STATE OF CALIFORNIA

Energy Resources Conservation and Development Commission

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In the Matter of:	)	
The Application for Certification of the CARLSBAD ENERGY CENTER PROJECT	)	**DOCKET NO: 07-AFC-6**

PREHEARING CONFERENCE STATEMENT OF INTERVENOR CENTER FOR BIOLOGICAL DIVERSITY AND REQUEST FOR DOCUMENTS FROM OTHER PARTIES

January 14, 2010

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Pursuant to the December 21, 2009 Revised Notice of Prehearing Conference and Evidentiary Hearing, Intervenor Center for Biological Diversity (the "Center") provides this Prehearing Conference Statement. Other Intervenors raise a host of issues in which the Center reserves the right to participate during the evidentiary hearings and to raise during the post evidentiary briefing. This Prehearing Conference Statement addresses the issues that the Center plans to focus on during the evidentiary hearings. The Center incorporates by reference the contested issues raised by other Intervernors.

1. The topic areas that are complete and ready to proceed to evidentiary hearing.

The Center is prepared to proceed to hearing on the following topics: Project Description, Greenhouse Gas Emissions Appendix to the Air Quality Analysis, and Alternatives Analysis. However, the Center does not view these topics as complete and ready for final hearing because there are inadequacies in the description of the environmental setting and project description, in the cumulative impacts analysis for greenhouse gas emissions, and in the alternatives analysis. The failure to find the Project's greenhouse gas emissions significant also resulted in the lack of identification of specific, enforceable mitigation measures for greenhouse gases, and the lack of robust alternatives analysis for this significant impact. The applicant proceeds at its own risk. The Center does not take a position on the readiness of the other topic areas to proceed to evidentiary hearing.

2. The topic areas that are not complete and not yet ready to proceed to evidentiary hearing and the reasons therefore:

The Center believes that there remain fundamental unresolved issues in the Project Description, Project Objectives, the Greenhouse Gas Analysis, and Alternatives Analysis. The Center does not view these topics as complete and ready for final hearing because there are

inadequacies in the description of the environmental setting and project description, in the cumulative impacts analysis for greenhouse gas emissions and the alternatives analysis. The failure to find the Project's greenhouse gas emissions significant also resulted in the lack of identification of specific, enforceable mitigation measures for greenhouse gases, and the lack of robust alternatives analysis for this significant impact.

The failure to adequately identify impacts, analyze those impacts, and provide documentary evidence or any other adequate basis for the staff's conclusions undermines public participation in this process and is a violation of CEQA. Moreover, while the Commission proceeds under a certified regulatory program that is intended to be the CEQA equivalent and provides some flexibility to the Commission (*see* § 21080.5; CEQA Guidelines § 15251(j).), that program does not allow the Commission to shift the Commission's duty to provide for adequate CEQA review, including identification and analysis of environmental impacts and alternatives, onto other parties or members of the public. It is the Commission's duty to comply with CEQA's substantive and procedural mandates. Cal. Pub. Res. Code §§ 21000, 21002; *Sierra Club v. Bd. of Forestry* (1994) 7 Cal.4th 1215, 1236; *Joy Road Area Forest and Watershed Association v. Cal. Dept. of Forestry and Fire Protection* (2006) 142 Cal.App.4th 656, 667-68.

The Center is not aware of any Exhibit list submitted by Staff. At the end of this statement, the Center requests copies of references from the FSA GHG and Alternatives sections. Documents relied on by Staff in the FSA should be submitted as Staff Exhibits. Failure to do so, places an unfair and unnecessary burden on Intervenors. The Center will raise this issue at the Prehearing Conference to ensure that Staff will be submitting the requested documents as Exhibits.[1]

[1] The Center will make a copy of the Staff Exhibits listed by the Center, Exhibits 600-605, available to the hearing officer but the Center does not plan on making additional copies until this issue is resolved.

3. The topic areas that remain disputed and require adjudication, and the precise nature of the dispute for each topic:

Again, the Center stresses that the FSA is incomplete. Some of the disputed issues identified below involve both legal and factual disputes while others are predominantly legal issues. The Center therefore respectfully reserves the right to address each disputed issue and any other disputed issues identified at the final prehearing conference and by other Intervenors at later stages in this process, including during briefing following the evidentiary hearing. The Center reserves the right to raise issues during the post evidentiary briefing that may arise during the hearings. The nature of the dispute is discussed by topic area below:

Project Description – Chap. 3: The project description is too narrow because it fails to include an analysis of the environmental effects of the use of LNG at the Project. The use of LNG should have been evaluated as part of the project because LNG is a foreseeable fuel source for the plant. Including this analysis would increase the projected greenhouse gas emissions of the Project.

Project Objectives: Two of the project objectives are too broadly drawn and improperly encompass a whole class of natural gas power plants. The project objectives should be specific to whether the specific siting of the CECP will provide for reliability and support renewable integration without creating additional fossil fuel infrastructure that can hinder the objective of a low carbon future. The analysis in the FSA does not support these conclusions specifically for CECP. The objectives at issue are:

- Meets the expanding need for new, highly efficient, reliable electrical generating resources that are dispatchable by the CAISO, and are located in the "load pocket" of the San Diego region; and

• Improves San Diego electrical system reliability through fast starting generating technology, creating a rapid responding resource for peak demand situations and providing a dependable resource to backup intermittent renewable resources like wind generation and solar.

Greenhouse Gas Emission - Air Quality Appendix AIR-1, AIR-2: The Greenhouse Gas Analysis has a series of deficiencies. First, the FSA failed to conduct an adequate cumulative impacts analysis for greenhouse gases by failing to adequately describe the nature of the cumulative problem, i.e. adding more greenhouse gases to a world in which significant reductions are required, and by failing to adequately discuss the past, present, and future projects that contribute to the cumulative effect of more greenhouse gas emissions. The FSA also uses an improper baseline relying on the relative efficiency of the electric system to determine the significance of the greenhouse gas emissions and fails to find the quantified emissions of more than 800,000 tons of CO2 equivalent greenhouse gases to be significant. The Staff improperly relies on a "displacement theory" rather than conducting the necessary analysis for air emissions, and only evaluates the CECP in the present rather than over the lifetime of the project. The Staff fails to support the claim that the project will result in a net reduction in greenhouse gas emissions. The Staff improperly uses a comparative ratio theory to determine significance and fails to analyze the threshold for which greenhouse gas emissions from the project would be significant.

CAISO and Staff fail to do the requisite analysis to show how this specific project is an appropriate addition to the electric system that will help achieve California's stated policies of achieving a 33% RPS by 2020 and will contribute to reducing greenhouse gas emissions by 80% by 2050. CAISO and Staff also fail to show that the CECP, a significant new source of

greenhouse gases, is actually needed. The FSA contains insufficient analysis to show that CECP will not interfere with new renewable integration or to show that there will be a reduction in system-wide greenhouse gas emissions or that CECP supports the goals and policies of AB 32. The FSA also improperly weighs purported environmental benefits of the project against the additive effect of the project on climate change.

Each of the subsections in the greenhouse gas analysis section reaches unsubstantiated conclusions based on insufficient analysis. These subsections include: construction impacts, direct/indirect operation impacts and mitigation, the integrated electric system and displacement of emissions, the role of CEC in local generation displacement, the role of CECP in local boiler generation displacement, the role of CECP in renewable energy goals/load growth, and the role of CECP in the Retirement/Replacement of aging power plants.

As a result of not finding the greenhouse gas emissions significant, the Staff fails to adequate analyze feasible greenhouse gas mitigations and fails to consider alternatives that have fewer greenhouse gas emissions and to adequately analyze whether the project could be smaller or be replaced in whole or in part by renewable energy.

Alternatives Analysis – Chap. 6: The alternatives analysis fails to consider lesser emitting greenhouse gas alternatives. In addition, the alternatives analysis fails to adequately analyze alternative energy sources and fails to the take into account the 33% renewable mandate that will dramatically increase the amount renewables powering the SDG&E service area. The FSA's analysis is inadequate to support its conclusions regarding generation technology alternatives and no "project" alternatives.

4. The identity of each witness sponsored by each party (note: expert witnesses must have professional expertise in the scope of their testimony); the topic area(s) which each witness will present; a brief summary of the testimony to be offered by each witness; qualifications of each witness; and the time required to present direct testimony by each witness:

The Center intends to present expert witnesses on the following topics. All experts listed below have submitted testimony and qualifications.[2] Below the Center provides a summary of the topic areas and time estimates for its witnesses.

Project Description:

Rory Cox will testify that LNG may be delivered to the CECP from a Sempra-owned LNG facility in Baja, California. He will establish that Sempra has a terminal in Baja and the regulatory authority and infrastructure to deliver the regasified LNG to the CECP. He will also testify that the use of the regasified LNG will increase the Project's greenhouse gas emissions.[3]

Mr. Cox is the Program Director for Pacific Environment's California Program, which works to ensure the proper implementation and enforcement of California's clean energy policies and regulations, especially in the natural gas industry. Mr. Cox coordinates a West Coast wide coalition of community groups opposed to the import of Liquefied Natural Gas. He has provided expert comments to several LNG import projects in California, Mexico, and Oregon. He has also provided expert comments on several natural gas power plants throughout California.

Mr. Cox's direct testimony is estimated to take no more than fifteen minutes.

Greenhouse Gas Analysis:

Tam Hunt submits rebuttal testimony to Mr. Jim McIntosh of CAISO. He will testify that the CAISO testimony provided by Jim McIntosh is overly general, with no particularized

[2] The Declaration of Rory Cox and his resume are submitted concurrently with this filing as well as the Rebuttal Testimony of Tam Hunt, his declaration and resume.
[3] Mr. Cox's testimony also applies to the greenhouse gas analysis and its failure to consider all of the emissions from the Project.

analysis for the proposed CECP. More generally, the CAISO testimony's conclusions are premature in light of numerous current initiatives designed to assess with far greater specificity what California's grid reliability needs are and how renewable energy projects resulting from the Governor's 33% by 2020 mandate can be integrated in relation to this specific plant. Mr. Hunt identifies omissions in the CAISO testimony and fills in the gaps explaining the potential for renewables in the San Diego region. Mr. Hunt concludes that the CAISO testimony and the related FSA GHG Analysis fail to support important assertions that the CECP will specifically foster the integration of renewables. Mr. Hunt concludes that more analysis is necessary and explains that just such analysis is already underway as part of at least three major state-wide efforts that are highly relevant to the proposed CECP. Without waiting for the statewide planning process to conclude and without performing an analysis specific to the CECP, the environmental analysis of the CECP is incomplete and inadequate.[4]

Mr. Hunt is an attorney with substantial experience in California renewable energy and energy efficiency legislation and regulatory policy. He currently is the managing member of Community Renewable Solutions LLC, a consulting and renewable energy project development firm that is developing community-scale wind and solar (20 megawatts and under) in Central California. From early 2005 to mid-2009, Mr. Hunt was the Energy Program Director and Attorney for the Santa Barbara-based Community Environmental Council, a non-profit organization active in state and local energy policy. He appeared regularly at the California Public Utilities Commission, Energy Commission, and Air Resources Board in proceedings related to renewable energy, energy efficiency, climate change, and liquefied natural gas submitting written comments, legal briefs, and testimony in workshops and hearings on a wide

[4] Mr. Hunt testimony also applies to FSA testimony related to the Alternatives analysis that relates to assertions and conclusions in the greenhouse gas section and to assertions about Project Objectives.

range of issues, including the CPUC's implementation of AB 32, SB 1368, AB 2021, and many other laws. He also served as part of the "high distributed generation" scenario working group in the CPUC's long-term procurement proceeding in 2007 and 2008 (R.08-02-007).

Mr. Hunt's direct testimony is estimated to take no more than thirty minutes.

5. The identities of the witnesses, if any, that the party desires to have testify via telephone:

None. If unforeseen circumstances arises, the Center may request to present telephonic testimony.

6. Topic areas upon which a party desires to cross-examine witnesses, a summary of the scope of such cross-examination, and the time desired for such cross-examination:

The Center requests the opportunity to cross-examine Staff, Applicant, and Intervenor witnesses on all topic areas in dispute. For topics not specifically identified below, the Center's cross will take no more than an estimated ten minutes per witness.

The Center anticipates that the scope of cross-examination will include at least the following:

Project Objectives:

Cross examination related to the projective objectives will occur in the cross for both the Greenhouse Gas and Alternatives Analysis.

Greenhouse Gas Analysis:

The Center will cross-examine Staff's witnesses William Walters and Matthew Layton on the scope and underlying premises of the greenhouse gas analysis. The cross will explore the scope and inadequacies of the cumulative impacts analysis, the staff's reliance on the displacement theory rather than using the actual plant as the baseline, why the analysis did not identify specific reductions of greenhouse gases resulting from the project, and the nature of the

analysis that was specific to CECP rather than a generic type of natural gas plant. This cross will explore the extent of analysis and the assumptions underlying each of the subtopic areas listed in the analysis including construction impacts, direct/indirect operation impacts and mitigation, the integrated electric system and displacement of emissions, the role of CEC in local generation displacement, the role of CECP in local boiler generation displacement, the role of CECP in renewables goals/load growth, and the role of CECP in the Retirement/Replacement of aging power plants. The cross will also explore the underlying assumptions and analysis that informs the section's claims of noteworthy public benefits and the consideration of potential mitigations for greenhouse gas emissions.

The Center is unclear whether the staff will have one or two witnesses for this subject. In either case, the Center estimates the cross-examination will take no more than an estimated hour and a half.

The Center will cross-examine Mr. McIntosh, the staff's witness from CAISO. This cross will explore underlying assumptions of Mr. McIntosh's testimony and how Mr. McIntosh's testimony provides analysis related to the specific operation of the CECP. The cross will also demonstrate the omissions, limited scope of the testimony, and the failure to conduct specific analysis for the CECP.

The Center estimates the cross-examination of Mr. McIntosh will take no more than an estimated thirty minutes.

The Center will cross examine the applicant's witness on this topic if the Applicant is putting forward testimony. However, it appears that the applicant simply agreed with Staff's FSA analysis on the Air Quality topic and does not appear to be propounding any additional

testimony. The cross would focus on the displacement theory, the baseline issue, and the other issues enumerated above in the greenhouse gas analysis.

If Applicant is putting forth a witness, the Center estimates the cross-examination of Applicant's witness will take no more than an estimated twenty minutes.

The Center will cross-exam Mr. Hogan, the City of Carlsbad's witness on cumulative impacts analysis related to greenhouse gas emissions. The cross will focus on the necessary elements of a cumulative impacts analysis and whether the Staff analysis included the requisite information and analysis for greenhouse gases.

The cross-examination of Mr. Hogan is estimated to take no more than fifteen minutes.

Depending on his testimony at the hearing, the Center may cross-exam Lane Sherman, expert for Intervenor Terramar, on his testimony related to the law, science, and societal impacts from greenhouse gases.

The cross-examination of Mr. Sherman is estimated to take no more than fifteen minutes

Alternatives:

The Center will cross-examine Staff's witnesses on generation technology alternatives and "no project" alternatives. The cross-examination will explore the analysis and underlying assumptions for the section's conclusions that the project would meet critical project objectives that are too broadly defined. The cross will also examine the failure of the alternatives analysis to adequately analyze alternative energy sources and take into account the 33% renewable energy mandate that will dramatically increase the amount of renewables powering the SDG&E service area. The cross will also examine the RFO status of CECP and its relation to reliability, as well as the "no project" alternative with respect to the purported benefits of CECP, the shut down of units 1-5, and the effect on once-through cooling.

The Staff has listed four authors for this section. The Center is unclear on who from the staff will testify on this subject. Whomever the Staff puts forth, the Center estimates the cross-examination will be no more than an estimated forty-five minutes.

The Center will cross examine the applicant's witness on this topic if the Applicant is putting forward testimony on the above referenced topic. However, it appears that the applicant simply agreed with Staff's FSA analysis of Alternatives and does not appear to be propounding any additional testimony. The cross would focus on the same issues and will be no more than an estimated twenty minutes.

The Center will cross-exam Mr. Garuba, the City of Carlsbad's witness on alternatives. The cross will focus on the RFO status of CECP and its relation to reliability, as well as the "no project" alternative with respect to the purported benefits of CECP, the shut down of units 1-5, and the effect on once-through cooling.

The cross-examination of Mr. Garuba is estimated to take no more than fifteen minutes.

7. A list identifying exhibits and declarations that each party intends to offer into evidence and the technical topics to which they apply:

A complete list of exhibits submitted to date is listed below. The Center reserves the right to provide additional exhibits and declarations if necessary after that time. The Center has identified the topic area for each document but reserves the right to use identified exhibits for other topic areas if the need arises.

The Center reiterates its position that documents cited by the Staff in the FSA should be made exhibits by the Staff because the Staff relied on those documents in their testimony. Although the Center has listed some of these documents as Exhibits, the Center maintains that these documents should be filed as Staff Exhibits. The Center reserves the right to question the Staff on any document referenced in the FSA even if that document is not listed below.

Exhibit	Date	Description	Web Link	Topic
600	12/03	2003 Integrated Energy Policy Report	http://www.energy.ca.gov/reports/100-03-019F.PDF	GHG & Alternatives
601	2007	2007 Integrated Energy Policy Report	http://www.energy.ca.gov/2007publications/CEC-100-2007-008/CEC-100-2007-008-CMF.PDF	GHG & Alternatives
602	12/09	2009 Integrated Energy Policy Report	http://www.energy.ca.gov/2009publications/CEC-100-2009-003/CEC-100-2009-003-CMF.PDF	GHG & Alternatives
603	7/06	Anders and Bialek, "Technical Potential for Rooftop Voltaics in the San Diego Region"	http://www.sandiego.edu/epic/publications/documents/060309_ASESPVPotentialPaperFINAL.pdf	Alternatives
604	5/27/09	Framework for Evaluating Greenhouse Gas Implications of Natural Gas-Fired Power Plants in California	http://www.energy.ca.gov/2009publications/CEC-700-2009-009/CEC-700-2009-009.PDF	GHG
605	10/08	ARB, Climate Change, Proposed Scoping Plan a Framework for Change Pursuant to AB 32.	http://www.arb.ca.gov/cc/scopingplan/document/adopted_scoping_plan.pdf	GHG
606	9/2/04	CPUC Rulemaking 04-01-025	http://docs.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/39721.htm	Proj. Descript.
607	8/09	Sempra LNG Update Presentation to CEC	http://www.energy.ca.gov/lng/documents/costa_azul/2009-08-04_Sempra_LNG_Update_Presentation.pdf	Proj. Descript.
608	2008	Sempra Energy 2008 Financial Report	http://www.sempra.com/annualreport/financial_report.pdf	Proj. Descript.
609	5/15/08	Sempra Energy Press Release re: Costa Azul	http://public.sempra.com/newsreleases/viewPR.cfm?PR_ID=2270&Co_Short_Nm=SE	Proj. Descript.
610	9/22/09	DOE Order Allowing Sempra to Import and Export LNG	http://www.fossil.energy.gov/programs/gasregulation/authorizations/Orders_Issued_2009/ord2699.pdf	Proj. Descript.

611	8/4/09	Royal Dutch Shell Press Release re: LNG and Natural Gas Contracts with Gazprom Global	http://www.shell.com/home/content/media/news_and_library/press_releases/2009/gazprom_shell_signing_contract_08042009.html	Proj. Descript.
612	4/17/09	DOE Order Allowing Gazprom to Import LNG from Various International Sources	http://www.fossil.energy.gov/programs/gasregulation/authorizations/Orders_Issued_2009/ord2629.pdf	Proj. Descript.
613	12/15/09	EPA: Endangerment and Cause or Contribute Findings for Greenhouse Gases	http://edocket.access.gpo.gov/2009/pdf/E9-29537.pdf	GHG
614	4/08	Hansen, J. *et al.*, "Target Atmospheric CO2: Where should Humanity Aim?"	http://arxiv.org/ftp/arxiv/papers/0804/0804.1126.pdf	Proj. Descript. & GHG
615	4/08	James Hansen, "Tipping Point: Perspectives of a Climatologist"	http://www.columbia.edu/~jeh1/2008/StateOfWild_20080428.pdf	Proj. Descript. & GHG
616	5/11/08	Bill McKibben OpEd in LA Times - Civilization's last chance	http://www.latimes.com/news/opinion/commentary/la-op-mckibben11-2008may11,0,2342317,print.story	Proj. Descript. & GHG
617	2/27/08	Matthews, H.D., and Caldeira, K. "Stabilizing climate requires near-zero emissions,"	(included on CD -- not available online)	Proj. Descript. & GHG
618	2008	Collision Course: How Imported Liquefied Natural Gas Will Undermine Clean Energy in California	http://www.pacificenvironment.org/downloads/PacEnvCollisionCourse%20FINAL.pdf	Proj. Descript. & GHG
619	5/7/06	Heede, LNG Supply Chain GHG Emissions Report	http://slc.ca.gov/Division_Pages/DEPM/DEPM_Programs_and_Reports/BHP_Deep_Water_Port/ERRATA_CSLC/Vol%20II/EDC%20Attachments%20Vol%20II-06a.pdf	Proj. Descript. & GHG
620	2007	Jaramillo, et al. "Comparative Life Cycle Air Emissions of Coal, Domestic Natural Gas, LNG, and SNG for Electricity Generation"	http://www.desertrockenergyproject.com/Griffin%20-%20Final%20LNG%20GHG%20analysis%20(2006).pdf	Proj. Descript. & GHG

621	7/06	California Climate Change Center, Our Changing Climate Assessing the Risks to California	http://www.climatechange.ca.gov/publications/biennial_reports/index.html	GHG
622	6/1/05	Governor Schwarzenegger's Executive Order S-3-05	http://gov.ca.gov/index.php?/print-version/executive-order/1861/	GHG
623	6/09	33% Renewable Portfolio Standard Implementation Analysis Preliminary Results	http://www.cpuc.ca.gov/NR/rdonlyres/1865C207-FEB5-43CF-99EB-A212B78467F6/0/33PercentRPSImplementationAnalysisInterimReport.pdf	GHG & Alternatives
624	10/08	Renewable Portfolio Standard Quarterly Report	http://www.cpuc.ca.gov/NR/rdonlyres/A7691A23-1B7E-4B02-8858-9D964A3B17A3/0/RPS_Rpt_to_Legislature_Oct_2008.pdf	GHG & Alternatives
625	1/6/10	Current Renewable Procurement Status	http://www.cpuc.ca.gov/PUC/energy/Renewables/index.htm	GHG & Alternatives
626	6/19/08	OPR Technical Advisory on CEQA and Climate Change	http://www.opr.ca.gov/ceqa/pdfs/june08-ceqa.pdf	GHG
627	10/24/08	CARB draft Recommended Approaches for Setting Interim Significance Thresholds for GHG under CEQA	http://www.arb.ca.gov/cc/localgov/ceqa/meetings/102708/prelimdraftproposal102408.pdf	GHG
628	12/5/08	South Coast Interim CEQA GHG Significance Threshold	http://www.aqmd.gov/hb/2008/December/081231a.htm	GHG
629	1/08	California Air Pollution Control Officers, CEQA and Climate Change	http://www.capcoa.org/rokdownloads/CEQA/CAPCOA%20White%20Paper.pdf	GHG
630	10/09	CEC: Combined Heat & Power Market Assessment	http://www.energy.ca.gov/2009publications/CEC-500-2009-094/CEC-500-2009-094-D.PDF	Alternatives
631	8/05	Anders, et al. "Potential for Renewable Energy in the San Diego Region"	http://scerpfiles.org/cont_mgt/doc_files/E-04-04.pdf	Alternatives

632	10/07	Powers, “San Diego Smart Energy 2020”	http://www.sdsmartenergy.org/11-oct-07_SD_Smart_Energy_2020_exec-summary_FINAL1.pdf	GHG, Alternatives & Proj. Descript.
633	12/8/09	CAISO Presentation on RETPP	http://www.caiso.com/247a/247affe4625c0.pdf	GHG
634	1/8/10	CAISO RETPP Draft Final Proposal	http://www.caiso.com/2718/2718b2a210830.pdf	GHG
635	7/09	Inter-Agency Implementation of OTC Mitigation Through Energy Infrastructure Planning and Procurement	http://www.energy.ca.gov/2009publications/CEC-200-2009-013/CEC-200-2009-013-SD.PDF	GHG
636	10/15/09	Reuters article “PG&E Calif Diablo Canyon reactor cut to 50 pct”	http://www.reuters.com/article/idUSN1554013320091015	GHG
637	2005	IEA Variability of Wind Power and Other Renewables	http://www.iea.org/papers/2005/variability.pdf	GHG
638	7/09	CEC 2008 Net System Power Report	http://www.energy.ca.gov/2009publications/CEC-200-2009-010/CEC-200-2009-010-CMF.PDF	GHG
639	11/24/09	DOE Energy Storage Demo Project List	http://www.energy.gov/news2009/documents2009/SG_Demo_Project_List_11.24.09.pdf	GHG
640	12/22/09	SolarReserve Press Release	http://www.solar-reserve.com/pressReleases/RicePPAPressRelease.pdf	GHG
641	1/7/10	Itron Presentation on SB 412, Self-Generation Incentive Program	http://www.cpuc.ca.gov/NR/rdonlyres/0DF241E8-EE28-4754-8348-2CB76D0333A5/0/Presentation2SGIPImpacts.pdf	GHG
642	12/9/09	E3 and Black & Veatch ReDEC Presentation	http://www.cpuc.ca.gov/NR/rdonlyres/FBB0837D-5FFF-4101-9014-AF92228B9497/0/ReDECWorkshopPresentation1ExistingAnalyses.ppt	GHG

643	6/09	Excerpts from Final Commission Decision on Chula Vista Energy Upgrade Project	http://www.energy.ca.gov/2009publications/CEC-800-2009-001/CEC-800-2009-001-CMF.PDF	GHG
644	1/09	Excerpts from RETI Phase 1B Report	http://www.energy.ca.gov/2008publications/RETI-1000-2008-003/RETI-1000-2008-003-F.PDF	GHG

Submitted declarations the Center intends to offer into evidence:

Declaration of Tam Hunt Incorporating Rebuttal Testimony, resume attached.

Declaration of Rory Cox Incorporating Opening Testimony, resume attached.

8. Proposals for briefing deadlines, vacation schedules, and other scheduling matters:

Counsel for the Center is the lead attorney in *Communities for a Better, et al. v. City of Richmond et al*., California Court of Appeal, First Appellate District, Case No. A125618. The appeal in this case is fully briefed. The Court informed the parties that it may schedule oral argument with as little as ten days notice. The oral argument has not been scheduled. However, oral argument may change the Center's scheduling needs. If so, the Center may request changes to the schedule proposed below and any necessary accommodations.

If possible, the Center requests that the topic areas on which it plans to actively participate—Greenhouse Gas Analysis, Alternatives, and Project Description—be grouped on the same day. Although the Center's witnesses have no current conflicts for the dates listed, both experts live outside of the San Diego area and will need to travel to the hearings. The Center would request to present witnesses after the first day of the hearings, preferably on the second day, if possible. The Center would also prefer that Greenhouse Gas Analysis section occur before Alternatives. Some of the facts developed during that section may be relevant to the Center's Alternatives cross examination.

The Center requests that the opening briefs following the evidentiary hearings should be due no earlier than 4 weeks after the close of the evidentiary hearings. Given the current schedule for evidentiary hearings and intervening holidays, the Center proposes that opening briefs be due no earlier than March 5, 2010. Any reply briefs would be due no earlier than three weeks later, March 26, 2010.

For post-evidentiary issues raised by the Center, the Center would like to discuss and request that Applicant and Staff consider an alternative briefing schedule where the Center files an opening brief, Applicant and Staff file opposition briefs, and the Center files a reply brief. This would allow Applicant and Staff to address the exact issue raised by the Center rather anticipating each issue in their opening brief. This procedure would in no way change the applicable burdens of proof.

The Center's counsel's vacation schedule is not completely set due to scheduling uncertainties in other cases. Currently, the following dates are scheduled for vacation: March 27- March 31 (possibly through April 2) and May 7-10. In addition, counsel plans on scheduling a one to two week vacation at the end of February or in March.

9. A description of any modifications to the Conditions of Certification listed in the Final Staff Assessment that the party intends to propose:

The Center proposes a permit condition that requires the shut down of units 4 and 5 to partially mitigate the new emissions of Greenhouse Gases from CECP. If the Commission finds the emission of greenhouse gases is a significant impact, the Center will request that the evidentiary hearings be reopened to consider other appropriate mitigation measures and to consider alternatives related to limiting the emissions of greenhouse gases.

10. Any preferences or objections regarding the taking of testimony on a particular topic in an informal manner:

The Center opposes informal hearings for the Greenhouse Gas analysis testimony. The Center respectfully requests the opportunity to cross-examine each of the witnesses described above on this topic. The Center prefers that its witness be subject to the same procedure, i.e. cross-examination by counsel. The Center's approach to these proceedings has been premised on being involved in a proceeding that used the formal CEC procedure. It is the Center's understanding that the informal procedure is much more dependent on exchanges between each parties' experts. In addition, the Center is concerned that an informal hearing procedure may reduce the time and ability for cross examination and prejudice its case. The Center believes its ability to effectively participate in the proceedings will be served by not using informal hearing procedures for this topic.

With respect to Alternatives, the Center will defer to the preference of other Intervenors who have put forth testimony on this topic for the type of proceedings that would be most appropriate. Irrespective of the manner in which this section proceeds, the Center requests that the opportunity to cross-examine the Alternatives' witnesses in the time requested above.

REQUEST FOR DOCUMENTS FROM OTHER PARTIES[5]

A. Request to CEC Staff

The Center requests that the Staff provide the following documents and make them Exhibits in the proceeding.

<u>AIR QUALITY SECTION – GHG APPENDIX</u>

CalEPA 2006 (California Environmental Protection Agency). Climate Action Team Report to Governor Schwarzenegger and the Legislature. March, 2006.

[5] The Center is amenable to discussing our request for documents with any of the identified parties.

CAISO 2007 (California Independent System Operator). Integration of Renewable Resources, November 2007.

CAISO 2008. 2011-2013 Local Capacity Technical Analysis Report and Study Results. http://www.caiso.com/20ad/20ad77d04d70.pdf. December 29, 2008.

CEC 1998 (California Energy Commission). 1997 Global Climate Change, Greenhouse Gas Emissions Reduction Strategies for California, Volume 2, Staff Report. 1998.

CEC 2003. 2003 Integrated Energy Policy Report. December 2003.

CEC 2007. 2007 Integrated Energy Policy Report. <http://www.energy.ca.gov/2007_energypolicy/documents/index.html. 2007>.

CEC 2009b. Framework for Evaluating Greenhouse Gas Implications of Natural Gas-Fired Power Plants in California, CEC-700-2009-009, MRW and Associates. May 27, 2009.

CPUC 2008 (California Public Utilities Commission). Final Opinion on Greenhouse Gas Regulatory Strategies, Joint Agency proposed final opinion, publication # CEC-100-2008-007-D. Posted: September 12, 2008.

CECP 2007a – Carlsbad Energy Center Project/T. Hemig (tn: 42299). Application for Certification for the Carlsbad Energy Center Project. 09/11/2007. Rec'd 09/11/2007.

ALTERNATIVES SECTION

Anders and Bialek 2006 – Scott Anders and Tom Bialek, Technical Potential for Rooftop Voltaics in the San Diego Region, July 2006, research paper, [online]: http://www.sandiego.edu/epic/publications/documents/060309_ASESPVPotentialPaperFINAL.pdf.

CEC 2009a – California Energy Commission 2009 Integrated Energy Policy Report (IEPR) forecast demand for electricity in San Diego region, publication pending.

CEC 2009b – California Energy Commission, Comparative Costs of California Central Station Electricity Generation, draft staff report, August 2009.

SDG&E 2009 – San Diego Gas and Electric Request for Offers for Demand Response and Supply Resources. July 9, 2009

Wiser et al 2009 – Tracking the Sun: The Installed Cost of Photovoltaics in the U.S. from 1998-2007, Ryan Wiser, Galen Barbose, Carla Peterman, Lawrence Berkeley National Laboratory, February 2009.

B. Request to Applicant

The Center requests any and all documents, testimony, and excerpts from the FSA that the Applicant intends use to support is position on greenhouse gases. For the Alternatives section any and all documents to support its position relating to the No Project Alternative and the Generation Alternatives described in the FSA.

C. Request to City of Carlsbad

The Center also requests a full set of the City's testimony and its testimony binder.

DATED: January 14, 2010

William B. Rostov
Earthjustice
Attorney for Center for Biological Diversity

STATE OF CALIFORNIA

Energy Resources Conservation and Development Commission

In the Matter of:	)	
The Application for Certification for the CARLSBAD ENERGY CENTER PROJECT	)	DOCKET NO: 07-AFC-6

Declaration of Rory Cox in Support of Opening Testimony Submitted on January 6, 2010 Carlsbad Energy Center Project Docket No. 07-AFC-6

January 14, 2010

Rory Cox
California Program Director
Pacific Environment
251 Kearny Street, Second Floor
San Francisco, CA 94108
Ph: 415-399-8850 x302
Fax: 415-399-8860
rcox@pacificenvironment.org

I, Rory Cox, declare as follows:

1. I am currently the California Program Director at Pacific Environment. I have worked with the organization for 11 years.

2. My relevant professional qualifications and experience are set forth in the attached resume and my opening testimony and are incorporated herein by reference.

3. I prepared the testimony attached hereto and incorporated herein by reference, relating to the likelihood the project will use natural gas derived from the Costa Azul LNG import terminal and that this use will increase the CECP's projected greenhouse gas emissions.

4. I prepared the opening testimony of Rory Cox submitted on January 6, 2010 and hereby incorporate that testimony on the proposed Carlsbad Energy Center.

5. It is my professional opinion that my testimony is true and accurate with respect to the issues that it addresses.

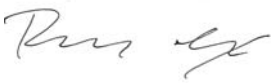
6. I am personally familiar with the facts and conclusions described within the attached testimony and if called as a witness, I could testify competently thereto.

I declare under penalty of perjury that the foregoing is true and correct to the best of my knowledge and belief.

Dated: 13 January 2010

At: San Francisco, California

Signed:



ATTACHMENT

RORY COX

Pacific Environment • 251 Kearny Street, Second Floor • San Francisco, CA (415) 399-8850 •

PROFILE

- Experience in energy policy analysis, greenhouse gas law, and advocacy.
- Leadership role in West Coast-wide clean energy coalition focused on LNG.
- Author of numerous reports, articles and opinion pieces on energy policy and markets, especially natural gas and LNG.
- Eleven years of program experience for international environmental non-profit organization.
- Over 20 years of writing, research, editorial, and publishing experience spanning non-profit, academic, and business environments.
- Extensive experience distilling complex information for diverse audiences.
- Management and recruitment experience.

PROFESSIONAL EXPERIENCE

Pacific Environment, San Francisco, CA, 2006 to Present
California Program Director

- Co-founder, lead facilitator and spokesperson of Ratepayers for Affordable Clean Energy, a coalition advocating for clean energy in California and Oregon, and against reliance on imports of LNG.
- Conducted thorough research and analyses on LNG global market trends, on purported need for LNG, and on alternatives to LNG on the West Coast
- Experience with CPUC intervener process and California energy legislation. Intervenor in CPUC proceedings on LNG and natural gas; actively supported LNG-related legislation.
- Using public relations and advocacy strategies, played key role in elevating Liquefied Natural Gas from local land use to regional energy issue.
- Authored several white papers and fact sheets on complex energy to educate lay audience on issues around LNG imports .
- Organized events, rallies, press conferences in support of clean energy.
- Project Manager for coalition website, www.RaceForCleanEnergy.org.
- Measurable results demonstrated in growth of RACE Coalition, shift in media coverage, increase in key lawmaker support, and in project cancellations.
- Member of organizational Senior Management Team.

Publications

- Co-Authored report *Collision Course: How Liquefied Natural Gas will Undermine Clean Energy in California (2008).* Published by Pacific Environment
- Editor of report, *Green Opportunity: How California Can Reduce Power Plant Emissions, Protect the Marine Environment, and Save Money (2010).* Published by Pacific Environment.
- Article: "LNG: A Dead Man Walking?" Published in *Natural Gas & Electricity Newsletter*, June 2009
- Op-Ed: "How Can China, US, Address Climate Change?" Published in *San Francisco Chronicle*, November 16, 2009
- Op-Ed: "Liquefied Natural Gas Terminal Would Undercut Green Economy" Published in *The Oregonian*, December 8, 2008
- Op-Ed: "PG&E's Big Fossil Play in Oregon." *California Progress Report*. 24 August 2009.
- Op-Ed: "Instead of Fossil Fuels, Invest Dollars in Clean Energy." *Ventura County Star* March 11, 2008.

RORY COX

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Comment Letters & Proceedings – Submitted substantive comments in the following cases on Behalf of Pacific Environment or Ratepayers for Affordable Clean Energy:

- California Public Utilities Commission, PG&E Application for Natural Gas Generation, A09-09-021, 2009
- California State Water Resources Control Board on Once Through Cooling Policy, 2009
- California Energy Commission, Permitting for Avenal, 08-AFC-01, 2009
- California Air Resource Board, Comments on AB32 Implementation Plan, 2008
- Federal Energy Regulatory Commission, Jordan Cove Energy Project, CP07-444-000, 2007
- Federal Energy Regulatory Commission, Pacific Connector Pipeline, CP07-441-000, 2007
- State Lands Commission and California Coastal Commission, Cabrillo Port LNG, 2007
- California Public Utilities Commission, Natural Gas Proceeding 04-01-025, 2004

Pacific Environment, San Francisco, CA, 1998 to 2005
Communications Coordinator

• Advocacy and Communications

- Leader of media campaigns, attracting coverage on global and local environmental issues from Wall Street Journal, New York Times, Los Angeles Times, Washington Post, NPR, OPB, The Oregonian, Bloomberg News Service, The Ecologist, and more.
- Founding editor of organizational newsletter, *Pacific Environments*. Cultivated and edited staff contributions. Managed and scheduled all phases of production.
- Project manager, editor, and co-author of report, *Unusual Suspects: Unearthing the Shadowy World of Export Credit Agencies*. Co-authored reports on Caspian Sea and North Pacific environmental issues.
- Authored and designed organizational case statement, four annual reports, and several issue-specific brochures and fact sheets.
- Producer and webmaster, www.pacificenvironment.org.

EDUCATION

- Completion of "Project Planning and Management Overview," PMI Certified Course at San Francisco State University College of Extended Learning (2009)
- M.A., International Relations, San Francisco State University (2001).
- Thesis--*Paper Tigers: Paper Consumption in Growing Asian Economies and its Effect on Deforestation.*
- B.A., Mass Communication, California State University, Chico, CA (1984). Music Director, KCSC Radio, 1981 to 1983.

STATE OF CALIFORNIA

Energy Resources Conservation and Development Commission

In the Matter of: APPLICATION FOR CERTIFICATION FOR CARLSBAD ENERGY CENTER PROJECT	DOCKET NO. 07-AFC-06

REBUTTAL TESTIMONY FOR TO THE OPENING TESTIMONY OF JIM MCINTOSH,

COMMENTS BY TAM HUNT, J.D., COMMUNITY RENEWABLE SOLUTIONS LLC
ON BEHALF OF INTERVENOR CENTER FOR BIOLOGICAL DIVERSITY

January 14, 2010

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STATE OF CALIFORNIA

Energy Resources Conservation and Development Commission

In the Matter of: APPLICATION FOR CERTIFICATION FOR CARLSBAD ENERGY CENTER PROJECT	DOCKET NO. 07-AFC-06

REBUTTAL TESTIMONY TO THE OPENING TESTIMONY OF JIM MCINTOSH

BY TAM HUNT, J.D., COMMUNITY RENEWABLE SOLUTIONS LLC
ON BEHALF OF INTERVENOR CENTER FOR BIOLOGICAL DIVERSITY

INTRODUCTION

I am an attorney with substantial experience in California renewable energy and energy efficiency legislation and regulatory policy. I am California Bar-certified (218673). I currently am the managing member of Community Renewable Solutions LLC, a consulting and renewable energy project development firm. My firm is partnered with Pacific Wind Power (Solvang, California) in a joint venture focused on developing community-scale wind and solar (20 megawatts and under) in Central California.

From early 2005 to mid-2009, I was the Energy Program Director and Attorney for the Santa Barbara-based Community Environmental Council, a non-profit organization active in state and local energy policy. I appeared regularly at the California Public Utilities Commission, Energy Commission and Air Resources Board in proceedings related to renewable energy, energy efficiency, climate change and liquefied natural gas. I submitted written comments, legal briefs and testified in workshops and hearings on a wide range of issues, including the CPUC's implementation of AB 32, SB 1368, AB 2021 and many other laws. I also served as part of the "high distributed generation" scenario working group in the CPUC's long-term procurement proceeding in 2007 and 2008 (R.08-02-007).

I am the lead author of the Community Environmental Council's *A New Energy Direction: A Blueprint for Santa Barbara County*, an action plan for weaning Santa Barbara County from fossil fuels by 2030 or sooner. I am also the lead author of the Community Environmental Council's report, *Does California Need Liquefied Natural Gas? The Potential*

for Energy Efficiency and Renewable Energy to Replace Future Natural Gas Demand. I served on the American Institute of Architects' Committee on the Environment in 2007 and 2008, advising that group regarding the merits of various California bills related to green building and renewable energy.

I am a Lecturer at UC Santa Barbara's Bren School of Environmental Science & Management, where I teach 10-week courses on renewable energy law and policy and climate change law and policy. Last, I am a regular columnist for www.renewableenergyworld.com and www.energypulse.net.

TESTIMONY

I. Summary

- A number of state-wide collaborative efforts, which are directly relevant to the proposed CECP, are currently underway and should be complete by early 2011; the McIntosh CAISO testimony and related Final Staff Assessment analyses are, accordingly, premature and incomplete
- The McIntosh CAISO testimony in this proceeding, in addition to being premature, is overly general, incomplete and inaccurate; for example, solar PV is well-established as a reliable peak power source and can help substantially in integrating wind power
- California's aggressive greenhouse gas and renewable energy mandates require "critical" scrutiny of any proposed new fossil fuel electricity generation
- The McIntosh CAISO testimony and the FSA fail to make the case that the proposed CECP is necessary to integrate renewable energy resources
- The Commission's most recent electricity demand forecast shows that the recession has obviated the need for about six power plants the size of the proposed CECP by 2018
- With this reduced demand forecast, the local reliability concerns should not be overshadowing the requisite environmental analysis.
- Adding unnecessary new fossil fuel electricity generation burdens ratepayers and makes renewable energy mandates more expensive

II. The CAISO testimony in this proceeding is an overly generalized and faulty analysis

The CAISO testimony provided by Jim McIntosh is overly general, with no particularized analysis for the proposed CECP. There are many omissions in this testimony, including a failure to even mention "resource adequacy" requirements or the

dramatic decline in forecasted energy demand throughout California from the current recession. More generally, the CAISO testimony's conclusions are premature in light of numerous current initiatives designed to assess with far greater specificity what California's grid reliability needs are, and how renewable energy projects resulting from the Governor's 33% by 2020 mandate can be integrated at the least cost to ratepayers.

A. The CAISO testimony is premature in light of three statewide initiatives that are directly relevant to the CECP

There are at least three major ongoing efforts that are highly relevant to the CECP: 1) The California Transmission Planning Group (CTPG); 2) CAISO's own 33% by 2020 integration analysis; and 3) the Inter-Agency Analysis of Generation and Transmission Options for Eliminating Reliance upon Once-Through Cooling Power Plants. These three efforts are collaborative and all involve the Commission itself.

With respect to the first effort, the 2009 Integrated Energy Policy Report ("2009 IEPR") states with respect to the CTPG and new federal efforts (p. 202)[1]: "With federal funding, western sub-regional transmission planning groups are taking on enhanced planning roles, including preparation of an integrated 10-year subregional transmission plan. Successful development and engagement of the CTPG and participation of the California ISO are essential to find consensus on projects and analyses reflective of California interests." The CTPG plans to release its revised draft plan in February of 2010 and a final conceptual plan by May.[2]

With respect to the second effort, the CAISO's Renewable Energy Transmission Planning Process (RETPP), the 33% by 2020 renewable energy integration analysis is due in "late 2010, or early 2011."[3] The "Draft Final Proposal" was released on January 6, 2010.[4] This report describes the tasks of the RETPP:

> The central objective of the ISO's proposed renewable energy transmission planning process (RETPP) is to enhance the existing transmission planning and generation interconnection processes to promote the development of infrastructure needed to achieve the state's 33 percent

[1] 2009 IEPR at 202. Available at http://www.energy.ca.gov/2009publications/CEC-100-2009-003/CEC-100-2009-003-CMF.PDF.

[2] CAISO presentation, Dec. 8, 2009: "Getting to 33% RPS by 2020 through a Comprehensive Renewable Energy Transmission Planning Process (RETPP)." P. 9.

[3] Id.

[4] Online at http://www.caiso.com/2718/2718b2a210830.pdf.

> renewable portfolio standard (RPS) by 2020. To this end, the proposed RETPP will: (1) develop a statewide conceptual transmission plan through collaboration among all transmission providers and owners in California; (2) finalize that plan for the ISO balancing authority area with sufficient detail both to establish needs and to elicit specific proposals to build the needed transmission; (3) establish, in the ISO tariff, access to renewable supply resources as a formal criterion for assessing need for specific transmission upgrades and approving their cost recovery through regulated rates; (4) enable transmission infrastructure development to move forward expeditiously and efficiently to support the state's environmental goals; (5) coordinate RETPP activities and milestones with key ongoing activities of the ISO's existing Order 890 compliant transmission planning process and the generation interconnection process in a practical way; and (6) provide opportunities for stakeholder participation and input to the process.

CAISO informed the RETPP working group convened on December 8, 2009, that the CAISO proposal is "still conceptual, many details to be developed."[5] This new 33% analysis comes on the heels of the 2007 CAISO study[6] cited by the CAISO testimony in the present proceeding. The CAISO 2007 study examined, however, the integration needs and costs of the 20% by 2010 renewable energy mandate and provided only the most generalized estimate of the costs for meeting the higher 33% by 2020 mandate.

With respect to the third effort, the Inter-Agency Analysis of Generation and Transmission Options for Eliminating Reliance upon Once-Through Cooling Power Plants is expected to produce a comprehensive plan for OTC mitigation in relation to electric system reliability concerns, though no date has been set yet for the final plan.[7]

Accordingly, it is premature to make any decision regarding the merits of the proposed CECP; the Commission should wait until the CTPG and CAISO RETPP processes have completed their analyses in late 2010 or early 2011, and should probably also wait until the Inter-Agency Analysis of OTC issues is complete.

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[5] CAISO presentation, Dec. 8, 2009: "Getting to 33% RPS by 2020 through a Comprehensive Renewable Energy Transmission Planning Process (RETPP)." P. 9.

[6] CAISO, *Integration of Renewable Resources*, online at http://www.caiso.com/1ca5/1ca5a7a026270.pdf ("CAISO 2007 study").

[7] Implementation of Once-Through-Cooling Mitigation Through Energy Infrastruction Planning and Procurement, Draft Joint Agency Staff Paper. (July 2009) Available at: http://www.energy.ca.gov/2009publications/CEC-200-2009-013/CEC-200-2009-013-SD.PDF

This conclusion is reinforced by the Commission's 2009 California Energy Demand electricity forecast, described below, which shows that conservation due to the recession will, by itself, eliminate the need for the equivalent of six new power plants the size of the proposed CECP. With this reduced demand forecast, the state has additional breathing room regarding grid reliability concerns and can afford to take more time in finding the optimal means for meeting its renewable energy mandates and local reliability concerns – before locking in new fossil-fuel generation for future decades.

This conclusion is also reinforced by the new 2009 Integrated Energy Policy Report ("IEPR"), which states (p. 209, emphasis added):

> In the California ISO balancing authority area, formal resource adequacy requirements established by both the CPUC and California ISO provide a framework for evaluating reliability. However, the need for dispatchable power plants in specific locations to support the California ISO's local reliability needs <u>remains analytically opaque</u> and there is, as yet, no mechanism to ensure that the needed resources will be built.

B. The CAISO testimony fails to establish that the CECP is necessary to balance additional renewable energy generation

1. Resource adequacy requirements for California utilities

Resource adequacy requirements are imposed on utilities and CAISO in order avoid blackouts and brownouts resulting from insufficient power supplies during high demand. A May 2009 report for the Commission, from MRW Associates ("MRW report"), describes the desired procedure for evaluating greenhouse gas emissions from natural gas power plants.[8] The MRW report describes the resource adequacy ("RA") system in California (p. 29):

> A regulatory framework exists to ensure that resource decisions result in a reliable electric system. The key element of this framework is resource adequacy (RA) requirements, which are generally presented as reserve margins and can be roughly divided as follows: planning versus operational reserve requirements and local versus regional reserve requirements. In general, planning reserve margins are imposed on load serving entities (LSE) at the state level with regulatory oversight from the California Public Utilities Commission (CPUC) and operational reserve margins are the responsibility of the grid operator under regulations from the

[8] MRW Associates, "Framework for Evaluating Greenhouse Gas Implications of Natural Gas-Fired Power Plants in California," (May, 2009).

> North American Electric Reliability Corporation (NERC) and the Western Electricity Coordinating Council (WECC) with oversight from FERC.

CPUC Decision 04-01-050 (2004) required all utilities to maintain 15-17% resource adequacy requirements, a level that has since been achieved by all utilities. RA requirements are not imposed only, or even primarily, for renewable energy integration, however. The MRW report states (p. 32): "Unscheduled outages provide a larger problem for transmission planning and are a principal motivation for resource adequacy planning." For example, the state's largest generation facilities, the nuclear power plants at San Onofre and Diablo Canyon (about 2,000 megawatts each) experience unscheduled outages not infrequently. In October of 2009, PG&E's Diablo Canyon Unit 1, with a capacity of 1,122 megawatts, was reduced to 50% capacity due to problems caused by a large storm.[9] This kind of incident happens on a fairly regular basis across the nation and afflicts all large power plants. As the MRW report states (pp. 32-33):

> If a large baseload plant were to go offline at the time of peak demand, system operators would likely struggle to supply power to meet demand, to maintain the proper operating frequency, and to avoid blackouts. In some cases the cause of an unexpected outage at a generator can be resolved within a short period of time, and the unit can be returned to duty quickly. In other cases, such as with nuclear power plants, an unexpected outage may be a symptom of a larger problem and may result in an outage on the order of months.

It is also important to note that the term "intermittency," generally used to describe wind and solar power, is a bit of a misnomer. As the International Energy Agency ("IEA") states in a major 2005 report, the more accurate term is "variability."[10] This is the case because renewables are not truly intermittent, in terms of completely starting and stopping on a regular or irregular schedule. Rather, they are <u>variable</u> because electricity generation generally ramps up and down fairly smoothly. This is an important difference when compared to planned or unplanned power outages from large baseload or shoulder power plants because when these often very large plants shut down the entire generation is generally lost – there is no variable ramp down or ramp up, as is generally the case with wind and solar facilities.

2. California's renewable energy portfolio and geographic dispersion

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[9] Online at http://www.reuters.com/article/idUSN1554013320091015.

[10] IEA, *Variability of Wind Power and Other Renewables*, 2005.

California currently has about 2,500 megawatts of wind power on the grid. This constituted only 2.4% of the total system power in California in 2008.[11] Renewable energy as a whole constituted 10.6% in 2008 – a reduction from previous years due to load growth and a stagnation in new renewable energy resource growth in recent years. However, 4.5% of California's power came from geothermal resources, which are baseload resources.[12] Another 3.5% came from biomass and small hydro, which are high capacity factor resources (though not necessarily baseload). Only 0.2% came from solar power in 2008. Accordingly, only 2.6% (wind and solar) of California's total electricity resources came from variable renewable energy resources in 2008. This is substantially less than the state receives from its small fleet of two in-state and one out-of-state nuclear power plants (about 15%), large components of which may experience unplanned outages requiring major backup sources to ensure grid reliability.

More importantly, however, wind and solar power are projected to provide about 60,000 gigawatt hours by 2020, or about 20% of the total system power, if the 33% by 2020 mandate is met. This will not all be variable generation, however, as significant energy storage projects are underway in conjunction with major wind and solar power projects. For example, both Southern California Edison and PG&E are planning to build energy storage projects pursuant to state and federal funding. PG&E received funds for a 300 megawatt "compressed air energy storage" project using salt formations near Bakersfield. Edison was awarded funds for an 8 megawatt lithium ion battery demonstration project.[13] Other companies, such as Solar Reserve, plan to include molten salt thermal storage facilities with their solar thermal power projects. Solar Reserve claims such storage facilities more than pay for themselves because they allow load shifting and sale of reliable power during peak demand times. Solar Reserve signed a contract with PG&E in December of 2009 for a 150 megawatt facility near Blythe, California, which will include storage.[14] This contract will require CPUC approval before it is finalized.

Moreover, as the Western Interconnect builds wind and solar resources throughout its geographic extent, variable resources need less balancing generation than would be the case if all facilities were located in the same area. This is known as "geographic dispersion" and results from the fact that the sun shines and the wind blows at different times throughout the Western Interconnect. The IEA report cited above highlights geographic dispersion as a potent tool for reducing net variability of wind and solar

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[11] 2008 Net System Power report, Table 2, p. 5.

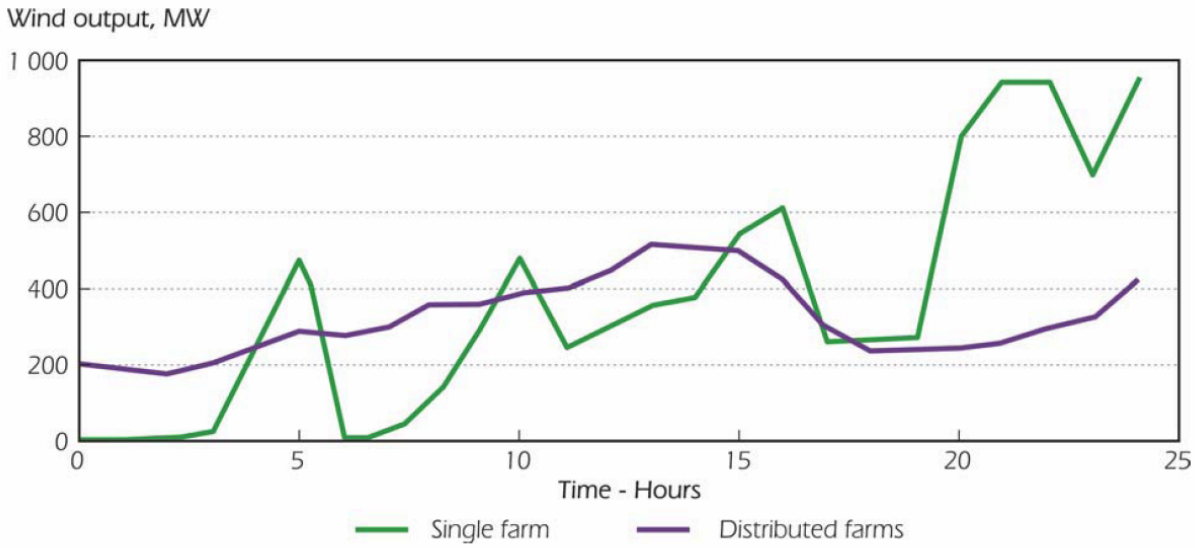
[12] Id.

[13] Online at http://www.energy.gov/news2009/documents2009/SG_Demo_Project_List_11.24.09.pdf (p.4).

[14] Online at http://www.solar-reserve.com/pressReleases/RicePPAPressRelease.pdf.

resources (p. 20). The following figure shows the hypothetical results of geographic dispersion of 1,000 megawatts of wind (p. 20):

Figure 3: The smoothing effects of geographical dispersion of a single wind farm and distributed wind farms, both rated at 1000MW (Mott MacDonald 2003:8)



In sum, assessing exactly what additional backup power facilities will be required to meet California's mandates, if any, by 2020 is a complex task. Utility resource adequacy requirements (15-17%) allow integration of far more intermittent/variable wind and solar into the system than California has today, and **CAISO is following up on its 2007 study with a detailed examination of new transmission and balancing generation requirements for the 33% by 2020 renewable energy mandate, as discussed above.**

The CAISO testimony fails to provide any quantitative analysis pertinent to the CECP, and fail to mention that the CAISO, CTPG, and Inter-Agency OTC groups are currently engaged in major analyses that are highly relevant to the CECP. How much additional generation should utilities build into their resource adequacy portfolio? And where? And how does the proposed CECP fit into these requirements? These are highly important questions that have yet to be answered. Without answers to these questions, the CAISO 2007 study, and the CAISO testimony based upon it, are no help at all in making decisions on actual projects. What if 50 such projects were proposed in California? Under the CAISO testimony's analysis all such projects would, all else being equal, be considered beneficial for integrating renewable energy into the grid. This is clearly an inadequate analysis.

The CAISO testimony acknowledges that CAISO has not engaged in an "independent analysis of the GHG emissions impacts of the proposed CECP. However, … the proposed CECP's generation characteristics would foster the integration of renewable

resources that will displace other less efficient fossil generation." (P. 10). As shown above, the CAISO testimony does not make the case that the proposed CECP is required to integrate renewable energy into the grid or that it will lead to a net reduction in GHG emissions. A particularized analysis is required to make this case and the CAISO testimony manifestly fails, under its own terms, in this regard.

3. The Final Staff Assessment also fails to demonstrate that the proposed CECP is necessary to integrate renewable energy resources

Based on the same theory as the CAISO testimony, the Final Staff Assessment ("FSA") Alternatives analysis makes two similar points (6-19): 1) the CECP is required to meet the expanding need for highly efficient dispatchable power plants in the San Diego load picket; and 2) the CECP will improve the San Diego region electrical system reliability by adding fast starting generation to respond to peak power demand and to integrate renewables. However, neither the FSA Alternatives analysis nor the CAISO testimony submitted in support of that analysis provides the specificity required to support these assertions. As discussed above, more analysis is required and is, in fact, underway with at least three state-wide efforts that relate directly to the proposed CECP.

The FSA GHG Analysis also states (4.1-100) that the "CECP would provide flexible peaking or mid-merit power necessary to integrate the growing generation from intermittent renewable sources, such as wind and solar generation."

However, the GHG Analysis fails to make the case that the CECP is necessary to integrate intermittent/variable wind or solar generation. As discussed further below, the dramatic drop in projected state-wide electricity demand by 2018-2020, in the Commission's 2009 electricity demand forecast, obviates the need for about six power plants the size of CECP.

In order to determine the firm capacity necessary for integrating up to 20% wind and solar power by 2020, the CAISO 33% by 2020 analysis and CPTG process need to be completed, which should happen by early 2011. Indeed, the MRW report makes this exact point (p. 4, emphasis added):

> Currently no public studies provide estimates of amounts and types of ancillary services needed to support intermittent renewable generation under a 33 percent RPS. Such studies are necessary to provide a better understanding of the need for flexible generation in the next decade and beyond.

Accordingly, the GHG Analysis conclusion that the proposed CECP is necessary to meet either the 2010 or 2020 renewable energy mandates, is unsupported by the analysis provided. The Commission must await completion of the CAISO 33% by 2020

and CPTG analyses before it can proclaim the value of the CECP in fostering the integration of renewables.

The joint agency staff paper on OTC mitigation (CEC-200-2009-013-SD) also supports this conclusion with its discussion of the impact of AB 32 on fossil fuel generation (p. 5):

> The energy industry's compliance with the detailed regulations that will implement the California Air Resources Board AB 32 *Climate Change Scoping Plan* presumably leads to a lower electricity demand forecast, because additional energy efficiency measures will reduce demand and rooftop photovoltaic and other distributed generation will displace sales of electricity from the bulk power system to end users. A lower demand forecast would require fewer central station generating facilities within load pockets to satisfy reliability criteria.

Indeed, the GHG Analysis itself states that all new generation must come from renewable energy to meet the 33% by 2020 RPS mandate (4.1-115): "[A]ll growth will need to come from renewable resources to achieve the 33 percent RPS, and some existing and new fossil units will generate less energy than they currently do, given the expected growth in retail sales."[15]

The GHG Analysis describes (4.1-116) how the state must retire, curtail or otherwise eliminate about 36,000 gigawatt hours (GWh) of fossil fuel electricity by 2020 to meet the 33% by 2020 renewable energy mandate. This amount is equivalent to about 12% of the state's projected annual electricity demand by 2020 (the statewide forecasts in the below figure have changed somewhat, as discussed in Section II above, but the below figures are close enough for present purposes):

[15] FSA footnote 6 (4.1-115) makes the point that there is still a need to increase short term fast ramping and starting natural gas generation to integrate renewable energy, even though on a net basis all new generation must be renewable. This is, however, simply a re-statement of the GHG Anlysis' broader point, which is unsupported by current statewide or local analyses.

Estimated Changes in Non-Renewable Energy Potentially Needed to Meet California Loads, 2008-2020

California Electricity Supply	Annual GWh	
Statewide Retail Sales, 2008, estimated [a]	265,185	
Statewide Retail Sales, 2020, forecast [a]	308,070	
Growth in Retail Sales, 2008-20	42,885	
Growth in Net Energy for Load [b]	46,316	
California Renewable Electricity	**GWh @ 20% RPS**	**GWh @ 33% RPS**
Renewable Energy Requirements, 2020 [c]	61,614	101,663
Current Renewable Energy, 2008	29,174	
Change in Renewable Energy between 2008 to 2020 [c]	32,440	72,489
Resulting Change in Non-Renewable Energy [d]	13,876 (-	36,173)

Source: Energy Commission staff

Notes:

a. Not including eight percent transmission and distribution losses

b. Based eight percent transmission and distribution losses, or 42,885 GWh x 0.08 = 46,316 GWh.

c. Renewable standards are calculated on retail sales and not on total generation, which accounts for eight percent transmission and distribution losses.

d. Based on net energy (including eight percent transmission and distribution losses), not based on retail sales.

As the GHG Analysis correctly describes, the broad trend that should occur as the state pushes toward the 33% by 2020 renewable mandate is an increasing retirement or curtailment of existing natural gas and coal-fired power plants. The state is currently at about 12% renewable energy, 1/8th of the total. This means that 20% or so new renewable energy generation will be added by 2020 (about 70,000 gigawatt hours), if the new mandate is met on time.

The CPUC's Renewable Portfolio Standard quarterly report from October of 2008 supports the GHG Analysis' conclusion that all new generation must be renewable (p. 10, emphasis added): "[I]f the state is required to generate 33% of its energy from renewable resources by 2020, then all new procurement of new energy resources between now and 2020 must be entirely renewable energy, except some new fossil for peaking capacity and to replace aging fossil plants critical to renewable integration." Accordingly, **the Commission must demonstrate that the CECP is "critical" for integrating higher levels of renewable energy into the grid**. Neither the CAISO testimony nor the GHG Analysis comes close to meeting this exacting standard.

Moreover, new fossil fuel plants result in additional costs for ratepayers if the plants aren't used as planned, such as the many existing peaker plants in the San Diego region. The GHG Analysis lists the following power plants in the San Diego load pocket, most of which are peaker plants that run at extremely low capacity factors (4.1-111,112):

Name	Capacity (MW)	2008 Capacity Factor
Palomar Energy Center	**559**	**73.1%**

South Bay Power Plant (1-4)	**696**	**16.7%**
Encina Power Plant (1-5)	**951**	**12.0%**
Larkspur Energy LLC (1-2)	**90**	**8.0%**
CalPeak Power - Border	**50**	**3.4%**
CalPeak Power – Enterprise	**49**	**3.0%**
CalPeak Power – El Cajon	**49**	**2.8%**
Kearny (1-3D)	**127**	**0.4%**
MMC Chula Vista, LLC	**44**	**0.5%**
MMC Escondido, LLC	**44**	**0.4%**
Miramar (1A-1B)	**33**	**0.3%**
El Cajon	**13**	**0.6%**
South Bay Peaking Turbine	**13**	**0.5%**

Encina Power Plant units 1-3, the units that will be retired if the CECP is constructed, had a combined capacity factor of 13.6% from 2002 to 2008.[16] All of the peaker plants that run at 3% or less constitute major costs for ratepayers because utilities must pay these power plant owners substantial fees whether they produce power or not. Every additional unnecessary fossil fuel peaker plant that is built adds to the costs of achieving California's renewable energy mandates. Even in the absence of renewable energy mandates, every unnecessary fossil fuel plant adds to ratepayer costs because costs are generally incurred by ratepayers even if the plants do not run.

Accordingly, California must retire or curtail fossil fuel generation plants, and not build new ones, while still maintaining grid reliability, in order to meet the 33% renewables by 2020 mandate. The GHG Analysis fails to demonstrate that the proposed CECP is "critical" for renewable energy integration. Such a determination cannot be made until additional statewide and local analyses from CAISO and the CTPG are completed.

C. The CAISO testimony is incorrect regarding the peak power and integration value of solar PV

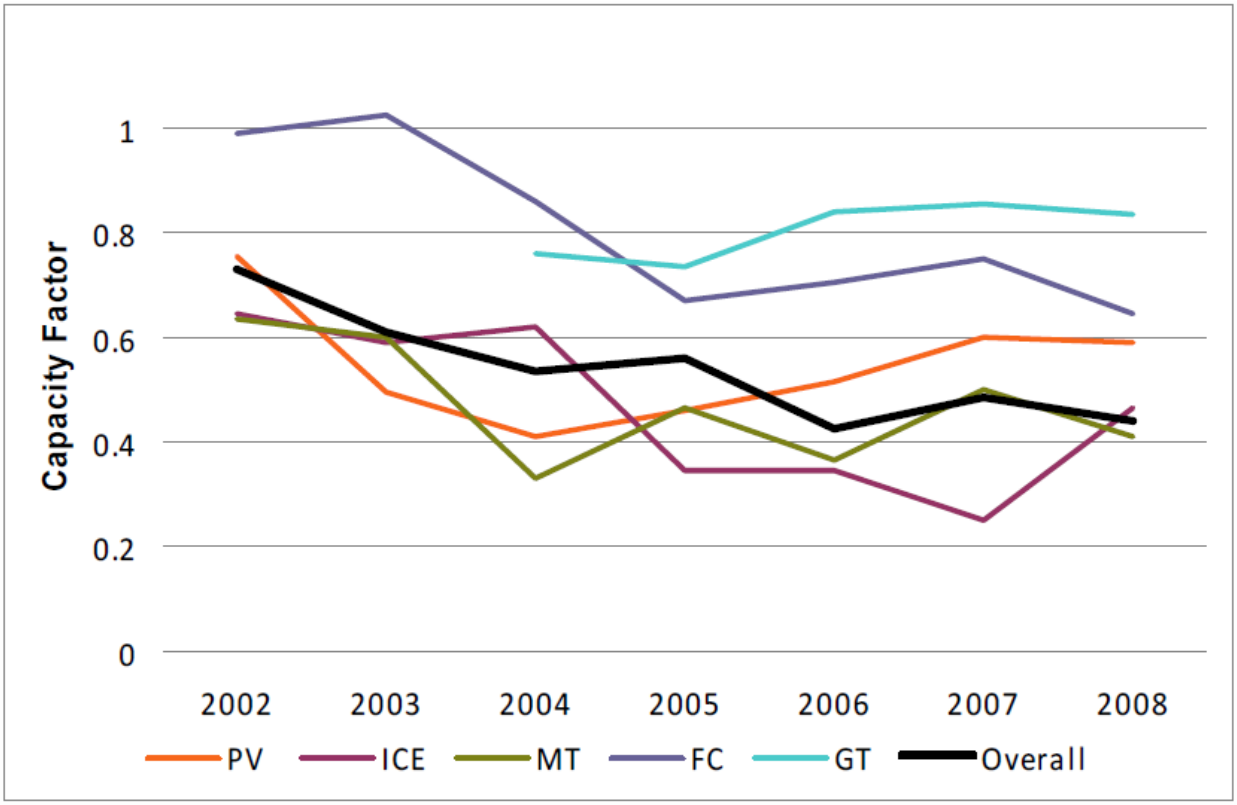
The CAISO testimony ignores the peak power value of solar PV, stating (p. 10): "Rooftop solar, both inside and adjacent to the San Diego area, is non-dispatchable and does not effectively assist in the integration of wind resources – unlike central solar with storage. As such, rooftop solar does not eliminate the need or reduce the value of flexible resources such as the proposed CECP that can ramp up and down and provide regulation services."

[16] GHG Analysis, 4.1-113, footnote 1.

To demonstrate the inadequacy of this analysis, a detailed examination of the solar PV potential in the San Diego region, and its natural complementarity to wind power, is warranted.

1. CSI and SDG&E solar PV programs

As described in the FSA, the California Solar Initiative incentivizes up to 3,000 megawatts of new solar installations by 2016. The expected proportion in the San Diego Region is 200 megawatts. This amount will not, by itself, obviate the need for the CECP. However, it helps substantially in reducing local peak demand because solar power is a reliable peak resource, with maximum power generation occurring in mid-afternoon, continuing into late afternoon, and occurring seasonally during summer and fall. A recent presentation[17] at the CPUC, as part of the SB 412 (Self-generation Incentive Program) proceeding, shows the peak power reliability benefits of solar PV to be quite high, at 60% in 2007 and 2008. This chart is entitled "CAISO Peak Hour Impact 2002 – 2008":



[17] Online at http://www.cpuc.ca.gov/NR/rdonlyres/0DF241E8-EE28-4754-8348-2CB76D0333A5/0/Presentation2SGIPImpacts.pdf.

Moreover, the CPUC has approved, or will soon approve, new wholesale distributed generation solar programs, administered by the utilities, based in large part on the peak power value of solar PV. Southern California Edison received CPUC approval for its 500 megawatt solar PV program in June of 2009. The CPUC decision, D.09-06-049, stated (p. 36, emphasis added):

> We find that the potential for building renewable projects on existing structures, thus minimizing environmental impacts, avoiding transmission upgrades, short-term cost reductions, program design that encourages technological improvements and the potential to deliver on-peak energy close to load are characteristics that set rooftop solar PV apart from other renewable technologies and make it unique.

SDG&E has a similar application pending, as the FSA notes (as does PG&E). SDG&E's program would result in an additional 52 megawatts of solar PV, a peak power resource, for a total under CSI and PV program of 252 megawatts, about half of the proposed capacity for the CECP.

There is, however, far more potential than this from solar PV on rooftops in the San Diego region. The CPUC recently completed an analysis of the state-wide potential for large rooftop PV, finding the technical potential for 604 megawatts in SDG&E territory, as shown in the following figure[18]:

Total Statewide Large Rooftop Potential

	Large Roof Potential
PG&E	2922 MWac
SCE	5243 MWac
SDG&E	604 MWac
Other	2774 MWac
Total	**11,543 MWac**

This 604 megawatt figure is, however, only the "technical potential," which assumes 100% participation by roof owners. This level of participation is not, of course, realistic, so a better analysis looks at "market potential," assuming that 50% of all roofs will participate by 2018-2020. This estimate is supported by the encouraging trends in solar installations, diminishing costs for solar PV, and the increasing interest at the local, state and federal level in easily deployable and environmentally-friendly tools for GHG

[18] E3 and Black & Veatch analysis, online at http://www.cpuc.ca.gov/NR/rdonlyres/FBB0837D-5FFF-4101-9014-AF92228B9497/0/ReDECWorkshopPresentation1ExistingAnalyses.ppt.

mitigation, as well as by the fact that the CPUC analysis did not include parking lot solar potential. Parking lot solar potential is not merely a theoretical potential in the San Diego region: a 750 kW parking lot array is already installed at the Navy's North Island base and a 235 kW parking lot array at the Kyocera manufacturing plant.

In a similar proceeding, the Chula Vista Energy Upgrade Project, the Commission declined[19] to approve the Application for Certification because the FSA was inadequate in various ways. One area in which the Commission found the FSA inadequate concerned the analysis of the potential for solar PV to meet peak demand. The Commission stated (pp. 29-30):

> Bill Powers, P.E., an engineer with over 25 years of experience in the energy field, testified that it may be feasible to install PV on rooftops and over parking lots in a quantity sufficient to meet or exceed the project's incremental increase in output. (Ex. 616, pp. 11- 14.) According to the FSA, rooftop PV would consume 4 acres per MW and for that reason is infeasible. (Ex. 200, p. 6-13.) We are unpersuaded by this evidence. Photovoltaic arrays mounted on existing flat warehouse roofs or on top of vehicle shelters in parking lots do not consume any acreage. The warehouses and parking lots continue to perform those functions with the PV in place. (Ex. 616, p. 11.) Mr. Powers provided detailed analysis of the costs of such PV, concluding that there was little or no difference between the cost of energy provided by a project such as the CVEUP compared with the cost of energy provided by PV. (Ex. 616, pp. 13 – 14.) In addition, while PV is not a quick-start technology which can be dispatched on ten minutes' notice any time of the day or night, PV does provide power at a time when demand is likely to be high—on hot, sunny days. Mr. Powers acknowledged on cross-examination that the solar peak does not match the demand peak, but testified that storage technologies exist which could be used to manage this. The essential points in Mr. Powers' testimony about the costs and practicality of PV were uncontroverted.

Therefore, the Commission itself has concluded, in a very similar case, that solar PV <u>may be</u> a peak power resource, a conclusion strongly supported by the SGIP program data showing a peak reliability factor of about 60% for solar PV, above.

Accordingly, when we sum the 200 megawatts expected from the CSI program and the 302 megawatt potential from SDG&E large rooftop potential (50% of 604 megawatts, which includes the 52 megawatts proposed for the SDG&E solar PV program), **we**

[19] Final Commission Decision (June 2009), online at http://www.energy.ca.gov/2009publications/CEC-800-2009-001/CEC-800-2009-001-CMF.PDF.

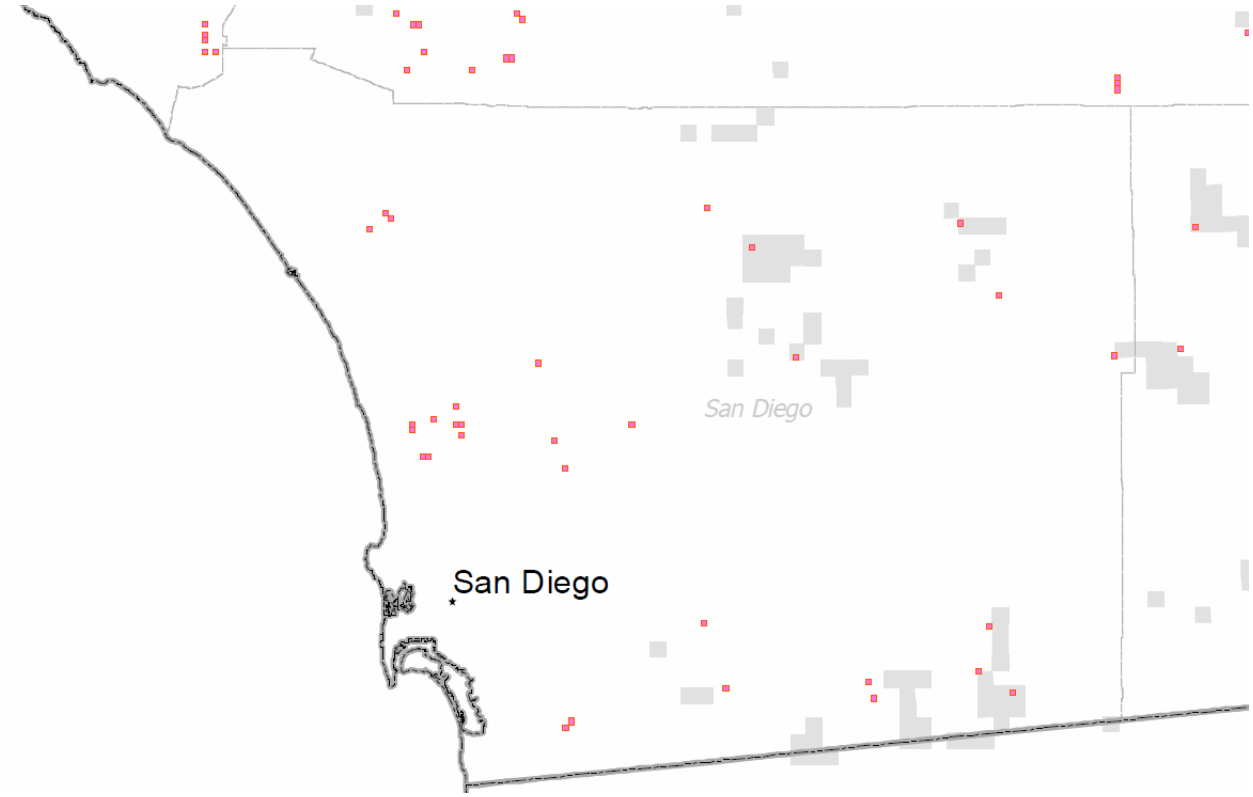
arrive at a total market potential of 502 megawatts of solar PV on large and small rooftops, almost equivalent to the proposed CECP. As we shall see below, this is not, however, the entire analysis.

2. RETI and REDEC community-scale renewable energy ("wholesale distributed generation")

The CAISO analysis also ignores the potential for community-scale renewable energy facilities, also known as "wholesale distributed generation," to meet peak and mid-merit power demand. Wholesale distributed generation interconnects on the supply-side (instead of the customer side) of distribution lines and sub-stations. These facilities don't require any new transmission lines and can often be interconnected without any upgrades. The state-wide Renewable Energy Transmission Initiative (RETI), administered jointly by the Energy Commission and CPUC, found a huge potential (28,000 megawatts) for 20 megawatt solar PV facilities around the state, utilizing existing sub-stations and requiring no new transmission lines.[20] As ground-mounted systems, requiring about 160 acres each, these facilities can use tracking technology (generally not feasible for rooftop systems) that can increase power production by up to 40% when compared to a non-tracking solar system. So while ground-mounted systems will necessarily use open space for new power generation – with associated environmental impacts – the cost-effectiveness of such systems is dramatically improved in most situations because of the use of tracking technology.

RETI found 620 megawatts of technical potential from thirty-one 20 megawatt solar PV systems in San Diego County. However, the RETI analysis did not consider urban sites for community-scale solar PV projects, nor did it consider sites that could accommodate smaller projects, from 5-15 megawatts, for example. Accordingly, the total technical potential is actually far higher than the 620 megawatts. The below figure shows the potential for these 20 megawatt facilities in the San Diego region (each pink square is a potential 20 megawatt site):

[20] RETI Phase 1A report, online at http://www.energy.ca.gov/2008publications/RETI-1000-2008-003/RETI-1000-2008-003-F.PDF



The CPUC has, in its long-term procurement proceedings ("LTPP"),considered various scenarios for meeting forecasted power demand, and meeting state GHG emission reduction and renewable energy mandates. The most recent LTPP is R.08-02-007. This proceeding, which is still underway, has been considering a "high distributed generation" scenario for meeting the 33% by 2020 RPS and I served as part of a working group examining this scenario during 2008 and 2009.

The CPUC recently convened a new group to follow up on the RETI wholesale distributed generation analysis, incorporating and expanding upon the analyses already completed in the LTPP. This group, the Renewable Distributed Energy Collaborative (ReDEC) met for the first time on December 9, 2009. **CPUC consultants E3 and Black & Veatch found 1,406 megawatts of total technical potential for solar PV in SDG&E territory, including 707 megawatts of ground-mounted solar PV**[21]:

[21] E3 and Black & Veatch analysis, online at http://www.cpuc.ca.gov/NR/rdonlyres/FBB0837D-5FFF-4101-9014-AF92228B9497/0/ReDECWorkshopPresentation1ExistingAnalyses.ppt.

Installed Capacity by PV System Type (MWac)

Utility	Ground Mounted (> 30%)	Ground Mounted	Large Roofs	Small Roofs	Total
PG&E	3,153	665	943	758	**5,519**
SCE	2,878	1,011	1,592	586	**6,067**
SDG&E	552	255	218	380	**1,406**
Other	2,417	335	1,057	500	**4,309**
Total	**9,000**	**2,266**	**3,810**	**2,224**	**17,300**

Applying the same 50% reduction applied above, to translate from technical to market potential by 2018-2020, we arrive at a total market potential of 703 megawatts from solar PV alone by 2018-2020, in SDG&E territory.

This analysis does not include, as mentioned, the potential for solar PV on parking lots; nor does it include the potential for wind or other renewable energy wholesale distributed generation throughout San Diego County. The CPUC consultants found an additional statewide technical potential of 1,054 megawatts of wind, biogas, biomass and geothermal wholesale distributed generation. Statewide renewable energy distributed energy technical potential (retail and wholesale) was calculated to be 18,355 megawatts, as shown in the following figure from the same presentation (this analysis does not include facilities larger than 20 megawatts, which are the focus of the utility Renewable Portfolio Standard programs):

Nameplate MW	DG Type					
Connection	Biogas	Biomass	Geothermal	Solar PV	Wind	Total
1. Customer Site	-	-	-	2,224	-	2,224
2. Feeder	249	34	-	3,810	-	4,093
3. Distribution Bank	-	-	-	2,267	-	2,267
4. Subtransmission	-	128	175	9,000	468	9,771
Total	249	162	175	17,301	468	18,355

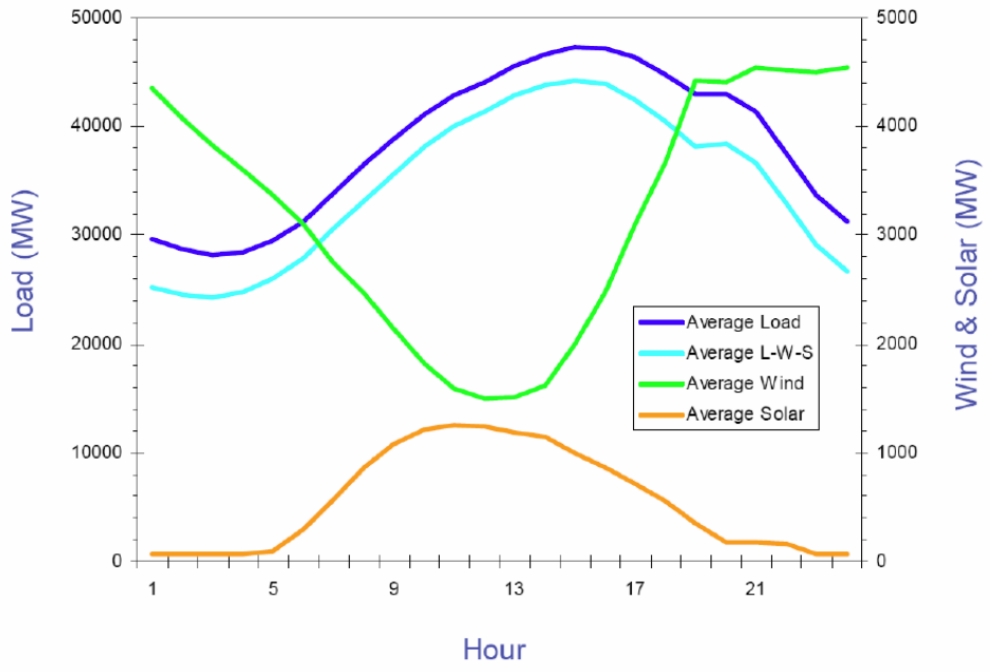
This analysis only looked at DG sites that require no new transmission lines or sub-stations and no upgrades to existing sub-stations (this is why the figure is lower than the initial RETI analysis, which did not consider whether upgrades would or would not be required).

3. Solar PV is a very good complement to wind power

Numerous analyses have found that solar power is a very good complement to wind power because solar power peaks in early to mid-afternoon and wind power generally

peaks in the early evening and morning, as the following chart shows (MRW Report, p. 41):

Figure 10: California Average Output of Wind and Solar, Load and Net Load, July 2003



As such, solar PV in the San Diego region will, contrary to the CAISO testimony, be of substantial help in integrating wind power, in the San Diego region and potentially around the state.

An additional important note: the FSA's GHG Analysis describes the expected new generation facilities in the San Diego Basin, totaling 766 megawatts (from natural gas combined cycle, peaker, biomass and hydro storage facilities) "prior to 2013." (4.1-111) The GHG Analysis concludes that 396 megawatts of new generation will still be necessary to meet the CAISO local capacity requirements. Accordingly, the actual amount of reliable renewable energy peak generation required to establish that the CECP is not necessary is not the 558 megawatt proposed capacity of the CECP; rather, the actual amount is the 396 megawatts remaining after Encina and South Bay are retired and the proposed new plants (other than CECP) are constructed. As I have demonstrated above, there are more than enough renewable energy resources available, adjusted for market potential and peak capacity factor, to provide the local capacity requirements by 2018-2020.

In sum, even without the dip in forecast electricity demand resulting from the recession (see Section II), there is more than enough market potential for solar and other

distributed generation technologies in SDG&E territory to meet the peak and mid-merit electricity demand that the proposed CECP would provide.

Accordingly, McIntosh's testimony regarding the lack of peak power value from solar PV is demonstrably wrong in this instance. Solar PV has a substantial impact on peak demand and the San Diego load pocket has enough market potential for solar PV to more than meet the peak power capacity of the proposed CECP.

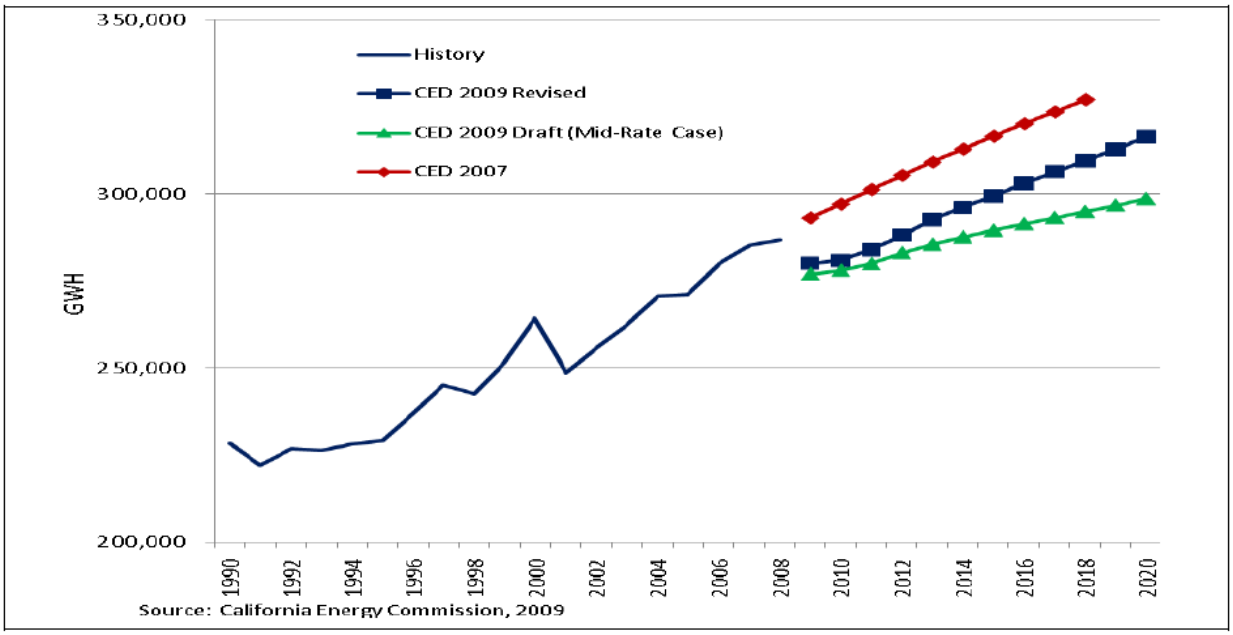
D. The CAISO testimony fails to demonstrate that the proposed CECP is necessary to meet local capacity requirements

CAISO completed a study in 2008 ("CAISO 2008 study") relating to local capacity requirements (LCR), a subset of resource adequacy requirements. The McIntosh CAISO testimony does not, however, acknowledge this study, which is a major omission. The CAISO 2008 study concluded that LCR for the San Diego region were lower than in previous analyses because of the Sunrise Powerlink 230/500 kV transmission project, which has been approved and will ostensibly bring solar, geothermal and fossil fuel power from Imperial County to SDG&E territory.[22] The study found that LCR for the San Diego load pocket falls from 3,051 megawatts in 2009 to 2,418 megawatts by 2013 (pp. 1-2).

The CAISO testimony omits any mention of the dramatic change in electricity demand forecasts released in early December. The recession has significantly reduced demand growth forecasts, obviating the need for new fossil fuel generation. The Energy Commission 2009 energy demand forecast ("CED 2009") states (p. 2): "Electricity consumption in *CED 2009 Adopted* is down by more than 5 percent and peak demand by almost 4 percent by 2018 compared to [the 2007 forecast]." This is a substantial difference and is illustrated in Figure 1 from CED 2009:

[22] CAISO, 2011-2013 LOCAL CAPACITY TECHNICAL ANALYSIS (2008), p. 3.

Figure 1: Statewide Electricity Consumption



Source: California Energy Commission, 2009

For comparison purposes, the proposed CECP would generate 2,297 GWh per year at a 47% capacity factor.[23] 2,297 GWh constitutes 0.74% of the CED 2009 forecast of 309,561 GWh annual electricity consumption by 2018. **With CED 2009 projecting a 5% reduction in electricity demand by 2018, this change alone obviates the need for more than six power plants the same size as the CECP.**

The CAISO testimony also ignores the fact that CAISO has authority to use non-RA power facilities to balance the grid and enjoys backstop authority to balance power demand within zones. (CPUC D.04-01-050, p. 11). Furthermore, the CAISO testimony states that the CAISO "expects the CECP would participate in the [CAISO's] ancillary services markets and provide regulation service," but makes no arguments as to why the CECP project is necessary for a successful ancillary services market in light of the new Market Redesign and Technology Update – which came online in early 2009 – day-ahead market more generally.

In sum, the CED 2009 forecast described above significantly reduced the electricity demand forecast for California, obviating the need for about six power plants the size of the proposed CECP. The 2008 CAISO study has not been updated in light of this reduced demand forecast. Section II.C also described in detail the ability of solar PV, both retail and wholesale distributed generation, to meet the peak demand requirements of the San Diego load pocket even without this reduction in demand.

[23] This is the capacity factor the Application for Certification seeks, though in actuality the CECP will probably have a capacity factor lower than this.

Accordingly, the McIntosh CAISO testimony fails to make the case that the proposed CECP is necessary to foster integration of renewables or to meet local capacity requirements.

III. Conclusion

The CAISO testimony and the related FSA GHG Analysis fail to provide the necessary analysis to support important assertions. More analysis is necessary and is underway as part of at least three major state-wide efforts that are highly relevant to the proposed CECP. Without completing an analysis specific to the CECP, the environmental analysis of the CECP is incomplete and inadequate.

Tam Hunt, J.D.

Community Renewable Solutions LLC

STATE OF CALIFORNIA

Energy Resources Conservation and Development Commission

In the Matter of:	)	
The Application for Certification for the CARLSBAD ENERGY CENTER PROJECT	)	DOCKET NO: 07-AFC-6

Declaration of Tam Hunt in Support of Rebuttal Testimony Carlsbad Energy Center Project Docket No. 07-AFC-6

January 14, 2010

Tam Hunt, J.D.
Community Renewable Solutions LLC
124 W. Alamar Ave. #3
Santa Barbara CA 93105
Ph: (805) 284-9028
tam@communityrenewables.com

I, Tam Hunt, declare as follows:

1) I am currently the managing member of Community Renewable Solutions LLC, a consulting and renewable energy project firm. I have worked in the renewable energy field for approximately eight years.

2) My relevant professional qualifications and experience are set forth in the attached CV and the attached testimony and are incorporated herein by reference.

3) I prepared the testimony attached hereto and incorporated herein by reference, relating to the impacts of the Project on California's greenhouse gas emissions and renewable energy goals.

4) I prepared the testimony attached hereto and incorporated herein by reference relating to the proposed Project in Carlsbad, California.

5) It is my professional opinion that the attached testimony is true and accurate with respect to the issues that is addressed.

6) I am personally familiar with the facts and conclusions described within the attached testimony and if called as a witness, I could testify competently thereto.

I declare under penalty of perjury that the foregoing is true and correct to the best of my knowledge and belief.

Dated: January 14, 2010 Signed: _____

At: Santa Barbara

ATTACHMENT

TAM HUNT
124 West Alamar Avenue, #3, Santa Barbara CA 93105
tam.hunt@gmail.com, (805) 705-1352

Tam Hunt is a renewable energy law and policy expert with substantial experience in California. He is a California Bar-certified attorney (UCLA School of Law) and is a Lecturer on renewable energy law and policy and climate change law and policy at UC Santa Barbara's Bren School of Environmental Science & Management. Hunt is a polished presenter and writer with a passion for the environment and socially conscious business. He served in the U.S. Army from 1990 to 1994.

Work Experience

Community Renewable Solutions LLC (Santa Barbara) *April, 2009 to present*

- Managing member of a new consulting company focused on climate change policy and developing medium-scale (1-20 megawatt) wind, solar and biomass projects in California (www.communityrenewables.biz)
- Consultant on renewable energy law and policy, financial analysis, climate change policy and planning, energy independence planning
- Specializing in Self-generation (SGIP) and non-FERC-jurisdictional utility-scale renewable energy projects
- Established relationships with numerous developers, policymakers, financiers and state and local agencies

University of California, Santa Barbara, Bren School *2007 to present*

- Visiting Lecturer for graduate level energy policy courses in "green MBA" program at the Bren School
- Courses include "renewable energy law and policy" and "climate change law and policy"
- http://www.bren.ucsb.edu/people/Faculty/tam_hunt.htm

Community Environmental Council (Santa Barbara) *Jan., 2005 to April 2009*

- Energy Program Director / Attorney
- Active in state climate change, energy efficiency, and renewable energy policy at California Public Utilities Commission, Air Resources Board, California Energy Commission. My work required extensive written comments and legal briefs, oral testimony at workshops and hearings, and collaboration with various coalitions. We were successful in influencing the shape of regulations in the various areas we were active.
- Created rigorous local energy and climate change solutions program (www.cecsb.org). Lead author of CEC's *A New Energy Direction: A Blueprint for Santa Barbara County*, a detailed plan for weaning our region from fossil fuels by 2030. I grew this new energy program from inception to four full-time staff, other part-time staff, and numerous interns and volunteers. We pioneered the locally-focused energy programs that are a key complement to state and federal renewable energy, energy efficiency and climate change initiatives.

- Assisted local governments in climate change policy and greenhouse gas inventories
- Lead author of the report: *Does California Need Liquefied Natural Gas? The Potential for Energy Efficiency and Renewable Energy to Replace Future Natural Gas Demand*

Jeffer, Mangels, Butler & Marmaro (Los Angeles) *Oct. 2003 to Feb. 2004*

- Associate Attorney
- Energy law, land use, environmental compliance and litigation

Hatch & Parent (Santa Barbara, now Brownstein, Hyatt, Farber & Schreck) *Sept. 2001 to Oct. 2003*

- Associate Attorney
- Water rights law, litigation, environmental law, and public law

U. S. Army *July 1990 to July 1994*

- 1/8 Field Artillery Regiment, Schofield Barracks, Hawaii and 3/5 Field Artillery Regiment, O'Brien Barracks, Germany
- Runner-up in Army-wide Air Assault Challenge, 1993

Education

University of California, Los Angeles, School of Law, J.D. *May 2001*

- Chief managing editor, 2000-2001, *Journal of International Law and Foreign Affairs*

University of California, San Diego, B.S. *June 1998*

- Major in Biology (Ecology, Behavior and Evolution sub-major), graduated *cum laude*
- Minor in Political Science

Publications

- Numerous reports for the Community Environmental Council, most importantly: lead author for *A New Energy Direction, A Blueprint for Santa Barbara County* (**www.cecsb.org**)
- Columnist for **www.renewableenergyworld.com**, **www.energypulse.net** and numerous other opeds and articles relating to energy policy and climate change
- "People or Power?: A Comparison of Realist and Social Constructivist Approaches to Climate Change Remediation Negotiations, " Spring/Summer 2001 issue of the *UCLA Journal of International Law and Foreign Affairs*

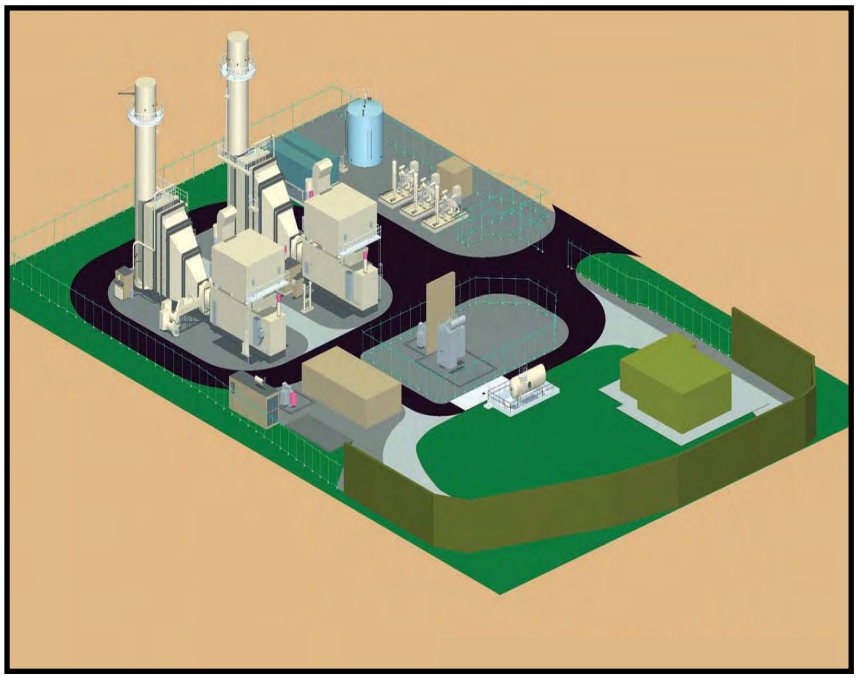
Interests

- Tennis, guitar, hiking, camping, politics, writing, philosophizin'

CALIFORNIA
ENERGY
COMMISSION

CHULA VISTA ENERGY UPGRADE PROJECT

Application For Certification (07-AFC-4)
San Diego County



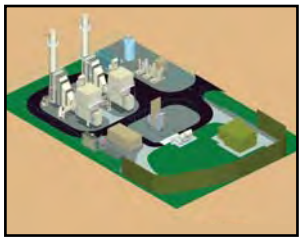
FINAL COMMISSION DECISION

JUNE 2009
(07-AFC-4)
CEC-800-2009-001-CMF

CALIFORNIA ENERGY COMMISSION

CHULA VISTA ENERGY UPGRADE PROJECT

Application For Certification (07-AFC-4)
San Diego County



FINAL COMMISSION DECISION

CALIFORNIA ENERGY COMMISSION

1516 9th Street
Sacramento, CA 95814
www.energy.ca.gov/sitingcases/chulavista/index.html

JAMES D. BOYD
Presiding Committee Member

RAOUL RENAUD
Hearing Officer

COMMISSIONERS-

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ARTHUR H. ROSENFELD
Commissioner

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Commissioner

JULIA A. LEVIN
Commissioner

BEFORE THE ENERGY RESOURCES CONSERVATION AND DEVELOPMENT COMMISSION OF THE STATE OF CALIFORNIA
1516 NINTH STREET, SACRAMENTO, CA 95814
1-800-822-6228 – WWW.ENERGY.CA.GOV

APPLICATION FOR CERTIFICATION FOR THE ***CHULA VISTA ENERGY UPGRADE PROJECT***	**DOCKET NO.** 07-AFC-4 **ORDER NO. 09-0617-28**

COMMISSION ADOPTION ORDER

This Commission Order adopts the Commission Decision on the Chula Vista Energy Upgrade Project, which we decline to certify because the proposed project is inconsistent with applicable local laws, ordinances, regulations and standards (LORS).

By this Order, we incorporate as the Commission Decision the following documents: the Presiding Member's Proposed Decision, the Committee Errata, and all exhibits referenced in those documents. The Commission Decision is based upon the evidentiary record of these proceedings and considers the comments received at the June 17, 2009 business meeting. The text of the Commission Decision contains a summary of these proceedings, the evidence presented, and the rationale for the findings reached.

This Order adopts by reference the text, Conditions of Certification, Compliance Verifications, and Appendices contained in the Commission Decision.

FINDINGS

The Commission hereby adopts the following findings in addition to those contained in the Commission Decision:

1. The Chula Vista Energy Upgrade Project does not comply with applicable LORS and the noncompliances cannot be corrected or eliminated at the proposed site. Therefore, consistent with Public Resources Code section 25523, the proposed project cannot be certified at the proposed site in Chula Vista, California.

2. This Commission Decision contains a discussion of the public benefits attributed to the proposed project as required by Public Resources Code section 25523(h).

3. The evidentiary record does not support a finding that the facility is required for public convenience and necessity and that there are not more prudent and feasible means of achieving public convenience and necessity.

4. If this Commission Decision to deny certification should be reversed or modified, the project owner would be required to implement the Conditions of Certification identified in the accompanying text.

5. The proceedings leading to this Decision have been conducted in conformity with the applicable provisions of Commission regulations governing the consideration of an Application for Certification and thereby meet the requirements of Public Resources Code sections 21000 et seq. and 25500 et seq.

ORDER

Therefore, the Commission **Orders** the following:

1. The Application for Certification of the Chula Vista Energy Upgrade Project, as described in this Decision, is hereby DENIED.

2. The denial of the Application for Certification means that the project owner shall not be subject to the Conditions of Certification and Compliance Verifications enumerated in the accompanying text and Appendices, unless this Decision is reversed or modified. As a result, the project owner is prohibited from commencing ground disturbance, site preparation, or any construction activities related to developing the Chula Vista Energy Upgrade Project site in Chula Vista, California.

3. This Decision denying certification is adopted, issued, effective, and final on June 17, 2009.

4. Reconsideration of this Decision is governed by Public Resources Code, section 25530.

5. Judicial review of this Decision is governed by Public Resources Code, section 25531.

6. The Executive Director of the Commission shall transmit a copy of this Decision and appropriate accompanying documents as provided by Public Resources Code section 25537 and California Code of Regulations, title 20, section 1768.

7. We order that the Application for Certification docket file for these proceedings be closed effective June 17, 2009, with the exception that the docket file shall remain open for 30 additional days solely to receive material related to a petition for reconsideration of the Decision.

Dated: June 17, 2009, at Sacramento, California.

KAREN DOUGLAS
Chair

JAMES D. BOYD
Vice Chair

ARTHUR H. ROSENFELD
Commissioner

JEFFREY D. BYRON
Commissioner

JULIA LEVIN
Commissioner

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II. PROJECT ALTERNATIVES

For projects such as the Chula Vista Energy Upgrade Project (CVEUP) that have been exempted from the Notice of Intention requirements by Public Resources Code section 25540.6(a),[3] the Commission is required to examine ". . . the feasibility of available site and facility alternatives. . . which substantially lessen the significant adverse impacts of the proposal on the environment." (20 Cal. Code Regs., § 1765; 14 Cal. Code Regs., § 15252.) This inquiry is consistent with the traditional Environmental Impact Report (EIR) process and the California Environmental Quality Act (CEQA) Guidelines.

The range of alternatives we are required to consider is governed by a rule of reason. This means that our consideration of alternatives is limited to those that would avoid or substantially lessen any of the project's significant effects while still continuing to attain most of the basic objectives of the project. This is especially relevant in the present case since, as discussed in the pertinent portions of this Decision, we have determined that the proposed project is in conflict with the General Plan and Zoning Ordinance of the City of Chula Vista. We also evaluated the “no project" alternative. We did not include those alternatives whose effects cannot be reasonably ascertained and whose implementation is remote and speculative. [See, *e.g.,* 14 Cal. Code Regs., § 15126.6.]

In this case, analysis of alternatives serves an additional LORS compliance function. Elsewhere in this Decision, we concluded that local LORS require the Applicant to avoid siting the project in proximity to sensitive receptors. We thus examine the alternatives analysis in both the AFC and the FSA to determine whether or not siting the project in the proposed location can be avoided.

Under both the traditional EIR process and our "functionally equivalent" process, the key issue is whether the selection and discussion of alternatives fosters informed decision making and informed public participation. (*Laurel Heights Improvement Association of San Francisco* v. *The Regents of the University of California* (1988) 47 Cal.3d 376.) To put the alternatives analysis into perspective, it is important to recognize that alternatives are considered at two stages in our process and that differing factors come into play at each stage.

[3] Public Resources Code section 25540.6(b) requires an Applicant for a power plant such as the CVEUP to include information on the site selection criteria, alternative sites, and the reasons for choosing the proposed site. Section 1765 of the Commission’s regulations further requires the parties to present evidence on alternative sites and facilities at the evidentiary hearings.

Alternatives are identified, and refined, beginning with the AFC filing (Ex. 1), and continuing through the Preliminary and Final Staff Assessments (Ex. 200), then examined once again during the Evidentiary Hearing stage. When selecting alternatives as part of its project analysis, Staff's task is to examine the objectives of the project and to identify a range of alternatives that will satisfy most of the basic project objectives while reducing or avoiding any significant impacts. The focus is on whether an alternative can, as a practical matter, be implemented. Alternatives that are not at least potentially feasible[4] are excluded at this stage because there is no point in studying those that cannot succeed.

At the project approval stage, the decision-makers evaluate the relative advantages and disadvantages of the project and its impacts, as well as any alternatives deemed to be potentially feasible, as developed through the foregoing process. The decision-makers can certify the project as fully mitigated, certify the project even with significant unmitigated impacts if there are overriding considerations, or deny certification to the project. The Commission makes this decision after considering the entire range of issues and policies relevant to its action on the project. CEQA does not mandate the choice of the environmentally "best" feasible alternative if, through the imposition of appropriate mitigation measures, a project's impacts can be reduced to an acceptable level. (*Laurel Hills Homeowners Association* v. *City Council of City of Los Angeles* (1978) 83 Cal.App.3d 515.)

SUMMARY AND DISCUSSION OF THE EVIDENCE

Applicant, Staff, and Intervenors City of Chula Vista (City) and Environmental Health Coalition (EHC) submitted evidence on this topic.

1. Project Objectives.

Applicant cited these basic objectives for the CVEUP project site:

- Site control readily available;
- Adjacent to or near an existing substation where additional peaking capacity would serve growing markets near load centers and provide system stability as well as peaking energy;

[4] "Feasibility" takes into account environmental, economic, legal, social, technological, and other considerations. (Pub. Res. Code § 21061.1; 14 Cal. Code Regs., § 15364.)

- Adjacent to or near high pressure natural gas transmission lines;
- Adjacent to or near water supply for process and sanitary purposes to maximize efficiency;
- Industrial land use designation with consistent zoning; and
- Potential environmental impacts can be mitigated and minimized. (Ex. 1, p. 6-2.)

In testimony provided at the Evidentiary Hearing, Applicant's expert witness, Sarah Madams, elaborated on the project objectives, and made it clear that one of the primary site selection objectives was to use "the existing infrastructure site." (10/2/2008 RT, 352:21-23.) As a result, Applicant limited its search for alternative sites to vacant lots in the immediate area, choosing two, both of which were closer to residences than the proposed site. (10/2/2008 RT, 349:21 to 351:15.) In responses to data requests, Applicant acknowledged that its siting objectives included using a site:

> "for which MMC holds site control, and for which there is existing infrastructure in the form of a transmission line with electrical capacity, a natural gas pipeline, and a sanitary sewer that currently serves the site. By definition, *there are no other sites that meet these objectives*." (Ex. 5, p. 25.) (emphasis added)

Staff adopted a broader set of objectives in its analysis. These objectives are:

- To construct and operate a cost-effective and efficient nominal 100 MW, natural-gas-fired, peaking load generating facility with quick-start capability;
- To minimize or eliminate the length of any project linears, including gas and water supply lines, discharge lines, and transmission interconnections;
- To deliver electricity to the SDG&E Otay Substation at 69 kV without the need for transmission system reconductoring; and
- To provide voltage support to the local 69 kV transmission system.

(Ex. 200, p. 6-5.)

Based on these objectives, Staff initially chose to analyze five alternative sites: the two nearby lots chosen by Applicant, as well as three chosen by Staff. However, two of Staff's alternatives were rejected early on in the analysis. Staff's Alternative Site A, a vacant site adjacent to the existing Wildflower Energy

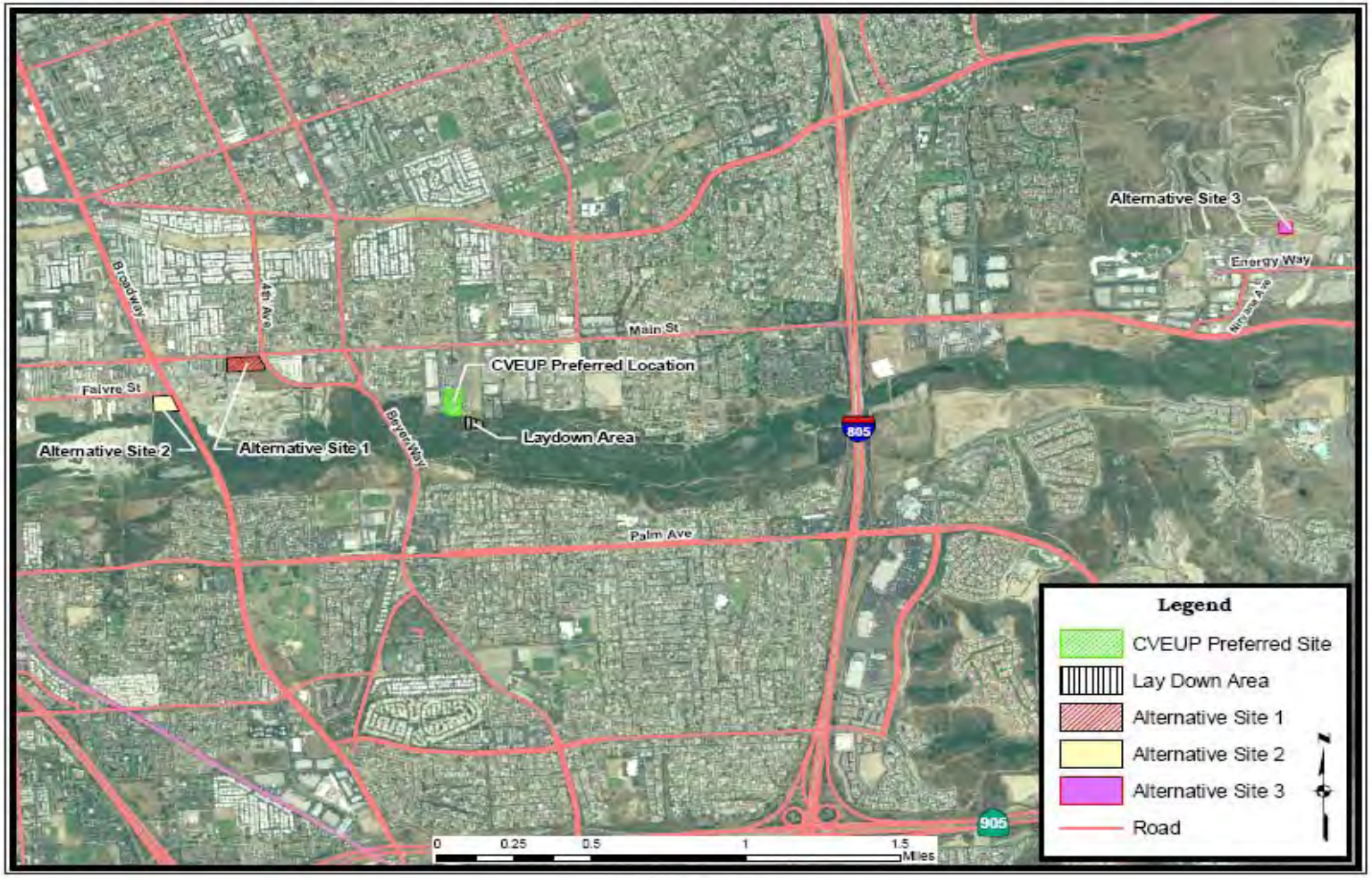
Larkspur Energy Facility, was rejected due to potential impacts to the Quino checkerspot butterfly and Otay tarplant habitat and the limited availability of suitable habitat compensation lands, the necessity of constructing a transmission line in excess of seven-miles long, and lack of site control. Staff's Alternative Site B was an unidentified site at the current South Bay Power Plant or within an undeveloped section of the SDG&E South Bay substation. Staff was unable to identify a portion of the South Bay Power Plant or substation that would support a peaker facility and be compatible with the Chula Vista Redevelopment Agency plans to develop recreational facilities in the area. Staff Alternative B was eliminated from further consideration because of considerable concern from the public and the City of Chula Vista over the redevelopment plans for the area. (Ex. 200, pp. 6-6 to 6-7.)

Staff's Alternative Site C, the Otay Landfill site, survived initial screening. It is a landfill facility which currently hosts two 3.4-MW methane-burning electrical generating plants owned and operated by Covanta Energy. (Ex. 200, pp. 6-8 to 6-9.)

As a result of the elimination of Staff Alternative Sites A and B, Staff's analysis included only its Alternative Site C, in addition to Applicant's two sites. These sites are depicted in **Alternatives Figure 1** of the FSA, which we reproduce below. We now discuss these sites, and the adequacy of the alternatives analysis performed by Applicant and Staff.

ALTERNATIVES - FIGURE 1

Chula Vista Energy Upgrade Project - Location of Alternate Sites



SOURCE: EX. 200

2. Analysis of Alternative Sites

Staff's Alternatives Table 1 below, compares the approximate lengths of linears (transmission line, gas pipeline, water and sewer lines) required for the proposed site and the three alternative sites retained for consideration. The distances to sensitive receptors and schools are also shown.

ALTERNATIVES Table 1
Comparison of Approximate Length of Linears/Distance to Receptors (feet)

	CVEUP Site	MMC Alternative Site 1	MMC Alternative Site 2	Staff Alternative Site C
Transmission Line Length	On-site	3160	6336	16,000
Gas Pipeline Length	On-site	Adjacent	4,500	2,000
Water/Sewer Connections	On-site	Adjacent	Adjacent	900
Distance to Sensitive Receptors	350	300	300	2,500
Distance to Schools	1,300	1,000	2,200	5,200

Staff also prepared a table showing a summary of its analysis of these sites in terms of their impacts relative to the proposed site. Alternatives Table 2 is reproduced below.

ALTERNATIVES Table 2
Comparison of Impacts of Alternatives to the Proposed CVEUP*

Issue Area	MMC Alternative Site 1 – Main Street & 4th Avenue	MMC Alternative Site 2 – Faivre Street & Broadway	Staff Alternative Site C – Otay Landfill
Environmental Assessment			
Air Quality	Similar to proposed site	Similar to proposed site	Similar to proposed site
Biological Resources	Greater than proposed site	Greater than proposed site	Greater than proposed site due to linear facilities
Cultural Resources	Greater than proposed site	Greater than proposed site	Greater than proposed site due to linear facilities
Hazardous Materials	Similar to proposed site	Similar to proposed site	Similar to proposed site

Issue Area	MMC Alternative Site 1 – Main Street & 4th Avenue	MMC Alternative Site 2 – Faivre Street & Broadway	Staff Alternative Site C – Otay Landfill
Land Use	Less than proposed site although a Conditional Use Permit would apply	Less than proposed site although a Conditional Use Permit would apply	Less than proposed site
Noise and Vibration	Less than proposed site	Less than proposed site	Less than proposed site
Public Health	Similar to proposed site	Similar to proposed site	Similar to proposed site
Socio-economic Resources	Similar to proposed site	Similar to proposed site	Less than proposed site
Soil and Water Resources	Similar to proposed site	Similar to proposed site	Similar to proposed site
Traffic and Transportation	Similar to proposed site	Similar to proposed site	Greater than proposed site due to linear facilities
Visual Resources	Greater than proposed site	Greater than proposed site	Similar to proposed site
Waste Management	Similar to proposed site	Similar to proposed site	Similar to proposed site
Worker Safety	Similar to proposed site	Similar to proposed site	Similar to proposed site
Engineering Assessment			
Geology, Mineral Resources, and Paleontology	Similar to proposed site	Similar to proposed site	Similar to proposed site
Transmission System Engineering	Similar to proposed site	Similar to proposed site	Similar to proposed site

*Shaded cells identify impacts greater or less than the proposed project

<u>MMC Alternative Site 1</u>: ***4th Avenue and Main Street Intersection***

MMC Alternative Site 1 (MMC Alt. #1) is located approximately 0.5 miles west of the CVEUP site near the intersection of Main Street and 4th Avenue. This property is currently used for strawberry farming and is approximately 3.87 acres in size. The property is zoned limited industrial, and is located near both a gas line and water line that run along Main Street. This site would require construction of a new switch yard and a 3,160-foot transmission line to connect to the Otay Substation. Installation of a short pipeline would be required in order to connect with SDG&E's gas pipeline in Main Street. Pipelines would also need to be installed in order to connect with the existing potable water and sewer adjacent to the site. The closest residential noise receptors are located approximately 300 feet from the site and a school is located approximately 1,000 feet east of the site.

As compared to the proposed site, MMC Alt. #1 would require a new transmission line connection to SDG&E's Otay Substation and the line would need to be underground to be compatible with the Chula Vista Redevelopment Agency plan for the Main Street corridor. Although the natural gas and water service pipelines are close to MMC Alt. #1, temporary traffic impacts and new trenching activities would be required for the short tie-ins to these lines. Although temporary, the construction of the linear facilities for this alternative would cause local traffic disruptions, leading to a greater traffic and transportation impact than the proposed CVEUP. The closest noise receptors are approximately 50 feet closer at this site as compared to the proposed site. The distance to public schools would be about approximately 300 feet closer than the proposed site. In addition, 4th Avenue and Main Street are considered Primary Gateways in the City of Chula Vista General Plan (Chula Vista General Plan, Chapter 5, p. LUT-22), increasing the visual sensitivity of this location.

The City of Chula Vista General Plan defines Primary Gateways as an entry into an important district of the City that "…*should appear visually inviting, provide adequate direction to key community places of interest, and have high quality architectural design."* The size of the LM6000 turbines, and their associated equipment, would have a greater visual resources impact at MMC Alt. #1 than the proposed CVEUP due to the proximity to Main Street and 4th Avenue gateways. The location of MMC Alt. #1 on undeveloped native soil increases the potential for impacts to both surface and buried cultural resources as compared to the construction of the proposed CVEUP on previously disturbed fill, thereby avoiding impacts to surface or buried cultural resources. In addition, the development of MMC Alt. #1 from farming to power generation could require additional mitigation for impacts to any adjacent biological resources.

Although biological surveys have not been conducted at the alternative sites, impacts to biological resources are generally greater from the development of farmed/undeveloped areas than the repowering or reuse of an existing power plant site. It is unknown if site control is possible at MMC Alt. #1. (Ex. 200, pp. 6-7 to 6-8.)

MMC Alternative Site 2: ***Faivre Street and Broadway***

MMC Alternative Site 2 (MMC Alt. #2) is located approximately 1 mile west of the CVEUP site near the intersection of Faivre Street and Broadway. The approximately 2.57 acre property is zoned limited industrial and is currently undeveloped. Construction of a new switch yard and a 6,336-foot transmission

line would be necessary in order to connect to the existing Otay Substation. The closest noise receptors are located approximately 300 feet from the site and a school is located approximately 2,200 feet northeast of the site.

As compared to the proposed site, MMC Alt. #2 would require a new transmission line connection to SDG&E's Otay Substation and the line would need to be underground to be compatible with the Chula Vista Redevelopment Agency plan for the Main Street corridor. The natural gas and water service pipelines are close to MMC Alt. #2. The size of the LM6000 turbines, and their associated equipment, would have a greater visual resources impact at MMC Alt. #2 than the proposed CVEUP due to the proximity to Broadway. The closest noise receptors are approximately 50 feet closer to this site than the proposed site. Public schools would be slightly closer. The location of MMC Alt. #2 on undeveloped native soil increases the potential for impacts to both surface and buried cultural resources. In addition, the development of MMC Alt. #2 from undeveloped land to power generation could require additional mitigation for impacts to any on-site or adjacent biological resources. Although biological surveys have not been conducted at the alternative sites, impacts to biological resources are generally greater from the development of farmed/undeveloped areas than the repowering or reuse of an existing power plant site. It is unknown if site control is possible at MMC Alt. #2. (Ex. 200, p. 6-8.)

Staff Alternative Site C: ***Otay Landfill***

Staff Alternative Site C (Staff Alt. C) is located at 1700 Maxwell Road in the City of Chula Vista. Owned by the Allied Waste Company, it is a landfill facility which currently includes two 3.4 MW methane-burning electrical generating facilities owned and operated by Covanta Energy. Covanta Energy leases several acres of land from Allied Waste Company for the methane-burning internal combustion engines and owns the gas rights under the landfill. Sufficient land is available adjacent to one of the existing power plants to site two LM6000 gas combustion turbines and the associated equipment. The Otay Landfill is currently designated as both Open Space and General Industrial, with the existing generating facility within the General Industrial Area. Staff Alt. C would not require a Conditional Use Permit if under the jurisdiction of the City of Chula Vista because electrical generating facilities are a permitted use under this zoning designation.

The Otay Substation is located approximately three miles from the site. One possible electrical transmission interconnection route to the substation would be overhead for approximately one mile before going underground to be compatible with the Chula Vista Redevelopment Agency plan for the Main Street corridor.

Staff Alt. C would require construction of a 0.45 mile gas pipeline and connection to the potable water pipeline approximately 0.2 miles south of the site. The site is located adjacent to auto wrecking yards and is about 2,000 feet from the nearest residence. The closest school is approximately one mile away.

Construction of the linear facilities for this alternative would cause temporary local traffic disruptions. Distances to sensitive receptors and schools would be much greater than in the proposed site, reducing noise impacts and land use concerns over the proposed CVEUP. Given its industrial setting, significant visual impacts are not expected. It is unknown if Staff Alt. C is available for development. (Ex. 200, pp. 6-8 to 6-9.)

3. Committee Discussion of Alternative Sites Analysis

In view of our determinations, as discussed in the **Land Use** section of this Decision, that the CVEUP is in conflict with LORS, we must now decide whether or not a feasible alternative site which would eliminate these conflicts exists. Both Applicant and Staff concluded that no feasible alternative site exists which would meet most project objectives. The evidence compels us to disagree.

A reasonable, feasible alternative must be one that meets most basic project objectives while avoiding or substantially lessening any of the significant effects of the project. [CEQA Guidelines, § 15126.6(a).] Stating project objectives too narrowly or too specifically could artificially limit the range of reasonable, feasible alternatives to be considered. Therefore, we have given careful consideration to the selection of project objectives in this case, especially the stated objectives of reusing the existing infrastructure and locating the project at a site designated for industrial use with consistent zoning.

The project objectives formulated by Applicant and Staff include, in one form or another, the reuse of the existing plant's infrastructure such as project linears. While it may be advantageous to reuse existing infrastructure as long as it is serviceable and up-to-date if the reuse does not create or perpetuate adverse environmental impacts, the evidence shows that in this case there are few advantages beyond the obvious economic ones, and there are disadvantages that could be avoided by the use of a site in a General Industrial-Zoned area of Chula Vista.

The objective of reusing the existing infrastructure reduced Applicant's number of alternative sites to two, both of them so near to the proposed site that any differences between them and the proposed site are best characterized as de

minimis. Neither of Applicant's alternative sites meets Applicant's own stated objective of being consistent with local zoning, nor resolves the LORS conflicts we have identified in the **Land Use** section of this Decision. Yet those LORS conflicts constitute adverse environmental impacts whose importance outweighs the largely economic advantages of reusing the existing site infrastructure.

The evidence leads us to conclude that the Applicant defined its objectives so narrowly as to preclude a reasonable range of alternatives. While it is true that a project's objectives should guide the selection of alternative sites for analysis, when objectives are defined too narrowly, the analysis of alternative sites may be inadequate. (*City of Santee v. County of San Diego (1989) 214 Cal. App. 3d 1438, 1455*.) In this case, by the Applicant's admission (10/2/2008 RT 349:21 to 351:15), the project objectives were defined so narrowly as to preclude all other sites.

Furthermore, given that both alternatives analyzed by the Applicant were closer to sensitive receptors than the proposed site, and have the same LORS conflicts, we find that Applicant has not met its duty to analyze a reasonable range of alternative sites. It appears to have limited its analysis to the two sites discussed above primarily based upon the project and site objectives—which we find to be impermissibly narrow. An alternative sites analysis that complies with CEQA and our CEQA-equivalent process must include a reasonable range of alternatives, chosen because they have the potential to avoid impacts caused by the proposed site. We find that Applicant's analysis fails to meet this standard.

Staff also concluded that none of the alternative sites was superior to the proposed site. Yet the Otay Landfill site is much farther from sensitive receptors than the other two sites, and it is in a General Industrial zone where power plants are a permitted use, thereby fulfilling the requirement that an alternative site lessen the impacts of the project. However, since its location would require construction of a three-mile long transmission line and a new gas line, Staff concluded that the costs of that construction, and the environmental impacts of construction and the overhead portion of the transmission line, outweighed the impacts of the Applicant's preferred site.

The record contains only speculation—to which we can assign no evidentiary weight--that the construction costs might render the Otay Landfill site economically unfeasible. MMC's Mr. Scarborough testified that constructing a three-mile long transmission line from the Otay Landfill site to the Otay substation would cost around a million dollars a mile. (10/2/2008 RT 355:9.) Other impacts

identified in connection with construction of linears from the Otay Landfill site were temporary in nature. Visual impacts were not expected. (Ex. 200, p. 6-9.)

The Applicant also voiced concern about the Otay Landfill site due to possible engineering issues. Applicant stated in response to Data Requests that siting a power plant on a landfill raised concerns over subsidence, disturbance of the landfill containment liner and complex engineering. (Ex. 5, p. 26.) Applicant provided no evidence or expert testimony to support these expressed concerns, and thus they, too, cannot be given any evidentiary weight.

The Otay Landfill site was rejected primarily for economic and engineering reasons on the basis of only an offhand estimate of the costs of constructing a transmission line and speculation as to whether or not there would be engineering problems that would make that alternative site infeasible. The evidence of record is silent as to whether the fact that alternative site C is consistent with local land use LORS, and thereby eliminates a known, significant impact, outweighs these cost and engineering concerns. A reasonable alternatives analysis must contain a meaningful level of detail showing why an alternative is infeasible. *Laurel Heights Improvement Association v. The Regents of the University of California*, (1988) 47 Cal. 3d 376, 399-407. On this basis, we conclude that the analysis of the Otay Landfill site is inadequate to support Staff's conclusion that it does not represent a feasible alternative.

Moreover, Applicant has stated that there may be appropriate alternative sites in eastern Chula Vista, and it is uncontroverted that Applicant analyzed no such sites. Applicant's witness stated that the eastern section of Chula Vista "is a very large area." (Ex. 5, p. 26; 10/2/2008 RT 352:13-19.) This, coupled with evidence in the record that the City encouraged MMC, prior to filing this AFC, to consider alternative sites so as to avoid siting the plant in the Main Street Redevelopment Area, and asked the Energy Commission Project Manager to consider sites in eastern Chula Vista (Ex. 200, pp. 6-15), leads us to the conclusion that not enough was done to select and analyze potential sites in eastern Chula Vista.

We cannot, on the basis of the record, find that the analysis of alternative sites performed by Applicant and Staff satisfies the requirement that an alternative sites analysis include a reasonable range of alternatives. For the same reasons, we find that the Chula Vista General Plan requirement to avoid siting power plants within 1,000 feet of a sensitive receptor has not been satisfied by the analysis of alternative sites described in the evidence of record, in violation of the

General Plan as discussed in the **Land Use** section of this Decision. We thus will require a more in-depth analysis of a reasonable range of alternative sites, by both Staff and Applicant, in the event the Applicant chooses to pursue this Application further.

4. Technology Alternatives/No Project Analysis

The evidence of record shows that both Applicant and Staff examined technological alternatives to the CVEUP as well as the consequences of not constructing the proposed project.

a. Generation Technology Alternatives

1. Conservation and Demand Side Management

One alternative to meeting California's electricity demand with new generation is to reduce the demand for electricity. Such "demand side" measures include programs that increase energy efficiency, reduce electricity use, or shift electricity use away from "peak" hours of demand.

In California the Energy Commission adopts comprehensive energy efficiency standards for most buildings, appliance standards for specific items not subject to federal appliance standards, and load management standards. At the federal level, the Department of Energy adopts national standards for appliance efficiency and building standards to reduce the use of energy in federal buildings and at military bases.

At the local level, most if not all investor-owned and municipal utilities administer demand side management and energy conservation programs. These include subsidies for the replacement of older appliances through rebates, building weatherization programs, and peak load management programs. In addition, several local governments have adopted building standards which exceed the state standards for building efficiency, or have by ordinance set retrofit energy efficiency requirements for older buildings.

Even with this great variety of federal, state, and local demand side management programs, the state's electricity use is still increasing as a result of population growth, growth in the size of homes and the energy requirements of appliances in homes, and business expansion. Current demand side programs are not sufficient to satisfy expected growth in electricity needs. Even if the more aggressive demand side programs envisioned in current state policy satisfy

expected growth in electricity needs, a significant amount of aging existing capacity will need to be replaced in the next ten to fifteen years. Both new generation and new transmission facilities will be needed in the immediate future and beyond in order to maintain adequate supplies.

2. Renewable Resources

Applicant and Staff compared various alternative technologies such as solar, wind, and biomass with the proposed project. There are no geothermal resources in the project vicinity and the region lacks water sources for hydroelectric power.

Both solar and wind generation have little or no air pollutant emissions and visible plumes. In the case of biomass, however, emissions can be substantially greater. Central station solar and wind resources require large land areas in order to generate 100 MW of electricity. Specifically, central receiver solar thermal projects require approximately five acres per MW; 100 MW would require approximately 500 acres, or 50 to 100 times the amount of land area taken by the proposed CVEUP facility. Parabolic trough solar thermal technology requires similar acreage per MW. Wind generation generally requires about 4.5 acres per MW; about 450 acres would be needed to generate 100 MW although in some cases this land can also be used for agricultural purposes in addition to wind generation. It is unlikely that this amount of acreage, and specifically acreage that offers the specific needs of these renewable resources would be available in the project area. The need for extensive acreage would also add to the complexities of local discretionary actions for land use modifications.

The Applicant effectively eliminated photovoltaic (PV) generation from its alternatives analysis when it stated that it did “not meet the project objective of utilizing natural gas available from the existing transmission system.” (Ex. 1, p. 6-13.) This is another example of a too-narrow project objective artificially limiting the range of potential alternatives. Requiring the use of natural gas as a project objective eliminates consideration of alternative fuel sources. Bill Powers, P.E., an engineer with over 25 years of experience in the energy field, testified that it may be feasible to install PV on rooftops and over parking lots in a quantity sufficient to meet or exceed the project’s incremental increase in output. (Ex. 616, pp. 11- 14.) According to the FSA, rooftop PV would consume 4 acres per MW and for that reason is infeasible. (Ex. 200, p. 6-13.) We are unpersuaded by this evidence. Photovoltaic arrays mounted on existing flat warehouse roofs or on top of vehicle shelters in parking lots do not consume any acreage. The warehouses and parking lots continue to perform those functions with the PV in

place. (Ex. 616, p. 11.) Mr. Powers provided detailed analysis of the costs of such PV, concluding that there was little or no difference between the cost of energy provided by a project such as the CVEUP compared with the cost of energy provided by PV. (Ex. 616, pp. 13 – 14.) In addition, while PV is not a quick-start technology which can be dispatched on ten minutes' notice any time of the day or night, PV does provide power at a time when demand is likely to be high—on hot, sunny days. Mr. Powers acknowledged on cross-examination that the solar peak does not match the demand peak, but testified that storage technologies exist which could be used to manage this. The essential points in Mr. Powers' testimony about the costs and practicality of PV were uncontroverted.

If new biomass technology is developed in the near future, increased energy production could come from the Otay Landfill and other landfills in the area, limiting the necessity for power from base-load power plants. Nonetheless, such technology is not currently available and thus cannot be considered a potentially viable alternative generation technology in this case. Thus, based upon the evidence of record, we find that, at this time, geothermal, hydroelectric, wind or biomass technologies do not present feasible alternatives to the proposed project.

We find the analysis of the PV alternative is insufficient to comply with the requirements of the California Environmental Quality Act, the Warren-Alquist Act, and their respective regulations. In the event the Applicant chooses to pursue this matter further, we will require a more in-depth analysis of the PV alternative by both Staff and Applicant.

b. The "No Project" Alternative

The "no project" alternative under CEQA assumes that the project is not constructed. In the CEQA analysis, the "no project" alternative is compared to the proposed project and determined to be superior, equivalent, or inferior to it. The CEQA Guidelines state that "the purpose of describing and analyzing a No Project Alternative is to allow decision makers to compare the impacts of approving the proposed project with the impacts of not approving the proposed project" [CEQA Guidelines, § 15126.6(i).] Toward that end, the "no project" analysis considers "existing conditions" and "what would be reasonably expected to occur in the foreseeable future if the project were not approved…" [§ 15126.6(e)(2).] CEQA Guidelines and Energy Commission regulations require consideration of the "no project" alternative. The "no project" alternative also

provides a baseline against which the effects of the proposed project may be compared.

If the "no project" alternative were selected, the construction and operational impacts of the CVEUP—including the violations of LORS discussed in the **LAND USE** section--would not occur. Demolition of the existing Chula Vista Power Plant would not occur nor would grading of the site and installation of new foundations, piping and utility connections be required. MMC Energy, Inc. or another entity would continue to operate the existing Chula Vista Power Plant as a peaking power plant. (Ex. 1, p. 6-3.) The existing Chula Vista Power Plant is not under the jurisdiction of the California Energy Commission and the operation of this facility would not be monitored nor would the permit conditions be enforced by the Energy Commission's specialized Compliance Unit under California Code of Regulations, title 20, section 1770.

Staff, in the FSA, stated that in the absence of the CVEUP, MMC Energy, Inc. or another power company would likely propose that other power plants be constructed in the project area to serve the demand that could be met with the CVEUP, and that those plants could consume more fuel and emit more air pollutants per kilowatt-hour generated than the CVEUP. This strikes us as purely speculative; it seems just as likely that MMC or another operator would continue to operate the existing plant and another plant would not be built instead of the CVEUP.

Nor are we convinced that the CVEUP would be a significant step toward removing the reliability-must-run (RMR) status of the South Bay Power Plant. Llena Green of CAISO, was questioned at length on this point by all parties at the evidentiary hearing. She made it clear that while the CVEUP's addition of 50 MW to the 45 MW of the existing facility would make a contribution toward removal of RMR, this contribution would be small in comparison to South Bay's 690 MW output, and that much more generation capacity would need to be developed to replace South Bay. (10/2/2008 RT 234:4; 235:2; Ex. 20; Ex. 804.)

Based upon the evidence of record, we find that it cannot be concluded that the "no project" alternative would have serious, long-term adverse consequences. (*See also,* Ex. 200, p. 6-15.)

FINDINGS AND CONCLUSIONS

Based upon the weight of the evidence of record, we make the following findings and reach the following conclusions:

1. The evidence of record shows that only one potentially feasible alternative site was analyzed.

2. The evidence of record shows that a reasonable range of alternative sites has not been considered.

3. The project objectives include reuse of the existing infrastructure and locating the project in an area consistent with land use LORS.

4. The objective of reusing the existing infrastructure severely limits the range of alternative sites.

5. Acceptable alternative sites are very likely to exist elsewhere in Chula Vista which avoid the adverse impacts of the proposed site, but only one such site was analyzed.

6. The analysis of the Otay Landfill site is insufficient to foster informed decision making and public participation.

7. The failure to examine other potentially feasible alternative sites does not meet the requirement to foster informed decision making and public participation.

8. The evidence of record shows that the Applicant established as a project objective the use of natural gas fuel.

9. The objective of using natural gas fuel artificially limited the range of alternative generation technologies evaluated.

10. Conservation and other demand-side management programs are currently not sufficient to satisfy California's <u>local</u> electricity needs.

11. Photovoltaic solar arrays on rooftops and over parking lots may be a viable alternative to the project.

12. Conservation and other demand-side management programs are currently not sufficient to satisfy California's electricity needs.

13. The "No Project" Alternative would maintain the status quo and avoid any new adverse impacts, but do nothing to alleviate any existing adverse impacts.

14. The CVEUP project would provide local area generation.

15. The existing project provides local area generation.

16. If the existing power plant is sufficient to meet the area's power generation needs the "No Project" Alterative would have no adverse impacts on local system reliability.

17. There is no evidence in the record to show that the existing project is insufficient to meet the area's needs.

We conclude, therefore, that the evidence of record lacks a sufficient analysis of a reasonable range of alternatives and fails to comply with the requirements of the California Environmental Quality Act, the Warren-Alquist Act, and their respective regulations. We will require a more in-depth analysis of a reasonable range of alternative sites and alternative generation technologies, by both Applicant and Staff, in the event the Applicant chooses to pursue this Application further.

No Conditions of Certification are required for this topic.

Summary of PV Potential Assessment in RETI and the 33% Implementation Analysis

Re-DEC Working Group Meeting

December 9, 2009

Energy and Environmental Economics, Inc.

BLACK & VEATCH

Renewable Energy Transmission Initiative

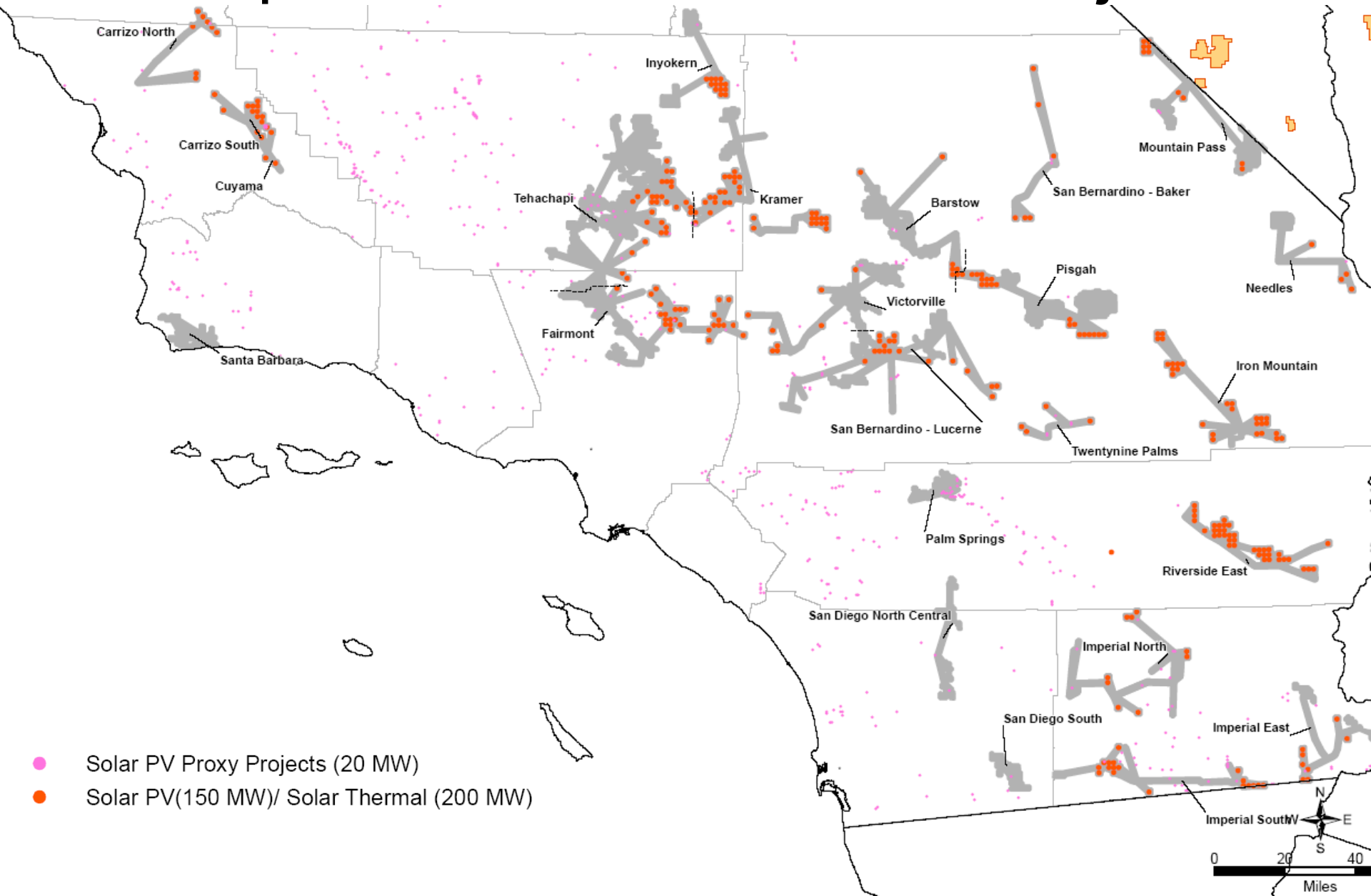
RETI is a statewide planning process to identify transmission projects needed to accommodate California's renewable energy goals.

- California law requires 20% of retail energy sales to come from renewable sources by 2010. The state has also adopted the goal of 33% by 2020.
- Development of renewable generation has slowed in CA. Transmission is a limiting factor.
- RETI is facilitating planning and permitting for competitive renewable energy zones (CREZs)

Solar in RETI

- Large Scale – 150-200 MW, solar thermal or solar PV. Detailed analysis.
- Distributed Wholesale Generation – 20 MW solar PV near substations. Very rough analysis.
- Smaller Systems – Behind the meter applications. Assumed to happen as part of RETI "Net Short" calculation.

Example RETI Phase 1 Solar Projects



- Solar PV Proxy Projects (20 MW)
- Solar PV(150 MW)/ Solar Thermal (200 MW)

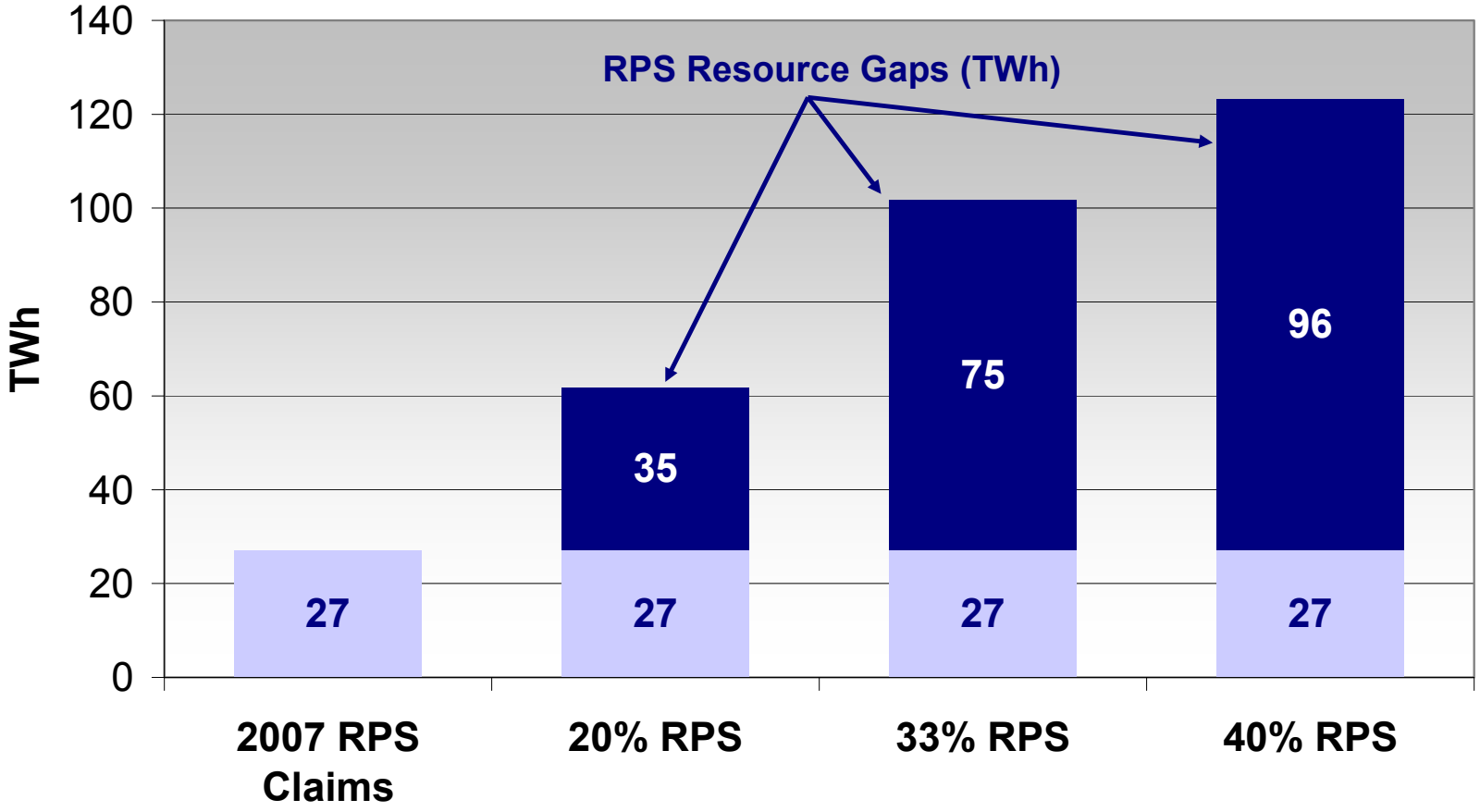
Solar PV Did Not Play a Significant Role In RETI Phase 1 (2008)

- Conventional tracking crystalline technology too expensive to compete
- Thin film technology deemed not fully proven and commercially available
- Thin film sensitivity showed potential for large scale competitiveness – if costs could be reduced ($3700/kW$_{ac}$)

CPUC 33% RPS Implementation Analysis

- CPUC commissioned 33% RPS Implementation Analysis as part of long-term procurement planning (LTPP) proceeding
- Goals of analysis:
  - Inform decision-makers about the likely cost and environmental impacts of implementing a 33% Renewables Portfolio Standard by 2020
  - Identify barriers to implementing a 33% RPS by 2020 and most likely timelines for achieving 33%
  - Inform decision-makers about the potential need for new transmission and new resources to integrate intermittent renewables
  - Inform California utilities' 2010 long-term procurement plans
- Report with preliminary results issued June 2009, available at www.cpuc.ca.gov/33percent

2007 Claimed RPS Resources for California Utilities and 2020 RPS Resource Gaps



Note: Gap based on 2007 CEC load forecast minus 2007 claims from CEC Net System Power Report. No adjustments for EE or CHP that is incremental to forecast.

33% RPS Cases Studied

1. **20% RPS Reference Case**: Existing state policy with 20% RPS
2. **33% RPS Reference Case:** Most likely case for reaching 33%, assuming that most contracts signed by IOUs with project developers proceed on schedule
3. **High Wind Case**: Meets 33% RPS resource gap with mix of new resources that includes substantial quantities of wind in California and Baja
4. **Out-of-State Delivered Case**: Meets 33% RPS resource gap with mix of new resources that includes wind resources in California and Wyoming and geothermal resources in Nevada
5. **High DG case**: Meets 33% RPS resource gap with mix of new resources that minimizes the need for new bulk transmission. These include 15,000 MW of distributed solar PV.

33% RPS Reference Case

Cost and Rate Impacts in 2020

- Total CA revenue requirement: ***$54.2 billion (16.9¢/kWh)***
- Incremental to 20% RPS Case: ***+$3.6 billion (+1.1¢/kWh)***
- New transmission investment: ***$12.3 billion***

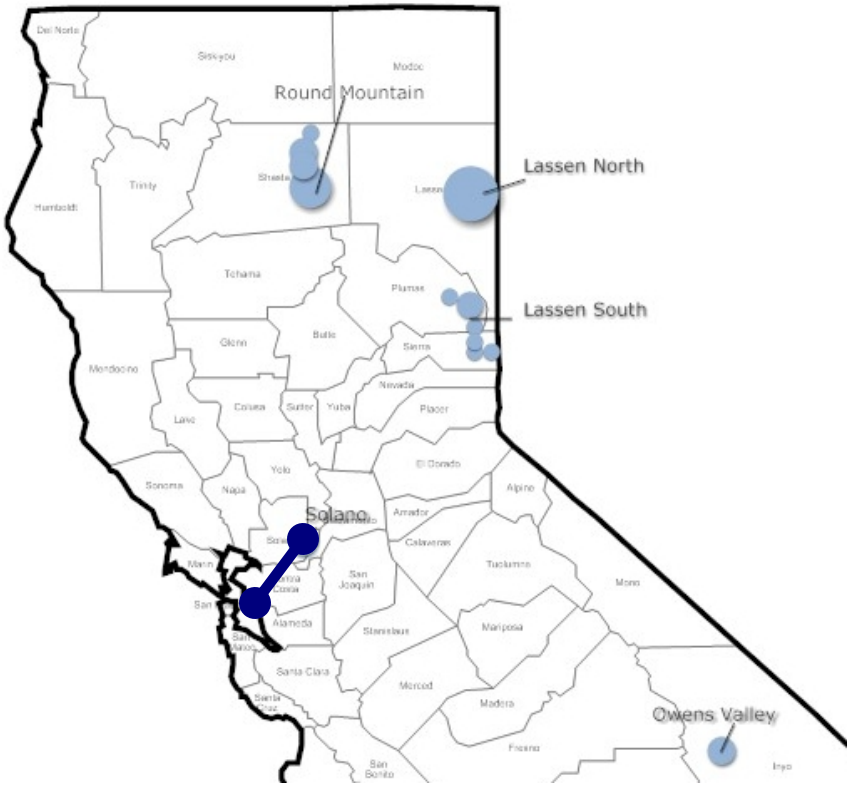
Resources Selected by Type

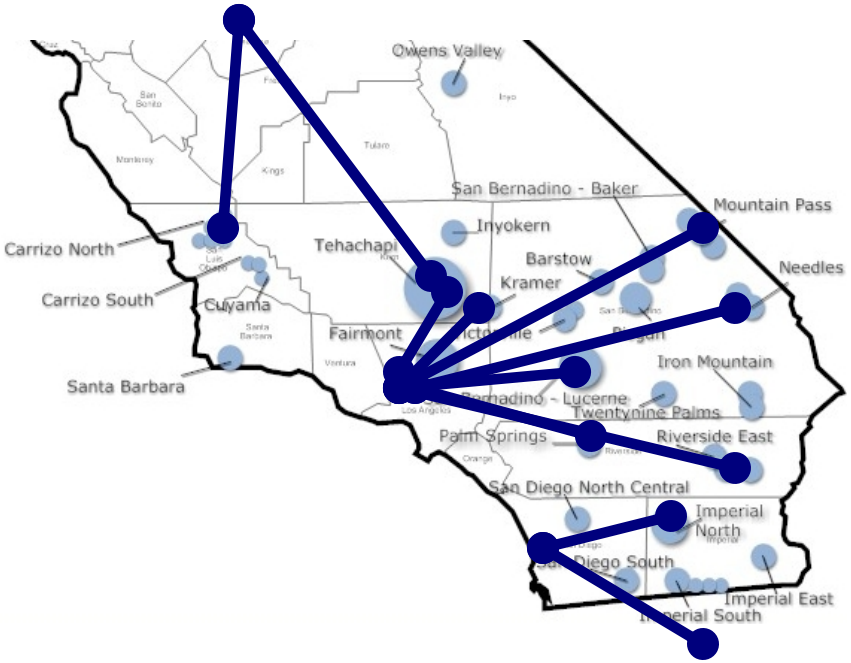
	In-State		Out-of-State		*Total*	
	MW	GWh	MW	GWh	*MW*	*GWh*
Biogas	279	2,078	-	-	*279*	*2,078*
Biomass	391	2,737	87	610	*478*	*3,346*
Geothermal	1,439	11,027	58	445	*1,497*	*11,471*
Hydro - Small	25	111	15	66	*40*	*177*
Solar PV	3,235	6,913	-	-	*3,235*	*6,913*
Solar Thermal	6,764	16,652	534	1,304	*7,298*	*17,956*
Wind	7,573	22,899	3,399	9,809	*10,972*	*32,709*
Total	***19,705***	***62,417***	***4,093***	***12,233***	***23,798***	***74,650***

Zones Selected

	MW	GWh	Notes
Total	***23,798***	***74,650***	
Tehachapi	3,000	8,862	Included in 20% Case
Distributed CPUC Database	525	3,118	Included in 20% Case
Solano	1,000	3,197	Included in 20% Case
Out-of-State Early	2,062	6,617	Included in 20% Case
Imperial North	1,500	9,634	Included in 20% Case
Riverside East	3,000	7,022	Included in 20% Case
Mountain Pass	1,650	4,041	
Carrizo North	1,500	3,306	
Distributed Biogas	249	1,855	
Out-of-State Late	1,934	5,295	
Needles	1,200	3,078	
Kramer	1,650	4,226	
Distributed Geothermal	175	1,344	
Fairmont	1,650	5,003	
San Bernardino - Lucerne	1,800	5,020	
Palm Springs	806	2,711	
Baja	97	321	

New Transmission Required for 33% RPS Reference Case





Interest in High DG Case

- A number of factors drive the CPUC's interest in studying a "High DG" case for meeting 33%:
  - High environmental impact of new transmission
  - High environmental impact of new central station generation
  - Increasing cost competitiveness and customer interest in PV – is PV nearing goal of "grid parity"?
  - Difficulties siting new transmission lines

"If it is conservatively assumed that only 10,000 MW of new high voltage transmission will be built by 2020 to realize the RETI net short target of 68,000 GWh, the estimated cost of this transmission will be in the range of $20 billion in 2008 dollars based on SDG&E's projections for the Sunrise Powerlink. How much thin-film PV located at IOU substations or at the point-of-use on commercial buildings or parking lots could the IOUs purchase for this same $20 billion? ... This equals an installed thin-film PV capacity of 14,000 to 18,000 MW for a $20 billion investment."

Bill Powers, PE, testimony in SDG&E's Sunrise Powerlink CPCN case

Resources Available for Selection in High DG Case

- Resources already selected for 20% Case
- RETI projects that can likely be interconnected without major transmission upgrades
  - Biomass: 2 projects in northern CA, 128 MW of total available capacity
  - Geothermal: 3 projects in northern CA, 175 MW of total available capacity
  - Wind: 6 projects across CA, 468 MW of total available capacity
- Out-of-state resources assumed deliverable over existing transmission (~2000 MW)
- Distributed solar PV resources

2. Identifying Potential Solar PV Sites

BLACK & VEATCH

Overview

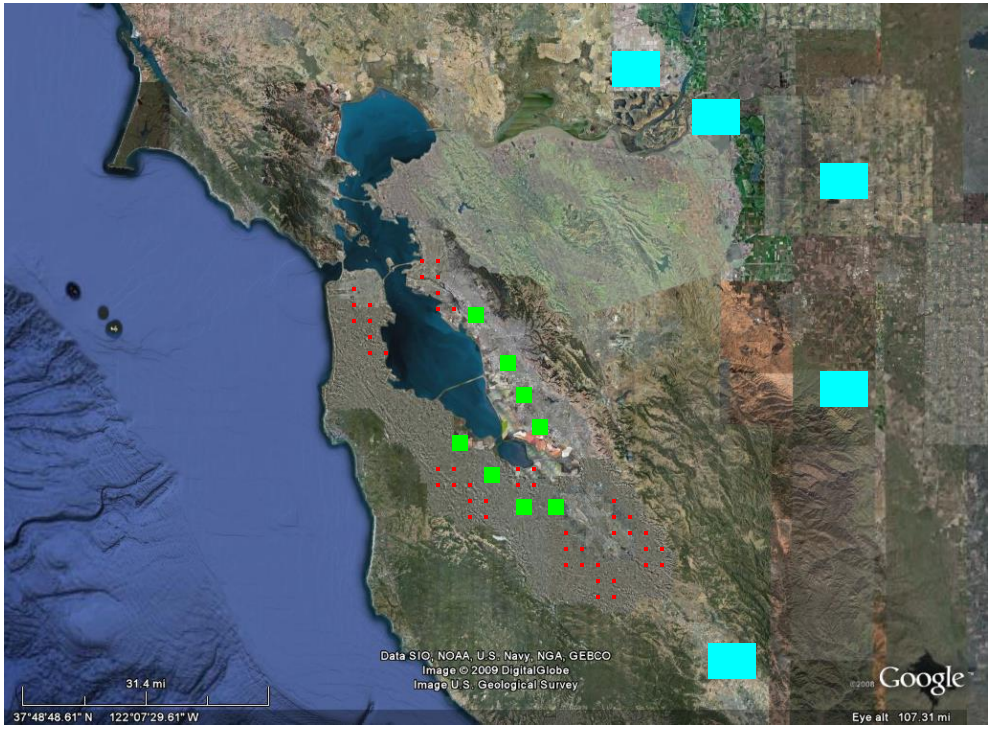
- Solar PV was assumed to be a major technology for DG
- B&V estimated the technical raw potential for DG
- Satellite imagery for rooftops and substation locations for larger utility scale

Distributed Solar PV

- 20 MW sites near non-urban 69 kV substations
- Smaller projects on rooftops, large commercial rooftops with 0.25 MW potential
- Limited by 30% peak load at a given substation

Illustrative Example of Distributed Solar PV

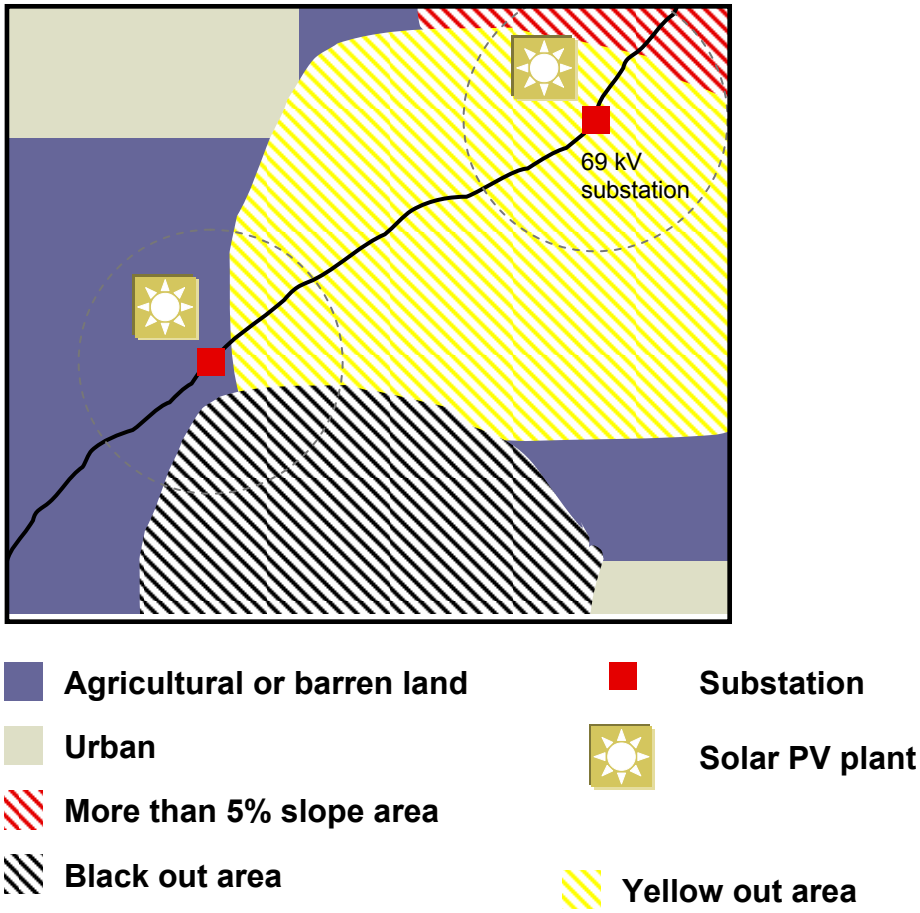
- 20 MW near substations
- Large commercial rooftops
- Residential rooftops



Ground Mounted PV

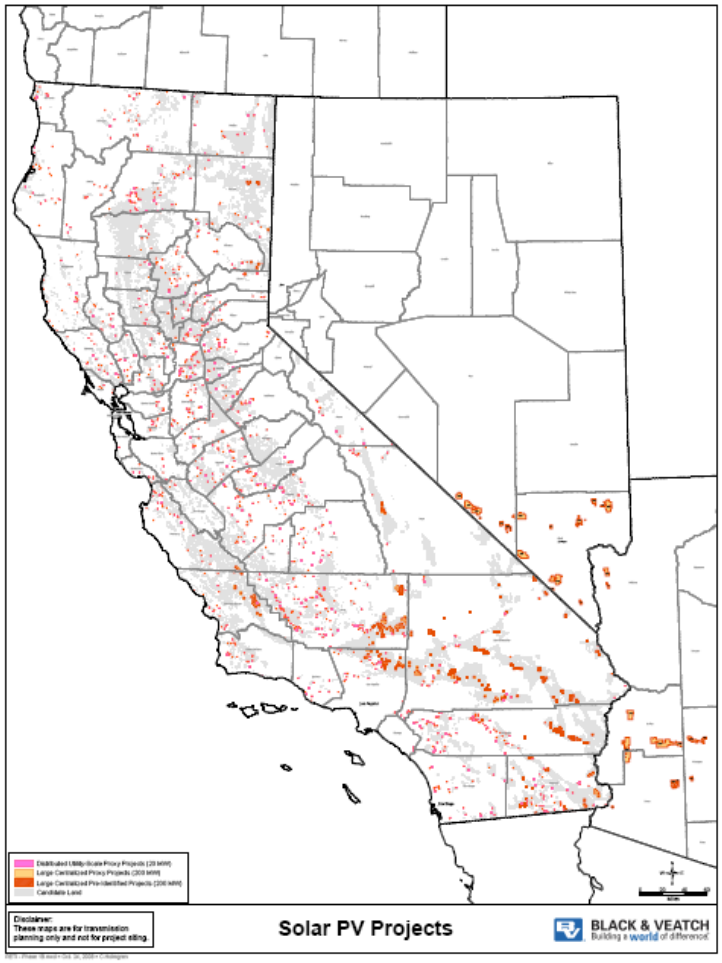
- Initial criteria
  - near sub stations equal or less than 69 kV
  - agricultural or barren land
  - less than 5% slope
- Environmental screen
  - Black out areas
  - Yellow out areas
- Land parcel
  - a continuous 160 acre plot (20 MWp)
  - within 20 miles

Example Map for Solar PV Non-Urban Projects



RETI Results on 20 MW Sites

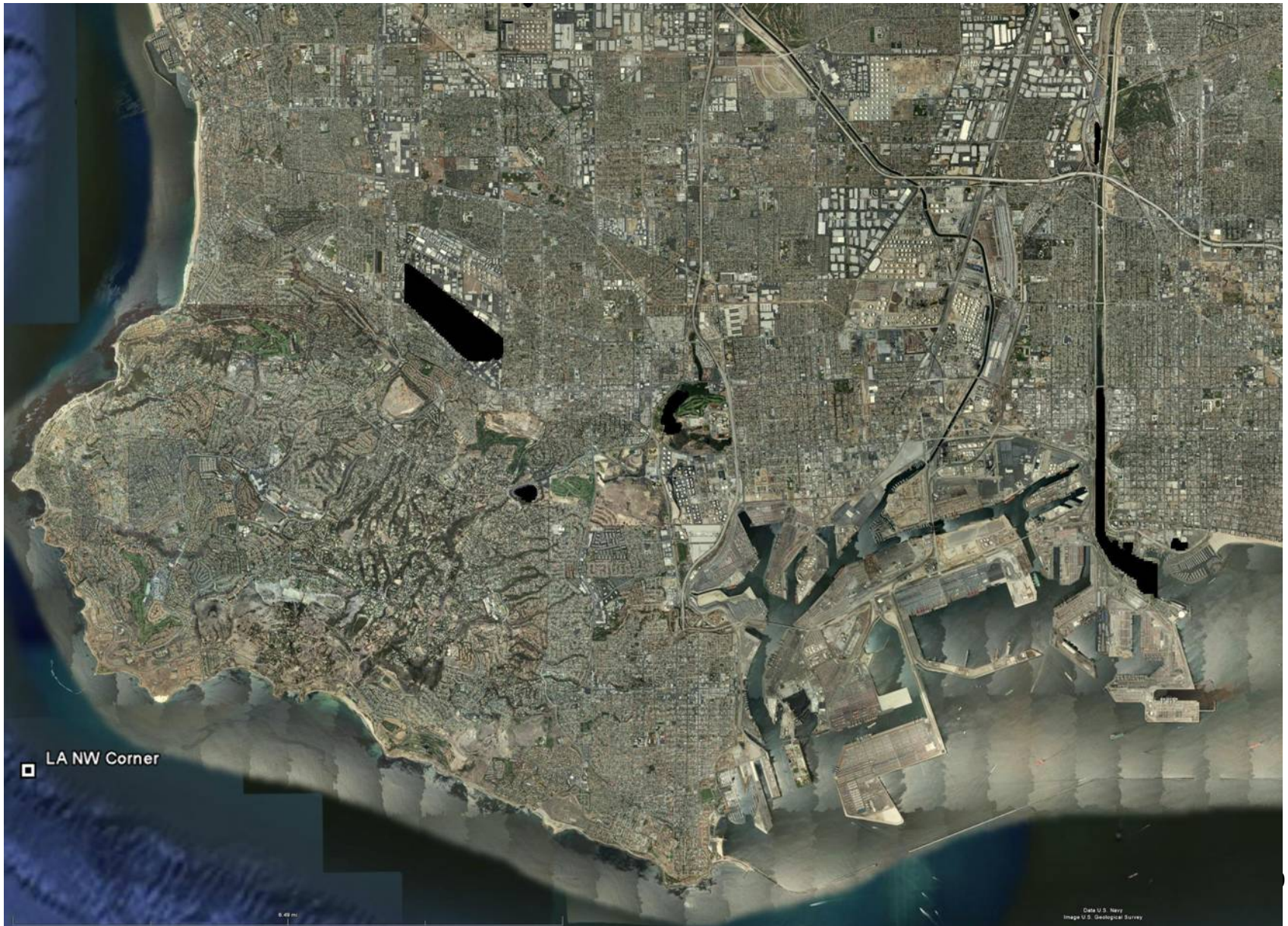
- 27,000 MW nameplate PV sites identified
- ~1300 sites identified
- Filters Applied
  - 160 acres + for 20 MW
  - No sites within 2 miles of urban zones
  - Near substations, most are 2 to 3 miles of the distribution subs with 69kV+ high-side voltage
  - Land slope < 5%
- 20 MW on substations with high side voltage of 69kV
- 40 MW on substations with higher voltage than 69kV
- Assumed not to be Rule 21 compliant



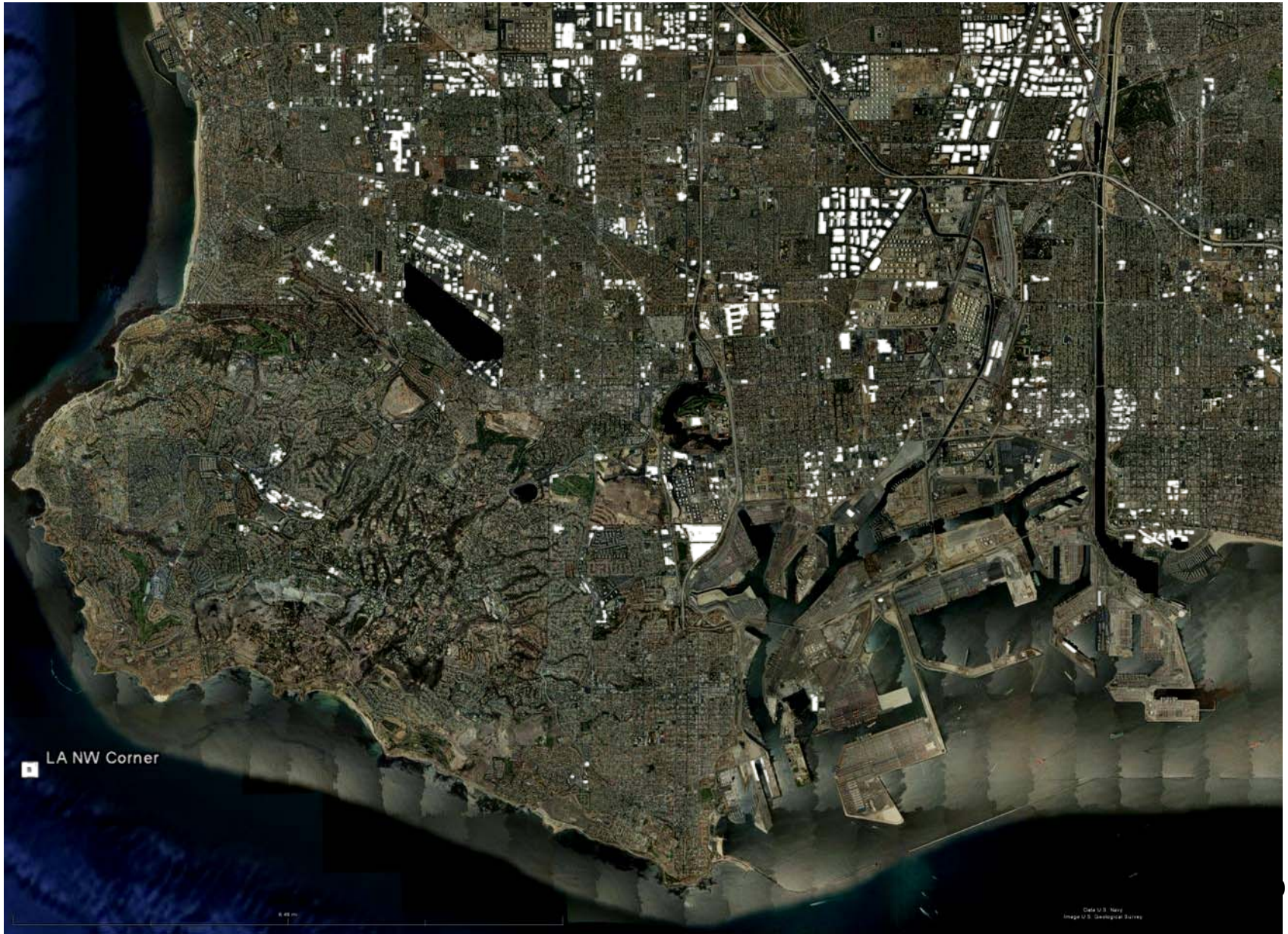
Black and Veatch Rooftop Analysis

- GIS used to identify large roofs in CA and count available large roof area
- Criteria
  - ‘Urban’ areas with little available land
  - Flat roofs larger than ~1/3 acre
  - Assumes 65% usable space on roof
  - Within 3 miles of distribution substation

Solar Photovoltaic Rooftop Identification

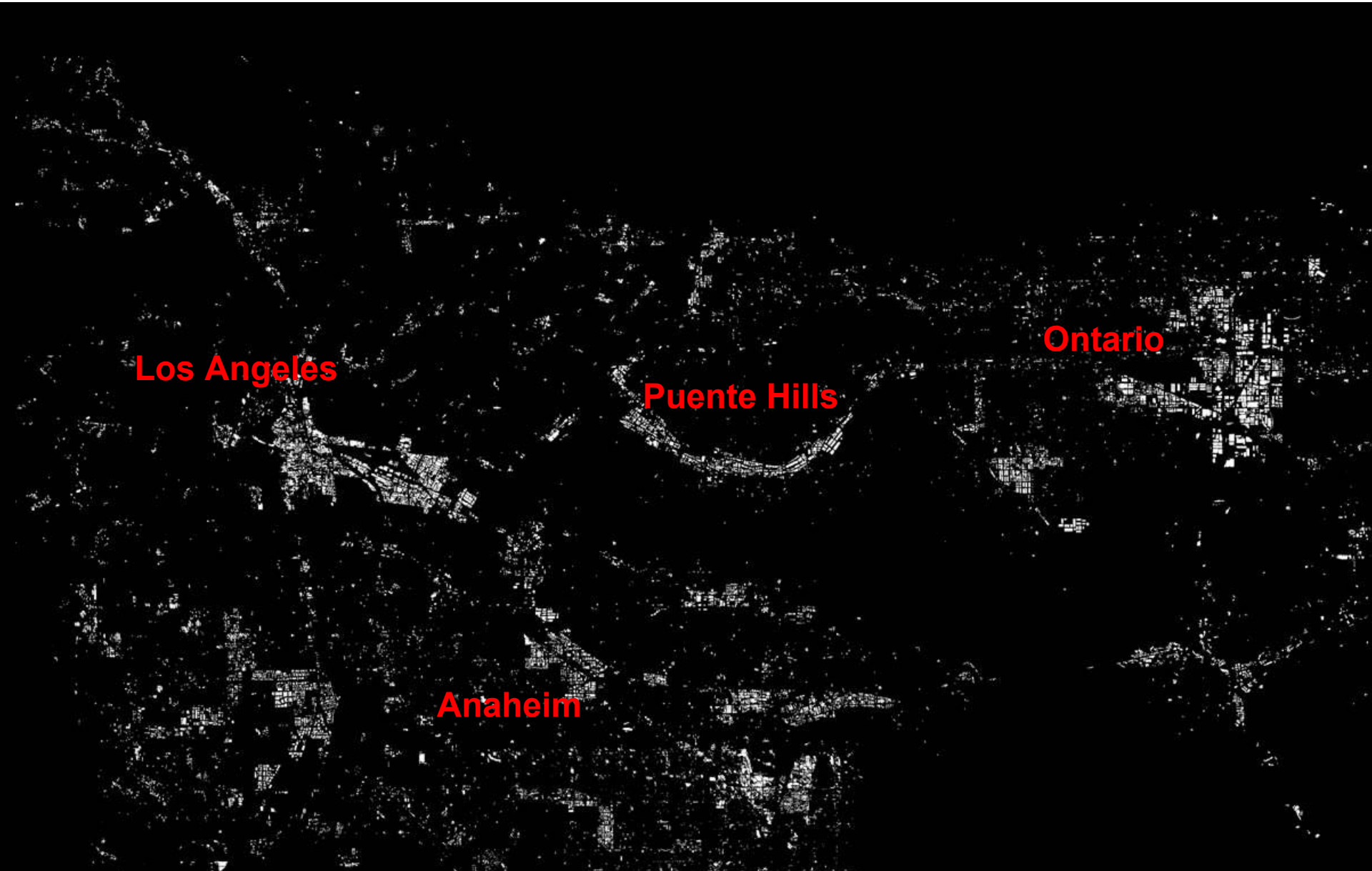


Solar Rooftop Identification



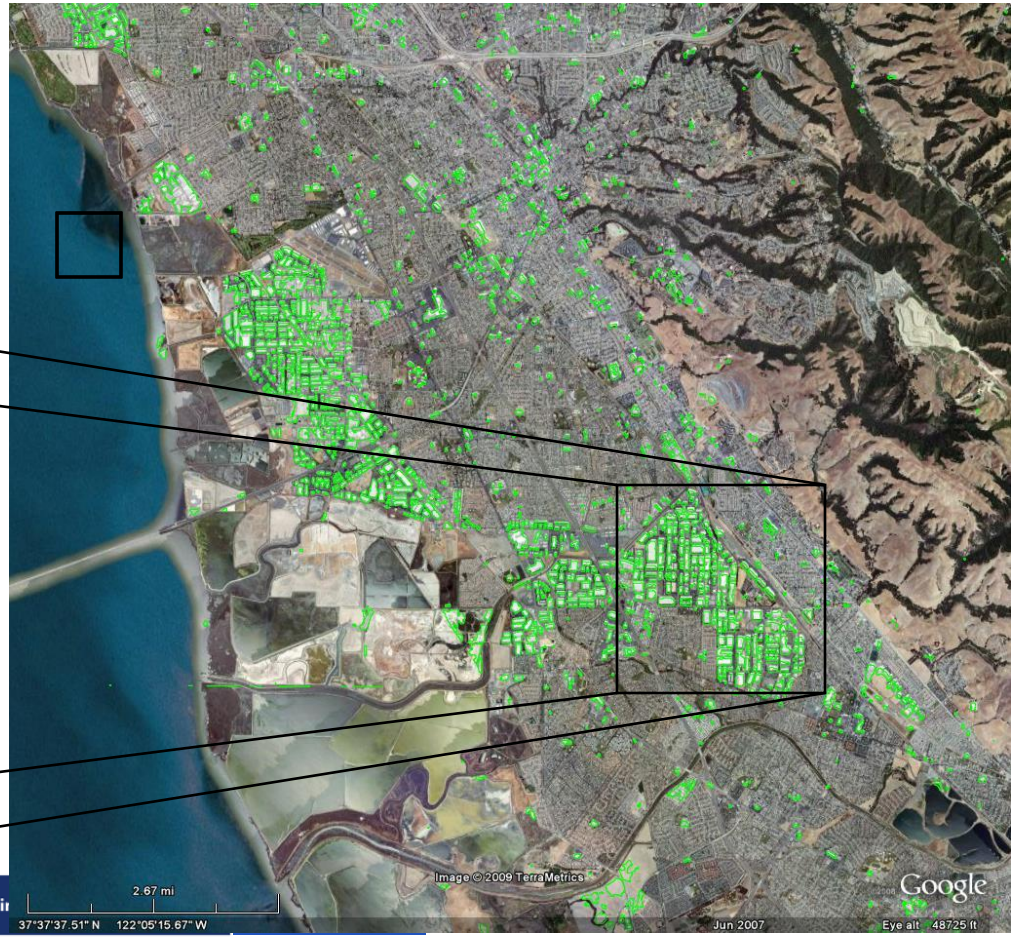
Solar Rooftop Identification

Los Angeles Area “Rooftop Resources”



East Bay Area Example

Analysis automates the counting of roof space and tallies total acreage of large roof space. Also checks proximity to distribution substation (not shown due to confidentiality).



Summary Results for Large Roofs

Raw Potential – Assuming 100% Participation

Total Statewide Large Rooftop Potential

	Large Roof Potential
PG&E	2922 MWac
SCE	5243 MWac
SDG&E	604 MWac
Other	2774 MWac
Total	**11,543 MWac**

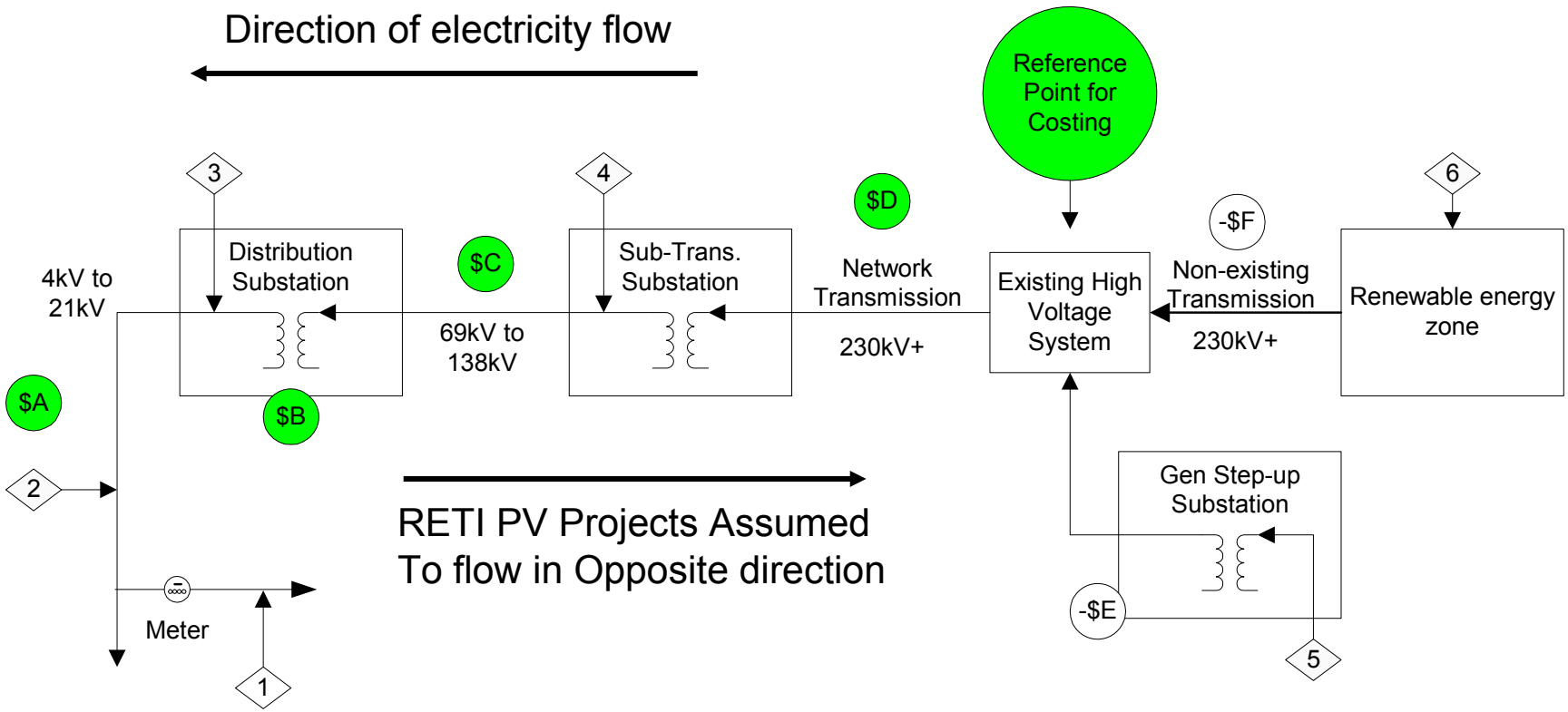
3. DG Interconnection Screening

Snuller Price, E3

Working Definitions of DG

- Distributed generation (DG) is small-scale generation interconnected at sub-transmission system or lower.
  - Broad definition includes generation that is not necessarily physically close to loads.
- Wholesale DG (WDG) is generation interconnected to the distribution or sub-transmission system
- Customer DG is generation on the customer's side of the meter
  - Does not count toward California's RPS

Diagram of Interconnection Points



Avoided Capacity Cost Assumption

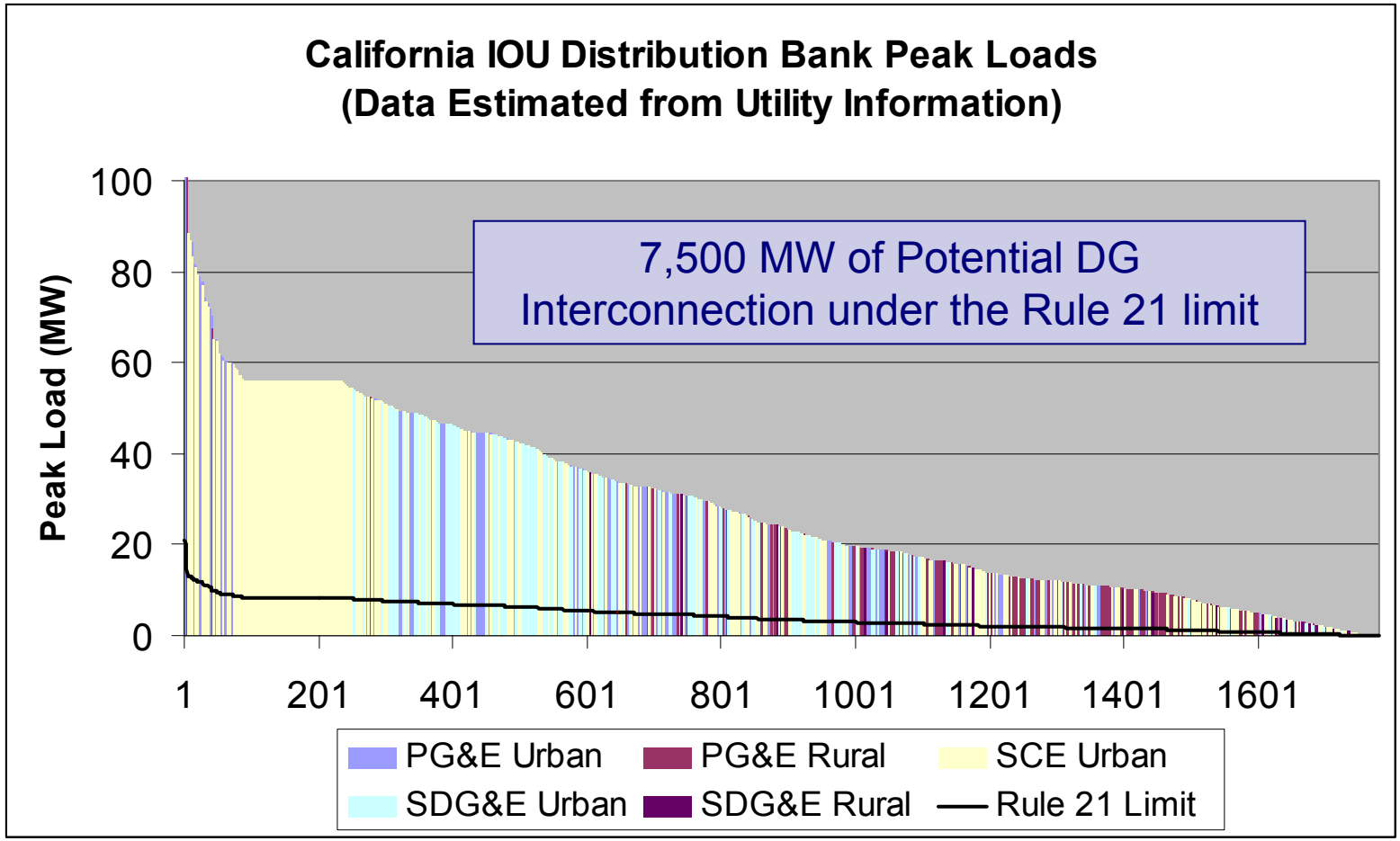
- **Distribution: $34/kW-yr**
  - Used average of EE avoided costs
- **Subtransmission: $34/kW-yr**
  - Used average of EE avoided costs
- **Transmission: $0/kW-yr**
  - Network is more difficult
  - Set to zero for 33% RPS analysis

See EE avoided costs, R.04-04-025

Issues

- Timeframe vs. geographic specificity – must use long time frame for avoided cost value
- Cost of non-Rule 21 RETI 20MW PV Installations not studied
  - Network transmission costs of $65/kW-year assumed for these resources

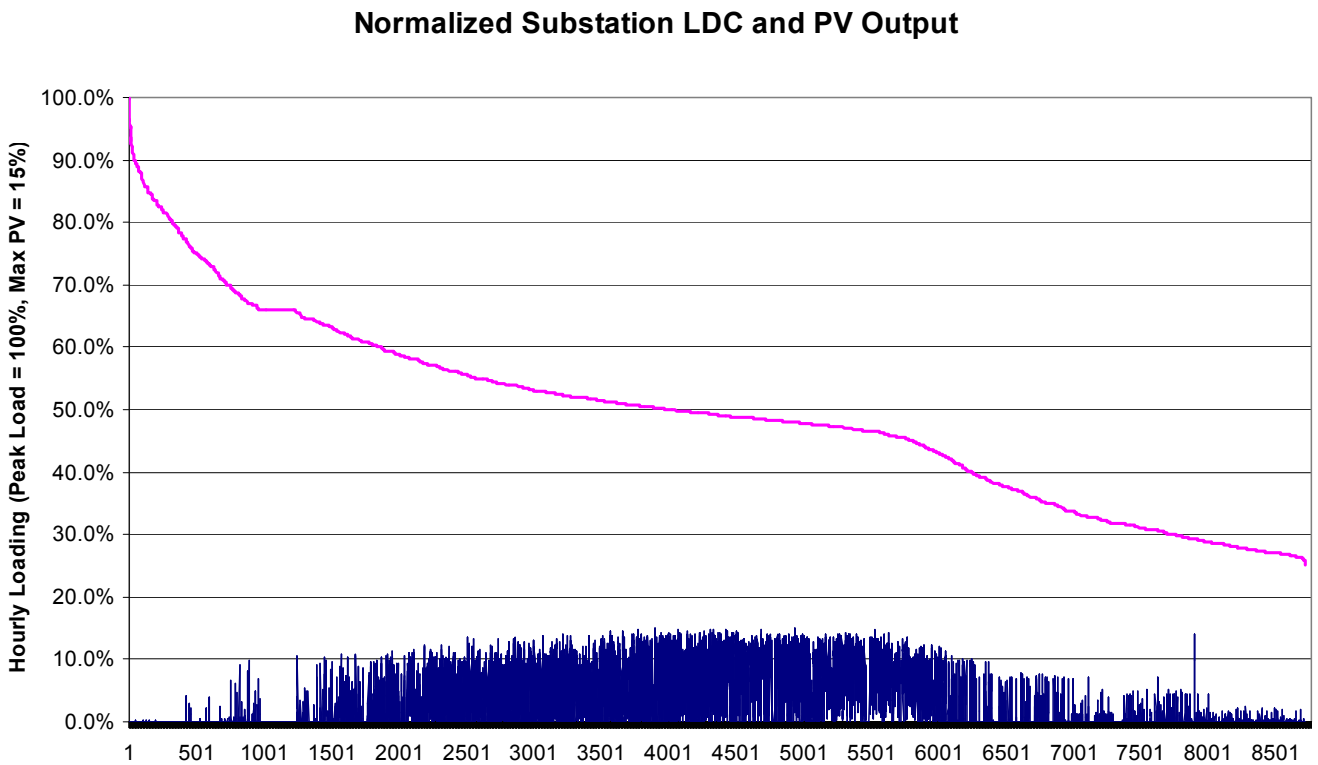
Utility Substation Bank Data



Rule 21 Interconnection sets 15% of line section peak limit

Revisit 15% threshold for some PV projects, given higher PV output at higher load levels

- Load Duration Curve compared to PV output

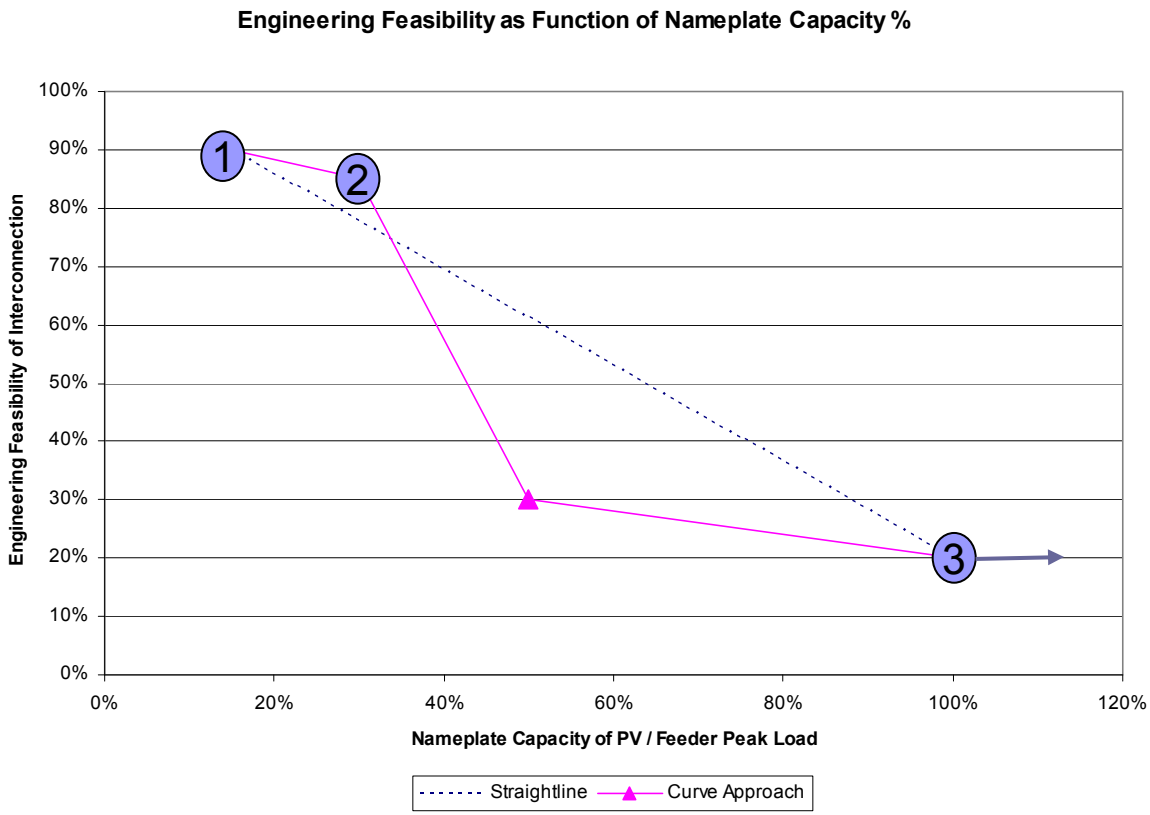


Actual data from a California public utility substation and PV installation

Technical Feasibility of PV Connections that are >15% & <100% of Peak Load

- Assumption on PV engineering feasibility

Caveat
These numbers are based on an educated guess not on any engineering analysis.

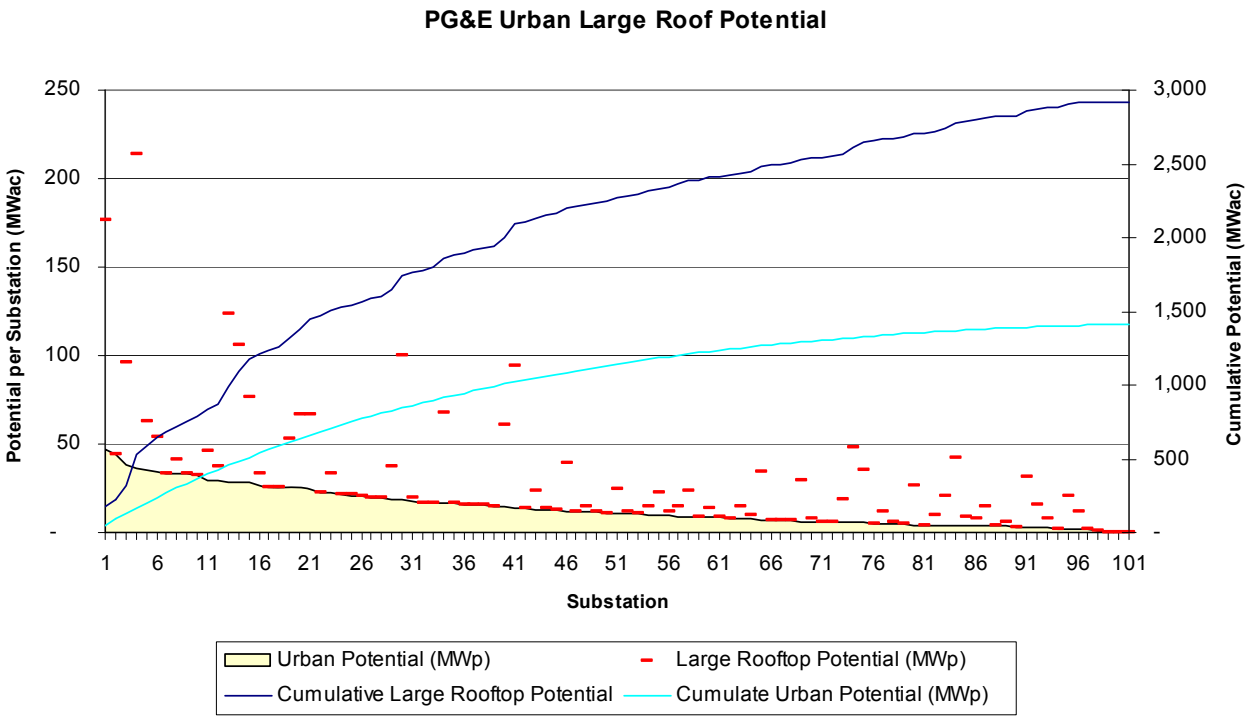


1 15% Peak Load
50% of in area PV

2 30% Peak Load
50% of in area PV

3 100+% Peak Load
RETI projects

PG&E Example – Bay Area



Clusters of large roofs make it impossible to do every roof and be below the 30% peak load.

PV Screening Criteria

	Land / Roof Availability	Interconnection	Participation
Urban Large Roofs	GIS Screening	Within 3 miles of substation, limited to 30% bank or feeder peak	33% Roofs max
Urban Small Roofs	Assumed available	30% bank or feeder peak	33% Roofs max
Rural <20MW	GIS Screening	30% bank or feeder peak	33% available land max
Rural >20MW	GIS Screening	Not constrained, but assigned interconnection cost of $68/kW-year	33% available land max

Total PV Availability for High DG Case by Type and Utility

Installed Capacity by PV System Type (MWac)

Utility	Ground Mounted (> 30%)	Ground Mounted	Large Roofs	Small Roofs	Total
PG&E	3,153	665	943	758	**5,519**
SCE	2,878	1,011	1,592	586	**6,067**
SDG&E	552	255	218	380	**1,406**
Other	2,417	335	1,057	500	**4,309**
Total	**9,000**	**2,266**	**3,810**	**2,224**	**17,300**

Other WDG Resources

- Biogas/Biomass
  - Resource potential developed based on discussion with stakeholders
  - Constrained by fuel availability
  - Total available capacity of 250 MW of Biogas, 35 MW of distribution-connected Biomass

Statewide DG Potential by Type

Nameplate MW	DG Type					
Connection	Biogas	Biomass	Geothermal	Solar PV	Wind	Total
1. Customer Site	-	-	-	2,224	-	2,224
2. Feeder	249	34	-	3,810	-	4,093
3. Distribution Bank	-	-	-	2,267	-	2,267
4. Subtransmission	-	128	175	9,000	468	9,771
Total	249	162	175	17,301	468	18,355

4. Results and Final Thoughts

High DG Case Results

- Case constructed to minimize the need for new transmission corridors
- Start from 20% case
- Replace central station solar and wind with 15,000 MW of mostly distributed solar PV

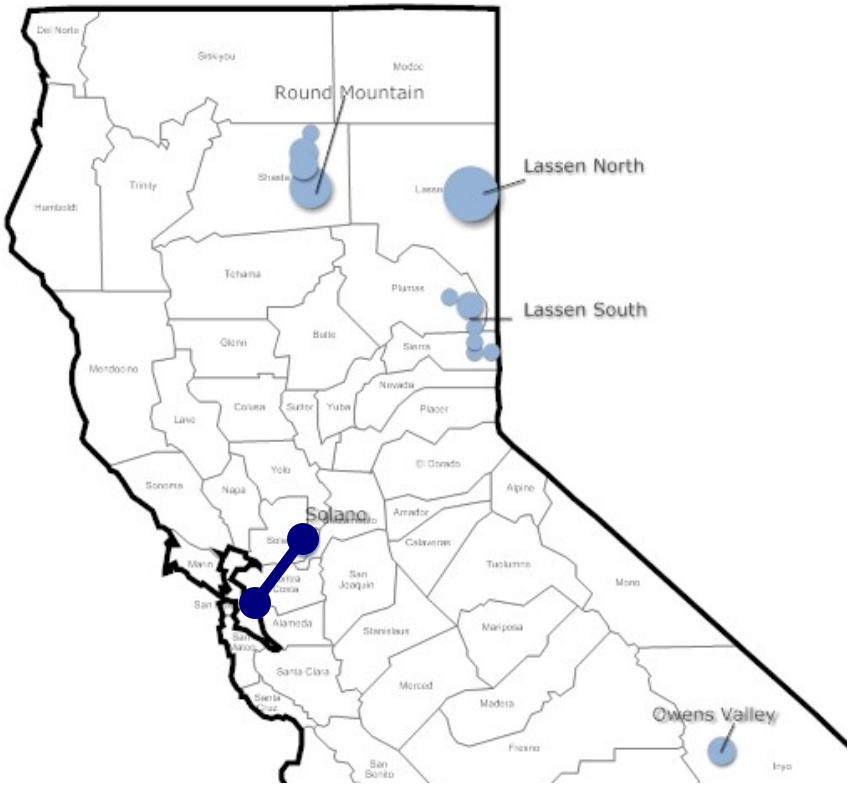
Zones Selected

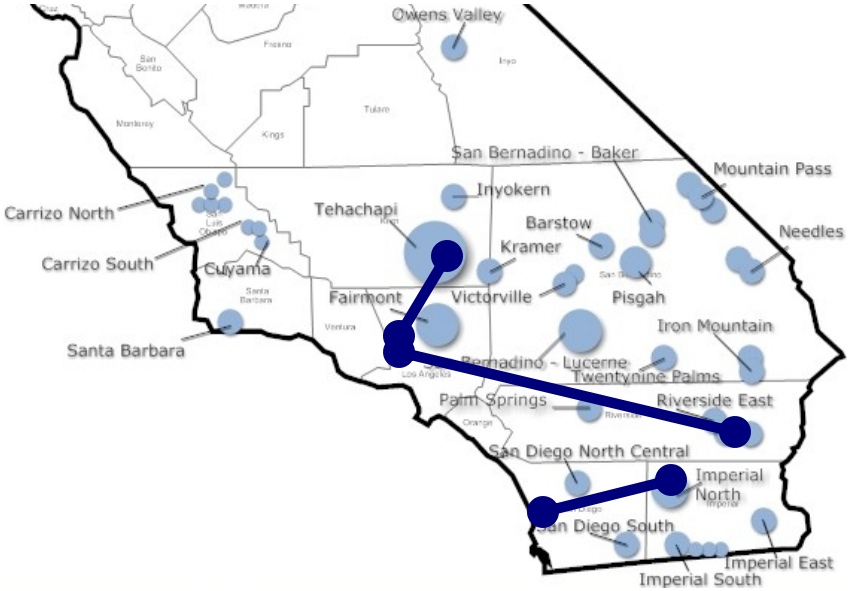
	MW	GWh	Notes
Total	*26,761*	*74,650*	
Tehachapi	3,000	8,862	*Included in Reference Case*
Distributed CPUC	525	3,118	*Included in Reference Case*
Solano	1,000	3,197	*Included in Reference Case*
Out-of-State Early	2,062	6,617	*Included in Reference Case*
Imperial North	1,500	9,634	*Included in Reference Case*
Riverside East	1,500	3,507	*Included in Reference Case*
Distributed Biogas	249	1,855	
Distributed	175	1,344	
Distributed Wind	468	1,289	
Out-of-State Late	1,934	5,295	
Distributed Biomass	162	1,138	
Remote DG	9,000	19,236	
Distributed Solar	5,186	9,558	

Resources Selected by Type

	In-State		Out-of-State		*Total*	
	MW	GWh	MW	GWh	*MW*	*GWh*
Biogas	279	2,078	-	-	*279*	*2,078*
Biomass	403	2,825	87	610	*490*	*3,435*
Geothermal	1,415	10,859	58	445	*1,473*	*11,303*
Hydro - Small	22	95	15	66	*37*	*161*
Solar PV	15,068	30,678	-	-	*15,068*	*30,678*
Solar Thermal	1,095	2,674	534	1,304	*1,629*	*3,978*
Wind	4,484	13,529	3,302	9,488	*7,785*	*23,017*
Total	***22,765***	***62,738***	***3,996***	***11,912***	***26,761***	***74,650***

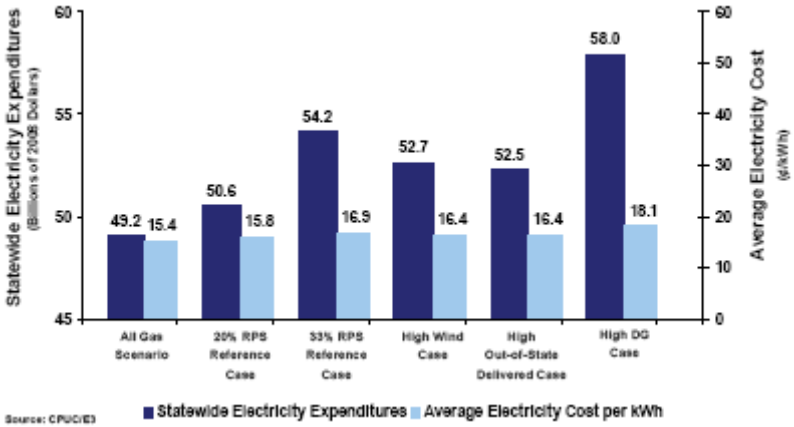
New Transmission Required for High DG Case





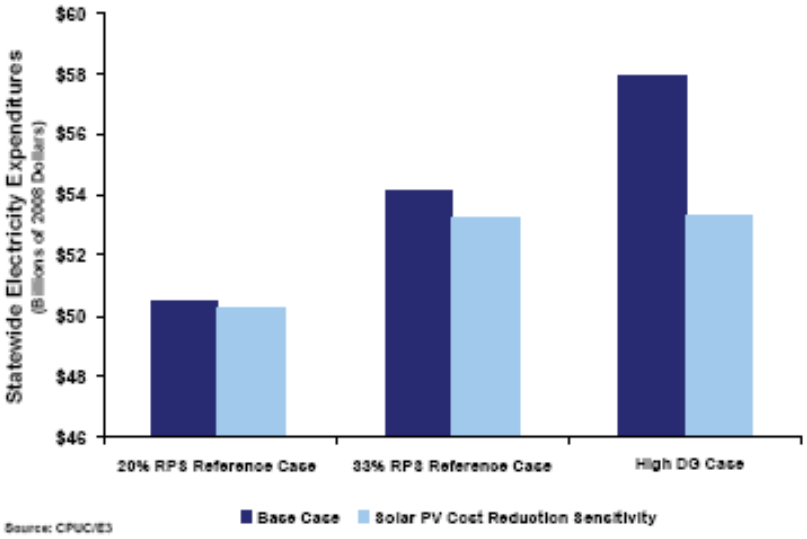
Cost Impacts of 33% RPS Cases

- Incremental cost of 33% Ref. Case in 2020:
  - +$3.6 billion relative to 20% RPS
  - Average retail rate: 16.9¢/kWh
  - 7% increase relative to 20% RPS
- Incremental cost of High DG Case in 2020:
  - +$3.8 billion relative to 33% Ref Case
  - +$7.4 billion relative to 20% RPS
  - Average retail rate: 18.1¢/kWh
  - 14.6% increase relative to 20% RPS



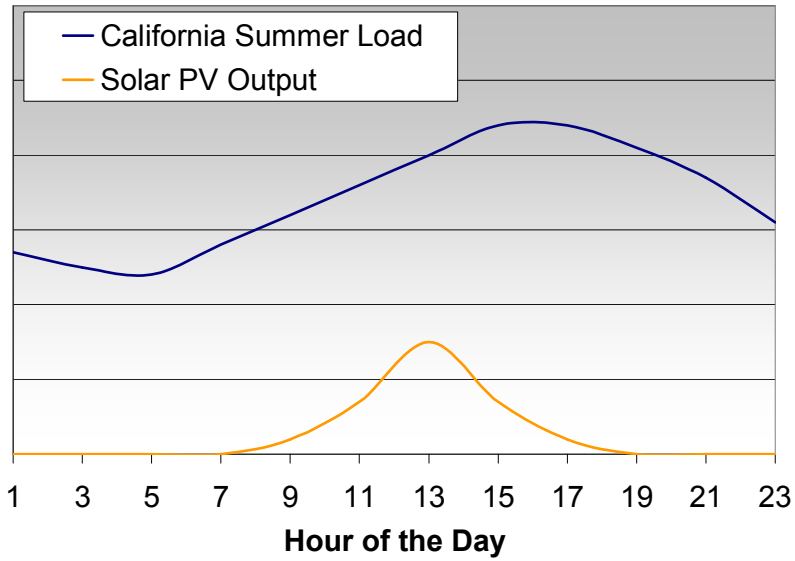
Solar PV Cost Reduction Sensitivity

- Delivered PV costs have come down substantially in the last year, and further reductions can be expected as the industry scales up
- We conducted a sensitivity analysis by reducing installed cost of PV from $7/We to $3.70/We
  - Price point developed for RETI to be in line with industry targets
  - Reduces levelized cost of PV from $306/MWh to $168/MWh
  - High DG case is similar in cost to 33% Reference Case



Final Thoughts and Next Steps

- We were not able to eliminate *all* transmission lines – assumed lines already approved go forward
- Much additional work could be done to refine the distributed PV potential estimates
- All cases assume indefinite continuation of current federal and state tax incentives
- We did not do any analysis on operations issues associated with high PV build
  - Ability of grid to absorb energy at PV output profile
  - Voltage and grid stability issues associated with lack of inertia
  - CAISO is now studying integration requirements of all 33% cases



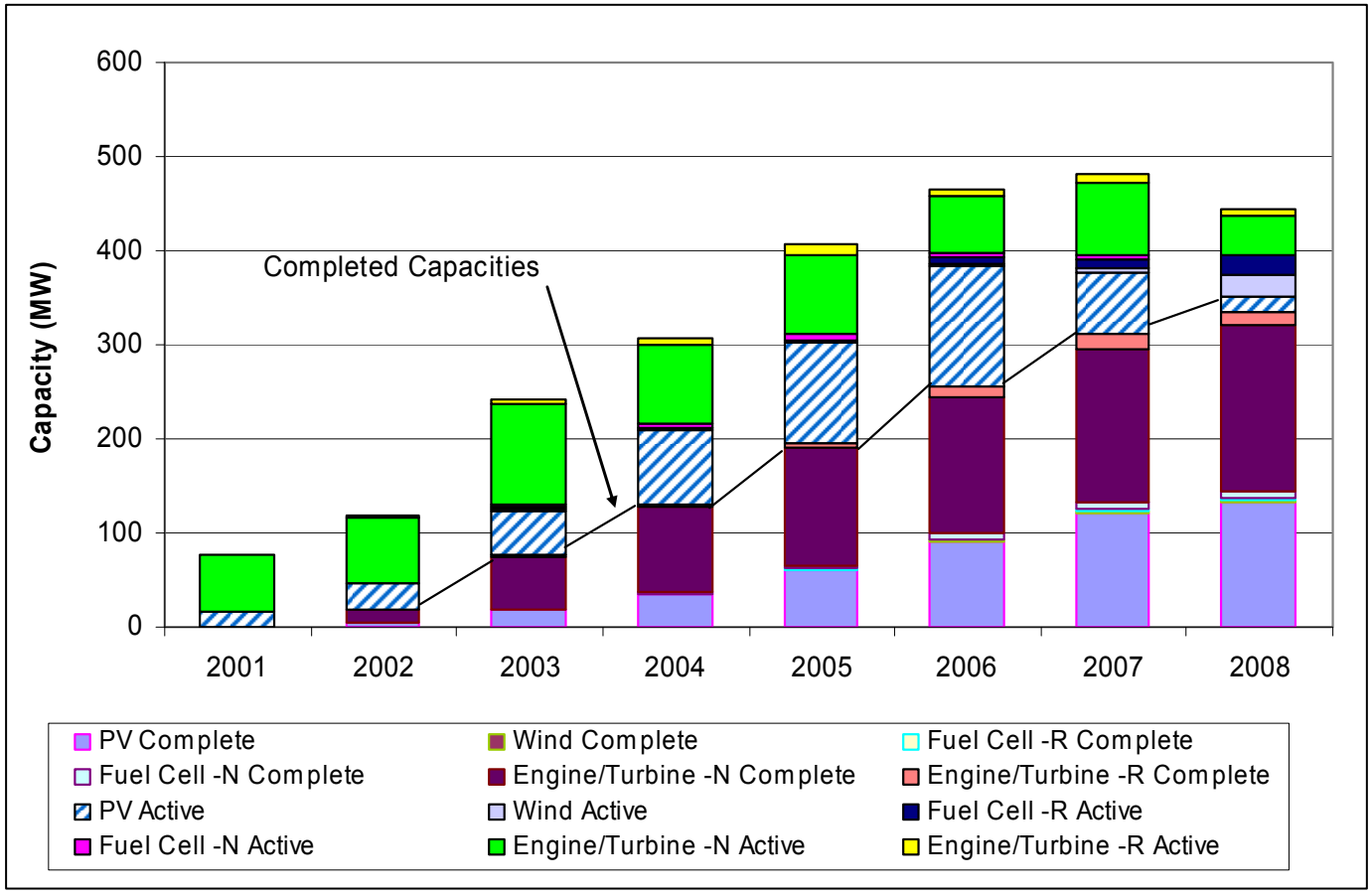
SB 412 Workshop

January 7, 2010

Order of Topics

- *Program*
  - *Status*
  - *Statistics*
  - *How Program Has Changed*
- *Peak Demand and Annual Impacts*
- *Trends of Impacts*
- *CHP System Efficiencies*
- *Greenhouse Gas Emission Reductions*
- *Conclusions and Recommendations*

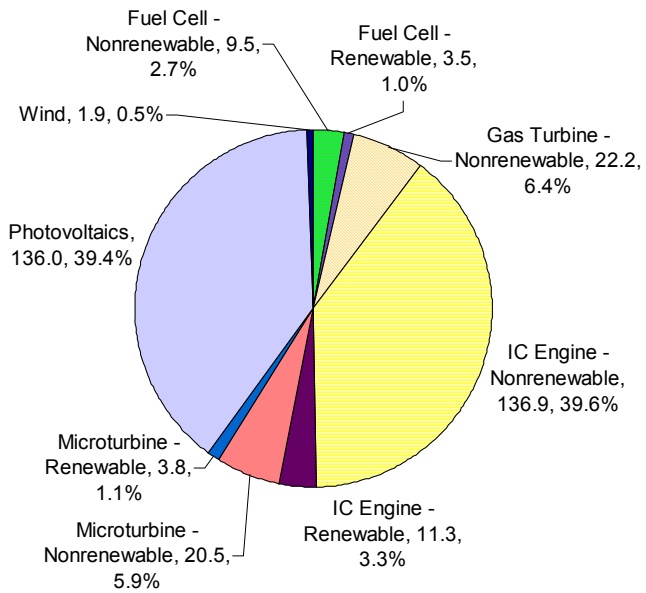
Trend on Complete and Active Projects: 2001-2008



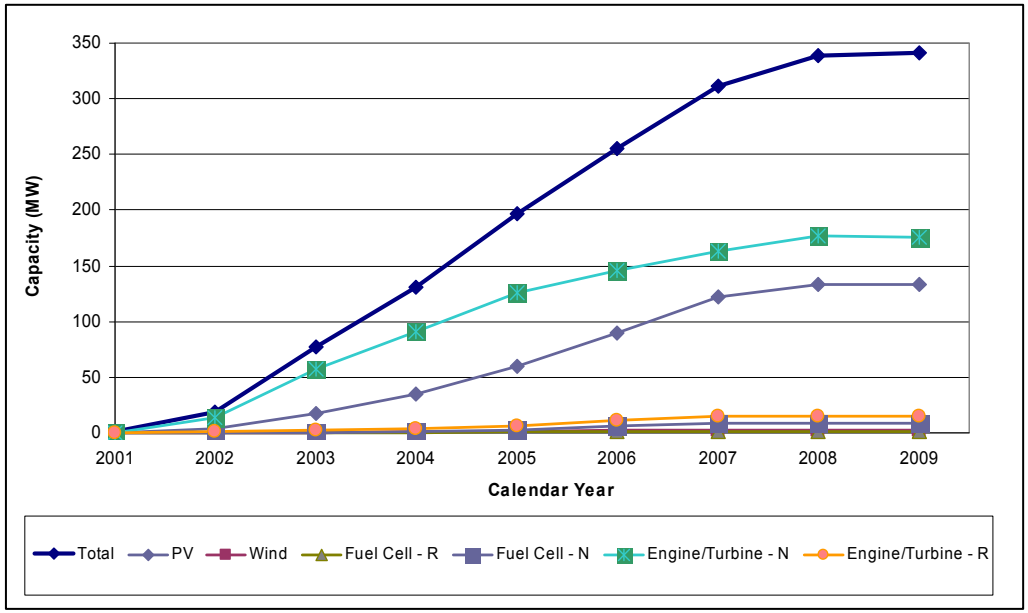
- *26 MW of capacity was added in 2008*
- *Only 2 MW of capacity has been added in Q1 – Q3 of 2009*
- *Through Q3 2009 there are 1,280 complete projects (340.2 MW) and 1 active project (0.6 MW) online for a total of 340.8 MW of generating capacity*

Program Status Through Q3 2009

Online Project Capacity by Technology and Fuel as of 9/30/2009

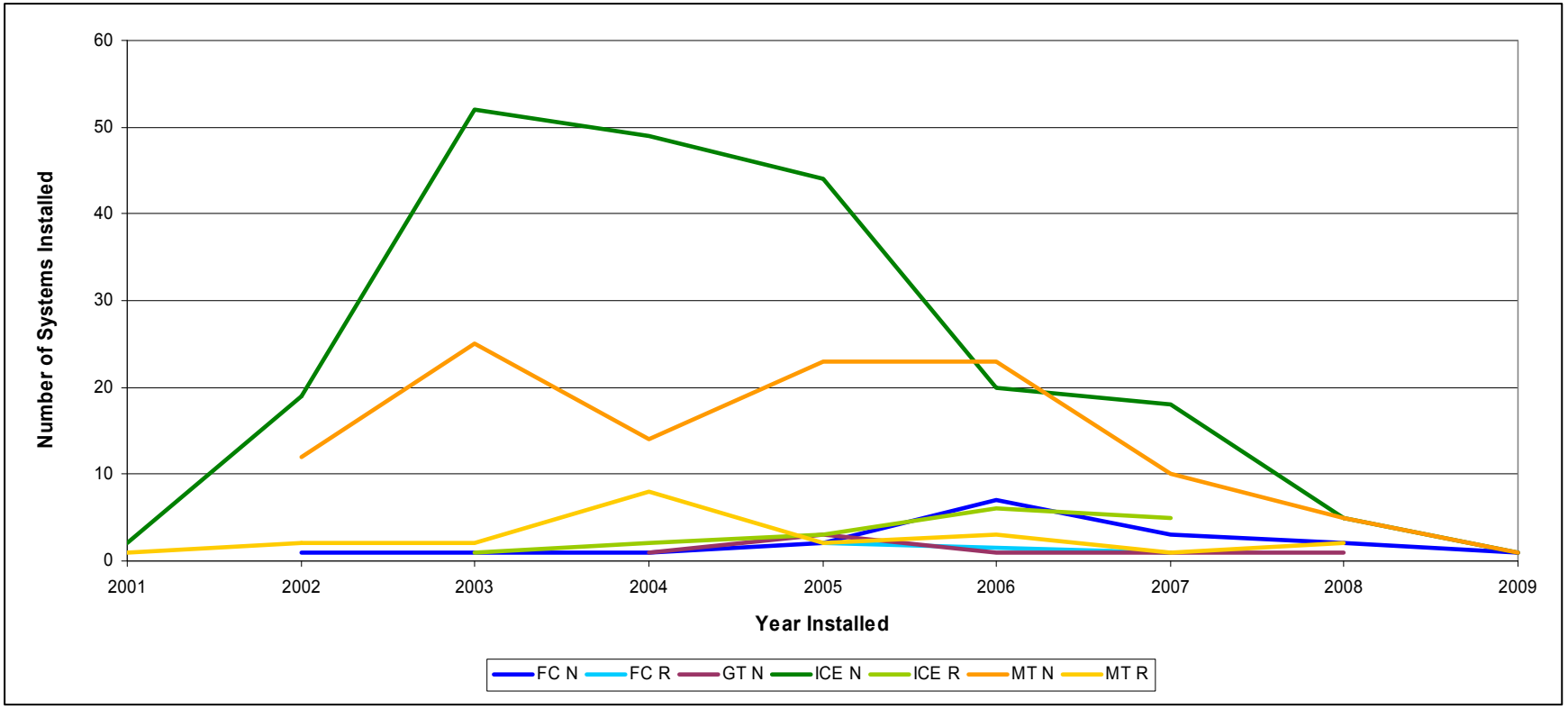


Growth in Completed Project Capacity



- *Slower growth in engine and turbine capacities began in 2005 and 2006.*
  - *In 2005 and 2006, non-renewable-fueled engine/turbine projects were required to meet the 2005 CARB NOx emission standard of 0.14 lbs/MWh.*
  - *In 2007, new non-renewable-fueled engine/turbine projects had to meet the CARB NOx emission standard of 0.07 lbs/MWh.*
  - *The CARB standard could be met by using a fossil fuel combustion emission credit for waste heat utilization so long as the system achieved the 60 percent minimum efficiency standard.*
  - *However, difficulties in meeting certification requirements, and extra permitting costs and NOx control costs may have discouraged technology adoption.*

Number of CHP and RFU Systems Installed Per Year

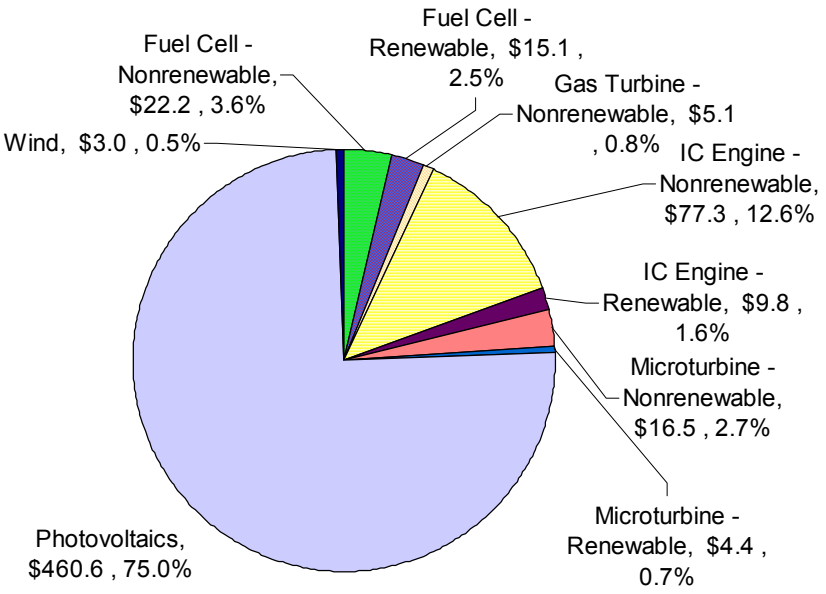


- Some changes in 2005 based on CARB NOx regulations
  - Increase in non-renewable MT systems and fuel cells which have low NOx air emissions
  - Increase in renewable-fueled IC engines, which have less stringent CARB NOx regulations
- In 2007 nearly all technologies saw a drop in installation rate, due to more stringent CARB NOx regulations

Incentives Paid Through Q3 2009

- *In the first 3 quarters of 2009, the SGIP had provided just under $14 million in incentives to projects*
  - *In comparison, the amount paid in 2008 was just over $112 million*
- *Breakout:*
  - *PV has received the majority of incentives*
  - *Non-renewable fuel systems have received the next largest amount of incentives at around 18% of the total*
- *For systems utilizing fuel*
  - *Ratio of Nonrenewable to Renewable fueled projects:*
    - *incentives approximately 4 to 1*
    - *rebated capacities approximately 10 to 1*

Total Incentives Paid through 9/30/2009 = $613.9 million



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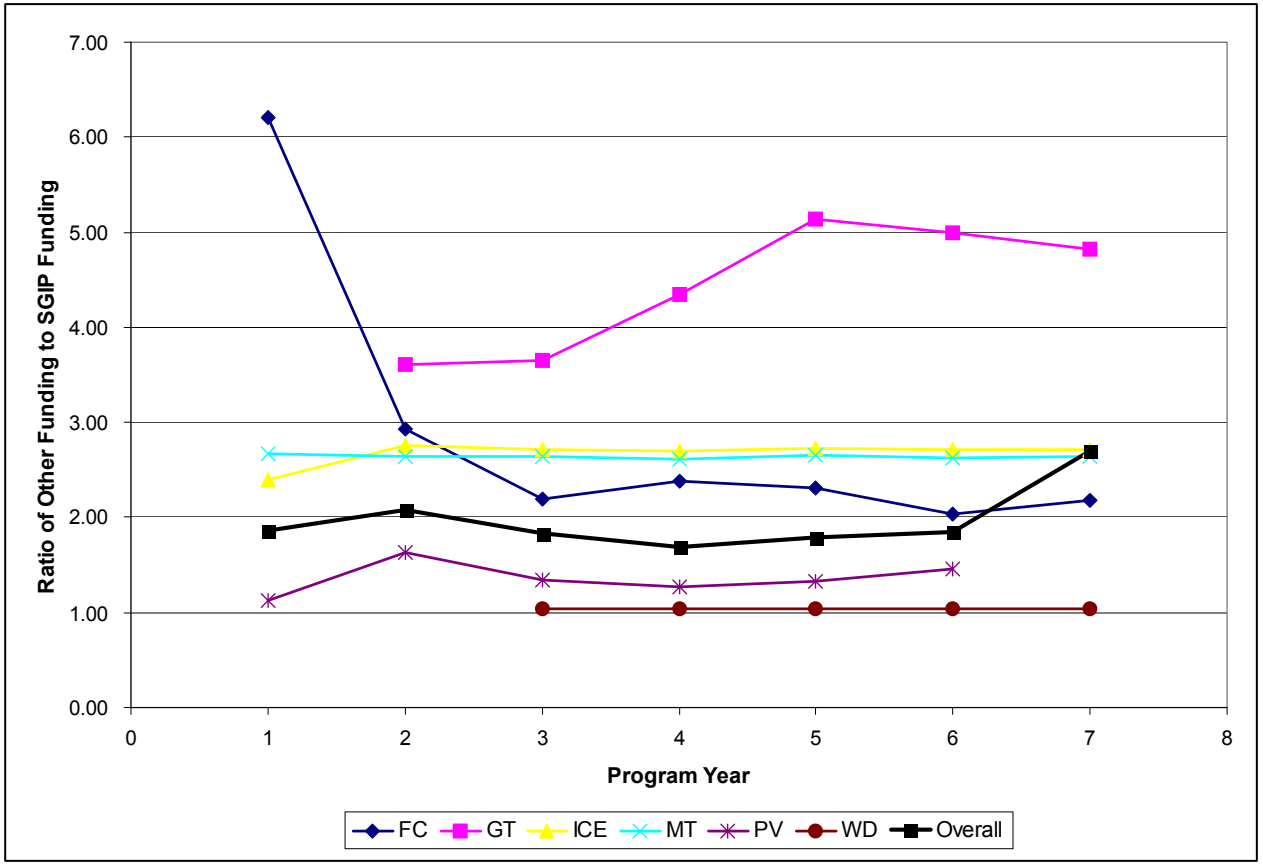
Ratio of Other Funding to SGIP Incentive by Application Year



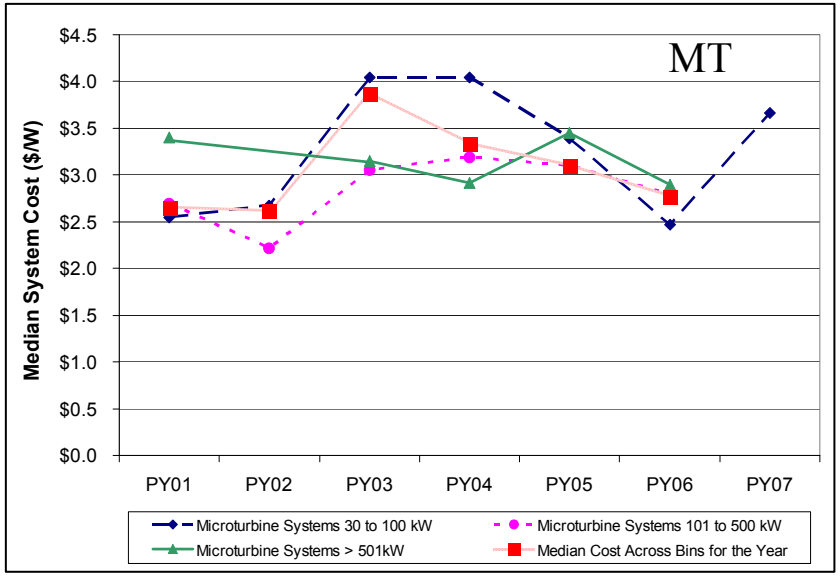
- PV and Wind Systems have the lowest ratio of other funding to SGIP funding
- MTs and IC Engines consistently received funding around 2.7 times the amount of SGIP funding
- FC and GT data is minimal and therefore the most variable
- All GT's are larger than 1 MW and SGIP only provides an incentive for the first MW installed

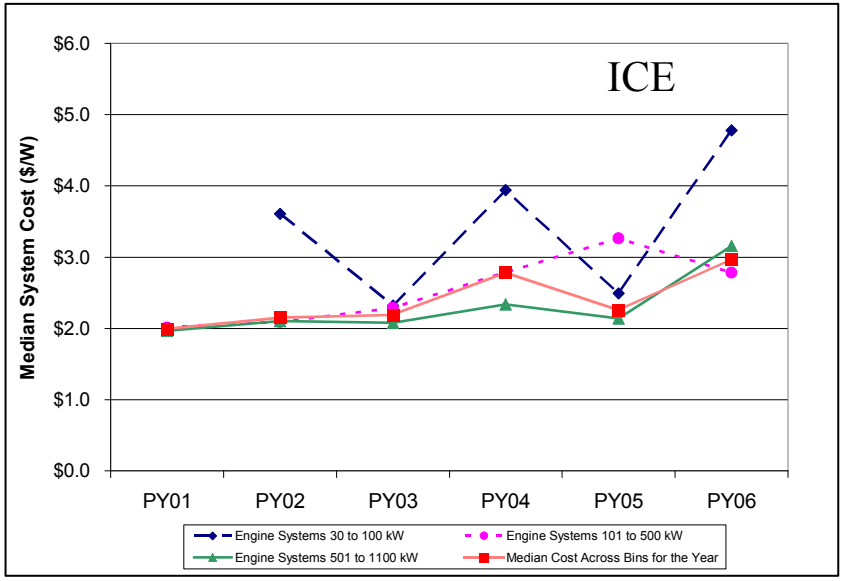
CHP and RFU Project Costs Through 2008

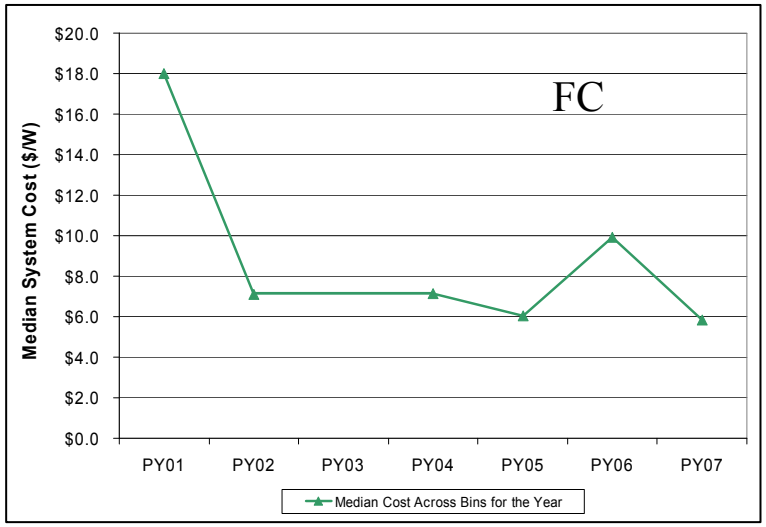
Technology & Fuel	Complete			Active		
	Total (MW)	Wt.Avg ($/W)	Total ($ MM)	Total (MW)	Wt.Avg ($/W)	Total ($ MM)
FC-N	8.5	$7.55	$64	1.4	$6.83	$10
FC-R	3.5	$5.98	$21	12.3	$5.24	$64
IC Engine–N	133.1	$2.26	$301	25.3	$2.86	$72
IC Engine–R	11.2	$2.47	$28	5.7	$2.64	$15
GT-N	17.6	$2.11	$37	9.6	$1.57	$15
GT-R	N/A	N/A	N/A	0.8	$2.28	$2
MT-N	18.0	$3.12	$56	6.5	$3.10	$20
MT-R	3.8	$3.44	$13	0.4	$7.70	$3
Total	**330.2**	**$5.21**	**$1,719**	**93.5**	**$3.51**	**$328**

- Microturbine and fuel cell capital are generally are more expensive on a per watt basis than other technologies (PV not included)
- Typically with clean up skids and other technology renewable fuel project should be more expensive.
- Capital costs and levelized cost of energy (LCOE) are different metrics

CHP Non-Renewable Project Cost Trends by Application Year







Costs have been variable with no clear trend

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CHP and RFU Project Impacts and Performance Trends

Energy Delivery by SGIP Projects During 2008

- *In 2008, SGIP's 1275 on-line projects delivered over 718,000 MWh of electricity to the grid*
  - *Could meet the needs of close to 109,000 homes for one year*
- *Engines/Turbines provided 65% of the SGIP energy delivery*
- *PV provided 27%*
- *Fuel cells provided 8%*
- *Biogas fueled projects provided 9%*

Technology	Fuel	Total** (MWh)
FC	N	44,050 †
FC	R	12,572 †
GT	N	114,156 †
IC Engine	N	227,930 †
IC Engine	R	47,848 †
MT	N	67,963 †
MT	R	6,863 †
PV		197,178
	TOTAL	**718,558**

*** [a] indicates confidence is less than 70/30. † indicates confidence is better than 70/30. No symbol indicates confidence is better than 90/10.*

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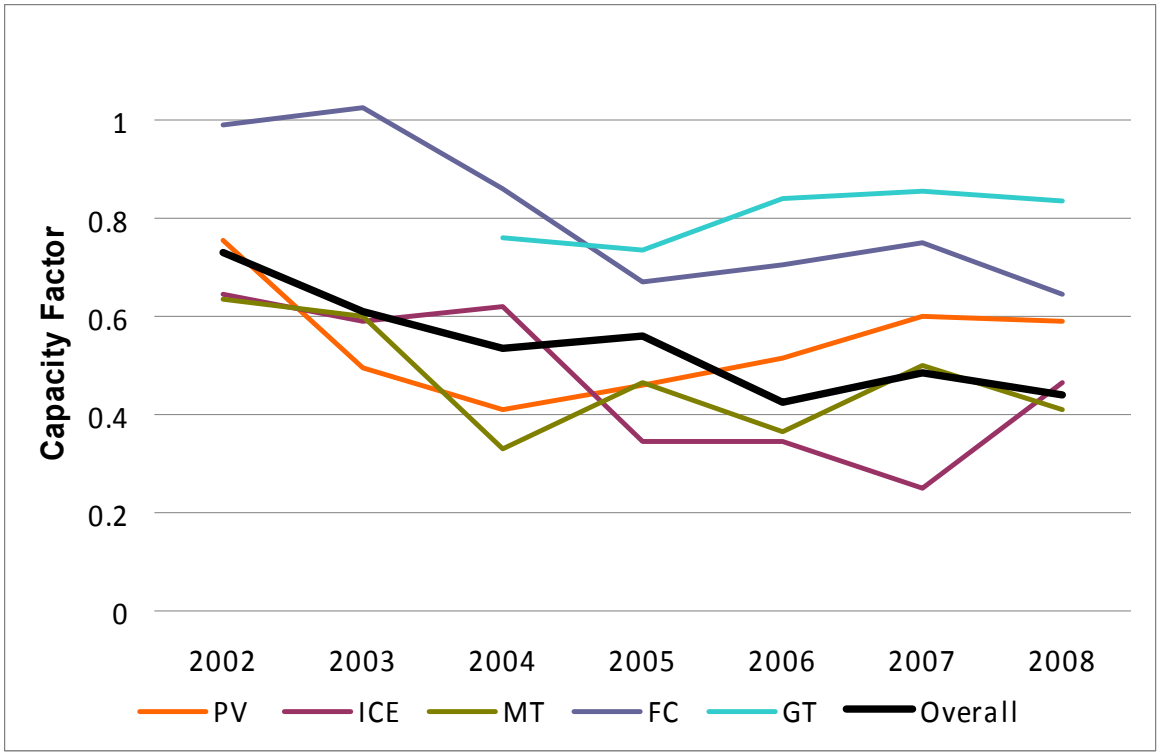
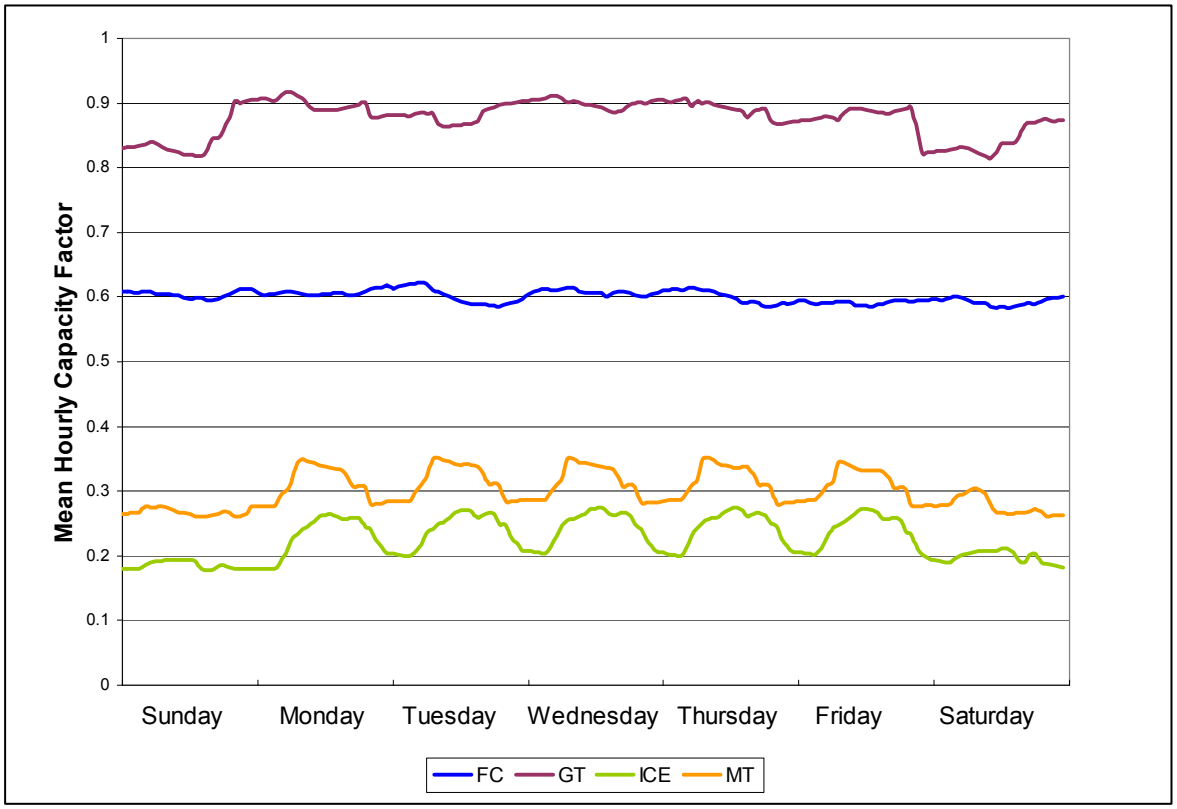
CAISO Peak Hour Impact 2002 - 2008



- *DG technologies make contributions to addressing peak electricity demand.*
- *Fuel cells and gas turbines deployed under the SGIP have consistently demonstrated ratios of on-line peak capacity to rebated capacity greater than 0.64 kW (peak) per kW (rebated).*

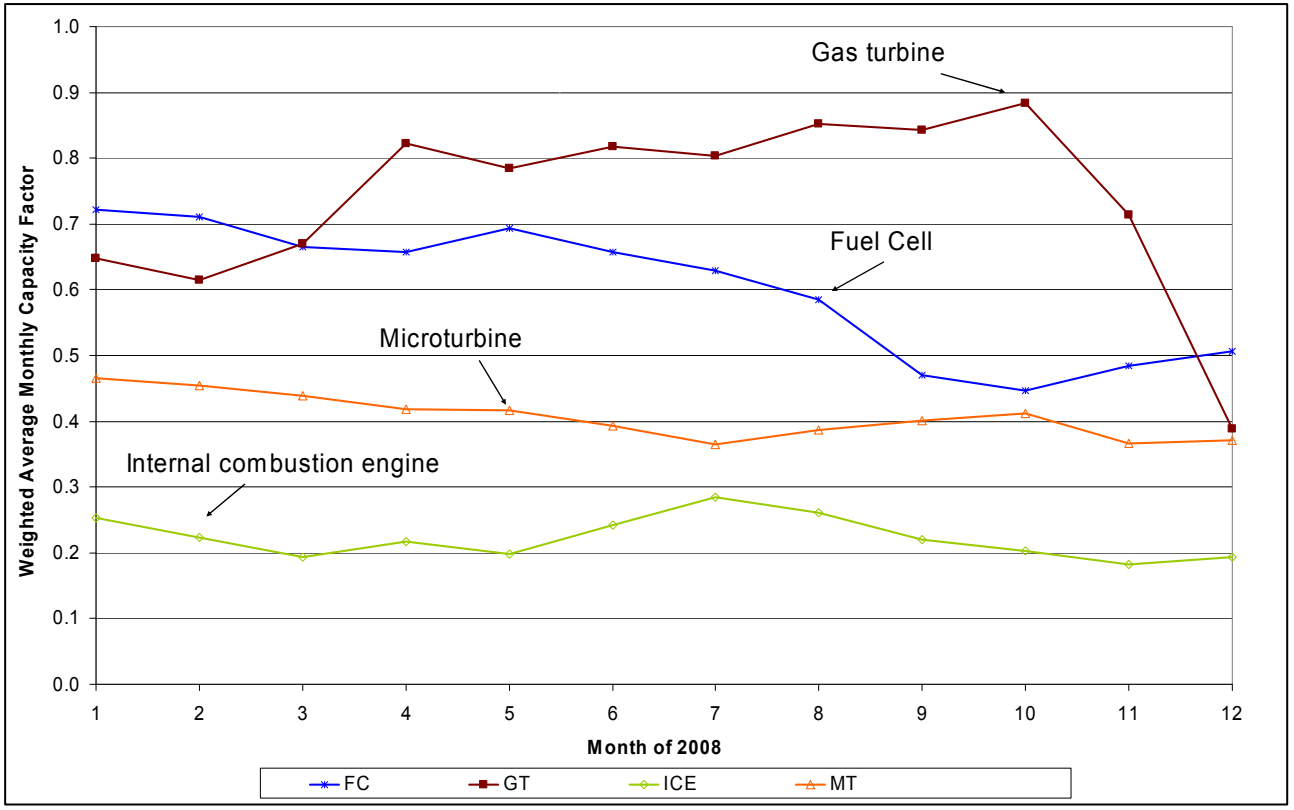
Mean Hourly Impact During Summer Weeks for CHP and RFU Projects



**Summer includes June, July, August, September*

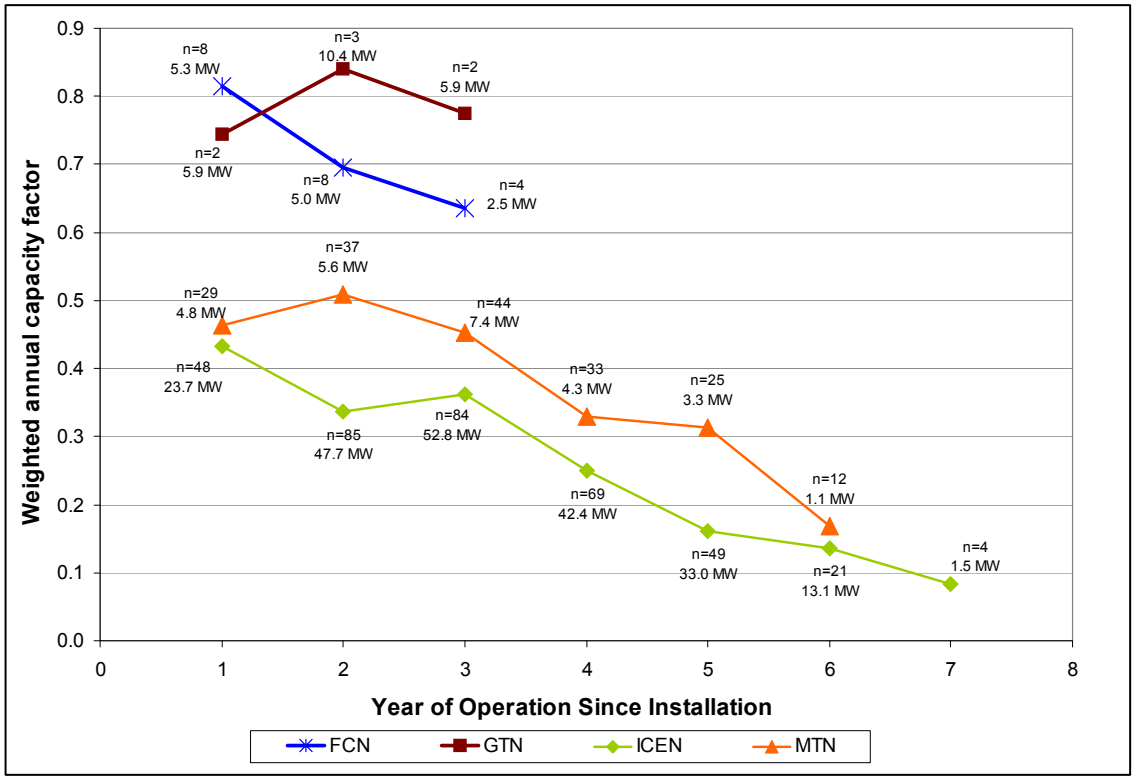
- *Gas turbines and fuel cells in the SGIP tend to operate at facility base load*
- *Some IC engines and microturbines operate at facility base load while others ramp up to offset facility peak load during the week and during the daytime*
- *Peak system demand generally occurs on weekdays*

Average Capacity Factors of Non-Renewable CHP Projects During 2008



- *Nonrenewable-fueled gas turbines and fuel cells showed the highest average capacity factors*
- *Average microturbine capacity factors consistently ranged from 35 - 45%*
- *Average IC engine capacity factors ranged from 20 – 30%*

Annual Average Capacity Factor : Running Year of Operation Since Install



- *Consistent and significant degradation in average annual CF for both ICE and MT (~ 30% over five years of operation)*
- *For PV (not shown) CF degradation has been (~ 6%) over 5 years of operation*
- *Degradation due in part to 20% of metered capacity for ICE and MT being off line*
- *Changes could be also be caused by a variety of factors such as equipment maintenance/reliability issues, and staff turnover*

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Technology Efficiencies and Renewable Fuel Use Compliance

Efficiency and Waste Heat Utilization Requirements

- *Efficiency and waste heat recovery have important impacts as cogeneration facilities comprise approximately 2/3 the generating capacity of SGIP*
- *Cogeneration facilities must meet certain efficiency and waste heat utilization levels required by PUC 216.6*
  - *216.6 (a): recovered useful heat must exceed 5% of the total recovered heat plus the electrical output of the facility*
  - *216.6 (b): sum of the electric generation plus ½ of the heat recovered must exceed 42.5% of the energy entering the facility*
  - *Or, a system must meet a minimum 40% electrical efficiency HHV (AB 2778 – applies to 2007 only)*

Element	Definition	Minimum Requirement
216.6 (a)	Proportion of facilities' total annual energy output in the form of useful heat	5.0%
216.6 (b)	Overall system efficiency (50% credit for useful heat)	42.5%

Cogeneration System Efficiency Summary

Cumulative Performance for Groups of Projects

Technology	Number of projects (n)	216.6 (a) Proportion as Useful Heat (%)*	216.6 (b) Avg. Efficiency Level Achieved (%, LHV)*
FC	15	27.9% †	48.3%
GT	6	45.% †	42.3% †
IC Engine	208	29.8%	36.6%
MT	113	44.2%	33.1%

- *Overall, SGIP projects significantly exceeded PUC 216.6 (a) useful waste heat recovery requirements*
  - *5% minimum was required; >25% was achieved*
- *Microturbine and IC Engine SGIP projects had challenges complying with PUC 216.6 (b) efficiency requirements*

60% HHV Efficiency Requirement (CHP)

Technology	Number of projects (n)	Overall System Efficiency (%, HHV)*
FC	15	50.6%
GT	6	49.3% †
IC Engine	208	38.8%
MT	113	38.4% †

* [a] indicates confidence is less than 70/30. † indicates confidence is better than 70/30. No symbol indicates confidence is better than 90/10.

- *<u>Assembly Bill 1685 (Leno, October 12, 2003)</u> required that all SGIP combustion-based technologies operating in a combined heat and power application achieve a 60% percent system efficiency on a higher heating basis.*
- *Currently none of the technologies are meeting this CARB standard on an annual basis.*

Renewable Fuel Use Projects

- *Biogas fueled IC engines, microturbines, gas turbines, and fuel cells have GHG benefits which are not as dependent on system efficiency*
- *CPUC Decision 02-09-051 has two requirements related to renewable fuel use:*
  - *Renewable fuel use facilities cannot receive more than 25% of their annual energy input from non-renewable sources*
  - *PAs are to monitor the cost differences between non-renewable and renewable projects to determine if renewable project costs are below those of non-renewable projects*
    - *Concern that exemption of renewable projects from waste heat recovery requirements could lead to a greater than necessary incentive being applied to renewable projects and lead to fuel switching*

RFUR Fuel-Use Compliance

Technology/ Fuel Type	Capacity (kW)	Operational Date	Annual Natural Gas Energy Flow (MM Btu)	Renewable Fuel Use (% of Total Energy Input)	Meets Program Renewable Fuel Use Requirements?
FC/ Digester gas	500	3/11/2005	655	>88	EXPIRED
IC Engine/ Digester gas	500	5/11/2005	NA	NA	EXPIRED
IC Engine/ Digester Gas	704	11/15/2005	NA	NA	EXPIRED
IC Engine/ Digester Gas	704	11/15/2005	NA	NA	EXPIRED
MT/ Digester Gas	240	3/6/2007	785	95	EXPIRED
FC/ Digester gas & Natural gas	900	3/4/2008	4551	≥85	Yes
FC/ Digester Gas & Natural gas	600	4/24/2008	3003	≥85	Yes
FC/ Digester gas & Natural gas	1200	10/27/2008	NA	NA	NA

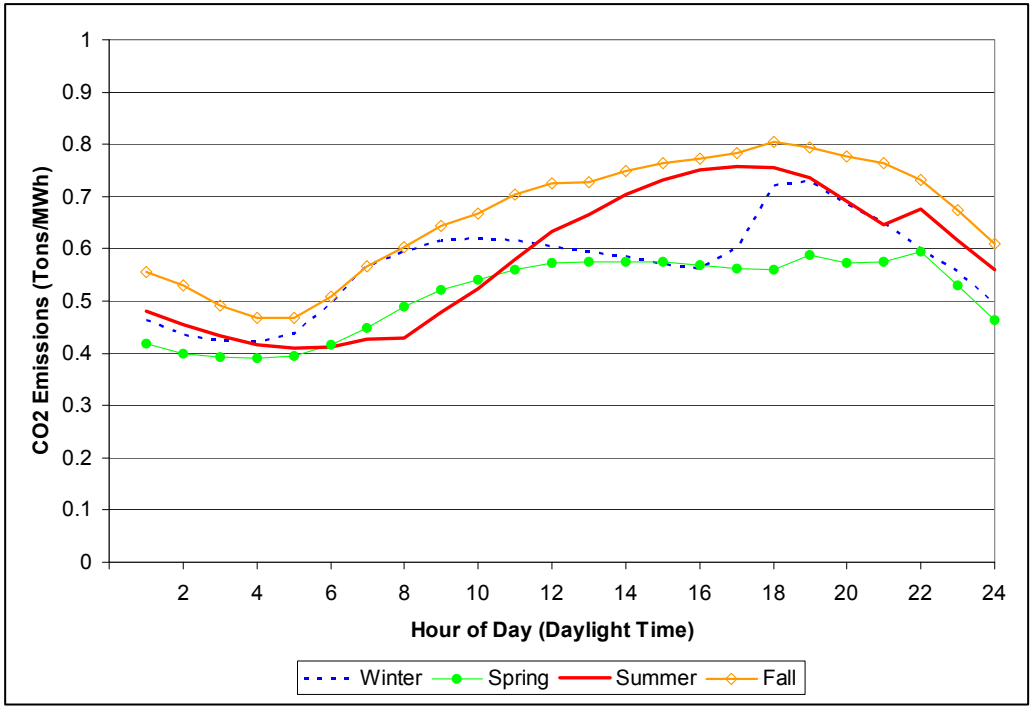
- *31 of the 39 RFUR projects operate solely on renewable fuel, and are therefore in compliance*
- *Overall between 34 (87 percent) and 39 (100 percent) of the RFUR sites are in compliance.*

GHG Impacts by Technology and Fuel

Greenhouse Gas Emissions Impacts from SGIP

- *Net GHG emissions from SGIP projects were developed relative to baseline GHG emissions from "grid electricity"*
  - *SGIP GHG emission sources considered:*
    - *Generation of electricity from SGIP projects that displaced electricity otherwise supplied by the grid*
    - *Recovered waste heat from SGIP projects that displaced combustion of natural gas used to provide process heat*
    - *Recovered waste heat from SGIP projects used in absorption chillers and therefore displaced electricity otherwise supplied by the grid for cooling purposes*
    - *Methane collected from SGIP renewable fuel projects*
  - *Grid GHG emissions:*
    - *Taken from CO_2 emission estimates developed by E3 to represent the utility generation mix*
    - *E3's GHG emission estimates take into account peaking versus baseline mix of generation by using marginal costs*

Average Grid CO_2 Emissions by Season and Hour of Day

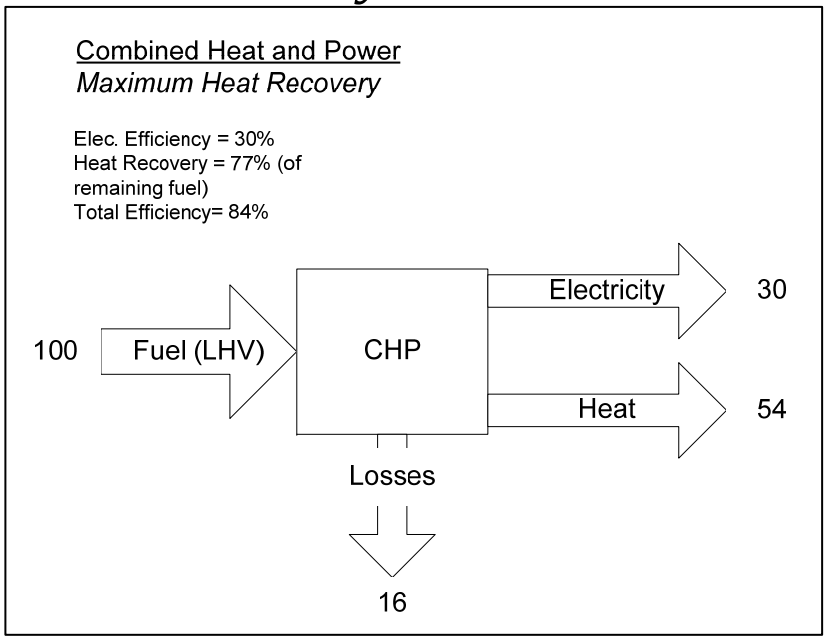


Energy and Environmental Economics. Methodology and Forecast of Long Term Avoided Costs for the Evaluation of California Energy Efficiency Programs. October 25, 2004. http://www.ethree.com/CPUC/E3_Avoided_Costs_Final.pdf

- *Seasonal variability is a function not only of weather but also of power plant maintenance schedules. This explains why values for Fall can be higher than values for Summer. During Fall and Summer the shape of the CO_2 emissions curve is similar to the CAISO load shape.*
- *CO_2 emissions rates are higher during the day than at night, all else equal.*

Efficiency of Utilizing Waste Heat for Heating vs. Cooling

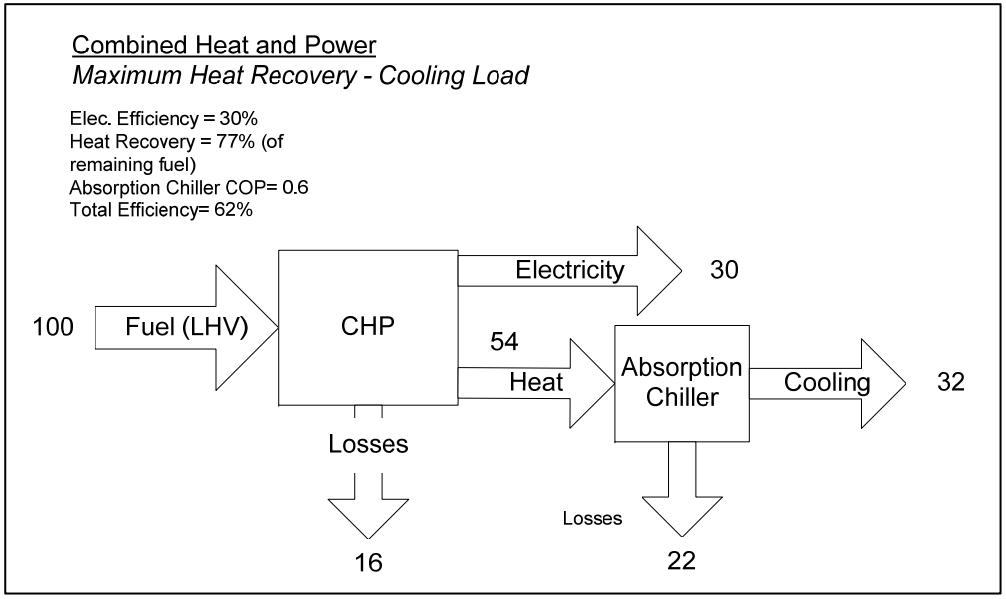
SGIP CHP system with Boiler



Displaces electricity from grid

Waste heat displaces natural gas fueled boiler

SGIP CHP system with Chiller

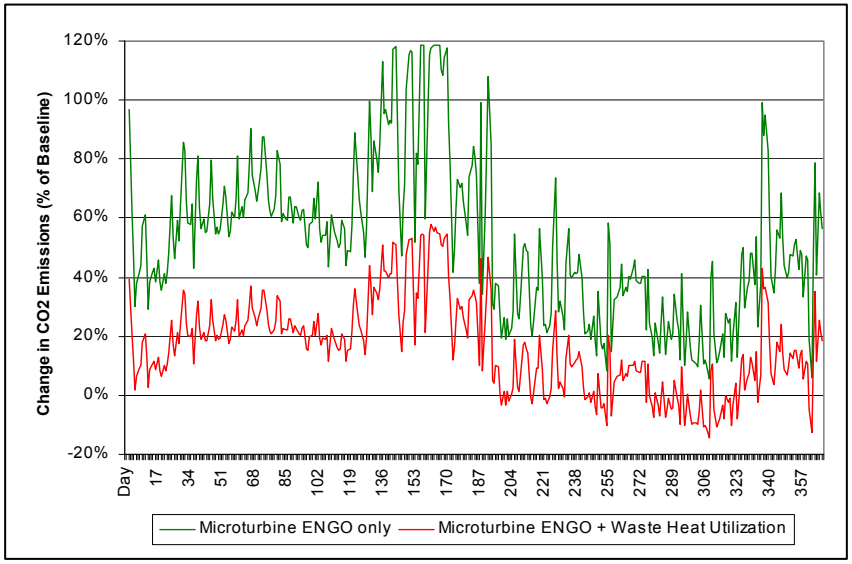


Displaces electricity from grid

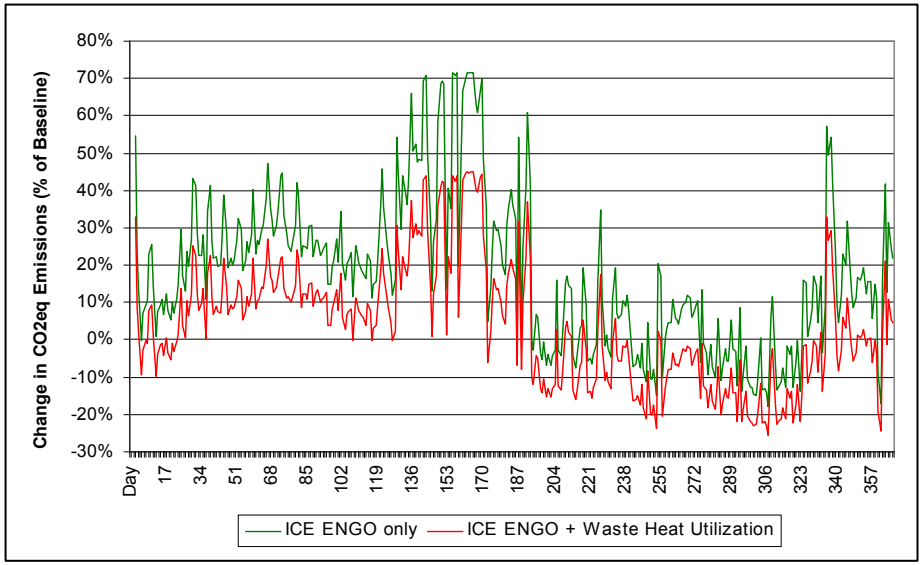
Waste heat displaces electricity to an electric chiller

Change of CO_2 Emissions Over 2008 for IC Engines and Microturbines with Waste Heat Utilization

MT with WHU - Boiler



ICE with WHU - Boiler



- *CO_2 emission reductions change over the year depending on generation emissions by the utility source being displaced and the amount of waste heat utilization*
- *However, waste heat recovery consistently shows significant impact on CO_2 emission reductions and for MT systems it is the only way they can reduce GHG emissions compared to the grid*

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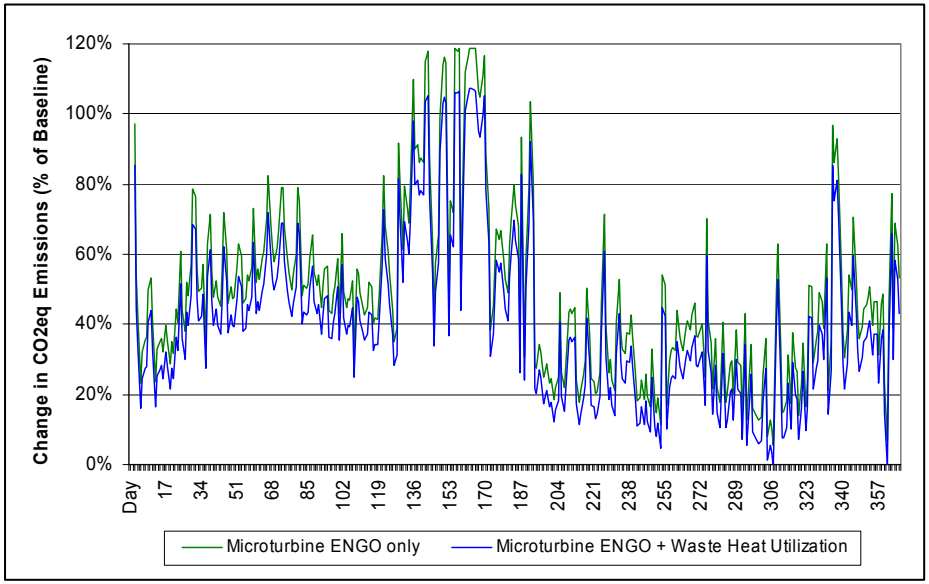
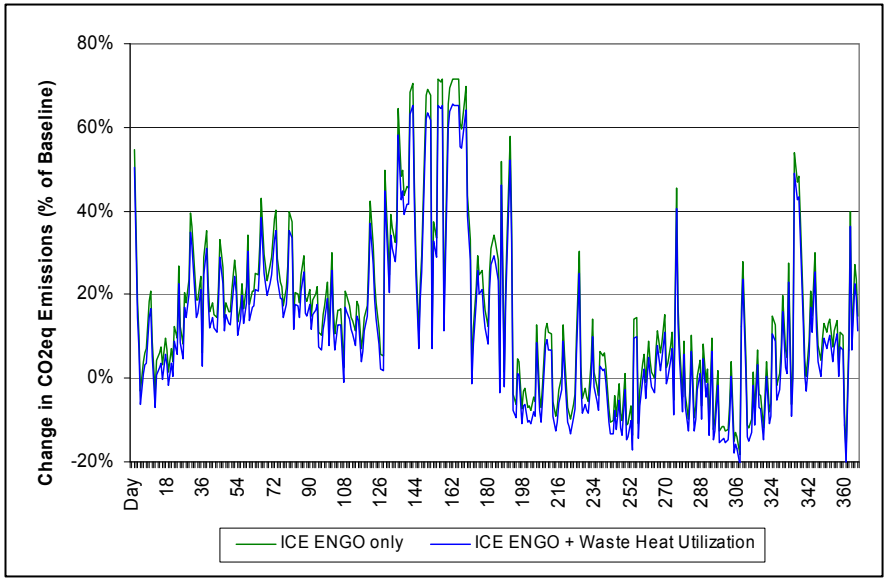
Change of CO_2 Emissions Over 2008 for ICEs and Microturbines with Waste Heat Utilization

MT with WHU – Absorption Chiller

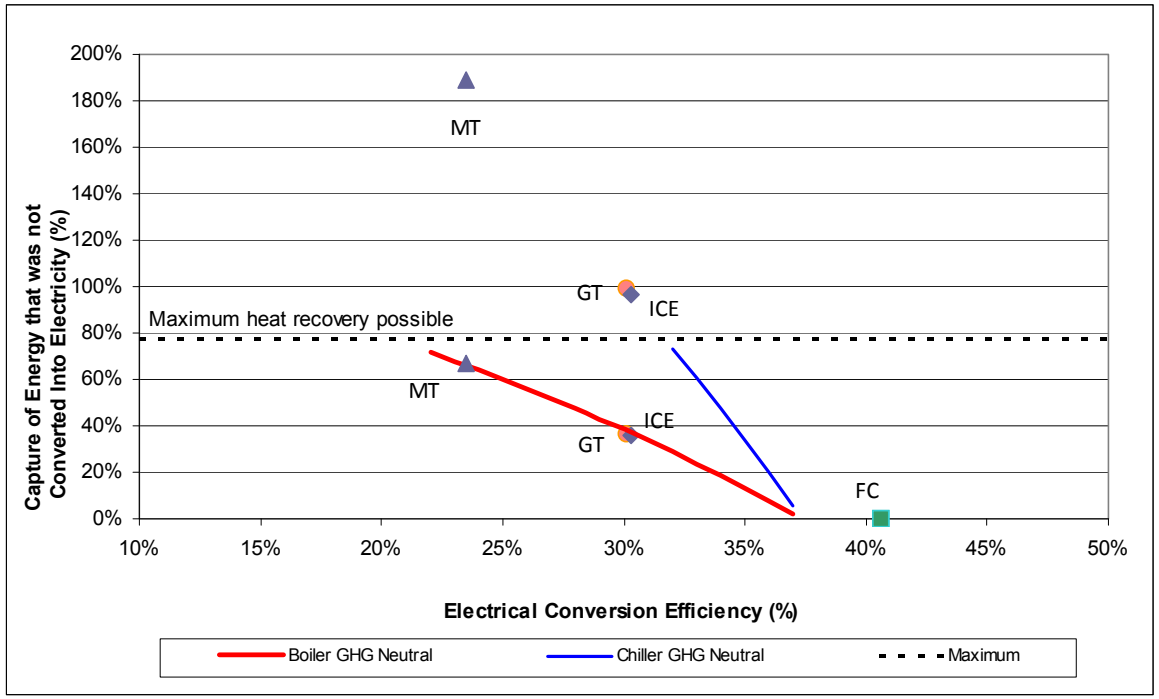


ICE with WHU – Absorption Chiller



- *Similarly, CO_2 emission reductions can be positively impacted during summer months if waste heat is used for absorption chilling applications*
- *Also remember that CHP systems with absorption chillers will reduce peak electric demand during summer (offsetting load from an electric chiller)*

CHP Non-Renewable Fuel System Performance Necessary to be GHG Neutral



Technology	Number of Metered Projects (n)	Measured Electric Conversion Efficiency in 2008 (%, LHV)
FC	8	40.6%
GT	3	30.1%
IC Engine	49	30.3%
MT	22	23.5%

- *This is on an annual basis*
- *Above the neutral line is GHG reducing, below is increasing*
- *Fuel cells are always GHG reducing because of their electrical conversion efficiency (ECE)*
- *Utilizing waste heat to offset natural gas to a boiler can achieve GHG reductions, but it becomes more difficult as the ECE decreases*
- *Utilizing waste heat to offset an electric chiller will not achieve GHG reductions on an annual basis, but could have positive impacts during peak hours*

SGIP CO_2 Emission Reductions by Source: Non-Renewable and Renewable

CO_{2eq} (tons) from Non-Renewable CHP Sources

Technology	Program	Baseline				Impact
	SGIP CHP System CO_2 Emissions (A)	Electric Power Plant CO_2 Emissions (B)	CO_2 Emissions Associated with Heating Services (C)	CO_2 Emissions Associated with Cooling Services (D)	TOTAL Baseline CO_2 Emissions (E) = (B)+ (C) + (D)	CO_2 Emission impacts from SGIP Projects (F) = (A) – (E)
FC	**20,576**	23,112	3,365	68	**26,545**	**-5,968**
MT	**54,247**	36,928	7,497	1,007	**45,432**	**8,815**
IC Engines	**142,650**	126,551	12,902	2,038	**141,491**	**1,159**
GT	**71,962**	62,820	11,639	2,299	**76,758**	**-4,796**
Total	**289,435**	**249,411**	**35,403**	**5,412**	**290,226**	**-790**

CO_{2eq} (tons) from Renewable CHP Sources

Technology	Program	Baseline					Impact
	SGIP System Emissions (A)	Electric Power Plant GHG Emissions (B)	CO_2 Emissions Associated with Heating Services (C)	CO_2 Emissions Associated with Cooling Services (D)	CO_2 Emissions From Flaring CH_4 (E)	TOTAL Baseline CO_2 Emissions (F) = (B)+ (C) + (D) + (E)	CO_2 Emission Impact from SGIP Projects (G) = (A) – (F)
FC	**5,873**	6,895	N/A	N/A	5,873	**12,767**	**-6,895**
MT	**4,566**	3,007	N/A	N/A	4,566	**7,573**	**-3,007**
IC Engines	**27,310**	23,598	391	N/A	27,310	**50,908**	**-23,989**
Total	**37,749**	**33,500**	**391**	**N/A**	**37,749**	**71,248**	**-33,891**

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GHG Emissions Impact Summary from CHP and RFU Systems

- *Methane emissions reductions strongly influence CO_2 equivalent results for renewable fuel projects*
  - *Largely due to the potency of methane as a GHG (21 times more potent than CO_2)*
- *Nonrenewable microturbines and IC engines are the only groups with a positive CO_2 Eq. Factor*
  - *Relatively low electrical conversion efficiencies and waste heat recovery*

Technology	Annual CO_2 Emissions Impact (Tons)	Annual CO_2 Emissions Impact (%)	Annual Energy Impact (MWh)	Annual CO_2 Impact Factor (Tons/MWh)
FC-N	-5,968	-22%	44,050	-0.14
MT-N	8,815	19%	67,963	0.13
IC Engines-N	1,159	1%	227,930	0.01
GT-N	-4,796	-6%	114,156	-0.04
FC-R	-6,895	-54%	12,572	-0.55
MT-R	-3,007	-40%	5,721	-0.53
IC Engines-R	-23,989	-47%	43,637	-0.55
PV	-115,057	-100%	197,178	-0.58
Total	**-176,244**	**-35%**	**718,558**	**-0.25**

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Conclusions and Recommendations

- *CHP technologies can provide significant GHG emission reductions.*
  - *The role of waste heat recovery is important to consider in establishing CHP programs that reduce GHG emissions.*
- *Determining the causes of lower-than-expected contribution to coincident peak demand or for performance degradation is likely to be important when developing other energy programs involving CHP*
- *Summit Blue is looking into the causes of performance issues.*

Conclusions and Recommendations (cont.)

- *The CEC has set a goal in the CHP roadmap to achieve 25 percent of California's supply of peak electricity from CHP facilities by 2020.*
- *Possible solutions could include:*
  - *Establishing tariffs that encourage CHP facilities to maximize electricity generation at critical peak times.*
  - *Developing policies that encourage CHP facilities to adopt the use of absorption chillers operated from waste heat recovered by the CHP facility.*
  - *Designing policies and approaches that require CHP system developers to identify and match thermal and electrical hourly load profiles for the host site for a minimum of the daily peak electricity demand hours of the host site.*
  - *Developing policies and incentives that encourage CHP system owners and operators to maintain their systems to minimize system degradation.*

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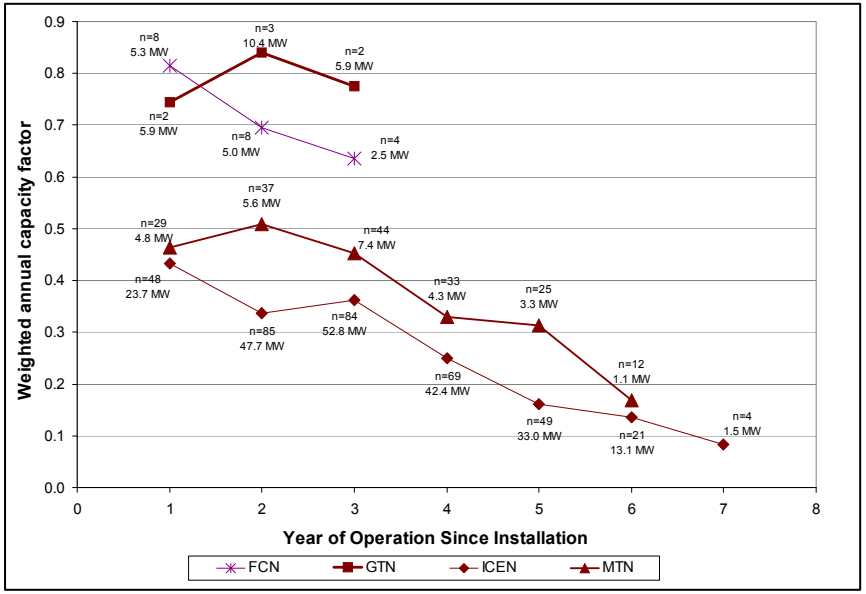
Appendix/Backup Slides

Objectives Covered in 2008 Impact Evaluation Report

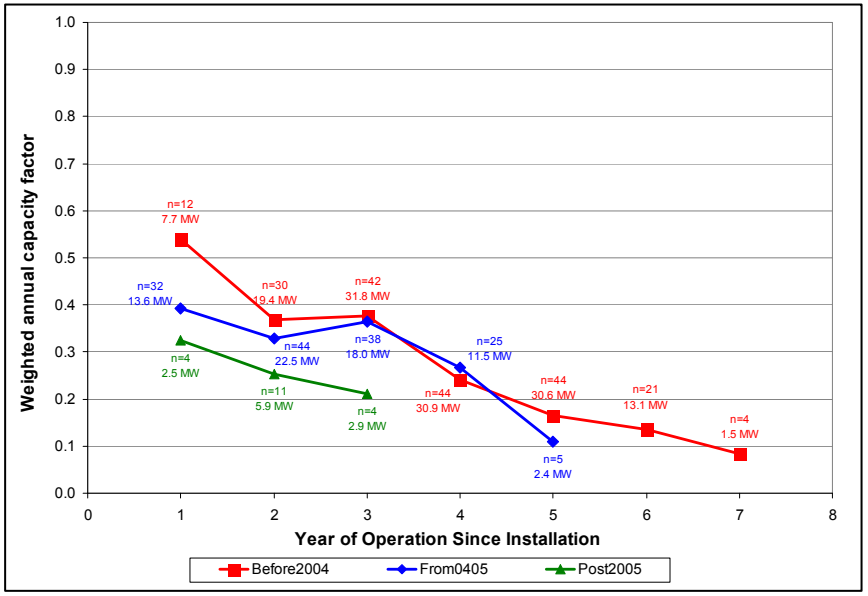
Impact Evaluation Objectives Addressed in 2008 Impact Evaluation Report
Electricity energy production and demand reduction ■ Annual production and production at peak periods during summer (both at Cal ISO system and at individual IOU-specific summer peaks) ■ Peak demand impacts (both at Cal ISO system and at individual IOU-specific summer peaks) ■ Combined across technologies and by individual technology category
Reliability and operating characteristics: ■ Average monthly capacity factors by individual technology categories across 2008 ■ Average annual capacity factors by individual technology trended against Program Year
Compliance of fuel cell, internal combustion engine, microturbine, and gas turbine technologies will be assessed against PUC 216.6 requirements ■ PUC 216.6 (a): useful recovered waste heat requirements ■ PUC 216.6 (b): system efficiency requirements
Compliance of fuel cells, internal combustion engines, microturbines and gas turbine systems with renewable fuel use requirements: not addressed in the impact evaluation (covered in RFU Reports)
Transmission and distribution impacts: to be covered in separate topical report
Provide greenhouse gas emission reductions by SGIP technology ■ Net against CO_2 emissions generated otherwise from grid generation ■ Methane captured by renewable fuel use projects
Trending of performance by SGIP technology from 2002 - 2008

Cogeneration Performance Trends

Annual Average Capacity Factor :
Running Year of Operation Since Install



Annual Average Capacity Factor :
Year of Operation Since Install by Vintage



- *Consistent and significant degradation in average annual CF for both ICE and MT (~ 30% over five years of operation)*
- *Later vintage years show higher starting CF but still show significant degradation in years 3 – 5 from date of installation*
- *Changes could be caused by a variety of factors (e.g., equipment maintenance/reliability issues, staff turnover, contract interruption, fuel prices, occupancy schedule, etc.)*

CHP Performance Trends

- *Trends show that IC engines and microturbines have experienced performance degradation over time.*
  - *Performance deteriorating by over 30 percentage points over five years of operation.*
  - *Can partly be attributed to systems that are no longer operational*

Technology	Number of Off-line sites (n)	Capacity Off-line (kW)	Percent of Total Metered Capacity* (kW/kW)
FC	0	0	0%
GT	0	0	0%
IC Engine	23	10,715	20.0%
MT	13	1,994	20.8%

Systems Sizes Through 2008

Technology & Fuel*	System Size (kW)				
	n	Mean	Minimum	Median	Maximum
PV	880	151	28	78	1,050
WD	2	824	699	824	950
FC–N	15	563	200	500	1,000
FC–R	5	690	250	600	1,200
IC Engine–N	210	634	60	475	4,110
IC Engine–R	17	658	80	704	1,080
GT–N	6	2,941	1,210	2,962	4,600
MT–N	112	161	28	114	928
MT–R	21	180	30	210	420

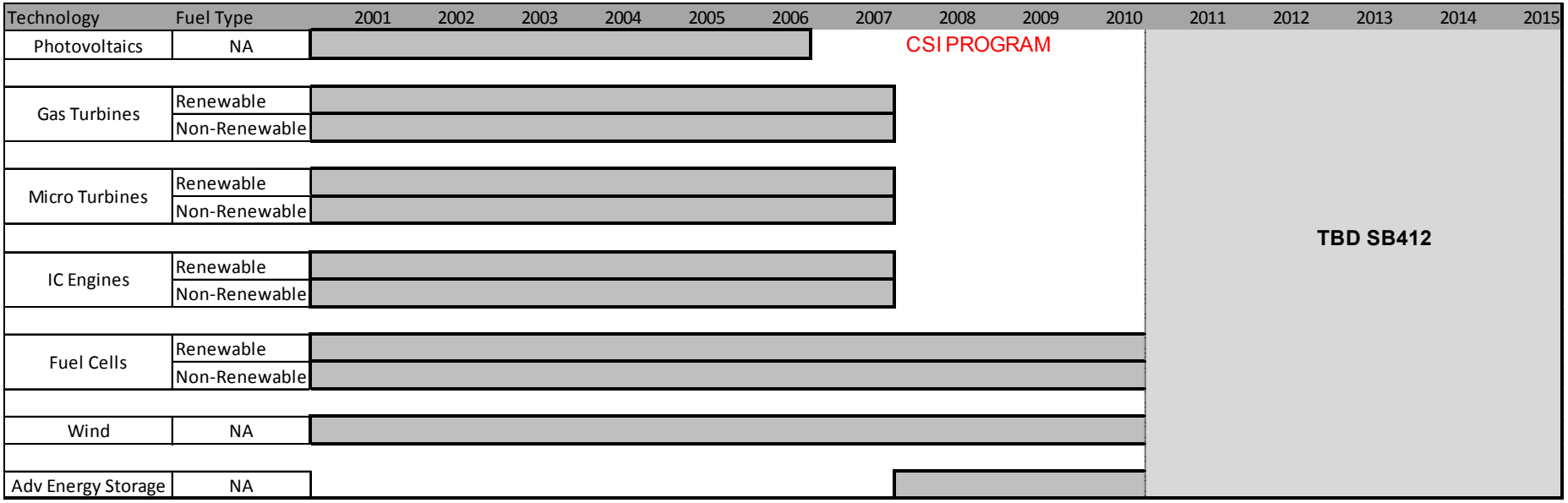
* PV = Photovoltaic; WD = Wind; FC = Fuel Cell; IC Engine = Internal Combustion Engine; GT = Gas Turbine; MT = Microturbine; N = Non-Renewable; R = Renewable

- *All gas turbine systems are larger than 1 MW*
- *PV systems are generally small (< 100 kW) compared to the other program technologies*
- *Renewable-fueled systems are generally larger than non-renewable-fueled systems*

SGIP Overview

- *Program Purpose*
  - *Incentives for customer side distributed generation originally established for peak demand reduction*
  - *Electric or gas customers of PG&E, SCE, SCG and SDG&E are eligible*
  - *Designed to off-set usage not for net export*
- *Eligible Technologies and fuels*
  - *PV, Wind, internal combustion (IC) engines, gas turbines, microturbines, fuel cells and energy storage*
  - *Renewable and non-renewable fuels*
    - *Non-renewable fueled systems must utilize waste heat or meet an efficiency standard*
    - *Renewable fueled systems are exempt from the waste heat requirement*
- *Program activity*
  - *26 MW of capacity was added in 2008 and 2 MW through Q3 2009*
  - *Through Q3 2009, the SGIP had 1,280 complete projects (340.2 MW) and 1 active project (0.6 MW) online for a total of 340.8 MW generating capacity*

SGIP Technology Eligibility 2001-2010



- *Program started in 2001*
- *PV systems were removed from the program in 2007 (CSI started in 2007)*
- *Since 2008, the only eligible technologies are fuel cells, wind turbines, and energy storage*

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SOLARRESERVE

FOR IMMEDIATE RELEASE

SOLARRESERVE SIGNS POWER CONTRACT WITH PG&E FOR UTILITY SCALE SOLAR POWER PROJECT IN CALIFORNIA

Project to Utilize Advanced Technology for a Large Scale Solar Thermal Project with Inherent Energy Storage

SANTA MONICA, Calif., December 22, 2009 - SolarReserve, the California-based developer of utility-scale solar power projects, today announced it has signed an agreement with Pacific Gas and Electric Company (PG&E) for the sale of electricity from SolarReserve's Rice Solar Energy Project. The 150-megawatt solar energy project will be located 30 miles northwest of the city of Blythe in eastern Riverside County, California. When completed, SolarReserve's facility will supply approximately 450,000 megawatt hours annually of clean, renewable electricity—enough to power up to 68,000 homes during peak electricity periods—utilizing its innovative energy storage capabilities.

The project will utilize an advanced molten salt system from United Technologies Corp. (UTC). SolarReserve holds the exclusive worldwide license for this groundbreaking technology which features efficient energy storage inherent in the design that can provide electricity reliably during peak demand periods to meet utility requirements whether the sun is shining or throughout the night.

"We are extremely pleased to contract with PG&E for the power generated from this important project," said Kevin Smith, SolarReserve's chief executive officer. "Throughout the process, we have worked hard to minimize the project's impact on local resources which is why the project is being developed on privately-owned land that had been previously used as an air field. Further, the project will use a dry cooling system that minimizes water usage without significantly impacting the plant's operational performance. We look forward to working with state and federal regulators in the permitting process to help bring this important project to reality for Californians."

Assemblyman Brian Nestande observed, "This project shows that revolutionary technologies will be an important factor in meeting our future energy needs. As a State we need to create a business climate conducive to private innovation and investment in the form of infrastructure and jobs."

Subject to comprehensive environmental review by cooperating state and federal agencies, the Rice project could break ground as early as spring of 2011 creating 450 construction jobs during the two-year construction period. The project will employ 45 permanent operations staff and will have an annual operating budget of more than $5.0 million, with the majority of that budget spent in Riverside and San Bernardino Counties.

In addition to direct employment, several thousand indirect jobs are expected to be created through various suppliers and service providers throughout the region. The project also supports SolarReserve and its suppliers' design, development, and engineering staffs with more than 150 scientists, engineers and green technical specialists working to further U.S. developed solar energy technology for potential export around the world.

About SolarReserve

SolarReserve LLC, headquartered in Santa Monica, California, is a solar energy project development company and holds the exclusive worldwide license to the molten salt, solar power tower technology developed by United Technologies Corporation. Since its formation in late 2007, SolarReserve's team of power project professionals have assembled a development portfolio of more than 25 projects featuring its licensed solar power technology with potential output of more than 3,000 megawatts in the United States and Europe; with early stage activities in Latin America, Africa, the Middle East, and Australia. SolarReserve's experienced management team has previously developed and financed more than $15.0 billion in renewable and conventional energy projects in more than a dozen countries around the world.

SolarReserve's molten salt, concentrating solar power tower technology was successfully demonstrated in California under a U.S. Department of Energy-sponsored pilot project in the late 1990s. The 10 megawatt pilot facility utilized a molten salt receiver designed, engineered and assembled by Rocketdyne, now a part of United Technologies Corporation. For more information, visit: www.SolarReserve.com

For more information about SolarReserve:

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Smart Grid Regional Demonstrations						
HQ State	**HQ City**	**Name of Primary Awardee**	**Project Title and Brief Project Description**	**Project Locations**	**Recovery Act Funding**	**Total Project Value Including Cost Share**
CA	Los Angeles	Los Angeles Department of Water and Power	**Los Angeles Department of Water and Power Smart Grid Regional Demonstration Project** - In partnership with a consortium of local research institutions, deploy smart grid systems at partners' university campus properties and technology transfer laboratories. The demonstration projects will also include gathering data on how consumers use energy in a variety of systems, testing on the next generation of cybersecurity technologies, and how to integrate a significant number of plug-in hybrid electric vehicles onto the grid.	Los Angeles, CA	$60,280,000	$120,560,000
	Rosemead	Southern California Edison Company	**Irvine Smart Grid Demonstration**- Demonstrate an integrated, scalable Smart Grid system that includes all of the interlocking pieces of an end-to-end Smart Grid system - from the transmission and distribution systems to consumer applications like smart appliances and electric vehicles. The project will focus on the interoperability and interactions between technologies and systems working at the same time - such as communications networks, cyber-security requirements, and interoperability standards.	Irvine, CA	$40,134,700	$80,269,400
California					**$100,414,700**	**$200,829,400**
MA	Westwood	NSTAR Electric & Gas Corporation	**NSTAR Automated Meter Reading-Based Dynamic Pricing -**Develop and implement a Smart Grid pilot program that will examine technologies to leverage existing automated home meters to include dynamic electricity pricing for homeowners (ie, lower rates when demand is lower). By building on the existing meter infrastructure and broadband internet networks, utilities would be able to access some of the benefits of the Smart Grid - such as collecting data at meters at shortened intervals, communicating energy use data to consumers, direct load control, automatically reporting outages, etc. - while avoiding the full costs of implementing smart metering infrastrastructure or the costs associated with replacing meters prematurely.	Newton and Hopkington, MA	$2,362,000	$4,724,000
		NSTAR Electric & Gas Corporation	**NSTAR Urban Grid Monitoring and Renewables Integration**- Demonstrate the use of advanced sensors and monitoring instrumentation on low voltage (secondary) networks in downtown Boston to improve grid reliability and safety. The project will provide additional visibility for operators, which will increase the system's capacity to integrate on-site energy technologies, such as solar photovoltaic energy systems, plug-in hybrid electric vehicles or battery storage. Knowledge gained from this demonstration will lay the groundwork for the broad application of smart grid and on-site energy generation programs for secondary area network grids in large urban areas such as New York City, Philadelphia, Chicago and Los Angeles.	Boston, MA	$5,267,592	$10,535,184
Massachusetts					**$7,629,592**	**$15,259,184**
MO	Kansas City	Kansas City Power & Light Company	**KCP&L Green Impact Zone Smart Grid Demonstration -**Demonstrate an end-to-end Smart Grid that will include advanced renewable generation, storage resources, distribution system automation, in-home customer systems and digital technologies, and innovative rate structures. The programs will benefit about 14,000 commercial and residential consumers, while providing the critical energy infrastructure required to support an urban revitalization effort, Kansas City's Green Impact Zone.	Kansas City, MO	$23,940,112	$48,125,315
	St. Louis	The Boeing Company	**Project Boeing SGS: Demonstrating a Cyber Secure, Scalable, Interoperable, and Cost-Effective Smart Selection for Optimizing Regional Transmission System Operation -** Demonstrate an advanced Smart Grid software technology with military-grade cybersecurity for improving regional transmission system planning and operation. The project includes Regional Transmission Operators (RTOs) and utilities that collectively serve all or part of 21 states and more than 90 million people. The Boeing Smart Grid Solution (SGS) software is designed to be scalable, secure, and compatible with multiple systems to help RTOs and utilities improve grid reliability and efficiency.	St Louis, MO; Sunnyvale, CA; Huntington Beach, CA	$8,561,396	$17,172,844
Missouri					**$32,501,508**	**$65,298,159**
	New York	Consolidated Edison Company of New York, Inc.	**Secure Interoperable Open Smart Grid Demonstration in New York and New Jersey** Demonstrate a scalable, cost-effective smart grid prototype that promotes cyber security, reduces electricity demand and peak energy use, and increases reliability and energy efficiency. The system will include renewable energy generation, grid monitoring, electric vehicle charging stations, transmission automation, and consumer systems that will help expand the use of renewable energy and lead to greater consumer participation in the electricity system.	Ramsey, NJ; Spring Valley and Nyack, NY; New York, NY (Long Island City, Queens, lower Manhattan)	$45,388,291	$92,388,217

	Smart Grid Regional Demonstrations					
	HQ City	**Name of Primary Awardee**	**Project Title and Brief Project Description**	**Project Locations**	**Recovery Act Funding**	**Total Project Value Including Cost Share**
NY	Uniondale	Long Island Power Authority	**Long Island Smart Energy Corridor -** Partner with two branches of the State University of New York (SUNY) to create a Smart Energy Corridor along the Route 110 business corridor, involving 800 customers. The project will demonstrate the intergration of a suite of Smart Grid technologies on the distribution and consumer systems, such as smart meters, distribution automation, distributed energy resources, and electric vehicle charging stations. The projecct will also include testing cybersecurity systems, identifying the optimal combination of features to encourage consumer participation, and educating the public about the tools and techniques available with the Smart Grid.	Long Island, NY	$12,496,047	$25,293,735
	White Plains	Power Authority of the State of New York	**Evaluation of Instrumentation and Dynamic Thermal Ratings for Overhead Lines -** Demonstrate the effects that Dynamic Thermal Circuit Ratings (DTCR) technology can have on areas of the New York State transmission system where there is abundant wind generation potential. This project could result in a 5 to 15% increase in transmission line capacity to allow for more wind power, defering millions of dollars in capital expenditures on transmission projects an enabling improved situational awareness for gird operators.	Massena & Chateaugay, NY	$720,000	$1,440,000
New York					**$58,604,338**	**$119,121,952**
OH	Columbus	Columbus Southern Power Company (doing business as AEP Ohio)	**AEP Ohio gridSMART Demonstration Project -** Demonstrate a secure, interoperable and integrated smart grid infrastructure for 110,000 consumers in the state that will maximize distribution system efficiency and reliability and enable consumers to reduce their energy use and save money. The project will include 13 different technologies from the substation to the customer, including distribution automation and control, smart meters and appliances, home area networks, plug-in hybrid electric vehicles, energy and battery storage, and renewable generation sources. These technologies are estimated to improve the reliability and efficiency of the distribution system 30-40%.	Approximately half of the State of Ohio	$75,161,246	$150,322,492
Ohio					**$75,161,246**	**$150,322,492**
TX	Austin	Center for the Commercialization of Electric Technologies	**Technology Solutions for Wind Integration in ERCOT -** Manage the fluctuations in wind power in the large Elecvtric Reliability Council of Texas (ERCOT) transmission grid through better system monitoring capabilities, enhanced operator visualization, and improved load management. Project includes the installation of synchrophasors to enhance monitoring of grid conditions as variable wind resources move through the system, and the use of integrated Smart Grid technologies, including household and community battery storage, smart meters and appliances, plug-in hybrid electric vehicles, and homes equipped with 1-3 kW solar photovoltaics.	Houston, TX	$13,516,546	$27,419,424
		Pecan Street Project, Inc.	**The Pecan Street Project Energy Internet Demonstration -** Develop and implement an Energy Internet microgrid, located in a large mixed-use infill development site in Austin, Texas. This effort will build on Austin Energy's existing Smart Grid programs by creating a microgrid that will initially link 1,000 residential smart meters, 75 commercial meters, and plug-in electric vehicle chaging sites. The project will be implemented by a unique Texas not-for-profit corporation created to research, develop and implement smart grid clean energy systems.	Austin, TX	$10,403,570	$24,656,485
	Dallas	Oncor Electric Delivery Company, LLC	**Dynamic Line Rating Project** - Demonstrate the use of Dynamic Line Rating (DLR) monitoring technology to reduce transmission-line congestion and increase the carrying capacity of the transmission lines. The data and results from the demonstration project will help better understand DLR technologies, so that transmission systems can be utilized to their full capacity, decreasing congestion and deferring upgrades and additional construction.	Dallas, TX	$3,471,681	$7,279,166
Texas					**$27,391,797**	**$59,355,075**
VA	Arlington	National Rural Electric Cooperative Association	**Enhanced Demand and Distribution Manaagement Regional Demonstration -** Install and operate of a suite of diverse Smart Grid technologies and aggregate the data from 17 rural electric cooperatives across 10 states. Technologies will include over 130,000 meters, over 18,000 demand response switches, nearly 4,000 in-home displays or smart thermostats, and others. In addition to customer-focused technologies, the project will include voltage sensors and fault detectors. The demonstration data will be centralized for all sites and include studies on total demand, distributed energy resources, peak pricing, customer appliance control, and self-healing technologies for improved reliability.	Camp Point, IL; Friendship, WI; Osceola, IA; Marshalltown, IA; Humboldt, IA; Delhi, NY; Reynolds, GA; Lihue, HI; Petersburg, IL; Plymouth, NH; Elizabethtown, KY; Owentown, KY; Jacksonville, IL; Bardstown, KY; Covington, GA; Markle, IN; Franklinton, LA	$33,932,146	$67,864,292
Virginia					**$33,932,146**	**$67,864,292**

	Smart Grid Regional Demonstrations					
	HQ City	**Name of Primary Awardee**	**Project Title and Brief Project Description**	**Project Locations**	**Recovery Act Funding**	**Total Project Value Including Cost Share**
WA	Richland	Battelle Memorial Institute, Pacific Northwest Division	**Pacific Northwest Smart Grid Demonstration Project**- Spanning five states and affecting more than 60,000 consumers, demonstrate and validate new smart grid technologies and inform business cases; provide two-way communication between distributed generation, storage, and demand assets and the existing grid infrastructure; quantify smart grid costs and benefits; and advance interoperability standards and cyber security approaches.	Seattle, WA; Kennewick, WA; Fox Island, WA; Ellensburg, WA; Salem, OR; Airway Heights, WA; Milton Freewater, OR; Pullman, WA; Helena and Georgetown, MT; Idaho Falls, ID; Libby and Kalispell, MT; Jackson Hole and Afton, WY	$88,821,251	$177,642,503
Washington State					**$88,821,251**	**$177,642,503**
WI	Waukesha	Waukesha Electric Systems	**Fault Current Limiting Superconducting Transformer -**Demonstrate a Smart Grid-compatible Fault Current Limiting Superconducting Transformer for a utility substation, that will help improve the stability of the system. The proposed 28 megavolt amp utility transformer will occupy approximately 50% of the physical size/weight of a conventional transformer, lower power consumption through reduction of losses, and increase the reliability of the electrical grid.	Irvine, CA	$10,744,409	$21,548,821
Wisconsin					**$10,744,409**	**$21,548,821**
Regional Demo Totals					**$435,200,987**	**$877,241,878**

Energy Storage Demonstrations						
HQ State	**HQ City**	**Name of Primary Awardee**	**Project Title and Brief Project Description**	**Project Locations**	**Recovery Act Funding**	**Total Project Value Including Cost Share**
CA	Alameda	Primus Power Corporation	**Wind Firming EnergyFarm™** - Deploy a 25 MW - 75 MWh EnergyFarm for the Modesto Irrigation District in California's Central Valley, replacing a planned $78M / 50 MW fossil fuel plant to compensate for the variable nature of wind energy providing the District with the ability to shift on-peak energy use to off-peak periods.	Alameda, CA; San Ramon, CA; and Modesto, CA	$14,000,000	$46,700,000
	Berkeley	Seeo, Inc	**Solid State Batteries for Grid-Scale Energy Storage** - Develop and deploy a 25kWh prototype battery system based on Seeo's proprietary nanostructured polymer electrolytes. This new class of advanced lithium-ion rechargeable battery will demonstrate the substantial improvements offered by solid state lithium-ion technologies for energy density, battery life, safety, and cost. These batteries would be targeted for utility-scale operations, particularly Community Energy Storage projects.	Berkeley, CA and Van Nuys, CA	$6,196,060	$12,392,120
	Fremont	Amber Kinetics, Inc.	**Amber Kinetics Flywheel Energy Storage Demonstration**- Develop and demonstrate an innovative flywheel technology for use in grid-connected, low-cost bulk energy storage applications. This demonstration effort, which partners with Lawrence Livermore National Laboratory, will improve on traditional flywheel systems, resulting in higher efficiency and cost reductions that will be competitive with pumped hydro technologies.	Fremont, CA	$4,000,000	$10,000,000
	Rosemead	Southern California Edison Company	**Tehachapi Wind Energy Storage Project -** Deploy and evaluate an 8 MW utility-scale lithium-ion battery technology to improve grid performance and aid in the integration of wind generation into the electric supply. The project will evaluate a wider range of applications for lithium-ion batteries that will spur broader demand for the technology, bringing production to a scale that will make this form of large energy storage more affordable.	Tehachapi, CA	$24,978,264	$53,510,209
	San Francisco	Pacific Gas & Electric Company	**Advanced Underground CAES Demonstration Project Using a Saline Porous Rock Formation as the Storage Reservoir**- Build and validate the design, performance, and reliability of an advanced, underground 300 MW Compressed Air Energy Storage (CAES) plant using a saline porous rock formation located near Bakersfield, CA as the storage reservoir.	Kern County, CA	$25,000,000	$355,938,600
California					**$74,174,324**	**$478,540,929**
MA	North Reading	Premium Power Corporation	**Premium Power Distributed Energy Storage System Demonstration for National Grid and Sacramento Municipal Utility District -** Demonstrate competitively-priced, multi-megawatt, long-duration advanced flow batteries for utility grid applications. This three-year project incorporates engineering of fleet control, manufacturing and installation of seven 500-kW/6-hour TransFlow 2000 energy storage systems in California, Massachusetts, and New York to lower peak energy demand and reduce the costs of power interruptions.	North Reading, MA; Syracuse, NY; Everett, MA; Sacramento, CA; and Rancho Cordova, CA	$7,320,000	$16,080,554
	Tyngsboro	Beacon Power Corporation	**Beacon Power 20MW Flywheel Frequency Regulation Plant -- Chicago, IL -** Design, build, test, commission, and operate a utility-scale 20 MW flywheel energy storage frequency regulation plant in Chicago, Illinois, and provide frequency regulation services to the grid operator, the PJM Interconnection. The project will also demonstrate the technical, cost and environmental advantages of fast response flywheel-based frequency regulation management, lowering the cost to build a 20 MW flywheel energy storage plant to improve grid reliability while increasing the use of wind and solar power.	Tyngsboro, MA and Chicago, IL	$24,063,978	$48,127,957
Massachusetts					**$31,383,978**	**$64,208,511**
MI	Detroit	The Detroit Edison Company	**Detroit Edison's Advanced Implementation of A123s Community Energy Storage Systems for Grid Support -** Demonstrate the use and benefits of Community Energy Storage (CES) systems for utilities and test the ability to integrate secondary-use electric vehicle batteries as part of the CES demonstration. This project will install 20 CES units, 25kW/2hr each, into a system that includes a 1 MW storage device integrated into a solar system.	Detroit, MI; Northville, MI; Fairfax, VA; Blacksburg, VA; Auburn Hills, MI; and Hopkinton, MA	$4,995,271	$10,877,258
Michigan					**$4,995,271**	**$10,877,258**
NC	Charlotte	Duke Energy Business Services, LLC	**Notrees Wind Storage** - Deploy a wind energy storage demonstration project at the Notrees Windpower Project in western Texas. The project will demonstrate how energy storage and power storage technologies can help wind power systems address intermittency issues by building a 20 megawatt (MW) hybrid-energy storage system capable of optimizing the flow of energy.	Goldsmith, TX	$21,806,232	$43,612,464
North Carolina					**$21,806,232**	**$43,612,464**

Energy Storage Demonstrations						
HQ State	**HQ City**	**Name of Primary Awardee**	**Project Title and Brief Project Description**	**Project Locations**	**Recovery Act Funding**	**Total Project Value Including Cost Share**
NH	West Lebanon	SustainX, Inc.	**Demonstration of Isothermal Compressed Air Energy Storage to Support Renewable Energy Production**- Design, build, and deploy a utility-scale, low-cost compressed air energy storage system to support the integration of renewable energy sources onto the grid. The 1 MW/4hr system will store potential energy in the form of compressed air in above-ground industrial pressure facilities. The technology utilizes isothermal gas cycling coupled with staged hydraulic compression and expansion to deliver an efficient and cost-effective energy storage solution.	West Lebanon, NH; Hanover, NH; and Saxonville, MA	$5,396,023	$10,792,045
New Hampshire					**$5,396,023**	**$10,792,045**
NM	Albuquerque	Ktech Corporation	**Flow Battery Solution for Smart Grid Renewable Energy Applications**- Demonstrate a prototype flow battery system that can be grid connected, charged and discharged, and scaled to utility power levels. The project will combine a proven redox flow battery chemistry with a unique, patented design to yield an energy storage system that meets the combined safety, reliability, and cost requirements for distributed energy storage.	Albuquerque, NM; Sunnyvale, CA; and Snelling, CA	$4,764,284	$9,528,567
	Albuquerque	Public Service Company of New Mexico	**PV Plus Storage for Simultaneous Voltage Smoothing and Peak Shifting -** Demonstrate how a 2.8MWh Zinc-Bromine flow battery along with a sophisticated control system turns a 500kW solar PV installation. into a reliable, dispatchable distributed generation resource. This hybrid resource will mitigate fluctuations in voltage normally caused by intermittent sources such as PV and wind andsimultaneously store more energy for later use when customer demand peaks.	Albuquerque, NM	$1,755,931	$5,851,303
New Mexico Total					**$6,520,215**	**$15,379,870**
NY	Binghamton	New York State Electric & Gas Corporation	**Energy East Advanced CAES Demonstration Plant (150MW)Using an Existing Salt Storage Cavern -** Demonstrate an advanced, less costly 150 MW Compressed Air Energy Storage (CAES) technology plant using an existing salt cavern. The project will be designed with an innovative smart grid control system to improve grid reliability and enable the intergration of wind and other intermittent renewable energy sources.	Watkins Glen, NY	$29,561,142	$125,006,103
New York Total					**$29,561,142**	**$125,006,103**
OH	Painesville	City of Painesville	**Painesville Municipal Power Vanadium Redox Battery Demonstration Program -** Demonstrate 1 MW vanadium redox battery (VRB) storage system at the 32 MW municipal coal fired power plant in Painesville. The project will provide operating data and experience to help the plant maintain its daily power output requirement more efficiently while reducing its carbon footprint.	Painesville, OH; Johnstown, PA; Alexandria, VA; Evansville, IN; Devens, MA; and Parma, OH	$3,743,570	$7,487,153
Ohio Total					**$3,743,570**	**$7,487,153**
PA	Lyon Station	East Penn Manufacturing Co.	**Grid-Scale Energy Storage Demonstration for Ancillary Services Using the UltraBattery Technology** - Demonstrate the economic and technical viability of a 3MW grid-scale, advanced energy storage system using the lead-carbon UltraBattery technology to regulate frequency and manage energy demand. This project will entail the construction of a dedicated facility on the East Penn campus in Lyon Station, PA that will be used as a working energy storage demonstration for UltraBattery modules.	Lyons Station, PA	$2,245,523	$4,491,046
	Pittsburgh	44 Tech Inc.	**Demonstration of Sodium Ion Battery for Grid Level Applications**- Partner with Carnegie Mellon University to demonstrate a new, low cost, long-life, highly efficient, environmentally friendly, stationary energy storage battery that uses a proven and fully novel cell chemistry. Specifically, an aqueous sodium-ion based electrolyte is used in conjunction with simple highly scalable electrode materials housed in low cost packaging.	Pittsburgh, PA	$5,000,000	$10,000,000
Pennsylvania Total					**$7,245,523**	**$14,491,046**
Energy Storage Totals					**$184,826,277**	**$770,395,378**

CALIFORNIA
ENERGY
COMMISSION

2008 NET SYSTEM POWER REPORT

COMMISSION REPORT

July 2009
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CALIFORNIA ENERGY COMMISSION

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Abstract

This report provides the California Energy Commission's annual calculation of net system power as required by state law. Net system power represents the mix of generation resources ***not*** included in the utility disclosure filings but that are used to serve California load. California utilities use this estimate to assign a mix of generation resources to the portion of their electricity that is not assigned to a specific source of generation in their disclosure filings. Thus, the *Net System Power Report* is then combined within each utility's electric generation mix as reported in their disclosure filings to report a complete profile of electric generation to consumers via the Power Content Label included within each utility's billing statements.

Keywords: Net System Power Report, electric generation, electricity, coal, natural gas, nuclear, renewables, wind, solar, geothermal, hydro, biomass, total system power, specified claims, power source disclosure, Power Content Label, imports

Introduction

The California Energy Commission's (Energy Commission) *2008 Net System Power Report* provides the annual calculation of net system power as required by state law (Public Utilities Code, § 398.1 - 398.5). California electric utilities, also referred to as energy service providers, must disclose the generation sources for the power serving their customer loads. Net system power represents the remaining mix of generation resources ***not*** included in the utility disclosure filings but that are used to serve California load. The report provides a description of how the net system power estimates are derived, the differences between net and total system power and why the net system measurement does not adequately reflect California resource mix. The state's total electricity supply mix is reflected in the Total System Power.

Definition and Calculation Method

California electric utilities meet their customer electricity demand from power plants they own, electricity supply contracts with other generators or marketers, and/or from short-term market purchases. Generators and marketers also purchase electricity from the western market to meet contract obligations or if spot prices are less expensive than their own generation costs. The generation is either located within California or imported from other regions in the West, including Mexico and Canada. The net electricity imports (total imports minus exports) are separated into two geographical regions: the Northwest (NW) and the Southwest (SW).[1]

Specific purchases are defined by law as "electricity transactions which are traceable to specific generation sources by an auditable contract trail or equivalent, such as a tradable commodity system, that provides commercial verification that the electricity source claimed has been *sold once and only once* to a retail consumer [emphasis added]."[2] Another term for these specific purchases is "claims."

Total system power is the sum of all in-state generation and net electricity imports by fuel type. All generators that are 1 megawatt (MW) or larger in California report actual generation and fuel use to the Energy Commission under the Quarterly Fuels and Energy Reporting requirements. The California control areas or balancing authorities report metered power flows on the main transmission lines that are used to represent electricity imports.

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[1] The Northwest includes Alberta, British Columbia, Idaho, Montana, Oregon, South Dakota, Washington, and Wyoming. The Southwest includes Arizona, Baja California, Colorado, New Mexico, Nevada, Texas, and Utah.

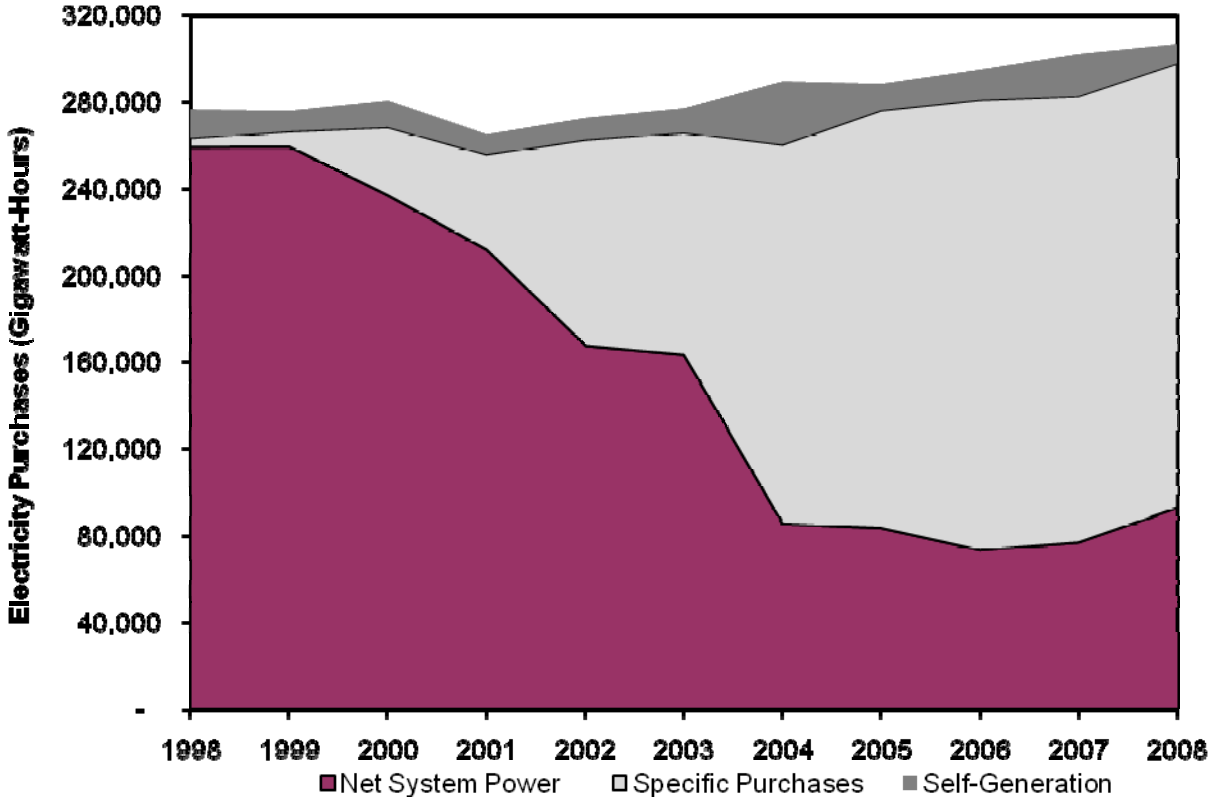
[2] Chapter 796, Statutes of 1997, Article 14, PUC, Section 398.2 (b). See http://www.leginfo.ca.gov/pub/97-98/bill/sen/sb_1301-1350/sb_1305_bill_19971009_chaptered.pdf

Net system power represents electricity used by California customers that no retailer has specifically claimed as to the source of the generation. It is calculated by taking California's total system power mix and then subtracting from this total the following amounts:

- Electricity procured by electricity retailers that they reported to the Energy Commission under the Power Source Disclosure Program as "specific purchases."
- Electricity generated in California for use on-site rather than for retail sales.

Figure 1 shows that as specific-purchase reporting by California's investor-owned and publicly owned utilities has increased over time, the amount of electricity defined as net system power has declined. In 1998, net system power represented 94 percent of retail electricity sales, but by 2008 accounted for only 30 percent of the total sales.

Figure 1: Net System Power Decreases as Reporting of Specific Purchases Increase



Source: Energy Commission Quarterly Fuels and Energy Report Database

The statute and associated regulations defining the format and content of the power content label were implemented when net system power was expected to remain a high

proportion of total electricity sales. Under those conditions, the power content label was envisioned as a means for reporting and comparing the "green" products offered by energy service providers with the net system power procured by the state's investor-owned utilities. As a result, net system power is referred to in the power content label as the "California Power Mix," a designation that misleads consumers into believing that these values represent California's power mix as a whole. Starting with the *2002 Net System Power Report*, the Energy Commission began including a total system power calculation to clarify the difference between net system power and California's whole electricity generation portfolio.

Retailers are required to participate in the Power Source Disclosure program; however, they can choose to disclose their specific purchases or use the "California Power Mix" percentages as a proxy for their own power mix. By using the "California Power Mix," a retailer avoids the annual requirement to report specific purchases. If a retailer claims that its mix of power is different from the "California Power Mix," however, then it is required to report specific purchases on its label and submit annual reports to the Energy Commission.

By disclosing specific purchases, the retailer demonstrates to its customers how its power mix differs from the "California Power Mix." The Energy Commission also publishes a *Reconciliation of Retailer Claims* report, which compares the sources of electricity that retailers have disclosed to their consumers with the actual energy generated for consumption by California consumers. The reconciliation report also provides an appendix summarizing statewide participation in the Power Source Disclosure Program and lists the renewable power content for all retailers making specific claims that year.

Net System Power Findings

Table 1 is the Energy Commission's estimate of net system power for 2008.

Table 1: 2008 California Net System Power Mix

Fuel Type	
Coal	33.7%
Large Hydroelectric	18.2%
Natural Gas	41.9%
Nuclear	4.6%
Eligible Renewables	1.6%
Total:	100.0%

Source: Energy Commission calculation

The following section explains why the California Net System Power Mix, as shown in **Table 1**, is not representative of California's actual power mix.

2008 Total System Power Findings and Method

Table 2 provides the Energy Commission's estimate of Total System Power and the generation mix that met California's 2008 electricity demand. This data is from a variety of information sources, including California power plant owners and control area operators. The in-state numerical values in the total system power table are a reasonably accurate snapshot of the entire California 2008 electricity generation power mix. The electricity import values, however, are not precise because there is no data tracking system available to identify the source of the generation associated with wholesale market transactions and interstate power flows. This will need to be addressed to monitor compliance with Assembly Bill 32 (Nunez, Chapter 488, Statutes of 2006) greenhouse gas emission reductions. Furthermore, the electricity generated from small-scale (less than 1 MW) facilities is not included in the total system power calculation because the locations and volumes of electricity generated by many of these facilities are not reported to the Energy Commission.

As comparisons are made to previous *Net System Power Reports*, it should be pointed out that an accounting error in 2007 incorrectly overstated the "Small Hydro" component of the *2007 Net System Power Report* under the Northwest imports category. While total imports calculated for 2007 do not change for either the Northwest or the Southwest categories, the 2007 report overstates the contribution of Small Hydro to the Renewables category in the Northwest. Specifically, total hydro accounted for approximately 61 percent of the Northwest imports. However, the split between Large Hydro and Small Hydro should have been reflected as 56.9 percent and 4.1 percent, respectively. Revised tables for both 2007 Total System Power and 2007 Net System Power are included in Appendix B. This accounting error highlights some of the difficulties in determining an appropriate breakdown among various generation types for imported electricity.

Table 2: 2008 Total System Power (Gigawatt Hours)

Fuel Type	In-State[1]	NW[2]	SW[2]	TSP	TSP %
Coal*	3,977	8,581	43,271	55,829	18.2%
Large Hydro	21,040	9,334	3,359	33,733	11.0%
Natural Gas	122,216	2,939	15,060	140,215	45.7%
Nuclear	32,482	747	11,039	44,268	14.5%
Renewables	28,804	2,344	1,384	32,532	10.6%
Biomass	5,720	654	3	6,377	2.1%
Geothermal	12,907	0	755	13,662	4.5%
Small Hydro	3,729	674	13	4,416	1.4%
Solar	724	0	22	746	0.2%
Wind	5,724	1,016	591	7,331	2.4%
Total	208,519	23,945	74,113	306,577	100.0%

Source: Energy Information Agency (EIA), Energy Commission Quarterly Fuels and Energy Report Database (QFER),and SB 1305 Reporting Requirements

*Note: In earlier years the in-state coal number included coal fired power plants owned by California utilities.

1 In-state generation: Reported generation from units 1 MW and larger.

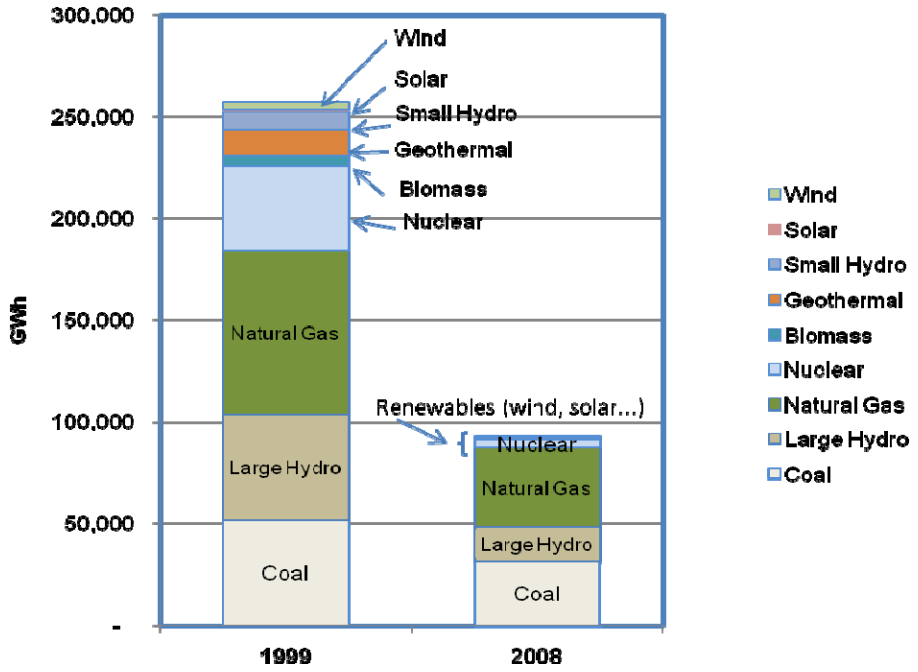
2 Net electricity imports are based on metered power flows between California and out-of-state balancing authorities. The resource mix is based on utility power source disclosure claims, contract information and calculated estimates on the remaining balance of net imports.

Net System Power and Sources of California Electric Generation

As California energy service providers have specified a larger and larger share of the sources of their power, net system power has changed in two ways. It has become a smaller share of total generation and is characterized by a higher percentage of "unclaimed" coal and natural gas generation.

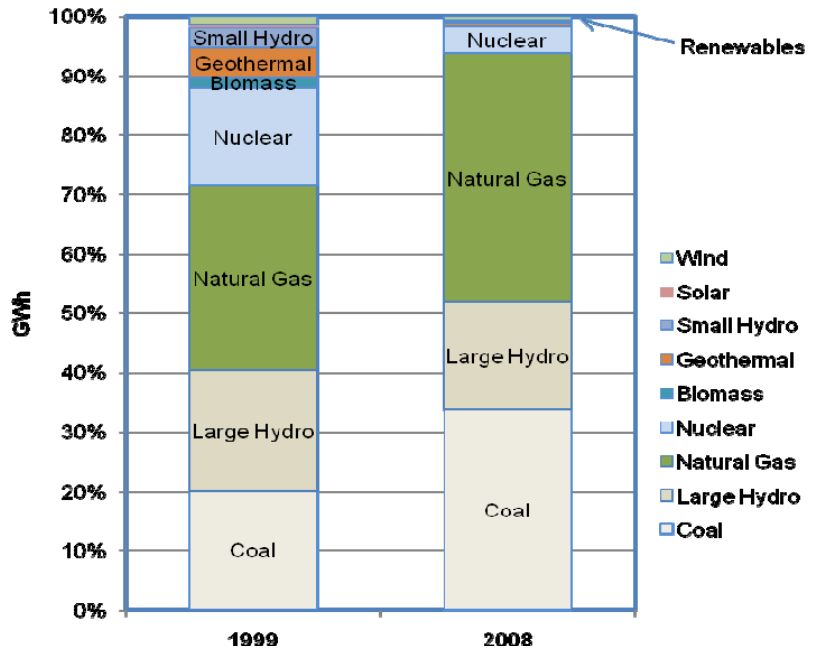
Figure 2 illustrates the decrease in net system power between 1999 and 2008. Although the volume of the net system power is lower in 2008, **Figure 3** shows an increase in the total share of net system power from fossil fuels (coal and natural gas). Unspecified imports now represent a larger portion of the net system power in 2008 compared to 1999. These two developments result in greater divergence between net system power and total system power. The method used to estimate the resource mix of unspecified imports has a direct influence on the net system power calculations.

Figure 2: Net System Power Becomes Smaller 1999-2008



Source: Energy Commission QFER Database (smallest values not labeled due to space limitations)

Figure 3: Natural Gas and Coal Shares of Net System Power Mix Become Larger 1999-2008



Source: Energy Commission QFER Database (smallest values of wind, solar, and other renewables not labeled due to space limitations)

Table 3 provides a comparison of the total system power mix percentages to the net system power estimates. The mandated Power Content Label represents net system power as the "California Power Mix" and gives customers the impression that the estimate represents actual statewide values. The net system power calculation gives the impression that coal generation represents 34 percent of the statewide mix instead of the 18 percent shown in the total system power mix and that renewable generation is only 2 percent of the state's resource mix instead of the actual 11 percent.

Currently, Power Content Label is a disservice to the public because the information listed does not allow consumers to monitor progress toward California's Renewables Portfolio Standard (RPS) goals. In addition, the definition of renewable resources for the RPS includes restrictions on municipal solid waste, biomass, and small hydropower and is not reflected in the Power Content Labels. As a result, parties reviewing Power Content Labels may believe that the labels accurately represent progress in meeting the RPS goal, when, in fact, it does not. The information reported to the Energy Commission regarding the quantity and mix of renewable energy for RPS compliance differs from that disclosed to electricity consumers under the Power Source Disclosure Program.

Table 3: 2008 Comparison of Net System Power and Total System Power

Fuel Type	NSP	TSP
Coal	33.7%	18.2%
Large Hydro	18.2%	11.0%
Natural Gas	41.9%	45.7%
Nuclear	4.6%	14.5%
Renewables	1.6%	10.6%

Source: Energy Commission Quarterly Fuels and Energy Report Database

Power Source Disclosure

Retail providers who make specific purchases claims to their customers are required by law to report the following: The name of the generating facilities and/or power pools where power was procured, total kilowatt hours (kWh) procured by generating facilities, total kWh purchased, total kWh resold or consumed on-site, and the total net specific purchases. Additionally, retail providers are required to provide a kWh total of purchases that cannot be tied to a power pool or generating facility. Program regulations require that these annual reports be verified by an internal auditor or for a publicly owned utility that claims one product, the governing board must attest to this report. This report is due to the Energy Commission by March 1 each year.

For 2008, the Energy Commission has received specific purchases information from these retail providers:

3 Phases
City of Anaheim
Azusa Light and Water
Bear Valley Electric
Cerritos
Coral Energy
Glendale
Imperial Irrigation District
Lompoc
Los Angeles Department of Water & Power
Merced Irrigation District
Modesto Irrigation District
Pacific Gas and Electric
Pasadena
Redding Electric Utility
Sacramento Municipal Utility District
San Diego Gas & Electric
Silicon Valley Power
Southern California Edison
Surprise Valley Electrification Corporation
Turlock Irrigation District

These retail providers did not submit annual reports on time and their 2007 specific purchases totals were used as placeholders where available:

Alameda Power and Telecom
Biggs Municipal Utilities
Burbank Water and Power
City of Colton
City of Healdsburg
City of Lodi
City of Needles
City of Palo Alto
City of Riverside
City of Shasta
City of Ukiah
Sempra Energy
Valley Electric Association

Estimating the Resource Mix of Out-of-State Power Imports

Currently there is no public, western-wide system that identifies deliveries of contracted generation sources and short-term market purchases to specific locations in California. As a result, the Energy Commission makes estimates and uses general assumptions to allocate the quantities of imported electricity to specific fuel types. This section explains the methodology used for allocating imports.

Senate Bill 1305 (Sher, Chapter 796, Statutes of 1997) requires electricity generators that report meter data to a control area operator to provide generation, fuel type and fuel consumption data on a quarterly basis. California control area operators are required to report to the Energy Commission the annual amounts of electricity crossing California's borders as imports and exports. For the *2008 Net System Power Report*, imports are reduced by electricity exports to reflect a net import requirement for California. While not perfect, the method is at least transparent.

Utility claims have been expanded to include specific line items in both the Northwest and Southwest categories. The remaining unclaimed imports are represented by the annual average power mix in each specific region. These average mixes were determined from generator output data reported annually to the U.S. Energy Information Administration by state and fuel type. **Appendix A** contains additional details on these calculations.

This averaging approach tends to overstate the amount of electricity imports from other out-of-state baseload generators. Using the average mix method ignores the likelihood that the output from low-cost baseload power plants that are owned by out-of-state utilities remains in each utility's service area to serve its own customers. Under the average power mix method used in this report, the out-of-state utility is assumed to export a portion of its share of baseload generation to serve California consumers. If all western utilities implemented a power source disclosure program similar to California's, it would be straightforward to identify the marginal generation plants serving spot market transactions.

Alternative accounting methods can result in variations in the estimated mixes of generation resources serving electricity imports and their calculated carbon content. For example, the Climate Change Registry applies regional average resource mixes for all imports, while marginal generation studies suggest that natural gas and hydroelectric power are the primary resources serving the western unspecified electricity market. The California Air Resources Board is using a default carbon-equivalent value of 1,100 pounds per megawatt hour for unspecified electricity sources. This default emission factor is intended to be only an interim measure, however, and is not demonstrated to be any more accurate than the approach used in this report.

A new analytical approach for imports is necessary to more accurately characterize how different types of generation facilities are likely to participate in the regional electricity markets. Since imports represent a significant portion of the electricity supply serving California demand, a ***realistic*** accounting of associated emissions will be important to design and implement in the greenhouse gas reduction program required under the *Global Warming Solutions Act of 2006* (AB 32). A flawed resource mix estimate may cause unintended market consequences that increase costs and provide no effect on total greenhouse gas emissions.

Calculation of Net System Power **Table 4** shows that net system power is total system power minus the claims of specific purchases and self-generation. Only the percentages for major fuel types are used on the power content label.

The Self-Generation category for 2008 corrects some past reporting inconsistencies that occurred in the *2007 Net System Power Report*. Some generators incorrectly reported power under the "Self-Generation" category instead of "sales for resale" on the CEC-1304 reporting form. The errors were based on genuine mistakes or by the assumption that a utility-owned generating unit was considered to be "Self-Generation" for

reporting purposes. The *2008 Net System Power Report* addresses this issue, as shown in **Table 4.** The revised Self-Generation figure for 2007 is 9,062 GWh. The revision for 2007 represents a reduction of approximately 50 percent, or 10, 511 GWh, from what was originally calculated. The revision of the Self-Generation category primarily affects the natural gas category by correcting an under-allocation of the natural gas category as determined in the 2007 Net System Power mix. A revised calculation for the *2007 Net System Power Report* is shown in **Appendix B**.

Table 4: 2008 Net System Power (GWh)

Fuel Type	TSP	Claims	Self-Gen	NSP	NSP %
Coal	55,829	(24,295)	(351)	31,183	33.7%
Large Hydro	33,733	(16,916)		16,817	18.2%
Natural Gas	140,215	(93,334)	(8,027)	38,854	41.9%
Nuclear	44,268	(39,979)		4,289	4.6%
Renewables	32,532	(30,447)	(601)	1,484	1.6%
Biomass	6,377	(5,820)	(601)	-44	0.0%
Geothermal	13,662	(13,093)		569	0.6%
Small Hydro	4,416	(4,133)		283	0.3%
Solar	746	(739)		7	0.0%
Wind	7,331	(6,662)		669	0.7%
Total	306,577	(204,971)	(8,979)	92,627	100.0%

Source: EIA, Energy Commission QFER, and SB 1305 Reporting Requirements

Summary

Retailers must disclose to their customers the sources of power that they purchase on behalf of their customers. Unless retailers make specific claims that they can verify, they must use the net system power values provided in this report for purposes of disclosure.

The Energy Commission is required to compute and report net system power and total system power annually. The Energy Commission relies on information from generators, control area operators, and electricity retailers, as well as staff expertise on the operation of the western interconnection to develop this report. The report represents the results of data collected for electricity generation and specific purchases in 2008.

Findings

- To provide consumers with the most accurate and transparent information regarding the sources of electricity being deployed to serve them, retail providers

should give their customers information on the utility's own electricity generation supply portfolio, thereby minimizing the use of net system power as the default power mix for California.

- The net system power fuel mix does not establish a representative greenhouse gas profile of electricity imports. The Power Content Label should not be used to estimate a utility's greenhouse gas emissions associated with its generation and power purchases.
- Consumers interested in monitoring the state's progress towards achieving the Renewables Portfolio Standard should not use the Total System Power table.

APPENDIX A – Calculating the Fuel Mix of Electricity Imports

The fuel mix of imported power was estimated similarly to the California power mix. It includes two parts: Specific imports based on the claims of California load-serving entities and regional non-specified imports by fuel type.

Determining specific imports is a relatively straightforward process. It is simply the claims of imports based on contractual relationships between the energy service providers and out-of-state generators reported as part of the power source disclosure reporting process. Other sources of contract information are also applied. The non-specified imports were calculated as the total imports less the imported specified claims. The non-specified imports mixes were then estimated using the percentage mix of generation in each region, excluding the specific claims (purchases or ownership shares).

The overall generation by resource type was calculated for the Northwest and Southwest regions based on United States Energy Information Administration (EIA) monthly generation for 2008 (EIA Forms 906 and 920). Generation for British Columbia Hydro, Integen's La Rosita power plant, and Termoelectrica de Mexicali's power plant are added to the EIA Western Electricity Coordinating Council (WECC) values. These facilities are part of the WECC, but are not reported by the EIA. Claims of specific purchases based on contracts with California energy service providers were subtracted from reported WECC generation by region and resource type. The percentage resource mix of the remaining generation in each region is then applied to the unspecified California imports.

Table A-1 reconciles total claims made by California utilities with fuel-specific imports from the Northwest and the Southwest. The resulting claims are considered to be what utilities have purchased from California-based electric generators.

Table A-1: 2008 Utilities Claims by Region (GWh)

Fuel Type	Total Claims	California Claims	NW Claims	SW Claims
Coal	24,295	2,235	829	21,231
Large Hydro	16,916	14,696	-	2,220
Natural Gas	93,334	92,752	280	302
Nuclear	39,979	32,570	-	7,409
Renewables	30,447	27,979	1,728	740
Biomass	5,820	5,284	536	-
Geothermal	13,093	12,353	-	740
Small Hydro	4,133	3,445	688	-
Solar	739	739	-	-
Wind	6,662	6,158	504	-
Total	204,971	170,232	2,837	31,902

Source: EIA, Energy Commission QFER, and SB 1305 Reporting Requirements

Table A-2 separates California's utility claims for fuel-specific electric generation imported from the Northwest. The remaining non-specified claims are then allocated based on the power mix for the Northwest as reported by the EIA.

Table A-2: 2008 Northwest Power Imports Reconciliation (GWh)

Fuel Type	Total NW Imports	California Utility Claims for NW Power Imports	Estimated Non-Specified NW Power Imports
Coal	8,581	829	7,752
Large Hydro	9,334	-	9,334
Natural Gas	2,939	280	2,659
Nuclear	747	-	747
Renewables	2,344	1,728	616
Biomass	654	536	118
Geothermal	-	-	-
Small Hydro	674	688	-14
Solar	-	-	-
Wind	1,016	504	512
Total	23,945	2,837	21,108

Source: EIA, Energy Commission QFER, and SB 1305 Reporting Requirements

Table A-3 separates California's utility claims for fuel-specific electric generation from total Southwest imports. The remaining non-specified claims are then allocated based on the power mix for the Southwest as reported by the EIA.

Table A-3: 2008 Southwest Power Imports Reconciliation (GWh)

Fuel Type	Total SW Imports	California Utility Claims for SW Power Imports	Estimated Non- Specified SW Power Imports
Coal	43,270	21,231	22,039
Large Hydro	3,359	2,220	1,139
Natural Gas	15,060	302	14,758
Nuclear	11,039	7,409	3,630
Renewables	1,385	740	645
Biomass	4	-	4
Geothermal	755	740	15
Small Hydro	13	-	13
Solar	22	-	22
Wind	591	-	591
Total	74,113	31,902	42,211

Source: EIA, Energy Commission QFER, and SB 1305 Reporting Requirements

Table A-4 summarizes the total electric generation for the Northwest and Southwest regions based on information from the EIA.

Table A-4: Electric Generation Profiles for Northwest and Southwest (GWh)

Fuel Type	Northwest Production	Percent	Southwest Production	Percent
Coal	96,411	36.6%	150,429	53.9%
Large Hydro	115,082	43.7%	8,894	3.2%
Natural Gas	33,066	12.6%	86,813	31.1%
Nuclear	9,210	3.5%	28,691	10.3%
Renewables	9,333	3.5%	4,520	1.6%
Biomass	1,992	0.8%	22	0.0%
Geothermal	-	0.0%	829	0.3%
Small Hydro	519	0.2%	75	0.0%
Solar	-	0.0%	128	0.0%
Wind	6,822	2.6%	3,466	1.2%
Other*	121	0.0%	166	0.0%
Total	263,223	100.0%	279,513	100.0%

Source: EIA

*Note: This category has been rounded to zero for the purposes of this report.

Table A-5 allocates the non-specified imports into California based on an unclaimed Northwest generation profile.

Table A-5: Northwest Electric Generation Reconciliation (GWh)

Fuel Type	Total Northwest Generation (A)	Claims by California Utilities on Northwest Generation (B)	Unclaimed Northwest Generation	Percent (C)	Non-specified Imports into California from Northwest (D)=((A) - (B)) * (C)	Total Imports into California from Northwest (B)+(D)
Coal	96,411	829	95,582	36.7%	7,752	8,581
Large Hydro	115,082	-	115,082	44.2%	9,334	9,334
Natural Gas	33,066	280	32,786	12.6%	2,659	2,939
Nuclear	9,210	-	9,210	3.5%	747	747
Renewables	9,333	1,728	7,605	2.9%	616	2,344
Biomass	1,992	536	1,456	0.6%	118	654
Geothermal	-	-	-	0.0%	-	-
Small Hydro	519	688	-169	-0.1%	-14	674
Solar	-	-	-	0.0%	-	-
Wind	6,822	504	6,318	2.4%	512	1,016
Total	263,101	2,837	260,264	100.0%	21,108	23,945*

Source: EIA, Energy Commission QFER, and SB 1305 Reporting Requirements

*Note: Net Imports into California from Northwest = 23,945 GWh per SB 1305 Control Area Reporting

Table A-6 allocates the non-specified imports into California based on an unclaimed Southwest generation profile.

Table A-6: Southwest Electric Generation Reconciliation (GWh)

Fuel Type	Total Southwest Generation (A)	Claims by California Utilities on Southwest Generation (B)	Unclaimed Southwest Generation	Percent (C)	Non-specified Imports into California from Southwest (D)=((A) - (B)) * (C)	Total Imports into California from Southwest (B)+(D)
Coal	150,429	21,231	129,198	52.2%	22,039	43,270
Large Hydro	8,894	2,220	6,674	2.7%	1,139	3,359
Natural Gas	86,813	302	86,511	35.0%	14,758	15,060
Nuclear	28,691	7,409	21,282	8.6%	3,630	11,039
Renewables	4,520	740	3,780	1.5%	645	1,385
Biomass	22	-	22	0.0%	4	4
Geothermal	829	740	89	0.0%	15	755
Small Hydro	75	-	75	0.0%	13	13
Solar	128	-	128	0.1%	22	22
Wind	3,466	-	3,466	1.4%	591	591
Total	279,348	31,902	247,446	100.0%	42,211	74,113*

Source: EIA, Energy Commission QFER, and SB 1305 Reporting Requirements

*Note: Net Imports into California from Southwest = 74,113 GWh per SB 1305 Control Area Reporting

Table A-7 reconciles California utility claims, non-specified California power generation, and non-specified imports to determine the net system power ("California Power Mix").

Table A-7: 2008 Net System Power Reconciliation (GWh)

Fuel Type	Total California Generation Excluding Self Generation (A)	California Utility Claims for California Generation (B)	California Non-Specified Generation (C) = (A) - (B)	Estimated Non-Specified SW Power Imports (D)	Estimated Non-Specified NW Power Imports (E)	NSP (C) + (D) + (E)	Percent
Coal	3,626	2,235	1,391	22,039	7,752	31,182	33.7%
Large Hydro	21,040	14,696	6,344	1,139	9,334	16,817	18.1%
Natural Gas	114,189	92,752	21,437	14,758	2,659	38,854	41.9%
Nuclear	32,482	32,570	-88	3,630	747	4,289	4.6%
Renewables	28,203	27,979	224	645	616	1,485	1.6%
Biomass	5,119	5,284	-165	4	118	-43	0.0%
Geothermal	12,907	12,353	554	15	-	569	0.6%
Small Hydro	3,729	3,445	284	13	-14	283	0.3%
Solar	724	739	-15	22	-	7	0.0%
Wind	5,724	6,158	-434	591	512	669	0.7%
Total	199,540	170,232	29,308	42,211	21,108	92,627	100.0%

Source: EIA, Energy Commission QFER, and SB 1305 Reporting Requirements

APPENDIX B – Revision of the *2007 Net System Power Report*

The following two tables revise the *2007 Net System Power Report* adopted by the Energy Commission at the April 16, 2008, Business Meeting. Two accounting errors were significant enough to warrant recalculations of the fuel-type allocations within both Total System Power and Net System Power estimates.

The first error was made in determining the split of total hydroelectric generation between the Large Hydro and Small Hydro categories under the Pacific Northwest (NW) imports column. The original report included an overestimated amount of NW generation from Small Hydro facilities, which instead should be included in the Large Hydro category. The correct NW 2007 Large Hydro generation is 12,494 GWh, instead of 9,263 GWh. The corrected NW 2007 Small Hydro generation is 1,469 GWh, instead of 4,700 GWh. The total for all fuel-types for the NW remains unchanged at 24,669 GWh. The correction reduces the amount of Small Hydro generation from imports, which changes the overall 2007 renewable generation estimates in the Total System Power and Net System Power mixes.

The second error affects the Self-Generation category. The original report listed 19,573 GWh when the correct figure should have been 9,062 GWh, a 54 percent reduction. This reduction impacts the determination of the revised *2007 Net System Power Report* by increasing the share of natural gas in the Net System Power mix.

Table B-1 details the calculation of 2007 Total System Power using the revised split between Large and Small Hydro for the NW category.

Table B-1: Revised 2007 Total System Power (GWh)

Fuel Type	In-State	NW	SW	TSP	TSP %
Coal*	4,190	6,546	39,275	50,011	16.6%
Large Hydro	23,283	12,494	2,686	38,463	12.7%
Natural Gas	118,228	1,837	16,363	136,428	45.1%
Nuclear	35,692	629	8,535	44,856	14.8%
Renewables	28,463	3,163	688	32,314	10.8%
Biomass	5,398	837	1	6,236	2.1%
Geothermal	12,999	0	440	13,439	4.5%
Small Hydro	3,675	1,469	18	5,162	1.7%
Solar	668	0	7	675	0.2%
Wind	5,723	857	222	6,802	2.3%
Total	209,856	24,669	67,547	302,072	100.0%

Source: EIA, Energy Commission QFER, and SB 1305 Reporting Requirements

Table B-2 calculates the revised 2007 Net System Power proportions based on the corrected Self-Generation data and the re-allocation of Large and Small Hydro categories carried over from **Table B-1**.

Table B-2: Revised 2007 Net System Power (GWh)

Fuel Type	TSP	Claims	Self-Gen	NSP	NSP %
Coal	50,011	(24,446)	(373)	25,192	28.9%
Large Hydro	38,463	(16,833)		21.630	24.8%
Natural Gas	136,428	(94,985)	(8,142)	33,301	38.2%
Nuclear	44,856	(42,447)		2,409	2.8%
Renewables	32,314	(27,063)	(547)	4,704	5.3%
Biomass	6,236	(5,077)	(547)	612	0.7%
Geothermal	13,439	(11,682)		1,757	2.0%
Small Hydro	5,162	(4,001)		1,161	1.3%
Solar	675	(670)		5	0.0%
Wind	6,802	(5,633)		1,169	1.3%
Total	302,072	(205,774)	(9,062)	87,236	100.0%

Source: EIA, Energy Commission QFER, and SB 1305 Reporting Requirements

Table B- 3 shows the original 2007 Total System Power table as adopted by the Energy Commission at the April 16, 2008 Business Meeting.

Table B- 3: Original 2007 Total System Power (GWh)

Fuel Type	In-State	NW	SW	TSP	TSP %
Coal*	4,190	6,546	39,275	50,012	16.6%
Large Hydro	23,283	9,263	2,686	35,232	11.7%
Natural Gas	118,228	1,838	16,363	136,063[1]	45.2%
Nuclear	35,692	629	8,535	44,856	14.8%
Renewables	28,463	3,163	688	35,545	11.8%
Biomass	5,398	837	1	6,236	2.1%
Geothermal	12,999	0	440	13,439	4.5%
Small Hydro	3,675	4,700	18	8,393	2.8%
Solar	668	0	7	675	0.2%
Wind	5,723	857	222	6,802	2.3%
Total	209,856	24,669	67,547	302,072	100.0%

Source: EIA, Energy Commission QFER, and SB 1305 Reporting Requirements
1 An original typo – the correct number, by adding across, is 136,429. Percentage is correct as listed.

See: http://www.energy.ca.gov/2008publications/CEC-200-2008-002/CEC-200-2008-002.PDF

Table B-4 shows the original 2007 Net System Power table as adopted by the Energy Commission at the April 16, 2008 Business Meeting.

Table B-4: Original 2007 Net System Power (GWh)

Fuel Type	TSP	Claims	Self-Gen	NSP	NSP %
Coal	50,011	(24,446)	(1,149)	24,416	31.9%
Large Hydro	35,232	(16,833)		18,399	24.0%
Natural Gas	136,428	(94,985)	(17,329)	24,114	31.4%
Nuclear	44,857	(42,447)		2,410	3.1%
Renewables	35,544	(27,063)	(1,095)	7,383	9.6%
Biomass	6,236	(5,077)	(1,092)	66	0.1%
Geothermal	13,439	(11,682)		1,757	2.3%
Small Hydro	8,393	(4,001)	(3)	4,389	5.7%
Solar	675	(670)		5	0.0%
Wind	6,802	(5,633)		1,169	1.5%
Total	302,072	(205,774)	(19,573)	76,725	100.0%

Source: EIA, Energy Commission QFER, and SB 1305 Reporting Requirements
http://www.energy.ca.gov/2008publications/CEC-200-2008-002/CEC-200-2008-002.PDF

INTERNATIONAL ENERGY AGENCY

VARIABILITY OF WIND POWER AND OTHER RENEWABLES

Management options and strategies

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Naturally, all remaining errors and omissions are the authors' own responsibility.

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Executive Summary

This working paper links the current debate about the 'intermittency' of wind power into the wider context of natural cycles of resource availability of all renewable energy technologies. It investigates whether there are technical limits to the market penetration of renewable energy technologies due to these cycles and it discusses some of the economic implications and outlines key cost variables. Being an inherent aspect of the renewable resource, they are, in the case of mature renewable energy technologies such as hydropower, biomass and geothermal, well understood and managed. 'New' renewable energy technologies such as wind power or solar PV have surfaced prominently in recent discussions among policy-makers, researchers and the media for two main reasons: Firstly, the rapid growth, especially of wind power, led to significant market share in some countries within a short timeframe thus magnifying grid integration issues. Secondly, these technologies introduce a new quality of natural cycles in that they can fluctuate over short timescales intra-day and intra-hourly which requires different management strategies than previously established. In the case of wind energy, it is analyzed how this affects the possibility of integrating renewables into electricity grids on a larger scale.

This review comes to the conclusion that a number of measures are necessary to integrate wind energy and other renewables into modern electricity grids, even though the fundamental technical principles are not new. The geographical aggregation of generators such as wind turbines reduces the volatility of output. Improved forecasting methods will make it more predictable. Both aspects are already widely used in electricity markets. Furthermore, careful attention needs to be paid to the provision of backup and reserve capacities and the timely extension of transmission and distribution grids in order to ensure system stability at all times. In particular, transboundary electricity exchange is going to play an increasing role which will have to be assessed. Although these issues are also central to market liberalisation and security of supply concerns, they will become even more important with increasing market penetration of wind power. Finally, as each renewable energy technology fluctuates over a different time-scale, important gains from the complementarity of these cycles can be achieved.

Beyond the above mentioned technical issues, the extent to which the intermittency of natural resources will become a barrier to renewables is mainly a question of economics and market organisation. Grid extensions and the provision of reserves which are attributable to wind power come at costs which have to be taken into account when considering the overall economics of wind power. The precise costs depend on a number of factors, including the level of market penetration of wind power, the availability of the renewable resource, the state of the existing grid and current technology mix. Transparent, inter-connected and well-functioning markets help to minimise these grid integration costs. This may require structural adaptation in some cases. In this context, market gate-closure times between final declaration of forecasted generation and actual real-time usage play an important role; weather forecasting and modelling techniques become more precise the closer they are to real time, thus shorter gate closure times would allow for more precise output estimates and consequently better management. Currently, some markets are still designed with long gate-closure times which impose additional economic costs which are not necessarily based on technical needs. Taking this into account produces the right incentives for the development of a portfolio of options to manage intermittency, including flexible new plants, storage technologies, distributed generation and demand-side response techniques.

This study draws mainly on experiences in Denmark and Germany and some theoretical analyses. In order to provide a more complete picture, in future analyses more countries will have to be considered and effects of trans-boundary electricity flows will have to be taken into account in more detail.

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1. Introduction

In many IEA countries, renewable energy technologies receive increasing attention and with the latest International Renewable Energy Conference in Bonn, 2004, several countries have set ambitious targets for renewables. As a result, the World Energy Outlook 2004 expects all renewables to account for a share of 19% in world electricity generation 2030 in the reference scenario, and even 24% in the alternative policy scenario (IEA 2004b).

Especially the electricity sector experiences major increases in renewables market penetration, accounting for 15.1% in IEA member countries in 2001 already, with hydropower providing some 13% (IEA, 2004a). 'Traditional' technologies such as hydropower and geothermal have maintained or increased their participation in the primary energy supply in some non-IEA countries around the world. In IEA member countries, despite the decreasing share of these 'traditional' technologies in total electricity production since the early 1970's, renewables are likely to play a more important role in the medium- to long-term. With the entry into force of the Kyoto-Protocol and the advent of an emissions trading-scheme among EU-member countries, first steps are now under way to include the costs of CO_2 emissions in energy markets. Already, 'new' renewable technologies such as wind and solar exhibit high annual growth rates in Total Primary Energy Supply (TPES). At current trends, this will ultimately lead to an overall increase, as shown in table 1.

Table 1: Average annual growth rates of renewable energy sources in IEA member countries in TPES in %

	1970-1980	1980-1990	1990-2001
Renewables	3.2	2.4	1.2
Biomass	3.5	3.0	1.6
Hydro	2.6	0.7	0.4
Geothermal	8.3	9.4	0.4
Solar PV/Wind	6.4	23.5	23.1

Source: IEA 2004a:43

In this light, the integration of larger amounts of renewables will become an increasingly important issue for the management of electricity grids. This comes at a time when demand for electricity continues to rise and electricity markets themselves are undergoing a series of institutional and technical changes, opening up to new market actors and re-organising the operation of key market segments. Traditional top-down approaches with only one company controlling all segments of the power market, delivering power from a small number of power plants with high capacity ratings, are broken up. Instead, the market is going through a liberalisation process, moving away from monopolistic approaches to electricity generation and retailing, allowing for an increasing number of players on all levels of the market - be it power production, distribution or transmission.

Today's electricity markets, in going through a market liberalisation process, can also open up more opportunities for decentralised and more flexible power generation from renewable energies, combined-heat and power plants (CHP) or gas turbines, depending on the regulatory structure. These developments have given rise to new technical challenges but also new opportunities for transmission and distribution grid operators.

With higher market penetrations of renewable energy technologies, however, some electricity systems in IEA countries will increasingly need to cope with an important variable: natural cycles of renewable energies. Natural cycles relate to a phenomenon, which all renewable energies have in common, as will subsequently be shown. Renewables by their very nature vary their output with natural conditions, albeit, depending on the technology, on different timescales. These fluctuations of renewable electricity output can pose challenges in managing electricity grids. On the other hand, hydropower (pumped-storage) has been used for a long time to level out short- and mid-term fluctuations in electricity production and consumption. Hence, the issue of unmatched demand and supply is not completely new and in many cases understood.

The most prominent example in media and policy discussions is wind power, where the natural fluctuations have received a great deal of attention in recent years and have led to concerns about wind integration. Regions such as Western Denmark and Northern Germany, where wind penetration levels have become significant, have become "case studies" for the integration of renewables in general, and wind power in particular. The challenges that the high share of wind power poses both for these countries and its neighbours are highlighted in chapter 3.

On the question of wind intermittency, a lot of research has been carried out on the American and European electricity markets. Initially, it was believed that only a small amount of intermittent capacity was permissible on the grid without compromising system stability. However, with practical experience gathering, for example in the Western Danish region where over 20% of the yearly electricity load is covered with wind energy, this view has been refuted. Instead of rejecting intermittent technologies outright for want of dispatchable capacity, a number of papers have recently focused on management techniques that minimise disruption to the grid and thus allow for higher penetration of renewable technologies.

Nevertheless, the questions whether natural cycles of renewables have impacts on renewable energy market potential, and whether there are upper limits to renewable energy share in electricity supply, have become critical for policy-makers. This study reviews and draws together the existing literature from a number of countries and puts it into the context of the current debate. It thus presents the current thinking on the technical and policy implications of variable electricity supply from renewable energy sources and offers insights and methodological guidance for interested parties who want to assess these issues within their own national circumstances. In chapter 2, it will give a detailed overview on the natural cycles of different renewable energy technologies to provide a context for the subsequent chapters. Chapter 3 will focus on the currently prominent example of the integration of wind power into electricity grids as an example for renewable energies in general. Options for grid management, reserves and policy are outlined and a review of current cost estimates of system integration is presented. Chapter 4 will summarise the key technical and policy challenges that arise for the system integration of wind while chapter 5 will broaden the picture and analyse the wider lessons learned for the integration of all renewable energy technologies into electricity grids and conclude.

2. Natural Cycles of Renewables Energy Technologies

Overview

All renewable technologies ultimately derive energy from natural sources that vary in their availability over different timescales. Even fossil fuels like oil, gas and coal have natural cycles of regeneration which, however, occur on a timescale several orders of magnitude longer than what is discussed in the context of this study.

In this chapter, an overview will be given on some key renewable technologies and the natural cycles on which they depend. These can range from changes occurring over decades, as in the case of geothermal technology, to minute-by-minute changes of cloud cover which, for example, affect Solar PV arrays.

As noted in the introduction, the natural cycle of wind has frequently received the greatest amount of attention by policy makers, industry and the media. Undeniably, the varying output of wind energy could destabilise electricity grids if no precautions are taken. However, the large-scale blackouts that have been witnessed in Western Europe and North America in recent years were completely unrelated to the wind energy installed in the respective countries.

Two factors have especially contributed to the prominence of the fluctuation of wind power in public awareness. Firstly, it has seen rapid growth in a number of countries, raising its share of electricity production to a significant proportion within a short amount of time. Secondly, it has introduced a new quality of intermittent supply which has been less important for other technologies, namely, that of intra-day and intra-hourly output changes.

Two Large scale research projects in Europe, the IRED-Cluster ("Integration of Renewable Energy Sources and Distributed Generation into the European Electricity Grid") and EU-DEEP ("The birth of a European Distributed EnErgy Partnership that will help the large-scale implementation of distributed energy resources in Europe"), have analysed and continue to examine the options and challenges to integrate renewable energy sources and notably wind energy into existing electricity grids.[1] The National Renewable Energy Laboratories (NREL) and Sandia National Laboratories in the US have a continuous research programme on grid-integration challenges of wind power.

In this context, the following paragraphs aim to show how the fluctuation of wind is part of the wider picture of variations in natural resources that affect a range of technologies, many of which have been used for long periods of times. Methods have been developed to successfully cope with seasonal fluctuations of a variety of technologies. Following research and development (R&D) efforts that were spurred by the oil price shock in the 1970s, three technologies became especially prominent[2]: Hydropower, geothermal and biomass. All three technologies have an inherent element of natural cycles which will be reviewed in the following paragraphs. The 'new' renewable energy technologies that are currently developed introduce new qualities of natural cycles. The main technologies considered for this section are solar PV, wind and wave/tidal.

1. More information on these research projects can be found on the websites www.ired-cluster.org and www.eu-deep.com.
2. See also IEA (2004a), which gives a timeline of IEA member countries' R&D efforts in renewable energy technologies.

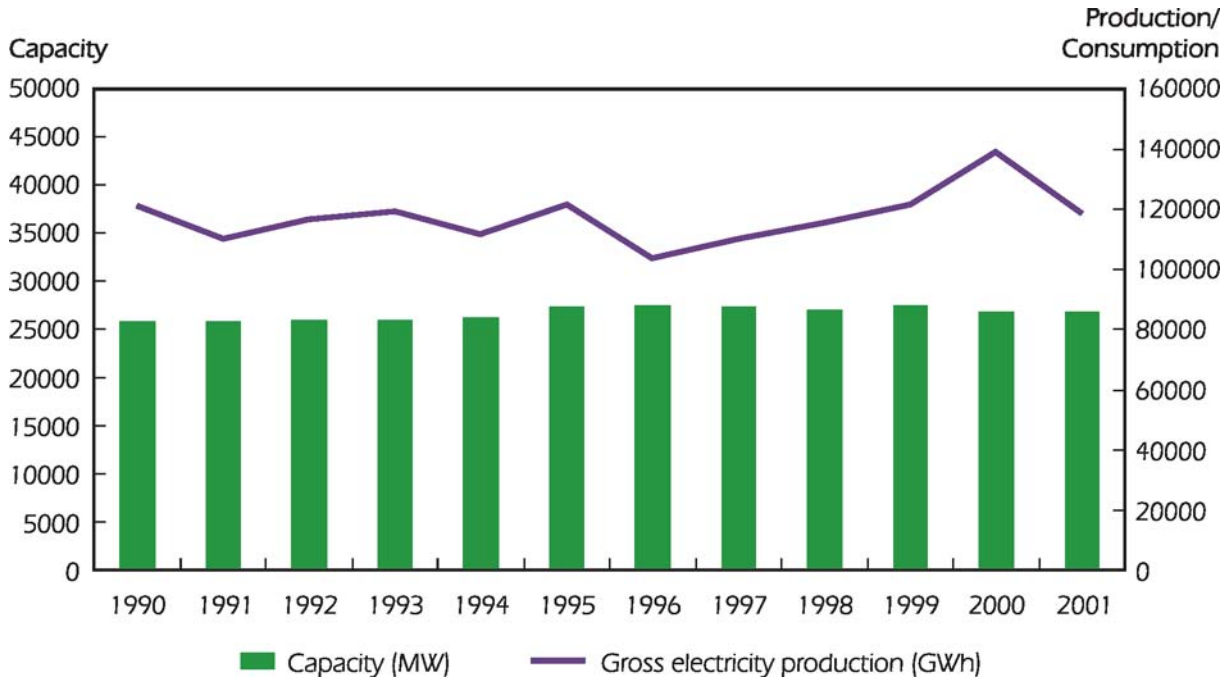
Hydropower

Hydropower plants had a 16.2% share in global electricity production in 2002. The two most important types of hydropower plants considered here are run-of-river plants and dams. The capacity of a hydro plant to produce electricity ultimately depends on the water cycle providing seasonal rain and runoff from snow pack. This has slightly different impacts in each of the two methods. Run-of-river plants produce electricity according to the flow of water in the river it has been built in. Water is shored at low-head hydroelectric plants and channeled through turbines using the natural force of the river flow. Seasonal variations determine the water level in the river and thus the strength of the water flow and its implicit available energy. Dams are often built in mountainous regions where the natural topography can be used to create artificial lakes at low costs. The runoff from rain and snow is thus collected and funnelled through dedicated pipes into a powerhouse downstream where it powers a turbine. Again, seasonal variability determines the availability of water and thus the total potential energy that can be stored in the artificial lakes.

Hydropower today is the main energy carrier to store electricity at a large-scale. Besides the natural accumulation of water in reservoirs, pumped-storage facilities offer the opportunity to pump water and thus potential energy upstream and release it again when required. The typical round-trip efficiency of this method is around 80%. The benefits of pumped-hydro storage reservoirs are further examined in chapter 3.

Figure 1 shows the experience of Norway, a country whose electricity system is 99% dependent on hydro power. For example, between 1995 and 1996, actual annual electricity production from hydro power dropped by about 17,000 GWh. This can be attributed to low annual rainfalls and thus lower potential energy to be utilised by hydro power plants. Conversely, between 1999 and 2000, annual hydroelectricity production rose by about 15,000 GWh.

Figure 1: Hydropower capacity and electricity production in Norway



Source: IEA, 2004a:510

Drought periods can become a problem when they coincide with periods of high electricity demand. For example in southern climates, hot periods are often associated with annual peak demand on the system as well as relative droughts.

Geothermal

Geothermal is energy available as heat emitted from within the earth, usually in the form of hot water or steam. Geothermal heat has two sources: the original heat produced from the formation of the earth by gravitational collapse and the heat produced by the radioactive decay of various isotopes. It is very site dependent and can be used for heating and power generation purposes. Since the earth's crust is continuously emitting heat towards its surface at a rate of 40 million megawatts, geothermal is in principle an inexhaustible energy source, with the centre of the earth having cooled down by only about 2% over the earth's lifetime of about 4 billion years.

There are no problems of intermittency in the utilisation of geothermal energy sources for direct heat applications or for electricity generation. A developed geothermal field provides what is essentially a distributed heat source, since the input to a power plant normally consists of the integrated outputs of several wells. Thus one or more wells may be shut for repairs or maintenance while others produce; proper dimensioning of the generating plant ensures that there is always enough steam or hot water available for operation. This feature and the low operational costs are the reasons why geothermal power plants are normally used as base load.

Natural variations of geothermal resources occur over extremely long periods, millennia or even longer time scales. However, man-induced processes lead to variations with shorter time-scales, typically in the range of decades.

Unwanted effects of over-exploitation and improper reinjection have been observed, especially in the early years of development of geothermal technology. However, present-day geothermal technology for field characterisation and modelling makes it possible to avoid improper practices, or at worst to detect their effects at an early stage before they become significant.

Biomass

Biomass can be used for a great variety of energy needs, from heating and transport fuel to power generation. There are technologies for using biomass as liquid and gaseous fuel, as well as traditional applications of direct combustion. The basis for all these applications is organic matter, in most cases plants and trees. There is a trend towards purposefully planted biomass crops although biomass can also be collected as a by-product and residue from forestry, industry and household waste.

It is projected that growth in biomass applications in IEA countries will mostly come from new technologies that depend on dedicated plantations and by-products from sustainable forestry. Thus, the supply of biomass depends to a significant extent on the seasonal cycle of these dedicated plants. To increase the use of biomass for electricity generation and heat production, there is an increasing focus on dedicated energy crops such as short-rotation coppice which allow frequent harvest cycles per year. The area that can be thus planted and the number of harvests per year will determine the maximum amount of energy that can be derived in this way. Should the use of biomass increase in all its applications, these limitations might become more pronounced.

A second, albeit man-made, variability arises when biomass is used in combined-heat-and-power plants (CHP). For example, in the Scandinavian countries, combined heat and power production is dominant for biomass. For industry residues this production is quite constant over the year but for district heating this results in electricity production of biomass having seasonal variation (production high at winter with high heat load), as well as some daily variations, according to temperature/heat load.

In principle, a global market for biomass products can be envisaged taking advantage of different climates and types of vegetation around the world. There is an increasing interest in ethanol as an alternative transport fuel but currently few countries plant significant amounts of plants such as sugar cane for this purpose. Brazil, one of the forerunners in this field, is a major exporter of this product with a volume of about 800 million litres and some 25% of the world's ethanol export market. The Netherlands forecast a significant biomass market in Europe in their energy transition strategy with major supplies expected to come from Scandinavian forestry. The boundaries that seasonal cycles put on the maximum amount of energy derived from biomass can thus be extended, but will ultimately run into competition from other land use interests and possibly competing uses of biomass itself. If current growth forecasts of biomass usage become reality seasonal cycles will surface more prominently on the policy agenda.

Solar PV

Photovoltaic cells convert sun light directly into electrical energy. The amount of energy that can be produced is directly dependent on the sunshine intensity and the angle at which solar PV cells are radiated. Thus, for example, PV cells are capable of producing electricity even in winter and even during cloudy weather albeit at a reduced rate. Natural cycles in the context of PV cells thus have three dimensions. As with the previously discussed technologies, it has a seasonal variation in potential electricity production with the peak in summer although in principle PV cells operating along the equator have an almost constant exploitable potential throughout the year. Secondly, electricity production varies on a diurnal basis from dawn to dusk peaking during mid-day. Finally, short-term fluctuation of weather conditions, including clouds and rain fall, impact on the inter-hourly amount of electricity that can be harvested. Short-term fluctuations are reduced by geographically distributed PV production.

Wind

Wind turbines convert wind power into electrical energy. The amount of energy that can be produced is directly dependent on the wind speed, more precisely on the cube of the wind speed. The wind speeds, at which wind turbines commonly operate, are between 2.5 to 25 m/s. Thus, wind power can become unavailable at times of low wind speeds, but also at times of very high wind speed, when wind turbines need to be shut down in order to avoid damage of equipment.

Wind power can fluctuate at various time scales; it is subject to seasonal variations of peak electricity production in winter or summer depending on the region, as well as diurnal and hourly changes. Generally, very short-term fluctuations - in the intra-minute and inter-minute timeframe - are small relative to installed capacity, compared to hourly or daily variations and levelled out when considering larger areas of production. Furthermore, wind forecasting and aggregation of wind turbines mitigate against short-term fluctuations, a topic which will be elaborated in chapter 3. Ultimately, the degree of variations is also very site dependent, as for example see breezes are much more constant than are land breezes.

Wave/Tidal

Utilizing the energy of the World's Oceans provides a very promising approach to produce electricity. However, despite a rather big potential, ocean energy systems have not yet passed the stage of demonstration projects and are yet limited to a few selected sites due to several drawbacks (technology related, location related, and economics). Although large ocean areas provide for a rather stable environment, wave and tidal power generation shows intermittent aspects as well.

Tides are generated by the rotation of the earth, causing periodical movements of the oceans' surface according to three interacting cycles:

- A half-day cycle caused by the rotation of the earth within the rotational field of the moon results in tidal movements every 12 hours and 25 minutes.
- A 14-day cycle based on the superposition of the gravitational fields of moon and sun.
- Interaction of the gravitational fields of sun and moon at new and full moon result in maximum spring tides. Minimum neap tides occur at quarter phases of the moon, when the sun's force of attraction cancels out that of the moon.

As these movements are generally well understood, the variability of tidal energy is highly predictable. Still, output from tidal plants varies by a factor of four over a spring-neap cycle (Pontes et al. 2001).

Wave energy largely depends on wind: Wind speed, duration of wind blow and fetch define the amount of energy transferred. Despite this wind dependency, fluctuations of wave energy are different, as waves in deep water lose their energy and by this smooth out only slowly and therefore can travel long distances. Wave energy, however, is subject to cyclic fluctuation as well, dominated by wave periods and wave heights. This lets power levels vary both on a daily and monthly basis, with seasonal variations being less in more temperate zones.

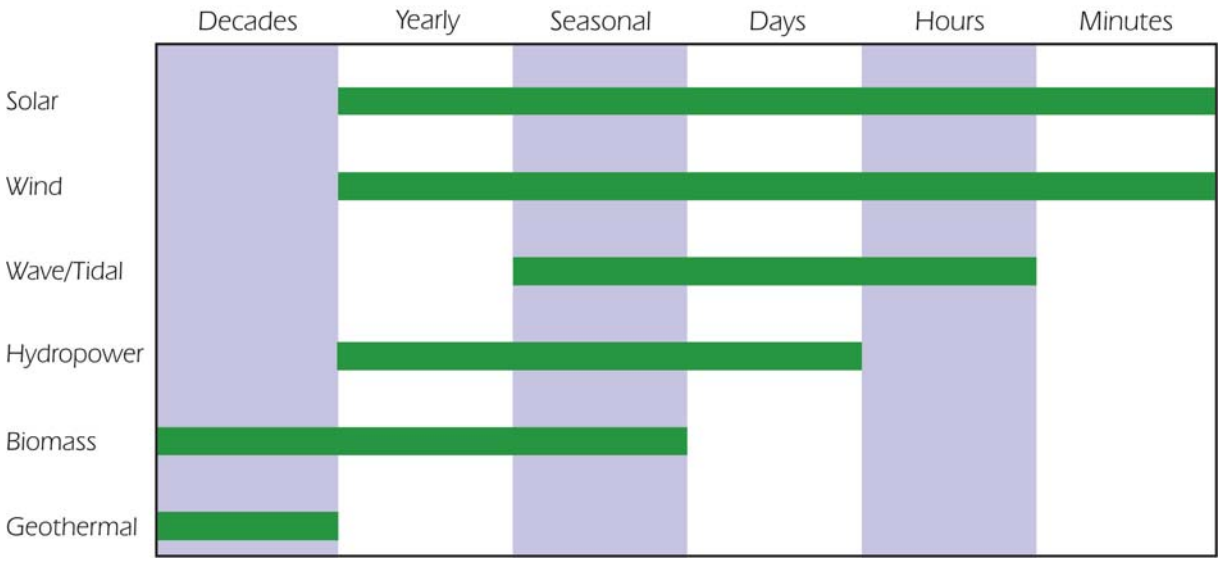
Summary

As discussed above, cyclic changes refer to the natural variability of renewable energy resources and are therefore a general phenomenon of all renewable energies. One can refer to natural cycles both as a relatively short-term (intra-day or inter-day) variation in output as well as a long-term variation (seasonal changes). Figure 2 summarises the time-scales over which the various technologies operate.

Since natural variations of resource availability do not necessarily correspond with the (also varying) need of the consumers, balancing supply and demand is a critical issue, potentially requiring backup by other means of energy supply. The variations can occur at any time-scale: hourly changes in output require balancing of short-term fluctuations by the so-called 'operational reserve', while days with low output require balancing of longer-term output fluctuations by so-called 'capacity reserves', as further discussed in chapter 3. Conversely, exceptionally windy days or rainy seasons can produce a surplus of supply and their might be an issue of handling excess capacity where grids are not sufficiently interconnected.

On the other hand, hydropower has played an important role as backup power and electricity storage for years. Together with other renewables such as biomass and geothermal it also has the potential to serve as backup power as shares of renewables in electricity supply increase.

Figure 2: Timescales of natural cycles of renewable energies



Currently, natural cycles of renewables have become an issue to grid operations on a regional level because of fluctuations in hydropower and wind. Other technologies have either not yet reached a level of penetration where their variations are of importance for balancing the electricity system, or have been integrated relatively successful.

In summary, although natural cycles of renewables have usually been considered in the context of wind power ("intermittency"[3]), this does not have to be the case, as has been demonstrated above. In the future, the wider application of other renewable energy technologies such as solar energy and biomass might necessitate similar analysis. Although natural cycles are inherent in all renewable technologies, solutions were found to manage them as in the case of hydropower. Norway's electricity production, for example, is 99% based on hydro power but it has to be prepared to cope with years of below-average as well as above-average rainfall to maintain its electricity supply. The main avenue used to cope with these fluctuations is hydro-storage and interconnection with its neighbouring countries in Scandinavia and a concomitant market liberalisation that allows for transparent signalling of supply shortages and overcapacities to induce market participants to adjust supply into and out of Norway when necessary. This issue will be re-examined when discussing the variability of wind in chapter 3.

As figure 2 showed, natural cycles of renewables operate over different time-scales. Utilising a variety of technologies that draw on a range of renewable resources will reduce the risk of any one cycle having a critical bearing on the system balance and will thus reduce costs. In fact, in a number of studies that will be considered in this report, a portfolio of renewable energy technologies have been considered concomitantly. One study by Sinden (2002) considered the optimal portfolio of renewables to supply a targeted amount of electricity per year. It found that requirements for backup

3. For simplicity, the terms 'natural variability' and 'intermittency' will be used interchangeably. See for example also the definition of the US Energy Information Administration (EIA, 2004): "Intermittent electric generator or intermittent resource: An electric generating plant with output controlled by the natural variability of the energy resource rather than dispatched based on system requirements."

capacity for wind power could be reduced by almost two thirds if the same amount of electricity is produced by a portfolio of renewable energy technologies rather than by wind power alone.

The two regions, where the natural variation of wind (often referred to as "intermittency") is currently most discussed in the context of changes to system operations are Western Denmark and Northern Germany, where wind power penetration has reached a considerable level, albeit a number of countries like the USA, UK, Portugal and Spain are investigating the demands on their grids as they expect wind to grow further in the near future. It is advisable for countries with ambitious renewable energy targets to discuss intermittency of wind and fluctuation of other renewables as early in the process as possible, and the efforts which are undertaken in a number of countries in this respect are commendable. The following chapter will now present a review of the issues associated with integrating wind energy into the electricity grid.

3. Integrating Wind into Electricity Grids

As noted in the previous section, the fluctuation of wind energy has recently received a great amount of attention in policy-making, academia and the media. New policies to integrate wind energy into existing electricity grids are currently formulated, major research initiatives investigate the challenges associated with this task and reports about the costs and benefits of wind energy are a frequent topic in the media. The recent fast growth in installed wind capacity in many countries and associated cost reductions mean that wind energy is considered one of the most important 'new' renewable energy source in the near-future. In order to illustrate the demands that the natural cycles of renewables can place on electricity grids, this chapter will discuss in depth the challenges that wind power poses to system operations.

Generally, the strategies to address the intermittency of wind vary between different national or regional grids. Important factors are the degree of interconnection, the natural resource and the availability of flexible generation capacity. In the first part, challenges that can arise with wind intermittency on the grid are presented. Here, grid operations are described and the functions of operational and capacity reserves are explained. Subsequently, the various options for mitigating the problems of wind intermittency are reviewed. Finally, cost estimates and market practices in a number of IEA countries are examined. Chapter 4 will then discuss some of the technical and policy lessons from this chapter in summary and conclude.

Grid operation and ancillary services

The term operation refers to daily and longer-term grid-management both on a distribution as well as a transmission level. Commonly, however, the distribution grid is not actively managed and plays only a passive role; this may change in the future due to different factors such as an increase of distributed generation. At present, however, the transmission network mostly manages the balancing of supply and demand.

As large energy systems operate with little storage capacities mostly for economic reasons, the guiding principle is to balance demand and supply continuously and, where necessary, to replace other capacity within very short lead times. As each national electricity system operates under tight security and quality standards, these so-called 'ancillary services' have to be relied on to 'secure' and 'fine-tune' the electricity provided, independent of whether intermittent renewables are connected to the grid or not.

Firstly, security standards dictate that the electricity grid must be designed to withstand outages of certain magnitude and high loads without losing service, so-called 'N-1' or 'N-2' events. Overall system reliability is determined by the 'loss-of-load probability' (LOLP) which can be defined as "the probability that the load will exceed the available generation" (Jenkins et al. 2000).

Secondly, quality standards define the exact nature of the electricity service delivered, the frequency and voltage being two important variables of this. This mandates that the operator keeps variations in frequency and voltage within specified limits so as not to damage electrical appliances.

Keeping these criteria in mind, an operator has to enable enough reserve capacity to be able to maintain the specified security and quality of electricity supply in the face of major events. Two

commonly considered events are the outage of the largest individual generating unit on the grid or the loss of the most significant transmission line. In the first case, these are typically large power stations like the Sizewell B nuclear power station in the UK (1188 MW), in the latter case this could similar be high-voltage transmission lines in the 1000 MW-class such as the interconnector between Germany and Denmark, for example.

These reserves are operating over different time-scales and many countries operate distinct markets for each of them. The exact definitions vary between countries, but typically, there is a short-term dimension to reserves with a market for 'spinning reserve' or 'fast-response' capacity, which is able to come online within seconds. Next, there is a more medium-term dimension to reserves that can come online within minutes to quarter of an hour. The actual operational act of buying or selling energy in the short-run is typically referred to as 'balancing'. Finally, there is a longer-term dimension to reserves, which operates over hours and days. An important variable which determines which type of technology is used for each of these timeframes is the time it takes to start up thermal power plants. All three dimensions are reflected in table 2, which shows the setups for three different countries and how these dimensions are understood.

Table 2: Reserve capacities in Germany, Ireland and the United States

	Short-term reserve	Medium-term reserve		Long-term reserve
Germany	Primary reserve: available within 30 seconds, released by TSO	Secondary reserve: available within 5 minutes, released by TSO	Minute reserve: available within 15 minutes, called by TSO from supplier	n/a
Ireland	Primary operating reserve: available within 15 seconds (inertial response/ fast response)	Secondary operating reserve: operates over timeframe of 15-90 seconds	Tertiary response: from 90 seconds onwards (dynamic or static reserve)	n/a
United States	Regulation horizon: 1 minute to 1 hour with 1- to 5-second	Load-following horizons: 1 hour with increments 5- to 10-minute increments (intra-hour) and several hours (inter-hour)		Unit-commitment horizon: 1 day to 1 week with 1-hour time increments

Sources: RWE 2004, SEI 2004, Smith et al. 2004

As the above table shows, reserves are neither defined nor treated equally in different countries. Thus, in order to simplify the ensuing discussion, this paper will in the following refer to the short- and medium-term reserves as operational reserve, whereas the long-term reserve will be labelled capacity reserve.

In the case of wind power, operational reserve is the additional generating reserve needed to ensure that differences between forecast and actual volumes of generation and demand can be met. Again, it has to be noted that already significant amounts of this reserve are operating on the grid due to

the general safety and quality demands of the grid. Wind imposes additional demands only inasmuch as it increases variability and unpredictability. However, these factors are nothing completely new to system operators. By adding another variable, wind power changes the degree of uncertainty, but not the kind - a fact that several authors referred to recently (DeMeo et al. (2003)). Wind power can be aggregated thus evening out imbalances of individual turbines, an issue picked up again in the next section.

Wind power has been referred to as a special case, because differences between forecasts and actual volumes can arise from other than 'common reasons'. Common reasons include planned and unplanned outages of generating plant or on the transmission or distribution networks on the supply side; and predicted and unpredicted changes in consumer demand levels due to TV pickups, weather patterns or other events on the demand side. Wind power, and ultimately all renewable energies if applied to a larger degree, includes another uncertainty on the supply side: unpredicted changes in wind speeds and, thus, altering wind generation levels. The most important tool for addressing this issue is weather forecasting. Significant research has been put into optimizing forecasting and modelling techniques and this will be discussed in more detail further in this chapter.

How balancing and the operational reserve is handled, differs according to the individual country setups. Plants can be literally in 'spinning reserve' mode as they are running below full power and thus have the ability to adjust output very quickly up- or downwards. Hydropower storage facilities can bring on capacity within minutes by opening gates for water. In countries with high penetration of wind power already today and only few flexible power stations or hydropower storage, the question of operational reserves is critical; for economic (as well as environmental) reasons, it is costly to use less flexible conventional power plants as backup.[4] As short-term weather forecasts and thus short-term output predictability improve the more critical variable for the utilisation of renewable energies and especially wind power the availability of longer-term capacity reserve. Good weather and thus wind output predictions allow wind to reduce exposure to the short-term (expensive) balancing market to a minimum, but longer-term capacity investments will still be needed for periods of generally calm winds. Capacity reserves are called upon between hours and days in advance. Thus, they operate in effect through conventional markets and part-loading is not normally an issue. Various options for this will be examined in more detail later in this chapter.

Wind power aggregation, grid operations and interconnection

The previous section has outlined the technical principles of providing certain ancillary services such as operational or capacity reserve to the grid. It is now aimed to give a managerial perspective on how this is operated in practice.

Liberalisation of electricity markets has resulted in a fragmentation of transactions. Traditionally, in many markets in IEA countries, either a publicly-owned organisation or a private monopoly had a licence to generate, transmit and sell electricity in a specified area. Today, a variety of market designs have evolved and financial markets for futures and options have been created alongside the

4. However, Dale et al. (2003) highlight that reserves still contribute useful energy to the system. With a conservative estimate of 10% for the reduced efficiency and a 20% load factor for wind power, they argue that emission savings from wind will be reduced by a little over 1%. In their scenario, 20% of electricity in 2020 is produced from wind power, so some 20% of fossil fuels are saved by applying wind.

physical electricity markets. In principle, physical balancing is a duty for the grid operator, but the precise market mechanism through which the associated financial transactions take place varies between countries.

When examining the impact of intermittency of wind on the grid, it firstly has to be noted that an analysis of individual wind turbines or wind farms in isolation does not capture the essence of the challenge posed. The fragmentation of the market might lead to the idea that each generator should provide individually for balancing reserve. However, this will not necessarily lead to a least-cost solution from a systems perspective. Thus, the objective of mitigating intermittency is not to provide a steady output from each renewable generator itself (*i.e.* individual wind turbines or -parks), but to equal demand and supply at minimised operation costs to the electricity system as a whole.

In this perspective, the grid plays an important role in mitigating the impact of intermittency. As discussed in the previous section, intermittent generators are not only likely to be geographically (i.e. north - south, up-hill - near-coast) dispersed but also technologically (wind, PV, ocean), which will smooth variations in output from the various sources as they are all connected to the same grid. This is a simple statistical phenomenon and the bigger the integrated grid (for example beyond national borders), the more pronounced this effect becomes. It is a general principle in electrical engineering that the larger a system becomes, the less reserve capacity it needs. Demand variations between individual consumers are mitigated by the grid interconnection in exactly the same way. Figuratively, just like consumers average out each other (in electricity demand), individual wind farms average out each other, too (in electricity supply). By way of an example, the peak load demand of an individual house can be over 15 times higher than the average load. In contrast, on the UK grid as a whole, peak demand is about 1.5 times higher than average demand.

In summary, the size of swings in output from wind farms and the volatility of average output are significantly reduced through geographical aggregation. Figure 3 below shows a typical situation for a (hypothetical) 1000MW wind farm in one place and having 1000MW of wind geographically dispersed but interconnected in the same grid. The size and volatility of output fluctuations is significantly reduced in the latter case.

Figure 3: The smoothing effects of geographical dispersion of a single wind farm and distributed wind farms, both rated at 1000MW (Mott MacDonald 2003:8)

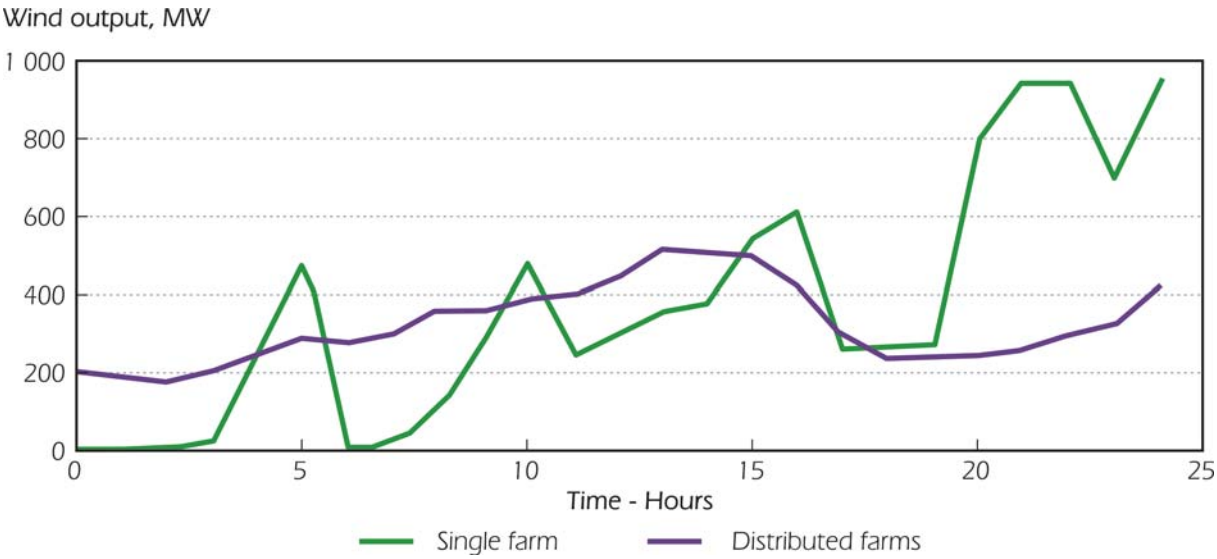
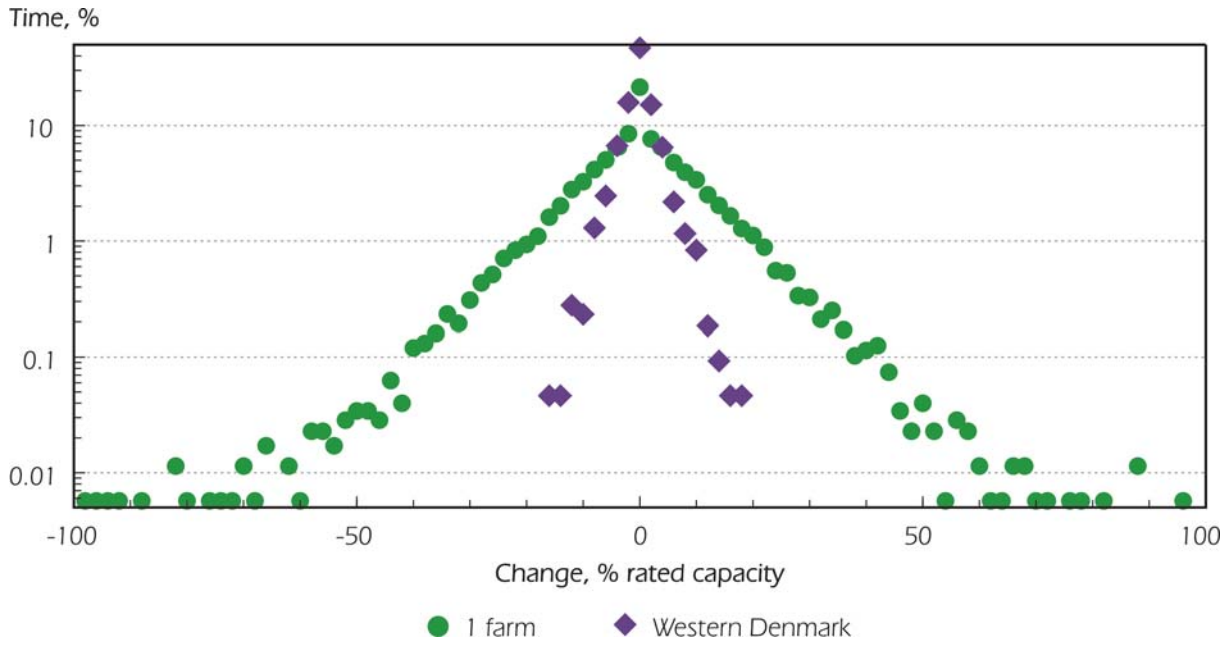


Figure 4 below shows real experience from wind farm operations in Western Denmark, comparing the variation in output from one hour to the next of one 5MW wind farm with the overall wind fluctuation on the Danish grid. This is a key variable for grid operators who often analyse variables in terms of their forecasted deviation from the present level. The horizontal axis shows the change in output after one hour as a share of the total installed capacity. The vertical axis gives the frequency of occurrence on a log-scale. In this case, the maximum one-hourly power swing from the wind farms installed in Western Denmark was 18% of installed capacity, and for almost 50% of the time it was less than 2% of installed capacity (Mott MacDonald 2003:8).

Figure 4: The smoothing effects of geographical dispersion on output variations (Mott MacDonald 2003:9)

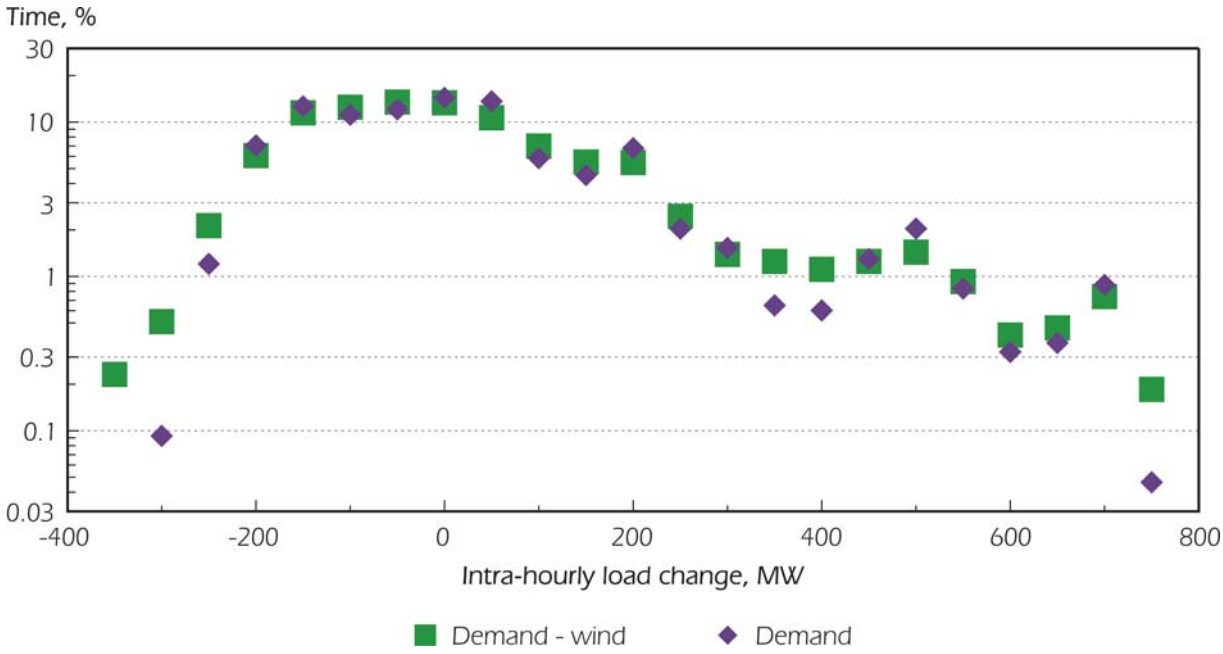


Finally, figure 5 shows the distribution of intra-hourly load (demand) changes in Western Denmark with and without a 20% wind share in electricity production (conceptualising wind output as negative load). The horizontal axis shows the change in demand (in MW) from one hour to the next, while the vertical axis shows the frequency of occurrence of each event. Again, the most frequent event seen on the system is no or little change in output (the area around '0' on the horizontal axis) between one hour and the next, irrespective of whether wind was present on the system or not.

From a grid management point of view, wind energy is a further variable impacting on overall system variability, but, just like demand, it fluctuates statistically random and thus can or cannot correlate with movements of other variables. This correlated movement might not be by the same amount in all cases, but it underlines once more, that the objective should not be to 'level' out fluctuations from every single wind turbine but to balance demand and supply in an appropriate area. Some further observations from Milborrow (2004b:5-6) in this respect, taken from studies on the German and Danish grid, are presented below.

- "The maximum hourly swing in output power from distributed wind rarely, if ever, exceeds 20% of the installed capacity of the wind plant. The standard deviation of the hourly swings is 3%. This information is important in the context of assessing the needs for additional reserves.
- The maximum measured change in output per minute from 2400 MW of wind in western Denmark is about 6 MW."

Figure 5: Intra-hourly load changes in Western Denmark, with and without 20% wind (Milborrow 2004b:7)



Consequently, it can be concluded that the interconnection into a common grid of intermittent renewables can significantly reduce the size and volatility of aggregate output swings that can occur due to weather conditions. It also makes use of the fact that both supply and demand exhibit a constant fluctuation and that it is thus not important to ensure steady supply of every single generator. The grid operator seems best placed to execute the physical balancing as all demand and supply information come together in real-time at this level. However, the exact market design to organise these 'balancing markets' is still an ongoing discussion in the electricity market regulation literature and will not be covered in depth here. The next paragraph will now discuss wind forecasting and modelling techniques that can further contribute to managing wind intermittency.

Weather forecasts and gate-closure times

From a grid management point of view, changes in electricity production are typically observed over short time-intervals (minutes, half-hourly or hourly intervals). Thus, for example, if current wind energy production runs at 2000MW, the question a system operator might ask is what will be the output in one hour? On the basis of weather forecasts and modelling results, the likely output is calculated and the operational reserve is planned accordingly.

The interest in wind forecasting has been growing over recent years along with the recognition of technical implications of higher penetrations of wind power. For wind penetrations of below around

5%, wind forecasting is generally believed as not necessary, since "deviations in wind output fail to show up in the ebb and flow of daily operation with [such] small grid penetrations" (Milborrow 2003:37).[5] As wind penetration rises, wind forecasting increasingly adds value to wind power.

For example, the German balancing market is divided into four zones (operated by E.On Grid, RWE, Vattenfall and EnBW respectively), all of which use a forecasting tool called Wind Power Management System (WPMS), which has been developed by the German Institut für Solare Energieversorgungstechnik (ISET). This system reaches a prediction margin of error averaging 9% in day-ahead forecasting, 8% for eight hours ahead, and only 2% for one hour ahead (Knight 2003). However, some forecasting errors are expressed in terms of rated power, while others express this in terms of deviation from actual electricity produced. Thus, Holtinnen (2004:40) states that "for the Nordpool electricity market [...] the mean absolute error of wind production is 8-9% of installed capacity" which, if expressed in terms of the amount of energy produced converts to "38% of the yearly wind power production". In summary, there does not appear to be a sizable difference in outcome between the Scandinavian and the German system but methodologies do differ. For comparison, prediction errors of consumption are generally in the region of 1-5%.

Electricity generation from wind turbines will always vary with weather conditions but the more precise the forecasting and modelling becomes, the smaller will be the error margin in forecasting this variability and thus the lower the requirements can become for operational reserves and balancing energy. This is reflected in figure 6 below, which contrasts the gap between simple "persistence forecasting" and "perfect forecasting" and the impact on required operational reserve. Persistence forecasting assumes constant power output for one hour ahead, i.e. no change in power output over the next hour.

Research programmes that focus on improving wind forecasting and modeling techniques are ongoing in Europe and the USA. The German Institut für Solare Energieversorgungstechnik (ISET), together with the UK meteorological office and the consultancy IT Power, recently completed part of an EU research project[6] to adapt and improve wind power prediction tools to market-based electricity trading systems. Further EU research investigates enhanced methods for forecasting, modeling and integrating wind power in liberalised markets.[7]

In summary, a sizable margin of error in weather forecasts can still exist and the longer the timeframe over which output has to be predicted, the higher the resultant error. This becomes important when actual markets for balancing capacity are considered. While the UK has a 'gate-closure time' of currently one hour (between final declaration of capacity and actual use of it), many IEA countries have gate-closure times between 12 and 36 hours in advance. These times have often developed out of historic structures and in many cases have no technological and economic background in the current system. Shorter times do not necessarily have to entail extra economic costs and there is a trade-off between reduced gate-closure times and thus better forecasts and the increased need for flexible operational reserve and thus potentially higher costs. Still, more investigation on the exact costs and benefits of this trade-off could reveal whether gate-closure times can be shortened in

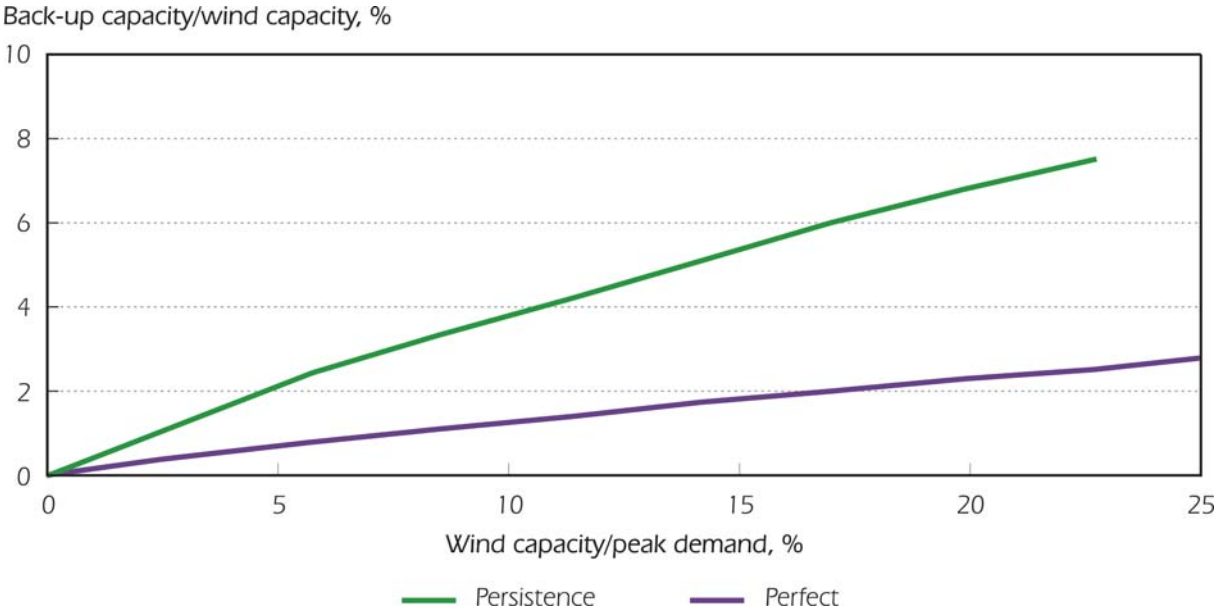
5. 5% as a level of wind penetration is here given as indicative. This may differ depending on the natural conditions of each individual region or country. As an example, the French TSO RTE (Réseau de Transport d'Électricité) estimates that a level of wind penetration of 3% could be met without increased wind forecasting.

6. For more information see the website www.dispower.org.

7. See for example the projects ANEMOS, HONEYMOON and WILMAR (http://anemos.cma.fr/, http://www.ucc.ie/serg/honeymoon/ and http://www.wilmar.risoe.dk/)

respective national or international markets. With the increased use of communication technology as a result of evolving market structures, the information flow is already improving in many markets and might facilitate the reduction of gate closure times further. Yet, even with reduced gate-closure times, liquidity in most electricity markets is highest in the day-ahead trades, while activity in short-term energy trades on the spot market for one- or two hour-ahead contracts is typically low. Thus, some of the benefits from reduced gate-closure times might be mitigated by reduced trading opportunities in the short-term markets in many IEA member countries. Further considerations on the market integration of wind power can be found in appendix 9 to IEA (2005) and Neuhoff (2005).

Figure 6: Reducing added back-up for wind



Source: Milligan/NREL cited in Milborrow 2003:37.

In summary, Milborrow (2003:37) notes: "The bottom line value of a prediction model is the reduction it is likely to achieve in the extra costs, either of additional reserve or balancing market charges. […] If these costs can be halved, as researchers claim, then the specific costs of adding an intermittent source of energy to the system such as wind come down accordingly." However, it has to be added that much the value of any improved forecasting also depends on the flexibility of the electricity system in which an intermittent generator is embedded. Better short-term prediction will only translate into reduced costs if the enough flexible technologies, possibly interconnected from another country, are available.

The value of wind forecasting will increase as wind energy reaches a higher penetration in markets, for example moving into the 10%-20% market share region. Hence, improved weather forecasts and output models are frequently cited in the literature as a key research priority to improve predictability of wind output.

Another aspect that is worth considering in this respect is that individual wind turbines generally have a very high technical availability (>97.5%) when compared to traditional power plants. Also, this availability is for one turbine, so any amount of significant wind power in an electricity system would never see all (hundreds or thousands of) turbines down at the same time. Availability in the

context of wind means being able to produce electricity when the wind is actually blowing. This would correspond to traditional power plants being able to produce when the fuel is available. The 'capacity factor' of wind farms is usually low (25-40% - depending on location) because the wind speed is variable and conventional power plants have a capacity factor in the 85% region because fuel supply is normally reliably organised. However, it should be recognised that better wind forecasting can reduce the need for operational reserve to a necessary minimum because wind turbines do have very few unexpected outages and need less maintenance than traditional power plants. The reason for conventional power plant's capacity factors being around 85% rather than 100% is primarily due to scheduled and unexpected outages which can take up more time on average than for wind turbines.

One phenomenon that has not been explored in much detail in the literature are high-impact, low-frequency events like long periods of still weather. Statistically, these 'outlier events' are at the edge of the probability distributions and in a contribution by Sinden (2002), the longest continuous time of calm weather in a 21-year hourly wind data set from 13 different locations in England and Wales was 11 hours, incidentally over night at a time of low demand. For the Scandinavian countries, 3-year data (2000-2002) showed that the longest duration of calm (production below 1 % of capacity) for Denmark was 58 hours in 2002 and 35 hours in 2000. For Finland and Sweden it was 19 hours and for Norway 9 hours. For the combined wind power production of these four countries, there were no totally calm periods in the data (Nørgård et. al. 2004:27).

Clearly, it is important to improve our understanding of long-term weather records and output data from wind farms from a variety of locations to have a better understanding of the probability of these events occurring. This will not only improve calibration of forecasting models, but will also allow market expectations of the long-term need for reserve capacity to adjust. Yet, it is clear that even improved forecasting will not change the fact that the variable nature of wind inevitably entails phases where there is no wind available. This and the remaining uncertainty in wind forecasting calls for additional measures to manage intermittency. Thus, some possible options are addressed in the following section.

Options for managing intermittency

Up to now, it was outlined how the impact of intermittency on the electricity grid can be mitigated by grid integration, geographic and technical distribution of generators and improved weather forecasting techniques. These techniques especially allow for a higher predictability of likely wind output, reducing the unpredictability element in the natural fluctuation to a minimum. Nevertheless, the residual unpredictability and the general variability - including periods where there is no wind available - have to be addressed.

Thus, this section outlines the various options for managing intermittency. As described in the first part of this chapter, the principal tools for this are the operational and capacity reserve, responding to short- to medium-term and long-term variability respectively. As has been outlined above, the short-term volatility and unpredictability of wind can be minimised to an extent where it disappears in the general fluctuation of the system. A recent study in Germany confirmed that the extension of wind power to some 36GW in 2015 would not require the addition of new plants to provide operational reserve (Dena 2005). Similarly, the French grid operator RTE estimates that the short-term fluctuations of 10GW installed wind capacity would not exceed 100MW within 1 minute, a figure which can be absorbed within current dimensioning of reserves without problems

(Bué 2005). Thus, for the future grid integration of wind power, the provision of flexible capacity reserve will become one of the key variables, reflecting the fact that even large wind capacity numbers will face climatic conditions where there is no or little wind. As will be discussed in the section on the economies of wind power integreation, this is also one of the most important cost items when considering the long-term integration of wind power into electricity grids.

From a policy point of view, it has to be analysed which are the least-cost options system-wide in each case and furthermore, whether market participants are facing the right incentive structure to exploit those opportunities. The list of options presented below should not be considered exhaustive nor should it be understood as an attempt to pre-empt any market decisions. It serves as a reference to the most-discussed resources at current available technology.

The six main options currently discussed are:

- power plants providing operational and capacity reserve;
- electricity storage;
- interconnection with other grid systems;
- distributed generation;
- demand-side response;
- curtailment of intermittent technology.

The principle behind all these options is the same - balancing demand and supply continuously both over long-term timeframes and, where necessary, backing up other capacity within very short lead times. It is likely that in future electricity markets no one option will provide all the balancing services and that a combination of the above-named will be operating in parallel. Choosing between these options, the trade-offs need to be spelt out clearly. Ideally, a market can be envisaged where all potential options can bid into and the least-cost solution for each point in time is thus selected.

Power plants providing operational and capacity reserve

This is the most frequently cited option in the literature and has often been used as a benchmark to calculate the extra costs of integrating intermittent generation into the system both over short- and long-term timeframes. Using power plants for balancing services is a well known and tested ancillary service in electricity systems. In today's grids, it is typically met by flexible plants with relatively short response times. Depending on national circumstances, these could be open-cycle gas turbines (OCGT) but also steam-fired power plants like coal and oil running at below full-capacity. Strbac et al. (2002) - which is discussed further in the section on costs of wind power integration - use OCGT as a benchmark in their methodology to determine the costs of operating reserve due to variations in renewable technologies.

A market for capacity reserves per se is not likely to open in many countries. They will expect to be operating similarly to peaking plants, but depending on the availability of natural resources for the renewable technologies used, can expect operating hours between about 4000 and 5000 hours a year. The costs for capacity reserves will be determined alongside the regular market development but are likely to show up in reduced capacity factors of conventional plants and a preference in technology choice for plants which provide increased flexibility in operation. The IEA (IEA 2004b) currently forecasts a bigger role for combined-cycle gas turbines (CCGT) in electricity supply, although coal-fired power stations will retain their dominant position globally. For the purpose of their study, Strbac et al. (2002) use CCGT as a benchmark to determine the costs of capacity reserves.

Overall, in terms of commercial availability, cost competitiveness and ease of system integration, power plants are the state of the art for providing the necessary ancillary services for intermittent wind generation in most countries and are certainly the most tried and time-tested from the point of view of the system operator.

Storage

Hydro storage facilities, whether in the form of pumped-hydro or hydro reservoirs, have played a key role in many countries in providing several grid balancing services. Their advantages are the potential for large-scale electricity storage (>1000MW capacity, depending on location), fast response times and relatively low operating costs. A fully loaded hydro facility can replace a conventional power station for several hours if needed. However, beyond hydro storage, there has been very little commercially available storage technology that operates on today's electricity grids. The main reason is that large-scale grid integration replaces to a certain extent the function of storage, as discussed in the previous sections and that other storage technologies are as yet not cost competitive. Storage systems within the grid have to compete against other technologies for the operational reserve services they could provide, and there is no a priori advantage to storage systems over generators for example. Only hydro-storage systems have a long history of utilisation and are thus well-established in today's markets.

Certain storage systems such as flywheels and certain battery types could become viable to provide specific support services for renewables in the frame of bridging very short-term output fluctuations (less than one minute) which also has the advantage of minimising the impact of power quality issues. One fundamental problem with storage is that where energy is converted from one type to another, conversion losses and thus inefficiencies are inevitably incurred, see table 3 below for details. This is true for batteries and hydrogen fuel cells (where electrical energy is converted to chemical energy storage) and flywheels (where electrical energy is converted to kinetic energy).

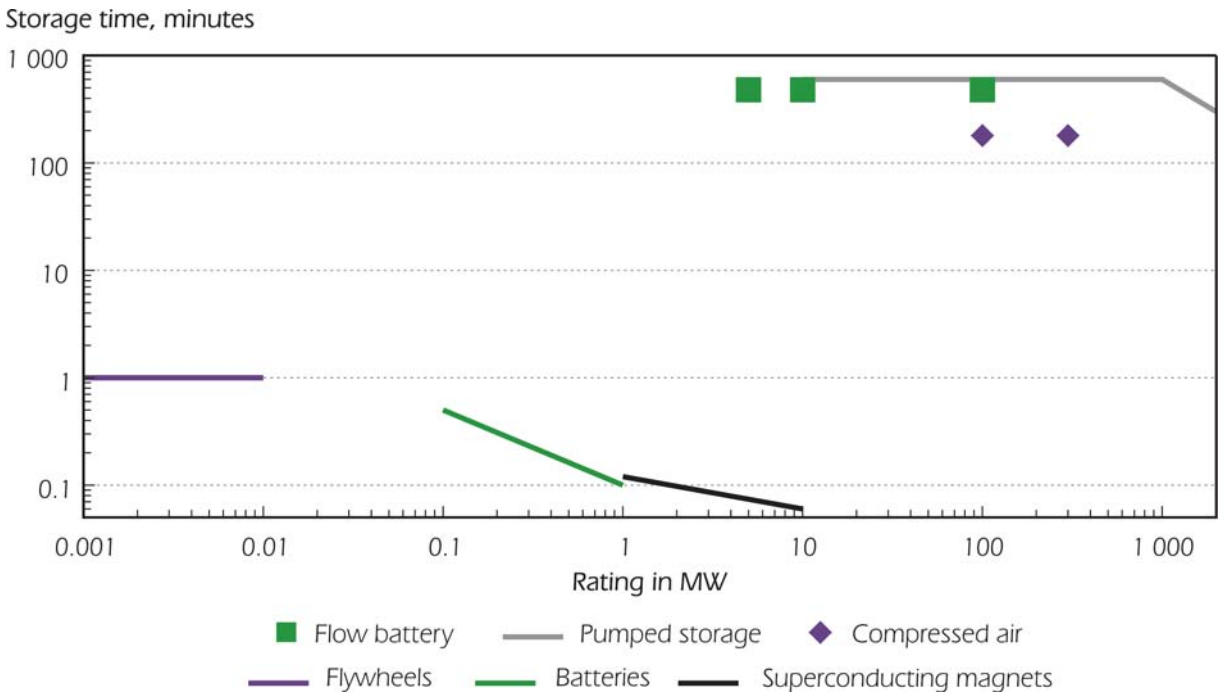
Table 3: Various storage technologies and typical technical performance

Storage technology	Typical round-trip efficiency (in %)	Typical capacity
Pumped-hydro station	~80	>100 MW - >1000 MW
Compressed air storage	~75	>50 MW - >100 MW
Flywheel	~90	>1 kW - >50 kW
Conventional batteries	~50 - ~90	>1kW - >10 MW
Flow battery	~70	~15MW
Hydrogen fuel cell	~40	>50 kW - >1 MW

Depending on available locations another viable form of storage is compressed air, which is stored in geologic structures under the ground and released when necessary. Typical places for such projects could include disused coal mines or salt domes. A number of projects have been developed in the USA and Europe for the purpose of 'peak shaving', whereby the potential energy is built up in periods when demand is low and released during hours of peak demand.

Batteries are typically operated on small-scale systems, and no commercially viable solution for large-scale battery storage has been demonstrated to the market yet. The UK company Innogy announced in 2001 the development of a 'flow-battery' labelled 'Regenesys', which was hoped to bridge this gap with a power rating of 15MW and storage capacity of 120MWh, but the project was cancelled by Innogy in 2003 for apparently technical reasons, although the exact circumstances were never fully disclosed. Still, batteries could play a role for intermittent renewables in smoothing short-term fluctuations, thus providing more stable energy in the intra-minute period. In the long-run, it is speculated whether hydrogen storage might become a viable option on different scales, however, currently high costs and relatively poor round-trip efficiency is preventing wider market penetration.

Figure 7: Time and power rating of various electricity storage options



Source: Milborrow 2001a.

Flywheels are a kinetic storage option - "electricity to be stored powers an electric motor which increases the speed of the flywheel, while electricity is recovered by running the motor as a generator which causes the flywheel to slow down." (Dell and Rand 2001:9) Again, this technology is of interest primarily as a short-term buffer to smooth local output fluctuations from a wind-farm or PV-array. It can remove the need for more expensive power electronics downstream to smooth such fluctuations and thus improve overall cost efficiency.

Figure 7 summarises the time- and power ratings of the various technologies. Overall, in the absence of major technological and cost break-throughs, storage in mature large scale power systems will only play a minor role in the short term, apart from hydro- and compressed air storage. Besides, technologies for bridging short-term power fluctuations such as flywheels or batteries may only gain importance at higher than current wind penetration levels. As mentioned previously, most IEA countries' existing operating reserves are sufficient to absorb current levels of fluctuation. However, the development of renewables and market liberalisation itself could act as powerful

incentives to intensify R&D efforts in this field. Experience from the Eltra system in Denmark suggests that spot prices can fall to zero or could even become negative in the future where there is a high penetration of intermittent renewables and furthermore combined-heat-and-power (CHP) plants. In other words, there are times of the day when the market offers to pay a storage-device operator to take up some electricity from the market. This can consequently be sold back to the market once prices return to positive again. Another example is differential pricing between base load and peak load which could be exploited by storage systems that charge during the cheap night-time period and release energy when demand is peaking and prices are high. As renewables penetration in the markets increases, the need for operational reserves become more important and could furthermore act as an incentive. Also, the full pricing of emissions of conventional reserve providing backup capacity would improve the relative economics of storage as an alternative.

Interconnection with other grids

As mentioned earlier, one reason why the western Danish grid can handle a high proportion of wind power very well is that it has good interconnectors with the Swedish, Norwegian and German grid and thus, for example, access to Norwegian hydro-power as reserve capacity. The Scandinavian 'Nord Pool' electricity market was established in 1996. One of the drivers for its establishment was the difference in generation mix, with Norway depending largely on hydropower, Sweden on a mix of hydropower and nuclear power, Denmark on thermal power plants and wind only emerging. 'Nord Pool' market participants trade power contracts for next-day physical delivery on a Spot Market, and on separate futures markets.

The benefit for a country such as Denmark, generating some 20% of its electricity from wind power, is apparent: Denmark can trade wind power on the spot market in times of excessive supply, and if this cannot be used at the time of production elsewhere in the market, it can be stored in hydropower storage facilities *i.e.* in Norway. In turn, Danish operators can purchase extra electricity on the 'Nord Pool' market at times of low wind generation.

The connection to the 'Nord Pool' market, together with the rather unique situation of strong interconnections to Germany, allows Denmark to balance the high penetration of wind power. Comparing Danish wind penetration levels to other countries such as Spain, where the system operator claims 17% of wind penetration to be the upper limit, is therefore to some extent misleading. However, it reflects (besides other factors) the importance of interconnections to other grids, as Spain is only poorly connected to its neighbours, as McGovern (2003) describes. A new Iberian pool ('MIBEL') will improve management of the strong interconnections between Spain and Portugal but physical transmission between Spain and France remains relatively weak for the moment.

However, the high concentration of wind power in the Northern Part of Germany and its proximity to the Danish grid with a similarly high share of wind capacity on the system can pose threats to systems despite good interconnection to the neighbouring countries. This is due to the fact that transmission grids have not been originally developed to accommodate increasingly large amounts of wind energy and associated cross-border trade. According to the Dutch system operator, this has led to a few events where transmission capacity between Germany and its Western neighbours in the Netherlands, Belgium and France was seriously congested and system stability was threatened. These events occurred either when wind output in both Germany and Denmark was high at times of low demand, thus exporting excess energy into neighbouring grids. Alternatively, at times of low output and high demand, additional energy was imported from France. This highlights not only the

need for further transmission grid development, including strengthening and upgrading existing lines, but also the fact that interconnection is only one - though clearly very important - measure in the portfolio of options to integrate wind power successfully. Failure to develop grids concomitantly to intermittent resources such as wind power is likely to threaten system stability.

Furthermore and critically, planning new grid capacity is a time-consuming process and building new transmission lines comes at additional costs. Initial capital outlays can add up to hundreds of million Euros invested and regular maintenance is required once these assets are installed. More importantly, planning procedures in many IEA countries can take between 3 and 10 years, which means grid extensions cannot be realised without significant lead times.

In general, interconnection of grids is frequently seen as an important step towards improved competition and full market liberalisation, for example in Europe and North America. Resources, both to power renewable energy sources and conventional power plants, are unevenly distributed and available across different power grids, thus limiting the options available on any one grid. Interconnection increases the number of available options and therefore provides significant value as lower cost balancing power stations can be accessed or even be shared. This allows for a more efficient utilisation of resources and can also contribute to system security.

Major interconnection plans are currently discussed, linking for example Norway and the Netherlands[8] through a sub-sea High-Voltage DC (HVDC) cable. The major driver here is better utilisation of resources, gains from market competition and trade and increased security of supply. Norway holds significant resources of hydro power which it will be able to utilise more efficiently when linked in with the Dutch and thus the continental electricity grid. It also serves as a further reserve option for the Norwegian grid in case of hydro resource shortages. New technology such as HVDC will improve power flow and reduce losses and costs. Underground cabling is investigated as an alternative to overhead power lines on land as well to circumvent lengthy planning procedures, but this significantly adds to the costs (Dena 2005). The EU has a priority plan for interconnecting its member states' electricity grids.[9]

The IEA (IEA 2004b) forecasts that electricity markets in the OECD countries alone will need investments of $1.8 trillion in transmission and distribution networks in the period up to 2030. This is merely to keep up with expected demand growth and to upgrade aging assets. A forward-looking policy should aim to integrate these investment needs with renewable energy related investments and thus create an integrated strategy to face future challenges in the transmission, distribution and interconnection field.

Distributed generation

IEA (2002:19) defines distributed generation (DG) as "… generating plant serving a customer on-site or providing support to a distribution network, connected to the grid at distribution-level voltages." DG can provide significant system benefits for local distribution companies by relieving congestion, reducing transmission losses and delivering ancillary services to the system. Thus, DG could provide

8. See announcement by Statnett http://www.statnett.no/default.aspx?ChannelID=1169&DocumentID=11438.

9. The EU priority plan for a Trans-European Energy Networks is outlined on the website of the Directorate General for Energy on http://europa.eu.int/comm/energy/ten-e/en/index.html

fast and longer-term reserve requirements to the grid on a regional level as an alternative to large-scale power plants. One of the most frequently cited DG options are combined-heat and power (CHP) plants, which produce heat much like a conventional boiler but also produce electricity at the same time, thus increasing the efficiency of fuel use. This is utilised in colder climates such as Scandinavia, for example, where electricity demand is higher in winter and load increases are typically greatest in the morning at the same time when the heat demand picks up.

However, as highlighted in IEA (2002), there currently exist a number of barriers to a wider integration of DG into electricity grids. One important area is information exchange, a topic that has already been highlighted earlier in connection with weather forecasting for wind farms. IEA (2002:98) notes: "If networks are managed in a decentralised way, for example with individual customers responding to the needs of the local network, they will require a greatly increased flow of information to ensure smooth operation of the system. The distribution utility of the future will need to be in a position to provide information, and to monitor and control its own system in a more sophisticated manner." Similar requirements could become important to operate a greater number of renewables such as wind farms in an efficient way. Thus in this area, DG and intermittency may have similar requirements for future grid operations and upgrades.

Demand Side Response (DSR)

In some ways, DSR has been the great enigma of electricity policy. The idea behind DSR is that electricity produced at different times of the day has different values, as can be witnessed by the price differential between base and peak load power on the wholesale market. If the marginal peak load price is higher than the value that a customer gets out of the services derived from the electricity delivered at peak times, he/she would be willing to modify demand if paid the peak price or slightly less instead. A grid operator is indifferent between paying a power producer to supply more output and paying the same amount to a customer to switch of his/her electric appliances instead, as both provide the identical balancing service. In principle, market mechanisms can be devised to capture such a market and DSR could be an important aspect of load management both to cope with peak demand and with intermittency. DSR makes the demand curve for electricity more elastic and thus sensitive to price changes which will reduce the need for reserves in an electricity market ceteris paribus.

In practice, however, contributions from DSR in many countries have so far been relatively small, with some exceptions such as Norway. It is however unclear, whether this is due to electricity users' marginal valuation of electricity being too high to stay on-line even at high prices, or whether there are transaction costs or informational barriers to access such a market. DeCarolis et al. (forthcoming) review some recent experience of DSR techniques. It is also proposed that participants in DSR use on-site distributed generation technologies to replace the supply from the grid but for such switching to become automatic electronic communication and an increased flow of information will be necessary. While households would be another attractive target for DSR, their electricity bill is often only a small fraction of total household spending which provides only a small incentive. However, aggregation or 'consolidation' service providers that represent a bundle of households at the wholesale market could explore this market niche. A recent action paper by Eltra (2004b), the Danish grid operator, has highlighted the potential of DSR in order to cope with large amounts of wind energy and CHP plant penetration and will be discussed in more detail in a further section below.

Curtailment of wind farms

Recently, with the expansion of wind farms offshore, curtailment of intermittent technologies has become a further option to cope with system variability (Gardner 2004). Large wind farms, with a significant number of megawatt-sized turbines can in principle provide the same ancillary services that conventional generators offer today. Switching off some wind turbines for operational reserve or running them at reduced output becomes a realistic option with modern large-scale wind farms. Furthermore, where transmission and distribution capacity is congested, curtailment of wind farms is an option to ensure system stability. Thus, as in the case of Northern Germany, at times of increased congestion on the grids, wind farm operators have switched off their turbines for short periods of time to ensure system stability. Associated requirements are emerging in some Grid Code documents for wind generation which Transmission System Operators are developing or publishing at the moment. Wind turbine manufacturers are also investing in associated technology as part of their business. Additionally, modern control technology of wind turbines can furthermore smooth sudden bursts and even out short-term fluctuations. Reducing output from a source that produces at almost zero marginal costs might sound unattractive. But the flexibility offered by wind turbines can be very valuable for an electricity system, as the alternative of shutting down or part-loading coal and combined cycle gas turbines implies higher energy and maintenance costs for subsequently heating them up. Therefore, tariff systems or contractual arrangements are required to ensure that wind turbine owners benefit from the system savings they can provide with a flexible operation of their turbines.

Summary of options

The resultant mix of options is likely to be different between different national grids. For example, where hydro power is available for balancing services, this is likely to be the predominant choice since it has been proven as very flexible at low prices for these services. Grids with a high proportion of gas-fired power plants might be more reliant on this technology again for its desirable characteristics. Greater interconnection between grids would allow for a greater availability of least-cost options on a wider geographic scale while mitigating the impact of intermittency further. On the other hand, this will probably require increased long-distance transportation of electricity with associated transmission losses and investment requirements for grid upgrades.

In any case, when choosing between the different options the trade-offs have to be visible in the market for it to deliver a least-cost solution. However, this is often not the case. For example, many grids do not 'see' distributed generation as dispatchable and thus cannot extract the potential benefits from this option. Without differential pricing at different times of the day, storage systems and demand side responses will not be economical. To upgrade grids and increase the interconnection between them, large-scale investments are often required but at current there is often no clear regulatory incentive for those who benefit from these investments to meet a share of the costs.

Depending on the strategy chosen and the options available, the costs will vary. In the following section, a number of studies are presented that have analysed the cost implications of integrating intermittent renewables - in most cases wind - into the electricity grid. They provide a range of estimates and actual numbers, and it should be remembered that most of them are country or system specific, reflecting technological options and market structure.

Costs of wind power integration

This section summarises a number of studies from Europe and the USA that attempted to quantify the additional system costs that wind power might impose on electricity systems. Assessing the added costs of integrating renewables into electricity grids involves four main parameters: Balancing, operational reserve, capacity reserve and extension of transmission and distribution lines. As has been summarised in the previous sections, grid operators estimate that the need for additional operating reserve is likely to be limited relative to the other two items. As wind power expands, the issues of additional capacity reserve and new transmission and distribution lines will grow in importance. The studies presented below use slightly different methodologies to assess the various cost items. Thus, while some aim to quantify all of the above-listed system integration costs, others focus specifically on the operating and capacity reserves. Also, it has to be borne in mind that the precise numbers are country-specific and there is no one cost figure that is universally applicable. In this sense, the studies below present an overview of different country experiences and expectations on the costs of system integration of renewables. A further discussion of the costs of grid integration of wind power can be found in appendix 9 to IEA (2005).

Strbac et al. (2002) were commissioned by the UK Department of Trade and Industry (DTI) to carry out a study 'Quantifying the System Costs of Additional Renewables' to the UK electricity grid in 2020 (also known as the SCAR report). A variety of scenarios, using different combinations of technologies were considered, and OCGT and CCGT power plants were used as benchmarks to quantify the additional system costs of operational and capacity reserve respectively. A comprehensive methodology was developed to assess all relevant aspects of system adaptation due to renewables. This included the reinforcement and management of the transmission system, the impact on transmission losses, the reinforcement and management of the distribution networks and balancing energy generation and demand. This methodology could well serve as a model for other countries to quantify their own system costs of integrating renewables.

In a scenario using a mix of biomass and wind, it was found that the total additional system costs per year for a 20% renewables share were €205m (£143m) in 2020, translating into total additional system costs of €4.9 per MWh of renewable electricity compared to current wholesale electricity prices in the UK of about €47 (£32). The highest additional system costs were found for a scenario where the renewables share would come predominantly from wind, mostly located in Scotland and off-shore, far away from load centres. Here the per annum additional system costs would be €570m (£398m) in 2020, translating into total additional system costs of approximately €14 per MWh of renewable electricity, in this case almost entirely from wind. An extensive sensitivity analysis of a variety of parameters can be found in the study. As expected, costs for upgrades in the transmission and distribution system were highest in the scenario with a high share of renewables far away from load centres, contributing about one quarter of the additional costs. In all scenarios, costs for operational and capacity reserves dominated, taking a share between 67% and 100% of the total costs. In the break down between operational and capacity reserve, costs for the latter dominated in all scenarios, typically at a ration of 2/3 to 1/3.

A second comprehensive study, which examined reserve as well as transmission and distribution requirements is presented in Auer (et al. 2004) from the "GreenNet" research project.[10] In reviewing

10. For further information see www.greennet.at.

international studies (incl. Strbac et al. 2002) and modeling their results in a number of European electricity markets, they establish a cost range for system integration costs specifically for wind power at different levels of market penetration and for different climatic conditions. For a 20% market share of wind power, they establish a cost range for operational and capacity reserves between €4.5 and €6, while transmission and distribution upgrades are modeled to lie between €2.5 and €3. Thus, total costs range from €7 to €9 at that level of market penetration.

Table 4 below summarises figures from different studies focusing on the operational and capacity reserve costs of wind in the UK, both in terms of absolute costs per annum and per MWh of wind generation. Note that this is different from the more comprehensive methodology in Strbac et al. (2002). However, as different studies analysed different aspects of wind integration a common basis on the assessment of these costs can be established in this way.

Table 4: Costs of extra balancing wind in the UK

	Wind penetration in % of total capacity			
	5.3	7.6	10	14.2
	Total cost in €million per annum			
Lower estimate	26	44	66	120
Median estimate	29	54	80	143
Upper estimate	41	79	119	215
	Cost in € per MWh of wind electricity			
Lower estimate	1.3	1.6	1.8	2.1
Median estimate	1.4	2.0	2.3	2.4
Upper estimate	2.1	2.9	3.4	3.7

Source: Mott MacDonald 2004:34; exchange rate used: 1£=1.43€.

The lower boundary costs were taken from an energy review by the cabinet office of the prime minister of the UK, conducted in 2001/2002 (PIU 2002). The Upper boundary represents figures calculated by the UK grid operator (National Grid Company) which are based on somewhat more conservative estimates of market prices for balancing services (NGC 2001). Finally, the middle estimates are again from Strbac et al. (2002). It should be noted that these figures, even in the most pessimistic case, represent about 8% of current wholesale market prices in the UK (€47/MWh or £32/MWh), noting that these include only balancing costs.

For Western Denmark, the Transmission System Operator (TSO) Eltra (2004a) reports that for the 3,368 GWh of wind power that they were mandated to purchase in 2003, the total balancing costs were €8.7m (65m DKK). This corresponds to about €2.6 per MWh of wind energy.

For Germany, E.ON reports 6250 MW of wind power on its grid in 2003 and costs of more than €100m (Winter 2004). It is not clear what these costs include. With wind energy production of 8.5 TWh in 2003, €100m corresponds to approximately 11.7€ per MWh of wind energy.

The large differences in reported balancing costs between the German and Danish grid appear striking at first glance. However, they might point to the fact that reported market prices for balancing services are not always equal to actual economic costs incurred or alternatively that a higher proportion or absolute quantity of wind power is more expensive to balance within a given grid.

Smith et al. (2004) summarise a total of eight studies from US utilities and research laboratories on the additional operational and capacity reserve costs of wind power. The studies had slightly different scopes depending on the precise system under investigation, and calculations were made for wind penetration levels ranging from 3.5% to 29%. Total additional system costs ranged between €1.13 per MWh (1.47$/MWh)[11] and €4.22 per MWh (5.50$/MWh) amounting to between 2 and 15% of current US average electricity prices. The authors note that "It is now clear that, even at moderate wind penetrations, the need for additional generation to compensate for wind variations is substantially less than one-for-one and is generally small relative to the size of the wind plant." (Smith et al. 2003:7) However, they also point to important areas of future research, among others a better understanding of how a market for ancillary services could operate. Also, improving available wind forecasts and the models operated by grid operators that implement the resultant data are identified as a priority area for improving the cost performance of wind power.

Table 5 (adapted from IEA 2005:214) presents an overview of the different costs for system integration of wind power that have been presented above. It has to be borne in mind that these numbers are highly dependent on the specific circumstances in each region, including geographical and climatic conditions, the state of existing electricity grids and available technologies and the precise market design. IEA's (2005) best estimate to date covers a range of between €5 and €15 for the total system integration costs of wind at 20-30% market penetration.

Table 5: Experienced and modeled costs of integrating wind power, euro per MWh of wind power*

	E.ON Netz**	Eltra	Smith et al. (2004)	Strbac et al. (2002)***	Auer (2004)***
Balancing	11.7	2.6	1.13 - 4.22	3.3	1.5-2
Operational reserves					
Capacity reserves				6.7	3-4
Transmission & distribution				4	2.5-3

*For comparison with other technologies it must be taken into account that all technologies require integration costs. ** E.ON Netz (2004): 8.5 TWh of wind power in 2003 and costs of more than 100 mil. Euro. It is not clear what these costs include. *** At 20% wind power shares of consumption.

In summary, from the findings presented above, a number of general conclusions can be drawn:

- Firstly, all the studies published have found that the integration of wind power at the levels considered thus far does not need one-for-one backup capacity. Electricity grids already operate with high levels of reserve due to the conventional mix of power plants connected, thus absorbing the incrementally added variability due to wind power thus far.

11. 1$=0.77€

- Secondly, the survey on costs also shows that large differences exist between countries. This is on the one hand due to different climatic and geographic conditions, the technology mix, the state of the grid and levels of wind power market penetration in each country. On the other hand, markets and incentives to manage intermittency in an efficient manner do not exist in all cases, thus the true economic costs are not always revealed in the reported prices.
- Thirdly, the cost ranges presented in table 5 are mostly for electricity markets where wind power has reached a share of 20% or more. Currently, only the Danish and Northern German region exhibit such a level of market penetration in practice.
- The range of these costs suggests that gains can be achieved by pushing costs to the lower end of this range through, for example, careful and efficient market design and optimised location of new wind plants.

Markets for managing intermittency

Having reviewed a number of studies that aimed to provide cost estimates of integrating wind into the electricity grid, it will now be asked, how markets are actually set up to manage this task. Taking one step back from the studies presented in the last section, two factors still have to be kept in mind. Firstly, costs will always differ between countries and regions due to different levels of market share of wind power, the availability of renewable resources and options to mitigate the effect of intermittency. Secondly, market regulation varies among IEA countries so prices might not always be reflective of the actual economic costs imposed. In the following some examples are presented of how countries have modified their markets to allow for a better management of renewables. This should in no way be seen as comprehensive, rather it is sought to present a range of contemporary issues of how market rules are adapted to better integrate intermittent renewables.

DSR in the United Kingdom and Scandinavia

Both the Scandinavian ('Nord Pool') and UK (NETA) market operate a short-term balancing market to make up for differences between actual and scheduled production, thus establishing an important prerequisite institution for DSR to operate. While most of the short-term balancing is still provided by generators regulating up and down their capacity, there have been market actors that have bid into these markets based on their demand, offering to lower or increase their electricity consumption at a specific time according to the price signals in the market.

Ofgem (2004), the UK electricity market regulator, recently quoted an example from a specific day, 28 January 2004, where during a peak winter period DSR provided about 1 GW of capacity (reduced demand), which represented about 2% of total demand at the time.

Eltra (2004b), the Danish grid operator, notes in a recent 'action plan' that DSR was a key to improved market functioning and better integration of large amounts of wind power onto the system. DSR is also appreciated for reducing the scope for the abuse of market power in the general electricity market, since the demand curve becomes more elastic and thus more responsive to price increases. A strategic generator would therefore need to withhold more output and lose more revenue to achieve the same price increase and would consequently be less inclined to do so. Moreover, from a system security point of view, DSR provides 'capacity' to cope with periods of low supply and/or high demand (and principally vice-versa). Eltra has proposed an action plan with a total of 22 projects to - among others - assess the viability of DSR, improve the information among likely participants, trial new business models and test new electricity meters to improve the share of DSR on the system. Most of these projects will be finished by 2008-2010 and it will be clearer by then what role DSR can play on the Danish grid.

Norway established a new power reserve market on 1 November 2000. Both generators and consumers can bid into this market and Statnett, the Norwegian grid operator, reports significant demand-side participation, mainly by large customers in the paper and steel industry. Participation is invited by a bidding system for a fixed balancing product. The minimum size of balancing power is 25MW, which must be available for DSR within 15 minutes of notification and last for at least one hour without interruption. Participants must be prepared to offer this service for at least 10 hours per week (Nilssen and Walther 2001). At the second bidding round in 2001, a total of 2967 MW of balancing reserve were offered to the grid operator through 80 offers of which 23 were accepted for a total of 944MW.

United States balancing market

Utilities in the northwest of the United States who want to add wind power to their portfolio but do not want to get involved in the day-to-day balancing of intermittency now have a new offer to choose from. To make utilities more acquainted with intermittent renewables and generally raise the profile of wind energy, the Bonneville Power Administration (BPA) recently started offering a new business service. Thanks to its vast 7000MW hydropower network, the BPA offers to 'soak up' any amount of intermittent renewable output and re-sell it as firm output from its hydropower network one week later (O'Bryant 2003).

Utilities will first have to secure a power-purchase agreement directly with the wind farm operator, organise for transmission through the BPA network and schedule the wind capacity. At a charge of €3.45 per MWh ($4.50/MWh), the BPA then absorbs this wind energy and delivers an equivalent amount as firm capacity one week later.

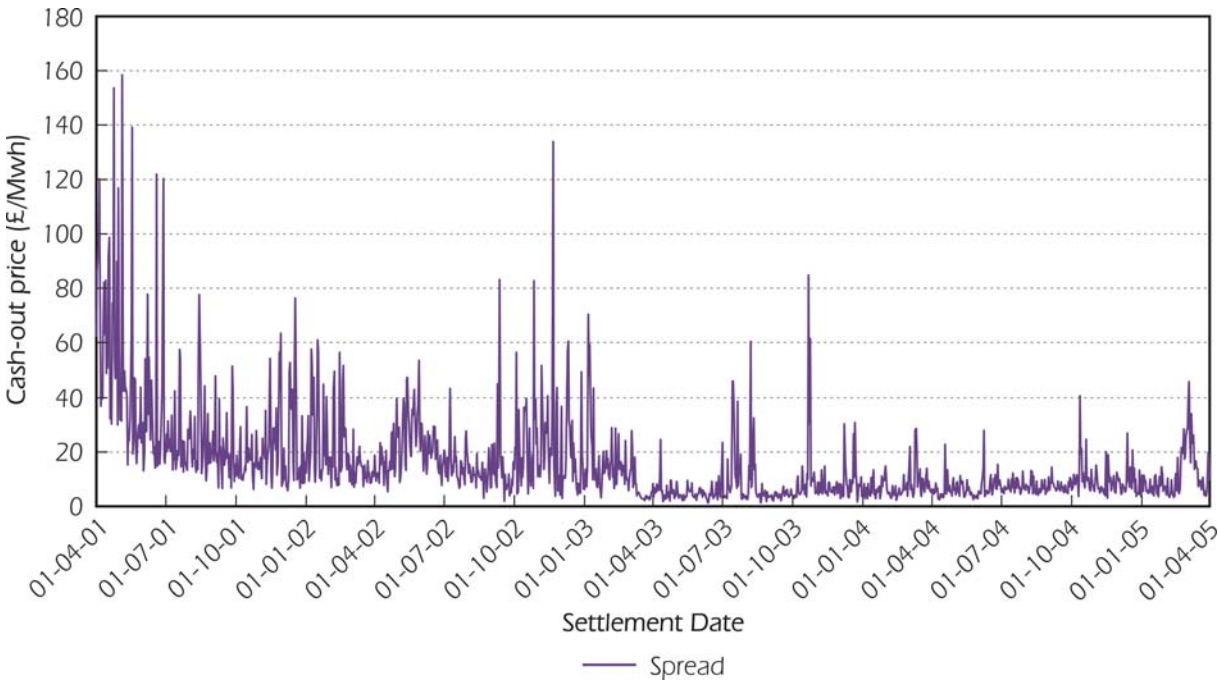
While this price is not necessarily cost reflective of the actual costs that BPA incurs, it could act to lower information barriers and increase interest in wind energy, taking out the perceived high risk that intermittency otherwise might inflict. It might also spur other operators to offer similar services at lower prices thus inducing some competition for the lowest cost way of managing intermittency. However, balancing services need to be supplied within a local region defined by potential transmission constraints, and are therefore typically only offered by a limited number of generators. Therefore, unless new storage technology offers low-cost small-scale storage options or balancing zones are enlarged, it is possible that competition for the provision of balancing services will stay limited and will require continued market power monitoring to achieve efficient prices and investment incentives.

United Kingdom NETA system

Following the start of the New Electricity Trading Arrangements (NETA) in the UK on 27 March 2001, one commentator observed that "The most profitable way of operating a wind farm so far has been to turn it off". The rules that were implemented in this new market changed the operating conditions for wind farms from one day to the next in such a way that they ran into serious trouble without any change in the underlying wind characteristics or physical operating conditions. Moreover, given the modest amounts of wind that were connected to the UK grid at that time, the real additional costs that were imposed by wind on the system were negligible compared to the amount that was actually charged under NETA. Under NETA, operators had to engage into supply contracts for half-hourly intervals at least 3.5 hours in advance on the sport market. Should the wind conditions change subsequently, each individual wind farm operator had to trade surplus or deficiency in a system balancing market, where prices differ from the spot market.

The purpose of these imbalance prices is to provide a commercial incentive to all participants to honor their positions. If a generator has a shortfall in generation, it must pay for that shortfall at the so-called System Buy Price (SBP). If a generator produces more energy, then it is paid for this excess at the so-called System Sell Price (SSP). In a working paper for the UK cabinet office, Milborrow (2001b) notes that NETA imposed additional costs of between €3.6 per MWh (£2.5/MWh) to €5.7 per MWh (£4/MWh) for about 500MW of wind power that were connected to the system at the time, about 1% of total capacity in the UK. In contrast, on the basis of the Danish experience with wind power, calculating the real technical system costs of balancing even 10% of wind would yield an imbalance price of only €2.1 per MWh (£1.5/MWh). Naturally, there were differences in the options available between the two grids, but this was insufficient to explain the large price difference actually witnessed.

Figure 8: Spread between System Sell Prices (SSP) and System Buy Prices (SBP) on the United Kingdom NETA markets since April 2001



Source: Elexon Ltd, London.

This was partly due to teething problems of NETA as, especially in the first few trading months, the spread between SSP and SBP in the balancing market was relatively large and relatively volatile in general (see figure 8 above). Especially the SBP had very high spikes so the penalty for being short in the market could climb above €140 per MWh (£100/MWh) for brief periods. This has narrowed significantly as market participants gained experience. Nevertheless, structural improvements were suggested that would recognise the specific technical situation of intermittent renewables without distorting the market or raising costs. After some lobbying by renewable energy groups and also combined-heat-and-power (CHP) plant operators, some changes were implemented to the market rules.

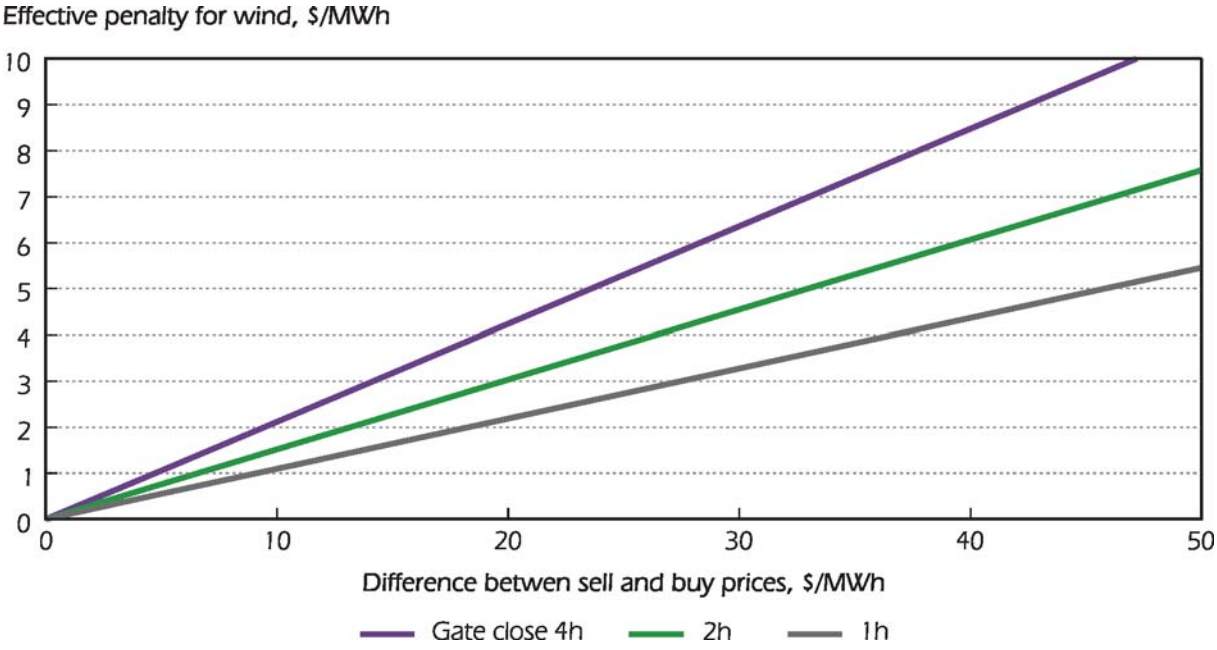
As noted initially, the gate-closure time, *i.e.* the time between notification and despatch was set at 3.5 hours when NETA was launched. This had a particularly negative impact on intermittent renewable generators since supply forecasts over this timeframe had a substantial margin of error.

After a review, Ofgem, the UK electricity market regulator, accepted a proposal to reduce this time period to one hour. This will allow all market participants to limit their exposure to imbalance charges. Significantly, wind forecasts and modelling that form the basis of the supply schedule for each half-hourly period of wind farm operators, have a significantly reduced margin of error over this timeframe. Figure 9 illustrates the effect of reduced gate closure times. Reduced gate-closure times contribute significantly in reducing the spread between system buy and sell price and thus the effective penalty that has to be paid by the operator.

Nevertheless, another criticism is that NETA has resulted in far more spinning reserve being scheduled by the individual suppliers than is really necessary. This argument goes back to the point of balancing demand and supply on a systems level rather than requiring each individual supplier to balance their output individually. Since suppliers have been especially keen to avoid the higher SBP, "suppliers have typically chosen to be over-contracted at Gate Closure and generators have chosen to part-load some of their plant so that they can increase their output to cover any unforeseen outages in their plant which might leave them short of electricity." (Ofgem 2002:4)

On a system-wide level, some of the over- and undersupply at every point in time will be naturally balanced out leaving only a residual of imbalance in the market. The grid as a whole can only either be short OR long in a half-hourly period. Nevertheless, generators who are short when the system overall is short pay the SBP, thus imposing costs on suppliers as if they were directly connected to their end-customer, ignoring the benefits the grid delivers in this respect.

Figure 9: The benefit of reducing gate-closure times in the United Kingdom



UK Source: Milborrow 2004a:38.

Connection of offshore wind

The development of offshore wind plays an important part in the market introduction strategy of many European Countries with access to coast lines. However, one unresolved key issue is the connection of these new wind farms into the national grids. At a recent workshop in Egmond aan

Zee, held under the auspices of the Dutch EU presidency, some of the important stepping-stones in this regard were agreed upon by representatives from governments, research institutes and industry. Even representatives from countries without a coast-line were invited since it was considered that the benefits from developing offshore wind could only be shared if a truly trans-European solution to grid integration was found. The declaration from the workshop makes this point strongly (Dutch Economic Ministry 2004): "In order to find European wide solutions to grid system issues like costs, size and dynamics related to system balance and interconnection, the European Commission should encourage, and where appropriate, support co-operation between Member States Governments, power plants and Transmission System Operators." The development plans for offshore wind in many countries could seriously surpass the narrow demand of coastal regions. Interconnection could allow a better sharing of both the costs to integrate these wind farms into the national grids as well as the benefits from high capacity renewable energy. While offshore wind farms are only magnifying this point by their sheer size, it has to be pointed out once more, that this principle applies to the integration of all kinds of intermittent electricity sources in general.

Already, three European interconnection projects that will aid the integration of offshore wind have been earmarked for up to 20% EU funding by the European Parliament, including an interconnector between the UK and continental Europe; an interconnector linking Ireland with the UK mainland; and increasing interconnection capacity between Denmark and Germany and other Baltic Ring countries (Windpower Monthly 2003).

Summary

The examples given above underline the fact the addressing intermittency of wind has only recently emerged as a priority concern of grid operators. Market rules are tested and revised and no clear preferred model of markets for ancillary services has been emerging yet. Similarly, upgrading of transmission lines and the interconnection of systems in general and for better wind integration is still in the planning stage and a model of sharing costs and benefits needs to be worked out. A recent study on the integration of wind energy into the national grid for example showed that the projected growth of wind power in Germany to some 36GW by 2015 necessitates an extension of the existing grid by about 5% of installed grid-km (Dena 2005).

In summary, policy-makers, regulators and grid operators as well as wind turbine manufacturers need to learn from the experience gathered and share information in order to arrive at solutions that work. The benefits of aggregation of wind power output have to be visible in balancing prices. The next chapters will summarise the key issues that should be considered in this context.

4. Summary and Lessons Learned

The question posed in chapter one was as follows: Given the expected rapid growth in renewable energy technologies over the next decades, are there technical limits to the integration of these technologies into electricity grids? The previous chapter examined in detail the evidence for this question in the case of wind power. This section will now draw together the main messages and will also discuss their policy implications.

Technical lessons from integrating wind energy

Although renewable energies and especially wind power already today play a non-negligible role in some IEA countries, the actual contribution to total primary energy supply is still limited. However, countries such as Germany integrate some 14,000 MW of wind power successfully, the United States and Spain more than 6,000 MW, Denmark around 2,300 MW. So far, problems with intermittency have occured only on a regional level, highlighted by the cross-border congestion problems between Denmark, Germany, the Netherlands, Belgium and France (see chapter 3).

Current trends suggest a larger future role for renewable energy in electricity supply. For OECD Europe, the IEA's World Energy Outlook (IEA 2004b) expects a 16% market share of non-hydro renewables in the baseline-case by 2030. In an alternative policy scenario this share is projected to be over 23%. Several countries have ambitious polices and targets for renewables to play a more important role.[12] The ambitious plans, indeed, present the question of whether intermittency imposes technical limits on renewables in the future.

The evidence presented in chapter three indicates firstly, that current market shares of wind power have been technically integrated successfully into electricity grids and secondly, that options do exist to manage higher market shares of intermittent renewables in the future but at additional economic costs. Grid operators already possess tools to respond to system fluctuations of greater magnitude than will be imposed by current levels of renewables. Modeling and forecasting, as well as new communication technologies are current research priorities and will further refine these options. Innovative technologies for long-distance transmission of electricity, such as HVDC cables, open new opportunities for long-distance bulk transport of electric energy with low transmission loses. Market liberalisation and integration is already a major driver for the deployment of this technology. However, a larger share of wind power will ultimately require more flexible capacity reserve, and new and upgraded transmission and distribution systems. If these components are not developed simultaneously to expected growth in intermittent renewables, the stability of electricity grids will be threatened. In the future, new technologies and increased use of demand-side response measures could furthermore add to a more reliable grid operation, and reduce costs of integrating higher proportions of renewable technologies.

What does this mean to upper limits for renewable energy penetration? A general rule cannot be given, and much depends on different country circumstances and setups. The issues that arise at 20% market penetration of wind power in one country might well be experienced at 5% market

12. See the IEA Policies and Measures database at http://repolicies.iea.org and the Johannesburg Coalition Policies and Measures database at http://jrec.iea.org for information on individual countries' programmes.

penetration in another country and vice-versa. Based on the practical experience gathered with wind power in a number of countries and the studies presented in this paper, table 6 below is a simplified summary of the issues that are likely to be encountered as wind power progressively increases its market share. The exact numbers will vary from country to country and new technologies might alter the picture significantly. Therefore, the table below attempts to differentiate three phases of increasing wind power market deployment rather than exact penetration levels, and shows how at each progressive stage, issues arise which should be considered in advance for the successful accommodation of wind power.

Table 6: Levels of wind penetration and corresponding issues

Wind development phases	Issues
Phase I	The added variability due to wind is not significantly noticed on the system, wind is treated as negative load; no major system adaptation is normally necessary and demands on transmission capacity are mostly within existing limits.
Phase II	Additional operational and capacity reserve will become necessary. Grid re-enforcements might become necessary, depending on wind location of wind resources and demand centres.
Phase III	Flexible capacity reserves increasingly gain in value; grid upgrades and new interconnections will become more important, depending on the historic structure of the grid.

Bearing the above in mind, a study of the Central Electricity Generating Board CEGB in the UK for example revealed that the existing system would need to reject a small amount of wind energy at certain times at a wind penetration of 10%, but could still work without major modifications even at 15% (BWEA 2004). It is stated, that even a wind capacity of 15,000 MW, *i.e.* enough to meet 13% of the UK's electricity demand at the time of the study in 1990, would still contribute to a smaller risk than one conventional power station being unexpectedly unavailable. This again underlines that a general rule cannot be given. Ultimately, the question whether there is an upper limit for renewables penetration into the existing grid, will be an economic and regulatory one rather than a technical issue.

Electricity systems as a whole continue to evolve and grid operators and utilities will ultimately have to adapt their methods, as they have in the past. The high concentration of wind power in northern Germany, and Western Denmark for example, might call for a joint operation of the balancing market, technical adaptation by the concerned utilities, collaborating on production forecasts, sharing data and possible grid extensions both on the German and on the Danish side, but all of these measures would add to the costs of reliable electricity provision. Potential future structural changes such as Distributed Generation with smaller flexible power generation units might become another driver of these types of system evolutions.

One relevant study in the context of structural changes was published by Kraemer (2003). This study aimed to optimise the costs for electricity generation in Germany under the assumption of high penetration of wind power (about 44 GW in 2020, so roughly a quarter of total electricity supply) and priority to wind power under the German Renewable Energy Sources Act. This study

shows that high penetration of wind power under cost optimised aspects and with the objective to reduce CO_2 emissions by 40% in 2020 will lead to displacement of base load power plants such as brown coal plants through a more flexible system based on wind and gas, with modest additional costs for wind power.

However, this approach would certainly require substantial changes in the energy systems and requires a change in paradigm; whether or not this change in paradigm is practical remains to be seen. Still, in many countries a significant number of conventional (fossil and nuclear fueled) power plants are to be replaced because of their age, thus opening the general opportunity for such a paradigm shift.

Economic and policy lessons

The discussion about intermittency of wind power has also brought about issues with wider electricity market implications. On a first level, the question arises whom grid integration costs are attributed to. In the context of intermittency, it has been argued that wind developers should be charged for transmission and distribution system upgrades and the increase in operational and capacity reserve that would become necessary as a consequence of wind power expansion. However, proponents of wind power argue that historically, these costs have always been recovered from all producers (and ultimately of course the customers) in the market and that new conventional power plant projects, such as the new nuclear power plant in Finland, also have wider system costs without that being necessarily charged to the relevant operator.

The difference between these views is substantial. For example, the additional system costs for renewables that have been calculated for a 20% wind and biomass scenario in the UK would be €4.9 per MWh (3.3£/MWh) of renewable generation but only €0.44 per MWh (£0.3/MWh) of total generation. From an economic point of view, each generator should be charged the proportion of costs that can be attributed to it in order to provide the right incentives to achieve a system-wide cost minimisation. However, given the legacy in the existing electricity markets of unspecific charges of system costs and the general network economics of electricity systems, structural changes in market designs and potentially new markets for reserves might become necessary.

In any case, it is clear that there has been as yet no universally adopted system of making the additional costs that intermittency imposes on the system transparent. The studies discussed above were often based on scenarios of coping with intermittency, without necessarily considering a market model of how these charges might be recovered. In many IEA member countries market designs have grown out of and in response to historic institutional structures and continue to evolve. Many markets have experienced phases of trial and error. Thus, in the following some general considerations for the charge of additional system costs are discussed, for the case of intermittent renewables as well as system balances in general.

In general, the most important issue which markets should address is cost reflectivity. For system balancing purposes, this means that market actors have the right incentives to increase their availability and provide precise schedules. Costs for maintaining system stability should be apportioned fairly according to how much each generator contributes to the need for keeping reserves, as well as potential transmission and distribution line upgrades. Here it might be important to highlight once more some first principles of system operation.

- Bigger units of power plants bring with them the need for both greater operational and capacity reserve since outages cause greater disturbances to the system, *ceteris paribus*.

- The higher the technical availability, the lower the probability of unexpected outages and thus the lower the requirements of short-term operational reserve, *ceteris paribus*. (Strbac and Kirschen 2000).

Wind power plants actually score favourable against both criteria, since they normally employ small individual units (currently up to 5MW) and have a record of high technical availability. Bad wind forecasting can diminish the second point, but as mentioned before, this is an area that currently receives a great deal of attention and promises significant improvements in the short term. Still, if a TSOs can pass on all balancing costs to customers then it faces little incentive to improve forecast accuracy, even less so if vertical integration implies that balancing services are contracted from own generation.

Strbac and Kirschen (2000) present a method to allocate the costs of reserve requirements based on both the capacity factor and outage rates of each plant. Milligan (2001) adapts this method for a model using real data from wind power plants in Minnesota, USA. The results show that in the most pessimistic scenario the highest reserve burden for the wind plants is 20% of its rated capacity, averaging about 3% throughout the year (Milligan 2001:4).

It might be asked whether in the context of cost-reflectivity the demand side would play a role as well since it also contributes to system uncertainty. Here, it has to be stressed that the current forecasting error of demand in most grids is in the order of 1%-5%, thus the scheduling of operational and reserve capacity is practically driven entirely by the supply side.

System operators will ultimately execute the physical balancing, as they are uniquely placed to have a system's view of imbalances. Thus, the smoothing effect of over- and underproduction of individual generating units is taken into account and only the residual imbalance is covered, providing a least-cost solution. Markets to organise the necessary resources should reflect this thinking and reward those generators that contribute to system's stability and only charge those that contribute to overall system imbalances.

Transparent, cost-reflective and interconnected markets for reserves will ultimately deliver the least-cost solution to grid integration of intermittent renewables. Market power by incumbent operators can prevent the development of such markets and is currently an important topic in electricity market regulation (Neuhoff 2005).[13] Securing a wide variety of options and competition between these products has to be stimulated. Solutions will be needed to let both consumers as well as producers participate in these markets. Issues include transaction costs for novel participants such as demand-side response and distributed generation and geographic spread of such markets. Operating these "balancing" or "regulating markets" is an issue which will become more important for electricity market reform in general but is further illuminated through the challenge of intermittency. New products, especially for capacity reserves for occurrences of low output from intermittent renewables over longer time periods might become necessary.

Another important sub issue that remains is the gate-closure times of spot markets, which is an important variable especially for intermittent renewables. As has been discussed earlier, reducing gate-closure times to a technically necessary minimum could have real advantages, most

13. See Platts (2005:1-2) for a report on suspected market collusion in the German balancing market where four separate balancing market zones are maintained, leading to higher levels of required reserve.

importantly for wind power but also for conventional generation in general and thus for the electricity consumers as well. There will be a trade-off, grid operators will not always have flexible fast-response capacity available and this will be an important driver in considering to what extent gate-closure times can be shortened without imposing additional economic costs. Markets might not always be liquid in short-term trades, reducing the potential value gained for wind farm operators. Nevertheless, improved schedules for wind power, which specifically depend on weather forecasting and modelling operations, are likely to have significantly reduced margins of error which will contribute to system stability and reduced overall costs.

Since the costs of integrating wind in the grid are location dependent, a general concern is that the best wind resources might not always be where they are cheapest to develop. This might for example be the case where the resources are far away from major demand centres and grids are only poorly developed. Thus, there might be a balance in the benefits from the exploitable resource and the system integration costs for different locations. Countries could share these costs and benefits through wider grid integration which could also have benefits in relation to the wider competition concerns in electricity markets. Yet, an approach that is cost reflective would give the right locational signals and would provide an efficient basis on which to decide new renewables developments.

5. Conclusions: Lessons Learned for all Renewables

This paper started by outlining how natural cycles affect all renewable technologies over different time frames. While wind or solar PV technologies can change their output within minutes or hours, other technologies like hydro or biomass have seasonal variations of available energy. Many renewable technologies are in use in IEA member countries for many decades and have coped with this variation in available energy successfully.

As has been argued in chapter 2, the introduction of 'new' renewable technologies like wind or solar PV has added a new quality to this variability in that it added intra-day variations. Moreover, this has been magnified by the rapid growth in some of these technologies. Nevertheless, the fundamental principles on which these variations operate are known and should not come as a surprise. 'Traditional' renewables like hydro, geothermal and biomass were either part of national electricity supply from the beginning and have comparable operation characteristics as other power stations.

Given the high prominence of wind power among policy-makers, the media and in the research community, chapter 3 specifically examined the integration of wind energy into electricity markets. The main issues in terms of grid management and technological options to address the variability of wind have been examined and a review of policy and market issues was presented subsequently. It was concluded, that the experience with wind power showed that integration was more an economic and political issue than a technical issue. However, the importance of developing technical solutions concomitant to the growth of intermittent renewables to ensure electricity system stability was highlighted, especially in the case of grid extensions.

When considering the integration of renewable energy technologies into electricity grids, the broader evolution of the electricity market has to be taken into account. The pre-dominant fuel in electricity supply has changed in many countries over the past decades and is forecasted to do so in the future. The IEA's World Energy Outlook (WEO - IEA 2004b) expects a total investment into global electricity markets of $10 trillion by 2030, of which almost $5 trillion will go in new and upgraded transmission and distribution assets.

As renewables gain more significant market shares, some of this investment will benefit the integration of these technologies. There are six main areas of structural change that will directly benefit renewables. The first four presented below are likely to occur as a consequence of continued evolution of electricity markets and electricity grids. Other options might require further policy guidance. Each will briefly be highlighted subsequently.

- Increased grid capacity and cross-boarder connections, corresponding to the projections from the IEA's WEO.
- Balancing/Regulating markets that are cost-reflective, transparent and interconnected with gate-closure times reflecting the technical and economic needs on the system.
- Enhanced uptake of efficient demand-side response mechanisms.

- Installation of more flexible generating capacity, including hydro-power and biomass, as capacity reserves and increased efforts to reduce costs of novel storage solutions to widen the number of strategic options.
- A mix of different renewable energy technologies, taking advantage of different natural cycles and thus reducing volatility and uncertainty.
- Improved forecasting and modelling of natural fluctuations and increased utilisation of communication technologies to disseminate this information between grid operators and markets.

As chapter 2 described, some renewable technologies actually complement one another in their cycles. Solar PV resources are most available in summer while this is in many climates a time of relative drought with respect to hydro resources. Winds are often stronger in winter which is also a time of peak demand in colder climates.

However, as has been noted in the section on wind energy, renewable energy resources might not always be distributed equally. Some countries benefit from very windy regions while others have good biomass or hydro resources. While relying on one technology alone might be feasible if there is relative abundance or low penetration into the market, in the long run wider interconnection, and thereby utilisation of dispersed renewable energy sources on a wider geographical scale, is likely to become an important means of mitigating problems with availability due to the natural cycles.

In the case of wind for example, various studies have pointed out that not only geographic diversity of wind turbines can minimise the impact of intermittency but also a diversity of different technologies, exploiting renewable resources that follow different natural cycles. Specifically in the UK, two studies have compared systems that rely on wind alone with systems that have a combination of wind and biomass (Sinden 2002, Strbac et al. 2002). In both cases, the need for ancillary services and transmission line upgrades and thus the overall costs of the system were significantly reduced when wind was complemented with biomass generating capacity. On a wider geographic scale, Scandinavia has an interconnected market where hydro from Norway and Sweden is interconnected with wind in Denmark. A new interconnector will soon link the Norwegian and Dutch markets. The Bonneville Power Authority (BPA) in the northwest of the USA has supported wind farms in the region as one of the options for drought proving their vast hydro capacity (Felton 2004).

In summary, renewable resources are unequally distributed but often complement each other if interconnected to the same grid. The full potential of renewable energy resources lies in their diversity. Few energy systems in IEA member countries rely on one fuel exclusively and renewables are sometimes treated as if they all are essentially the same. As chapter 2 demonstrated, this is not the case and a strategy to develop renewables needs to take account of the different natural cycles that influence their availability. The global theoretical potential of renewable resources is vast, although estimates of what is economically recoverable vary. This potential varies regionally and a portfolio of technologies has to be used to harvest it to the full extent.

Traditional renewables such as hydro power and geothermal have participated in electricity markets for many decades. The intra-day intermittency of some of the new renewable energy technologies such as wind and solar PV makes it more difficult for these technologies to compete in mainstream markets. As has been reviewed ealier, what renewables are charged for in balancing markets is not always reflective of the actual economic costs that intermittency might impose. Transaction costs for hedging against these risks are high, especially for small operators, and balancing markets themselves are not always organised efficiently.

As markets continue to evolve and participants learn and better understand what the best rules and designs are to operate such institutions, this problem should gradually be addressed. The implementation of new communication and improved forecasting and modelling technologies will furthermore aid this task. Renewable energy technologies stand to benefit from markets which are widely integrated and where a wide variety of options, including demand-side response, storage, distributed generation and flexible power plants compete to offer the various ancillary services. In this way, renewables will become 'mainstream' in its characteristics and much akin to what market participants are familiar with today from conventional power plants. Furthermore, some of the integration efforts fall into the needs for restructuring electricity grids for better performance and more efficient operation.

Overall, should renewable energy technologies make a more significant contribution to energy supplies in the future, it is likely to be through a variety of technologies which will not be identical globally but will vary with the regional availability of natural resources and their cycles. In this perspective, higher contributions from renewable energy sources seem feasible. The technical barriers to such a strategy are well understood and current estimates of associated costs of system integration indicate that the economically exploitable potential remains significant.

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UPDATE 1-PG&E Calif Diablo Canyon reactor cut to 50 pct

Thu, Oct 15 2009

(Adds reason for reduced output)

HOUSTON, Oct 15 (Reuters) - PG&E Corp's <PCG.N> 1,122-megawatt Diablo Canyon 1 nuclear power unit in California was reduced to 50 percent output on Thursday to clean debris from the cooling water system, a plant spokeswoman said on Thursday.

Tuesday's storm that crossed the California coast pushed kelp and debris into the station's cooling water system, the spokeswoman said, prompting operators to move up a scheduled condenser cleaning.

The curtailment is is expected to be short, she said, but declined to give a specific timeline.

Diablo Canyon 2, rated at 1,118-MW, shut in early October for an expected month-long refueling outage.

The station is located in Avila Beach, in San Luis Obispo County, about 195 miles northwest of Los Angeles.

One MW powers about 700 homes in California.

PG&E, of San Francisco, owns and operates more than 6,200 MW of generating capacity, markets energy commodities, and transmits and distributes electricity to almost 5.3 million customers and natural gas to 4.2 million customers in California. (Reporting by Eileen O'Grady; Editing by Steve Orlofsky)

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IMPLEMENTATION OF ONCE-THROUGH COOLING MITIGATION THROUGH ENERGY INFRASTRUCTURE PLANNING AND PROCUREMENT

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DRAFT JOINT AGENCY STAFF PAPER

DISCLAIMER

This paper was prepared by staff of the California Energy Commission, California Public Utilities Commission, and California Independent System Operator Corporation. It does not necessarily represent the views of these entities or the State of California. The Energy Commission, the State of California, its employees, contractors and subcontractors make no warrant, express or implied, and assume no legal liability for the information in this paper; nor does any party represent that the uses of this information will not infringe upon privately owned rights. This paper has not been approved or disapproved by the California Energy Commission nor has the California Energy Commission passed upon the accuracy or adequacy of the information in this paper. This paper has not been approved or disapproved by the full Commission.

July 2009
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California ISO
Your Link to Power

Arnold Schwarzenegger, *Governor*

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Abstract

This paper outlines a joint proposal by the California Energy Commission, the California Public Utilities Commission, and the California Independent System Operator Corporation to the State Water Resources Control Board intended to assure reliability of the electrical grid while substantially reducing the use of once-through cooling in existing coastal power plants. Rather than focusing on refitting existing power plants to reduce once-through cooling water intake/discharge, the proposed approach develops replacement infrastructure such that existing plants would no longer be needed for local reliability. This replacement infrastructure encompasses refitting existing plants to alternative cooling systems; repowering existing plants; and retiring the current site, possibly requiring transmission system upgrades to rely more upon remote generation. The State Water Resources Control Board has released its proposed once-through cooling mitigation policy, which substantially relies upon this joint agency proposal. The complexities of electrical system planning differ by region within California; thus the proposed approach can be implemented immediately for some regions but requires substantial further analysis of options in other cases. Such analyses would flow into California Public Utilities Commission procurement activities, California Independent System Operator Corporation transmission planning and project approval processes, and Energy Commission power plant licensing proceedings.

Keywords: California Independent System Operator Corporation, California Public Utilities Commission, California Energy Commission, State Water Resources Control Board, South Coast Air Quality Management District, Los Angeles Department of Water and Power, once-through cooling, local capacity requirements, electric system reliability, power plants, priority reserve

Summary

This paper outlines a proposal by the California Energy Commission (Energy Commission) and California Public Utilities Commission (CPUC), in conjunction with the California Independent System Operator Corporation (ISO), to the State Water Resources Control Board (SWRCB) intended to assure electrical grid reliability while substantially reducing once-through cooling (OTC) in existing coastal power plants.[1] The SWRCB's March 2008 preliminary OTC policy report established reliability as a condition for the design and implementation of an OTC mitigation policy but did not propose a mechanism to ensure that reliability is maintained.

In June 2008, the SWRCB formed an Inter-agency Working Group (IWG) to foster communication among seven agencies. The Energy Commission, the CPUC, and the ISO (Energy Agencies[2]) were encouraged to propose alternatives to the fixed compliance schedule proposed by the SWRCB staff in the March 2008 preliminary policy report.

The Energy Agencies propose to adapt existing planning, procurement, and project permitting processes to induce appropriate generation and transmission development to replace existing OTC facilities with some combination of repowered technologies onsite, new generation located in other areas, and/or upgrades to the transmission system. The Energy Agencies understand that the proposal has been accepted by the SWRCB staff and references to it were published as an element of the draft OTC policy on June 30, 2009.

This paper includes in its entirety the proposal made to the SWRCB on May 19 as well as an illustrative schedule for replacing existing OTC facilities. These two items appear as Appendices A and B of this paper. The SWRCB published Appendices A and B of this paper as Appendix C of its Substitute Environmental Document on July 15, 2009.

Background

In June 2006, the SWRCB issued a preliminary proposal concerning reduction of OTC impacts from existing power plants. The preliminary proposal elicited substantial comment expressly cautioning the SWRCB to consider electricity system reliability. In March 2008, the SWRCB issued a second preliminary OTC policy report for electric power plants that established reliability as a condition for the design and implementation of an OTC mitigation policy. The second proposed policy contemplated a phased compliance schedule with time included for the Energy Agencies and the transmission and generation industries to build new infrastructure or identify new resources quickly, thus assuring adequate electrical system reliability. The proposal used historic capacity factors as the basis for establishing fossil power plant compliance dates. Those plants with annual capacity factors below 20 percent were to comply with OTC mitigation by 2015, all other fossil plants by 2018, and the four nuclear units by 2021.

Staff from the Energy Agencies were concerned that the large number of power plants with low capacity factors now largely serving a reliability role could not be replaced realistically

[1] This paper has been reviewed and sanctioned through the management structures of the Energy Commission, the California Public Utilities Commission, and the California Independent System Operator Corporation, but it has not been formally approved or adopted by any of these organizations.

[2] For purposes of expressing collective recommendations, this paper will refer to these three organizations as the Energy Agencies.

by 2015 and that excessive "bunching" of compliance dates would risk creating reliability problems. This stimulated a discussion about the timeline to achieve a systematic schedule for replacement infrastructure.

In December 2008, the Energy Agencies made an initial proposal to the SWRCB that sketched a sequence of analysis, planning decisions, procurement and permitting, and construction of new infrastructure that would establish an operating time horizon for existing OTC power plants to be terminated as new infrastructure became operational. In subsequent meetings and discussions, the SWRCB staff and other members of the IWG communicated broad support for the proposal but also requested refinements that defined milestones and accelerated compliance timelines wherever possible. In particular, the SWRCB staff requested consideration for applying the general approach on a regional rather than statewide basis.[3]

This paper describes the final proposal submitted to the SWRCB on May 19, 2009, focusing on regional analysis and implementation, and leading to a specific schedule when each existing OTC power plant would no longer be required for reliability (updated chart provided on June 22, 2009, and shown in Appendix B).

Energy Agencies' Presumptions About Once-Through Cooling Mitigation

The SWRCB has been engaged in an effort to develop an OTC mitigation policy, and on June 30, 2009 published a draft policy that establishes closed cycle wet cooling towers as the benchmark for compliance. The Energy Agencies agree that a fixed-year outer bound on OTC mitigation compliance can be established, provided it allows for the orderly development of necessary replacement infrastructure and can be amended if conditions, such as permitting and construction delays, indicate that amendment is needed to ensure reliability. The Energy Commission is currently discouraging power plant applications that use once-through ocean water or fresh water-cooling technologies, so the general concept being applied by the SWRCB is already accepted practice for new power plants. This proposal also elaborates upon a general practice adopted by the CPUC in its 2006 Long-Term Procurement Plan (LTPP) rulemaking final decision, directing the investor-owned utilities (IOUs) to acquire new generation that will allow some retirement of existing aging power plants while integrating increasing amounts of renewable energy:

> To support the types of needs we anticipate in a [greenhouse gas]-constrained portfolio and to replace the aging units on which some of this authorization is based, we require [the IOUs] to procure dispatchable ramping resources that can be used to adjust for the morning and evening ramps created by the intermittent types of renewable resources. Preference should be given to procurement that will encourage the retirement of aging plants, particularly inefficient facilities with once-through cooling, by providing, <u>at minimum</u>, qualitative preference to bids involving repowering of these units or bids for

[3] While there are several alternative regional definitions in use among agencies for various specific purposes, for this purpose the local capacity areas used as the basis for resource adequacy requirements are the starting point. The relevant regions that are local capacity areas are San Diego, Los Angeles Basin, Ventura/Big Creek, Greater Bay Area, and Humboldt. To these the Central Coast has been added to encompass all once-through cooling facilities.

new facilities at locations in or near the load pockets in which these units are located.[4]

Preferred Approach

It is possible that the majority of power plant operators will retire their existing facilities rather than invest money to refit the old technologies to meet the proposed SWRCB requirements.[5] To preserve reliability in this case, repowers or new green field facilities enabled by upgraded transmission system capabilities will likely be the mechanism that allows OTC facilities to retire and to reduce or eliminate OTC impacts on the environment.[6] Until then, however, the existing OTC plants must continue to operate in most cases.

As identified in the ISO's P*reliminary Analysis of Reliability Impacts from Restrictions on Once-Through Cooling in California*, retiring plants currently viewed as necessary for local reliability will require replacement in the same area or transmission upgrades to meet local reliability needs must be made in addition to development of replacement generation somewhere else.[7] The preliminary analysis also lays out considerations for power plant development and retirement timing. The study evaluated generation shutdown scenarios of facilities that currently rely on OTC and provided conceptual transmission options, including their order-of-magnitude costs for mitigating the shutdown of these power plant groups. Although clearly preliminary and subject to change, the preliminary analysis reveals the extensive required system upgrades and high cost of relying upon transmission and remote resources that would allow large amounts of capacity to retire without replacement nearby.

The SWRCB's mission is to create policy that guides OTC mitigation for existing power plants. It cannot know whether operators of these existing power plants will choose to comply with the proposed requirements or retire. The more costly the requirements compared to the net revenues available from these facilities under expected market conditions, the more likely retirement becomes.

Meshing the environmental regulator perspective with that of the Energy Agencies is critical to ensure reliability. From the Energy Agency perspective, most capacity cannot be allowed to retire until replacement capacity needed to assure reliability is operational. Analyses of options to satisfy future requirements, planning decisions, procurement processes, permitting, and construction all take time and carry uncertainties that are not easily reduced to a specific date when replacement infrastructure can be certain to be operational. The Energy Agencies would prefer that an OTC mitigation regulation be specified in a conditional manner, that is, an existing OTC plant continues to operate until its replacement

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[4] California Public Utilities Commission, D.07-12-052, http://docs.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/76979.htm, p. 106, [111-112, and 115].

[5] With limited exceptions, representatives of the existing OTC plants confirmed this presumption at a May 11, 2009, workshop on OTC mitigation conducted by the Energy Commission as part of the *2009 Integrated Energy Policy Report* proceeding, transcript available at http://www.energy.ca.gov/2009_energypolicy/documents/2009-05-11_workshop/2009-05-11_Transcript.pdf.

[6] Some plant owners may choose to bring the cooling systems into compliance with the proposed SWRCB rules. This alternative is not presented in depth as it is presumed this process will take less time and, therefore, have fewer reliability impacts than building a new or repowered plant.

[7] California Independent System Operator, November 25, 2008, http://www.caiso.com/208b/208b8ac831b00.pdf

is operational. At that point, it can retire, and OTC harm ceases. On the other hand, the SWRCB must establish a policy that creates a deadline to force action by the operator of the plant. Creating a policy with a fixed compliance deadline allows its regional boards to issue necessary permits to the existing plants with knowledge that OTC mitigation will occur on a fixed schedule.

Therefore, the Energy Agencies strongly believe that implementation of an OTC mitigation policy for existing generators has to be integrated with planning and development of the replacement infrastructure necessary to support system reliability. Although estimated dates for new infrastructure being operational have been provided as part of the proposal to the SWRCB, these must be periodically reviewed and updated. Such updates must be reviewed by the SWRCB and, where significant changes have been made, must be used as the basis for changing the permits for existing OTC plants. The Energy Agencies are committed to working together and with the SWRCB to achieve this objective.

Energy Agency Policy Objectives and Constraints

State law and agency policies set forth objectives for the electricity industry that OTC replacement can help achieve. At the same time, reliability and other objectives constrain how quickly OTC replacement can occur. In examining infrastructure development, the approach preferred by the Energy Commission and the CPUC is to pursue system modernization compatible with three key policy objectives, while assuring reliable operation of the system:

- Retire and/or repower all aging power plants unless cost-effectiveness analysis justifies continued use of a specific unit at an aging plant.
- Facilitate sufficient power plant development to meet operational requirements to integrate intermittent renewable resource development, while complying with statewide and air basin air quality attainment plans for criteria pollutants.
- Implement Assembly Bill 32 (Núñez, Chapter 488, Statutes of 2006) goals for energy efficiency, demand response, and customer-side of the meter generation technologies to achieve the economy-wide greenhouse gas (GHG) reductions needed for AB 32 and the Governor's Executive Order S-20-06.[8]

Within the broad umbrella of linking OTC mitigation to the development of replacement infrastructure, many alternative plans could be developed. State agency policies emphasize preferred resource types. Taking these considerations into account would probably lead to a different set of proposed fossil power plants than would reliance upon a conventional fossil power plant replacement strategy, most likely a smaller set enabled by more renewable generation and its associated transmission, energy efficiency, distributed generation, and demand response. The following discussion identifies the broad consequences of pursuing these policy initiatives through the analyses of replacement infrastructure options and ultimately making procurement and construction decisions based on the options.

Repowering/Retiring Existing Plants

Since the *2005 IEPR*, the Energy Commission has pursued a policy of repowering or retiring aging power plants. In many instances, the OTC power plants targeted by SWRCB OTC policy were also identified in past *IEPR*s as aging. Closing or repowering such facilities to a

[8] Office of the Governor, October 17, 2006, http://gov.ca.gov/index.php?/executive-order/4484/.

new power plant using a cooling technology other than OTC resolves two concerns simultaneously. Some units may be cost-effectively refitted with alternative cooling systems.

The CPUC has authority to approve cost-based contracts for repowering facilities under Assembly Bill (AB) 1576 (Núñez, Chapter 374, Statutes of 2005), but would need to modify the procurement process to approve designated power plants for long-term contracts with IOUs. In May 2007, the CPUC held public workshops in the 2006 LTPP proceeding (R.06-02-013) to discuss AB 1576 implementation, but to date the CPUC has not used this authority.

Local Air Quality Constraints on New Power Plant Development

The July and November 2008 Superior Court decisions voiding the South Coast Air Quality Management District's (SCAQMD) Priority Reserve Rule and other related rules favorable to repowering of existing generation make unclear how some recently permitted projects, and any current and future power plant proposals in the Energy Commission licensing process, would be constructed in the SCAQMD air shed. SCAQMD's air quality permitting processes affect 7,500 megawatts (MW) of existing fossil capacity in the Los Angeles load capacity area of the ISO and the Los Angeles Department of Water and Power (LADWP) control area. Serious limitations will be placed upon power plant development in the South Coast Basin and nearby areas for some time. New facilities totaling 1,750 MW in capacity have power purchase agreements with Southern California Edison but cannot be licensed because they do not have access to the Priority Reserve. If this issue remains unresolved, these facilities will not be available to reduce the reliability threat from the proposed limitation on the use of OTC. This would significantly increase the challenge of siting new power plants needed to implement the OTC policy and steer solutions to rely more upon transmission system upgrades to tap remotely located generation.

Greenhouse Gas Mitigation

The energy industry's compliance with the detailed regulations that will implement the California Air Resources Board AB 32 *Climate Change Scoping Plan*[9] presumably leads to a lower electricity demand forecast, because additional energy efficiency measures will reduce demand and rooftop photovoltaic and other distributed generation will displace sales of electricity from the bulk power system to end users. A lower demand forecast would require fewer central station generating facilities within load pockets to satisfy reliability criteria. An AB 32 compliance plan presumably also strengthens the role of renewable power generation, which encourages more transmission development, lessening the need for energy from traditional fossil generation but simultaneously increasing the need for dispatchable facilities to provide reliability services. Recognizing these likely consequences from AB 32 implementation could lead to changes in both the mix and capabilities of fossil generation needed in load pockets, whether from repowered OTC plants or from new facilities that are electrically equivalent. Post-AB 32 goals announced by Governor Schwarzenegger in Executive Orders establishing a 33 percent Renewables Portfolio Standard and giving preference to renewable power generation would move even further in this direction than the legislative mandates of AB 32. CPUC staff recently issued a

[9] California Air Resources Board, *Climate Change Scoping Plan*, December 2008, http://www.arb.ca.gov/cc/scopingplan/document/scopingplandocument.htm.

report analyzing the costs, risks, and timing of meeting a 33 percent Renewables Portfolio Standard.[10]

Need for Further Analyses

The Energy Agencies are developing enhanced Local Capacity Requirement (LCR) analyses for the ISO Balancing Authority Area. Some areas lack excess capacity, and every megawatt of peak load increase or power plant retirement means replacement capacity must be developed. Some local capacity areas have surpluses, and some retirement could be tolerated. An Energy Commission staff paper illustrates how constraints on air credits in the Los Angeles Basin would lead to delays in OTC retirement.[11] Based on load and resource assumptions, these analyses will extend current LCR requirements out to 10 years and identify the amount of and various operating characteristics needed to plan for retirement of OTC capacity in some load pockets. The results of these analyses would be the key inputs into an Energy Agency OTC Power Plant Infrastructure Replacement Plan producing specific reliability designations, or dates that specific power plants could retire, as determined by the need for and expected timing of replacement infrastructure development. The plan would identify, for each region, the course of action required to eliminate reliance upon a power plant or unit using OTC. Most importantly, this plan would identify the complete set of infrastructure additions that, once operational, would allow OTC to be eliminated. Recognizing these problems, multiple bills addressing OTC mitigation and restoration of a functioning air quality credit mechanism for new power plants in the South Coast air basin have been proposed in the current session of the legislature.

Applying Existing Planning and Procurement Processes Regionally

To accomplish the retrofitting, repowering, or retirement of more than 30 percent of the power generating capacity in California, significant planning decisions, procurement authorization, and, ultimately, permitting of specific energy infrastructure projects will be necessary.[12] Of the five balancing authorities in California, all of the 19 generation plants with OTC units are encompassed within only two (the ISO and the Los Angeles Department of Water and Power [LADWP]). Of the 16 OTC plants in the ISO control area, 13 are located in transmission-constrained regions. Transmission constraints on the LADWP system also influence both the need for and options among refitting, repowering, and replacing the three OTC plants within the LADWP balancing authority. In sum, the need for OTC plants and options for retrofitting/refitting, repowering, or replacing them are more readily understood at this regional level. Thus, the Energy Agencies propose a process that does not have uniform schedules for all OTC facilities; rather, the regions whose problems are better

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[10] California Public Utilities Commission, *33% Renewables Portfolio Standard Implementation Analysis Preliminary Report*, June 2009.
http://www.cpuc.ca.gov/PUC/energy/Renewables/hot/33implementation.htm

[11] Energy Commission Draft Staff Paper, *Potential Impacts of the South Coast Air Quality Management District Air Credit Limitations and Once-Through Cooling Mitigation on Southern California's Electricity System*, February 2009, CEC-200-2009-002-SD.

[12] Retrofitting or refitting refers to the installation of a cooling system that complies with the proposed SWRCB policy. Repowering entails replacement of the existing boiler with advanced generation technology – improving thermal efficiency – and installing a compliant cooling technology. Retirement may, and often does, require replacement of the foregone capacity with generation at another location.

understood and where solutions are at hand should be required to reduce OTC harm more quickly than those regions where constraints on implementing solutions are more extensive.

Multi-Step Implementation Proposal

The implementation proposal submitted to the SWRCB encompasses three broad efforts. First, the agencies would conduct a series of studies examining the consequences of retiring individual or clusters of existing OTC power plants under a range of alternative futures and transmission system configurations to identify generation and transmission options for replacing each OTC facility. The Energy Commission would facilitate a review of the LADWP power plants, which are outside of the jurisdiction of the CPUC or the ISO. Second, key analytic results would be reviewed by the agencies to determine a broad strategy that is compatible with broad energy policy preferences. When results are available, they would be entered into the 2010 or 2012 CPUC LTPP proceeding for further analysis by the IOUs and consideration by the CPUC, with the objective of issuing procurement guidance to IOUs to acquire resources, and to the ISO transmission planning process to identify specific transmission projects. Third, necessary power plant additions would be approved by the CPUC and licensed by the Energy Commission, and necessary transmission projects would be licensed by the CPUC. Finally, staff of the Energy Agencies would monitor progress; the Energy Agencies would periodically inform the SWRCB regarding progress and, as appropriate, recommend changes.

Appendix A spells out this effort in greater detail. In particular, the analysis step is likely to have to be repeated periodically as new information is developed or in response to electricity system issues that could not be anticipated in earlier cycles. The SWRCB has acknowledged this possibility and built periodic review into its OTC mitigation policy.

Appendix A also identifies five key uncertainties that had not yet been resolved by the time this proposal had to be submitted to the SWRCB. These are:

- Availability of air pollution credits in SCAQMD for new power plants displacing OTC power plants, or repowers of existing OTC plants/units to eliminate OTC cooling technologies.
- Sequencing of bidding into utility request for offers (RFOs) versus permitting of a facility.
- The degree of reliance upon conventional generating facilities versus preferred technologies.
- Analyses of nuclear generating units at San Onofre and Diablo Canyon.
- Development of a comprehensive plan and preferential treatment of elements of the plan in licensing proceedings compared to proposed facilities not included within the plan.

Expected OTC Replacement Schedule

Appendix B provides a nominal schedule for creating replacement infrastructure for all OTC power plants. The table and its footnotes identify that construction of replacement infrastructure for some OTC plants is already underway or even operational. The replacement infrastructure for other power plants requires substantial analysis of the

options, decisions among the Energy Agencies, and then procurement, permitting, and construction lead times. The complexities of these analyses differ from one region to another, with the Los Angeles Basin expected to be the most problematic given severe limitations on the air credits needed for new generation development. For this reason, the schedule of dates for replacement infrastructure typically is further into the future for the existing OTC plants located in the Los Angeles Basin.

Next Steps

This paper presents the background necessary to understand the two components of the proposal by the Energy Agencies submitted to the SWRCB on May 19, 2009, (with minor updates to the OTC chart made on June 22, 2009). The two components are reproduced as Appendices A and B. The Energy Agencies are now compiling information about the evaluations that are relevant to the OTC power plants in the various regions, and preparing a workplan for those further analyses that are needed. The analytic work will be initiated in the third quarter of 2009 and continued through 2010 with results for various regions released as completed.

The Energy Commission and the CPUC will conduct a joint workshop as part of the Energy Commission's *2009 Integrated Energy Policy Report* proceeding and the CPUC's 2008 LTPP rulemaking on July 28, 2009, to solicit input from the generator community, environmental groups, agencies with environmental responsibilities, and the public. Technical staff of the three Energy Agencies will be available to answer questions about this proposal.

APPENDIX A: Specific Proposal for Planning and Procurement of Electricity Infrastructure

This narrative description of the Energy Agency proposal was submitted to the SWRCB on May 19, 2009.

Background

In March 2008, the State Water Resources Control Board (SWRCB) issued a preliminary once-through cooling (OTC) policy report for electric power plants establishing reliability as a condition for the design and implementation of an OTC mitigation policy. The proposed policy contemplates a phased compliance schedule that would allow sufficient time for the energy agencies and the transmission and generation industries to build new infrastructure or identify new resources in a timely manner, thus assuring adequate electrical system reliability. The following outline identifies the steps that the California Public Utilities Commission (CPUC), California Energy Commission, and California Independent System Operator Corporation (The California ISO) intend to undertake to support the SWRCB efforts. This proposal seeks to address the replacement or repowering of OTC power plants through an approach that (1) maintains reliability of the electric system; (2) meets California's environmental policy goals; and (3) achieves these goals through effective long-term planning for transmission, generation and demand resources. The proposal relies upon use of competitive procurement and forward contracting mechanisms to identify low cost solutions.

The SWRCB recognized that its implementation process could create transitional problems, so it created an Inter-agency Working Group (IWG) to review these implementation challenges and other aspects of the proposed policy.

In a December 15, 2008 paper, the Energy Commission and the CPUC in conjunction with the California ISO proposed an alternative approach to the fixed time schedule to reduce OTC in existing coastal power plants, while assuring reliability of the electrical grid.[13] That paper broadly sketched out changes to planning, procurement and project permitting processes to encourage repowering or new infrastructure so that retirement of OTC facilities can occur without threatening reliability. In subsequent meetings and discussions, the SWRCB staff and other members of the IWG communicated broad support and requested refinements that defined milestones and accelerated compliance timelines wherever possible. In particular, the SWRCB staff requested consideration of applying the general approach on a regional, rather than statewide basis.[14] This paper modifies the original proposal, focusing on regional analysis and implementation.

Proposal for Planning and Procurement of Electricity Infrastructure

To accomplish the retrofitting, repowering or retirement of more than 30 percent of the power generating capacity in California, significant planning decisions, procurement authorization, and ultimately permitting of specific energy infrastructure projects will be necessary.[15] Of the five balancing authorities in California, only two (the California ISO and the Los Angeles Department of Water and Power (LADWP)) are needed to encompass all of the 19 generation plants with OTC units. Of the 16 OTC plants in the California ISO, 13 are located in transmission constrained regions. Transmission constraints on the LADWP system also influence both the need for and options among refitting, repowering and replacing the three OTC plants within the LADWP balancing authority. In sum, the need for OTC plants and options for repowering or replacing them are more readily understood at this regional level. Thus, the Energy Agencies propose a process that does not have uniform schedules for all OTC facilities; rather, the regions whose problems are better understood and where solutions are at hand should be required to reduce OTC harm more quickly than those regions where constraints on implementing solutions are more extensive.

Listed below are the key steps of this approach that will result in an OTC Power Plant Replacement Infrastructure Plan (Plan) and the permitting and procurement steps that will implement it.

1. Establish regional basis for analyses and identify existing transmission and system operations studies relevant to establishing constraints on the retirement of specific OTC plants/units:

[13] For purposes of expressing collective recommendations, this paper will refer to these three organizations as the Energy Agencies.

[14] While there are several alternative regional definitions in use among agencies for various specific purposes, for this purpose the local capacity areas used as the basis for resource adequacy requirements are the starting point. The relevant regions that are local capacity areas are San Diego, Los Angeles Basin, Ventura/Big Creek, Greater Bay Area, and Humboldt. To these the Central Coast has been added to encompass all once-through cooling facilities.

[15] Retrofitting refers to the installation of a cooling system that complies with the proposed SWRCB policy. Repowering entails replacement of the existing boiler with advanced generation technology – improving thermal efficiency – and installing a compliant cooling technology. Retirement may, and often does, require replacement of the foregone capacity with generation at another location.

a. Review definition of the regions to understand local reliability issues and assign OTC facilities to each region.

b. Review existing Local Capacity Requirement (LCR) studies of those regions containing OTC plants. Review specific new generation and transmission project proposals and licensing decisions by regulatory agencies for impacts on future LCR values.

c. Review other regional and system studies to determine the operating characteristics of the current generating fleet, how the amount of needed characteristics could change going forward under preferred resource (energy efficiency, renewable, and demand response) and transmission to support those resources, and the implications of OTC plant/unit retirements for the necessary characteristics of replacement facilities.[16]

d. Compile results of Steps 1.a through 1.c and identify, to the extent possible, a realistic development schedule for needed replacement infrastructure to establish the dates by which existing OTC power plants/units will no longer draw in and discharge ocean water above levels allowed by the SWRCB policy. For those plants/units requiring further analyses, Step 2 is needed.

2. Complete an enhanced Local Capacity Requirement evaluation, or other relevant assessment, for each region that contains OTC power plants, and update amounts of necessary operating characteristics as needed.[17]

   a. The Energy Commission and the CPUC will develop scenarios of annual load projections for each region, any projected generation or resource additions or non-OTC retirements for each region, and any transmission project upgrades or additions+ in each year from 2012 up to and including 2019 reflecting alternative ways in which preferred resource development policies could be implemented. The Energy Commission and the CPUC, in consultation with the California ISO, will review these scenario results and select the assumptions to be used for the following enhanced LCR evaluation.

   b. The California ISO will prepare an enhanced LCR evaluation for each year 2012 to 2019 based on those projections and available The California ISO –performed transmission studies.[18] These enhanced LCR evaluations will identify expected

[16] As an illustration, the California Independent System Operator study of the implications of 20 percent penetration of renewable generation, November 2007.

[17] Enhanced implies conducting an local capacity requirement-style analysis of capacity needs, but doing so 10 years forward and identifying the impacts of specific once-through cooling retirements or transmission developments on the area's local capacity requirement projections.

[18] Three of the facilities that use once-through cooling are operated by the Los Angeles Department of Water and Power. As a publicly-owned utility, Los Angeles Department of Water and Power makes investment decisions in the interests of its customers and does not come under the jurisdiction of the California Public Utilities Commission. As a separate control area, it is responsible for its own reliability studies and is not part of the California Independent System Operator's balancing authority area. The Energy Agencies believe the elimination of once-through cooling at these facilities will require the development of new infrastructure. Therefore, it is possible that the Los Angeles Department of Water and Power will need to compete with generator owners to secure Emission Reduction Credits (ERCs) in the air shed under SCAQMD jurisdiction. The Energy Commission hopes to facilitate the Los Angeles Department of Water and Power's cooperation in the Plan; however, absent such cooperation the Energy Agencies will proceed to develop the Plan as it pertains

generation capacity needed within the LCR Areas and OTC regions for each year for given transmission system configurations.

c. The Energy Agencies will then compare projected LCR needs with total expected generation less the capacity represented by OTC power plants/units in each LCR Area to identify the necessary capacity to replace OTC power plants/units in each region. The sequence for removing OTC plants/units through time will be based on effectiveness in mitigating various system contingencies, plant/unit-specific characteristics, and other operational needs in maintaining reliability.

d. The California ISO, in consultation with the CPUC and Energy Commission, will identify the specific characteristics of that capacity (e.g. ramping ability, minimum load constraints, regulation requirements, etc.) needed to meet systems needs once the OTC plants are retired.

e. The Energy Agencies will jointly identify what additional system capacity is needed in connection with replacing each OTC power plant/unit. While replacement capacity needed in an LCR area may be less than that provided by OTC plants/units, system-wide capacity needs may require additional power plant development elsewhere in the California ISO balancing authority area.

f. The California ISO envisions performing enhanced LCR studies each year that can support efforts to refine capacity requirements set forth in the Plan. Any updates to the Plan would occur in consultation and agreement by the Energy Agencies and would be made available to the IWG (or the Statewide Task Force) which would be formalized upon approval of the OTC Policy and the SWRCB. Any Plan updates may also reflect transmission and/or generation infrastructure constructed and completed).

g. For those OTC power plants that are not located in LCR Areas, the Plan would consider the need for capacity located within the California ISO balancing authority area (or LADWP balancing authority area) to serve system need.

3. The Energy Agencies will review the results of Steps 1 and 2 and, for each region, describe the course of action required to eliminate reliance upon a power plant/unit using OTC as a cooling technology. A specific schedule for each existing OTC plant/unit would be developed that identifies the latest date it would operate using OTC technology. After such date, the plant/unit will lose its reliability designation. New generating capacity would satisfy the characteristics identified in Step 2d. Collectively this set of decisions about OTC elimination and replacement infrastructure would be referred to as the "Plan." This initial version of the Plan would be updated periodically as a result of actual experience with generation and transmission project development timelines, or other material changes in assumptions affecting infrastructure needs.

4. The SWRCB and its regional boards would use the Plan as the basis for establishing an OTC mitigation policy and for issuing NPDES permits for each plant/unit based on its reliability designation. The projected date of operation of the specific replacement

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to once-through cooling power plants within the California Independent System Operator's balancing authority area.

infrastructure needed to assure reliable operation of the grid without the facility using OTC technology should be the basis for the expiration date for that plant/unit's permit.

5. The Energy Commission would review the Plan to determine how its power plant licensing process may be affected, and to facilitate air quality management district (AQMD) review by:

    a. Providing an estimate to each local AQMD of the magnitude of air quality credits likely to be required for licensing the new or repowered generating facilities included within the Plan.

    b. Obtaining AQMD concurrence that the volumes of credits used in the studies were credible, or working with an AQMD to devise valid sources of credits and estimates of their costs.

    c. Communicating any significant change in assumptions about air credit availability and costs back to other entities involved in studies and procurement activities.

6. The CPUC would authorize IOU procurement mechanisms to require the IOUs to conduct a large set of targeted RFOs following the 2010 and subsequent long-term procurement proceedings. These targeted RFOs would focus on acquiring needed replacement capacity in appropriate locations with operational characteristics that would allow existing OTC plants/units to retrofit, repower or retire consistent with the Plan.

7. The California ISO will consider SWRCB directives and schedules limiting or canceling water permits required to operate OTC plant/units in the 2011 and subsequent annual Transmission Planning Process. The California ISO will conduct an analysis as part of its Transmission Planning Process reflecting projected OTC plant/unit retirements as a result of SWRCB permitting directives and schedules, which shall be incorporated into the California ISO's annual Transmission Plan that serves as a basis for further economic or reliability based transmission upgrades or additions.

8. Once each targeted RFO was complete, generator retrofits, repowers or new generating facility development assumptions would be updated in the Plan, to the extent the results from the RFOs differ from the previous edition of the Plan. Any updates to the Plan would result in the SWRCB, or its regional boards, modifying permits for various power plants/units depending upon their role in carrying out the Plan.[19]

9. If there are changes (e.g. delays in project development or major modifications to forecast assumptions) in the infrastructure development assumptions (e.g. transmission upgrades or additions are not on schedule, or new generating capacity is not operational) upon which the Plan is based, the Energy Agencies will perform appropriate analysis and inform the SWRCB, or its regional boards, of the new time period that a specific OTC plant/unit is required for system reliability.

[19] For some once-through cooling power plants, this would mean issuing a time-limited permit allowing the plant to operate without change until a specific date at which time it would be shut down and no permit extensions allowed. For other power plants with longer timelines for continued operations, some modification of water intake structures and water usage patterns would be required, but still the plant would not be required to undergo major change because it is scheduled to be retired by a specific date. For still other plants, shifts to closed cycle cooling would be required consistent with long-term continued usage of the power plant.

10. The Energy Agencies will periodically update the Plan to reflect changing system conditions and transmission and generation developments to ensure that OTC mitigation is timely while preserving system reliability. It is possible that transmission upgrades and additions associated with California's Renewable Energy Transmission Initiative may address some system reliability concerns raised by OTC power plant retirements. The Energy Agencies intend to review these developments and incorporate them into the Plan for OTC power plant retirements.
11. The SWRCB would periodically review the Plan and, for each unit with an official reliability designation, modify the OTC permit expiration date to match the reliability designation of the unit. For units without such a designation, the SWRCB would establish compliance requirements and a schedule that transforms these into a water use permit.

Unresolved Issues for this Proposal

Some elements of this proposed approach remain unresolved. These include the following elements that are discussed below:

- Air pollution credits in South Coast Air Quality Management District (SCAQMD) for new power plants displacing OTC power plants, or repowers of existing OTC plants/units to eliminate OTC cooling technologies,
- Sequencing of bidding into utility RFOs versus permitting of a facility,
- Reliance upon conventional generating facilities or preferred technologies,
- Analyses of nuclear generating units at San Onofre and Diablo Canyon, and
- Development of a comprehensive Plan and preferential treatment of elements of the Plan in licensing proceedings compared to proposed facilities not included within the Plan.

Air Pollutant Credits in SCAQMD

Acquiring sufficient air credits through a revitalized Priority Reserve or some other mechanism is necessary for new or repowered generators in the SCAQMD. Only limited OTC retirement can happen without serious reliability consequences unless new or repowered plants can be constructed in the SCAQMD's jurisdiction.[20] The July and November 2008 court decisions in the challenge of the SCAQMD's "priority reserve" requirements has complicated the situation, making it extremely difficult for new power plants to be sited in the Los Angeles Basin. This challenge will make it difficult for most aging power plants to be closed in the Los Angeles coastal region, until new generation or transmission can be constructed. Tradeoffs exist between the need to protect water quality, satisfy air quality requirements and ensure electrical system reliability, while moving toward greater levels of renewable generation as called for by Assembly Bill 32 (AB 32) and the Governor's recent Executive Order calling for increased levels of renewable generation.

[20] Energy Commission Draft Staff Paper, *Potential Impacts of the South Coast Air Quality Management District Air Credit Limitations and Once-Through Cooling Mitigation on Southern California's Electricity System*, February 2009, CEC-200-2009-002-SD.

Sequence of Bidding and Permitting of Proposed Facilities. The sequence of Energy Commission permitting versus generator bidding into an IOU RFO raises several questions:

- Whether power plants would be required to have an Energy Commission permit as a condition of bidding into an IOU RFO.
- Whether power plants would be required to have entered the Energy Commission permitting process and have satisfied specific milestones as a condition of bidding into an IOU RFO.
- Whether winners of an IOU RFO would receive expedited treatment from the Energy Commission in the permitting process compared to other applicants.
- Whether advance guidance can steer proposed power plants into locations likely to be permitted by the Energy Commission.

Conventional versus Preferred Technologies to Replace OTC Facilities

A straightforward solution to the OTC problem is to repower existing OTC facilities by installing a new prime mover that does not use ocean water for cooling.[21] This approach makes use of the existing electrical switchyard, perhaps eliminates consideration of new transmission lines that would allow retirement of some facilities without replacement on site, and essentially preserves the existing electrical system as much as possible. However, this approach would likely have considerable problems in SCAQMD in finding needed air credits and it would fail to address the policy preferences established by the Energy Agencies through the Energy Action Plan process or the need to reduce reliance upon fossil power plants to achieve AB 32 GHG emission reduction goals. Assessing the feasibility of major changes to the system through increased reliance upon renewable, resources, upon rooftop solar PV and other distributed generation technologies, enhanced energy efficiency program impacts reducing load, etc. is necessarily more complex and time consuming than simply endorsing a repowering strategy with little thought to the very long term consequences.

Analyses of Nuclear Generating Units

The four nuclear generating units located at San Onofre and Diablo Canyon represent unique elements of California's electrical generating system and both its positive and negative dimensions. From the perspective of the SWRCB, these four units are the largest source of biologic harm. From traditional air quality criteria pollutant or GHG perspectives, nuclear plants are viewed as highly beneficial, and OTC mitigation requirements that might cause them to shut down would exacerbate overall problems to be overcome. The nuclear units supply a significant percentage of the energy used by California end-users, operating as baseload units with very high capacity factors. Refitting these plants with alternative cooling systems or replacing their capacity and energy require special studies. Unfortunately, studies of the generation versus transmission tradeoffs of the aging fossil fleet may have different results depending on whether the nuclear units are assumed to operate as they do today for an indefinite future, or whether they are retired when their current Nuclear Regulatory Commission permits expire in 2021-2023.

[21] A prime mover is the basic source of heat energy for running the generating turbine, e.g. a steam boiler, a combustion turbine, a nuclear reactor.

Creation of a Comprehensive Plan to Enable Preferential Treatment for Some Projects

Creating a formal Plan and adopting that Plan through a CEQA-compliance process could have value by subsequently providing preferential treatment (reduced consideration of alternatives, accelerated time schedule, etc.) in the applicable licensing processes for individual projects or facilities included within the Plan. Multiple agencies now have licensing authority over various infrastructure projects, although the Energy Commission licenses the majority of the likely power plant additions and the CPUC licenses the majority of the expected transmission line upgrades. The individual CEQA reviews now implemented for new power plants and transmission lines might be conducted en masse for infrastructure additions part of the Plan. Since the Plan represents a comprehensive, multi-facility replacement of multiple existing facilities, it may be appropriate to revise Energy Agencies' review processes to consider multiple facilities as a package, and to accelerate this consideration. This will be among the alternatives that Energy Agencies will consider when fully developing this alternative approach to OTC mitigation.

Next Steps

This present document represents an attempt to incorporate the feedback to date and internal discussions among the Energy Agencies. The Energy Agencies are now compiling information about the evaluations that are relevant to the OTC power plants in the various regions, and preparing a workplan for those further analyses that are needed. The analytic work will be conducted over the second quarter of 2009.

The Energy Commission will conduct a joint workshop as part of the Energy Commission's 2009 Integrated Energy Policy Report proceeding on May 11, 2009 to solicit input from the generator community, environmental groups, agencies with environmental responsibilities, and the public. The Energy Agencies will participate in this workshop.

Following the workshop, technical staff of the Energy Agencies will determine whether and how to modify this proposal, and inform the SWRCB staff of any such suggested changes.

APPENDIX B: Draft Infrastructure Replacement Milestones and Compliance Dates for Existing Power Plants in California Using Once-Through Cooling

The following tabular chart shows the milestones for each OTC power plant using the key steps of the joint Energy Agency implementation proposal was submitted to the SWRCB on May 19, 2009, and updated on June 22, 2009.

Draft Infrastructure Replacement Milestones and Compliance Dates for Existing Power Plants in California Using Once-Through Cooling

Region (Balancing Authority)	Existing Facility Name	Infrastructure Replacement Milestones[i]							
		CAISO Enhanced LCR Study[ii]	CAISO-CPUC-CEC Infrastructure Replacement Plan[iii]	CPUC Procurement[iv]		CAISO Annual Transmission Plan[8]	CPUC Transmission Permitting[7]	Known Replacement Infrastructure Operational[9]	Unspecified Replacement Infrastructure Operational[9]
				LTPP Approval[v]	Gen Project Approval[vi]				
Humboldt	Humboldt Bay Power Plant[10]	Not required[19]	Pre-Plan[20]	Complete	Complete	Gen solution	N/A	Q3 2010	N/A
San Diego	South Bay Power Plant (partial capacity)[11]	Not required[19]	Pre-Plan[20]	Complete	Complete	Gen solution	N/A	Q4 2009	N/A
	South Bay Power Plant (remaining units)[12]	Not required[19]	Pre-Plan[20]	Trans solution	Trans solution	Complete	Complete	Q3 2012	N/A
	Encina Power Plant	Q4 2009	Q1 2010	2011	2013	2011	2015	N/A	2017
Bay Area	Potrero Power Plant (Unit 3)[13]	Not required[19]	Pre-Plan[20]	Trans solution	Trans solution	Complete	Complete	Q1 2010	N/A
	Contra Costa Power Plant (1 of 2 units)[14]	Not required[19]	Pre-Plan[20]	Complete	Complete	Gen solution	N/A	Q2 2009[21]	N/A
	Contra Costa Power Plant (second unit)	Q4 2009	Q1 2010	2011	2013	2011	2015	N/A	2017
	Pittsburg Power Plant								
Central Coast	Moss Landing Power Plant[15,16]	Q4 2009	Q1 2010	2011	2013	N/A	N/A	N/A	2017
	Morro Bay Power Plant[16]	Not required	Pre-Plan	complete	complete	N/A	N/A	Q1 2009[22]	N/A
Ventura/Big Creek[17]	Mandalay Generating Station	Q4 2010	Q2 2011	2013	2015	2012	2016	N/A	2020
	Ormond Beach Generating Station								
Los Angeles Basin[17] (CAISO)	El Segundo Generating Station	Q4 2010	Q2 2011	2013	2015	2012	2016	N/A	2020
	Huntington Beach Generating Station								
	Redondo Generating Station								
	Alamitos Generating Station								
Los Angeles Basin[17] (LADWP)	Haynes Generating Station[18]	Not under The California ISO balancing authority or the CPUC jurisdiction. The Energy Commission is conferring with LADWP to understand in-basin capacity requirements and processes for accomplishing OTC mitigation.							
	Harbor Generating Station[15,18]								
	Scattergood Generating Station[18]								
Nuclear Plants	Diablo Canyon Power Plant								
	San Onofre Nuclear Generating Station								

[i] These infrastructure milestones assume no litigation about facility permits following appropriate agency approvals.

[ii] California Independent System Operator Corporation (The California ISO) would conduct an enhanced Local Capacity Requirement (LCR) study identifying the impacts of specific OTC retirements or transmission developments on the local area's LCR projections 10 years out. The California ISO will use assumptions about load and generation developed jointly with the California Energy Commission (Energy Commission) and the California Public Utilities Commission (CPUC).

[iii] The Infrastructure Replacement Plan developed jointly and updated by the California ISO, Energy Commission, and the CPUC would identify the complete set of infrastructure needed to make OTC plants/units redundant for grid reliability. It would advise the SWRCB about the reliability designations of specific power plants.

[iv] CPUC would modify its Long-Term Procurement Plan (LTPP) proceeding and procurement processes to require the investor-owned utilities (IOUs) to assess replacement infrastructure needs and conduct targeted request for offers (RFOs) to acquire replacement or repowered generation capacity. CPUC also has authority to approve cost-based contacts under AB 1576.

[v] CPUC has authority to order the IOUs to procure new (or repowered) fossil generation for system reliability in the LTPP proceeding. LTPP proceedings are conducted on a biennial cycle and plans are normally approved in odd-numbered years.

[6] Once authorized to procure by a CPUC LTPP decision, it takes 18 months for the IOUs to issue an RFO for generation (new or repowered), sign contracts and submit applications to the CPUC for approval. Approval by the CPUC takes 9 months. If the contract involves a facility already licensed by the Energy Commission, then financing and construction can begin. Generation permitting for thermal technologies >50 MW in capacity is under Energy Commission authority, and may take place before, after or during the CPUC contract approval process. The Warren-Alquist Act authorizes the Energy Commission to license certain categories of power plants and related structures. The Energy Commission's siting process has been determined to be a certified regulatory program under the California Environmental Quality Act (CEQA) and the functional equivalent of preparing environmental impact reports (EIRs). The Energy Commission is the lead agency and consults with other relevant agencies. The standard licensing process is normally conducted in 12 months, but streamlining of the permitting process may be an option so multiple facilities can be considered as a package (planning level EIR). Reviews should be somewhat faster because impacts to water resources are by definition minimized; impacts to the grid reliability are already considered and mitigated; and conformity to state laws and regulation has been considered under the Plan.

[7] Transmission permitting is under CPUC authority. Proposed transmission facilities to meet needs identified in the California ISO Annual Transmission Plan to replace OTC plants/units would be brought to the CPUC for approval.

[8] Transmission solutions (upgrade and/or new addition) that would make specified OTC system redundant would be analyzed in the California ISO Annual Transmission Plan. The California ISO will consider SWRCB directives and schedules limiting or canceling water permits required to operate OTC plants/units in the 2011 and subsequent annual Transmission Planning Process (TPP). The California ISO will conduct analysis as part of its TPP reflecting projected OTC plant/unit retirements as a result of SWRCB directives and schedules, which shall be incorporated in to the California ISO's annual Transmission Plan that serves as the basis for further transmission upgrades or additions.

[9] These compliance dates may change subject to the California ISO-Energy Commission-CPUC Infrastructure Replacement Plan produced in Q1 2010 and updated periodically. All dates assume a generation solution that requires an Energy Commission permit. If a permit has been acquired prior to CPUC contract approval, then an earlier on line date is possible. If transmission solutions are selected, then longer time lines would be expected.

[10] Humboldt Repower generation project is approved by the CPUC and expected operational by Q3 2010. This new infrastructure will eliminate OTC at the Humboldt Power Plant.

[11] Otay Mesa Power Plant is in construction and expected operational by Q4 2009. This new infrastructure is expected to displace a portion of the need for the capacity of the South Bay Power Plant.

[12] Sunrise Powerlink transmission project is approved by the CPUC and expected operational in 2012. This new infrastructure is expected to displace the need for remaining South Bay Power Plant capacity.

[13] TransBay Cable transmission project is expected operational by Q1 2010. This new infrastructure is expected to replace the need for Potrero Unit 3.

[14] The new Gateway Generating Station became operational in January 2009. This new infrastructure is expected to replace the need for one unit at the Contra Costa Power Plant.

[15] Units that have recently been repowered will be addressed separately.

[16] Not needed for local network reliability, according to a November 26, 2008 preliminary The California ISO Study, although may be needed for system resource adequacy requirements.

[17] Due to siting/land use and air quality constraints, it is likely that a combination of new generation and transmission infrastructure will be necessary to replace the need for OTC plants/units in the Ventura/Big Creek and L.A. Basin regions.

[18] Owned and operated by the Los Angeles Department of Water and Power, its own balancing authority (not controlled by The California ISO).

[19] No further study is required. Existing studies are sufficient to determine reliability designation of specified OTC facilities.

[20] Replacement infrastructure sufficient to determine reliability designation of specified OTC facility was identified prior to development of the Infrastructure Replacement Plan.

[21] Contra Costa Power Plant is under contract to PG&E until 2011.

[22] Morro Bay units 3-4 have contracts with SCE through Q4 2011.

Renewable Energy Transmission Planning Process (RETPP)

Draft Final Proposal

January 8, 2010 – Two minor corrections (pages 2 and 11) have been made to this draft final proposal. Corrected text is highlighted in yellow.

January 6, 2010

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Renewable Energy Transmission Planning Process

Draft Final Proposal

I. EXECUTIVE SUMMARY

The central objective of the ISO's proposed renewable energy transmission planning process (RETPP) is to enhance the existing transmission planning and generation interconnection processes to promote the development of infrastructure needed to achieve the state's 33 percent renewable portfolio standard (RPS) by 2020. To this end, the proposed RETPP will: (1) develop a statewide conceptual transmission plan through collaboration among all transmission providers and owners in California; (2) finalize that plan for the ISO balancing authority area with sufficient detail both to establish needs and to elicit specific proposals to build the needed transmission; (3) establish, in the ISO tariff, access to renewable supply resources as a formal criterion for assessing need for specific transmission upgrades and approving their cost recovery through regulated rates; (4) enable transmission infrastructure development to move forward expeditiously and efficiently to support the state's environmental goals; (5) coordinate RETPP activities and milestones with key ongoing activities of the ISO's existing Order 890 compliant transmission planning process and the generation interconnection process in a practical way; and (6) provide opportunities for stakeholder participation and input to the process.

The draft final proposal retains the three-phase approach described in the prior straw proposals. In Phase 1 the ISO and other members of the California Transmission Planning Group (CTPG), building on the work of the Renewable Energy Transmission Initiative (RETI) and supported by a substantial effort with state agencies, RETI and other stakeholders, will produce by May 2010 a statewide conceptual transmission plan. In Phase 2 the ISO will accept further input from stakeholders on the Phase 1 plan and will refine the portion of the Phase 1 plan that applies to its balancing authority area to arrive at a final plan to present to its Board of Governors in December 2010 for approval of need for the Phase 2 plan elements. In Phase 3 the ISO will receive proposals to build specific elements of the Phase 2 plan and will present these to its Board for final or conditional approval starting in March 2011.

In addition to providing further details on the three RETPP phases, this draft final proposal improves upon the previous straw proposals by:

- More fully integrating the ISO's existing Order 890 transmission planning process (TPP) and large generation interconnection process (LGIP) into the RETPP structure; and

- Clarifying the role of the right of first refusal to build and own elements of the final December 2010 transmission plan, and the potential roles for independent transmission companies (ITCs) under the RETPP.

The ISO expects that certain aspects of the proposed RETPP and the related changes to the existing TPP and LGIP needed to enhance their coordination with the RETPP will likely require supporting tariff changes. The ISO will present this proposal to its Board of Governors at the February 2010 meeting and given Board approval will file the tariff changes with the Federal Energy Regulatory Commission shortly thereafter.

This section begins by providing the overarching rationale and design of the new RETPP and the accompanying changes needed to the current TPP and the LGIP. The section then provides a high-level overview of the three phases of the draft final RETPP proposal; subsequent sections fill in additional details of the proposal.

1. Design of the RETPP Planning Framework

The primary driver of new transmission infrastructure over the coming decade will be the need to integrate new renewable generation resources into the transmission grid and support the delivery of energy from these resources to end-use customers to achieve the state's target of 33 percent renewable energy on an annual basis by 2020. For this reason the new RETPP is best viewed as an extension or enhancement of the generation interconnection process. In other words, the objectives of the RETPP are essentially the same as those of the interconnection process, namely, to reliably interconnect new resources, to mitigate network impacts downstream from each new interconnection, and in most cases to ensure that energy from such resources is fully deliverable to end-users that rely on the ISO grid.

The existing interconnection process must be enhanced, however, to address the expected volume and geographic distribution of new generation resources that will be coming on line between now and 2020, and to do so from a perspective that reflects the statewide applicability of the renewable portfolio standard. Moreover, given the central role of new renewable generation as the driver of new transmission infrastructure, it is essential to integrate as far as practical all planning functions into a single coordinated process. This will make efficient use of ISO and stakeholder resources and ensure that the resulting transmission plans are truly comprehensive and not fragmented into separate reliability, economic and generation interconnection tracks with overlapping implications for transmission to meet RPS goals. Thus the draft final RETPP proposal offers a comprehensive annual planning framework designed to meet reliability, economic and environmental needs. As such the proposed RETPP will entail some major changes to how the ISO conducts transmission planning. The core changes are described below.

Statewide assessment of transmission needs. As evidenced in the RETI process, a statewide renewable transmission plan, along with mechanisms for regional and sub-

regional coordination, are needed to enable efficient development and delivery of state and regional renewable energy resources. Under the new RETPP structure the annual transmission planning process will begin with a process for initially creating and then updating the comprehensive statewide transmission plan, as reflected in Phase 1 of this proposal.

Access to renewable resources as a new criterion for determining need for transmission upgrades. The ISO's prior straw proposals have discussed the need to adopt a renewable energy access criterion for approving transmission upgrades. The current TPP has reliability and economic criteria for approving the need for an upgrade, whereas the LGIP provides for reliability and deliverability network upgrades to accommodate new generation resources that satisfy the requirements of the ISO interconnection queue. These processes do not have a basis to approve transmission that will be needed for access to anticipated new renewable resources beyond the current queue unless such transmission can be justified based on the existing reliability or economic criteria. The RETPP tariff changes will address this gap.

Effective integration and consolidation of ISO planning processes. In the initial September 15 issue paper the ISO sought to address RPS needs simply by modifying the current TPP to incorporate a renewable access planning criterion. The ISO and stakeholders quickly recognized, however, that the current TPP and the companion LGIP were not initially designed for the comprehensive planning approach required to meet state policy goals. In later straw proposals the ISO developed a separate renewable energy track that would parallel the current TPP and LGIP with certain linkages between the tracks at designated milestones. In response the stakeholders pointed out, and the ISO agreed, that the three-track process would be too fragmented and would not achieve the ISO's stated objective to do comprehensive planning.

As a key advance over prior proposals the ISO now proposes to establish a new, substantially consolidated planning structure under the RETPP, rather than simply trying to build a new criterion and new coordination steps into the existing TPP and LGIP. Although the RETPP will require significant changes to existing processes and creation of new ones, the ISO believes that the RETPP structure proposed now represents a logically integrated planning process that can achieve the needed statewide coordination while fulfilling the requirements of the existing TPP and LGIP.

Shift from a project proposal approach to a comprehensive plan approach. The new RETPP proposal departs from today's TPP whereby the ISO provides detailed reliability and economic (congestion) study results and then parties respond by submitting project proposals into a request window. Instead, under the RETPP the ISO will provide a comprehensive plan that specifies the actual transmission elements needed, to which parties can respond by submitting proposals to build specific elements of that plan. The limited exceptions to this new paradigm are the ability of parties to submit merchant transmission projects (i.e., projects not seeking cost recovery through

the transmission access charge) in Phase 2 of the RETPP, and the treatment of the existing reliability and economic TPP project categories discussed in the next paragraph.

Treatment of the existing reliability and economic TPP categories. Under the current TPP, request window proposals that address reliability needs are the responsibility of the incumbent PTOs through an obligation to build as specified in the ISO tariff. The RETPP will retain and will integrate the current TPP approach for developing reliability projects, which will become baseline assumptions for renewable transmission planning. In contrast, other projects submitted to the current TPP request window are evaluated by the ISO to determine whether there is sufficient economic basis to justify funding them through the ISO's transmission access charge. If the ISO justifies such a project based on economics, the PTO or independent entity that proposed the project would have the right to build and own the project. Under the proposed RETPP, however, where statewide renewable energy goals require comprehensive planning, it is no longer meaningful, appropriate or even feasible to evaluate economic request window projects using the methodology of the current TPP. Rather, the economic benefits of any particular new transmission element must be assessed relative to a comprehensive plan that reflects the transmission needs of new renewable generation resources. Under the RETPP economic studies of the final Phase 2 plan will provide the appropriate basis against which the ISO can evaluate other projects that may offer economic benefits and are not already reflected in elements of the Phase 2 plan. For the 2010 cycle of the RETPP the ISO intends to apply this approach to evaluate economic projects that were submitted in the 2008-9 TPP request windows. For subsequent cycles the ISO would accept economic project proposals from both PTOs and non-PTOs during the Phase 3 period following Board approval of the Phase 2 plan.

Rights and obligations for renewable transmission project development. The ISO proposes that PTOs with service territories will receive rights of first refusal to build and own transmission projects corresponding to the transmission elements contained in the final Phase 2 plan approved by the ISO Board. For elements that are partially in the territories of more than one PTO, each relevant PTO will have the right to build and own the portion of the element that is within its territory or to negotiate an alternative joint arrangement. If any PTO fails to exercise all of its rights of first refusal by submitting proposals to build within the first 90 days of Phase 3, the ISO will accept proposals from other parties to build and own the affected plan elements. For plan elements for which no acceptable proposal was submitted by either the relevant PTO or another party, the ISO may impose an obligation to build on the relevant PTO. The ISO believes that the right of first refusal and obligation to build as structured here are consistent with such rights and obligations in the ISO tariff today as they apply to generation interconnection

related projects, reliability projects identified through the TPP, and economic projects that are identified by the ISO.[1]

Opportunities for independent transmission companies under RETPP. Under the proposed RETPP the ISO identifies at least four types of opportunities for ITCs to build and own transmission:

- ITCs may submit merchant transmission projects for consideration in Phase 2, and can build and own such projects subject to the same requirements and criteria that apply today.
- ITCs may submit potential economic project proposals for consideration in Phase 3 in response to the ISO's economic study of the final Phase 2 plan. (For the 2010 cycle of the RETPP the ISO will consider economic projects submitted in the 2008-9 TPP request windows at this stage of the process.)
- ITCs may propose to build elements of the final Phase 2 plan in instances where the relevant PTO has not exercised its right of first refusal within the first 90 days of Phase 3.
- ITCs may develop collaborative projects with one or more of the PTOs, or may submit a proposal to the CPUC in competition with a PTO proposal if the ITC believes it can offer a superior or more cost-effective project.

Order 890 compliance. The ISO will ensure that the key decision-making phases of the RETPP for the ISO balancing authority area (i.e., Phases 2 and 3) will, like the current TPP, be Order 890 compliant.

2. RETPP Phase 1

Phase 1, already in progress, is a collaborative effort among the various transmission providers and owners in California under the structure of the CTPG. The goal of Phase 1 is to complete a statewide 33 percent RPS conceptual transmission plan by the end of May 2010, with a draft version released for comment in March 2010.[2] Some early concerns by non-participants about the transparency and openness of the CTPG planning process have been partially resolved through publication of information on the new CTPG web site[3] and the start of a stakeholder process to elicit public review and

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[1] The parties involved in the generation interconnection process are the ISO, the PTO and the Interconnection customer. (See ISO Tariff Appendix U, Section 1.2.2; Appendix V, Section 1.2.2.) PTOs have the obligation to build reliability projects as set forth in ISO Tariff Section 24.1.2, and PTOs have the right of first refusal to construct and own ISO-proposed and approved economic projects according to ISO Tariff Section 24.1.1(c).

[2] The draft and final conceptual plans would identify specific facilities to be added to the transmission system or upgraded, including new lines at specific voltage levels between designated points of interconnection, substation upgrades, etc., but would not include all the engineering details required to develop accurate cost estimates for proposals to build the facilities.

[3] CTPG materials are available at www.ctpg.us.

input. This aspect of CTPG is still undergoing further development with participation of the ISO, other CTPG members and State agencies, and the ISO expects to provide addition information about the CTPG process for developing the final Phase 1 plan in the near future.

As described more fully in the next section, the CTPG has studies in progress that will result in an initial public report to be issued in early January in draft form and by mid February in final form. While the March and May 2010 conceptual plans will build upon these early CTPG results, the ISO is aware of the need to perform further studies based on different planning assumptions and scenarios in order to produce the May 2010 plan. The ISO is working with the CTPG members to develop a plan for conducting these further studies. In the near future the ISO will hold substantive discussions with stakeholders regarding the specifics of the additional studies to be performed and the proposed CTPG approach for developing the May 2010 statewide conceptual plan.

An important qualification of the CTPG process and the May 2010 conceptual plan is that they will not make decisions or otherwise determine the outcomes of any decisions regarding approval of specific projects or allocation of project costs. Such decisions will be made by the relevant CTPG member entities in accordance with their own processes for such decisions. Thus the May 2010 statewide plan is intended to be truly conceptual, not prescriptive, and the CTPG is intended to be a vehicle for statewide collaboration on planning but not a decision making body.

3. RETPP Phase 2

In Phase 2 of the RETPP, the ISO and the other California planning authorities will use the Phase 1 conceptual plan as a starting point for each to develop and finalize a transmission plan for its own balancing authority area. Thus in Phase 2 the ISO will refine the portion of the Phase 1 plan that applies to its balancing authority area to arrive at an ISO transmission plan by December 2010 that will then be submitted to the ISO Board of Governors for approval. Board approval of the Phase 2 plan will constitute a finding of need for the new or upgraded transmission elements identified in the December 2010 plan, thereby setting the stage for approving project proposals to build specific elements of the plan and allowing the costs of these elements to be recovered through the ISO's transmission access charge mechanism. The ISO expects that the CTPG members will continue to collaborate as a group during Phase 2 so that all member planning authorities can maintain the statewide perspective that guided Phase 1. More specifics on the CTPG role in Phase 2 will be forthcoming at a later time.

The ISO will conduct a four-month stakeholder process as part of Phase 2, starting in April 2010 after the March release of the draft CTPG statewide conceptual plan and continuing through the end of July. During this time the ISO will provide opportunities for stakeholders to provide written comments on the March draft and May final CTPG plans, and to offer ideas for potential enhancements such as inter-state lines that would enable

access to additional renewable resources outside California. The ISO does not envision that contribution of comments or ideas by stakeholders in Phase 2 would establish rights to develop any specific elements of the final Phase 2 plan that may be based on those ideas. Rights to build and own elements of the Phase 2 plan will follow the principles of Phase 3 discussed below. The four-month Phase 2 stakeholder process will also be the submission opportunity for proposed merchant transmission projects, which would be evaluated by the ISO in accordance with existing requirements and criteria.

The ISO will refine the Phase 1 transmission plan by applying specific criteria for ranking alternative transmission elements to access particular renewable zones, which will include commercial interest, economic costs, measures of renewable energy development potential, renewable integration requirements, and environmental considerations. The draft final proposal retains the provision for distinguishing Category 1 (unconditional or final approval) versus Category 2 (conditional approval) elements of the December 2010 final plan. Category 2 approvals are intended to enable pre-construction development work to proceed on projects whose ultimate need depends on factors that cannot yet be known with sufficient certainty, with assurance of recovery of project costs for any projects that are eventually denied final approval.

4. RETPP Phase 3

In Phase 3, which starts in January 2011 following ISO Board approval of the December 2010 plan, the ISO will receive project proposals to build specific elements of that plan. The ISO then expects to submit specific project proposals to its Board for approval starting in March 2011.

As summarized in the paragraph above on right of first refusal, the ISO proposes that the elements of the final Phase 2 plan will be developed by first applying a right of first refusal to the relevant PTOs with service territories within the ISO, then opening plan elements to third-party proposals where the right of first refusal was not exercised, and finally applying an obligation to build on the relevant PTOs if necessary. Phase 3 would also include an opportunity for any party to submit an economic project proposal, subject to requirements and criteria comparable to those of the current TPP request window. As noted above, the ISO will evaluate economic project proposals based on a congestion analysis that includes the elements of the Phase 2 final plan.

5. Linkages between the RETPP, the current TPP and the LGIP

In the December 2 straw proposal the ISO provided some initial ideas on how to integrate the new RETPP with the existing transmission planning process (TPP) and the large generator interconnection process (LGIP). The motive for such integration is the recognition that much if not most of the new transmission infrastructure needed over the next decade will be driven by access to renewable resources or support for renewable integration, and as such these activities cannot be conducted apart from one another. In

particular, the ISO must ensure that consistent study assumptions are being developed for all of the studies that will be conducted in the TPP and the RETPP, beginning with the 2011 study cycle. The ISO will provide a more complete proposal for integrating these processes in the near future, but as a starting point offers the following ideas it is considering for 2010 and 2011.

First, under the TPP structure the ISO has just completed the 2009 request window into which participants have submitted 80 reliability projects and 33 economic and other projects. In addition there are 11 economic and other projects that were submitted in the 2008 TPP request window. For the reliability projects the ISO is proceeding with the existing 2010 TPP timetable to present a transmission plan to its Board for approval this coming March. This aspect of the existing TPP for 2010 would therefore be unaffected by the new RETPP.

Second, the ISO will consider economic and other non-reliability projects from the 2008-09 request windows to identify their potential renewable access benefits within both Phase 1 and Phase 2. As stated earlier, the current TPP methodology for how to assess economic projects cannot be meaningfully done prior to establishing the Phase 2 final plan as a baseline for the assessment. Thus if any elements of these economic project submissions appear as elements of the final Phase 2 plan they would do so because they are needed for renewable access, and as such would be subject to the Phase 3 right of first refusal provisions.

Third, because reliability assessments and other studies (congestion studies, feasibility of long term congestion revenue rights, short-term assessments and locational capacity technical studies) are conducted annually as part of the existing TPP and therefore must be done again for 2011, the ISO will accelerate this process during 2010 so that its results converge with the December 2010 results of the RETPP Phase 2. The idea is to enable ISO management to present a single plan to the Board of Governors at the end of 2010 that reflects proposals to build the needed reliability upgrades identified under the existing TPP, and the additional infrastructure needed to support access to renewable resources, to ensure deliverability of renewable energy to load and to support access to other resource types needed for renewable integration. During this process the ISO would also accept and evaluate merchant transmission project proposals, in accordance with existing requirements and criteria. To complete the 2011 reliability assessment on the shorter time frame (i.e., to be ready for the ISO Board by December 2010 rather than March 2011 per the normal TPP), the ISO is developing a schedule for developing the study plan, performing the studies and publishing the study results that will allow sufficient time for PTOs to submit reliability project proposals by the end of the RETPP Phase 2 comment period on July 31. The ISO intends to commence stakeholder discussions on this schedule in the near future.

Fourth, with regard to the LGIP, the ISO is already engaged in its study process to address the interconnection and deliverability needs of the projects currently in the queue, including the serial projects and the transition cluster. Many of the projects in the

queue are renewable resources located in areas that are likely to have further generation development beyond the current queue projects. For this reason, as the ISO stated in the December 2 straw proposal, many LGIP related transmission upgrades would be significant enough to warrant consideration from the larger perspective of the RETPP, rather than the narrower perspective of the current LGIP. Several stakeholders who commented on this aspect of the straw proposal expressed a concern that moving the significant LGIP upgrades into the RETPP process would delay their implementation. The ISO believes that any such delays will be minimal. Under the current LGIP study time line the ISO would complete the study process for the interconnection queue by October 2010. Under the RETPP time line the ISO would take the final plan, including any LGIP related upgrades that are moved into the RETPP, to the Board in December 2010, which is essentially a difference of two months for final approval of these upgrades. Later in this paper the ISO provides further discussion of the criteria it proposes to use for identifying the significant LGIP related upgrades to be considered within the RETPP. LGIP related upgrades that are not identified as significant would proceed to approval under the existing LGIP procedures and time line.

II. BACKGROUND

The stakeholder process that led to the present RETPP draft final proposal began on September 15, 2009 when the ISO launched its "Getting to 33% RPS" initiative by publishing an issue paper and straw proposal outlining a new tariff category for network upgrades to support renewable energy access and a framework for comprehensively planning the transmission upgrades that will be needed to reach California's 33 percent renewable energy target by 2020. The issue paper was followed up with a stakeholder meeting on September 23, after which interested parties had an opportunity to submit written comments by September 30. Since then the ISO issued revised straw proposals on October 30 and December 2, each followed by a stakeholder meeting or conference call and another opportunity to submit written comments. The last round of written comments in this process was submitted on December 15. [4]

As a result of these activities and in consideration of the thoughtful and constructive comments of stakeholders the ISO reached the following conclusions, which are reflected in the present draft final RETPP proposal.

1. To develop transmission infrastructure to achieve the state's 33 percent renewable energy target it will be neither sufficient nor efficient to approach transmission planning in a piecemeal fashion, project by project. A more comprehensive planning approach is needed.
2. The comprehensive approach should take a full statewide perspective in collaboration with the other planning authorities in the state. For this purpose the established California Transmission Planning Group (CTPG) is considered the appropriate vehicle to create a statewide conceptual transmission plan.

[4] All comments are available at http://www.caiso.com/242a/242abe1517440.html.

3. To accommodate a reasonable lead time for building transmission by 2020, the initial statewide conceptual plan should be completed in the first half of 2010 to enable further necessary analysis and development efforts to proceed.
4. The transmission plan developed by the CTPG should be truly conceptual in the sense that it would not entail decisions to approve specific transmission projects or allocate project costs. The member planning authorities would each make such decisions in accordance with their own procedures with regard to transmission facilities that would be part of their balancing authority areas.
5. The conceptual transmission plan developed by the CTPG would not perform sufficient analysis or planning activities to address all the reliability and operating needs of its members. Again, each member planning authority will be responsible for planning to meet these needs, but with awareness of the statewide plan as a context for planning.
6. Based on the previous two points, the ISO must conduct its own Order 890 compliant transmission planning process and its generation interconnection process, both of which have activities in progress that cannot be delayed significantly.
7. At the same time the critical need for a comprehensive approach to planning means that the current transmission planning and generation interconnection activities should be integrated as far as possible. In particular the ISO will tailor the RETPP and modify existing procedures so that a single annual transmission planning process can address both renewable energy access and the other infrastructure needs of the ISO grid, leading to a single annual transmission plan that is presented to the ISO Board for approval.

Several of the above conclusions were already reflected in the ISO's December 2 revised straw proposal. In general, stakeholders have supported the ISO's revised structure for the planning process as described in the December 2 straw proposal, but have offered several recommendations for revisions and clarifications. The ISO's proposal for right of first refusal has been contentious among stakeholders, and is the subject of further discussion in this paper. Stakeholder comments referenced in the text of this proposal will refer to comments on the December 2 proposal, unless otherwise dated.

In order to bring this RETPP proposal to the ISO Board of Governors for approval at the February 2010 Board meeting and to enable a timely tariff filing with the Federal Energy Regulatory Commission, the ISO proposes the following updated schedule for the stakeholder process:

- January 12 – Stakeholder meeting and conference call to discuss draft final proposal
- January 19 – Stakeholder comments due on draft final proposal
- February 11-12, 2010 – ISO Board of Governors meeting
- February 2010 – Tariff stakeholder process and tariff filing.

III. REVISED RETPP PROPOSAL

This section provides additional details regarding each of the three phases of the proposed RETPP.

A. Phase 1 – Statewide Renewable Energy Conceptual Transmission Plan

As the central objective and deliverable of Phase 1, the ISO will work with the other members of the California Transmission Planning Group (CTPG) to develop a comprehensive state-wide conceptual transmission plan, focusing on the transmission elements required to achieve the 33 percent renewable energy target by 2020. The target date for this deliverable is May 2010, with a draft version available for discussion and comment in March. The ISO is currently working with the other CTPG members to develop a plan and timetable for creating the Phase 1 deliverable, and will be able to provide the stakeholders more information on these activities in the near future.

The CTPG was formed as a result of discussions facilitated by FERC to address the state's transmission needs in a manner that would be coordinated statewide and would respect the various business and regulatory models of the participants. The CTPG includes transmission owners with service territories and transmission operators, i.e., parties that have both the responsibility for transmission planning and the technical capabilities to perform the required activities. The statewide 33% RPS plan will build on the RETI Phase 2A report and the ISO's September 15 report regarding transmission within its footprint,[5] and will include input from the other stakeholders and coordination with state agencies. One explicit CTPG objective is to identify opportunities for joint transmission projects, which the ISO believes is an important focus and potential benefit of developing a statewide 33 percent renewable transmission plan.

Conceptual transmission planning as the ISO envisions for the Phase 1 process is performed when it is necessary to identify and evaluate numerous potential new transmission elements. More detailed engineering studies are typically performed after the conceptual analysis is vetted with stakeholders, by ranking the most promising potential elements and then analyzing them in more detail. Conceptual planning can utilize different types of analytical approaches. For example, RETI's Phase 2A conceptual plan, which sought to identify sufficient transmission elements to support access to a large number of possible renewable zones, did not conduct power flow analysis, but rather used generation shift factors to identify transmission elements that would be impacted by renewable energy projects at particular locations. In contrast, the ISO's September 15 study using the RETI data did conduct power flow analysis to evaluate potential transmission elements, but was still conceptual in nature. Similarly,

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[5] California Independent System Operator, "2020 Renewable Transmission Conceptual Plan Based on Inputs from the RETI Process: Study Results," September 15, 2009; available at http://www.caiso.com/242a/242ae729af70.pdf.

CTPG, using a different input assumption set than the ISO used, is conducting power flow and stability studies to support an initial statewide conceptual plan. The statewide conceptual plan will identify potential transmission upgrades that support the state's 33% RPS goals, but is not intended to address all the reliability and operational needs of the CTPG balancing authorities, nor will it provide all the engineering details required to develop accurate cost estimates for proposals to build the facilities.

One important implication of the point just noted – that the conceptual plan will not attempt to address all the reliability and operating needs of the member balancing authorities – is that the Phase 1 collaborative effort will not obviate the need for the ISO to conduct its own Order 890 transmission planning process to address all of its transmission needs. Thus the ISO is now preparing to begin the stakeholder process to develop unified planning assumptions and a study plan for the annual reliability and congestion studies specified in the existing ISO TPP. As described elsewhere in this paper, this effort will enable the ISO to accept PTO proposals for reliability projects in July of this year and ultimately to provide its Board of Governors with a comprehensive Phase 2 plan in December that addresses both the new transmission needed for renewable energy access and the reliability needs of the ISO grid. In the near future the ISO will provide stakeholders additional details and a schedule for its upcoming Order 890 process activities, as well as the proposed tariff and BPM changes that will be required to effect these modifications to the ISO TPP.

CTPG Process Status and Next Steps

Many stakeholders have expressed concern about the planning process of the CTPG. They note the nascent state of the CTPG process, and are concerned that, despite the intentions of some CTPG members, its process cannot be Order 890 compliant and will lack fairness, accountability and transparency.[6] There is also concern that CTPG will not place sufficient weight on the RETI results,[7] and that its membership excludes key stakeholders in the RETI process including state agencies, generators, and ITCs.[8]

The ISO recognizes that many of these stakeholder concerns cannot be definitively answered in this paper because the CTPG process is still under development. As a member of CTPG, the ISO is working with other CTPG members[9] to address these concerns and expects that although the CTPG process may not be established as a fully

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[6] See, e.g., November 10 comments by CPUC at 3-6; eSolar at 1; Large-scale Solar Association at 4-5; Solar Millennium at 1; California Wind Energy Association at 1; NCPA at 1; Green Energy Express LLC at 1; IEP at 1-2;Pattern Energy at 1; DayStar Farms at 2.

[7] A process for CTPG-RETI coordination is underway.

[8] See, e.g., comments by CPUC at 5-6.

[9] See, e.g., comments by PG&E at 3.

Order 890 compliant process,[10] it will become more transparent and allow for meaningful input by stakeholders.

Since the ISO's December 2 revised straw proposal, the CTPG has implemented its web site,[11] posted a study plan reflecting the studies its members currently have underway, and held a stakeholder conference call on December 17 to discuss its study plan.[12] The studies described in this plan will form the basis for the CTPG's initial draft study report to be published in January 2010, followed by a stakeholder meeting to discuss the draft report.

The CTPG report is expected to provide one component of the conceptual transmission plan. Based on the limited time for developing the this initial CTPG study and the limited scope of their studies, the ISO believes that additional scenario analysis will need to be conducted using additional base-case assumptions to those used by CTPG. These scenarios and renewable portfolio assumptions would examine the impact of regulatory, technological and economic drivers on renewable resource development.[13] They may also include consideration of transmission enhancements that are based on operational needs stemming from renewable integration, such as greater access to dispatchable resources needed to smooth intermittent renewable resources in real time. The ISO intends to develop these scenarios and base case assumptions in conjunction with the CTPG and in consultation with state agencies and stakeholders. These scenarios and input assumptions will be captured in a study plan that will provide direction for the next iterations of the studies needed to develop the statewide plan.

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[10] As discussed elsewhere in this paper, the ISO does not expect the CTPG to be a decision making body that will approve specific transmission projects and determine allocation of project costs, which are essential elements of a fully Order 890 compliant transmission planning process. ISO Board and Management will make any such decisions that affect the ISO balancing authority area in a manner that is consistent with the existing Order 890 compliant planning process.

[11] See www.ctpg.us.

[12] http://www.ctpg.us/public/images/stories/downloads/CTPG_revised_Study_Plan_Nov_2_draft.pdf

[13] Such analysis could reflect, for example, the scenarios being studied in the ISO's current 33% RPS operational study, which is evaluating the operational impacts of renewable integration (e.g., ramping, load following, and regulating reserve requirements) for alternative renewable resource scenarios based on the CPUC's renewable implementation analysis and adjusted for updated 2020 CEC load forecasts reflecting different levels of demand side policies. A number of stakeholders proposed ideas on the use of planning scenarios to determine the core set of lines that would be unconditionally approved. See, e.g., PG&E at 2-3 (November 10); California Wind Energy Association, Sept. 30, at 5-7. The ISO and CTPG have not yet determined how to structure any specific scenarios to be evaluated for 33% RPS transmission planning, but intend to be responsive to stakeholder comments and resource planning processes at the state agencies (see, e.g., comments by CPUC November 10 at 7-8).

The ISO is working with CTPG to finalize and communicate the proposed ISO's RETPP Phase I timeframe and work toward a common schedule to support the delivery of a draft conceptual plan in March and a final conceptual plan in May.

B. Phase 2 – Identifying the Infrastructure Needed to Reach 33% RPS

The objective of Phase 2 will be to develop, starting from the Phase 1 statewide conceptual plan, a refined, cost-effective final plan for renewable transmission that will be submitted for formal determination of need for specific projects to the ISO Board in December 2010, and the corresponding decision makers of the other CTPG transmission operators. Phase 2 will be coordinated with the reliability and other study processes that must be conducted under the ISO's Order 890 process and will incorporate large LGIP network upgrades (with smaller LGIP projects being evaluated outside the RETPP), such that the ISO can present a comprehensive, integrated plan in December 2010 that includes all the ISO's transmission planning processes.

Organization of Phase 2

Phase 2 is divided into two sub-phases: a formal stakeholder comment period, which will also be the window for submission of limited types of project proposals, followed by a subsequent period for plan finalization. However, it is expected that the ISO will be conducting analysis and informally exchanging technical data with stakeholders, as well as holding stakeholder meetings to provide updates and gather additional feedback, throughout this phase.

Comment Period and Limited Project Submission Window

Following release of the draft conceptual plan in March 2010 during the RETPP Phase 1, stakeholders will have a four month opportunity (April through July) to review and comment on the plan, and at that time may suggest amendments to the plan, which could include recommendations for consideration of interstate projects. As noted, this period will also be the window for submission of limited types of project proposals, specifically merchant projects, location-constrained resource interconnection facilities (LCRIF) and PTO project proposals for addressing identified reliability needs. This comment period should be long enough to allow ample opportunity for additional stakeholder comments on any plan modifications that appear when the conceptual plan is finalized in May 2010. The ISO will seek sufficient stakeholder input to ensure that the infrastructure alternatives that are considered in Phase 2 reflect broad agreement on the efficient and robust transmission facilities that best support the state's 33% RPS goal, in accordance with the criteria discussed below.

With the exception of merchant projects, LCRIF projects and PTO-submitted reliability projects, the comment period is not considered to be equivalent to the current TPP's request window since the ISO is not requesting project proposals from project sponsors. A "comment" is defined here as

- Provision of additional technical information on transmission elements in the conceptual plan that may affect the specifications of those elements in the final plan;
- Alternative interconnection points for in-state or interstate transmission lines; or
- Additional information that could cause the ISO to revise some of its study assumptions (e.g., updated data on behind the meter distributed generation).

If a detailed project proposal is submitted, the ISO may use some or all of the information provided in that proposal on an as-needed basis to support its RETPP planning, but will not evaluate the project separately from the overall plan. Moreover, such comments, including any full project proposals, do not confer rights to build or own transmission upon the submitting party (see discussion of rights of first refusal in the next section of the paper). The ISO will evaluate all comments initially using the set of criteria that are established to select and rank alternative transmission elements. The ISO may reject particular comments with less than a formal analysis consisting of, for example, power flow studies or production simulations. The ISO will seek to catalogue and consider all comments, and will provide reasons for its decisions in stakeholder forums if requested.

Phase 2 Study Period and Final Plan Specifications

Following the stakeholder input on the conceptual transmission plan, that plan and the proposed adjustments to that plan will be subject by the ISO (for the plan components in its territory), in continued coordination with CTPG, to economic, environmental, commercial and other criteria to arrive at an efficient, reliable, and operationally sound final 33% RPS transmission plan. Specific criteria could also be augmented by some renewable resource “scenario” analysis that would further screen for the transmission elements likely to be needed across a range of scenarios.

Transmission planning during Phase 2 will result in transmission needs identified in the final Phase 2 comprehensive transmission plan for the ISO footprint that will be sufficiently refined and detailed to serve as the basis for Phase 3 submission and approval of proposals to construct the facilities in the plan. There are often many transmission alternatives for meeting a particular transmission need, each of which can have trade-offs in terms of reliability, economic and operational benefits. The ISO’s intention is to address these considerations and trade-offs in its Phase 2 planning process such that the final plan will be extremely specific and not subject to further consideration of comparable alternatives. The final plan would provide sufficient engineering details for the PTOs or other parties to develop accurate cost estimates as part of their proposals to build specific elements of the plan. Information provided may include, but is not limited to: conductor size, line impedance, series compensation levels, substation bus and breaker configuration, breaker clearing times, transformer characteristics (capacity, impedance, tap range), shunt capacitor and reactor sizes, FACTS device specifications, SPS requirements, among others.

Phase 2 Methodology

Phase 2 has the following objectives:

- Select and rank transmission elements for purposes of renewable generation interconnection and integration;
- Appropriately size the identified transmission elements to reflect future generation interconnection ("right-sizing") and/or to facilitate meeting renewable integration operational requirements;
- Provide information that can demonstrate the cost-effectiveness of the set of transmission elements in the final plan.

On the basis of the criteria specified below, the Phase 2 process will distinguish two categories of specific transmission elements. Category 1 will be comprised of plan elements that are considered foundational and can be approved without further conditions. Category 2 elements will be those that are approved conditionally as supporting achievement of the 33% RPS target, but whose final design and approval will be subject to future development of generation or demonstrations of commercial interest.[14]

The ISO has adopted the above nomenclature in order to clarify the concepts behind these categories of transmission projects. Although ISO Category 1 conceptual projects will be roughly consistent with the intent of the RETI concept of "least regrets" transmission projects – what the RETI called "renewable foundation" and "renewable delivery" – they will not necessarily be identical with the projects identified through the RETI process.[15]

Analytical Process for Selecting the Transmission Elements for Generation Interconnection

In Phase 2, the ISO will utilize all relevant information to establish a proposed final plan for the ISO-controlled grid (in the context of the state-wide plan) based on transparent criteria that can be used for need determination. As noted, ISO expects that the ranking criteria used in Phases 2 and 3 of the RETPP would include the commercial interest criteria discussed in the prior proposal, with similar or different thresholds. Proposed

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[14] A number of stakeholders have raised concerns about conditional approval status, in particular that such approvals will not provide sufficient certainty for making logistical and financial commitments for generation project development and construction. See, e.g., comments of Solar Millenium at 1 (November 10); IEP at 3 (November 10). Other stakeholders have endorsed the concept of unconditional versus conditional approval for transmission projects, while providing their own ideas on how to determine the unconditional set. See, e.g., comments of PGE&E at 2-3 (November 10); California Wind Energy Association, at 5-7 (September 30). At this stage, ISO believes that the guiding concept of "least regrets" infrastructure development should remain integral to the planning process, while acknowledging that it needs to be further elaborated.

[15] See RETI, Phase 2A Draft Report, June 2009, pp. 1-6 to 1-7.

criteria for ranking projects in Phase 2 to minimize the risk of stranded investment are set forth below.

The ISO is open to other criteria to be used for distinguishing between Category 1 and Category 2 transmission elements, and between alternative elements that could enter Category 2. While no stakeholders have submitted very specific comments on the criteria (listed below), some stakeholders have requested additional information on them as well as the opportunity to help shape the final ranking criteria.[16] The ISO expects that these criteria, as listed or as revised following further stakeholder comments, will be submitted in its RETPP tariff filing (similarly to the way similar criteria are in the tariff rules for LCRIF). However, the exact ranking methodology (i.e., the exact weighting among criteria and other methodological aspects) will not be filed, thus allowing time for the ISO and stakeholders to begin a more focused process to refine the methodology as soon as possible and certainly prior to Phase 2.

Another aspect to the ranking of transmission elements is the alignment between the CPUC's Long-Term Procurement Planning (LTPP) proceeding and transmission development. CPUC notes that "consistency between the resource assumptions" used in RETPP and LTPP "for the IOUs could significantly streamline the CPUC's need determination in the transmission project permitting process and reduce the risk of delays from litigation."[17] ISO notes that it has worked cooperatively with the CPUC and stakeholders to align resource assumptions between LTPP and its 33% RPS operational study. It will be more difficult to conduct multiple renewable resource scenarios in the transmission planning process, due to the large numbers of transmission studies that will need to be conducted. However, the ISO intends to work with the CPUC in reviewing resource assumptions and ensuring that RETPP and LTPP are as closely aligned as possible. As requested by the CPUC, if this alignment does not take place satisfactorily in Phase 1, it will be continued into Phase 2.

Selection and Ranking of Transmission Elements

Category 1 – Transmission Upgrades or Additions Eligible for Final Approval

Category 1 transmission elements will be eligible for final ISO approval at the end of Phase 2 and will be designed to facilitate access to renewable generation with a high commercial interest level in multiple resource areas under various resource location and integration assumptions. Transmission elements will be ranked, using the following criteria:

1. commercial interest in the zone(s) accessed by the transmission element, as evidenced by signed and approved power purchase agreements and interconnection agreements;

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16 See, e.g., SCE comments at 5.

17 CPUC comments at 7.

2. the expected cost of the transmission element compared to the expected costs of other transmission elements;
3. the qualifying capacity (MW) and expected energy (MWh), as well as the supply cost function of renewable resources in particular zones;
4. the extent to which the transmission element will provide additional reliability or economic benefits to the ISO grid;
5. potential future connections to other renewable resource areas and transmission elements;
6. renewable integration requirements and costs associated with the resources in particular zones;
7. the potential for a particular transmission element to provide access to generation and non-generation resources needed to support renewable integration (e.g., pumped storage); and
8. the effect of uncertainty associated with the above criteria, and any other considerations, that could affect the risk of stranded investment.

Some further detail and comment on some of these criteria is presented below.

Category 2 – Transmission Upgrades or Additions Eligible for Conditional Approval

If the renewable resource target is not achieved by counting the capacity of renewable resources made deliverable by Category 1 transmission elements, the ISO will rank transmission elements that are eligible for conditional approval, in order of risk of stranded investment, using the same criteria set forth above in Category 1, except that:

(a) transmission elements eligible for conditional approval must be designed to access renewable resources in at least one renewable resource area;
(b) there must be some level of commercial interest in the capacity of the transmission element as evidenced by signed and approved power purchase agreements and interconnection agreements.

Treatment of LGIP-Driven Upgrades

The ISO proposes that requests for interconnection in the LGIP (network upgrades in LGIAs), including any decisions to “right-size” any upgrades made in that process, will largely be incorporated into the RETPP and the renewable resources accessed by these network upgrades will be counted towards the 33% RPS target. As a starting point, as proposed in the prior paper, the ISO will distinguish between LGIP network upgrades that are considered necessary for evaluation within the RETPP and those that aren’t. The threshold for inclusion in the RETPP would consist of:

(a) LGIP Network Upgrades that are new transmission lines requiring new rights of way and are 200 kV and above and have an estimated cost exceeding $50M.
(b) LGIP Network Upgrades that are new substations and are 500 kV and above and have an estimated cost exceeding $50M.

Several stakeholders and the CPUC argue that a lower threshold for moving LGIP projects into RETPP is needed to prevent delays in LGIA execution.[18] One suggestion is that only right-sized projects would be placed into the RETPP, or only a subset of right-sized projects that are considered to affect the overall RETPP planning. The ISO considered these options. As a practical matter, the ISO believes that any such delays will be minimal, while having an integrated planning approach that includes all significant transmission elements will be valuable in developing a cost-effective plan. Under the current LGIP study time line the ISO would complete the study process for the interconnection queue by October 2010. Under the RETPP time line the ISO would take the final plan, including any LGIP related upgrades that are moved into the RETPP, to the Board in December 2010, which is essentially a difference of two months for final approval of these upgrades. This minimal planning delay must be weighed against the fact that line facilities of the size described will require a CPCN and are expected to have a lead time of 5 to 7 years, so analysis within the RETPP should not significantly delay the commercial operation date. The location of the new substation facilities of the size described should be approved as part of a long-term statewide plan because they can significantly influence future bulk system transmission expansion options and costs.

The ISO proposes that the remaining LGIP upgrades, which consist largely of short lead time and incremental projects such as reconductoring projects and transmission upgrades to existing substations, should not be required to go through RETPP. That is, these upgrades would be evaluated within the existing LGIP, as described in the Executive Summary. In addition, LGIP upgrades already in the LGIA phase of the process will not be required to go through the RETPP.

Consideration of Renewable Integration Requirements and other Economic Benefits

RETPP transmission planning will consider all transmission needs to support access to, and integration of, renewable resources. Such planning will thus potentially include location and/or sizing of transmission lines to facilitate access to needed integration resources (such as pumped storage) as well as to provide congestion relief that also relieves operational constraints that would otherwise impede renewable energy production (such as generation operational constraints in Southern California) or otherwise could provide economic benefits.

The determination of renewable integration requirements will be an ongoing task for the ISO. In November 2007, the ISO released a study of the integration requirements associated with a 20% RPS achieved through wind resource development in the Tehachapi region.[19] That study pointed to expected needs for Regulation and load

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[18] Comments by CPUC at 8, CalWEA/CEERT at 4, SDG&E at 1.

[19] California ISO, "Integration of Renewable Resources: transmission and operating issues and recommendations for integrating renewable resources on the California ISO-controlled grid," (November 2007), available at http://www.caiso.com/1ca5/1ca5a7a026270.pdf.

following capacity as well as generic ramp requirements. Production simulation was subsequently used to verify the capabilities of the generation fleet to provide those capabilities. The ISO, working with the CPUC and other stakeholders, is now updating the integration study methodology to evaluate alternative 33% RPS scenarios, with initial results expected in early 2010. The ISO expects that in RETPP during 2010, such results will inform transmission planning qualitatively.

Cost-Benefit Analysis of Alternative RETPP Scenarios and Final Plan

Several stakeholders have argued that the ISO should conduct cost-benefit analysis during the development and finalization of the renewable transmission plan. For example, SDG&E recommends that the ISO use TEAM to "compare costs and benefits of various scenarios that would satisfy the state's environmental goals."[20]

As noted above, the ISO agrees that production simulation and other estimates of benefits could be used in both Phase 1 and Phase 2 of the RETPP to examine alternative resource scenarios and transmission configurations. Some of these results will be made public through the stakeholder process and provided as part of the final plan description and analytical justification. However, given the significant computational requirements of Phase 2, the ISO will attempt to limit the number of different production simulations that it conducts to a reasonable number considered sufficient to support its final plan. The ISO will also be providing information on alternative resource portfolio costs in its 33% RPS operational study, the first phase of which is due for completion in early 2010.

Additional Congestion Studies and Economic Projects

As noted above, the RETPP will first conduct a comprehensive planning process motivated by renewable generation interconnection along with consideration of renewable integration. Following that analysis, the ISO will undertake additional congestion studies to assess the potential economic benefits of transmission in addition to that proposed under RETPP. This further analysis will then provide the basis for the category of "economic" transmission projects. For the 2010 cycle of the RETPP, the ISO will evaluate the economic projects submitted in the 2008-9 TPP request windows at this stage of the process. If any of those projects are selected, the project sponsors will have the right to build and own these projects. The ISO will then allow new economic projects based on this information to be submitted into the Phase 3 project submission window for subsequent evaluation.

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[20] SDG&E comments at 1-2.

C. Phase 3 – Project Evaluation and Approval, and Plan Recalibration

Phase 3 represents another significant departure from the current ISO transmission planning process, as it seeks to translate the comprehensive plan into a large number of specific transmission projects that can be approved within the timeframes needed to achieve policy goals. Following the approval of the ISO BAA elements of the final state-wide 33% RPS transmission plan by the ISO Board at the conclusion of Phase 2, this next phase will focus on the approval and development of the specific transmission projects identified in that plan. Phase 3 will include an ongoing process for annual recalibration of the comprehensive statewide plan to reflect new developments as well as to determine if any Category 2 projects should move into Category 1 or be terminated. The Phase 3 process described here is mostly similar to that delineated in the ISO's prior proposal. In the prior paper, the ISO proposed that to facilitate project development, PTOs with service territories are offered a right of first refusal to build Phase 3 projects. This issue is explored further in this paper.

A New Project Submission Period

Following Board approval at the end of 2010 of those elements of the state-wide 33% RPS plan that would be under ISO operational control, the ISO will provide an opportunity for parties to submit project proposals to build the specific transmission elements identified in the 33% RPS plan that are within the ISO balancing authority area and that would be turned over to the ISO's operational control. This period would also be open to any new economic project proposals based on the assumptions noted above.

Submission of proposals for elements of the final Phase 2 plan will be structured in three steps. In the first step the eligible PTOs as defined above will have the first opportunity to submit proposals to build plan elements. Parties may also work with the eligible PTOs to collaborate on joint projects. The ISO will evaluate these proposals to determine which ones can be approved. To the extent the eligible PTOs have not fully exercised their rights of first refusal in the first 90 days of Phase 3, or any of their submitted proposals are not approved by the ISO, in the second step the ISO will allow other parties to submit proposals to build Phase 2 plan elements that are not accounted for by the approved PTO proposals. In the third step, after evaluating the third-party proposals submitted in the second step, if there are still some final plan elements that are not addressed in any of the submitted proposals, the ISO may assign these to the appropriate PTO under an obligation to build. The ISO expects that the first two steps of this Phase 3 process will take three to four months.

Evaluation of Competing Projects for Approved Transmission Facilities and Right of First Refusal

In the December 2 proposal, the ISO proposed that PTOs that have service territories will have both a right of first refusal to build plan elements, and an obligation to build

those elements for which no acceptable proposal is submitted in the first two steps of the Phase 3 submission window. [21] In that proposal, we provided several justifications for granting this right of first refusal, including that it ensures that PTOs are not treated in an unduly discriminatory manner as the result of joining an ISO or RTO, as well as providing the appropriate incentives for PTOs to join or retain membership in the ISO.[22]

With some modifications from the prior proposal – such as the evaluation of economic projects that would, if selected, then obtain right of first refusal for the project developer (as described above) – the ISO continues to support the right of first refusal to PTOs with service territories for renewable transmission projects. Here we provide the further clarification that under the current ISO tariff, these PTOs have an obligation to build certain facilities found to be needed by the ISO, including reliability projects, generation interconnection-related projects, and economic projects identified by the ISO.[23] Given that the ISO expects that most if not all renewable transmission to achieve 33% RPS can be justified ultimately on the basis of generation interconnection and associated planning decisions (e.g., to "right-size" those transmission lines and upgrade other elements to facilitate renewable integration), the rights proposed here are viewed as an appropriate application of the existing tariff obligations and not as a significant expansion of right of first refusal.

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[21] On this issue, the ISO has recently submitted initial comments and reply comments in response to a FERC Notice of Request for Comments regarding the development and implementation of the Order 890 transmission planning process. California ISO, "Initial Comments of the California Independent System Operator," FERC Docket No. AD09-8-000, November 23, 2009; "Reply Comments of the California Independent System Operator," FERC Docket No. AD09-8-000, December 18, 2009. For the reasons set forth in its comments, the ISO supports a narrow, carefully crafted right of first refusal for projects primarily designed to support achievement of the 33% RPS goal and the effective and reliable integration of renewable resources. The ISO's initial comments can be found at http://www.caiso.com/246f/246fd23976c0.pdf and reply comments at http://www.caiso.com/2488/2488c34f5e800.pdf

[22] The eligible PTOs are or are affiliated with load serving entities with an obligation to serve the load in their service territory. If these PTOs were not members of the ISO, they could build new transmission projects to serve their load by simply obtaining a certificate of public convenience and necessity from the state regulatory commission. They would not encounter the competition to build transmission projects that would result from being a member of the ISO absent a right of first refusal for such PTOs. Thus, the absence of a right of first refusal mechanism would serve as an unnecessary and inappropriate disincentive for PTOs to join or retain membership in the ISO. Not providing for a right of first refusal would result in unfair and unduly discriminatory treatment of PTOs that are participating members of an ISO or RTO.

[23] The parties involved in the generation interconnection process are the ISO, the PTO and the Interconnection customer. (See ISO Tariff Appendix U, Section 1.2.2; Appendix V, Section 1.2.2.) PTOs have the obligation to build reliability projects as set forth in ISO Tariff Section 24.1.2, and PTOs have the right of first refusal to construct and own ISO-proposed and approved economic projects according to ISO Tariff Section 24.1.1(c).

In the event an eligible PTO fails to submit a proposal to build a transmission element identified in the final plan and in its service territory within the Phase 3 timeline, the right of first refusal for that project will expire and the ISO will allow other project developers (including ITCs) to submit proposals to build the project.

Comments on Right of First Refusal and ISO Response

Both in comments to the ISO and in comments under the FERC Notice of Request for Comments regarding the development and implementation of the Order 890,[24] stakeholders have set forth strongly divergent positions on the right of first refusal. As noted above, the ISO feels that its decision on right of first refusal is rooted in the rights and obligations in the current tariff, and does not reflect a major expansion of those rights. Hence, our reply to comments here will be limited to selected issues and questions about the application of right of first refusal.

A number of parties, including ITCs and State regulatory agencies, argue for a rejection or substantial modification of the ISO's proposed expansion of PTO right of first refusal by allowing direct competition by ITCs.[25] CPUC argues that ITCs can offer lower cost transmission development through "additional access to capital, skilled human resources and ideas."[26] CPUC suggests that the process for selecting transmission developers should target and limit PTO right of first refusal to address "real, substantiated risks"; limit the exercise of such a right to a limited timeframe; and allow competition by ITCs where the targeted right of first refusal does not apply.[27]

Several municipal entities seek clarification that right of first refusal will not inhibit their opportunities to influence transmission solutions or enter into joint transmission projects with any developer, whether existing PTO or independent entity.[28]

The ISO continues to believe that the right of first refusal mechanism proposed here is sufficiently narrow and transparent that it will not chill or delay the development of needed transmission. Moreover, it will not unduly preclude third-parties from building transmission, including through joint projects. Under the proposed RETPP the ISO identifies at least four types of opportunities for ITCs to build and own transmission:

- ITCs may submit merchant transmission projects for consideration in Phase 2, and can build and own such projects subject to the same requirements and criteria that apply today. Such merchant projects will have the benefit of the

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[24] FERC Docket No. AD09-8-000.

[25] See, e.g., comments by DayStar Farms, Green Energy Express, IEP, LS Power Transmission, Indicated Independent Transmission Parties, Pattern Transmission, Startrans, and TANC.

[26] CPUC comments at 4.

[27] CPUC comments at 4-5.

[28] Comments by BAMx at 3, NCPA at 1-2, Six Cities at 1-2, TANC at 1-3.

Phase 1 final conceptual plan and supporting documentation to help clarify the opportunities for merchant transmission under alternative 33% RPS scenarios.

- ITCs may submit potential economic project proposals for consideration in Phase 3 in response to the ISO's economic study of the final Phase 2 plan. (For the 2010 cycle of the RETPP the ISO will consider economic projects submitted in the 2008-9 TPP request windows at this stage of the process.)
- ITCs may propose to build elements of the final Phase 2 plan in instances where the relevant PTO has not exercised its right of first refusal within the first 90 days of Phase 3.
- ITCs may develop collaborative projects with one or more of the PTOs, or may submit a proposal to the CPUC in competition with a PTO proposal if the ITC believes it can offer a superior or more cost-effective project.

The right of refusal to eligible PTOs will also ensure that multiple parties will not be incurring similar expenses in preparation to propose and build projects to meet the same transmission needs. If no party submits a project to build the transmission element, the PTO will be required to build it under its obligation to build. This revised proposal thereby ensures that necessary transmission will be built and the incurrence of duplicative costs will be avoided.

NextEra proposes in addition that PTOs offered the right of first refusal submit project milestones and timelines that allow the ISO (and presumably the relevant regulatory authorities) to determine whether they are overcommitted such that construction could be delayed.[29] The ISO notes that both in the prior proposal and in this proposal in Section III B above, it has discussed requiring submission of construction schedules and other information that could help minimize the risk of delays.

SCE suggests that a PTO that obtains right of first refusal should retain that right in the event that the scope of the particular project changes after the right is initially exercised.[30] The ISO agrees and considers that any change in project scope after the initial acceptance to construct and own the project will not alter the right of first refusal for the project. The ISO notes that the intent of the recalibration process is to ensure that the most recent information is considered when Category 2 type projects are being assessed for transitioning to a Category 1 status and that even though the initial project scope changes, the eligible PTO's right to construct that project is not affected.

Several stakeholders point out that the RETPP approach will require consideration of how rights of first refusal are allocated among projects that physically interconnect in the service territories of several PTOs, or are located entirely outside the PTO service territory or partly outside the ISO footprint but intended to help the PTO (or an LSE that does not own transmission but intends to participate in transmission development) to

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[29] NextEra comments at 3.

[30] SCE comments at 6.

meet its RPS obligations.[31] In this regard, municipal entities are concerned that right of first refusal granted to PTOs with service territories could exclude municipal entities from constructing lines that do not touch their relatively small service territories, depending on the definition of service territory.[32] NCPA asks for clarification that the right of first refusal is interpreted to preserve the existing rights of municipal entities to build lines necessary to serve load and meet their RPS obligations, regardless of where the lines are located.[33]

ISO notes that under the current tariff (section 24.1.1), the ISO has the authority to allocate development responsibility among multiple PTOs when the ISO proposes an addition or upgrade.[34] In principle, as described above, the RETPP Phase 2 final plan is intended to be an ISO proposal, rather than driven by project proposals. Hence, the ISO should be the party that assigns proportionate responsibility among all eligible entities with possibly just minor modifications needed to its current authority under the tariff in this regard.

Once the Phase 2 plan is complete, the ISO proposes that eligible PTOs will be granted the right of first refusal over transmission elements that have a terminus in their service territories. As noted above, we do not believe that a right of first refusal should inhibit opportunities for joint development of transmission, given the scale of infrastructure investment needed.

Project Approval by the ISO Board

The ISO will recommend for Board approval transmission project proposals addressing the needs identified in the final state-wide plan. The ISO will evaluate the proposed

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31 Comments by SCE at 6, CPUC at 4, Six Cities at 1.

32 NCPA comments at 1-2.

33 NCPA comments at 1-2.

34 Section 24.1.1 (c) of the Tariff states that: Where the CAISO proposes a transmission addition or upgrade during the CAISO's Transmission Planning Process and the project is approved by the CAISO Governing Board or included in the CAISO annual Transmission Plan and approved by CAISO management, as appropriate. In determining whether to approve the CAISO proposed transmission addition or upgrade, the CAISO Governing Board and CAISO management shall apply the same factors set forth in Section 24.1.1(b). If approved by the CAISO Governing Board or CAISO management, as appropriate, the CAISO will designate one or more of the Participating TOs with PTO Service Territories in which the terminus of the transmission addition or upgrade will be located to act as Project Sponsor. Where two or more Participating TOs are designated as Project Sponsors, such CAISO designation will include the proportionate responsibility between or among Participating TOs to own, construct, and finance the transmission addition or upgrade. If a Participating TO refuses to act as a Project Sponsor under this Section 24.1.1(c), the CAISO will first request other designated Participating TO(s) to assume the remainder or greater proportionate responsibility, and if no other Participating TO had been designated or is willing to increase its proportionate responsibility, the CAISO may solicit bids to finance, own, and construct the transmission addition or upgrade.

transmission upgrades or additions submitted during the Phase 3 request window to determine whether the project proposal:

- is consistent with a Category 1 or Category 2 transmission element;
- satisfies Applicable Reliability Criteria and ISO Planning Standards; and
- is a cost effective means by which to deliver the renewable resource capacity associated with the transmission element identified in the final renewable resource transmission plan for the ISO Balancing Authority Area or annual update to the final plan.

These project proposals will be presented to the ISO Board for approval beginning in March 2011. Category 1 projects that have been given final approval can proceed with siting and permitting. The ISO is aware of stakeholder concerns that the Category 2 conditionally approved projects will not proceed due to the risk of incurring unrecoverable costs. At the same time, because there are expectations that IOU contracts and shortlists for renewable projects will achieve or exceed the 33% RPS requirement within the coming year, especially given changes to the 2020 demand forecast, it would be imprudent to grant final approval to projects that may ultimately lead to underutilized capacity. Hence, it is appropriate to condition project approval upon further market and regulatory developments to ensure that infrastructure development is efficient. To mitigate the risks to project developers of incurring unrecoverable costs, the ISO proposes that Category 2 projects be eligible for abandoned cost recovery for activities undertaken based upon conditional approval for a project that does not ultimately receive final approval.

Annual Recalibration of the RETPP Final Plan and Final Approval of Conditionally Approved Projects

As proposed in the October 30 proposal, the state-wide 33% RPS plan will be evaluated each year based on new developments to determine whether the Category 2 projects should receive final approval, and whether any new plan elements or projects should be evaluated and conditionally approved.[35] It is anticipated that the annual recalibration study will provide the information required by project proponents to determine whether the triggers identified in the criteria have been met, although other information may be provided to the ISO in support of an application for final approval.

Specifically, the ISO proposes a process for the annual recalibration of the 33% RPS plan that replicates the three-phase RETPP on an annual cycle. Thus there would be a Phase 1 revised conceptual plan targeted for June 2011, a Phase 2 revised final plan targeted for September 2011, followed by the Phase 3 proposal submission window leading to approval of project proposals by December 2011.

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[35] In comments on the October 30 RETPP paper, there was broad support for an annual recalibration study. Stakeholders suggested that the 33% RPS study be updated to include information on renewable generation, PPAs and commercial viability, load and generation forecasts, LGIP and regional information from TEPPC/WECC/CTPG, energy policy developments and major market uncertainties.

Phase 1 would again include collaboration with CTPG beginning in the first quarter of 2011, and would consider and adopt modifications to the 33% RPS statewide conceptual plan adopted in the previous cycle.

Following the release of the revised statewide conceptual plan the ISO would establish a two-month period during which the ISO and interested parties may propose updates to the revised conceptual transmission plan for the ISO Balancing Authority Area. Such updates may include, but are not limited to:

- Information from the LGIP and the ISO Interconnection Queue;
- The status of projects approved in the prior annual renewable resource transmission plan;
- System operational information and the need for transmission projects to provide access to resources providing renewable integration capabilities;
- Technological changes; and
- Resource procurement information from the California Public Utilities Commission long term procurement proceedings.

The ISO will evaluate the new information against the existing 33% RPS plan for the ISO BAA and post recommended updates on the ISO website. Such updates may include, but are not limited to:

- Final approval for projects conditionally approved in prior plans;
- Elimination of the need for projects conditionally approved in prior plans;
- Identification of needs for transmission upgrades or additions not included in prior plans.

The ISO will hold, at a minimum, one stakeholder meeting to discuss the updated renewable resource transmission plan and provide an opportunity for stakeholder comment. The updated plan, and the stakeholder comments, will then be submitted to the ISO Board of Governors for approval.

Following approval of the updated plan, the ISO will follow the process described above for Phase 3 of the RETPP to solicit projects and designate project sponsors to meet needs not previously identified in prior renewable transmission plans for the ISO Balancing Authority Area.

On an annual basis, the ISO, in coordination with CTPG, will update the RETPP final plan until the transmission upgrades and additions needed to achieve the state RPS targets have been finally approved.

Cost Allocation

The capital costs of specific transmission projects that receive final ISO Board approval at the conclusion of Phase 3 are eligible for recovery as part of the applicable PTO's transmission revenue requirement through the ISO transmission access charge. If a non-PTO specific project is approved by the ISO Board, the non-PTO is eligible to become a PTO and to recover the capital costs of the project through the ISO transmission access charge, or may elect merchant transmission status, forego

regulated recovery of the project costs and receive congestion revenue rights commensurate with the capacity the project adds to the ISO controlled grid.

IV. APPENDIX – REVIEW OF ORDER 890 REQUIREMENTS

In Order No. 890, the Federal Energy Regulatory Commission identified the following nine principles that must be satisfied for a transmission provider's planning process to be considered compliant with Order No. 890: coordination; openness; transparency; information exchange; comparability; dispute resolution; regional participation; economic planning studies; and cost allocation for new projects. The ISO's transmission planning process (TPP) reflects these nine principles, and the Commission has found it to be compliant with Order No. 890.

The ISO's proposed 33% RPS planning process will include coordination with the California Transmission Planning Group (CTPG), as well as an ISO-specific process that runs parallel to and separately from the CTPG process. The ISO expects that many, though not all, of the nine transmission planning principles adopted in Order No. 890 will be reflected in the CTPG planning process. The dispute resolution and cost allocation principles, for example, are not applicable to CTPG because the ISO does not believe CTPG will have any final decision making authority regarding which transmission lines will be approved and built. Ultimate findings of need for a specific transmission line will occur in the separate transmission planning processes of the individual transmission operators such as the ISO and in the processes of the regulatory agencies that have siting authority.

On the other hand, the ISO anticipates that the certain key Order No. 890 principles such as transparency, coordination, and information exchange will apply to the CTPG process. Transmission providers will share information necessary to ensure effective coordination and develop any plans and base cases. CTPG's assumptions, results and recommendations will be transparent and available. Transmission providers will coordinate to identify potential joint projects and other lines that might be needed to achieve the State's RPS and other goals in a reliable, cost-effective manner, based on the assumptions utilized in the CTPG process.

Even though the CTPG process may not fully reflect all of the Order No. 890 principles, the ISO will be conducting its own separate and parallel planning process. That process will be fully compliant with all of the Order No. 890 principles. Thus, all of CTPG's assumptions, results and recommendations will ultimately be vetted in the ISO's Order No. 890-complaint process, along with other assumptions, results and proposals that the CTPG process may not have addressed. This structure will ensure maximum coordination among the transmission operators in the State, while also ensuring satisfaction of all the Order No. 890 principles. The ISO's parallel process, compliant with Order No. 890, will test the CTPG inputs and determine whether they are sustainable and appropriate for the ISO footprint. Also, it will be the ISO, not CTPG, that determines whether a specific project within the ISO footprint is needed and the project's costs should be included in the ISO's transmission access charge.

California ISO
Your Link to Power

Getting to 33% RPS by 2020 through a Comprehensive Renewable Energy Transmission Planning Process (RETPP)

Stakeholder Meeting

December 8, 2009

Meeting Agenda

10:00-10:10	Introduction	Tom Cuccia
10:10-10:30	Overview of Updated Proposal	Cindy Hinman
10:30-11:30	Phase 1	Lorenzo Kristov
11:30-1:00	Phase 2 (with lunch break)	Udi Helman
1:00-1:45	Phase 3	Lorenzo Kristov
1:45-2:30	Proposed Coordination of, and Revisions to TPP, LGIP, and RETPP	Gary DeShazo
2:30-3:00	Tariff Changes and Remainder of Stakeholder Process	Cindy Hinman

California ISO
Your Link to Power

Getting to 33% RPS – A new transmission planning process and project approval criterion

- A Renewable Energy Transmission Planning Process (RETPP) to plan and develop transmission to meet environmental goals
  - Separate from but coordinated with existing TPP and LGIP
  - Includes a new “renewable access” project approval criterion, not dependent on traditional reliability & economic criteria
  - Features collaborative, state-wide planning process starting with current CTPG effort
- Proposal still conceptual, many details to be developed
- Aiming for Board approval and FERC filing in February 2010, and major results by late 2010 – early 2011

RETPP proposal has 3 phases

- Phase 1 – Formulate statewide conceptual 33% RPS transmission plan with CTPG, including joint projects
  - Draft plan March 2010; final conceptual plan May 2010
- Phase 2 – Refine conceptual plan to arrive at 33% RPS needs assessment for ISO BAA portion of statewide plan
  - Stakeholders may offer additions to Phase 1 plan (e.g., interstate lines)
  - ISO will perform studies to establish final needs
  - Seeking ISO Board approval Dec. 2010 of needed elements, not projects
  - Approval of plan elements may be unconditional (final) or conditional
- Phase 3 – Receive & assess concrete project proposals – for ISO Board approval of ISO BAA projects Spring 2011
  - Projects for conditionally approved lines may proceed with engineering, etc., & will receive cost recovery if project does not get final approval.

Additional features of Revised Proposal

- PTOs will have right of first refusal to build elements of final Phase 2 plan
- Statewide plan & needs will be recalibrated yearly to reflect new developments and decide final approval for conditionally approved plan elements & projects
- RETPP will apply Order 890 principles of transparency & stakeholder participation … but …
- Statewide (CTPG) process will not approve projects or determine cost allocation
  - For ISO BAA projects, ISO will make these decisions
  - For joint projects, the project participants will decide

Renewable Energy TPP
Phase 1

Phase 1 – RETPP will adopt a statewide framework for developing a conceptual transmission plan

- Collaborative effort with CTPG members will provide the framework for a statewide conceptual transmission plan, including joint projects; this effort will:
  - Seek agreement on planning assumptions
  - Agree as far as possible on criteria for approving specific plan elements and projects, yet also allow for different planning authorities to adopt other criteria to meet their needs
  - Include an open stakeholder process to enable all parties to provide input
- ISO will conduct additional analyses to address cases or scenarios not included in CTPG study plan

Objectives of Phase 1 Conceptual Plan

- Conceptual transmission planning is done to develop and rank a large number of alternative candidate transmission facilities
- CTPG (and ISO separately to examine other cases for its BAA) will conduct power flow and stability studies to support a state-wide conceptual plan
  - Would identify specific facilities as candidates to be added to the transmission system or upgraded, including new lines at specific voltage levels between designated points of interconnection, substation upgrades, etc.
  - Would not include all the engineering details required to develop accurate cost estimates for proposals to build the facilities

Phase 1 Schedule

- Already begun with CTPG process
- CTPG public outreach planned
  - December 17 conference call
  - Early January release of initial draft plan
  - January 20 public meeting
  - Mid-February revised draft plan
- ISO will hold mid-January stakeholder meeting to identify need for ISO to study additional cases or scenarios
- CTPG Draft Conceptual Plan by March 2010
  - ISO will open stakeholder process for Phase 2 at this time
- CTPG Final Conceptual Plan by May 2010

Renewable Energy TPP
Phase 2

Phase 2 – Refining the Conceptual Plan to Arrive at Final Determination of Needs

- Stakeholders will have a three-month period to comment on the conceptual plan
  - Stakeholder comments April – June 2010
  - ISO will consider proposed adjustments to conceptual plan, including potential interstate lines, but not specific transmission projects at this time
- With the new input, ISO will refine the plan in Phase 2 to define an efficient build-out for ISO BAA
- The final plan will establish determination of need for both Category 1 (unconditional) and Category 2 (conditional) lines based on commercial, economic and other criteria
- The final plan will be presented to the ISO Board for approval by December 2010

Criteria for Revising the Conceptual Plan

- Criteria will support both refinement of conceptual plan and Category 1 or 2 designations
- Transmission elements within ISO BAA may be ranked based on:
  - Commercial interest in the zone(s) accessed by the transmission element, as evidenced by signed and approved power purchase agreements and interconnection agreements
  - Cost of the transmission element
  - Capacity (MW) and expected energy (MWh) to be accessed
  - Supply cost function of renewable resources in each zone
  - Additional reliability or economic benefits to the ISO grid provided by the transmission element

Criteria for Revising the Conceptual Plan (cont.)

- Transmission elements within the ISO BAA may be ranked based on:
  - Potential future connections to other renewable resource areas and transmission elements
  - Renewable integration impacts and costs associated with the resources in particular zones
  - Potential for a particular transmission element to provide access to generation and non-generation resources needed to support renewable integration (e.g., pumped storage)
  - Risk of stranded investment due to uncertainty associated with the above criteria or other considerations

Final plan will include sufficient detail to support submission of project proposals

- Elements evaluated by Final Plan will include
  - conductor size and line impedance,
  - series compensation levels,
  - substation bus and breaker design,
  - breaker clearing times,
  - transformer characteristics (capacity, impedance, tap range),
  - shunt capacitor and reactor sizes,
  - FACTS device specifications,
  - SPS requirements
- An expected construction schedule would be included along with a timetable for building the overall plan in phases to minimize the risk of stranded assets

Role of CTPG in Second Phase

- ISO expects that CTPG will continue as coordinating body to maintain statewide perspective
- ISO will focus on evaluating transmission elements within ISO-Controlled Grid
- ISO planning decisions will inform CTPG process to allow for refinement of the state-wide plan

Renewable Energy TPP
Phase 3

Phase 3 – Project Submission and Approval, and Annual State Plan Recalibration

- Specific project proposals may be brought to ISO in January to March 2011, for Board approval starting March 2011
- PTOs with service territories within ISO BAA will have right of first refusal to build final plan projects
- ISO will establish criteria to allow subsequent conversion of Category 2 (conditionally-approved) transmission needs or projects into Category 1 (unconditional approval)
- ISO will develop a recalibration process to update the ISO plan on a regular basis (and the state-wide plan, coordinated with CTPG)

Phase 3 Schedule and ISO Board Approval

- Final plan for ISO BAA will be presented to Board for approval of needs in December 2010
  - Approval may be conditional or unconditional for any specific plan element
- Project submission period January – March 2011
- Presentation of project proposals to Board beginning March 2011, for approval based on:
  - Consistency with an approved final plan transmission element
  - Applicable Reliability Criteria & ISO Planning Standards
  - Cost-effectiveness for renewable access
- Annual three-phase recalibration cycle begins thereafter, from April to December

Right of First Refusal

- PTOs with service territories will have ROFR for ISO BAA elements of the final Phase 2 plan
- Justification for this proposed rule includes:
  - PTOs have obligation to build
  - PTOs are or are affiliated with LSEs having RPS requirements
  - PTOs would not face competition for building network facilities if they were not an ISO member
- Independent transmission developers can jointly develop projects with PTOs, focus on projects not proposed by PTOs, or build as Merchant Transmission Sponsors

Recalibration Process

- ISO proposes a process for the annual recalibration that replicates the three-phase RETPP on an annual cycle
  - Phase 1 revised conceptual plan under CTPG targeted for June 2011
  - Phase 2 revised final plan targeted for September 2011
  - Phase 3 proposal submission window leading to approval of project proposals by December 2011
- This process would continue into subsequent years and may be merged with TPP

Recalibration Process – Information used for Phase 2 updates

- Such updates may include, but are not limited to:
  - Information from the LGIP and the ISO Interconnection Queue;
  - The status of projects approved in the prior annual renewable resource transmission plan;
  - System operational information and the need for transmission projects to provide access to resources providing renewable integration capabilities;
  - Technological changes; and
  - Resource procurement information from the California Public Utilities Commission long term procurement proceedings.

Coordination of RETPP, TPP and LGIP

The RETPP will address all major infrastructure decisions in a comprehensive manner

- Current Transmission Planning Process will plan & approve reliability projects
- Large Generator Interconnection Process will plan & approve network upgrades pursuant to LGIAs that can be assessed apart from the RETPP comprehensive plan
- Projects approved under TPP & LGIP will be inputs to 33% RPS process so all RPS benefits are accounted for.

Economic projects would be assessed within the RETPP

- Economic projects will be difficult to assess outside RETPP framework because of uncertainty about:
  - which generation resources in the existing fleet will remain operational;
  - location of renewable resources needed for 33% RPS;
  - how new resources will be effectively integrated into the grid;
  - what the new congestion patterns will be;
  - what renewable energy areas show sufficient commercial interest to ensure achievement of the 33% goal;
  - what specific transmission facilities will be needed to ensure that these goals are achieved in a cost-effective and reliable manner

Tariff Changes and Schedule for Stakeholder Process

New Tariff Provisions Needed

- Structure of three-phase RETPP
  - Coordination with regional planning entities
- New RPS criterion for project approval
  - For final RETPP plan elements
  - High-level criteria for Category 1 (unconditional or final) and Category 2 (conditional) approval
- Right of first refusal for PTOs with respect to final RETPP plan elements
- Many details will be incorporated into Planning BPM

Updated Schedule for Stakeholder Process

- December 15 – Stakeholder comments due on second revised straw proposal
- December 31 – ISO posts draft final proposal
- January 6 – Stakeholder conference call to discuss draft final proposal
- January 13 – Stakeholder comments due on draft final proposal
- February 11-12, 2010 – ISO Board of Governors meeting
- February 2010 – Tariff stakeholder process and tariff filing

RENEWABLE ENERGY TRANSMISSION INITIATIVE

PHASE 1B

FINAL REPORT

January 2009

Reflects changes from the December 17, 2008, Stakeholder Steering Committee meeting.

RETI Coordinating Committee

Prepared for

RETI Coordinating Committee
RETI Stakeholder Steering Committee

RETI-1000-2008-003-F

RETI Stakeholder Steering Committee

Renewable Energy Transmission Initiative

RETI Phase 1B – Economic Analysis of Competitive Renewable Energy Zones

FINAL REPORT
B&V Project Number 149148

Contract Manager

University of California, Office of the President
California Institute for Energy and the Environment

January 2009

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1.0 Summary

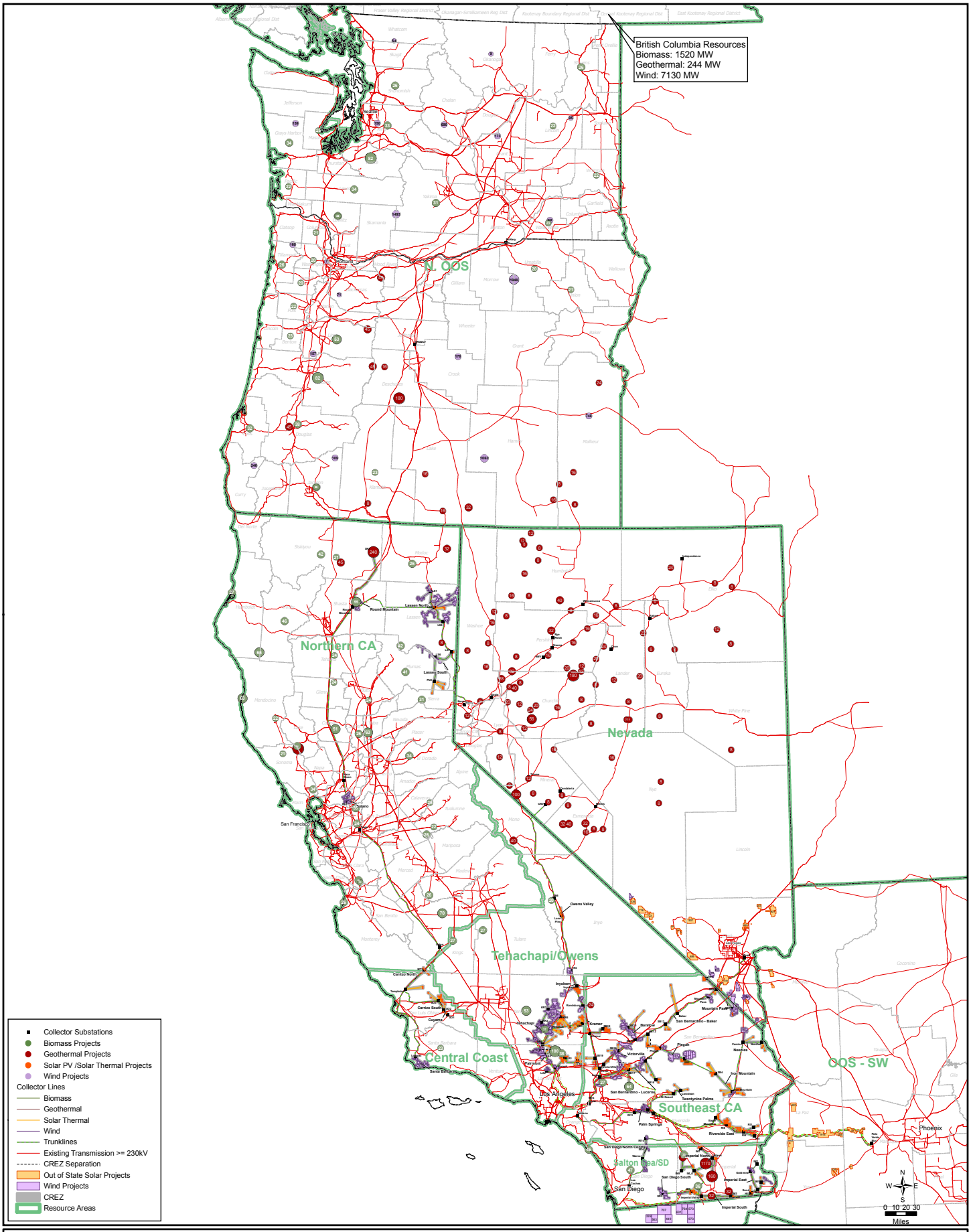
Black & Veatch is pleased to provide this Final Report on the Phase 1B activities of the California Renewable Energy Transmission Initiative (RETI) to the Stakeholder Steering Committee (SSC). This report includes the identification and economic analysis of renewable energy zones, resource areas and discrete renewable projects that may assist California in achieving its renewable energy goals. Additionally, this report identifies and characterizes the individual renewable resources evaluated in the RETI project.

This report is the final Black & Veatch deliverable for the Phase 1 portion of the RETI. In May 2008 the SSC accepted the RETI Phase 1A Report on study methodology, resources and economic assumptions, as well as the methodology to identify and value resources to be included in RETI analyses. In August, 2008 Black & Veatch provided the Draft Resource Report as in interim deliverable for the Phase 1B portion of RETI. That report identified potential resources to be used in the RETI analysis. This report, which replaces the Draft Resource Report, details the resources that were used in the RETI analysis and provides the economic valuation and ranking of Competitive Renewable Energy Zone (CREZ) areas in California and out-of-state resource areas with the potential to deliver renewable energy to meet California Renewable Portfolio Standard requirements.

This report is released in conjunction with an environmental ranking of the CREZs prepared by the RETI Environmental Working Group (EWG). The two reports are designed to provide the SSC the technical information necessary for the SSC to recommend transmission requirements to be considered in Phase 2 of RETI.

1.1 Identification and Ranking of Competitive Renewable Energy Zones and Resource Areas

RETI identified over 80,000 MW of potential renewable resources within 29 CREZs in California, and 40,000 MW located outside of California with the potential to deliver energy to California. Additionally, RETI identified over 25,000 MW of non-CREZ resources in California. The overwhelming majority of this non-CREZ capacity comes from distributed photovoltaic (PV) systems, as well as smaller stand-alone projects (such as biomass) that do not need large-scale transmission upgrades. For discussion purposes, CREZs, stand-alone projects and out-of-state resources have been aggregated into seven Resource Areas. Figure 1-1 depicts the resources and CREZs that are included within each resource area.



Disclaimer:
These maps are for transmission planning only and not for project siting.

Resource Map

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RETI - Phase 1B Resource Maps.mxd = Nov. 13, 2008 = C.Holmgren

1.2 California CREZ Economic Rank Cost and Supply Curve

Using the criteria developed and approved by the SSC, Black & Veatch has developed an economic ranking of the 29 identified CREZs. Within seven of these CREZs, Black & Veatch identified and characterized "sub-CREZs," or sets of projects that share common transmission, development timeframe and similar economics. Defining sub-CREZs allows for the development of a supply curve of resources within a CREZ, providing the SSC with finer granularity of the potential cost and development of resources within a CREZ. Table 1-1 provides the weighted average ranking cost of each CREZ and sub-CREZ in California. The rank cost for a resource includes the cost of generation and transmission, less the capacity and energy value.[1] At the request of the SSC, an alternative rank cost was also developed and is shown in the far right-hand side of the table. This rank cost excludes the capital cost of new transmission lines needed to access the CREZs. If this alternate rank cost were used to rank CREZs, the order of the CREZs in Table 1-1 would be slightly different.[2]

CREZ rankings as presented in Table 1-1 and the figures in this Summary do not include the uncertainty bands discussed later in this report.

The RETI analysis shows the need ("net short") for approximately 68,000 GWh/yr of renewable generation in 2020. To meet this need with only CREZ resources in California, the first ten CREZs in Table 1-1 would be required (using the base case transmission cost assumption). These CREZs are:

- Solano
- Palm Springs
- Victorville-A
- Imperial North-A
- Round Mountain-A
- Fairmont
- Tehachapi
- Riverside East-A
- Victorville-B
- Kramer

[1] All dollar amounts in this report are in 2009 dollars, unless otherwise stated. Further, unless otherwise stated, all economic figures in this report represent the midpoint of a range of costs, as discussed further in the uncertainty analysis in Section 5.

[2] The alternate rank cost formulation was developed to demonstrate the effect that the capital cost of transmission has on CREZ rank costs. Transmission cost estimates at this early stage of analysis are known to have a large amount of uncertainty. The alternative rank cost shows that even if transmission capital costs were not considered in the assessment, there would be minimal impact on the CREZ rank order.

Table 1-1. Weighted Average CREZ Rank Costs.

CREZ Name	Net Capacity (MW)	Annual Energy (GWh/yr)	Cumulative Energy (GWh/yr)	Weighted Average Rank Cost ($/MWh) *	
				Base Trans. Cost	No Trans. Cap. Cost
Solano	894	2,721	2,721	-29	-29
Palm Springs	770	2,465	5,186	-20	-26
Victorville-A	800	2,112	7,298	-17	-21
Imperial North-A	1,370	10,095	17,393	-13	-13
Round Mountain-A	240	1,598	18,990	-11	-22
Fairmont	6,918	18,318	37,308	-9	-11
Tehachapi	9,642	25,091	62,400	-3	-9
Riverside East-A	1,000	2,339	64,739	3	3
Victorville-B	895	2,267	67,006	4	-2
Kramer	6,627	16,251	83,257	5	-3
Inyokern	2,887	7,136	90,393	8	-3
Owens Valley	1,400	3,433	93,826	10	-7
Lassen South-A	1,000	3,010	96,836	14	3
Twentynine Palms	800	1,944	98,779	15	9
San Bernardino - Lucerne	4,290	10,722	109,501	16	7
Pisgah-A	1,800	4,283	113,785	16	-1
San Diego South	678	1,829	115,614	16	12
San Diego North Central	281	702	116,316	19	15
Carrizo North	1,600	3,225	119,541	19	11
Barstow	2,136	5,106	124,647	21	8
Lassen North-A	333	982	125,629	22	12
Riverside East-B	6,800	15,552	141,181	22	16
Cuyama	400	847	142,028	24	8
Pisgah-B	3,790	8,844	150,872	27	11
Mountain Pass	2,878	6,942	157,814	27	14
Iron Mountain	5,662	12,713	170,527	27	13
San Bernardino - Baker	1,200	2,705	173,232	28	23
Imperial North-B	1,830	4,282	177,514	29	14
Victorville-C	340	860	178,373	29	12
Imperial South	3,745	8,776	187,149	31	16
Imperial East	1,723	3,991	191,140	34	28
Round Mountain-B	187	705	191,845	38	14
Needles	1,061	2,517	194,361	39	17
Carrizo South	3,000	6,118	200,480	41	18
Santa Barbara	433	1,121	201,601	43	13
Lassen South-B	1,200	2,379	203,980	48	14
Lassen North-B	2,001	4,140	208,119	49	25

* The base transmission cost case (first column) includes all elements of the rank cost formulation as described in this report. The second column excludes the capital cost component of the transmission cost from the rank cost formula.

These CREZs represent the most cost-effective large scale resources in the state. The resources include geothermal, wind, and solar resources throughout the state, though the overwhelming majority of these resources are located in southern California, specifically in the Tehachapi Mountains, Salton Sea area of Imperial County, and the Mohave Desert. Southern California resources rank highly due to the quality of solar resource and the assumed transmission availability in these areas.[3]

There are relatively few cost-competitive resources located in northern California, as the solar and wind resource in northern California is poor relative to southern California. Additionally, northern California resources tend to be located in isolated areas way from the bulk transmission system, and the cost to interconnect these resources to the grid contributes to the poor economics.

Figure 1-2 depicts the California CREZs that are available to meet the net short requirement by cost and resource quantity. This figure depicts the rank cost with the base case transmission cost assumption. This figure shows that California has sufficient resource to meet its renewable energy goals, albeit at increasingly higher costs of development. This figure also includes out-of-state resources for comparison. Some of these resources may be cost competitive with California CREZs, as discussed further in the next section.

Figure 1-3 depicts the same information as Figure 1-2 except the transmission capital cost component has been removed from the rank cost formulation. While the apparent rank costs of nearly all CREZs/resource areas would fall if no transmission costs were assumed, the only resource area that would shift into the top ten CREZs/resource areas would be the British Columbia-B resource. British Columbia resources areas are the furthest away of all resources studied in this project. This scenario is discussed further in Section B of this report.

Rank costs presented in the remainder of this report include the transmission capital cost component unless otherwise indicated.

[3] Discussed in Section 3, RETI assumed CAISO-approved and publicly-owned utility (POU) approved transmission would be constructed, including Southern California Edison's Tehachapi and Devers-Palo Verde 2 lines, San Diego Gas & Electric's Sunrise Project, and Imperial Irrigation District's / Los Angeles Department of Water and Power's Green Path line. The capital costs for this transmission were assumed to be included in utility transmission rates, and were not considered as an incremental cost to the resources interconnecting to this transmission.

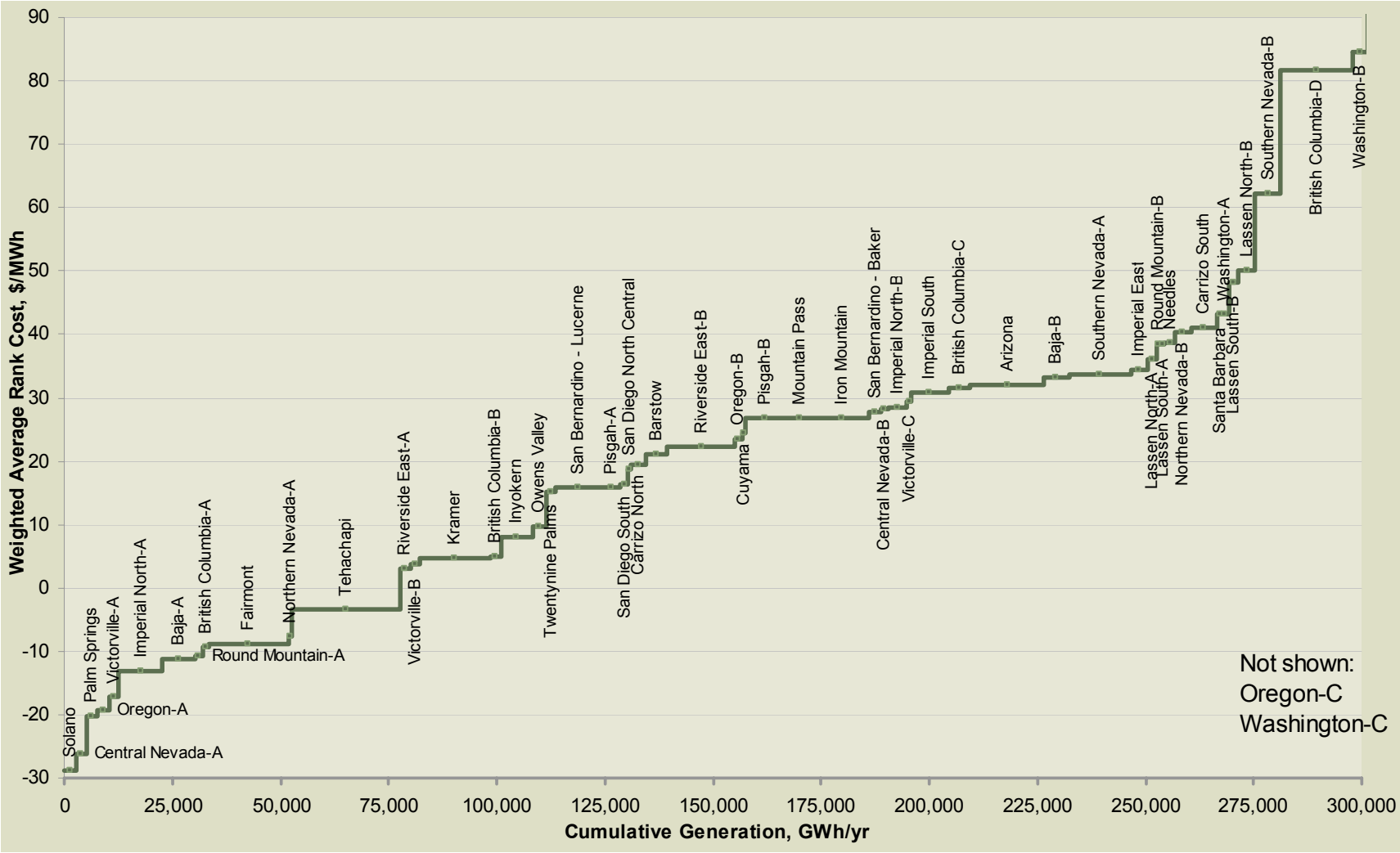

Figure 1-2. Weighted Average Rank Cost ($/MWh) for CREZ and Resource Areas.

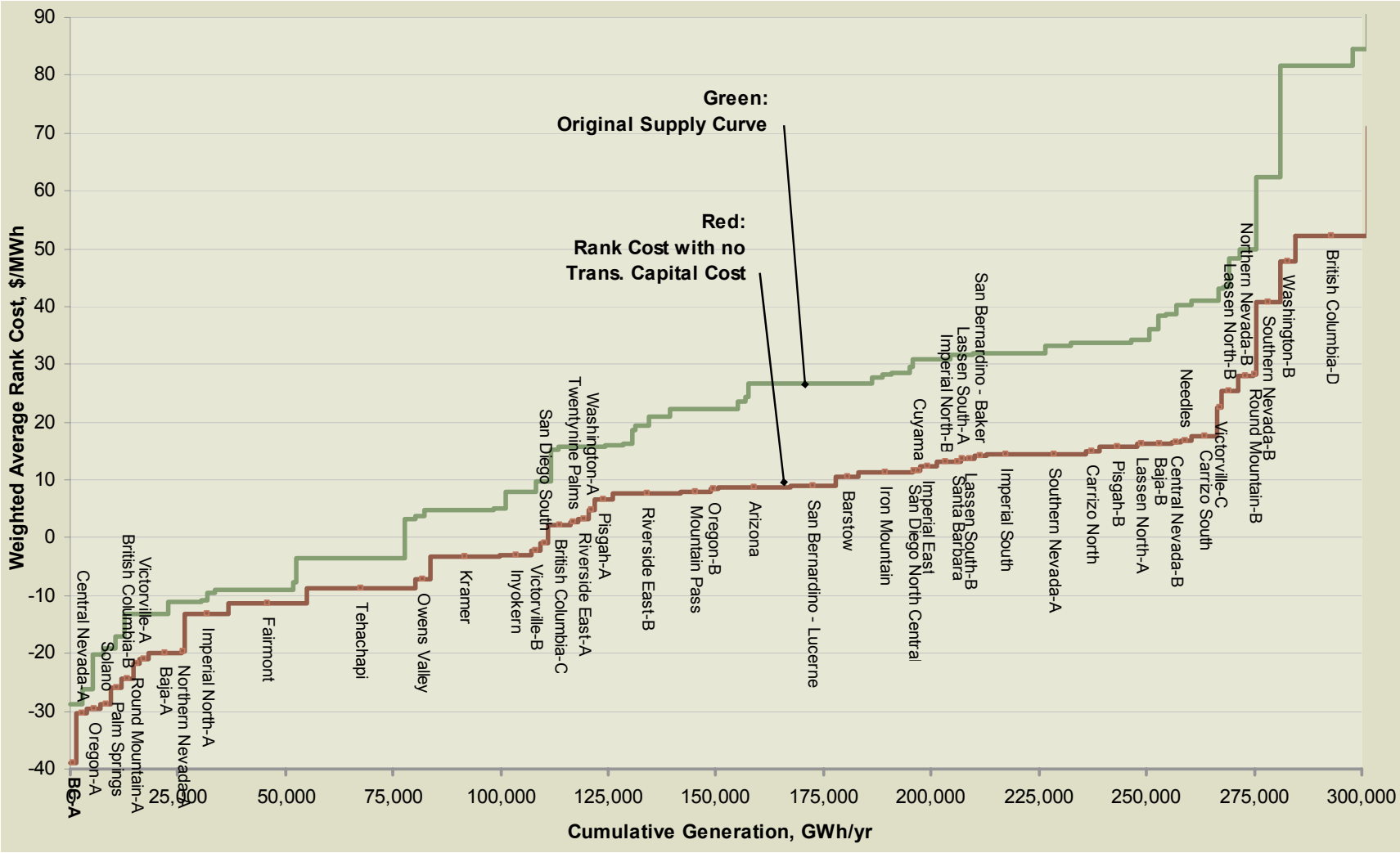

Figure 1-3. Impact of Removing Transmission Capital Cost from all Resources (in Ascending Order).

1.3 Economics of Out-of-State Resources

In addition to the California CREZs, there appear to be out-of-state resources that could justify the cost of new transmission construction and still be competitive with in-state California resources. RETI identified over 40,000 MW of potential resources out-of-state, with generation potential of approximately 110,000 GWh/yr. Resources were identified in Arizona, Nevada, Oregon, Washington, British Columbia, Canada (B.C.) and Baja California Norte, Mexico ("Baja"). Of these, about 15,000 GW/yr were modeled to be competitive with California CREZs, as summarized on Table 1-2. These resources include wind and geothermal in B.C, geothermal in Oregon and Nevada, and wind resources in Baja. Wind resources in Mexico look particularly promising, and more study is recommended to refine the economic estimates and the environmental factors.

In addition to the base case economic assessment, several sensitivity investigations were performed that included out-of-state resources. The result of these studies was that there could be scenarios where almost double the capacity shown in Table 1-2 could be cost competitive.

Table 1-2. Base Case Cost-Competitive Out-of-State Resources.

Region	Capacity (MW)	Annual Energy (GWh/yr)	Weighted Average Rank Cost ($/MWh)
Nevada	427	2,976	-21
Oregon	392	2,848	-19
Baja California Norte*	2,368	7,633	-11
British Columbia**	340	1,553	-9

Notes:

* Assessment of Baja wind resources in this project was preliminary. Evidence exists that additional resources may be cost effective, and this should be further explored in Phase 2.

** An additional 700 MW of resource (1040 MW total) is available at a relatively competitive cost of $5/MWh.

1.4 Economics of Non-CREZ Resources

As with out-of-state resources, there are several non-CREZ resources (areas less than 250 MW) that are cost competitive and may be used to serve California's energy requirements and satisfy the RPS goals. About 70,000 GWh/yr of smaller-scale non-CREZ resources were modeled in California, the majority of which were 20 MW solar

PV projects. Most biomass projects are also not within CREZs, as they are generally smaller and can be sited to take advantage of existing transmission infrastructure. Many of the non-CREZ resources are located in northern California.

Resources that are not reliant on large-scale transmission planning to be integrated into the system may be able to be brought on-line faster and at lower cost than CREZ resources that are reliant on such transmission.

Of the non-CREZ resources, a total of seven wind and geothermal projects were considered competitive with California CREZs in the base case. These projects total about 430 MW and 2,200 GWh/yr of annual generation. This is a relatively small fraction of the total supply needed to meet California's RPS. Because of the uncertainty of the costs and timing for the large scale transmission needed to reach CREZs, it is very likely that significantly more than 430 MW of non-CREZ resources will be developed in California.

1.5 Uncertainty and Sensitivity Analysis

It is very important to consider the uncertainty in the estimates used to quantify and value resources. By their very nature, these estimates include a margin of error due to the assumptions made by the RETI team. In addition to general uncertainty, there are wide variety of plausible future scenarios which may affect the modeling results and the ranking of the CREZs. An uncertainty and sensitivity assessment was carried out to identify which CREZs and resources areas might be economically viable under certain situations. As a result of this assessment it was found that the following CREZs and resource areas could be cost-competitive under certain scenarios[4]:

- Twentynine Palms
- San Bernardino - Lucerne
- Pisgah-A
- San Diego South
- San Diego North Central
- Carrizo North
- Lassen North-A
- Lassen South-A
- Santa Barbara
- Victorville-C

[4] This list includes CREZs identified by the sensitivity analysis to be potentially cost competitive. If the full range of the uncertainty bands is considered, nearly every CREZ and resource area is potentially cost competitive under certain scenarios. For example, if costs have been significantly overestimated only for high cost resources, they may be cost competitive with lower cost resources.

- Round Mountain-B

In addition, a sensitivity assessment of reduced solar costs was performed with significant implications. The sensitivity study used thin-film manufacturer cost targets as the basis for the solar capital cost. This assessment indicated that the costs for the large-scale solar CREZs would drop significantly. Figure 1-4 shows how the resource supply curve would be impacted by assuming lower costs for solar deployment. Another significant conclusion from the sensitivity study is that large amounts of distributed non-CREZ solar PV resources could be economic. The cost-competitive non-CREZ resources increase to about 45,000 GWh/yr, over two-thirds of the net short requirement. It is important to note that the non-CREZ resources were assumed to be connected to smaller substations on the 50-200 kV transmission system. Large scale deployment of hundreds of such systems would likely require system upgrades and reinforcements; however, this was beyond the scope of this study.

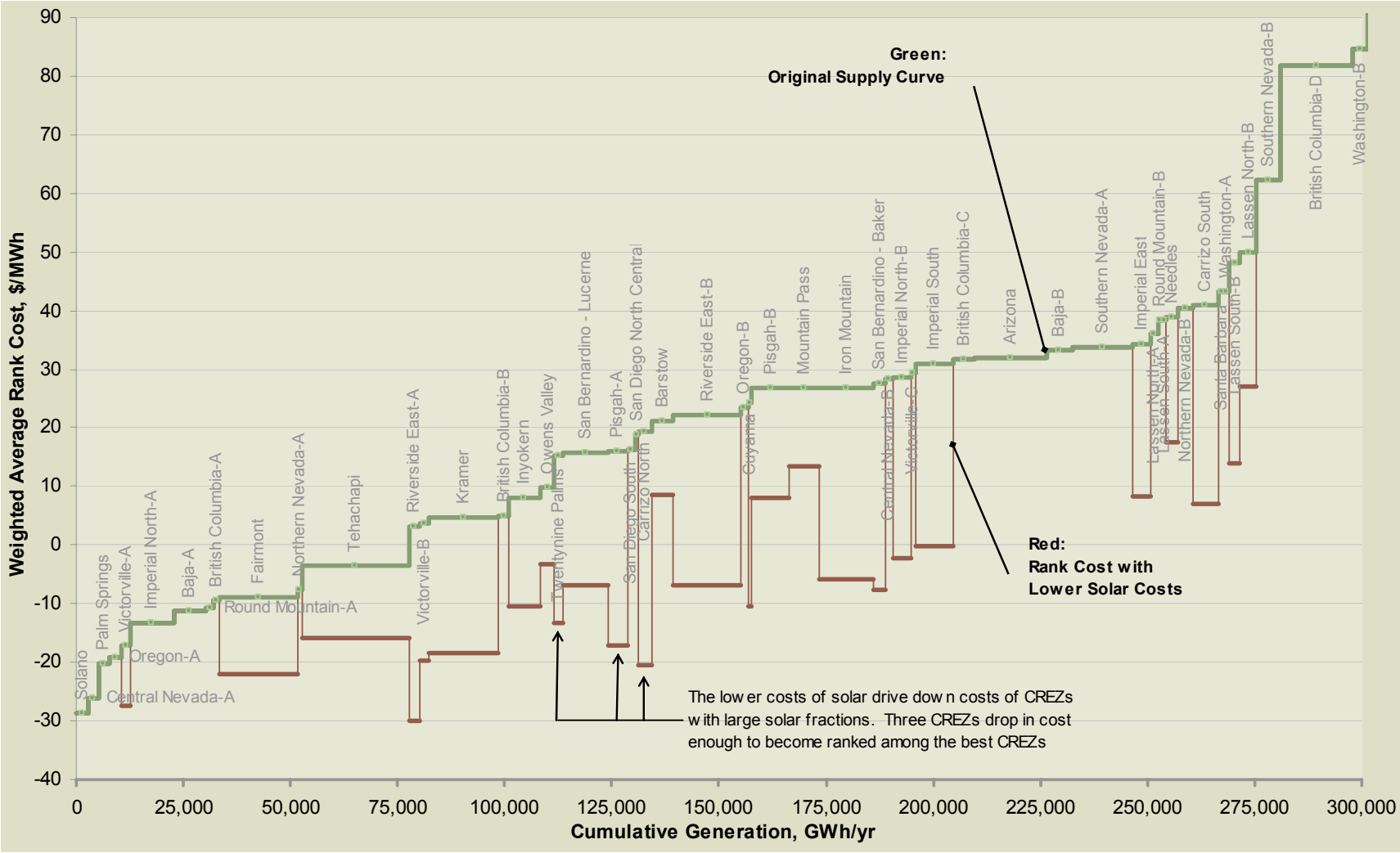

Figure 1-4. Effect of Reduced Solar Costs on CREZ Supply Curve.

Note that this figure does not show the reduced output (generation, GWh) of thin film solar PV. It is intended to just highlight the potential cost savings.

1.6 Summary of Renewable Energy Resources

This report identifies and characterizes over 2,100 individual projects. Black & Veatch initially identified over 3,600 projects, with a total capacity of over 500 GW, which were detailed in August 2008 Phase 1B Draft Resource Report. Based on recommendations by the SSC, Black & Veatch culled this list using economic screens to focus the analysis to the most economically developable resources. Table 1-3 presents a summary of resources by type and resource area. Individual resource identification and characteristics are included in Appendix D.

Table 1-3. RETI Resource Summary by Resource Area

	Biomass	Geo-thermal	Dist. Solar PV[a]	Large Solar[b]	Wind	Total
Capacity (MW)						
Central Coast	23		920	5,000	509	6,452
Northern CA	1,150	460	16,480	2,400	3,518	24,008
Salton Sea/SD	159	1,434	1,640	7,000	1,128	11,361
Southeast CA	91		4,020	29,000	5,579	38,690
Tehachapi/Owens	302	24	4,400	21,800	5,474	32,000
N. OOS[c]	2,423	764			15,080	18,267
Nevada		1,283		7,429	1,475	10,186
OOS – SW[d]			40	7,129	5,000	12,169
Total	**4,148**	**3,965**	**27,500**	**79,758**	**38,020**	**153,390**
Generation (GWh/yr)						
Central Coast	159		2,046	10,727	1,410	14,342
Northern CA	8,060	3,381	33,951	4,858	9,889	60
Salton Sea/SD	1,112	11,074	3,785	16,580	3,121	35,673
Southeast CA	638		9,215	70,621	15,571	96,046
Tehachapi/Owens	2,118	168	9,683	56,428	16,102	84,500
N. OOS	16,980	5,827			37,427	60,234
Nevada		9,165		17,761	3,203	30,130
OOS – SW			95	17,722	14,449	32,266
Total	**29,068**	**29,616**	**58,775**	**194,698**	**102,497**	**414,653**

Notes:

[a] This column quantifies the potential of small-scale, distributed solar PV projects 20 MW in size. Potential solar PV resources are much larger than shown in this table.

[b] This column quantifies the potential of large-scale solar plants. These project sites can utilize either solar thermal (200 MW per project) or solar PV (150 MW per project) technology. Solar thermal resource potential is quantified in this table. Solar PV technology is evaluated elsewhere in this report.

[c] North out-of-state = Oregon, Washington, British Columbia.

[d] Southwest out-of-state = Arizona and Baja.

1.7 Use and Purpose of this Report

This report is intended to provide the SSC the economic ranking and valuation of California CREZs and the economic valuation for non-CREZ resources located within and outside of California. This information, coupled with the EWG analysis of the California CREZs, will assist the SSC in developing recommendations for transmission projects to access renewable resources in Phase 2 of RETI.

1.8 Recommended Phase 2 Issues

During the Phase 1 analysis Black & Veatch encountered numerous issues that it recommends be further explored in Phase 2. These are discussed further in this section.

RETI is intended to be a long-term and dynamic process designed to identify promising renewable resources for California and the transmission to access these resources. The information included in this Phase1B report is designed to provide RETI participants and stakeholders with the best available economic analysis of currently-known resources. The Phase 1B report includes a base case and several scenario analyses designed to reflect a plausible range of potential future scenarios. In subsequent phases, RETI is anticipated to be adapted to eliminate resources and areas with limited potential and to incorporate new information on resources, requirements, economics and other significant factors as it becomes available. The RETI analysis will be tailored in the future to meet the needs of the time.

There is a plethora of potential alternative assumptions, sensitivities, and analytical approaches that could be used in the RETI process, both in this phase and future phases. There is no single "correct" approach to conducting such a broad economic assessment. Comments on the report identified several areas where alternative methodologies may be considered in the future, and others identified critical assumptions that may need to be reviewed as they have substantial impact on the analysis results. Highlight below are several of the areas where alternative assumptions and approaches may ultimately result in different resource rankings.

1.8.1 Transmission Methodology

RETI employed an incremental transmission cost approach, adding transmission capacity to deliver all energy identified within in a CREZ to a designated major load area. This incremental cost approach includes the aggregate cost of transmission lines, substations and ancillary facilities, taking into account line losses and variable costs. RETI Phase 1 added transmission capacity to transmit renewable energy based on potential generator production. No load-flow analyses were conducted, nor were potential reliability benefits of new transmission considered in the transmission costs. In

addition, regional transmission benefits and potential cost sharing (such as with out-of-state utilities) were not captured in the analysis.

The advantage to using the incremental facility approach in RETI is that it identifies, quantifies and costs specific transmission facilities required to deliver a quantity of energy to the grid and to load areas. Alternative approaches, such as a simple percentage of resource cost or estimating a flat dollar-per-MW-mile, will provide for a transmission cost but do not adequately account for the cost of transmission based on distance from generation site to delivery point. A limitation to this approach is that it may not mirror the development of transmission, even among the same resources identified in RETI. Transmission lines will likely be added to the California grid to not only interconnect specific renewable resources to a specific load area, but to enhance reliability and reinforce the transmission system in total. This level of analysis can only be completed by conducting comprehensive load-flow modeling, which is the focus of the RETI Phase 2 effort.

The relative costs of CREZs may change when a more accurate transmission system cost assessment is complete. This assessment would include the potential to serve multiple zones and balancing areas as opposed to the incremental approach taken in Phase 1B.

1.8.2 Capacity Costs and Integration Costs

To value the capacity of renewable resources RETI used an assumption developed by the California Energy Commission in their cost of generation analysis that the installed cost of a fully dispatchable combustion turbine is $204/kW-year. This assumption was agreed to among the Phase 1A working group in Spring 2008 and used in the resource valuation and rank cost calculation used in RETI. To understand the sensitivity of the resources and CREZs to changes in the capacity value, Black & Veatch conducted a sensitivity analysis assuming the capital cost of a CT was half of the cost identified by the CEC.

The appropriate method to value capacity from resources is hotly debated. One could argue that to the extent that a renewable resource results in avoiding the development of conventional resources, the total cost of developing that generation is part of the capacity value. This “raw” capacity value is equal to the capital cost of the avoided resource. This value does not however, consider the market revenues of energy generation when dispatching that resource. Arguably, one would only build generation with the intention of using it at least partly to serve demand, and the revenues earned from selling energy from the facility when it is infra-marginal should be considered when valuing the capacity benefit of the resource. In this case the value of capacity is the

inferred value between the total cost of the resource less the market revenues earned by the resource. Appropriate capacity valuation methods should be explored further in the next phase of RETI.

In addition to capacity value, integration costs have not yet been included in the RETI analysis. As information is developed on appropriate assumptions to use for the cost to integrate intermittent wind and solar resources, these should be included in the RETI analysis.

1.8.3 Baja California Norte Wind Resources

Black & Veatch conducted resource assessments for all resources areas located in the United States. Due to limited available public information, Black & Veatch relied on a variety of primary and secondary sources of information to assess the developable potential of renewable resources in these regions. Based on CAISO queue applications, Black & Veatch identified approximately 5,000 MW of developable wind potential in Baja. Comments were received that this substantially understates the resource potential of the region.

Upon further review Black & Veatch identified a technical potential of approximately 25,000 MW of wind resources, though this estimate has no consideration for development constraints. Further analysis is required to determine the developable potential to result in an estimate consistent with those developed for American locations, factoring in environmental constraints, infrastructure requirements (for example, roads and transmission ROW) and development costs.

1.8.4 Project Identification Limitations

Black & Veatch conducted resource assessments and project identification for all resource areas to assess the developable potential of renewable resources in these regions. The assessment is based on the best available public information on resource potential; however, Phase 1 was not a detailed siting investigation. There are known issues with certain CREZs such as land ownership fragmentation that should be further investigated in Phase 2.

To insure that RETI includes the best available data in future phases, Black & Veatch recommends that project development and resource assessments be continuously monitored and the RETI dataset be refreshed to insure that it includes the broadest set of viable and developable projects.

BEFORE THE ENERGY RESOURCES CONSERVATION AND DEVELOPMENT COMMISSION OF THE STATE OF CALIFORNIA
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APPLICATION FOR CERTIFICATION FOR THE *CARLSBAD ENERGY CENTER PROJECT*

Docket No. 07-AFC-6
PROOF OF SERVICE
(Revised 12/30/2009)

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DECLARATION OF SERVICE

I, Jessie Baird, declare that on January 14, 2010, I served and filed copies of the attached, CENTER FOR BIOLOGICAL DIVERSITY'S PREHEARING CONFERENCE STATEMENT; DECLARATION OF RORY COX; REBUTTAL TESTIMONY OF TAM HUNT; DECLARATION OF TAM HUNT and EXHIBITS. The original of these documents, filed with the Docket Unit, is accompanied by a copy of the most recent Proof of Service list, located on the web page for this project at: **[http://www.energy.ca.gov/sitingcases/carlsbad/index.html].** The documents have been sent to both the other parties in this proceeding (as shown on the Proof of Service list) and to the Commission's Docket Unit, in the following manner:

(***Check all that Apply***)

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X sent electronically to all email addresses on the Proof of Service list;

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1516 Ninth Street, MS-4
Sacramento, CA 95814-5512
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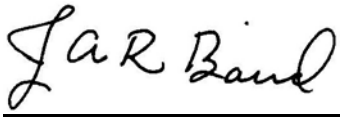
I declare under penalty of perjury that the foregoing is true and correct.



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