DRAFT CONSULTANT REPORT

SMALL-SCALE BIOENERGY: RESOURCE POTENTIAL, COSTS, AND FEED-IN TARIFF IMPLEMENTATION ASSESSMENT

PREPARED FOR

California Public Utilities Commission

9 APRIL 2013

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1.0 Executive Summary

KEY FINDINGS

- **Lack of a Robust Existing Market May Delay Project Starts.** Few SB 1122 eligible projects have passed the ReMAT (Renewable Market Adjusting-Tariff) eligibility screens (only seven are estimated to be in the interconnection queues of the utilities). As a result, it appears that a very limited number of small-scale bioenergy generators could take advantage of the market-based pricing mechanism recently adopted by the CPUC for the feed-in tariff program. Given these factors, there may be a delay of three years or more from tariff implementation to project completions. Modifications to the ReMAT mechanism or eligibility rules may accelerate this schedule by more quickly leading to a higher tariff, but the time required for development, permitting, and interconnection must also accelerate.
- **Disproportionate Resource Availability.** Approximately 1,000 MW of SB 1122 eligible resources are available in the utility service territories, four times what is required by the statute. However, these resources are located disproportionate to load, with PG&E having more than 70 percent and SDG&E less than three percent. This may create compliance issues for SDG&E, since SB 1122's procurement requirements are based on load. As a consequence of this disproportionate resource availability, allocating the statutory capacity targets across utilities will be challenging.
- **Potential for High Costs to Meet Statutory Targets.** The cost of generation can vary considerably among bioenergy technologies, but is likely to average $120 to 185/MWh for a blended rate. This would be higher than recent costs seen in the Renewable Auction Mechanism (RAM) and large scale renewable solicitations. Incentives, strategic placement of projects, and coproduct values may help to lower the cost. This price reflects delivered cost to the utility, but does not reflect the full range of potential value that small scale bioenergy brings to the state.
- **Modification of the Statute May Reduce Costs and Improve Equity.** Removal of the Section 399.20 statutory requirement that feed-in tariff projects must be located in the service territory of the procuring utility and modification of the utility procurement requirements to better reflect resource availability (rather than by share of peak load, as currently in statute) may lower costs to ratepayers, be more equitable between utilities, reduce market manipulation, and be less administratively burdensome.
- **Feedstock Classification.** Clarification is needed for what classifies as "sustainable forest management material" pursuant to SB 1122. Separately, clarification is also needed for how to classify projects seeking to use multiple feedstock types, and how to verify that a generator continues utilizing the same feedstock for which it signed a ReMAT contract.

1.1 SCOPE OF WORK

Senate Bill (SB) 1122 directed the California Public Utilities Commission (CPUC) to establish a standard tariff for at least 250 megawatts (MW) of bioenergy projects with nameplate capacities of 3 MW or smaller in three feedstock categories:

- **Category 1:** Biogas from wastewater plants and green waste (110 MW)
- **Category 2:** Dairy and other agricultural bioenergy (90 MW)
- **Category 3:** Bioenergy from sustainable forest management material in fire threat treatment areas (50 MW)

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The tariff is available to projects that commence operations after 1 June 2013. The three large investor-owned utilities (IOUs) – Pacific Gas & Electric, Southern California Edison, and San Diego Gas & Electric – in California must comply with the procurement targets based on their proportionate share of statewide peak demand. The CPUC and other state agencies have the flexibility to determine if the allocation of the 250 MW by resource is appropriate or if it should be modified.

As part of its continuing work with the CPUC on renewable distributed generation (DG), Black & Veatch was retained by the CPUC to assist with implementation of SB 1122. The intent of this analysis is to determine the likely availability of resources and projected cost of electricity for projects eligible for the SB 1122 tariff. Implementation issues to be resolved prior to tariff availability and allocation options are also considered.

Future areas of evaluation may include identifying and quantifying the full range of benefits and costs from the use of distributed bioenergy. These may include items such as avoided capacity, energy, transmission and distribution costs, as well as reduced GHG emissions, line losses, and load impacts relative to a base scenario. Additional impacts specific to bioenergy, such as criteria pollutant changes, reduction in open burning, reduced high intensity forest fire threat, landfill diversion, CHP benefits, and methane capture may also merit further analysis.

1.2 APPROACH AND METHODOLOGY

Estimates were made for the magnitude of the resources available for SB 1122 compliance. Technical availability[1] in both dry tons per year and equivalent MW of power generation were estimated for the following resources:

- **Category 1**
  - Wastewater Treatment Plant (WWTP) Biogas
  - Low Solids Green Waste Biogas (food waste, leaves and grass, and fats, oils, and grease (FOG))[2]
- **Category 2**
  - Dairy Cattle Manure Biogas
  - Agricultural Residues and High Solids Food Waste Biomass

[1] "Technical availability" refers to material deemed possible for collection and use in a bioenergy facility, taking into account environmental concerns, topography and collection efficiencies, material needed for soil fertility and erosion control, and other factors. For these reasons, the availability estimates are lower than the gross or full potential in the state.

[2] Separation of high and low solids green wastes was required due to wording in SB 1122 and differences in how each material would be converted to power. Wetter, low solids materials (up to roughly 40 percent solids) are suitable for biogas production through anaerobic digestion, while high solids material would be combusted or gasified. Leaves and grass are assumed to be part of the municipal organic waste diversion for biogas allocation, while drier, high solids food waste such as nut shells are categorized as agricultural bioenergy.

- **Category 3**
    - Sustainable Forest Management Byproducts

Publicly available, peer reviewed datasets were the basis for the majority of the resource assessments. The goal was to capture the magnitude of the resources available and allocation by utility service territory. This assessment is not intended to reflect all potential resources that could be used for SB 1122 compliance.

To estimate the energy generation potential, assumptions for feedstock quality and operational performance of commercially available anaerobic digestion and biomass gasification units coupled with internal combustion (IC) engines were used.[3] Estimates were then created for the levelized cost of electricity (LCOE) needed to support SB 1122 projects based on low, medium, and high capital and operating cost assumptions. These assumptions were entered into a financial pro forma to estimate the LCOE. The intent of the LCOE estimates are to bracket the range of likely SB 1122 project costs, and are not intended to reflect any particular project. LCOEs will vary considerably based on site specific development requirements, feedstock costs, coproduct values, and available incentives.

1.3 RESULTS

1.3.1 Resource Potential

Table 1-1 provides an estimate of SB 1122 potential by resource and within each utility service territory.

Table 1-1 Utility Resource Technical Potential, MW

UTILITY	CATEGORY 1: WWTP AND GREEN WASTE BIOGAS (MW)	CATEGORY 2: DAIRY AND AG. BIOENERGY (MW)	CATEGORY 3: FOREST (MW)	TOTAL POTENTIAL	SB 1122 TARGET
PG&E	101	340	277	718	109
SCE	115	118	15	249	118
SDG&E	26	1	2	29	23
Total Potential	**241**	**460**	**295**	**996**	**250**
SB 1122 Target	110	90	50	250	

[3] While a range of technologies could be used to convert these resources to power, the most commercially available, lowest cost technologies that could feasibly be permitted in California were chosen.

From a resource perspective, this estimate indicates that there is roughly four times more total material technically available to meet SB 1122 requirements when compared to the requirements of the statute. Dairy/agricultural residues have the largest availability with biogas from WWTPs and green waste the lowest. Forest material is most abundant in Northern California and lower than other statewide assessments due to the exclusion of material from shrubland. While shrub biomass is an eligible resource and in significant fire threat areas, cost, resource collection issues, and potential technical challenges in utilizing this material have led to it rarely being used. This analysis is intended to capture the current magnitude of the resources available by applying reasonable discounts to the gross statewide potential. Changes in waste and land management practices,[4] resource competition, industry regulations, market economics, recovery efficiencies, and policy shifts could all impact these estimates.

If only material in each utility's service territory is used to meet SB 1122 requirements, PG&E would have by far the most feedstock availability. PG&E will need to procure approximately 109 MW to meet its SB 1122 procurement requirement; roughly seven times this level of feedstock is available in its service territory. SCE has roughly twice as much feedstock available relative to its SB 1122 procurement requirement (118 MW), while SDG&E has barely enough technically available feedstock to meet its requirement (23 MW).

Using load shape data at IOU substations developed as part of the renewable DG technical potential analysis being performed at the CPUC, over 11,000 MW of low-cost interconnection potential is estimated to exist throughout the IOU service territories. However, many types of bioenergy resources are located in rural areas, which may not have as much transmission availability as urban areas with more robust grids. In comparing county wide transmission and bioenergy resource availability, the areas most likely to face interconnection challenges are in PG&E's service territory. Specifically, projects in the far northern section of PG&E's territory (namely Humboldt, Mendocino, Glenn, Plumas, and Sierra counties) may have the greatest issues, while interconnection in some Central Valley locations may also face challenges. The ability of many bioenergy projects to move to more strategic interconnection locations should help mitigate some of the transmission issues.

1.3.2 Cost of Generation

Estimates of the LCOEs for each of the feedstock types can be seen in Table 1-2 and Figure 1-1. A proxy project size is used for each feedstock based on what was considered reasonable for development. No financial incentives and limited coproduct values are assumed in the economic model. It is assumed that forest and agricultural residue projects pay for feedstock (average $30/dry ton) while green waste projects receive a tipping fee (average $20/dry ton). Unique factors that could greatly influence the project cost are also listed.

[4] Including both federal and state land management practices.

Table 1-2 SB 1122 LCOE Summary by Feedstock Type, $/MWh

RESOURCE AND SIZE	LOW ESTIMATE	MED. ESTIMATE	HIGH ESTIMATE	UNIQUE COST FACTORS
Category 1				
WWTP, New Digestion (0.3 MW)	448	591	709	Requirements to add digestion, solids disposal costs, size, digester type, fertilizer value
WWTP, Existing Digestion (0.3 MW)	148	190	233	Size, gas cleaning and infrastructure requirements
Low Solids Green Waste (3 MW)	80	139	204	Tipping fee, coproduct value, digester type
Category 2				
Dairy Cattle Manure (1 MW)	211	278	334	Solids disposal costs, fertilizer value, AB32 credits, codigestion, digester type
Agricultural Residues (3 MW)	134	199	251	Interconnection cost, coproduct value, fuel costs, cogeneration applications
Category 3				
Forest Material (3 MW)	134	199	251	Interconnection cost, coproduct value, fuel costs, cogeneration applications
Generic project estimates not taking into account incentives or coproduct values/disposal costs, with the exception of steam from anaerobic digestion for digester heating.				

Figure 1-1 shows the above data graphically, with comparisons to the range of costs recently seen for projects with executed PPAs from recent Renewable Auction Mechanism (RAM) and large-scale renewable solicitations. Without incentives or value for the coproducts, the required LCOE for most SB 1122 compliant projects will be higher. However, if SB 1122 projects are able to take advantage of some of the currently available incentives and/or obtain value for their coproducts, the LCOEs for some resources may become more comparable to the range of prices recently seen in other solicitations. However, given the lack of an existing market for small-scale bioenergy generators and the range of unique incentive scenarios possible in the state, analysis of the true value that a combination of incentives and coproduct values may deliver can only be performed on a project specific basis. More detail on incentives is provided in the Appendix.

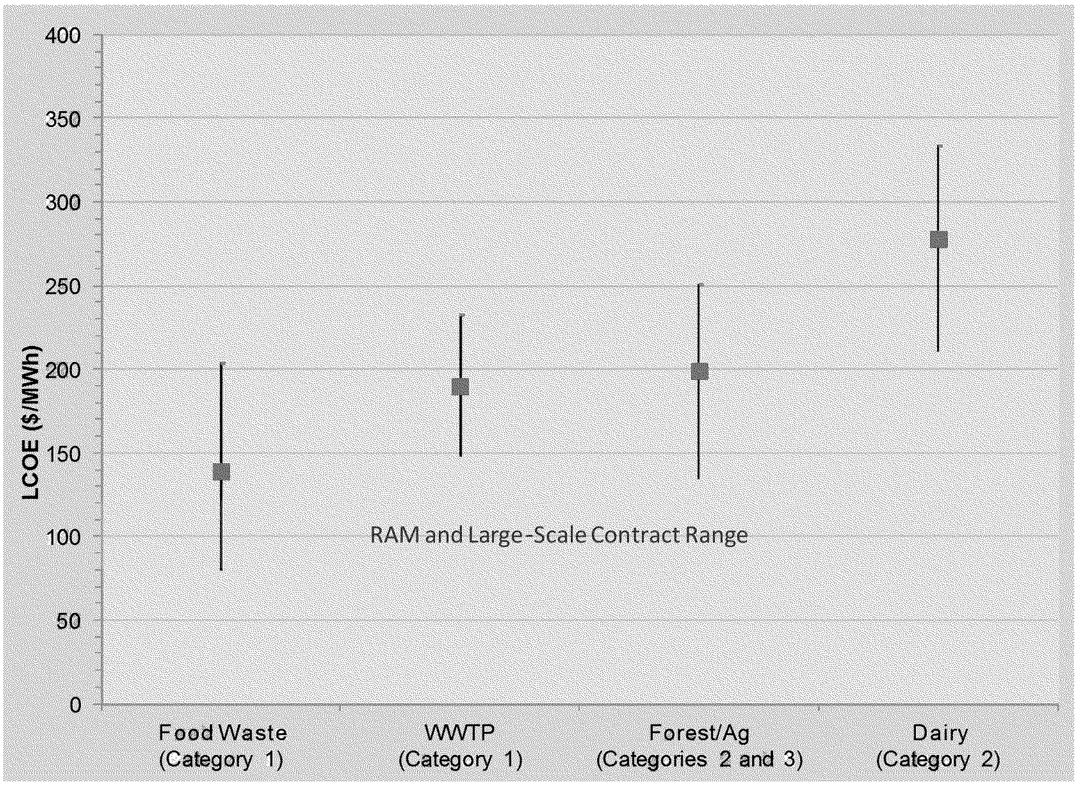


Figure 1-1 SB 1122 LCOE Range, No Incentives

SB 1122 eligible projects that can receive a fee for their feedstock (green waste anaerobic digestion) or that have a readily available resource (WWTPs with existing digesters) will have the lowest LCOEs. However, the number of economically feasible, SB 1122-eligible WWTPs is very small (roughly 4 MW). The lower gas yield and lack of a tipping fee for dairy manure digestion relative to green waste digesters leads to a higher LCOE. Unlike food waste digestion projects, dairy manure digesters are eligible for AB 32 greenhouse gas offset credits (not reflected above), which may add an additional revenue stream in the future.

Forest and agricultural residue projects may also be able to obtain revenue through the marketing of coproducts such as heat and biochar. These projects are sensitive to changes in feedstock price. If feedstock was free, LCOEs would drop by 15 to 20 percent; conversely, if the feedstock cost in the base case rises to $40 per dry ton, this would increase the LCOE by roughly $10/MWh.

1.3.3 Implementation Challenges

A range of technical and procedural issues must be addressed to be able to implement projects that use the SB 1122 tariff. While the use of certain types of anaerobic digestion technology and IC engines for power generation is proven for many feedstocks in this size range, other types of technologies are less proven, namely "dry" digestion (up to roughly 40 percent solids) and small scale biomass gasification. There is likely to be an operational learning curve until greater experience is gained on these units in California.

Since SB 1122 was codified within §399.20 of the Public Utilities Code, the code section which authorizes California's existing renewable FIT program, the ReMAT pricing mechanism will be used to set the price for SB 1122 projects. The ReMAT is a market-based pricing mechanism designed to allow a competitive market by adjusting the offered tariff payment rate based on the level of demand. Given the lack of an existing market for small-scale bioenergy generators in California however, several issues with the ReMAT pricing mechanism may be a concern for SB 1122 use:

- **Development Experience:** Meeting this screen will depend on how the definition of "similar technology/project" is applied. More anaerobic digestion project developers would be able to meet this criterion relative to developers wanting to use small scale biomass gasification.
- **Tariff Level and Ramp Rate:** Under the ReMAT pricing mechanism as currently structured, the tariff rate is initially set at $89.23/MWh. The tariff adjusts every two months based on a rate defined by the CPUC, provided at least five projects have passed the eligibility screens and entered the queue. Given the limited amount of eligible project development and the challenges in meeting the other screens, there may be a delay in the tariff ramp until five eligible projects have entered the queue. Even after the ramp begins, it may be some time until the rate provides sufficient economic incentive based on the LCOE estimates projected in this study.
- **Interconnection Screen:** Updated information shows only seven SB 1122 eligible projects currently in the IOU's interconnection queues, meaning few projects would currently pass this screen. In addition, the five projects in PG&E's current interconnection queue have very high interconnection costs (ranging from $858,000 to $2.6MM) which may not meet the definition of a "strategically located" project.

Assuming that a set of new projects will need to pass the interconnection screen before the ReMAT adjustment period can begin, it is estimated that it will take approximately 33 months for new SB 1122 eligible projects to begin operation under the current structure, assuming that a tariff rate of roughly $150/MWh is needed, as shown in Figure 1-2.

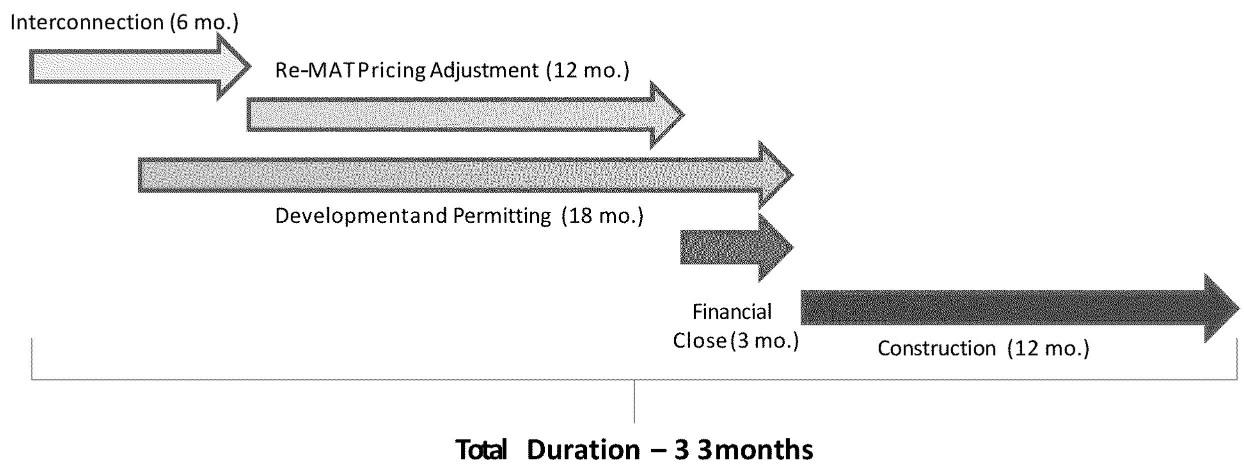


Figure 1-2 Generic Project Development Timeline

Modifications to the ReMAT pricing mechanism could be considered to allow SB 1122 projects to become operational more quickly, while additional modifications could then be considered to potentially limit the costs to ratepayers. Options include the following:

- Faster tariff ramp or larger price step changes
- Starting the tariff ramp with less than five eligible projects in the queue
- Accept international experience during the development experience evaluation
- Consider a seller concentration limit
- Price caps

The statutory language authorized by SB 1122 requires significant interpretation by the CPUC during its implementation process prior to the SB 1122 tariff being offered. Some of the issues initially identified as potentially requiring CPUC interpretation are listed below:

- Definition of "sustainable forest management"
- Classification of projects that use multiple feedstocks
- Definition of "commence operation"
- Feedstock definitions and eligibility of out of state feedstocks
- Verification of feedstock after operation commences

1.3.4 Options for Allocating SB 1122 Resource Targets by Utility

Since resource specific procurement targets are required by SB 1122, different tariffs and resource goals by utility will need to be defined by the CPUC in its implementation of the statute. Three main compliance options are considered here for establishing resource allocation targets by utility:

- **Option 1:** Proportional by peak load
- **Option 2:** Proportional allocation by resource availability
- **Option 3:** Allocation by resource availability, modified for market competition factors

A summary of the procurement targets, resource availability, projected cost ranges, and yearly compliance costs for each utility in Options 1 and 2 can be seen in Table 1-3 and Table 1-4. Proposed procurement targets for each utility by resource type are shown, along with the resource potential estimates (in parenthesis). Option 1 will likely be impractical given the limited amount of forest material in SCE and SDG&E service territory (if shrublands are excluded), as well as a lack of available dairy/agricultural material for SDG&E. Each of these utilities would likely need to transport material from distant locations to locally developed projects, increasing the delivered cost of energy to ratepayers. This is reflected in the higher compliance cost (annual net expenditure) estimates with this option.

Table 1-3 Utility Resource Targets and Projected Costs, Proportional by Load

UTILITY	CATEGORY 1: WWTP AND GREEN WASTE BIOGAS (MW)	CATEGORY 2: DAIRY AND AG. BIOENERGY (MW)	CATEGORY 3: FOREST (MW)	ESTIMATED BLENDED COST RANGE ($/MWH)	NET EXPENDITURE PER YEAR ($MM)
PG&E	48 *(101)*	39 *(340)*	22 *(277)*	110-170	95-148
SCE	52 *(115)*	43 *(118)*	24 *(15)*	130-190	124-180
SDG&E	10 *(26)*	8 *(1)*	4 *(2)*	145-200	27-37
Procurement Totals	110	90	50		245-365
Targets for each utility and resource are shown, along with the estimated service area potential in parenthesis.					

A second option is to assign targets based on the availability of resources in each service territory. To do this, the resource percentages in each service territory were calculated, and then the utility procurement target was multiplied by this percentage. Note that while this will assure that each utility capacity target is met, it will change the net allocation by resource type.

Table 1-4 Utility Resource Targets and Projected Costs, by Resource Availability

UTILITY	CATEGORY 1: WWTP AND GREEN WASTE BIOGAS (MW)	CATEGORY 2: DAIRY AND AG. BIOENERGY (MW)	CATEGORY 3: FOREST (MW)	ESTIMATED BLENDED COST RANGE ($/MWH)	NET EXPENDITURE PER YEAR ($MM)
PG&E	15 *(101)*	52 *(340)*	42 *(277)*	125-190	109-164
SCE	55 *(115)*	56 *(118)*	7 *(15)*	120-185	114-172
SDG&E	20 *(26)*	1 *(1)*	2 *(2)*	145-210	27-38
Procurement Totals	90	109	51	--	249-374
Targets for each utility and resource are shown, along with the estimated service area potential in parenthesis.					

Under the current statute, Option 2 meets all requirements and takes into account local resource availability but would require a resource reallocation which could delay tariff implementation.[5] Compliance costs for PG&E may be more expensive than Option 1 due to more agricultural and forest residues, while SCE costs have decreased slightly due to the use of less forest residue. A hybrid option (Option 3) would be to use Option 2 as a starting point for utilities that are resource constrained, and then reallocate the remaining resources so that the original targets are preserved. In this scenario, SDG&E's targets from Option 2 could first be maintained, with further allocation by resource availability and cost. This option could also eliminate the procurement requirement for some resources within SDG&E and SCE's service territory due to lack of local availability. Taking these steps may reduce the administrative burden of having to establish a separate process for the procurement of very few megawatts in one particular category. However, even if SDG&E was to focus solely on WWTPs and green wastes within the county, it may still be challenge to meet SB 1122 procurement goals given the resource limitations.

There are a number of other options available for resource allocation, but most would require a change in the net allocation by resource or utility. An option currently prohibited by statute that would result in the most equitable sharing of costs by ratepayers across utilities would be to allow the utilities to procure energy from projects located in any of the three IOU service territories. Resource targets then could be based on total statewide potential, with allocation by utility still performed on a percent of peak load basis. This type of allocation would allow greater flexibility in project selection and reduce market power implications for resources that may attract little

[5] Any reallocation of the resource targets must be done by the CPUC in consultation with the California Energy Commission, the California Air Resources Board, CAL FIRE, Department of Food and Agriculture, and CalRecycle.

competition. Administratively, allowing the freedom to select projects regardless of service territory would make policy implementation easier. While the FIT under SB 32 has similar service territory constraints, most of the SB 32 projects likely to be approved are solar PV which is far less resource constrained by service territory when compared to bioenergy.

2.0 SB 1122 Background

SB 1122 (Rubio), signed into law by Governor Brown on 27 September 2012, directed the CPUC to establish a new feed-in tariff (FIT) specific to bioenergy. The bill outlined specific requirements for project and resource eligibility, allocation by feedstock type, tariff structure, and utility obligations. This section provides background on the legislation and the intent of this report's analysis.

2.1 REQUIREMENTS

A summary of the bill's requirements, as defined by the statute itself, is provided below[6]:

> *This bill would require the commission…to direct the electrical corporations to collectively procure at least 250 megawatts of cumulative rated generating capacity from developers of bioenergy projects that commence operation on or after June 1, 2013. The bill would require the commission, for each electrical corporation, to allocate shares of the additional 250 megawatts based on the ratio of each electrical corporation's peak demand compared to the total statewide peak demand. The bill would require the commission to allocate those 250 megawatts to electrical corporations from specified categories of bioenergy project types, with specified portions of that 250 megawatts to be allocated from each category. The bill would authorize the commission, in consultation with specified state agencies, if it finds that the allocations of those 250 megawatts are not appropriate, to reallocate those 250 megawatts among those categories.*

The three categories of bioenergy defined in the bill and their allocations under SB 1122 are:

- **Category 1:** For biogas from wastewater treatment, municipal organic waste diversion, food processing, and codigestion, 110 MW
- **Category 2:** For dairy and other agricultural bioenergy, 90 MW
- **Category 3:** For bioenergy using byproducts of sustainable forest management, 50 MW. Allocations under this category shall be determined based on the proportion of bioenergy that sustainable forest management providers derive from sustainable forest management in fire threat treatment areas, as designated by the Department of Forestry and Fire Protection.

2.2 STUDY INTENT

Black & Veatch was retained by the CPUC to support timely implementation of SB 1122. The intent of this report's analysis is to determine the likely availabiliy of resources, projected costs for compliance, barriers to implementation, and resource allocation options. Estimating the likely resource potential will help determine if the allocation of the 250 MW by resource is appropriate or if it needs to be modified per the instructions in §399.20(f)(3)(B). In addition, the allocation by

[6] Full bill information is available at http://leginfo.legislature.ca.gov/faces/billTextClient.xhtml;jsessionid=cd36e5138d18004eeb1fc4f367a0?bill_id=201120120SB1122

utility is based on the ratio of peak demand to total statewide peak demand (§399.20(f)(2)), not the availability of bioenergy resources in a particular service territory. Identifying suitable resources by service territory will help determine if a utility may face challenges meeting its obligation and if more flexible measures may be warranted. Estimates of levelized cost will provide insight into the amount of participation that may be expected if a tariff level is developed through the ReMAT mechanism and pricing levels that may be required to meet the statutory procurement obligations in each category. Finally, potential challenges with policy implementation, project development, and use of the ReMAT pricing mechanism are also discussed.

2.3 STUDY LIMITATIONS

This analysis is intended to be a high level analysis of the resource availability and costs to comply with SB 1122. It is not intended to capture all potential resources that could be used for SB 1122 compliance. Rather, the goal was to use public datasets that have been peer reviewed to capture a general understanding of the magnitude of the resources available and the allocation by utility service territory. Cost estimates reflect a generic plant that may be located in California and do not take into account the variability of available coproduct values, incentives, interconnection costs, and technology options.

3.0 Resource Quantification

The initial task was to provide an estimate for the magnitude of the resource available for SB 1122 compliance. Availability in both dry tons per year and equivalent MW of power generation in California were estimated for the following resources:

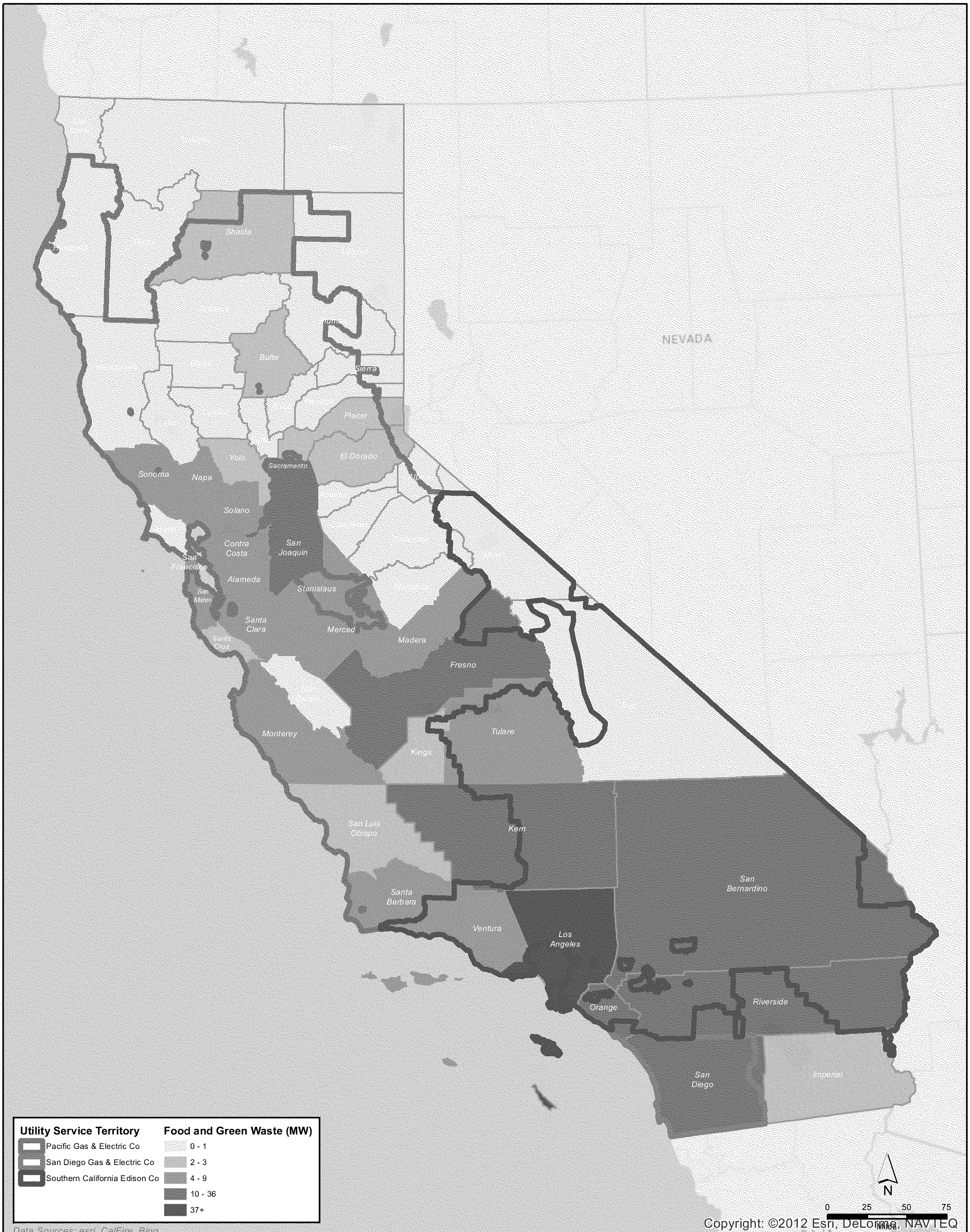
- **Category 1**
  - Wastewater Treatment Plant (WWTP) Biogas
  - Low Solids Green Waste Biogas (food waste, leaves and grass, and FOG)
- **Category 2**
  - Dairy Cattle Manure Biogas
  - Agricultural Residues and High Solids Food Waste Biomass
- **Category 3**
  - Sustainable Forest Management Byproducts

The methodology to quantifying each resource can be seen in Appendix A. This section outlines the results by county and IOU service territory.

3.1 TECHNICAL POTENTIAL

Using the assumptions in Appendix A, Black & Veatch identified just under 1,200 MW of statewide SB 1122 resource potential, with 996 MW of resources located within the IOU service territories. The resource potential in MW by county and by utility service territory is shown on the maps below. Tables are provided in Appendix B for green waste, dairy manure, forest material, and agricultural residues by county both in MW and dry tons/year.

Figure 3-1 Green Waste Bioenergy Potential (Category 1)



CPUC Food & Green Waste Bioenergy Potential

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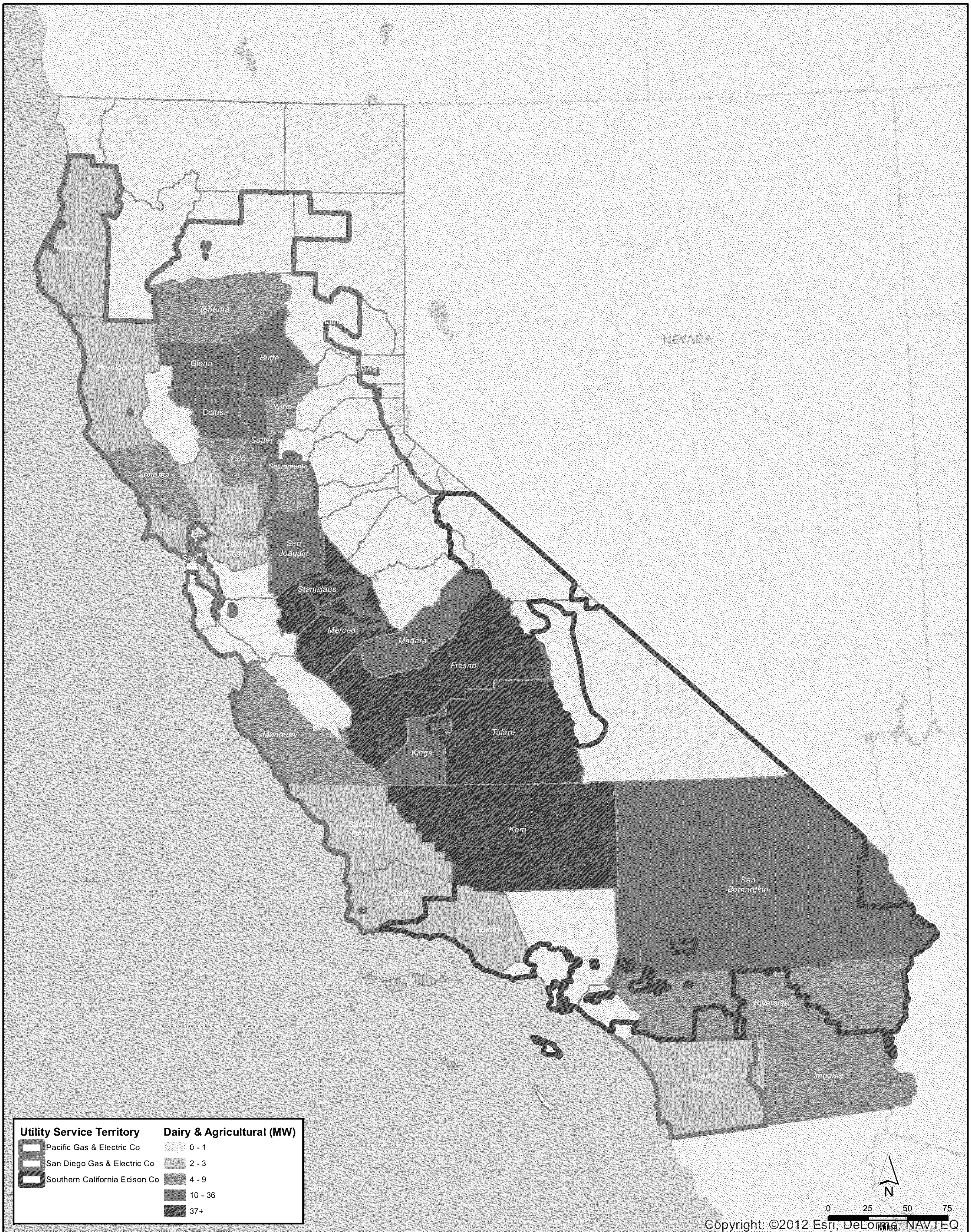
CPUC Food and Green Waste Bioenergy Potential V2.mxd | C.Holmgren | 01/02/2013

Figure 3-2 Dairy and Agricultural Bioenergy Potential (Category 2)



CPUC Dairy & Agricultural Bioenergy Potential

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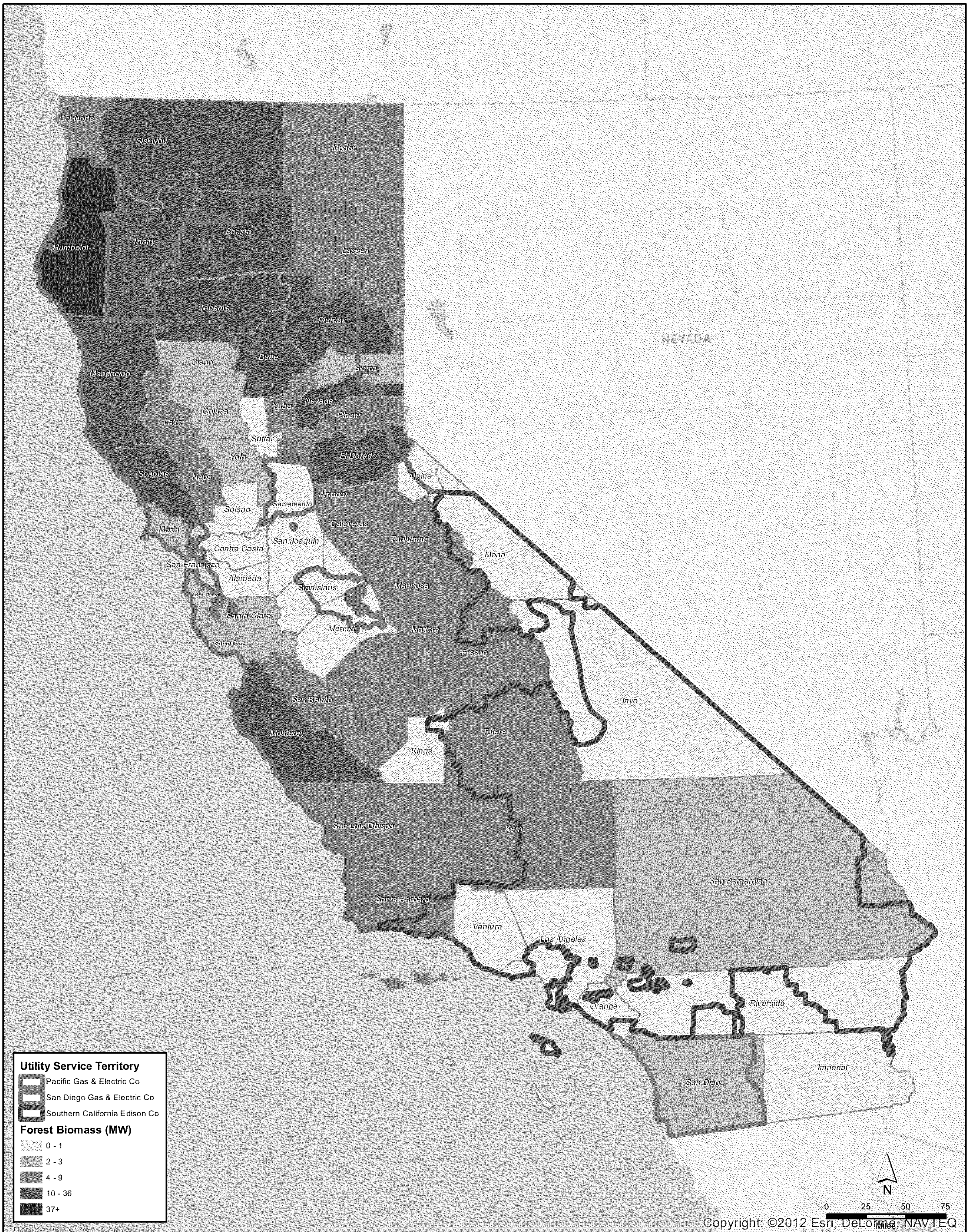
CPUC Dairy and Ag Bioenergy Potential V2.mxd | C.Holmgren | 02/06/2013

Figure 3-3 Forest Bioenergy Potential (Category 3)



CPUC Forest Resource Potential

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CPUC Forest Residue.mxd | C.Holmgren | 01/03/2013

Approximately 4 MW of WWTP biogas potential that would be SB 1122 compliant was identified as shown in Appendix B. Since most large WWTPs already possess an anaerobic digestion system and are using their biogas, this greatly limits the resource available for the SB 1122 tariff. The two largest WWTPs on the list (Martinez and Palo Alto) are currently burning their biosolids; converting to anaerobic digestion would be a major change in operation.

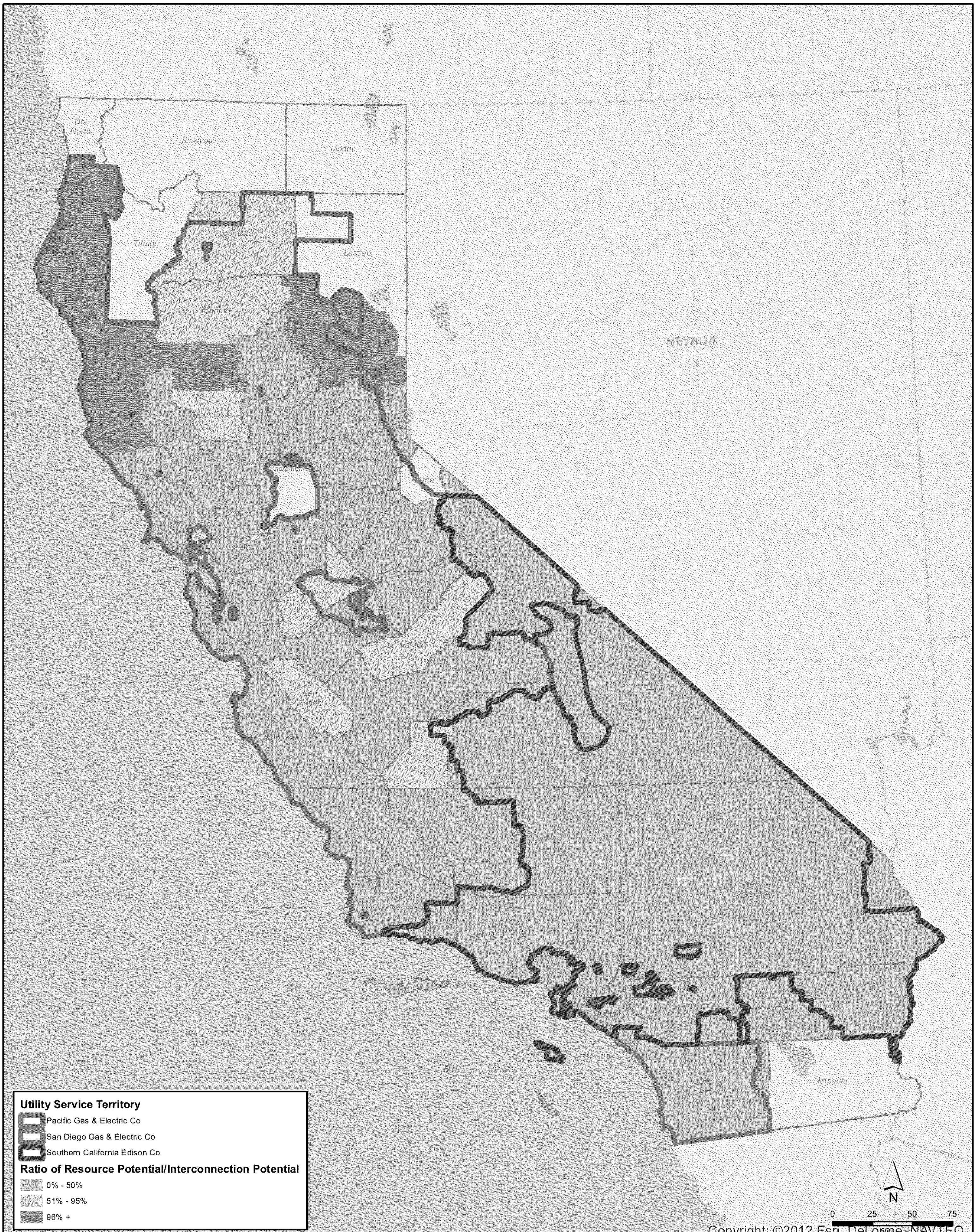
3.2 TRANSMISSION AVAILABILITY

Cost and availability of transmission are issues that have been raised by small bioenergy projects looking to interconnect to the grid and export power. Many types of bioenergy resources are located in rural areas, which may have less transmission availability compared to urban areas with more robust grids. However, unlike wind and solar resources, most bioenergy resources are transportable and can be moved to better locations for interconnection.

To determine the counties where interconnection may present a challenge, Black & Veatch worked with Energy + Environmental Economics (E3) to compare substation transmission availability to bioenergy resource availability. Counties that have significantly greater transmission availability compared to the resource potential should, in general, face fewer burdens to SB 1122 project interconnection. E3 began by using 2010 load shape data at IOU substations developed as part of the renewable DG technical potential analysis being performed at the CPUC. To estimate the interconnection potential available without significant upgrades, the minimum substation load at each location was calculated to determine the maximum feasible interconnection without backflow that can occur. The county specific resource estimates were divided by the estimates for IOU low-cost interconnection potential to provide a relative understanding of the locations that may face the greatest interconnection constraints. Figure 3-4 shows the results of this analysis. Counties with a resource to low-cost transmission potential ratio of 0.5 or lower are shown in green, 0.5 to 0.95 are yellow, and greater than 0.95 are red. These categories are arbitrary and should be used for understanding relative difficulties; they do not mean that siting a project in a yellow or red county will be infeasible, or that there will be no issues in siting a program in a green county.

From the analysis in Figure 3-4, interconnection challenges are most likely to be faced in PG&E's service territory. Specifically, projects in the far northern section of PG&E's territory (namely Humboldt, Mendocino, Glenn, Plumas, and Sierra counties) may have the greatest issues, while interconnection in some Central Valley locations may also face challenges. Figure 3-5 through Figure 3-7 show detail for the forest resource locations and current substation interconnection capacities to provide insight for where constraints may exist in Humboldt, Plumas, and Mendocino counties. Forest resource provides the vast majority of the biomass potential in these counties which were identified as potentially being transmission constrained.

Figure 3-4 Interconnection and Resource Availability Comparison



CPUC Interconnection and Resource Availability Comparison

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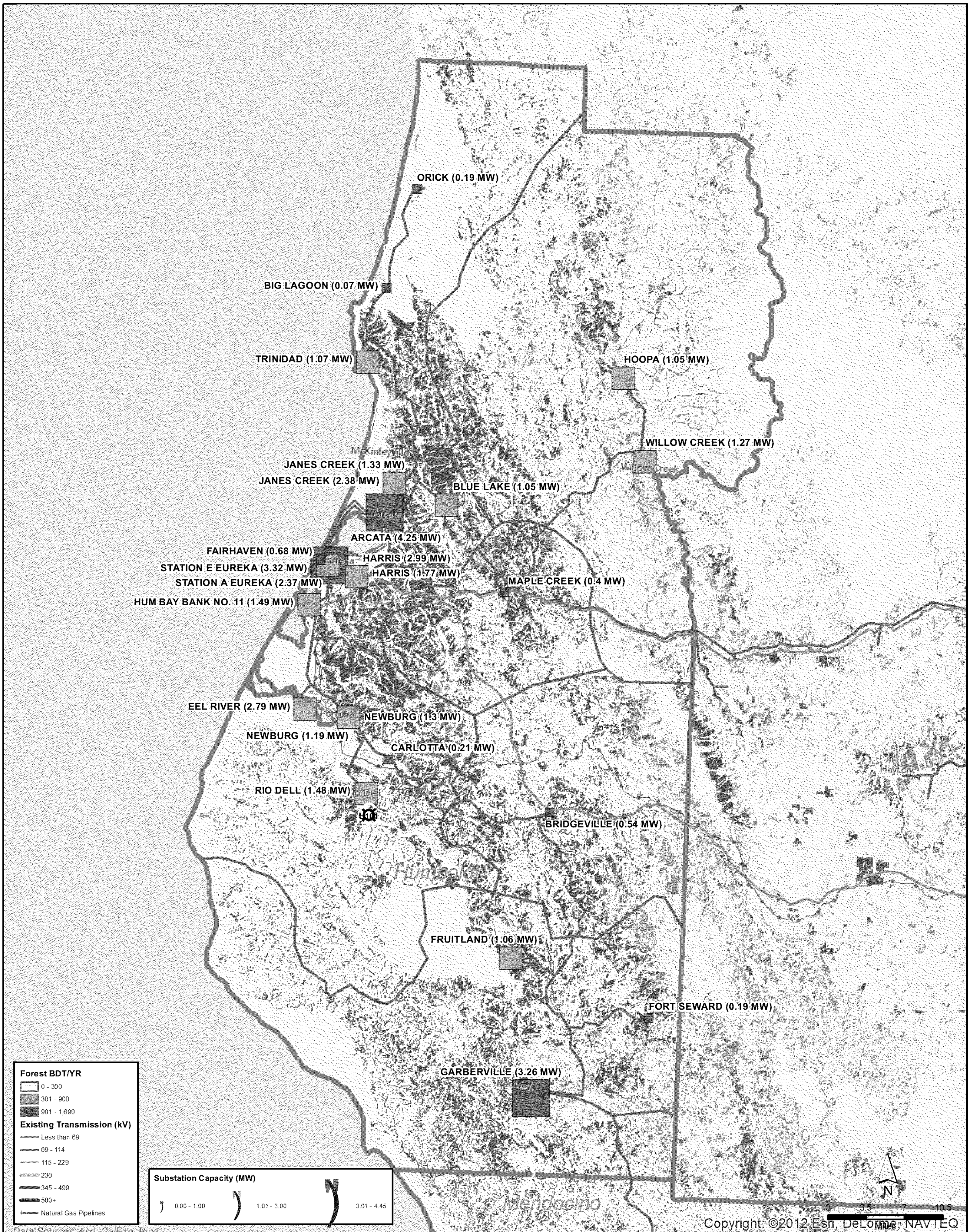
CPUC Interconn Rsrc Compare.mxd | C.Holmgren | 02/14/2013

Figure 3-5 Humboldt County Forest Resource and Substation Information



CPUC Forest Resource Potential - Humboldt

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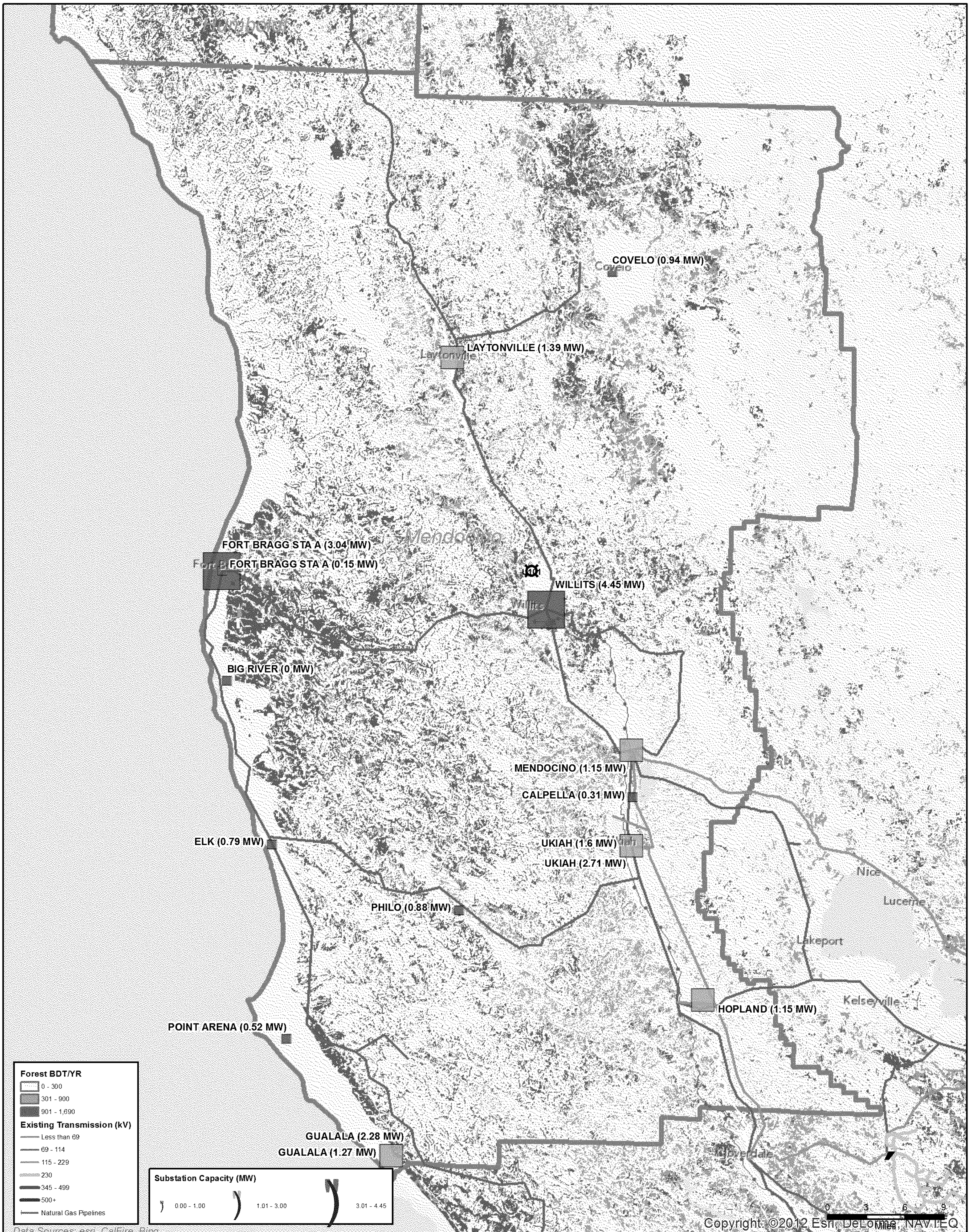
Figure 3-6 Mendocino County Forest Resource and Substation Information



CPUC Forest Resource Potential - Mendocino

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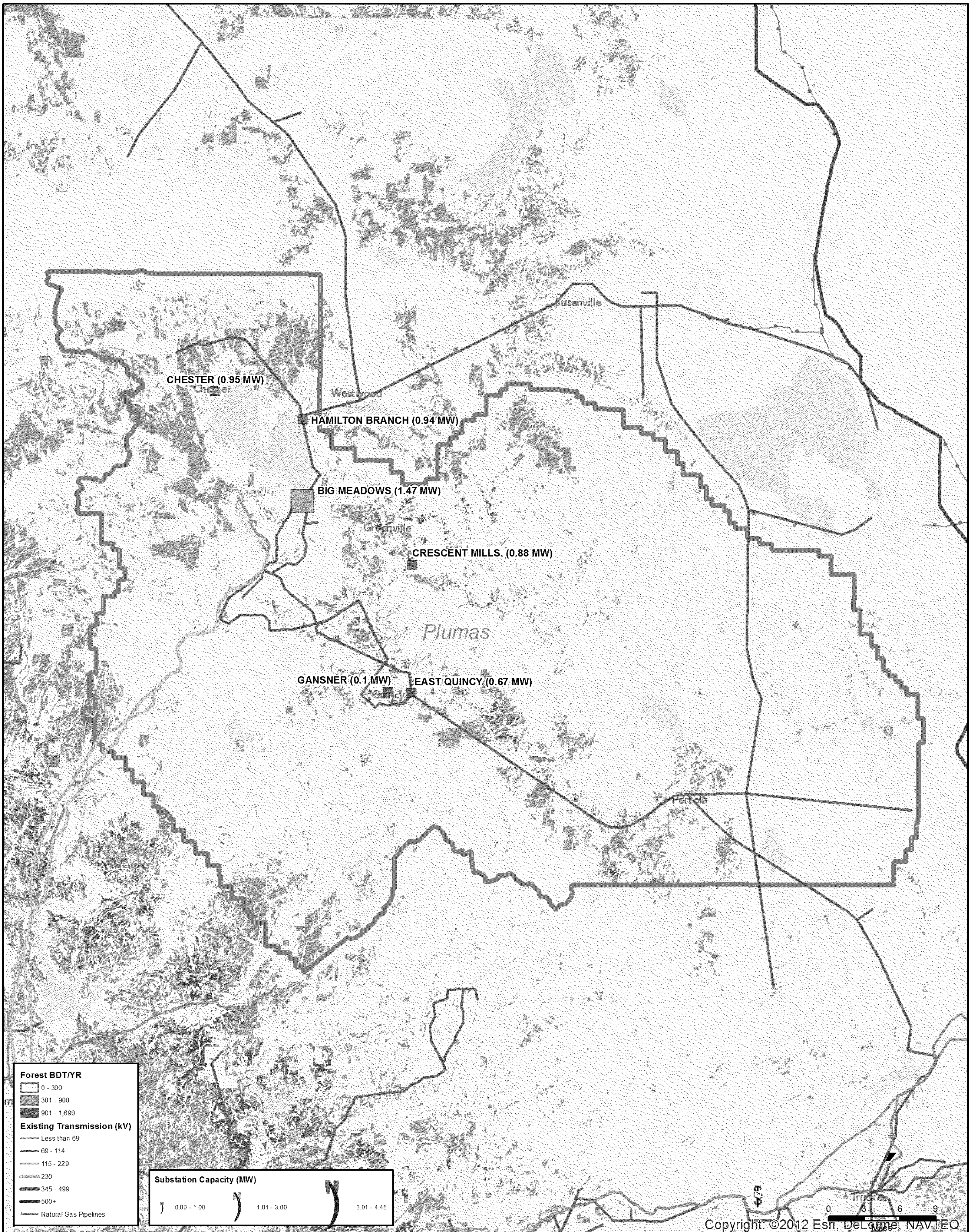
Figure 3-7 Plumas County Forest Resource and Substation Information



CPUC Forest Resource Potential - Plumas

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Information from these maps shows that interconnection issues will be very site specific. Counties identified as red may not necessarily have interconnection issues if the appropriate project location is selected. For example, much of the forest resource in Humboldt County is located within a 10 to 20 mile radius of some of the major substations with capacity in the Eureka area. However, Mendocino and Plumas counties have less substation capacity and more distance between the resource and substations with significant capacity.

The ability of bioenergy projects to move to more strategic interconnection locations should help mitigate some of the transmission issues. For projects located in an area with multiple feedstock providers, moving 10 miles to a better interconnection point may have little impact on overall costs or feasibility. In addition, recent utility interconnection data shows that few small generation facilities have triggered more than $300,000 in network upgrades, although the frequency of triggering large upgrades have been more common in bioenergy and fossil plants than solar PV. Recently released data from PG&E showed that nine out of 156 recent projects under 3 MW triggered network upgrades over $300,000, indicating that this largely has not been an issue for most distributed energy projects (although most data is for solar PV). For biogas, biomass, landfills, and reciprocating engine projects only, the frequency was four out of 17.

3.3 SUMMARY AND COMPARISON TO SB 1122 GOALS

Table 3-2 provides an estimate of SB 1122 potential by resource and by utility service territory. The estimates take into account only the resources physically located within each service territory. Statewide resource potential is higher; since material can be moved, this estimate is conservative but represents a reasonable proxy for estimating the potential for each utility to meet SB 1122 requirements with local resources.

Table 3-1 Utility Resource Technical Potential, MW

UTILITY	CATEGORY 1: WWTP AND GREEN WASTE BIOGAS (MW)	CATEGORY 2: DAIRY AND AG. BIOENERGY (MW)	CATEGORY 3: FOREST (MW)	TOTAL POTENTIAL	SB 1122 TARGET
PG&E	101	340	277	**718**	109
SCE	115	118	15	**249**	118
SDG&E	26	1	2	**29**	23
Total	**241**	460	**295**	**996**	250
SB 1122 Target	110	90	50	250	

From a resource perspective, this estimate indicates that there is roughly four times more material technically available to meet SB 1122's procurement requirements. Dairy/agricultural residues and forest material have the largest availability, with roughly five to six times the amount of material technically available when compared to their SB 1122 procurement targets. Forest biomass would be higher, with more available in Southern California, if shrublands were included. While shrub biomass is an eligible resource and in significant fire threat areas, cost, resource collection issues, and potential technical challenges in utilizing this material have led to it rarely being used. Biogas from WWTPs and green wastes has the lowest availability, with just over twice the statutory procurement target available. Food waste from MSW represents the largest share of green waste potential, representing just over 50 percent of this resource type. Collecting and separating this food waste can be a challenge relative to other SB 1122 resources given the heterogeneous nature of municipal solid waste and the multitude of different haulers and local regulations that must be addressed in order to collect sufficient material.

If only material in each utility's service territory is used to meet SB 1122 requirements, PG&E would have by far the most feedstock availability. PG&E will need to procure approximately 109 MW to meet its SB 1122 procurement requirement; roughly seven times this level of feedstock is available in its territory. SCE has roughly twice as much feedstock available relative to its SB 1122 procurement requirement, while SDG&E has barely enough technically available feedstock to meet its procurement requirement. SCE has more dairy potential than agricultural residues in its service territory, which is an important distinction given the difference in energy generation cost between these two resources within the same SB 1122 category. Projects in SDG&E's service territory would need to rely upon food and green waste feedstocks if local supply was desired, since there are few other options for bioenergy production in the area. Alternatively, material could be transported to SDG&E's service territory, but this may raise the overall cost to SDG&E ratepayers to comply with the statute.

Another goal of SB 1122 is to create a market for forest material that when harvested helps reduce the risk of high intensity wildfires in the state. According to CAL FIRE, millions of acres of California forests are at high risk for wildfire. Placing greater incentive on better managing both public and private forests for wildfire prevention could lead to economic benefits if this threat of wildfire is reduced. More information on the wildfire threat and the potential impacts of SB 1122 can be seen in Appendix C.

4.0 Levelized Cost of Generation Estimates

Black & Veatch created estimates for the levelized cost of electricity (LCOE) that would be needed to support SB 1122 projects based on a broad set of capital and operating cost assumptions. These assumptions were entered into a financial pro forma to estimate the LCOE. Major financial and technology specific assumptions can be seen in Appendix D.

The LCOE estimates are intended to bracket the range of likely SB 1122 project costs, and are not intended to reflect any particular project. LCOEs will vary considerably based on site specific development requirements, feedstock costs, coproduct values, and available incentives. Detailed, project specific analysis should be performed when attempting to estimate the LCOE for any individual projects.

4.1 CATEGORY 1: WASTEWATER TREATMENT AND GREEN WASTES

4.1.1 Wastewater Treatment Plants

The results for both the projects with and without existing digesters can be seen below. Sizing is based on the market analysis shown in Appendix B.

Table 4-1 Wastewater LCOE Estimate, New Digestion

	LOW ESTIMATE	MED. ESTIMATE	HIGH ESTIMATE
Project Size (MW)	0.3	0.3	0.3
Capital Cost ($/kW)	17,840	22,300	31,220
Operating Cost ($/kW-yr)	1,672	2,090	2,926
LCOE ($/MWh)	448	591	709

Table 4-2 Wastewater LCOE Estimate, Existing Digestion

	LOW ESTIMATE	MED. ESTIMATE	HIGH ESTIMATE
Project Size (MW)	0.3	0.3	0.3
Capital Cost ($/kW)	7,120	8,900	10,680
Operating Cost	544	680	816
LCOE ($/MWh)	148	190	233

The cost to install new anaerobic digestion equipment at the largest size typical for many available WWTPs without existing digesters (10 MGD) will lead to very expensive LCOEs if no other incentives or coproduct values are available. This is why larger units are typically considered and why digestion at WWTPs is driven by factors other than just power generation (decreased biosolids disposal costs, for example).

Adding new reciprocating engines at small WWTPs not utilizing their biogas leads to LCOEs in the $148 to $233/MWh range. These costs include gas cleaning, environmental controls, cogeneration, interconnection, development infrastructure, and credit for natural gas that is assumed to be replaced through heat recovery. Costs for biogas cleaning and flue gas emissions controls leads to a LCOE higher than typical for natural gas cogeneration units in the United States.

4.1.2 Low Solids Green Waste

The results for the green waste digestion cases can be seen below.

Table 4-3 Low Solids Green Waste LCOE Estimate

	LOW ESTIMATE	MED. ESTIMATE	HIGH ESTIMATE
Project Size (MW)	3	3	3
Capital Cost ($/kW)	7,760	9,700	11,640
Operating Cost ($/kW-yr)	392	490	588
Tipping Fee ($/ton)	30	20	10
LCOE ($/MWh)	80	139	204

The economy of scale advantage for building a large green waste digestion project can be seen when comparing the LCOE of power shown above to the LCOE for the 300 kW WWTP digestion system. Obtaining a tipping fee for the green waste brought to the digestion unit provides a significant revenue stream that is helpful to reduce the overall cost of exported power. It should be noted that this cost estimate assumes the largest possible SB 1122 compliant project, which would be likely only in large metropolitan areas in California. Smaller projects would likely have higher LCOEs.

4.2 CATEGORY 2: DAIRY BIOGAS AND AGRICULTURAL BYPRODUCTS

4.2.1 Dairy Cattle Manure

The results for the dairy manure digestion cases can be seen below. The basis for this cost estimate was a complete mix, stand-alone facility at a large flushed freestall dairy consisting of roughly 5,500 head of cattle. The size of the facility is roughly the same as that for the green waste unit, but the power production is significantly lower due to the lower gas yield for dairy manure relative to food waste. Few individual dairies in the state are larger than this size; while a larger project would likely have a lower LCOE, most dairies would be this size or smaller.

Table 4-4 Dairy Cattle Manure LCOE Estimate

	LOW ESTIMATE	MED. ESTIMATE	HIGH ESTIMATE
Project Size (MW)	1	1	1
Capital Cost ($/kW)	8,720	10,900	13,080
Operating Cost ($/kW-yr)	760	950	1,140
LCOE ($/MWh)	211	278	334

The lower gas yield and lack of a tipping fee for dairy manure digestion relative to green waste digesters leads to a higher LCOE than the previous anaerobic digestion analysis. However, unlike food waste digestion, dairy manure digesters are eligible for AB 32 offset credits. While offset credits are not included in the base case analysis given the uncertainty for offset prices, demand, and eligibility, a $20/tonne CO_2 credit value would produce revenue of roughly $500,000/year for a manure digestion project, lowering the LCOE by $70/MWh from the numbers listed above (to roughly $200/MWh for the medium case). Codigestion with higher gas yield feedstocks would also be helpful in lowering the LCOE.

4.2.2 Agricultural Residues

The technology and cost for producing power from agricultural residues is assumed to be similar to that of forest residues presented in the next section. While the handling and treatment of these materials will differ prior to feeding them to a gasifier, the cost difference is expected to be within the range of uncertainty in this analysis.

4.3 CATEGORY 3: FOREST MANAGEMENT BYPRODUCTS

The cost estimates presented here assume use of the same technology for solid biomass, regardless of the feedstock used (woody material or agricultural residues). Cost estimates associated with the development, construction and operation of a 3 MW biomass power generation facility are summarized in Table 4-5. Site specific situations can further vary the costs beyond the ranges presented here.

Table 4-5 Forest and Agricultural Residue LCOE Estimate

	LOW ESTIMATE	MED. ESTIMATE	HIGH ESTIMATE
Capital Cost ($/kW)	5,000	6,000	7,500
Non-fuel Operating Cost ($/kW-yr)	347	553	590
Size (MW)	3	3	3
Feedstock Cost ($/dry ton)	20	30	40
LCOE ($/MWh)	134	199	251

As can be seen above, the cost of generation from these facilities can vary considerably based on the cost assumptions used. Of particular importance is the feedstock cost; projects located at facilities with an ample supply of inexpensive feedstock, such as those at sawmills and nut processing facilities, will have much lower LCOEs compared to facilities that must procure material from further away. If feedstock was free, LCOEs would drop by 15 to 20 percent; conversely, if the feedstock cost in the base case rises to $40 per dry ton, this would increase the LCOE by roughly $10/MWh. If properly sited, the scale of the facility will significantly reduce both the quantities of biomass fuel required and the distance from which fuel must be collected relative to utility-scale (i.e., 20 MW and greater) biomass power generation facilities.

4.4 LARGE DISTRIBUTED BIOENERGY AND OTHER RESOURCES

As part of the broader DG work performed by Black & Veatch for the CPUC's Energy Division, the costs for bioenergy DG projects up to 20 MW have also been developed. This size represents the largest size DG project that could be built. While a project of this size would not be eligible for the SB 1122 tariff, it would be allowed to bid into the Renewable Auction Mechanism (RAM). As a point of comparison, Black & Veatch analyzed whether bioenergy generators utilizing SB 1122 eligible resources would be more cost effective if developed at the RAM size, rather than at SB 1122's statutorily mandated 3 MW maximum project size. Of the resources considered, only low-moisture biomass (forest or agricultural residues) conversion would be feasible due to the large amount of feedstock energy required to sustain a plant of this size.

Cost estimates associated with the development, construction and operation of a 20 MW biomass power generation facility using woody biomass are summarized in Table 4-6. As with the other technologies, site specific situations can further vary the costs beyond the ranges presented here.

Table 4-6 20 MW Low Solids Biomass LCOE Estimate

	LOW ESTIMATE	MED. ESTIMATE	HIGH ESTIMATE
Capital Cost ($/kW)	5,140	5,770	6,810
Non-fuel Operating Cost ($/kW-yr)	310	347	379
Size (MW)	20	20	20
Feedstock Cost ($/dry ton)	40	50	60
LCOE ($/MWh)	143	168	198

When compared to 3 MW biomass projects, the cost of 20 MW projects tends to be better understood, has less variation, and is typically lower. While feedstock costs are higher and capital costs are comparable or slightly lower, the much lower non-fuel operating costs and better heat rates typically lead to lower LCOEs. Biomass facilities at this size use technologies that are more commercially proven, likely leading to greater reliability and capacity factors.

4.5 COST SUMMARY

A summary of the range of LCOEs, along with the unique factors that may influence the delivered cost of power, is shown in Table 4-7. A graphical representation of the range of likely costs for projects without financial incentives, coproduct values, or disposal costs is shown in Figure 4-1.

Table 4-7 SB 1122 LCOE Summary by Feedstock Type, $/MWh

RESOURCE AND SIZE	LOW ESTIMATE	MED. ESTIMATE	HIGH ESTIMATE	UNIQUE COST FACTORS
Category 1				
WWTP, New Digestion (0.3 MW)	448	591	709	Requirements to add digestion, solids disposal costs, size, digester type, fertilizer value
WWTP, Existing Digestion (0.3 MW)	148	190	233	Size, gas cleaning and infrastructure requirements
Low Solids Green Waste (3 MW)	80	139	204	Tipping fee, coproduct value, digester type
Category 2				
Dairy Cattle Manure (1 MW)	211	278	334	Solids disposal costs, fertilizer value, AB32 credits, codigestion, digester type
Agricultural Residues (3 MW)	134	199	251	Interconnection cost, coproduct value, fuel costs, cogeneration applications
Category 3				
Forest Material (3 MW)	134	199	251	Interconnection cost, coproduct value, fuel costs, cogeneration applications
Generic project estimates not taking into account incentives or coproduct values/disposal costs, with the exception of steam from anaerobic digestion for digester heating.				

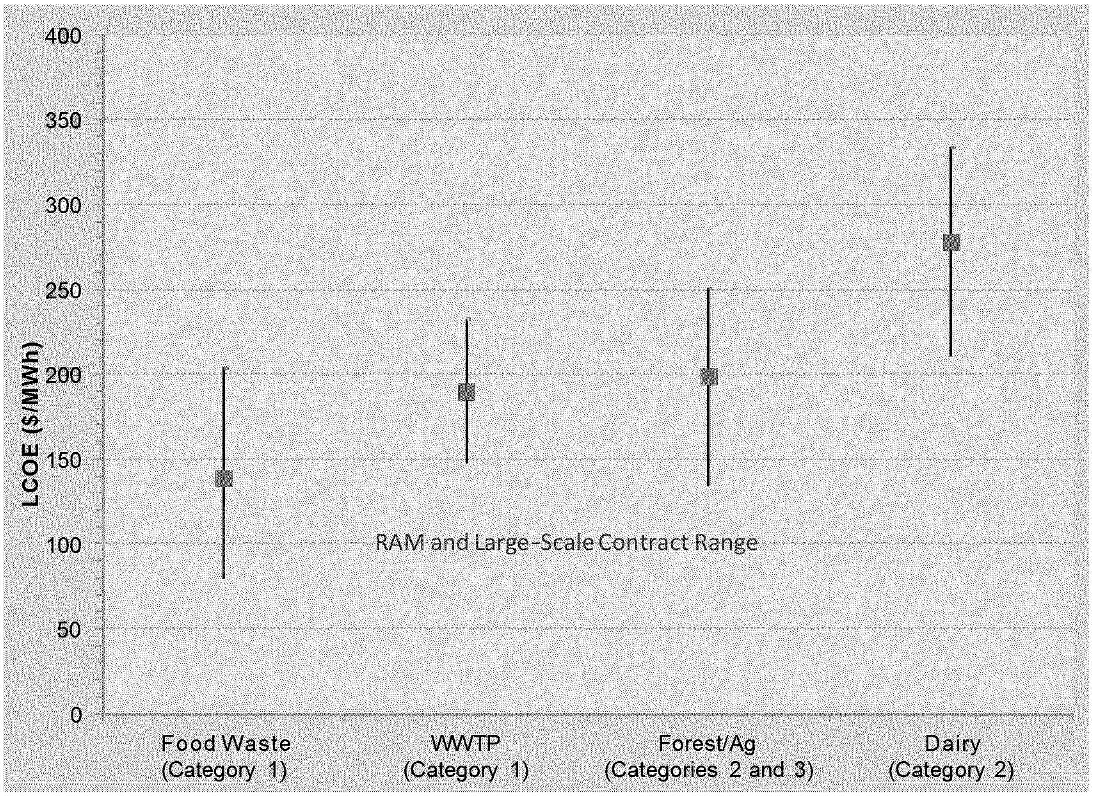

Figure 4-1 SB 1122 LCOE Range, No Incentives

SB 1122 eligible projects that can receive a fee for their feedstock (green waste anaerobic digestion) or that have a readily available resource (WWTPs with existing digesters) will have the lowest LCOEs. However, the number of economically feasible, SB 1122-eligible WWTPs is very small (roughly 4 MW). The lower gas yield and lack of a tipping fee for dairy manure digestion relative to green waste digesters leads to a higher LCOE. However, unlike food waste digestion, dairy manure digesters are eligible for AB 32 greenhouse gas offset credits (not reflected above), which may provide revenue in later years. Forest and agricultural residue projects may also be able to obtain revenue through the marketing of coproducts such as heat and biochar.

Without incentives or value for the coproducts, the required LCOE for most SB 1122 compliant projects will be higher than PPAs recently signed by the IOUs as part of the RAM and large scale procurement efforts. Many of the contracts signed under these solicitations have been larger solar PV projects which have recently come down substantially in price. If SB 1122 projects are able to take advantage of some of the currently available incentives and/or obtain value for their coproducts, the LCOEs for some resources are likely to become more comparable to the range of prices recently seen in other solicitations. Figure 4-2 shows the LCOE range for SB 1122 projects if projects took advantage of the 30 percent ITC.

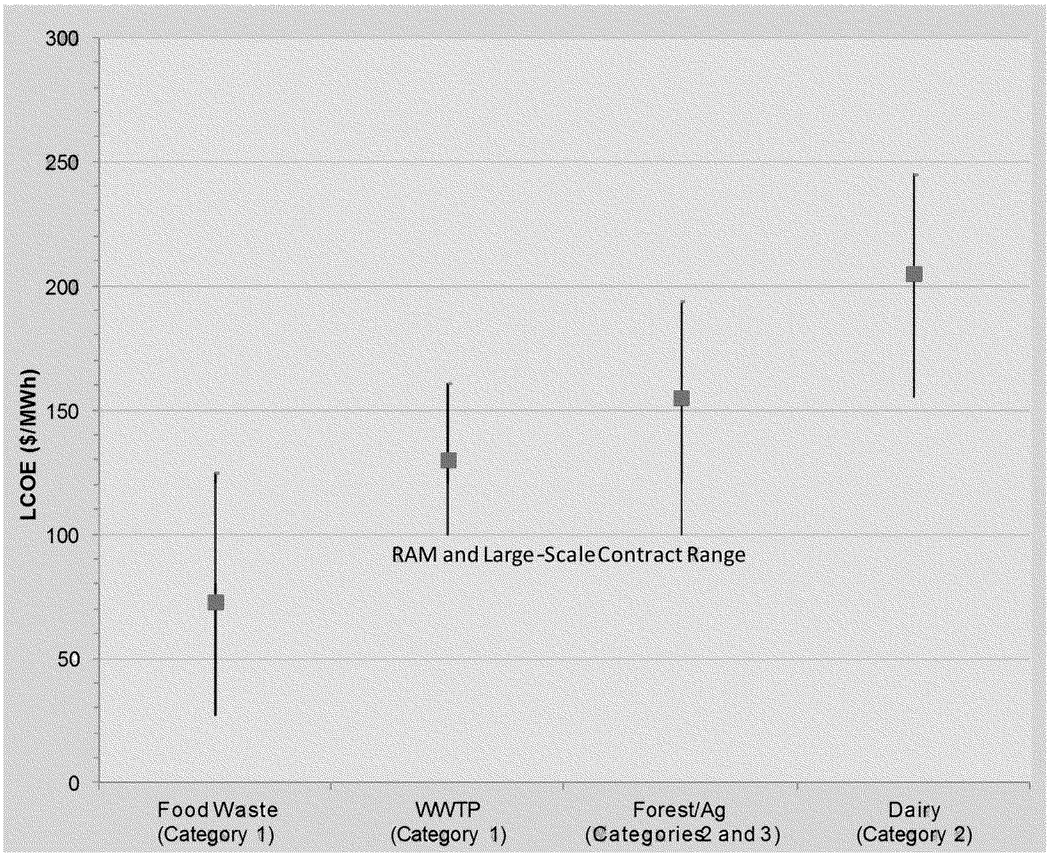

Figure 4-2 SB 1122 LCOE Range, With 30 Percent Investment Tax Credit

There are a few examples of currently operating bioenergy projects that have applied for and received a FIT PPA from one of the IOUs using an SB 1122 eligible feedstock. The project names, sizes, and accepted FIT price can be seen in Table 4-8. Each project is in PG&E's service territory and each meets the requirements of AB 1969. No SB 1122-type projects have been awarded contracts under the RAM.

Table 4-8 On-line Biomass and Digester Gas Projects with FITs

PROJECT NAME/TECHNOLOGY	SIZE (KW)	PRICE ($/MWH)	DATE TARIFF ACCEPTED	NOTES
Castelanelli Bros. (Digestion)	300	100.43	2009	Lagoon digester, high incentives, already operating
Blake's Landing Farms (Digestion)	80	84.48	2010	Lagoon digester, high incentives, already operating
Ortigalita Power (Biomass)	750	110.46	2011	Incentives, coproduct value

Each of the projects listed above received incentives, has strong coproduct values, and/or sunk costs that make the tariff rate required to be economically feasible fairly low. Each of the dairy digestion projects use a simple technology with a low gas yield (lagoon digestion), received multiple funding sources, and were initially placed into operations years before the FIT. The biomass facility, which gasifies orchard trimmings and almond shells, receives value for coproduct heat and biochar. These examples demonstrate the types of additional incentives that would be required to be competitive with current renewable energy procurement prices.

5.0 Implementation Assessment

A range of technical and procedural issues may need to be addressed to be able to develop projects that utilize the SB 1122 tariff. Given the lack of an existing market for small-scale bioenergy generators, of key importance is whether the ReMAT mechanism as currently designed is adequate. Additionally, given the state's resource potential by SB 1122 category and its distribution, consideration was made for whether the existing statutory targets by resource are appropriate. These issues are addressed in this section.

5.1 TECHNICAL ISSUES

Both anaerobic digestion and biomass combustion or gasification would be used for SB 1122 compliant projects. The use of anaerobic digestion technology and internal combustion engines for power generation is proven for projects under 3 MW. Wet digestion (under roughly 15 percent solids) is the industry standard in the United States, with the greatest deployment at WWTPs. "Dry" digestion (up to roughly 40 percent solids) is being used more frequently for food wastes and other green wastes. This technology is proven in Europe, but few projects using this technology have been implemented in the United States. There is likely to be an operational learning curve until greater experience is gained in dry digestion units in California.

Relative to anaerobic digestion at this scale, there is less experience and greater operational risk in the development of biomass gasification facilities for power generation. The vast majority of operational biomass units in the state and throughout the United States are of a much larger scale, utilizing conventional steam boilers and turbines.[7] This adds uncertainty to the likely costs and operational performance for this type of facility.

Other major technical and development issues include the following:

- Siting and Development
    - Rigorous environmental regulations in California will require advanced emission control equipment, which may increase permitting timing, along with raising capital and O&M costs.
    - Development costs are high relative to other types of distributed generation, namely solar PV.
    - Financing can be challenging due to the small size, limited experience, and lack of long-term, mature markets for feedstock and coproducts.
    - Siting of new bioenergy projects may face some public and agency resistance

[7] The Biomass Power Association shows very few operational solid biomass power projects specifically for power export to the grid (http://www.usabiomass.org/docs/biomass_map.pdf). In addition, only 8 of the 101 biomass projects certified or pre-certified by the CEC as RPS compliant are 3 MW or less.

- Digestion
  - Digestion might not fit into a WWTP's biosolids management plan. For example, WWTPs that incinerate biosolids might not want to install digestion, which decreases the heating value of solids fed to the incinerator.
  - Sidestreams from digestion will increase loadings to the liquid treatment processes at WWTPs.
  - Footprints for digestion and CHP facilities are relatively large, which might be a concern for potential sites with limited land availability or high land lease costs.
  - Green waste feedstocks for digestion are typically comingled or contaminated with other materials, requiring separation that will add to project costs and can impact operational performance.
  - Prices for biosolids coproducts from digestion could be volatile due to quality, supply, and market demand.
  - Residues generated in the digestion process must be further processed for beneficial use as a fertilizer or for disposal.
- Gasification
  - There are relatively few gasification technology suppliers for small-scale gasification systems that have demonstrated the capability to provide and fulfill performance guarantees and secure project financing.
  - Designs will need to carefully address syngas quality to assure reliable operation of equipment downstream of the gasifier.

5.2 REMAT APPLICATION

The ReMAT pricing mechanism has been adopted by the state for any contracts executed under the FIT program after the CPUC implements SB 32's revisions to § 399.20 of the Public Utilities Code[8]. This section was originally added to the Public Utilities Code by AB 1969. As initially enacted by AB 1969, § 399.20 created the renewable FIT Program. This law originally only required electrical corporations to make a tariff or standard contract available only to public water and wastewater customers. Since 2007, the Legislature has adopted several amendments to this code section, including those contained in SB 380 (2008), SB 32 (2009), and SB 2 1X (2011). The CPUC first implemented the § 399.20 FIT program through its adoption of Decision 07-07-027. Consistent with the statutory requirements under AB 1969, codified in § 399.20(5)(d), D.07-07-027 adopted the Market Price Referent (MPR) as the § 399.20 FIT Program price. In 2012, D. 12-05-035 supplanted the MPR with the ReMAT as the mechanism used for setting the price for FIT programs established under § 399.20. The ReMAT pricing mechanism will take effect upon final implementation of SB 32's revisions to the FIT program, expected in mid-2013.

The intent of the ReMAT is to establish a more dynamic price setting mechanism for FIT programs that takes into account market pricing and technological changes. It establishes a set of binary

[8] See CPUC Decision 12-05-035.

project screens to help manage the project queue and reduce the impact of market manipulation. Instead of just defining a set price for projects applying for a FIT, the ReMAT starts at a level established by recent RAM pricing, then will adjust based upon the number of projects entering the queue and accepting (or not accepting) the current price. This price will move up or down based upon the level of capacity subscription. Once the price adjusts to the level where acceptance of the tariff is equal to the capacity desired, this will be the market clearing price offered to the accepted projects as a fixed rate for the duration of their contract term.

There are a set of project viability criteria that must be met before a project can be considered eligible for the ReMAT. The CPUC adopted these criteria to promote the participation of viable projects capable of achieving commercial operation in a timely manner, and to efficiently manage the project queue if projects fail to comply with these criteria. The ReMAT eligibility criteria include the following:

- **Bid Fee:** $2/kW bid fee
- **Interconnection:** System Impact Study, Phase I study, or passed the Fast Track screens or supplemental review
- **Site Control:** Attest to 100 percent site control through (a) direct ownership, (b) lease, or (c) an option to lease or purchase that may be exercised upon contract execution
- **Development Experience:** Attest that one member of the development team has (a) completed at least one project of similar technology and capacity or (b) begun construction of at least one other similar project
- **Online Date:** 24 months with one six month extension for regulatory delays

Issues that may arise with the use of these viability criteria and other concerns with application of the ReMAT pricing mechanism in its current format are outlined below.

5.2.1 Requirement that FIT Projects be "Strategically Located"

The feed-in tariff statute requires that all projects be "strategically located." The CPUC, in D.12-05-035, found "strategically located" to mean that a generator must be interconnected to the distribution system and sited near load, meaning in an area where interconnection to the distribution system requires $300,000 or less of upgrades to the transmission system. In some instances and locations, this may require that potential SB 1122 project sites be moved to maintain their eligibility with this requirement. Completing the interconnection studies required by the ReMAT eligibility screens will help with queue management and project prioritization, allowing generators to evaluate whether they comply with this requirement.

Based on the current interconnection queue data, the current ReMAT requirement that projects must have completed a Phase I, System Impact Study, or Fast Track may delay the ability of bioenergy projects to use the SB 1122 tariff. Updated interconnection queue information (both

Rule 21 and WDAT) were reviewed from both on-line information and data recently produced by the IOUs as part of the CPUC's Open Interconnection Proceeding, R.11-09-011. From this data, it appears that there are very few SB 1122 projects that would have passed the ReMAT interconnection eligibility screen; SDG&E has zero projects, PG&E five, and SCE two. SCE also has six projects listed as MIC (Internal Combustion – Methane) which may or may not use methane derived from bioenergy sources. Data from PG&E shows that it took roughly six months between the application and the completion of the initial interconnection study for projects added to the queue in 2012.

Moreover, this data shows that the projects currently in the interconnection queues may not be consistent with the CPUC's interpretation of the statutory requirement that projects be "strategically located." For instance, the five PG&E projects in the interconnection queue have interconnection and network upgrade costs in excess of the $300,000 maximum imposed by the CPUC, ranging from $858,000 to $2.6MM.

5.2.2 Development Experience

Meeting the Development Experience screen will depend on how the definition of "similar technology/project" is applied. For anaerobic digestion projects, wet digestion technology at WWTPs is common, but digestion of green wastes and animal manure is much less common in the United States. However, there are a number of European developers and technology providers that are interested in participating in the US market that likely have the proper experience if foreign experience is acceptable and the feedstocks used are deemed similar enough. Thousands of small-scale green waste anaerobic digestion projects are in operation worldwide. Small-scale solid biomass power plants using gasification technology have a much smaller commercial track record throughout the world. There is a limited number of operating commercial facilities, although there are many technology developers that have operating pilot plants.

5.2.3 Tariff Level and Ramp Rate

The ReMAT is initially set at $89.23/MWh. Once at least five eligible projects that meet the project viability criteria have entered the SB 1122 project queue, the price will adjust every two months based on whether the amount of capacity offered by the utility is oversubscribed (adjusts down) or undersubscribed (adjusts up). The tariff adjusts every two months based on a rate defined by the CPUC. If no projects accept the tariff by the 12th month after the initial offering, for instance, the tariff will be $60/MWh over the base price (i.e., the offered price would be $149.23/MWh).

Given the limited amount of development that has occurred on SB 1122 eligible projects and the challenges in meeting the Interconnection screen, there may be a delay in the tariff ramp until sufficient projects have entered the queue. Assuming that a set of new projects will need to pass this screen before the ReMAT adjustment period can begin, it is estimated that it will take roughly 33 months for a set of SB 1122 eligible projects to begin operation under the current structure, assuming that a tariff rate of roughly $150/MWh is needed. This estimate takes into account interconnection screening, ReMAT adjustments, development needs, permitting, financial close, and construction, as shown in Figure 5-1.

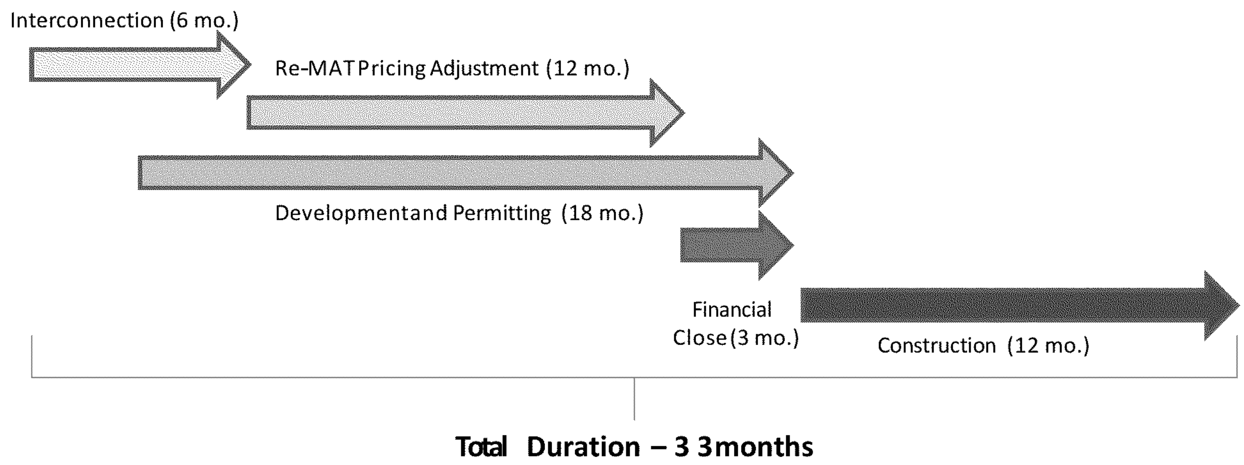

Figure 5-1 Generic Project Development Timeline

The project timing could be reduced if projects already under development apply for the tariff, if a lower tariff value is required for economic development, or if ReMAT is adjusted to provide a faster tariff ramp. Note however that reductions in both development timing and ReMAT changes would be needed to significantly reduce the overall timing; reducing one and not the other may not be sufficient. It is expected that most SB 1122 projects will require three years or more after the tariff becomes effective before achieving commercial operation.

5.2.4 Seller Concentration and Feedstock Availability

Some markets, namely San Diego, currently have a limited set of resources with which to meet SB 1122 obligations. This implies that most projects applying for a FIT there will be approved due to a lack of applications, potentially leading to higher prices due to limited competition. If a small number of providers had the majority of access to available resources in the area, this also could impact prices. Reenactment of a seller concentration guideline may be helpful to limit seller concentration, especially in San Diego. This screen was recently proposed for removal from the ReMAT.

There is no price cap currently in place that would protect ratepayers in the event that limited resource availability leads to undue price impacts, although the IOUs do have the ability to file a motion with the CPUC to suspend the program if there is evidence of market manipulation or malfunction. Price caps may need to be considered given the wide range of resources that must be procured and the potential for high costs.

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5.2.5 Potential Tariff Modifications

Given that few SB 1122 eligible projects are currently in the utility interconnection queues, several possible changes could be made to ReMAT to stimulate the market. Listed below are some possible options for modifying the existing ReMAT program rules to either stimulate the market or, on balance, to protect ratepayers:

- **Faster Tariff Ramp or Larger Price Step Changes:** As shown in Section 4, few bioenergy projects have signed FIT contracts due in part to the low price relative to what is likely needed to provide enough financial incentive. Since some projects may be viable at the ReMAT starting price of $89.23/MWh, the starting price should not be changed. However, many projects may need higher prices to be economically viable. A faster tariff ramp rate or larger price adjustments may accelerate the pace of overall project development by providing an earlier pricing incentive. However, given how few projects are currently in the interconnection queues and the expected project development timelines, it still may take three years or more for SB 1122 projects to achieve commercial operation.
- **Start Tariff Ramp with Less Than Five Projects:** Waiting until five eligible projects have entered the queue may create development delays and may be unachievable in some instances, given the small amount of procurement required for some service territories and feedstock types. Project viability screens should remain since they are important to prevent projects unlikely to be developed from taking up queue space. The number of eligible projects needed to start the price changes could be uniformly reduced or set proportional to the procurement target. These changes could have a negative consequence if it leads to gaming of the ReMAT price.
- **Accept International Experience:** There is a large amount of experience in small scale bioenergy projects outside the United States. This experience should be accepted as part of the project viability screens to open the market to a wide range of developers.
- **Consider Seller Concentration Requirements:** A CPUC proposed decision issued in March 2013 removed the seller concentration screen from the ReMAT. Depending on the targets set for each utility and resource, it may be prudent to reinstate seller concentration limits to avoid market manipulation in locations that may face limited competition. A limit based on a percentage of the capacity target (e.g., less than 25 percent) may be appropriate.
- **Price Caps:** Limited supply of certain types of feedstocks in some of the service territories could create very strong feedstock demand, which could raise prices and impact the overall cost of generation. For this reason, price caps may be considered as an option to protect ratepayers and prevent disproportionate cost burdens. Utilities would not be obligated to meet SB 1122 requirements if the price cap is reached.

5.3 STATUTORY INTERPRETATION

The wording of SB 1122 leaves some implementation issues unclear and subject to the interpretation of the CPUC. Some of the potential issues are identified below:

- **Eligibility of Out of State Feedstocks:** SB 1122 defines an eligible “electric generation facility” as being one located in a utility service territory, but the statute does not require that the feedstock for that facility originate from within California. This opens the possibility, for instance, that out of state biogas could be pipelined into California to an SB 1122 eligible facility. Most biogas that is imported to California is combusted in large combined cycle facilities. It is unlikely that there will be a significant economic incentive to develop an anaerobic digestion out of state, clean the gas to pipeline quality, then combust the biogas in a small electric generation facility. In addition, implementation of AB 2196 is providing further guidance on RPS eligibility of out of state biogas. Since economics will likely make out of state projects less viable than in-state projects, there is unlikely to be a need for the CPUC to restrict the feedstock type.
- **Feedstock Definitions:** There are a range of biomass feedstocks that could be used to meet SB 1122 requirements. The CPUC may need to clarify the definitions for what falls into each of the SB 1122 allocation categories. Specifically, a distinction should be made for the difference between feedstocks used for food processing and agricultural bioenergy production, and the types of feedstocks that qualify for “codigestion”.
- **Use of Multiple Feedstock Types:** Some existing anaerobic digestion and solid biomass conversion units in California use multiple SB 1122 eligible feedstocks. The majority of anaerobic digestion facilities use only one type of SB 1122 feedstock, although there are some planned digesters looking to use agricultural residues and food wastes, or manures coupled with green wastes. Gasification facilities under 3 MW will have more dedicated feedstock supplies than much larger facilities, but may still be interested in using different feedstock types. If different tariff rates are established for each feedstock type utilizing the ReMAT pricing mechanism, projects will need to declare a single product category for which they are applying for a contract. As a result, the CPUC may need to consider a requirement that a project source a majority (or some other percentage) of its feedstock from the category to which the project applies for a contract. Fuel switching during project operation does not appear to meet the statute’s intent, which was developed to incentivize specific feedstock types.
- **Definition of “Commence Operation”:** SB 1122 states that eligible projects will “commence operation on or after June 1, 2013”. For the purposes of this resource and cost assessment, eligible projects are assumed to mean new projects that are not currently producing power. It is also assumed that changing the feedstock or power disposition (from on-site use to power export) will not qualify an operating project as SB 1122 eligible.
- **Definition of “Sustainable Forest Management”:** Only forest products that are harvested sustainably qualify for the SB 1122 tariff. The resource potential shown here uses CAL FIRE data and assumptions for forest material that would be considered sustainable. The CPUC may need to consider whether to adopt a definition of “sustainable forest management” for projects seeking a contract in this category.
- **Verification of Feedstocks Used:** Because projects will be selected partially on the basis of the feedstock used that fits into a specific allocation category, the CPUC or utilities may need to perform some sort of feedstock monitoring and verification.

5.4 OPTIONS FOR RESOURCE TARGETS AND COST OF COMPLIANCE

SB 1122 does not require that utility specific goals or tariffs be established for the different potential resources. Having one tariff or capacity goal per utility regardless of the feedstock will lead to the least expensive projects being developed first, which will likely favor certain technologies and resources. This could be a low-cost option if the resource specific goals are not required.

If resource specific targets are required, different tariffs and resource goals by utility likely need to be defined to provide incentives for each resource type in every service territory. Failure to do so could lead to some resource types being fully subscribed through projects in one utility, making it difficult or expensive for other utilities to meet their goals. For example, if green waste projects are quickly developed in PG&E and SCE service territories, taking up all the statewide allocation, SDG&E would have a challenge in economically meeting its net procurement goal given a lack of other resource types.

Three main options are considered here for resource allocation targets by utility: 1) proportional by load, 2) by resource availability, and 3) by resource availability with adjustments for market competition factors. Equivalence by cost was also considered, but as shown below, this may be a challenge given the lack of identified resources in San Diego. Besides these options, alternative procurement options which would require changes in the statute are also discussed. The allocation goals under each method and the range of potential costs are outlined below.

5.4.1 Assumptions

A blended cost of SB 1122 compliance by utility in $/MWh and estimated net yearly expenditure was estimated by using the LCOE estimates determined earlier in this report. The range of potential incentives and coproduct values make compliance cost estimates a challenge. The intent is to provide a relative understanding of the different costs in each service territory given resource availability and likely procurement choices. Unless otherwise specified, a few major assumptions were applied in each case:

- The Low and Medium LCOE estimates were used to bracket the cost range in service territories that have sufficient resources to meet the procurement target. Medium and High LCOE estimate are used if more than 50 percent of the resource within the service territory is utilized.
- Agricultural bioenergy projects are selected in PG&E's and SDG&E's service territory over dairy digestion due to lower cost and higher availability. SDG&E imports agricultural residues to meet its obligation when insufficient material is available locally.
- SCE complies with the dairy/agricultural goal through a mix of 50 percent dairy digestion and 50 percent agricultural resources. Half the dairy digestion projects are assumed to receive AB 32 carbon reduction credits.

5.4.2 Compliant Option 1: Proportional by Load

The first allocation performed is on a proportional basis per the overall procurement goal and the split of resource defined in the statute. For example, since forest biomass represents 20 percent of the overall SB 1122 goal (50 MW of the 250 MW target), the forest-based capacity target for each utility was also made to be 20 percent of its overall procurement target. A summary of the procurement targets, resource availability, and projected cost ranges for each utility can be seen in Table 5-1. Targets for each utility by resource type are shown, along with the resource potential estimates (in parenthesis) developed in Section 3.

Table 5-1 Utility Resource Targets and Projected Costs, Proportional by Load

UTILITY	CATEGORY 1: WWTP AND GREEN WASTE BIOGAS (MW)	CATEGORY 2: DAIRY AND AG. BIOENERGY (MW)	CATEGORY 3: FOREST (MW)	ESTIMATED BLENDED COST RANGE ($/MWH)	NET EXPENDITURE PER YEAR ($MM)
PG&E	48 *(101)*	39 *(340)*	22 *(277)*	110-170	95-148
SCE	52 *(115)*	43 *(118)*	24 *(15)*	130-190	124-180
SDG&E	10 *(26)*	8 *(1)*	4 *(2)*	145-200	27-37
Procurement Totals	110	90	50	--	245-365

Targets for each utility and resource are shown, along with the estimated service area potential in parenthesis.

This allocation will likely be impractical given the limited amount of forest material in SCE and SDG&E service territory (if shrub resources are not utilized), as well as a lack of available dairy/agricultural material for SDG&E. To meet this allocation, each of these utilities may need to bring in material from distant locations or use lower quality materials, increasing the LCOE. This is reflected in the higher compliance cost estimates developed for this table.

5.4.3 Compliant Option 2: By Resource Availability

A second option is to assign targets based on the availability of resources in each service territory. To do this, the resource percentages in each service territory were calculated, and then the utility procurement target was multiplied by this percentage. As an example, forest residues in PG&E's service territory represents 38.6 percent of the SB 1122 compliant resources in their service territory (277 MW forest potential / 718 MW net potential). PG&E's forest target would therefore be 38.6 percent times its 109 MW target, or 42 MW. Note that while this will assure that each utility capacity target is met, it will change the net allocation by resource type. Targets based on this analysis are shown in Table 5-2.

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Table 5-2 Utility Resource Targets and Projected Costs, by Resource Availability

UTILITY	CATEGORY 1: WWTP AND GREEN WASTE BIOGAS (MW)	CATEGORY 2: DAIRY AND AG. BIOENERGY (MW)	CATEGORY 3: FOREST (MW)	ESTIMATED BLENDED COST RANGE ($/MWH)	NET EXPENDITURE PER YEAR ($MM)
PG&E	15 *(101)*	52 *(340)*	42 *(277)*	125-190	109-164
SCE	55 *(115)*	56 *(118)*	7 *(15)*	120-185	114-172
SDG&E	20 *(26)*	1 *(1)*	2 *(2)*	145-210	27-38
Procurement Totals	90	109	51	--	249-374

Targets for each utility and resource are shown, along with the estimated service area potential in parenthesis.

This resource allocation leads to 15 percent of each resource type in PG&E's service territory being used, 48 percent of SCE's, and 78 percent of SDG&E's. While the net use of forest resources remains nearly the same as those originally defined by SB 1122, the overall target for green wastes and dairy/agricultural resources have changed. Green waste procurement decreased by 20 MW, while dairy/agricultural procurement has increased by 19 MW. While the CPUC may perform this type of reallocation per §399.20(f)(3), this would require coordination across state agencies which could delay enactment of the tariff.

This allocation of resources has impacted the likely costs. Compliance costs for PG&E would likely be more expensive than the proportional by load case due to use of more agricultural and forest residues, while SCE costs have decreased slightly due to the use of less forest residue. SDG&E's compliance costs may not change considerably; while the amount of dairy, agricultural, and forest residues have all declined, the amount of green waste that must be procured has doubled from the proportional by load case. Using such a large amount of this resource and the lack of competition may keep procurement costs high.

5.4.4 Compliant Option 3: By Resource Availability, Using Market Competition Factors

As can be seen from the results of Options 1 and 2, allocating by load only may be impractical while allocating by resource availability only would require a reallocation of resource targets. A hybrid option would be to use Option 2 as a starting point for utilities that are resource constrained, and then reallocate the remaining resources so that the original targets are preserved. In this scenario, SDG&E's targets from Option 2 could first be maintained, with a decision then made on an appropriate target for SCE's forest resource given its constraints. This would set PG&E's forest resource target. The targets for green waste and dairy/agricultural residues for SCE and PG&E could then be reallocated taking into account resource availability and cost.

If insufficient resource is available to create a large enough market for certain types of material, the CPUC could eliminate the procurement requirement for some resources within SDG&E and SCE's service territory due to lack of local availability. These resources would be reallocated to PG&E, with other targets adjusted. Taking these steps may reduce the administrative burden of having to establish a process to procure such a low level of capacity. The net impact on the net expenditure by utility would likely be low if only a few MW of capacity is reallocated. Even if SDG&E was to focus solely on WWTPs and green wastes within the county, it may still be challenge to meet SB 1122 procurement goals given the resource limitations. Given this issue, the viability of using shrub biomass in San Diego should be carefully considered to determine if it should be included in the list of resources.

5.4.5 Other Options, Currently Non-Compliant with SB 1122

There are a number of other options available for resource allocation, but most would require a change in the net allocation by resource or utility compared to what is currently defined in SB 1122. Obtaining cost equivalence, where each utility is roughly paying the same blended cost, is unlikely to be possible if the utility procurement targets are not modified. The lack of resources in SDG&E's service territory will likely create challenges in meeting SB 1122 targets at a price commensurate with PG&E and SCE.

If the allocation by service territory could be modified, greater flexibility and potentially lower net compliance costs may be possible. Two major options for new procurement targets if the amount by utility was changed are:

- Option 4: A flat procurement percentage based on resource availability
- Option 5: Amounts equal to the ratio of the resource availability in each service territory compared to the statewide potential

A flat target of 25 percent by resource within each service territory would greatly change the allocation by utility. The 250 MW statewide goal would now be comprised of 180 MW from PG&E, 63 MW from SCE, and 7 MW from SDG&E. This also increases the net forest procurement by 25 MW over the current SB 1122 goals, largely at the expense of green waste projects. The breakdown by resource and utility is shown below.

Table 5-3 Utility Resource Targets, 25 Percent Resource Procurement Level (MW)

UTILITY	CATEGORY 1: WWTP AND GREEN WASTE BIOGAS (MW)	CATEGORY 2: DAIRY AND AG. BIOENERGY (MW)	CATEGORY 3: FOREST (MW)	ESTIMATED BLENDED COST RANGE ($/MWH)	NET EXPENDITURE PER YEAR ($MM)
PG&E	25 *(101)*	85 *(340)*	70 *(277)*	125-190	179-270
SCE	29 *(115)*	30 *(118)*	4 *(15)*	120-185	60-91
SDG&E	6 *(26)*	0.3 *(1)*	0.6 *(2)*	85-150	5-8
Procurement Totals	60	115	75	--	244-369

Targets for each utility and resource are shown, along with the estimated service area potential in parenthesis.

This option creates rate equity between PG&E and SCE, along with greatly lowering the compliance cost for SDG&E. However, PG&E will pay significantly more on an annual basis, and the net compliance cost is no better than the previous cases due to the shift from green wastes to more forest and dairy/agricultural residues.

Option 5 would be to allocate by the percentage of statewide resource potential. This percentage would be multiplied by the overall target for that resource type to develop the procurement target. For example, PG&E has 94 percent of the identified forest resource (277 MW of the 295 MW statewide utility potential), so it would receive 94 percent of the 50 MW target, or 47 MW. Targets using this approach can be seen below.

Table 5-4 Utility Resource Targets, by Resource Potential (MW)

UTILITY	CATEGORY 1: WWTP AND GREEN WASTE BIOGAS (MW)	CATEGORY 2: DAIRY AND AG. BIOENERGY (MW)	CATEGORY 3: FOREST (MW)	ESTIMATED BLENDED COST RANGE ($/MWH)	NET EXPENDITURE PER YEAR ($MM)
PG&E	46 *(101)*	67 *(340)*	47 *(277)*	120-180	149-228
SCE	52 *(115)*	23 *(118)*	3 *(15)*	105-165	65-103
SDG&E	11 *(26)*	0.3 *(1)*	0.4 *(2)*	85-140	8-14
Procurement Totals	110	90	50	--	222-346

Targets for each utility and resource are shown, along with the estimated service area potential in parenthesis.

This option has the lowest net cost of all the options considered, up to $30MM lower than the previous cases. PG&E would likely pay the most per MWh and on an annual basis in this scenario. This would also create a greater administrative burden on PG&E based on the number of SB 1122 projects that would now be interconnected to their system.

The two tables above assume that projects must be developed within a utility's service territory to count toward their compliance requirement. Another option, which would require a modification in the SB 1122 statute, would be to permit utilities to remove this siting restriction (Option 6). For example, if SDG&E was allowed to procure energy from projects located in other utility service territories, this could lower the cost of compliance even once electric wheeling charges are included. Resource targets could then be based on total statewide potential, with allocation by utility still performed on a percent of load basis. Using the resource estimates developed in Section 3, this would set a target of 61 MW for green waste (24 percent of statewide potential, thus 24 percent of the 250 MW target), 115 MW for dairy/agricultural residues (46 percent), and 74 MW for forest residues (30 percent). Allocating this potential by utility load would lead to the following distribution.

Table 5-5 Utility Resource Targets, by Resource without Locational Constraints

UTILITY	CATEGORY 1: WWTP AND GREEN WASTE BIOGAS (MW)	CATEGORY 2: DAIRY AND AG. BIOENERGY (MW)	CATEGORY 3: FOREST (MW)	ESTIMATED BLENDED COST RANGE ($/MWH)	NET EXPENDITURE PER YEAR ($MM)
PG&E	26	50	32	120-185	104-159
SCE	29	54	35	120-185	112-172
SDG&E	6	11	7	120-185	22-33
Procurement Totals	61	115	74		238-364

This type of allocation would allow greater flexibility in project selection and reduce market power by setting resource allocation targets based on total availability while maintaining the targets by utility. These goals also are the most equitable since costs for each utility per MWh will likely be similar, and the net procurement levels remain set by peak load. This would not necessarily be the least expensive option since resource availability, not price, sets the procurement targets, and some utilities will need to pay transmission fees to move the power to their service territory. Administratively, allowing the freedom to select project regardless of location makes policy implementation easier since utility specific resource availability is no longer a concern in setting procurement targets. While the FIT under SB 32 has similar service territory constraints, most of the SB 32 projects likely to be approved are solar PV which is far less resource constrained by service territory when compared to bioenergy. A bioenergy specific FIT should take greater consideration of the resource limitations and adapt the policy appropriately.

Under the current statute, Option 2 meets all requirements and takes into account local resource availability. The CPUC would need to reallocate resources by type in order to enact this option. Option 3 would take this allocation on step further, by eliminating resource categories for certain utilities if the procurement efforts are deemed too burdensome for the potential benefit. Option 6 provides the most equity on both a resource availability and utility procurement basis, but would require a statute modification that removes the service territory requirement. Option 5 (and other potential permutations) may be able to meet the overall SB 1122 obligation at the lowest cost, but these may require major changes in the allocations and lead to disproportionate ratepayer costs by service territory.

Appendix A. Resource Potential Methodology

The methodology for quantifying each resource is outlined below. Peer reviewed public datasets developed by state agencies were largely relied upon for the assessment. Any major screens used, items excluded, and major uncertainties or issues with the data are highlighted.

Wastewater Treatment Plants

Two types of WWTPs were identified as possible candidates to develop projects under SB 1122: 1) facilities that have operating anaerobic digestion but are not beneficially using the biogas produced and 2) facilities that do not have operating anaerobic digestion for biogas production. It was assumed that WWTPs that are already utilizing biogas would not be eligible for the tariff.

The unit cost of power generation at WWTPs using biogas decreases as the installed capacity increases. The consensus of many in the wastewater industry is that combined heat and power (CHP) applications are economically unfeasible for most WWTPs with average influent less than 10 million gallons per day (MGD). Therefore, when evaluating the potential to install a new digestion unit, this study only focused on WWTPs greater than 10 MGD. While biogas production varies in relation to the characteristics of the WWTP raw wastewater and liquid stream treatment processes, this evaluation was based on the assumption that a "typical" 10 MGD facility will produce enough biogas to support roughly 300 kW of power generation. Smaller digestion and CHP facilities are technically possible but will require a higher feed-in tariff rate. All facilities with operating digesters that are not currently using their biogas regardless of size were included in the resource potential estimates.

An online database (www.biogasdata.org) was used to identify candidate WWTPs in California. This newly released website presents data collected by a team of biosolids and biogas experts across the country, including Black & Veatch, the North East Biosolids and Residuals Association (NEBRA), and many other organizations. Potential biogas and electricity production rates were estimated based on average plant influent flows of identified WWTPs.

After identification of candidate facilities, the MW potential for each facility was estimated using assumptions for the total solids, volatile solids, solids reduction, gas production rate, and methane content. Gas is assumed to be used in a reciprocating engine generator with a 35 percent electrical generation efficiency. The engine generator is assumed to have selective catalytic reduction technology for NOx control and a catalytic oxidizer for CO reduction.

Low Solids Green Waste

Four types of low solids green waste were quantified: food processing waste, food waste present in the municipal solid waste (MSW) stream sent to landfills, leaves and grass in MSW, and FOG. These resources were characterized together since all would be eligible for the 110 MW biogas requirement.

Different datasets were used to quantify these resources. For food processing waste, the 2011 California Biomass Collaborative (CBC) and California Energy Commission (CEC) report *California Food Processing Industry Organic Residue Assessment* was used. This report quantifies low solid residues from food processors including fruit and vegetable canneries, fruit and vegetable processors, dairy creameries, wineries, and meat processors. The report excludes data from soft drink manufacturers, sugar refineries, and snack producers, as responses to the CBC surveys were limited. For food waste, leaves, and grass, data from the 2007 CEC and CBC report *An Assessment of Biomass Resources in California* was used. This report quantifies the recoverable potential of different MSW components that are currently being landfilled. SB 1122 eligible resources that are currently being diverted from the MSW stream and resources already being used in operating anaerobic digesters were not included in the resource potential estimates. Finally, gross state FOG potential was developed based on NREL estimates for FOG production per person. CEC 2017 population estimates by county and recoverability approximations (50 percent of the gross stream) were then applied to develop a technical potential.

Power generation potential using these resources was made through operating plant and literature estimates for methane yield per dry ton of material. Food waste yields are from operating experience at EBMUD's facility in Oakland (13,300 ft^3 methane/dry ton), while FOG (39,900 ft^3 methane/dry ton) and leaves/grass (6,650 ft^3 methane/dry ton) are based off of literature surveys from multiple sources. The biogas produced is assumed to be combusted in a reciprocating engine generator with a roughly 35 percent electrical generation efficiency.

Dairy Cattle Manure

Several publicly available resources were consulted to develop an estimate of dairy cattle manure in California:

- Dapper, K., G. Dashiell, L. Tang, *California Dairy Statistics 2011 Data,* California Department of Food and Agriculture, Dairy Marketing Branch
- United States Department of Agriculture, National Agricultural Statistics Service
- United States Environmental Protection Agency, AgSTAR database of operating anaerobic digester projects updated as of September 2012
- Kitto, B., *Final Dairy Waste to Energy Site Selection Report – Addendum No. 1, Attachment 1 (California Dairies)*, California Energy Commission, Contract No. 500-00-036, Task 3.1.2 – Site Selection (2005)

The California Department of Food and Agriculture (CDFA) publication summarizes total head counts of dairy cattle and farms per county in 2011. While this was used as the primary data source, total dairy cattle head counts were omitted for certain counties. The National Agricultural Statistics Service (NASS) database was consulted to obtain dairy cattle head counts as of January 1, 2012 for counties omitted from the CDFA report.

The total dairy cattle head counts per county were used as the baseline to quantify gross MW potential. Based on the head counts, capacity estimates were made using USDA assumptions for methane production per cow at a flushed freestall dairy using plug flow digesters. Energy generation potential was then based off the use of an internal combustion engine with a roughly 35 percent electrical generation efficiency. Electricity generation capacities associated with existing anaerobic digesters in California were subtracted from the gross potential for counties with operating dairy manure digesters. The estimate assumes the same methane production rate regardless of how specific dairies are configured, which may overstate production for some locations that use different systems for manure collection.

Sustainable Forest Management Byproducts

The data used to quantify the amount of sustainable forest management byproducts in fire threat treatment areas (FTTAs) was provided by the CEC and California Department of Forestry and Fire Protection (CAL FIRE). The 2005 CEC/CAL FIRE report *Biomass Potentials from California Forest and Shrublands Including Fuel Reduction Potentials to Lessen Wildfire Threat* is the basis for the resource assessment, focusing only on non-merchantable forest slash and thinnings in FTTAs. Conference calls were held with CAL FIRE and USFS staff to confirm that the approach for forest resources assessments was reasonable and that the data satisfies SB 1122 requirements. These resource potentials have already been screened so that only material that can be accessed by commercial harvesting operations sustainably is reflected in the resource estimates.

Material classified as "shrub" was excluded from the resource assessment. This material is more difficult to collect, is typically at locations of higher slope, and of poorer quality than forest biomass. Very little shrub biomass is currently used for power generation given these issues and potential impacts on feeding and conversion at the energy facility. In addition, environmental constraints to large scale shrub collection in Southern California may create limitations on the amount of material than can be harvested.

GIS data from CAL FIRE was provided to Black & Veatch for the layers appropriate for resource quantification. This data for total resource potential (dry tons/yr) was overlaid onto county and utility service area maps to estimate the geographic resource potential. This resource potential was converted to MWs of capacity using assumptions for feedstock heating content (9,027 BTU/dry lb) and the operational efficiency of a small scale biomass gasification unit with a close coupled gas combustion engine (80 percent capacity factor and a net efficiency of roughly 21 percent). Different heat content, conversion efficiencies, and geographic boundaries produce net capacity estimates lower than those estimated by CAL FIRE.

Agricultural Residues and High Solids Food Processing Waste

Two types of agricultural residues were quantified: field residues, such as orchard prunings and material left over during harvest and land maintenance, and high solids food processing waste that would be produced during material processing and packaging. The data used to quantify field residues came from the 2007 CEC/CBC state resource report, specifically looking at orchard/vineyard, field/seed crop, and vegetable crop residues. The technical potential defined by the CEC in 2017 was used as the starting point, with discounts applied for already operating facilities, assumptions for future competing uses, and availability.

The 2007 and 2011 CBC/CEC reports used to quantify low solids food processing waste was also used to quantify high solids wastes. The 2011 report was the main data source, with the majority of the potential from nut shells and hulls. The 2007 CEC report was used to supplement this analysis by including estimated quantities for rice hulls and cotton gin waste.

This resource potential was converted to MWs of capacity using different assumptions for feedstock heating content, ranging from 7,387 to 8,598 BTU per dry pound. The same type of conversion unit (gasification with close coupled engine operating at 21 percent efficiency) used in estimating forest resource potential was used to quantify agricultural residues and high solids food waste capacity.

Appendix B. Resource Potential by County and WWTP

Table B-1 County Resource Technical Potential, Dry Tons/Year

COUNTY	GREEN WASTE	DAIRY	FOREST	AG. RESIDUES	TOTAL
Alameda	59,551	0	2,623	760	62,934
Alpine	55	0	971	0	1,026
Amador	2,271	0	35,682	0	37,954
Butte	9,687	987	67,828	82,322	160,824
Calaveras	2,070	0	43,134	351	45,555
Colusa	4,282	0	12,364	82,484	99,130
Contra Costa	38,906	0	1,222	6,302	46,430
Del Norte	865	10,581	21,861	0	33,306
El Dorado	7,374	0	83,890	846	92,110
Fresno	85,634	375,374	54,442	220,897	736,348
Glenn	3,159	56,992	8,019	87,543	155,713
Humboldt	4,397	43,716	247,908	0	296,021
Imperial	11,591	25,112	0	21,559	58,263
Inyo	667	0	466	5	1,138
Kern	57,585	539,086	34,225	140,367	771,263
Kings	12,241	601,754	15	62,457	676,466
Lake	3,669	0	46,808	4,339	54,816
Lassen	987	0	51,885	327	53,199
Los Angeles	428,441	0	4,114	330	432,886
Madera	29,625	246,270	32,433	79,852	388,181
Marin	8,297	31,190	6,612	30	46,128
Mariposa	630	0	44,317	125	45,072
Mendocino	5,762	0	208,931	5,574	220,266
Merced	22,001	837,181	1,819	113,832	974,833
Modoc	291	0	33,764	2,092	36,147
Mono	1,557	0	4,050	2	5,609
Monterey	28,672	0	57,825	33,658	120,156
Napa	19,579	0	29,633	13,157	62,370
Nevada	3,321	0	60,150	109	63,580
Orange	143,725	0	515	37	144,277

COUNTY	GREEN WASTE	DAIRY	FOREST	AG. RESIDUES	TOTAL
Placer	13,963	0	38,763	0	52,726
Plumas	875	0	84,222	0	85,098
Riverside	109,980	151,754	1,629	3,608	266,972
Sacramento	70,027	47,737	209	22,427	140,399
San Benito	4,757	0	24,725	2,883	32,365
San Bernardino	92,501	247,037	7,213	1,295	348,046
San Diego	145,131	7,687	14,952	6,256	174,026
San Francisco	24,595	0	0	0	24,595
San Joaquin	71,975	338,576	1,012	69,119	480,681
San Luis Obispo	16,128	0	50,833	14,534	81,495
San Mateo	25,033	0	7,137	127	32,298
Santa Barbara	19,438	0	22,569	9,814	51,821
Santa Clara	57,593	0	16,424	1,883	75,900
Santa Cruz	8,222	0	19,075	1,204	28,502
Shasta	7,454	0	216,750	2,139	226,343
Sierra	162	0	13,190	0	13,352
Siskiyou	1,377	2,245	180,291	4,209	188,123
Solano	19,738	0	880	12,691	33,309
Sonoma	29,063	92,807	91,940	17,955	231,766
Stanislaus	44,174	576,204	5,975	134,812	761,164
Sutter	5,079	0	1	81,360	86,441
Tehama	3,711	12,417	89,170	14,138	119,436
Trinity	458	0	145,567	27	146,052
Tulare	25,434	1,564,107	44,760	90,533	1,724,834
Tuolumne	1,809	0	42,647	0	44,456
Ventura	41,750	0	5,050	7,583	54,383
Yolo	16,576	0	11,219	36,278	64,073
Yuba	3,320	10,811	33,813	29,152	77,096
TOTAL	1,857,215	5,819,626	2,367,524	1,523,387	11,567,752

Table B-2 County Resource Technical Potential, MW

COUNTY	GREEN WASTE	DAIRY	FOREST	AG. RESIDUES	TOTAL
Alameda	7	0	0	0	7
Alpine	0	0	0	0	0
Amador	0	0	6	0	6
Butte	2	0	11	15	27
Calaveras	0	0	7	0	7
Colusa	1	0	2	15	17
Contra Costa	3	0	0	1	5
Del Norte	0	0	3	0	4
El Dorado	1	0	13	0	14
Fresno	13	15	9	40	77
Glenn	0	2	1	16	20
Humboldt	1	2	39	0	41
Imperial	2	1	0	4	6
Inyo	0	0	0	0	0
Kern	9	21	5	25	60
Kings	2	24	0	11	37
Lake	1	0	7	1	9
Lassen	0	0	8	0	8
Los Angeles	68	1	1	0	69
Madera	5	10	5	14	34
Marin	0	1	1	0	2
Mariposa	0	0	7	0	7
Mendocino	1	0	33	1	35
Merced	3	33	0	20	57
Modoc	0	0	5	0	6
Mono	0	0	1	0	1
Monterey	5	0	9	6	20
Napa	3	0	5	2	10
Nevada	1	0	9	0	10

COUNTY	GREEN WASTE	DAIRY	FOREST	AG. RESIDUES	TOTAL
Orange	23	0	0	0	23
Placer	2	0	6	0	8
Plumas	0	0	13	0	13
Riverside	17	6	0	1	24
Sacramento	10	0	0	4	14
San Benito	1	0	4	1	5
San Bernardino	12	10	1	0	23
San Diego	23	0	2	1	26
San Francisco	4	0	0	0	4
San Joaquin	11	13	0	12	37
San Luis Obispo	3	0	8	3	13
San Mateo	4	0	1	0	5
Santa Barbara	3	0	4	2	9
Santa Clara	5	0	3	0	8
Santa Cruz	1	0	3	0	5
Shasta	1	0	34	0	36
Sierra	0	0	2	0	2
Siskiyou	0	0	28	1	29
Solano	3	0	0	2	6
Sonoma	5	4	14	3	26
Stanislaus	7	22	1	24	54
Sutter	1	0	0	15	15
Tehama	1	0	14	3	18
Trinity	0	0	23	0	23
Tulare	4	61	7	16	89
Tuolumne	0	0	7	0	7
Ventura	6	0	1	1	8
Yolo	3	0	2	7	11
Yuba	1	0	5	5	12
TOTAL	278	227	371	274	1,149

Table B-3 Wastewater Treatment Plant Resource Potential

WWTP	CITY	COUNTY	HAVE OPERATING DIGESTERS?	AVERAGE FLOW, MGD	ELECTRICITY POTENTIAL, MW
Coachella VWD - WRP	Indio	Riverside	No	10	0.3
Vallejo Sanitation and Flood Control District	Vallejo	Solano	No	13	0.4
Palo Alto RWQCP	Palo Alto	Santa Clara	No	22	0.7
Central Contra Costa Sanitary District	Martinez	Contra Costa	No	54	1.6
Beale Air Force Base	Beale AFB	Yuba	Yes	0.4	0.01
Crescent City WWTP	Crescent	Del Norte	Yes	1.9	0.06
Pinole/Hercules WPCP	Pinole	Contra Costa	Yes	2	0.06
Banning WWTP	Banning	Riverside	Yes	2.2	0.07
El Centro WWTP	El Centro	Imperial	Yes	4	0.1
Yuba City WTF	Yuba	Sutter	Yes	6	0.2
Manteca WQCF	Manteca	San Joaquin	Yes	6.2	0.2
Simi Valley WQCP	Simi Valley	Ventura	Yes	9.1	0.3

Appendix C. Fire Threat Impacts and Bioenergy Plants

California faces a widespread threat of high intensity forest fires. Based on data from CAL FIRE reported in Appendix A, 48 percent of the state's 101 million acres of forest land are classified as facing high, very high, or extreme fire threats. In recent years, CAL FIRE has seen increased acres burned, greater fire severity, and modification of historic fire regimes. Regions of major fire threats can be seen in Figure C-1.

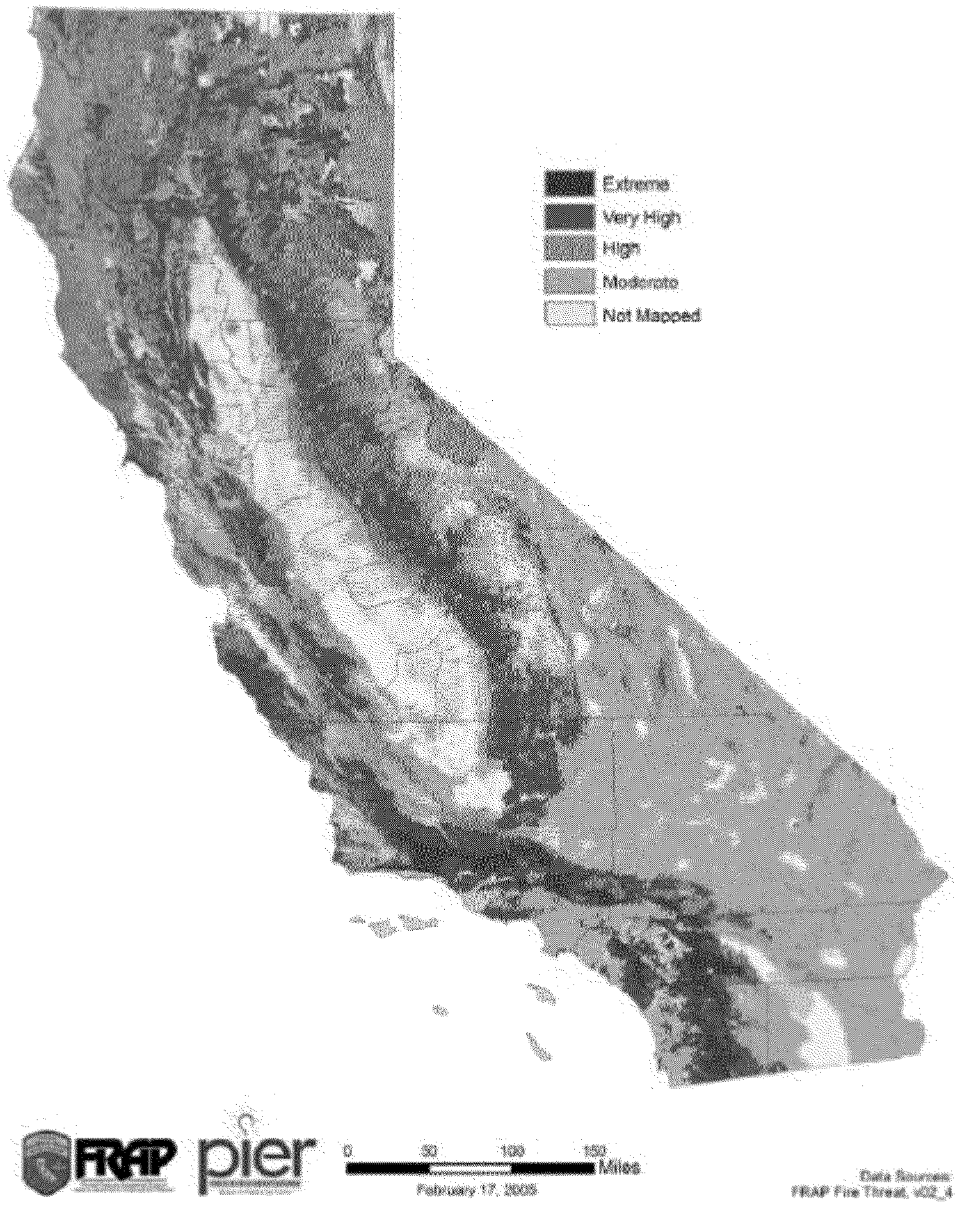

Figure C-1 California Fire Threat Classifications

One of the major intended goals of SB 1122 is to create a market for material that will be harvested from fire threat treatment areas in an effort to reduce the risk of high intensity forest fires in California. CAL FIRE estimates that the SB 1122 goals amounts to roughly 12 percent of the available non-merchantable material in state FTTAs. If these acres were treated for forest thinning, CAL FIRE states that significant reduction in high intensity fire threat on these acres would be expected. Ideally, the areas harvested would need to be selected and treated according to the treatment schedule outlined by CAL FIRE to maintain their fire hazard benefits. Scheduling issues could create interruptions to feedstock availability, since the geographic locations of the treatment areas are scattered, and individual stands are only treated periodically.

The California Biomass Collaborative reports that there are just over 700 MW of solid biomass power plants operational or under active conversion in the state. In addition, there is roughly 150 MW of idle or not operational capacity and another 123 MW of proposed new capacity. These facilities have an average size of 20 MW and use either urban wood waste, agricultural residues, or forest residues as their main feedstock, with many facilities using a blend of multiple feedstocks. Facilities are typically located near their feedstock source. The vast majority of the operational facilities are in PG&E's service territory, with projects spread throughout the Central Valley, Sierras, and Coast Range. Providing incentives for operating facilities or idle capacity to utilize material from FTTAs could help reduce the threat of high intensity forest fires. However, the size and operational history of these projects would not make them SB 1122 compliant, requiring an altogether different policy to provide these incentives.

Appendix D. LCOE Assumptions

Capital costs include all developer and owner's costs required for project development. These include costs for contractor mobilization, sitework, facilities, equipment, equipment installation, engineering, interconnection, contingencies, and fees. O&M costs include imported utilities, consumables, and labor based on average California rates. Maintenance costs are based on vendor quotes where available; otherwise, general technology assumptions were applied. Given that costs can vary substantially depending on the unique requirements for each specific project, a range of LCOEs representing low, medium, and high cost cases were made.

Because the cost estimates are for a generic facility and are not based on site-specific information, capital cost estimates presented within this report are considered to be Order of Magnitude (OOM) estimates. OOM estimates rely to a large extent on publicly available cost data and engineering judgment rather than vendor quotations. These OOM estimates are comparable to Class 5 estimates as defined by AACE, International.[9] Similarly, estimates of O&M costs are based on engineering judgment and Black & Veatch experience with facilities of similar type and size. All costs are in 2013 dollars.

Financial Model Assumptions

For every case, the same sets of economic assumptions were used. They reflect typical ownership by a taxable entity with power being sold under a power purchase agreement (PPA) back to a utility. These assumptions will change based on the tax status of the owner and the financing arrangement. The assumptions used are:

- Debt/Equity: 60/40
- Debt Rate: 7 percent
- Cost of Equity: 10 percent
- Debt Length: 15 years
- Project Life: 20 years
- Depreciation: 7 year MACRS
- Tax Rate: 40 percent
- O&M and Fuel Cost Escalation: 2 percent/year

No financial incentives are assumed in the economic model. There are a range of federal and state incentives that may be available for future projects, depending on future legislative rules and funding. Any incentives likely to be taken advantage of by project developers should be taken into account in FIT pricing. For example, projects that begin construction in 2013 would be eligible for

[9] "Cost Estimate Classification System," AACE International Recommended Practice No. 17R-97. Originally released August 1997.

federal investment or production tax credits due to new rules passed under the American Tax Payer Relief Act of 2013. SB 1122 states that projects may use state ratepayer funded incentives, but that the CPUC may require that incentive payments are refunded. Major incentives that may be available to SB 1122 compliant projects include, but are not limited to, the following:

- Federal
  - Investment Tax Credit (ITC)
  - Production Tax Credit (PTC)
  - Biomass Crop Assistance Program (BCAP)
  - New Market Tax Credits (NMTC)
  - Accelerated Depreciation
  - U.S. Department of Agriculture and other Federal Grants
- State
  - Electric Program Investment Charge (EPIC) funds
  - Renewable Energy Credits (RECs)
  - AB 32 Greenhouse Gas (GHG) Offset Revenue

In most cases, no values or disposal costs for coproducts (such as fertilizer, biosolids, and ash) outside of their use in the power generation process have been assumed. The exception is in cogeneration at WWTPs with existing digesters. In this case, it is assumed that the heat from the cogeneration unit displaces imported natural gas used for digester heating. For new anaerobic digestion projects regardless of the location, any heat produced is assumed to be used for digester heating, which is credited by assuming no natural gas purchases. Coproduct values or costs can be significant and greatly impact a project's economics. However, appropriate values are often location specific.

Interconnection costs can vary considerably depending on the location of the project and the desired power delivery point. Simple interconnections to circuits with available capacity that do not require system upgrades are assumed in the analysis. While this makes interconnection a minor cost in the analysis, this will not be the case for all projects.

Technology Specific Assumptions

Wastewater Treatment Plants

The main assumptions used in developing the capital and operating cost estimates for the WWTP biogas units are listed below. Cost estimates were made for both existing WWTPs with anaerobic digestion that are not currently utilizing their biogas and those without digesters greater than 10 MGD.

- Costs for a 10 MGD (roughly 300 kW) WWTP were developed for both cases.
- Digestion system consists of two primary digesters and one secondary digester for WWTPs that do not have digestion. All new digesters are complete mix with glass-lined steel tanks. Solids residence time is 15 days and feed total solids are 4.5 percent.
- A gas cleaning system is included that removes moisture, H_2S, and siloxanes.
- IC engines equipped with selective catalytic reduction (SCR) for NOx reduction and catalytic oxidation equipment for CO removal were selected for CHP.
- Capital costs include costs associated with digestion (for WWTPs that do not have digestion), gas cleaning, and CHP.
- O&M costs include power, labor, equipment maintenance for digestion, gas cleaning, and CHP.
- Costs associated with digested solids treatment and disposal was not included.
- Revenues associated with fertilizer sales were not included.
- It is assumed that sufficient heat is recovered from the CHP system for process heating where new digestion units are built (no supplemental heat is needed). In the existing digestion case, it is assumed that the heat recovered is used for process heating and displaces natural gas. This credit is taken into account as coproduct value.
- Feedstock is provided at no cost.

Low Solids Green Waste

The main assumptions used in developing the capital and operating cost estimates for the low solids green waste units are listed below. For this cost estimate, the basis was the largest project possible that would be SB 1122 eligible to take advantage of economy of scale benefits.

- Costs were developed for a 3 MW food waste digestion facility.
- Feedstock compositions were used for food waste from supermarkets and food processors. A methane yield of 13,300 ft^3 per dry ton and delivered solids content of 30 percent was assumed.
- The digestion system, gas cleaning, and power generation designs follow a design basis similar to that for the WWTP design, adjusted for size.
- Capital costs include costs associated with food waste pretreatment and storage, digestion, gas cleaning, and CHP.
- O&M costs include power, labor, equipment maintenance for digestion, gas cleaning, and CHP.
- The food waste digestion facility will receive a tipping fee for suppliers of the feedstock since the hauler no longer has to pay to take material to the landfill. The tipping fee is lower than the landfill tipping fee to incentivize taking material to the digester and takes into account costs for separating green waste from the MSW stream.
- Costs associated with digestate treatment (such as solid/water separation, nutrient recovery, and drying) and disposal was not included.
- Revenues associated with fertilizer sales were not included.
- It is assumed that sufficient heat is recovered from the CHP system for process heating. No supplemental heat is needed.

Dairy Cattle Manure

The main assumptions used in developing the capital and operating cost estimates for a dairy manure digestion project are listed below. For this cost estimate, the basis was for a complete mix, stand-alone facility at a large flushed freestall dairy consisting of roughly 5,500 head of cattle. The size of the facility is roughly the same as for the green waste unit (on a tons per day basis), but the power production is significantly lower due to the lower gas yield for dairy manure relative to food waste.

- Costs were developed for a 1 MW dairy manure digestion facility.
- The digestion system, gas cleaning, and power generation designs follow a design similar to the green waste design. While less expensive systems can be developed (such as a covered lagoon), the low gas yield of these units makes them less suitable for power export projects.
- Capital costs include equipment associated with manure pretreatment and storage, digestion, gas cleaning, and CHP.
- O&M costs include power, labor, equipment maintenance for digestion, gas cleaning, and CHP.
- Costs associated with digestate treatment and disposal was not included.
- Revenues associated with sales of fertilizer or AB 32 GHG offsets were not included.
- It is assumed that sufficient heat is recovered from the CHP system for process heating. No supplemental heat is needed.
- Feedstock is provided at no cost.

Forest and Agricultural Residues

For small-scale biomass power applications utilizing solid fuels (e.g., forest management byproducts or agricultural residues), it is assumed that the generation facility will employ a gasification system to produce a syngas that may be fired in IC engine generators. While a combustion system (generating steam to drive a turbine) may be feasible, it is assumed that a gasification/engine system is the most cost-effective. In addition, from a commercial perspective, internal combustion engines at this size are common while small scale steam turbines are rare.

To develop capital cost estimates for solid fuel biomass applications, the following assumptions were employed:

- The site where the project is to be located is assumed to be well suited for construction, with the following characteristics:
    - The site is relatively level and clear, with no major excavation and clearing required.
    - Utilities will be available at the site boundary.
- The facility has a net generation capacity of 3 MW. The facility consists of a 75 ton per day gasification system with necessary syngas cleanup equipment and 3- 1 MW IC engines.

- Capital costs associated with balance of plant and Owner's Costs include the following:
  - Site/civil work (including foundations)
  - Feedstock receiving/storage equipment
  - Syngas cleanup
  - Electrical switchgear
  - Facility structures
  - Interconnection to distribution grid (studies and installation of tie-line)
  - Project development (permitting, engineering, financing, legal)
- Heat rate ranges from 15,000 to 18,000 BTU/kWh, depending on the case being evaluated.
- Woody biomass from forest slash or thinning is assumed. The use of shrub biomass may impact the costs.

To develop estimates of non-fuel O&M costs for solid fuel biomass applications, the following assumptions were employed:

- Annual capacity factor of 85 percent.
- Non-fuel O&M costs include labor costs, administrative costs, major equipment maintenance, consumables, land lease, insurance, and property taxes.
- Major equipment maintenance is conducted under service contracts.
- Annual O&M budget includes no contingency and no allowance for capital expenditures.

Large Distributed Bioenergy

To develop estimates of capital cost for larger scale bioenergy DG projects, the following assumptions were employed:

- Use of a combustion system (e.g., bubbling fluidized bed or stoker boiler) to generate steam that is utilized to drive a steam turbine generator.
- The facility has a net generation capacity of 20 MW. The facility consists of:
  - A nominal 300 ton per day biomass combustion system
  - Necessary air quality control equipment (e.g., SCR for control of nitrogen oxides and an ESP for control of particulate matter)
  - A 20 MW steam turbine generator
- The project site is assumed to be well suited for construction, with site conditions similar to those assumed for the 3 MW unit.
- Heat rate ranges from 12,500 to 14,500 BTU/kWh, depending on the case being evaluated.
- Capital costs and non-fuel O&M costs associated with balance of plant and owner's costs include the cost categories for the 3 MW facility.