APPENDIX D

Supporting Documentation for the Environmental Analysis

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Appendix D
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Appendix D1

GHG Benefits

A. GHG Emissions Benefits From Renewable Generation

This section discusses staff's evaluation of the GHG reductions from the various types of renewable generation.

1. Description of Renewable Generators Evaluated for GHG Benefits

Table D1-1 lists the renewable fuels and resources that are eligible for the RES program and describes the case being evaluated for these fuels and/or resources. Note that the description for the cases evaluated does not include all the applicable requirements that must be satisfied for the resource or technology to be eligible for the RES. As discussed above, resources need to satisfy the eligibility requirements of the RPS to be eligible for the RES.[a] The CEC Guidebook for RPS eligibility should be consulted for all applicable eligibility requirements.[1]

Table D1-1
Description of Renewable Generators Evaluated

Resource and/or Technology	Description of Case Evaluated
Biogas Injection into Natural Gas Pipeline	Renewable fuel injected into pipeline to be used in a power plant. The renewable fuel is processed to satisfy utility gas standards. The biogas injected into the natural gas pipeline must be delivered to California for use in an RPS-eligible facility.
Biomass Combustion	Combustion of biomass in a biomass boiler or fluidized bed to generate electricity.
Conduit Hydroelectric	A hydroelectric facility that uses only the potential of an existing pipe, ditch, flume, siphon, tunnel, canal, or other mandated conduit that is operated to distribute water for a beneficial use. A conduit hydroelectric facility may be considered a separate project even though the facility itself is part of a large hydroelectric facility.

[a] The delivery requirements of the RPS are not applicable to the RES.

Converting Biomass To Renewable Diesel	Biomass is converted by a chemical process to renewable diesel and the renewable diesel is used as fuel in an engine or turbine to generate electricity.
Geothermal Energy	Uses the earth's heat to generate steam to be used in a power plant to generate electricity. The four types of geothermal power plants are: Flash, dry stream, binary, and flash/binary combined power plants. CO_2 is contained in carrier stream and CO_2 can be emitted unless the carrier stream is re-injected.
Fuel Cell	Converts the energy of a renewable fuel directly to electricity and heat, without combustion. Only the electricity generated by the fuel cell is RPS eligible.
Landfill / Digester Gas-to-Energy	Use landfill/digester gas as fuel in an engine or turbine to generate electricity.
MSW Conversion	Convert the municipal solid waste (MSW) into thermal energy by combustion or the MSW is converted into fuel gases or liquid fuels through non-combustion thermal process that does not use air or oxygen in the conversion process, except ambient air to maintain temperature control and produces no discharges of air contaminants or emissions, including GHG emissions. This clean burning gas is then burned to generate electricity.
Ocean Thermal	This technology uses the thermal potential of different depths of the ocean to generate electricity.
Ocean Wave	Converts the energy in ocean wave motion into electric energy. Technologies include, but are not limited to: point absorbers, oscillating water column, overtopping terminator, and attenuator.
Photovoltaic	Converts solar radiation into electricity using a semiconductor. PV panels can be used in a central station or located on rooftops. PV located on rooftops is referred to as distributed generation.

Small Hydroelectric	Uses a turbine to convert the kinetic energy of flowing water into electrical energy. A small hydroelectric project is defined as providing 30 MW or less, except for eligible efficiency improvements that meet certain criteria.
Solar Thermal	Converts solar radiation into thermal energy. Technologies including, but not limited to solar trough, Stirling engine, solar dish, and solar tower.
Tidal Current	Uses the potential energy difference caused by the change in tide levels to drive turbines to generate electricity.
Wind	Converts the kinetic energy of wind into electrical energy.

2. GHG Reductions From Renewable Generators

a. Methodology for Evaluating GHG Reductions

The GHG emission reduction for each renewable resource or technology is based upon the “net” GHG emissions from the renewable generator technology, the GHG emissions associated with the operation of the renewable resource or technology, and the GHG emissions associated with the incremental displacement of fossil fuel generation from the grid by renewable energy. Because this review considers the emission reduction provided by displacing one MWh of power from the grid with renewable energy, a capacity factor is not included in determining the GHG benefit for each renewable technology.

(1) Net GHG emissions

The net GHG emissions are the difference between the GHG emissions from using the renewable resource in an energy technology and GHG emissions from the typical use or disposal of the same amount of renewable resource. For example, for landfill gas, the energy technology case is where the landfill gas is burned in an internal combustion engine ("engine"). The combustion of the landfill gas in an engines results in GHG emissions. Otherwise, landfill gas would be required to be flared. The net GHG emissions are the GHG emissions from the combustion of the landfill gas in an engine minus the GHG emissions from flaring the same amount of waste gas.

Some technologies do not emit GHG. Therefore, the net GHG emissions for the technology are zero. This applies to small hydroelectric and ocean technologies. For wind and solar generation, there are no GHG emissions from the technology using the resource. However, wind and solar are considered variable renewable generation in that the electricity output can vary hourly, depending upon the wind intensity or, for the case of solar generation, the meteorological conditions. Consequently, some natural gas generation may be used to backup this generation.

In the case where biomass is combusted directly to generate electricity, staff concluded the GHG emissions would be very similar if the biomass was allowed to decay in its natural environment or if the biomass was combusted to generate electricity. Consequently, the net GHG emissions are zero.

Finally, for some technologies, the GHG benefit was adjusted. For geothermal power plants, the GHG benefit was adjusted to account for operational GHG emissions. GHG emissions from the conversion process were subtracted from the benefit (This is applicable only to the biomass to renewable diesel application and the biogas injection application.). GHG emissions for landfill and digester energy projects and MSW conversion projects are adjusted for the conversion of methane to CO_2.

(2) GHG Emissions from Support Operations

Staff also evaluated related activities included with each GHG activity. This includes the GHG emissions from trucks used to transport material to the facility and the operation and maintenance activities. Staff evaluated the GHG emissions from trucks used in transportation and on-site activities for the different types of solar plants, biomass combustion, and renewable diesel energy technologies. Staff determined that, except for the biomass combustion technology, the GHG emissions related to transportation and operation and maintenance are minor. For the biomass combustion technology, the GHG emissions from transportation will be subtracted from the benefit determined for that technology.

As documented in the subsequent discussion, staff evaluated the following activities for the renewable resources and technologies:

- Transportation emissions for biomass combustion and renewable diesel deliveries (for conversion of biomass to renewable diesel case);
- Maintenance emissions from cleaning of mirrors or PV panels at central station solar plants; and
- GHG emissions from boilers used at central station solar plants

For both the biomass combustion plant and the biomass conversion to renewable diesel cases, the “fuel” needs to be transported to the generation plant. In the case of the biomass combustion plants using agricultural waste, the waste is picked up in the field and delivered to the biomass facility. Alternatively, if the fuel is wood waste diverted from the landfill, the waste would be collected from the landfill and transported to the biomass combustion plant. For the renewable diesel case, where the renewable diesel is manufactured from biomass, the renewable diesel must also be transported to an energy plant. For this evaluation, staff assumed that the renewable diesel would be used in an engine based energy plant.

There is only one facility authorized to participate as a renewable energy resource. This facility is located adjacent to a landfill. Staff did not evaluate transportation emissions for an MSW application located at a landfill. Consequently, there would not be additional truck activity as a result of the MSW facility. Therefore, for MSW applications, we assumed there would be no additional GHG emissions associated with transportation.

Table D1-2 provides information on the transportation needs for each of the types of renewable generation being evaluated. In the case of the biomass combustion plant, the fuel needs for the plant is two tons per MWh,[2] and the type of truck used to deliver the fuel is a 20 ton dump truck.[3] Based on the truck size and the plant’s fuel needs, the plant would require nearly 17 truck deliveries a week for each MWh of electricity generation. The truck is assumed to be operated during working hours, or a 10 hour work day, and the truck travels 80 miles roundtrip (one hour travel each way) for each trip. The truck itself is assumed to use 6.0 miles per gallon. Based on the above and a GHG emission factor of 23 lbs CO_2e per mile,[4] the GHG emissions are estimated to be 70 pounds (lb) CO_2e/MWh. In the case of the renewable diesel deliveries, the calculations are similar, but the major differences are that there are relatively few truck deliveries due to the higher energy content of renewable diesel, as compared to biomass, and the large carrying capacity of tanker trucks.[5] Consequently, the GHG emissions are much lower, about 12 lb CO_2e/MWh.

Table D1-2
Transportation GHG Emissions

	Input Required per MWh	Truck Type	Truck Visits per Week	Miles Traveled per Trip (Roundtrip)	GHG Emissions (lb CO_2e/MWh)
Biomass	2 tons wet feedstocks per MWh	20 ton Dump truck	16.8	80	70
Renewable Diesel	74 gallons per MWh	7,000 gallon tanker	1.7	100	12

The above analysis shows that the transportation emissions represent one percent of the GHG emissions from the utility; therefore, the transportation emissions for renewable diesel are minor. However, the transportation emissions for biomass combustion are significant enough to be included in the evaluation of the GHG emissions reductions for biomass combustion generation.

At central solar plants, the solar reflectors are cleaned on a daily basis. The GHG emissions associated with the cleaning of solar reflectors are from maintenance vehicles driven around the solar energy complex. Because of the significant amount of miles driven in this operation, staff evaluated the potential GHG emissions from this activity. For example, maintenance vehicles used to clean the solar reflectors were driven up to 1,750 miles a day for the Mojave solar project. The proposed miles driven were higher than other solar thermal installations. Based on the miles driven and the type of vehicle being used, the daily GHG emission from maintenance vehicles is estimated to be 0.5 lb/MWh. At this low emission rate, the GHG emissions associated with maintenance vehicle emissions are not considered significant and staff did not include the emission estimates in the benefit table.

Many solar thermal power plants have fossil-fueled boilers and heaters that assist in the startup of the solar plant and provide freeze protection for the working fluid of the power plant. The boilers support the plant’s electricity generation on cloudy days. The boilers typically operate at a low capacity factor. However, the operation will vary year-to-year depending upon the yearly meteorological conditions and the condition of the boilers and heaters. The estimated average boiler GHG emissions, in pounds per MWh, are 37 for new a solar thermal plant. This is based on a highly efficient boiler operating sparingly. Staff notes that these plants have not yet been constructed. There are several existing solar thermal tower plants in California that use boilers and the boiler burner technology is approximately 20 years old. The average GHG emissions from the boilers used in these plants are approximately 380 lbs/MWh. Furthermore, the maximum emissions from the boilers and heaters will be determined by the operational limits specified in the local districts' air quality permits.

Other equipment that emits GHG emissions includes backup generators and fire pumps. Due to the infrequent operation of this backup equipment, the GHG emissions from this equipment were not included in the evaluation.

(3) Marginal Power

The major benefit from using renewable power is the displacement of power produced by burning carbon-based fuels that would otherwise be used to meet the demand on the utility grid. The power being displaced is incremental power provided by generators to address load changes ("marginal power"), which is typically provided by natural gas power plants. With the integration of 33 percent renewable energy into the grid by 2020, the incremental power being displaced by renewable energy in 2020 is likely different than the incremental power that would be displaced by renewable energy today. That is, by 2020, the fossil fuel power plant fleet will differ from today's fleet in that older and less efficient power plants, mainly utility boilers, will be retired and new more efficient gas turbine combined cycle combustion turbine (CCCT) power plants will be added to the fleet. Consequently, the GHG emissions associated with the incremental power generation will likely be lower in 2020 than it is today. A better understanding of the utility system in 2020 will allow for a more accurate estimate of the GHG reductions resulting from the influx of renewable generation.

The State Water Resources Control Board (SWRCB) has recently finalized the Once Through Cooling (OTC) policy.[6] This policy affects generation that uses ocean water for cooling to significantly modify the use of ocean water for cooling. Most of affected facilities are utility boilers that initially began operation in the 1960s and are reaching the end of their useful life.[7] To comply with the requirements, operators of these facilities will need to do one of the following: modify the cooling intake system and operate the system to comply with the requirement, switch to a dry cooling or wet cooling system, replace the units with generation that complies with the OTC requirements, or simply retire the utility boiler and not replace its capacity at the existing site.

As the OTC policy has been finalized recently, it not clear how the OTC requirements will be satisfied. Based on the age of the affected facilities, staff expects that many of these generators are likely to be retired by 2020. Some of the boilers will be repowered with more efficient CCCTs or combustion turbines (CTs). Beyond the impact of the OTC requirements, the PUC has approved about 9,400 MW of new generation, which will be a combination of CCCTs and CTs that are expected to be on-line by 2020. Hence, by 2020, several of the units that have high GHG emission rates (utility boilers) will be retired and a significant addition of more efficient generation, with much lower GHG emission rates than boilers, will be coming on line. These anticipated changes will result in the natural gas generating fleet, in the future, likely having a lower overall GHG impact.

As discussed above, the marginal power is typically provided by natural gas generation. This generation will likely be a combination of new CCCTs and new CTs. The CPUC expects that, for the majority of the hours in a year, the marginal power plant will be a new CCCT 95 percent of the time and a new CT the other five percent of the time. Based on this ratio, the GHG emissions associated with the marginal power is 830 lbs CO2e per MWh.[8,9,10,b]

Using this estimate for the GHG emissions for the marginal generator will likely underestimate the potential GHG reductions from the proposed RES regulation. Occasionally, the marginal generator will be a less efficient unit with higher GHG emissions. For example, during the hottest days in the summer, the marginal generator, at the time when the maximum load occurs, may be a less efficient CT. For the typical California summer, these units will operate sparingly. Staff expects that less efficient CTs will only operate a few days each year and for those days, will operate a few hours. Until CAISO completes its 33 percent integration study, the average GHG emissions associated with the marginal generation cannot be easily quantified. As an approximation of the marginal generation, staff will use 830 lbs CO2e per MWh as the GHG reduction resulting from the displacement of one MWh of generation from the grid by renewable resources. Staff recognizes that using this value will underestimate the GHG benefits from the proposed RES regulation.

b. Results and Discussion

Table D1-3 is entitled GHG Benefit Determination for Renewable Sources. The table provides a summary of the GHG emission reductions available for each of the renewable energy technologies eligible for the RES. A detailed discussion of the evaluation for each technology is given below. Of the technologies discussed below, wind and solar generation are the most important in that wind and solar generation are expected to account for 85 percent of the renewable generation to satisfy the 33 percent renewable goal.

(1) Wind and Solar

As discussed above, wind and solar resources are expected to provide a significant portion of the renewable generation that will be used to satisfy the

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[b] CPUC recommends that the heat rate for a new CCCT is 6,917 Btu/KWh (6.9 MMBtu/MWh) or and the efficiency for a new CT is 10,807 Btu/KWh (10.8 MMBtu/MWh). Based on these values, the efficiency for the CCCT is 49 percent (3412/6,917) and the CT is 32 percent. The EIA GHG emission factor for natural gas is 53.06 kg CO_2/MMBtu. To determine the GHG emissions for the CCCT and the CT, the heat rates for the turbines are multiplied by the GHG emission rate. For the CCCT, the GHG emissions are 366 kg CO_2/MWh (6.9 * 53), and the CT are 572 kg CO_2/MWh. The average GHG emissions, based on CCCTs operating 95 percent of the time and CTs operating 5 percent of the time, is 377 kg CO_2/MWh or 830 lb CO_2/MWh.

RES. Staff evaluated the GHG benefits for wind and several types of solar energy plants. There are no GHG emissions from the technology itself. However, wind and solar energy plants are variable generating sources, and as such, the balancing authority may need to obtain electricity from other generators to makeup shortfalls. Typically, natural gas generators are used. The GHG emission reductions are the GHG emissions avoided from the grid minus the GHG emissions associated with the resource backing up wind and solar generation.

The addition of renewable generation to satisfy the 33 percent requirement will reduce the overall operation of California's natural gas fleet. This fleet is generally composed of boilers, CCCTs, and CTs. CCCTs provide the majority of the load-following generation. The generation from renewable generation will largely displace generation provided today by CCCTs.

The variable nature of wind and solar[11,12] poses several issues that affect the integrating of wind and solar generation, including sudden changes in wind and solar generation, and the potential for over-generation. Additionally, solar generation is valued more than wind in that solar generation is the strongest during the day when generation is most needed while wind generation is most consistent and the strongest overnight, when the generation is least needed. As more wind and solar generation are added to the grid, these issues become more difficult to manage by the balancing authority.

As discussed earlier, balancing authorities are required to provide ancillary services for various reliability and operational purposes.[13] One ancillary service provided is the matching of supply (electrical generation) to demand on a minute-by-minute basis. Each day, the balancing authority estimates the generation needed for the next day on a hour-by-hour basis. At the appointed hour, the minute-by-minute scheduling allows an exact match of supply to demand. If the supply is short of the demand, the balancing authority must request a generator(s) to increase production in the upward direction to match the demand. Conversely, if the supply is projected to be greater than the demand, the balancing authority will request that a generator(s) reduce production. For the current amount of wind and solar generation, the existing generation used to provide backup power for the entire grid is adequate to back up the variable generating sources. As more variable generation is added to the grid, the generation used to provide load-following will be reduced—mainly combined cycle combustion turbine plants (CCCTs).

Natural gas generation will be needed to back-up the variable generation. To the extent that wind and solar are not providing the expected generation, CCCTs and to a lesser extent, combustion turbines (CTs) will need to increase generation to replace the missing wind and solar generation. During these instances, the benefit attributed to wind and solar generation would not be fully realized. Because this form of backup generation results in a reduction in the emission reductions expected from variable generation, staff is not including the GHG emissions associated with CCCT operating to firm variable generation as part of the backup emissions for wind and solar generation.

As discussed in Chapter V, there are periods when wind and solar generation experience sharp increases and decreases in generation. In these situations, CTs and occasionally, hydroelectric generation, will be needed to balance the generation with load. The operation of the CTs in this manner is directly attributable to the additional variable renewable generation being added to the grid. To the extent that the emission attributed to the operation of the CTs can be attributed to the RES program, these emissions will be included as backup emission and subtracted from the benefits that result from wind and solar generation displacing CCCT generation.

CAISO has initiated studies to investigate the impacts of integrating large amounts of variable generating resources into the grid and CAISO is in the process of identifying the additional services that will be needed. As part of this study, CAISO would be able to estimate the GHG emissions associated with backing-up variable generation. The results of this study should be available by the end of 2010.

The overall GHG emission reduction from adding wind and solar generation is 830 lbs CO_2e per MWh (GHG emissions from displaced generation) minus emissions from CTs used to backup wind and solar generation. Until CAISO completes the 33 percent integration study, staff can only estimate that the overall emissions reductions would be less than 830 lbs CO_2e per MWh—at this time, staff estimates that the GHG reductions resulting from wind and solar generation is 830 lbs CO_2e per MWh.

(2) Biomass Combustion

As discussed above, the net GHG emissions from biomass combustion is assumed to be zero. For the case where the biomass is agricultural waste, agricultural waste is expected to emit a similar amount of GHG emissions if the same amount of waste is used as fuel in an energy plant, left in the field to decay, or is open burned. Some biomass-to energy plants also use construction waste as fuel. In this case, the waste is being diverted from the landfill pursuant to local policies at landfills.[14] This waste that would have been landfilled would be converted to other applications. Some of the uses for the diverted waste includes: reuse of wood as lumber, feedstock for engineered products, or wood chips for landscape applications.[15] Staff concludes that for the reuse applications discussed above, the diverted wastes would eventually emit similar amounts of GHG emissions whether the same amount of the waste is used as fuel in a biomass combustion facility or recycled.

Beyond the use of biomass as a fuel, as discussed above, there are additional GHG emissions associated with the transportation of the waste to biomass-to-energy plants. Staff estimated transportation GHG emissions as 70 lbs CO_2 equivalent per MWh.

The overall GHG emission reduction for a biomass combustion facility would be 830 lbs CO_2e per MWh (GHG emissions from displaced generation) minus 70 lbs CO_2e per MWh (GHG emissions associated with transportation) or 760 lbs CO_2e per MWh.

(3) Geothermal

For geothermal plants, there may be emissions of CO_2. As discussed earlier, geothermal plants use the steam that results from the earth's natural heat to generate electricity. This steam typically contains non-condensable gases such as CO_2. Consequently, emissions of non-condensable gases will occur if the gases are vented to the atmosphere as is typically done with a flash steam plants. In dry steam and flash steam power plants, the gases are removed from the process stream to prevent backpressure on the steam turbine. The gases are either vented to the atmosphere or to reduce the emissions, the gases are compressed and re-injected into the earth with the condensed steam. If injection is used, CO_2 and other non-condensable gases would not be emitted as a direct result of the geothermal plant's operation. Fugitive CO_2 and other pollutants could still be emitted from plants that inject the non-condensable gases. Current emission controls on geothermal power plants are to address H_2S and criteria pollutants emissions. Therefore, the control of GHG emissions that result from emission control systems is an indirect benefit of controlling other pollutants.

GHG emission reductions for geothermal power plants are the combination of the GHG emissions avoided from the grid minus the emissions from the plant. GHG emissions are site-specific in that the emissions can vary depending upon the location of the geothermal plant, the plant type, and the strata used by the plant for steam. Based on the reported GHG emissions for 2009 for 13 geothermal facilities, the emissions for geothermal power plants vary between 30 to 800 lbs CO_2e per MWh,[16] with the average GHG emissions being 310 lbs CO_2e per MWh. Consequently, the overall GHG emission reduction would be 830 lbs CO_2e per MWh (GHG emissions from displaced generation) minus the emissions from the plant, or 520 lbs CO_2e per MWh.

(4) Landfill

The GHG benefit for landfill gas-to-energy projects is the sum of the benefits based on: 1) the difference between GHG emitted by the gas-to-energy project and regulatory requirements and 2) displacement of electricity generation from the grid. As discussed below, significant GHG benefits can be obtained from adding gas-to-energy projects to landfills that are not subject to air quality regulations. For landfills that are subject to regulations, as discussed below, the gas-to-energy technology chosen to satisfy the regulation project could result in additional GHG emissions as compared to other technologies that can be used to satisfy the regulation.

(a) Background

Waste interned in a landfill will emit a combination of methane and CO_2. These emissions are caused by the anaerobic breakdown of the biomass portion of the waste in the landfill.[17] The amount of methane and CO_2 emitted will depend upon a number of factors. These factors include the types of waste in the landfill, the structure of the landfill, and the moisture available (typically provided by rainfall). Landfill gas emissions will be much less if there is little biological waste interned at the landfill or the landfill is located within an arid area. Since landfill gas emissions are based on anaerobic breakdown of a portion of the waste, the gas emissions will cease once there is no longer material in the landfill that would be affected by the anaerobic process. To harness the gas as energy, a collection system must be installed at the landfill and the gas routed to a gas-to-energy project.

(b) Air Quality Regulations for Landfills

Landfills of certain sizes are required by regulation to install landfill gas collection systems and a device capable of reducing ROG by 98 percent. The federal program, implemented through the New Source Performance Standard (NSPS) and Emission Guidelines (EG) programs affect larger landfills.[18,19] Both the NSPS and EG applies to all states.[c] Smaller landfills not subject to the NSPS or EG can be regulated by state, or local agencies (the air agencies for the Canadian provinces of British Columbia and Alberta can also regulate landfills not subject to the requirements promulgated by Environment Canada). For example, local air pollution control agencies in California and Washington, through their broad ability to regulate emissions from stationary sources, impose similar requirements on smaller landfills. Finally, ARB has recently approved a regulation requiring additional landfills in California satisfy the above criteria. The 98 percent destruction efficiency is typically satisfied with a flare. Note however, that Washington agencies have required the use of carbon absorbers for the smallest landfills to achieve the same level of emission reduction. The effect of these regulations is that the GHG emission reductions for landfill projects subject to these regulations are based on the difference between the GHG emissions from the energy recovery system and a flare. If the destruction efficiency for the flare and the energy recovery system is the same, then there is no net increase in GHG emissions.

As discussed above, only California and Washington regulate the emissions from landfills that would not be subject to the NSPS or EG.[20] Greater GHG reductions would be achieved by adding gas-to-energy projects to landfills that are currently

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[c] Similar requirements have been promulgated by Environment Canada that are applicable to large landfills in Canada. As discussed earlier, the WECC includes both British Columbia and Alberta.

not regulated—smaller landfills not subject to the NSPS or EG that are located within the WECC, but not in California and Washington. In this case, the GHG emission reduction would be the difference between the GHG emissions that would have been emitted by the landfill and the GHG emissions from the energy recovery system.

(c) Effects of Technology on GHG emissions

For landfills subject to air quality regulations, the GHG benefit is based on the difference between the GHG emissions from the energy recovery system and a flare. To generate renewable power from landfill, energy recovery systems using engines or small combustion turbines are used in place of a flare. Prior to installing these waste-to-energy projects, these projects are subject to local district pre-construction review requirements. Both engines and turbines will emit substantially more NO_x emissions than a flare. Consequently, in many districts, proponents for these types of projects will need to reduce the emissions from the engine or turbine by using best available control technology (BACT) and mitigate the remaining increased emissions. Typical emission controls for engines or turbines are catalytic controls such as selective catalytic reduction (SCR) or three-way catalysts. However, landfill gas contains small amounts of contaminants, such as siloxanes, that adversely affect the use of these catalytic systems. Consequently, BACT for engines and turbines using landfill gas have focused on the lowest emitting engines, which are lean-burn engines, and combustion turbines.[21]

As part of the development of the landfill regulation, ARB staff determined that lean-burn engines used to combust landfill gas have destruction efficiencies of 87 to 95 percent—below the 99 percent destruction efficiency for a flare. Consequently, the use of these lean-burn engines will lead to higher emissions of methane. Other energy technologies that can be used to generate power, such as a turbine and rich-burn engine, have similar destruction efficiencies as a flare—consequently, there is no net increase in GHG emissions.

As discussed above, the use of a lean-burn engine to replace a flare will lead to an increase in methane emissions. Landfill gas is a mixture of methane (typically 42 percent) and CO_2 (typically 58 percent). Using an average ROG destruction efficiency of 91 percent for a lean-burn engine, the replacement of the flare with the lean-burn engine would result in an increase in methane emissions of 32 lbs per MWh. Considering that methane is 21 times more potent as a GHG than CO_2, the net GHG emissions increase by 670 lbs CO_2e per MWh. In summary, the overall GHG benefit for landfill-to-energy projects in California is 830 lbs CO_2e per MWh (GHG emissions from displaced generation) minus 670 lbs CO_2e per MWh (GHG emissions increase resulting from using an engine, which is less efficient than a flare in destroying methane) or 160 lbs CO_2e per MWh.

For states other than California and Washington (including British Columbia and Alberta), but within the WECC, landfills that are not subject to NSPS or EG for landfills are not subject to air quality requirements.[22] Consequently, if a landfill operator adds a landfill gas-to-energy system to these landfills, there will be significant GHG reductions. Similar to the discussion above, the landfill gas-to-energy system would convert the methane that would otherwise be emitted by the landfill to CO_2, thereby reducing 32 lbs of methane per MWh or 670 lbs CO_2e per MWh. The overall GHG benefit for out-of-state projects is 830 lbs CO_2e per MWh (GHG emissions from displaced generation) plus 670 lbs CO_2e per MWh (GHG emissions reduced from the landfill) or 1,500 lbs CO_2e per MWh.

Because of the air quality concerns for many areas in California, it is a challenge to develop additional in-state landfill-to-energy projects or conversely, digester-to-energy projects, which are discussed below. For example, areas like the San Joaquin Valley Air Pollution Control District and South Coast Air Quality Management District Staff have significant air quality concerns with satisfying ozone and particulate matter ambient air quality standards. There are emerging technologies that can be used to generate electricity from biofuels and satisfy district air quality requirements. These technologies include fuel cells, microturbines, and improved gas clean-up technologies.

(5) Digester Gas

Digester gas is generated from anaerobic digestion at wastewater plants and digesters installed at dairies. This gas, similar in quality to landfill gas, can be used in boilers to provide heat for the digestion process or in an engine to generate electricity in addition to heat for the digestion process.

Unlike landfills, there are no national or local regulations that affect digester emissions. Instead, these sources are subject to district permit pre-construction programs. The requirements that must be satisfied differ for a digester located at a wastewater versus a digester located at a dairy. In the case of digesters located at wastewater plants, the districts have typically required that the digester gas emissions be flared to reduce ROG emissions. Consequently, similar to landfills, the net GHG emissions would be the difference between the GHG emissions from the flare and the GHG emissions from the engine, or some other energy producing equipment.

For dairies that choose to add digesters to process animal waste and recover energy by using energy recovery systems, there will be a significant reduction in GHG emissions in that the digester/energy recovery system would capture methane that would otherwise be emitted and the methane is subsequently converted to CO_2 when the digester gas is combusted in the energy recovery system.

For digesters located at wastewater plants, staff believes the same operating requirements that are applicable in California are also applicable WECC-wide. Consequently, the GHG emission reductions discussed above for in-state landfill gas-to-energy projects are also applicable to digester gas applications at wastewater plants—160 lbs CO_2e per MWh. For digesters located at dairies, the GHG reductions is 1,500 lbs CO_2e per MWh, which accounts for both the GHG emissions from displaced generation and the conversion of methane to CO_2.

(6) Biomass Conversion to Renewable Diesel

Biomass can be converted into renewable diesel (that is, a diesel fuel derived from biomass) via a chemical process and the resulting renewable diesel can be used in an energy system, such as an engine generator set, to produce electricity. The GHG emission reduction for this process is the GHG emissions avoided from the grid minus the GHG emissions associated with converting the biomass to renewable diesel. The biomass itself would emit a similar amount of GHG emissions whether it is converted to renewable diesel and subsequently used as fuel in an energy device, or allowed to decay naturally in the field, or open burned.

To estimate the energy needed to convert biomass into renewable diesel, staff evaluated the energy needed to use the Fischer-Tropsch (F-T) process to produce diesel.[23] The F-T process is energy intensive, but in addition to producing diesel, electricity and naphtha are produced as co-benefits. The Antares Group report Strategic Assessment of Bioenergy Development in the West: Task 2: Bioenergy Conversion Technology Characteristics, 2008, provided operational information for an F-T plant producing diesel from biomass. This proposed F-T plant would produce 61 million gallons of renewable diesel per year as well as 1,200 GWh of electricity. The energy input to produce these products is estimated to be 8.8×10^{12} Btu annually. As discussed above, there are no net emissions of GHG for the biomass.

The GHG emissions for the F-T plant is the GHG emissions represented by the electricity, a co-benefit, minus the GHG emissions associated with the energy needed to operate the F-T plant, which staff assumed would be GHG emissions associated with a natural gas boiler. To generate one MWh of electricity from an engine, 74 gallons of renewable diesel[d] are used.

The electricity co-benefit on a production of renewable diesel basis is 19 kw per gallon of renewable diesel or 1.4 MWh that is produced when 74 gallons of renewable diesel is manufactured. This 1,4 MWh of electricity co-benefit provides a GHG reduction of 1,200 lbs CO_2e per MWh.[e]

Based on an energy input of 144,000 Btu per gallon[f] of renewable diesel manufactured, the boiler will use 11,000,000 Btu to produce 74 gallons of renewable diesel. Based on a GHG emission factor of 0.054 g CO_2e /Btu,[24] the GHG emissions from the boiler is estimated at 1,300 lbs CO_2e per MWh.

[d] The engine is assumed to be 33 percent efficient

[e] The electricity is assumed to be produced by the marginal generation, so the benefit is 830 lbs CO_2e per MWh

[f] 8.8×10^{12} Btu / 61 million gallons

Consequently, the overall GHG emission reduction resulting from converting biomass to renewable diesel is 830 lbs CO_2e per MWh (GHG emissions from displaced generation) minus 1,300 lbs CO_2e per MWh (GHG emissions associated with converting biomass to renewable diesel) plus 1,200 lbs CO_2e per MWh (GHG emissions associated with electricity co-benefit) or 730 lbs CO_2e per MWh. As discussed earlier, the transportation emissions associated with this technology, about 12 lbs CO_2e per MWh were considered minor.

Finally, staff believes that renewable diesel produced from biomass will have a significantly higher value as a transportation fuel than as fuel to be used to produce electricity. Consequently, staff does not expect that renewable diesel to be used to produce electricity.

(7) Biogas Injection

Biogas injection refers to the injection of a renewable biogas, such as landfill gas, into a natural gas fuel line. Biogas is typically composed of methane, CO_2, and other contaminants. Prior to injection into the fuel line, the biogas must be processed to satisfy pipeline requirements.[25] The process involves the removal of the CO_2 and other contaminants from the biogas.[26] The resulting biogas is added to the natural gas pipeline to be subsequently combusted in a natural gas power plant. The biogas is often referred to as biomethane because of its similarities with methane.

Assuming that a power plant burns 100 percent biomethane, the GHG emission reduction is the GHG emissions avoided from the grid minus the emissions from processing the biofuel. Biomethane is typically a portion of the total fuel mix into a power plant. Consequently, the GHG emission reduction for a typical project will be less than discussed here. Additionally, for this application, there are no net GHG emissions from the combustion of the biomethane in the power plant. As discussed previously, biogas is subject to air quality regulations that require the biogas to be flared. Hence, a similar amount of GHG emissions would have been emitted by the flare at the landfill or from the power plant.

Staff also evaluated the GHG emissions associated with processing the biogas. Based on information for a landfill gas pipeline treatment facility,[27] staff determined that about 45 KWh is used to process enough landfill gas to generate one MWh of electricity, or about 20 lbs CO_2e per MWh of electricity. Since these emissions represent about two percent of the GHG emissions avoided from the grid, staff has determined that the resulting emissions are minor, and have not included these emissions in the emission reduction determination.

Therefore, the GHG reduction for biogas injection using renewable fuels is the GHG emissions avoided from the grid, or 830 lbs CO_2e per MWh.

(8) Hydroelectric and Ocean Technologies

For small hydropower and ocean technologies, staff assumed that the technologies themselves have no GHG emissions. Ocean technologies, which include ocean wave, ocean thermal, and tidal current, are still in the development stage. For these technologies, there may be GHG emissions associated with the operation of the technology. For example, ocean technologies may prove to be as variable as wind and solar generation. In this case, additional emissions from natural gas generation used to backup this generation would need to be included in the emission reduction determination. As more information becomes available about these technologies, staff will revise the analysis. At this time, staff assumes that the GHG benefit for all these technologies is simply the GHG emissions avoided from the grid, or 830 lbs CO_2e per MWh.

(9) Fuel Cells Using Renewable Fuel

The fuel cell is assumed to be using a renewable fuel, such as digester gas from a waste water treatment facility. As discussed above, in California, air quality regulations require that these gases be flared. Since the destruction efficiency of the fuel cell performs as well as a flare, there is no net emission increase. Therefore, the GHG reductions for fuel cells using renewable fuels are the GHG emissions avoided from the grid, or 830 lbs CO_2e per MWh.

(10) MSW Applications

To generate electricity from MSW, the waste can either be directly combusted, or the MSW can be converted to a fuel via a gasification or pyrolysis process. Pursuant to the eligibility requirements for the RPS, one MSW facility that directly combusts MSW is eligible for the RPS program, and MSW conversion technologies are eligible for the RPS as long as the conversion process does not emit any air contaminants.

Today, only the combustion technology is considered commercial. The gasification and pyrolysis processes are still in the commercial development stage. Consequently, the GHG emissions reduction for MSW is largely based on staff’s evaluation of the direct combustion technology. For MSW, the GHG emission reductions are composed of three components: the GHG emissions resulting from the combustion process, the GHG emissions associated with the reduction in landfill gas emissions, and the GHG emissions for the electricity displaced from the grid. As discussed earlier, because these facilities are usually located at landfills, there are no additional GHG emissions associated with transportation that is attributed to the MSW facility.

The GHG emissions from the conversion process are affected by the amount and types of waste that can be segregated from the waste stream. Most local jurisdictions require waste diversion and recycling of certain waste, such as green waste and wood waste that can be turned into wood chips. Based on data for a waste-to-energy facility in California, about 50 percent of the biogenic waste was removed from the waste stream prior to the MSW being combusted.[28] Based on this amount of waste reduction, the GHG emission from combusting the remaining waste is 1,700 lb CO_2e per MWh. If all the biogenic material is removed, then the GHG emission from combusting the waste is 1,200 lb CO_2e per MWh.

The GHG emissions resulting from landfilling MSW is based on the expected GHG emissions from a landfill that is equipped with a gas recovery system. In California, air quality regulations requiring the collection and control of landfill gas affects over 95 of the total emissions from landfills—consequently, most landfill operators are required to collect and control landfill gas emissions. Overall, these landfills will emit 0.53 lb CO_2e per metric ton of MSW that is landfilled.[29] This equates to an emission of 1,100 lb CO_2e per metric ton of MSW. Based on an average of 1.9 tons of MSW being combusted to generate a MWh, the MSW that is not landfilled will prevent 2,100 lb CO_2e per MWh from being emitted.

Overall, for the typical waste reduction case, the GHG emission reduction is based on the following: 830 lbs CO_2e per MWh for the marginal power minus 1,700 lb CO_2e per MWh for the conversion of MSW to energy plus 2,100 lb CO_2e per MWh for the decrease in landfill gas emissions from the landfill or about 1,200 lb CO_2e per MWh. Similarly, for the case where all the biogenic material is removed from the MSW, the GHG emission reduction is about 1,700 lbs CO_2e per MWh.

The GHG benefit for a MSW conversion project will be project-specific, depending upon the amount of waste reduction prior to the conversion process. For an MSW conversion project to be eligible for the RES, the applicable eligibility requirements for the RPS must be satisfied. This includes removing, as much as possible, "the recyclable materials and marketable green waste compostable materials from the solid waste stream before the conversion process."[g] Based on these requirements, most MSW conversion projects will likely provide a GHG benefit.

[g] California Energy Commission, Renewables Portfolio Standard Eligibility, Third Edition, 2008

Table D1-3
GHG Benefit Determination for Renewable Sources

Technology	Potential Avoided GHG Emissions[h] (lb CO_2e per MWh)	Comments
Biogas Injection	830	Benefit based on 100 percent use of biogas pipeline fuel—for existing projects, the biogas represents a portion of fuel used by generator
Biomass Combustion	760	Includes GHG emissions from transportation[i]
Converting Biomass to Renewable Diesel	730	Includes GHG emissions from conversion of biomass to renewable diesel[j]
Digester	160	Digesters at wastewater plants
Digester	1,500	Digesters at dairies
Geothermal	520	GHG emissions resulting from operation—no emissions if heat stream is re-injected[k]
Hydropower and Conduit Hydropower	830	
Landfill	1,500	Estimate for out-of-state projects
Landfill	160	Estimate for in-state engine projects
Landfill	830	Estimate for in-state turbine and fuel cell projects
Municipal Solid Waste	1,200 to 1,700	Includes GHG emissions from conversion of MSW and benefit for conversion of methane; range dependent upon amount of waste separation
Ocean Technologies	830	
Wind and Solar	Less than 830	

[h] Benefit is based on one MWh renewable generation.
[i] GHG emissions for transportation are based upon the operational data from the late 1990's for six California biomass-to-energy plants. The data include the amount of biomass used by each plant and the GWh produced by each plant. Using this information and assuming each truck would carry 20 tons of biomass per trip and the truck would travel 80 miles roundtrip, staff estimated transportation GHG emissions as 70 lbs CO_2e per MWh.
[j] To estimate the energy needed to convert biomass into renewable diesel, staff evaluated the energy needed to use the Fischer-Tropsch (F-T) process to produce renewable diesel. The F-T process is energy intensive, but in addition to producing renewable diesel, electricity and naptha are produced as co-benefits. Information on the process taken from Strategic Assessment of Bioenergy Development in the West. Task 2: Bionenrgy Conversion Technology Characteristics, Antares Group, 2008. For the purposes of the GHG benefit analysis, the benefit was reduced by 1,300 lbs CO_2e per MWh, but electricity co-benefit of 1,200 lbs CO_2e per MWh was added—a net reduction of 730 lbs CO_2e per MWh.
[k] Based on range of emissions for several geothermal generators.

B. GHG Emissions Calculation

This section shows the GHG emission reduction calculation, using GHG emission factors from the RES Calculator. These GHG emission factors were derived from Table D1-3, except the emission factors for fossil-fuel generation, such as natural gas and coal. Tables D1-4 and D1-5 show the details of WECC-wide GHG emission estimates in 2020 for high load forecast, 20 percent RPS and proposed RES, respectively. The following formula was used to estimate the GHG emissions by region:

$$(GHG\ Emissions)_i = (Emission\ Factor)_i \times (Electricity\ Generation)_i \times 1{,}000 \times 0.454 \times 1/(1{,}000 \times 1{,}000{,}000)$$

Where:

GHG Emissions = greenhouse gas emissions per year ($MMTCO_2e$/yr)
Emission Factor = greenhouse gas emissions per unit energy (lbs CO_2e/MWh)
Electricity Generation = electricity production per year (GWh/yr)
i = in-state or out-of-state region
1,000 = conversion from GWh to MWh
0.454 = conversion from pounds (lbs) to kilograms (kg)
1/(1,000 x 1,000,000) = conversion from kg to million metric tonnes (MMT)

As shown in both tables, the 'REC GHG Credits' represent the avoided GHG emissions from out-of-state natural gas generation that was displaced by out-of-state renewable generation that does not serve California's load. Using the above formula, the GHG emission credits associated with out-of-state unbundled RECs are about -4.8 $MMTCO_2e$/yr and -5.3 $MMTCO_2e$/yr for the 20 percent RPS and proposed RES, respectively.

These GHG credit estimates were based on the sum of all out-of-state renewables, both existing and new resources. As shown in Tables D1-4 and D1-5, the sum of all out-of-state renewables is about 12,000 GWh and 13,400 GWh for the 20 percent RPS and proposed RES, respectively (minus sign signifies emissions credit or avoided emissions).

Table D1-4
2020 WECC-Wide GHG Emissions
20 Percent RPS, High Load

Resource	Emission Factors (lb CO_2e/MWh)		Electricity Generation (GWh/yr)		GHG Emissions ($MMTCO_2$e/yr)		
	In-State	Out-Of-State	In-State	Out-Of-State	In-State	Out-Of-State	Total
EXISTING:							
Traditional Sources							
NG Peaker	1,133	1,133	10,500	8,120	5.4	4.2	9.6
NG Baseload	833	833	55,100	45,600	20.8	17.2	38.1
Nuclear	0	0	32,600	8,490	0.0	0.0	0.0
Large Hydro	0	0	39,900	2,630	0.0	0.0	0.0
Coal	2,224	2,027	1,320	19,300	1.3	17.8	19.1
Renewable Sources							
Wind	0	0	5,720	504	0.0	0.0	0.0
Solar Thermal	0	0	724	0	0.0	0.0	0.0
Solar PV	0	0	0	0	0.0	0.0	0.0
Geothermal	310	310	12,900	740	1.8	0.1	1.9
Solid-Fuel Biomass	70	70	5,720	536	0.2	0.0	0.2
Landfill/Digester Gas	0	-670	0	0	0.0	0.0	0.0
Small Hydro	0	0	3,730	688	0.0	0.0	0.0
NEW:							
Traditional Sources							
NG Peaker	1,123	1,123	16,600	3,970	8.5	2.0	10.5
NG Baseload	810	810	20,900	12,800	7.7	4.7	12.4
Renewables Sources							
Wind	0	0	7,620	5,860	0.0	0.0	0.0
Solar Thermal	0	0	2,500	2,440	0.0	0.0	0.0
Solar PV	0	0	1,060	22	0.0	0.0	0.0
Geothermal	310	310	6,540	680	0.9	0.1	1.0
Solid-Fuel Biomass	70	70	1,150	12	0.0	0.0	0.0
Landfill/Digester Gas	0	-670	1,310	16	0.0	0.0	0.0
Small Hydro	0	0	214	543	0.0	0.0	0.0
OTHER:							
REC GHG Credits		873		-12,000		-4.8	-4.8
		Total	**226,000**	***113,000**	**46.6**	**41.3**	**88.0**

* Total excludes out-of-state generation associated with the 'REC GHG Credits.'

Table D1-5
2020 WECC-Wide GHG Emissions
Proposed 33 Percent RES, High Load

Resource	Emission Factors (lb CO_2e/MWh)		Electricity Generation (GWh/yr)		GHG Emissions ($MMTCO_2e$/yr)		
	In-State	Out-Of-State	In-State	Out-Of-State	In-State	Out-Of-State	Total
EXISTING:							
Traditional Sources							
NG Peaker	1,133	1,133	8,420	6,470	4.3	3.3	7.7
NG Baseload	833	833	43,200	35,500	16.3	13.4	29.7
Nuclear	0	0	32,600	8,490	0.0	0.0	0.0
Large Hydro	0	0	40,000	2,630	0.0	0.0	0.0
Coal	2,224	2,027	1,300	19,300	1.3	17.8	19.1
Renewable Sources							
Wind	0	0	5,720	504	0.0	0.0	0.0
Solar Thermal	0	0	724	0	0.0	0.0	0.0
Solar PV	0	0	0	0	0.0	0.0	0.0
Geothermal	310	310	12,900	740	1.8	0.1	1.9
Solid-Fuel Biomass	70	70	5,720	536	0.2	0.0	0.2
Landfill/Digester Gas	0	-670	0	0	0.0	0.0	0.0
Small Hydro	0	0	3,730	688	0.0	0.0	0.0
NEW:							
Traditional Sources							
NG Peaker	1,123	1,123	11,600	3,190	5.9	1.6	7.5
NG Baseload	810	810	20,900	10,000	7.7	3.7	11.4
Renewables Sources							
Wind	0	0	17,300	6,990	0.0	0.0	0.0
Solar Thermal	0	0	13,800	2,440	0.0	0.0	0.0
Solar PV	0	0	3,330	22	0.0	0.0	0.0
Geothermal	310	310	18,100	680	2.5	0.1	2.6
Solid-Fuel Biomass	70	70	1,150	236	0.0	0.0	0.0
Landfill/Digester Gas	0	-670	1,310	16	0.0	0.0	0.0
Small Hydro	0	0	214	543	0.0	0.0	0.0
OTHER:							
REC GHG Credits		873		-13,400		-5.3	-5.3
		Total	**242,000**	***99,000**	**40.1**	**34.7**	**74.8**

* Total excludes out-of-state generation associated with the 'REC GHG Credits.'

Similarly, Tables D1-6 and D1-7 show the GHG emission estimates for low load case.

Table D1-6
2020 WECC-Wide GHG Emissions
20 Percent RPS, Low Load

Resource	Emission Factors (lb CO_2e/MWh)		Electricity Generation (GWh/yr)		GHG Emissions ($MMTCO_2$e/yr)		
	In-State	Out-Of-State	In-State	Out-Of-State	In-State	Out-Of-State	Total
EXISTING:							
Traditional Sources							
NG Peaker	1,133	1,133	7,570	5,810	3.9	3.0	6.9
NG Baseload	833	833	37,400	30,800	14.1	11.6	25.8
Nuclear	0	0	32,600	8,490	0.0	0.0	0.0
Large Hydro	0	0	40,000	2,630	0.0	0.0	0.0
Coal	2,224	2,027	1,300	19,300	1.3	17.8	19.1
Renewable Sources							
Wind	0	0	5,720	504	0.0	0.0	0.0
Solar Thermal	0	0	724	0	0.0	0.0	0.0
Solar PV	0	0	0	0	0.0	0.0	0.0
Geothermal	310	310	12,900	740	1.8	0.1	1.9
Solid-Fuel Biomass	70	70	5,720	536	0.2	0.0	0.2
Landfill/Digester Gas	0	-670	0	0	0.0	0.0	0.0
Small Hydro	0	0	3,730	688	0.0	0.0	0.0
NEW:							
Traditional Sources							
NG Peaker	1,123	1,123	8,520	2,910	4.3	1.5	5.8
NG Baseload	810	810	20,900	8,890	7.7	3.3	10.9
Renewables Sources							
Wind	0	0	2,730	5,860	0.0	0.0	0.0
Solar Thermal	0	0	1,820	2,440	0.0	0.0	0.0
Solar PV	0	0	999	22	0.0	0.0	0.0
Geothermal	310	310	6,490	680	0.9	0.1	1.0
Solid-Fuel Biomass	70	70	1,150	0	0.0	0.0	0.0
Landfill/Digester Gas	0	-670	1,310	0	0.0	0.0	0.0
Small Hydro	0	0	214	478	0.0	0.0	0.0
OTHER:							
REC GHG Credits		873		-11,900		-4.7	-4.7
		Total	**192,000**	***90,700**	**34.3**	**32.6**	**66.9**

* Total excludes out-of-state generation associated with the 'REC GHG Credits.'

Table D1-7
2020 WECC-Wide GHG Emissions
Proposed 33 Percent RES, Low Load

Resource	Emission Factors (lb CO_2e/MWh)		Electricity Generation (GWh/yr)		GHG Emissions ($MMTCO_2$e/yr)		
	In-State	Out-Of-State	In-State	Out-Of-State	In-State	Out-Of-State	Total
EXISTING:							
Traditional Sources							
NG Peaker	1,133	1,133	5,870	4,480	3.0	2.3	5.3
NG Baseload	833	833	27,700	22,600	10.5	8.5	19.0
Nuclear	0	0	32,600	8,490	0.0	0.0	0.0
Large Hydro	0	0	40,000	2,630	0.0	0.0	0.0
Coal	2,224	2,027	1,300	19,300	1.3	17.8	19.1
Renewable Sources							
Wind	0	0	5,720	504	0.0	0.0	0.0
Solar Thermal	0	0	724	0	0.0	0.0	0.0
Solar PV	0	0	0	0	0.0	0.0	0.0
Geothermal	310	310	12,900	740	1.8	0.1	1.9
Solid-Fuel Biomass	70	70	5,720	536	0.2	0.0	0.2
Landfill/Digester Gas	0	-670	0	0	0.0	0.0	0.0
Small Hydro	0	0	3,730	688	0.0	0.0	0.0
NEW:							
Traditional Sources							
NG Peaker	1,123	1,123	4,620	2,280	2.4	1.2	3.5
NG Baseload	810	810	20,900	6,700	7.7	2.5	10.1
Renewables Sources							
Wind	0	0	17,300	6,990	0.0	0.0	0.0
Solar Thermal	0	0	13,000	2,440	0.0	0.0	0.0
Solar PV	0	0	3,170	22	0.0	0.0	0.0
Geothermal	310	310	6,490	680	0.9	0.1	1.0
Solid-Fuel Biomass	70	70	1,150	236	0.0	0.0	0.0
Landfill/Digester Gas	0	-670	1,310	16	0.0	0.0	0.0
Small Hydro	0	0	214	543	0.0	0.0	0.0
OTHER:							
REC GHG Credits		873		-13,400		-5.3	-5.3
		Total	**204,000**	***79,800**	**27.8**	**27.1**	**54.9**

* Total excludes out-of-state generation associated with the 'REC GHG Credits.'

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Appendix D2

Methodology For Assessment Of Air Quality Impacts

Statewide criteria pollutant emissions in 2020 were estimated for electricity generation for each possible scenario. The amount of in-state electricity generation for each resource type was predicted for each scenario by the RES Calculator. This analysis accounts for in-state emissions from electricity generated in California, including electricity that is exported out-of-state. The results of the analysis for the 20 percent RPS and the proposed RES are contained in Chapter IX. The results of the analysis for the RES alternative are contained in Chapter XI.

The sources of electricity generation from the RES Calculator are divided into two groups based on eligibility for the renewable portfolio standard:[1] traditional sources and renewable sources. The traditional sources of electricity generation include natural gas peaker plants, natural gas baseload plants, coal, nuclear, and large hydro. The renewable resources are wind, solar thermal, solar photovoltaic (PV), geothermal, solid-fuel biomass, landfill/digester gas and small hydro. Emission factors for the criteria pollutants (ROG, NO_x, SO_x, CO and $PM_{2.5}$) were developed for each resource type. To calculate emissions of a criteria pollutant for each generation resource, the following equation was used:

$$\textit{Emissions} = (\textit{Emission Factor}) \times (\textit{Electricity Generation}) \times (1/2{,}000)$$

Where:

Emissions = criteria pollutant emissions per year (tons/yr)
Emission Factor = criteria pollutant emissions per unit power (lbs/MWh)
Electricity Generation = electricity production per year (MWh/yr)
1/(2,000) = conversion from pounds (lbs) to tons

Criteria pollutant emissions for a given scenario were calculated by multiplying the appropriate emission factor by the electricity generation for each resource and then summing emissions from all resource types for each pollutant.

Emission Factors for Criteria Pollutants

Table D2-1 presents the emission factors used to evaluate the criteria pollutant emission impacts of the possible scenarios. For each resource, separate emission factors were developed for existing and new resources. New resources are those that will begin generation between now and 2020. New resources are expected to have lower emissions because air districts require the best available control technology for new sources, and the generation technology is improving.

The emission factors presented in Table D2-1 account for stationary source operating emissions only. They do not include vehicular emissions associated with plant maintenance and feedstock hauling, or fugitive road dust. These factors also do not account for emissions offsets that may be purchased to comply with new source review (NSR) programs because these offsets are project-specific. Electricity generation by nuclear, large hydro, wind, solar PV, and small hydro is assumed to have no operating emissions for criteria pollutants.

Table D2-1
Criteria Pollutant Emission Factors for
Existing and New Sources of Electricity Generation

	Emission Factors (lbs/MWh)				
Resource	**ROG**	**NO_x**	**SO_x**	**CO**	**$PM_{2.5}$**
EXISTING:					
Traditional Sources					
Natural Gas Peaker	0.07	0.4	0.02	0.4	0.06
Natural Gas Baseload	0.04	0.1	0.01	0.1	0.04
Nuclear	0	0	0	0	0
Large Hydro	0	0	0	0	0
Coal	0.02	3.9	1.2	7.1	0.5
Renewable Sources					
Wind	0	0	0	0	0
Solar Thermal	0.03	0.2	0.003	0.04	0.03
Solar PV	0	0	0	0	0
Geothermal	0.03	0.003	0.0009	0.0007	0.03
Solid-Fuel Biomass	0.2	1.8	0.4	7.5	0.4
Landfill/Digester Gas	0.5	2.5	0.2	7.1	0.6
Small Hydro	0	0	0	0	0
NEW:					
Traditional Sources					
Natural Gas Peaker	0.02	0.1	0.02	0.2	0.06
Natural Gas Baseload	0.02	0.07	0.01	0.1	0.03
Renewable Sources					
Wind	0	0	0	0	0
Solar Thermal	0.01	0.004	0.0009	0.005	0.006
Solar PV	0	0	0	0	0
Geothermal	0.002	0.003	0.0001	0.0002	0.02
Solid-Fuel Biomass	0.01	0.4	0.1	0.2	0.4
Landfill/Digester Gas	0.4	0.3	0	1.9	0.03
Small Hydro	0	0	0	0	0

Detailed Description of Emission Factors for Criteria Pollutants

All emission factors for existing resources are based on the most recent emissions data reported by districts to ARB for facilities currently generating electricity in California as contained in the CEIDARS database, except for coal. These are average emission factors weighted by the electricity generation of each facility. Because data from coal plants were limited, emission factors for coal are based on emission factors published in AP-42.[2] Coal emission factors were developed assuming bituminous coal with 1.2 percent sulfur content, fluidized bed combustion and 33 percent plant efficiency. These assumptions are based on common practices for coal plants in California.

Emission factors for new natural gas peaker plants, new solar thermal plants, and new geothermal operations are based on environmental analyses in Applications for Certification filed with the CEC.[3,4,5,6,7,8,9,10] These applications provide estimates of the maximum annual operating emissions and the total expected annual electricity generation for the new facilities. Again, these are average emission factors weighted by electricity generation.

For ROG, NO_x and CO, the emission factors for natural gas baseload plants are equal to the limits set by ARB's 2007 Distributed Generation Certification Regulation[11] for fossil fuel electrical generation technologies. Emission factors for SO_x and $PM_{2.5}$ from new natural gas baseload plants are based on environmental analyses in Applications for Certification filed with the CEC.[12,13,14]

Emission factors for new solid-fuel biomass generation are derived from emissions data reported by an air district to ARB for a modern biomass plant expected to have similar emissions characteristics as newly constructed facilities.

Most biogas electricity generation is derived from burning landfill gas, only a small fraction comes from digesters. Thus, emission factors for electricity generation by landfill/digester gas are based on electricity generation processes at landfills. The new landfill/digester gas emission factors are based on best BACT limits. Most current landfill facilities burn the gas generated on site with a flare to limit ROG and methane emissions. This flaring process emits criteria pollutants. When electricity generating engines are installed, gas is diverted from the flare to the engines, reducing flaring emissions. Thus, the emission factors for direct engine emissions were decreased to account for the avoided flaring emissions when developing emissions factors associated with electricity generation. Emission factors for flares are derived from emissions data reported to ARB by air districts and emission factors for engines are based on BACT limits. An engine efficiency of 33 percent was assumed to allow comparison of engine and flaring emission factors on an equal basis of lbs/MWh. All sulfur in the gas is assumed to be oxidized to SO_x in both the flare and the engine, thus SO_x emissions are the same from a flare or an engine. As a result, adding electricity generating engines where gas was previously flared is expected to have no impact on SO_x emissions, and the SO_x emission factor for electricity generation by landfill/digester gas is zero.

Statewide 2020 criteria pollutant emissions from electricity generation were estimated for possible compliance scenarios using the emission factors presented in this section. The results of those calculations are provided in Section C (Air Quality Impacts) of Chapter IX.

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Appendix D3

Supporting Information for the Analysis of Possible Effects on Impacted Communities

In Chapter IX, staff presented an analysis of the potential impacts of the proposed RES regulation on existing natural gas generation that is located within or near impacted communities. The results of the analysis were summarized in Tables IX-18 and IX-19. This appendix provides additional information on the facilities reviewed as part of this analysis.

The following information is presented in this appendix: (1) a summary of staff's analysis of the operation of various combustion turbines (CTs), combined cycle combustion turbines (CCCTs), and cogeneration facilities located within or near impacted areas; (2) sample calculations for converting requirements in district permits to operating limitations and comparing the permit limits to actual operation of the facility in 2008; (3) 2007 and 2008 operational information for facilities located within the Bay Area Air Quality Manage District (BAAQMD), the South Coast Air Quality Management District (SCAQMD), and the San Joaquin Valley Air Pollution Control District (SJVAPCD); and (4) a summary of operating limits imposed by district permits and regulations.

The methodology for selecting facilities to review was based on the facility's proximity to impacted locations. As discussed in Chapter IX, the impacted areas were selected based upon the criteria developed for the Carl Moyer program to identify impacted communities. Section A of Appendix D3 summarizes information for each facility evaluated, including the type of generation (either CCCT , CT, or cogeneration), the NO_x emission limit, the types of limits applicable to the unit (permit limit or NO_x limit), the hours the unit operated in 2008, the allowed hours of operation based on district permit or regulatory requirements, and the percent of operation by the unit in 2008 (hours operated in 2008 divided by allowed hours of operation). This information was summarized by type of generation in Table IX-18 in Chapter IX.

For the facilities located in SJVAPCD and SCAQMD, the allowed hours of operation are based on staff's review of applicable district permit restrictions. The operating restrictions applicable to each facility, as listed on the permit issued by the district, are summarized in Section D of this appendix. The sample calculations given in Section B provide the methodology used by staff to convert the operation restrictions listed in the permit to hourly limitations. The limits in the permits are typically expressed as either fuel use limits (for example: 6,400,000,000 Btu per year of natural gas) or emissions limits (for example: 149 lbs per day of NO_x) applicable on a daily and/or annual basis.

Section C contains the facility operating data for 2007 and 2008. This information is compared to the allowed hours of operation to determine each facility's level of operation. For the facilities located within BAAQMD and SJVAPCD, the districts provided the information on the facility's operation. The districts typically provided either the hours the unit operated or the amount of natural gas the unit consumed for the year in question. For the operating data provided as fuel consumption, the sample calculations in Section B present the methodology for converting the fuel consumption data to hours of operation. For projects located within the SCAQMD, information was taken from the district's webpage, shown in Section C of Appendix D3, that provided the 2007 and 2008 NO_x emissions for each facility queried. Section B, Appendix D3 provides the methodology used to determine the hours of operation from the reported facility's emissions.

Section D summarizes the operation requirements listed in the applicable district permit for facilities located in either SJVAPCD or SCAQMD. For the facilities located within BAAQMD, the operating limits are set by Regulation 9, Rule 9: Nitrogen Oxides from Stationary Gas Turbines; a copy of the regulation is presented in Section D.

Finally, Section E provides the information staff used to estimate emissions for a new solid-fuel biomass plant.

A. Summary of Facility Information

Table D3-1 summaries information on NO_x emissions limits and operating limits for 28 facilities that are located within or near impacted areas. The summary shows that most facilities have operating limitations imposed upon them. For example, the simple cycle unit in the Fresno Cogeneration Partners Facility located in San Joaquin is limited, by the district permit, to 5,000 hours of operation a year. The operating restrictions imposed by district permits range from 400 hours per year to no restrictions. Only 10 units of the 44 units included in this analysis did not have operating restrictions imposed by the district permits.

The average capacity factor for CTs is particularly low, with 22 of the 37 CTs, or 60 percent of the CTs reviewed, operating at a capacity factor that is less than the average capacity factor for CTs. This information is consistent with the CTs providing peaking generation—generally 3-4 hours a day during the summer season. Because CCCTs provide load-following generation and cogeneration facilities provide baseload generation, both CCCTs and cogeneration facilities are expected to operate more than CTs. For the facilities being reviewed, the CCCTs and cogeneration facilities are operating two to thee times more than the CTs.

Additionally, the table indicates that the natural gas-fueled generating fleet is well controlled. Nearly all units evaluated were required to install best available control technology (BACT) to reduce NO_x, VOC, and CO emissions (the table presents only information for NO_x because that is the most important criteria pollutant of concern due to its impact on ozone and particulate matter.) Those few units that are not equipped with BACT are subject to limited operating hours.

Table D3-1
Summary of Natural Gas Generation Facilities
Located Within or Near Impacted Areas

District	Facility	City	Type	MW	NO_x Limit (ppm)	Fuel Limit (Y/N)	Emission Limit (Y/N)	Allowed operation (hr/year)	Hours operated in 2008	% operation in 2008	Comments
SJVAPCD	Fresno Cogeneration Partners	San Joaquin	Simple Cycle	23	5	y	y	5,000	50	1	Limiting requirement is 24 tons NO_x limit applies to both turbines--high operation of peaker will limit operation of facility; if both turbines operate equally, NO_X limit facility to 4800 hours or 55 percent of capacity
			Combined Cycle Cogeneration	55	2	y		7,700	2,385	30	
SJVAPCD	Coalinga Cogeneration Co.	Coalinga	Cogeneration	43	5	y	y	8,760	8,322	95	Permit limits do not limit operation
SJVAPCD	California Power Holdings	Chowchilla	Engines for Peaking	49.6	9	n	y	40,000	20,327	50	Facility total hours limit is most stringent limit–limited to 30% capacity factor
SJVAPCD	Cal Peak power	Firebaugh	Simple Cycle	24.7	3.4	n	y	3,200	140	4	Facility NO_x cap limits facility operation to 37 percent capacity factor
				24.7	3.4				140		

Table D3-1
Summary of Natural Gas Generation Facilities
Located Within or Near Impacted Areas (Continued)

District	Facility	City	Type	MW	NO_x Limit (ppm)	Fuel Limit (Y/N)	Emission Limit (Y/N)	Allowed operation (hr/year)	Hours operated in 2008	% operation in 2008	Comments
SJVAPCD	Well head power	Huron	Simple Cycle	45	3.5	y	y	3,500	170	5	Annual facility NO_x cap (19,958 lb/yr) limits operation to 40 percent capacity factor (may be less depending upon operation of other units at facility)
SJVAPCD	Well head power	Firebaugh	Simple Cycle	49.9	2.5	y	y	3,700	139	4	Facility cap limits emissions to 42 percent capacity factor
SJVAPCD	GWF Energy	Lemoore	Simple Cycle	46.9	3.6	n	y	8,000	685	8	Emission limits for each unit cap operation to 90 percent of capacity factor
				46.9	3.6	n	y	8,000	663	8	

Table D3-1
Summary of Natural Gas Generation Facilities
Located Within or Near Impacted Areas (Continued)

District	Facility	City	Type	MW	NO_x Limit (ppm)	Fuel Limit (Y/N)	Emission Limit (Y/N)	Allowed operation (hr/year)	Hours operated in 2008	% operation in 2008	Comments
SJVAPCD	Algonquinn Power	Sanger	Simple Cycle	49	5	y	y	3,400	2,640	61	Annual facility fuel cap (1,386 MM* SCF/yr) limits operation to 39 percent capacity factor (may be less depending upon operation of other units at facility)
SJVAPCD	Kingsburg Cogen Facility	Kingsburg	Cogeneration	35	5	y	y	7,700	2,130	28	Limited by daily fuel limit to 88 percent capacity factor
SJVAPCD	Kings River Conservation District	Fresno	Simple Cycle	50	2.5	n	y	4,500	1,961	44	Limited by annual fuel limit to 51 percent capacity factor
				50	2.5	n	y	4,500	1,935	43	
SJVAPCD	San Joaquin Cogen	Lathrop	Cogeneration	49	3.8	n	y	8,760	162	2	Emissions limit does not limit operation of unit

*MM is 1,000,000; 1,386 MM SCF is 1,386,000,000 SCF

Table D3-1
Summary of Natural Gas Generation Facilities
Located Within or Near Impacted Areas (Continued)

District	Facility	City	Type	MW	NO_x Limit (ppm)	Fuel Limit (Y/N)	Emission Limit (Y/N)	Allowed operation (hr/year)	Hours operated in 2008	% operation in 2008	Comments
SJVAPCD	Turlock Irrigation District	Turlock	Simple Cycle	26	25	n	y	1,000	35	4	NO_x limited to 25,551 lb/qtr (w/ Unit #2); Limited to 877 hr/yr; Fuel oil backup w/ limits
				26	25	n	y	1,000	23	2	NO_x limited to 25,551 lb/qtr (w/ Unit #1); Limited to 877 hr/yr; Fuel oil backup w/ limits
SJVAPCD	Northern California Power Agency	Lodi	Simple Cycle	49	3	n	y	8,760	1,237	14	Operational emissions limit does not effect operation of unit
SJVAPCD	Turlock Irrigation District	Modesto	Combined Cycle	48	3	n	y	8,760	1,960	22	Operational emissions limit does not effect operation of unit
SJVAPCD	Walnut Energy Center Authority	Turlock	Combined Cycle	134	2	n	y	8,760	6,513	74	Operational emissions limit does not effect operation of unit
				134	2	N	y	8,760	6,411	73	

Table D3-1
Summary of Natural Gas Generation Facilities Located Within or Near Impacted Areas (Continued)

District	Facility	City	Type	MW	NO_x Limit (ppm)	Fuel Limit (Y/N)	Emission Limit (Y/N)	Allowed operation (hr/year)	Hours operated in 2008	% operation in 2008	Comments
BAAQMD	Potrero	San Francisco	Simple Cycle	52	65	y	n	400	170	10	District turbine rule limits to 400 hrs for 65 ppm; 877 hrs in Title V permit
				52	65	y	n	400	132	10	
				52	65	y	n	400	89	10	
BAAQMD	Alameda	Oakland	Simple Cycle	22.5	65	y	n	877	20	2	District turbine rule limits
				22.5	65	y	n	877	12	1	
BAAQMD	Oakland	Oakland	Simple Cycle	52	65	y	n	877	125	14	877 hrs in Title V permit
				52	65	y	n	877	179	20	
				52	65	y	n	877	129	15	
SCAQMD	Grapeland peaker	Cucamonga	Simple Cycle	49	2.5	y	n	1,650	215	13	
SCAQMD	Mira Loma peaker	Ontario	Simple Cycle	49	2.5	y	n	950	428	45	
SCAQMD	Norwalk peaker	Norwalk	Simple Cycle	49	2.5	y	n	1,300	0	0	22 percent capacity factor in 2007

Table D3-1
Summary of Natural Gas Generation Facilities Located Within or Near Impacted Areas (Continued)

District	Facility	City	Type	MW	NO_x Limit (ppm)	Fuel Limit (Y/N)	Emission Limit (Y/N)	Allowed operation (hr/year)	Hours operated in 2008	% operation in 2008	Comments
SCAQMD	Harbor	Wilmington	Combined Cycle	138	5	n		8,760	560	6	Fully Offset; 3 percent capacity factor in 2007
			Combined Cycle	138	5	n		8,760	560	6	
			Simple Cycle	47	5	y		5,129	1,307	25	11 percent capacity factor in 2007
			Simple Cycle	47	5	y		5,129	1,307	25	
			Simple Cycle	47	5	y		5,129	1,307	25	
			Simple Cycle	47	5	y		5,129	1,307	25	
			Simple Cycle	47	5	y		5,129	1,307	25	
SCAQMD	Harbor Cogen	Wilmington	Combined Cycle	106	7.5	n		8,760	373	4	11 percent capacity factor in 2007
SCAQMD	Long Beach	Long Beach	Combined Cycle	65	2.5	y		1,900	382	21	27 percent capacity factor in 2007
				65	2.5			1,900	382	21	
				65	2.5			1,900	382	21	
				65	2.5			1,900	382	21	

B. Sample Calculations

Sample Calculations are given in this appendix for determining the limits in district operating permits that may limit the hours of operation for the facility. These requirements were placed on the facility typically at the time the facility owner is issued a permit to construct from the air district. This permit would be issued only after the project proponent has demonstrated that all applicable district regulations that were in effect at the time a permit application was filed are satisfied. The permit typically has both fuel limits and emission limits. These permit based operating limits are then compared to operating information for 2008 to determine the capacity factor for the facility.

Presented below are sample calculations for a project located within San Joaquin Valley Air Pollution Control District (SJVAPCD) and another project located within the South Coast Air Quality Management District (SCAQMD). The staff of the Bay Area Air Quality Management District (BAAQMD) provided the limitation on the hours of operation for the three facilities located within their district.

1. Description of Calculation Methodology and Sample Calculation for a Facility located in San Joaquin Valley Air Pollution Control District

Description of project

- Project Name: Algonquin
- Location: Sanger
- Project Description: 49 MW simple cycle gas turbine generation; Gas Turbine is General Electric LM6000
- Gas Turbine is equipped with Selective Catalytic Reduction to abate NO_x emissions to 5 ppm

Air Permit Operating Requirements

- Fuel limits:
  - 11,000,000 standard cubic feet (SCF) of natural gas per day
  - 1,386,000,000 SCF per year for the turbine, dryer, and boiler combination

- NO_x limits
  - 7.6 lb/hr
  - 134 lb/day
  - 31,086 lb/day for the turbine, dryer, and boiler combination

Fuel Limit Impacts

Staff considered both the emission limits and the fuel limits to determine which limit results in the most stringent operation limits. Staff must first estimate the fuel use of the turbine. The efficiency is based on literature review. Turbine efficiencies can vary from 25 percent to 42 percent, depending upon the specific turbine model.

$$\text{Fuel used by gas turbine} = \frac{\text{3,412 Btu/KWh x 1,000 KWh/MWh x 49 MW}}{\text{0.39 (turbine efficiency)}}$$

$$= \text{428,687,179 Btu per hour}$$

1. Daily limit

Daily fuel limit: 11,000,000 SCF natural gas

11,000,000 SCF natural gas / day x 1050 Btu / SCF natural gas =

11,550,000,000 btu per day

Daily hourly limit based on fuel limit =

11,550,000,000 Btu per day / 428,687,179 Btu per hour = 26.9 hours

Because fuel limit in the permits allows the turbine to operate beyond 24 hours a day based on maximum fuel consumption, the turbine's operation is not limited by fuel limit.

2. Facility limit

The limit is shared by the turbine, boiler, and dryer. The turbine provides heat in lieu of the boiler and dryer. Consequently, the boiler and dryer only operate when the turbine is not operating. The following calculation assumes the turbine is the only unit operating.

Annual fuel limit: 1,386,000,000 SCF natural gas

1,386,000,000 SCF natural gas / year x 1,050 Btu / SCF natural gas =

1,455,300,000,000 Btu per day

Daily limit based on fuel limit =

1,455,300,000,000 Btu per day / 428,687,179 Btu per hour

= 3,394 hours per year

Emission Limits

31,086 lb / year / 7.6 lb/hr = 4,090 hrs per year

Conclusion: based on the above analysis, the applicable limit is the daily fuel limit which is equivalent to 3,394 hours per year.

Facility Operation

Reported fuel use in 2008: 1,078 MM SCF or 1,078,000,000 SCF

Hours of operation = 1,078,000,000 SCF * 1,050 Btu/SCF / 428,687,179 Btu/hour
= 2,064 hours

Capacity factor = 2,064 hours / 3,394 hours limit
= 61 percent

2. Description of Calculation Methodology and Sample Calculation for Turbines in South Coast Air Quality Management District

ARB staff provided the SCAQMD with a preliminary list of identified power plants with electrical generating combustion turbines located in highly impacted communities in their jurisdiction. Staff requested information on permitted NO_x limits, operating hour limits, and 2009 (or most recent year) actual operating hours. SCAQMD provided staff with a table containing available information (see Section D-4-3). A description of the methodology used to estimate turbine capacity factors, as well as a sample calculation, is provided below.

Maximum Permitted Annual Operating Hours
In most cases, the power plants opted to take permit limits based on total emissions (translated into fuel use restrictions) rather than specific operating hours, in order to provide operational flexibility while remaining under emission thresholds. SCAQMD staff provided the maximum fuel usage rates. ARB staff used the fuel consumption limits along with turbine heat rate data to estimate the maximum permitted operating hours. Sources identified by the SCAQMD as

having no fuel use limits are allowed unlimited operation and were fully offset during permitting. For these sources, ARB staff assumed the maximum 8,760 hours per year.

Actual Annual Operating Hours
SCAQMD staff could not provide actual operating hour data, because the only data available is for total facility fuel consumption. Instead, ARB staff used the short-term permitted NO_x limits (in parts per million, ppm) in conjunction with turbine heat rate data and the reported actual NO_x emissions from the source (in tons per year, tpy)[a] to calculate allowable operating hours. SCAQMD staff agreed that this was a reasonable approach to estimating actual operating hours since the turbines are the primary permitted emissions units on site and contribute the majority of the stationary source emissions.

Sample Calculation

Description of project:

- Project Name: Grapeland Peaker
- Location: Rancho Cucamonga
- Project Description: 49 MW GE LM6000 SPRINT simple cycle gas turbine generator.
- Turbine Heat Rate: 8,434 Btu/kWh[b]
- Emission Control: water injection, selective catalytic reduction
- Reported Facility Nox, 2008: 0.429 tpy

Air Permit Operating Requirements:

- Fuel limits:
  - 683 MMscf/yr (equivalent to 717,150 MMBtu/yr[c])
- Nox limits:
  - 2.5 ppmv @ 15% O_2

[a] Facility actual NOx emission rates obtained from the South Coast AQMD's Facility Information Search (FIND) database, available at: http://www.aqmd.gov/webappl/fim/default.htm.
[b] In cases where ARB staff did not have permit information on the rated heat input of the turbine, it was calculated using a literature search of heat rate data for the class of turbine, available at: http://www.gepower.com/prod_serv/products/aero_turbines/en/downloads/lm6000_sprint.pdf (for GE LM6000 SPRINT) and http://www.gepower.com/prod_serv/products/gas_turbines_cc/en/downloads/ge10.pdf (for GE 10).
[c] Assumes natural gas heating value of 1050 Btu/scf.

Maximum Permitted Annual Operating Hours Using Fuel Consumption Limit:

Where turbine heat rate data was unavailable through a copy of the permit, ARB staff estimated turbine fuel use through an efficiency calculation and a literature review of turbine heat rates.

Step 1: Calculate turbine fuel consumption

Turbine efficiency = 3,412 Btu/kWh[d] ÷ 8,434 Btu/kWh
= 0.405

Turbine fuel use = 49,000 kW x 3,412 Btu/kWh x MMBtu/10^6 Btu ÷ 0.405
= 413.266 MMBtu/hr

Step 2: Calculate annual hours

Annual hours = 717,150 MMBtu/yr ÷ 413.266 MMBtu/hr
= 1,735 hr/yr

Actual Annual Operating Hours Using Reported Facility NO_x Emissions:

Step 1: Calculate hourly NO_x emission rate

Convert from ppm @ 15% O_2 to lb/MMBtu:

lb/MMBtu = $C_{15\%\ O2}/10^6$ x M x (1 lb-mole/385 ft^3) x (20.9/(20.9-15)) x F_{factor}
= 2.5 ppmv/10^6 x 46 lb/lb-mole x (1 lb-mole/385 ft^3) x (20.9/(20.9-15)) x 8,710 dscf/MMBtu
= 0.0092 lb/MMBtu

where,

C = effluent gas concentration on dry basis, ppm
M = molecular weight in lb/lb-mole (46 for Nox)
385 = standard volume in cubic feet of one lb-mole
F_{factor} = ratio of stoichiometric volume of dry gas generated for complete combustion of a fuel with air to the amount of heat produced (8,710 dscf/MMBtu for natural gas)

Hourly NOx = 0.0092 lb/MMBtu x 413.266 MMBtu/hr
= 3.81 lb/hr NO_x

Note: At sites with more than one turbine, the facility actual Nox emission rate was divided equally amongst all turbines to estimate the actual emission rate from each turbine.

[d] At 100% efficiency, the conversion from heat to electricity is at a rate of 3412 Btu/kWh. Actual generation efficiencies, fall short of this.

Step 2: Calculate actual operating hours:

Annual operating $hours_{2008}$ = 0.429 tons/yr NO_x x 2000 lb/ton ÷ 3.81 lb/hr NO_x
= 225.3 hr/yr

Capacity factor = actual hours operated ÷ maximum permitted hours x 100
= 225.3 hr/yr ÷ 1,735 hr/yr x 100
= 13%

Note: There may be some inherent rounding and significant figures embedded into the Excel spreadsheet ARB staff used to generate numbers. Therefore, the values in the sample calculation may not exactly match.

C. Facility Operation Information

This appendix contains summaries of operational information for projects located in the BAAQMD, SJVAPCD, and SCAQMD for the years 2007 and 2008. For facilities located within the BAAQMD and the SJVAPCD, the specific districts provided the information or, in the case of 2007 data for BAAQMD facilities, the information came from CAISO. For facilities within the SCAQMD, the operating hours are based upon emission data that are available on-line at the district's webpage.

Table D3-2
Operating Information for Generating Facilities
Located Within or Near Impacted Communities in BAAQMD

Facility	Unit Number	Hours Operated in 2007	Hours Operated in 2008
Potrero	4	253	170
	5	253	132
	6	193	89
Alameda	1	232	20
	2	193	12
Oakland	1	291	125
	2	301	179
	3	229	129

Sources: BAAQMD for 2008 data and Potrero data for 2007; CAISO Reliably Must Run report for contract year 2007 for Alameda and Oakland 2007 data.

Annual NO_x Emissions Data for Turbines in South Coast Air Quality Management District

(Obtained from District's Facility Information Detail {FIND} Database at: http://www.aqmd.gov/webappl/fim/prog/search.aspx)

Example FIND Database Entry

Facility INformation Detail (FIND)

Search Again | Search Results | Facility Details | Equipment List | Compliance | Emissions | Hearing Board | Transportation

Emissions

Facility ID	149620
Company Name	SOUTHERN CALIFORNIA EDISON
Address	12408 6TH ST
	RANCHO CUCAMONGA, CA 91739

Select AER Year: 2008

Criteria Pollutants (Tons per Year):

Pollutant ID	Pollutant Description	Annual Emissions
CO	Carbon Monoxide	0.460
NOX	Nitrogen Oxides	0.429
ROG	Reactive Organic Gases	0.087
SOX	Sulfur Oxides	0.014
TSP	Total Suspended Particulates	0.257

Toxic Pollutants (Pounds per Year):

Pollutant ID	Pollutant Description	Annual Emissions
106990	1,3-Butadiene	0.079
91576	2-Methyl naphthalene [PAH, POM]	0.007
83329	ACENAPHTHENE	0.000
208968	ACENAPHTHYLENE	0.001
7664417	Ammonia	827.442
191242	B[GHI] PERYLENE	0.000
71432	Benzene	0.656
205992	Benzo[b]fluoranthene	0.000
192972	Benzo[e]pyrene [PAH, POM]	0.000
56235	Carbon tetrachloride	0.008

Table D3-3
Operating Information for Generating Facilities
Located Within or Near Impacted Communities in SJVAPCD

Facility Name	Facility City	Generation	Hours Operated 2008	Fuel Usage 2008 ($1x10^6$ SCF)	Hours Operated 2007	Fuel Usage 2007 (1x106 SCF)
FRESNO COGENERATION PARTNERS	SAN JOAQUIN	23,000 kW	51			28
FRESNO COGENERATION PARTNERS	SAN JOAQUIN	55,000 kW	2,385			572
COALINGA COGENERATION CO	COALINGA	42,700 kW		3,770		3,837
KINGSBURG COGEN FACILITY	KINGSBURG	34,500 kW		842		940
CALIFORNIA POWER HOLDINGS LLC	CHOWCHILLA	3,100 kW	1,360		413	
CALIFORNIA POWER HOLDINGS LLC	CHOWCHILLA	3,100 kW	1,211		373	
CALIFORNIA POWER HOLDINGS LLC	CHOWCHILLA	3,100 kW	1,346		388	
CALIFORNIA POWER HOLDINGS LLC	CHOWCHILLA	3,100 kW	1,353		373	
CALIFORNIA POWER HOLDINGS LLC	CHOWCHILLA	3,100 kW	1,354		366	
CALIFORNIA POWER HOLDINGS LLC	CHOWCHILLA	3,100 kW	1,358		381	
CALIFORNIA POWER HOLDINGS LLC	CHOWCHILLA	3,100 kW	1,338		380	
CALIFORNIA POWER HOLDINGS LLC	CHOWCHILLA	3,100 kW	1,279		394	
CALIFORNIA POWER HOLDINGS LLC	CHOWCHILLA	3,100 kW	1,340		393	
CALIFORNIA POWER HOLDINGS LLC	CHOWCHILLA	3,100 kW	1,346		384	
CALIFORNIA POWER HOLDINGS LLC	CHOWCHILLA	3,100 kW	1,310		373	
CALIFORNIA POWER HOLDINGS LLC	CHOWCHILLA	3,100 kW	1,343		377	
CALIFORNIA POWER HOLDINGS LLC	CHOWCHILLA	3,100 kW	1,354		378	
CALIFORNIA POWER HOLDINGS LLC	CHOWCHILLA	3,100 kW	1,340		367	
CALIFORNIA POWER HOLDINGS LLC	CHOWCHILLA	3,100 kW	495		339	
CALIFORNIA POWER HOLDINGS LLC	CHOWCHILLA	3,100 kW	1,201		390	
CAL PEAK POWER – PANOCHE, LLC	FIREBAUGH	24,700 kW		36		61
CAL PEAK POWER – PANOCHE, LLC	FIREBAUGH	24,700 kW		36		61
WELLHEAD POWER GATES, LLC.	HURON	45,400 kW		55		115
WELLHEAD POWER PANOCHE, LLC.	FIREBAUGH	49,900 KW		37		110
GWF ENERGY LLC – HENRIETTA	LEMOORE	46,900 kW		247	304	
GWF ENERGY LLC – HENRIETTA	LEMOORE	46,900 kW		240	297	

Table D3-3
Operating Information for Generating Facilities
Located Within or Near Impacted Communities in SJVAPCD (Continued)

Facility Name	Facility City	Generation	Hours Operated 2008	Fuel Usage 2008 ($1x10^6$ SCF)	Hours Operated 2007	Fuel Usage 2007 (1x106 SCF)
ALGONQUIN POWER SANGER LLC	SANGER	49,000 kW		1,078		NA
KINGS RIVER CONSERVATION DISTRICT	FRESNO	49,700 kW	1,961		1,430	
KINGS RIVER CONSERVATION DISTRICT	FRESNO	49,700 kW	1,935		1,430	
SAN JOAQUIN COGEN, LLC	LATHROP	48,600 kW		64		66
TURLOCK IRRIGATION DISTRICT	TURLOCK	25,800 kW	35			9
TURLOCK IRRIGATION DISTRICT	TURLOCK	25,800 kW	23			7
NORTHERN CALIFORNIA POWER	LODI	49,000 kW		546		650
TURLOCK IRRIGATION DISTRICT	MODESTO	48,000 kW	1,960		2243	
WALNUT ENERGY CENTER AUTHORITY	TURLOCK	134,000 kW		6,495	6,682	
WALNUT ENERGY CENTER AUTHORITY	TURLOCK	134,000 kW		6,393	6,756	

Source: SJVAPCD

D. Permits and Other Information to Determine Operational Status

This section contains summaries of applicable air permits for facilities located within SJVAPCD and SCAQMD. For facilities located within the BAAQMD, the operating limits are set by Regulation 9, Rule 9: Nitrogen Oxides from Stationary Gas Turbines. The applicable sections that apply to the BAAQMD turbines reviewed in this analysis are sections 9-9-116: Limited Exemption, Very Limited Use Turbines and 9-9-302: Emission Limit Low Use.

Table D3-4
Permit Information for Turbines in South Coast Air Quality Management District
(Data provided by District Staff)

Operator	Address	Location	Impact Area	OTC	Equipment	MW Rating	Control	NOx ppmv	Status	Comments	Permitted Operating Limit
SCE	12408 6th St Rancho Cucamonga, CA 91739	San Bernardino	Ontario	n	49 MW (2008)	49	SCR/H2O inj	2.5	Operating		683 mmscf/yr
SCE	13568 Milliken Ave, Ontario, CA 91761	San Bernardino	Ontario	n	49 MW (2008)	49	SCR/H2O inj	2.5	Operating		392 mmscf/yr
SCE	10601 E Firestone Blvd, Norwalk, CA 90650	Los Angeles		n	49 MW (2008)	49	SCR/H2O inj	2.5	Operating		543 mmscf/yr
SCE	8662 Cerritos Ave, Stanton, CA 90680	Los Angeles		n	49 MW (2008)	49	SCR/H2O inj	2.5	Operating		489 mmscf/yr
Purenergy LLC	661 S Cooley Dr, Colton, CA 92324	San Bernardino	Railto	n	Turbine 1, simple	10.5	SCR	5	Operating		354 mmscf/mo and 1188 mmscf/yr combined for all 4
				n	Turbine 2, simple	10.5	SCR	5	Operating		
				n	Turbine 3, simple	10.5	SCR	5	Operating		
				n	Turbine 4, simple	10.5	SCR	5	Operating		
Purenergy LLC	559 Pepper Ave, Colton, CA 92324	San Bernardino	Railto	n	Turbine 1, simple	10.5	SCR	5	Operating		354 mmscf/mo and 1188 mmscf/yr combined for all 4
				n	Turbine 2, simple	10.5	SCR	5	Operating		
				n	Turbine 3, simple	10.5	SCR	5	Operating		
				n	Turbine 4, simple	10.5	SCR	5	Operating		
SCE	2492 W San Bernardino Ave, Redlands, CA 92374	Riverside	San Bernardino	n	Turbine 3-1, combined	264	SCR/DLNB	2	Operating	Initial startup Aug 2005	None
				n	Turbine 3-2, combined	264	SCR/DLNB	2	Operating	Initial startup Aug 2005	None
				n	Turbine 4-3, combined	264	SCR/DLNB	2	Operating	Initial startup Oct 2005	None
				n	Turbine 4-4, combined	264	SCR/DLNB	2	Operating	Initial startup Oct 2005	None
LADWP	161 N Island Ave, Wilmington, CA 90744	Los Angeles	Wilimington	y	Turbine, combined	138.725	H2O/SI, SCR	5	Operating	CC plant: (2) 95.6 MW CT, 86.25 MW ST	None
				y	Turbine, combined	138.725	H2O/SI, SCR	5	Operating		None
				n	Turbine, simple	47.4	H2O/SI, SCR	5	Operating		190 mmscf/mo and 790 mgal/mo
				n	Turbine, simple	47.4	H2O/SI, SCR	5	Operating		190 mmscf/mo and 790 mgal/mo
				n	Turbine, simple	47.4	H2O/SI, SCR	5	Operating		190 mmscf/mo and 790 mgal/mo
				n	Turbine, simple	47.4	H2O/SI, SCR	5	Operating		190 mmscf/mo and 790 mgal/mo
				n	Turbine, simple	47.4	H2O/SI, SCR	5	Operating		190 mmscf/mo and 790 mgal/mo
Harbor Cogen	505 Pier B Ave, Wilmington, CA 90744	Los Angeles	Wilimington	n	Turbine, combined	106.3	H2O/SI, SCR	7.5	Operating	82.3 MW CT, 12.5 MW ST, 11.5 MW ST	none
NRG El Segundo	2665 W Seaside, Long Beach, CA 90802	Los Angeles	Wilimington	n	Turbine, simple	65	H2O inj, SCR	2.5	Operating	CTs rebuilt and repowered in 2005	128.13 mmcf/mo
				n	Turbine, simple	65	H2O inj, SCR	2.5	Operating		128.13 mmcf/mo
				n	Turbine, simple	65	H2O inj, SCR	2.5	Operating		128.13 mmcf/mo
				n	Turbine, simple	65	H2O inj, SCR	2.5	Operating		128.13 mmcf/mo

Table D3-5
Permit Information for Turbines and Engines in San Joaquin Valley Air Pollution Control District
(Data provided by District Staff)

			Fuel Limits			NO_x Emission Limits				
Facility Name	**Location**	**Type**	**Daily limits**	**Annual Limits**	**Hourly Limits**	**Hourly**	**Daily**	**Annual**	**Other**	**Comments**
Fresno Cogeneration Partners	San Joaquin	CT		1,320,000 MMBtu		6.2			209 lbs per day for both units; 48,539 lbs per year for both units	
Fresno Cogeneration Partners	San Joaquin	CCCT		2,284,250 MMBtu		na				
Coalinga Cogeneration Co.	Colinga	CT	11,381 MMBtu			8.6	248			
California Power Holdings	ChowChilla	engines			40,000 hours for all 16 engines		42.6	8,800		
Cal Peak power	Firebaugh	CT				3.08	74		6.2 lb per hour, 148 lb per day, and 20,000 lb per year for both units	
Cal Peak power	Firebaugh	CT				3.08	74			
Wellhead Power	Huron	CT		1,547,100 MMBtu		5.6	135	19,958		Annual limits apply to other units
Wellhead Power	Firebaugh	CT		2,480,000 MMBtu		6.2	149	22,816		Limits apply to both CT

Table D3-5
Permit Information for Turbines and Engines in San Joaquin Valley Air Pollution Control District (Continued)

			Fuel Limits			NO_x Emission Limits				
Facility Name	Location	Type	Daily limits	Annual Limits	Hourly Limits	Hourly	Daily	Annual	Other	Comments
GWF Energy	Lemoore	CT			8,000 hours per year	6.2	150	49,510		
GWF Energy	Lemoore	CT			8,000 hours per year	6.2	150	49,510		
Algonquin Power	Sanger	CT	11 MMSCF; 1,386 MMSCF for turbine and dryer			7.6	134		31,086 lb per year applies to turbine and dryer	
Kings River Conservation	Fresno	CT				4.25		19,009		
Kings River Conservation	Fresno	CT				4.25		19,009		
Kingsburg Cogen	Kingsburg	Cogeneration		6,480 MMBtu for turbine and 2,300 MMBtu for duct burner			149			
San Joaquin Cogen	Lathrop	Cogeneration					148			

Table D3-5
Permit Information for Turbines and Engines in San Joaquin Valley Air Pollution Control District (Continued)

			Fuel Limits			NO_x Emission Limits				
Facility Name	**Location**	**Type**	**Daily limits**	**Annual Limits**	**Hourly Limits**	**Hourly**	**Daily**	**Annual**	**Other**	**Comments**
Turlock Irrigation District	Turlock	CT			877 hours per year				1,020 lbs per day and 25,551 lbs per quarter for both units	
Turlock Irrigation District	Turlock	CT			877 hours per year					
Northern California Power Agency	Lodi	CT					112			
Turlock Irrigation District	Modesto	CCCT					142	52,049		Includes startup and shutdown emissions
Walnut Energy Center Authority	Turlock	CCCT					442		35,000 lbs per quarter and 140,00 lbs per year for both units	Includes startup and shutdown emissions
Walnut Energy Center Authority	Turlock	CCCT		`			442			

BAAQMD REGULATION 9, RULE 9:
NITROGEN OXIDES FROM STATIONARY GAS TURBINES

REGULATION 9
INORGANIC GASEOUS POLLUTANTS
RULE 9
NITROGEN OXIDES FROM STATIONARY GAS TURBINES

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REGULATION 9
INORGANIC GASEOUS POLLUTANTS
RULE 9
NITROGEN OXIDES FROM STATIONARY GAS TURBINES

(Adopted May 5, 1993)

9-9-100 GENERAL

9-9-101 Description: The purpose of this Rule is to limit emissions of nitrogen oxides (NO_x) from stationary gas turbines.

9-9-110 Exemption, Small Gas Turbines: This Rule shall not apply to stationary gas turbines with a heat input rating less than 5 MM Btu/hr.

(Amended December 6, 2006)

9-9-111 Exemption, General: The requirements of this Rule shall not apply to:

111.1 Testing of aircraft gas turbine engines for flight certification.

111.2 Gas turbines used solely for firefighting and/or flood control.

111.3 Deleted December 6, 2006

(Amended December 6, 2006)

9-9-112 Limited Exemption, Low Usage: The requirements of this Rule shall not apply to the operation of gas turbines rated less than 50 MM Btu/hr heat input that operate less than 877 hours in any 12-month period, provided the requirements of Section 9-9-502 are satisfied.

(Amended December 6, 2006)

9-9-113 Exemption, Inspection and Maintenance Periods: The emission limits of Section 9-9-301 shall not apply during inspection and maintenance periods, with the following limitations:

113.1 Inspection and maintenance periods shall be limited to a total of 48 hours between May 1 and October 31 in a calendar year.

113.2 For a calendar year in which a boiler inspection required by California Labor Code Section 7682 is not performed, inspection and maintenance periods shall be limited to a total of 144 hours.

113.3 For a calendar year in which a boiler inspection required by California Labor Code Section 7682 is performed, inspection and maintenance periods shall be limited to 144 hours plus additional time required for the boiler inspection, provided, however, that the additional time shall not cause the calendar-year total of all inspection and maintenance periods to exceed 312 hours.

(Adopted 9/21/94; Amended 12/6/06)

9-9-114 Exemption, Start-up and Shutdown Periods: The emission limits of Sections 9-9-301 and 302 shall not apply during start-up or shutdown periods.

(Adopted 9/21/94; Amended 12/6/06)

9-9-115 Limited Exemption, Minor Inspection and Maintenance Work: The requirements of Section 9-9-301 shall not apply during periods of inspection and maintenance work on a gas turbine or associated components, not to exceed 4 hours on any day and 48 hours in any 12-month period, that are planned and scheduled at least 24 hours in advance. The operator shall keep records of these planned inspection and maintenance events and make them available to the APCO on request. This exemption shall not apply to low-usage turbines subject to Section 9-9-302. Any annual emissions limit required by permit condition shall include emissions resulting from this minor inspection and maintenance work.

(Adopted December 6, 2006)

9-9-116 Limited Exemption, Very Limited Use Turbines: The emission limits in Section 9-9-302.2 shall not apply to turbines that operate less than 1200 hours between January 1, 2007 and January 1, 2010, and do not operate more than 400 hours during any 12-month period after January 1, 2010, provided the requirements in Section 9-9-502 are met. Turbines that initially qualify for this limited exemption based on the number of hours of operation between January 1, 2007 and January 1, 2010, but operate more than 400 hours per 12-month period after January 1, 2010, shall continue to comply with the emission limits in 9-9-302.2 subject to the compliance schedule set forth in Section 9-9-405. This limited exemption does not apply to the emission limits in Section 9-9-302.1.

(Adopted December 6, 2006)

9-9-120 Interchangeable Emission Reduction Credits: Until such time as the December 6, 2006 amendments to this rule are approved into the State Implementation Plan by the EPA, the emission limits of Sections 9-9-301.2 and 9-9-302.2 may be complied with by interchangeable emission reduction credits used pursuant to and as limited by the provisions of Regulation 2, Rule 9. An operator must still comply with the emission limits of Sections 9-9-301.1 and 9-9-302.1 without using interchangeable emission reduction credits.

(Adopted December 6, 2006)

9-9-200 DEFINITIONS

9-9-201 Commercially Available: Any control technology or equipment that is offered for a specific make and model of gas turbine by at least one vendor, is guaranteed by the vendor to achieve the emission control performance required by this Rule, has been demonstrated in practice at 3 or more sites, achieves the required emission control performance utilizing similar fuel composition for a regular or full-scale operation within the United States, and demonstrates at least 90% availability.

(Adopted December 6, 2006)

9-9-202 Dry Low-NO_x Combustion Technology (DLN): A turbine combustor design that uses multiple staging, air/fuel premixing or other modifications to achieve lower levels of NO_x emissions as compared to conventional combustors.

(Adopted December 6, 2006)

9-9-203 EFF: Thermal efficiency.

(Renumbered December 6, 2006)

9-9-204 Emergency Use: Operation during a natural or civil disaster or emergency situation, as requested or ordered by any federal, state or local agency to protect the public, life or property.

(Adopted December 6, 2006)

9-9-205 Essential Gas Turbine: A gas turbine that cannot be taken out of service without shutting down the process unit which it serves.

(Adopted 9/21/94; Amended, Renumbered 12/6/06)

9-9-206 Heat Input Rating: The heat input requirement (based on fuel HHV) of a gas turbine at its International Standards Organization (ISO) 3977 nameplate rated power output at standard conditions of 1 atmosphere, 15^{o} Centigrade, and 60% atmospheric humidity.

(Adopted December 6, 2006)

9-9-207 HHV: The higher heating value of fuel.

(Renumbered 9/21/94; 12/6/06)

9-9-208 LHV: The lower heating value of fuel.

(Renumbered 9/21/94; 12/6/06)

9-9-209 Inspection and Maintenance Period: A period of time during which the heat recovery steam generator associated with an essential gas turbine is taken out of service for inspection or maintenance, and during which gas turbine emissions are vented to a bypass stack rather than through the heat recovery steam generator.

(Adopted 9/21/94; Amended, Renumbered 12/6/06)

9-9-210 Natural Gas: Any mixture of gaseous hydrocarbons containing at least 80 percent methane by volume, as determined according to Standard Method ASTM D1945.

(Adopted 9/21/94; Amended, Renumbered 12/6/06)

9-9-211 Nitrogen Oxide (NO_x) Emissions: The sum of nitric oxide and nitrogen dioxide (NO_2) in the flue gas, collectively expressed as nitrogen dioxide.

(Adopted 9/21/94; Renumbered 12/6/06)

9-9-212 Non-Gaseous Fuel: Any fuel which is not a gas at 68^{o} F and one atmosphere.

(Adopted 9/21/94; Renumbered 12/6/06)

9-9-213 Power Augmentation: An increase in the gas turbine shaft output or the decrease in turbine fuel consumption by the addition of energy recovered from exhaust heat.

(Renumbered 9/21/94; 12/6/06)

9-9-214 Power Output Rating: The continuous megawatt (MW) rating or mechanical equivalent by a manufacturer for gas turbine(s) without power augmentation.

(Renumbered 9/21/94; Amended, Renumbered 12/6/06)

9-9-215 Refinery Fuel Gas: A mixture of hydrogen and gaseous hydrocarbons generated by petroleum refinery processes and used by the refinery for on-site combustion in boilers, process heaters, turbines, and other combustion equipment.

(Adopted 9/21/94; Renumbered 12/6/06)

9-9-216 Selective Catalytic Reduction (SCR): A post-combustion NO_x control technique in which a reducing agent (for example: ammonia) is used in a gas-phase reaction with oxides of nitrogen in the presence of a catalyst to convert the oxides of nitrogen into nitrogen and water.

(Renumbered 9/21/94; Amended, Renumbered 12/6/06)

9-9-217 Shutdown Period: A period of time, not to exceed two hours, during which a gas turbine is brought from normal operating power output to inactive status.

(Adopted 9/21/94; Amended, Renumbered 12/6/06)

9-9-218 Start-up Period: A period of time, not to exceed four hours (six hours for cold steam turbine starts at combined cycle facilities), during which a gas turbine is brought from inactive status to normal operating power output.

(Amended 9/21/94; Amended, Renumbered 12/6/06)

9-9-219 Stationary Gas Turbine: Any gas turbine system that is attached to a foundation and is gas and/or liquid fueled with or without power augmentation. Two or more gas turbines powering one shaft shall be treated as one unit.

(Renumbered 9/21/94; Amended, Renumbered 12/6/06)

9-9-220 Waste Gas: A mixture of hydrogen, gaseous hydrocarbons and other diluent gases generated by sewage treatment or landfill biomass and used by the facility for on-site combustion in gas turbines or other combustion equipment.

(Adopted December 6, 2006)

9-9-221 Water Injection / Steam Injection Enhancement: A retrofit design improvement to water or steam injection location, orientation, or turbine combustor or other modifications to achieve lower levels of NO_x emissions as compared to existing water or steam injection design.

(Adopted December 6, 2006)

9-9-300 STANDARDS

9-9-301 Emission Limits, General:

301.1 A person shall not operate a stationary gas turbine unless nitrogen oxides (NO_x) emission concentrations, corrected to 15 percent O_2 (dry basis), do not exceed the compliance limits listed below:

301.1.1 Gas turbines rated at 0.3 MW to less than 10.0 MW shall not exceed 42 ppmv, except that, for refinery fuel gas firing, the limit shall be 55 ppmv, and for non-gaseous fuel firing during natural gas curtailment or short testing periods, the limit shall be 65 ppmv.

301.1.2 Gas turbines rated at 10.0 MW and over, without SCR, shall not exceed 15 ppmv, except that, for non-gaseous fuel firing during natural gas curtailment or short testing periods, the limit shall be 42 ppmv.

301.1.3 Gas Turbines rated at 10.0 MW and over, with SCR, shall not exceed 9 ppmv, except that, for non-gaseous fuel firing during natural gas curtailment or short testing periods, the limit shall be 25 ppmv.

301.2 Effective January 1, 2010, a person shall not operate a stationary gas turbine unless nitrogen oxides (NO_x) emissions, corrected to 15 percent O_2 (dry basis), are less than either of the alternative compliance limits listed below for the turbine heat input rating and type of fuel burned:

Turbine Heat Input Rating	Natural Gas	Refinery Fuel Gas, Waste Gas or LPG	Non-gaseous Fuel
< 5 MM Btu/hr	Exempt	Exempt	Exempt
5 - 50 MM Btu/hr	2.12 lbs/MWhr or 42 ppmv	2.53 lbs/MWhr or 50 ppmv	3.28 lbs/MWhr or 65 ppmv

Turbine Heat Input Rating	Natural Gas	Refinery Fuel Gas, Waste Gas or LPG	Non-gaseous Fuel
> 50 – 150 MM Btu/hr - no retrofit available[(a)]	1.97 lbs/MWhr or 42 ppmv	2.34 lbs/MWhr or 50 ppmv	3.04 lbs/MWhr or 65 ppmv
> 50 – 150 MM Btu/hr - WI/SI enhancement available [(b)]	1.64 lbs/MWhr or 35 ppmv	2.34 lbs/MWhr or 50 ppmv	3.04 lbs/MWhr or 65 ppmv
> 50 – 150 MM Btu/hr - DLN technology available [(c)]	1.17 lbs/MWhr or 25 ppmv	2.34 lbs/MWhr or 50 ppmv	3.04 lbs/MWhr or 65 ppmv
> 150 – 250 MM Btu/hr	0.70 lbs/MWhr or 15 ppmv	0.70 lbs/MWhr or 15 ppmv	1.97 lbs/MWhr or 42 ppmv
> 250 – 500 MM Btu/hr	0.43 lbs/MWhr or 9 ppmv	0.43 lbs/MWhr or 9 ppmv	1.17 lbs/MWhr or 25 ppmv
> 500 MM Btu/hr	0.15 lbs/MWhr or 5 ppmv	0.26 lbs/MWhr or 9 ppmv	0.72 lbs/MWhr or 25 ppmv

(a) The emission limits on this line apply to turbines for which no Water Injection or Steam Injection enhancement or DLN combustion technology is commercially available.

(b) The emission limits on this line apply to turbines for which Water Injection or Steam Injection enhancement is commercially available.

(c) The emission limits on this line apply to turbines for which DLN combustion technology is commercially available and which have not been required to install Water Injection or Steam Injection enhancements to comply with this Section 301.2.

301.3 If a turbine burns a mixture of fuels, the turbine's NO_x emission limit shall be the highest of the limits applicable to any of the fuels in the mixture.

301.4 Violation of either of the alternative standards in Section 301.2 applicable to a particular turbine shall create a rebuttable presumption that the turbine is in violation of Section 301.2. The operator of the turbine may rebut the presumption of violation by demonstrating that the turbine is in compliance with the other alternative standard.

(Amended 9/21/94; 12/6/06)

9-9-302 Emission Limits, Low Usage:

302.1 Until January 1, 2010, or other date provided under a compliance schedule pursuant to Section 9-9-402.2, a person may operate a stationary gas turbine for up to 877 hours in any 12-month period (not counting hours of emergency use) without complying with the emission limits Section 9-9-301 as long as nitrogen oxides (NO_x) emission concentrations, corrected to 15 percent O_2 (dry basis), do not exceed 42 ppmv when firing with natural gas and 65 ppmv when firing with non-gaseous fuel, and the requirements of Section 9-9-502 are satisfied.

302.2 Effective January 1, 2010, a person may operate a stationary gas turbine rated at 50 MMBtu/hr or greater for up to 877 hours in any 12-month period (not counting hours of emergency use) without complying with the emission limits set forth in Section 9-9-301 as long as nitrogen oxides (NO_x) emissions, corrected to 15 percent O_2 (dry basis), are less than either of the of the alternative limits listed below for the turbine's heat input rating and the type of fuel burned, and the requirements of Section 9-9-502 are satisfied:

Turbine Heat Input Rating	Natural Gas	Refinery Fuel Gas, Waste Gas or LPG	Non-gaseous Fuel
< 50 MMBtu/hr	Exempt	Exempt	Exempt
50 – 150 MMBtu/hr (3 – 10 MW)	1.97 lbs/MWhr or 42 ppmv	N/A	3.04 lbs/MWhr or 65 ppmv
> 150 – 250 MMBtu/hr (10 – 19 MW)	1.97 lbs/MWhr or 42 ppmv	N/A	3.04 lbs/MWhr or 65 ppmv
> 250 – 500 MMBtu/hr (19 – 40 MW)	1.17 lbs/MWhr or 25 ppmv	N/A	1.97 lbs/MWhr or 42 ppmv
> 500 MMBtu/hr (40+ MW)	0.72 lbs/MWhr or 25 ppmv	N/A	1.21 lbs/MWhr or 42 ppmv

302.3 If a turbine burns a mixture of fuels, the turbine's NO_x emission limit shall be the highest of the limits applicable to any of the fuels in the mixture.

302.4 Violation of either of the alternative standards in Section 302.2 applicable to a particular turbine shall create a rebuttable presumption that the turbine is in violation of Section 302.2. The operator of the turbine may rebut the presumption of violation by demonstrating that the turbine is in compliance with the other alternative standard.

(Amended9/21/94; 12/6/06)

9-9-303 Deleted December 6, 2006

9-9-304 Deleted December 6, 2006

9-9-305 Deleted December 6, 2006

9-9-400 ADMINISTRATIVE REQUIREMENTS

9-9-401 Certification, Efficiency: If a person who operates a gas turbine subject to the limits of subsections 9-9-301.1.2 or 301.1.3 can demonstrate a thermal efficiency (EFF) greater than 25 percent in accordance with subsections 401.2.1 or 401.2.2, the emissions limit may be adjusted in accordance with Section 9-9-401.1.

401.1 $$Adjusted\ Emission\ Limit = \frac{Emission\ Limit \times EFF}{25}$$

401.2 EFF (percent efficiency) is the higher of 2.1 or 2.2. An EFF that is less than 25% shall be assigned a value of 25%.

2.1 $$EFF = \frac{3412 \times 100\%}{Actual\ Heat\ Rate\ at\ HHV\ of\ Fuel \times \frac{BTU}{KW - HR}}$$

which is the demonstrated percent efficiency of the gas turbine only as calculated without consideration of any downstream energy recovery (not used for power augmentation) from the actual heat rate, (BTU/KW-HR) or 1.34 (BTU/HP-HR); corrected to the HHV (higher heating value) of the fuel and standard conditions, as measured at peak load for that facility.

or

2.2 $$EFF = Manufacturer's\ Rated\ Efficiency\ * \times \frac{LHV}{HHV}$$

*With Air Pollution Equipment at LHV

which is the manufacturer's continuous rated percent efficiency of the gas turbine with air pollution equipment after correction from LHV to HHV of the fuel.

(Amended 9/21/94; 12/6/06)

9-9-402 Compliance Schedule:

402.1 A person who must modify existing sources or install new control equipment to meet the requirements of Section 9-9-301.2 or 302.2 shall submit an application for any

Authority to Construct for the modification or installation of new control equipment by July 1, 2008, or by the date required pursuant to Section 9-9-404.3.

402.2 Any turbine subject to Sections 9-9-301.2 or 9-9-302.2 shall comply with the applicable emission limits set forth in those sections by January 1, 2010, or by the date required pursuant to Section 9-9-404.3, unless the turbine has not had a scheduled major maintenance outage by January 1, 2010, in which case the turbine shall comply with the applicable emission limits 30 days after the end of the next scheduled major maintenance outage, but in no event later than January 1, 2012.

(Amended December 6, 2006)

9-9-403 Deleted December 6, 2006

9-9-404 Compliance Schedule for Future Commercial Availability of Retrofit Technology: If water injection or steam injection enhancement retrofits or Dry Low NO_x combustion technology become commercially available for a specific make and model of turbine after December 31, 2006, subjecting operators of that make and model of turbine to lower NO_x emissions limits pursuant to Section 9-9-301.2, affected operators shall comply with Section 9-9-301.2 according to the following schedule.

404.1 Upon determining that water injection or steam injection enhancement retrofits or Dry Low NO_x combustion technology are commercially available for a specific make and model of turbine, the APCO shall notify all operators of that make and model, in writing, of the commercial availability of the technology.

404.2 If any affected operator disagrees that the technology is commercially available for its turbine, as that term is defined in Section 9-9-201, the operator may object to the APCO in writing within 90 days of such notification. Within 30 days after receiving an objection, the APCO may amend the determination of commercial availability for the turbine for which the objection is made. If no objection is made for a particular turbine, or an objection is made and the APCO does not change the determination of commercial availability, the technology shall be deemed commercially available for that turbine. The APCO shall conduct a cost-effectiveness analysis prior to making a final determination of commercial availability.

404.3 Any affected operator that must install new equipment or modify its operation in a manner that requires a permit amendment in order to comply with the applicable NO_x emissions limit in Section 9-9-301.2 shall (i) submit an application for Authority to Construct to install the new equipment or modify its operation within 18 months of the date of the initial notification from the APCO of the commercial availability, and (ii) comply with the more stringent emission standards associated with the commercially available technology within 36 months of the date of the initial notification, or 30 days after the end of the next scheduled major maintenance outage if no such outage is scheduled within 36 months of the date of the initial notification, but in no event more than 60 months after the date of initial notification.

404.4 If an affected operator can comply the applicable NO_x emissions limit in Section 9-9-301.2 without having to install new equipment or modify its operation in a manner that requires a permit amendment, the operator shall (i) so inform the APCO in writing within 90 days of the date of the initial notification from the APCO of the commercial availability, and (ii) comply with the more stringent emission standards associated with the commercially available technology within 30 days thereafter.

(Adopted December 6, 2006)

9-9-405 Notification and Compliance Schedule, Very Limited Use Turbines: If a gas turbine exceeds 400 hours of operation in any 12-month period and is not compliant with the emission limits in Section 9-9-302.2, the operator must notify the APCO of that fact and must provide its best estimates for future operation of the turbine. Based on a review of these estimates, if the APCO determines that the turbine will likely continue to be operated at a rate exceeding 400 hours per 12-month period in the future, the APCO will provide written notice of that determination to the operator. If the APCO determines that the turbine will be operated at a rate exceeding 400 hours in the future, the turbine shall comply with the emission limits in Section 9-9-302.2. If the operator will have to modify existing sources or install new control equipment to meet the emission limits in Section 9-9-302.2, the operator shall submit an application for Authority to Construct the modification or installation of new control equipment within 18 months of such notification, and shall comply with the emission limits in Section 9-9-302.2 within 36 months of such notification, or 30 days after the end of the next scheduled major maintenance outage if no such outage is scheduled within 36 months of the date of the initial notification, but in no event more than 60 months after the date of initial notification. The limited exemption in Section 9-9-115 shall cease to apply if the turbine violates this compliance schedule.

(Adopted December 6, 2006)

9-9-406 Other Useful Heat Recovery: Any operator who wishes to get credit for other useful heat recovery for their gas turbines shall propose a calculation method to determine Po, as used in Section 9-9-605. This calculation method shall be subject to approval by the APCO.

(Adopted December 6, 2006)

9-9-500 MONITORING AND RECORDS

9-9-501 Monitoring and Recordkeeping Requirements: A person who operates any stationary gas turbine with a heat input rating equal to or greater than 150 MMBtu/hr for more than 4000 hours in any 36-month period shall install, operate and maintain in calibration a continuous emissions monitor (CEM), or alternative monitoring system, capable of determining exhaust gas NO_x concentrations. A CEM must meet the requirements of the District Manual of Procedures, Volume V. Any operator choosing to demonstrate compliance with Section 9-9-301.2 or 9-9-302.2 using the output-based NO_x limits expressed in lbs/MWhr must also monitor and record fuel consumption by the gas turbine and any supplemental duct burners, electrical and mechanical output from both combustion and steam turbines, any steam production flow rates and steam enthalpy. Any alternative monitoring system must be approved by the APCO. Such approval will only be granted upon a determination, pursuant to the criteria of 40 CFR Part 75, Subpart E, that the alternative monitoring system provides information with the same precision, reliability, accessibility, and timeliness as that provided by a CEM for the source.

(Amended 9/21/94; 12/6/06)

9-9-502 Records, Low Usage: A person claiming to be exempt from Section 9-9-301 based on the number of hours of turbine operation, or seeking exemption per Sections 9-9-112 or 9-9-116 of this Rule, shall maintain a daily gas turbine operating record that includes the actual start-up and stop time, total hours of operation, and type (liquid or gas) and quantity of fuel used. This information shall be available to District staff upon request for at least two years from the date of entry.

(Amended December 6, 2006)

9-9-503 Initial Demonstration of Compliance: A person who must modify existing sources or install new control equipment shall conduct a District approved source test to demonstrate compliance with 9-9-301.2 or 302.2, and submit the results to the District within two months of initial operation of the new or modified equipment.

(Amended 9/21//94; 12/6/06)

9-9-504 Annual Demonstration of Compliance: The operator of any turbine subject to this Rule that operates more than 400 hours in any 12-month period and is not equipped with a Continuous Emissions Monitor shall conduct a District-approved source test of the turbine at least once per calendar year, and at intervals not to exceed 15 months between tests, and shall submit the test results to the District within two months of the test date. The operator of any turbine that operates 400 hours or less in any 12-month period shall conduct a District-approved source test of the turbine every two calendar years, at a rate not to exceed 25 months.

(Adopted December 6, 2006)

9-9-600 MANUAL OF PROCEDURES

9-9-601 Determination of Emissions: Source tests for determining compliance with the NO_x emissions standards of this rule as specified in Sections 9-9-301 and 302 shall be conducted as prescribed in the District Manual of Procedures, Volume IV, ST-13A.

(Amended 9/21/94; 12/6/06)

9-9-602 Determination of Stack Gas Oxygen: Oxygen content of the exhaust gas shall be determined by using District Manual of Procedures, Volume IV, ST-14.

9-9-603 Continuous Emission Monitoring: Continuous Emissions Monitoring (CEM) procedures shall be determined using District Manual of Procedures, Volume V. For purposes of determining compliance with the NO_x emissions standards of this rule, NO_x emissions shall be calculated as the three hour average NO^x emissions corrected to 15 percent O_2 (dry basis). Results of source tests conducted as prescribed in the District Manual of Procedures shall be deemed to be representative of three-hour average NO_x emissions.

(Amended December 6, 2006)

9-9-604 Determination of HHV and LHV: The HHV and LHV shall be determined using 1) ASTM D240-87 or ASTM D2382-88 ASTM D4809 for liquid hydrocarbon fuel; or 2) ASTM 1826-88 or ASTM 1945-81 in conjunction with ASTM D3588-89 for gaseous fuels.

(Amended December 6, 2006)

9-9-605 Compliance With Output Based NO_x Emissions Standards: For purposes of complying with the emissions standards in Section 9-9-301.2 and 9-9-302.2, emission rates expressed in lbs/MWhr shall be calculated in accordance with the following equations:

$$E = \frac{1.194X10^{-7} * (NOx)_c * Q_{std}}{(Pe)_t + (Pe)_c + Ps + Po}$$

E = hourly NOx emission rate, in lb/MWh
$(NO_x)_c$ = Average NO_x concentration, in ppmv adjusted to 15% O2
Q_{std} – stack gas volumetric flow rate, in dry scf/hr
$(Pe)_t$ = electrical or mechanical energy output of the combustion turbine in MW
$(Pe)_c$ = Electrical or mechanical energy output of the steam turbine (if any) in MW
Ps = useful thermal energy of steam production
Po = other useful heat recovery.

$$Ps = \frac{Q * H}{3.413X10^{6}\, Btu / MWh}$$

Q = measured steam flowrate in lb/hr.
H = enthalpy of the steam at measured temperature and pressure in Btu/lb.

(Adopted December 6, 2006)

E. New Solid-Fuel Biomass Facility

This section describes the detailed analysis for diesel truck emissions associated with a new solid-fuel biomass facility. Table D3-6 shows emission factors for the 2020 diesel truck fleet[1].

Table D3-6
Emission Factors for Diesel Trucks in 2020

Emission Factors (g/mile)				
ROG	**NO_x**	**SO_x**	**CO**	**$PM_{2.5}$**
0.52	7.86	0.18	3.32	0.22

Source: ARB, Proposed Regulation to Implement the Low Carbon Fuel Standard, March 5, 2009, Vol. II, Table F4-2, p. F-28.

Staff assumed a 20 ton truck capacity, 80 miles round trip to deliver feedstocks to the facility, and 10 MWh electricity generation per truck load of feedstock (see Table D1-2). Based on the truck emission factors from Table D3-6 and the assumptions from Table D1-2, Table D3-7 shows the truck emission estimates for a new solid-fuel biomass facility with 50 MW capacity, generating 425 GWh per year (i.e., 97 percent capacity factor). Each column of the table shows every step of the calculations. For example, in the Emissions per Truck Trip column [c] is the product of the Emission Factors [a] and the Round Trip Distance [b].

Table D3-7
Total Diesel Truck Emission Estimates
Supplying Solid-Fuel Biomass Facility (50 MW Capacity)

	Emission Factors (g/mi)	Round Trip Distance (miles)	Emissions per Truck Trip (g)	Power Generation per Truck Load of Feedstocks (MWh)	Emission Factors (g/MWh)	Power Generation (MWh/yr)	Total Emissions (g/yr)	Total Emissions (tons/yr)
Pollutants	**[a]**	**[b]**	**[c]=[a]x[b]**	**[d]**	**[e]=[c]/[d]**	**[f]**	**[g]=[e]x[f]**	**[i]=[g]/(1.102×10^6)**
ROG	0.52	80	41.6	10	4.16	425,000	1,822,080	2
NO_x	7.86	80	628.8	10	62.88	425,000	27,541,440	30
SOx	0.18	80	14.4	10	1.44	425,000	630,720	1
CO	3.32	80	265.6	10	26.56	425,000	11,633,280	13
$PM_{2.5}$	0.22	80	17.6	10	1.76	425,000	770,880	1

REFERENCES

[1] ARB, 2009. Proposed Regulation to Implement the Low Carbon Fuel Standard, Volume II: Appendices (Table F4-2, page F-28), http://www.arb.ca.gov/regact/2009/lcfs09/lcfsisor2.pdf

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