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February 23, 2007

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California Public Utilities Commission
Lynda Kastoll
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Re: Comments on second Sunrise Powerlink scoping period (Application 06-08-010)

Dear Ms. Blanchard and Ms. Kastoll:

Thank you for the opportunity to participate in the second scoping period on the Sunrise Powerlink under the California Environmental Quality Act (CEQA) and National Environmental Policy Act (NEPA). These comments are provided on behalf of the Center for Biological Diversity, Sierra Club, Desert Protective Council, and Denis Trafecanty.

The purpose of these comments is to identify outstanding issues that should be fully considered in the Environmental Impact Statement / Environmental Impact Report (EIS/EIR). As indicated in our comments on the first scoping period, nothing in this letter should be construed as an endorsement for any physical route or mitigation for the Powerlink and in fact we will continue to vigorously oppose construction of this unnecessary and extremely harmful project.

As an initial matter, the second scoping notice's inclusion of "no-wires" and some system alternatives appears to be an important first step towards upholding the public interest and minimizing harm from the Sunrise Powerlink on people and nature. Bundled no-wires alternatives alone and/or in combination with appropriate system alternatives are likely the only legitimate means to encourage energy efficiency and conservation, encourage local development of renewables and cleaner and more efficient fossil-fired generation, improve energy grid security, and reduce energy costs, all while simultaneously protecting people and nature.

Unfortunately, the second scoping notice still mischaracterizes San Diego Gas and Electric's preferred alternative as feasible. In fact, SDG&E's preferred alternative and other stand-alone transmission alternatives are not feasible because they clearly do not advance the public interest and are inferior to other less harmful alternatives to achieve project objectives. For these reasons, SDG&E's preferred alternative should be eliminated from consideration in the EIR/EIS.

The draft EIS/EIR should thoroughly and independently consider the following additional information and issues:

I. "Basic Project Objectives" should be revised in the EIR/EIS to uphold law and the public interest

Basic Project Objectives identified in the second scoping notice improperly emphasize SDG&E's self-serving, transmission-biased agenda over law and the public interest.

Consideration of broad objectives is necessary to ensure that energy projects uphold public priorities to prevent global warming, encourage energy efficiency and conservation, and development of renewables and local cleaner and efficient fossil-fired generation before consideration of long distance, polluting, fossil fuels-based transmission. In contrast, SDG&E's Powerlink objectives are crafted so narrowly that their desired project becomes the only feasible alternative.

CEQA requires that an EIR discuss a range of alternatives that would "feasibly attain most of the basic project objectives but would avoid or substantially lessen any of the significant effects of the project." CEQA Guidelines § 15126.6(a). This requirement does not just limit the range of alternatives that needs to be evaluated in an EIR; it also is a limitation on how narrowly the project objectives may be drawn. These objectives may not be defined so narrowly that only the preferred project is capable of meeting them. SDG&E's objectives violate this fundamental requirement of CEQA.

In addition, the Powerlink "Basic Project Objectives" do not advance the public interest as represented by laws comprising California's loading order, the California Renewables Portfolio Standard Program (SB 1078), and laws to reduce global warming, including the California Global Warming Solutions Act of 2006 (AB 32) and Executive Order S-3-05, because they appear overly focused on summarizing SDG&E's objectives versus those that which would best advance the public interest.

The EIR/EIS should include at least four additional Basic Project Objectives: 1) to apply and advance California's loading order; 2) to apply and advance California's Renewable Portfolio Standard; 3) apply and advance California laws to reduce global warming; and 4) to apply and advance state and federal laws and regulations to avoid, minimize, and mitigate any environmental harm.

The EIR/EIS should also include a thorough discussion of how each particular Powerlink alternative will uphold and advance the public interest as reflected in California's loading order, Renewable Portfolio Standard, global climate change laws, and the National Environmental Policy Act, California Environmental Quality Act, and other environmental law.

II. The EIR/EIS Must Analyze the Powerlink's Contribution to Global Warming and Consider Measures to Mitigate this Impact

The second scoping notice does not appear to anticipate necessary analysis in the EIR/EIS of the harmful contributions of the Powerlink to global warming.

Concentrations of greenhouse gases are increasing in the earth's atmosphere, primarily from the burning of fossil fuels for energy and destruction of forests for other human activities. These gases cloak the earth like a blanket, absorbing solar radiation that would otherwise be radiated back into space, causing the earth's climate to warm much like the interior of a greenhouse. This phenomenon is called global warming and is leading to profound changes in the earth's climate. The world's leading scientists agree that society's production of greenhouse gases, including carbon dioxide (CO_2), methane (CH_4), and nitrous oxide (N_2O), is responsible for the unprecedented rate of warming observed over the past century.

Carbon dioxide accounts for approximately 85% of total emissions, and methane and nitrous oxide together account for almost an additional 14%. Because of the persistence and mixing of these gases in the atmosphere, emissions anywhere in the world impact the climate everywhere equally. Therefore, the impact of greenhouse gas emissions produced in California (the 12th largest emitter in the world) will impact not only California, but the rest of the world as well. In the absence of substantial reductions in greenhouse gas emissions, global warming and its impacts on human health, the environment, and the economy will rapidly worsen in this century.

The EIR/EIS must analyze the impacts posed by greenhouse gas emissions resulting from the Powerlink. The State of California recognizes the threats posed by global warming. To address and rectify the State's increasing contributions to greenhouse gas emissions the State of California has enacted requirements for state and local agencies to address the issue of global warming by analyzing and reversing the emissions of greenhouse gases. Executive Order S-3-05 calls for greenhouse gas emission reductions and analysis of the impacts of climate change. The legislature and the Governor again reaffirmed their commitment to address the issue of climate change by passing the "The California Global Warming Solutions Act of 2006." AB 32.

California is extremely vulnerable to the impacts of global warming and is also responsible for a significant portion of the U.S. and global emissions of greenhouse gases. The significant risks climate change poses to California as well as the considerable benefits the state could realize if it addresses these risks prompted Governor Schwarzenegger to issue Executive Order S-3-05 on June 1, 2005. The Executive Order called for specific emissions reductions and a periodic update on the state of climate change science and its potential impacts on sensitive sectors, including water supply, public health, coastal areas, agriculture and forestry. The

Executive Order established the following greenhouse gas (GHG) emissions targets: by 2010, reduce GHG emissions to 2000 levels; by 2020, reduce GHG emissions to 1990 levels; and by 2050, reduce GHG emissions to 80 percent below 1990 levels.

In response to Executive Order S-3-05, the California Environmental Protection Agency (CalEPA) formed a Climate Action Team with members from various state agencies and commissions, The Team has issued a series of reports, including a March 2006 Climate Action Team Report to Governor Schwarzenegger and the Legislature. This and other reports issued by CalEPA, the California Energy Commission (CEC), Department of Water Resources and other California agencies are available at http://www.climatechange.ca.gov/documents/index.html and should be used in preparing environmental documents under CEQA.

Some of the major impacts identified in recent reports include:

- Reduction of Sierra snowpack up to 90 percent during the next 100 years threatens California's water supply and quality as the Sierra accounts for almost all of the surface water storage in the state;

- Impacts to the health of Californians due to increases in the frequency, duration, and intensity of conditions conducive to air pollution formation, oppressive heat, and wildfires. Increasing temperatures from 8 to 10.4°F, as expected under the higher emission scenarios, will cause a 25 to 35 percent increase in the number of days Californians are exposed to ozone pollution in most urban areas. This will slow progress toward attainment of air quality standards and impede many of the state's efforts to reduce air pollution. Temperature increases are likely to result in an increase in heat-related deaths. Children, the elderly, and minority and low-income communities are at greatest risk;

- Potential impacts from limited water storage, increasing temperatures, increased carbon dioxide concentrations, pests and weeds threaten agriculture and its economic contribution to the state. Direct threats to the structural integrity of the state's levee system would also have immense implications for the state's fresh water supply, food supply, and overall economic prosperity;

- Erosion of our coastlines and sea water intrusion into the state's delta and levee systems may result from a 4 to 33-inch rise in sea level during the next 100 years. This will further exacerbate flooding in vulnerable regions;

- Increasing temperatures and pest infestations would make the state's forest resources more vulnerable to fires. Large and intense fires threaten native species, increase pollution, and can cause economic losses; and

- Increasing temperatures will boost electricity demand, especially in the hot summer season. By 2025 this would translate to a 1 to 3 percent increase in demand resulting in potentially hundreds of millions of dollars in extra energy expenditures.

The California Global Warming Solutions Act of 2006 (AB 32), acknowledges the threats of global warming and places a cap on California's greenhouse gas emissions and thus brings the state closer to meeting these targets. The state of California recognizes the significant threats to the natural environment posed by global warming:

> Global warming poses a serious threat to the economic well-being, public health, natural resources, and the environment of California. The potential adverse impacts of global warming include the exacerbation of air quality problems, a reduction in the quality and supply of water to the state from the Sierra snowpack, a rise in sea levels resulting in the displacement of thousands of coastal businesses and residences, damage to marine ecosystems and the natural environment, and an increase in the incidences of infectious diseases, asthma, and other human health-related problems.

AB 32 § 38501(a) 2006.

> Global warming will also have significant impacts on the California economy, which must be addressed by all levels of government.
>
> Global warming will have detrimental effects on some of California's largest industries, including agriculture, wine, tourism, skiing, recreational and commercial fishing, and forestry. It will also increase the strain on electricity supplies necessary to meet the demand for summer air-conditioning in the hottest parts of the state.

AB 32 § 38501(b) 2006. In order to address the threats and impacts of global warming the California Global Warming Solutions Act requires the state to reduce the levels of greenhouse gas emissions to 1990 levels by the year 2020. AB 32 § 38550.

CEQA requires an EIR to analyze any "significant environmental effects" of a proposed project. Pub. Res. Code § 21 100(b)(l); Cal. Code Regs., Title 14, §§ 15126(a), 15126.2(a), 15143. "Significant effect on the environment' means a substantial, or potentially substantial, adverse change in the environment." Pub. Res. Code § 21068. CEQA also provides that the CEQA Guidelines "shall" specify certain criteria that require a finding that a project may have a significant effect on the environment:

> (1) A proposed project has the potential to degrade the quality of the environment, curtail the range of the environment, or to achieve short-term, to the disadvantage of long-term, environmental goals.

> (2) The possible effects of a project are individually limited but cumulatively considerable. As used in this paragraph, "cumulatively considerable" means that the incremental effects of an individual project are considerable when viewed in connection with the effects of past projects, the effects of other current projects, and the effects of probable future projects.
>
> (3) The environmental effects of a project will cause substantial adverse effects on human beings, either directly or indirectly.

Pub. Res. Code § 21083(b).

The EIR/EIS must therefore disclose the Powerlink's net contribution to greenhouse gas emissions from all sources and incorporate feasible mitigation measures and alternatives to reduce this impact. Sources that should be evaluated include all emissions associated with construction, operation, and maintenance of the project. This analysis should include a projection of the sources of the power to be transmitted by the project, and a discussion of how these projected sources contribute to greenhouse gas emissions. For example, if the project will purchase a portion of the power transmitted from coal- or natural gas-fired plants, the EIR/EIS must disclose this reliance and discuss the life cycle carbon emission consequences of these fuels.

Feasible measures exist to reduce the Powerlink's contribution to greenhouse gas emissions, including improved efficiency and conservation, increased reliance on renewable power sources, at-source emissions controls including capture and sequestration of carbon emissions, and purchase of carbon emissions credits. For identified greenhouse gas emissions impacts, each of these measures should be considered with the goal of achieving carbon neutrality (no net emissions of greenhouse gases) for the Powerlink.

The EIR/EIS should also evaluate and compare each alternative's net contribution to greenhouse gas emissions.

III. The EIR/EIS should include a thorough and independent analysis of SDG&E cost estimates

Cost estimates for construction of the Powerlink generated by SDG&E do not appear to be accurate or reliable.

SDG&E's corrected Gridview model results submitted on January 19, 2007 indicate the in-basin combined-cycle alternative is less expensive than the Powerlink by over $60 million/year. SDG&E augmented the corrected model one week later (January 26) and now claims that Sunrise is less expensive by $80 million/year. The EIR/EIS should include a thorough and independent analysis of the legitimacy of SDG&E's January 26th modifications to the January 19th corrected Gridview model results.

The EIR/EIS should also include a thorough and independent assessment of the legitimacy of SDG&E's power cost calculations submitted by the company to support their claim that Imperial Valley renewable energy resources will be less costly than natural gas combined cycle generation in Baja California or Arizona, such that all foreseeable renewable generation in the Imperial Valley will automatically have a market at price rates necessary to justify construction without a long-term power contracts.

These cost estimates are intimately related to the analysis of the project's environmental impacts. We anticipate that economic factors will be used as one basis for rejecting otherwise feasible and environmentally superior alternatives. An objective comparison of alternatives will require full disclosure and independent analysis of project costs. In addition, the project's actual costs will depend on how the power that is purchased for transmission by the project is generated. Different sources have different environmental impacts, which must be fully disclosed and analyzed. In particular, the EIR/EIS should disclose the extent to which SDG&E's cost estimates rely on purchasing power generated by cheaper, dirtier sources.

IV. The EIR/EIS should evaluate the viability and cost of claimed Imperial Valley renewables

Serious questions have arisen over the viability and cost of several potential Imperial valley sources of renewable energy cited by SDG&E as justification for construction of the Powerlink.

The Stirling Solar Project does not appear to be technologically or commercially viable. To the extent the Powerlink relies on the Stirling Solar Project, the EIR/EIS should thoroughly and independently evaluate the feasibility of this source and consider likely alternatives if it does not prove feasible.

Geothermal energy development appears significantly limited by natural barriers (e.g. the location of a large area of potential geothermal energy underneath the Salton Sea) and by market forces. To the extent the project relies on projected geothermal energy development, the EIR/EIS should evaluate the feasibility of this source and consider likely alternatives if it does not prove feasible.

The Powerlink is not located near planned and viable wind energy sites. To the extent the project relies on planned or potential wind energy development, the EIR/EIS should evaluate the feasibility of using power generated by this source and consider likely alternatives if it does not prove feasible.

The implications of reduced renewables availability on the purported need for the Powerlink should be thoroughly and independently evaluated in the EIR/EIS.

The EIR/EIS should acknowledge that ultimate control over the type of energy transmitted over the Powerlink rests with government agencies, not SDG&E, and consider the implications of this on the purported need for the Powerlink. The Powerlink will only transmit renewable energy to the extent this is available, cost-effective, reliable, and perhaps most importantly, contracted to SDG&E instead of the Imperial Valley Irrigation District or other agencies. Otherwise this is just another transmission line benefiting fossil-fuel and nuclear generators.

SDG&E is projecting renewable energy production in Imperial Valley in 2015 that is 114% of SDG&E's total predicted retail power sales. The EIR/EIS should address: 1) The legitimacy of the assumption that 21,260 GWh of total renewable energy will be generated in Imperial Valley in 2015, and; 2) Identify the regulatory or other motivation likely to compel SDG&E to import more renewable energy than the 20% required under California law.

V. The EIR/EIS must evaluate the current and future capacity of existing or other planned transmission lines to accommodate delivery of Imperial Valley renewables

The production of renewable energy in the Imperial Valley is not likely to exceed planned export capacity by the Imperial Irrigation District and others, and existing export capacity already controlled by SDG&E.

SDG&E has stated in both Powerlink applications that they can meet their Renewable Portfolio requirements with existing transmission facilities. SDG&E responses to UCAN data requests in January 2007 identify no cost or other constraints that might limit importation of 21,260 GWh of Imperial Valley renewables in 2015, a rate six times higher than that required to meet SDG&E's 2010 renewables requirements.

Expiration of California energy contracts in 2010 will release significant additional capacity for renewables transmission on the existing Southwest Powerlink.

The implications of the availability of renewables transmission alternatives on the purported need for the Powerlink should be thoroughly and independently evaluated in the EIR/EIS.

Existing Imperial Irrigation District transmission lines and the proposed "Green Path North" would likely provide all necessary capacity for transmission of renewables. The EIR/EIS should include consider of one alternative including a combination of the Green Path North project along with any combination of no-wires alternatives and the "Path 44 Upgrade Alternative" to achieve project objectives. SDG&E's partnership with the Imperial Valley Irrigation District should facilitate consideration of the Green Path North as a feasible Powerlink alternative to move Imperial County renewables and achieve basic project objectives.

VI. The EIS/EIR should evaluate improved energy efficiency as part of one or more no-wires alternative bundles

The second scoping notice appears to unreasonably exclude or limit improved efficiency programs, conservation, and demand response from the mix of no-wires alternative bundles.

Instead, the notice appears to rely on SDG&E's Preliminary Environmental Assessment portrayal of limited future cost-effective energy efficiency (page 22). This reliance may be misplaced given the company's significant and obvious transmission bias.

Exclusion of energy efficiency from any of the proposed no-wires alternative bundles is contrary to the second scoping notice statement that "Potential non-wires alternatives to the project consist of energy efficiency, demand response, renewable generation, distributed generation, and clean fossil-fired generation." (Emphasis added.)

The EIR/EIS analysis of no-wires alternatives should include a thorough and independent analysis of the feasibility of a mix of possible new or expanded energy efficiency measures in SDG&E's service area.

Specifically, the EIR/EIS should include programs to improve energy efficiency such as those requiring that buildings and appliances to be constructed in a manner that use less energy, that provide incentives for purchasing energy efficient equipment, and that provide information and education to encourage people to save energy. The EIR/EIS should also include demand response programs such as new rate designs to provide customers lower electricity prices during most hours in exchange for higher prices during higher peak hours, as well as programs that provide incentives for on-peak load reductions. To the extent the EIR/EIS excludes measures for improved efficiency, the document must thoroughly and independently analyze why such measures are not feasible and consider other efficiency measures.

VII. The reduced likelihood of construction of a new power plant on San Diego Bay in Chula Vista in no way reduces the viability of stand-alone and/or bundled no-wires and/or system alternatives

The City of Chula Vista has voted to reject the location of a new power plant on San Diego Bay inside City limits. Yet this decision should in no way reduce the viability of any no-wires alternative to the Powerlink. In just one example, the proposed Otay Mesa Generating Station (a 561 MW Baseload plant) provides a conventional alternative to a South Bay power plant on San Diego Bay.

In addition to improved efficiency measures identified above, the EIR/EIS should expand consideration of no project and no-wires Powerlink alternatives to include all potential in-basin renewable and conventional power sources, including those identified by the Environmental Health Coalition in their document, Green Energy Options to Replace the South Bay Power Plant (http://www.environmentalhealth.org/GEOreport.htm).

VIII. The EIR/EIS must evaluate all possible future or related phases of the project

An EIR must evaluate the cumulative impacts of a project in combination with other closely related past, present, and reasonably foreseeable probable future projects. CEQA

Guidelines §§ 15130, 15355(b). In addition, if the project is a part or a precedent of a larger future project, this relation must be disclosed and addressed in the EIR. CEQA Guidelines § 15165. At a minimum, an EIR must discuss the cumulative effect of the future related project. Id.

The second scoping notice appears to neglect one of the single most likely sources of significant cumulative impacts from the Powerlink – SDG&E and Sempra's planned Full Loop. SDG&E maps and presentations on future transmission line projects from as recently as July 2005 portrayed the Powerlink as part of a larger project to connect the Imperial Valley Substation to the Serrano Substation near Riverside with 500kV lines. This link is clearly a reasonably foreseeable project directly related to the Powerlink.

Any future Full Loop project would result in even greater unnecessary impacts to people and nature than the proposed Powerlink and exposes the true motives of SDG&E and parent company Sempra Energy – The Powerlink is just phase one of a master plan to extend the line north to expand their California market for imported cheap, polluting, fossil-fuel power from Sempra's Mexicali power plant and others.

The environmental impacts of the Full Loop should therefore be fully disclosed and analyzed in the EIR/EIS, and measures identified to avoid, minimize, and mitigate any harm to people and nature.

IX. The EIR/EIS must disclose and evaluate one of the most significant potential land use impacts from the Powerlink – the inappropriate and incompatible location of the project through Anza-Borrego Desert State Park and designated state wilderness

The second scoping notice appears to accept SDG&E's premise that the company owns a 100ft. right-of-way for the entire 23 miles of Anza-Borrego Desert State Park traversed by the Powerlink (page 11). Yet evidence exists suggesting that SDG&E's easement may be only 24 ft. wide through portions of the park. The EIR/EIS should provide a thorough and independent analysis of this apparent conflict including maps clearly identifying easement widths along the entire length of the line through the park, and include any documents establishing SDG&E's park right-of-way.

X. The EIR/EIS must thoroughly disclose and evaluate the most likely significant impacts of SDG&E's preferred alternative and others on environmental issue areas beyond those described in the scoping notices

The second scoping notice inexplicably neglects to identify key environmental impacts of SDG&E's preferred alternative and other alternatives that must be evaluated in the EIR/EIS. The word "significant" is used only twice in the second scoping notice to describe impacts to environmental issue areas and both are in reference to impacts to paleontological resources. The EIR/EIS should acknowledge the myriad significant impacts of the preferred alternative and others identified in the first round of scoping and identify measures to avoid, minimize, and mitigate this harm to people and nature. Likely significant impact from the Powerlink include but are not limited to:

- Significant impacts to aesthetic and visual resources such as sweeping, undeveloped desert views and the pastoral Santa Ysabel Valley;
- Significant impacts to sensitive biological resources like bighorn sheep, California gnatcatchers, southern maritime chaparral, and mature oak trees;
- Significant impacts to the people of the Imperial Valley who must breath air polluted by power plants in Mexico;
- Significant impacts to existing land uses such as preserves established for species and habitat protection under the San Diego Multiple Species Conservation Plan as well as to private property;
- Significant impacts to cultural resources such as Native American sites;
- Significant impacts to recreational opportunities in natural areas free of industrial development, and others.

XI. All of the "Southwest Powerlink Alternatives" would result in significant impacts to environmental issue areas

The EIR/EIS should acknowledge the many significant impacts of the Southwest Powerlink Alternatives, including but not limited to:

- Significant incompatible land uses with Alternative BCD through the In-Ko-Pah Mountains Area of Environmental Concern, and with Alternative D through the Eagle Peak Roadless Area in the Cleveland National Forest;
- Significant impacts to mature oak trees, coastal sage scrub, California gnatcatchers, and Quino checkerspot butterfly habitat, and many other sensitive biological resources from all Southwest Powerlink alternatives;

The "BCD Alternative," "Route D," and "West of Forest" alternatives would likely result in the greatest number of significant impacts to environmental issue areas;

The EIR/EIS should identify all necessary measures to avoid, minimize, and mitigate harm from any Southwest Powerlink Alternatives on people and nature.

XII. The "Partial Underground 230kV ABDSP SR78 to S2 Alternative" should be eliminated from consideration in the EIR/EIS

This alternative is not feasible because it would require construction of towers inside designated state wilderness, impact bighorn sheep and their designated critical habitat, and scar the scenic San Felipe Valley among other significant impacts.

XIII. The MCAS Miramar Alternative should be eliminated from consideration in the EIR/EIS

This alternative is not feasible because it would result in significant impacts to sensitive species and habitats among other significant impacts.

XIV. Map figures should be corrected to reflect the true extent of Powerlink impacts on protected natural lands

Map figures in the second scoping notice do not appear to accurately represent the extent of protected natural land that will be harmed by the Powerlink.

Map Figure 2 should be revised in the EIR/EIS to clearly identify designated Bureau of Land Management Areas of Environmental Concern including the Coyote Mountains Fossil Site, San Sebastian Marsh, Table Mountain, Yuha Basin, and West Mesa. The San Sebastian Marsh ACEC is not identified at all in this figure, and none of these areas are identified as areas of critical environmental concern on the map or legend.

"State Lands" identified in map figures 5 and 8 are preserve areas that should be identified as such and by name in the EIR/EIS. The same is the case for Bureau of Land Management Land on map Figure 8 located immediately south of the Barona Reservation and managed by the County of San Diego as a natural open space preserve. One state land area identified on Figure 5 located east of Highway 67 may actually be the County of San Diego's Boulder Oaks Open Space Preserve. Also, the County of San Diego's Sycamore Canyon Open Space Preserve should be shown on Figure 5.

"Other Federal Land" identified on map Figure 6 should be identified in the EIR/EIS by its correct name, the "San Diego National Wildlife Refuge." The City of San Diego's "Del Mar Mesa Preserve," which includes and anticipates joint management of the National Wildlife Refuge properties and other protected public properties, should also be shown. Properties owned by the City and County as part of the Del Mar Mesa Preserve should also be shown. A magenta colored property inside the Del Mar Mesa Preserve does not appear to be identified in the legend.

Map Figure 8 should be revised in the EIR/EIS to show the Eagle Peak and Sill Hill designated roadless areas and any others on the Cleveland National Forest.

Figures 6 and 7 should be revised in the EIR/EIS to show the "Carmel Mountain Preserve" as well as City ownership inside the preserve.

Thank you for your consideration.

Sincerely,

/s/
David Hogan
Center for Biological Diversity

Bill Corcoran
Sierra Club

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February 23, 2007

To Ms. Blanchard, CPUC, and Ms. Kastoll, BLM:

Thank you for the opportunity to contribute to the Scoping Process for the Sunrise Powerlink.

I am greatly impressed at the increase of stated alternatives to this project between the first and this, the second round of scoping. This only goes to show that the words, "it's impossible to do otherwise" are simply not true!

This project would be understandable if this were the only and best way. But one thing that I have noticed, and my observation gets more clear as the months go by: ***There are such great alternatives, there is no need for this project!!***

The **Mexico Light and Path 44** system alternatives are elegant examples of simple elements of a whole solution. If we are patient, diligent, and use human ingenuity, I believe a wholesome solution will arise, as have the many alternatives in your scoping book. It would indeed rival that of the utility, through its sleek function, while using vastly less expensive and destructive infrastructure. Likewise, the SPL, which is not nearly as sleek or elegant, is an element of a larger system of resources, energy-generating sources, customers, and links, designed as an integral part of a full loop scenario, which, rightly, should be examined for potential total impacts. Please include how much potential energy could travel through the region if the SPL is approved; one need only calculate the total amount of possible transmission from close to the origination of the SPL during the19 other hours of the day when solar energy does not transit transmission lines, to find out what the actual import through the region could be.

I believe that the issue of active versus passive impacts on Global Warming is directly related to the transportation capacity of the Sunrise Powerlink. The SPL touts its wonderful connection to the solar energy rich Imperial Valley, however, it also connects to the fossil-fuel generated energy plants across the border. Please include the maximum potential subsequent environmental impact the SPL would have on the regional role in contributions to Global Warming.

The rewiring of the existing transmission service lines, such as the Southwest Powerlink, would also surely reduce our energy needs. Please examine the cost benefit analysis of re-wiring the SWPL to bring it up to the highest possible transmission efficiency.

Stricter energy conservation measures should be mandated before even one pole is raised for the Sunrise Powerlink. Please research conservation measures of other communities that have been able to reduce their overall per-capita energy consumption through energy efficiency planning or retrofitting. Please also research energy efficiency measures that have been proposed for San Diego City and County that have not been adopted yet.

Meanwhile, emerging thin-film photovoltaic technologies, such as “Nanosolar,” in San Francisco, are proving to be more cost-effective than other solar energy systems, and can be used in any community, particularly the Mediterranean regions of coastal and inland San Diego and Southern California. Please research the viability of these technologies for local use in the various climate zones of San Diego County in comparison to the expensive imported solar energy of the Sunrise Powerlink, including actual cost including the transmission costs to consumers.

Again, I would like to state, as I did in my first public appearance at the pre-hearing conference in Ramona before Judge Kim Malcolm and Commissioner Greuenich, I implore that you are patient, careful and thorough in your consideration of all of the facts, as this Sunrise Powerlink proposal affects virtually each and every place that my husband and I have lived and worked in as we have raised our family in beautiful rural North San Diego. Yes… it promises to affect all of rural North San Diego… just look at Figure 10 of the Notice of Second Round of Scoping Meetings on Alternatives to the Proposed Sunrise Powerlink Project. If the SPL is built, it is poetic to say that we would die with broken hearts, surrounded by the kind of infrastructure that would ruin so many rural sunrises thereafter.

As in the infamous taking of the water resources of the Owens Valley for the growing Los Angeles region, I fear that these special rural places, designated for the heaviest of the SPL and Central East Substation impacts, would never recover. I’m not certain that anyone can really say whether the importing of water should have been favored over the local development of the Owens Valley, when you look at the two regions today. I wonder if you have noticed the overwhelming sentiment of doubt or downright opposition from the thousands of other rural and resource loving San Diegans and Californians who have spoken up over the Sunrise Powerlink. Those in favor, as in the taking of the Owens Valley, are in a different position. They may be adamantly opposed to energy conservation, or fear the next black or brown out, utility manipulated or not.

Our County Supervisor, Bill Horn, owns stock in SDG&E, and has refused to represent us!! So, whether it is the CPUC or the FERC, whether the transmission line is proposed to run along roads or hidden away in the hamlets, or over someone’s house or barn or ranch animals, whether the Massive Substation would be set in plain view or up against a hidden knoll, it would forever change the way of life here, the “Central Link” of the utility’s maps, our home, where our family has grown to love life, where we have hoped to live when we are old, where the utility wants to put their gigantic switching station, with one, two, eventually 8, maybe more tendrils, pumping international energy to Los Angeles and other places in Southern California.

Again,
Thank you for the opportunity to contribute.
Sincerely,

Mary Aldern
Community Alliance for Sensible Energy
Ranchita, CA

Environmental Health Coalition

COALICION de SALUD AMBIENTAL

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February 23, 2007

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Dear Ms. Blanchard and Ms. Kastoll:

Environmental Health Coalition (EHC) is a nonprofit environmental and social justice organization working in the San Diego Tijuana region for over 27 years. EHC testified at the February 8th Scoping meeting in Temecula. While we are very supportive of a No Wires alternative to the proposed project, we are very concerned about the direction some elements of the No Wires alternatives appear to be proceeding and would like to make the following comments on the proposed alternatives for your consideration.

The proposed LSPower project, the South Bay Replacement Project (SBRP) on the Chula Vista Bayfront should be dropped from the alternatives analysis.

The heavy reliance on the specific LSPower proposal on the Bayfront is ill-advised and will create a fatal flaw in the analysis. In a recent joint workshop of the City of Chula Vista and the Port District, indications were made that the Port would not proceed with a new lease for the SBRP if the City Council did not support the project on the bayfront. On February 20, 2007, the full Chula Vista City Council took a unanimous position reconfirming and formalizing their opposition to a power plant located on the Bayfront. Without a lease from the Port, LS Power cannot build a new power plant on the Bayfront making the project non-viable. (Recent news articles attached)

The No Wires Alternatives are too heavily reliant on one specific gas-fired option.

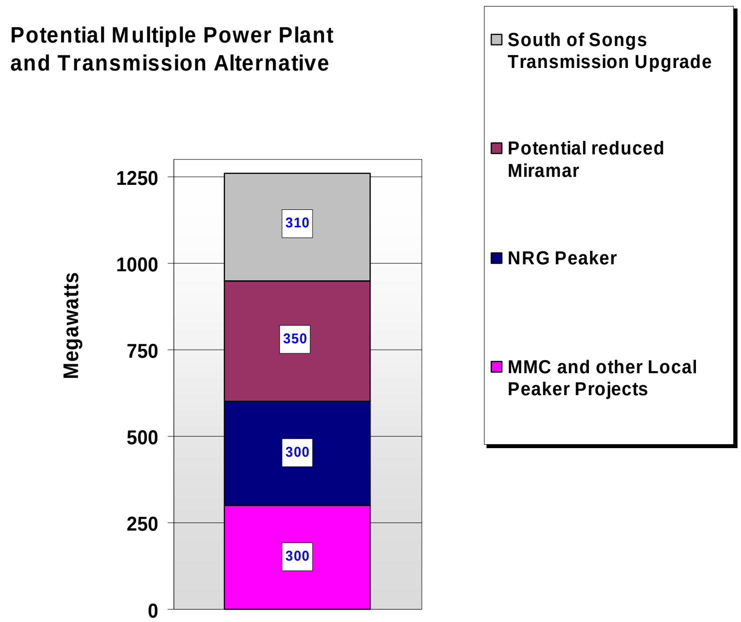
In both the description in the Scoping notice and in comments made at the meeting, it appeared that the LSPower proposal is a cornerstone for the No Wires Alternatives. This is inappropriate. There are many options, renewable and conventional, for in-basin generation. There have been additional power plant proposals announced recently in the media and others that should be explored. The CPUC should also do its own assessment of sites that were discussed in the LSPower CEC application for the SBRP and evaluate them with more updated criteria than LSPower used to reject them in their analysis.

Environmental justice factors militate against any concentrating any additional large scale gas-fired generation or transmission in the South Bay.

The No Wires All Source Alternatives rely too heavily on concentrating undesirable energy infrastructure in one, already heavily impacted, area. From the description in the Scoping notice, it appears that the in-area alternatives would result include at least two gas-fired plants in the South Bay, an area already host to considerable energy infrastructure. This area is currently endures the impacts of the existing SBPP, the future Otay Mesa Generating Station (a 561 MW Baseload plant scheduled to go on–line in 2009), three peaker power plants, and several large transmission projects including the Southwest Powerlink, and the Otay Metro Loop.

A Combination of Smaller Generator Plants should be evaluated.

In a highly developed area, such as San Diego County, it is difficult to site large gas-fired plants due to the large geographic area of impact that their air pollution emissions have. However, smaller plants, especially load following or intermediate baseload plants can offer an appropriate energy source that may be easier to site. Having more smaller plants can also increase reliability as compared to larger more centralized generation. We urge that the core "No Wires All-Source" conventional generation alternatives rely on strategically and appropriately located smaller (peaker, intermediate baseload or load-following) power plants combined with other renewable alternatives be considered. Such generation can provide back up capacity to clean renewables generation projects that may have intermittent capacity shortfalls. We have provided a potential alternative below that we request be analyzed as an in-basin multiple power plants and transmission alternative.



The No-wires alternative should include an analysis of potential in-basin renewable energy generation
EHC is submitting with this letter Local Power's Green Energy Options report that details energy technologies that could be sited in-basin, provide dispatchable capacity, and help the San Diego region meet the renewable energy portfolio standard. Such alternatives are consistent with the San Diego Association of Government's (SANDAG's) current Regional Energy Strategy, which sets a goal that 50% of renewable energy generation that serves the San Diego region be sited in-basin.

Customer-side demand shaving alternatives should be considered
Aggressive deployment of energy efficiency measures, demand response technologies, and on-site photovoltaic and other distributed generation should be evaluated as an alternative.

A '*Regulatory Barriers Removal Option*' should be added.

An option that relies in whole or part on the removal of barriers to energy efficiency and renewable energy investment should be evaluated in the context of a viable alternative. Removing these barriers would greatly accelerate deployment of clean renewables in the region and offset the need for the power line or dirty energy projects. Steps that would remove such barriers should include, but not be limited to:

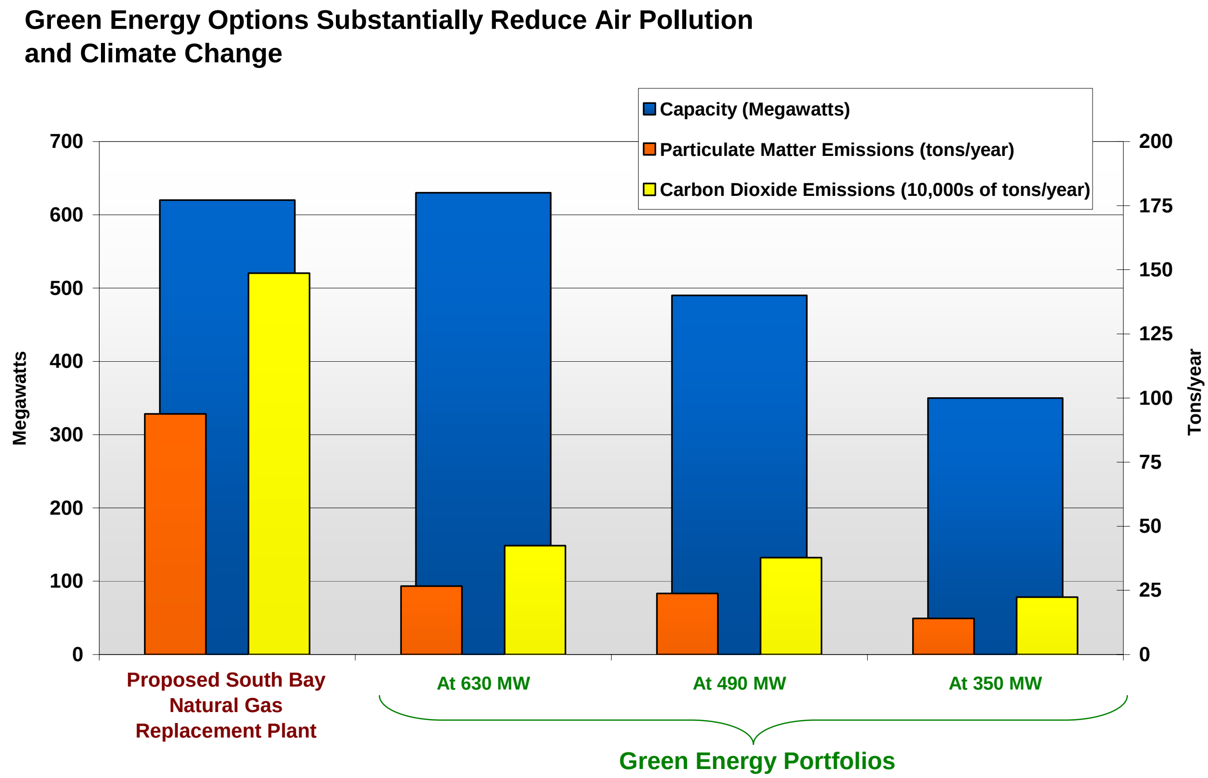
- Enable commercial businesses, building owners, residents and government agencies to realize maximize rooftop PV incentives through net metering regulations that would allow PV owners to get credit for excess generation provided to the grid, and 'wheel' electricity PV generated electricity to other locations.

- Remove or significantly increase the net-metering cap to facilitate additional renewable energy project development.
- Expand and extend the financial incentives for PV systems and EE projects , and allow for maximum third party administration and oversight.
- Support an open electricity market through review of direct access where it has the potential to encourage more large-scale renewable energy projects.
- Remove disincentives inherent in the current rate structure that discourage deployment of technologies that are consistent with the state's approved loading order (EE and renewables and ultra-clean DG).
- Remove incentives that encourage development of technologies at the bottom of the state's loading order (large-scale fossil generation, large scale transmission).
- Ensure that all available, reliable resources are counted toward resource adequacy assessments in CPUC proceedings.
- Require energy efficiency and renewable energy for building construction at the levels adopted by the AIA and Architecture 2030.

An assessment of the energy potential from each of these actions should be determined and their potential for to assist in reaching the RPS Standards in-area.

A '*Maximum Greenhouse Gas (GHS) Emission Prevention Alternative*' should be added.

One option should assess the work done by the Renewable Energy Study Group (sdrenewablesg.org) on the technical potential for clean energy resources in the region and develop and analyze an alternative based on those clean energy sources. The hazards of climate change will impact coastal areas hardest of all. As a coastal region, we will be devastated by the many impacts of climate change. Flooding of coastal areas and shrinking of water supplies among other impacts will be severe if we do not take maximum action to reduce GHG emissions. While in the past some argued that the costs of preventing GHG emissions out-weighed the benefit, it is no longer true (if it ever was). Now, the cost of doing nothing far exceeds the cost of doing the most that we can to preserve our climate. EHC has submitted to the Local Power report detailing Greener Energy Options for Replacing the South Bay Power Plant. These options should be evaluated for application of a diversified option that reduced GHG emissions and provide in-basin generation. Examples of reductions of air pollution based on technology type are listed below.



Source: Local Power *Green Energy Options to Replace the South Bay Power Plant* February 2007.
Graph by Environmental Health Coalition Feb 2007

All alternative with gas-fired components must include the costs of climate change and health impacts from criteria air pollution in their cost-benefit analysis.

Any alternative that proposes to run on fossil-fuels must include in the cost-benefit analysis externalities associated with climate change and criteria air pollution impacts.

Thank you for your consideration of our comments.

Sincerely,
ORIGINAL SIGNED BY

Laura Hunter, Director
Clean Bay Campaign

Attch. Two news articles
Green Energy Options Report and Appendices

VOICE OF SAN DIEGO

Chula Vista Council Formally Opposes Power Plant

The decision could lead to the demolishing of the South Bay plant and free up prime bay-front land.

By ROB DAVIS Voice Staff Writer

Wednesday, Feb. 21, 2007 | The Chula Vista City Council unanimously voted Tuesday night to oppose building a new power plant on the city's bay front and support the existing South Bay Power Plant's demolition.

The vote could effectively kill New Jersey-based LS Power's plan to build a smaller power plant on bay-front land being considered in the Chargers stadium push. LS Power had proposed to demolish the existing South Bay Power Plant and replace it with a more efficient plant.

The council's vote was largely ceremonial. The city of Chula Vista does not have legislative authority over the power plant. The final decision on its future rests with the Unified Port of San Diego, which owns the existing power plant and the land it sits on. Three of its seven commissioners are on record saying the port's board will follow the council's recommendation.

The decision is a major step toward freeing up Chula Vista's bay front, though major work will remain before the existing power plant is demolished.

The California Independent System Operator, which oversees the state's electricity grid, requires the plant's operation to maintain the region's energy reliability. Though it produces power less efficiently than newer plants, it must remain in place until other power sources are found or the reliability label is removed.

Chula Vista council members say they are hopeful the label will be removed and the inefficient power plant demolished by Jan. 1, 2010.

That's within the timeframe the Chargers hope to build a new stadium. The power plant site is one of several in Chula Vista under consideration for stadium sites. But council members sought to distance themselves from the Chargers on Tuesday night. They avoided mention of the team by name and downplayed any connection between their opposition to the power plant and potential support for a new stadium.

Councilman Jerry Rindone alluded to the Chargers, calling them "other interests." Mayor Cheryl Cox also referred indirectly to the team. "As your mayor," she told the audience, "I have no ulterior motive other than to open the bay front."

The vote to oppose a new plant had been expected, but for a time it appeared in question. Councilman Steve Castaneda said in a Friday interview the council would recommend that no new leases be granted for power plants on the bay front.

But by Tuesday night, the language was not as clear. Castaneda and Mayor Cheryl Cox offered a recommendation that the council "not enter into any contracts or contract extensions that would violate" the steps needed to demolish and decommission the existing plant.

It did not mention the new plant proposal. Castaneda suggested that the LS Power lease be discussed at a special March 8 council meeting. He had not mentioned such a meeting Friday.

The recommendation left some council members confused. Councilman Rudy Ramirez asked several times for clarification of the recommendation's language; Cox said it clearly stated that building any bay-front power plant would be counter to the council's wishes.

Opponents urged the council to take a clearer stand, suggesting that the recommendation's wordiness -- and omission of any reference to the proposed new plant -- was the result of last-minute lobbying efforts by LS Power. LS Power officials declined comment after the meeting.

LS Power has said the most reliable and efficient way to guarantee the larger existing plant is torn down is to build the smaller power plant nearby, allowing it to tap into the existing transmission infrastructure. Kevin Johnson, an LS Power vice president, reiterated that point Tuesday night, asking the council not to oppose his company's proposal.

The council ultimately unanimously agreed with a new motion from Castaneda: "The city of Chula Vista does not want a power plant on its bay front -- old or new."

"I don't know that it gets any clearer than that," Cox said.

Port Commissioner Mike Najera, who represents Chula Vista and attended the meeting, said he expects the port will heed the council's wishes. The issue is expected to come before the port March 13. Two other commissioners have said they will follow the council's recommendation.

"This is a great moment for Chula Vista," Najera said. "This is something that's long overdue."

The Unified Port of San Diego purchased the South Bay plant and the 160 acres surrounding it in 1999 with the intent of demolishing the plant and opening up western Chula Vista's bay front for redevelopment. But when Chula Vista city officials told the port they wanted to retain the financial boost that came from the power plant's taxes, the port backed off. That has changed since the November election of a new Chula Vista City Council.

"I'm glad the council was clear about what they want, and I'm glad they said it now as opposed to when it may not mean as much," said Laura Hunter, a spokeswoman for the National City-based Environmental Health Coalition, the plant's leading opponent.

Making the decision later, she said, may have allowed the replacement plant to have been more seriously considered in plans evaluating potential alternatives to the Sunrise Powerlink, a controversial $1.4 billion power line proposed by San Diego Gas & Electric between Imperial County and San Diego.

SDG&E officials have said they had no plans to buy power from a South Bay replacement plant, because the company needs power to meet peak demand, not everyday demand. Even if the Powerlink isn't built, SDG&E has said, the company still did not intend to buy power from the plant's proposed replacement.

Please contact Rob Davis directly with your thoughts, ideas, personal stories or tips. Or send a letter to the editor.

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San Diego Union Tribune

Bayfront power facility blocked in vote

Council wants plant to be moved inland

By Tanya Mannes
STAFF WRITER

February 21, 2007

CHULA VISTA – Hoping to carve out more bayfront land for redevelopment, the Chula Vista City Council voted last night to block an energy company's plan to build a new power plant along the water.

LS Power Generation, which leases the current South Bay Power Plant, wants to build a replacement plant on land next to it, also on the bayfront.

SOURCE: Port District UNION-TRIBUNE

The Chula Vista City Council hopes to block a plan to build a replacement power plant.

On Jan. 22, Mayor Cheryl Cox made a public announcement opposing that plan. Cox said she wants the 47-year-old South Bay Power Plant goneand replaced somewhere inland.

Last night, Cox's council colleagues followed her lead, unanimously approving Councilman Steve Castaneda's motion to transfer plant power generation off the bayfront. “The city of Chula Vista does not want a power plant on its bayfront, old or new,” Castaneda said.

LS Power has asked the state for permission to build a plant on the smaller bayfront parcel. The company then would demolish the old plant.

The San Diego Port Commission will consider Chula Vista's position next month, when the commission is scheduled to vote on whether to lease land to LS Power for the smaller replacement plant.

Despite her announcement in January, Cox early last night was reluctant to vote on blocking LS Power's replacement project. She and Castaneda, who comprise the council's energy subcommittee, suggested postponing a vote until after a subcommittee meeting with state energy regulators March 7. Councilmen John McCann and Rudy Ramirez argued that the council needed to state its position. “I'm ready to take action now,” McCann said. “Nobody can tell me that putting a power plant on the bayfront is the best and highest use of that land.” Ramirez described the LS Power proposal as “a project that would not, in any circumstance, work in our community.”

Castaneda said that after hearing those comments he believed the council was ready to make a formal recommendation to the Port Commission.

Chula Vista's 550-acre bayfront stretches from the Sweetwater Marsh National Wildlife Refuge to just south of the power plant. Gaylord Entertainment company wants to develop part of the land with a hotel, convention center and condominiums. The San Diego Chargers also are looking for land for a new stadium and are considering sites in Chula Vista, including the bayfront.

Chula Vista officials long have wanted to remove the South Bay Power Plant, with its smokestacks and scaffolding.

The California Independent System Operator has given the plant a “must run” designation, meaning it must remain open. Cal-ISO is responsible for grid reliability for much of the state. San Diego Gas & Electric is responsible for power needs in the region.

Before the vote, LS Power Vice President Kevin Johnson urged the council not to block the proposal. Johnson said the new plant would help in lifting South Bay Power Plant's must-run status. Castaneda and Cox said they plan to meet with Cal-ISO and other state regulators to remove that designation so the plant can be decommissioned without a need for a replacement plant of equal capacity.

Lending support to that effort, SDG&E said in January that the company is confident the region's electricity demands can be met without another bayfront plant.

LS Power's plan for financing the new plant is based on selling power to SDG&E. The company also could sell electricity to Los Angeles or elsewhere by hooking into the power grid

Green Energy Options
to Replace the South Bay Power Plant

Alternative Energy Plan on the Feasibility and Cost-Effectiveness of Replacing the South Bay Power Plant by 2010 With Local, Competitively Priced Green Energy Sources

Prepared By

local power
4281 Piedmont Avenue Oakland, CA 94611 510 451 1727

Paul Fenn - Executive Director
Robert Freehling - Research Director

Prepared for

Environmental Health Coalition

February 15, 2007

Table of Contents

Figures and Tables

1. Executive Summary

Background and Purpose

The existing South Bay Power Plant, over 40 years old, is outdated, inefficient to run, devastates the South San Diego Bay ecosystem and pollutes the air. The power company LS Power, all of whose merchant power plants (including the South Bay Power Plant) were recently acquired by Houston-based Dynegy[1], is in the permitting process for a South Bay Replacement Project (SBRP) which includes the demolition of the current South Bay Power Plant and the construction of a new gas-fired power plant near the current site. There is little disagreement that the existing plant needs to be shut down. There is debate, however, about how the energy capacity provided by the existing plant should be replaced. This decision will shape the region's energy future, the health of Chula Vista residents, and the character of the Chula Vista Bayfront for decades to come.

The SBRP decision will have global impacts. Climate Crisis is upon us. Power plants are the largest cause of greenhouse gas pollution in the United States, which as a nation is the world's largest greenhouse gas polluter – and California's greenhouse gas emissions have continued to increase for the past fifteen years. A major opportunity to answer the Climate challenge is in our front yard, and will shortly present itself for local decision-making. In the Chula Vista region, by far the largest single cause of climate pollution is the South Bay Power Plant. While Dynegy's acquisition of the plant has increased pressure to approve a larger power plant replacement, green power alternatives – and the means to develop them cost-effectively – now exist, which if developed by Chula Vista and potential local partners will render power generation at the South Bay Power Plant site unnecessary for the regional transmission grid. Recognition of urgency and opportunity is essential to solving the Climate Crisis. The SBRP decision may be the community's only major chance to do something about this mounting catastrophe.

While the existing plant runs at a relatively low capacity most of the time, it does provide 700 Megawatts (MW) (reduced to 515 MW for 2007) of "Reliability Must Run" (RMR) capacity to the grid, a special designation instituted to ensure grid stability. A number of options exist to provide the energy and capacity that the San Diego region will need into the future, including demand response, renewable energy, natural gas plants in other parts of the County, and other options. For a number of reasons – to protect public health and promote environmental justice, to protect our economy from over dependence on natural gas with its price volatility, to reduce greenhouse gas emissions, and to meet state-mandated requirements for renewable energy – the replacement of the existing South Bay Power Plant should include a major commitment to green energy options. This report identifies and analyzes local opportunities for more sustainable, secure energy development in San Diego County in order to reduce the need for, or the scale of, a natural gas generation facility to replace the South Bay Power Plant (SBPP).

[1] On September 15, 2006, Independent Power Producer Dynegy announced it has agreed to pay more than $2B in stock and cash for the merchant plant portfolio of private equity fund LS power Group, including SBPP and eight other power plants acquired from Duke Energy for $1.6B in May. LS Power Group will retain a 40 percent stake in the combined company. Dynegy's management team, including CEO Bruce Williamson, will run the company.

The "Green Energy Options" (GEO) outlined in this report, demonstrate how Chula Vista and neighboring communities can now move to develop solar, wind and other green power technologies at market prices, stabilize local electricity rates, win energy independence, and eliminate a major contributor of pollution and greenhouse gases. The City of Chula Vista has already taken a leadership role in promoting energy sustainability and taking responsibility for reducing the hazards associated with the global climate crisis. By investing in energy development described in this Green Energy Options report, the City of Chula Vista can take a major step toward ensuring energy and economic security for Chula Vista and the region, and can set an example for the region, state, and beyond.

Summary of the Green Energy Option Portfolios

The Green Energy Options (GEOs) described in the report are viable, and the technologies are readily available. The GEOs are three electric energy portfolios designed to meet three different levels of capacity replacement for the South Bay Power Plant. They address a range of possible regional needs and provide a range of investment options. The current power plant supplies electricity in the period of high demand during the day and early evenings, and the GEO portfolios are designed to meet that same requirement. Each GEO portfolio includes diverse technologies in order to avoid "putting all eggs in one basket".

The hazards of going to a 100 percent natural gas portfolio are numerous. Natural gas has a high level of price volatility, and when the fuel price shoots up, electricity prices are sure to follow soon. Residents of San Diego County have seen what happens when they put too much trust in natural gas. Natural gas also has other problems. It is a limited resource that is bound to become more difficult to obtain over time. It is also a fossil fuel that emits or creates many tons of pollutants annually, including lung-clogging particulates, nitrous oxides, corrosive ozone, as well as carbon dioxide and methane that are destabilizing the global climate.

The GEO portfolios are designed to meet all of these challenges, to cut pollutants dramatically, reduce reliance on fossil fuel, and serve as a hedge strategy against future price swings in natural gas. The GEOs provide three levels of capacity replacement relative to the current 700 megawatt power plants. The nominal capacity of the GEO options range between 500 megawatts and 970 megawatts, but this translates into a smaller equivalent capacity for the purposes of replacing the existing plant. This is because some renewable technologies, mainly wind power, only produce electricity part of the time. But the wind resource is given a boost relative to its otherwise intermittent nature, since one portion of the wind power is delivered to pump water uphill into a reservoir during the evening so it is available the next day to power generators when demand for electricity is high. Nearly all the rest of the portfolio's generation capacity is considered to be able to carry its weight in electrical system support, without any greater degree of help than other types of electrical generation routinely receive. This rating, called the Effective Load Carrying Capacity, is a product of the full capacity of the power generation equipment and the availability of the energy resource. In the case of wind, studies have shown that the *lowest* "carrying capacity" for actual major California wind farms is about 25 percent. We have been even more conservative, and assumed that only 20 percent would "count".

To confuse matters somewhat, yet another measure of reliable capacity is used by the state grid operator, the California ISO. This measure is exceedingly restrictive and actually has never established satisfactory rules for renewables like wind and solar power. With the increased legal mandate for renewable energy in the state, such rules will become increasingly necessary, and the ISO will not be able to ignore the contribution of renewables to the state's electric grid reliability, as they have in the past. This issue is not academic. During the 2000 to 2001 California "Energy Crisis", many commercial vendors of electricity took their conventional generators off-line. This caused serious problems that threatened grid stability, and resulted in greatly increased prices for their product. While these and other rather overt manipulations were going on, California's renewable generators continued to operate and they helped significantly to maintain the state's electric grid, and even to avoid blackouts. Thus, there is historical evidence, as well as ongoing demonstrated performance, to show how wind and solar power contribute greatly to the reliability of California's energy supply.

We established the size of the three green energy portfolios to meet 50%, 70% and 90% of the current South Bay Power Plant's capacity for supplying power during the hours of peak demand. Thus the portfolios are designed to meet the same needs and have similar functionality to the existing plant, though with a number of extended capabilities that the current plant does not have. For instance, the pumped storage plant can respond nearly instantly to changes in demand for electricity, a factor that can be critical during a power emergency. Other features will be described in this report. This report also shows how any capacity shortfalls can be replaced in other ways without resorting to adding new transmission lines leading out of the region.

A Range of Options

The GEO options contain a variety of portfolio elements, design sizes, and potential for siting of energy facilities, that allows for flexibility to meet different system needs and market conditions. There is really very little that is constrained about this portfolio, and in fact the GEO options show general strategies, as well as how to apply these strategies in very specific and practical ways. It is certainly possible to change these elements to respond to changes in the cost of renewables and of conventional power sources. Thus there is an adaptability that is completely lacking in the current plan to build another power plant on the same site as the existing power plant.

90% Replacement Option

Facility	MW	Est. Annual GWh
Wind Farm	400	1200
Pumped Water Storage Facility	150	420
Concentrating Solar Thermal Peaker with Natural Gas Backup	160	450
Natural Gas Peaker	220	620
Photovoltaics	20	30
Peak Demand Reduction	20	35
Transmission	----	----

RMR Replacement Target: 630 MW

Electricity Generation: 2220 GWh/year

Portfolio Average Peak Power Cost: 8.4-10.3 cents/kwh

70% Replacement Option

Facility	MW	Est. Annual GWh
Wind Farm	325	990
Pumped Water Storage Facility	90	250
Solar Thermal Concentrator Plant Powering a Peaker Plant with 30% Natural Gas Backup	160	450
Natural Gas Peaker	190	530
Photovoltaics	20	30
Peak Demand Reduction	20	35
Transmission	----	----

RMR Replacement Target: 490 MW

Electricity Generation: 1960 GWh/year

Portfolio Average Peak Power Cost: 8.3-10.4 cents/kwh

50% Replacement Option

Facility	MW	Est. Annual GWh
Wind Farm	150	460
Pumped Water Storage Facility	60	170
Solar Thermal Concentrator Plant Powering a Peaker Plant with 30% Natural Gas Backup	160	450
Natural Gas Peaker	90	250
Photovoltaics	20	30
Peak Demand Reduction	20	35
Transmission	----	----

RMR Replacement Target: 350 MW

Electricity Generation: 1170 GWh/year

Portfolio Average Peak Power Cost: 8.6-10.0 cents/kwh

Findings

The Green Energy Options (GEO) portfolios presented in this alternative energy plan are economically sound. The low-interest municipal bonds available to cities like Chula Vista can achieve significantly lower financing costs for renewable generation. Also, the largely fixed cost of the renewable GEO portfolios provides a hedge against substantial risk of increasing natural gas prices over the next 20 to 30 years.

The GEO Portfolios offer a number of benefits over a future commitment to a 100% natural gas-fired plant on the bay front. One benefit is cleaner air – the GEO portfolios would result in 60-80% lower emissions of particulate pollution and carbon dioxide every year when compared to a new "all natural gas" plant. Pursuing the GEO options would also get us firmly down the road of a more secure and sustainable energy future: they would produce more local jobs, decrease the region's over-reliance on natural gas, and keep more money in the local economy.

Community Choice Aggregation (CCA) is the best approach to eliminating the need for power generation on the South Bay. CCA would enable a full range of options, including transmission of power. If Chula Vista forms a CCA or builds a power generation facility, it may elect to obtain transmission services within or outside Chula Vista, by acquiring access to existing transmission capacity, arranging with SDG&E to provide transmission access, pursuant to Federal Energy Regulatory Commission (FERC) Order 888, or arranging to purchase transmission services from another party such as a tribal government. No option would require adding transmission lines leading outside the county, and all would make use of existing transmission pathways.

This Plan finds that the initiative would be best led by Chula Vista. Over the past four years, the City of Chula Vista has prepared extensively for the implementation of Community Choice Aggregation ("CCA") and/or development of a power generation facility. CCA would allow Chula Vista to find an alternative electricity supplier to SDG&E, and to decide what kinds of electricity to purchase. In addition, Chula Vista and a number of potential public partners may issue municipal revenue bonds ("H Bonds") to finance renewable energy and conservation facilities. These mechanisms are analyzed in this Plan.

The GEO Plan shows how CCA in conjunction with H Bonds can be used to develop a cost-effective, cleaner and more sustainable replacement of the South Bay Power Plant ("SBPP").

This report identifies several specific opportunities available to Chula Vista, allowing a variety of locally feasible technologies and partnerships. However, even if CCA is not pursued by Chula Vista, other governance structures and initiative options are available for the City to pursue some or all of the green energy options outlined in this report. Financial analysis of the energy options has been performed with this in mind, to demonstrate the cost of electricity by considering the portfolios as independent investments.

A critical facet of the GEO options is to include local power resources that require little or no transmission facilities to deliver the power to customers. Chula Vista and the San Diego County region offer opportunities to develop a variety of green energy resources. These opportunities include solar energy, energy conservation, and cogeneration, in coordination with parties interested in participating in the development of the facilities and/or the purchase of power from such facilities. Where transmission of electricity is required, the GEO options have sought to insure that existing transmission corridors can be used, to avoid most of the expense and environmental impact of any new facilities. The GEO options are also designed to reduce the need for importing renewable power, and natural gas, from outside the county.

These proposals are more local in nature than the renewable power supply now being proposed by SDG&E for residents and businesses in its service territory. The options presented are financially feasible at competitive wholesale and retail prices, with either a CCA or a city-owned merchant facility, or both, being the structuring principle of the project.

Photovoltaics (PV) on Chula Vista rooftops, energy efficiency, demand response may be fundable with existing ratepayer revenue if a CCA is formed and would be facilitated by submitting a request to administer the funds to the California Public Utilities Commission.

Other distributed generation may be undertaken within the City under a CCA or a revenue bond funded ("H Bond") program, and Chula Vista may invest General Funds in renewable energy projects for non-CCA customers if the City wishes to operate the plant as a public enterprise. Because a range of project sizes may be necessary to eliminate or meet hundreds of megawatts of regional demand in order for the Independent System Operator (CAISO) to accept a downscaling of new power generation on the South Bay site, this report identifies several physically viable, legally developable and economically competitive green power facilities, estimates facility costs, schedules for payback and power pricing. The range of facility scales in each Scenario are also based on a variety of potential market and financing structures, including Community Choice Aggregation (CCA) the use of H Bonds, rebates for photovoltaics under the California Solar Initiative, and state funding for energy efficiency programs pursuant to the Community Choice law, AB117.

This report finds that a significant level of public sector investment is essential to replace any potential need for power at the South Bay site. The ability to eliminate or reduce the need for power generation at the South Bay Power Plant site depends on the municipality's degree of public investment, as well as investment by potential strategic partners in the region. This investment may be structured as a municipal enterprise using municipal bonds, and/or as a CCA to add even larger-scale private sector purchasing power to public financing.

This report finds that a Chula Vista investment in renewable energy and conservation facilities involves a lower degree of municipal risk than investment in a 100% natural gas generation power plant, because of reduced exposure to the highly volatile price of natural gas. Fuel usually constitutes from 50% to 80% of the life cycle cost of a natural gas-fired power plant. This Plan identifies benefits from the GEO portfolios, including:

- Profits realized from renewable energy or conservation facilities, could benefit taxpayers by contributing funds to the City of Chula Vista General Fund
- Should the City initiate a Community Choice Aggregation (CCA) the portfolios can be used as insurance to protect the ratepayers from escalating electricity prices

- Renewable and conservation facility assets will retain their market value and generate revenue after H Bonds or other financing are repaid, in some cases for decades, offering both returns on public investment and very low cost energy for local government, residents and businesses.

This Plan finds that the GEO Portfolios are consistent with existing local, state and federal policy, regulations and law, and meet the stated project objectives in the AFC for the South Bay Replacement Project:

- Commercially viable and capable of supplying economical electrical services – capacity, reliability, ancillary services, and energy supply – to the San Diego Region.
- Capable of ensuring the timely removal of the existing South Bay Power Plant and that fulfills the obligation found in Article 7.1.a of the Cooperation agreement, which states, "use commercially reasonable efforts to develop, finance, construct and place into commercial operation a new generation plant replacing the South Bay Power Plant…which shall have a generating capability at lease (sic) sufficient to cause the ISO to terminate (or fail to renew) the must run designation application to the South Bay Power Plant on or before termination of the lease" and upon which the size of replacement power is based.
- Meets applicable laws, ordinances, regulations, and standard (LORS) of the California energy Commission, Chula Vista, the Unified Port of San Diego and other agencies, and complies with the Applicant's Environmental Policy
- Consistent with the objects, guidelines and timing goals of the emerging Bay Front Master Plan.
- Assists in maintaining and/or increasing the regional electrical systems' efficiency and reliability.
- Supports implementation of the state-mandated 20 percent Renewable Portfolio Standard (RPS) requirements for renewable energy.

Recommendations

- Chula Vista should present evidence to the ISO and other regulatory bodies, proving why a replacement for the current plant is not needed on the Bayfront. ***This report shows that nearly 2000 megawatts of alternative options exist within San Diego County***, some of which would cost far less than replacement of the South Bay Power Plant at its current site. In some cases merely changing regulatory status or evaluation of existing or planned resources, or the need for them, is all that is required. It is exceedingly unlikely that replacement of more than a fraction of the current plant is really necessary to meet the needs of the region for years into the future. That is the most important reason why a range between 50% and 90% replacement of existing capacity has been proposed in this report.

- Chula Vista should further investigate the options identified in this report to begin discussions with potential site owners, financing sources and partners for different projects. In other words, scoping needs to move to the next level of specificity to answer critical questions.

- Chula Vista should fund and prepare an Implementation Plan and draft a Request for Proposals for Community Choice Aggregation and H Bonds that includes designing, building, operating and maintaining a solar concentrator, wind and pumped storage facility in conjunction with local solar photovoltaics, distributed generation, energy efficiency and conservation. These measures should be supplemented with natural gas fired co-generation to balance out the portfolio risk and energy costs, as well as to insure the full reliability requirements are met.

- Chula Vista should only entertain sites for facilities that minimize the need for new transmission, and only allow transmission that is placed on existing rights of way. Any new lines should be occupied only by clean energy capacity. No major power lines on new corridors are needed, as they will impose billions of dollars in costs on ratepayers as well as make the region even more dependent upon energy imports. These imports send dollars and jobs out of the region while new transmission corridors would spoil the county's landscape and natural beauty.

- Chula Vista should participate in the ISO RMR designation to ensure the RMR is calculated appropriately to include all renewable and other green energy sources.

- Chula Vista should participate actively at the California Energy Commission, Independent System Operator (CAISO), California Public Utilities Commission, and Federal Energy Regulatory Commission to propose the options identified in the GEO as preferable to repowering the South Bay Power Plant site.

- At present two of the largest generating plants in the region, representing about 1000 megawatts of capacity, contribute nothing to grid reliability, according to ISO evaluation.

San Onofre Nuclear Generating Station (SONGS) is not counted at all toward regional generation, even though it supplies over 400 megawatts of power, 24 hours a day, to San Diego County. That is because it uses up capacity on the same transmission line that is used for importing electricity. And the new Palomar plant, at over 500 megawatts, is uncounted due to a mere technicality. Chula Vista should urge the ISO, CEC and CPUC to move forward with assuring that the Palomar power plant is fully accounted for as reliable generation capacity, and that a short transmission line be added to the existing South of SONGS (SOS) corridor to connect the plant directly to the regional grid without casting a transmission shadow for electricity imports from the north. These two tasks would together supply approximately 500 megawatts of additional reliable capacity to the region for by far the least cost and environmental impact.

- Chula Vista should challenge the "bait and switch" tactic of justifying a new 24-hour a day "all natural gas" powered base-load replacement plant on the bay, based upon the ISO reliability contract on the existing plant. The current plant is considered necessary for meeting peak demand when power is urgently needed for grid stability, and only runs its generators part-time. The function of the current plant is completely different from the one proposed to replace it, and should require a separate evaluation of need.

- Chula Vista and other local and regional land use authorities should adopt stringent building standards that maximize energy efficiency, demand response, and development of clean, renewable energy sources integral to new and renovated building construction.

2. Introduction

The Green Energy Options (GEO) alternative energy plan has been developed by Local Power for Environmental Health Coalition (EHC) to be considered by the City of Chula Vista and other governmental entities in the San Diego County region. The Plan identifies and analyzes local opportunities for more sustainable, secure energy development in San Diego County in order to reduce the need for, or the scale of, a natural gas generation facility to replace the South Bay Power Plant (SBPP).

The GEO will include appropriately scaled renewable generation, energy storage, and energy efficiency measures. More broadly, the GEO will develop opportunities for Chula Vista to act singly, as well as inter-governmental or regional opportunities to eliminate the need for any power plant at the SBPP site, and to reduce the region's need for another large gas-fired power plant. These options will support reliability of San Diego County's regional electric transmission grid, which is run by the California Independent System Operator.

This report presents a series of scenarios, location- and time-specific opportunities that are supported under current California and federal law, for Chula Vista to negotiate with energy suppliers, undertake public works projects, and administer energy efficiency programs to reduce or eliminate the need for a power plant at the South Bay Power Plant site. Every scenario and proposal outlined in this report can provide opportunities for the City of Chula Vista to operate a profitable energy facility and/or provide residents, businesses and agencies with competitively priced energy services.

The profit structure will depend upon how the projects are financed, and implemented. For example, *the lower cost of capital for bond-financed wind farm or natural gas peaking plant essentially locks in a long term price advantage over any private or utility competitor.* The fact that renewables are now being required by law for all utilities and Community Choice Aggregators means that there is a built in market for the foreseeable future. The target requirement for purchasing renewable energy grows each year. Twenty percent of all utility company electric supply must by "green" by 2010. After that year a new target is likely to be set at 33 percent, a level that is fully supported by the governor and all the regulatory bodies. Legislation has been introduced that would write this higher goal into state law, and mandate that it be achieved by 2020. Utility companies have complained that it has been difficult to access sufficient renewable supplies; thus a growing market is wide open to those who can successfully develop green energy projects.

Municipalities are in a unique position to benefit from this arrangement. Renewables face certain hurdles that municipalities hold the power to overcome. The first hurdle is financing. Private developers are faced with the challenge of raising capital for projects with certain risks. For example, wind projects may be eligible for special tax credits, but only if they are built by certain dates. If those dates pass, because of delay for any reason, then the project loses its financial viability. Municipal governments do not receive tax credits, and thus are not bound by such considerations. Their low cost, tax free bonds provide superior benefit to the tax credit, and is available to them at all times without being subjected to the risk of federal tax policies over which they have no control.

A second financing risk is associated with finding a long term buyer for the electricity. While renewable standards do provide some assurance, lenders want to see contracts running out into the future as far as 10 to 20 years. This can be quite difficult to achieve. Municipalities that form Community Choice Aggregations (CCAs) have a built in market integration that no private developer could ever have, in that a CCA is both a seller and buyer of electricity. The market risk is thus greatly reduced, since the CCA can agree to purchase some or all of the electricity provided from its own renewable plant for up to 20 years into the future. This lowers borrowing cost, a critical component for making renewables cost effective or profitable.

The fact that renewables greatly reduce reliance upon fuel means that once the capital expense is paid off, the cost of generating electricity is reduced to relatively small operating expenses. Electricity sold at full price from these facilities, after the financing cycle, will likely realize higher prices on the market at the same time that ongoing costs are greatly reduced. In this sense, renewables are an investment in the future. Renewables can also provide more near term benefit, as valuable insurance against spikes in fuel prices, protection against liability for— and damage from—pollution, and the possibility to benefit from carbon markets under California's new greenhouse gas reduction law.

This GEO plan presents three South Bay Power Plant replacement scenarios with portfolios that contain mixes of wind with pumped storage, solar concentrators with gas backup, as well as photovoltaics and natural gas cogeneration. The GEO can be combined with conventional electrical capacity from available wholesale markets.

Facilities are modeled according to two basic criteria: they would generate power at prices competitive with wholesale market power prices, and could provide this power within the portfolio of electric service under a Community Choice Aggregation. Thus, the GEO presents these investments in an apples-to-apples comparison with both wholesale peak and base load power prices, and reflects potential changes in natural gas and electric generation prices in SDG&E's rates, which are subject to change every six months.[2] The purpose of this modeling is to provide real, buildable, financable, and feasible investments that can eliminate the need of the Independent System Operator for the South Bay Power Plant, and can also be sound public investments in green power generation and conservation facilities.

The investments are also described in a suitable manner for a CCA to incorporate these assets in a larger portfolio to supply its full electric power needs and compare this to SDG&E retail rates. This GEO may be adopted by the City of Chula Vista, and may be followed by drafting and adoption of a CCA Implementation Plan and Request for Proposals to solicit bids from suppliers, who will conduct a full CCA portfolio analysis and enter into a contract to build facilities and provide power service to participating communities. What this report does establish is that investments in a diverse set of peak power assets could benefit Chula Vista and surrounding communities over a 30 year expected equipment lifecycle, especially in the context of a CCA, and secondarily in the context of a municipally financed, locally developed green power facility.

[2] This document contains forward looking projections about the prices of commodities and infrastructure; Local Power in no way warrants or guarantees, or will in any way be held liable for, such investments. All investments carry risks, and it is the responsibility of those who make such investments to verify all claims, and assume all associated risks, express or implied.

If implemented, any one of the proposed scenarios would form a landmark achievement following a decade of growing leadership in energy independence and entrepreneurial sustainability in Chula Vista. It would also be a positive, substantial contribution toward international efforts to reverse the Climate Crisis.

The Proposed South Bay Replacement Project

The existing South Bay Power Plant, over 40 years old, is outdated, inefficient to run, and has significant adverse water and air quality impacts. There is little disagreement that the existing plant needs to be shut down. The plant has materially damaged the South San Diego Bay ecosystem and creates significant air pollution. The power company LS Power, all of whose merchant power plants (including the South Bay Power Plant) were recently acquired by Houston-based Dynegy[3], is in the permitting process for a South Bay Replacement Project (SBRP) which includes the demolition of the current South Bay Power Plant and the construction of a new gas-fired power plant near the current site. The SBRP is proposed as a 620 MW net combined cycle generating facility using two natural-gas-fired combustion turbine generators and one steam turbine to be cooled with air cooling.

The proposed South Bay Replacement Project would not use Bay water for cooling, which represents a significant environmental improvement. The SBRP would, however, still create a substantial air pollution hazard for neighboring residents. Like the existing plant, the proposed replacement plant would be directly upwind of residents and schools, and would perpetuate degraded air quality for west Chula Vista residents. The west Chula Vista zip code registers childhood hospitalization rates for asthma that are 20% higher than the overall county rate in 2003.[4] The SBRP is being promoted as a plant that will reduce air pollution impacts. Although more energy is expected to be generated for the pollution produced, total pollution impacts to the densely populated low-income neighborhood that is immediately downwind of its smokestacks are not expected to be appreciably reduced, and in fact may even increase. Though a new plant would be more efficient, it is planned to run far more often and burn more fuel, and so could produce comparable if not greater total pollution. The California Energy Commission and the SBRP project proponents have not yet come to an agreement on the estimated pollution impacts from the proposed project. We estimate that total particulate matter pollution could increase from about 73 tons per year to about 94 tons per year when comparing the existing South Bay Power Plant to the proposed replacement plant (Appendix H). The LS/Dynegy project offers *no* mitigation or additional offsets for impacts to air quality, and claims that particulates will remain the same as the current plant without giving adequate information to back up this claim.

The existing South Bay Power Plant is a significant contributor to greenhouse gases, large enough on its own to have a significant climate impact (approximately 1/10,000th of global greenhouse gas emissions). The proposed new gas-fired replacement plant would continue to contribute significantly to the global climate crisis, when excellent local solar and wind

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[3] On September 15, 2006, Independent Power Producer Dynegy announced it has agreed to pay more than $2B in stock and cash for the merchant plant portfolio of private equity fund LS power Group, including SBPP and eight other power plants acquired from Duke Energy for $1.6B in May. LS Power Group will retain a 40 percent stake in the combined company. Dynegy's management team, including CEO Bruce Williamson, will run the company.

[4] California Office of State Planning and Development, 2003 Public Patient Discharge Data; 2000 Census.

conditions are available for renewable generation of electricity, as this Plan has surveyed, analyzed, and modeled.

The important question at hand is how the energy capacity provided by the existing plant will be provided. This decision will shape the region's energy future and the health of Chula Vista residents for decades to come. The current replacement proposal does not adequately assess viable alternatives for the power plant design, as required by US and California state law, nor has there been adequate assessment of the ability for other already permitted and proposed plants in the region to meet the goals of the project.

Meeting the Appropriate Energy Needs

Any replacement of the plant with renewable resources must address regional power needs. The scenarios for Chula Vista in this report will present model solutions on a graduated scale to ensure that regional transmission grid requirements of the California Independent System Operator (ISO), the non profit agency charged with maintaining transmission grid stability, would be met in each proposed scenario.

The Green Energy Options portfolios presented here are designed to meet the energy service provided by the existing South Bay Power Plant. The California Independent System Operator's (ISO) designation of the South Bay Power Plant as "Reliability Must Run" ("RMR") requires that it provide peak energy production to ensure regional electric system reliability. SDG&E has built – and is still building – new power plants and transmission lines connected to the regional grid. As a result, the ISO's designation of need for power generation from the South Bay Power Plant is changing. This report presents three portfolios that would replace 50%, 70% and 90% of the existing 700 megawatt capacity of the 2006 RMR contracts on the plant. (the 2007 RMR contract is lower, at 515 MW). The portfolios are designed to meet a range of possible RMR demands so that changing ISO requirements can be met with little or no adjustment to the portfolios.

The Reliability-Must-Run (RMR) role that the South Bay Power Plant serves is related to the plant's capacity, or the most that the plant can produce at a given instant, measured in megawatts (MWs). The plant's electricity service can also be thought of in terms of how much electricity capacity it provides to the grid over a period of time. This is measured in Megawatt Hours (MWh). The South Bay Power Plant currently runs essentially as a load-following plant that ramps up output at times of highest demand in the afternoon and evening, and a large portion of the plants capacity is rarely used. This is further explained in the next section of this report.

On a capacity basis, 700 megawatts of the South Bay Power Plant are under contract with the ISO for 2006 (515 megawatts for 2007). On a megawatt-hour electric generation basis, the current plant produces about 1.9 million Megawatt-hours per year.[5] Notably, the proposed South Bay Replacement Plant would only provide 120 megawatts of added peak energy, far less than the current plant or the GEO options do.

[5] LS Power. Application for Certification to the California Energy Commission for the South Bay Replacement Project. Pg 6-2

3. ISO Reliability Must Run (RMR) Criteria Analysis & Scale of Replacement Energy Needs

Other than a much cleaner and more sustainable power source and competitive pricing, the other main criteria for the scenarios in this report are that each must conform to the ISO's Reliability-Must-Run ("RMR") designation of the current South Bay Power Plant (SBPP), and that any replacement portfolio must fulfill the current function of the plant, which is to provide power during the peak hours of the day.

There are a number of variables that will impact the final ISO designation for the site, including adjustments in predicted regional demand and other regional generation assets. These can change significantly from year to year, and it is not uncommon for projected requirements to be revised downward to lower levels. For 2007, the ISO will seek contracts on only three of the four units at the South Bay Power Plant.[6] This will result in a reduction to 515 MW under RMR contract.[7]

In the recent past, opinions on the need for replacement power on the Bayfront have run the gamut from nothing more than a substation to maintain grid stability, to massive power plants upwards of 1200 MW. As utility forecasts often change, or may be manipulated, Chula Vista should evaluate a range of options to fulfill the energy needs required to replace the existing SBPP. Chula Vista would be free to pursue any of the scenarios described in this report with projects that range from 10 Megawatts of local photovoltaics to a 400 MW wind farm. First we will examine factors related to the current scale and use of the South Bay Power Plant, and then discuss several variables in play that should be addressed prior to establishing the real size of the RMR deficiency, if any, that is needed to be filled by a replacement plant.

Capacity factor is the normal way in which degree of plant utilization is measured. This is expressed with a percentage, which is calculated by taking the number of megawatt-hours generated over a year divided by the total number of megawatt-hours the plant could generate *if it operated full time at full capacity*. Because "capacity factor" is a compound of total capacity and hours of operation, the concept creates some ambiguity. For example, a power plant operating at a fifty percent (50%) capacity factor could mean that it is running at half its rated capacity all of the time, or it could mean that the plant operates at full capacity half of the time. Or, it could mean any varying level of operation between these two extremes that created the same mathematical result.

The operation of RMR facilities is complex, as they may run at various levels at different times of the day and year. Then they may be suddenly asked in the summer, when other resources are strained, to ramp up to full capacity for just a few hours.

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6 Motion: 2006-09-G1 Decision on Local Area Reliability Services Requirements for 2007

7 California Independent System Operator. Local Area Reliability Service 2007, Report of Gary DeShazo, August 31, 2006.

Current Scale and use of the South Bay Power Plant

Any replacement facility or facilities will have to fill the specific role served by the existing South Bay Power Plant. This plant is composed of four main generator units that together are considered to have 690 megawatts of dependable capacity. The following table shows some basic facts about the generating units at the South Bay Plant:

Table 1. Operating Profile of the existing South Bay Power Plant.

Unit	Built	Dependable Capacity (MW)	Output per Year (MWh)	Capacity Factor	Fuel Use (MMBtu)	Heat Rate (Btu/kwh)
1	1960	147	459,135	0.357	4,654,5 31	10,138
2	1962	150	466,098	0.355	4,400,057	9,440
3	1964	171	319,847	0.214	3,312,646	10,357
4	1971	222	84,940	0.044	1,023,633	12,051
Total		**690**	**1,330,020**	**0.220** [8]	**13,390,867**	**10,068**

Source: Resource, Reliability and Environmental Concerns of Aging Power Plant Operations and Retirements. California Energy Commission, Aug. 13, 2004, 100-04-005D.

In addition, there is a 16 megawatt combustion turbine, bringing the total capacity to 706 megawatts. The 2005 RMR evaluation by SDG&E rates the units a little differently and comes to a total of 689 megawatts for the four larger units, which would lower the plant total to 705 megawatts. In general, power plants as they age lose a small amount of rated capacity. For the sake of this report we assume a rounded total of 700 megawatts for the rated size of the power plant in 2009. The actual capacity requiring replacement is likely to be significantly less, and by a much larger factor than this marginal adjustment, for reasons described in this report.

Since the South Bay Power Plant is old and inefficient, it is not desirable to have it running most of the time. This is mainly because it consumes more fuel than competing plants, and thus cannot recoup its fuel and other costs unless the price for electricity is high. High prices occur during the peak hours of the day, when other expensive power sources are also brought on line.

The actual cost of running the plant is a function of the cost of natural gas fuel, the efficiency of the generators, and the fraction of the time the plant is running. The less the plant runs, the more expensive the electricity is. The fuel cost for natural gas is given in dollars per million British Thermal Units (MMBtu), which is a standard measure of energy content. It is the energy in very close to 1000 cubic feet of natural gas. Prices for natural gas on the New York Mercantile Exchanges (NYMEX) are around $7.00 per MMBTU for near term futures contracts. This is

[8] The SBRP AFC before the California Energy Commission lists the current capacity rating as 30%.

triple the prevailing cost of natural gas during the 1990s, but considerably lower than the historical highs following hurricane Katrina in 2005.

Higher natural gas prices have a dramatic effect on the cost of generating electricity, particularly for aging facilities like the South Bay Power Plant. The following table estimates how much it costs to generate electricity from the four South Bay Power Plant units at different prices for natural gas. The lowest price, of $6 per million BTU (about 1000 cubic feet) is on the low to mid range for recent prices of natural gas for electric generators, while $8/ million Btu is near to the average projected price for natural gas by the US Dept. of Energy for the period until 2030. Most analysts expect a long term trend of increasing natural gas prices, and the DOE projects a nominal price of $11.74/million Btu in the year 2030, which is reflected by the upper range in the table below. Because the financial life of an electric generator built over the next few years will continue in operation well beyond 2030, it is very likely that even higher prices will be seen during that period. Note that a new power plant could have *even higher costs*, because the increased efficiency would be more than offset by the increased capital cost:

Table 2. Approximate cost of generating electricity (in nominal cents/kilowatt-hour) with the South Bay Power Plant and with a new gas-fired replacement peaker plant.

Unit	Heat Rate (Btu/kwh)	Capacity Factor				
		Natural Gas price (per mmbtu)	**$6.00**	**$8.00**	**$10.00**	**$12.00**
1	10,138	0.357	7.8	9.8	11.8	13.8
2	9,440	0.355	7.4	9.2	11.1	13.0
3	10,357	0.214	9.0	11.1	13.2	15.2
4	12,051	0.044	20.9	23.3	25.7	28.1
Total SBPP	**10,068**	**0.220**	**8.8**	**10.8**	**12.8**	**14.8**
Modern equivalent	**9,400[1]**	**.220**	**11.9**	**13.8**	**15.7**	**17.6**

Source: California Energy Commission

The capacity factor for the current four generators ranges between 4.4% and 35.7%. In general, we have chosen to assume a 32% operating capacity for the GEO options for a variety of reasons. It falls within a feasible range of performance of renewable facilities; it allows a common baseline of comparison for economic purposes; and it allows financial targets to be met. It may turn out, however, that the optimal capacity factor for any future plant may differ from what we have assumed. The plant owner and operator should evaluate market conditions, such as the value of peak power and the price of natural gas. It may also be advantageous in some cases to sell power outside of the peak period for supplemental income. The wind plant is specifically designed in this manner in that it is oversized compared to the needs of the pumped storage. This will allow for additional electricity sales that offset higher cost peaking resources. Similarly, the natural gas plant might be operated at a higher capacity factor to serve reliability needs of the wind plant during hours when its peaking service is not required. This would supply additional revenue that could offset the natural gas plant costs or improve the value of the wind plant by providing firm electric generation.

Current RMR Contract with the ISO

Until 2006, the full South Bay Power Plant was bound by a contract with the California ISO, the agency responsible for the operation of the state's electric grid. This contract, called a Reliability Must Run (RMR) agreement, requires the plant to remain available up to its full capacity in order to assure the reliability of the electric system in the San Diego County Region. However, in January 2007, it was reduced by 174 MW to 515 MW, with the releasing of unit #3 from this obligation. RMR contracts are effective for one year, and the contract on unit #3 could potentially be reinstated in 2008 if the ISO and plant operator agree.

The RMR contact is particularly designed to assure that power plants are available during times of high demand, when other grid facilities, including generators and transmission lines, are being fully utilized and need extra support. The full power of all four generator units is rarely needed for actual operation, but they all must be on call if needed. This is particularly true of generator number four, the largest and least efficient of the units, which only operates a small fraction of the time.

Variables that Influence RMR Calculations and Designations

There are a number of variables that influence RMR designations. These must be accurately evaluated to establish the real size of the RMR requirement.

Peak Demand and Types of Power Plants

During the course of a day, electric power consumption reaches a low level around 3 to 4 o'clock in the morning. Then demand rises like a great wave during the day until a peak demand occurs, any time between noon and early evening. After the peak, the daily power demand wave ebbs and then returns to its lowest level again early the next morning. This is a "typical" daily pattern, though there is significant variation in different locations, on different days of the week and in different seasons of the year.

It is the responsibility of the electric generators, state regulators, and the business enterprise that purchases power for customers, to ensure that the available electricity on the grid always meets or exceeds the demand. This is critical, since even a small shortfall in generation can cause disruptions of service ranging from poor quality power, to rolling blackouts, or complete collapse of the grid.

In response to this daily wave of demand for electricity, power plants are differentiated into three main functional types. A generator is used most efficiently, and is cheapest to operate, if it is run 24 hours a day at a steady rate. Those that run 24/7 are called base-load plants.

A second type of power plant increases and decreases its level generation of electricity to follow up and down the daily demand wave. These are referred to as load-following plants. Because they are less efficient, the electricity from these plants is often more expensive than the electricity from a base-load plant.

The third type of plant is only turned on for short periods when the power needs spike upward, and cannot be met by the base-load or load-following plants. These are called 'peaker plants'. Since this is the least efficient way to use a power plant, this is the most expensive source of electricity. Due to its extreme age and inefficiency, the South Bay Power Plant has been essentially changed over time from a base-load to a peaking facility. However there is considerable difference in the degree to which the four generator units are used.

Firming up the Capacity of Renewable Generation

Some renewable energy sources, such as wind and solar power, generate varying amounts of electricity on their own schedule rather than in accordance with the needs of the electric grid. For example, wind turbines in California tend to be most productive in the summer evenings when the coastal winds pick up. This is usually after the time when solar energy facilities have dropped out, but demand from residential customers is high. Yet, the wind often continues into the night, long after the demand has fallen and thus does not fully match the peak needs for electricity.

On the other hand, solar energy facilities typically are producing during peak hours in the middle of the day. Flat plate, stationary photovoltaic modules pointing south and angled toward the mid-summer sun will begin producing small amounts of electricity early in the morning, peak in production around noon, and gradually decrease in output over the afternoon. Thus there will be no solar power available to meet the high evening demand that often lasts to 10 or 11 pm.

On top of the above problems, individual solar energy systems can be interrupted when, for example, the sun is behind a tree or a cloud passes overhead. Low winds can cause a wind plant to produce little or no power, while short gusts can cause sudden spikes in output that cannot be absorbed by the grid.

The three significant technical shortcomings to renewable electricity sources such as wind and solar energy are:

- The production of electricity cannot easily be increased or decreased in response to electricity demand.
- The resources are subject to short term, unpredictable fluctuations that may be difficult to integrate into the grid.
- Natural cycles do not necessarily match the exact time, or full duration, when added power is needed.

There are means to address all of these problems and “firm up” the supply of power. Renewable generation facilities and other support systems can be joined together in a variety of ways to cancel each other’s idiosyncratic production patterns, and to supply power when it is needed:

- Geographic separation. Spreading out generation units, such as wind turbines, over a wide geographic area helps greatly to regulate the combined output, since it is very unlikely that the wind will suddenly dip or spike in all locations at the same instant. In the same way, if solar energy systems are widely dispersed, there is little likelihood that a small cloud will cover them all at the same time.

- Integration of intermittent generators. This involves using different types of renewable generation, such as solar and wind, together in a way that provides a more robust service. The sun allows for production during the day, while wind picks up in the evening.
- Integration with conventional generation. A common practice is to back up the solar or wind power with existing sources of power from the grid. This usually comes from a peaking or load-following gas fired power plant that is coordinated to the measured output of a wind or solar facility. In other cases, the gas generator may be built together with the renewable facility, and share the same transmission wires. This maximizes utilization of the power line, and can avoid the surcharges that are often levied against wind plants that need to reserve more line capacity than they can reliably use. An even better source for back up of renewables that produce intermittently is hydroelectricity, which has the extraordinary capacity of being able to respond almost immediately to changes in the electric system. It can use this ability to enhance the efficiency of wind farms.
- Integration with power storage systems. Power storage, such as batteries or flywheels, can absorb extra power from a wind or solar facility, and release it at times when the power is most needed. This allows the solar and wind generators to be fully "dispatchable", meaning that they can be tapped when they are needed most. Batteries and flywheels are useful for relatively modest power needs, for a single building or for very short periods of time on a larger scale. Much larger amounts of power can be stored by using the renewable generation to pump large quantities of water from a lower to an upper reservoir. When the power is most needed the water is allowed to flow downhill through a turbine powering an electric generator. This sort of technology has been used for many decades. Almost all conventional energy storage systems are efficient, but they can add significant cost.
- Integration with demand response and energy efficiency. Photovoltaic facilities are always better investments when combined with energy efficiency and conservation measures. A more advanced application is to use these tools in a coordinated way to provide reliability for the grid.

San Diego Regional Electricity Supply and Demand

San Diego County's electric system is essentially an island connected to the outside transmission system at two points. One of the transmission connections is in northwest San Diego County leading toward Orange County (WECC Path 44). Path 44 is the only connection into the rest of the California ISO system. The other transmission connection, the Southwest Power Link (SWPL), begins at the Miguel substation east of San Diego and heads through the east county, just north of the Mexican border, and then leads into the Imperial Valley. This 500 kilovolt line allows for power to be brought in from generator plants in Arizona. The total import capacity of the two transmission corridors is 2850 megawatts. The 2005 projected peak electricity generation requirement for SDG&E was 4370 megawatts, meaning that 65% of the summer peak demand could be met by electricity imported through the transmission wires alone.

The electric resource potential is defined by the generation resources inside the country and the import capacity at the two transmission entry points. ISO rules require that the regional grid be resilient to some degree against failure of system components; specifically the grid must have resources to withstand the removal of the largest generator and one transmission line. This is referred to as the "G-1/N-1" criteria.

These criteria require that all reliable resources be added up, and then the largest generator and one transmission line are subtracted. For this purpose the 350 megawatt capacity of the Southwest Power Link line is subtracted from 2850 megawatts of total transmission capacity to result in 2500 megawatts of capacity that is considered to meet the reliability criteria. The main generator resources are 945 megawatts of steam generators (of a total 971 MW) at the Encina Plant, 689 megawatts of steam generators (of 706 MW) at South Bay. In 2005, there were another 395 megawatts of capacity under RMR contracts, including the remaining capacity at Encina and South Bay that are gas turbines. This brings the total RMR generator capacity to 2030 megawatts. In San Diego County the largest generator for 2005 was the 329 megawatt unit at Encina, called Encina 5. The largest generator in the region contributes nothing to the reliability requirements except to serve as the discounted resource. Similarly, one transmission line is worth 350 megawatts of carrying capacity, and also gets subtracted from the total. The available resources are then compared with assumed projections about future peak demand, which is based upon a probabilistic model. The generators and transmission capacity are supposed to meet a spike in demand that has a 1 in 10 year probability of occurring. The following table shows in summary the region's 2005 resources as calculated by SDG&E.

Table 3. SDG&E 2005 RMR Resource Calculation

	Capacity (MW)	Cumulative Total (MW)
Peak Demand plus line losses	4370	4370
Transmission Import capability	-2850	1520
N-1 loss of one transmission line	350	1870
QF generation resources	-180	1690
Removal of largest generator (Encina 5)	329	2019
Designated RMR units	-2030	**-11**

While the above was valid for 2005, significant changes occurred in 2006. Specifically, the Palomar facility was brought online, making it the largest generator in the region; Encina 5 lost its designation as the subtracted generator. Since about 8.6% of the electricity produced by generators is lost in the transmission and distribution system, this loss must be added to the peak demand in order to figure out how much the generators need to produce. Thus, included in the 4370 megawatts is about 375 megawatts of power lost in the electric grid, mostly in the form of dissipated heat caused by the electrical resistance of power lines and transformers. This is important, because *the 8.6% loss is avoided whenever an energy resource is placed where the demand is located*. Partly for this reason, utility companies like to consider on-site generation, like photovoltaic systems on a customer's roof, as removed load rather than as generation; it makes the calculation of the power resource simpler for them.

When you take the total requirement to meet demand and subtract all available resources, then the result for 2005 was a negative 11 megawatts. This means that there was 11 megawatts more estimated electric system resource than was required to meet RMR criteria in that year. Retirement of the South Bay Power Plants' 700 megawatts in 2009 would have to be replaced with other resources in the form of new generation within the county, new transmission to bring power into the county, or peak demand reduction. These resources not only must replace South Bay, but they also must meet future growth in demand in the SDG&E territory. This requirement can be met in a number of ways *without any need to build new transmission capacity that goes out of the county*. In addition, at a meeting of the Energy Working Group representatives of ISO and of the Resources Subcommittee stated that there were several options to close any reliability gaps, and that building several smaller power plants would be a better option than a large base-load plant.[9]

Addition of New Power Plants

Two new power plants have been brought on-line since the resource calculations were made by SDG&E in 2005. A 44 megawatt peaking plant in Escondido (MMC) and the 546 megawatt plant at Palomar/Escondido built by Sempra. This adds a total of 590 megawatts to the region's power generation; nearly the anticipated replacement capacity for the South Bay plant. Since the Palomar plant is now the largest generator, the Encina 5 plant adds back its 329 MW.

Future Power Plant proposals

An additional 561 megawatts of capacity has been permitted and contracted at Otay Mesa, with an anticipated on-line date of January, 2008. This project has been postponed a number of times, leading to questions about when and if the power plant will be completed. Yet, if this power is brought on-line, as is expected since a long-term contract was signed with SDG&E, then there will be major implications regarding the South Bay Power Plant. So large is this addition that it will certainly reduce, and may even eliminate, the need for an SBPP replacement. A 22 megawatt biofuel plant has also been announced, bringing the total possible additions to 612 megawatts in the SDG&E system by the 2009 retirement date of the South Bay plant. A proposal by ENPEX for the Community Power Project could result in electric generation capacity located at the Sycamore Substation of 750-1500 MW, proposed to be operable by 2011.

[9] "Ms. Hunter asked whether options to close the gap were evaluated in the CAISO study. Mr. Shirmohammadi explained that there is a multitude of ways to address this issue but that large power plants were not the solution to the problem. Mr. Shirmohammadi stated that if building more power plants were the decided route, building several smaller one would be a better option." Minutes of SANDAG's Energy Working Group, July 27, 2006, p. 13

Local Targeted Upgrades in Transmission

The San Onofre Nuclear Generator Station (SONGS) has 2200 megawatts of capacity. The SONGS facility is jointly owned by San Diego Gas and Electric (SDG&E), Southern California Edison (SCE), and two municipal utilities. SDG&E's share is 20% of the power output, or 440 megawatts. Even though the nuclear plant is in San Diego County, it is not included in the resource base. This is because it relies on the northern transmission line (WECC Path 44) for moving its electricity into the rest of the county. Therefore it takes up transmission capacity and effectively removes 440 megawatts of power from being brought into the region from out of the county.

One option would be to add to the transmission system *within the county*, using existing rights of way, to bring the SONGS electricity far enough south into the regional grid so it does not block the northern imports. An additional factor to consider is the planned decrease in capacity of the nuclear plant. The past 440 megawatt share is expected by SDG&E to be reduced to 377 megawatts by the year 2009, and to 311 megawatts thereafter. This means that the actual capacity advantage of the new transmission line may be 311 megawatts in future years.

Energy Efficiency and Loading Order Requirements

New electric resource plans are required to follow the state's new concept of the "loading order." The loading order requires utility companies to make energy efficiency resources their top priority, above conventional generation. New resource planning since 2004 must include energy efficiency resources that were not included in the earlier RMR calculations.

Energy efficiency may reduce resource needs, if the removed load occurs during times of peak demand. Lowering the amount of street lighting, for example, would reduce energy consumption, but does so mainly at night. It thus would be of little value in meeting RMR requirements. A much better approach would be to implement higher efficiency air conditioning, forced ventilation to cool buildings at night, or improve insulation and ductwork. This form of efficiency usually corresponds well to patterns of peak summer demand, when electric system resources are most strained.

Demand Response

Demand response is an agreement with the utility company, usually by large commercial or industrial customers, who agree to reduce their electricity consumption during hours of peak demand. This reduction may result in absolute savings in their consumption, or they may simply defer electricity usage until hours when the demand reduction is not needed. Whether or not Demand Response reduces electricity consumption, it does reduce the total load during peak hours. This reduces the need for new power plant capacity. It also means that there is less need for operation of power plants that would meet the peak demand. In fact, typically the dirtiest and least efficient plants would be removed from operation first. So, Demand Response reduces fuel consumption for power generation and reduces pollution. A Demand Response contract can be considered equivalent to power plant capacity as far as reliability is concerned, and is actually worth more than a power plant due to avoided electrical line losses.

Distributed Generation

Distributed Generation ("DG") includes any generation capacity that is installed near or at the location where the electricity is consumed. Particularly relevant is any form of solar energy, such as photovoltaics, that meets peak demand, or Combined Heat and Power (CHP) plants, which generate electricity whenever it is required. The amount of CHP is unpredictable at this point, but there is a major expansion in the works for photovoltaics in the state due to the California Solar Initiative, which should result in the installation of 100 megawatts per year, or more, over the next decade in the investor-owned utility regions.

As San Diego has excellent solar resources, and the highest utility rates in the state, it would be reasonable to assume that up to 10 megawatts of photovoltaics will be installed each year in SDG&E service territory. By 2009, this could add 30 megawatts to the region, of which 60% might be considered to be reliable for the RMR criteria. This will add 18 megawatts of reliable demand side resource, to which about 9% must be added to make it equivalent to generation side resources. Thus, 18 megawatts of reliable photovoltaic capacity would be worth nearly 20 megawatts of RMR capacity.

Existing and Future Energy Supply and Demand

The following table summarizes the existing and future potential resources by 2009 that have been discussed above, none of which were included in the SDG&E forecasts in 2003 as reliability resources. It shows the possibility for an additional capacity of 1848 megawatts, without any more new power plants than those already announced, and without any additional transmission projects for bringing in power from out of the region:

Table 4. Actual and Potential New Peak Resources for SDG&E between 2003 and 2009.

Strategy	Capacity
New Power Plants (2003 to 2006)	590 Megawatts
Planned Power Plants (online 2007 to 2009)	612 Megawatts
Upgrading SOS transmission (within county)	311 Megawatts
Uncommitted Efficiency in 2009	55 Megawatts
Dispatchable Demand Response in 2009	260 Megawatts
Distributed Generation in 2009	20 Megawatts
Total New Resources by 2009 (actual plus potential)	**1848 Megawatts**

Of course, all these resources may not necessarily be up and running by 2009, but at least half of this capacity, including power plants already built, demand response, energy efficiency and distributed generation is a reasonable "base case" assumption. This would mean about 900 megawatts added to 2003 projected resources.

In order to determine what level of resource is sufficient, the added capacity must be compared to projected demand. This is complicated by the fact that past demand projections have been overestimated. For example, in 2003 SDG&E submitted projections to the California Public

Utilities Commission that in 2005 they would need to meet a demand of 4504 megawatts, and that their resources could not meet this target. The projected shortfall was 69 megawatts. Two years later (in 2005), they changed the 2005 demand figure to 4370 megawatts, a downward revision of 134 megawatts. **In addition, the 2003 SDG&E projection relied on the assumption that no power generation in the San Diego basin would come on-line between 2004 and 2023. Both of these assumptions turned out to be false.**

New resource requirements were all shown to be met by major new transmission lines that have so far proven to be unnecessary, 700 megawatts in 2008 and another 1000 megawatts in 2013. In fact, generation had come online before the end of 2005: revisions plus the 46 megawatt Miramar plant pushed the new resource requirements downward by 180 megawatts in just 2 years. The result was a robust 2005 surplus of 111 megawatts rather than the projected 69 megawatt shortfall.

A comparison between projections is instructive. The revised November 2005 projection removes 605 megawatts from the generation resource requirement in 2016, compared to the 2003 projection, roughly equivalent to a full replacement of the South Bay Power Plant. This shows how changing from one projection to another can add or subtract the need for large power plants with relative ease.

Table 5. Comparison of Demand Projections made by SDG&E in 2003 and 2005

	2009	2010	2011	2012	2013	2014	2015	2016
Peak Customer Demand (2005 "base case")	3921	3984	4046	4109	4171	4232	4290	4348
Reserve Margin (15% Demand)	588	598	607	616	626	635	644	652
2005 est. Firm Peak Requirement	4509	4582	4653	4725	4797	4867	4934	5000
2003 Projection (90/10)	4937	5031	5125	5219	5313	5408	5506	5605
2003 Demand Overstatement vs. 2005 Base Case Projection	**+428**	**+449**	**+472**	**+494**	**+516**	**+541**	**+572**	**+605**

Using the updated 2005 "base case" projection is thus equivalent to building a new South Bay Power Plant replacement. Note that this does not say that a replacement plant is or is not needed. Such a decision would depend on matching demand projection with actual resources brought online, and must subtract the capacity of any power plants that are retired. **Yet, the comparison of projections just two years apart shows how important it is to keep an eye on revisions in projected demand.**

During the same period, between 2009 and 2016, additional demand response, energy efficiency and local distributed generation resources are projected, beyond the figures cited above. The following table shows expected deployment:

Table 6. San Diego Region Generation from 2009 to 2016

2003 Projected Generation (G-1)	1935	1935	1935	1935	1935	1935	1935	1935
New Generation	590	590	590	590	590	590	590	590
Retirement of SBPP	-700	-700	-700	-700	-700	-700	-700	-700
Total Generation	**1825**	**1825**	**1825**	**1825**	**1825**	**1825**	**1825**	**1825**
Projected Transmission (N-1)	2500	2500	2500	2500	2500	2500	2500	2500
Transmission Plus Generation (G-1/N-1)	**4325**	**4325**	**4325**	**4325**	**4325**	**4325**	**4325**	**4325**
Efficiency	55	118	175	225	278	345	417	486
Demand Response (DR)	260	264	267	271	276	279	282	286
Distributed Generation (DG)/ and CHP (to be developed with CEC)	-	-	-	-	-	-	-	-
Total On-site Resources (Efficiency plus DR and DG)	315	382	442	496	554	624	699	772
Total Resources	**4640**	**4707**	**4767**	**4821**	**4879**	**4949**	**5024**	**5097**
2005 Peak Requirement (including 15% reserve)	**4509**	**4582**	**4653**	**4725**	**4797**	**4867**	**4934**	**5000**
Surplus/(Shortfall)	**131**	**125**	**114**	**96**	**82**	**82**	**90**	**97**

The above chart makes several assumptions. First, it includes only power plants and transmission line that have been brought online to date. Second, it relies on current projections for on-site resources, which excludes distributed generation and Combined Heat and Power (CHP) that may be added in the future. Requirements for including distributed generation in utility resources are supposed to be established this year by the California Energy Commission and the California Public Utilities Commission. Both agencies place high priority on distributed generation, so this should add significantly to the numbers on the resource side, or make up for potential shortfalls in efficiency and demand response projections.

The scenario above also assumes that planned new in-basin generation, and the additional in-county transmission line in the South of SONGS (SOS) corridor, *is not built*. These combined equal another 923 megawatts of potential capacity, which if they were included could bring regular surpluses in excess of 1000 megawatts even with full retirement of the South Bay Power Plant. Yet, surpluses of 82 to 131 megawatts are projected even without the additional power plants or the SOS added transmission. This also assumes full retirement of the South Bay Power Plant, with no capacity replacement.

In summary, the region has numerous options in addition to the Green Energy Options Portfolios presented in this report to replace the energy capacity provided by the South Bay Power Plant; a full capacity replacement should only be necessary if all the other options fail. The resources listed below can be used to meet projected demand requirements, replace a shortfall in meeting on-site resource targets, replace further generation capacity retirements, or meet an unanticipated increase in future demand. These options in total can add more than 2300 megawatts of electric system capacity, which should be able to meet the contingency needs of the county for years out into the future. The options include:

- SDG&E fulfills its responsibilities to deploy demand response, energy efficiency, distributed renewables and Combined Heat and Power Facilities, adding 772 or more megawatts.[10]
- Future additional electric generation capacity, such as the Otay-Mesa Generating Station, and/or other smaller plants, results in 612 megawatts or more of new capacity.[11]
- Construction of the South of Songs Transmission line adds 311 megawatts of capacity.[12]

10 SDG&E, Annual Aggregate Energy Resource Accounting Tables, Appendix IIA, Table B17, November 15, 2005.

11 California Energy Commission Energy Facility Status, updated February 18, 2004.

12 SDG&E, Annual Aggregate Energy Resource Accounting Tables, Appendix IIA, Table B17, November 15, 2005.

Summary of ISO RMR status and Scale of Energy Replacement Needs

The RMR rating for the South Bay Power Plant is a moving target partly because of new generation and transmission projects that are coming on line or that will be built in the future. We are presenting three scenarios that provide capacity for different RMR replacement levels, as what capacity will actually be needed to replace the existing South Bay Power Plant's capacity is highly uncertain.

Two different strategies are possible for addressing a high case RMR requirement. The first is to apply the highest, 90 percent replacement scenario. The second would be to supplement a smaller Bay front power plant with the smaller portfolio.

The ISO board has removed the RMR status from Unit #3 of the South Bay Power Plant for 2007. Unit #3 is considered to 174 MW of dependable capacity. This reduced the total RMR burden on the SBPP down to 515. As the language of the Cooperation Agreement states the replacement plant only has to be as large as needed to remove RMR from South Bay, the solutions presented in this report will become significantly more affordable.

Finally, there are a number of resources that are not counted in the current RMR projections for the San Diego region. Some of these resources, such as demand response, distributed generation, and energy efficiency, are required by state regulation to come on line over the next three to ten years amount to literally hundreds of megawatts of capacity. Others, such as insuring the proper, full accounting for the Palomar Plant, and adding an extra transmission line on the existing corridor to the San Onofre Nuclear Plant, are least cost solutions for adding capacity. Addressing these issues is essential before any decision is made to commit hundreds of millions of dollars of ratepayer funds into a new bay front power plant, particularly when other solutions to the region's energy needs exist which are environmentally superior, carry lower risk, and represent a far better investment than betting the entire bank on natural gas.

4. Green Energy Options: Three Portfolios for Cleaner More Sustainable Energy for the Region

This section outlines the Green Energy Options (GEO) portfolio alternatives to a new 620 MW replacement power plant, for a range of possible RMR capacities for the South Bay Power Plant.

90% Replacement Capacity Green Energy Option

Portfolio that replaces 90% of 700 MW Capacity

- 400 MW Wind Farm with 150 MW Pumped Storage and Transmission project
- 220 MW Natural Gas Plant
- Solar Concentrator Plant powering a 160 MW Peaker with natural gas backup,
- 20 MW Photovoltaics
- 20 MW Peak Demand Reduction

70% Replacement Capacity Green Energy Option

Portfolio that replaces 70% of 700 MW Capacity

- 325 MW Wind Farm with 90 MW Pumped Storage and Transmission project
- 190 MW Natural Gas Plant
- Solar Concentrator Plant powering a 160 MW Peaker with natural gas backup,
- 20 MW Photovoltaics
- 20 MW Peak Demand Reduction

50% Replacement Capacity Green Energy Option

Portfolio that replaces 50% of 700 MW Capacity

- 150 MW Wind Farm with 60 MW Pumped Storage and Transmission project
- 90 MW Natural Gas Plant
- Solar Concentrator Plant powering a 160 MW Peaker with natural gas backup,
- 20 MW Photovoltaics
- 20 MW Peak Demand Reduction

5. Description of Green Energy Technology Options

The three portfolio alternatives to installing 650-700 MW firm capacity generation replacement on the Chula Vista Bayfront utilize technology and investment options that are viable and ready for implementation, involving multi-year commitments of local jurisdictions that may be used to finance alternative energy portfolios and accelerate renewable investment in Chula Vista and throughout San Diego County. This section describes in detail these technology options and how they could be developed here.

Hybrid Wind Farm & Pumped-Water Storage Facility

Size Range:	**150 to 400 Megawatt Capacity Wind Farm,** **60 to 150 Megawatts Pumped Storage**
Cost Range:	**$170 to $540 Million for the Wind Farm;** **and $80 to $210 Million Pumped Water Storage**
Est. Power Cost from Wind Farm:	**4.8 cents/kwh**
Est. Power Cost from Wind plus Pumped Storage: (See Appendix A)	**9.6 cents/kwh**

A wind farm and pumped storage serve as insurance against increasing natural gas prices, as the cost is essentially fixed and is the part of the portfolio that is completely independent of fuel prices. Wind power also partly serves to round out load requirements that are not fully met by solar energy alone. While wind is intermittent, the pumped storage facility makes the electricity generated by the wind highly reliable and usable at any time it is required. Thus the pumped storage, while adding significant expense, also adds great utility and value.

Wind power is easily the lowest cost renewable generation option, in the last several years globally averaging $1000 to $1200 per kilowatt of capacity for a large wind farm. High demand has recently pushed the cost of wind farms higher, with a range between $1300 to $1750 per kilowatt; the lower range should be achievable with good planning and also once manufacturing capacity catches up to demand. In fact, 2006 DOE projections are that wind farms should return to the previous low levels by the end of the decade, though our cost projections do not assume this. Should this happen, then economics of the wind farm will become very favorable.

Wind turbines have become very reliable, and warranties on product defects cover investors from the most serious capital risks during the early years of operation. With proper operation and maintenance, wind turbines have a life expectancy of 20 to 30 years.

The most important factor in the cost of electricity from a wind farm is the available wind resource. Wind power resource goes up geometrically in proportion to the cube of the wind speed. Thus, even small increments of average wind speed can make a significant difference in wind generation. It is critical first to find areas with the best wind and then to follow this up with careful measurements of at least one year at the locations under consideration.

Wind resources are conventionally measured according to "Classes" ranging from 1 to 7. A class 3 wind is the usually the minimum for commercial development. A class 3 site would ordinarily only be used when other factors make it desirable, such as a location close to where the power will be delivered. For sites that require transmission of electricity over a distance, a minimum of class 5 is highly recommended.

Parts of Eastern San Diego County have some of the finest wind resources in California (Class 5 and Class 6). A considerable amount of this area is in national park, forest or other protected areas, and thus is effectively off limits to development. However, there are high wind areas in the Southeast County that may be more suitable for a large wind farm (Figure 1).

Figure 1. San Diego County Wind Resource Regions.

The second major factor affecting the cost of wind is financing. Private developers require significant rates of return that can add to the cost of wind. This is usually offset by the federal wind tax credit, currently 1.8 cents per kilowatt-hour paid for the first 10 years of the wind farm's operation. Since Chula Vista is not a tax paying entity it is not eligible for the tax credit, however its low cost financing resources using municipal bonds can essentially equal the benefit of the tax credit. This means development plans can be independent of federal tax policy, a frequent stumbling block for wind projects. In addition, the benefit of low cost financing extends for the full life of the asset, while the tax credit is limited to 10 years.

Utilizing municipal financing for a large wind farm with class 6 winds would likely result in wholesale electricity costs of 5 cents per kilowatt-hour or less. This makes wind power competitive with the long-range expected cost of electricity generation from base load plants. Wind powered electricity can be sent directly over the transmission grid, but its variability means that it is not reliably producing power at the times it is most needed. To make the wind generation reliable, it must be backed up with other generation resources. Vendors of contract wind power usually make use of natural gas generation to provide a 24-hour base load service.

Since this off-peak character of wind power is not part of the service provided by the existing South Bay Power Plant, selling the power to wholesale buyers or a CCA requires a way to transfer the energy output to those hours when it is needed, and the design of this component must be included (and is included in this Plan) in its financial modeling. In order to project the competitiveness of the large scale solar concentrator turbine facility and wind turbine facility, this Plan includes the fully integrated "Hybrid" packages rather than just isolated RMR-related component, investment scale, and paybacks. An energy storage system, which takes the power produced at night and makes it available during the day, is the way to achieve this functionality. Pumped Storage is the only affordable, practical way to store this amount of energy, in which water is pumped to the top of a reservoir at night when the wind blows, and the water is released the following day to run hydroelectric turbines. Modern systems allow for a single unit to serve both as pump and turbine, which reduces the capital expense.

The GEO's proposed Pumped Storage facility places an additional cost for peak power that can add about 3 to 4 cents/kwh to the cost of energy that is used to pump the water into the storage. At current and forecast future natural gas prices, pumped storage can be competitive to projected peak power from competing natural gas power plants. Hybridizing the facility also enables the lower-cost wind power to offset the higher cost Pumped Storage power. This is because only a part of the power generated by the Wind Farm is used for running pumps on the Pumped Storage Facility, with the remainder of the wind power being sold as part of a competitively priced, stable energy supply. While pumped storage facilities can be expensive, their cost can be reduced by using existing reservoirs. There are reservoirs in San Diego County, most notably in the East County, which might be suitable from the standpoint of location, size and sufficient elevation drop below the reservoir. Also, the Lake Hodges Pumped Storage project may provide a feasible market for selling excess wind generation, and should be evaluated by Chula Vista and any partners. Finally, while Pumped Storage adds substantially to the cost of the Wind Farm's power, power delivered during peak hours has a large premium value in the wholesale power market. This facility will serve as a hedge should natural gas prices increase in the future, which is widely predicted. In addition, the pumped storage facility will outlast the wind equipment by decades. Once financing costs have been covered during the financing period, the pumped storage cost will be reduced to operation and maintenance, which means that the cost to generate electricity will be very cheap and the profit margins quite large. In this way, the pumped storage facility is a long term investment.

Hybrid Solar Concentrator Turbine with Natural Gas Backup and Cogeneration

Size Range:	**160 MW**
Cost Range:	**$350 to $450 million**
Power Cost without Cogeneration:	**10.2 to 12.2 cents/kwh**
Power Cost with Cogeneration:	**9.1 to 9.28 cents/kwh**

(see appendix B)

Solar thermal generators have been reliably delivering hundreds of megawatts of power into the California grid since the 1980s. This technology uses parabolic mirrors to collect light and concentrate the heat of sun onto a long tube filled with a fluid. These mirrors track the sun, and thus produce power all day long at a fairly consistent level in sunny locations. In one variation, the fluid transfers the heat to a second fluid, such as water, that turns to steam and runs a conventional turbine. The conventional turbine can also be run off of natural gas on days when the sun is not available. This provides a very high level of reliability while greatly limiting use of natural gas. Such a system can completely replace the functionality of the current South Bay Plant.

One major problem with solar thermal generation has, in the past, been lack of availability. This limitation is rapidly disappearing, as new solar thermal manufacturers and installers are beginning to emerge all over the world, including in the US. Recently a one megawatt solar thermal power plant in Arizona was completed, and a 64 megawatt plant in Nevada is under construction. The 1 megawatt plant was quite expensive: at about $6000 per kilowatt it is 5 times more costly than equivalent sized wind farms. The larger plant in Nevada reduced the unit cost by about 40%, due to improved design, experience, and some economy of scale. This technology is expected to continue to decrease in cost, which will be necessary to make it directly cost competitive with peak power from natural gas generators. However, it is easier to acquire and permit real estate for Solar Concentrators, making it feasible in many areas of California where there is sufficient relatively level land.

For a local resource, power prices from solar concentrators are expected in the next 5 to 10 years to become a competitive, locally available power source, especially when transmission already exists or no new significant transmission is required. The Nevada solar-trough thermal generating plant costs about $3500 per kilowatt, but the installer says that a larger plant of 160 megawatts, such as Local Power is recommending for Chula Vista, will be significantly cheaper. A combination of further development of the industry, and a larger scale project, should begin to make solar thermal technology directly competitive with long-term expected cost of comparable natural gas plants. The projection of $2500 per kilowatt is in line with industry expectations and DOE price projections.

We also strongly recommend that a solar thermal project be co-located with a facility that can use and purchase the "waste" heat; an application referred to as co-generation or combined heat and power (CHP). This can make solar thermal generation significantly more cost effective, and also provide a secondary commercial development opportunity.

Solar concentrators have been around for over a hundred years. We estimate that a 160 megawatt project would require approximately 900 acres; however, if the cost for solar concentrators continues to drop, a smaller facility may become economical. The sites mentioned in this report, such as those near Sycuan, and Ream Field, have been initially evaluated and may prove adequate in size and solar conditions to provide affordable local power. The resource for solar energy is optimal in the East County, but a development nearer to Chula Vista would come close to matching the effective cost to produce electricity if transmission charges can be avoided. Further site acquisition and permitting analysis is warranted and land-owners would need to be solicited about their interest in such a project in a timely manner.

A natural gas plant that provides assured power is an essential part of the portfolio. It provides a benefit if natural gas prices are lower than the threshold required to make the fixed cost renewables profitable. It is thus a kind of insurance should natural gas prices remain below current levels of $6 to $7 per MMBtu. But even if prices are sustained at $5 per MMBtu, the total portfolio cost of energy is only a fraction of a cent per kilowatt-hour above prevailing costs to run a natural gas turbine generating at an equivalent capacity, an increment that is less than half the premium that the renewables would have by themselves. This illustrates why the natural gas component is a critical part of the GEO investment portfolio. This hedge is more valuable than it would be for a private third-party investor, because the low return on municipal bonds decreases the expense of owning a power plant. This margin of savings is larger for a peaking plant than for a base load plant, since the cost of the plant becomes more significant as less fuel is consumed. The relative savings due to municipal financing, however, are not nearly as large as they are for highly capital intensive renewables like wind, pumped storage and solar thermal, where the fuel cost is very low to non-existent.

Photovoltaics with Energy Storage or Demand Response

Size Range: **20 MW**
Cost Range: **$120 to 160 million**
Power Cost: **25 to 30 cents/kilowatt-hour after rebates; 8 to 12 cents/kilowatt-hour for commercial owners who can also get tax credits.**
(See appendix D)

Photovoltaic power is the direct conversion of sunlight into electricity using semiconductors. The most common semiconductor is a thin wafer of silicon with minute amounts of boron and phosphorous that gives the silicon an electric charge. The silicon wafers are mounted in panels that generate electricity any time they are placed in sunlight. The materials are highly durable, with some testing suggesting lifecycles as high as 80 years or more. Since the technology is modular and flat, the panels can be placed almost anywhere. Frequently rooftops are chosen, but shading structures over parking areas or placement in open areas are also frequently seen.

Present full installed costs for small residential systems average about $9500 per kilowatt, while larger commercial or industrial sized systems average about $8000 per kilowatt, though some facilities have been installed for as little as $5000 per kilowatt.[13] Over the next five to ten years, the cost of photovoltaics is expected to continue to decrease, and numerous technology options and economies of manufacturing scale will facilitate this.

Photovoltaics are still one of the most expensive electric generation technologies, resulting in a full cost of electricity (before rebates) ranging between 20 and 40 cents per kilowatt hour. Yet, despite this fact, there are opportunities to make an investment in this technology cost effective.

Deploying photovoltaic systems at the location where electricity is consumed gives it a premium value over the wholesale power which cost the utility company 5 to 8 cents per kilowatt hour. SDG&E sells this power at 13 to 18 cents per kilowatt hour to customers, and this is much closer to the cost of photovoltaic electricity. Photovoltaics, however, does not compete with the *present cost of electricity*, but rather with the *expected cost of electricity* over the next decades against which it represents insurance. This fact enhances its value substantially. (This point is also an important factor for evaluating the other renewables in the portfolio.) NOTE: Since photovoltaics, as envisioned in the GEO, are developed as generators at customer sites, and may even be owned directly by customers, they are not included in the wholesale electricity price calculations for the GEO portfolios.

If customers take advantage of state rebates and tax credits, then the balance can be shifted decisively in favor of these solar energy systems. The fact that thousands of customers have taken advantage of subsidies shows that the potential market is quite large. The recently enacted California Solar Initiative provides rebates out to 2015, currently $2500 per kilowatt, and set to decrease when specified benchmarks of solar installation are met. Solar energy systems over 100 kilowatts in size will receive a performance incentive, paid out over a few years based on the electric generation of the system. Smaller photovoltaic installations will usually get their rebate at the time of purchase. In addition, businesses can take a tax credit for 30% of the installed cost

[13] Data: California Public Utilities Commission.

of the photovoltaic system until 2008. This will either revert to a 10% credit unless the 30% credit is extended, which several bills in Congress propose to do.

Building to larger scale is another way to save on cost, as small home-sized installations can be about 10% to 20% more expensive on a unit basis. The economy of scale is not at present great enough to make building large photovoltaic generating stations cost effective, though this may change over the next decades as solar energy costs drop and electric rates continue to rise. Last year 1.5 billion watts of photovoltaics were installed around the world, about a ten-fold increase since 1995. During that time the average cost dropped by at least 35 percent. Installing two megawatts per year would require development of multiple sites, since the cap for rebates is likely to be 1 megawatt. Two megawatts was selected as an annual target as this is believed to be the minimum demand required to attract a solar panel manufacturer to the region to support part of regional goals for promotion and development of a green energy economy. Also, the electricity must be usable on-site and few customers use this much electricity. The cost would be about 12 to 15 million dollars per year, assuming large scale deployment and economies of scale. This range is likely to be valid until the end of this decade, though technology improvements will continue gradually to lower the cost over time.

Cogeneration for peak capacity

Cogeneration, also called Combined Heat and Power, uses thermal sources such as natural gas for more than one purpose simultaneously. The heat is first used to generate electricity, which typically only uses about 35 percent of the energy, though the most efficient modern combined cycle base load plants can reach up to 60 percent efficiency. The rest of the heat normally is wasted in the atmosphere, but cogeneration uses the heat to do further work. Normally this is for an industrial process that would use the fuel in any case, but now the fuel does double duty. This can raise the net efficiency to as high as 90 percent, which a substantial savings in both cost and fuel. There are also environmental benefits, while CO2 reductions can approach even the most aggressive climate protection goals. The most efficient way to use combined heat and power is to match it with the on-site needs for heat. But using it intermittently for peak power also realizes significant savings and environmental benefits. This is an important way to help bring down the cost of solar thermal and natural gas peak power generation, though the expected efficiency levels are not as high as for base load plants.

Energy Efficiency, Demand Response and Conservation

Energy efficiency can also be turned into a peaking resource, if the load that is made more efficient matches the peak periods. Determining this may require some research into local demand patterns. Examining the load curves will show what sector the demand is coming from, but it is equally important to find out what appliances are creating the load at the particular time in question. Daytime loads might be offset by more efficient office lighting and other office equipment. Evening summer peak load in California frequently comes from air conditioning. Building insulation, sealing ductwork and building envelopes, measuring internal thermal flow and pressure patterns, and installing more efficient air conditioning are keys to addressing this late afternoon to early evening demand. Adequate training of personnel and inspection of air conditioning refrigerants also help. Any efficiency program requires the most stringent monitoring, which just as important as prescreening. The program should set clear goals that match the load requirements that the power plant currently fills, and they should be monitored for actual savings in kilowatt hours and peak building demand patterns. This is much more efficiently done in large commercial structures, but addressing the residential sector may be critical for offsetting the electric system's evening power demand.

Demand response is far more easily accepted by the ISO as a legitimate power resource, particularly if customers in a demand response program are bound by usage contracts that specify when and how much demand curtailment will be applied. This is done by central dispatch, using automated controls, though up to this point such dispatch can be rather brutal. A CCA could create its own demand response program that allows for flexibility and customer choice. Importantly, such a program can be implemented with little capital investment, and forming an agreement with a customer is an ideal entry point for bringing in a wide range of attractive energy services, including photovoltaics, efficiency measures, backup emergency power, power conditioning equipment to assure high quality, and energy audits. Demand response is much more cost-effective with large commercial or industrial customers. Programs are more successful when the customer receives a financial reward, such as lower rates. Since many of these customers are on time-of-use rates, there is built in support in their electric rate structure. The key is to enhance this value while minimizing sacrifice from the customer.

6. Key Investment Mechanisms and Financing

This section identifies the process and programs by which the City of Chula Vista could recoup their green investments and raise revenue. It contains an analysis of implementation structures that would be needed, financing, and public programs that support or affect clean energy projects.

Community Choice Aggregation (CCA)

Community Choice is a key strategy in Chula Vista's ability to develop the renewable energy facilities on a scale that will reduce or eliminate the need for generation on the SBPP site.
CCA is technically easier to implement and less risky than a municipalization, but facilitates local control over energy resource planning. Under a CCA, Chula Vista would procure power on behalf of residents and businesses; SDG&E will continue to provide distribution, meter-reading and billing services, and would remain the Provider of Last Resort.

CCA is an established, successful method of procuring competitively priced energy services. Nationally, CCA uses economies of scale to leverage lower prices, cleaner power and better service. Since 1997, CCA Laws have been passed by New Jersey, Ohio, Massachusetts, California, and Rhode Island. All of Cape Cod formed the nation's first CCA in 1997, and has provided electricity service and energy efficiency services at below-market prices since then. The Cape Light Compact is a regional services organization made up of all 21 towns of Cape Cod and Martha's Vineyard, and Barnstable and Dukes counties. The purpose of the Compact is to represent and protect consumer interests in a restructured utility industry. As authorized by each town, the Compact operates the regional energy efficiency program and works with the combined buying power of the region's 197,000 electric consumers to negotiate for lower cost electricity and other public benefits. The Compact provides

1) Aggregated power supply

2) Consumer advocacy

3) Energy efficiency programs such as low income, residential, commercial and industrial, and education programs

Cape Light Compact, emphasizes a comprehensive approach, undertaken with legal and technical support – as the electric industry continues in its transition to a competitive market.

In Ohio, CCA represents nearly all of the state's competitive electricity market, with the Northeast Public Energy Council serving approximately 500,000 customers since 2000, with a 70% cleaner portfolio than utility service at prices consistently lower, even after changing suppliers. Forty California municipalities and counties are now evaluating Community Choice, 27 of them are seeking to double or more the state Renewable Portfolio Standard (RPS) targets.

Apart from providing revenue for the repayment of renewable energy investments, CCA offers Chula Vistans transparent, structured rates. "Political rate-setting" may be avoided by requiring prospective suppliers to "meet or beat" SDG&E's current rates, be selected through a competitive bidding process, and commit to a locally-set rate schedule. Chula Vista, or a regional CCA, may set a Renewables Portfolio Standard (RPS) for the community and require suppliers to design, build, operate and maintain renewable energy and conservation facilities as portfolio components of the service. CCA enables a maximum level of performance risk to be placed on the energy rather than the City's General Fund. With significant revenues secured under a CCA contract, City program costs can be self-funded from a small increment of revenues. A single supplier approach allows for greater performance accountability, protecting both the City's General Fund and new customers against energy market risk. Double-Bonding may be used to insure risks associated with both commodity services and facilities construction. Finally, participation is voluntary. After the City signs a contract under specific terms, every customer will receive four notifications comparing the CCA's deal to SDG&E's terms, and be free to opt-out without penalty over a 120-day period.

The repayment of Chula Vista energy investment may be made directly through CCA, or indirectly by selling power to another party. Directly, Chula Vista could provide for the power needs of its own residents, businesses and public agencies, guaranteeing power sales from a renewable energy facility integrated into the Specific Plan – delivering fixed prices and energy independence to the local economy. Indirectly, Chula Vista could build a facility to sell power to the Southern California Public Power Agency (SCPPA), or to the wholesale power market. With other municipalities in the region considering CCA, power may also be shared among CCAs. Either approach would enhance the uniqueness and sustainability of the renewable energy facility development and deliver profits to the city and significant local economic development – all at very low risk.

Community Choice is an authority granted by California law (AB 117, Migden) that allows cities and counties to take charge of their own energy future. Under Community Choice, local governments can serve as a virtual "electricity buyer's cooperative" for local residents, businesses and government agencies. Unlike ordinary cooperatives, however, the day-to-day management for securing electricity supplies is managed by a qualified and experienced third party, while the local government is placed in the role of strategic planner.

The government entity, called a Community Choice Aggregator (CCA), contracts with existing licensed suppliers called "Electric Service Providers" (ESPs). Other public entities, such as SCPPA or other inter-municipal association, may also purchase and sell power. ESPs are often the optimal vehicle because they are risk-bearing retail entities, in the business of providing reliable and cost-competitive electricity for large businesses and government agencies. About 12 percent of California's electricity is currently purchased from Electric Service Providers.

If it were to desire to form a **CCA Joint Powers Agency**, Chula Vista should investigate partnering with other municipalities, principally, National City and Imperial Beach. Imperial Beach in particular has articulated interest in such partnering concepts.

Municipal Revenue Bonds (H Bonds)

The Chula Vista City Council has the authority to issue revenue bonds unilaterally, or to form a partnership with other local government entities in a joint venture to share the risks and benefits of a renewable energy network with other governments on a regional basis.

Joint Powers Agencies, Native American Tribes, other cities and ports also have the authority to issue revenue bonds, either based on a new revenue stream or existing assets or contracts. There are several key entities in or near Chula Vista which should be considered for a potential financing partnership. We have identified specific opportunities for Chula Vista to issue H Bonds in conjunction with other local public entities, any of which could participate in a CCA, co-finance and co-own green power facilities, and host facilities on their list of lands and properties:

- Native American Tribal Governments in or near San Diego County have land suitable for Solar Concentrator and Wind Power Facility, and are pursuing commercial green power development;
- Southern California Public Power Agency members already co-develop power plants and could partner to develop and take power from a Solar Concentrator or Wind Farm Hybrid as municipal utilities;
- San Diego County owns reservoirs and land suitable for the proposed Wind and Pumped Storage Facility;
- Port of San Diego could co-finance a green power facility and purchase power as a member of a CCA;
- U.S. Navy is an active developer of solar photovoltaics, has land suitable for green power facilities, and is a major energy user.

The specific scenarios involve an integrated use of H Bonds in conjunction with a CCA. H Bonds are generic municipal revenue bonds used to finance renewable energy and energy conservation facilities. Chula Vista, and any other city, has the opportunity to issue H Bonds based on a new revenue source. There are three categories of H Bonds:

- First, a municipality, JPA or public agency partnership may own its electric utility, and secure H Bond repayment through the guaranteed monthly bill payments of captive utility customers. This option has been foreclosed by Chula Vista's Franchise Agreement with SDG&E in 2004, which appears to prevent Chula Vista from providing wires services alone or with another party, including transmission;
- Second, a municipality may issue H Bonds to finance facilities that will operate without a guaranteed retail customer, selling power with a degree of risk mitigated by long-term contracts with public agencies such as the Southern California Public Power Authority in a long-term agreement, and/or selling power in long-term contracts on the wholesale power market.
- Third, a municipality may form a Community Choice Aggregator (CCA) formed pursuant to AB117 (2002 – Migden) and secure repayment of H Bonds based on monthly electric bill payments of participating residents, businesses and public agencies.

H Bonds and CCA

H Bonds provide CCAs with considerable flexibility. They can be used to finance renewable energy generating units and other revenue producing elements of CCA, such as storage facilities and conservation facilities. H Bonds can be supported by existing public agency assets and enterprises, or by new assets or enterprises such as renewable energy generating units. Finally, revenues from a contract with an Electric Services Provider ("ESP") may support H Bond repayment, with or without assets or enterprises.

H Bonds and CCA are extremely synergistic. Together, they (a) provide both the means to develop renewable energy and energy efficiency resources, and the market to utilize and pay for those resources; and (b) provide CCA with a secure base of resources with which to serve its customers and, thus, avoid excessive dependence on a volatile energy market. Whether the H Bonds will qualify for tax-exempt status and other factors affecting their marketability are dependent on the structure of the transaction being financed. Specific structures are discussed below.

As a rule, in order to qualify for tax exemption, the facilities that are financed must be owned by a governmental entity or operated by Chula Vista or other governmental entity – or by a nongovernmental entity on behalf of Chula Vista pursuant to a contract that meets certain requirements prescribed by the Internal Revenue Service. Even if not tax-exempt, H Bonds could still be issued to finance facilities which make solar and other technologies more affordable to local residents and businesses, albeit at a slightly higher interest cost than government-owned facilities would pay – but could also take advantage of significant federal tax benefits.

Application of H Bonds to CCA [14]

H Bonds can be used in a variety of ways. From a strategic business perspective, H Bonds and CCA were developed to work together. Without CCA, renewable energy and energy efficiency projects financed by H Bonds would have to search for a market for the power output. With CCA, major recurring revenues from community-wide retail electric sales will repay the investment in clean energy projects.

Alternately, without resources of the sort authorized by H Bonds, a CCA program could not finance new green power facilities; moreover, without a secure base of resources, a CCA would be extremely dependent of the energy market to serve its customers. The energy crisis of 2000-2001 dramatically demonstrated the danger of over-dependence on a volatile energy market – a lesson reinforced by fossil fuel price fluctuations this past year, and SDG&E's increasingly volatile electricity rates, reflecting its predominantly natural-gas fired power plant fleet. The specifics of how H Bonds are used in connection with CCA depend on what types of projects are to be financed. Because a driving factor behind most local government's interest in CCA is to utilize renewable energy and energy conservation, a number of projects that meet the parameters for H Bonds would probably be part of a Chula Vista CCA energy plan. Those projects can be financed with H Bonds.

The specific use of H Bonds to most effectively further CCA depends on the particular projects. Three of the threshold questions that must be addressed are (i) what assets or programs would best assist with the implementation of CCA, (ii) what revenue source will secure repayment of the H Bonds, and (iii) whether the H Bonds are tax-exempt or taxable. These items are discussed

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[14] "How H Bonds can be used to implement an adopted CCA Implementation Plan," Nixon Peabody LLP, "Analysis for San Francisco Local Agency Formation Commission," November 10, 2005, Accepted by San Francisco Local Agency Formation and San Francisco CCA Task Force, 2006.

briefly below. The first two are somewhat related in that if the items financed do not have an independent or sufficient revenue stream to support the bonds to be issued, a separate revenue stream for the H Bonds must be identified. The question of tax exemption will turn generally on the specific facts relating to ownership and use of the financed items.

Chula Vista General Plan, Policy E 7.5 states that the City sets a goal of 40% clean renewable energy by 2017.[15] San Francisco[16], Marin County, and other cities implementing Community Choice Aggregation have set goals of 50% or higher by 2017. To achieve this objective, Chula Vista's Implementation Plan would contemplate a number of elements that should fall within H Bond financing in order to provide for the development of renewable energy facilities, and could also establish replacement capacity and power for the RMR-contracted elements of the South Bay Power Plant.

The bond financing can cover renewable energy generation from wind farms, distributed generation utilizing photovoltaic technology, an electrolysis hydrogen facility, and energy efficiency programs. This can include the developmental costs such as preparation of requests for proposals, environmental studies, and permitting, accounting and legal expenses, in addition to "hard-costs" of construction.

Sources of Repayment

H Bonds are "revenue bonds" issued by a municipality, county or Joint Powers Agency, which are to be secured by the revenues derived from fees and charges associated with the operation of an enterprise. Revenue bonds are commonly issued by state or local governmental entities and secured by the revenues of electricity or water enterprises or other revenue producing enterprises such as ports. The major point is that H Bonds may not be secured by or payable from Chula Vista's general funds. Rather, revenues from an operating enterprise must be the source of security or repayment.

H Bonds allow, but do not mandate, the potential use of revenues produced by a facility to be built with proceeds of H Bonds to secure and repay those bonds. But revenues from other revenue producing enterprises may be used as security in lieu of or in connection with revenues from an H Bond financed facility. Under California law, revenue bonds such as H Bonds are excluded from the voter approval requirement of Article XVI, Section 18 of the California Constitution if they meet the requirements of the so-called "special fund doctrine." Under this exception, a debt otherwise requiring voter approval is not required if such debt is solely payable from and secured by revenues produced by an appropriate enterprise. No general fund or other tax revenues may be pledged to the repayment of such bonds.

In order to constitute permitted "revenue bonds," Chula Vista will need to identify a dedicated revenue source by which H Bonds are to be secured and repaid, whether revenues of a new source or an existing source. As noted, Chula Vista can structure H Bonds to be secured by the revenues from an existing revenue producing entity. Other financing scenarios also exist and are discussed below.

[15] Chula Vista General Plan, Policy E7.5.

[16] San Francisco Community Choice Aggregation Draft Implementation Plan, San Francisco Local Agency Formation Commission, May 13, 2005.

H Bonds can be secured by revenues from a new enterprise such as the CCA or a facility such as a renewable energy source that has not yet commenced producing revenues. This has the advantage of a logical nexus between the bonds' purpose and source of repayment. A disadvantage is the need to borrow additional moneys to pay interest on H Bonds during the construction period until such time as the facilities can produce revenues to pay the bonds, though obtaining a construction loan is a normal way of doing business for energy projects.

Such a structure also has "construction" or "completion" risk that may result in a slightly higher interest rate on the bonds. In addition, the revenue production of a new facility to be built is uncertain which may also affect the interest costs that are attainable.

Securing the H Bonds with the revenues of an existing revenue producing entity avoids the disadvantages discussed above. However, such a structure does "tie up" a revenue producing enterprise of the City. A potential "hybrid" structure is to use a combination of the foregoing structures. Under this alternative structure the H Bonds could be secured by both a pledge of revenues from an existing enterprise and from any new enterprise. The pledge on the existing enterprise could be limited to the construction period during which the new facilities are not producing revenues or could be for the life of the H Bonds.

Another possibility would be to secure H Bonds with revenues available from a contract with a California-registered Electric Service Provider ("ESP") providing CCA services. Such revenues could be structured to constitute revenues of the enterprise(s), which would be the security for the H Bonds. For example, lease payments received from an ESP would constitute revenues that could be pledged as security.

Ultimately, the projects Chula Vista desires to finance with H Bonds will have a strong bearing on the security structure chosen. For example, if a significant portion of the proceeds of H Bonds will be used to acquire or implement non-revenue producing programs, the use of an existing revenue-producing enterprise will be required. On the other hand, if a significant portion of the proceeds is used to acquire revenue-producing facilities, such facilities or related activities could serve as the security and source of repayment for the H Bonds.

In any event, a bond rating will be required for H Bonds secured by new or existing enterprises that do not already have a rating. The credit quality analysis conducted by the rating agency will, among other things, focus on the "coverage" provided by the pledged revenues. Generally, the rating agencies prefer pledged revenues that are 125% or more of the scheduled debt service on the bonds.

Alternative Structures for using H-bonds and Implications for Tax Exemption.

Chula Vista has a wide degree of discretion regarding the use of H Bond proceeds for renewable energy and conservation projects. However, the particular programs and users of facilities financed with the proceeds of H Bonds will impact whether the interest on such bonds will be tax-exempt under the provisions of the Internal Revenue Code of 1986, as amended (the "Code").

In other words, Chula Vista could use H Bond financing to provide its residents and businesses with the opportunity to purchase and own solar power with no money down.

In general, the "use" of facilities or items financed with the proceeds of H Bonds by an entity other than a state or local government could result in such bonds constituting "private activity bonds." In that case, under Section 141 of the Code, the interest is not tax-exempt. Such use is often referred to as "private use". Private use is present where there are any types of privately held "legal entitlements" with respect to the financed facility. Nongovernmental ownership constitutes private use as do long-term contracts regarding the output to be produced by the facility. For example, a long-term contract with a nongovernmental entity in which that entity agrees to purchase the energy output of a facility will generally constitute private use. In addition, contractual arrangements with nongovernmental entities regarding the operations and maintenance of a financed facility will constitute private use, unless such contractual arrangement is consistent with certain contract parameters approved by the Internal Revenue Service and described below.[17] Last, it should be noted that loans of the proceeds of H Bonds to a nongovernmental person or entity will generally cause the H Bonds to fail to qualify for tax exemption. However, a tribal government could issue tax-exempt H Bonds in conjunction with Chula Vista or a group of public agencies in order to develop or co-develop a renewable energy facility and enter into power purchase agreements for the capacity and power of the facility between the tribal government and the municipality or group of municipalities such as a Joint Powers Agency.

Therefore, the facts regarding the ownership and operational structure of the financed facility will determine whether the bonds may be issued as taxable or tax-exempt. If Chula Vista owns and operates the facility, and if the power is delivered to customers of Chula Vista, then the facility will probably qualify for tax-exempt financing. It will also be possible to qualify for tax-exemption if Chula Vista contracts the management of that facility to a private party, provided the management contract requirements of Internal Revenue Service Revenue Procedure 97-13 (discussed below) are satisfied. On the other hand, if an ESP or other nongovernmental entity owns the financed facility or operates it pursuant to an arrangement that does not meet the requirements of Revenue Procedure 97-13, it will probably not qualify for tax-exempt financing.

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[17] Generally, bonds constitute private activity bonds if they meet either of the following tests:
A. Both the private business use test ("Private Use Test") AND the private security or payment test ("Private Payment Test" and together with the Private Use Test, the "Private Business Tests")); or
B. the private loan financing test "("Private Loan Test").
A bond issue meets the Private Use Test if more than 10 percent of the proceeds of the issue are to be used for any private business use. A bond issue meets the Private payment Test if the payment of the Implementation Plan of, or the interest on, more than 10 percent of the proceeds of such issue is (under the terms of such issue or any underlying arrangement) directly or indirectly --
A. secured by any interest in property used or to be used for a private business use, or payments in respect of such property; or
B. to be derived from payments (whether or not to the issuer) in respect of property, or borrowed money, used or to be used for a private business use.
For purposes of these tests, the term "private business use" means use (directly or indirectly) in a trade or business carried on by any person other than a governmental unit. Use as a member of the general public shall not be taken into account. A bond issue meets the Private Loan Test if the amount of the proceeds of the issue which are to be used (directly or indirectly) to make or finance loans to persons other than governmental units exceeds the lesser of X) 5 percent of such proceeds, or Y) $5,000,000.

H Bond proceeds can be used to fund energy conservation programs. However, to the extent such purpose is accomplished through a loan program wherein residential and business customers can make use of low-interest loans in a CCA program to make energy conservation and efficiency improvements, the loans of bond proceeds will cause the program to not qualify for tax exempt financing. Grants of bond proceeds could be made to individuals and businesses for conservation and other expenditures so long as an adequate project revenue stream is identified to secure and pay the bonds.

The fact that such H Bonds are not tax-exempt does not in and of itself make such a program nonviable. Taxable rates on such H Bonds could potentially still be substantially less that the rate of interest otherwise available on loans to residential and business customers; and with longer lifecycle periods to facilitate a lower monthly payment.

There are a number of ways H Bonds could be used to finance renewable energy facilities. This can be accomplished either in a structure wherein Chula Vista (or other local government) undertakes acquisition, construction, ownership and management of the facilities or through structures wherein an ESP undertakes some or all of the activities. As noted, the tax-exempt status of H Bonds will vary depending on the structure.

Structures wherein an ESP takes on one or more of the roles present issues under the Private Business Tests discussed above. Any lease or other similar arrangement with an ESP would likely result in the H Bonds being categorized as taxable "private activity bonds." Again, such a result would not prohibit the structure but rather would result in a higher cost for these components of the program.

An alternative involving an ESP would be to utilize the management contract provisions under IRS Revenue Procedure 97-13 ("Rev Proc 97-13"). Rev Proc 97-13 describes safe harbor contractual arrangements that may be made with nongovernmental entities to provide management, operations or other services with respect to a tax-exempt bond financed facility.

Pursuant and subject to the requirements of Rev Proc 97-13, Chula Vista could engage an ESP to manage and operate renewable energy facilities financed with H Bonds without the ESP's involvement being in violation of the Private Business Tests discussed above. As discussed below, Rev Proc 97-13 would permit a contract between Chula Vista and an ESP for managing and operating a renewable energy facility financed and owned by Chula Vista for as long as 20 years. Rev Proc 97-13 defines "management contract" as "a management, service or incentive payment contract between a governmental person and a service provider under which the service provider provides services involving all, a portion of, or any function of, a facility."

In this report, we assume a twenty-year maximum bond repayment within the context of a CCA contract period. However, a 30 year period is used for economic evaluation of a project, since this reflects the normal economic lifecycle. (see Appendix F, Financing). Rev Proc 97-13 focuses generally on the term of the contract and the manner and amount of compensation paid to the service provider. Generally, the more fixed in periodic amount the compensation paid to the service provider, the longer the permitted term of contract. Contracts pursuant to which the service provider's compensation is 80% fixed may be as long as 20 years in the case of service contracts relating to "public utility property". On the other hand, contracts pursuant to which the service provider's compensation is 50% fixed may not have a term in excess of five years. "Public utility property" is defined as property used predominantly in the trade or business of the furnishing or sale of (i) water, sewage disposal services, electrical energy, (ii) gas or steam through a local distribution system, and (iii) certain telephone services and communication services.

Thus, for example, if the ESP is paid an annual fee equal to 8x and is also paid additional compensation in each year based on a variable component not in excess of 2x, then the contract can be for as long as twenty years. In addition, the ESP may be paid a one-time incentive award during the term of the contract, equal to a single, stated dollar amount, under which compensation automatically increases when a gross revenue or expense target, but not both, is reached. Further, a contract that satisfies the requirements of Rev Proc 97-13 may be renewed at the expiration of its term.

A variety of the foregoing structures involving H Bonds could be used in tandem. For example, Chula Vista could enter into an energy supply contract with an ESP, which would not directly require the use of H Bonds. Chula Vista could then issue H Bonds to construct renewable energy facilities to be owned by the City. Chula Vista could then enter into a management contract permitted under Rev Proc 97-13 to manage and operate the facilities. Such a structure could allow for the H Bonds to be tax-exempt.

Engagement of CPUC and other funding

Several funding sources have emerged in the recent months. These or other programs should be accessed by the City to provide renewable energy for its residents.

California Solar Initiative

Enacted by the California Public Utilities Commission, this program provides rebates for photovoltaic systems less than 1 megawatt, currently set at $2.50 per watt and decreasing 25 cents per watt as target MW levels of installed solar are met statewide. For systems over 100 kilowatts the rebate will be paid in the form of a performance-based incentive based upon the kilowatt-hours generated in the first years of operation. This will have an effect on financing, since the payment is not made up-front. The CPUC is examining a similar program for smaller photovoltaic systems as well.

The recently enacted SB1, the former "Million Solar Roofs" bill, will place restrictions on the California Solar Initiative, e.g., it rolls back the PUC photovoltaic system size limit of 5 megawatts back to 1 megawatt, and has strict requirements for locating photovoltaic systems at customer sites. This may limit opportunities for a PV landfill project.

PGC Energy Efficiency Funds

These are currently administered by the utility companies in most areas of the state, except San Diego. AB 117 requires opening up funds to community administration for programs of their own design, and SDREO was able to take control of the funds away from SDG&E. This could be quite advantageous for Chula Vista, as a regional planning agency is more likely to be open to a systematic and creative efficiency program of the type necessary to meet grid reliability needs.

This will require coordination between the energy efficiency component and the renewable energy systems, such as local photovoltaic systems and demand response capacity. A well designed program will look at the load curves met by each of these and work to optimize customer as well as system value.

Federal Energy Tax Credits

Private developers of energy projects may be eligible for certain tax benefits that are not available to public agencies. For this reason, it is wise to consider different ownership and financing models to determine which alternative can best meet the desired goals. In some circumstances the low cost of public capital may result in lowest energy costs for publicly owned and financed facilities. On the other hand, very generous tax credits may favor private, third party ownership.

For many years there has been a 10% tax credit for solar installations purchased by commercial enterprises. The 2005 National Energy Policy Act (NEPA) increased this credit to 30% of installed cost of photovoltaic systems for commercial entities; but this will revert back to 10% in 2008 unless it is extended by Congress. Under the same law, homeowners can take up to a $2000 credit on solar energy systems. Public and non-profit entities are not eligible for this credit, since they have no tax liability. In fact, if government agencies provide rebates, or extend credit, to commercial enterprises for photovoltaic or other solar energy systems, they risk voiding eligibility for part or all of the credit based upon the portion financed. Hybrid ownership or financing models can be designed that optimize the balance between the benefit of public funding (such as rebates) and the ability to take advantage of tax credits.

Commercial power project developers may take a 1.9 cent/kilowatt-hour production credit for certain renewable energy generators, paid out over the first ten years of operation according to the amount of electricity generated by the project. The rate of tax credit is indexed to inflation, and thus has increased over time. Congress, in 2005, extended this production tax credit to other renewables such as geothermal and solar projects; this is also due to expire at the end of 2007. A payment system has been set up by the federal government to make equivalent payments to public agencies as well, but this has mostly gone unfunded or underfunded in the past. There is wide interest in extending the solar and renewable production tax credits in the energy industry, in Congress and in the White House.

The production tax credit has existed for a number of years, but Congress only approves this for a year or two at a time. This has created considerable instability in the US wind power industry, with customers clamoring to get their project on line before eligibility ends. Then Congress lets the tax expire for a year or so, and the demand for wind turbines completely dries up. Some renewable projects cannot occur within this time frame, particularly since regulatory approval, environmental review, planning and construction all have to be completed before the tax credit expires. Wind farms are most suited to taking advantage of the tax credit, since the development time can be as little at 18 months, assuming the process goes smoothly. But, in all cases, it is best for a project to begin planning stages in advance, so the project is ready to go when the tax credit opens up again.

Supplemental Energy Payments (SEPS)

This payment structure covers the excess cost of renewable electricity over the prevailing price of natural gas generation. It applies to wholesale power purchased by utilities through contractual agreements that must be approved by the CPUC. *This program may be changed or eliminated in the future, so it may not necessarily be relied upon for project planning.* However, the elimination of SEP payments may leave Chula Vista's renewables at a competitive advantage compared to privately developed facilities. The principle concern is not if the SEPs are eliminated, but rather if they are retained. In this case, it will be important to make sure the city's renewable facilities are eligible for the same payments as any potential competitor.

7. Benefits Comparison of GEO Options to Gas-fired Replacement

This section provides a brief comparison of the risks and rewards of investment in a new gas-fired plant vs. the portfolios outlined above. The three GEO options have significant projected benefits over their lifecycle. Criteria for this comparison include the protection of public health, environmental justice, enhancing energy security, and competitiveness with SDG&E's projected conventional power prices. Financial analysis of renewable facilities is provided in the appendices and supporting spreadsheets. In the analysis it is shown how the lower cost of capital of a municipality achieves a significant long term cost advantages over municipal or private investors in similar projects.

Economic Benefits

Financial Return on Investment

The interest on a commercial loan, and the high rate of return demanded by private investors, imposes a cost on renewables that can be much larger than the original cost of the power plant. For example, a favorably priced large wind plant today might cost about $1.3 million per megawatt (and an unfavorably priced version would likely not get built), which implies that the first GEO portfolio option of a 400 megawatt wind plant would cost $520 million. A private investor, averaging in loans and profits, might require over 11 percent rate of return every single year on the entire capital investment. The interest rate on a municipal revenue bond places a much smaller cost of money on the project, and such bonds are modeled to bear a 5.5 percent or less rate of return. (Current long term municipal revenue bond rates, for well rated bonds, are closer to 4.5 percent). The municipal owner's cost of money is thus half that of a private investor, as the following table shows:

Investor	Cost of Wind Farm	Cost of Money	Term (yrs)	Total Rate	Total Interest plus ROI
Private	$520,000,000	11%	20	220%	$1,144,000,000
CCA Revenue Bond	$520,000,000	5.5%	20	110%	$572,000,000

The private investor pays twice again the cost of the wind farm over a 20 year period, over a billion dollars. The cost of interest on the municipal bond is exactly half as much, which saves $570 million. This savings is worth more than the entire wind farm. While the private developer does have tax credits to offset some of this difference, the main tax credit only lasts for the first 10 years. This gives the municipal investor a large advantage that is difficult to overcome. Since both SDG&E and a CCA would need to procure renewable power, the cost incurred on the customers of SDG&E for a similar supply would be higher. Given that few renewables cost less than wind, this would make it difficult for SDG&E to match the price of such a power supply. This extra cost is embedded in customers' rates one way or another.

The cost of wind power also intersects the likely cost of power from natural gas, even for a private investor. This is partly because of expected increases in the price of natural gas over the next 20 to 30 years, which is the financial life of a wind farm. The DOE expects that natural gas will decrease in price over the next several years, reaching a low of $6.30/mmbtu in 2011. Thereafter, it is projected to increase in price at about 2% per year for the foreseeable future, roughly following general inflation, eventually reaching $11.74/mmbtu. An average price of $8.40/mmbtu during the period implies a cost of natural gas fueled base load electric generation of about 6.6 cents per kilowatt-hour. By comparison, a 20 year investment by a CCA in a wind farm would lead to a cost of 5.5 to 6 cents per kilowatt-hour, to which one must add about half a cent to firm up the capacity so that the power can be sold on the market. If the wind farm is financed using 30 year bonds backed by the capital value rather than a CCA revenue stream, then the cost of the wind power could drop below 5 cents per kilowatt-hour.

Clearly wind is a good investment if you expect the price of natural gas to increase by anywhere close to the rate of inflation or higher. This is one reason why wind is one of the larger elements of the portfolios. But this also illustrates some of the reasons why a CCA or municipality can maintain wholesale energy costs competitive with the utility company. In fact, the CCA might find at some point that the utility company will wish to purchase some of the CCA's lower cost wind power for its customers, too, particularly since SDG&E is required by law to have 20 percent of its electricity supply come from renewables. While an analytical comparison between the GEO portfolio and SDG&E future wholesale power costs is outside the scope of this project, the above discussion shows in principle why CCA's can remain competitive. Reports by Navigant Consulting have demonstrated how nearly every municipality of reasonable size can achieve substantial savings, usually in the tens of millions of dollars or more, by this sort of financial leverage.

In general, our methodology has been to compare the cost of GEO portfolio elements with the comparable electric supply product derived from natural gas power plants owned by private investors. This is the basic method of analysis used by the CPUC, in which the price of natural gas is a benchmark for calculating what a typical generator must charge to recoup its money and make a standard rate of return. This, however, is not necessarily the same as calculating whether an investment will make or lose money. It is an important guideline in California, because so much of our energy comes from natural gas, yet it must not be forgotten that most of the electricity comes from other sources, including renewables. So, the natural gas benchmark cannot be used as the only guide.

An additional factor is that a low carbon portfolio may become a carbon asset, with the ability to sell carbon credits. This could become a significant revenue stream if carbon prices rise, as many analysts expect.

More Local Jobs

Renewable energy systems create several times the level of ongoing employment than fossil fuel generation. This is partly a function of the fact that money is not being expended into high fossil fuel commodity costs that will be lost from the local economy. A 180 MW solar thermal peaking plant can be expected to produce about 70 ongoing jobs, while a large wind farm about 16 employment positions for each 100 megawatts of capacity. Thus a 400 megawatt wind farm would provide about 64 ongoing jobs. The natural gas peaking facility will produce between 15 and 20 jobs while the Pumped Storage facility will produce about 10 jobs. Thus the total direct employment would amount to approximately 164 people. This compares with approximately 22 employees that would be needed to run a 500 to 600 MW natural gas-fired power plant such as the SBRP.[18]

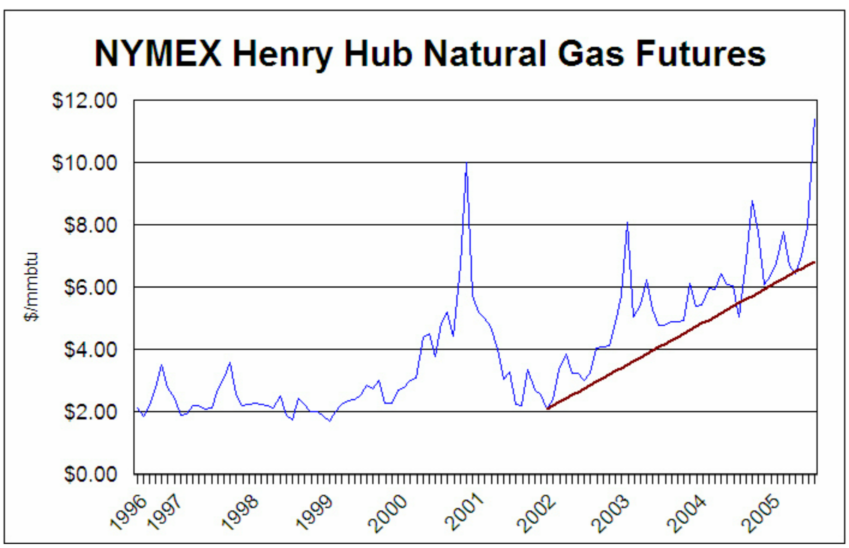
More Money in the Local Economy

The amount of money saved on fuel expenditure is likely to be large, as the investment in renewables is a 20 to 30 year commitment that avoids most of the fuel that would be necessary to produce the same amount of electricity. A new natural gas plant running at the same capacity as the existing SBPP would use about 18.5 million MMBtu/year. This energy content translates into about 18 billion cubic feet of natural gas per year. At a cost of $6 per thousand cubic feet, this represents $110 million of fuel cost per year. Over a 30-year period this would be $2.3 billion worth of fuel, assuming fuel costs were to remain at current levels. Even the most optimistic cost projections do not assume decreasing nominal prices for natural gas, so an increase in fuel cost of about 2% per year or more is reasonable. Since not all the capacity of the plant will be replaced with renewables, the exact[19] amount of fuel savings will depend on the scenario chosen, as well as the future price of natural gas.

Decreased Reliance on Natural Gas

The GEO portfolios provide more energy security than continued heavy dependence on gas-fired power plants. A replacement plant would consume 18 million MMBtu of natural gas per year. The GEO options would use far less than that, about 4-7 million MMBtu per year, and would considerably reduce ratepayer exposure to natural gas price volatility.

Figure 2. New York Mercantile Exchange Futures Prices for Natural Gas.



[18] Comparative Cost of California Central Station Electricity Generation Technologies, California Energy Commission Staff Report, August 2003, Doc. 100-03-001.

[19] California Energy Commission Staff Report, August 2003. Natural Gas Market Assessment. http://www.energy.ca.gov/reports/2003-08-08_100-03-006.PDF#search=%22natural%20gas%20market%20assessment%22. Accessed October 2006.

Overexposure to one fuel makes SDG&E's monthly electric bill also volatile. In 2000, gas spot-market prices quadrupled in less than nine months peaking in January, 2001. Domestic gas supplies are constrained, yet SDG&E is planning new gas-fired power plants and seeking to obtain the gas via its holding company, Sempra, from overseas. By focusing resources on accelerated renewable energy and conservation development, Chula Vista can reduce ratepayers' exposure to increasingly volatile natural gas prices, and steer away from SDG&E's new dependency on Liquefied Natural Gas imported from overseas at great expense.

Environmental Benefits

The Green Energy Options outlined in this report would provide a number of significant environmental benefits, including improved air quality, environmental justice, and reduced global warming emissions. In this section, we evaluate the operating impacts in these areas of the GEO options compared to the proposed South Bay Replacement Project, and to a load-following natural gas plant.

In comparing the Green Energy Options to natural gas burning plants, it is important to understand that the manner in which a natural gas power plant is run determines its air pollution and greenhouse gas emissions. Like a car, a plant's efficiency will be different if it is run steadily, (as in freeway driving) as opposed to ramping up and down (as in City driving or driving in stop and go traffic). Thus, when we compare air pollution and greenhouse emissions from the Green Energy Options to those from a natural gas plant, we must be clear about what energy needs and market conditions the GEO portfolios and the natural gas plants are designed to meet.

As is explained in Section 3, the GEO portfolios are designed to meet the energy needs currently being met by the South Bay Power Plant. The SBPP runs as a load-following plant that ramps up during periods of high demand, which usually occur from midday through the evening, with highest demand typically needed to meet air conditioning needs on hot summer days. For this reason, we compare the GEO options to a new state of the art load-following natural gas plant, whose energy production 'follows' the daily and seasonal fluctuations in energy demand 'load'.

We also compare the GEO portfolios' environmental impacts to those of the proposed South Bay Replacement Project (SBRP). The SBRP is proposed to be a base-load plant, that is, a plant that runs relatively steadily to meet 24-hour daily energy demand. The plant will, however, have a duct- firing component to it, which would allow a part of the plant's capacity to run more as a load-following or peaker plant. The plant's efficiency is much lower when it is producing energy through duct firing. It is unclear at this point how much duct firing the plant is planning to use, but we have used the best available information on the plant as provided in LS Power's CEC permit application (AFC) to estimate emissions from the SBRP.

The GEO options are designed to meet RMR needs, and provide dispatchable energy on demand. To meet the RMR criteria, the GEO options rely in part on some natural gas capacity that can kick-in when the solar and wind components of the portfolios are unavailable. This is why the GEO portfolios would create some emissions of air pollution and greenhouse gases, though far less than either the current or proposed replacement plant.

Air Quality Benefits

Chula Vista's air quality is currently unhealthy, and particulate matter emissions are a major concern. Levels of particulate matter (PM) measured at the San Diego Air Pollution Control District's Chula Vista monitor exceed state and national air quality standards.[20] While there are many sources of PM – including cars and trucks – a power plant can be a significant source of this pollutant, especially in a localized area near the plant. The manner in which the SBPP is replaced will thus be an important factor in determining future air quality in Chula Vista.

The size of particulate matter from natural gas plants is almost all 2.5 microns or less, which is designated $PM_{2.5}$. $PM_{2.5}$ particles travel deep into the lungs where they can seriously damage lung tissue. They are so small that they can get into the blood stream through the lungs, and carry pollutants that are adsorbed to the particles throughout the body.[21] A battery of studies has linked PM to a number of health hazards, including aggravated asthma and lung disease, decreased lung function, heart attacks and premature death.[22] Natural gas power plants also emit nitrogen oxides (a precursor to ozone or smog) as well as other air pollutants.

The South Bay Power Plant is a major source of air pollution. In 2003 (the most recent year for which a San Diego Air Pollution Control District inventory is available), it emitted nearly 95 tons of particulate matter (PM) and 86 tons of nitrogen oxides (NOx).[23] LS Power, the developer of the South Bay Replacement Project (SBRP) has proposed that the new plant will emit no more pollution than the existing South Bay Power Plant.[24] The California Energy Commission has raised concerns about the methods used in LS Power's CEC permit application to estimate emissions from the existing and proposed plant. It is thus unclear at this point what the actual emissions from the SBRP are likely to be.[25] LS Power has estimated the existing plant's actual PM emissions are at 69 tons per year and the proposed SBRP's maximum emissions to be about 69 tons PM per year. Our estimates put the SBRP's likely emissions at about 94 tons per year, running as a typical base-load plant (at 80% capacity factor) with intermittent duct firing (at 9% capacity factor).

A new plant could emit a comparable amount of pollution as the existing plant because, although the new SBRP will be more efficient than the existing plant, it will be run more often. Therefore, under the current proposal, the West Chula Vista community could see *no improvement* in air quality with the shutdown and replacement of the South Bay Power Plant, and might even see an increase in air pollution.

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20 San Diego Air County Air Pollution District. Monitoring data from the Chula Vista monitoring station 2000-2005. Available at: http://www.sdapcd.org/air/reports/smog.pdf

21 Lipmann, M. et. al. (2003). The U.S. Environmental Protection Agency Particulate Matter Health Effects Research Centers Program: A Midcourse Report of Status, Progress, and Plans. *Environmental Health Perspectives* 111 (8) 1074-1092.

22 US Environmental Protection Agency. Health and Environmental Effects of Particulate Matter http://www.epa.gov/ttn/oarpg/naaqsfin/pmhealth.html. Accessed February 17, 2006.

23 SDAPCD Emission Inventory at http://www.sdapcd.org/toxics/Project1/SourceEmissions.html Accessed 11/8/2006.

24 LS Power. 2006. Application for Certification to the California Energy Commission for the South Bay Replacement Project. Page 8.1-54, Table 8.1-34.

25 CEC Data Requests to LS Power Generation LLC as of October 31, 2006, Docket 06-AFC-3.

If the existing SBPP were to be replaced with a load-following plant that generated a comparable amount of electricity as the existing plant (32% capacity factor), its total PM emissions would be slightly lower than the existing plant's, at about 68 tons per year.[26] The GEO portfolios would only emit from 14 to 27 tons per year.[27] The GEO portfolios would thus emit 60-80 percent less particulate matter than a load-following natural gas plant. The portfolios would emit 70-85 percent less pollution than would the proposed SBRP. (Appendix H)

The air quality *impacts* that are created by a given project's *emissions* are a product of the project's location and other project-specific factors. The SBRP is proposed to be located next door to the existing SBPP on the Chula Vista Bayfront, directly upwind of the residential and densely populated area of West Chula Vista. While it is not clear if any natural gas capacity is needed on the bay, the preferred option would be to have no, or very little, capacity at this site. Nonetheless, even if all the natural gas portions of the GEO portfolios were located at this site, the PM emissions would still be much lower than the SBRP's.

Environmental Justice

For over 40 years, the community downwind of the existing power plant has borne the pollution burden of a facility that serves the energy needs of a good portion of the County. The proposed plant would generate far more electricity than is needed by the City of Chula Vista. Even if we look into future energy demand in Chula Vista, and assume minimal energy efficiency improvements, projected energy demand in the City of Chula Vista is estimated to be 1,345 GWh by the year 2023.[28] The proposed SBRP would produce about 3,600 GWh per year, so West Chula Vista residents would continue to bear the pollution burden for others' energy use.

Locating another large plant near the site of the existing power plant would perpetuate environmental injustice. The community living within a six-mile radius of the South Bay Power Plant is 77% Latino, with 21% of residents closest to the plant living below the poverty level.[29] As does everyone, residents in West Chula Vista deserve healthful air to breathe. Replacing the energy currently being provided by the SBPP with the GEO options would move Chula Vista in the right direction, toward attaining air quality standards and environmental justice.

Reduced Global Climate Change Impacts

The GEO portfolios would avoid significant emissions of greenhouse gases, and reduce the region's contribution to the global climate crisis. The predicted impacts from Global Climate Change are severe. In California, global warming is predicted to create more severe heat, worsened air quality, threatened agriculture, coastal flooding, increased wildfires, and decreased Sierra snow pack which provides water resources to much of the State, among other serious

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26 Assuming a 32% capacity factor and a heat rate of 9,400 MMBtu/kwh, a typical heat rate for a new load-following plant.

27 Also assuming a 32% capacity factor and a heat rate of 9,400 MMBtu/kwh for natural gas portion of the GEO portfolios.

28 Navigant Consulting, Study for City of Chula Vista on MEU Feasibility. March 19, 2004. Based on SANDAG growth projections.

29 Western Chula Vista Revitalization Population, Market, and Housing Trends, City of Chula Vista, Feb 2, 2006, p.9

threats.[30] The GEO portfolios offer Chula Vista and the San Diego region an excellent opportunity to reduce this major threat to our State and the World.

If the proposed SBRP were running as a typical base load plant with intermittent duct firing, it would produce about 1.5 millions tons per year of carbon dioxide (CO_2). A load following natural gas plant would produce about 1.1 million tons/yr of CO_2. In aggregate, the SBRP would produce more carbon dioxide, but per unit of energy produced, the load-following plant would produce about 1100 tons per megawatt hour of electricity produced as compared to about 830 tons/MWh for a base-load SBRP (Appendix H).

The GEO portfolios would emit far less carbon dioxide per year than either the SBRP or a natural gas burning load-following plant: about 220,00-420,000 tons of CO_2 per year. This is 60-80 percent lower than a load-following natural gas plant and 70-85 percent lower than the proposed SBRP. The annual savings in carbon dioxide emissions provided by the GEO portfolios is equivalent to taking 200,000 – 250,000 cars off the road.[31] On a CO_2 emissions per unit of energy basis, the GEO portfolios would also emit far less, with emissions of from 382 to 386 tons of CO_2 per megawatt hour, or about only ⅓ to ½ of the emissions from the exclusively natural gas options.

Chula Vista has been a leader in pursuing local initiatives to reduce the City's contribution to the global climate crisis. In 2000, the City adopted a CO_2 reduction plan as part of its participation in the International Council for Local Environmental Initiatives (ICLEI). This plan directs the City to seek green power purchase options. The City's facilitating the development of the Green Energy Options outlined in this report would set the City firmly on a path to global climate responsibility and leadership.

[30] California Climate Change Center, a project of the State of CA. July 2003. Our Changing Climate, Assessing the Risks to California.
[31] US Climate Technologies Cooperation Gateway, Greenhouse Gas Equivalency Calculator. http://www.usctcgateway.net/tool/ Accessed October 2006.

GEO Report Findings

The Greener Energy Options Portfolios are economically viable

The low cost financing available to a city through municipal bonds can leverage significantly lower cost for renewable generation. Also, the he largely fixed cost of the renewables provides a hedge against substantial risk of increasing natural gas prices over the next 20 to 30 years. There are essentially two scenarios examined here. The first assumes portfolio costs under a 30 year capital or revenue bond, which would optimize cash flow in the earlier years of the investment. This is how the different projects are evaluated as separate investments.

This contrasts with the second scenario examined in the report, a 20 year term investment under a CCA revenue bond, where the cost to own and operate a plant on a per kilowatt-hour basis is significantly higher during the bond period. Once the bond is paid off, however, the capital cost is removed. The result is that, from year 20 to year 30, the only real cost will be operation and maintenance, and possibly some equipment replacement. This will mean very inexpensive overhead, especially when compared to the earlier years, which may amount to only a few cents per kilowatt-hour for peak power generation. The result is that substantial returns on the investment can be made during these “out years”, when cost of operation is low and fuel and retail electric rates are likely to be higher than today. It may well be worthwhile for Chula Vista to invest in the capital asset to accumulate an equity position at a rate that preserves the cash flow of the projects during the 20 year CCA revenue bond period. The return on this investment will then be achieved in the out years (year 20 to 30).

A full economic evaluation of a CCA is outside the scope of this report, and would involve base load power supplies, transmission and distribution, and other operating expenses not considered here. These in turn would need to be modeled against expected future SDG&E rates. While some renewables owned by the CCA may cost more than natural gas power plants, this ‘higher price” will be offset by similar renewable requirements for SDG&E. Thus it is unlikely that the portfolio considered here would result in any higher cost than for any other customers in the region. In particular, the low cost financing is likely to provide the least cost option for the renewable portion of the portfolio that will significantly offset the compressed timeframe (20 year CCA bond term) for repayment of the assets.

We have used the Market Price Referent (MPR) methodology, derived from the price of natural gas electric generation, as a basis for comparison between GEO energy supplies and to provide a general sense of the viability of an investment. Yet the investments are not taken in isolation; they serve as hedges one against the other. A significant portion of natural gas generation is included for reliability of power supply, but also to take advantage of any drop in natural gas prices. The wind and solar components protect against any increases in the price of natural gas. Losses that may occur in one segment are offset by other parts of the portfolio; and the losses should not be examined in isolation, since a change in market conditions may reverse the loss. In general the natural gas component is designed either to make money on the open market, or save CCA ratepayers on their bills, under all scenarios. That is because, first, the price of natural gas is similar for all generators over the long run, but the CCA has lower cost of money. This locks in a differential with other natural gas generators with which the CCA gas plant is competing.

Second, the plant is intended to operate as a cogenerator, which means that waste heat is capture and sold at or below cost. Most commercial power plants do not operate in this way, and older cogeneration plants will be less efficient than a modern one. Thus the CCA natural gas plant can provide a double revenue stream, while conserving natural gas.

The GEO Portfolios offer significant benefits

As is detailed in the preceding section, the GEO portfolios offer a number of benefits over a gas-fired plant. The GEO portfolios would result in 60-80 percent less emissions of particulate matter air pollution and would promote environmental justice. The GEO options would also produce more local jobs, decrease the region's over-reliance on natural gas, and keep more money in the local economy. Pursuing the GEO options would get us firmly down the road of a more secure and sustainable energy future for the region, and would lessen the region's contribution to the global climate crisis.

The initiative must be led by Chula Vista

Over the past four years, the City of Chula Vista has prepared extensively for the implementation of Community Choice Aggregation ("CCA") and/or development of green and renewable power generation facilities. CCA would allow Chula Vista to find an alternative electricity supplier to SDG&E, and to decide what kinds of electricity to purchase. In addition, municipalities and other local public agencies like Chula Vista may issue municipal revenue bonds ("H Bonds") to finance renewable energy and conservation facilities. These mechanisms will be analyzed in this Plan.

A strong argument can be made that CCA in conjunction with H Bonds allows the greatest potential for cost-effective, cleaner and more sustainable replacement of the South Bay Power Plant ("SBPP"):

- First, as a Community Choice Aggregator (CCA), Chula Vista would be poised to solicit competitively priced power from competitive suppliers for its residents, businesses, and municipal facilities.[32]

- Second, Chula Vista may profitably develop a revenue-producing renewable energy facility with pumped storage or gas-fired facilities for capacity balancing. Using the unique leverage that municipal revenue bonds and CCA facilitates, it is now possible to serve Chula Vista residents, businesses, and public agencies with this qualitatively superior, greener, more reliable energy source. New, city-owned, facilities could generate electricity, at rates equal to or lower than SDG&E's rates, both for local use and profitable sale of excess power in wholesale markets or to other public agencies. As stated above, this level of analysis is beyond the scope of this report. However, the conclusion is supported by the fact that both the CCA and SDG&E will require a substantial renewable portfolio, and the CCA has at its disposal a significantly lower cost for capital that places it at a significant advantage. In addition, if the city elects to sell power, it will be able to command a market price comparable to private vendors, and any

[32] Chula Vista commissioned Navigant Consulting to prepare a Feasibility Study on CCA in Chula Vista, conducting peer review with several public hearings.

"over market" costs (i.e. costs above natural gas generation) will thus be rate-based for SDG&E customers, since SDG&E will need to meet its renewable obligation.

This report identifies several specific opportunities available to Chula Vista, with a variety of locally feasible technologies and partnerships. However, even if CCA is not pursued by Chula Vista, other governance structures and initiative options are available for the City to pursue some or all of the green energy options outlined in this report

Community Choice Aggregation (CCA) and Public Investment is the best Approach

Unless Chula Vista forms a CCA, any transmission facilities must either be owned by SDG&E or some other transmission entity such as a Tribal Government. The City of Chula Vista signed a 20-year franchise agreement with SDG&E in 2004 committing "*that the City will not participate in the provision of electric or natural gas Distribution Services by itself or others within its jurisdictional boundaries for the term of the franchises.*" Thus, Chula Vista may not sell "distribution" services to consumers. The MOU defined "distribution" as "*the ownership and/or operation by the City itself, or with or by any third party, of any facilities, including pipes, wires, and electric and gas utility plant and related services for the transmission or distribution delivery of electricity or natural gas to consumers within the boundaries of the City of Chula Vista.*" The MOU excluded from this rule the "*performance of (i) those rights and duties specific to Community Choice Aggregation…within or outside CITY limits if authorized and as approved and implemented by the CPUC, if such is required or (ii) generation of electric power.*"[33]

However, a CCA and renewable generation project would enjoy a full range of options. Thus, if Chula Vista forms a CCA or builds a power generation facility, it may elect to sell transmission services within or outside Chula Vista. There are at least two options to accomplish this.

The first option is to develop future renewable energy and conservation facilities that require transmission service by taking action to:

- Acquire access to existing transmission capacity;
- Arrange with SDG&E to provide transmission access, pursuant to Federal Energy Regulatory Commission (FERC) Order 888, or;
- Arrange to purchase transmission services from another party such as a tribal government.

The second, and probably more important, option is to develop local power resources that require little or no transmission facilities to deliver the power to customers. As this report will show, the Chula Vista region offers opportunities to develop a large solar concentrator and other renewables in the immediate Chula Vista and neighboring areas interested in participating in the development of the facilities and/or the purchase of power from such facilities.

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[33] Memorandum of Understanding Between San Diego Gas & Electric Company and the City of Chula Vista, October 12, 2004, p. 11, Section 1.14.A.

Both options are more local in nature than the power supply now being provided to residents and businesses in Sempra's service territory. Both options are financially feasible at competitive wholesale and retail prices, with either a CCA or a city-owned merchant facility, or both, being the structuring principle of the project.

CCA is by far the best way to ensure success and achieve the kind of scalability needed to physically alter the need for generation in this part of the electric grid. Photovoltaics (PV) on Chula Vista rooftops, energy efficiency, demand response may be fundable with existing ratepayer funds if a CCA is formed and the opportunity to administer the funds is requested at the California Public Utilities Commission.[34]

Other distributed generation may be undertaken within the City under a CCA or a revenue bond funded ("H Bond") program, and may invest General Funds in renewable energy projects for non-CCA customers if the City wishes to operate the plant as a public enterprise. Because scaled projects such as those presented in this Plan are necessary to eliminate multi-hundred Megawatts of regional demand in order for the Independent System Operator (CAISO) to accept a downscaling of new power generation on the South Bay site, this report identifies several physically viable, legally developable and economically competitive green power facilities, estimates facility costs, schedules for payback and power pricing. Specific facility scales in each Scenario are based on a variety of potential market structures, including Community Choice Aggregation (CCA) the use of H Bonds, and potentially available state of California funding for energy efficiency programs pursuant to the Community Choice law, AB117[35].

The ability to eliminate or reduce the need for power generation at the South Bay Power Plant site depends on the municipality's degree of public investment, as well as investment by potential strategic partners in the region. This investment may be structured as follows:

- Municipal Enterprise. Chula Vista can meet their interest in an entrepreneurial energy venture by owning renewable energy and conservation facilities as a municipal enterprise while also meeting its mandate for first-class environmental leadership;
- Creation of a CCA adds even larger-scale private sector purchasing power to public financing, enables a commensurate scaling-up of renewable energy development, and provides a secure revenue stream for the H Bonds that the city and/or its other public partners elect to issue for solar photovoltaics and the other locally feasible investments in the Chula Vista area and East County;
- Chula Vista investment in renewable energy and conservation facilities involves a lower degree of municipal risk than investment in a 100% natural gas generation power plant, because there is reduced exposure to the highly volatile price of natural gas that constitutes 50% to 80% of the life cycle cost of a gas-fired power plant.

34 CPUC Proceeding R.01-08-028.
35 Migden, 2002

Such investments can provide benefits including:

- As free-standing investments, any profits realized from renewable energy or conservation facilities, they can benefit taxpayers by contributing funds to the City of Chula Vista General Fund.
- If the renewable energy or conservation facilities are incorporated into a CCA, then they can realize long term savings for ratepayers compared to market prices for similar energy supply.
- Renewable and conservation facility assets will retain their market value and generate revenue for decades after H Bonds or other financing are repaid, offering both returns on public investment and a lower cost of energy for local residents and businesses.

The GEO Portfolios are consistent with existing local, state and federal policy, regulations, and law

All alternatives proposed in this Alternative Energy Plan meet the stated project objectives in the AFC for the South Bay Replacement Project. These are:

- Commercially-viable and capable of supplying economical electrical services – capacity, reliability, ancillary services, and energy supply – to the San Diego Region.
- Capable of ensuring the timely removal of the existing South Bay Power Plant and that fulfills the obligation found in Article 7.1.a of the Cooperation agreement, which states, "*use commercially reasonable efforts to develop, finance, construct and place into commercial operation a new generation plant replacing the South Bay Power Plant…which shall have a generating capability at lease (sic) sufficient to cause the ISO to terminate (or fail to renew) the must run designation application to the South Bay Power Plant on or before termination of the lease*" [36] and upon which the size of replacement power is based.
- Meets applicable laws, ordinances, regulations, and standard (LORS) of the California energy Commission, Chula Vista, the Unified Port of San Diego and other agencies, and complies with the Applicant's Environmental Policy.
- Consistent with the objectives, guidelines and timing goals of the emerging Bay Front Master Plan.
- Assists in maintaining and/or increasing the regional electrical systems' efficiency and reliability.

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[36] LS Power. 2006. Application for Certification for the South Bay Replacement Plant, footnote 5, page 1-7

- Supports attainment of the state-mandated 20 percent Renewable Portfolio Standard (RPS) requirements for renewable energy, which will be required if a Chula Vista CCA is formed.[37] The renewable generation could also support SDG&E to achieve compliance with its RPS requirements under potential power purchase agreements.

- The GEO options would have a lower cost of electric generation over the life of the assets than if Chula Vista CCA or SDG&E were to purchase similar legally required renewable power supplies on the open market, due to the low cost of municipal financing. This meets one of the key requirements of state regulation (CPUC) that electric generation resources be "least cost".

- The GEO options can replace the function of the current plant, to provide urgently needed power during times of peak demand, when the stability of the electric grid is most at risk. The proposed "all natural gas" replacement on the bayfront would achieve this to a much smaller degree, since it is mainly designed to supply 24 hour a day base load. Thus, the GEO meets the other key requirement of the CPUC that electric generation resources be "best fit".

[37] Application for Certification for the South Bay Replacement Plant, page 1-7

Recommendations

- Chula Vista should present evidence to the ISO and other regulatory bodies, proving why a replacement for the current plant is not needed on the Bayfront. ***This report shows that about 2000 megawatts of alternative options exist within San Diego County***, some of which would cost far less than replacement of the South Bay Power Plant at its current site. In some cases merely changing regulatory status or evaluation of existing or planned resources, or the need for them, is all that is required. It is unlikely that replacement of more than a fraction of the current plant is really necessary to meet the needs of the region for years into the future. That is the most important reason why a range between 50% and 90% replacement of existing capacity has been proposed in this report.

- Chula Vista should further investigate the options identified in this report to begin discussions with potential site owners, financing sources and partners for different projects. Scoping needs to move as soon as possible to the next level of specificity to answer critical questions.

- Chula Vista should fund and prepare an Implementation Plan and draft a Request for Proposals for Community Choice Aggregation and H Bonds that includes designing, building, operating and maintaining a solar concentrator, wind and pumped storage facility in conjunction with local solar photovoltaics, distributed generation, energy efficiency and conservation. These measures should be supplemented with natural gas fired co-generation to balance out the portfolio risk and energy costs, as well as to insure the full reliability requirements are met.

- Chula Vista should only entertain sites for facilities that minimize the need for new transmission, and only allow transmission that is placed on existing rights of way. Any new lines should be occupied only by clean energy capacity. No major power lines on new corridors are needed, as they will impose billions of dollars in costs on ratepayers as well as make the region even more dependent upon energy imports. These imports send dollars and jobs out of the region while new transmission corridors would spoil the county's landscape and natural beauty.

- Chula Vista should participate in the ISO RMR designation to ensure the RMR is calculated appropriately to include all renewable and other green energy sources.

- Chula Vista should participate actively at the California Energy Commission, Independent System Operator (CAISO), California Public Utilities Commission, and Federal Energy Regulatory Commission to propose the options identified in the GEO as preferable to repowering the South Bay Power Plant site.

- At present two of the largest generating plants in the region, representing nearly 1000 megawatts of capacity, contribute nothing to grid reliability, according to ISO evaluation.

San Onofre Nuclear Generating Station is not counted at all toward regional generation, even though it supplies over 400 megawatts of power, 24 hours a day, to San Diego County. That is because it uses up capacity on the same transmission line that is used for importing electricity. And the new Palomar plant, at over 500 megawatts, does not count either due to a mere technicality. Chula Vista should urge the ISO, CEC and CPUC to move forward with assuring that the Palomar power plant is fully accounted for as reliable generation capacity, and that a short transmission line be added to the existing South of SONGS (SOS) corridor to connect the plant directly to the regional grid without casting a transmission shadow for electricity imports from the north. These two tasks would together supply approximately 500 megawatts of additional reliable capacity to the region for by far the least cost and environmental impact.

- Chula Vista should challenge the "bait and switch" tactic of justifying a new 24-hour a day "all natural gas" powered base-load replacement plant on the bay, based upon the ISO reliability contract on the existing plant. The current plant is considered necessary for meeting peak demand when power is urgently needed for grid stability, and only runs its generators part-time. The function of the current plant is completely different from the one proposed to replace it, and should require a separate evaluation of need.

- Chula Vista and other local and regional land use authorities should adopt stringent building standards that maximize energy efficiency, demand response, and development of clean, renewable energy sources integral to new and renovated building construction.

Appendices

List of Tables in Appendices

Appendix A Cost Factors for a Wind Farm

The cost of wind power has dropped from a range of 30 to 50 cents per kilowatt hour in the early 1980s to between 5 and 8 cents per kilowatt hour today. This is now competitive with other forms of electric generation, especially natural gas and nuclear power. On the low end of its price range wind may even compete with new coal plants, due to pollution control requirements, and long term risk of carbon emission liability.

There are three key factors that determine the cost of the electricity generated from wind power: the installed cost of the wind farm, the financing cost, and the wind resource. The installed cost of wind farms was between $1000 and $1200 per kilowatt in 2003; however a few factors have combined recently to increase that cost. The unpredictable US production tax credit for wind causes a “boom and bust” cycle in demand for wind turbines in this country. The credit has been in effect for the last two years, which has pushed up demand to historical highs with a new wind farm being built every two to four weeks. In fact, far more wind than coal capacity is currently being added.

State policies requiring utilities to put renewable electricity sources into their portfolios, as well as increases in the price of natural gas and higher retail electric rates, has helped drive growth in wind power. In the late 1990s only a few hundred megawatts of wind were installed each year in the US; this reached 2431 megawatts in 2005 and 2454 megawatts of new capacity was added in 2006. Manufacturers can barely keep up, and most production capacity is reserved in advance for the next two years. Increased demand, higher raw material prices, and the low value of the dollar have caused the price of wind turbines to go up. The result is that wind farms in the US now range from $1300 to $1750 per kilowatt. We project a lower end cost, assuming that the project will be well planned, and that the current overheated market will cool as manufacturing capacity catches up to demand.

There are important factors that can offset this recent trend. The cost of the tower and turbine is only about half the installed cost, which also includes labor, access roads, power lines, etc. Thus, even a 50% increase in material costs will result in a smaller impact on a total project.

Manufacturers are also helping in important ways. The size of individual wind turbines is increasing, which lowers unit costs. Efficiency and performance of wind turbines is steadily increasing year by year. This is a function of improved design, careful measurement of wind resources, and better placement of wind turbines. The effect has been dramatic. The electric generation from a given sized wind farm has increased by more than 50% since the early 1980s. There have also been great improvements in quality and durability, with the result that wind turbines need less servicing, and are available 98% of the time for generating electricity.

An opportunity may come for Chula Vista when the Federal wind tax credit expires, and the city should prepare to take advantage if a window opens up. The tax credit is paid to private investors in wind farms, based on the electric generation of the facility, at the rate of 1.9

cents per kilowatt hour presently, but this is indexed to inflation; we project a rate of 2 cents/kwh by 2009 if the credit is reinstated. Since government entities do not get tax credits, Chula Vista is not dependent on the credit to make wind power an attractive investment. The low-interest financing from municipal bonds can bring the cost of wind power to an even lower level than a private investor would achieve with the support of the credit, Because the private investor’s tax credit expires after the first ten years of the project's operation, a municipal owner of a wind farm has a long term competitive edge over other owners.

The value of low cost financing is substantial. A 400 Megawatt wind farm installed at the rate of $1350 per kilowatt will cost $480 million. A private investor that has an average cost of capital of 11.8% will incur about $1.9 billion in expenses to cover interest on borrowed funds and profit for investors over a 30 year period. By comparison, a publicly financed wind farm need not provide any profit for investors, and is only obligated to repay the bond principal and interest. At 5.25 percent interest over 30 years this will cost about $850 million. *The low-interest municipal financing saves over $1 billion dollars over the 30 year period, far more than the entire installed cost of the wind farm. This demonstrates the huge effect of low cost borrowing on renewable generation sources like wind, and why there is a unique opportunity for municipalities.*

At the time when other investors will be leaving the market, municipalities will retain their low cost financing advantage. This places them in a unique position when tax credit expires to take advantage of any price reductions in wind farms.

Wind resource is also vitally important for project viability. The East County has class 5 and class 6 winds. By placing a wind farm in the higher class region, a significant improvement is performance is very likely. Improving the output of a wind farm from a 32% operational capacity (capacity factor) to 35% would reduce the cost of the electricity generated and achieve a more rapid payback on investment. It also increases the cost threshold for a viable project.

Maintaining a high capacity factor is important for economic viability not only of the wind farm but also of the pumped storage portion of the facility. The cost assumption for the pumped storage of $1000 per kilowatt is conservative to high if an existing reservoir is used, but may be low if a new reservoir must be built. We recommend using existing reservoirs in the San Diego region, of which there are several. The given price is the maximum that would make the proposition viable for a CCA, thus it is only likely to make sense as an investment if an existing reservoir is used. There are also considerable environmental advantages when compared to building a new reservoir, creating an alignment between environmental and economic goals.

Table A-1. Wind Cost Summary

	Private Investor	Chula Vista/ municipality
Installed Cost Rate	$1350 per kilowatt	$1350 per kilowatt
Tax Credit	2 cents/kilowatt hour, first 10 years	none
Financing Cost	11.8%	5.25%
Economic Lifecycle	30 years	30 years
Wind Class	6	6
Operation / Capacity	35%	35%
Cost per kilowatt-hour	7.4 cents/kwh	4.8 cents/kwh
1st 10 year cost after credit	5.4 cents/kwh	not applicable
Electricity sale price (initial)	5.2 cents/kwh	4.8 cents/kwh
Simple Payback	8 years	9 years

Table A-2. Wind Farm Electric Generation Cost with Private and Public Financing

Levelized Cost Analysis in Class 6 Region*

Private Finance			Public Finance		
11.8% Avg. Cost of Capital; 2 cent/kwh Production Tax Credit.			Bond financing no tax credits		
Capital Cost:			Capital Cost:		
Installed Cost Rate	$1,350	per kw	Installed Cost Rate	$1,350	per kw
Capacity	400,000	kw	Capacity	400,000	kw
Total Cost	$540,000,000		Total Cost	$540,000,000	
Tax Credit	0%		Tax Credit	0%	
Net Cost	$540,000,000		Net Cost	$540,000,000	
Utility Finance:			Public Finance:		
Avg. Cost of Capital	11.8%		Bond Rate	5.25%	
Term	30	yrs	Term	30	yrs
Financing Cost	$1,911,600,000		Financing Cost	$850,500,000	
Operation and Maintenance:			Operation and Maintenance:		
Personnel	64		Personnel	64	
Assumed avg. Salary	$55,000		Assumed avg. Salary	$55,000	
Annual Personnel Cost	$3,520,000		Annual Personnel Cost	$3,520,000	
Maintenance &other rate/capital-yr.	1.6%		Maintenance &other rate/capital-yr.	1.6%	
Maintenance & other cost/year	$8,640,000		Maintenance & other cost/year	$8,640,000	
Annual O&M	$12,160,000		Annual O&M	$12,160,000	
Lifecycle O&M	$364,800,000		Lifecycle O&M	$364,800,000	
Electric Generation:			Electric Generation:		
Capacity Factor	35%		Capacity Factor	35%	
Generation rate	3,066	kwh/kw	Generation rate	3,066	kwh/kw
Gross Annual generation	1,226,400,000	kwh	Gross Annual generation	1,226,400,000	kwh
Parasitic Load factor/loss	0.1%		Parasitic Load factor/loss	0.1%	
Annual Loss	1,226,400	kwh	Annual Loss	1,226,400	kwh
Net Annual Output	1,225,173,600	kwh	Net Annual Output	1,225,173,600	kwh

Private Finance

Electric Generation Cost:		
Lifecycle Cost	$2,816,400,000	
Lifecycle Output	36,755,208,000	kwh
Avg. O&M rate	$0.010	
Cost of Electricity	**$0.077**	per kwh
Production Tax Credit (2009)	$0.020	per kwh
Net first 10 year cost	$0.057	per kwh
Wind Purchase Price	$0.052	per kwh
Generation per year	1,225,173,600	kwh
Annual Avg. revenue	$63,709,027	
Annual Avg. Cost	$93,880,000	
Annual Avg. Cost first 10 years	$69,376,528	
Simple Payback Wind	8.48	yrs

Public Finance

Electric Generation Cost:		
Lifecycle Cost	$1,755,300,000	
Lifecycle Output	36,755,208,000	kwh
Avg. O&M rate	$0.010	
Cost of Electricity	**$0.048**	
Production Tax Credit	$0.000	
Net first 10 year cost	$0.048	
Sales from Wind Farm		
Wind Wholesale Price	$0.052	
Direct sales per year	664,533,600	kwh
Annual revenue from Direct Sales	$34,555,747	
Sales rate to Pumped Storage	$0.048	
Sales to Pumped Storage	560,640,000	kwh
Annual Income from Pumped Storage	$26,774,203	
Total Wind Farm Annual Revenue	$61,329,950	
Annual Operating Cost	$58,510,000	
Annual Wind Farm Net	$2,819,950	
Simple Payback Wind	8.80	years

*Levelized cost does not show the time-dependent changes in O&M cost for wind farms.

Appendix B Solar Thermal w/ Natural Gas and Cogeneration

The cost of solar thermal power has decreased in the last two years, and there is general agreement that it will continue to drop. Current cost of solar thermal generation can range between 13 and 25 cents per kilowatt-hour, depending on scale of the installation, financing and availability of tax breaks. Private developers can take a generous 30% tax credit until 2008, which will revert to 10% unless the higher credit is further extended.

DOE projects that solar thermal electric generation will fall to about 4 cents per kilowatt-hour within a decade, but Local Power considers this projection too optimistic. Those in the industry currently consider it reasonable to expect that the price will fall below 10 cents per kilowatt-hour, a range that will make solar thermal potentially cost competitive with the peak power generated by natural gas power plants.

The first spreadsheet analyzes the cost and performance of a Concentrating Solar Thermal power plant. The first column shows the economics of a privately financed facility to allow comparison with a publicly financed one. The proposed solar thermal project would have about 10% to 15% lower solar resource than the recently developed solar thermal plants in Nevada and Arizona if located in the East County, and 20% to 25% lower if placed in the vicinity of Chula Vista. It would also not be eligible for a tax write-off due to the fact that it would be owned by a municipality. Countering this disadvantage is the much lower cost of capital, which is only the interest payment on the bond. Recycling the heat through a cogeneration system will bring the cost down further.

The net cost to produce a kilowatt-hour, and the profitability of the plant, is significantly influenced by the efficiency with which the heat can be recycled. The assumption is only 50% of the waste heat can be recovered and sold at prevailing energy rates. This is very conservative, as such systems can achieve 75% to 80% recovery on the high end. If the recovery is efficient enough, then the heat can be sold at a discount to make the proposition attractive to a commercial venture.

A solar thermal plant’s economic viability is to a large extent locked in at the time of purchase. Unlike a natural gas power plant, very little of the long term cost is bound up in fuel. The major expense is the purchase cost itself, and the cost of financing. Whether this will be competitive with natural gas peak power depends on the future cost of natural gas. The second sheet shows the breakeven costs for the solar plant assuming a range of average prices for natural gas. In this sheet, the assumption is that the plant is financed over a 30 year period by a capital bond as a “self supporting” investment.

Table B-1. Concentrating Solar Thermal Power

Private Finance, 2010 to 2015

w/ tax credit & 11.5% Cost of Capital

Reference Natural Gas Price

Capital Cost:		
Installed Cost Rate		
Target	$2,500	per kw
Capacity	160,000	kws
Total Cost	$400,000,000	
Tax Credit (enter 10% or 30%)	10%	
Net Cost	$360,000,000	
Private Finance		
Avg. Cost of Capital	11.8%	
Term	30	years
Financing Cost	$1,274,400,000	
Operation and Maintenance:		
Personnel	70	
Assumed avg. Salary	$55,000	
Annual Personnel Cost	$3,826,087	
Maintenance &other rate/capital-yr.	0.6%	
Maintenance & other cost/year	$2,400,000	
Annual O&M	$6,226,087	
Lifecycle O&M	$186,782,609	
O&M per kwh	$0.021	

Public Finance, 2010 to 2015

w/no tax credit & 5.25% 30 year municipal bond financing

Reference Natural Gas Price

Capital Cost:		
Installed Cost Rate		
Target	$2,500	per kw
Capacity	160,000	kws
Total Cost	$400,000,000	
Tax Credit	0%	
Net Cost	$400,000,000	
Public Finance:		
Bond Rate	5.25%	
Term	30	years
Financing Cost	$630,000,000	
Operation and Maintenance:		
Personnel	70	
Assumed avg. Salary	$55,000	
Annual Personnel Cost	$3,826,087	
Maintenance &other rate/capital-yr.	0.6%	
Maintenance & other cost/year	$2,400,000	
Annual O&M	$6,226,087	
Lifecycle O&M	$186,782,609	
O&M per kwh	$0.021	

Public Finance, 2010 to 2015

w/no tax credit & 5.25% 30 year municipal bond financing

High Natural Gas Price Scenario

Capital Cost:		
Installed Cost Rate		
Target	$2,500	per kw
Capacity	160,000	kws
Total Cost	$400,000,000	
Tax Credit	0%	
Net Cost	$400,000,000	
Public Finance:		
Bond Rate	5.25%	
Term	30	years
Financing Cost	$630,000,000	
Operation and Maintenance:		
Personnel	70	
Assumed avg. Salary	$55,000	
Annual Personnel Cost	$3,826,087	
Maintenance &other rate/capital-yr.	0.6%	
Maintenance & other cost/year	$2,400,000	
Annual O&M	$6,226,087	
Lifecycle O&M	$186,782,609	
O&M per kwh	$0.021	

Private Finance, 2010 to 2015

w/ tax credit & 11.5% Cost of Capital

Reference Natural Gas Price

Solar Electric Generation:		
Capacity Factor	23%	
Generation rate	2,015	kwh/kw
Gross Annual generation	322,368,000	kwh
Parasitic Load factor/loss	8%	
Annual Loss	25,789,440	kwh
Net Annual Output	296,578,560	kwh
Solar 'Electric Generation Cost:		
Lifecycle Cost	$1,861,182,609	
Lifecycle Output	8,897,356,800	kwh
Cost of Solar Electricity	**$0.209**	per kwh
Gas Electric Generation:		
Capacity Factor	11%	
Generation rate	964	kwh/kw
Gross Annual generation	154,176,000	kwh
Fuel Cost	$6.50	per MMBtu
heat rate	9400	btu/kwh
efficiency	0.36	
annual energy input	1,449,254	MMBtu
annual energy cost	$9,420,154	

Public Finance, 2010 to 2015

w/no tax credit & 5.25% 30 year municipal bond financing

Reference Natural Gas Price

Solar Electric Generation:		
Capacity Factor	23%	
Generation rate	2,015	kwh/kw
Gross Annual generation	322,368,000	kwh
Parasitic Load factor/loss	8%	
Annual Loss	25,789,440	kwh
Net Annual Output	296,578,560	kwh
Solar 'Electric Generation Cost:		
Lifecycle Cost	$1,216,782,609	
Lifecycle Output	8,897,356,800	kwh
Cost of Solar Electricity	**$0.137**	per kwh
Gas Electric Generation:		
Capacity Factor	11%	
Generation rate	964	kwh/kw
Gross Annual generation	154,176,000	kwh
Fuel Cost	$6.50	per MMBtu
heat rate	9400	btu/kwh
efficiency	0.36	
annual energy input	1,449,254	MMBtu
annual energy cost	$9,420,154	

Public Finance, 2010 to 2015

w/no tax credit & 5.25% 30 year municipal bond financing

High Natural Gas Price Scenario

Solar Electric Generation:		
Capacity Factor	23%	
Generation rate	2,015	kwh/kw
Gross Annual generation	322,368,000	kwh
Parasitic Load factor/loss	8%	
Annual Loss	25,789,440	kwh
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Solar 'Electric Generation Cost:		
Lifecycle Cost	$1,216,782,609	
Lifecycle Output	8,897,356,800	kwh
Cost of Electricity	**$0.137**	per kwh
Gas Electric Generation:		
Capacity Factor	11%	
Generation rate	964	kwh/kw
Gross Annual generation	154,176,000	kwh
Fuel Cost	$10.00	per MMBtu
heat rate	9400	btu/kwh
efficiency	0.36	
annual energy input	1,449,254	MMBtu
annual energy cost	$14,492,544	

Private Finance, 2010 to 2015

w/ tax credit & 11.5% Cost of Capital

Reference Natural Gas Price

Lifecycle energy input	43,477,632	MMBtu
Lifecycle electricity output	4,625,280,000	kwh
Lifecycle cost of fuel	$282,604,608	
Combined Cost of Solar/Natural Gas Generation		
Generation	13,522,636,800	kwh
Capacity Factor	32.2%	
Total Cost	$2,143,787,217	
Combined Cost of Electricity	**$0.159**	
Thermal Energy		
annual natural gas	1,449,254	MMBtu
annual solar thermal	2,780,500	MMBtu
annual total thermal input	4,229,754	MMBtu
annual generation	450,754,560	kwh
annual heat value	1,537,073	MMBtu
residual heat value	2,692,681	MMBtu
Cost of Electricity Using Cogeneration		
cogen heat repurchase rate	$6.50	per MMBtu
recovery rate	50%	
heat recovered per year	1,346,341	MMBtu

Public Finance, 2010 to 2015

w/no tax credit & 5.25% 30 year municipal bond financing

Reference Natural Gas Price

Lifecycle energy input	43,477,632	MMBtu
Lifecycle electricity output	4,625,280,000	kwh
Lifecycle cost of fuel	$282,604,608	
Combined Cost of Solar/Natural Gas Generation		
Generation	13,522,636,800	kwh
Capacity Factor	32.2%	
Total Cost	$1,499,387,217	
Combined Cost of Electricity	**$0.111**	
Thermal Energy		
annual natural gas	1,449,254	MMBtu
annual solar thermal	2,780,500	MMBtu
annual total thermal input	4,229,754	MMBtu
annual generation	450,754,560	kwh
annual heat value	1,537,073	MMBtu
residual heat value	2,692,681	MMBtu
Cost of Electricity Using Cogeneration		
cogen heat repurchase rate	$6.50	per MMBtu
recovery rate	50%	
heat recovered per year	1,346,341	MMBtu

Public Finance, 2010 to 2015

w/no tax credit & 5.25% 30 year municipal bond financing

High Natural Gas Price Scenario

Lifecycle energy input	43,477,632	MMBtu
Lifecycle electricity output	4,625,280,000	kwh
Lifecycle cost of fuel	$434,776,320	
Combined Cost of Solar/Natural Gas Generation		
Generation	13,522,636,800	kwh
Capacity Factor	32.2%	
Total Cost	$1,651,558,929	
Cost of electricity	**$0.122**	
Thermal Energy		
annual natural gas	1,449,254	MMBtu
annual solar thermal	2,780,500	MMBtu
annual total thermal input	4,229,754	MMBtu
annual generation	450,754,560	kwh
annual heat value	1,537,073	MMBtu
residual heat value	2,692,681	MMBtu
Cost of Electricity Using Cogeneration		
cogen heat repurchase rate	$10.00	per MMBtu
recovery rate	50%	
heat recovered per year	1,346,341	MMBtu

Private Finance, 2010 to 2015

w/ tax credit & 11.5% Cost of Capital

Reference Natural Gas Price

total lifecycle heat	40,390,219	MMBtu
total economic value	$262,536,422	
net electric cost	**$0.139**	per kwh
Electricity Wholesale Price/MPR	$0.095	per kwh
Generation per year	450,754,560	kwh
Annual Sales	$42,866,759	
simple payback	9.3	years
Financial Cycle Balance	-$595,248,035	
Annual Net	-$19,841,601	
30 Year Net	-$595,248,035	
generation fuel output cost	$0.061	
with mpr capital and variable cost	$0.095	$0.034

Public Finance, 2010 to 2015

w/no tax credit & 5.25% 30 year municipal bond financing

Reference Natural Gas Price

total lifecycle heat	40,390,219	MMBtu
total economic value	$262,536,422	
net electric cost	**$0.091**	per kwh
Electricity Wholesale Price/MPR	$0.095	per kwh
Generation per year	450,754,560	kwh
Annual Sales	$42,866,759	
simple payback	9.3	years
Financial Cycle Balance	$49,151,965	
Annual Net	$1,638,399	
30 Year Net	$49,151,965	
generation fuel output cost	$0.061	
with mpr capital and variable cost	$0.095	$0.034

Public Finance, 2010 to 2015

w/no tax credit & 5.25% 30 year municipal bond financing

High Natural Gas Price Scenario

total lifecycle heat	40,390,219	MMBtu
total economic value	$403,902,188	
net electric cost	**$0.092**	per kwh
Electricity Wholesale Price/MPR	$0.128	per kwh
Generation per year	450,754,560	kwh
Annual Sales	$57,696,584	
simple payback	6.9	years
Financial Cycle Balance	$483,240,769	
Annual Net	$16,108,026	
30 Year Net	$483,240,769	
generation fuel output cost	$0.094	
with mpr capital and variable cost	$0.128	$0.034

Appendix C Natural Gas Costs

Table C-1 uses DOE projections for natural gas prices until 2030, and extrapolates these to 2040, showing fixed 2004 dollars as well as the corresponding higher nominal inflated dollar equivalent. This places natural gas at a nominal average of $10 per MMBtu between 2009 and 2040, which we use as a HIGH natural gas price scenario. The BASE CASE price is set at $6.50 per MMBtu, while the LOW CASE is $5.00 per MMBtu. We see this as conservative, particularly for a date range running from 2010 to 2040. It is important to take into account this conservative basis when evaluating the investments in the renewable portfolio, as this offers opportunity to profit from upside natural gas risk. Since a significant part of the portfolio is also tied to natural gas, any decreases in natural gas prices will partly offset the renewables that would become relatively more expensive. On the other hand, if natural gas prices rise above current levels, as reflected in the base case, then the renewables will be the lower cost investment. Diversification of the portfolio leads to a double hedge.

The gas price figures are input into a model for electric generation cost for a peaking plant, assuming a heat rate of 9400 Btu per kilowatt-hour for a simple cycle combustion turbine. Variable and fixed costs are set for a plant that operates at 32% capacity factor.

A higher natural gas price will tend to favor renewable facilities, making these investments into natural gas price hedges, as they lock in the cost of generating electricity just as a fuel futures contract would. The difference, however, is that renewables provide this hedge out to 30 and 50 or more years, much longer than any available natural gas contract. By this time, it is expected that the US may face serious depletion of natural gas fuel. Facilities that either do not rely on natural gas, or that rely on it minimally, will be at a great advantage.

Tables C-2 through C-4 compare a variety of natural gas plant investments. The current plant is relatively cheap to run, (with the exception of unit #4), because the capital expense is mostly paid off. A newer peaking plant is not necessarily much more efficient in fuel consumption, as heat rates for simple cycle combustion turbines range from about 9000 Btu/kwh to 10,000 Btu/kwh, with the higher end quite close to the existing plant. For this reason, a new natural gas plant is not likely to avert any future fuel consumption or expense.

The economics of a peaking plant is only partly determined by the heat rate. More important is how many hours per year it is run. The fewer the hours, the more expensive the power, since capital cost becomes more important than fuel as capacity utilization drops. A simple cycle plant is modeled here, because the report examines a functional replacement for the current plant. However, it would be possible to purchase a combined cycle plant with baseload or multiple functionality.

The other major factor is financing cost, as for the renewables. The CCA, using low cost bonds, is at a great advantage in this regard, and can use the natural gas peaker to offset some of the potential near term losses for the fixed cost, renewable generators. Tables C-5 and C-6 show the cost of operating a natural gas peaker plant under private and CCA ownership at low, base, and high natural gas price projections.

Table C-1. Natural Gas Price Projections to 2040

in dollars per million btu

Year	***delta***	***2003***	***2004***	***2005***	***2006***	***2007***	***2008***	***2009***	***2010***	***2011***	***2012***	***2013***	***2014***	***2015***
NG for electric power; 2004 dollars	0.30%	$5.81	$6.07	$8.29	$7.43	$6.71	$6.38	$5.92	$5.60	$5.40	$5.38	$5.49	$5.41	$5.21
Nominal dollars		$5.66	$6.07	$8.50	$7.77	$7.16	$6.96	$6.60	$6.38	$6.30	$6.44	$6.73	$6.80	$6.70
Heat rate		9400	9400	9400	9400	9400	9400	9400	9400	9400	9400	9400	9400	9400
efficiency		36.28%	36.28%	36.28%	36.28%	36.28%	36.28%	36.28%	36.28%	36.28%	36.28%	36.28%	36.28%	36.28%
generation fuel output cost		$0.053	$0.057	$0.080	$0.073	$0.067	$0.065	$0.062	$0.060	$0.059	$0.061	$0.063	$0.064	$0.063
with capital and variable cost	$0.034	$0.087	$0.091	$0.114	$0.107	$0.101	$0.099	$0.096	$0.094	$0.093	$0.095	$0.097	$0.098	$0.097
Consumer price index														
GDP Chain-Type Price Index (2000=1.000)	2.00%	1.063	1.091	1.119	1.141	1.164	1.189	1.216	1.242	1.273	1.306	1.338	1.370	1.404
2004 index		0.974	1.000	1.026	1.046	1.067	1.090	1.114	1.139	1.167	1.197	1.226	1.256	1.287

Year	***2016***	***2017***	***2018***	***2019***	***2020***	***2021***	***2022***	***2023***	***2024***	***2025***	***2026***	***2027***	***2028***
NG for electric power; 2004 dollars	$5.19	$5.23	$5.40	$5.54	$5.53	$5.66	$5.73	$5.79	$5.90	$6.02	$6.08	$6.17	$6.21
Nominal dollars	$6.83	$7.05	$7.46	$7.85	$8.03	$8.42	$8.74	$9.04	$9.42	$9.84	$10.16	$10.55	$10.86
Heat rate	9400	9400	9400	9400	9400	9400	9400	9400	9400	9400	9400	9400	9400
efficiency	36.28%	36.28%	36.28%	36.28%	36.28%	36.28%	36.28%	36.28%	36.28%	36.28%	36.28%	36.28%	36.28%
generation fuel output cost	$0.064	$0.066	$0.070	$0.074	$0.075	$0.079	$0.082	$0.085	$0.089	$0.092	$0.096	$0.099	$0.102
with capital and variable cost	$0.098	$0.100	$0.104	$0.108	$0.109	$0.113	$0.116	$0.119	$0.123	$0.126	$0.130	$0.133	$0.136
Consumer price index													
GDP Chain-Type Price Index (2000=1.000)	1.436	1.471	1.508	1.546	1.584	1.624	1.663	1.703	1.742	1.783	1.824	1.866	1.909
2004 index	1.316	1.348	1.382	1.417	1.452	1.488	1.525	1.561	1.597	1.634	1.671	1.710	1.749

Year	*2029*	*2030*	*2031*	*2032*	*2033*	*2034*	*2035*	*2036*	*2037*	*2038*	*2039*	*2040*	*Average*	
NG for electric power; 2004 dollars	$6.28	$6.41	$6.43	$6.45	$6.47	$6.49	$6.51	$6.53	$6.55	$6.57	$6.59	$6.60	**$6.09**	Fixed $
Nominal dollars	$11.24	$11.74	$12.01	$12.29	$12.57	$12.86	$13.16	$13.46	$13.77	$14.09	$14.41	$14.74	**$9.44**	Nominal $
Heat rate	9400	9400	9400	9400	9400	9400	9400	9400	9400	9400	9400	9400		
efficiency	36.28%	36.28%	36.28%	36.28%	36.28%	36.28%	36.28%	36.28%	36.28%	36.28%	36.28%	36.28%		
generation fuel output cost	$0.106	$0.110	$0.113	$0.115	$0.118	$0.121	$0.124	$0.127	$0.129	$0.132	$0.135	$0.139		
with capital and variable cost	$0.140	$0.144	$0.147	$0.149	$0.152	$0.155	$0.158	$0.161	$0.163	$0.166	$0.169	$0.173	**$0.123**	per kwh Nominal $
Consumer price index														
GDP Chain-Type Price Index (2000=1.000)	1.953	1.998	2.038	2.079	2.120	2.163	2.206	2.250	2.295	2.341	2.388	2.435		
2004 index	1.790	1.831	1.868	1.905	1.943	1.982	2.022	2.062	2.103	2.146	2.188	2.232		

Projections to 2030 from: Annual Energy Outlook 2006 with Projections to 2030 Report #: DOE/EIA-0383(2006) Release Date: December 2005 Table 19. Macroeconomic Indicators

Table C-2. New Combustion Turbine Peaker, CCA Ownership

Natural Gas to Generate 1 KWh					
Cost/MMBtu	$6.50		Size of Plant	160,000	kw
conversion to kwh	3419	btu/kwh	Annual Generation	448,512,000	kwh
fuel-cost/kwh	$0.022		Lifecycle Generation	8,970,240,000	kwh
heat rate	9400	btu/kwh			
efficiency	36.4%		**Lifecycle Costs**		
factor	2.75		Capital Cost	$76,000,000	
electricity fuel-cost/kwh	**$0.061**		Cost of Money	$83,600,000	
			Lifecycle Fuel Cost	$548,081,664	
Cost of Gen Facility			Variable Cost	$51,918,348	
Cost of Equipment	$0.48	per watt	Total Lifecycle Cost	$759,600,012	
lifecycle	20	years			
capacity factor	32%		Savings Vs. Private Ownership	-$30,720,384	
output rate	2803	kwh/kw-yr			
life output/watt	56.06	kwh			
unfinanced cost	$0.008	per kwh			
interest rate + ROI	5.5%				
cost of money	$0.009	per kwh			
total cap cost	$0.018	per kwh			
Variable costs	$0.006	per kwh			
Total Gen Costs	**$0.085**	**per kwh**			

Table C-3. New Combustion Turbine Peaker, Private Ownership

Natural Gas to Generate 1 KWh					
Cost/MMBtu	$6.50		Size of Plant	160,000	kw
conversion to kwh	3419	btu/kwh	Annual Generation	448,512,000	kwh
fuel-cost/kwh	$0.022		Lifecycle Generation	8,970,240,000	kwh
heat rate	9400	btu/kwh			
efficiency	36.4%		**Lifecycle Costs**		
factor	2.75		Capital Cost	$76,000,000	
electricity fuel-cost/kwh	**$0.061**		Cost of Money	$179,360,000	
			Lifecycle Fuel Cost	$548,081,664	
Cost of Gen Facility			Variable Cost	$51,918,348	
Cost of Equipment	$0.48	per watt	Total Lifecycle Cost	$855,360,012	
lifecycle	20	years			
capacity factor	32%				
output rate	2803	kwh/kw-yr			
life output/watt	56.06	kwh			
unfinanced cost	$0.008	per kwh			
interest rate + ROI	11.8%				
cost of money	$0.020	per kwh			
total cap cost	$0.028	per kwh			
Variable costs	$0.006	per kwh			
Total Gen Costs	**$0.095**	**per kwh**			

Table C-4. New Combined Cycle, Base Load, Private Ownership

Natural Gas to Generate 1 KWh					
Cost/MMBtu	$6.50		Size of Plant	500,000	kw
conversion to kwh	3419	btu/kwh	Annual Generation	3,591,600,000	kwh
fuel-cost/kwh	$0.022		Lifecycle Generation	107,748,000,000	kwh
heat rate	6200	btu/kwh			
efficiency	55.1%		**Lifecycle Costs**		
factor	1.81		Capital Cost	$325,000,000	
electricity fuel-cost/kwh	**$0.040**	74.27%	Cost of Money	$1,150,500,000	
			Lifecycle Fuel Cost	$4,342,244,400	
Cost of Gen Facility			Variable Cost	$243,367,254	
Cost of Equipment	$0.65	per watt	Total Lifecycle Cost	$6,061,111,654	
lifecycle	30	years			
capacity factor	82%				
output rate	7183	kwh/kw-yr			
life output/watt	215.50	kwh			
unfinanced cost	$0.003	per kwh			
interest rate + ROI	11.8%				
cost of money	$0.011	per kwh			
total cap cost	$0.014	per kwh			
Variable costs	$0.002	per kwh			
Total Gen Costs	**$0.056**	**per kwh**			

Table C-5. Cost of operating a natural gas peaker plant at low, base, and high natural gas projections under private ownership.

Natural Gas to Generate 1 KWh	**Low**		**Base**		**DOE/High**	
Cost/MMBtu	$5.00		$6.50		$10.00	
conversion to kwh	3419	btu/kwh	3419	btu/kwh	3419	btu/kwh
fuel-cost/kwh	$0.017		$0.022		$0.034	
heat rate	9400	btu/kwh	9400	btu/kwh	9400	btu/kwh
efficiency	36.4%		36.4%		36.4%	
factor	2.75		2.75		2.75	
electricity fuel-cost/kwh	**$0.047**		**$0.061**		**$0.094**	
Cost of Gen Facility						
Cost of Equipment	$0.48	per watt	$0.48	per watt	$0.48	per watt
lifecycle	20	years	20	years	20	years
capacity factor	32%		32%		32%	
output rate	2803	kwh/kw-yr	2803	kwh/kw-yr	2803	kwh/kw-yr
life output/watt	56.06	kwh	56.06	kwh	56.06	kwh
unfinanced cost	$0.008	per kwh	$0.008	per kwh	$0.008	per kwh
interest rate + ROI	11.8%		11.8%		11.8%	
cost of money	$0.020	per kwh	$0.020	per kwh	$0.020	per kwh
total cap cost	$0.028	per kwh	$0.028	per kwh	$0.028	per kwh
Variable costs	$0.006	per kwh	$0.006	per kwh	$0.006	per kwh
Total Gen Costs	**$0.081**	**per kwh**	**$0.095**	**per kwh**	**$0.128**	**per kwh**

Table C-6. Cost of operating a natural gas peaker plant at low, base, and high natural gas projections under public ownership.

Natural Gas to Generate 1 KWh	Low		Base		DOE/High	
Cost/MMBtu	$5.00		$6.50		$10.00	
conversion to kwh	3419	btu/kwh	3419	btu/kwh	3419	btu/kwh
fuel-cost/kwh	$0.017		$0.022		$0.034	
heat rate	9400	btu/kwh	9400	btu/kwh	9400	btu/kwh
efficiency	36.4%		36.4%		36.4%	
factor	2.75		2.75		2.75	
electricity fuel-cost/kwh	**$0.047**		**$0.061**		**$0.094**	
Cost of Gen Facility						
Cost of Equipment	$0.48	per watt	$0.48	per watt	$0.48	per watt
lifecycle	20	years	20	years	20	years
capacity factor	32%		32%		32%	
output rate	2803	kwh/kw-yr	2803	kwh/kw-yr	2803	kwh/kw-yr
life output/watt	56.06	kwh	56.06	kwh	56.06	kwh
unfinanced cost	$0.008	per kwh	$0.008	per kwh	$0.008	per kwh
interest rate + ROI	5.5%		5.5%		5.5%	
cost of money	$0.009	per kwh	$0.009	per kwh	$0.009	per kwh
total cap cost	$0.018	per kwh	$0.018	per kwh	$0.018	per kwh
Variable costs	$0.006	per kwh	$0.006	per kwh	$0.006	per kwh
Total Gen Costs	**$0.071**	**per kwh**	**$0.085**	**per kwh**	**$0.118**	**per kwh**
rate savings	$0.011	per kwh	$0.011	per kwh	$0.011	per kwh

Appendix D Photovoltaics

Table D-1 examines the effect of various financial inputs into the cost per kilowatt-hour of electricity generated by solar photovoltaic system. One assumption here is that commercial entities will purchase the photovoltaic systems, and be eligible to receive tax credits and state rebates. The federal tax credit is conservatively assumed to revert to 10%, as it will naturally do after 2007 if no legislative action is taken. If the current 30% credit is extended, then the economics of photovoltaics will significantly improve for commercial/industrial sector customers that have a tax liability. The model assumes that commercial customers will borrow money for a 5 year period, paying 7.5% interest on a conventional commercial loan with a declining balance. The interest is taken on the full purchase price, not the after rebate price of the solar system. That is because we expect the new rebate program under the California Solar Initiative to pay out performance incentives over a 5 year period, so they will not affect the amount of the initial borrowing. However, upfront rebate payments under the current program design will be offered for photovoltaic systems smaller than 100 kilowatts.

The model also makes some generic assumptions about electric rates, such as a 5% local tax on sales of electricity and an initial 12 cent a kilowatt-hour rate. These only represent approximations for comparison sake. The lifecycle costs are modeled for a medium to large (10+ kilowatt) sized commercially owned photovoltaic system, and would have to be significantly modified for publicly owned or publicly financed systems, or for small home sized systems.

The analysis uses a range of cost per watt for capital expense as the basic input on the left side, running from $6.00 to $9.00 per watt of direct current electric generation capacity, a range that most photovoltaic systems would fall into. This installed capacity cost is then translated, using the various input values for performance, tax credits, loan terms and rebate, entered in the boxes in the lower part of the spreadsheet, into an effective electric rate expressed as a cost per kilowatt-hour over the life of the photovoltaic system. The lifecycle is assumed to be 30 years, which is likely to be conservative since photovoltaic modules can usually produce electricity for many more years. Most of the cost is upfront, but there is a small ongoing operation and maintenance expense, and every 10 to 20 years the inverter needs to be replaced. The larger the system, the longer the inverter is likely to last (and the lower the unit cost for replacement).

Table D-1. Photovoltaic Power Production Full Lifecycle Accounting: Commercial Ownership

PV System	PV System	after rebate	Interest*	O&M	inverter	total cost	pretax cost/kwh	Tax benefit	net cost	PV net cost/kwh
	cost/watt	cost/watt	cost/watt							
cost/watt (dc)	(ac)	(ac)	(ac)		$0.60			48%		
$9.00	$10.84	$8.84	$2.19	$0.33	$0.60	**$11.97**	$0.272	$5.49	**$6.47**	$0.147
$8.50	$10.24	$8.24	$2.07	$0.33	$0.60	**$11.24**	$0.255	$5.16	**$6.09**	$0.138
$8.00	$9.64	$7.64	$1.95	$0.33	$0.60	**$10.52**	$0.239	$4.82	**$5.70**	$0.129
$7.50	$9.04	$7.04	$1.83	$0.33	$0.60	**$9.79**	$0.223	$4.48	**$5.31**	$0.121
$7.00	$8.43	$6.43	$1.71	$0.33	$0.60	**$9.07**	$0.206	$4.14	**$4.93**	$0.112
$6.50	$7.83	$5.83	$1.58	$0.33	$0.60	**$8.35**	$0.190	$3.80	**$4.54**	$0.103
$6.00	$7.23	$5.23	$1.46	$0.33	$0.60	**$7.62**	$0.173	$3.47	**$4.15**	$0.094

* assumes pbi paid out over time, full upfront cost on declining balance loan

Underlined row shows the typical cost within the last two years for commercial-scale projects in California

INPUTS		
DC output	1400	kwh/kw-yr
years	30.0	
loan term	5	years
interest rate	7.5%	
Rebate/watt**	$2.00	
tax on electric	0%	
initial electric rate	$0.120	per kwh
solar peak premium	$0.015	per kwh
cool roof	$0.000	per kwh
local tax	5%	
customer premium	$0.000	per kwh
annual escalation	2%	
REC/environmental	$0.000	per kwh

PV SYSTEM OUTPUT			
AC derate	83%	1.20	
Initial output (ac)		1687	kwh/kw-yr
Final		1248	
average		1467	
total electricity/watt		44.02	kwh

LIFECYCLE VALUE		
initial PV value rate	$0.142	
total inflation	81.1%	
final value rate	$0.257	per kwh
avg. eff. rate	$0.199	per kwh
after tax rate	$0.199	per kwh
accumulation	$8.77	per watt ac

TAX BENEFITS	rate	years	value
tax credits	10%	1	10%
Fed tax rate	33%	5	33.00%
state tax add	7%	12	7.00%
federal basis	95%		
net tax benefit			48.00%

LIFECYCLE COSTS		
inverter cost	$0.60	per watt
inv. lifecycle	20	years
replacements	1	
total inverters	$0.60	
o&m	0.0075	per kwh

Appendix E SDG&E Rates and San Diego Electric Resources

Tables E-1 and E-2 give some basic facts about electric generation in San Diego County. Table E-1 shows current rates for electric commodity charges by SDG&E, which pulls out the cost of electricity at different times of the day and year for time of use customers. These rates shown in the upper part of Table E-1 exclude distribution and service charges, as well as surcharges and taxes, which form the rest of the bill. These costs tend to reflect the average wholesale cost of generating electricity, and range from 4 to over 11 cents per kilowatt-hour.

The bottom part of the table adds the full charges back into the rate, showing an annual average cost of electricity of 15.44 cents per kilowatt-hour for customers on this rate schedule. It is noteworthy that the full cost range for photovoltaic electricity in Table D-1 falls below this rate, which makes photovoltaics an excellent hedge against future electric rate increases, *effectively freezing a commercial customer's rate below what they are presently paying*.

Table E-2 shows new power plants in San Diego County since 2001, and planned through 2008. A total of 1437 Megawatts of capacity will have been added during this period. This is likely enough to supply all the electricity needs of San Diego County's one-million-plus residential customers.*

* According to the California Energy Commission, San Diego County had 1,013,799 residential customers in 2000 that consumed a total of 6,041 million kilowatt-hours, which equates to 5959 kilowatt-hours per account per year. This represents an average load of 5959 / 8760 = 0.68 kilowatts. Therefore, 1437 Megawatts of capacity would provide 1,437,000 divided by 0.68 = 2,113,345 customers' average load, about double the actual total number of customers. Of course, the electric system capacity has to be sized for maximum, not average, load. Yet, just the *added capacity* from 2001 through 2008 should meet all the needs of the county's one million residential customers, both base and peak load.

Table E-1. SDG&E Energy and UDC Charges as of 2/1/2006

ELECTRIC ENERGY COMMODITY COST (EECC)

Schedule DR – Residential customers on separate meters

	Baseline		101%-130% of Bsln		131%-200% of Bsln		210%-300% of Bsln		above 300% of Bsln	
Effective Date	**Summer**	**Winter**	**Summer**	**Winter**	**Summer**	**Winter**	**Summer**	**Winter**	**Summer**	**Winter**
02/01/2006	0.06855	0.04678	0.6855	0.04678	0.06855	0.04678	0.06855	0.04678	0.06855	0.04678

Schedule AL TOU- Time of Use rate for non-residential customers whose use is greater than 20kw

Effective Date	On Peak	Semi Peak	Off Peak
02/01/2006	0.11515	0.06637	0.04537

Schedule A- Residential and commercial customers whose use does not exceed 20 kw

Effective Date	Summer	Winter
02/01/2006	0.08144	0.05617

Department of Water Resources (DWR) Bond Charge

Effective Date	
01/01/2006	0.00485

care and medical baseline excluded

ELECTRIC ENERGY COMMODITY COST (EECC) PLUS UTILITY COMPANY DISTRIBUTION (UDC) RATES

Schedule A- Residential

Effective Date	**EECC Summer**	**UDC Summer**	**TOTAL Summer**	**EECC Winter**	**UDC Winter**	**TOTAL Winter**	**Annual avg.**	Service fee per month	demand avg. kw	electricity kwh	service/kwh
02/01/2006	0.08144	0.08515	0.17144	0.05617	0.07647	0.13749	**0.154465**	$9.10	5	3600	0.002527778

Table E-2. San Diego County Power Plant Construction 2001-2009.

Project	Docket number	Status	Capacity (MW)	Construction Completed (percent)	Date Approved	Construction Start Date	Original On-line Date	Actual On-line Date
Wildflower Larkspur - Intergen	01-EP-1	Operational	90	100	04/04/2001	04/05/2001	07/01	07/16/2001
Escondido - Calpeak	01-EP-10	Operational	49.5	100	06/06/2001	06/07/2001	09/01	09/30/2001
Border - Calpeak	01-EP-14	Operational	49.5	100	07/11/2001	07/12/2001	09/01	10/26/2001
Palomar Escondido - Sempra	01-AFC-24	Operational	546	100	08/06/2003	06/01/2004	03/06	04/06
Miramar Plant		Operational	46	100				07/2005
online 1/2006	**781**	**MW**						
MMC Escondido		On-Line 2006	44	90%				07/2006
Biofuel Peaker		Announced	22					
Otay Mesa - Calpine	99-AFC-5	Construction	590	9	04/18/2001	9/10/01	9/10/0	01/08
by 2008	**1437**	**MW**						
Chula Vista 2 - Ramco	01-EP-3	Cancelled	62	0	06/13/2001	Cancelled	Cancelled	Cancelled

Appendix F Portfolios and Financing

Table F-1 shows the cost range of three different portfolio options, the expected annual electric generation, and the effective load carrying capacity of the facilities individually and in each of the portfolios. Some of the elements, such as photovoltaics, and perhaps wind, may not be counted by the ISO for reliability purposes. Partly for this reason, each portfolio is rated a bit higher than the stated level, but it would be possible to add to the size of the natural gas plant to make up for the difference. This would incur the least capital cost as a remedy. In addition, adjustments in the natural gas plant size may be necessary as different models come into production. If the City elects to get a mixed-use combined cycle natural gas plant, then the cost for a given size plant will likely be about 25% higher. On the other hand, the fuel efficiency may also be significantly higher.

On the other hand, adding capacity to a natural gas power plant should be a last resort, used only if other strategies do not meet the requirements. We recommend meeting the resource needs by 1) examining the full range of resource options within the county using updated demand figures, 2) evaluating construction of the appropriate Green Energy Option, and 3) challenging the ISO to account adequately for the full range of clean energy sources.

The financing assumptions are contained in Table F-2. It shows four different investor categories for power plants. These figures are used for all the plants evaluated, such as wind, pumped storage, concentrating solar thermal, and natural gas:

1) A 3rd party, private investor that borrows half the money from a bank and invests the other half out of their own resources. The expected rate of return for the portion they own is 14%; in reality this is likely to vary depending on the perceived risk. Half the money is assumed to be equity and half on borrowed funds from a bank. When the return on equity is averaged with a bank loan of 7.5%, the average cost of money is shown to be 11.8%. These figures do not account for the effect of taxes.

2) Utility owner. These have lower borrowing rates than private investors, and lower rates of return on equity in the power plant.

3) City or JPA ownership. This is a 30 year bond financed facility based upon the capital asset and long term contracts to sell power. The rate of return, 5.25 percent, is interest paid annually on the full amount of the bond, which differentiates a bond from the standard declining balance mortgage or credit card loan with which most people are familiar. Current interest rates on municipal 30 year bonds are about one percent lower. This reflects conservative assumptions, as well as embedded finance costs.

4) CCA ownership. This would be a revenue bond, limited to 20 years, with repayment based on the general ratepayer revenue stream from electric bills to the CCA. The interest rate is shown as ¼ point higher at 5.5 percent, to reflect the higher rate of return required for revenue bonds compared to bonds that are secured by a capital asset.

Table F-1. Green Energy Options-South Bay Replacement Generation Portfolios with Cost of Electricity (COE) \ for Wholesale Peak Power Generation Supply

	Capacity	Percent Load Carrying capacity	Effective Load Carrying Capacity	Capacity Factor	Annual Generation + DR	Estimated Cost		Peak COE low case		Peak COE base case		Peak COE high case	
						Cost/ watt	Total Cost	per kwh	annual	per kwh	annual	per kwh	annual
Current Plant Value	700		700	23%	1,410,360,000	$0.15	$105,000,000						
Current Plant Replacement (potential)	620		620	80%	4,344,960,000	$0.65	$403,000,000						
Natural Gas Peaker						*See Table C-5 for calculations →*		$0.081		$0.095		$0.128	
Green Energy Portfolios													
90% Solution													
Wind Plant	400	20%	80	35%	1,226,400,000	$1.35	$540,000,000						
Pumped Storage net adjust	-183	100%		35%	-560,640,000								
Pumped Storage	150	100%	150	32%	420,480,000	$1.00	$150,000,000	$0.094	$39,525,120	$0.094	$39,525,120	$0.094	$39,525,120
Natural Gas Plant	220	100%	220	32%	616,704,000	$0.48	$105,600,000	$0.071	$43,785,984	$0.085	$52,419,840	$0.118	$72,771,072
Solar Thermal w/gas cogen	160	100%	160	32%	448,512,000	$2.50	$400,000,000	$0.091	$40,814,592	$0.091	$40,814,592	$0.092	$41,263,104
Photovoltaic	20	60%	12	17%	29,784,000	$7.00	$140,000,000						
Demand reduction	20	100%	20	20%	35,040,000								
Total	970		642		2,216,280,000		$1,335,600,000	$0.084	$124,125,696	$0.089	$132,759,552	$0.103	$153,559,296
ELCC Target			630	32%	1,766,016,000								

	Capacity	Percent Load Carrying capacity	Effective Load Carrying Capacity	Capacity Factor	Annual Generation + DR	Estimated Cost		Peak COE low case		Peak COE base case		Peak COE high case	
						Cost/ watt	Total Cost	*per kwh*	*annual*	*per kwh*	*annual*	*per kwh*	*annual*
70% Solution													
Wind Plant	325	20%	65	35%	996,450,000	$1.35	$438,750,000						
Pumped Storage net adjust	-120	100%		35%	-336,384,000								
Pumped Storage	90	100%	90	32%	252,288,000	$1.00	$90,000,000	$0.094	$23,715,072	$0.094	$23,715,072	$0.094	$23,715,072
Natural Gas Plant	190	100%	190	32%	532,608,000	$0.48	$91,200,000	$0.071	$37,815,168	$0.085	$45,271,680	$0.118	$62,847,744
Solar Thermal w/gas cogen	160	100%	160	32%	448,512,000	$2.50	$400,000,000	$0.091	$40,814,592	$0.091	$40,814,592	$0.092	$41,263,104
Photovoltaic	20	60%	12	17%	29,784,000	$7.00	$140,000,000						
Demand reduction	20	100%	20	20%	35,040,000								
Total	805		537		1,958,298,000		$1,159,950,000	$0.083	$102,344,832	$0.089	$109,801,344	$0.104	$127,825,920
ELCC Target			490	32%	1,373,568,000								

	Capacity	Percent Load Carrying capacity	Effective Load Carrying Capacity	Capacity Factor	Annual Generation + DR	Estimated Cost		Peak COE low case		Peak COE base case		Peak COE high case	
						Cost/ watt	Total Cost	per kwh	annual	per kwh	annual	per kwh	annual
50% Solution													
Wind Plant	150	20%	30	35%	459,900,000	$1.35	$202,500,000						
Pumped Storage net adjust	-80	100%		35%	-224,256,000								
Pumped Storage	60	100%	60	32%	168,192,000	$1.00	$60,000,000	$0.094	$15,810,048	$0.094	$15,810,048	$0.094	$15,810,048
Natural Gas Plant	90	100%	90	32%	252,288,000	$0.48	$43,200,000	$0.071	$17,912,448	$0.085	$21,444,480	$0.118	$29,769,984
Solar Thermal w/gas cogen	160	100%	160	32%	448,512,000	$2.50	$400,000,000	$0.091	$40,814,592	$0.091	$40,814,592	$0.092	$41,263,104
Photovoltaic	20	60%	12	17%	29,784,000	$7.00	$140,000,000						
Demand reduction	20	100%	20	20%	35,040,000								
Total	500		352		1,169,460,000		$845,700,000	$0.086	$74,537,088	$0.09	$78,069,120	$0.10	$86,843,136
ELCC Target			350	32%	981,120,000								
Efficiency of Pumped Storage			*75%*										

Table F-2. Financing Assumptions

		Private	Utility	Public	CCA
Equity		50%	50%	0%	0%
Annual Return on Investment (ROI)		14.0%	10.5%	0.0%	0.0%
Term	years	30	30	30	20
Total ROI on Investment		2.10	1.58	0.00	0.00
Loan		50%	50%	100%	100%
Interest rate		7.50%	7.00%	5.25%	5.50%
Term	years	20	30	30	20
Total Interest		0.75	1.05	1.58	1.10
Balance of term on equity		10	0	0	0
Balance on equity		$0.70	$0.00	$0.00	$0.00
Total Cost of Capital per dollar of principal		$3.55	$2.63	$1.58	$1.10
Average Effective Rate of Capital		11.8%	8.8%	5.3%	5.5%

Appendix G Pollution Comparison Calculations

Table G-1 shows the estimated particulate matter and carbon dioxide emissions from the existing South Bay Power Plant, the proposed South Bay Replacement Project, and the three Green Energy Option portfolios. Of the criteria pollutants, we chose to estimate emissions of particulate matter (PM), as this is the primary air pollution concern from the existing and proposed plants. Emissions of PM from power plants are significant, and PM levels in Chula Vista exceed state and national air quality standards. We also estimated carbon dioxide emissions to illustrate the differences in greenhouse gas emissions among the energy portfolio options.

Table G-1. South Bay Power Plant Replacement Options, Comparison of Air Pollution and Greenhouse Gas

Scenario	Capacity	Capacity Factor	Annual Generation	Heat Rate	Natural Gas Use		Emissions		Emissions	
							PM10/2.5	CO2	PM10/2.5	CO2
	MW		GWh/year	btu/ kwh	MMBtu/ year	MMscf/ year	Tons/ year	Tons/ year	lbs/ MWh	lbs/ MWh
Existing South Bay Power Plant	**700**	**32%** [1]	**1,962**	**10,068**	**19,755,832**	**19,180**	**72.9**	**1,155,716**	**0.074**	**1178**
Proposed South Bay Replacement Plant	running as a base-load plant w/ intermittent duct firing									
Base load	500 [2]	80%	3,504	6993 [3]	24,503,472	23,790	90.4	1,433,453	0.052	818
With duct firing	120	9% [4]	96	9488	910,848	884	3.4	53,285	0.070	1110
Total for SBRP	**620**	**66%**	**3,600**		**25,414,320**	**24,674**	**93.8**	**1,486,738**	**0.052**	**826**
New Natural Gas Peaking Plant	**700**	**32%**	**1,962**	**9400**	**18,445,056**	**17,908**	**68.0**	**1,079,036**	**0.069**	**1100**

[1] For comparison with the Green Energy Portfolios, the capacity factor is consistent with that of the GEOs. LS Power's AFC on the South Bay Replacement Project states that the SBPP's capacity factor is currently at about 30%.
[2] SBRP AFC before CEC page 2-38
[3] Table 2.3-6 in SBRP AFC before the CEC
[4] Assumes 800 hours duct firing per year per CEC data request.

Scenario	Capacity	Capacity Factor	Annual Generation	Heat Rate	Natural Gas Use		Emissions		Emissions	
							PM10/2.5	CO2	PM10/2.5	CO2
	MW		GWh/year	btu/ kwh	MMBtu/ year	MMscf/ year	Tons/ year	Tons/ year	lbs/ MWh	lbs/ MWh
Green Energy Portfolios										
90% Solution	**630 MW ELC Capacity**									
Wind Plant	400	35%	1,226							
Pumped Storage net adjust	-183	35%	-561							
Pumped Storage	150	32%	420							
Natural Gas Plant	220	32%	533	9400	5,797,158	5,628	21.4	339,126	0.069	1100
Solar Thermal	160	21%	294							
Natural Gas from Solar Thermal	160	11%	154	9400	1,449,254	1,407	5.3	84,781	0.359	5693
Photovoltaic	20	17%	30							
Demand reduction	20	20%	175							
			2,216		**7,246,242**	**7,035**	**26.7**	**423,907**	**0.024**	**383**
70% Solution	**490 MW ELC Capacity**									
Wind Plant	325	35%	996							
Pumped Storage net adjust	-110	35%	-336							
Pumped Storage	90	32%	252							
Natural Gas Plant 1	190	32%	533	9400	5,006,515	4,861	18.5	292,881	0.069	1100
Solar Thermal	160	21%	294							
Natural Gas from Solar Thermal	160	11%	154	9400	1,449,254	1,407	5.3	84,781	0.069	1100
Photovoltaic	20	17%	30							
Demand reduction	20	20%	175							
Total	**945**		**1,958**		**6,455,770**	**6,268**	**23.8**	**377,663**	**0.024**	**386**

Scenario	Capacity	Capacity Factor	Annual Generation	Heat Rate	Natural Gas Use		Emissions		Emissions	
							PM10/2.5	CO2	PM10/2.5	CO2
	MW		GWh/year	btu/ kwh	MMBtu/ year	MMscf/ year	Tons/ year	Tons/ year	lbs/ MWh	lbs/ MWh
50% Solution	**350 MW ELC Capacity**									
Wind Plant	150	35%	460							
Pumped Storage net adjust	-73	35%	-224							
Pumped Storage	60	32%	168							
Natural Gas Plant	90	32%	252	9400	2,371,507	2,302	8.7	138,733	0.069	1100
Solar Thermal	160	21%	294							
Natural Gas from Solar Thermal	160	17%	238	9400	1,449,254	1,407	5.3	131,026	0.069	1100
Photovoltaic	20	17%	30							
Demand reduction	20	20%	175.2							
			1,169		**3,820,761**	**4,477**	**14.1**	**223,515**	**0.024**	**382**

Notes:

Efficiency of Pumped Storage	75%		
Btus natural gas/cubic foot	1030		
<u>Emission Factors:</u>			
Particulate Matter	7.6	lbs/scf	EPA AP 42 emission factor for total PM
CO2 emission factor	117	pounds per MMBtu of NG burned	US EPA. Personal Emissions Calculator References. www.epa.gov/climatechange/emissions/ind_assumptions.html

From: WBesuden@aol.com [mailto:WBesuden@aol.com]
Sent: Friday, February 23, 2007 04:11 PM
To: sunrise@aspeneg.com
Subject: Sunrise Powerlink Comments

Dear Ms. Susan Lee, Ms. Billie Blanchard, CPUC, Ms. Lynda Kastoll, BLM, et al,

Pursuant to my conversation with Susan Lee, this letter comes to you to confirm our support for the preferred alignment of the Powerlink, underground along San Vicente Road, through the San Diego Country Estates vicinity. Please find attached a letter sent last year explaining our position and objection to the Creelman Lane alignment. We feel very strongly that the aforementioned selected prefered alignment best serves not only the local landowners, but also all of the general public.

Respectfully submitted by,

Wally Besuden
Pres. Spangler Peak Ranch, Inc.
(702)429-7525

Spangler Peak Ranch, Inc.
04/20/2006
PO Box 1959
Escondido, Ca. 92033

SDG&E
Or
PUC

Re: SUNRISE POWER LINK

Dear SDG&E or PUC,

This letter comes to you to express our concern regarding the proposed routing of the Sunrise Power Link, hereinafter called "SPL", near or through our property, Spangler Peak Ranch, 219 Creelman Lane, Ramona Ca., hereinafter called "SPR".
My name is Wally Besuden, President of SPR, and along with my partners, Mr.'s Bill and Matt Witman, we own the two hundred eighty acres that comprises SPR. We purchased SPR in 1996, an avocado and grapefruit farm, with the intention of continuing and improving the agribusiness, but primarily as a land investment for future development.
The three of us were previously and have continued to farm leased tracts in San Diego County, growing a variety of agricultural products, on tracts totaling more than one thousand acres. Our cumulative tenure in San Diego County agriculture spans three generations and more than ninety years. Also, my background and current resume includes real estate investment and development.

In addition to avocados and grapefruit production at SPR, we also have approximately ten thousand palm trees and other ornamentals in various stages of production. These trees require heavy equipment including large cranes to transport from and around the site.
We have completed conceptual planning for the future master planned community at SPR, including meetings with the San Diego County planning staff. Plans include custom home site view lots with an extensive trails system, executive and practice golf facility, and an equestrian center, all in an agricultural setting with the existing incredible north county vistas.
We believe that if you choose to use the proposed preferred Creelman Lane alignment, with above ground transmission lines, that we will be greatly damaged. The current and future agricultural enterprise value of SPR as well as the damage to the future development potential will be extremely costly. Currently our access point to SPR is the east end of Creelman Lane.
Our objection to the SPL Creelman alignment is the overhead transmission portion of the route affecting our view shed and access as well as the alternate route to San Vicente Road dividing SPR.
We respectfully request that if the Creelman Lane route is used for SPL, all the lines remain underground from San Diego Country Estates through Creelman Lane,
Please call me if there are questions or a need for discussion. We look forward to your response .

Respectfully submitted by,

Wally Besuden
President
(702) 429-7525

Cc:Bill Witman
Matt Witman
Linda Bartz, Asaro Keagy Freeland McKinley & Bartz LLP
Richard Freeland, Asaro Keagy Freeland McKinley & Bartz LLP

From: Michael/Lisa Page [mailto:oakhollowranch@wildblue.net]
Sent: Friday, February 23, 2007 03:05 AM
To: sunrise@aspeneg.com, SLee@aspeneg.com, ''Hedy Born''
Cc: ''Old Julian Co'', ''Paula Payne'', ''Teresa Wechsler''
Subject: Sunrise Powerlink Comments - Oak Hollow Road Underground Alternative

Hello to everyone at Aspen Environmental Group from Starlight Mountain Estates Owners (SMEO).

We would like to provide a brief comment regarding the Oak Hollow Road Underground Alternative listed in the second round of scoping on alternatives.

SMEO obviously and sincerely approves and appreciates the Oak Hollow Road Underground Alternative being carried forward into this second round. We also hope that further investigations into the various aspects of our specific alternative and it's updated route, prove it to be a recommendation worth carrying forward all the way into the draft and final versions of the EIR.

SMEO is willing and eager to provide any assistance necessary to continue the Oak Hollow Road Underground Alternative.

Thank you again!

Michael Page

For SMEO

OPPOSITION TO ALL ROUTES OF SUNRISE

SUPPORT OF NO WIRES ALTERNATIVE

February 24, 2007

Introduction

The CPUC acts in the interest of the public by denying the SDG&E proposal for a long haul, 150 mile transmission line originating in Imperial County and spanning the San Diego County from East to West with points of distribution in North San Diego. The reason for the denial rests on many arguments, not a single one. There are severe economic, environmental, ecological, climatological, political, social, and psychological impacts. The costs of these impacts are quantifiable and many documents from constituent groups have documented the costs for CPUC review. I would like to make the argument that the 1.4 billion dollar price tag represents too great an opportunity loss to impose on the ratepayers of SDG&E. What is the opportunity loss and why is it so timely?

Characterizing the Future

The body of knowledge to predict climate warming with certainty is based on rigorous observations of current trends and known molecular behaviors of carbon-based gases to trap heat. The best debate is "how do we dampen the worst-case scenario?". California is a colossal emitter of greenhouses gases. Any infrastructure that ties together greenhouse-emitting power plants marries the profit-making engine to these technologies. It guarantees carbon emissions for the long term.

SDG&E can find plenty of real estate and sun within its service areas to generate energy. Imperial County is not a dependency. SDG&E argues that Sunrise is required to fulfill state mandates that 20% of its energy come from renewables. Are renewables from Imperial County that much more efficient when so much energy is lost in transmission?

That argument is full of holes. Stirling-based technology remains in the labs. CPUC knows this. It can and should steer SDG&E to work with people, companies and locales of San Diego County to increase its supply, improve efficiency, and reduce summer loads.

Are the ratepayers of SDG&E together with California as a whole served by such a colossal investment in networking remote and mega, fossil-fuel based plants? Do the ratepayers know what 1.4 billion dollars of investment could return if invested in renewable infrastructure and generation? Isn't a transmission line of this type a significant opportunity loss? How would San Diego react to “In-Community Generation”? Isn't the ratepayer better served by a distributed, secure, and forward-looking investment?

<u>In Community Renewables</u>

In response to the situation, my company (Acctiva Corporation) is forming a separate division called ***In Community Renewables***. The mission is to demonstrate how to design, build, maintain and upgrade modular, mid-range renewable power stations. Located proximate to existing substations and major consumers, the plants emit no greenhouse gases, can produce energy at competitive rates, and require ratepayer buy-in for accelerated depreciation. The plants provide for local generation of base load demands in a service area. Surplus energy is added to the local grid. Plant design is plug and play and redundant. It allows for single arrays to be swapped in and out. The plant design allows for composite energy generation including photovoltaics and other non-emitting sources.

<u>Conclusion</u>

The CPUC can and will send a signal to SDG&E. Invest in the future that avoids the worst-case scenario. Lead in the adoption of renewables which lessen our dependence on shrinking and insecure supplies of natural gas, coal, and oil. Communities in San Diego are hungry to see SDG&E and Sempra demonstrate leadership in combining economic and environmental stewardship. The majority of San Diegans want a future that is not the worst-case scenario. The future depends on leadership by example.

Lane Sharman
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San Diego, CA 92130
SDG&E Ratepayer
lane@opendoors.com
858-755-2868

Back Country Coalition
Post Office Box 70 • Santa Ysabel, CA 92070 • 760-765-2132

February 24, 2007

Billie Blanchard, CPUC/Lynda Kastoll, BLM
c/o Aspen Environmental Group - sunrise@aspeneg.com
235 Montgomery Street, Suite 935
San Francisco, CA 94104-3002

SUBJECT: Sempra/SDG&E Proposed Sunrise Powerlink Project
Response to Second Round of Scoping Meetings and Alternatives
Regulatory Oversight of Sempra's Apparent Master Project

The Back Country Coalition (**BCC**) is an organization of concerned citizens dedicated to the protection of natural, cultural and scenic resources, responsible land use planning and the enhancement of quality of life throughout San Diego County. We have joined with other concerned individuals and groups to help ensure that decisions made for our communities regarding future energy supplies provide for modern, diverse, economical, sustainable and renewable energy generation and those decisions are made in the best interests of all residents and environmental resources.

<u>Proposed Sunrise Powerlink Project</u>

The proposed project is a "150-mile transmission line between the El Centro area of Imperial County and northwestern San Diego County. SDG&E's stated purpose for the project is to bring renewable resources into San Diego County from Imperial County, reduce energy costs in the San Diego area, and to improve electrical reliability for the San Diego area."

This letter addresses BCC's perception of the increased oversight required by the California Public Utilities Commission of Sempra Energy's apparent plans for energy generation and transmission throughout southern California and the southwest United States, through and beyond the Sunrise Powerlink portion of that international utility corporation's overall scheme.

<u>CPUC Regulation</u>

Acting as a Responsible Agency, we believe that the California Public Utility Commission must address the entirety of the proposed Sunrise Powerlink transmission lines as the project relates to the consuming public. In this consideration – and coinciding with the PUC Mission – we request that thorough analysis be afforded the following topics. We believe that detailed and specific studies of the potential impacts inflicted by Sunrise on the ratepayer public and the electrical distribution system as whole require examination.

The CPUC's most relevant goals include:

- **Monitoring the safety of utility operations and oversee markets to inhibit anti- competitive activity;**
- **Prosecute unlawful utility marketing and resolve complaints by customers against utilities;**
- **Implement energy efficiency and conservation programs**
- **Oversee the merger and restructure of utility corporations and enforce the California Environmental Quality Act;**
- **Work with other state and federal agencies in promoting water, environmental protection and safety;**
- **Intervene in Federal proceedings on issues that affect California utility rates and services.**

Our intention in this scoping period is to alert the Commission of conflicts that Sunrise Powerlink transmission lines would present to the Commission's Goals, their potential impacts to ratepayers, the environment and competitive electrical generation, transmission and distribution network in California. More focused and specific comments have been addressed pending your Commission's degree of thoroughness in the EIR/EIS statements and findings.

A great deal of public concern has been directed toward the enormous cost of Sunrise Powerlink. If constructed, the cost to rate and taxpayers will certainly exceed the $1.3 billion SDG&E estimate. The Duke Energy brief http://www.cpuc.ca.gov/static/HotTopics/1energy/z05_briefdukeenergy.pdf of 2-24-06 demonstrates the utlty's calculations to be incomplete, inaccurate – as well as not compliant with Commission cost requirements for end of service removal.

Other recent examples of Sempra's forecasting methods have been exposed in your Commission's requests for economic studies; forecasts characterized best as inaccurate - some to the point of wildly so. See attached "Power line benefits downsized" article for an indication of Sempra's ability to hit accurate numbers – first claiming $447 million in savings before revising that down to $85 million. The savings figure continues to fluctuate at Sempra's will, depending on what goes into the computer model.

Costs of the Sunrise Powerlink Project

The impacts of these enormous costs are compounded with the realization that ratepayers will be footing this bill in its entirety. Incredibly, and as in no other business, customers will bear all the risks, costs, and overruns associated with Powerlink. All cost factors from eminent domain to easement road maintenance will be borne by ratepayers. This is even more painful with the realization that Sunrise isn't needed, and in fact could act as a major detriment to development of cheaper, cleaner and more abundant future energy supplies. As will be explained, even if Sunrise were "free", the costs associated with powerlink retarding future in-area renewable, sustainable energy development is far too high a price to pay.

While these construction costs are mind numbing to contemplate, they are also distracting from the true effect of the Sunrise powerlink installation. Once in place, Powerlink provides a virtual floodgate of cheap, dirty Mexican power. The Mexicali power plant production has not only polluted Calexico and Mexicali, contributing to some of the worst air quality in California, it also has the ability to expand at the speed of the Mexican approval process.

Duplication of Mexican plants is already in the planning stage, with as many as 22 gas-fired generating plants being considered, all reliant on the approval and implementation of Sunrise Powerlink. While not all proposed power plants can or would use Sempra's Sunrise Powerlink, the cross-border transmission concept is the critical key: Sending cheap, environmentally unregulated power north to lucrative American markets, with LNG as the fuel and using lines such as Sunrise for feeding the entire American southwest. That is the equivalent of a utility company jackpot.

Keys to Overall Plan

Sempra is creating a schematic for the entire energy industry to emulate and profit from. As the first on the ground with LNG plant capacity and a high capacity functioning re-gasified line to Mexicali, Sempra will hold a position unique to vertically integrated companies with market dominance power. It will have the ability to move natural gas in both directions on the border, supply north and south American competitors, fuel its own gas fired plants and transmit nearly unlimited electric power north at costs that have every potential to be the lowest wholesale prices in the continental US. But none of this can be accomplished without Sunrise powerlink…The Mexican market does not have the advanced industrial/technical workplace required to utilize the power capacity generated by Sempra. There simply is not a single market for the enormous power generating capacity that Sempra can scale up to in Mexicali. Sunrise would allow this pivotal transfer of electrical energy to new American markets in California and beyond.

Why through California? Because the costs of transmission planning, environmental review, construction and maintenance are essentially underwritten by the state of California:

Free is the operative descriptor. This state-sanctioned form of corporate welfare is a cash cow vestige to an era of fully regulated utilities. And one that Sempra is fully exploiting. Please bear in mind that viewed simply as a line of power towers that Sunrise appears to be merely a long distance extension cord. Seen in its broadest form, Sunrise is the key example of global corporate market power domination - aided and abetted by its very regulators. The entire (and vast) resources of the numerous unregulated Sempra companies are working in unison to advance this project's feasibility. Every facet of the operation appears to have been geared to pull out costs, dodge effective regulation and compound the efficiencies of scale, market strength and political connections to regulatory agencies. In essence, Sunrise is the perfect project for Sempra Corporation; and the worst one conceivable for ratepayers and taxpayers in California. The immense market power that Sempra could derive from Sunrise has the ability to destabilize the electrical generation market throughout the southwest, if not the entire western half of the US.

<u>Winners and Losers</u>

And what's wrong with cheap power? In this case, nearly every aspect of the Sunrise Powerlink as proposed. The "cheap" comes at a very high price. The first casualty is innovation by competitors. Power that is cheaper to buy than produce removes any incentive for entrepreneurial in-basin energy conservation or generation. The allure of having "green power" only exists when there are comparable economies of use. These renewable markets will never be developed in a market where electrical power is cheaper to buy than produce. Sempra's overwhelming market efficiencies via foreign fossil fuel consumption transmitted over Sunrise powerlink will effectively kill attempts at commercial scale power generation.

Energy that is so cheaply produced allows Sempra enormous opportunity on the wholesale side of generation. The use of Malaysian LNG (which in many instances previously didn't have a value, being flared off of oil wells) creates a fuel source far cheaper than domestic natural gas or any form of fuel oil, domestic or imported. Once in operation, with all systems synchronized, Sempra may find that its costs are so low that it effectively could underbid any competitor, and do so with impunity.

Once established, with that dominance Sempra could effectively control the wholesale electrical market through its bids for generation. From that price floor Sempra could choose to make immediate but lower profit on high generation volume or far higher profits margins on less generation – at the whim of management or the demands of Wall Street. What Sempra has accomplished is actually electrical generation outsourcing. Sempra has achieved power outsourcing in Mexico through political skills, and a lack of international regulatory interference from the state or federal levels.

<u>Single Source Energy?</u>

Here is the point that "cheap" could be transformed into a very high price to pay in the form of monopoly. It occurs when the leading power distributor gains the highest production capacity along with the cheapest energy costs - and there are not emerging markets to distribute the extra capacity. Monopolist scenarios are easy to design, though they differ considerably from the previously regulated utility construct in that there is now an unregulated side to the energy provider. Again, Sempra as an entire entity defies regulation, seemingly following the predictable "race to the bottom" tactics of multi-national companies that engage in outsourcing and doing business beyond U.S. or California regulatory reach in Third World and developing countries.

Should Sempra be allowed to build Powerlink, the "Cheap" in cheap dirty power may not hold true for long, especially in health care costs for residents of Mexicali and Calexico. These impoverished cities have not yet found effective voices to sound out against Sunrise. With two Mexican power plants in full production schedules and no environmental regulation in place to control pollution, the air quality has already been affected. It's easy to see what ten near-term planned plants would do, especially operating under the Mexican government – arguably the most corrupt in the world.

From that regulation standpoint, the only limitations on burning this fossil fuel is the LNG capacity of Sempra's Costa Azul facility. It is not clear what the refilling capacity will be, however Sempra has constructed two additional foundations there for future LNG storage. With those numbers, it is not inconceivable that a total of 22 power plants could cover Mexicali, pumping out energy (and pollution) on a 24-hour per day cycle.

<u>No Deal and Anti-trust</u>

While anti-trust and non-competitive actions are complex topics, the symptoms and results are easy to recognize. Chief among the characteristics of a monopoly are higher prices than other similar markets. This is noted in the San Diego Union Tribune editorial "Power Crossroads" of February 17, 2007 (attached). A second feature commonly associated with monopoly is a trait termed "Refusal to Deal".

A particularly egregious example of "Refusal to Deal" surfaced recently in a public and widely reported event. While copied entirely below, the abbreviated version is that SDG&E's vice president suddenly proclaimed that he didn't have use for extra in-area generating power, even though for more than a year espousing in-area generation had been SDG&E's public relations mantra. While the public has grown accustomed to ever-changing sales spiels by Sempra, we can only request that the CPUC take notice of such anti-competitive actions. Clearly, a lack of competition, especially in a partially de-regulated market, can be anticipated to harm the consumers.

We request that the CPUC explore all facets of anti-trust laws as they relate to regulated markets and the unique structure of SDG&E and its parent Sempra.

We feel that particular attention should be paid to:

- **Monopolization and attempts to monopolize**
- **Anticipating demand growth by building excess capacity**
- **Foreclosing markets to potential or future competitors.**
- **Boycotts or refusals to deal**
- **Price squeezes**
- **Predatory behavior**
- **State action doctrine in California prior and post deregulation**

We also believe it is incumbent to request legal opinions from experts in the prosecution of regulatory antitrust violations. The California Attorney General's office and Department Justice have historically shown a high degree of interest in antitrust prosecutions.

Conclusion

This letter has demonstrated the potential for the creation of a monopoly and possible anti-trust activities by the proponents of the Sunrise Powerlink. We believe it is within the purview, indeed, the responsibility of the CPUC and other regulatory entities to assure that the immense social and environmental harm that might be caused by such actions as could come to be because of the proposed project are not permitted to occur. The public trusts its agencies to consider its well being first and foremost and not inflict on them any project or development that would result in more harm than benefit. We believe the Sunrise Powerlink is a corporate ploy to acquire, through the "back door," one piece at a time, energy power on a scale heretofore not considered possible.

It is BCC's view that the proposed Sunrise Powerlink represents the greatest threat and danger to the people of southern California and the American southwest in general and San Diego County in particular. It is our hope that these comments will trigger some oversight and regulatory action by CPUC in protecting and defending the California public from future predatory energy control.

We respectfully request the CPUC to consider these comments and respond to them in the EIR/EIS for the proposed Sunrise Powerlink portion of Sempra/SDG&E's project(s).

Thank you for the opportunity to comment on this enormously expensive and potentially dangerous project.

Sincerely,

George Courser
BCC Director

Bonnie Gendron
BCC Coordinator

Sunday, January 28, 2007
Last modified Wednesday, January 24, 2007 10:35 PM PST

Power line benefits downsized; project expected to save customers $85 million a year, not $447 million

By: DAVE DOWNEY - Staff Writer
NORTH COUNTY -- A large power line San Diego Gas & Electric Co. wants to string across the backcountry of San Diego and Imperial counties would deliver only a fraction of the savings the utility earlier said it would provide, according to a new report.

When the utility filed its application Aug. 4 with the California Public Utilities Commission seeking the green light to build a $1.3 billion transmission line, SDG&E estimated the project would save California electric ratepayers $447 million a year.
But now, according to a Friday filing with the commission, SDG&E estimates the savings to electric customers around the state would total

$85 million annually over the 40-year life of the project between 2010 and 2050.

SDG&E says the substantial reduction was triggered by miscalculations about the cost of natural gas -- the fuel for many power plants -- and about the efficiency of plants, as well as a wrong assumption that some power plants would switch from natural gas to oil because of oil's lower cost. In California, officials said, oil plants may be fired up only in emergencies.

The reduction follows much suggestion from project opponents in recent months that the utility was exaggerating benefits.

"It's pretty much the opposite of what SDG&E represented a couple of months ago about the economic benefits of the Sunrise power line," said Michael Shames, executive director for the San Diego ratepayer advocacy group Utility Consumers' Action Network.

"It just goes to show how quickly SDG&E's case for its power line is crumbling," Shames said.

Jim Avery, vice president of electric for SDG&E, countered that its case for Sunrise is "not at all" crumbling.

"That's kind of funny, actually," Avery said. "It's just simply not true. When you look at this case in the context of SDG&E customers, the economic benefits are overwhelming."

Avery said the utility is still refining its projections and expects to file in a couple of days another revision that will boost the statewide benefit. Regardless of what the final statewide figure comes to, he said he is sticking by earlier public statements that SDG&E customers collectively would save more than $100 million a year on electric bills if the line is built.

SDG&E's customers include 1.2 million homes and 100,000 businesses in San Diego County and southern Orange County.

The region's electricity supply totals 4,600 megawatts, and that capacity was nearly exceeded on a particularly hot and muggy day last July. The utility says it needs another 1,000 megawatts by 2010 to meet the region's growing demand, and that is how much power Sunrise Powerlink would deliver.

A megawatt is the standard measuring unit for electricity. Most of the time it is enough to keep the lights on in 750 to 1,000 homes, although much more power is needed in summer to keep air conditioners humming.

The Sunrise proposal is for a 150-mile transmission line that would wind its way north and west from El Centro in Imperial County, cross the Anza-Borrego Desert State Park, and slice through Ranchita, Santa Ysabel, Ramona and Rancho Penasquitos on its way to the coast. The system would carry 500-kilovolt and 230-kilovolt wires on giant metal towers as tall as 150 feet, while parts of it would be buried in the ground in residential areas.

Construction would begin in 2008 and wrap up in 2010. But first the utility must obtain permission from the Public Utilities Commission, which is expected to complete an environmental analysis in August and deliver a decision in January 2008.

Besides shoring up a looming shortfall, SDG&E says the project would improve the reliability of San Diego County's power supply by providing another way for electricity to get into the county. Like congested freeways, the existing transmission lines along the coast and Interstate 8 have trouble delivering all the power the region needs at times, SDG&E officials say.

Officials also say that the project would plug San Diego County into an emerging mecca of nonfossil-fuel power in the Salton Sea area, where solar farms and geothermal plants that tap underground geysers are proposed. Like other major utilities in Calfornia, SDG&E is facing a state deadline of providing 20 percent of its power from such sources, called renewable energy, by 2010.

"Keep in mind, it (Sunrise) didn't have to provide economic benefits," Avery said. "All it had to do was improve reliability and provide access to renewables. Even if the economic benefits were zero, the project would still be beneficial."

But as it is, Avery said, the project still would save customers money on their monthly bills.

However, Shames, of the utility consumers organization, said his group's calculations show a move to fill the future gap by building new modern power plants locally would save customers $61 million a year more than Sunrise would.

Avery disagreed. "That is simply comparing apples and oranges," he said.

-- Contact staff writer Dave Downey at (760) 740-5442 or ddowney@nctimes.com.

UNION-TRIBUNE EDITORIAL

Power crossroads

Build generators to avert new crisis

February 16, 2007

Nearly seven years after San Diego County became Ground Zero of California's energy crisis, the region once again faces a real threat of chronic power shortages. It's time to build generating plants.

Demand for electricity is growing faster than expected. People are building bigger homes in hot, inland areas that boost the use of energy-hungry air conditioners. Just last summer, utility engineers scrambled to prevent blackouts when consumption broke records that state planners didn't expect to reach for years.

Meanwhile, key local supplies may soon dry up. The hulking power plants on the coast in Chula Vista and Carlsbad were built more than 40 years ago, and their owners are making plans to tear them down. New generators in Escondido and Otay Mesa will make up for about two-thirds of the resulting loss in output, but they won't cover the inexorable growth in local consumption.

So it's time to build new power plants. This is the proper context to view the little political dustup last week in Santee.

City officials reported some hurt feelings after they opened The San Diego Union-Tribune to learn that Enpex, a Del Mar energy developer, and NRG Energy, the owner of the Carlsbad generators, had formed a partnership to build a power plant at Miramar Marine Corps Air Station, near the base's border with Santee.

Let's stipulate here that the energy executives involved, Richard Hertzberg of Enpex and Steve Hoffman of NRG, committed a diplomatic foul when they forgot to call Santee Mayor Randy Voepel to introduce themselves and their project. We say this even though this project has been around since 2002, when the Navy signed an option with Enpex. But now it is time to forgive, and banish this talk in Santee of wasting tax dollars to try to block the project.

On paper, a Miramar power plant makes sense for San Diego County. New generators are ultra-clean, energy-efficient and fit into low, unobtrusive profiles compared to the relics along the coast. The Enpex site is close to fuel pipelines, near high-voltage transmission lines and deep within an area of surging demand for power.

And it is inland. The owner of the Chula Vista plant wants to build new generators on the bay, but that is not a good use of waterfront property. That's why NRG says it will eventually redevelop its Carlsbad real estate. Indeed, finding viable sites for power plants is getting more difficult over time, as public, residential and commercial development crowd the county's dwindling industrial land.

Given the stakes, we hope that competitors to Enpex emerge with proposals elsewhere. San Diego Gas & Electric wants to build a $1.3 billion power line through Imperial County to reach distant supplies. Yet planners say the region needs new local power, too.

A real concern is that SDG&E, which buys power for consumers and controls the Escondido and Otay Mesa plants, will dominate the market. If we don't want to keep paying the nation's highest electricity rates, we must make San Diego safe for private-sector competition.

http://www.signonsandiego.com/uniontrib/20070216/news_lz1ed16top.html

SDG&E Spurns South Bay Replacement Power Plant

The local electricity giant says it has no need for power from a proposed power plant on

Chula Vista's bay front, calling its future into question.

By ROB DAVIS Voice Staff Writer

Friday, Jan. 19, 2007 | The aging South Bay Power Plant's future appears to rest in the hands of the Chula Vista City Council, a group that expressed skepticism Thursday at building a replacement plant along the city's bay front, on land being considered for a possible Chargers stadium.

The decision would not only impact the region's future air quality, but could also buoy Chula Vista's negotiations with the Chargers.

It's a decision that San Diego Gas & Electric is heavily influencing.

At a joint four-hour meeting of Chula Vista City Council and the Unified Port of San Diego's commissioners Thursday afternoon, SDG&E's Jim Avery said his company has no need to buy power from the existing South Bay plant nor from a replacement.

That announcement left the plant's opponents giddy and eroded the foundation that LS Power, which operates the South Bay plan, had used to justify building a replacement plant on the waterfront.

LS Power, a private New Jersey-based company, assumed the 706-megawatt plant's lease from Duke Energy in May. The company has planned to replace the South Bay plant with a more efficient 620-megawatt natural-gas-fired plant that would create enough energy to power about 600,000 homes. The replacement would produce energy more efficiently and free up 115 acres of bay-front land for redevelopment.

Opponents argue that the new plant, while more efficient, would pollute nearly as much as the existing plant, which has operated at 30 percent of its capacity the last two years. LS Power has agreed to not exceed the current plant's emissions from 2004-2005.

Before Avery spoke, Kevin Johnson, an LS Power vice president, had said his company was counting on SDG&E to give them a long-term contract, buying 25 to 50 percent of the plant's power. The contract would be a vital part of financing the plant's estimated $400 million cost.

But Avery unequivocally told council members and port commissioners that SDG&E has no plans to buy power from a South Bay replacement. As the South Bay replacement is currently proposed, Avery said, "it does not meet our long-term resource needs." SDG&E does not need local plants that provide the region's base power loads, Avery said.

Even if a delay impacted the construction of the Sunrise Powerlink, a 120-mile transmission line bringing potentially 1,000 megawatts from Imperial County, neither the South Bay plant nor its replacement would be needed, Avery said. SDG&E wants to eliminate the need to use inefficient plants such as the existing facility, he said.

"This is a huge cost to our customers," he said. "It costs our customers hundreds of millions of dollars a year."

The Unified Port of San Diego purchased the South Bay plant and the 160 acres surrounding it in 1999 with the intent of demolishing the plant and opening up western Chula Vista's bay front for redevelopment. But when Chula Vista city officials told the port they wanted to retain the financial boost that came from the power plant's taxes, the port backed off.

The ultimate goal, though, had always been to remove the plant, said Stephen Cushman, a port commissioner.

"My dream was that this plant would come down," Cushman said. "It was not for a second plant. It was to eliminate the plant."

LS Power could build the plant without selling to SDG&E, Johnson said. The power could potentially be sold to the city of Los Angeles, Avery suggested.

But Cushman said he had no interest in a Chula Vista bay-front plant that would not benefit the San Diego region.

"Bluntly," he said, "I don't really care about Los Angeles."

LS Power is seeking a 30-year lease with two five-year options from the port district. While Cushman doesn't support the lease extension, he and Port Commissioner Sylvia Rios said they would follow the desires of Chula Vista City Council.

Two council members -- John McCann and Mayor Cheryl Cox -- said they opposed building a replacement plant.

"I'm struggling with coming up with a rationale for the continued presence of [a power plant] on the bay front," Cox said.

McCann said alternative sites should first be considered. LS Power says the site is ideal because transmission lines and other infrastructure are already in place.

The councilman is also leading the city's efforts to build a new football stadium for the San Diego Chargers. Several sites are in play, both inland and on the bay front, including the power plant site -- if a new one isn't built. Cox, who was elected after negotiations with the football team began, has so far been supportive of the talks.

The existing power plant, which opened in 1960, is located on the waterfront because it requires millions of gallons of seawater to cool its internal processes. Its replacement would not need seawater, which would be a boon for sea life that gets trapped and killed by water intake. Opponents say that affords the perfect opportunity to move the plant out of western Chula Vista.

But opponents were buoyed by Thursday's meeting and SDG&;ampE's announcement. While addressing the joint meeting, Laura Hunter, director of the National City-based Environmental Health Coalition's Clean Bay Campaign, called Avery her "new best friend."

A second joint meeting on the plant's future is planned but has not been scheduled. Chula Vista's council is expected to form a subcommittee to further discuss the plant's future, but no action was taken Thursday.

Please contact Rob Davis directly with your thoughts, ideas, personal stories or tips. Or send a letter to the editor.

Back Country Coalition

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February 24, 2007

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SUBJECT: Sempra/SDG&E Proposed Sunrise Powerlink Project
Response to Second Round of Scoping Meetings and Alternatives

The Back Country Coalition (**BCC**) is an organization of concerned citizens dedicated to the protection of natural, cultural and scenic resources, responsible land use planning and the enhancement of quality of life throughout San Diego County. We have joined with other concerned individuals and groups to help ensure that decisions made for our communities regarding future energy supplies provide for modern, diverse, economical, sustainable and renewable energy generation and those decisions are made in the best interests of all residents and environmental resources.

Proposed Sunrise Powerlink Project

The proposed project is a "150-mile transmission line between the El Centro area of Imperial County and northwestern San Diego County. SDG&E's stated purpose for the project is to bring renewable resources into San Diego County from Imperial County, reduce energy costs in the San Diego area, and to improve electrical reliability for the San Diego area."

We have reviewed the "Notice of Second Round of Scoping Meetings on Alternatives to the Proposed Sunrise Powerlink Project." This letter will address aspects of the proposed Sunrise Powerlink as detailed in the subject document, insofar as current project planning has advanced: Project Objectives, Growth Inducing Impacts, Cumulative Impacts, Alternatives, Central Link Alternatives, Proposed Central East Substation, Biological Impacts, Electromagnetic Field Impacts produced by the Sunrise Powerlink, andSocioeconomic Impacts. Legal considerations, including CEQA/NEPA non-compliance by the proposed project and anti-trust factors are discussed in detail in separate BCC letters to CPUC/BLM dated February 12, 2007 and February 24, 2007, respectively.

Objectives of the Proposed Project

In this section we examine the failure of the Sunrise Powerlink to meet its stated objectives.

1. "Avoid siting the Proposed Project parallel to SWPL for long distances especially avoiding areas with fire history or fire potential."

This objective fails because the project IS sited within areas of both fire history and high fire potential. While desert fires are only somewhat less problematic than those in mountain areas, there is much documentation to support the contention that the proposed project should not traverse areas near San Felipe Valley, Ranchita, Julian, Warner Springs, Mesa Grande, Santa Ysabel or Ramona because of the numerous, massive, well documented, devastating fires that have occurred in those communities in recent years. The extensive 2002 Pines Fire in Julian was due to a <u>fallen electric line</u>, clipped by a helicopter blade.

As recently as last November (see attachment 1, <u>North County Times,</u> 11/30/06, *"Wind whipped brush forcing evacuations"*), a fire burned many acres in Mesa Grande, Santa Ysabel and Ramona. That fire, as well, was caused by a <u>downed electric line</u> in strong Santa Ana winds. Indeed, the writers have noted that the <u>low-flying fire planes could not have been used with the existence of 150-foot electric towers running through the Santa Ysabel Valley, or anywhere in the area.</u> Fire planes are crucial to early containment of wildfires in San Diego's mountains because of the inaccessibility of many areas to other effective fire fighting methods. Without the fire planes to drop fire retardants on rapidly-advancing flames, we could easily have another devastating scenario such as the Cedar Fire of 2003 - the largest wildfire in California's recorded history.

The Cedar Fire of 2003 burned 280,000 acres in San Diego County, cost 17 human lives, destroyed 2400 homes, countless lives of domestic stock and wildlife and destroyed many important recreation areas such as in Cuyamaca Rancho State Park. The importance of maintaining every fire-fighting option available cannot be overemphasized nor can it be discounted in project planning: Fire planes are paramount among those options. The mountains of San Diego County are no place for 150-foot towers that would impede fire-fighting efforts. Indeed, fire fighters will not approach within 1,000 feet of high voltage electric lines, which also inhibits fire fighting and rescue efforts. <u>The EIR/EIS must show how many homes would be inaccessible to evacuation assistance or fire fighting efforts because of their proximity to the proposed towers in the Sunrise Powerlink portion of Sempra's energy project. How many human lives would be at risk because of the impairment of fire fighting efforts caused by the proposed project?</u>

This additional risk to human lives is quantifiable data that must be analyzed and presented in the EIR/EIS, along with an evaluation of the properties now placed at risk of destruction, threatened by firefighters' inability to access the property. The reality of increased insurance rates, or the denial of any insurance coverage imposed by the presence of high voltage transmission lines must also be thoroughly addressed. Property in high-risk fire areas is reduced to no value if insurance coverage is denied, or the price of insurance premiums renders the property uneconomic to the majority of potential buyers.

This proposed project's alignment and substation siting in the areas listed above, where there are frequent very strong Santa Ana winds during many months of every year, sometimes with gusts of up to 100 mph, dry brush throughout most of the year, and nearby residences, create risks that cannot be ignored. <u>This objective clearly fails to meet the goal of safety to human lives by siting major portions of the Sunrise Powerlink in extremely dry, highly-flammable areas of the county.</u>

<u>We expect the EIR/EIS to address how the proposed project will eliminate these risks, because anything less than total elimination of wildfire risk caused by the proposed project is unacceptable given the already-volatile nature of the areas of the preferred alignments in high risk wildlife urban interface zones.</u>

2. This objective describes the need to provide transmission facilities that allow for system expandability for short-term (2010) and long-term (2015 and beyond) load growth through San Diego and to <u>support regional expansion of the electric grid.</u> (underline ours)

The "support of regional expansion of the electric grid" would certainly be possible with the construction and implementation of the Sunrise Powerlink through the Central East Substation with its 500kV capacity, much more than is necessary for San Diego's short- or long-term needs, given the other energy generation/transmission options described in this letter. This "objective" validates the assertion that Sempra/SDG&E's master project is to extend the Sunrise Powerlink beyond the limits of San Diego County. The more-capacity-than-required-for-San Diego's needs Central East Substation proximity to the northern boundary of the county clearly indicates the direction the next phase of the master project would take.

This objective assumes and implies that there are no options other than the proposed project to provide "voltage level and transfer capabilities" as well as "regional expansion of the electric grid." According to a report by Bill Powers, P.E. of the Border Power Plant Working Group , "There are a number of low impact/no impact transmission upgrade or expansion options proposed by SDGE that the company is now ignoring in favor of Sunrise Powerlink." (a copy of Powers' report, "Regional Power Needs, Sunrise Powerlink, and Alternatives" dated February 5, 2006, was attached to BCC's February 12, 2007 letter to CPUC and BLM regarding CEQA issues and is incorporated herein in its entirety by reference, including all attachments).

We expect to see the other options described in the forthcoming EIR/EIS for the proposed project. Inasmuch as there are other, superior options, we do not believe this "objective" is relevant.

It must be noted that Aspen and Sempra have dismissed numerous superior alternatives from consideration of the CPUC. These consultant and proponent predisposition actions effectively remove these superior alternatives from Commission and public discussion - and thereby any meaningful consideration by the affected ratepayers. Determinations of superiority of alternatives by Aspen Environmental and SDG&E are blatantly self-serving, with high likelihood of being antithetical to the very workings of the Commission and its commitment to the public good and trust. Basing the suitability of alternatives on the profit demands of a family of proponents is at face value an absurdity when considering public benefit.

SDG&E 's involvement with selection of superior alternatives is by nature a conflict, and in reality a severe impediment to public benefit. To have this project's huge cost underwritten with ratepayer funding serves only to compound the blatant conflicts – and potential financial bonanza – that awaits Sempra companies by playing both sides of the border with an unregulated multi-national controlling a partially regulated public utility "growing the business" at the public trough. This issue is discussed more thoroughly in BCC's February 24, 2007 letter to CPUC and BLM regarding "Regulatory Oversight" of energy regulation in general and the Sunrise Powerlink project in particular.

3. "Provide transmission capability for Imperial Valley renewable resources for SDG&E customers to assist in meeting or exceeding California's 20% renewable energy source mandate by 2010 and the Governor's proposed goal of 33% by 2020."

Again from Bill Powers' report posted on his web site www.borderpowerplants.org, : **"SDGE to CPUC in 12-14-05 Sunrise Application: p-36, "The 20% renewable goal in 2010 can be met with imports 'even if the Sunrise Powerlink were not built.'"** (emphasis added)

Has SDG&E begun the application process for renewable energy production in Imperial Valley? If the answer is "no," then this objective merely provides an attractive spin, or another bogus reason for supposedly "needing" the proposed project.

We would like to review Sempra/SDG&E's proposals for achieving the San Diego Regional Energy Strategy 2030 (SDRES) Goal 2, and Goals 3A and 3B in the EIR/EIS now in preparation for the Sunrise Powerlink and how they compare to other plans. The relevant SDRES goals are as follows:

• Goal 2: Achieve and maintain capacity to generate 65% of summer peak demand with in-county generation by 2010 and 75% by 2020.

• Goal 3A: Increase the total electricity supply from renewable resources to 15% by 2010 (~740 MW), 25% by 2020 (~1,520 MW) and 40% by 2030 (~2,965) MW).

• Goal 3B: Of these renewable resources, achieve 50% of total renewable resources from resources located within the County (~370 MW by 2010, ~760 MW by 2020, and ~1,483 MW by 2030).

We, and many others, do not believe that the Sunrise Powerlink is necessary to accomplish the increase in renewable energy from Imperial Valley as claimed by Sempra/SDG&E Upgrades to existing lines as outlined in the CAISO Southwest Transmission Expansion plan and the Green Path Transmission plan would move Imperial Valley renewables to the coast via Los Angeles Department of Water & Power, as detailed in Bill Powers' report of February 2006.

San Diego County Second District Supervisor Dianne Jacob stated in a speech to the CPUC in Ramona on January 31, 2006: "SDG&E says the new line will support renewable power from Imperial County. With the exception of one solar project, SDG&E has not been forthcoming about its efforts to secure renewable sources from that area. Further, experts say a 500 kV line far exceeds the capacity appropriate for renewable transmission and is designed for energy produced from fossil fuels."

"Many point to Sempra Energy's 600 megawatt plant in Mexicali and see the proposed line as a veiled attempt to profit from cheap Baja power by selling it to customers north of SDG&E's service territory." (emphasis ours)

BCC agrees with Supervisor Jacob's assessment. We, too, believe the claim to need the proposed project to move renewables from the Imperial Valley is blatantly false and lacks the faintest semblance of credibility. With all the money (ratepayers') being spent on this project, one would think more imagination could have been brought to selling the public on the pretense of needing the proposed Sunrise Powerlink to move renewables.

4. It is interesting that Sempra/SDG&E is claiming to "reduce the above-market costs associated with maintaining reliability in the San Diego area" when the $1.4 billion cost of the proposed project, not to mention the studies and the environmental document, are being borne by California ratepayers, many of whom are also Sempra/SDG&E ratepayers. If the TRUE cost of the proposed project, including those costs to ratepayers for eminent domain procurement and legal proceedings, construction and maintenance of all aspects of the Sunrise Powerlink were

amortized into a per-ratepayer analysis, there doubtless would be no savings but a huge defiicit. We know from experience of the not-too-distant past who pays for utility deficits in California, and it is not utility executives and shareholders.

The so-called "reduction" of costs is based on present costs being inflated because Sempra, under a "$7 billion, 10-year contract" signed by Gray Davis, is **"artificially causing congestion that SDGE says it will relieve by building Sunrise Powerlink."** (Powers report)

Moreover, Utilities Consumer Action Network (UCAN) and other organizations have revealed the exaggeration of monetary benefits to San Diego ratepayers by Sempra/SDG&E: "Shames, of the utility consumers organization, said his group's calculations show a move to fill the future gap by building new modern power plants locally would save customers $61 million a year more than Sunrise would." And, ". . .according to a Friday filing with the commission, SDG&E estimates the savings to electric customers around the state would total $85 million annually over the 40-year life of the project between 2010 and 2050" rather than the $440 million initially claimed by Sempra/SDG&E." (<u>North County Times</u>- 1/07)

Inasmuch as the estimates for cost savings and reliability appear to be changing, and not in favor of the proposed project, it is highly likely that this objective also cannot be met by any honest evaluation.

In addition, it is disingenuous of Sempra/SDG&E to characterize the South Bay and Encina Power Plants as "inefficient" at the same time it refuses to purchase power from an upgraded South Bay plant. (U-T 1.20.07 - "<u>SDG&E won't buy power from new plant</u>.") It has been widely observed that <u>Sempra/SDG&E is creating a problem so it can solve it with the proposed project.</u> It is worth repeating the San Diego 2030 Regional Energy Plan's Goal 2: "generate 65% of peak demand with **in-county generation** by 2010, 75% by 2030, **with priority to replacement of South Bay and Encina power plants."** (emphasis added)

It would be most beneficial to have CPUC or another <u>qualified</u> <u>independent, objective</u> agency review the proposed project's claims for cost benefit and reliability compared with other proposed scenarios and provide an accurate, objective analysis for review and comment in the forthcoming EIR/EIS. Clearly, it is foolhardy to rely on the applicant to provide complete, unbiased and balanced information regarding its proposed Sunrise Powerlink project.

5. "Improve regional transmission system infrastructure to provide for the delivery of adequate, reliable and reasonably priced energy supplies and to implement the transmission elements of state and local energy plans."

This "objective" implies that only the proposed project can provide results as outlined, however, other people and organizations disagree, as related in the quote by Michael Shames in a previous paragraph of this communication.

Additionally, Bill Powers states in his February 5, 2006 report that the "Garamendi Principle" . . . "Transmission Siting SB 2431 (Garamendi), Chapter 1457, 62, Statutes of 1988" calls for:

"1. Encourage the use of existing rights-of-way (ROW) by upgrading existing transmission facilities where technically and economically feasible.

2. When construction of new transmission lines is required, encourage expansion of existing ROW, when technically and economically feasible.

3. Provide for the creation of new ROW when justified by environmental, technical or economic reasons defined by the appropriate licensing agency."

Also from the Powers report: "Direct testimony of David Korinek, SDGE Transmission Planning Manager, April 15, 2003, California Public Utilities Commission proceeding R.01-10-024:

Is Sunrise Powerlink Only/Best Option? No.

Map source: SDGE Transmission Comparison Study Status Report, December 2004
Repowering 700 MW South Bay Power Plant extends until at least 2015 any import need."

It is easy to see how this project objective seemingly can be met by relying solely on information provided by the project applicant. However, if reliably independent analyses and information were to be provided, the objective would no doubt fail.

Moreover, recent CPUC approval of the Palo Verde-Devers No. 2 high-voltage transmission line to deliver 1,200 MW capacity into Southern California (attachment 2, "Energy Prospects," 2/07), and the promising Enpex-NRG Energy proposed for the Miramar Marine Corps Air Station to produce 750 MW within San Diego (attachment 3, <u>San Diego Union-Tribune</u>, *"Miramar plant plan receives support"*) combine to obviate the "need" for the Sunrise Powerlink.

<u>We expect to review factual information derived from a qualified, independent source in the EIR/EIS to reach an objective informed conclusion regarding San Diego's "need" for the proposed project and how it compares to that "need" when other recommended energy generation projects for San Diego County are factored into the equation.</u>

6. "Obtain electricity generated by diverse fuel sources and decrease the dependence on increasingly scarce and costly natural gas."

We find this statement amazing because of Sempra's ongoing construction of the liquid natural gas plant in Costa Azul in Baja, Mexico, with an estimated start-up in 2008, plans for facility expansion and a pipeline running to its electricity-generating plant in Mexicali, conveniently poised to import the product of the "costly natural gas" into the U.S. and throughout western states. We assume the high cost of LNG would be offset by the lack of environmental standards and requirements, the lower maintenance and labor costs of Sempra's various Mexican facilities.

According to the above-referenced Powers report, Sempra has refused to re-negotiate the 10-year contract by Gray Davis signed in 2001 which allows Sempra to determine which plants will provide power: "(. . .rate payers buy fuel for Sempra).

- Contract allows Sempra to determine which plants will provide power
- Sempra choosing to provide power from Mexicali and Arizona plants over SDGE lines.
- Sempra gets paid to not congest SDGE lines. Rate payers pay.
- Sempra has opposed having SCE contract transferred to SDGE, which would greatly reduce congestion."

Because Sempra is already selling power from the Mexicali plant, it is reasonable to assume the practice would continue and expand with and through the implementation of the Sunrise Powerlink.

7. "Avoid to the extent feasible, the taking and relocation of homes, businesses or industries, in the siting of the transmission line, substation and associated facilities."

This most commendable "sounds good" objective relies on the assumption that the proposed project is necessary and would be approved. We believe that many behind-closed-doors meetings with public officials have taken place in an effort to ensure approval. This objective, however, while looking good on paper, is simply filler public relations material and its ostensible public benefit reduced significantly by "to the extent feasible" clause. Eminent domain proceedings would not reduce the profit margin for Sempra/SDG&E, because ratepayers have to shoulder that burden as well.

8. "Minimize the need for new or expanded transmission line ROW [right-of-way] in urban or suburban areas of the SDG&E service territory already traversed by multiple high voltage transmission facilities and, to the extent feasible, assist in implementing local land use goals. . ."

Because of the "Garamendi Principle" detailed above, and other upcoming local power projects described in subsequent paragraphs, that prove there is no "need" for the Sunrise Powerlink, there is therefore no need to "minimize. . .new or expanded transmission line ROW, etc."

The fact that so many San Diego citizens and communities are uniting in ever-increasing numbers in opposition to the proposed Sunrise Powerlink indicates that local land use goals and community needs are **not** being considered.

The San Diego County's General Plan 2020 Plan is not yet completed, and we defer comments regarding the impacts of the proposed project to that Plan to their expertise. We do believe that **Growth Inducing Impacts** caused by the Sunrise Powerlink must be addressed in the EIR/EIS, because the magnitude of that proposed project is far greater than San Diego's short- or long-term needs. Placing new, surplus electrical availability within rural areas would lead to new growth that is not currently being planned for our back country communities and is not in accordance with the General Plan 2020 goals.

Cumulative Impacts to traffic, schools, agricultural resources, scenic and biological resources, increased risk of fires and impacts to services as well as all other environmental and socioeconomic considerations must also be addressed in the EIR/EIS as a result of the additional growth caused by the Sunrise Powerlink.

Moreover, according to Dianne Jacob, San Diego County Supervisor, District 2, the district which would be the most stricken victim of the proposed project, stated in a speech to the CPUC in Ramona on January 31, 2006: "The people who live in the Second Supervisorial district *already* have an east-west 500 kV line traversing their backyards. To saddle them with a second line is inequitable and unfair. . .and especially if SDG&E has other options for reliability.

There are far less costly and less obtrusive options to this gigantic proposal!" BCC agrees.

The three additional basic project objectives identified by the CPUC and BLM (page 7 of the subject document) are analyzed in the following paragraphs:

- **Basic Project Objective 1: to maintain reliability in the delivery of power to the San Diego region.**

As has been demonstrated in the preceding paragraphs of this letter, the proposed project is NOT NECESSARY to meeting this objective. There are better ways to maintain reliable power in the San Diego region: upgrading existing facilities, upgrading and authorizing new local power generating facilities and generation of renewable energy resources, which do not require the Sunrise Powerlink to facilitate them. The project applicant has paid a great amount of attention and made claims of needing the project to attain renewable goals, but has apparently taken no steps in the direction of achieving it as a goal, that is, applying to the CPUC to begin work on creating them. Please see our comments under Objective 3 in preceding paragraphs.

- **Basic Project Objective 2:` to reduce the cost of energy in the region.**

It has been shown in preceding paragraphs that the cost of energy in the region has been kept artificially high by Sempra's refusal to renegotiate a lucrative contract whereby rate payers buy fuel for that corporation, Sempra is compensated for artificial congestion and rate payers are now expected to pay $1.4 billion for the proposed project to relieve problems Sempra has artificially caused (Powers report). This false economy is being exposed and the claim for cost reduction has been analyzed as being far less than heralded.

- **Basic Project Objective 3: to accommodate the delivery of renewable energy from geothermal and solar resources in the Imperial Valley and wind and other sources in or outside of San Diego County.**

The San Diego 2030 Regional Energy Strategy's vision for "Local Control, Local Benefits" is at odds with Sempra's plan for outside of San Diego County renewable energy sources as detailed in preceding paragraphs. This is underscored by the fact that no application has yet been made to CPUC for such renewables. Also, the proposed project is not needed to deliver those renewables to greater San Diego County, as detailed in Bill Powers' report referenced above.

It is our belief, which is shared by many other project opponents, that the proposed project would actually <u>guarantee</u> renewables are never implemented in San Diego County, because they would not enhance Sempra/SDG&E's financial bottom line. The continuation of importing cheap, dirty energy from Mexico would preclude the development of more expensive than Sempra's, but environmentally friendly renewable energy sources. That, in our opinion, explains why the project applicant has been less than forthcoming regarding its role in developing renewable resources for our region: **there is no intention to develop them in the first place.**

<u>Conclusion on Objectives</u>

Because the proposed project objectives as described in the Scoping Report II are based on clearly faulty premises, present inherently unsubstantiated claims and lack factual validation, it could easily be claimed or determined by the energy utility/proposed project applicant that almost any alignment, alternative or system alternative would "accomplish most of the basic project objectives."

BCC has shown herein that the proposed project fails to meet each of its stated objectives.

Alternatives

We have chosen to forgo commenting on "alternative feasibility" inasmuch as one of the main criteria for acceptance is that the alternative "still [meet] most of the project objectives." We have demonstrated that none of the overall project objectives can be met by the proposed project, therefore feasibility is not an issue.

To engage in selecting alternatives might be perceived as tacit approval by the reviewer that the proposed project is necessary or conceived with the public good as the primary consideration of the public utility. Such selection might create the perception that BCC and others would entertain approval of the proposed project if a particular alignment were not included in the overall scheme or were somehow reduced in scope or impact. <u>We do not approve of any aspect of the proposed Sunrise Powerlink segment of Sempra Energy's overall southern California-wide project.</u>

We have demonstrated in this letter that the proposed Sunrise Powerlink is a corporate scheme to deliver cheap, old fashioned, dirty energy throughout San Diego County and beyond, at the expense of ratepayers and a plan, the San Diego Regional Energy Strategy 2030, of which the project proponent and applicant is a signatory. Clearly, the parent company, Sempra Energy/Global et al, has influenced the previous planning of San Diego Gas and Electric for the benefit of enhancing its bottom line and not "to keep the lights on in San Diego" as is so often disingenuously and craftily claimed as a fear tactic to win public approval and deflect attention or somehow attempt to justify the horrific impacts the project would cause.

Nevertheless, we are gathering relevant information on the Central Link Alternatives, any of which would significantly and negatively impact the Santa Ysabel Valley and its watershed area. Our comments herein will focus on that alignment, not as a tacit approval of any aspect of the project, but simply to reveal the devastating and irreversible social and environmental impacts the proposed project, if approved and implemented, would create in just one area of the 150-mile planned alignment.

We believe the **Non-Wires Alternatives** are the only acceptable alternatives because the environmental impacts of any future energy action with any or all of them would not be as horrendously, pervasively and unnecessarily damaging to communities or environmental resources as the proposed Sunrise Powerlink would be.

- **New In-Area Renewable Generation** meets the SDRES 2030 goals and the State of California's renewable mandates (or "suggestions" as has been alleged by many) and are the least environmentally impacting alternatives.

- **New In-Area All-Source Generation** would build local reliability of future energy needs to the Renewable Generation Alternative. It would have the added benefit to local generation stations such as "the South Bay Replacement Project" from which a SDG&E vice-president recently stated it would not purchase power (referenced above).

- **Resource Bundles 1 & 2** are also consistent with the SDRES 2030, to keep energy sources local, as well as with CPUC demand response goals.

- **In-Area Generation Plus Transmission Upgrades** should not be eliminated, because as demonstrated in preceding paragraphs, it is our opinion that the Sunrise Powerlink's function to provide renewable project objectives would never occur with the Sunrise Powerlink implementation. The renewable resources would be too expensive compared with the cheap, dirty power provided from Sempra's Mexicali plants. <u>The Sunrise Powerlink's "need" likewise has been demonstrated to be based on false information and bogus congestion created by Sempra/SDG&E to justify this project as well as to facilitate designation of a federal energy corridor for Sempra's master project to be the sole energy provider for most of the southwestern United States.</u> (attachment 4, <u>North County Times</u>, *"Federal agency to designate national power line corridors,"* 8/06; *"Naming of national power corridor delayed,"* 12.06)

Indeed, the scenarios on page 10 of the subject document describe three possible consequences that may occur if the No Project/No Action Alternative were selected and the proposed project disapproved. Any and/or all of the three consequential actions would be preferable to the county-wide community and environmental degradation that would occur with approval and implementation of the proposed Sunrise Powerlink. In fact, they are in perfect consonance with the In-Area Non-Wires Alternatives mentioned in the preceding paragraph. The "consequences" of the No Project/No Action Alternative are as follows:

- **Increased Dependence on Generation in San Diego.** Reliance on local energy generation is what the San Diego Regional Energy Strategy 2030 signatories, including Sempra/SDG&E, agreed was best for the energy needs of the San Diego region. (**Vision: Local Control, Local Benefits**).

- **Accelerated Development of Other Major Transmission Projects or Upgrades.** We believe this is preferable to the enormous $1.4 billion ratepayer subsidized proposed project that would result in such horrendous environmental and social damage throughout the county simply to benefit Sempra/SDG&E's corporate growth schemes. Smaller, local, less impactive, and renewable energy generation sources are exactly what should be planned for San Diego's regional future energy needs.

- **Accelerated Development of New Generation in San Diego.** This scenario is also a benefit to the ratepayers and ratepayers of San Diego (and of California since ratepayers outside of San Diego County also would be footing the bill for the proposed project). This would accelerate the development of renewables that otherwise could not compete with Sempra/SDG&E's environmentally destructive 155-170-foot towers carved through our wilderness, parks, nature preserves communities and suburban towns simply to allow one corporation to control dirty energy generation to the entire southwestern United States.

The five scenarios listed in **"Table 2. Foreseeable Development Under No Project Alternative"** are infinitely preferable to the proposed Sunrise Powerlink project. Again, it is in consonance with the county's General Plan and the San Diego Regional Energy Strategy 2030. Indeed, the **"New In-Area Thermal Power Plants: Repower South Bay or Encina or new San Diego Community Power Project"** scenario supports what Sempra/SDG&E has recently stated it would not do, resulting in seeming to create a "need" it can fulfill with the unnecessary proposed SP project. (San Diego Union-Tribune 1.20.07 "*SDG&E won't buy power from new plant*," attachment 4)

Central Link Alternatives

Even though BCC most strongly recommends the "Non-Wires Alternative", we believe that highlighting the enormous impacts of just one link of the project as proposed is important to emphasize the reasons for our opposition to the entire project.

- **Santa Ysabel Existing ROW Alternative:** This discussion claims that this alternative was retained because "it would reduce visibility of the new 230 kV lines through Santa Ysabel Valley by locating the 230 kV line along the base of the hills on the east side of the valley, parallel to the existing 69 kV line and because it would reduce agricultural impacts. Locating the new line closer to SR79 may reduce fire risk in comparison to Proposed Project."

We hope that the EIR/EIS will present REALISTIC visual simulation graphics of the area showing how the proposed towers will appear in reality. We believe the visual impacts will be horrendous wherever the lines are placed, especially in scenic parks, preserves, mountains and valleys of San Diego's back country. (BCC believes the fake visuals presented at the February 8, 2007 Anza-Borrego Desert State Park hearing that depicted towers to be about one-tenth the size and configuration they would appear in reality are **not** a good-faith attempt to present true impacts and offer adequate mitigation. Indeed, it highlights the continuous and pervasively disingenuous stance of Sempra/SDG&E to present to the public and decision makers false information in order to disguise the extent and reality of the environmental impacts the Sunrise Powerlink would actually create).

Placing high tension wires anywhere in this area, with the frequent very high, almost-hurricane force winds coupled with very dry brush is simply a formula to guarantee wildfires in the area. Please refer to our comments in the previous Objectives section of this letter.

- **Santa Ysabel Partial Underground Alternative:** BCC appreciates the nice tone of this Alternative, however, it is merely a public relations ploy and not a possibility. At the Anza-Borrego Desert State Park de-designation hearing on February 8, 2007, SDG&E's representative, Jim Avery, stated unequivocally that no undergrounding of 500 kV power lines could or would be done in an earthquake fault zone. Attachment 5 from the *"Final Report - Application of Skylab and ERTS Imagery to fault Tectonics and Earthquake Hazards of Peninsular Ranges, Southwestern California"* dated July 1975, prepared by California Earth Science Corporation, clearly shows that the Santa Ysabel Valley is surrounded by the Elsinore Fault and the San Diego Fault. There are many linear, smaller fault lines occurring around the valley emanating from them and the San Andreas Fault. In fact, the entire length of the Sunrise Powerlink alignment from Lake Henshaw to the U.S./Mexican border is underlain with faults and linears, as depicted in the attachment to this letter referenced above. With this extensive faulting in the Santa Ysabel Valley, undergrounding 250kV lines would also not be a realisitic alternative.

We expect to review comprehensive information regarding the Elsinore Fault, adjacent faults and linears throughout the length of the Sunrise Powerlink and how the proposed project would prevent catastrophic collapses of the 150-170-foot electric towers or their wires carrying up to 500 kV of electricity as a result of seismic activity along these active faults in the likely chance that a major (or minor) seismic event should occur.

With the extreme fire hazard throughout the back country of San Diego County, constructing high tension wires along seismically active fault lines presents an additional factor that amplifies the magnitude of risk of another devastating wildfire with the approval and implementation of the proposed project. <u>We assume that Sempra/SDG&E, forewarned of these newly imposed dangers to San Diego County residents, would assume all liability for wildfires caused by their hazardous electric wires if the Sunrise Powerlink were to be approved and implemented.</u>

Proposed Central East Substation

At the February 8, 2007 CPUC/BLM hearing at the Borrego Springs Resort, Susan Lee of the Aspen Environmental Group stated that the proposed Central East Substation would require about 100 acres of grading because of the steep slopes on which it would be built. <u>That is almost one square mile of grading, carved out of a mountainside to accommodate this substation which is larger than necessary for San Diego's needs.</u> We have demonstrated how this 500 kV substation could be planned to facilitate more towers heading north for Sempra Energy to complete the overall master project of providing cheap, dirty power from its Mexicali plant through Imperial and San Diego counties into the Los Angeles region, because only 250 kV would run south from it through the Santa Ysabel Valley to the coast.

Carving one square mile out of any of San Diego's beautiful mountainsides to create profits for an international corporation is unconscionable and completely unacceptable. We normally would request adequate mitigation measures in the EIR/EIS for environmental impacts, however, the impacts of this proposed substation ALONE are completely unmitigable.

Socioeconomic Impacts

The communities of Ramona, SantaYsabel and Julian depend on tourism for much of their income. Most of the merchants in Santa Ysabel and Julian are very dependent on the many people who flock by the hundreds and thousands every weekend to these small, rural towns. Since the 2003 Cedar Fire and the decimation of the Cuyamaca Rancho State Park, more and more tourists travel through Ramona and Santa Ysabel Valley to enjoy the recreational driving, hiking, spiritual renewal, shopping, dining, camping, scenic wilderness areas and rural vistas unpolluted for the most part by scars of human habitation throughout the mountains and valleys. Manmade changes to date actually enhance the bucolic vistas in most cases, unlike the irreparable, extensive scars that would be caused by massive grading, road building, and 150-foot electric erector-set style towers involved with the Sunrise Powerlink footprint. The appeal of Santa Ysabel and Julian for many of these urban and suburban dwellers would be enormously diminished if they were confronted by huge,ugly towers marching across the landscape of San Diego's pristine back country.

The EIR/EIS must accurately determine, study, assess and report the loss of business to the merchants in the above mentioned communities by the implementation of the proposed project. What mitigation would be offered to the merchants to remedy the income losses to those individuals and communities over a reasonable period of time, such as ten years?

Biological Impacts

The impacts created by the Sunrise Powerlink would not be confined to the 300-foot "footprint" of the 150-mile power line. The enormous direct destruction of habitat and indirect or secondary impacts to the adjacent Santa Ysabel Preserve, and all other wilderness habitats and preserve and wilderness natural resources along the proposed route, including construction and maintenance roads, construction of the towers and impacts caused by their maintenance and the use of herbicides for control of plant growth around the towers. What precautions would be taken to prevent "overspray" from contaminating and decimating the natural habitats and ecosystems adjacent to the towers, including impacts to humans, crops, domestic animals and wildlife?

The "*Baseline Biodiversity Survey for the Santa Ysabel Ranch Open Space Preserve*" USGS Technical Report prepared by the U.S. Department of the Interior in 2004, for The Nature Conservancy and San Diego County Department of Parks and Recreation, details the incredibly rich and diverse natural resources that exist in the Santa Ysabel area, not only in the Preserve itself. The report is accessible on the internet and is incorporated herein in its entirety by reference. We recommend that this report be reviewed before completing decisions on the Sunrise Powerlink alignment through the Santa Ysabel Valley.

The Sunrise Powerlink natural habitat impacts by the proposed project are as unacceptable as they is unnecessary. A new, updated, expanded report has been commissioned by BCC from Ms. Virginia Moran and will further document the environmental impacts that project approval would visit on the Santa Ysabel area, just one small portion of the 150-mile proposed alignment carved through one of the most biodiverse system of natural communities in the world.

Biological (as well as Cultural) impacts to the entire proposed preferred 150-mile alignment must be documented in the EIR/EIS for public review and comment.

Electromagnetic Field Impacts

Additional impacts caused by the electromagnetic fields from the proposed power lines must be analyzed in the EIR/EIS for the entire alignment of the Sunrise Powerlink. These impacts include, but are not limited to the effects of:

- increased noise on humans, domestic stock, pets, wildlife and flora in the vicinity of the power lines;
- the increased risk of electrocution of avian life, especially raptors;
- increase in temperatures around the electromagnetic fields for the entire length of

the Sunrise Powerlink, especially in summer months;

- all forms and range of communication interference that could be caused by the power lines of the proposed project;
- increased health hazards to sensitive receptors such as heart patients and other relevant ailments such as increased risk of cancer must be disclosed;
- the action of smoke on the electromagnetic fields and possibility of arcing in smoke as the carbon emanating from burning organic material provides electrical conduction during wildfire events;
- ` the possibility of lines sparking and the increased risk of wildfire created to all of San Diego County by the enormity of this unnecessary project;
- the results that can be anticipated to the power lines by lightning strikes, which often occur in San Diego's mountains, reducing the specious claim of "reliability";
- all the potential risks involved with live high-power lines disengaged from their towers in the event of an earthquake, or airplane or ground vehicle strike to the lines or towers.

BCC will not accept a response to these issues that diminishes the very real risks and dangers from EMF's introduced by the proposed project where they currently do not exist. Please review attachment 6 which includes recent reports on the effects of electromagnetic fields on human and domestic animal health.

Legal Considerations

BCC has written and circulated a letter to CPUC and BLM as lead agencies for the Sunrise Powerlink, dated February 12, 2007, outlining the significant lack of proposed overall environmental project review as required by the California Environmental Quality Act (CEQA). That letter details how Sempra/SDG&E are circumventing environmental review required of their entire planned energy generation and transmission project from Mexico through San Diego and Imperial counties, extending the Sunrise Powerlink segment into Riverside, Orange and Los Angeles counties through the Central East Substation, by piecemealing the many aspects of the overall project, creating many smaller ones. This results in chopping up or segmenting the whole project, including the proposed Sunrise Powerlink portion, denying the public the opportunity to review ALL environmental impacts associated with the project as a whole. Indeed, to comply with CEQA, a Program or Master EIR/EIS must be prepared for the entire planned project, not just the Sunrise Powerlink segment of it.

BCC has also written a letter and timely forwarded a letter this date describing reasons for enhanced "regulatory oversight" of the proposed project by CPUC. We request these issues also be included in the EIR/EIS for the Sunrise Powerlink.

Please note that BCC and other individuals and organizations in San Diego will not accept a "CEQA light" review of the proposed environmental impacts to be imposed on our parks, wilderness lands, preserves and communities. We expect nothing less than full and complete environmental review as required by the letter and spirit of California Environmental Quality Act.

Conclusion

This environmental catastrophe is unacceptable and outrageous. As has been shown in this letter, we believe San Diego county is being used by Sempra and SDG&E; our communities and pristine back country natural, cultural and scenic resources are planned to be sacrificed, trashed so that Sempra might create an unnecessary, unethical, illegal monopoly in the southwestern United States for its private gain.

There is no public benefit that would be great enough to justify any aspect of this dangerous and destructive project. We are being asked to pay an enormous price to facilitate the destruction of our own parks, preserves, mountains, wilderness, deserts, communities for the benefit of Sempra Energy and SDG&E's financial gain. While they may be "public utilities" it cannot be ignored that these utility corporations are in the BUSINESS of generating and transmitting energy, and the very fact that they could spend so much of ratepayer's money just to get this far is a very clear indication that they are not concerned in the least about public well being, producing clean energy or providing the most reasonable and logical in-basin energy through local plants.

We depend on CPUC and BLM for responsible and objective regulatory oversight of proposals of such magnitude and to consider this project very carefully as stewards of the well being of all Californians through provision of our energy needs. We do not believe you could possibly approve a project with as much potential to cause irreparable harm as the Sunrise Powerlink, where no need for it can be proven. The writers' individual 50+ years of living in San Diego County, one being a native San Diegan, we can testify that there has never been a project that proposes such enormous damage claimed to be for public benefit that amounts to none at all, especially when compared with the incalculable, horrific losses we the public would have to suffer permanently.

We respectfully request that you stop the hemmorhage of ratepayers' money on this unnecessary and dangerous business proposition that benefits no one but the corporate executives and shareholders.

We appreciate the opportunity to comment on the proposed Sunrise Powerlink segment of Sempra/SDG&E's master project.

Sincerely,

Bonnie Gendron
BCC Coordinator

George Courser
BCC Director

cc: U.S. Senator Barbara Boxer
U.S. Senator Dianne Feinstein
U.S. Representative Bob Filner
California Governor Arnold Schwarznegger
California Attorney General Edmund G. Brown, Jr.
San Diego County Second District Supervisor Dianne Jacob
San Diego County Third District Supervisor Pam Slater-Price
San Diego Chapter of the Sierra Club
Center for Biological Diversity, San Diego
Mussey Grade Alliance
Communities United for Sensible Power (CUSP)
Interested Parties

Attachment 1

Thursday, November 30, 2006
Last modified Thursday, November 30, 2006 8:28 AM PST

Wind-whipped brush forcing evacuations near Santa Ysabel

By: North County Times -
SANTA YSABEL ---- A fast-moving brush fire whipped by cold, gusty Santa Ana winds forced evacuations this morning in the Sutherland Dam area west of Santa Ysabel in north San Diego County. The blaze near the tiny town at highways 78 and 79 in a rural valley west of Julian had scorched more than 100 acres in less than two hours after it was reported at 5:30 a.m., a California Department of Forestry and Fire Protection spokeswoman said.

By mid-morning, smoke from the blaze was drifting under blue skies farther west through North County.
"It looks like they're getting a good handle on the fire right now," the CDF spokeswoman said at 8:10 a.m. "It looks like we're holding it at the road."

The road was a truck trail between Santa Ysabel and Oak Bridge, according to the California Highway Patrol.

The agency reported that if the fire couldn't be stopped there it could head into the Ramona area.

The CDF spokeswoman said no one had been hurt and evacuations were voluntary after 8 a.m.

Two air tankers, four bulldozers, 10 fire engines, nine hand crews, and four bulldozers were working the blaze as firefighters struggled to surround it earlier.

Chilly winds out of the desert of 20 to 20 mph were spreading the flames westward as officials were asking the public to avoid the area.

The cause of the fire was still under investigation.

Authorities said it started on a hillside about 300 to 400 yards west of Highway 78 and north of Highway 79.

The entire county is under a red flag warning because of critical fire weather conditions until 5 p.m. Sunday.

Authorities said even though the region is coping with a cold snap and despite a mild rain storm early this week, the area is still very dry, humidities are below 15 percent, and the winds will fan any fires.

Attachment 2

http://www.signonsandiego.com/uniontrib/20070208/news_1b8miramar.html

Miramar plant plan receives support

Enpex, NRG Energy to promote project
By Craig D. Rose
STAFF WRITER
February 8, 2007

The long-simmering proposal to build a major electric generating plant at Miramar Marine Corps Air Station has recruited a key partner, one that experts say is likely to improve prospects for the project.

Enpex, a Del Mar company that has held an option to build a power plant on the military base since 2002, and NRG Energy said yesterday that they will team up to promote the project.

Among the key assets NRG brings to the Miramar proposal are air-emission credits, which NRG says it would make available by closing the Encina Power Plant in Carlsbad and transferring the hard-to-obtain credits to the new project at the Marine base.

The Miramar project could provide 750 megawatts – enough to power about 500,000 homes – while the Encina plant has a maximum output of 965 megawatts and typically operates at about 15 percent of capacity.

The new plant would be fueled by natural gas, as are all non-nuclear plants in California. In addition, Enpex and NRG said they would configure the new plant to meet the characteristics of San Diego's anticipated electricity demand, which is expected to require plants with more flexible generating levels than those built in the past.

To build the Miramar plant, however, NRG and Enpex said they probably will need a contract from San Diego Gas & Electric Co. to buy its power, though the promoters added that was not the only option. The partners emphasized that financing the new facility would require a contract in hand from creditworthy customers.

Enpex is a small, 23-year-old company specializing in power projects. The company's largest completed project was a 150-megawatt plant in New Jersey, which it sold to El Paso Energy in 1999.

Richard Hertzberg, the company's chief executive officer, said he was disappointed that the Miramar project wasn't accepted when it was proposed to

SDG&E three years ago, one of a host of proposals submitted in a competitive bidding process.
At that time, SDG&E opted instead to buy the Palomar Energy Center from its parent company, Sempra Energy, and to buy electricity from a second plant planned by Calpine on Otay Mesa.
But SDG&E now plans to open another round of bidding for power projects with a total capacity of about 1,000 megawatts within the next month or so. Hertzberg said the Miramar project will again be submitted, with the addition of NRG as a partner.
“There is a really good fit between NRG and ourselves,” Hertzberg said. “We need the air credits – they are of extreme importance.”
Electric generating plants must obtain permits for their air emissions, which are limited to minimize pollution. To offset pollution from new plants, a power-plant developer must either reduce a like quantity of emissions from other sources or obtain existing emission credits from previously approved projects.
Hertzberg said the proposed plant, which would be on a 60-acre parcel in the far southeastern corner of the Marine base near Santee, is targeted for a site near a key electric substation in the SDG&E system.
Jim Avery, the SDG&E vice president who oversees electricity assets for the utility, said the Enpex project was bypassed in the 2003 procurement because other projects were superior.
But Avery said the Miramar might be more attractive this time.
“All things being equal, yes, a project with with air credits is more credible than one without the credits,” Avery said. He added that selection would still depend on the outcome of a competitive process for selecting new projects.
Avery said San Diego will need additional power plants and new transmission lines to satisfy its expected electricity demand.
Steve Hoffmann, president of NRG's western region, said closing the Carlsbad plant and shifting air credits to a new power plant at Miramar made strong sense to the company.
NRG has concluded that it will be unable to profitably build a power plant at the Carlsbad site, and it has received significant interest in using the parcel for other purposes.
“From a shareholder perspective, the highest and best use of the site is to develop the real estate,” Hoffmann said. NRG, based in Princeton, N.J., owns nearly 50 power plants worldwide, with total capacity of about 25,000 megawatts.
Although SDG&E would be an ideal customer for the Miramar plant's electricity, Hoffmann added that there was interest from other unspecified customers, who are shopping for electricity as a consequence of California's increased requirements for reserve electric generating capacity.
The state raised reserve generating requirements to ensure a reliable electric supply.
Enpex obtained the right to develop 60 acres at Miramar for a power plant in December 2002, when language granting that option was inserted into the 2003 Defense Department appropriations bill by then-Rep. Randy “Duke” Cunningham. The former congressman from San Diego is now serving federal

prison time for conspiracy and tax evasion, after admitting he accepted millions of dollars in bribes.
The Enpex option, which came in the aftermath of California's electricity crisis, allows the secretary of the Navy to transfer the property in exchange for the company's providing the military with family housing in the area.
Hertzberg said there was nothing illegal involved in Cunningham's advocacy of the project and that there was no money transferred to the congressman before the legislation passed.
He said that after passage, he was asked by Cunningham's staff to support a golf tournament that would benefit the congressman's political action committee. Hertzberg said he contributed $1,500.
The revived Miramar proposal comes as SDG&E is scrambling to satisfy what it says is burgeoning power demand in the region. But there is significant controversy over power projects that have been proposed, including SDG&E's plan to build the Sunrise Powerlink, a 150-mile power line across Anza-Borrego Desert State Park, and a proposal to build a new electric generator near the site of the South Bay Power Plant.
Environmental and community groups said they were at least initially interested in the Enpex-NRG proposal.
Laura Hunter, a spokeswoman for the Environmental Health Coalition, which is resisting the plan to build a large plant near South Bay, said the Miramar project was deserving of further consideration.
“That plant would be near the Sycamore substation, and that is where SDG&E says they need electricity,” Hunter said. “But there are still concerns about the impact on residents downwind from any plant.”
Hunter added that global-warming concerns also made it necessary to “find ways to have less natural-gas-fired electricity in our future.”
Jeanette Hartman, who works with People's Powerlink, a group opposing the Sunrise project, said any project that would produce electricity within the San Diego area is worthy of consideration.
“That would be an improvement over building Sunrise,” she said.

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Attachment 3

Federal agency to designate national power line corridors

By: DAVE DOWNEY - Staff Writer
NORTH COUNTY ---- Energy officials are poised to make a move that would allow the federal government to step in and pave the way for a controversial power line to be built across North County.

On Tuesday, U.S. Energy Department officials declared the region encompassing San Diego, Riverside and Los Angeles to be one of two

"critical congestion areas" in the nation's vast network of electrical superhighways and said they intend to designate, by year's end, corridors of "national interest" where new transmission lines would be a priority. A new report released by the agency says the prime candidates for the corridors are Southern California and the heavily populated Atlantic Seaboard between New York and Washington.
The federal plan has huge implications for the proposed $1.3 billion Sunrise Powerlink transmission line that San Diego Gas & Electric Co. wants to build along a 150-mile route stretching from El Centro to Carmel Valley. That's because SDG&E already has petitioned the Energy Department to designate San Diego County as one of those national corridors.

Such a designation would give SDG&E a trump card to play. If a state regulatory agency was to take longer than a year to review its amended application, SDG&E could ask the Federal Energy Regulatory Commission to step in and take over, said Megan Barnett, a spokeswoman with the Energy Department in Washington, D.C.

The utility filed the application Friday with the California Public Utilities Commission.

"It doesn't make the state process moot," Stephanie Donovan, an SDG&E spokeswoman, said of the option to ask the federal commission to step in. "But it might sharpen the state's focus on possible solutions if that energy corridor includes the Sunrise Powerlink."

The proposal has created a fierce battle between SDG&E, which maintains that San Diego County needs the electricity Sunrise Powerlink would deliver, and residents of communities in the path of the line's 160-foot towers who maintain there are less destructive ways to quench the region's growing thirst for power.

Bill Powers, a San Diego engineer and activist who has extensively studied power plants in the region and opposes Sunrise, said a shift of review authority to the Federal Energy Regulatory Commission would greatly increase the chance that Sunrise would be approved because the body is predisposed to approving new transmission lines.

"If anyone has a favorite project that they want to pound through, there has never been a better time to do it because there is a favorable climate in Washington," Powers said.

While the report did not specify where national corridors might be designated, it did say there is a need for transmission lines to move power from the desert Southwest into Southern California ---- one of the things Sunrise would be designed to do.

"The federal government is now clearly pointing to Southern California as a place where there is a need to relieve transmission congestion, to improve reliability, and that the problem is not phantom, it's not fake, it's real," Donovan said. "Congestion is blocking the development of renewable resources and their delivery into Southern California."

She was referring to emerging plans to build power plants in the Salton Sea area to tap the power of the sun and underground geysers ---- plants that could deliver their electricity to San Diego County and points north through Sunrise Powerlink.

Powers, however, sharply disputed the report's conclusion that Southern California is crippled by an inadequate system for producing and delivering electricity. He noted the system managed to hold up during the record heat wave that persisted through July, and he said Southern California Edison is building a 500-kilovolt line from Los Angeles through Palm Springs to western Arizona.

The federal report, 122 pages long, concluded there is a "severe" threat of outages in Southern California and in the East Coast urban area that encompasses New York, Philadelphia, Baltimore and Washington.

However, the report does not list new power lines as the only potential solution. It also states that power plants near major cities would ease the threat.

In addition to the two critical regions, the report listed New England, Phoenix-Tucson, Seattle-Portland and the San Francisco Bay Area as "congestion areas of concern," where the demand for electricity is growing and beginning to tax regional systems for delivering power.

Donovan said Tuesday's development is a welcome sign that the federal government wants to play an active role in upgrading the nation's energy system. For Powers, the development is anything but welcome.

"The federal government is establishing itself as a partisan player who is taking the side of developers and is accelerating the permitting of these facilities rather than being a neutral party," Powers said.

The report, titled the "National Electric Transmission Congestion Study," switches on a two-month public review process that runs through Oct. 10.

The study may be viewed online at www.oe.energy.gov and comments may be submitted to congestionstudy.comments@hq.doe.gov.

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Naming of national power corridor delayed

By: DAVE DOWNEY - Staff Writer
Area residents and utility officials will have to wait until sometime in 2007 to learn whether Southern California will be named an electric transmission corridor of "national interest," a federal official said Tuesday.

Such a designation could make it easier for proponents of a new power line in San Diego County to win approval for the project and make it tougher for opponents to fight it.
San Diego Gas & Electric Co. has proposed a $1.3 billion, 150-mile transmission line stretching from El Centro in Imperial County through Anza-Borrego Desert State Park and Ramona to metro San Diego. Scheduled to be completed by 2010, the line would boost the region's power supply by 20 percent and plug into proposed solar and geothermal farms in the Salton Sea area that tap the power of the sun and geysers.

A report released by the U.S. Department of Energy in August said there was a need for new lines to move electricity from an anticipated mecca of nonfossil-fuel power at the Salton Sea to urban Southern California, including San Diego, Riverside, Orange and Los Angeles counties. At the time, federal officials said they would designate two corridors of national interest somewhere in the United States by the end of this year.

The August report concluded that the biggest holes in the nation's electric transmission system were on the West and East coasts, fueling speculation that Southern California would be designated one of the two national corridors.

However, Poonum Agrawal, project manager on the Department of Energy's electric transmission congestion study, said that more time is needed and that the agency will not make its December target for naming the corridors.

Instead, federal energy officials will propose national transmission corridors of interest sometime in the next few months, Agrawal said by telephone from Washington, D.C.

If federal officials were to name a Southern California corridor that includes San Diego County as a priority for new transmission, it would give SDG&E an alternative path to approval. The utility's $1.3 billion Sunrise Powerlink project is undergoing review by the California Public Utilities Commission, which currently has jurisdiction over the matter and expects to decide whether to grant permission for the line's construction by January 2008.

If San Diego County were a corridor of national interest, the state agency would have one year to make a decision. It is unclear when the clock would start in that case, although a commission spokeswoman has said the timetable likely would be tied to the agency's September declaration that the utility's application was complete.

In any event, after one year SDG&E would have the option of requesting that its application be shifted from state control to federal oversight, Agrawal said. And the Federal Energy Regulatory Commission would take it over.

Power-line opponents sharply oppose including San Diego County in a corridor of national interest.

"There's going to be a lot of push to make sure that Sunrise doesn't get put on that list," said Bill Powers, a San Diego engineer and activist who has extensively studied power plants in the border region and opposes the backcountry transmission line. "It would completely short circuit the California process that we have all invested so much effort in."

Powers suggested the Federal Energy Regulatory Commission would be predisposed to giving the utility the green light.

"The only reason for the feds to do that (take the application over) would be to approve the project," he said.

While Powers acknowledges a need for wires to move power from the Salton Sea to urban Southern California, he said a planned Los Angeles Department of Water and Power transmission line would serve the purpose. He maintains there are other ways to shore up San Diego County's electricity supply.

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Attachment 4

SDG&E won't buy power from new plant

Stance surprises some in South Bay

By Tanya Mannes and Craig D. Rose
UNION-TRIBUNE STAFF WRITERS
January 20, 2007

San Diego Gas & Electric Co. said this week it had no interest in buying electricity from a new generating facility proposed to replace the aging South Bay Power Plant.

While the utility insisted that position wasn't new, it surprised key decision makers involved in planning for new uses of the bayfront site in Chula Vista and prompted criticism that the utility was discouraging projects it does not own or control.

LS Power Generation, which owns the lease on the South Bay Power Plant, is seeking a lease from the San Diego Port Commission for a site just south of the existing plant on which it would build a modern, 620-megawatt power plant with a smaller footprint.

Under the company's plan, the existing plant – which can generate 700 megawatts, or enough to power nearly 500,000 homes – would be demolished.

But at a public forum Thursday, Jim Avery, a senior vice president of SDG&E, disputed the need for replacing the South Bay Power Plant. He said the utility has no plans to purchase power from the proposed plant and that SDG&E is confident it can meet the region's power needs without it.

The San Diego region has a need for peaker power plants, not a larger baseload generator that LS is planning for the site, Avery said.

Peaker plants are designed to operate sporadically to meet periods of extraordinary demand. Using a baseload plant for peak needs, Avery said, would be like using an 18-wheel truck to give someone a ride to church.
“The existing power plant has operated as an inefficient peaking plant,” Avery said at the forum, organized jointly by the Chula Vista City Council and San Diego Port Commission.
“What we need are peaker plants. We don't need baseload plants,” Avery said.
Last year the utility began operation of the Palomar Energy Center, a baseload plant that it owns in Escondido. And it has an option to buy a plant being built on Otay Mesa by Calpine Corp.
In addition, SDG&E is proposing to build and own the Sunrise Powerlink, a $1.4 billion transmission line that would bring electricity into the region from Imperial County.
Nonetheless, David Hicks, a spokesman for LS Power, says the company believes the San Diego region will need more baseload generating plants. He added that the company would press forward with its plans for the new plant.
“If it can provide clean, safe, reliable energy at a competitive price, why wouldn't SDG&E consider it?” Hicks asked.
The forum was called after some Chula Vista city officials objected to the Port Commission's consideration of leasing the bayfront site to LS Power. In response, the port postponed the lease decision, saying it wanted to know the official position of the Chula Vista City Council.
More than 150 people attended the four-hour meeting Thursday at Chula Vista City Hall. The big issues were whether a replacement power plant is needed – and, if so, whether it should be built on the city's valuable bayfront land.
Avery's statements appeared to contradict an earlier statement by LS Power Vice President Kevin Johnson. Johnson, who had described SDG&E as a “customer,” said his company's business plan was based on selling power to the San Diego utility.
Councilman John McCann asked Avery to state definitively whether SDG&E would purchase power from the planned replacement power plant.
“That's a 'no,' ” Avery said. “Our objective is: the day the lease is over, there will be no more need for it.”
He also cited plans for the Otay Metro Powerloop – a new, 52-mile transmission line – saying it would help meet the region's energy needs.
If a replacement power plant is not built, it opens up the possibility of using the Chula Vista bayfront for purposes other than an industrial plant.
McCann said Avery's statement casts doubt on whether LS Power's plan to build a replacement plant is feasible. “The bottom line is, if they don't have the contract, they can't operate the plant,” he said.
Port Commissioner Stephen Cushman said Avery's comments are good news. If SDG&E doesn't need electricity from a replacement plant, and if state electric reliability experts say the existing facility can be phased out, he would like to see the plant dismantled after the current lease expires in 2009.
Councilman Rudy Ramirez said Thursday was the first time he had heard such a strong statement from an SDG&E representative, although he was aware of uncertainty surrounding the plan to sell power.

But Councilman Steve Castaneda, who is designated by the council to deal with energy issues, said SDG&E's statement wasn't a surprise.
“I've known for several months that SDG&E had no plans to buy power from the new LS Power plant, which gave me great concern that the old plant would be up and running for longer than we'd like,” Castaneda said.
Laura Hunter, director of the Environmental Health Coalition, which has called for alternatives to a traditional power plant, said that SDG&E's statement about not needing the power is “something we suspected from our review” but she was glad to hear it said publicly.
An SDG&E critic, meanwhile, said the utility's disinterest in buying power from a modern South Bay power plant amounted to creating a problem “so they can solve it and make a lot of money.”
Harvey Payne, an attorney who is chairman of Rancho Peñasquitos Concerned Citizens, noted that SDG&E's application to state regulators for approval of the 150-mile Sunrise Powerlink assumes that the South Bay plant will be closed.
His group calls the project environmentally damaging and unnecessary. The line would cost $1.4 billion and reach from Imperial County, across Anza-Borrego Dessert State Park, and cut across a broad swath of North County communities.
“I believe we should not retire our in-basin generation and rely on electricity generated hundreds of miles away,” Payne said. “It is smarter to rely on locally generated electricity from modern plants.”
SDG&E maintains that Sunrise is needed primarily to ensure regional electric reliability by giving it the ability to tap generating sources from Imperial County. But Avery denied that SDG&E was seeking to create a need that could be satisfied only through Sunrise.
He added that SDG&E would be seeking proposals for new power plants.
“I want over 1,000 megawatts of new generating capacity – but what I want are all peakers or intermediate plants,” Avery said after the meeting.

TECHNICAL REPORT 75-2

FINAL REPORT

APPLICATION OF SKYLAB AND ERTS IMAGERY TO FAULT TECTONICS AND EARTHQUAKE HAZARDS OF PENINSULAR RANGES, SOUTHWESTERN CALIFORNIA

July 1975

by

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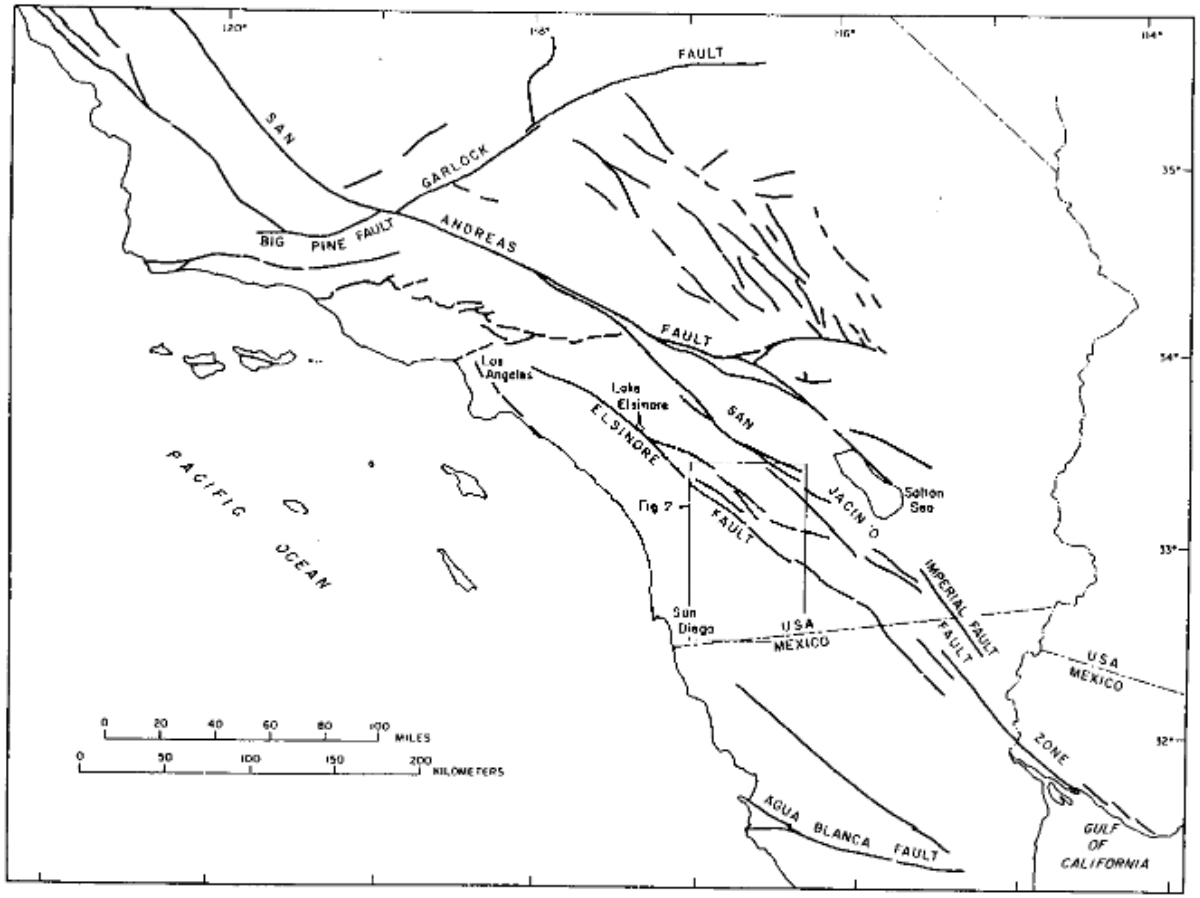

Fig. 1 - Index map showing major faults and area covered by generalized fault and linear map (Fig. 2). Redrawn from Proctor (1973).

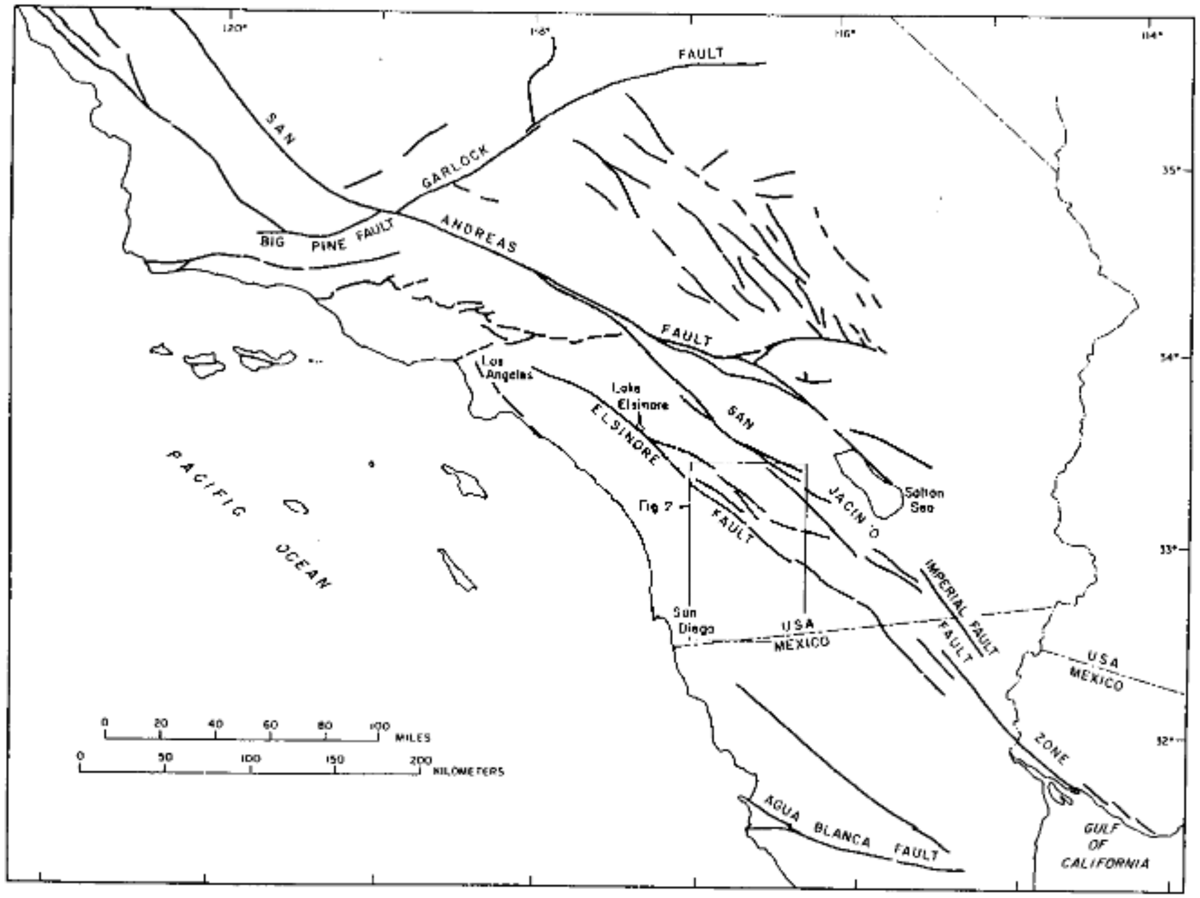

Fig. 1 - Index map showing major faults and area covered by generalized fault and linear map (Fig. 2). Redrawn from Proctor (1973).

Attachment 9

Electronic smog

The curse of the mobile phone age: around your home there are countless gadgets whose electrical fields, scientists now warn, are linked to depression, miscarriage and cancer

By Geoffrey Lean, Environment Editor

Published: 07 May 2006

Invisible "smog", created by the electricity that powers our civilisation, is giving children cancer, causing miscarriages and suicides and making some people allergic to modern life, new scientific evidence reveals.

The evidence - which is being taken seriously by national and international bodies and authorities - suggests that almost everyone is being exposed to a new form of pollution with countless sources in daily use in every home.

Two official Department of Health reports on the smog are to be presented to ministers next month, and the Health Protection Agency (HPA) has recently held the first meeting of an expert group charged with developing advice to the public on the threat.

The UN's World Health Organisation (WHO) calls the electronic smog "one of the most common and fastest growing environmental influences" and stresses that it "takes seriously" concerns about the health effects. It adds that "everyone in the world" is exposed to it and that "levels will continue to increase as technology advances".

Wiring creates electrical fields, one component of the smog, even when nothing is turned on. And all electrical equipment - from TVs to toasters - give off another one, magnetic fields. The fields rapidly decrease with distance but appliances such as hair dryers and electric shavers, used close to the head, can give high exposures. Electric blankets and clock radios near to beds produce even higher doses because people are exposed to them for many hours while sleeping.

Radio frequency fields - yet another component - are emitted by microwave ovens, TV and radio transmitters, mobile phone masts and phones themselves, also used close to the head.

The WHO says that the smog could interfere with the tiny natural electrical currents that help to drive the human body. Nerves relay signals by transmitting

electric impulses, for example, while the use of electrocardiograms testify to the electrical activity of the heart.
Campaigners have long been worried about exposure to fields from lines carried by electric pylons but, until recently, their concerns were dismissed, even ridiculed, by the authorities.

But last year a study by the official National Radiological Protection Board concluded that children living close to the lines are more likely to get leukaemia, and ministers are considering whether to stop any more homes being built near them. The discovery is causing a large-scale reappraisal of the hazards of the smog.

The International Agency for Research on Cancer - part of the WHO and the leading international organisation on the disease - classes the smog as a "possible human carcinogen". And Professor David Carpenter, dean of the School of Public Health at the State University of New York, told The Independent on Sunday last week that it was likely to cause up to 30 per cent of all childhood cancers. A report by the California Health Department concludes that it is also likely to cause adult leukaemia, brain cancers and possibly breast cancer and could be responsible for a 10th of all miscarriages.

Professor Denis Henshaw, professor of human radiation effects at Bristol University, says that "a huge and substantive body of evidence indicates a range of adverse health effects". He estimates that the smog causes some 9,000 cases of depression.

Perhaps strangest of all, there is increasing evidence that the smog causes some people to become allergic to electricity, leading to nausea, pain, dizziness, depression and difficulties in sleeping and concentrating when they use electrical appliances or go near mobile phone masts. Some are so badly affected that they have to change their lifestyles.
While not yet certain how it is caused, both the WHO and the HPA accept that the condition exists, and the UN body estimates that up to three in every 100 people are affected by it.

Case History: 'I felt I was going into meltdown'
Until a year ago, Sarah Dacre reckoned she had a "blessed life". Running her own company, and living in an expensive north London home, the high-earning divorcee described herself as "fab, fit and 40s". Then suddenly the sight in her right eye failed: she first noticed it when she was unable to read an A-Z map. Soon she was getting pains and numbness in her joints. She could not sleep and spent nights "pacing about like a caged lion". Her short-term memory failed and if she took notes to remind her, she would forget she had made them.

The symptoms got worse whenever she was exposed to electricity. She could not use a computer for more than five minutes without becoming nauseous. Even using a telephone landline gave her a buzzing in the ear and made her feel she was "going into meltdown".

* * * * * * * * * *

A Smarter Approach to Resolving Power-Line Noise

Sep 1, 2004 12:00 PM
By Mike Martin, RFI Services; Riley Hollingsworth, FCC; and Jody Boucher, Northeast Utilities

Although the problem has been around since the dawn of radio communications and broadcasting, power-line noise issues are A on the rise. The proliferation of electrical, electronic, mobile and wireless devices — which are susceptible to power-line noise — have contributed to this increase. The law requires utilities to rectify power-line interference, but this does not have to be a budget-breaking experience. By using proper approaches, utilities find that dealing with a power-line noise complaint is seldom time consuming or expensive.

Power-line noise can interfere with radio communications and broadcasting. Essentially, the power lines or associated hardware generate unwanted radio signals that override or compete with desired radio signals. Power-line noise can impact radio and TV reception, including cable TV head-end pick-up and Internet service. Disruption of radio communications, such as amateur radio, can also occur. Loss of critical communications, such as police, fire, military and other similar users of the radio spectrum, can result in even more serious consequences.

Sparking or arcing across power-line related hardware causes virtually all power-line noise that originates from utility equipment. A breakdown and ionization of air occurs, which results in a current flow between two conductors in a gap. The gap may be caused by broken, improperly installed or loose hardware, which causes inadequate hardware spacing, such as the gap between a ground wire and staple.

Should Utilities Be Concerned?

There are obvious reasons why utilities should be concerned and aware of potential issues. To begin, interference impacts quality of life. It's a matter of good customer service to be diligent in responding to customer complaints. In addition, arguing or avoiding customers can be time consuming and may lead to litigation. Next, it's in a utility's best interest to act immediately, because most power-line noise is caused by arcing conditions, which can lead to utility equipment or material failures. Last, interference issues must be addressed. FCC regulations require utilities not to cause harmful interference to licensed services and to cease operating any device, upon notification by the FCC, that is causing interference.

What Does the FCC Require?

FCC Part-15 regulations govern radio and TV noise most likely to come from utility-owned equipment. These rules specify three classes of emitters that may apply to power-company equipment:

- **Incidental emitters**
- Most interference complaints from power-company equipment result from an incidental emitter, such as an electric motor or sparking power-line hardware. Incidental emitters don't intentionally generate radio energy but do so incidentally as a result of their operation.
- **Unintentional emitters**
- These may be found in some power-company equipment. Unintentional emitters intentionally generate an internal radio signal, but do not intentionally radiate or transmit it. Examples include some types of “switch-mode” power supplies and microprocessors used in some power-company equipment. Unintentional emitters have specific limits on radiated and conducted emissions.
- **Intentional emitters**
- These are transmitters that intentionally radiate RF. In general, they are not found in power company equipment, although some remote-reading usage meters may use intentional emitters.

Most radio noise on power-company equipment comes from incidental emitters. These have no specific limits on conducted or radiated emissions. But all unlicensed emitters of radio energy have a requirement not to cause harmful interference. If they do, the operator of the device causing the interference must take whatever steps are necessary to correct it.

Keep in mind, electric utilities are responsible for correcting only the noise generated by the equipment and hardware that they actually own. In cases where utility customers use an appliance or device that generates noise, they must correct the problem, even if the noise is conducted and radiated by the utility's power line.

Locate the Source of Interference

A good first step is to eliminate the device itself as the source of the problem. If the device is suspect, remove the antenna connection to the radio to see whether the noise goes away. Proceed with the following steps to determine if the source of interference is located within the home or business.

1. Go to the main breaker panel or fuse box. Check the presence of the noise with a battery-powered radio.
2. If the noise is present, shut off all power to the premises by turning off the MAIN circuit breaker or by pulling the MAIN fuses or meter. If the noise on the AM radio stops while the power is off, the source of the interference is within

the residence. If the noise continues, you can assume it is coming from a point external to the customer's home.

3. Restore the main circuit breaker or fuses or meter.
4. If the noise stopped while the power was off, locate the circuit supplying the power to the noise source using an AM radio as before, and de-energize the individual circuit breakers one at a time until the noise stops.
5. Next, determine what is on the circuit by going from room to room to isolate outlets, appliances and lights until the offending device is found.

If the noise source is not in the customer's home, check with the closest neighbors. If one of the neighbors has a similar problem, ask them to run the breaker test to try to locate the faulty equipment. A household appliance or electrical device rarely causes interference that extends beyond a few houses on a secondary system.

Note that if the source is not in the customer's home or a neighbor's home, the noise is originating from an outside source. Direction-finding techniques may then be used to isolate the noise to a particular residence or an area of the utility's power-line system.

Identifying Power-Line Noise

Noise that varies with the time of day is related to what people are doing, usually pointing to an electrical device or appliance. Noise from consumer-type devices often comes and goes with periods of human activity, frequently correlating with evenings and weekends. Unless it is associated with climate control or an HVAC system, an indoor RFI source is less likely to be affected by weather than power-line noise. The importance of maintaining a good and accurate interference log cannot be overstated. Ask the customer to record dates, times and weather conditions. Correlating the presence of the noise with periods of human activity and/or weather often provides important clues to identifying power-line noise.

Weather-Related Interference

If the interference appears and varies in intensity depending on weather conditions, and if a breaker test excludes sources inside the home, the interference may be caused by faulty components associated with the electrical power lines near the home. Wet weather may temporarily reduce or eliminate the noise by shorting out spark gaps on the power line. Windy weather may cause the noise to vary or even stop for a while, as loose hardware is affected.

Is There a Smoking Gun?

Virtually all radio noise originating from utility-company equipment is caused by a spark or arcing. The radio noise is only generated during the times when a breakdown and ionization of air occurs.

Once an ionized path is established in the gap, current flows at all parts of the cycle where the voltage is higher than the breakdown voltage of the gap. This typically occurs only near the positive and negative voltage peaks, the times of highest instantaneous voltage. Sometimes the gap may break down on only one polarity of the waveform.

Because power lines carry 60-Hz ac, the voltage on them passes through two peaks each cycle (one positive and one negative) and passes through zero twice each cycle. This gives 120 peaks and 120 zero crossings in each second.

Power-line noise follows this pattern, generally occurring in bursts at a rate of 120 (sometimes 60) bursts per second. This gives power-line noise a characteristic sound that is often described as a harsh and raspy hum or buzz. Because the peaks can occur twice per cycle, true power-line noise usually has a strong 120-Hz modulation.

Typically, power-line noise is a broadband type of noise starting at the low end of the radio spectrum and is usually stronger at lower frequencies. It occurs continuously across each band, up through the spectrum to some upper frequency where it tapers off.

Indoor and power-line noise can be identified with an oscilloscope, which should show the bursts occurring every 1/120 seconds, or 8 1/3 ms. Investigate the suspect noise from a radio's audio output using the AM mode. Use the wide filter settings and tune to a frequency without a station. Power-line noise bursts should repeat every 8.33 ms. If this is not the case, you probably don't have power-line noise (Fig. 2).

Alternately, you can perform a similar test if the noise pattern is visible on a TV set. The noise occurs in two horizontal groups or bands. Typically, these two bands drift slowly upward on the screen. One group is a result of arcing during the positive half of the 60-Hz sine wave. The other group is a result from the negative half of the sine wave.

Usually, it is best to perform this test at the lower VHF TV channels and with an antenna (as opposed to a cable hookup). The positive and negative power-line noise burst also may have slightly different characteristics. This can cause each half of the cycle to have a slightly different pattern on the screen. As you turn the channel selector to higher frequency channels, the interference should diminish. If the interference can be observed on UHF channels, the source is probably relatively near (Fig. 3).

Locating Power-Line Noise

A simple step-by-step procedure handout, plus instructions for “locating inside sources” and “locating the residence” can be downloaded from www.rfiservices.com. Providing it to your complainant as a first step can reduce your on-site investigations by as much as 65%.

Once you've eliminated the possibility of an internal noise source, always start the RTVI locating process at the interference site using the customer's equipment. Whether a TV interference (TVI) or radio frequency interference (RFI) complaint, monitor the customer's equipment while the problem is active.

Finding the Source

Attach a Defect Direction Finder (DDF) receiver to the customer's antenna (Fig. 4). This specialized equipment enables you to monitor the symptoms as received by the customer's antenna. The setup should include a broadband AM receiver that covers the frequency range affected by the problem, an oscilloscope (scope) and an attenuator or RF gain control to adjust the RF signal level. With these tools, utility personnel can monitor the sound and pattern produced by the RTVI source(s).

Scope patterns show many important facts about the source(s) affecting the customer's equipment. They can reveal the number of simultaneous sources, determine which source is the strongest, and even provide an indication as to the size of gap across which the spark is occurring. When working with TVI complaints, the scope can show which source is having the most impact on the TV picture.

Signature or Fingerprint Method

Each sparking interference source exhibits a unique pattern. By comparing the characteristics between the pattern taken at the customer's residence with those found in the field, it can be determined which is the offending source because each provides its own “fingerprint” or “signature” (Fig. 5).

Interference locating receivers, such as the Radar Engineers Model 240 shown in Fig. 4, have a built-in oscilloscope display and waveform memory, providing the ability to toggle between the pattern saved at the customer's house and those obtained from sources located in the field.

Once armed with the customer's noise fingerprint, start the search in front of the customer's residence. Travel in a circular pattern around the customer's house, block-by-block, street-by-street, until you find the noise pattern matching the one recorded at the customer's house. Use VHF or UHF if you can hear the RFI at these frequencies. The longer wavelengths associated with the AM Broadcast Band (and even HF) can create misleading “hot spots” along a line when searching for a noise source.

At these frequencies, you may find that the noise peaks at certain poles with different types of hardware mounted on them. As a general rule, only use the lower frequencies when you are too far away from the source to hear the offending RFI at VHF or UHF. Work at the highest frequency on which the noise can be heard. As you approach the source, keep increasing the frequency (Fig. 6). Once you've matched the pattern obtained at the customer's house with one in the field, you're close to locating the structure containing the source.

An Amateur Radio Complaint

A Smarter Approach to Resolving Power-Line Noise

Imagine you have received a complaint from an amateur radio operator. The rules are still pretty much the same as with the TVI complaint:
The source must be active at the time of our investigation.

- Observe the symptoms on the customer's equipment.
- Start the investigation by verifying the source is not located in the customer's residence.
- Connect the DDF receiver to the customer's antenna before investigating the area outside his house.

In this example, however, tune the DDF receiver, while connected to the customer's radio antenna, to the offending frequency. Observe and record the noise pattern for future viewing. Once ready to begin the hunt, start traveling in a circular pattern away from the customer's house until you find the matching noise fingerprint. If the customer has a rotating antenna, use it to your advantage. Determine the direction of the noise source from the customer's house and reduce travel to a minimum.
Whether the complaint is TVI or RFI, a rotating antenna is always helpful. Instead of traveling spirally away from the house to find the noise, you can focus searching in one direction.
Another important clue can be obtained by tuning the DDF receiver to higher frequencies. Listen to the noise at VHF and UHF and make note of the frequency at which it starts to diminish. This frequency can provide an important clue to the proximity of the source. The closer the source, the higher in frequency you can receive it. If the noise can be heard at 440 MHz, you can expect it to be relatively near — perhaps within less than a quarter-mile radius. If it diminishes around 4 MHz, however, the source can be more than one mile away.

An Important Rule

By now, you can see a tremendous improvement in noise locating efficiency. Perhaps the most difficult hurdle to overcome in this process is to ignore those noises not affecting the customer's equipment. An important rule for efficient and economic RFI troubleshooting is to locate and repair only the source causing the complaint.

Locating the Utility Source

Head in the direction from which the antenna indicated the noise was the strongest. After a few blocks, you might expect to receive a noise with the exact pattern as the one recorded at the complainant's house. Now, reduce the signal level on the DDF receiver. In most cases with a modern DDF receiver, simply turn the RF gain control down to achieve a minimum signal level (as indicated by the receiver's signal strength meter) and still have a clear noise pattern on the

scope. If the receiver does not have an RF Gain control, an attenuator between the antenna and receiver can be used to reduce the signal level at the receiver's input.
If the signal level increases, you are approaching the source. Continuously adjust the gain to accommodate changes in the signal level. The importance of this rule cannot be overstated.

Directional Antennas

With an omni directional or whip antenna, you must move to determine the direction of the higher signal level. If you use a handheld or vehicle-mounted Yagi (directional) antenna, you can follow the direction of the strongest signal to the noise source. This will greatly reduce the amount of time and travel distance required during the hunt.
Radio Direction Finding (RDF) techniques typically offer the best and most efficient approach to locating most power-line noise sources. A handheld Yagi works at VHF and UHF within a specified frequency range. Not only are VHF and UHF antennas typically smaller, but direction headings are more reliable. An attenuator is required between the antenna and the receiver if the receiver does not have one (Fig. 7).

Pinpointing the Source

The investigator must be able to pinpoint the source on the structure down to a component level. An investigator also can use a hot-stick-mounted device to find the source. An ultrasonic dish is useful for pinpointing the source of an arc. An unobstructed direct line-of-sight path is required between the arc and the dish. It is only useful for pinpointing a source once it has been highly localized and is ideally suited for pinpointing the arcing hardware once the offending pole has been isolated (Fig. 8).

Common Source and Locating Misperceptions

Note that transformers are not listed among the most common power-line noise culprits. Despite their reputation, only a small percentage of transformers are actually found to be the cause of an RTVI complaints. Many times transformers are replaced because they are believed to be RTVI sources, when in reality, the transformers' loose hardware merely needs to be tightened. Sometimes, locaters are fooled by the hardware associated with a transformer pole. A transformer pole has a driven ground conductor, lightning arrestor, and often a down guy or other hardware that can act as an antenna to radiate noise. This can cause a high level of noise at the pole, but it is actually being generated by another source.
Corona discharge also gets a bad rap as another RTVI source when it rarely, if ever, is a source of power-line noise. Corona discharge is defined as the partial breakdown of the air that surrounds an electrical element such as a conductor, hardware or insulator. Corona typically is nothing more than a minor annoyance,

as corona noise is usually confined to lower frequencies. This noise does not propagate far from the source because it is a low-current phenomenon that does not couple into adjacent wires. Hence, corona cameras are not recommended for locating RTVI sources.

Another type of equipment that has little directional locating capability is thermal/infrared detectors. Ultrasonic detectors, on the other hand, are very useful but often misunderstood. As previously discussed, they are not practical for finding the general source location, but they can be of great assistance in pinpointing the exact noise source once the structure is located.

How to Fix

RFI repairs on the utility system usually involve eliminating an arc of some type. Arcs can occur due to loose hardware, cracked insulator, tracking, corrosion between two pieces of metal, or a loose tie wire.

Long-term repairs eliminate arcing by replacing the offending part, tightening hardware, or cleaning to prevent tracking. Freezing and thawing can cause hardware to loosen, especially in colder climates. Helical spring washers added to the bolts can absorb the expansion and contraction of wood poles and maintain hardware tension to prevent gaps from forming.

New products and materials for line construction are constantly evolving in the industry. For example, polymer construction of various types of post top insulators, dead ends and fused cut outs provide higher Basic Insulation Level, lighter weight and are less prone to stress cracks. Vice top polymer insulators are far superior to wire ties that can arc when loose, especially in cases involving covered wire.

Acknowledgments and Resources

The authors would like to thank Mike Gruber and Ed Hare of ARRL Laboratory, and Terry Rybak of General Motors for their contributions to this article.

RFI Services provides locating and consulting services. Visit its Web site at www.rfiservices.com for additional information. Help is also available from the ARRL at http://www.arrl.org/tis/info/utility.html.

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Common Household Items That Cause Interference

- Door bell transformers
- Electric blankets
- Heating pads (of all kinds)
- Recessed ceiling light fixtures
- Furnace control circuits
- Refrigerators (becoming a frequent problem)
- TV top and stereo, amplified antennas
- Light dimmers
- Aquarium heaters
- Screw-in photocells
- Low-energy compact (screw-in) fluorescent lights
- Touch control lamps
- Clean air machines (table top and furnace type)

Common Power-Line Noise Sources

(Listed in order from most common to least common)

- Loose staples on ground conductor
- Loose pole top pin
- Ground conductor touching nearby hardware
- Corroded slack span insulators
- Guy touching neutral
- Loose hardware
- Bare tie wire used with insulated conductor
- Insulated tie wire on bare conductor
- Loose crossarm braces
- Lightning arrestors

* * * * * * *

http://www.cpuc.ca.gov/environment/info/aspen/sunrise/sunrise.htm
http://www.cpuc.ca.gov/environment/info/aspen/sunrise/scoping/app%20d4%20oral_comments.pdf

The impacts of stray voltage and therefore electricity in general have been well-documented. Studies have shown that it would be necessary for the line to be located a minimum of one mile away from livestock in order to prevent impacts to the health and productivity of the animals. The Van Leeuwens, owners of Bullfrog Farms, have determined, based on studies and real-life experience, that they would lose ten pounds of production per cow per day due to impacts from the electrical line. And I actually have specific figures in here, but I'm going to let Richard address those since he's up next. Basically, a 3200 cow dairy cannot survive a loss of this magnitude. It will surely put them out of business

Promoting Professionalism In California State Parks

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February 24, 2007

Billie Blanchard, CPUC / Lynda Kastoll, BLM
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The California State Park Rangers Association strongly opposes the proposed Sunrise Powerlink project.

CSPRA feels that the aesthetic, biological, cultural, and recreational impacts of the project would be significant and unacceptable. Routing of the transmission line through or near the park would destroy irreplaceable resources of the state's largest State Park.

The line would shatter the wilderness feel of the Park, discourage the tourism that feeds the economies of nearby communities, threaten the unique and extraordinary paleontological, archaeological, historical, and geological resources contained within Anza-Borrego Desert State Park. The proposed towers would destroy the unique viewshed in and near the park, provide unnatural predator perches, with ground disturbance contributing to erosion and impacting subsurface resources. The project would reduce recreational opportunities.

Alternatives to the project such as demand reduction would be far superior environmentally yet would achieve the goals of the proposed project.

California State Park Rangers Association is a professional organization of more that 700 active and retired state park rangers, maintenance professionals, administrators, resource specialists, and interpreters dedicated to protecting our State Parks.

California State Parks are set aside for the health, education and inspiration of the people of California and protect the State's extraordinary resources while providing recreational opportunities. State Parks do not exist to provide transmission routes for urban utilities.

We urge you to adopt the No Project alternative.

Sincerely,

Gail Sevrens
Legislative Director

Cc: Public Advisor, California Public Utilities Commission
Ruth G. Coleman, Director, California State Parks

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February 24, 2007

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Subject: Topics and alternatives that should be included in the Draft EIS/EIR for the proposed Sunrise Powerlink powerline

Dear Ms. Blanchard and Ms. Kastoll:

Thank you for this opportunity to offer scoping comments on the proposed Sunrise Powerlink powerline.

The California Wilderness Coalition (CWC) is a non-profit organization incorporated under the laws of the State of California with its central office in Oakland, California, and field offices in Riverside and Redding. CWC has more than 5,000 members and more than 200 member organizations and business sponsors. The CWC protects the landscapes that make California unique – providing clean air and water, a home to wildlife, and a place for recreation and spiritual renewal. In particular, the CWC focuses on the management of roadless areas on National Park Service, United States Forest Service (USFS) and Bureau of Land Management (BLM) land.

The great ecological transition zone between the deserts of eastern San Diego and western Imperial County and the coastal sage scrub of central San Diego County is one of the most biologically diverse and scenic areas in California. The steady growth of cities and suburbs in the region has resulted in significant habitat loss. federal, state and local public lands in southern California are more important than ever before as refuges for sensitive plant and wildlife species and for maintaining the quality of life for the area's residents.

Given the ecological and social importance of the region's natural places, it is no surprise that it has an exceptional array of designated federal and state wilderness areas, BLM wilderness study areas (WSA), USFS inventoried roadless areas and citizen-proposed wilderness areas (hereafter referred to collectively as "wilderness-quality lands"). Other ecologically and socially important areas include state parks and areas managed for non-motorized recreation by the BLM and USFS.

We are appalled by San Diego Gas and Electric Company's (SDG&E) unprecedented proposal to violate the boundary of a designated state wilderness within Anza-Borrego Desert State Park. The California Wilderness Act (Public Resources Code 5093.30-5093.40) states at 5093.31 that the purpose of wilderness is to:

> …assure that an increasing population, accompanied by expanding settlement and growing mechanization, does not occupy and modify all areas on state-owned lands within California, leaving no areas designated for preservation and protection in their natural condition, it is hereby declared to be the policy of the State of California to secure for present and future generations the benefits of an enduring resource of wilderness.

The CPUC and other state agencies should honor both the letter and spirit of the California Wilderness Act by treating designated state wilderness as a truly enduring resource, and not one to be defiled whenever a major corporation proposes a development project. Remember: infrastructure can be moved, wild places cannot.

The following wilderness-quality lands appear to be either penetrated by or are adjacent to the various powerline routes under consideration as illustrated in the Notice of Second Round of Scoping Meetings on Alternatives to the Proposed Sunrise Powerlink Project, Figures 1-8.

- Vallecito Mountains State Wilderness
- Pinyon Ridge State Wilderness
- Grapevine Mountain State Wilderness
- San Felipe Hills WSA
- Sawtooth Mountains Wilderness
- Sin Nombre State Wilderness
- Carrizo Canyon State Wilderness
- Sombrero Peak State Wilderness
- Agua Caliente State Wilderness
- Whale Peak State Wilderness
- Granite Mountain State Wilderness
- Grapevine Mountain State Wilderness
- Vallecito Mountains State Wilderness
- Sawtooth Mountains A WSA
- Desert Oasis State Wilderness
- Santa Rosa Mountains State Wilderness
- Wil-yee State Wilderness
- Sheep Canyon State Wilderness
- Pinyon Ridge State Wilderness
- Hauser South Inventoried Roadless Area

- Eagle Peak Proposed Wilderness (a proposed wilderness included in Senator Barbara Boxer's S. 493)
- Fish Creek Wilderness
- Coyote Mountains Wilderness

We request that the CPUC, BLM, California Resources Agency and USFS honor the federal Wilderness Act, Federal Land Policy Management Act, California Wilderness Act, 2001 Roadless Area Conservation Rule, and legislation currently pending before Congress by prohibiting the construction of powerlines in the areas listed above. We also request that these agencies compel SDG&E to follow a route that limits ecological disruption and disturbance to the maximum extent possible. Instead of plowing the powerline corridor through wilderness-quality lands and other special places, we request that SDG&E be required to place the corridors along existing paved roads whenever possible and appropriate. In addition, existing utility corridors should be used to the maximum extent possible.

By placing the powerline along or immediately adjacent to existing infrastructure, the California Environmental Quality Act and National Environmental Policy Act (NEPA) analyses may be reduced in both scope and depth. Often, areas that have been previously disturbed require less analysis for expansion of existing disturbance than would be required for new disturbance of pristine and/or wild areas.

The approval of a powerline route affecting federal wilderness must be made in accordance with the Wilderness Act of 1964 and other applicable laws and policies. The approval of a route affecting state wilderness must be made in accordance with the California Wilderness Act and other applicable laws and policies. The approval of a route affecting BLM WSAs must be designated in accordance with the Federal Land Policy Management Act and other applicable laws and policies. If a route will affect USFS inventoried roadless areas, please note that the 2001 Roadless Area Conservation Rule was reinstated by a federal judge in September, 2006 in the case of The Wilderness Society, California Wilderness Coalition, et al. v. United States Forest Service, et. al.. The 2001 Roadless Area Conservation Rule prohibits the construction of roads in inventoried roadless areas, including roads needed for utility construction.

In addition, if a powerline is proposed where California State Park, BLM or USFS land use plans do not currently provide for approval of rights-of-way or construction of facilities, or require compliance with protective measures (such as visual resource management classifications), a formal amendment process and appropriate environmental analysis must precede imposing a powerline corridor on the affected lands. Also, if a proposed route crosses through a newly-acquired federal or state parcel that has never had a wilderness suitability study, we request that the public land management agencies inventory the wilderness characteristics of these lands and, based on this information, exclude lands with wilderness characteristics from the proposed powerline route.

Some of the issues that should be studied, described and discussed for each alternative in the Environmental Impact Report (EIR)/ Environmental Impact Statement (EIS) include:

- The risk of reducing water quality.
- Impacts to air resources.
- Consequences of and for fire and fuels management, including the risk of plant community type-conversion from accelerated fire cycles.
- Impacts of development at various elevation distributions.
- The cumulative impacts of the proposed project in light of other federal, state, local and private projects in the region that will impact habitat, scenery and recreation.
- Impacts to terrestrial animal and plant habitat, including fragmentation and connectivity, edge effects, habitat suitability and effectiveness, early-successional habitat, game species and late-successional habitat.
- Impacts to aquatic animal habitat and species.
- Impacts to threatened, endangered, proposed and sensitive species.
- Impacts to research, monitoring and reference landscapes.
- Consequences for non-mechanized, mechanized and motorized recreation.
- The risk of opening previously trackless areas to unauthorized off-road vehicle use as a result of new road construction.
- Impacts to scenic quality.
- Consequences to heritage resources.
- Mitigation measures to off-set the visual impacts of development that may be visible from lands important for recreation and scenery, including wilderness, WSAs, inventoried roadless areas, proposed wilderness, state parks, the Pacific Crest National Scenic Trail corridor and the California Riding and Hiking Trail corridor. Again, we request that powerlines not be proposed inside any of these areas because the impacts, visual and otherwise, are simply unmitigable.
- The risk of introducing non-native plant species such as yellow starthistle and medusahead to previously uninfected areas.

The "scoping" stage of preparing an EIS requires BLM to make two determinations: (1) what is the scope of the project to be analyzed in the EIS and (2) what are the issues that will be analyzed "in depth" in the EIS. 40 C.F.R. § 1501.7(a). See also BLM Handbook H-1790-1.V.B.1; BLM Handbook H-1601-1.III.A.1; 43 C.F.R. § 1610.4-1. Other environmental reviews (such Biological Assessments and consultation for species listed pursuant to the Endangered Species Act) should be identified so that they can be done concurrently with the EIS and integrated with it. We believe the issues identified in these comments are within the legal scope of this review, and therefore they should be analyzed in depth in the EIS.

In determining the scope of the EIS, BLM must consider “connected actions,” “cumulative actions,” and “similar actions.” 40 C.F.R. § 1508.25. Connected actions are actions that are “closely related” to the proposed action. Closely related actions include any reasonably foreseeable development projects that would not occur “but for” authorization provided in the EIS. The EIS should address each of these types of connected actions/projects in detail so as to foster informed public participation in the plan revision and informed decision-making by BLM. Cumulative actions are actions that, incrementally, have cumulatively significant impacts, even if the individual impacts are minor. Thus, BLM should define the scope of the EIS to include analysis of the cumulative effects of actions/projects that have impacts in common. Impacts and actions that should be addressed in a cumulative fashion include, but are not limited to: road construction and activities leading to soil and vegetation disturbance, changed habitat structure, habitat fragmentation and air or water pollution. These cumulative impacts result from a number of cumulative actions and thus they must be addressed in a comprehensive manner.

An issue closely associated with the consideration of connected, related, and cumulative actions and impacts is the Reasonably Foreseeable Development (RFD) scenario. Development of a realistic, well supported, economically rational, and scientifically based RFD is crucial for a proper analysis and determination of connected, related, and cumulative impacts.

Council on Environmental Quality (CEQ) regulations require a reasonable range of alternatives to be presented and analyzed in the EIS so that issues are “sharply defined” and the EIS provides “a clear basis for choice among options . . .” 40 C.F.R. § 1502.14. CEQ regulations and court decisions make clear that the discussion of alternatives is "the heart" of the NEPA process. Environmental analysis must "[r]igorously explore and objectively evaluate all reasonable alternatives." Such objective evaluation is gravely compromised when agency officials bind themselves to a particular outcome or foreclose certain alternatives at the outset. Therefore, BLM must use the scoping process to develop alternatives that emphasize needed environmental protection even if such alternatives limit and/or strongly regulate development. Such options should not be dismissed without a thorough and careful analysis in the EIS.

BLM must bear in mind that the "primary purpose" of an EIS is to "insure that the policies and goals defined in [NEPA] are infused into the ongoing programs and actions of the Federal Government." 40 C.F.R. § 1502.1. The policies and goals of NEPA include,

- Encouraging a "productive and enjoyable harmony between man and his environment",
- Promoting "efforts which will prevent or eliminate damage to the environment and biosphere",
- Using "all practicable means and measures . . .to create and maintain conditions under which man and nature can exist in productive harmony . . .",
- Fulfilling "the responsibilities of each generation as trustee of the environment for succeeding generations",
- Assuring "all Americans safe, healthful, productive and esthetically and culturally pleasing surroundings",
- Allowing beneficial use of the environment "without degradation . . . or other undesirable or unintended consequences",
- Preserving "important historic, cultural and natural aspects of our national heritage . . .",
- Achieving a "balance between population and resource use . . .", and
- Enhancing "the quality of renewable resources" and maximizing recycling of depletable resources.

42 U.S.C. §§ 4321-4331. See also BLM Handbook H-1790-1.V. B.2.a.(3). Thus, the issues that BLM must identify for analysis in its EIS include the above goals and policies, and we ask BLM to "insure" that these considerations are "infused" into all activities considered in the EIS.

NEPA requires BLM to make a number of considerations that we specifically urge BLM not to overlook. NEPA requires the BLM to "insure that presently unquantified environmental amenities and values" are given consideration, "recognize the worldwide and long-range character of environmental problems and thus support international efforts to prevent declines in the world environment," and "initiate and utilize ecological information in the planning and development of resource-oriented projects." 42 U.S.C. § 4332, 40 C.F.R. § 1507.2. See also BLM Handbook H-1790-1.V. B.2.a.(3). Thus, in preparing the EIS, BLM should consider, analyze and, wherever appropriate, facilitate international efforts to prevent environmental decline. These include a number of international agreements and treaties for resource protection, such as United Nations biosphere reserves, migratory bird treaties, the Convention on International Trade in Endangered Species, and international efforts related to biological diversity preservation.

The EIS/EIR should also explicitly address unquantified environmental values and ensure they are given equal emphasis relative to economic analyses, and ensure up-to-date ecological information is utilized in developing the EIS/EIR.

The BLM NEPA Handbook requires BLM to identify the purpose and need of the project being analyzed, BLM Handbook H-1790-1.V.B.e., as well as the desired outcomes or desired future conditions resulting from implementation of the EIS. BLM Handbook H-1601-1.II.B.1. The requirement for BLM to prevent unnecessary or undue degradation of the public lands should be paramount in such balancing. Furthermore, some statutes, such as the Endangered Species Act, require that where there are conflicts between what is desired for some activities versus other resources, certain activities must recede. The EIS should acknowledge this and make provisions for meeting this requirement. For example, closure of lands to certain resource uses, such as oil and gas development, is specifically provided for as a means to achieve desired outcomes. BLM Handbook H-1601-1.II.B.2. Measures for protecting the land to achieve desired outcomes should be developed at an appropriate scale, with a landscape or bioregional scale being the appropriate scale for many actions, particularly endangered species protection. BLM Handbook H-1601-1.III.A.4.

It is rarely possible for any federal agency to obtain perfect amounts of information. BLM must not allow this fact to stymie environmentally informed decision-making by BLM. CEQ regulations essentially establish a presumption in favor of obtaining information that is essential to reasoned decision-making. See 40 C.F.R. § 1502.22. See also BLM Handbook H-1790-1.III.A.2.d. BLM should take steps to gather needed information in all but the narrow range of exceptions permitted by the CEQ regulations. But if BLM concludes information is not essential to reasoned consideration of alternatives, or the cost of obtaining the information is exorbitant, or the means for acquiring the information are unknown, the BLM must nevertheless scrupulously abide by CEQ guidance in this regard, namely that "credible scientific evidence" be presented relative to reasonably foreseeable significant adverse impacts (including low likelihood but catastrophic impacts) so that the impacts can be assessed based on approaches that are "generally accepted in the scientific community." See 40 C.F.R. § 1502.22(b). See also 40 C.F.R. § 1502.24 (requiring professional and scientific integrity in an EIS).

Monitoring of EIS/EIR implementation and the impacts resulting from plan implementation are crucial. A number of legal requirements apply to plan monitoring, and they should be carefully adhered to. See, e.g., 43 C.F.R. §§ 1610.4-9, 1610.5-3; BLM Handbook H-1601-1.IV-VII. Likewise, the EIS/EIR should make provision for the effective enforcement of its provisions. "In managing the public lands the Secretary shall, by regulation or otherwise, take any action necessary to prevent unnecessary or undue degradation of the lands." This provision from the FLPMA is a mandatory requirement applicable to all resource uses and decisions affecting BLM lands. 43 U.S.C. § 1732(b). Consequently, it must serve as bedrock for all analyses in the EIS. Clearly, the BLM bears a heavy responsibility before it can authorize activities that may degrade the public lands.

We urge BLM not to define "unnecessary or undue degradation" by default, in a negative fashion. Instead, we urge BLM to require, in a direct and positive fashion, that all activities not cause unnecessary or undue degradation and to ensure that this is the case. The confusing, circuitous approach of defining unnecessary or undue degradation by default leads is contrary to the direct, unambiguous command from Congress to do whatever is necessary to prevent unnecessary <u>or</u> undue degradation and the plan should define, and prevent, unnecessary or undue degradation in an equally direct, positive fashion.

It will not be enough for the Draft EIS to make "conclusory" or "perfunctory references" to cumulative impacts or to continue to use the same boilerplate language throughout the document. *Natural Resources Defense Council v. Hodel*, 865 F.2d 288, 298-99 (D.C. Cir. 1988). Cumulative effects analysis requires "some quantified or detailed information. . ." *Neighbors of Cuddy Mountain v. U.S.F.S.*, 137 F.3d 1372, 1379 (9th Cir. 1998). "General statements about 'possible' effects and 'some risk' do not constitute a 'hard look' absent a justification regarding why more definitive information could not be provided." *Id*. at 1380.

Please note that neither the public, nor the CPUC and BLM can make informed decisions regarding the fate of the lands threatened by the proposed Sunrise Powerlink when contradictory information is coupled with an incomplete analysis. The Draft EIS must therefore meet the standards set forth in NEPA, 40 CFR Part 1500.2 (e) and Part 1500.1 (b) which requires the federal government to ensure "that environmental information is available to public officials and citizens before decisions are made and before actions are taken," and that the information provided to public officials and citizens "must be of high quality."

Thank you for considering our comments. Please notify us of any further opportunities to comment on the Sunrise Powerlink Project in the future.

Sincerely,

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