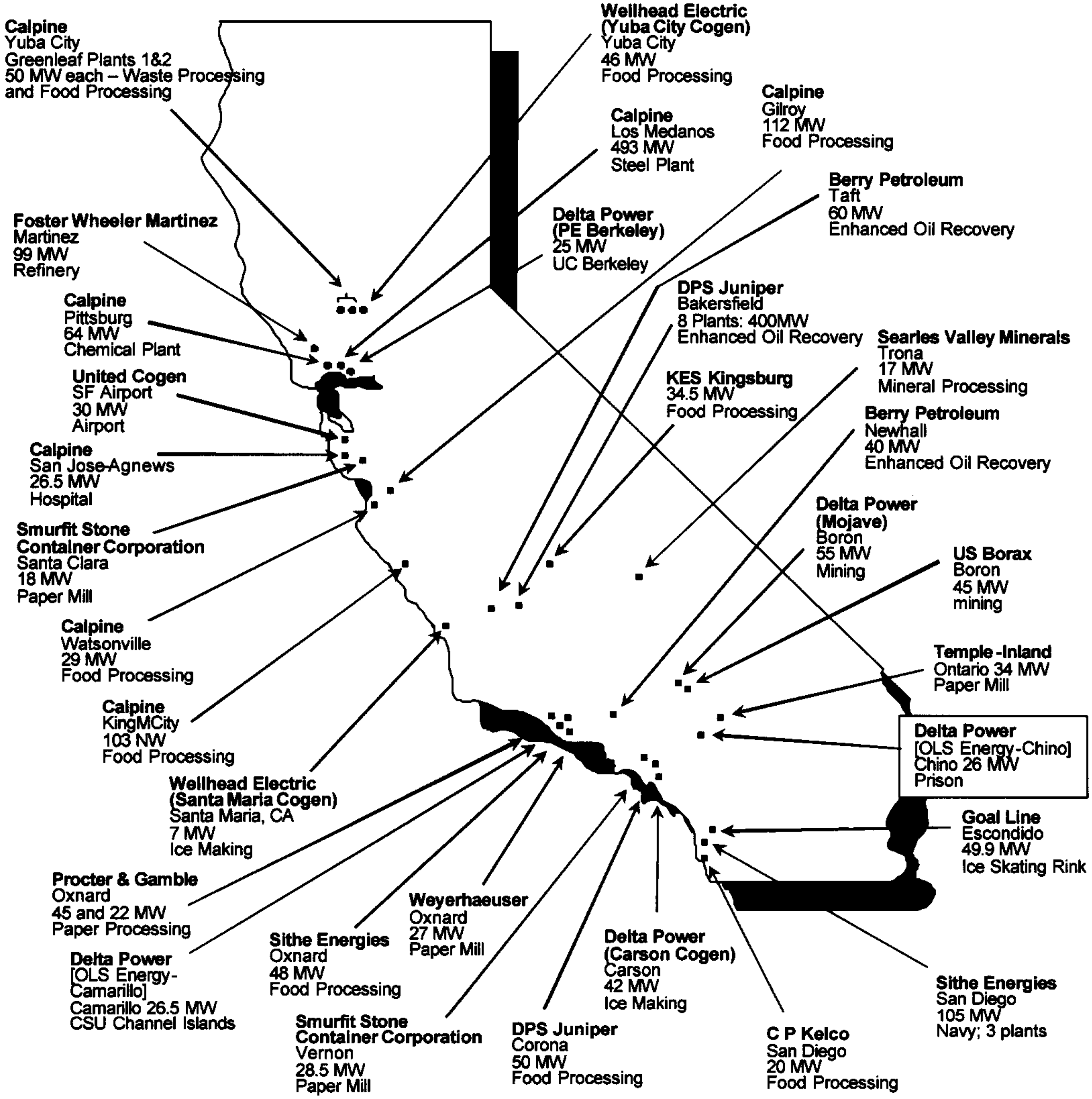
Attachment 1:

Map of CCC's CHP Projects

CALIFORNIA COGENERATION COUNCIL
A Combined Heat and Power Association

Combined Heat and Power Facilities Energize California with Clean, Reliable Power

The California Cogeneration Council (CCC) represents operating cogeneration facilities located throughout the state. These Combined Heat and Power facilities are integrated into schools, hospitals, food processors, paper manufactures and other diverse California businesses. CCC member companies operate 32 different cogeneration projects, which produce nearly 2,000 megawatts of electricity—enough power to serve more than 2 million homes. CCC members use only clean-burning natural gas to generate power.



For information, contact Maureen Lennon, Executive Director - mlennon@whitecase.com – 213.620.7742

Attachment 2:

Energy and Environmental Analysis, “Natural Gas Impacts of Increased CHP” (October 2003)

ENERGY AND ENVIRONMENTAL ANALYSIS, INC.

Natural Gas Impacts of Increased CHP

Submitted to:
U.S. Combined Heat and Power Association

October 2003

Submitted By:
Energy and Environmental Analysis, Inc.
1655 N. Fort Myer Drive, Suite 600
Arlington, Virginia 22209

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Executive Summary

Recent increases in natural gas prices have raised concerns about the balance of U.S. natural gas supply and demand. While there are efforts to increase gas supply, there is agreement that increased efficiency will be a primary requirement to address the issue in the near to medium term. Although combined heat and power (CHP) is among the most immediately available and widely applicable efficiency options, the fact that it involves the installation of new gas-fired equipment may raise concerns about its ability to reduce overall gas consumption.

The United States Combined Heat and Power Association (USCHPA) asked Energy and Environmental Analysis, Inc. (EEA) to investigate the implications of increased CHP on natural gas markets and demand. EEA prepared an initial analysis focusing on three markets:

- The Northeast (New York and New England)
- Texas
- California

These three regions have historically been high CHP users, have a high concentration of gas-using industries and a gas-intensive electricity sector. These three regions account for approximately 40 percent of U.S. gas consumption. All of these factors make them good candidates for an initial analysis of the gas impacts of increased CHP. If the impacts are small in these regions, they would likely be even smaller in other regions. On the other hand, if the impacts are significant here, it would be worth analyzing other regions.

EEA first estimated the technical potential for new CHP in these regions based on the commercial and industrial sector populations and the availability and suitability of CHP equipment. EEA used assumed market penetration rates ranging from 5 to 50 percent as a function of size and application to estimate the probable penetration of CHP in these markets. Table ES-1 summarizes the assumed penetration for new CHP facilities compared to existing CHP and central grid generation. The assumed new CHP is about half of the existing CHP capacity.

The consumption of gas and generation of steam and electricity for the projected CHP facilities were calculated using five technology characterizations for different sized systems using combustion turbine and reciprocating engine technology. The gas displaced by the CHP facilities was calculated as the fuel required by conventional separate generation (onsite boiler and electric grid) to produce the equivalent CHP system thermal and electric generation. All of the new CHP facilities were assumed to be gas-fired. The energy consumption avoided in on-site boilers was also assumed to be gas-fired for Texas and California. For the Northeast, the avoided on-site gas consumption was assumed to be 66 percent gas (due to high oil use in the region). The extent of gas utilization in the displaced electric grid generation was assessed separately. EIA and FERC data on electricity markets and fuel mix were used to determine that all of the displaced electric generation would be gas-fired in the California and Texas markets while 87 percent of the displacement in the Northeast would be gas-fired.

Table ES-1
Comparison of Assumed CHP Penetration

	California		Texas		Northeast	
	Units	MW	Units	MW	Units	MW
Existing Grid	1,442	54,574	504	39,508	2,032	68,354
Existing CHP[1]	795	9,438	135	15,639	414	8,708
Assumed CHP Additions	3,190	5,071	2,284	5,297	3,503	4,238

Table ES-2 summarizes the natural gas demand reduction achieved through the assumed increased use of CHP. The demand reductions range from 4 to 9 percent of the existing gas consumption in each region, averaging 6.4 percent across the three regions. Other analyses have shown that national gas demand reductions in this range can result in much greater percentage reductions in gas price. In addition, due to the integrated national nature of natural gas markets, regional reductions in gas demand affect the national price of natural gas.

Table ES-2
Gas Reduction Comparison
(MMcf)

	Northeast	Texas	California
Current Gas Consumption ('01)	1,892,059	3,915,959	2,404,176
Gas Displacement from CHP	78,546	235,526	215,247
Percent Reduction	-4.2%	-6.0%	-9.0%

While this analysis took a simplified approach, there is no reason to expect that a more rigorous approach would yield significantly different results. In addition, the results could be different in other regions of the country due to different potential market sizes for CHP and particularly due to different fuel mix characteristics of the power generating system. While some regions are more reliant on coal generation and would be likely to show less gas displacement in the power generation sector, others are more similar to the regions already analyzed and will likely show similar gas reduction results. The overall effect is expected to be a net national reduction in gas consumption.

This study indicates that achievable increases in CHP utilization can have a significant effect to reduce natural gas consumption and an even larger effect to reduce gas prices. These results could be verified through a more detailed analysis or extended through evaluation of additional

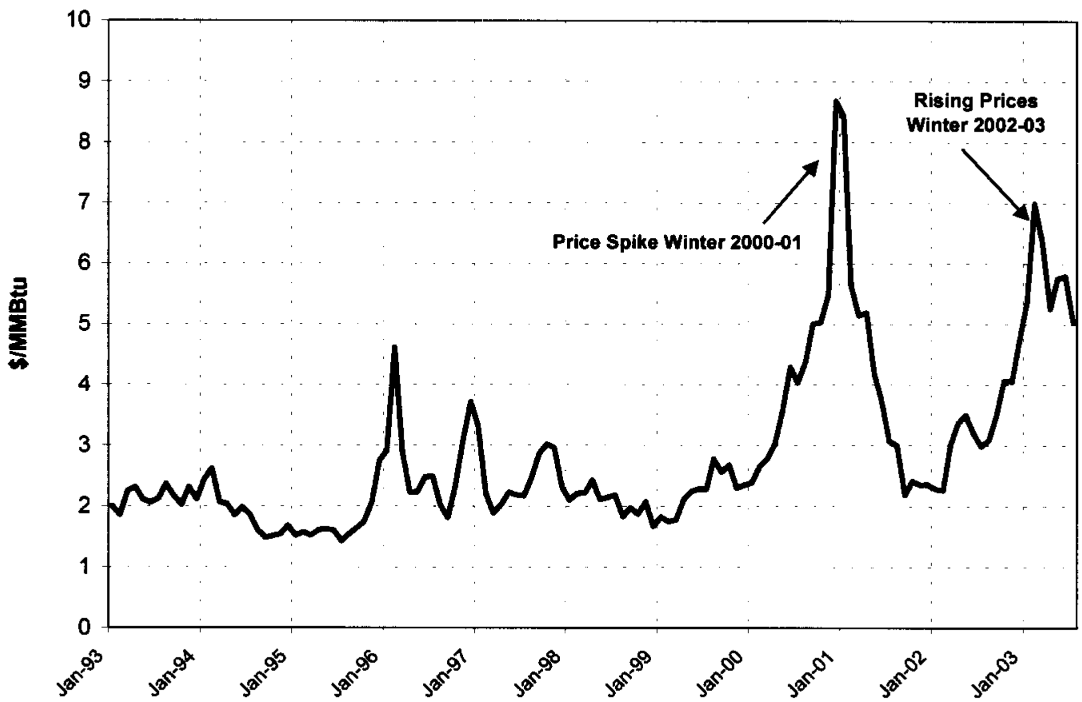
[1] Existing CHP data from EEA 2003 database of U.S. CHP installations.

regions. A variety of policy and regulatory measures could be used to promote the increased use of CHP to achieve these benefits.

1 Introduction

The last few years have seen short term spikes in natural gas prices and now a sustained period of higher gas prices (Figure 1). There is increasing concern over the price of U.S. natural gas and the ability of the natural gas industry to supply the increasing demand for gas, largely driven by gas consumption for power generation. There is wide consensus that little can be done to increase gas supply in the short term due to the long lead time needed to develop new gas production. Longer term supply increases will require very large investments and additions to U.S. energy infrastructure. Given this, there is also wide consensus that increased efficiency will be a primary method of improving the natural gas supply/demand balance.

Figure ES-1
Natural Gas Price at Henry Hub
($/MMBtu)



Combined heat and power (CHP) is one of the most readily available and widely applicable methods of increasing efficiency for electric and thermal generation. In the current situation, the USCHPA is interested in a general question: What is the impact of increasing use of CHP on natural gas markets? This question leads to several related questions:

- Will increased use of CHP increase or reduce overall demand for natural gas?

- What are the key factors affecting the potential change?
- How large a change would result?
- Are there other infrastructure effects?

The goal of this project is to provide a quick, first cut assessment of the potential and lay the groundwork for a more detailed assessment if the initial results are positive.

Chapter 2 of this report provides some background on CHP. Chapter 3 presents the methodology and results of the analysis. Chapter 4 presents some conclusions and implications of the analysis.

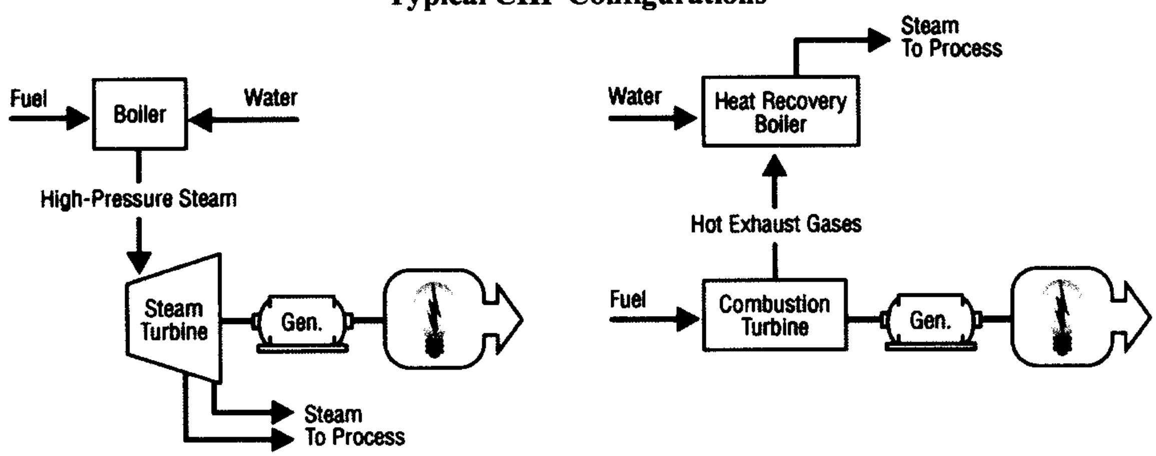
2 CHP Background

Combined heat and power (CHP) is the sequential generation of electric and thermal energy from a common energy source. CHP is recognized as a highly efficient and environmentally beneficial technology. It has been specifically singled out for encouragement by the U.S. Environmental Protection Agency and Department of Energy, which have committed to doubling U.S. CHP capacity between 2000 and 2010. CHP was also highlighted in the Presidential National Energy Policy Document in 2003. This chapter provides some background on CHP technology and benefits.

2.1 CHP Configurations

There are two common configurations for CHP system, shown in Figure 2-1. The steam boiler/turbine approach historically has been the most widely used CHP system. In this approach, a boiler makes high-pressure steam that is fed to a turbine to produce electricity. However, the turbine is designed so that there is steam left over to feed an industrial process. Thus, one fuel input to the boiler supplies electric and thermal energy by recovering waste heat from the steam turbine electric generator. Typically, two thirds of the energy in a conventional power plant is lost when waste steam is condensed in the cooling tower. This type of system typically generates about 5 times as much thermal energy as electric energy. Steam boiler/turbine systems are widely used in the paper, chemical and refining industries, especially when there is waste or byproduct fuel that can be used to fuel the boiler.

Figure 2-1
Typical CHP Configurations



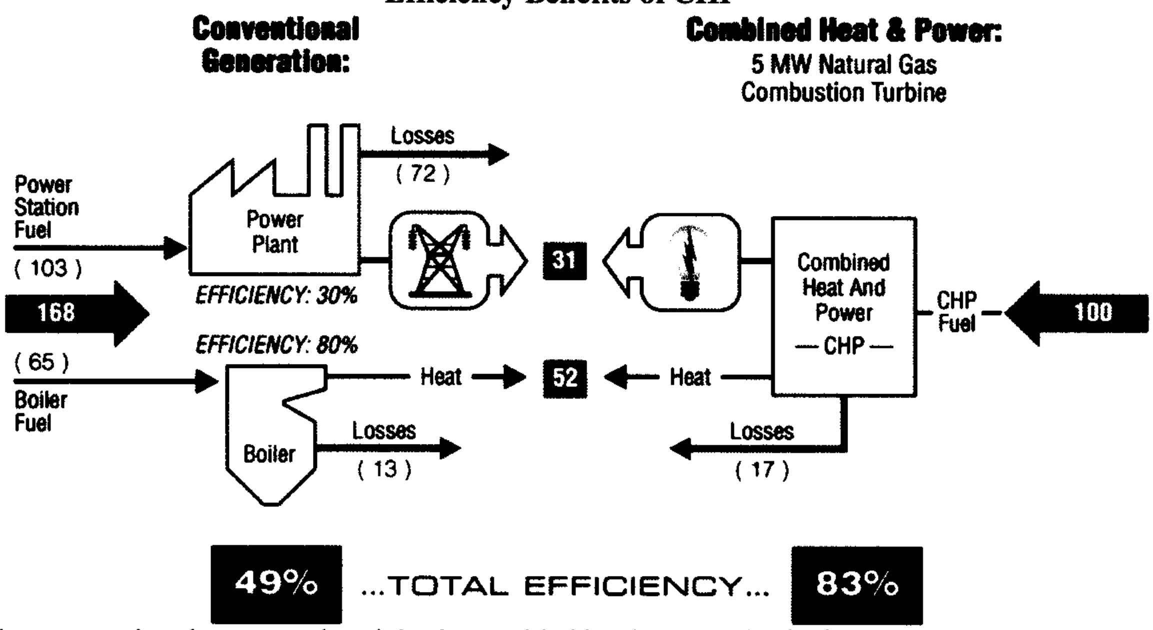
In newer CHP systems, a combustion turbine or reciprocating engine is used to generate electricity, and thermal energy is recovered from the exhaust stream to make steam or supply other thermal uses. Turbines and engines have become the dominant CHP technologies in recent years as their cost and performance have improved. These types of CHP systems can use very large (hundreds of MW) gas turbines or very small (tens of kW) microturbine, engine, or fuel cell systems. In these systems, the thermal energy is typically 1 to 2 times the electric energy generated.

CHP is especially attractive because it can be applied with almost any combustion technology and fuel. This means that it can be applied in many different end uses and can use whatever fuels are economically available. It is a well-known and well-demonstrated technology. The National Energy Policy stresses the importance of increased application of CHP. The U.S. DOE and EPA have set a goal to double the capacity of CHP from a base of 46 GW in 1998 to 92 GW by 2010. With about 77 GW of CHP capacity in place in the U.S. today, the CHP community is well on the way to meeting that goal. Yet there is still substantial work to be done and substantial remaining potential for expansion.

2.2 Efficiency Benefits of CHP

By providing electric and thermal service from a common fuel input, CHP significantly reduces the associated fuel use and emissions. Figure 2-2 compares the efficiency and fuel use of a CHP facility to the efficiency and fuel use from conventional systems providing the same delivered energy service – 31 units of electricity and 52 units of thermal energy (e.g., steam).

Figure 2-2
Efficiency Benefits of CHP



In the conventional system, electricity is provided by the central grid from a power plant that averages 30 percent efficiency, considering turbine generator losses and the transmission and distribution losses (about 8 percent U.S. average). Thermal energy is provided by an on-site boiler that may be as high as 80 percent efficient. Combined, the two systems use 168 units of fuel to provide the energy service. The combined efficiency to provide the thermal and electric service is 49 percent.

In the CHP system, one system located at or close to the point of consumption provides the same combined thermal and electric service by using a prime mover (engine or turbine) to generate electricity and recovering the waste heat from the prime mover to provide the thermal energy. In this case, the CHP system satisfies the same energy demand using only 100 units of fuel. This system is 83 percent efficient.

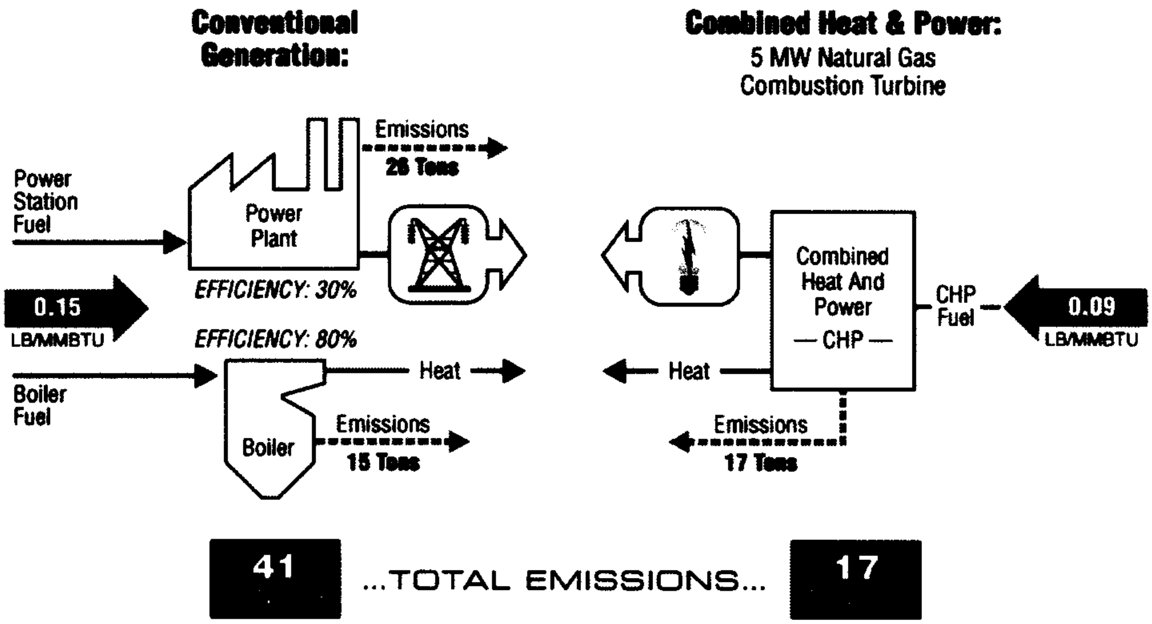
Although the total fuel consumption from the CHP system is lower than for the conventional separate approach, all of the CHP fuel is consumed on-site and the on-site consumption is typically higher than the on-site consumption for the conventional boiler. In calculating the impact on gas consumption, we must assess the amount and type of fuel used in the CHP system vs the amount and type of fuel used in the conventional boiler and central electric generator. Although CHP systems can use almost any fuel, most new systems are natural gas-fired. Most existing on-site boilers are also gas-fired. Thus, most new CHP facilities will result in increased gas consumption on-site. The potential reduction in gas use comes from the displacement of central electric generation. Central electric generation is much more fuel diverse, with the majority of the fossil energy coming from coal. Thus calculating the potential reduction in gas consumption requires an analysis of what fuel is displaced on the central grid. This is discussed in Chapter 3.

2.3 Emission Benefits of CHP

Figure 2-3 shows the emissions benefits of the CHP system. Because it uses nearly 50 percent less fuel, the CHP system has much lower emissions, even if the combustion process has the same emission input-based rates as the conventional equipment. Because new CHP systems often replace old conventional systems, the emission rate for the new system is often lower, further reducing emissions. In the case shown, the CHP system emits about half as much as the conventional system.

In this case, a significant portion of the avoided emissions are from central power plants. The on-site emissions from the CHP system are slightly higher than the original on-site boiler because more fuel is burned. Depending on the characteristics of the boiler and CHP prime mover, the on-site emissions could be higher or lower with CHP than with a conventional system, though the total regional emissions are almost always lower.

Figure 2-3
Emissions Benefits of CHP



3 Analysis and Results

The basic approach to this analysis was to calculate the gas consumed by the increased deployment of CHP in commercial and industrial facilities compared to the gas that would have been consumed by conventional separate generation of the same thermal and electric output. The main steps in this calculation were:

- Estimate potential new CHP installations
- Calculate gas consumption for new CHP capacity
- Calculate avoided gas consumption from displaced on-site boiler and electric generation.

The approach and results are summarized below.

3.1 Potential New CHP Installations

This analysis focused on three regions:

- The Northeast (New York and New England)
- Texas
- California

These three regions have historically been high CHP users, have a high concentration of gas-using industries and a gas-intensive electricity sector. These three regions account for approximately 40 percent of U.S. gas consumption. All of these factors make them good candidates for an initial analysis of the gas impacts of increased CHP. If the impacts are small in these regions, they would likely be even smaller in other regions. On the other hand, if the impacts are significant here, it would be worth analyzing other regions.

The estimate of potential new installations starts with an estimate of the technical potential for new CHP. The technical potential comprises those installations where CHP is technically feasible based on demand for electric and thermal energy and the capabilities of existing CHP technologies. The estimate of technical potential for CHP is based on an analysis of electricity and steam demand at existing commercial (including institutional and multifamily applications) and industrial facilities. Target applications were identified based on electric and thermal energy consumption data for various building types and industrial facilities. Data sources included:

- EIA Commercial Buildings Energy Consumption Survey (CBECS)
- EIA Manufacturing Energy Consumption Survey (MECS)
- The iMarket, Inc. MarketPlace Database
- Market summaries developed by the Gas Research Institute and the American Gas Association

The database of technical potential CHP sites is aggregated by industrial/commercial sector, state, SIC group and unit size. The unit size was split into five categories:

- 50 to 500 kW
- 500 kW to 1 MW
- 1 MW to 5 MW
- 5 MW to 20 MW
- > 20 MW

Table 3-1 summarizes the technical potential for the three regions. The total technical potential is 55,014 MW, including 112,204 facilities fairly evenly divided over the three regions. The average size is 500 kW. The Texas facilities are larger on average, making for slightly fewer facilities than the other two regions. California has a slightly higher total MW potential than the other two regions.

Table 3-1
CHP Technical Potential

	Industrial		Commercial		Total	
	Sites	MW	Sites	MW	Sites	MW
Northeast	11,523	4,369	33,880	13,003	45,403	17,372
Texas	8,719	7,411	19,061	10,412	27,780	17,823
California	16,222	5,929	25,799	13,890	42,021	19,819
Total	36,464	17,709	78,740	37,305	112,204	55,014

The scope of this project did not allow for a detailed economic assessment of CHP penetration. Instead, EEA assumed some reasonable market penetration values for CHP in each size, SIC and sector category. These market penetration values are summarized in Table 3-2. They are lower for the smaller sizes and higher for the larger sizes, reflecting the economies of scale in equipment, project development and host tolerance for alternative infrastructure.

Table 3-2
Assumed Market Penetration Rates

Size	Penetration (%)
50 to 500 kW	5
500 kW to 1 MW	10
1 MW to 5 MW	25
5 MW to 20 MW	50
> 20 MW	50

Applying these factors to the technical potential yields the projected CHP penetration summarized in Table 3-3. It yields almost 9,000 sites and over 14,000 MW. This yields an average system size of 1.5 MW, reflecting the better economics and acceptance of larger size CHP systems. That said, this estimate reflects the development of CHP facilities much smaller than the multi-hundred MW size systems that dominated the CHP market in the 1990s. The mid-size CHP market (4 to 100 MW) represents a large untapped potential for CHP development.

Table 3-3
Assumed Penetration of New CHP

	Industrial		Commercial		Total	
	Sites	MW	Sites	MW	Sites	MW
Northeast	920	1,309	2,584	2,928	3,503	4,238
Texas	830	2,949	1,454	2,348	2,284	5,297
California	1,281	1,702	1,909	3,369	3,190	5,071
Total	3,031	5,960	5,947	8,645	8,977	14,606

Table 3-4 compares this estimated penetration to the existing CHP and central grid capacity in each state. The table shows that these penetration levels are approximately half of the existing CHP levels in the three regions. The much larger number of sites in the assumed new CHP penetration indicates a move towards smaller CHP applications. Mid to smaller sized CHP represents a currently under-addressed market that can now be addressed in part due to availability of new technology. This estimated market penetration forms the basis for the calculation of natural gas impacts.

Table 3-4
Comparison of Assumed CHP Penetration

	California		Texas		Northeast	
	Units	MW	Units	MW	Units	MW
Existing Grid	1,442	54,574	504	39,508	2,032	68,354
Existing CHP	795	9,438	135	15,639	414	8,708
Assumed CHP Additions	3,190	5,071	2,284	5,297	3,503	4,238

3.2 Calculate gas consumption for new CHP

EEA identified CHP technologies and characteristics appropriate for each size range. Table 3-5 summarizes these technologies.

Table 3-5
CHP Technologies

Size Range	50 to 500 kW	500 kW to 1 MW	1 MW to 5 MW	5 MW to 20 MW	> 20 MW
Technology	Gas Recip Engine	Gas Recip Engine	Gas Recip Engine	Gas Turbine	Gas Turbine
Capacity (MW)	0.3	1	3	10	40
Power to heat ratio	0.67	0.92	1.04	0.73	1.07
Elec. Efficiency-HHV (%)	31.0%	34.0%	35.0%	29.0%	37.0%
Heat rate (HHV)	11,010	10,038	9,751	11,769	9,224
Hours per year	4,000	6,000	6,000	8,700	8,700

Based on these technology characteristics and the assumed penetration, EEA calculated the annual gas use for the projected CHP facilities in each region as well as the thermal and electric output from the CHP systems. Table 3-6 summarizes the results of this calculation.

Table 3-6
Gas Consumption and Energy Production

	Northeast	Texas	California
Gas Consumption (MMcf)	322,942	422,626	393,350
Electricity Generation (1,000 MWh)	31,138	41,578	38,234
Steam Generation (million MMBtu)	124.6	161.9	151.5

3.3 Calculate Avoided Gas Consumption From Avoided On-Site Boiler and Electric Generation

The final calculation was the avoided gas consumption from displaced on-site boiler use and electric generation. The first step is to calculate how much fuel would be displaced to generate the same thermal and electric energy generated by the CHP facility. An average boiler efficiency of 75 percent was used to calculate the displaced boiler fuel consumption for the steam generated by the CHP facility.

An average heat rate of 10,000 Btu/kWh was used to calculate the fuel consumption for the electricity generated by the CHP facility. This is actually more efficient than the current average of gas-fired central power plants according to EIA data, slightly underestimating the gas displaced. However, gas-fired generation is getting more efficient with the construction of new combined cycle plants. The fuel consumption for generation also was adjusted for line losses. Since some electricity is lost in transmission and distribution, more electricity must be generated than is used on-site. An average line loss factor of 8 percent was used to adjust for this increase in generation and fuel use, based on EIA data. (Peak losses can be as high 20 percent.)

The last step was to determine what fuel is displaced by the CHP facility. CHP facilities can use a variety of fossil, renewable and byproduct fuels but most new CHP facilities use natural gas. This analysis assumes natural gas fuel for all the CHP cases. This is a conservative assumption since non-gas projects would not increase gas use. Similarly, industrial and commercial boilers can use many different fossil, renewable and byproduct fuels. Most of these boilers that use fossil fuel currently use natural gas. Those that use waste or byproduct fuel are unlikely to switch to gas, since their current fuel is “free”. This is also true, to a lesser extent, for coal-fired due to their lower fuel cost. In addition, many industrial coal boilers already apply CHP.

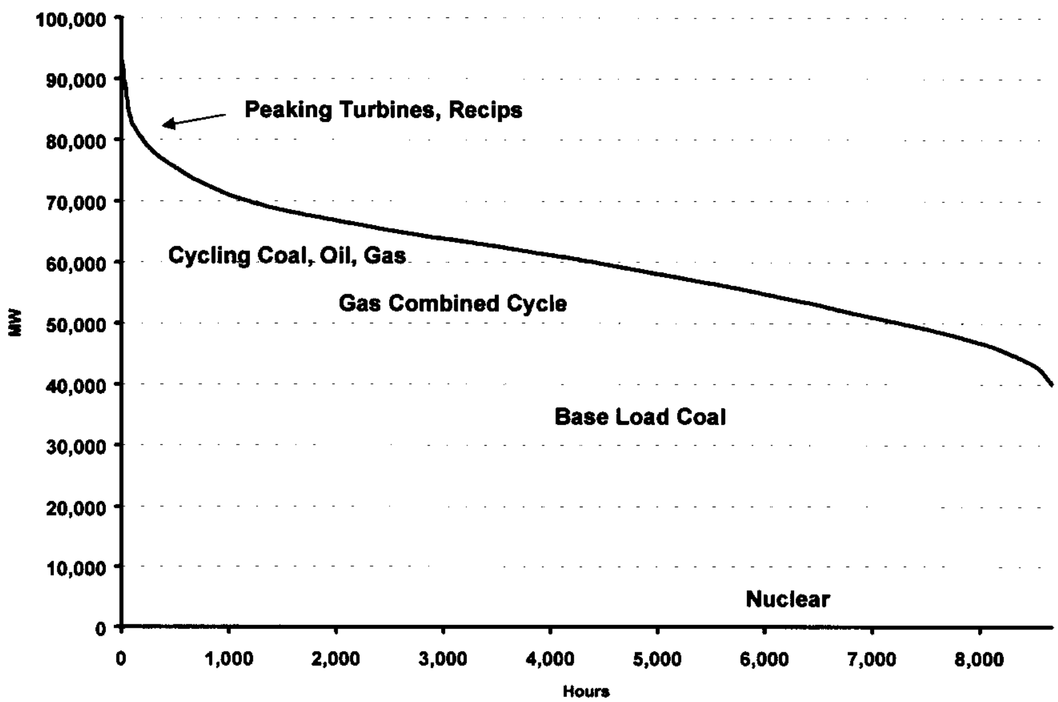
The primary market for new gas-fired CHP considered in this study was gas and oil boilers. EIA and EEA data indicated that there is almost no oil consumption in boilers in Texas and California. However, there is significant oil consumption in the Northeast. The study therefore assumed that all of the avoided energy consumption from boilers was gas for the Texas and

California markets. It assumed that 66 percent of the avoided energy was gas for the Northeast markets.

The assessment of fuel displaced for electricity generation is more complicated. To properly answer this question, one should use an electricity capacity dispatch model to see how the dispatch mix for a given region is changed by the increased CHP generation and what generation/emissions are displaced. While this type of complete analysis is quite complex, we can get many of the same insights, an intuitive understanding of the issues and some useful rules of thumb through a simplified graphical approach to the analysis.

Electric generation is often represented as a load curve that shows the hourly demand for electricity in MW sorted from the highest hour of demand to the lowest. Figure 3-1 shows a typical load curve. In each hour, electric generating capacity is dispatched to meet the demand. The generating equipment is typically dispatched based on the variable operating cost. Plants with low operating cost, such as nuclear plants and some hydro plants, are the first to be used, followed by base load coal plants. Oil and gas plants are typically the last plants, at the top of the "stack" due to their higher operating cost. While this is the general pattern, the reality is more complicated due to factors such as limitations on starting and stopping plants and local electric grid support requirements. Nevertheless, this study made a simplifying assumption that natural gas units are the marginal units in the load stack whenever they are running. This is reasonable assumption given the cost of gas relative to other fuels, since fuel cost is the largest component of variable cost.

Figure 3-1
Example Electricity Load Curve



When the CHP units are running, they will displace the marginal unit, the top unit in the load stack for those hours. The question for this analysis was to what extent gas units would be the displaced units on the load curve in each region. In order to calculate this, EEA used information submitted by utilities and ISO's on FERC form 713 to construct the state or regional load curve. The load curves were adjusted to the total state or regional generation to account for imports and exports and incomplete state coverage. EIA data on gas-fired generation were then used to calculate the extent of gas generation by "filling in" the load curve from the top to the extent of the gas generation.

Figures 3-2 and 3-3 summarize the analysis for California and Texas. It shows that gas is on the margin for all hours of the year and will be displaced by all of the electricity generated by the CHP facility. Figure 3-4 shows the analysis for the Northeast. In this case, gas is not on the margin for all hours. Gas is displaced only during the peak 7,000 hours of operation.

Figure 3-2
California Load Analysis

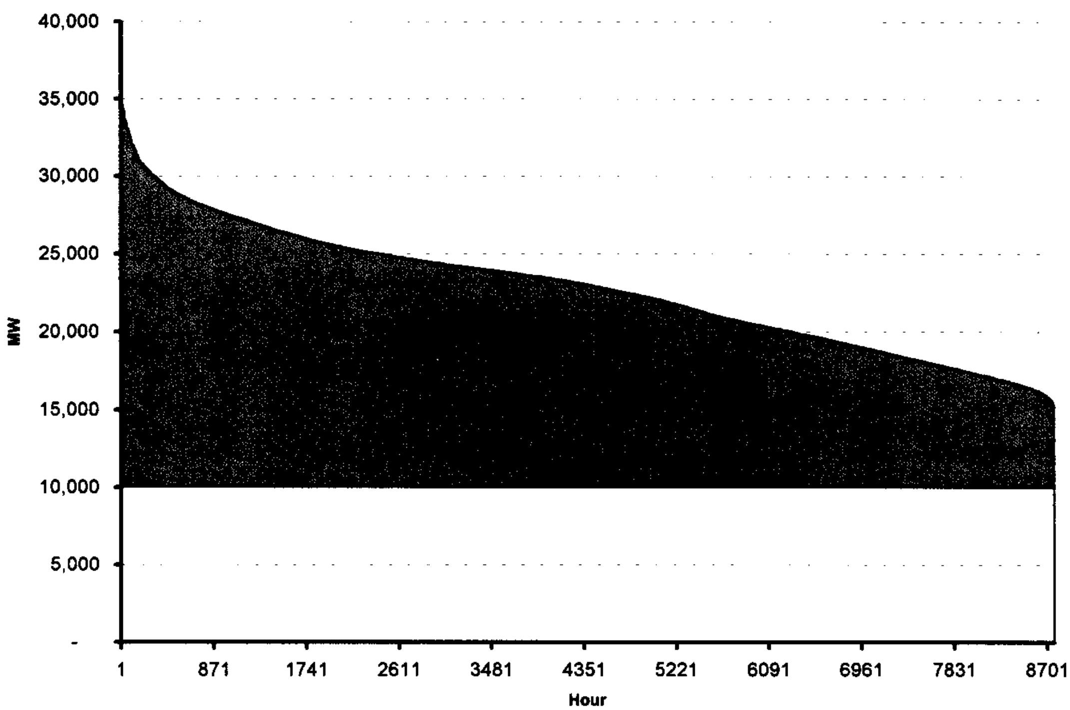


Figure 3-3
Texas Load Analysis

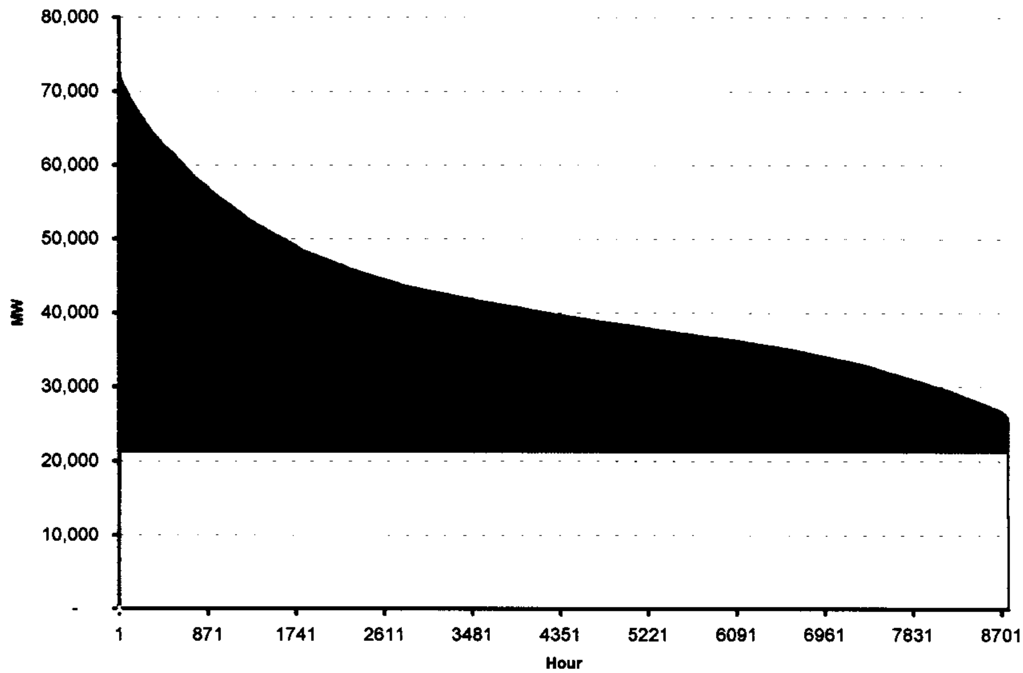
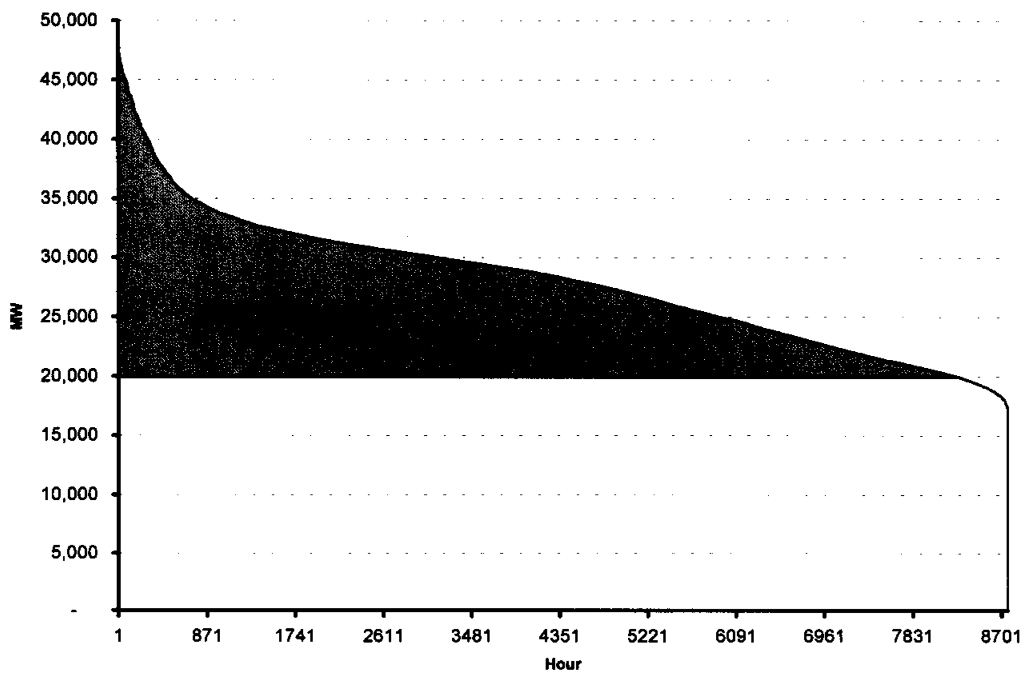


Figure 3-4
Northeast Load Curve Analysis



Using the efficiency factors, the line loss adjustment and the factor for marginal generating units, EEA calculated the amount of gas displaced by the CHP facilities. Table 3-7 summarizes the calculation. The first two rows show the natural gas consumption for conventional separate generation of steam and electricity that is displaced by the CHP systems. The third row shows the total conventional gas consumption that is displaced by the CHP systems. The fourth row shows the gas consumption for the CHP facilities. While the CHP gas consumption is higher than the original on-site gas consumption, it is lower than the total on-site and grid gas consumption. The reduction in gas consumption for these three regions is approximately 529,300 million cubic feet (MMcf) per year.

Table 3-7
Summary of Gas Displacement
(MMcf)

	Northeast	Texas	California
On-Site Gas Consumption Displaced by New CHP	106,440	209,631	196,147
Baseline Gas Consumption for Grid Electricity Displaced by CHP	295,047	448,521	412,450
Total Baseline Consumption	401,488	658,152	608,597
Gas Consumption for New CHP	322,942	422,626	393,350
Net Gas Reduction	78,546	235,526	215,247

Table 3-8 puts this reduction in context by comparing it to the total natural gas consumption in these states in 2001. It shows that the CHP facilities achieve gas consumption reduction of 4 to 9 percent or an average of 6.4 percent for the three regions.

Table 3-8
Gas Reduction Comparison
(MMcf)

	Northeast	Texas	California
Current State Consumption ('01)	1,892,059	3,915,959	2,404,176
Gas Displacement from CHP	78,546	235,526	215,247
Percent Reduction	-4.2%	-6.0%	-9.0%

4 Conclusions and Implications

This study indicates that there is a substantial remaining market for additional CHP and that increasing CHP capacity by 50 percent over existing levels could reduce natural gas consumption by an average of 6.4 percent in the three regions examined. While this analysis took a simplified approach, there is no reason to expect that a more rigorous approach would yield significantly different results.

The areas considered for this analysis already account for approximately 40 percent of U.S. natural gas consumption. However, the results could be different in other regions of the country due to different potential market sizes for CHP and particularly due to different fuel mix characteristics of the power generating system. While some regions are more reliant on coal generation and would be likely to show less gas displacement in the power generation sector, others are more similar to the regions already analyzed and will likely show similar gas reduction results. The overall effect is expected to be a net national reduction in gas consumption.

The results have a number of significant implications for natural gas markets and prices:

- CHP is commercial technology that is readily available
- There is a significant market for new CHP installations in the mid-size (5 to 100 MW) range.
- Small changes in demand can have large effects on gas price. The gas market today is at a very inelastic point on the price curve. A recent study by ACEEE[2] and EEA showed that a 7.5 percent reduction in national gas demand could result in a 20 percent reduction in gas price, about $1/MMBtu at today's prices.
- Gas commodity prices are determined by a national market. Demand reductions anywhere in the country affect the national price of gas.
- Increased use of CHP moves electric generation from the potentially volatile central grid market to more base loaded CHP facilities. This provides more constant gas use and can reduce volatility in gas markets.
- Many of the smaller CHP facilities projected in this study will purchase gas via a local distribution company rather than directly via a pipeline as large generators do.
- There are a number of policy options that could be pursued to encourage the kind of growth in CHP suggested by this analysis.
- The analysis should be extended to other regions to evaluate the full potential for reductions.

[2] Elliott, N., "Impacts of Energy Efficiency and Renewable Energy on Natural Gas Markets", ACEEE, September 2003.

Attachment 3:

Gas Turbine World article on Delta Power's Carson Repowering Project (June - July 2004)

LM6000 transplant boosts plant reliability, revenues, performance

By Robert Farmer

Instead of a major IM5000 gas turbine overhaul and plant upgrade, scheduled for 100,000 hours, owners opted for an LM6000 retrofit to realize 8 MW more output, 3% higher efficiency, new gas turbine life expectancy and reliability.

Delta Power, an independent power producer in California, recently repowered its nominal 45-MW Carson Cogeneration combined cycle plant by replacing a 13-year old IM5000 gas turbine with an LM6000PC.

At the same time they upgraded balance-of-plant equipment, installed more efficient NOx and CO catalysts, added a new gas turbine control system:

☐ **Cost Options.** Repowering, budgeted at $11.5 million, won out over an estimated $5.8 million overhaul cost to replace the IM5000 gas generator hot section, free power turbine assembly, and gas turbine controller.

☐ **Performance.** Net combined cycle output has been increased to 50.4 MW from 42.0 MW and the average annual heat rate reduced to 7590 Btu/kWh (45.0% efficiency) from 8135 Btu/kWh (42.0% efficiency).

☐ **Upgrade.** Retrofit included a major steam turbine overhaul, partial condenser re-tube, complete re-wedge of the generator, continuous emissions monitoring, and new data acquisition and handling systems.

Carson Cogeneration facility, jointly owned by Delta Power and equity partner, Energy Investors Fund, started selling electric power to Southern California Edison in 1990 under a 30-year power purchase agreement.

Original combined cycle plant was designed around an IM5000 gas turbine, a three-pressure level Vogt heat recovery steam generator, and a Shin Nippon steam turbine generator.

The gas turbine engine itself was built around a General Electric LM5000 gas generator and a separate power turbine assembly designed, manufactured and packaged by Ishikawajima-Harima Heavy Industries.

Project background

Only a few of those IHI power turbines are still in service. According to industry operators, most of them generally fail between 100,000 and 130,000 running hours due to high-temperature creep of the power turbine rotor wheel metallurgy.

Carson's power turbine was scheduled for replacement during a 25,000-hr overhaul of the LM5000 hot section at which time a new gas turbine controller to replace a faulty 1990s vintage system was also to be installed.

Operating and maintenance people at Carson had also become increasingly concerned over the long-term availability of gas turbine replacement parts, particularly in the event of a forced outage, because General Electric discontinued manufacturing the LM5000 engine in 1997.

A new power turbine along with the LM5000 hot section major overhaul and new gas turbine controller would have cost an estimated $5.8 million, and done nothing to improve plant output or efficiency.

Considering there were 17 years still to go on the power purchase agreement, replacing the old IM5000 gas turbine engine with an LM6000 made a lot more sense because it would also result in more power, lower fuel consumption, and reduced maintenance costs.

LM6000 option

As pointed out by Dean Vanech, president of Delta Power, the more efficient LM6000 gas turbine presented an opportunity to improve the financial return of the facility for a reasonable added investment.

Total budget cost for a complete retrofit was estimated at $11.5 million. This included a new LM6000 engine and controller, major plant upgrade, permitting, legal and financial costs, new NOx and CO catalysts, continuous emissions monitoring, improved data handling system, contingency and spare parts.

That $11.5 million also reflected credit for the estimated salvage value of removed equipment as an offset against the cost of repowering. As it turned out, says Vanech, the actual final cost to carry out the complete retrofit project was less than budgeted.

Operationally, repowering has also significantly improved hot day performance. Before, during summer months, Carson found it increasingly difficult to make full 42 MW output with the IM5000 as required to earn capacity and bonus payments from Southern California Edison.

The LM6000 combined cycle plant can deliver about 8 MW more power than the IM5000 design. However, since the utility has limited the Carson capacity payment to the original 42-MW plant output, the higher output earns energy-only revenue.

Plant performance

To qualify under Federal PURPA standards, the Carson Cogeneration facility originally had to export approximately 21,800 lb/hr of steam on an annual average basis.

Since the LM6000 combined cycle efficiency is higher, better than 45%, the facility can now qualify with significantly less exported steam.

Steam no longer required for export can be run through the steam turbine to generate an additional 4900 MW-hrs of electricity that can be sold -- yearly.

At a hypothetical price of $50 per MW-hr, for example, this would be worth $245,000 per year in extra revenues.

Net heat rate of the original IM5000 plant averaged around 9030 Btu/kWh (HHV) per year which is equivalent to 8135 Btu/kWh (42.0% efficiency) on an LHV basis.

At the same site conditions, with 15% more power output, the equivalent average LM6000 combined cycle heat rate is 8424 Btu/kWh (HHV) or 7590 Btu/kWh (45.0% efficiency) on an LHV basis.

Assuming the same fuel and electricity prices, say project engineers, the higher power output and better heat rate of the LM6000 retrofit plant generates a significantly better net revenue stream than did the original IM5000 plant. It has improved plant gross margin by 17% (electrical revenue minus fuel cost).

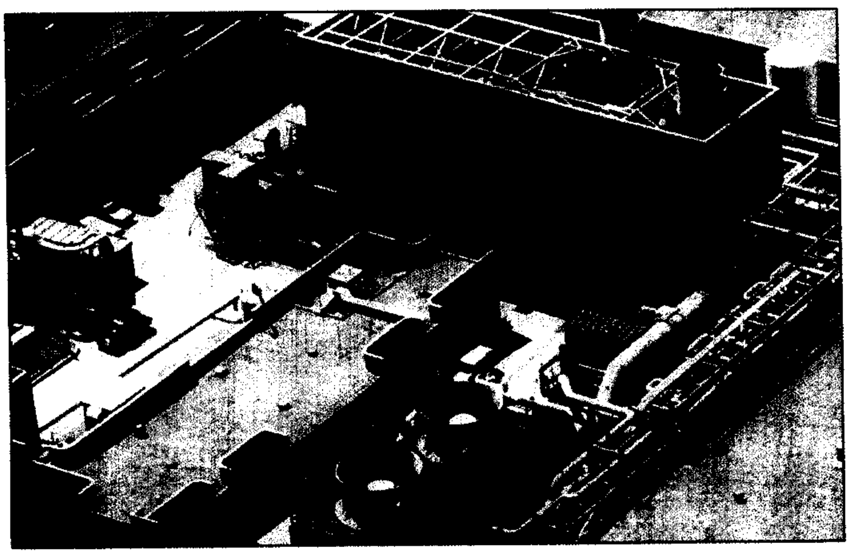
Cooling system installation. New electric generator lube oil cooler skid and piping installation. From left to right: Jim Amarel, Energy Services project manager, Rich Shevr, GE Contractual Services lead plant operator; Dan Richardson of GE Contractual Services.

Permit issues

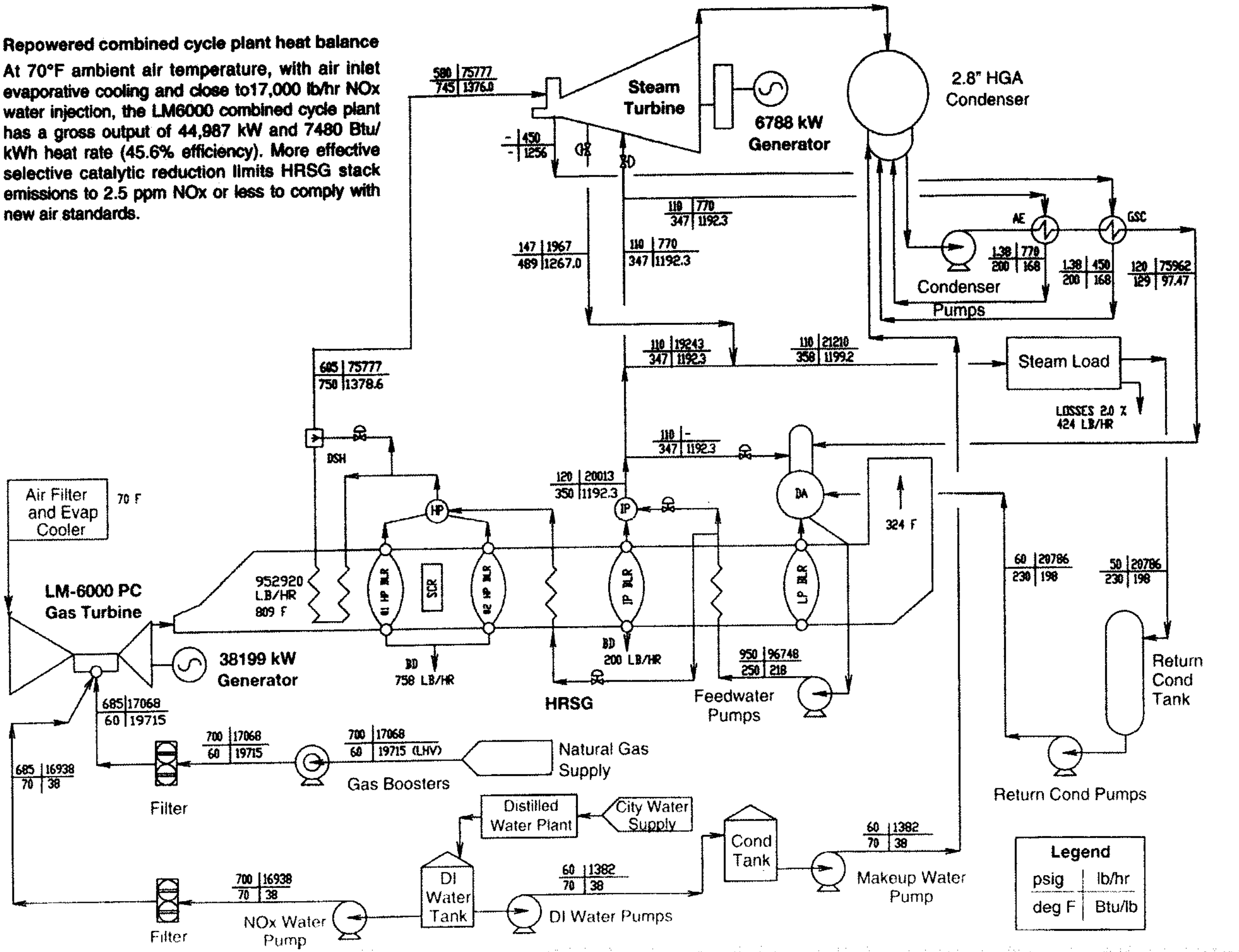
Carson Cogeneration filed an application on August 20, 2002 with the local South Coast Air Quality Management District to upgrade the plant.

At that time, the agency ruled the proposed LM6000 was not "a like kind replacement" and, because the gas turbine was able to burn more fuel, a new source permit review would be required.

It took SCAQMD and the EPA nine



LM6000 plant layout. The 50-MW combined cycle Carson Cogeneration facility is sited in the center of the town, with the gas turbine plant located on the street side of the HRSG (in the background). The cooling towers are for the steam turbine condenser and the process cooling water.



Repowered combined cycle plant heat balance

At 70°F ambient air temperature, with air inlet evaporative cooling and close to17,000 lb/hr NOx water injection, the LM6000 combined cycle plant has a gross output of 44,987 kW and 7480 Btu/kWh heat rate (45.6% efficiency). More effective selective catalytic reduction limits HRSG stack emissions to 2.5 ppm NOx or less to comply with new air standards.

months to complete that review process and issue a permit. By then, the new permit required the plant to meet much more stringent "best achievable control technology" air emission levels.

In addition, the facility is now required to make on-line emissions reporting to the EPA in addition to previously-required reporting to the SCAQMD agency. The maximum permitted NOx emissions level is 2.5 ppm.

Meeting these new air standards calls for higher levels of water injection in the LM6000 gas turbine than needed for the original IM5000, more efficient downstream NOx and CO catalysts.

Retrofit scope

Delta Power awarded the engineering, procurement and construction project for gas turbine retrofit and plant upgrade to Energy Services Inc.

Total site work for demolition, gas turbine removal and installation, associated plant upgrade, commissioning and startup was completed in 52 days from start to finish. Most demanding part of the job, say field engineers, was removing the power turbine.

First, the LM5000 gas generator was removed. Next the IHI power turbine package, which was around 12 by 12 ft in size and weighed about 80,000 lbs, had to be literally lifted out of the enclosure for removal. The electric generator was left in place.

Instead of replacing the enclosure, ESI modified the old one around a new exhaust collector for the more compact LM6000 gas turbine installation. Major changes included a new transition duct, new exhaust area enclosure, and cutting openings in the existing roof for bleed valve ducting.

To keep the gas turbine exhaust on the centerline of the boilers, the design engineers also added a 2-ft extension to the output shaft connecting to the electric generator coupling. They also had to change the direction of rotation on the electric generator.

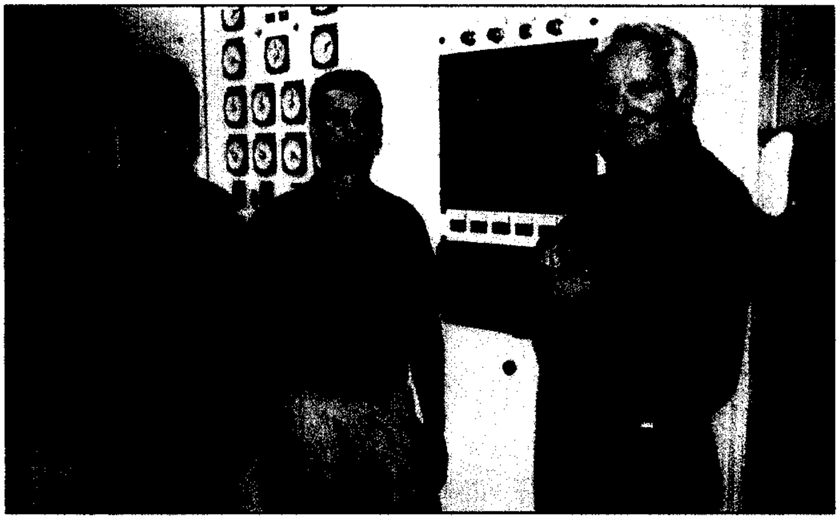
Plant upgrade

During the plant outage, while the retrofit project was being carried out, Carson's service group removed the Hitachi NOx and Engelhard CO catalysts for recycling and replaced them with more efficient catalysts supplied by the same suppliers.

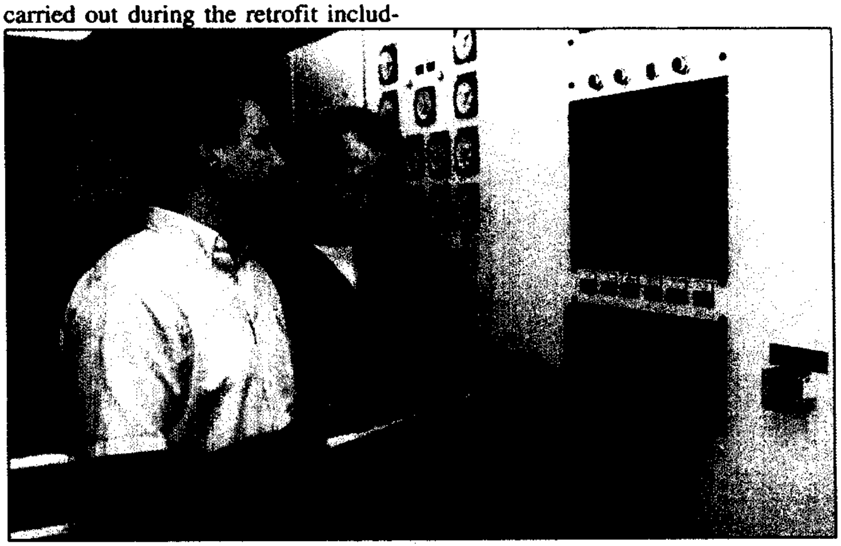
They also installed a new continuous emissions monitoring system and new data acquisition and handling system, manufactured by ESC Inc., to provide the new level of required air emissions reporting.

Other major onsite maintenance carried out during the retrofit included a major overhaul of the steam turbine, a partial condenser re-tube, and a 100 percent re-wedge of the electric generator.

Since renewal of service in November, the combined cycle plant has logged over 4,800 hours of operation (as of June 2004) and is scheduled for its first hot section overhaul of the new LM6000 gas turbine engine in November 2006. ■



Carson plant managers. From left to right: Kevin Fullerton, project manager for Delta Power; Dan Richardson, GE Contractual Services (facilities manager responsible for day to day operations of the plant); Ken Smith, director of project management for Delta Power.



Gas turbine control display. Computer screen displays real-time performance parameters. Jim Amarel of Energy Services, shown here on the left, is reviewing control system data with Mike Malsey, electricity and instrument technician for GE Contractual Services.

Attachment 4:

Missed Opportunities for Additional CHP Capacity in California

1. Procter & Gamble Oxnard

Procter & Gamble's (P&G) Oxnard site is a full-time, "24/7" Charmin and Bounty paper manufacturing operation with 500 employees. P&G operates two gas-fired turbines with 66 megawatts (MW) of combined electrical generation capacity. Of this total, 21 MW is used to support the plant load and 45 MW are sold to Southern California Edison (SCE) under a firm power sales contract . The useful thermal output provides all the steam and hot air to meet P&G's paper-machine drying needs.

Because of limitations in the SCE contract, a new, more efficient replacement turbine is delivering 3 MW of firm power less than full machine and station capacity. P&G's Oxnard manufacturing site is regularly considered for expansion and must compete with other paper sites nationally. The preferred plan that will meet the site's energy needs, as well as deliver improved air emissions, calls for upgrading one of the existing turbines. Due to the lack of an option for a long term power sales contract for the additional 9 MW of firm power that would be available from the turbine upgrade, the site cannot predict the economic benefit of an upgrade and it is therefore less competitive than it might be compared to P&G sites in other states.