Consultant's Report

Anaheim Canyon Power Project: Combined Cycle versus Simple Cycle Peaking Power Plant Configuration

DOCKET	
07-AFC-9	
DATE	May 2009
RECD.	May 26 2009

Prepared for

The City of Yorba Linda

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May 2009

Synopsis

The City of Anaheim (Anaheim) has proposed to build a 200 MW natural gas fired turbine generator peaking power plant, the Canyon Power Project, on property located near the north central border of Anaheim adjacent to the City of Placentia and proximate to the City of Yorba Linda (Yorba Linda). The power plant is proposed to consist of four General Electric LM6000 Sprint PC turbine generator sets equipped with ammonia selective catalytic reduction for NOx control and CO oxidation catalyst for reduction of carbon monoxide and unburned hydrocarbon emissions. The proposed plant design represents current state of the art in terms of simple cycle power plant efficiency and emissions control, and has been designed to comply with all applicable air quality and plant efficiency standards.

Elected officials and the City Manager's Office in Yorba Linda have expressed concern about this plant and have requested an independent evaluation of the risks the plant poses to Yorba Linda residents. The expressed rationale for Yorba Linda's concern is simple: prevailing winds from the plant will carry the exhaust plume across the adjacent communities of Placentia and Yorba Linda. This will carry the plume across numerous schools, hospitals and regions of low-income housing. This means that any public health or other risk posed by the plant will most likely be borne by the residents of Placentia and Yorba Linda, while the benefits of the plant will largely be enjoyed by the residents of Anaheim. Some Yorba Linda officials and residents have stated that they are not objecting to construction of the plant, and have even recognized the need for additional electric capacity to support development of renewables and eventual displacement of out of state coal generation capacity. However, there has been express concern that the Canyon Power Project, as proposed, will not be as clean as it could be.

On 25 February 2009 the South Coast Air Quality Management District (SCAQMD) issued a notice of intent to issue a final permit to construct for the Canyon Power Project, subject to public comments received within 30 days, or a hearing request received within 15 days. This prompted the Yorba Linda City Manager to request a briefing on the power plant during a planned meeting of the Yorba Linda City Council.

At a meeting of the Yorba Linda City Council on Tuesday, 3 March 2009 it was reported that the health risks posed by the proposed plant should be *de minimus* and well within normally acceptable limits. However, it was also pointed out that even though pollution from the power plant was small, reducing that pollution even further might be less expensive than other options for reducing pollution in the area. It was further suggested that one straightforward approach to reducing pollution from the plant might be simply to increase its efficiency by designing it as a combined cycle, rather than simple cycle plant.

City officials (the mayor and city council, via the city manager's office) responded by requesting a rapid turnaround analysis of the permitting process of the Canyon Power Project to determine whether there might be justification for requesting a public hearing to air concerns and suggest alternatives for the project. That analysis yielded some seeming irregularities in the permitting process – in particular a distinct lack of transparency during the period from about July 2008 through February 2009. Negotiations with regulators during this period were spurred by a court ruling that voided the ability of the Canyon Power Project to obtain PM10 credits from the Priority Reserve Account of the SCAQMD. The Canyon Power Project at this time negotiated and received approval for substantive changes in the operating profile of the plant that eliminated the need to access the Priority Reserve. These changes and approvals were done without an opportunity for input from the public or other intervenors. As of early March 2009, most of the documents pertaining to these negotiations were still not a part of the public record and it was only in two documents released by the CEC in mid January[1] and late February 2009[2] that the existence of many of these documents was acknowledged.

This information, along with a suggestion that the Canyon Power Project may have improperly dismissed the option of installing a combined cycle power plant (citing specific examples of combined cycle peaking power plants elsewhere in the U.S.) were submitted to SCAQMD by Yorba Linda in a formal request for a public hearing on 12 March 2009.

In response to the Yorba Linda request for a public hearing, Anaheim prepared a document entitled "Canyon Power Plant Simple Cycle Plant Justification". That document was dated 16 April 2009 and submitted to the CEC on that date by the law firm Galati Blek LLP for inclusion in the project docket. The document was released to the public by the CEC on 22 April 2009.

Upon review of the Anaheim "Justification" document Yorba Linda requested that a more in depth independent review be conducted and a report prepared that would support an alternative interpretation of material facts concerning whether a combined cycle configuration could meet the requirements of the Canyon Power Project, while better protecting the residents of Yorba Linda and other affected communities. The following report is intended to address Yorba Linda's request.

[1] "Southern California Public Power Authority's Canyon Power Plant Status Report #1 Docket No. 07-AFC-9", dated November 5, 2008, and noted as received into the CEC docket on November 5, 2008. However, this document did not appear in the public record until 14 January 2009 and shows up on the CEC website with the filename 2009-01-14_CANYON_STATUS_REPORT_1.pdf

[2] "CANYON POWER PLANT (07-AFC-9) STATUS REPORT #3. February 26, 2009.

Introduction

Combustion turbines, also known as gas turbines (to distinguish them from steam turbines and water turbines) were originally developed in the 1930s and 1940 to power “jet” aircraft. As the technology matured, however, it became obvious that in some applications combustion turbine technology might have advantages over reciprocating engines and steam turbines for producing mechanical power, rather than jet propulsion. The introduction of combustion turbines for electricity generation was slow to take hold for a number of reasons. By the 1970s, however, combustion turbine generators became commonplace, and by the 1980s they began to replace conventional steam boiler technology for large power generation and even to replace reciprocating engines for smaller distributed and backup power generation.

The reasons for this change were largely economic. Combustion turbines, while not yet as efficient as extant boilers had become, could be much less expensive to build and install. During a period of relatively low fossil fuel costs this could be advantageous. And in comparison with reciprocating engines, combustion turbines were more suited to scaling to very large sizes, while also being able use a range of liquid and gaseous fuels without expensive modifications to the engine.

A solution to the lower efficiency of gas turbines had also long since been identified in the form of combined cycle technology. Combined cycle, in the simplest of terms is the use of two or more different thermodynamic cycles to generate power. An example familiar to many is using the hot high pressure exhaust of an automobile engine to drive a turbocharger. The turbocharger in turn compresses air for the engine, which increases engine power and improves fuel efficiency.

The advent of combined cycle for combustion turbines marked a new paradigm in electrical power generation. By combining the attributes of gas turbines with well-established steam boiler technology, electric power generation became significantly cleaner, more efficient, lower in installed capital cost, and easier and faster to install. Turbines could be delivered “just in time” to a prepared site, and as gas turbines, out of necessity, came in standardized configurations; it became practical to construct their associated boilers in standard configurations as well. In order to distinguish combined cycle turbines from their predecessors, the terms “combined cycle gas turbine” and “simple cycle gas turbine” came into common usage.

At its simplest, a combined cycle gas turbine, or CCGT consists of the following:

- a combustion turbine that drives an electric generator
- a boiler that uses the combustion turbine exhaust as its source of heat for generating steam; and
- a steam turbine that drives an electric generator

In other words, as with the automobile turbocharger example, the hot gases generated in the gas turbine get used twice: first to produce power in the gas turbine itself, and secondly to produce steam which powers a steam turbine.

In a combined cycle power plant it is also common to have auxiliary burners in the turbine exhaust to raise the temperature upstream of the boiler; thereby increasing power output further, though with some reduction in total fuel efficiency. When operated close to 100 percent of their full power output (i.e. near full load), the latest CCGTs have exceeded 60 percent efficiency, roughly twice that of simple cycle turbine technology of 30 years ago. Depending on the system design, a combined cycle power plant scaled for the Canyon Power Project would be about 20 – 25 percent more efficient that the simple cycle turbine alone, with a commensurate reduction in both pollutants and greenhouse gas emissions for the same amount of electricity generated.

In addition to base load power, CCGT could also be useful for dispatch power. In conventional steam boilers, the rate of steam production could be changed only slowly. However, gas turbines could respond in a matter of seconds to a needed load change. CCGT thus aided in improved electrical grid efficiency and stability. Smaller CCGTs could be distributed physically to be near the load and thus reduce transmission losses, while responding to local power requirements.

One area where CCGTs initially did not perform well, however, was in peak shaving power generation. Peak shaving is the practice of bringing an electric generation facility on line for only a few hours at a time to meet transient needs for power. The steam boilers and steam turbines used in CCGTs generally required an extended period to start up. Thermal stresses that can damage boiler tubes and other components are avoided by starting the gas turbine up slowly, and gradually bringing the boiler on line. The steam turbine, likewise generally needs to be started up slowly, so metal components can undergo coordinated thermal expansion, thereby avoiding excessive wear and reduction in useful operational life.

One way around the peaking shaving issue is to oversize the gas turbine so that it operates at part load most of the time, with the additional capacity available to rapidly bring it up to full load when demand is high. This partially negates the major advantages of CCGT, however. When a gas turbine is operated at part load, its efficiency can fall dramatically. For example, a large modern gas turbine that might be 48 percent efficient at full load, might be only 30 percent efficient at half load.

As a result, so-called peaking power plants, or “peakers”, were developed using either used simple cycle gas turbines or reciprocating engines. While less efficient than CCGT, simple cycle peaking turbines could be relatively inexpensive. In addition, by handing the transient loads, peakers allowed the generally larger, more efficient CCGTs to operate closer to their “sweet spot” in terms of both efficiency and pollutant emission rates.

It thus became a “known fact” in both regulatory and industry circles, that combined cycle was not suitable for peaking power generation. Yet while this *known fact* became more and more deeply embedded in power generation consciousness, technology continued to change.

Combined Cycle Peaking Power Plant Technology

Nearly 30 years ago, the U.S. Navy, looking to reduce fuel consumption and extend the range of their gas turbine powered ships, began to explore CCGT technology. The program, initiated in the early 1980s was known as RACER (for **RA**nkine **C**ycle **E**nergy **R**ecovery)[3]. This project was carried out by Solar Turbines, in San Diego, CA.

The Navy program focused on advancing an alternative to conventional steam boiler technology known as the Benson Cycle. The Benson Cycle, now referred to as once-through steam generation, or OTSG, was developed in 1923 and subsequently sold to what is now Siemens AG. The Benson Cycle was interesting because it enabled rapid changes in the rate of steam production and could be started up faster than conventional boilers. A key challenge, however, was that the initial start up was still not fast enough to meet the needs of the Navy program.

Between 1923 and the early 1980s, however, tremendous advances had been made in materials science. New metal alloys were developed that, while more expensive than more conventional stainless steels, could not only tolerate higher temperatures and thermal stresses, but could also be heated up completely dry, with no water or steam to prevent overheating. With this new "run dry" boiler technology, combined cycle power generation systems could be started up as fast as the combustion turbine would allow, and the boiler and steam turbine could be brought on line simultaneously, later, or even not at all if the extra power was not needed[4].

With additional advances in technology methods were developed that made it possible to start both the boiler and turbine much more rapidly than had been possible with conventional boiler technology. Although their first installation in Okarche, Oklahoma was started in 1985, Solar Turbines eventually abandoned the RACER concept and their technology was acquired by Innovative Steam Technologies in 1992.

The underlying technology, the Benson Cycle, still remains the property of Siemens AG. Their list of licensees[5] for Benson Cycle heat recovery steam generators is shown in the following table.

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[3] Pike, John, "RACER (Rankine Cycle Energy Recovery)" *GlobalSecurity.ORG*, 9 February 2007.

[4] Brady, Michael, "Once Through Steam Generators Power Remote Sites" *Power Engineering*, June 1998.

[5] Siemens AG 2007 – Corporate Information.

Siemens-Licensed Suppliers of Once Through Steam Generator HRSG Equipment	
ALSTOM Power	USA
Ansaldo Caldaie	Italy
Babcock Hitachi	Japan
Balcke-Dürr	Germany
CMI	Belgium
Doosan Heavy Industries	Korea
Innovative Steam Technologies (IST)	Canada
Kawasaki Heavy Industries	Japan
NEM	Netherlands
Nooter/Eriksen	USA
Siemens Power	Germany
STF	Italy
Vogt Power International	USA

Rapid Start Combined Cycle Peaking Power Plants

The earliest power plant capable of rapid start and peaking operation that was identified in this study is the York Cogen Facility, located in Pennsylvania. Cogen is short for cogeneration, a technology closely related to combined cycle, but in which the steam produced from the heat of the combustion turbine exhaust is used for a purpose other than electricity generation. The York Cogen Facility consists of six 8 MW turbines equipped with OTSG boilers provided by Solar Turbines in 1989. The first recipient of the Siemens OTSG peaking technology was the Cottam Development Centre in Nottinghamshire, UK, which employs the prototype SGT5-4000F combined cycle gas turbine package.

A plant similar to the proposed Canyon Power Project, at least in configuration, is the Las Vegas Cogen II Facility, consisting of four 43 MW GE LM6000 Sprint PC turbines. However, these turbines are also equipped with IST OTSG technology and two 26 MW steam turbines. The plant frequently starts up daily, though at times operates for extended periods depending on electrical demand.

In all, searching through vendor literature, trade publications, and (in the U.S.) government databases, 44 CCGT existing and planned power plants were identified worldwide that use (or will use) OTSG and that were installed with peaking (or rapid start) capability in mind. These are identified in the following table. The combustion turbines in these power plants range in size from 5 MW to 292 MW, indicating that scalability is not an issue.

Combined Cycle Peaking Power Plants

Plant Name	Location	Owner	Year Online	Configuration	Boiler Technology	City	State or Province	Country/ Region	Peaker	Combustion Turbine MW
Agawam Station	Massachusetts	Berkshire Power Associates Limited P	1999	1 x GT24	Alstom OTSG	Agawam	Massachusetts	US	Capable	1 x 270
AKSA Enerji Uretim A.S.	Turkey			4 x LM6000	IST OTSG	Antalya	Antalya	Turkey	Capable	4 x 48
Altek Alarko Power Plant	Turkey		2002	2 x LM2500	IST OTSG	Kitreli		Turkey	Capable	2 x 28
Ataer Enerji	Turkey			1 x LM6000	IST OTSG	Ismir	Ismir	Turkey	Capable	1 x 48
Balazac	Alberta	Encanna/EPCOR	2001	4 x LM6000	IST OTSG	Calgary	Alberta	Canada	Yes	4 x 43
Bear Creek Cogen	Alberta	EPCOR	2002	1 x Trent	IST OTSG	Grand Prarie	Alberta	Canada	Capable	1 x 50
Bethpage Expansion	New York	Calpine	2005	1 x LM6000	IST OTSG	Hicksville	New York	US	Yes	1 x 43
Big Hanaford Power Plant	Washington	Transalta	2002	4 x LM6000	IST OTSG	Centralia	Washington	US	Yes	4 x 43
Calstock Power Plant	Ontario	EPCOR		RB211, LM1600	IST OTSG	Calstock	Ontario	Canada	Capable	26, 13
Cottam Development Centre	Nottingham	Powergen	1998	1 x SGT5-4000F	Siemens Benson	Cottam	Nottinghamshire	UK	Yes	1 x 292
El Segundo Power Redevelopment	California	ESP II LLC	2010	2 x SGT6-5000F	Siemens Benson	El Segundo	California	US	Yes	2 x 280
Empresa Guaracachi S.A.	Bolovia	C.C. Guaracachi Project		2 x 6FA	IST OTSG	Santa Cruz		Bolivia	Capable	2 x 75
Entek Elektrik, Uretim A.S.	Turkey	Entek Elektrik		1 x LM6000	IST OTSG	Izmit		Turkey	Capable	1 x 48
Escatron Power Plant	Spain	Global 3 Energia	2006	4 x LM6000	IST OTSG	Escatron	Zaragosa	Spain	Capable	4 x 48
Gorizia Power Plant	Italy	ElecttroGorizia	2005	1 x LM6000	IST OTSG	Gorizia	Gorizia	Italy	Capable	1 x 43
GTAA Cogen Plant	Ontario	Greater Toronto Airport Authority	2005	2 x LM6000	IST OTSG	Mississauga	Ontario	Canada	Cogen/Capable	2 x 43
Hamm Uentrop Power Station	Germany	Trianel Energy	2007	2 x V94.3A	Ansaldo Benson	Hamm-Uentrop	Westphalia	Germany	Yes	2 x 266
Hanford Energy Peaker Project	California	GWF Energy LLC	2012	3 x LM6000	IST OTSG	Hanford	California	US	Yes	3 x 60
Hawaii Electric Light Company	Hawaii	Hawaii Electric Light Company		2 x LM2500	IST OTSG	Keahole	Hawaii	US	Capable	2 x 25
Henrietta Peaking Plant	California	GWF Energy LLC	2012	2 x LM6000	IST OTSG	Kings County	California	US	Yes	2 x 60
Irsching - 4	Bavaria	E.ON Kraftwerke	2007	1 x SGT5-8000H	Siemens Benson	Vohburg	Bavaria	Germany	Yes	1 x 340
Kapuskasing Power Plant	Ontario	EPCOR	1996	2 x RB211, 1 x FT8	IST OTSG	Kapuskasing	Ontario	Canada	Capable	2 x 26, 1 x 25
Lake Road Power	Connecticut	PG&E NEG	2002	3 x GT24	Alstom OTSG	Dayville	Connecticut	US	Yes	3 x 264
Las Vegas Cogen	Nevada	Black Hills Energy	2001	4 x LM6000	IST OTSG	Las Vegas	Nevada	US	Yes	4 x 43
Maalaea Power Plant	Hawaii	Maui Electric	2006	2 x LM2500	IST OTSG	Kihei	Hawaii	US	Capable	2 x 25
Murrin Murrin	Western Australia	Murrin Murrin Operations pty Ltd	1998	2 x GT10B	Alstom OTSG		Western Australia	Australia	Yes	2 x 37.5
Nipigon Power Plant	Ontario	EPCOR	1998	2 x RB211, 1 x LM2500	IST OTSG	Nipigon	Ontario	Canada	Capable	2 x 26, 1 x 21
North Bay Power Plant	Ontario	EPCOR	1996	1 x RB211, 1 x FT8	IST OTSG	North Bay	Ontario	Canada	Capable	1 x 26, 1 x 25
North Pole Power Plant	Alaska	GVEA	2005	1 x LM6000	IST OTSG	North Pole	Alaska	US	Capable	1 x 43
Nova Scotia Power	Nova Scotia	Nova Scotia Power		2 x LM6000	IST OTSG	Tuffs Cove	Nova Scotia	Canada	Capable	2 x 48
Osenberg D Statoil-Hydro	Norway	Statoil Hydro		2 x LM2500	IST OTSG	Osenberg		Norway	Capable	2 x 28
Phosphate Hill Power Station	Queensland	Western Mining Co.	1999	4 x Taurus 60	IST OTSG	Perth	Queensland	Australia	Capable	4 x 5
Pine Creek Power Station	Queensland	Energy Developments Ltd.	1995	2 x Mars	IST OTSG	Richlands	Queensland	Australia	Capable	2 x 10
Pinelawn Power Station	New York	Pinelawn Power LLC	2005	1 x LM6000	IST OTSG	Babylon	New York	US	Yes	1 x 43
Pulrose Power Station	Isle of Man	Manx Electric Authority	2002	2 x LM2500PK	IST OTSG	Douglas		Isle of Man	Capable	2 x 31
QE Power Station	Sasketchewan	SaskPower	2002	6 x H25	IST OTSG	Saskatoon	Saskatchewan	Canada	Yes	6 x 25
Ruswil Compressor Station	Switzerland	Nuovo Pignone	2001	1 x PGT25	IST OTSG	Ruswil	Lucerne	Switzerland	Capable	1 x 25
Sherritt Power	Cuba	Energas Boca de Jaruco	2010	5 x 6B	IST OTSG	Boca de Jaruco	Havana	Cuba	Capable	5 x 30
Sloe Power Plant	Netherlands	Delta N.V./EDFI	2009	2 x SGT5-4000F	CMI Benson	Sloe	Zeeland	Netherlands	Yes	2 x 292
Tanir Bavi Power Barge	India	Tanir Bavi Power Company	2000	4 x LM6000	IST OTSG	Bangalore	Karnataka	India	Capable	4 x 43
Tunis Power Plant	Ontario	EPCOR	1994	1x Avon, 1 x Mars, 1 x LM6000, 1 x RB211	IST OTSG	Timmons	Ontario	Canada	Capable	1 x 8, 1 x 14, 1 x 40, 1 x 26
Ugur Enerji	Turkey	Ugur Enerji		1 x LM6000	IST OTSG	Ugur		Turkey	Capable	1 x 43
Wuppertal-Barmen Heating Power Station	Germany	Wuppertaler Stadwerke AG	2005	2 x H25	IST OTSG	Wuppertaler	Rhine-Westphalia	Germany	Yes	2 x 25
York Cogen Facility	Pennsylvania	Caterpillar	1989	6 x Mars	Solar (IST) OTSG	York	Pennsylvania	US	Yes	6 x 8

Startup times for the power plants in this table are not all well documented. One of the plants, the Irsching-4, a Siemens SGT5-8000H, located in Bavaria was reported to have a 45 minute start up time, as was the Lake Road Power Station in Dayville, CT[6]. Alstom reports that their latest OTSG can reach full output in 25 minutes, with no restriction on combustion turbine start up. Siemens states that their rapid start combined cycle turbine packages prior to 2007 would achieve full steam load in 40 minutes, while their latest Flex-Plant™ 30 designs, that are being installed now, are capable of 20 – 25 minutes to full steam load[7] – in each case the combustion turbine is at full load in 10 minutes or less.

According to vendor information from IST, the CCGT power plants equipped with their OTSG boilers – which comprise the majority in the previous table – are able to achieve full combustion turbine power in about 10 minutes. In addition, those designed with "hot standby" capability can be at full steam power output in 35 minutes. Otherwise, according to IST, if the OTSG boiler and turbine were cold and completely depressurized it would take at least 55 minutes (and no longer than 95 minutes) to bring the steam boiler and turbine up to full load. This is significantly faster than conventional combined cycle, and whether hot or cold, OTSG technology still allows the combustion turbine to be generating electricity at full load within 10 minutes of receiving the start signal.

The CCGT/OTSG start sequences for both cold and hot start, provided by IST, are as follows (times are in minutes):

***Hot Start** (Pressure is maintained in BOP piping and the STG is warm and on turning gear)*
Time 0: GT start
Time 5: OTSG ramp sequence can start if OTSG temperature is 550F and stack temp is 300F
Time 10: GT at full load.
Time 35: OTSG at 100% of unfired steaming capacity and the STG is at load.

***Cold Start** (or any start where system has been completely de-pressured)*
Time 0: GT start
Time ~5: OTSG ramp sequence can start if OTSG temperature is 550F and stack temp is 300F
Time 10: GT at full load.
Time ~17: OTSG has reached minimum turndown flow and is held here until the BOP is up to pressure and temperature. This can take anywhere from 20 minutes

[6] McNeely, Mark, Reliability, Availability are Keys to Plant's Success *Diesel & Gas Turbine Worldwide*, January – February 2003

[7] McManus, Michael, Boyce, David, Baumgartner, Raymond, "Integrated Technologies that Enhance Power Plant Operating Flexibility" *POWER-GEN International 2007.* New Orleans, LA, Dec 11 – 13, 2007.

to an hour and beyond, depending on the configuration of the plant and size/model of the steam turbine.
Time ~37-77: BOP ready to accept steam and OTSG continues start-up ramp.
Time ~55-95: OTSG at 100% unfired steaming capacity and the STG is at load.

According to IST, the difference between 55 minutes and 95 minutes in the cold start sequence is a matter of overall hardware design. In other words, the shorter start up time is determined before the plant is built, and needs to be included in the specifications, so that omission of rapid start capability must be a conscious decision on the part of the project developer. *Regardless, however, the combustion turbine itself is still at full power in 10 minutes or less!* This philosophy, that designing to bring the steam turbine on line rapidly is only a matter of intelligent design, is reflected in many literature and marketing brochure references from both Siemens and Alstom as well.

One of the issues cited with respect to CCGT power plants – regardless of whether or not they are designed for peaking operation – is the need for additional personnel over and above what would be required to run and operate a simple cycle gas turbine power plant. This has been true in the past with conventional combined cycle, where establishing steam balance might even require manual operation of valves. However, current technology, as reported by both vendors and their customers is capable of single operator start/stop and even fully automated start sequencing – according to Siemens and Alstom.

Combined Cycle and Peaking Power Plants in California

Currently there are no peaking power plants located in California that employ combined cycle technology. However, the technology is gaining ground as project developers begin to recognize its benefits. Presently there is one fully new combined cycle peaking power plant planned in California, and two existing peaking power plants have applied to the California Energy Commission to upgrade to combined cycle operation using OTSG hardware. At least one other project in California considered OTSG but eventually rejected it for non-operational reasons as part of their CEQA evaluation. These are discussed below.

El Segundo Power Redevelopment Project

The El Segundo Power Redevelopment Project (ESPR) was originally approved by the California Energy Commission in 2005 as a 630 MW conventional combined cycle power plant comprising two GE 7FA gas turbines equipped with conventional drum-type HRSGs and a single steam turbine generator. Near the time of project approval, however, Siemens fully commercialized their R2C2 (rapid response combined cycle), which was being prototyped at the Cottam facility in Nottinghamshire in the U.K. In June 2007 ESPR submitted a petition to amend the project permit to instead utilize the Siemens technology, which will consist of two SGT6-5000F combustion turbines with separate Benson Cycle HRSGs and steam turbines. The plant generation capacity will be reduced to 560 MW. However, with the Benson Cycle HRSG and associated balance of plant the plant will be able to achieve 300 MW electrical output in 10 minutes or less.

There were many factors driving the decision to reconfigure. Most important, it would appear from the docket, was elimination of once-through cooling. However, the petition to amend includes a summary list of benefits as follows:

> ***1. The use of the R2C2 technology eliminates the need for once-through cooling and the associated impingement and entrainment effects on marine resources.***
> ***2. Unprecedented rapid response design that provides comparable start-up rates to simple cycle units with the efficiency of a combined cycle power plant; specifically, each unit can deliver 150 MWs of capacity within 10 minutes of startup;***
> ***3. The rapid starting capability also supports wind and solar renewable generation by providing reliable localized generation that can quickly respond should wind or solar resources not be available during peak electrical demand periods.***
> ***4. Elimination of the discharge of industrial wastewater to the ocean and the associated reliance on the existing intake/outfall 001. There will be no discharge of industrial wastewater from the project.***
> ***5. Reduced onsite construction activity associated with ability to transport larger prefabricated modules via beach delivery and/or via the modified plant entrance road;***
> ***6. Modified plant entrance road, which will improve the safety and efficiency of the plant entrance; and***
> ***7. Significant improvement in the visual aesthetics associated with the change from the previously permitted vertical heat recovery steam generators (HRSGs) to the proposed R2C2 BENSON-type HRSG.***

ESPR also points out that the Benson Cycle HRSGs will allow the plant to bring full emission controls on line sooner, thus reducing start up emissions.

GWF Energy LLC

In July 2008, GWF Energy LLC submitted petitions to the California Energy Commission to modify three of their peaking power plants to combined cycle configurations in order to increase capacity and utility. Two of these are proposing to use OTSG technology so as to retain their peaking capability, while reducing fuel consumption and pollutant emission rates across the board. The Hanford Energy Peaker Plant and Henrietta Peaker Plant will each be modified by adding two OTSG HRSGs and a single steam turbine to two GE LM6000 Sprint PC combustion turbines.

This conversion will result in a roughly 24 percent increase in planned overall operating efficiency for the plants, with a concomitant reduction in emission rates for all priority pollutants. Water consumption as a result of conversion to combined cycle operation will increase from a current 150 AFY (acre feet per year) to 158 AFY – a mere 5.3 percent increase.

In the proposed license amendments for both the Hanford and Henrietta plants the justification for selecting OTSG was the same:

> ***"The reason for retaining the option to operate in simple-cycle configuration is to preserve the plant's current 10-minute start capability to provide the Cal-ISO with rapid response peak generation resources."***

Orange Grove Peaking Facility

The Orange Grove Peaking Facility, which has just recently received approval to construct, will be located in Northern San Diego County. This plant was originally envisioned as a simple cycle peaking power plant using two GE LM6000 Sprint PC combustion turbines. As part of due diligence, however, the developers considered the alternative of taking advantage of OTSG to improve efficiency, reduce carbon footprint, and lower the levelized cost of electricity generated by the plant. Upon review of the new plant layout, the developers realized that there would be significant changes in both stack height and physical appearance of the plant that could trigger reevaluation of visual impacts under CEQA[8]. As a result, the developers elected to stay with the original configuration in order to avoid potential schedule slippage.

Section 5.6.2.1 of the Orange Grove application to the CEC states in part:

[8] Personal Communication April 2009 – Caleb Lawrence, Innovative Steam Technologies, commenting on the additional complication CEQA introduces in the power plant development process, and specifically citing his experience with the Orange Grove Peaking Project.

" …some systems that include once-through steam generators (OTSG) allow for relatively rapid start-up times, at least to part load…

"… plant footprint and vertical height are greatly increased, adversely affecting visual impact. Considering these factors, the proposed Project does not incorporate combined-cycle technology." [9]

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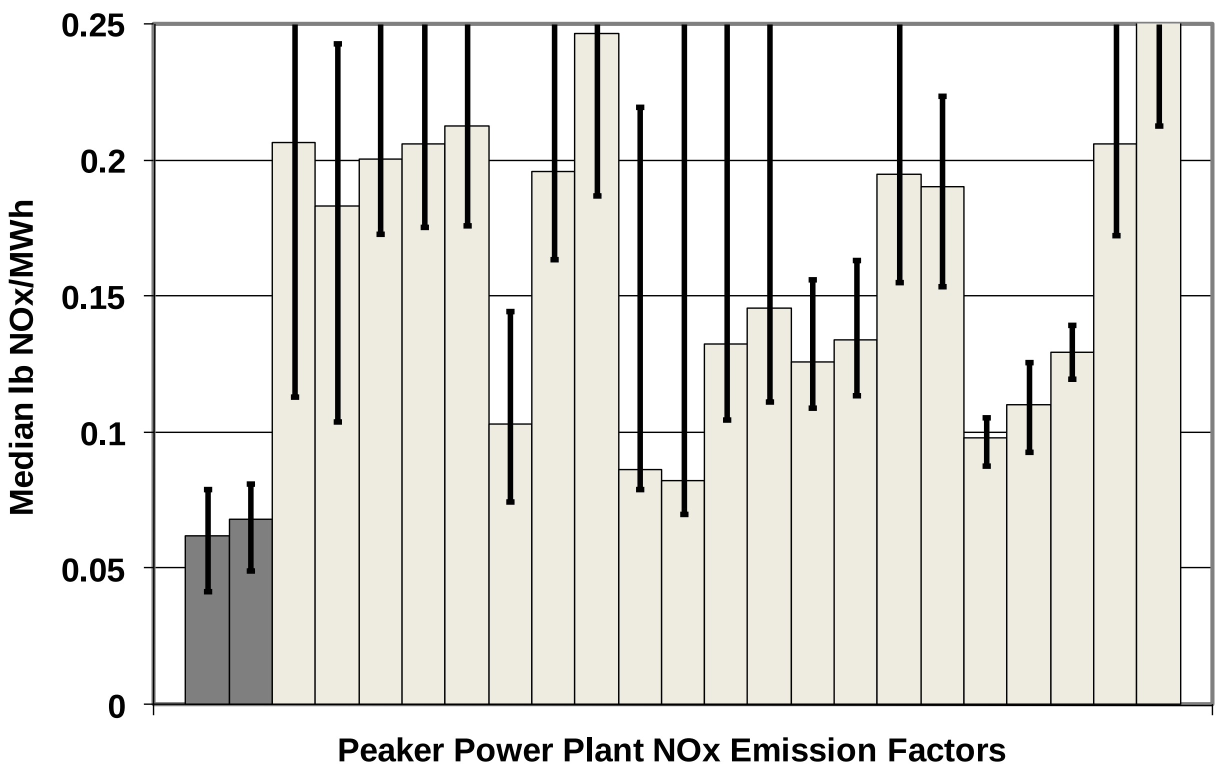
[99] Author note: the Orange Grove document also *incorrectly* states that OTSG would result in greatly increased water usage at the site. Relative to simple cycle operation of the LM6000 Sprint PC, combined cycle utilizing OTSG results in only a 5 – 6 percent increase in water usage, as the makeup water for the boiler is significantly less than the amount of water injected into the turbine, which is not recovered.

Comparison of Emissions from Combined Cycle and Simple Cycle Power Plants

Emissions from different power plants are difficult to compare on a snapshot basis. Nor are emissions averaged over long periods of time necessarily relevant, since different plants operate under different loading schedules. However, in comparing combined cycle with simple cycle peaking power plants it is possible to see the benefits of the combined cycle configuration by looking at performance trends that transcend such distinctions as that between a “merchant” peaking plant and a municipal plant designed to provide reserve peaking capacity.

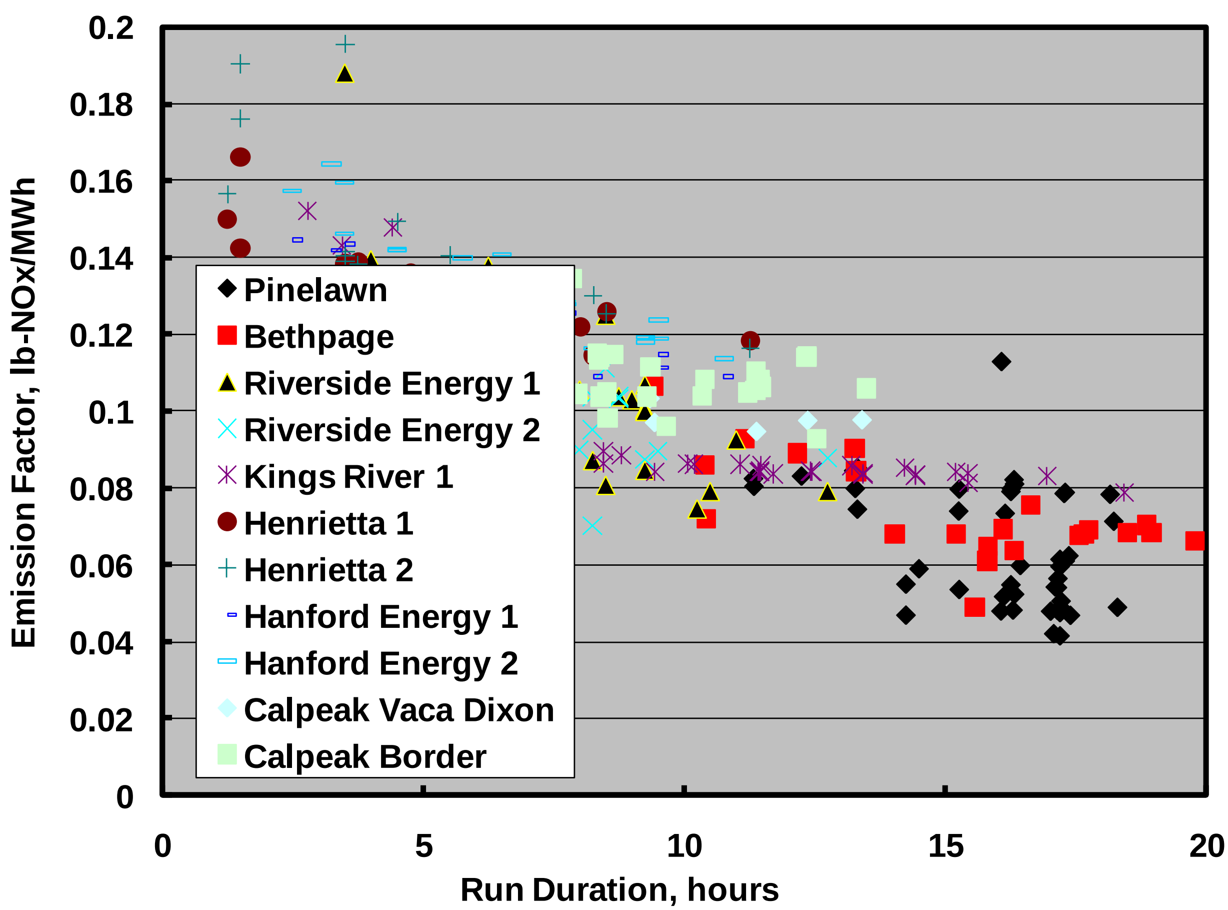
The figure below shows median NOx emission factors for a sample of both combined cycle and simple cycle peaking power plants. Data shown are taken from hourly reported performance and emissions data reported to the U.S. EPA for the months of July and August 2007, and downloaded from the EPA Clean Air Markets database. The darker shaded bars on the left of the graph are for the Pinelawn (first column) and Bethpage (second column) combined cycle peaking power plants located in the State of New York. These are both GE LM6000PC Sprint turbines equipped with OTSG and steam turbines. The remaining data are from peaking power plants across the State of California.



The main bars in this graph represent median NOx emission factors for each start/stop sequence reported over the two month period. Arithmetic mean data did not provide a satisfactory comparison, as some of the plants in California experience a few very short run periods with exceptionally high emission factors that strongly biased the data. The upper limits on the error bars represent one standard deviation above the median, while the low limits on the error bars represent the lowest value reported for any start/stop sequence over the two month period.

The California plants closest in emissions performance to the two combined cycle peaker plants are the Kings River units 1 and 2 indicated in columns 11 and 12 from the left. However, the best emissions factor from Kings River is only comparable to the median value from Bethpage. Some of this might be attributed to the longer average run times at Bethpage and Pinelawn, which allows the start up and shut down emissions to be averaged out over a longer period of time.

This is not borne out across the board, however, when we consider Calpine Gilroy units 3 and 4, shown in columns 17 and 18 from the left. These units frequently operated for durations in excess of 12 hours during the two month period under consideration; and yet in comparing emissions factors with those of Pinelawn and Bethpage for similar operating periods, the Calpine Gilroy units had emission factors more than twice as high. The next figure illustrates the distinction between combined cycle and simple cycle performance more clearly.



These results are NOx emission factors for individual start/stop cycles for the plants shown over the period of July – August 2007. At this level of granularity it can be seen that for individual one-on-one comparisons there are some cases where the cleanest peaking power plants in California can be comparable to or even cleaner than the combined cycle examples. This comparison does not factor in other externalities, however, which could include time since last shut down (which affects start up time and emissions), ambient temperature, and even the rapidity of the startup sequence. On the whole, nonetheless, combined cycle technology shows up as being on average on the order of 20 – 30 percent cleaner than simple cycle technology in peaking applications.

Combined Cycle Peaking and Canyon Power

In their "justification" document, Anaheim provide a series of figures labeled as Table 1A, Table 1B and Table 1C, that purport to show projected operational schedules for the four LM6000 turbines from 7/30/2012 through 9/3/2012. These figures show the turbines operating on approximately six days during each calendar week over this period. Over some of this time only one turbine is operated in a single day, and for as little as three hours. However, during much of the period one or more of the turbines are in fact operated for as much as 15 hours.

These figures are used in the "justification" document as evidence that operation of the Canyon Power Plant is inconsistent with combined cycle operation. But this is only supported if we consider combined cycle to be 1990s state of the art technology. It has been shown in the earlier section of this report, that advanced combined cycle peaking power plant technology has been in existence for nearly 30 years, and that the earliest examples of this technology were fielded over 20 years ago. The technology being proposed by Anaheim for the Canyon Power Project was deemed highly advanced and reliable in the 2000 – 2001 time frame, but by now has been superseded – and *that* needs to be recognized.

In the figures labeled as Tables 1A through 1C in the "justification" document, there are no examples of the turbines starting up in a ten-minute time frame. In fact, in the document "URS Project Emissions Information"[10] on page 4 it is stated:

> ***"Table 3-1 has been revised to reflect the increase in startup time from 20 minutes assumed in the original application to 35 minutes which is necessary to achieve full compliance with the steady state emission limit."***

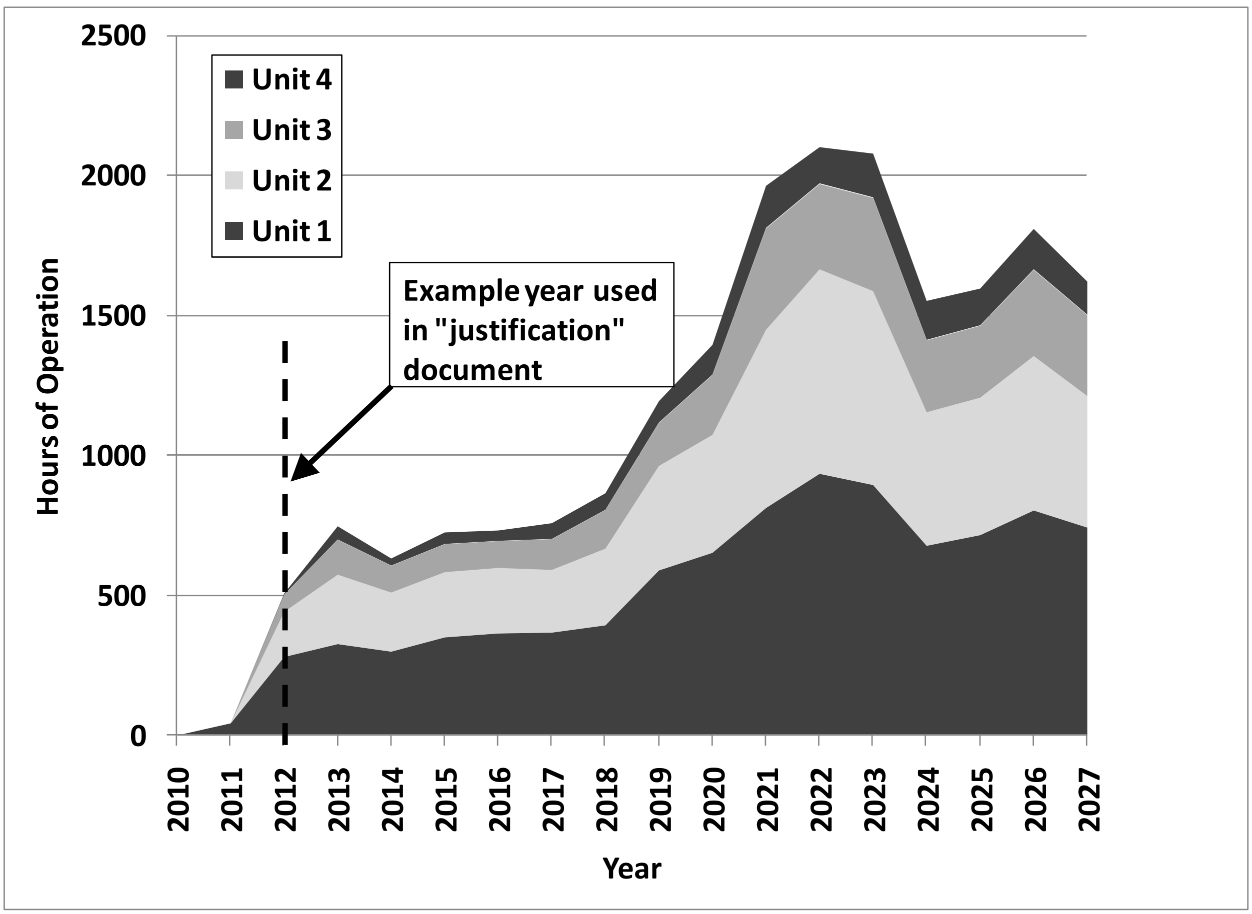
This operation is fully compatible with the capabilities of current combined cycle power plant operation where, with OTSG, these turbines can start up and meet these capabilities for power generation without sacrificing reliability or availability.

> *In fact, the Big Hanaford power plant in Centralia, Washington, cited in Yorba Linda's request for a public hearing, and again referenced in the "justification" document is an excellent example for this situation. Big Hanaford is in fact a large base loaded coal-fired power plant, that happens to have four GE LM6000 Sprint PC turbine equipped with OTSG and steam turbines. According to information on the U.S. EPA Clean Air Markets Database, these turbines normally start up rapidly and run with no steam turbine operation at all. In fact, the steam turbines are there "in case" there is need for the extra capacity. So that in fact, they present no hindrance at all to the peaking capability of the plant.*

[10] *URS Project Emissions Information*, California Energy Commission Docket 07-AFC-9 Log# 50457, March 10, 2009.

During the majority of this period of the year 2012, in fact, these turbines could be operating in combined cycle mode with all the consequent reductions in both GHG and priority pollutant emissions, while still generating the needed power and meeting the availability needs required under CAISO.

Even this picture is misleading however. Tables 1A – 1C presented by Anaheim in the "justification" document, with the accompanying text, fail to tell the entire story of the plant operations. Table 2 of that document points out that by 2022 the plant is expected to be operating at least four times as many annual hours as envisioned in the year 2012. The following figure illustrates the anticipated hourly operation of the Canyon Power plant, by turbine unit, from project conception through the year 2027. At 2000+ hours per year, Canyon Power Plant can hardly be considered to be a "peaking" power plant any longer. If operations are restricted to the summer months of peak demand, then the operating hours for units 1 and 2 will be consistent with extended periods of operation, perhaps up to 15 hours per day, at which point combined cycle is the technology of choice.



By this point the Canyon Power Plant will in fact be a part-time base load power plant with peaking capability. Long before it achieves that status – no later than 2015 or 2016 – it should have demonstrated its capability and have operators become familiar with operation as a true combined-cycle peaking power plant. It is no stretch to go even one step further and point out that even at 2,078 annual operating hours per year, as currently proposed for the year 2023, the plant will be only operating at half the annual capacity that was needed to economically justify construction of the plant as described in the *Fact Sheet* issued by Anaheim Public Utilities on April 15, 2008[11].

The Anaheim fact sheet states that the $200 million project will save Anaheim utility customers up to $12 million per year in fees to CAISO. In total it was projected to result in a potential net benefit to Anaheim of $17 million per annum, even after debt service. However, this was based on total operational hours in excess of 4,000 per year. Reducing the total operating hours to half those originally planned would reduce the total wholesale revenue benefits to *less than what would be required to service the debt* on the originally planned project – bringing the entire project into question.

Into question, that is, until we consider the modifications to the permit that were negotiated in order to make it possible to build the plant without needing to access the SCAQMD priority reserve under rule 1309.1. Those modifications included:

- An increase in the number of turbine starts/stops per year from 129 to 240 per turbine
- An increase in the maximum annual hours of operation per turbine from 602 hours per year to 90 hours of operation per turbine per month for a total maximum of 1080 hours per turbine per year – when startup and shutdown times are included the second revised application to the permit results in a maximum of 1260 hours of operation per year for any one turbine[12].
- A reduction in total combined turbine operating hours from 4,006 to either 2,000[13] or 2,408[14], depending on which document is the more accurate[15].

While the reduction in total operating hours will indeed reduce annual average emissions from the plant, the increase in the permitted number of starts and stops will in fact increase the levelized emissions from the plant in terms of mass emissions of pollutant per MW-hr of electricity produced. It also means that there will be a greater number of acute "bursts" of emissions, as each turbine operates

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[11] Canyon Power Project Fact Sheet, *Anaheim Public Utilities,* 15 April, 2008.

[12] Preliminary Determination of Compliance (PDOC) for Canyon Power Plant (CPP) Proposed 200 Megawatt Power Plant Project (Facility ID No. 153992), to be located at 3071 E. Miraloma Avenue, Anaheim, CA 92805 (07AFC-9). South Coast Air Quality Management District, February 18, 2009.

[13] Canyon Power Plant (07-AFC-9) Status Report #3. February 26, 2009.

[14] Southern California Public Power Authority's Canyon Power Plant Status Report #1 *op.cit.*

[15] Author's note: The California Energy Commission Preliminary Staff Assessment for the Canyon Power Plant, dated April 2009 and entered into the project docket on May 7, 2009, still states that the plant is intended to operate for a total 4,006 hours per year, with each turbine operating approximately 1,000 per year.

with essentially no emissions control until the pollution control system achieves "light off" at approximately 15 minutes into the start cycle.

These relaxed constraints on the number of plant start ups will provide the Canyon Power Project with more flexibility to respond to short term demands for electric power within CAISO. In fact, by maintaining both spinning and non-spinning reserves, the Canyon Power Project will be able to deliver power to the grid at short notice and for brief periods when the spot market price for electricity is quite high. This would enable the plant to better meet its debt service obligations and help provide justification for the public investiture needed to build the plant in the first place. This would not, however be done to service the electric power need of the rate payers of Anaheim and surrounding communities. Rather it would simply serve the purposes of revenue generation for the project developers and the city.

This admittedly cynical interpretation of the present circumstances is not, however, the most likely scenario to play out. In fact, there is every reason to expect that once the SCAQMD adequately revises its rules under Regulation XIII to the satisfaction of the courts and plaintiffs, including new source review (NSR) guidelines, the Canyon Power Project will apply for and receive a modified permit to operate that more closely resembles the original intent of the plant; and further, that this is likely to play out within the timeline for construction and commissioning of the plant.

Summary and Conclusions

If Canyon Power Project is reconfigured as a combined cycle power plant, under the operating scenario described in the modified permit application, turbine start up, time to power and emissions will be unaffected by OTSG in normal cold start operation.

Use of OTSG combined cycle technology in lieu of simple cycle turbines will result in a small, but real reduction in on site water consumption as a result of eliminating one combustion turbine and associated steam injection. Furthermore, the absence of a steam drum and blow-down tank in the OTSG configuration will reduce the demands for water quality and corrosion inhibitors in the boiler feedwater.

Personnel and maintenance requirements for OTSG- based combined cycle operation are manageable and not likely to be as great as projected by Anaheim.

All indications are that steam turbine start up times will be significantly shorter than envisioned in the "justification" document – especially if hot standby procedures are implemented during high demand periods when daily operation can reasonably be anticipated. In addition, hot standby can allow for earlier start up of the SCR emissions control system and earlier light off of the CO oxidation catalyst. This would result in reduced startup emissions that could provide justification for increasing hours of operation, as long as net annual emissions do not increase.

The year 2012 turbine operations profiles used as example by Anaheim are completely compatible with combined cycle operation with OTSG technology. On certain days during this profile turbines are running up to 15 hours per day. But even the shortest runs, at three hours would benefit from combined cycle operation, especially if the steam path were maintained in hot standby. It also needs to be emphasized that the year 2012 scenario is not typical of plant operation over its lifetime. In planning for future energy needs Anaheim should be thinking ahead and applying the most advanced and energy efficient technology currently proven and available – and not relying on ten year old approaches to handling peak power needs.

Installed costs will be higher, as suggested by Anaheim. However in later years this should result in reduced fuel consumption and, as other plant operators have found or are projecting. This translates into a reduced levelized cost of electricity over the life of the plant.

It is all but certain that the operating permit for Anaheim will be changed over time to permit increased operating hours. It can also be expected that likely that future circumstances, including natural disaster (fires, earthquakes, grid failure, other) will result in executive orders temporarily suspending restrictions on hours of operation. All of this points to a need to install a more efficient and cleaner power plant now.

It is recognized that a more efficient power plant will find a more favorable position on CAISO loading order. However, this still means displacing less efficient and more polluting plants in the basin, effectively reducing emissions regardless (as being more efficient will not result in greater electricity demand).

As more renewable energy resources come on line, Canyon will be needed to provide load leveling as well as peaking support to the local grid. Ramping of the simple cycle turbines results in emissions increases that can be at least partially mitigated by ramping the steam turbine as well.

While the City of Anaheim make many good points in their “justification” document, the evidence presented here supports a countervailing conclusion that in looking forward, the installation of combined cycle capability in the Canyon Power Plant *today* will provide the best *overall* solution to *current and future* needs for electrical power in Anaheim and across the South Coast Basin.