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APPENDIX A

SGIP Working Group
Recommendations for Program Modification Requests[1]

[1] Please note: this document includes SGIP Program Administrators' recommendations only. Attachments and appendices referenced below are not included in this document.

Self-Generation Incentive Program
Proposed Modification to Current Rule Regarding Diesel Operation
PMG04-001-PGE

Summary

A potential Self-Generation Incentive Program (SGIP) Applicant, St Helena Hospital, requests a modification to the rules found in the Self Generation Incentive Program Handbook, specifically as noted in Section "2.4.8 Not Eligible under the Program" covering diesel operation and reads as follows:

- *Any system/equipment that is capable of operating on diesel fuel or Diesel Cycle for start up or continuous operation*

The Applicant proposes that ***the rule be modified to allow an exemption*** for "Emergency Only" operation as permitted under the Bay Area Air Quality Management District (BAAQMD) rules, which would limit the hours and purpose of operation. The suggested change is:

- *"Any system/equipment that is capable of operating on diesel fuel or Diesel Cycle for start up or continuous operation.*
- ***EXEMPTION: An exemption shall be allowed for a facility, providing necessary public services and operating in an emergency condition when normal operation on natural gas or other primary fuel is not possible."***

Background

On April 13, 2004, a first draft of a Program Modification Request (PMR) package was submitted to the Sponsoring Program Administrator (SPA), Pacific Gas and Electric (PG&E), on behalf of St. Helena Hospital[2]. The SPA reviewed the draft PMR in consultation with an outside engineering consultant[3] hired by the SPA to provide assistance with matters concerning the Self-Generation Incentive Program (SGIP). Comments and questions on the contents of the initial draft PMR package – as they related to completeness in satisfying the Program Modification Guidelines – were then forwarded to the PMR Applicant for incorporation into the final package.

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[2] Industrial Power Technology prepared the PMR on behalf of St. Helena Hospital
[3] Alternative Energy Systems Consulting, Inc. (AESC)

On May 7, 2004, a final PMR application package was submitted to the SPA and was deemed complete (Attachment B). The package was distributed to the SGIP Working Group for review prior to the next scheduled monthly meeting.

On May 18, 2004, the Working Group reviewed and discussed the proposal as an agenda item at the regularily scheduled monthly meeting. Thom Shelton from Industrial Power Technology joined the discussion by conference call. Five follow-up questions resulted from this presentation and Working Group discussion. These questions, and the subsequent answers provided by Mr. Shelton, follows:

1. What is the incremental cost of purchasing an engine, which is capable of operating on both natural gas and liquid fuel versus one, which can operate only on natural gas? How is this incremental cost to be estimated or determined -- since if this modification was approved, this incremental cost would be considered ineligible?

   The incremental cost of a dual-fuel turbine vs. a natural gas only turbine is approximately $35,000 per engine and we would agree that this amount should be excluded from the SGIP calculation. I may have quoted a lower cost earlier, as I thought the above figure was for both machines.

2. What is the definition of a "facility providing critical public services"? There is some concern that a wide variety of facilities, not just hospitals, will try and qualify for this exemption (based on recent experience with the many exemptions requested for participation in rolling outages due to ISO calls). The Energy Division is researching the definition used for facilities to be exempted from being included in the rolling-blackout blocks to see if this could be used.

   The term "facility providing critical public services" was employed naturally to include the hospital, but not to exclude other public serving entities that may fall into the category and determined to be eligible. However, if the SGIP Working Group prefers to narrow the definition to include only hospitals, clinics or public entities providing emergency services, we have no objection. As noted above, the hospital is currently exempted from service interruption or curtailment. Perhaps the Group could consider adopting a criteria similar to what has been defined in the "Electric Emergency Plan"

3. What is the definition of an "emergency condition when normal operation on natural gas or other primary fuel is not possible"? If a utility calls for a natural gas curtailment for all on-site generation due to a shortage, is that considered an emergency condition? The description states that for St. Helena Hospital, the waste heat from the generators will supply "100% of the hospital's thermal requirement for heating, cooling and hot water" -- this would seem to indicate that the generation needs to be available on a continuous basis, regardless of what condition might cause an interruption in the natural gas supply.

This may be a little tougher to define as the hospital is on a PG&E primary distribution line and natural gas is virtually always available at this point. The contemplated interruption for this modification request was a natural or man-made event, which severed the supply or caused the supply to be shut down due to a hazardous condition(s). However, during any interruption in gas service, it would always be preferable to operate the turbines and exhaust fired chillers due to their higher operating efficiencies and lower total emissions.

4. What will happen to the existing "less efficient and higher emission" back-up diesel generators if the new dual-fuel Kawasaki's are installed? The write-up implies that they would be removed ("Under the current rule excluding diesel operation, the hospital would have to preserve and maintain older, less efficient generators and boilers which would be operated on diesel fuel in any emergency which disrupted PG&E's supply of natural gas to the Hospital.") -- but in the conference call on May 18th you said they would probably remain in place.

   The backup generation will be required to stay in place as required by NFPA 99 & 110 as applied to hospitals. In addition, the cost of removing the boilers would outweigh the possible benefits of having them as redundant backup should anything preclude the operation of the Kawasaki/Broad primary systems and the space gained by removing these systems would have little value to the hospital's operation.

5. If there is an electric interruption on the grid, and the hospital uses the dual-fuel generators to provide back-up power, what assurance is there that they won't operate on diesel fuel even though natural gas is available (possibly because of the high price of natural gas, or the need to periodically run the generators on diesel and the BAAQMD hourly limitation has not been reached)? The CPUC decision specifically excluded rebates for these kinds of systems.

   As the units are base loaded and supplying the hospital's electrical and thermal loads, they will be operating regardless of PG&E's electrical supply situation.

   St Helena Hospital is currently and will continue, to purchase natural gas under long-term contract. This serves to minimize gas price volatility to the hospital and the likelihood of choosing a fuel based on price. Another consideration, which would restrain operation on liquid fuels, is the fact that catalyst life would be significantly reduced, resulting in replacement costs, which would offset any perceived fuel savings.

Concerns and Issues Considered

a. **Original CPUC Decision Establishing the Self-Generation Incentive Program Specifically Excludes Diesel-Fired and Backup Generation**

The original March 27, 2001 CPUC decision which established the Self-Generation Incentive Program[4], references the report prepared by the Energy Division, including the following reference concerning diesel-fired and emergency or backup systems as being ineligible:

- **3.2 Self-Generation Program**
  In its report, Energy Division defines "self-generation" as "distributed generation (DG) installed on the customer's side of the utility meter, which provides electricity for a portion or all of that customer's electric load." (Report, p. 5.) DG units sited on the utility-side of the customer's meter or owned by the distribution utility or a publicly-owned utility would not be eligible for incentives under Energy Division's proposal.

  For the purpose of this program, Energy Division defines DG technologies as internal combustion engines, microturbines, small gas turbines, wind turbines, photovoltaics, fuel cells, and combined heat and power or cogeneration. A subset of these technologies is considered renewable and eligible for differential incentives, as required by § 399.15(b) paragraph (7), including wind turbines, photovoltaics and fuel cells. **Diesel-fired DG resources and emergency or backup systems would not be eligible under the program** ***(emphasis added).***

- **Attachment 1**

  "Hybrid" self-generation systems that incorporate technologies from different incentive categories will receive payments based on the appropriate category. **Diesel-fired systems are ineligible for participation in this program** ***(emphasis added).***

b. **Definition of "Facility Providing Critical Public Services" Which Would Qualify for Exemption – Many Applicants May Try to Qualify for Exemption**

It has been suggested by the PMR Applicant that the same facilities which qualify to be on "essential customer lists" for exemption from curtailments under utility rotating outage plans be used to qualify for the proposed Self-Generation Incentive Program modification. See Attachment A for further information on Essential Use Customers.

There is a concern by the SGIP Working Group that this will result in on-going interpretations by the Program Administrators about who would in fact qualify, given there have been a number of different CPUC decisions addressing which customers are considered "essential" and the impact of self-generation

[4] D.01-03-073, March 27, 2001, page 10, section 3.2

capabilities on retaining that definition (except for hospitals and skilled nursing facilities, SNFs).

The following section comes from D.02-04-060, April 22, 2002, on this issue:

> **Section 4.2.6:**
> Essential customer classification is not dependent upon whether or not the customer has self-generation. That is, each customer is or is not essential based on the customer's service to the community as determined by our essential customer categories (e.g., police, fire, prison, national defense, hospitals), or other factors which result in essential customer status (e.g., areas served by networks, transmission level customers, OBMC participants). **We remind utilities, however, that they are required to assess the adequacy of an essential customer's backup or standby generation, and consider removing that customer from the essential customer list, with the exception of hospitals. (D.01-04-006, mimeo., pages 65-66; D.01-06-085, mimeo., pages 13-14; D.01-09-020, mimeo., page 15.)** ***(emphasis added).***

Consensus Recommendation

The Self-Generation Incentive Program Working Group unanimously recommends that the proposed program modification to grant an exemption to Section 2.4.8 of the SGIP Handbook for critical facilities not be approved.

Rationale for Consensus Recommendation

The SGIP Working Group bases it's recommendation to oppose the proposed Program Modification Rule change on the balance of following considerations:

Pros:

a. In the event of an emergency or natural disaster where natural gas is unavailable for the self-generation system, there would be less pollution generated in operating the self-generation system on diesel fuel than from a dedicated diesel backup generator. It was felt, however, that the likliehood and duration of such an event is probably very small.

Cons:

a. The original CPUC decision specifically excludes diesel-fired and backup generation from the program. Although the Applicant agrees that the incremental costs associated with providing this added capability be removed for purposes of calculating the eligible rebate, it would still be counter to the program's stated objectives at the time the system is commissioned and paid a SGIP rebate.

b. The customer group who would benefit from this change is small.

c. Added administrative burden and uncertainty regarding who would qualify for the exemption and what impact installing self-generation may have on continued qualification.

d. The firm preparing the PMR has indicated that the diesel-fired capability can be installed later as a retrofit to the original genset. Customers who wish to add this functionality after installing and receiving a Self-Generation Incentive Program rebate may pursue this approach.

Attachment A

Essential Use Customers[5]

To implement the California Public Utilities Commission's (CPUC) Priority System for Rotating Outages, Pacific Gas and Electric Company has exempted from rotating outages all circuits that serve identified essential use customers (except those that are nonexempt).

- What are Essential Use Customers?
- Criteria
- Backup and Standby Generation
- Hospitals and Nursing Facilities
- Water and Sewage Treatment Facilities

What are Essential Use Customers?

Non-residential customers that provide certain essential public health, safety, and security services are referred to as essential use customers. Examples include facilities such as fire stations, police stations, prisons, hospitals, skilled nursing facilities, communication utilities, radio or television stations, water or sewage treatment facilities, rail transit systems, petroleum refineries, national defense installations and navigation communication facilities.

Depending on the status of back-up generation at the facility, Essential Use customers that provide these services are usually exempt from rotating outages ordered by the California Independent System Operator when there is an insufficient supply of electricity. If you believe your facility meets the criteria below, complete and return Application for Essential Use Customer Status and fax it to PG&E at the number shown on the application.

Criteria

1. Government and other agencies providing essential fire, police and prison services.
2. Government agencies essential to the national defense.
3. Hospitals and skilled nursing facilities.
4. Communication utilities, as they relate to public health, welfare, and security, including telephone utilities.
5. Navigation communication, traffic control, and landing and departure facilities for commercial air and sea operations.
6. Electric utility facilities and supporting fuel and fuel transportation services critical to continuity of electric power system operation.
7. Radio and television broadcasting stations used for broadcasting emergency messages, instructions, and other public information related to the electric curtailment emergency.

[5] This information comes from the PG&E Internet site: http://www.pge.com/news/latest_topics/power_watch/essential_status/index.html

8. Water and sewage treatment utilities may request partial or complete (rotating outage) exemption from electric utilities in times of emergency identified as requiring their service, such as fire fighting.
9. Areas served by networks, at utilities' discretion.
10. Rail transit systems as necessary to protect public safety, to the extent exempted by the commission.
11. Customers served at transmission voltages to the extent that (a) they supply power to the grid in excess of their load at the time of the rotating outage, or (b) their inclusion in rotating outages would jeopardize system integrity.
12. Optional Binding Mandatory Curtailment Program (OBMC): Any customer, or customers, meeting the following criteria:

    The customer must file an acceptable binding energy and load curtailment plan with the utility. The customer must agree to curtail electric use on the entire circuit by the amount being achieved via rotating outages. The customer's plan must show how reduction on the entire circuit can be achieved in 5 percent increments to the 15 percent level, and show how compliance can be monitored and enforced. The customer must maintain the required reduction during the entire rotating outage period. The required curtailment level is requested prior to commencement of Stage 3. Several customers on a circuit may file a joint binding plan to guarantee the required curtailment from the entire circuit. Each utility shall facilitate communication between customers on a circuit if any customer expresses interest in enrolling in the OBMC program.
13. Limited other customers as necessary to protect public health and safety, to the extent exempted by the commission. Exemptions granted September 6, 2001, by the CPUC under category M had a limited duration of 24 months. Category M customers received a 30-day notice prior to the exemption expiration date of September 6, 2003.
14. Petroleum refineries, vital ancillary facilities, and other customers in the critical fuels chain of production, to the extent exempted by the commission. Petroleum refineries are facilities that separate or alter the components in crude oil, and convert the components into usable fuels or feedstock for further processing. Vital ancillary facilities are facilities that, if curtailed during a rotating outage, would cause one or more petroleum refineries to significantly curtail production, initiate a controlled shutdown, or initiate an emergency shutdown. Eligible refineries and vital ancillary facilities must be firm electricity service customers served at transmission level, or served at distribution level in an outage block exempt from rotating outages.

The CPUC noted that even for these customers, "Protection cannot be guaranteed because daily circuit switching may temporarily change a customer's outage block and priority classification."

Backup and Standby Generation

In 1982, the commission directed the utilities "to evaluate the adequacy of the standby generating equipment of [essential] customers and to consider removing them from the lists of essential use customers." Decision No. 82-06-021 at p. 12. The commission reasoned that "[essential use] customers that have sufficient standby generating equipment for their essential load should not be routinely protected from rotating outages because this double protection may be jeopardizing other equally essential customers at the higher load reduction levels." For that reason, some essential customers may be "nonexempt" - that is, subject to rotating outages - if they have

sufficient and adequate backup generation to support their critical activities for up to two hours, the expected typical upper duration of a rotating outage.

Hospitals and Nursing Facilities

On March 23, 2001, in an Assigned Commissioner's Ruling, the utilities were ordered to provide an automatic and unqualified exemption for all hospitals with 100 or more beds, whether or not those hospitals have any backup generating facilities. That Ruling was subsequently modified on April 3, 2001, in Decision 01-04-006 to exempt all hospitals from rotating outages regardless of the number of beds. The Ruling was again modified on April 22, 2002, in Decision 02-04-060 to exempt skilled nursing facilities licensed by the California Department of Health Services, regardless of the status of backup or standby generation.

Water and Sewage Treatment Facilities

With regard to water and sewage treatment facilities, the CPUC clarified its position in Decision No. 92315, concluding that such customers would not be automatically exempted from rotating outages. However, water and sewage facilities may request an exemption from a specific rotating outage if an emergency exists [requiring their service].” The CPUC noted that the utilities were expected to grant such requests, but that water and sewage facilities were not to request an exemption “unless absolutely required to ensure the public’s health and safety.” Decision No. 92315 at p. 4.

PMG-04-002-SDREO
Self-Generation Incentive Program
Proposed Modification for a New Technology
Solar Distributed Thermal Power Generation

1.0 Summary

On March 5, 2004, Solel, Inc. submitted a proposal to the Self-Generation Incentive Program (SGIP) Working Group (WG) requesting the addition of the following new technology for Self-Generation Incentive Program (SGIP) eligibility:

- **Solar Thermal Electric Power Generation**

Solar Thermal Electric power generation appears to meet the intent of SGIP goals of encouraging peak demand reduction, renewable energy generation and deployment of generating technologies having low and zero operational emissions.[6] The proposed technology, available in capacity ranges from 240kW – 1500kW, can be solar-only fueled or alternatively operated with either a renewable or natural gas back-up fuel source.

2.0 New Technology Screening Criteria and Issues Considered

2.1 California Market Potential

Large scale Solar Thermal Electric technology has been commercially available and operational in California since the mid 80's. Solel, Inc. would like to integrate the smaller, more compact technology into the U.S. market.

The SGIP WG is still unclear on the California market potential for Solar Thermal Electric. Appendix 1, Section IX, indicates the market potential is between 100 and 200 MW based on a 1999 Combined Heat and Power (CHP) Market Assessment and a 20% Renewable Portfolio Standard (RPS) goal. In Appendix 3, Solel, Inc. indicates that relevant applications must be installed in locations, which have both the required amount of direct solar radiation[7] and also sufficient space to mount the collectors.[8] Comparisons to the photovoltaic (PV) market were inconclusive.

The WG comments that the limited market potential could be compared to the limited market potential and/or low market penetration of fuel cell and wind turbine technologies currently eligible for the program.

2.2 Demand Reduction Potential

[6] D01-03-073, Section 3.2 – Energy Division Program Recommendations, Self-Generation Program.
[7] As per Appendix 3, Item 8, the practical minimum amount of sunlight required is 5,500 – 6,000 kWh
[8] As per Appendix 1, Section II.1 – Solar Field, the area for one collector module is 3,477ft.^{2}

The SGIP WG comments that the impact of Solar Thermal Electric technology appears to meet the intent of program goals and compares similarly to photovoltaics, which are currently eligible.

2.3 Equipment Life

Equipment life is comparable to that of current eligible technologies. As per Appendix 1, Section 11.8, the systems are designed to operate a minimum of 25 years and parts with a shorter lifespan are replaced within a preventative maintenance and operational plan. Solel, Inc. also provides a full five-year warranty.

2.4 Financial Need

As per Appendix 1, Section III, Solel, Inc. indicates that the installed system costs for solar-only fueled systems are comparable to photovoltaics ($8.40/W - $9.10/W). As per Appendix 3, #1, the total installed system costs for a system installed at Solel, Inc. headquarters was $1,244,000 ($15.80/W installed), yet Solel also noted that economies of scale would reduce the cost to $8.40/W installed for a 1MW system.

2.5 Potential for Practical and Safe Application

The Solel, Inc. Solar Thermal Electric technology has been certified according to European standards for solar collectors and CE (European Conformity) marking. A list of equivalent UL tests performed within this standard was also provided.

Solel, Inc. anticipates the technology will meet all interconnection requirements as well as meet current air permitting requirements in the cases where a natural gas back-up fuel is used.

2.6 Environmental Impacts

The SGIP WG comments that the solar-only fueled systems appear to have an environmental impact comparable to photovoltaics. Systems operating with a renewable fuel back-up appear to have an impact similar to fuel cells, IC engines and microturbines operating on renewable fuel sources. The impact of systems operating with a natural gas back-up will depend on the amount of natural gas input and compliance with air permitting requirements.

2.7 Compliance with Current Program Requirements

The SGIP WG comments that the proposed Solar Thermal Electric technology appears to meet the over arching SGIP goals: peak demand reduction and emphasis on renewable energy and zero-emissions self-generating technologies. Additionally, the proposed technology falls within the minimum-maximum allowable system size range, meets program maintenance requirements, and is anticipated to meet interconnection and air permitting requirements.

3.0 Consensus Recommendation

The Self-Generation Incentive Program (SGIP) Working Group (WG) unanimously recommends Solar Thermal Electric be added to the list of eligible technologies for the Self-Generation Incentive Program and provides the following comments.

3.1 Solar Thermal Electric Definition

For the purposes of the SGIP, the WG recommends that Solar Thermal Electric technology be defined as a solar field driven turbine system fueled solely by a solar field or fueled by a solar field in combination with either a renewable or natural gas back-up fuel system contributing 25% or less of the fuel input for the following reasons:

- Systems meeting this definition meet the Public Utilities code for systems operating on a renewable fuel.[9]
- Solel, Inc. proposes two scenarios for SGIP eligibility: 1) solar only and 2) systems with a maximum 25% natural gas back-up.[10]

For systems with either a renewable or natural gas back-up fuel system >25%, a proposed incentive level was **not** addressed for three reasons. First, the WG believes incentive eligibility would have a direct relationship to the emission characteristics of the Solar Field Backup. Second, the applicant provided no emission data. Third, the applicant did not request this be considered. Therefore the WG proposes that systems with either a renewable or a natural gas back-up fuel system >25% not be considered at this time.

3.2 Incentive Level Recommendation

The SGIP WG recommends that Solar Thermal Electric systems be classified as a Level 1 technology.

For systems incorporating a back-up fuel source not more than 25% of the total energy source, the WG recommends that these systems be sized based on the net generating capacity derived from the "Solar Collectors" only for the following reasons:

- Though the Solar Field Backup unit is thought to be comparable to an oil heater, steam boiler or industrial liquid heater and most likely has similar emission characteristics, the applicant provided no emission performance information. Hence we were not able determine if the emissions from the solar field back-up unit are comparable to that of a fuel cell (close to nothing) an I.C. engine, a turbine or a micro-turbine.
- The current SGIP allows for systems using fuel combustion as a driver as an eligible technology when used in micro-turbines, IC engines and small turbines. Since the Solar Field Backup is comparable to a boiler for driving a steam-turbine system, the Working Group could not justify this

[9] Systems operating with a fossil fuel back-up of 25% or less are defined as a renewable fueled system by Section 2805 of the Public Utilities Code.
[10] Appendix, 1, Section III – Proposed Incentive Level, p. 14.

portion of the overall system as an eligible technology. Our concern was that it would then set precedent to allow other projects using a steam driven turbine type system to be an eligible technology.

For systems incorporating a back-up fuel source of greater than or equal to 25%, the WG recommends that these systems not be eligible.

The SGIP WG is unable to provide a $/W incentive amount. The last system installed by the Applicant resulted in a cost of $15.8/W for a 50kW system installed at the Solel, Inc. headquarters. Numbers for a 1MW system were estimated between $8.40/W - $11.20/W. Installed system costs for commercially available systems in the U.S. were not provided.

3.3 System Sizing

The SGIP WG recommends that the system size be determined as a function of the net generating capacity of the solar collector only. Any generating capacity derived from relevant back-up fuel input equipment ("Solar Field backup") is not eligible for an incentive, but would not disqualify the overall system from being eligible for the SGIP.

In order to determine system size, the WG acknowledges that a standard Solar Collector Capacity rating will need to be used, similar to the current PTC rating used for photovoltaics. The WG is unclear as to whether or not a standard exists in the market today. If not, the WG recommends that Solel, Inc. work with other solar thermal electric industry participants and an independent testing agency to develop a standard methodology for determining the Solar Collector Capacity, which can then be proposed to the Commission for approval.

3.3.1 Proposed Methodology

In the case where the proposed Solar Thermal Electric technology input relies only on the solar collector field, the system size would need to be determined as a function of both the solar field capacity and turbine nameplate rating. A methodology similar to that recently approved by the WG and submitted to the commission for photovoltaics could be used. This method is as follows:

Lesser of:	**# of modules * PTC Rating * Inverter Efficiency**
or:	**Maximum Inverter Rated Capacity**

In the case of Solar Thermal Electric, the WG suggests the following methodology:

Lesser of:	**Solar Collector Capacity Rating * System Efficiencies**
or:	**Maximum Turbine Nameplate Rating**

3.4 Certification

One year of documented commercial use is not currently available for the proposed technology. The SGIP WG recommends that Solel, Inc. pursue having the equipment tested and certified by an independent lab to verify its performance. The SGIP WG comments that in the early years of the program, other technologies (fuel cells, renewable fueled microturbines) were asked to provide similar certifications.

As noted in Section 3.3 above, the WG comments that Solel, Inc. work with an independent testing agency as well as with other solar thermal electric industry participants to develop and propose a Solar Collector Capacity standard in order to assess the rated capacity for solar collectors on the market. This standard would be comparable to the current PTC rating used for photovoltaics.

4.0 Supplemental Appendices

4.1 Appendix 1
Solel, Inc. Solar Distributed Thermal Power Generation Proposal (Rev.1)

4.2 Appendix 2
CD and Zip File of Proposal Appendices and Certification Documents

4.3 Appendix 3
Solel, Inc. Response to SGIP WG Questions dated June 17, 2004.

4.4 Appendix 4
Solel, Inc. Monthly Accumulated Energy Chart

4.5 Appendix 5
Solel, Inc. Yearly Accumulated Energy Chart

4.6 Appendix 6
California Direct Solar Radiation Distribution Map

PMG04-003-SDREO
Self-Generation Incentive Program
Proposed Modification for a New Technology
Organic Rankin Cycle Waste Heat to Electricity Generation

5.0 Summary

On December 3, 2004, United Technologies Corporation (UTC) submitted a proposal to the Self-Generation Incentive Program (SGIP) Working Group (WG) requesting the addition of the following new technology for SGIP eligibility:

- **Organic Rankin Cycle (ORC) Waste Heat to Electricity Generation**

Waste Heat to Electricity Generation systems operate on the thermodynamic principle of a Rankin cycle. The system is referred to as an organic Rankin cycle due to the use of a refrigerant as the working fluid. Rankin cycles use waste heat to vaporize a working fluid which is then expanded through a turbine to generate electricity.

UTC Power, a business unit of UTC, has developed the PureCycle™ 200, a waste heat to electricity generation system that produces 200 kW of electric power. UTC is requesting that Waste Heat to Electricity Generation Systems, including the PureCycle™ 200, be included as eligible SGIP technologies. UTC has requested the technology be considered for Level 1 incentives.

6.0 New Technology Screening Criteria and Issues Considered

6.1 California Market Potential[11]

UTC states that California has a potential 42 trillion BTU/yr of waste heat available for waste heat recovery systems.[12] UTC comments that given the state's need to reduce peak demand, this equates to a market potential of 1,195 PureCycle™ 200 units or 239 MW of electrical generation at 100% capacity factor.[13]

UTC also states that the PureCycle™ 200 is best suited for the following market segments:

- Industrial sites with process waste heat sources;
- Industrial sites with on-site prime movers for power generation[14]; and
- Landfills and wastewater treatment plants.

[11] UTC PMG, Section 4.2.4, p. 12 and Appendices A & B.
[12] UTC PMG, p. 4.
[13] UTC presentation to SGIP Working Group, Slide 16.
[14] UTC PMG, p. 23 – Site with gas turbines greater than 1.5MW and reciprocating engines greater than 3.5MW.

6.2 Demand Reduction Potential[15]

Waste Heat to Electricity Generation Technologies capture waste heat that is typically vented to the atmosphere and convert it into usable electricity. UTC identified market segments suited for its PureCycle™ 200 system as large energy users with industrial processes where waste heat is currently being exhausted. UTC comments that the California economic peak load reduction potential of its technology is 129 MW.[16]

UTC's comments describe the PureCycle™ 200 as a system that operates continuously and, similar to IC Engines, routine maintenance can be planned for off-peak hours and/or weekends.

6.3 Equipment Life

UTC did not describe or provide data on the expected equipment life. With regard to the PureCycle™ 200 unit, UTC provides a standard one year warranty for parts and labor as well as an optional maintenance contract on parts/labor for up to five years of service. A copy of the Standard Terms and Conditions of UTC Warranty is provided in Appendix A of the PMG proposal. UTC cites 2,800 hours as the longest running system as of the date of UTC's PMG submittal.[17] UTC also notes that upon completion of the 2,800 hour trial period, this unit was sold to Austin Energy.[18]

6.4 Financial Need[19]

In its PMG request, UTC estimates that the installed costs with a five year warranty and maintenance agreement range from $526k to $630k ($2.63/W to $3.15/W).[20] UTC uses a value of $3.10/W in their examples of payback periods. UTC estimates that the simple payback period without incentives is 5.6 years, which UTC states is beyond the payback criteria for most industrial facilities. With a 30% incentive, the simple payback is 3.9 years and with a 50% incentive the payback is 2.8 years. UTC comments that a payback period less than 3 years is important for market traction and adoption of their new technology.

These figures are in conflict with UTC's current marketing materials. In UTC's PureCycle™ 200 system marketing brochure (dated 2004), UTC states, "If the PureCycle™ 200 system operates in certain regions of California, you could enjoy payback in as little as 2 years…" The brochure also indicates that Customers with electricity cost between 12.0 ¢/kWh and 14.0 ¢/kWh can expect paybacks in less than 2 years."[21] These figures do not appear to demonstrate a

[15] UTC PMG Section 4.2.8 p. 15.
[16] UTC Presentation to SGIP WG, Slide 17.
[17] UTC PMG Section 4.2.12, p. 25.
[18] 2950 hours of operation at the time of the UTC Presentation to SGIP WG, Slide 13.
[19] UTC PMG, Appendix B, p. 21.
[20] UTC PMG, Table 2, p. 12.
[21] UTC Marketing Brochure PureCycle 200 System Payback Chart, p.5.

financial need. It is unclear as the whether the quoted payback period indicated in the marketing brochure assumes incentives.

Commercial Availability[22]
The UTC PureCycle™ 200 has been commercially available since July 2004. All components of the PureCycle™ 200 technology (turbine/generator, compressor/motor) have all been commercially available for a significantly longer period. To date, UTC has installed the following two demonstration systems[23] (the first of which was sold to the end user after a 2800 hour trial period):

- Landfill Application – Austin, TX
- Landfill Application – Danville, IL

In addition to UTC Power, two other companies – Ormat and Turboden – are known to have commercially available waste heat recovery generators.

6.5 Certifications[24]
As of March 1, 2005, UTC has not passed the UL requirements and has not met Rule 21 interconnection requirements. UTC states that it is in the process of UL testing for the PureCycle™ 200 and anticipates UL Approval under UL 1995 by April 2005. UTC also believes that the PureCycle™ 200 will be certified to meet CA Rule 21 and anticipates CA Rule 21 certification at the end of Q1 2005.

6.6 Environmental Impacts
UTC states that Waste Heat to Electricity Generating technologies do not require any additional fossil fuel inputs and produce zero emissions. Thus, UTC believes the environmental impacts are negligible. UTC proposes that the SGIP classify "waste heat" as a renewable fuel.

The system's working fluid is a hydro fluorocarbon (HFC), which is commonly used as a refrigerant and does not pose any environmental risk.

6.7 Compliance with Current Program Requirements
UTC's PureCycle™ 200 falls within the minimum-maximum allowable system size range and meets program maintenance requirements. However, the PureCycle™ 200 system has not yet met interconnection and air permitting requirements, and does not have UL certification.

Although ORC Waste Heat to Electricity Generation technologies could have a significant peak load reduction potential, UTC admittedly states that the PureCycle™ 200 units suffer a performance penalty with increases in ambient temperatures. The effect of this penalty on peak demand reduction potential is unclear.

[22] UTC PMG, Section 4.2.5, p. 14.
[23] UTC PMG, Appendix C, p. 25.
[24] UTC PMG, Section 4.2.6, p. 15

Further while the Waste Heat to Electricity Generating Technologies produce no additional emissions, the Commission has previously ruled that these systems cannot be considered in isolation of the host heat source because the whole system relies on fossil fuel or other fuel inputs.[25] Therefore, the environmental impact of the entire system, including the source of the waste heat, needs to be considered given the various forms of fuel (including diesel) that can be used in the waste heat producing process. Furthermore, the PureCycle™ 200 cannot not meet the Level 3-N waste heat recovery requirement, as it utilizes waste heat to generate electricity.

The SGIP WG agreed that the PureCycle™ 200, and similar waste heat recovery systems, do not constitute stand alone self-generation technologies and the WG majority felt this to be criteria for ineligibility.

In a minority opinion, SDREO acknowledges that the PureCycle™ 200, and similar waste heat recovery systems, do not meet the Level 1 Renewable Fuel criteria. Yet SDREO believes that the ORC Waste Heat to Electricity Generation systems could be considered for Level 3-R.

Rationale for both recommendations are given below.

6.8 CPUC Decisions D.03-01-006 and D.03-12-036 (Mafi-Trench)

The SGIP WG considered and reviewed the following two previous Commission Decisions:

- Decision 03-01-006 - Interim Opinion Regarding Mafi-Trench Corporation's Petition for Modification of Decision 01-03-073.
- Decision 03-12-036 - Interim Opinion Denying the Inclusion of Turbo-Expanders in the Assembly Bill 970 Self-Generation Program.

The WG agrees with the Commission in its conclusion that similar to turbo-expanders, the proposed ORC Waste Heat to Electricity Generation technology does not operate as a stand alone generation technology but rather as a waste heat recovery system or "bottoming cycle."

7.0 Majority Recommendation

The following members of the SGIP WG: PG&E, SCE, SoCalGas and SDG&E (the Majority) recommend that ORC Waste Heat to Electricity Generation technologies be rejected for eligibility in the SGIP.

7.1 Rationale for Majority Recommendation

The Majority recommends that ORC Waste Heat to Electricity Generation technologies be rejected for eligibility in the SGIP. In Decisions 03-01-006 and 03-12-036, the Commission ruled on the applicability of units which use process or waste heat to generate electricity noting, "Turbo-expanders represent a waste heat recovery technology that cannot be considered in isolation for the purpose

[25] CPUC Decision 03-12-036.

of evaluating its eligibility under AB 970 self generation incentives program." These Decisions dealt with Mafi-Trench's petition to include "bottoming cycle" turbo expanders as eligible for incentives under the SGIP and are instructive here. In D.03-01-006, the Commission found that turbo expanders (the Mafi-Trench system) and cogeneration which uses process or waste heat to produce electricity (a bottoming cycle) are conceptually the same and should be considered as such. The Working Group majority shares this opinion.

In the Interim Opinion Denying the Inclusion of Turbo-Expanders in the Assembly Bill 970 Self-Generation Incentive Program (D.03-01-006), the Commission found that Mafi-Trench's system relied on fossil fuel inputs and thus total energy input must be considered before SGIP eligibility, if any, could be determined. The Commission raised several questions concerning Mafi-Trench's turbo expander technology, including questions regarding (1) the installed system costs; (2) the market potential for the application of the technology; (3) system efficiency considering total system inputs; and (4) how the technology would meet the waste heat recovery and reliability requirements for Level 3 incentives, assuming the technology was eligible for the incentives. The Commission denied Mafi-Trench's petition, but allowed Mafi-Trench to resubmit the technology for inclusion in the SGIP if Mafi-Trench answered these questions and others. Mafi-Trench resubmitted its petition, but in D.03-12-036, the Commission found that Mafi-Trench failed to adequately address the Commission's concerns.

In particular, Mafi-Trench did not address the energy efficiency question, and therefore, there was no record on which the total energy input could be considered. The Commission reiterated its finding that the Mafi-Trench's system could not operate in isolation of fossil fuels, and was therefore not a stand-alone self generation technology as contemplated by AB 970. As such, total energy inputs must be taken into account before SGIP eligibility can be contemplated. Mafi-Trench never demonstrated how its system met the efficiency requirements for Level 3-N incentives. Additionally, Mafi-Trench failed to provide sufficient information on project costs, performance, or benefits of completed projects. Thus, the Commission rejected Mafi-Trench's petition, finding that: 1) the equipment was not a standalone self generation technology as contemplated under AB 970; 2) the technology was neither super clean nor renewable because it relied on fossil fuel inputs; 3) allowing the technology would be inconsistent with previous Decisions regarding eligibility of project components which include thermal load equipment that utilize waste heat; and 4) there was very little data available to allow the Commission to assess the costs, performance, and benefits of completed projects.

As with Mafi-Trench, UTC's submission for program modification has failed to satisfactorily address the concerns raised by the Commission. In particular, like Mafi-Trench's turbo-expanders, UTC's PureCycle™ 200 system is a waste heat recovery system that cannot generate electricity in isolation of fossil fuel or other

gas inputs.[26] The PureCycle™ 200 is in fact a piece of thermal load equipment as described by the Commission. The system therefore cannot be considered super clean or renewable due to its fossil fuel input requirements.

While there may be some application of UTC's PureCycle™ technology to recover waste heat from a landfill gas-fired generator, the real opportunities for waste heat recovery are in "energy intensive industries." Unfortunately, UTC provided limited information on the availability of waste heat from landfill applications, and there are only two pilot systems on which to judge system effectiveness and both average and actual project cost information.

Moreover, the issues of cost, performance and benefits have not been adequately addressed. Similar to Mafi-Trench, UTC has not adequately demonstrated system installed costs, expected performance, and net benefit. With respect to costs, only two pilot projects have been completed to date at a cost of $2.75/W and $3.00/W. Due to the pilot nature of these projects, the installed cost may not be representative of actual customer field installations. Current Program experience indicates a larger sample of installations is needed to accurately estimate the final installed costs. In its PMG submittal, UTC maintains a payback period of 5.6 years without incentives and a displaced energy charge of 10.0 ¢/kWh. UTC argues that the extended payback period is well beyond the payback criteria for most industrial facilities, contending the system needs to demonstrate a payback period less than 3 years for market attraction and that an incentive will help achieve this goal. As indicated earlier, this position is in direct conflict with current marketing and sales materials. In the attached marketing brochure UTC maintains a 2.3 year payback and a displaced energy charge of 10.0 ¢/kWh. A payback of 2 years or less is possible if the displaced energy cost is between 12.0-14.0 ¢/kWh. Based on UTC's arguments, these claims make the PureCycle™ 200 system viable without incentives, and undermine the claims made in the PMG. This demonstrates the ambiguity regarding actual installed costs for the PureCycle system, and the difficulty the Commission and the Working Group have in determining appropriate incentive levels, if any.

Further, in discussing the applicability of the Waste Heat to Electric Generation Technologies, UTC states that there are "significant opportunities for waste heat recovery due to the temperature of the exhausts from various processes and equipment."[27] UTC further acknowledges that the "major producers of waste heat" are "energy intensive industries" such as petroleum, chemical, and metal industries. However, the UTC PureCycle™ 200 system suffers a significant performance penalty as ambient temperature climbs. Based on UTC performance charts provided in Appendix F of the PMG, a system installed at 2,000 ft above sea level in a 75° F ambient temperature environment could

[26] "Turbo–expanders represent a waste heat recovery technology that cannot be considered in isolation for the purposes of evaluation its eligibility under our AB970 self-generation incentive program." (Finding of Fact 1 D.03-12-036).
[27] UTC PMG, p. 3.

expect an approximately 30% reduction in output capacity, from 200 kW to 140 kW. A sea level installation in a 100° F environment can expect a 60% reduction in output capacity, from 200 kW to 80 kW. Neither of these estimates includes parasitic loads required for ID fans, which could reduce the output by another 2 – 3%. Performance degradation on this scale raises concerns regarding the PureCycle™ 200 system's cost effectiveness and peak load reduction potential.

Like Mafi-Trench, UTC has not adequately addressed why the ORC Waste Heat to Electricity Generation technologies are deserving of Level 1 status. Despite the "organic" label and comparisons to Level 1 technologies provided by UTC, the ORC Waste Heat to Electricity Generation is a basic waste heat recovery Rankin cycle that cannot be considered either super clean or renewable because of its fossil fuel dependence.[28] Thus, as discussed above, ORC Waste Heat to Electricity Generation technologies are not appropriate for Level 1 on the basis of fuel inputs. It is also not appropriate for Level 1 on the basis of capital costs. UTC provided estimated installed costs for the PureCycle™ system of $2.63/W to $3.15/W. As the new SGIP incentive structure eliminates the percentage of project cost cap, Level 1 status would result in the Program overpaying for the technology. At its current level, a Level 1 incentive would result in an overpayment of up to $1.87/W based on installed cost ($4.50-$2.63=$1.87).[29]

The majority opinion reaffirms that ORC Waste Heat to Electricity Generation technologies should not be eligible for SGIP incentives. UTC has not demonstrated how the PureCycle™ system overcomes the Commission's previous rulings regarding process and waste heat recovering technologies. ORC Waste Heat to Electricity Generation technologies cannot operate as a stand-alone generator. Target installations for landfill and waste water treatment facilities include existing reciprocating and gas turbine generators.[30] Installing the PureCycle™ 200 on these generators confirms that the PureCycle™ 200 system is a heat recovery system similar to those deemed ineligible for incentives by the CPUC in D.03-12-036. The system relies on fossil fuel inputs, and it therefore cannot be considered for Level 1 or 3-R status. Nor are Waste Heat to Electricity Generating Technologies eligible for Level 3-N incentives.

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[28] The Majority acknowledges that there may be some application of UTC's technology to recover waste heat from a landfill gas-fired generator. However, as acknowledged by UTC, the real opportunities for waste heat recovery are in "energy intensive industries." In determining whether the PureCycle 200 system is eligible for incentives under the SGIP, the probable use of the technology should govern. Moreover, UTC provided limited information on the availability of waste heat from landfill applications, and there are only two pilot systems on which to judge average and actual project cost information. There is also a likelihood that the waste heat recovery system attached to an existing generator that burns landfill gas would be considered a waste heat recovery project component ineligible for incentives under D.03-12-036 (Finding of Fact 2). Thus, although there may be some value in revisiting in the future the eligibility of the PureCycle 200 system as applied to landfill gas projects, there is insufficient information at this time to justify eligibility in the SGIP.

[29] As an alternative to Level 1 eligibility, UTC has recommended a Level 3 incentive of $1.55/W. This would result in an incentive covering approximately 71% to 60% of installed costs, based on installed costs of $2.18/W and $2.60/W respectively. The installed cost does not include the cost of a five year maintenance agreement.

[30] UTC PMG Section 4.2.12, p. 23.

In D.03-01-006, the Commission left the door open to consider waste heat technology as eligible for Level 3-N, if it could be demonstrated that the efficiency characteristics of the overall system would meet SGIP requirements. Similar to Mafi-Trench, UTC has not offered information as to how the PureCycle™ 200 system can meet the energy efficiency requirements for Level 3-N. Moreover, the PureCycle™ system appears to be marginally effective in meeting the peak reduction goals of the Program. Finally UTC has not met the safety requirement and interconnections requirements of the Program. For these reasons, the majority of the Working Group recommends that ORC Waste Heat to Electricity Generation technologies be rejected.

8.0 Dissenting Recommendation

SDREO agrees that as per the current program guideline ORC Waste Heat to Electricity Generation is ineligible for SGIP Incentives. However, SDREO feels the significant California demand reduction potential of 129 MW[31] should not be ignored, and recommends the Commission consider defining "waste heat" as a renewable fuel.

If "waste heat" were a renewable fuel, ORC Waste Heat to Electricity Generation technologies could be added to the list of eligible Level 3-R technologies.

8.1 Rationale for Dissenting Recommendation

Although not currently considered a renewable fuel in California, waste gas is recognized as having similar benefits to renewable resources in other states, namely:

- Nevada - eligible for RPS goals per AB429,[32]
- North Dakota - equivalent to other renewable energy electric generating resources,[33]
- Ohio - considered waste gas technologies eligible for property tax exemptions similar to renewable sources,[34]
- Pennsylvania - eligible for Alternative Energy Credits,[35] and
- South Dakota- equivalent to other renewable energy electric generating resources.[36]

Furthermore, two additional states have introduced bills to consider waste heat for renewable energy credits/goals:

- Connecticut - introduced bill to consider waste heat as Class 1 renewable energy resource in January 2005 session,[37] and

[31] UTC Presentation to SGIP WG, Slide 17.
[32] Nevada Assembly Bill 429, Section 6 (a), p.3. http://www.leg.state.nv.us/72nd/bills/AB/AB429_EN.pdf
[33] North Dakota Department of Commerce Letter dated July 1, 2003.
[34] Database of State Incentives for Renewable Energy (DSIRE) (http://www.dsireusa.org).
[35] Pennsylvania Senate Bill 1030, Act 213, Section 12 (iii) http://www.palrb.us/pamphletlaws/browse/plgetrecactnspage.asp?sessyr=2004&spsess=0&typedoc=act
[36] South Dakota Department of Tourism and State Development Letter dated July 1, 2003.
[37] Connecticut Raised Bill No. 6906, Introduced January Session, 2005 http://cga.ct.gov/2005/tob/h/2005HB-06906-R00-HB.htm.

- Texas – introduced House Bill 1565 to consider emerging generation technology credits for waste heat technologies.[38]

SDREO recommends the Commission act to follow the precedence set in other states by considering waste heat as a renewable source and/or having benefits similar to renewable sources.

While, ORC Waste Heat to Electricity Generation is not a "stand alone" self-generation technology, SDREO believes the technology meets the required intent of the following SGIP goals: peak demand reduction and emphasis on zero emissions generation technologies. Waste heat recovery systems require no additional fossil fuel input, produce zero emissions and have a significant California market potential of 239 MW.[39] The technology recovers waste heat that would otherwise be vented or rejected to the atmosphere and converts that waste heat into usable electrical energy. This is a largely untapped non-fossil fuel resource of electric capacity and energy which should not be discounted.

In its PMG submittal, UTC provides the following market potential for three specific market segments:[40]

- Industrial sites with process waste heat sources – Potential for 338 PureCycle™ 200 units or 67.6 MW.
- Industrial sites with on-site prime movers for power generation – Potential for 117 PureCycle™ 200 units or 23.4 MW.
- Landfills and Wastewater Treatment Plants – Potential for 68 PureCycle™ 200 units or 13.6 MW.

SDREO disagrees with UTC that ORC Waste Heat to Electricity Generation technologies should be considered a Level 1 – Renewable Technology. Waste heat recovery technologies, although zero emissions technologies, are "bottoming cycle" technologies and therefore the type of equipment producing the waste heat must be considered. Waste heat recovery generators are placed in line with process applications such as, gas turbines, reciprocating engines, etc. Thus, it appears more fitting to consider waste heat recovery systems as Level 3 technologies. SDREO recommends Level 3-R for reasons discussed below.

Total installed costs presented by UTC resemble Level 3-R technologies and UTC has recommended a $1.55/W incentive,[41] which is similar to the $/W incentives for current Level 3-R technologies. Furthermore, as waste gas is utilized to "fuel" the generator, the Level 3-N Waste Heat Recovery Requirement would not apply. SDREO comments that contingent on UL Approval, the

[38] Texas House Bill 1565 http://www.capitol.state.tx.us/cgi-bin/tlo/textframe.cmd?LEG=79&SESS=R&CHAMBER=H&BILLTYPE=B&BILLSUFFIX=01565&VERSION=1&TYPE=B
[39] UTC Presentation to SGIP WG, Slide 16.
[40] UTC PMG, Appendix B p. 23
[41] UTC Presentation to SGIP WG, Slide 18.

PureCycle™ 200 system proposed by UTC appears to meet all other SGIP requirements.

The dissenting recommendation reaffirms that ORC Waste Heat to Electricity Generation recycles waste heat that would otherwise be rejected to the atmosphere and converts it into usable electrical energy. SDREO believes the technology meets the intent of SGIP for reducing peak demand and promoting zero emissions methods to secure additional power. Based on this pretense and the actions by other states, SDREO recommends the Commission elect to include "waste heat" as a renewable fuel and ORC Waste Heat to Electricity Generation technologies be eligible for Level 3-R incentives. The recommended incentive should be set at a $1.00/W similar to the current incentive for Level 3-R IC Engines, Large Gas Turbines.

9.0 Supplemental Appendices

9.1 Appendix 1
UTC PMG Request Form and Proposal dated December 3, 2004.

9.2 Appendix 2
UTC Presentation to the SGIP WG dated December 14, 2004

9.3 Appendix 3
UTC 2004 Marketing Brochure for the PureCycle™ 200.

9.4 Appendix 4
Nevada Assembly Bill 429

9.5 Appendix 5
North Dakota Department of Commerce Letter dated July 1, 2003.

9.6 Appendix 6
Pennsylvania Senate Bill 1030

9.7 Appendix 7
South Dakota Department of Commerce Letter dated July 1, 2003.

9.8 Appendix 8
Connecticut Raised Bill 6906, Introduced January 2005 Session.

9.9 Appendix 9
Texas House Bill 1565

9.10 Appendix 10
UTC Response to SGIP Recommendation dated April 18, 2005.

PMG03-003-SCE
Self-Generation Incentive Program
Program Modification Proposal to Add STM PowerUnit (Stirling Engine) to SGIP

SUMMARY

This Program Modification proposal, submitted by STM, requests the addition of Stirling engine generators as an eligible technology under Levels 3-R and 3-N.

A Stirling engine has a gaseous working medium that is sealed within the machine. A portion of the engine is maintained at a constant high temperature (either by burning fuel in the combustor or from an external heat stream) and another portion is maintained at a constant low temperature. The working gas is transferred back and forth between the hot and cold portions of the machine by the movement of the engine's pistons. Stirling engines can be designed in a number of configurations; single piston, double pistons, or multiple pistons.

Stirling engines are unique in that they are especially well suited for multiple fuels because they are powered by an external heat source; no internal combustion takes place. That heat source can be fossil fuels, waste gas, landfill gas, digester gas, solar thermal, an external heat stream or nuclear energy.

BACKGROUND

Aloha Systems, representing Solar Thermal Motors (STM) submitted a proposal to add Solar Thermal Motors Stirling engine generators to the SGIP Level 3-R and 3-N technologies to SCE on September 24,2004. A presentation was made to the Working Group on November 17, 2004, by Mark Shirilau (Aloha Systems), Mike Brack and Joe Silva (CalPWR). A set of questions developed by the Working Group (WG) were sent to Aloha Systems and STM shortly after the meeting. Aloha Systems and STM provided answers to the questions in a memo dated November 23, 2004.

CONCERNS AND ISSUES CONSIDERED

In D.OI-O3-073 the CPUC prescribed the technologies currently eligible in the SGIP. These eligible technologies are classified by incentive level.

Incentive Levels	Eligible Technologies
Level 1	• Photovoltaics • Fuel cells operating on renewable fuel • Wind turbines
Level 2	• Fuel cells operating on non-renewable fuel and utilizing sufficient waste heat recovery
Level 3-R	• Micro-turbines, internal combustion engines and small gas turbines operating on renewable fuel
Level 3-N	• Micro-turbines, internal combustion engines and small gas turbines operating on non-renewable and Waste Gas fuels, utilizing sufficient waste heat recovery, emissions, efficiency and meeting the reliability criteria as applicable

The Stirling engine is distinctly different from the technologies currently eligible in SGIP. It is an external combustion technology, when utilizing renewable or non- renewable fuels, and its thermodynamic cycle is unique compared to gas turbine or reciprocating engine technologies.

Their were five concerns regarding this Program Modification Request (PMR) expressed by WG members; first the technology is not widely deployed commercially and long term reliability data is scarce, second Stirling engines are capable of fuel switching to diesel which is ineligible, third the technology is not CARB certified, fourth the system cost for emerging technologies can be high, and fifth Stirling engines can use process waste heat in a bottoming cycle, which is not eligible.

Commercial Availability: Stirling technology has been in development since the early 19th century. STM has beta tested fifty 25 kW units: 10 at the STM factory and 40 in the field. Learning from that experience STM has developed and deployed nine 55 kW units in the U.S. Another five were shipped to China and six more will be shipped to various locations in the U.S. and Europe for landfill, digester gas, natural gas, propane and heat recovery from incinerators. In addition to the STM unit, other commercial manufacturers of the technology exist including WhisperTech (1,200 kW, New Zealand). STM has licensed distributors to market and supply commercial units. These distributors are; California Power Partners (CA), Stirling Power (OR), DTE Energy Technologies (MI), Mariah Energy (Canada), Unison Solutions (IA) and Charles Equipment (IA). STM has also developed a larger Model 260, five of which were endurance tested for six months and eight units that were installed in a number of locations.

The Working Group, through its investigation, believes the systems could be ordered and delivered within a reasonable period, which supports the applicant's position that these systems are commercially available.

Diesel Fuel: Stirling technologies are promoted as fuel flexible, which caused concern among the WG members. In fact, the Aloha/STM PMR states that the technology has "combustor versatility". The SGIP rules strictly prohibit the use of Diesel fuel in the program. Aloha/STM has explain, in follow-up correspondence, that the current models are not designed for liquid fuel and the gaseous fuel models are not easily converted to liquid fuels. Aloha stated, "The sentence in the 'combustor versatility' section on page 4 of the PGM in which I mentioned diesel and other liquid fuels was taken from a draft

STM product brochure. The new brochure no longer references these fuels because STM does no produce equipment that burns them."

CARD Certification: STM states in their November 23,2004 letter that their units are under CARB evaluation at this time. They also state in the PMR, that with full waste heat credit their NOx emission rate for the 55 kW unit is 0.18 lb/MWH, which does not meet the SGIP requirements for 2005 (0.14 lb/MWh). No amount of thermal load or waste heat utilization at any site, with the current STM product without additional emissions controls, could provide enough emission credits so it could meet the SGIP's emissions standard. It is evident that STM will have to use post combustion cleanup equipment (e.g., 3-way catalysts) or a redesigned combustor to reduce their emissions to comply with SGIP emission standards for 2005 and beyond. Aloha/STM provided no engineering or performance data for the addition of a 3-way catalyst. No data was provided to date and no systems have been permitted to operate in California to date. Hence the Working Group has some concerns if this technology can meet the requirements for Level3-N.

System Costs: Aloha Systems and STM report that the system costs are from $4,582/kW and $3,945/kW for a single unit renewable fuel and natural gas fuel system respectively. Costs for single and multiple unit installations are provided by Aloha/STM in the following table.

Estimated Installation Costs of STM PowerUnit					
Number of Units	kW	Waste Gas Cost	Cost per kW	Natural Gas Cost	Cost per kW
1	55	252,000	4,582	217,000	3,945
2	110	370,000	3,364	325,000	2,955
3	165	475,000	2,879	428,000	2,594
4	220	565,000	2,568	505,000	2,295

In multiple unit installations, the installed cost of the project is such that, under the PY2004 rules, forty percent of the project cost would result, approximately in an incentive amount of $1/Watt. This appears to be inline with incentives provided to IC engines for the 2005 program.

Waste Energy Conversion: Currently SGIP does not allow waste energy conversion systems in the program. Waste energy conversion systems capture waste heat or pressure and convert it into electric output. STM has provided systems to convert waste heat from incinerators to electric output.

Additionally Mafi-Trench filed a Request for Modification to the Commission requesting to make turbo-expanders an eligible technology to the SGIP. However, Findings of Fact #1 from D.O3-12-036, states:

Turbo-expanders represent a waste heat recovery technology that cannot be considered in isolation for the purpose of evaluating its eligibility under our AB 970 self-generation incentives program.

The Working Group draws a direct parallel between these two technologies. The Stirling Engine can be set up in a way to generate electricity for a waste heat stream (waste heat recovery).

DISCLOSURE Southern California Gas Company is a shareholder in STM Power. It holds no offices or directorships or employee positions in the company and has no direct management control of the company. Southern California Gas Company shareholder's interest is approximately 6% and that its ownership position was purchased with ratepayer balancing account dollars and not shareholder funds.

MAJORITY (CONSENSUS) RECOMMENDATION

All members who took part in the review (SCE, PG&E, SoCalGas, SDREO and SDG&E) make their recommendations based on the type of fuel supplying this technology.

- If the Stirling engine generating system is fueled by a **waste heat stream we** unanimously recommend it **not be eligible** for SGIP for the reasons previously stated.

- If the Stirling engine generating system is fueled by a renewable fuel as defined by the SGIP Handbook, we unanimously recommend it be eligible for SGIP as a Level3R technology with an incentive rate *of* $l.00/watt for the reasons previously stated.
- If the Stirling engine generating system is fueled by a nonrenewable fuel as defined by the SGIP Handbook, the Working Group does not have a unanimous recommendation.
    - PG&E and SCE recommend it not be eligible for the SGIP for the reasons stated below.
    - SDREO, SDG&E and SoCalGas recommend it be eligible for the SGIP as a Level 3N technology with an incentive rate equivalent to that of an I.C. engine for the reasons stated below.

RATIONALE FOR MAJORITY (CONSENSUS) RECOMMENDATION

The SGIP Working Group bases its recommendation to allow Stirling generators into the program on the balance of following considerations:

Pros:

a. Stirling generating technologies show promise to be more compatible with combustion fuels as a fuel source or renewable fuels than conventional technologies. Although the technology is in its early commercial stage, it appears that a distribution network has been established and commercial sales of systems have occurred. SGIP can help the market by imposing performance and warranty of the purchased units. Fuel switching concerns are mitigated by the existing requirements for renewable fuels. Waste energy conversion is prohibited by the program and is controlled by the application of the technology.

Cons:

a. The technology would find limited markets because of cost and performance concerns of the buyers. Emissions from the STM technology appear to be a problem given the requirements for Level 3-N technologies starting in PY2005, even when giving emissions credit for full waste heat utilization.

DISSENTING RECOMMENDATION & RATIONALE

See specific comments of each Program Administrator

Specific Comments by Program Administrator

SoCalGas, SDREO and SDG&E feel Stirling engine technology should be an eligible technology for the SGIP provided the system is directly fueled by either a renewable fuel or non-renewable fuel as defined by the SGIP Handbook. These systems would then only be eligible for Level 3R or Level 3N incentives respectively and would be required to meet the SGIP requirements of those incentive levels. Furthermore, SoCalGas, SDREO and SDG&E recommend the incentive level be consistent with Level 3-R and 3- N IC Engines, currently set at $1.00/W and $0.60/W respectively, per the new incentive structure.

The fact that Aloha Systems has not demonstrated these systems are capable of meeting the LeveI3-N emissions requirement of 0.14 ppm NOx/MWh is not an immediate concern at this time. Meeting this requirement will be site specific and depend on the application, system design, the type of emissions clean-up equipment, the overall efficiency of the system and the determination of the emissions credit allowed by AB 1685. At this time SoCalGas, SDREO and SDG&E are not aware that any of the current technologies eligible for Level 3-N meet the required emissions criteria without a NOx credit.

SCE **and** PG&E approve the addition of Stirling generating technology to Level 3-R only. At the present time STM can not substantiate that the unit meets the emission requirements for 2005 including credits prescribed in AB 1685 even with emissions credit for the full waste recovered by the unit. It is recommended that the unit not be deemed eligible for Level 3-N until it can demonstrate meeting the emission requirements with or without emissions credit. SCE and PG&E both feel that any new

technology must meet the requirements of the program in order to take part in the program.
Currently eligible technologies appear to be able to meet the new emissions requirement (see attached Capstone letter) and new technologies should be allowed into the program only if they show potential to meet the current eligibility requirements.

APPENDIX A - ALOHA/STM PMR AND CORRESPONDENCE

Self-Generation Incentive Program
Proposed Modification to Current Definition of Renewable Fuel
PMG05-004-PGE

A potential Self-Generation Incentive Program (SGIP) Applicant, Intellergy Corporation, requests a modification to the rules found in the Self Generation Incentive Program Handbook, specifically as noted in Section "2.10.1: Renewable Fuels". The Program Rule Modification requested is to change the definition of a Renewable Fuel to include syngas created from medical waste.

Background

Fuel cells that use renewable fuels are currently eligible for a Level 1 incentive. Fuel cells that use non-renewable fuel are currently eligible for a Level 2 incentive.

On September 19, 2002, Decision D02-09-051 was issued, in which the Commission revised the Self-Generation Incentive Program (SGIP) to create the 3-R category to provide preferential incentives for combustion technologies (e.g., micro-turbines) that use renewable fuels. In this decision, the definition of a Renewable Fuel was adopted to: "A renewable fuel is a non-fossil fuel resource other than those defined as conventional in Section 2805 of the Public Utilities Code, that can be categorized as one of the following: solar, wind, biomass, digester gas, or landfill gas. A facility utilizing a renewable fuel may not use more than 25 percent fossil fuel annually, as determined on a total energy input basis for the calendar year."

Further, CALIFORNIA CODES HEALTH AND SAFETY CODE SECTION 25140-25145.4 states: 25143.5.(g)(2) "Biomass" or "biomass waste" means any organic material not derived from fossil fuels, such as agricultural crop residues, bark, lawn, yard and garden clippings, leaves, silvicultural residue, tree and brush pruning, wood and wood chips, and wood waste, including these materials when separated from other waste streams. "Biomass" or "biomass waste" does not include material containing sewage sludge, industrial sludge, medical waste, hazardous waste, or radioactive waste.

Thus under current SGIP definitions, medical waste or syngas created from medical waste would qualify as a non-renewable fuel, and therefore would be eligible for a Level 2 incentive if used with a fuel cell or Level 3-N if used with an IC engine or combustion turbine.

Program Modification Request Summary

On November 05, 2004, a first draft of a Program Modification Request (PMR) package was submitted to the Sponsoring Program Administrator (SPA), Pacific Gas and Electric

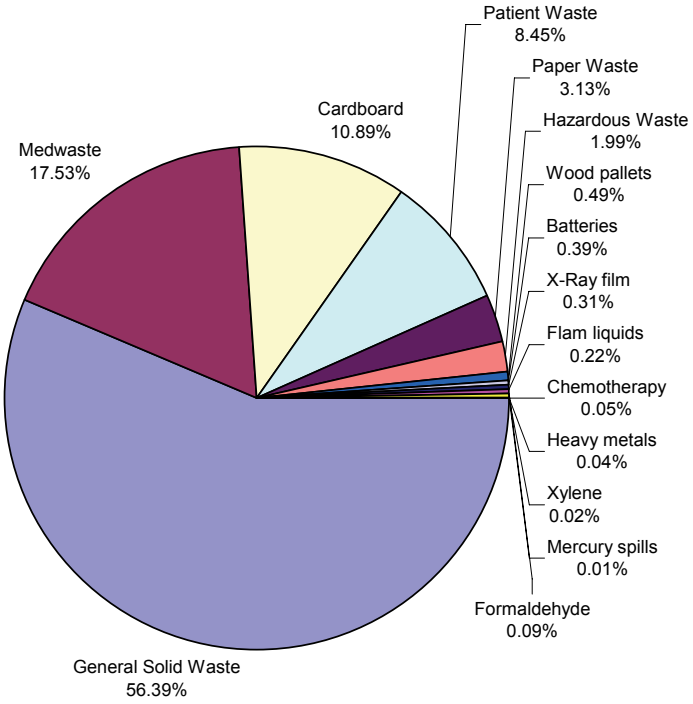
(PG&E), on behalf of Intellergy Corporation. The SPA reviewed the draft PMR in consultation with an outside engineering consultant[42] hired by the SPA to provide assistance with matters concerning the Self-Generation Incentive Program (SGIP). Comments and questions on the contents of the initial draft PMR package – as they related to completeness in satisfying the Program Modification Guidelines – were then forwarded to the PMR Applicant for incorporation into the final package.

On Feb 7, 2005, a final PMR application package was submitted to the SPA and was deemed complete (Attachment A). The package was distributed to the SGIP Working Group for review prior to the next scheduled monthly meeting.

On March 17, 2005, Dr Terry Galloway from Intellergy Corporation gave a presentation to the Working Group with a summary of his technology and proposal.

California hospitals no longer incinerate medical waste on-site, but current standard practice is to send their waste to a landfill. Typical medical waste consists of garbage, including cafeteria waste, office paper waste, cardboard, patient waste, hazardous waste and other waste streams (including wood pallets, and clinical lab waste). On page 3 of the PMR, the Composition of Medwaste is given in Figure 1 below:

Figure 1: Composition of Medwaste



Intellergy Corporation has developed a process which uses steam/CO_2 reforming chemistry to convert medical waste into hydrogen-rich syngas, which would then be used to operate a fuel cell. According to Intellergy Corporation, this process would also

[42] Alternative Energy Systems Consulting, Inc. (AESC)

have the additional benefit of reducing the waste stream to be sent to a landfill. For a detailed discussion on the process and chemistry involved, please refer to Attachment A.

Intellergy Corporation has requested that the definition of renewable fuel be changed to include medical waste processed into a syngas. Intellergy Corporation has argued this is appropriate because this process is analogous to landfill gas, that it would add positive environmental benefit to our landfills, and have a net positive life cycle energy production that does not draw on any types of fossil fuels.

Consensus Recommendation

While the SGIP Working Group agrees this technology may have a sufficient benefit to the waste stream directed to landfills, it is clear that the current definition contained in the California Health and Safety Code does not include medical waste as “biomass” or “biomass waste”. In addition, the SGIP Working Group has a concern about the commercial availability and reliability of this process and technology. To date there has not been any of these systems in operation and therefore there is no available data on the performance or cost of this process.

The Self-Generation Incentive Program Working Group unanimously recommends that the proposed program modification to change the definition of a renewable fuel be declined. While the SGIP Working Group agrees this technology may have a sufficient benefit to the waste stream directed to landfills, the decision to change the definition of a renewable fuel and biomass outside of the jurisdiction of the SGIP Working Group.

PMG06-013-SDREO
Self-Generation Incentive Program
Proposed Modification for a New Technology
Advanced Energy Storage

10.0 Summary

On December 4, 2006, StrateGen Consulting LLC and VRB Power Systems Inc. submitted a proposal to the Self-Generation Incentive Program (SGIP) Working Group (WG) requesting the addition of the following new technology for SGIP eligibility:

- **Advanced Energy Storage (AES)**

AES technologies provide viable means to collect, store, and dispatch, upon demand, large quantities of energy. The lifecycle, efficiencies, and scalability of many AES technologies far exceed a standard Lead Acid battery system.

VRB Power Systems Inc. developed the vanadium-based redox regenerative fuel cell that converts chemical energy into electrical energy (vanadium redox battery or VRB energy storage system (VRB ESS)). The VRB ESS capacity can range from 5kW to 10MW with an adaptable discharge period (typical 1-10+ hours). StrateGen has requested the technology be considered for the Level 3 fuel cell incentive.

11.0 New Technology Screening Criteria and Issues Considered

11.1 California Market Potential[43]

StrateGen contends, "Many findings and conclusions of the PIER report on market penetration for CHP systems are relevant to the market potential for AES." StrateGen points out an AES could overcome the emissions barriers CHP is set to run up against in the future. AES could effectively satisfy the need of prospective CHP adopters to reduce their overall cost of energy and increase power reliability for approximately 1,966 MW between 2005 and 2020.

StrateGen highlights the following market segments for greatest impact:

- Direct Access customers
- Back-Up Generator Replacement (BUGS)
- Distributed Generation

[43] StrateGen PMG, Section I-4, p. 8-10

11.2 Demand Reduction Potential[44]

StrateGen stated the benefit potential of an AES system to reduce the peak demand from a utility customer by shifting the power draw to off-peak hours is vast. The ability of the AES system to support onsite renewable generation in conjunction with peak-demand arbitrage adds energy cost savings to the end user and improves T&D infrastructure by reducing demand on the system.

11.3 Equipment Life[45]

The VRB ESS has a 25 year expected equipment life. VRB sells a fixed cost operations and maintenance contract for a complete cell stack replacement occurring over a period of 4 years (years 12-15) as part of the system. VRB also provides a 25-year O&M service for the system. StrateGen proposes the warranty requirements for the AES are consistent with the 3-year requirement for other Level 3 technologies.

11.4 Financial Need[46]

In its PMR, StrateGen assumes some criteria for a large scale system to calculate the estimated payback term for SCE and PG&E service territories. StrateGen notes that rate data was not modeled for SDG&E because of the difficulty in interpreting SDG&E's rate structure. The economic model shows that under the more favorable SCE TOU-8 rate, the best case payback for the VRB ESS without incentive is currently 10 years for a commercial customer and 17 years for a tax-exempt customer. PG&E's E-19 rate would put the payback for commercial and tax exempt customers at 16 and 20, respectively.

StrateGen proposed an incentive structure for both capacity based ($2.50/W) and performance based ($0.15/kWh) incentives. The capacity based incentive was selected due to the technological similarity between the VRB ESS and a non-renewable fuel cell. Although the SGIP currently deploys capacity based incentives, StrateGen also proposed a performance based incentive that would achieve a 10%-15% IRR for both SCE and PG&E with the intention that the performance based model would better fit the benefit mode of the technology by incentivizing the use of the system during the local utility's peak periods.

The proposed capacity based incentive would have the effect of reducing the payback period for the example system to 5 and 10 years for commercial and tax-exempt customers respectively for the SCE service territory. It would also push the commercial customers for PG&E's rate to 6 years, but tax exempt customers would still fall short at a 16 year payback.

[44] StrateGen PMR Section I-8, p. 13
[45] StrateGen PMR Section I-3, p. 6
[46] StrateGen PMR Section I-3, p. 6-8

Commercial Availability[47]

AES systems are commercially available and claims they have been so since the late 1990's. The first North American VRB ESS installed was for PacifiCorp in Utah, 2004. Additional sales and deliveries include:

- **Tapbury Management** – 1.5MW x 8hr VRB-ESS for Irish wind farm
- **PacifiCorp –** 250kW x 8hr VRB-ESS (3 years of successful operation)
- **Pinnacle -** 1MWH and 2 x 10kWh VRB-ESS for RAPS applications in Australia
- **Magnetek** – Letter of Intent for Eighty, 5kW VRB-ESS systems
- **Risø –** 15kW x 8hr (120kWh) VRB-ESS, Danish wind applications
- **Eskom** – 10kWh VRB-ESS, back-up for substation of major South African utility
- **Solon AG** – 10kWh VRB-ESS, solar applications in Germany
- **University of Alaska** – 10kWh VRB-ESS, assessment in RAPS applications
- **South Carolina Air National Guard** – 30 / 60 kW x 2hr VRB-ESS, back-up power
- **National Research Council Of Canada** – 10kWh VRB-ESS, RAPS
- **Sitel (Slovenia) –** 10kWh VRB-ESS - Telecoms

11.5 Certifications[48]

Certifications are technology specific and StrateGen did not speak of certifications held by potential technologies other than the VRB ESS. AES claims the VRB ESS does not require specific system level certifications as it is a chemical plant. AES claims technologies related to the energy system such as inverters, transformers, etc. are 'off the shelf' and meet all required IEEE certifications.

11.6 Environmental Impacts

StrateGen characterizes the VRB ESS as the lowest ecological impact of all energy storage technologies. [49] Although, some forms of AES do contain potentially toxic substances such as lead, zinc, or cadmium, the VRB ESS does not. When compared to lead-acid batteries for use in stationary applications, the VRB ESS produces 75-93% fewer emissions of key environmentally damaging components (CO2, SO2, CO, CH4, NOx) during its life cycle.

The VRB ESS's working fluid is a vanadium electrolyte, which AES claims has an indefinite life with no disposal or contamination issues. However, due to the chemical nature of the electrolyte, the vanadium does have to be treated as a hazardous material if spilled.[50]

[47] StrateGen PMR, Section I-5, p. 10-12
[48] StrateGen PMR, Section I-6, p. 12
[49] StrateGen PMR, Section I-2, p. 5
[50] StrateGen PMR, Section I-11, p. 14

11.7 Compliance with Current Program Requirements

VRB's energy storage system falls within the minimum-maximum allowable system size range and meets program warranty/maintenance requirements.

Due to StrateGen proposing AES be added as new technology group, not just the VRB ESS, StrateGen also proposed criteria for eligibility in the new AES technology group.

The SGIP WG agreed that the VRB ESS, and similar AES systems, do not constitute stand alone self-generation technologies and SoCalGas and SCE felt this to be criteria for ineligibility.

CCSE (formerly SDREO) and PG&E acknowledge an AES system does not directly generate electricity. However, CCSE and PG&E believe the peak-load reduction capabilities and demand-response potential of the technology could greatly benefit both the utilities and the utility customers by providing an environmental alternative to onsite distributed generation. CCSE and PG&E believe AES systems such as the VRB ESS could greatly enhance the reliability and load distribution for CA. CCSE and PG&E believe StrateGen made a convincing argument for providing incentives for AES systems to tip the economic impact in favor of getting more projects installed.

Rationale for both recommendations are given below.

12.0 Do Not Include - Recommendation (DNIR)

The following members of the SGIP WG: SCE and SoCalGas recommend that AES technologies not be accepted for eligibility in the SGIP.

12.1 Rationale for DNIR

The SCE and SoCalGas recommend that AES technologies be rejected for eligibility in the SGIP. SCE and SoCalGas point to AB970 which clearly identifies differential incentives for super clean distributed "generation" resources:

> Section 399.15. Notwithstanding any other provision of law, within 180 days of the effective date of this section, the commission, in consultation with the Independent System Operator, shall take all of the following actions, and shall include the reasonable costs involved in taking those actions in the distribution revenue requirements of utilities regulated by the commission, as appropriate:...
> (6) Incentives for load control and distributed generation to be paid for enhancing reliability.
> (7) Differential incentives for renewable or super clean distributed generation resources.

In Decision 01-03-073, the Commission defined "self-generation" as, "…distributed generation technologies (microturbines, small gas turbines, wind turbines, photovoltaics, fuel cells and internal combustion engines) installed on

the customer's side of the utility meter that provide electricity for a portion or all of that customer's electric load." Furthermore, the Commission prescribed for the program cost-effectiveness evaluation, "The measurement and verification protocols established by the administrators include some sampling of actual energy production by the funded self-generation unit over a statistically relevant period." SCE and SoCalGas share the opinion that based on the explicit definition of "self-generation" set forth by the Commission whereby the onsite distributed generation system produces electricity onsite and the SGIP cost-effectiveness is determined by the effect of onsite energy production, the AES technology does not fit the intent of the SGIP. The AES technology is strictly an energy redistribution system which captures and utilizes energy produced from other sources.

SCE and SoCalGas are not convinced that gas rates should be higher to subsidize markets where AESs are highlighted as having the "greatest impact" by StrateGen such as Direct Access customers and subsidizing Back-Up Generator Replacement (BUGS). SCE and SoCalGas also do not believe AES electric arbitrage projects are warranted to subsidize higher gas rates.

SoCalGas believes AES technology would benefit primarily PV, wind projects, and to a lesser extent load following technologies like fuel cells, internal combustion engines, and microturbines. Since there are very few wind projects subscribed to the SGIP, the largest potential beneficiary would seem to be PV projects. Therefore, SoCalGas recommends AES's PMR be transferred to the CSI program.

13.0 Move To Include - Recommendation (MTIR)

CCSE and PG&E feel that while the AES technologies do not fit a current technology grouping for the SGIP; the SGIP Working Group has the authority to recommend to the Commission new technologies for inclusion in the SGIP; and AES technologies could provide significant benefits associated with the on demand capture and discharge of energy using AES technologies. These benefits could be realized by California's utility customers, utility grid operators, and electricity providers in addition to expediting the adoption of renewable energy generation systems.

13.1 Rationale MTIR – Program Intent

This section reviews the relevant California statutes and decisions of the California Public Utilities Commission ("Commission") that have defined the scope of the SGIP, the role of the SGIP Working Group ("Working Group"), and the direction that the Commission is currently embarked on to re-define the scope of the SGIP. It provides historical legal support for the following propositions:

1. Advanced energy storage has been a potential eligible technology since the SGIP was first established.

2. The Working Group has the authority to recommend to the Commission that advanced energy storage technology should be made eligible under the SGIP if it chooses to do so.

3. Based on evidence provided by StrateGen and the upcoming renewal of the SGIP, now is the optimum time for the Working Group to advocate for a Commission decision to include advanced energy storage as an SGIP-eligible technology.

13.1.1 Introduction

The fact that the SGIP is intended to encourage development of preferred clean and renewable distributed generation of electricity is indisputable. It is equally clear, however, that the purpose of the SGIP was from the inception, and is today, not confined simply to generation. Rather, the SGIP is intended to be part of the much broader subject of electricity supply and demand management. From the enactment of AB 970 that authorized the Commission to create the SGIP in 2001[51], it was designed as a flexible program that has progressively evolved in step with advances in energy technology and California's energy policy.

The Working Group, established to administer the SGIP, has also matured over time to fine-tune the SGIP and help the Commission develop policy initiatives in order to keep current with environmental concerns and technical solutions. The Program Modification Request process, administered by the Working Group, is the regulatory vehicle for the Working Group to propose changes to the SGIP, and to advocate for new ideas that are brought to it for evaluation by stakeholders in the business of electricity supply and demand management.[52] Whether specific program modifications proposing addition of new technologies to the SGIP are embraced by the Working Group or not, it serves an important function in identifying emerging issues for consideration by the Commission.

Electricity storage, either stand-alone or coupled with renewable generation technologies such as solar and wind, has long been considered the “holy grail” of distributed energy resources. This has been recognized since well before the Commission created the SGIP. Until now, however, storage technology has been steadily been working its way from the laboratory through demonstration and the beginning of commercial deployment. Today, storage technology has come of age, and is at exactly the stage that the SGIP is intended to support.

[51] AB 970, codified as Public Utilities Code Section 399.15(b), Paragraphs 4-7; Load Control and Distributed Generation Initiatives (2000).

[52] See the Self-Generation Incentive Program Modification Guidelines (July 1, 2006, Rev. 2). "For the evaluation of proposed program rule changes, the Working Group will consider the original intent and purpose of the SGIP. The SGIP was established as a unified statewide program with the intent of producing sizeable public benefits in the form of electric peak-demand reductions, environmental benefits and other benefits, relative to their cost." (at, p.3).

The Commission is on record as looking to the SGIP as the regulatory vehicle of choice to "elide" the largely arbitrary distinctions between the supply and demand sides of the distributed energy equation.[53] The Working Group is perfectly positioned to aid the Commission in achieving the policy goal of linking advanced load management with renewable energy generation. CCSE and PG&E believe including advanced electricity storage as a technology that is eligible for incentives under the SGIP is the right thing to do at this point in its development, and this is the perfect time for the Working Group to recommend adding it as an eligible technology to the Commission.

13.1.2 History of Eligible Technologies

Advanced electricity storage has been contemplated as potentially part of what later became the subject of the SGIP well before it was created by the Commission. Writing about the competitive aspects of the subject and assessing its impact on investor-owned utilities, in D.99-10-065, issued on October 21, 1999,[54] the Commission articulated the frame of reference for encouraging development of distributed electricity technology:

> "In this decision we use the term 'distributed generation' to refer to those small scale electric generating technologies such as internal combustion engines, microturbines, wind turbines, photovoltaics, and fuel cells. We use the term DER to refer to the distributed generation technologies, storage technologies, end-use technologies and DSM technologies.

'Distributed generation' has also been referred to as 'distributed energy resources' (DER) or 'distributed resources' (DR). (OIR, p. 2, fn. 1).[1] DER appears to be the broadest of all three terms, and includes distributed generation, as well as energy storage technologies such as battery energy storage, superconducting magnetic energy storage, flywheel energy storage, and compressed air energy storage. DER can also refer to targeted "end-use technologies" or targeted DSM techniques.

In general, a DER has the following attributes: the DER is usually located at or near the load center; it may be connected to the distribution system or it can operate independently of the distribution system; it provides an enhanced value other than its energy and capacity; the DER is usually small in terms of electric power output; and the DER facility is usually automated, modular and mass produced. (Mimeo, p. 14).

[53] See R.04-03-017, filed March 16, 2004, at p. 4.
[54] Rulemaking on the Commission's Own Motion to Solicit Comments and Proposals on Distributed Generation and Competition in Electric Distribution Service, R.98-12-015, filed December 17, 1998.

[1]In footnote 1 of the OIR, we stated that distributed generation 'generally refers to generation, storage, or demand-side management (DSM) devices, measures, and/or technologies that are connected to or injected into the distribution level of the transmission and distribution (T&D) grid….'"

The statutory foundation for the SGIP was laid with passage AB 970 in February 2000. The statute provides in relevant part as follows:

> "SEC. 7. Section 399.15 is added to the Public Utilities Code, to read:
>
> 399.15. Notwithstanding any other provision of law, within 180 days of the effective date of this section, the Commission, in consultation with the Independent System Operator, shall take all of the following actions, and shall include the reasonable costs involved in taking those actions in the distribution revenue requirements of utilities regulated by the commission, as appropriate: (b) In consultation with the State Energy Resources Conservation and Development Commission, adopt energy conservation demand-side management and other initiatives in order to reduce demand for electricity and reduce load during peak demand periods. <u>Those initiatives shall include, but not be limited to, all of the following: . . . (6) Incentives for load control and generation to be paid for enhancing reliability. (7) Differential incentives for renewable or super clean distributed generation resources</u>." (Emphasis added).[55]

As directed by the legislature, the Commission began implementation of AB 970 with D.01-03-073, issued March 27, 2001[56]:

> "AB 970, signed by the Governor on September 6, 2000, requires the Commission to initiate certain load control and distributed generation activities within 180 days. By ruling dated October 17, 2000, we assigned the implementation of Pub. Util. Code § 399.15(b) (codifying AB 970), paragraphs 4 through 7 to this proceeding. . .
>
> In the same October 17, 2000 ruling, we directed the Energy Division to 'develop specific program plans for implementing load control and distributed generation initiatives per § 399.15(b) for our consideration.' (Mimeo, pp. 5-6).
>
> . . .
>
> In its report relied upon the Commission, the Energy Division defines 'self-generation' as 'distributed generation (DG) installed on the customer's side of the utility meter, which

[55] Order Instituting Rulemaking on the Commission's Proposed Policies and Programs Governing Energy Efficiency. Low Income Assistance, Renewable Energy Research Development and Demonstration, R.98-07-037, filed July 23, 1998.

[56] Statutes 2000, Chapter 329, September 7, 2000.

> provides electricity for a portion or all of that customer's electric load.' (Report, p. 5.) [Attached to the Decision].
>
> For the purpose of this program, Energy Division defines DG technologies as internal combustion engines, microturbines, small gas turbines, wind turbines, photovoltaics, fuel cells, and combined heat and power or cogeneration. A subset of these technologies is considered renewable and eligible for differential incentives, as required by § 399.15(b) paragraph (7), including wind turbines, photovoltaics and fuel cells." (Mimeo, p. 9).

It was clear from the Commission's initial decision that the SGIP was intended to be expanded in the future:

> "Should general fund appropriations be made available for demand-responsiveness and self-generation programs through subsequent Legislative action, we will consider augmenting today's approved programs. As described further below, the Energy Division's proposed programs consist of a focused set of pilots that can be broadened to encompass additional market sectors, technologies and system sizes, if and when appropriate." (Mimeo, pp. 11-12).

It became obvious with the Commission's Opinion granting a Petition for Modification of D.01-03-073 filed by the South Coast Air Quality Management District in D.02-04-004, issued April 4, 2002[57] that the SGIP that was approved by the Commission was essentially made out of whole cloth by the staff of its Energy Division with intention to be fit as time progressed:

> "In considering SCAQMD's Petition, we first look to the language of the statute and the Commission decision authorizing the self-generation program. We agree with SCE that an examination of AB 970 and § 399.15(b) quickly reveals that the Legislature expressed no guidance on the extent or scope of incentives for distributed generation. The Legislature simply directed the Commission to adopt demand-side management and other initiatives to reduce the demand for electricity and reduce load during peak periods, including incentives for distributed generation resources. Based on the plain language of the statute, it is impossible to glean any legislative intent on the issue raised by SCAQMD's Petition." (Mimeo, p. 5).

The Commission dealt with another Petition for Modification of D.01-03-073 in D.02-09-051, issued September 19, 2002. In rejecting changes proposed by Capstone regarding renewable fuel micro-turbines, the Commission relied on an attached Energy Division Report titled

[57] R.98-07-037.

Technologies Utilizing a Renewable Fuel in the Self-Generation Incentive Program (April 2002) and simply quoted the bare bones of the statute to reach its decision:

> "Assembly Bill 970 (AB 970), signed by Governor Davis on September 6, 2000, required the CPUC to initiate certain load control and distributed generation activities, including the following financial incentives:
>
> - Incentives for load control and distributed generation to be paid for enhancing reliability;
> - Differential incentives for renewable or super clean distributed generation resources.[1]
>
> [1] Codified as Public Utilities Code Sec. 399.15(b)(6) and (7)."

The Self-Generation Incentive Program approved by the Commission in D.01-03-073 is the program through which these incentives are being offered. (Report, p. 2).

Public Utilities Code Section 399.15 was augmented by enactment of AB 1685 in October 2003. The Legislative Counsel's Digest described the purpose of AB 1685 as follows:

> "AB 1685, Leno. Energy: self-generation incentive program: peak reduction. Existing law requires the Public Utilities Commission on or before March 7, 2001, and in consultation with the Independent System Operator, to take certain actions, including, in consultation with the State Energy Resources Conservation and Development Commission (Energy Commission), adopting energy conservation demand-side management and other initiatives in order to reduce demand for electricity and reduce load during peak demand periods, including, but not limited to, differential incentives for renewable or superclean distributed generation resources…"[58]

The statute imposed more restrictive air quality compliance requirements on eligible combined heat and power generators, and otherwise left the SGIP intact.

In summary, from the beginning, the Commission intended the SGIP to encompass not only distributed generation technologies, but also other distributed energy resources such as storage and other demand side technologies. This was the basic concept embodied in AB 970. Further, it is clear from the Commission's early decisions implementing AB 970 that the SGIP was expected to be expanded to embrace new technologies in the future.

[58] See also, Opinion Responding to Petition of the California Independent Petroleum Association, D.05-10-025, issued October 27, 2005; Opinion Denying the Petition of Tecogen for Modification of D.04-12-045, issued February 16, 2006.

13.1.3 The Role of the Working Group

In D.03-01-006, issued January 16, 2003, in rejecting a change proposed by Mafi-Trench regarding turbo-expanders, the Commission determined that the Petition for Modification process was too cumbersome and directed the Energy Division to form a staff-level formal SGIP modification process to be managed by the Working Group. The Commission also noted in passing that, "[o]ne of the primary objectives of the SGIP is peak load reduction." (p.6). The Commission established the Program Modification process proposed by the Energy Division in its entirety in D.03-08-013, issued August 21, 2002:

> "Our goal today is to establish a process by which we can give careful consideration to proposed new technologies for the self-generation program. Petitions to modify do not facilitate such a process because the information presented to the Commission is, by definition, driven by the petitioners' submittal and the individual views of parties who elect to respond. We believe that Energy Division's proposal meets our goal with the minor modifications and clarifications discussed below.
>
> First, we clarify that the process adopted today will also apply to any other type of proposed program modifications, including changes to incentive levels or proposals to include 'ancillary' technologies (i.e., absorption chillers and other waste heat devices) as an eligible cost. To date, we have addressed such proposals via the procedures related to petitions for modification, as we have for proposals to add technologies. We believe that the process established today for evaluating proposals to include new generation technologies lends itself to other types of program modifications as well. In addition, we also see no reason to limit that process to changes suggested by non-Working Group members. It should also apply to changes proposed by the Working Group itself." (Mimeo, p. 6).

The Commission substantially accomplished its objective of streamlining the Petitions for Modification process by effectively delegating consideration of changes and addition of technologies to the Working Group under the supervision of the Assigned Commissioner in R.98-07-037, and successor Rulemaking proceedings on the subject of distributed energy resources.[59]

[59] See e.g. Interim Change to 2006 Handbook, January 27, 2006 - Rev. 0, containing 20 administrative program modifications adopted by the Working Group in 2006.

13.1.4 Energy Storage for the SGIP

Having approved the SGIP and established the Working Group, the Commission next opened a successor proceeding to R.98-07-037, for the purpose of articulating a more comprehensive framework for distributed energy resources, Order Instituting Rulemaking Regarding Policies, Procedures and Incentives for Distributed Energy Resources, R.04-03-017, filed March 16, 2004:

> "In this proceeding we continue our consideration of rules and policies impacting distributed generation (DG). DG has taken on greater significance in the energy industry since this Commission opened its last DG rulemaking in October of 1999 (R.99-10-025). The technologies of DG continue to evolve, and their potential benefits present a compelling set of options to be considered in the resource planning and procurement context. As expressed in state legislation, in the joint agency Energy Action Plan and the California Energy Commission's (CEC) recently adopted Integrated Energy Policy Report, evaluating and deploying DG is a priority for California's energy future.[1] There are multiple efforts underway to achieve these goals. (Mimeo, p. 1).
>
> [1]This Rulemaking will update the record of our predecessor DG rulemakings, taking a broad look at the reality and potential of DG, and will allow the Commission to make informed decisions from a base of facts that we will strive to keep current. (p.2).
>
> . . .
>
> Distributed generation encompasses many technologies and is subject to a seemingly equal number of definitions. We will offer our own below, subject to update as our understanding develops in this Rulemaking. Part of this confusion about definitions results from the existence of a range of technologies and resource options that share similar characteristics on or near the demand- or customer-side of the meter, such as the ability to serve or otherwise mitigate load without the sustained, direct involvement of the utility.
>
> In addressing what we consider to be the three central issues in this rulemaking – cost-benefit analyses, incentives and IOU procurement guidance – we intend to develop a conceptual framework that will allow us to evaluate these similar resource options on an equal footing. *With this Rulemaking we will begin to employ the name Distributed Energy Resources (DER) to encompass distributed generation, energy efficiency, demand response and electrical storage. These resource options share common characteristics in their ability to serve or otherwise manage*

> *onsite load, and in the potential benefits they can provide to the electrical network if employed with sufficient care and foresight. . .*
>
> In future iterations of our proceedings addressing efficiency, demand response, and electrical storage (*when and if storage technologies become a cost-effective resource option*[2]), we will introduce the concept of DER and seek to develop and employ a uniform cost-benefit test in judging the suitability of these options for utility planning and procurement. This standard framework will in turn influence our consideration of incentives for utilities and their customers. (pp. 3-4).
>
> [2] *Energy storage does not presently have a place in a Commission proceeding, and given the relatively experimental nature of such technologies is not likely to warrant a proceeding of its own. Unless or until it does, we will utilize this proceeding to increase our understanding of storage technology options.*" (Emphasis added).

The Commission took the occasion of opening this successor distributed energy resource proceeding to forecast where it saw the future direction of distributed generation:

> "DG Issues for the Future: DG technologies and the industries that support them are evolving and offer a range of possibilities for the energy future, as well as a potential source of economic development for the state. The CEC's programmatic emphasis on market transformation, and the DG work undertaken as part of its PIER program – upwards of $80 million in ratepayer funds to date - should be more directly incorporated into this Commission's resource planning and procurement process to take advantage of this potential. *In this area of the Rulemaking the Commission will expand its understanding of the potential for advanced DG systems in areas such as fuel cells, hydrogen production, microgrids, storage, and modular systems that provide energy for stationary and mobile uses*." (Mimeo, pp. 23-24). (Emphases added).

In fact, the Commission went on to pose the following specific policy question to stake holders in the proceeding:

> ". . . Which advanced DG technologies, such as fuel cells, microgrids and *storage systems*, should be actively considered in this proceeding? What specific resource needs could be met by these technologies, at present or in the near future? What policy issues, if any, must be addressed to effectively deploy these strategies?" (Emphasis added) (Mimeo, p 27).

The Commission's currently active successor proceeding devoted to distributed energy resources, Order Instituting Rulemaking Regarding Policies, Procedures and Rules for the California Solar Initiative, the Self-Generation Incentive Program and other Distributed Generation Issues, R.06-03-004, filed March 2, 2006:

> "This rulemaking evolves from and builds on the work we began in three previous proceedings, Rulemaking (R.) 98-12-015, R. 99-10-025, and R.04-03-017. These previous rulemaking orders describe our fundamental view of DG and its role in providing the state with clean, reliable energy resources and remain useful as background documents guiding our work here. (Mimeo, p.1).
>
> . . .
>
> The SGIP is currently set to sunset at the end of 2007. We are strongly inclined to continue the program past that date, but will need to determine, in this proceeding, the exact nature of that program continuation, including funding levels, timeframe, incentive amounts, as well as other ongoing policy and program modifications.
>
> We will also consider changes to incentive levels and technologies as market conditions change. As we stated in R.04-03-017, our ongoing collaboration with the CEC will help us to understand and incorporate these technologies when and if they become viable, and we encourage other parties to propose ways to motivate sound technological development as well." (Mimeo, p. 4).

In April 2006, the Commission subsequently established a three-phased schedule for dealing with the many subjects that are within the scope of R.06-03-004:[60]

> . . .
>
> "Phase III of this rulemaking will handle issues surrounding SGIP Rules and Management, participation by small multi-jurisdictional utilities in the CSI program, and net metering for community choice aggregators (CCA).
>
> As stated in R.06-03-004, the Commission will determine whether to extend the SGIP which is currently set to sunset at the end of 2007. In addition, the scope of this case will review the exact nature of SGIP continuation, including funding levels, timeframe, incentive amounts, and eligible technologies. We understand that several pending SGIP program modification requests remain to be resolved, and ongoing interconnection issues will also need to be

[60] Scoping Memo and Ruling of Assigned Commissioner and Administrative Law Judge, issued April25, 2006.

> reviewed. If time allows, we may propose a method in Phase I for resolving program modification requests more quickly. (Mimeo, pp.7-8).
>
> . . .
>
> […Phase III] will address SGIP Management and participation by small multi-jurisdictional utilities. A detailed schedule for Phase III will be issued once the Commission has achieved significant progress in Phases I and II. Based on the schedules for Phase II above, it does not appear the Commission or the parties will be able to turn their resources toward Phase III issues until at least the first quarter of 2007. Resolution of issues in Phase III may take up to 12 months." (Mimeo, p.11).

13.2 Rationale for MTIR – Technology Benefit

Although not a direct producer of electricity, AES technologies benefit the end user, the supplying utility, and the growing renewable energy industry by:

- empowering the end-use utility customer to purchase lower cost electric power during off-peak periods for use during on-peak periods. It would also empower users of DG system fueled by natural gas another alternative to purchasing fuel during peak pricing periods.
- reducing peak-demand load on the grid, thereby reducing the load strain and extending the lifecycle of the T&D grid
- adding power reliability and quality to high-need industries such as high-tech electronic manufactures, hospitals, emergency infrastructure, etc.
- complimenting renewable energy generation equipment by creating a way to capture energy generated at times when energy is not needed (solar (day)/wind(night)) and empowering the end-use customer to decide when that energy will be utilized. For example, this benefit would lend to increased adoption of wind where the power generation is dependent on unpredictable factors and in most cases is generated at night during off-peak periods with a low need. In addition, the AES technology can mitigate the power variability that affects grid stability and is quickly becoming a key issue for the wind power industry.

CCSE and PG&E believe this technology group meets the required intent of the following SGIP goals: peak demand reduction and emphasis on zero emissions generation technologies. AES technologies generally require no additional fossil fuel input, produce low GHG emissions and have a significant California market potential upwards of 5,846 MW.

In its PMG submittal, StrateGen provides the following market potential for three specific market segments[61]:

[61] StrateGen PMG, Section I-4, p. 8-10

- Direct Access customers – Best potential for peak-load arbitrage due to their ability to negotiate off-peak power purchases.
- Back-Up Generator Replacement – Potential for replacement of 3,880 MW.
- Distributed Generation Alternative – Potential for replacement of 1,966 MW.

StrateGen's economic justification for inclusion in the Level-3 incentive group is meaningful and relevant. CCSE's recommendation is for the AES technologies incentive to mirror the incentive amount assigned to non-renewable fuel cells. Technically, the VRB ESS technology is a regenerative fuel cell, therefore that category distinction is a comparable fit. CCSE and PG&E recommend the Commission consider the AES technology group for addition to the SGIP eligible technologies for incentives.

14.0 Supplemental Appendices

14.1 Appendix 1

StateGen Request Form and Proposal dated December 4, 2006

14.2 Appendix 2

StrateGen Presentation to the SGIP WG dated December 1

PMG07-002-SCE
Self-Generation Incentive Program
FuelCell Energy
Proposed Modification to Replacement Generator Rules

July 11, 2007

FuelCell Energy ("FCE") is requesting a modification to the existing Self Generation Incentive Program ("SGIP") Rule 2.5.10. Specifically, FCE requested that 2.5.10 part D be deleted from the SGIP Handbook. This part of the rule currently requires existing generation systems to be de-activated for at least 12 months prior to the host customer achieving eligibility for SGIP participation.

Program Modification Request Summary

FCE has encountered several host customers expressing an interest in SGIP participation via new fuel cell projects, however, de-activation of their existing generation systems for 12 months would be prohibitive. Negative economic impacts as well as emissions limitations from the presiding air quality management districts ("AQMD") prohibit the 12-month curtailment of generator operations. In these cases, biogas generated from wastewater treatment operations is used in legacy type internal combustion engines ("ICE's") and the requisite deactivation of engine operations for 12 months would violate AQMD limitations. Furthermore, the emissions benefits of transferring the affected biogas to a fuel cell as opposed to either a flare or ICE are both significant and consistent with the state's green house gas ("GHG") reduction goals identified in AB32. It should be noted explicitly that none of the affected legacy generation systems were subsidized by SGIP incentives or other prior programs and the owners wish to replace them with fuel cells based on operational, economic, and emissions improvements.

FCEs argument to delete 2.5.10 part D can be summarized in the following two statements:

> "In order to meet the market demand for more efficient and cleaner generation systems that mitigate both excessive GHG emissions and costly AQMD penalties, SGIP's current Rule 2.5.10.D needs to be deleted."
> "As noted in the most recent SGIP Impact Report, renewable fueled fuel cells attained the highest net GHG reduction of any participating SGIP technology including the acknowledged GHG impacts of both wind and solar."

Rule 2.5.10 Background

Rule 2.5.10 of the replacement generator rules (2.5.10 Eligibility of Replacement Generation, pg 2-15 of Self Generation Incentive Program Handbook, rev 3, May 8, 2007) states the following:

> 2.5.10 Eligibility of Replacement Generation
>
> Installation of new generating systems intended to replace or augment existing on-site generation is allowed only in the following situations.
>
> A. An eligible generating system may be installed in addition to existing on-site generation if the capacity of the proposed generator(s) meets the maximum size eligibility requirement defined in Section 2.5.6. For fuel cells, microturbines, internal combustion engines and gas turbines, the combined capacity of the proposed and existing generators (excluding any back-up generators) must be no more than the Host Customer's Maximum Site Electric Load for the previous twelve months. For wind turbines, the combined capacity of the proposed and existing generators (excluding any back-up generators) must be no more than twice Host Customer's Maximum Site Electric Load for the previous twelve months.
>
> B. An eligible wind turbine or renewable fueled generator system may directly replace an existing on-site fossil-fired generating system. The proposed renewable generator(s) must meet the maximum size eligibility requirements defined in Section 2.5.6.
>
> C. An existing fossil-fired generating system may be converted to renewable fuel and will be considered, for the purpose of determining SGIP eligibility, as new equipment as long as all other program requirements are met including renewable fuel requirements.
>
> D. An eligible fuel cell, microturbine, internal combustion engine and gas turbine may directly replace an existing cogeneration or non-cogeneration system of equal or larger capacity than the new system, pursuant to eligibility requirements in Section 2.5 of the SGIP Handbook, where the Host Customer can demonstrate that the existing generating system has been out-of-service for the past 12-months.

The purpose of part D was to prevent use of ratepayer funding towards replacement of existing generators, resulting in no grid demand reduction benefit. Other provisions in 2.5.10 (parts B & C) allow for replacement of a fossil fuel generator by a renewable fuel generator to encourage clean generator installations.

SGIP rules governing replacement generators were included in the 2003 version of the SGIP Handbook.

Consensus Recommendation

The SGIP WG believes there is merit in FCEs arguments and is in favor of modifying Rule 2.5.10. Encouraging renewable fuel cells will increase SGIP GHG reduction benefits, and will enable the installation of fuel cell and wind turbine technologies which have had a historical low SGIP participation rate compared to other technologies.

Basically, the SGIP WG believes it makes sense to alter the rules so that (1) renewable projects can replace non-renewable or renewable with no down time requirement, and (2) non-renewable projects can replace non-renewable or renewable projects only after a 12-month down time requirement.

The SGIP WG is mindful that making this change allows new systems to replace an existing system, a situation in which it might appear ratepayers would not be getting much, if any, net self-generation for the replacement project. However, as the SGIP enters its seventh year, the WG realizes that some systems have reached the end of their useful lives. And, not replacing them would most likely lead to the systems being abandoned. Or, in the case cited by FCE, there may be significant logistical or legal issues with AQMDs if the system is shut down with the intent of meeting the arbitrary 12-month-downtime restriction called for by rule 2.5.10 part D.

The SGIP WG is also mindful that in approximately two months, effective January 1, 2008 fuel cells and wind projects will be the only eligible SGIP technologies. For this reason, the WG believes that modifications made now should be most appropriate for those technologies.

The WG believes SGIP funds should not be used to fund new systems that replace systems that were funded the SGIP, i.e., ratepayers should not be asked to pay for the same generation load more than once.

Rule 2.5.10 of the replacement generator rules (2.5.10 Eligibility of Replacement Generation, pg 2-15 of Self Generation Incentive Program Handbook, rev 3, May 8, 2007) states the following:

> 2.5.11 Eligibility of Replacement Generation
>
> Installation of new generating systems intended to replace or augment existing on-site generation is allowed only in the following situations.
>
> A. An eligible generating system may be installed in addition to existing on-site generation if the capacity of the proposed generator(s) meets the maximum size eligibility requirement defined in Section 2.5.6. For fuel cells, microturbines, internal

combustion engines and gas turbines, the combined capacity of the proposed and existing generators (excluding any back-up generators) must be no more than the Host Customer's Maximum Site Electric Load for the previous twelve months. For wind turbines, the combined capacity of the proposed and existing generators (excluding any back-up generators) must be no more than twice Host Customer's Maximum Site Electric Load for the previous twelve months.

B. An eligible wind turbine and/or renewable fuel cell system may directly replace an existing on-site fossil-fired generating system. The proposed renewable generator(s) must meet the maximum size eligibility requirements defined in Section 2.5.6.

C. An existing fossil-fired generating system may be converted to renewable fuel cell and/or wind turbine and will be considered, for the purpose of determining SGIP eligibility, as new equipment as long as all other program requirements are met including renewable fuel requirements.

D. An eligible renewable fuel cell and wind turbine may directly replace an existing cogeneration or non-cogeneration system of equal or larger capacity than the new system, pursuant to eligibility requirements in Section 2.5 of the SGIP Handbook.

E. A replacement system is not eligible for SGIP funds if the system it is replacing was funded by the SGIP AND is still under SGIP contract for the technology permanency period.

2008 SGIP Eligible Generating Systems		Current system **WAS FUNDED** by SGIP and **still under SGIP warranty**						
		Non-renewable Fuel Cell	Renewable Fuel Cell	Wind Turbine	Microturbine	Internal Combustion Engine	Gas Turbine	Cogen
Non-renewable Fuel Cell	May Replace >	*No*	*No*	*No*	*No*	*No*	*No*	*No*
Renewable Fuel Cell	May Replace >	*No*	*No*	*No*	*No*	*No*	*No*	*No*
Wind Turbine	May Replace >	*No*	*No*	*No*	*No*	*No*	*No*	*No*

2008 SGIP Eligible Generating Systems		Current system was **NOT** funded by SGIP or it was funded by SGIP **but no longer under SGIP warranty**						
		Non-renewable Fuel Cell	Renewable Fuel Cell	Wind Turbine	Microturbine	Internal Combustion Engine	Gas Turbine	Cogen
Non-renewable Fuel Cell	May Replace >	*Yes*	*Yes*	*Yes*	*Yes*	*Yes*	*Yes*	Yes
Renewable Fuel Cell	May Replace >	*Yes*	*Yes*	*Yes*	*Yes*	*Yes*	*Yes*	Yes
Wind Turbine	May Replace >	*Yes*	*Yes*	*Yes*	*Yes*	*Yes*	*Yes*	Yes

(END OF APPENDIX A)