

Clean and Diversified Energy Initiative



WESTERN GOVERNORS' ASSOCIATION



Biomass Task Force Report

**Supply Addendum
January 2006**

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The Western Governors' Association's Clean and Diversified Energy Advisory Committee (CDEAC) commissioned this task force report in February 2005. Members of the Task Force are listed below. This is one of several task force reports presented to the CDEAC on December 8, 2005 and accepted for further consideration as the CDEAC develops recommendations for the Governors. While this task force report represents the consensus views of the members, it does not represent the adopted policy of WGA or the CDEAC. At their Annual Meeting in June, 2006, Western Governors will consider and adopt a broad range of recommendations for increasing the development of clean and diverse energy, improving the efficient use of energy and ensuring adequate transmission. The CDEAC commends the Task Force for its thorough analysis and thoughtful recommendations.

Members of the Biomass Task Force

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Quantitative Working Group

The quantitative working group was created by the CDEAC to compare the analysis of data among task forces in order to ensure consistency in assumptions across the reports.

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Quantitative Working Group

Supply Working Group Mission: Provide the Clean and Diversified Energy Advisory Committee (CDEAC) and its Biomass Task Force with a credible projection of biomass resources for power generation by 2015 and 2025. The working group must provide an analysis of raw resources and conversion systems coupled to the electric grid to estimate potential electricity supply in the WGA states.

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1. Feedstocks – Current and Future (2015 and 2025)

1.1 Feedstocks Overview

Biomass feedstocks are as diverse as the biosphere that produces them. An assessment of biomass resources was undertaken as part of the Western Governors' Association evaluation of the potential for generating additional electrical energy from clean and diversified energy resources in the WGA member states and territories. A preliminary analysis of the potential supply of biomass feedstocks in the region suggests that 12 GW_e of generating capacity could be produced from biomass. Development of biomass resources could achieve approximately a third of the CDEAC goal of 30 GW_e in new generation capacity. Preliminary results are summarized in this report, noting that many of the data are still uncertain and in need of additional research and analysis. The working group has used the best available data sources on quantity, quality, environmental constraints and cost. Included in this report are potential contributions from the following resource categories:

- Agricultural resources
- Forest Resources
 - Unused logging slash
 - Primary mill residues
 - Forest fuels treatment biomass (Timberland and other forest land treatments)
- Urban Biomass Resources
 - Biomass recovered from solid waste streams
 - Biosolids
 - Landfill gas
 - Biogas from waste-water treatment plants

Efficiency increases in the use of spent pulping liquor (black liquor) may also contribute to increased generating capacity from biomass, but good data are currently lacking and this resource is not included in the estimate. Dedicated crops also are not included in the base resource estimate described here as they do not currently contribute substantial amounts of biomass in the WGA states. Estimates for these categories will be developed for future projections.

1.2 Current Feedstock Supplies

Data were developed for each of the resource categories as outlined in the following sections. Where possible, data were compiled at the county level for each of the WGA states in the contiguous US along with Alaska and Hawaii. Data limitations resulted in Guam, American Samoa, and the Northern Mariana Islands being excluded from the current assessment.

Resource data were used to estimate potential annual electrical energy (MWh per year) and electricity generating capacity (MWe). Energy from landfill gas and biogas from waste-water treatment plants were estimated on the basis of total waste-in-place and waste-water influent rates. All other categories used estimated annual bone-dry (oven-dry) tons (BDT per year).

1.2.1 Agricultural Residues Biomass

Agricultural residue biomass resource estimates have so far been developed for all WGA states only for field and seed crops and animal manures. Data for orchard and vineyard residues, vegetable crop residues, and food processing residues (not including waste water from food processing operations) were included from the recent biomass assessment conducted for California,¹ but similar resource estimates have not yet been made for the other states. For this assessment, field crops include only wheat and corn residues estimated according to the methodology of Nelson² with the exception of the addition of rice straw in California.³ The assessment so far ignores a number of other crops for which residues may be available, but which constitute a smaller amount of resource. For wheat and corn residues, quantity of residue available was estimated on the basis of price as described below.

Agricultural crop residues are lignocellulosic biomass that remains in the field after the harvest of agricultural crops. The most common residues include stalks and leaves from corn (stover) and straw from winter and spring wheat production. Agricultural crop residues play an important role in

maintaining/improving soil tilth, protecting the soil surface from water and wind erosion, and

Energy Crops – a Future Biomass Resource

For the timeframe considered for reaching the CDEAC Goals the Biomass Task Force does not believe that energy crops will be able to play a significant role. Energy Crops used in a Biorefinery to produce products, liquid fuels as well as heat and power hold significant promise for expansion of U.S. supplies of the biomass resource in the long term. Herbaceous energy crops such as switchgrass and big bluestem have been successfully employed for co-firing in electric generating facilities in conjunction with coal in a number of applications in the United States and Europe. In certain parts of the land base that comprises the Western Governors' Association, these types of herbaceous energy crops could be produced with aid of irrigation and their production and use offers attractive energetic and environmental benefits compared to conventional fossil fuels. Implementation of switchgrass production for electricity generating facilities would provide significant and tangible energetic and environmental benefits through decreased soil erosion versus conventional agricultural practices. Reductions in soil erosion through the implementation of switchgrass averaged 98% on all cropland types.

¹ Jenkins, B.M. (ed.). 2005. Biomass resources in California: preliminary 2005 Assessment, PIER Collaborative Report, California Energy Commission Contract 500-01-016, Sacramento, CA, (<http://faculty.engineering.ucdavis.edu/jenkins/CBC/UpdateFiles/ResourceUpdate.html>)

² Nelson, R.G. 2002. Resource assessment and removal analysis for corn stover and wheat straw in the Eastern and Midwestern United States—rainfall and wind-induced soil erosion methodology. Biomass and Bioenergy 22:349-363.

³ Jenkins, B.M. (ed.). 2005. Biomass resources in California: preliminary 2005 Assessment, PIER Collaborative Report, California Energy Commission Contract 500-01-016, Sacramento, CA, (<http://faculty.engineering.ucdavis.edu/jenkins/CBC/UpdateFiles/ResourceUpdate.html>)

helping to maintain nutrient levels. While agricultural crop residue quantities produced are substantial, only a percentage of them can potentially be collected for bioenergy and bioproduct use primarily due to their effect on soil productivity and especially soil erosion. The amount of soil erosion agricultural cropland experiences is a function of many factors: crop rotation, field management practices (tillage), timing of field management operations, physical characteristics of the soil type (soil erodibility), field topology (% slope), localized climate (rainfall, wind, temperature, solar radiation, etc.), and the amount of residue (cover) left on the field from harvest until the next crop planting. A recent analysis demonstrated that under certain conditions, agricultural residue removal can potentially occur without exceeding tolerable soil loss limits.⁴

State-level supply curves expressed in terms of total dry tons available at the field edge at a given price over nine different price levels (\$12.50 to \$50.00 per dry ton) for 16 of the 18 states in the Western Governors' Association region were obtained from a private biomass consultant and utilized in this analysis. These values were estimated utilizing National Agricultural Statistics Service (NASS) corn and wheat production data for 2000-2003 and employing a procedure that estimates crop residue retention levels after harvest from continuous corn- and wheat-based rotations subject to three different field management (tillage) scenarios (conventional tillage, CT; conservation/reduced tillage, RT; and no-till, NT) such that rainfall and/or wind erosion rates did not exceed NRCS soil-specific tolerable soil loss limits. County-level supply curves at each of nine price levels were arrived at by assuming residue quantities available at any one of the nine price levels was proportional on a percentage basis to the four-year average (2000-2003) corn or wheat production level in that particular county.

In general, the amount of field crop residue available for bioenergy or bioproduct use in the WGA region is small which can be attributed to the following two reasons:

- 1) Supply for the WGA region is based primarily on the wind erosion equation (WEQ) which was not specifically developed to analyze residue removal and in utilizing residue retention or removal with WEQ, several broad-reaching agronomic assumptions had to be made to analyze residue removal even at the county-level. These assumptions probably had a rather pronounced effect.
- 2) Residue removal is heavily dependent upon field management (tillage) practices and the tillage "mix" in the 2000-2003 time period in the WGA region is heavily skewed toward conventional (one or more passes of disking and field cultivation) which, due to the large residue burial rates (>50%) associated with disking and heavy field cultivation, leaves little or no residue available for removal. The data reflect the influence of potentially employing an all no-till practice with somewhat greater residue removal amounts.

In select counties, and possibly areas within a county, there are probably "pockets" (small areas) that are not subject to the CTIC "average" tillage mix, climate conditions, soil erosion, etc. that could potentially produce enough residue for alternative end uses. Also, these numbers do not

⁴ Nelson, R.G. 2002. Resource assessment and removal analysis for corn stover and wheat straw in the Eastern and Midwestern United States—rainfall and wind-induced soil erosion methodology. *Biomass and Bioenergy* 22:349-363

directly account for any carbon losses. Included in the database are quantities available from no-till operations at the highest price, \$50.00/BDT, yielding the maximum potential resource. Lower prices and continuation of conventional tillage will reduce the amounts available.

Estimates of animal manures were derived from animal populations as reported by the National Agricultural Statistics Service (NASS) for the 2002 Census of Agriculture. Included were dairy, beef, and other cattle, hogs and pigs, and poultry. Estimates of electrical energy were based on an overall conversion factor derived from a recent California biomass assessment assuming primarily anaerobic digestion⁵.

1.2.2 Forest Biomass

Unused logging slash

Estimated quantities of unused logging slash were obtained from the Timber Products Output (TPO) interactive web assessment tool maintained by the US Forest Service⁶. Output from the TPO database in cubic feet of logging residue was converted to dry tons using a density of 25 lbs/ft³.

Forest fuel treatment & thinning biomass – Timberland and Other Forest Land

The two sections below indicate estimates of wood biomass that may be supplied annually for fuel from: 1) timberland; and 2) other forest land given selected assumptions about treatments. Timberland and other forest land area in the sixteen Western states are 141 million acres, and 80 million acres, respectively.

Two sources are cited for biomass supply estimates from timberland: 1) FTE 3.0 and 2) the DOE/USDA “Billion-ton-supply” report (references below). The Billion-ton-supply report indicates wood biomass supply that may be removed from timberland area that has a higher density of trees that would benefit from thinning, including areas that are and are not currently at high risk for stand replacement fire - 10.8 million od tons per year. The FTE 3.0 estimate indicates supply from treatments focused on areas currently at high risk for stand replacement fire – 6.2 million od tons per year. The FTE 3.0 estimate would treat a subset of the area identified for treatment by the Billion-ton-supply report. The FTE 3.0 estimates are included in Exhibit 1-1 based on the assumption that there would be greater focus on treating land with high fire hazard. Annual biomass supply from timberland could be larger if some areas with lower fire risk are treated for other forest health reasons or because they could be treated to reduce fire hazard at low cost along with nearby high fire hazard areas.

⁵ Jenkins, B.M. (ed.). 2005. Biomass resources in California: preliminary 2005 Assessment, PIER Collaborative Report, California Energy Commission Contract 500-01-016, Sacramento, CA, (<http://faculty.engineering.ucdavis.edu/jenkins/CBC/UpdateFiles/ResourceUpdate.html>)

⁶ http://ncrs2.fs.fed.us/4801/fiadb/rpa_tpo/wc_rpa_tpo.ASP

Estimates for biomass supply from other forest land area are from the “billion-ton-supply” report and indicate thinning for all forest health purposes including high fire hazard – 10 million od tons per year.

Forest fuel treatment & thinning biomass - Timberland

Estimates of forest thinning biomass to be removed in order to mitigate fire hazard *on timberland*⁷ were obtained using the Fuel Treatment Evaluator Version 3.0.⁸ The Fuel Treatment Evaluator identified 23 million acres of timberland in 12 Western states⁹ at high risk for stand replacement fire (crowning index (CI) or torching index (TI) less than 25 mi/h).¹⁰ Several thinning treatments were simulated for these acres to improve CI and TI values.¹¹ Treatments include (a) taking trees across all diameter classes (uneven-aged treatment) or (b) taking small trees first and then progressively larger trees until CI and TI targets are met (even-aged treatment).¹² For this Western Governors' Association study, a composite treatment scenario was developed for which half the eligible area (11.5 million acres) was considered for treatment *a* and half for treatment *b*. Treatment would be carried out on an eligible area only if it produced at least 300 ft³ (or about 4 oven-dry (od) tons) of merchantable wood per acre. Sales of merchantable wood (wood that can be used for higher value products, including pulpwood, lumber, posts, and poles) could offset thinning costs. Thinnings would also provide additional biomass from small trees, tops, and branches.

The 300-ft³ amount was chosen to ensure minimal revenue from merchantable wood to help offset thinning costs. We assume that areas not providing 300 ft³/acre of merchantable timber may be more inexpensively treated using other mechanical and/or burning treatments, without biomass removal. That is, the loss incurred in utilizing a small volume of small trees may exceed the cost of treating without utilization.

This composite scenario would treat 10.6 of the 23 million acres identified; more than half the eligible area did not meet the 300-ft³/acre criterion. The 10.6 million acres would provide 270 million od tons of biomass. If 0.5 million acres were treated per year, then 12.3 million od tons of total biomass would be provided per year over 22 years. One-half million acres is chosen as a tentative annual treatment area to represent a plausible moderate increase in thinning area on public and private timberland. If 50% of the biomass would be used for higher value products,

⁷ This and the following section prepared by Ken Skog and Jamie Barbour, USDA Forest Service. Timberland is forest land that has not been withdrawn from timber utilization by statute or regulation and is capable of producing 20 ft³/acre/year of merchantable wood in natural stands.

⁸ Miles, Patrick D. Aug-04-2005. Fuel Treatment Evaluator web-application version 3.0. St. Paul, MN: U.S. Department of Agriculture, Forest Service, North Central Research Station. [Available only on internet: http://www.ncrs2.fs.fed.us/4801/fiadb/fte_test2/fte_test2.asp]

⁹ Arizona, California, Colorado, Idaho, Montana, Nevada, New Mexico, Oregon, South Dakota, Utah, Washington, and Wyoming.

¹⁰ Eligible timberland acres excluded forest types where high severity fire regimes are the norm—lodgepole pine type and spruce–fir type—with the qualification that these types received limited treatment in wildland urban interface areas. Eligible timberland acres also excluded inventoried roadless areas.

¹¹ The hazard reduction targets are to (1) increase CI and TI both to >25 mi/h *or* (2) increase CI to >40 mi/h. The attainment of TI and CI targets is limited for scenarios used here by a limitation to take no more than 50% of the initial basal area in order to limit change in ecosystem structure and habitat. Removing this constraint increases biomass yield and number of acres treated to a limited degree but ensures that TI and/or CI target are attained.

¹² The treatments exclude from treatment (1) timberland in counties west of the Cascade Mountains in Oregon and Washington, (2) timberland in inventoried roadless areas, and (3) timberland in severe fire regime forest types (lodgepole pine and spruce–fir). An exception to exclusion (3) was that severe fire regime forest types received limited treatments in wildland–urban interface areas—they were treated with a thinning from below until TI and/or CI targets were met or 25% of basal area was removed.

then the remaining 50%, or 6.2 million od tons per year, may be available for fuel (included in biomass estimates for the Forest portion of Exhibit 1-1 of the WGA full report). After 22 years, more area will have moved into the higher fire hazard class, and continued thinnings would likely be required on at least 0.5 million acres per year.

Total numbers of eligible and treated acres and amount of biomass to be removed were determined using treatment features developed by specialists in fire science, silviculture, wood utilization, and economics.¹³ Features of these treatments may differ when implemented. The total number of acres treated and the total amount of biomass removed could be increased by lowering the 300-ft³/acre merchantable wood requirement, removing the limitation to harvest no more than 50% of basal area, treating more area with the uneven-aged treatment rather than the even-aged treatment, treating areas with less stand replacement fire risk (higher CI and TI), or requiring hazard to be reduced by more than indicated by the current CI and TI targets. For example, if the requirement to provide at least 300 ft³/acre were eliminated, then 23 million acres of timberland would be thinned (versus 10.6 million acres) and 318 million od tons would be removed in the 12 Western States (versus 270 million od tons).

In comparison to the 6.2 million od ton annual biomass supply for fuel estimated above, the DOE/USDA report *Biomass as feedstock for a bioenergy and bioproducts industry: The technical feasibility of a billion-ton annual supply* estimated 10.8 million od tons annual supply for fuel and bioproducts for 14 Western States. The DOE/USDA report estimated a total of 323 million od tons to be removed for fuel over 30 years while the estimate above would provide 135 million od tons for fuel over 22 years. The DOE/USDA estimate is higher primarily because it considered thinnings on all timberland without screens for fire hazard, fire regime severity, or change in structural diversity (BA removal limit).

Forest fuel treatment & thinning biomass – Other forest land

Estimates of forest thinning biomass to be removed in order to mitigate fire hazard on “other forest land” were obtained from the report *Biomass as feedstock for a bioenergy and bioproducts industry: The technical feasibility of a billion-ton annual supply*.¹⁴ Other forest land is forest land other than timberland or reserved forest land. It includes forest land that is incapable of producing 20 ft³/year of merchantable wood. 16 western states¹⁵ contain 141 million acres of timberland and 80 million acres of other forest land. The “billion-ton” report estimates 10 million od tons of wood biomass could be supplied annually for fuel or bioproducts from other forest land (included in biomass estimates for the Forest portion of Exhibit 1-1 of the WGA full report). State-level estimates of biomass removals were apportioned to the county level in proportion to the amount of “other forest land” in each county in each state.

¹³ USDA Forest Service researchers designing the treatments include Elizabeth Reinhardt and Wayne Shepperd, Rocky Mountain Research Station; Jamie Barbour, Pacific Northwest Research Station; and Ken Skog, Forest Products Laboratory.

¹⁴ Perlack, R.D. et al. 2005 *Biomass as feedstock for a bioenergy and bioproducts industry: the technical feasibility of a billion ton supply*. Oak Ridge National Laboratory, Oak Ridge, TN 60 p. http://feedstockreview.ornl.gov/pdf/billion_ton_vision.pdf

¹⁵ Arizona, California, Colorado, Idaho, Kansas, Montana, Nebraska, Nevada, New Mexico, North Dakota, Oregon, South Dakota, Texas, Utah, Washington, and Wyoming.

Primary Sawmill Residues

Estimates of unused mill residues were obtained from the Timber Products Output database¹⁶. The mill residue estimate does not so far include potential additional residues from sawlogs removed as part of forest thinning operations.

1.2.3 Urban Biomass Resources

Biomass in Municipal Solid Waste (MSW)

Values for biomass in MSW were available for California at the county level.¹⁷ Data for the remaining states with the exception of Alaska and Montana were obtained from a recent survey of state solid waste and recycling officials¹⁸. A value for annual MSW generation per capita, 1.38 tons per person per year, was calculated from the data available for the 16 states. This annual per capita factor was applied to the populations of Alaska and Montana to estimate their MSW generation. Values for moisture content (30% wet basis) and biogenic fraction of MSW (56%)¹⁹ were applied to the MSW values to arrive at estimates of biogenic dry matter in MSW for each state. This resource includes only the biomass component of MSW and not the entire MSW stream. This includes paper and cardboard, green waste, food waste, construction wood waste, and specifically excludes plastics, tires, and other non-biomass materials. Biomass in MSW diverted from landfill was determined by subtraction of disposal from generation.

Biosolids

Values for biosolids generation (dry basis) at the county level were available for California²⁰ and Hawaii²¹. Data for the remaining states with the exception of Arizona, Idaho, Kansas, and Nebraska were obtained from a recent survey of state wastewater management officials²².

¹⁶ http://ncrs2.fs.fed.us/4801/fiadb/rpa_tpo/wc_rpa_tpo.ASP

¹⁷ Jenkins, B.M. (ed.). 2005. Biomass resources in California: preliminary 2005 Assessment, PIER Collaborative Report, California Energy Commission Contract 500-01-016, Sacramento, CA, (<http://faculty.engineering.ucdavis.edu/jenkins/CBC/UpdateFiles/ResourceUpdate.html>)

¹⁸ Kaufman, S.M., N. Goldstein, K. Millrath, and N.J. Themelis. 2004. The state of garbage in America. Biocycle, January, 2004

¹⁹ See, California waste stream composite data (<http://www.ciwmb.ca.gov/WasteChar/Study1999/OverTabl.htm>), Accessed 3 May, 2004; California Solid Waste Generation and Diversion (<http://www.ciwmb.ca.gov/lgcentral/Rates/Diversion/RateTable.htm>) Accessed 3 May, 2004; Tchobanoglous, G., Theisen, H. and Vigil, S. 1993. Integrated Solid Waste Management, Chapter 4. McGraw-Hill, New York; Themelis, N. J., Kim, Y. H., and Brady, M. H. 2002. Energy recovery from New York City municipal solid wastes. Waste Management & Research, 20(3), 223-233.

²⁰ Jenkins, B.M. (ed.). 2005. Biomass resources in California: preliminary 2005 Assessment, PIER Collaborative Report, California Energy Commission Contract 500-01-016, Sacramento, CA, (<http://faculty.engineering.ucdavis.edu/jenkins/CBC/UpdateFiles/ResourceUpdate.html>)

²¹ Turn, S.Q., V.I. Keffer, and M. Staackmann. 2002. Biomass and Bioenergy Resource Assessment, State of Hawaii. Department of Business, Economic Development & Tourism, State of Hawaii. <http://www.hawaii.gov/dbedt/ert/biomass-assessment.html>

²² Goldstein, N., J. Glenn, C. Madtes 1998. Biosolids management update. BioCycle. January 1998.

Information regarding diversion of biosolids from landfill disposal was also available for California and Hawaii and is included in the table.

Wastewater (Biogas from waste-water treatment plants)

Values for wastewater generation at the county level were available for California²³. The California state total was used to calculate an annual per capita wastewater generated value of 97 gallons per day, similar to the national average value of 100 gallons per capita per day²⁴. This factor was applied to the population data to estimate wastewater generation in each of the 17 remaining states.

Landfill Waste in Place (Landfill gas-to-energy)

Data on the amount of waste currently in place in landfills in the WGA region were obtained from the USEPA Landfill Methane Outreach Program (LMOP)²⁵. Data for individual landfills were aggregated at the county level. Several California counties did not have entries in the LMOP data base and data from the California assessment²⁶ were used.

1.2.4 Total Resource Estimates

Biomass resources identified in the WGA study region total 179 million dry tons per year, of which 100 million dry tons are estimated to be available for power generation in this estimate (Exhibit 1-1). Additional resource exists in waste-in-place in existing landfills (2 billion as-is tons) and in influent flows (9 billion gallons per day) to waste-water treatment facilities (Exhibit 1-1). Of the annual biomass allocated within the WGA region, agriculture accounts for 42%, forestry 24%, and municipal or urban sources 34% (Figure 1). Animal manures account for 76% of the total agricultural biomass included, and 51% of agricultural biomass allocated to the power generation estimate.

Total estimated potential electrical energy from biomass in the WGA study region amounts to 90 million MWh (Exhibit 1-2) with an estimated generating capacity of more than 12,000 MW_e (Exhibit 1-3). Agriculture accounts for 31%, forestry 27%, and municipal sources including landfill gas-to-energy and waste-water treatment plants total 42% (Figures 2 and 3). Conversion efficiency for categories other than animal manures, landfill gas, and biogas from waste-water treatment was assumed to be 20% overall. Capacity factor was in all cases assumed to be 85%. Incremental generating capacity over existing generation from biomass remains to be explicitly

²³ Jenkins, B.M. (ed.). 2005. Biomass resources in California: preliminary 2005 Assessment, PIER Collaborative Report, California Energy Commission Contract 500-01-016, Sacramento, CA, (<http://faculty.engineering.ucdavis.edu/jenkins/CBC/UpdateFiles/ResourceUpdate.html>)

²⁴ Reynolds, T.D. and P.A. Richards. 1996. Unit operations and processes in environmental engineering, PWS Publishing, Boston.

²⁵ Anon. Landfill Methane Outreach Program. 2005. (<http://www.epa.gov/lmop/proj/xls/lmopdata.xls>) Accessed 29 May, 2005

²⁶ Jenkins, B.M. (ed.). 2005. Biomass resources in California: preliminary 2005 Assessment, PIER Collaborative Report, California Energy Commission Contract 500-01-016, Sacramento, CA, (<http://faculty.engineering.ucdavis.edu/jenkins/CBC/UpdateFiles/ResourceUpdate.html>)

determined. Current capacity in the WGA region appears to exceed 2,100 MW_e²⁷, leaving approximately 10,000 MW_e as potential new generation. Capacity in California is currently above 1,000 MW_e²⁸. As noted earlier, these resource and generation estimates require further quality assessment, review, and in some cases, updating.

²⁷ Energy Information Administration. 2004. EIA-906 database as compiled for WGA states by J. Kerstetter, New Mexico Clean Energy Development Council, 18 April 2005, personal communication

²⁸ Aldas, R.E. and M.C. Gildart. 2005. An assessment of biomass power generation in California: status and survey results. Draft California Biomass Collaborative/PIER Consultant Report, Contract 500-01-016, California Energy Commission, Sacramento, CA.

EXHIBIT 1-1 BIOMASS RESOURCES IN THE WGA REGION (AVAILABLE BDT/Y)

Note: gross total resource is on the order of 179 Million BDT/Y limits and constraints were applied to determine amounts available for use for biomass power projects.

State	Totals (BDT/y)				Totals	
	Agriculture	Forestry	Total Biomass in Municipal Wastes	Total Annual Solids	Landfilled MSW	Waste-water Treatment
					Landfill Waste in Place (as-is tons)	WWTP Influent (MGD)
Total Available	41,413,299	16,650,489	34,263,095	92,326,883	2,049,010,508	8,756
Alaska	17,022	841,148	395,191	1,253,362	4,350,000	61
Arizona	1,320,954	188,272	2,356,364	3,865,590	85,200,000	500
California	16,341,314	5,962,913	37,673,064	59,977,291	994,313,075	3,301
Colorado	4,854,834	439,931	2,039,640	7,334,405	185,977,449	419
Hawaii	694,655	0	693,223	1,387,877	15,275,033	118
Idaho	6,839,558	2,045,715	427,193	9,312,466	3,000,000	126
Kansas	8,239,709	23,947	1,841,373	10,105,028	52,270,924	262
Montana	3,605,578	1,830,625	499,550	5,935,754	12,510,766	88
Nebraska	8,555,040	52,466	938,688	9,546,193	21,124,091	167
Nevada	592,996	9,189	1,379,034	1,981,219	51,937,093	195
New Mexico	2,394,339	306,740	841,093	3,542,172	13,500,000	177
North Dakota	2,383,160	1,620	253,360	2,638,140	4,100,000	63
Oregon	3,691,655	1,510,025	1,653,052	6,854,732	52,535,000	333
South Dakota	5,065,515	122,188	219,036	5,406,738	8,185,033	74
Texas	18,554,646	1,386,460	11,632,128	31,573,235	398,285,574	2,032
Utah	1,625,351	161,592	1,003,593	2,790,535	38,530,470	218
Washington	7,865,761	1,537,766	3,471,675	12,875,202	103,726,737	574
Wyoming	1,640,599	229,890	275,507	2,145,997	4,189,263	48

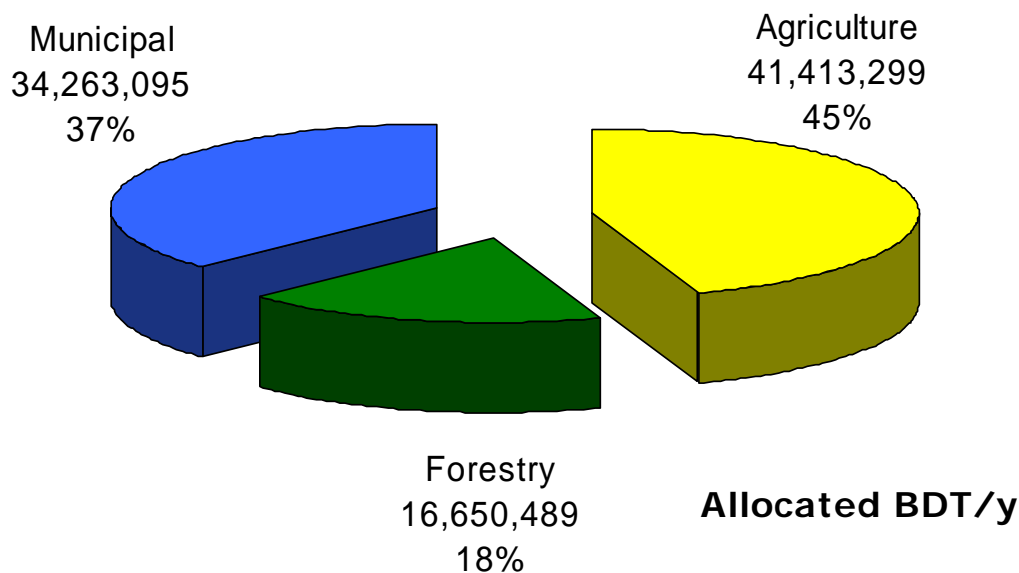


Figure 1. Biomass (BDT/y) in the WGA region allocated for power generation (does not include LFGTE and WWTP).

**EXHIBIT 1-2 POTENTIAL ANNUAL ELECTRICAL ENERGY GENERATION (MWH)
FROM ALLOCATED BIOMASS IN THE WGA REGION.**

State	Annual Generation Totals (MWh)						Annual Total (MWh)
	Annual Solids				Landfilled MSW	Waste-water Treatment	
	Agriculture	Forestry	Total Biomass in Municipal Wastes	Total Annual Solids	Landfill Waste in Place	WWTP Influent	
Total Allocated	28,365,023	16,605,671	28,412,456	73,383,149	7,242,399	1,533,322	82,158,871
Alaska	2,323	848,051	173,114	1,023,489	15,375	10,699	1,049,563
Arizona	299,776	189,817	965,128	1,454,722	301,147	87,559	1,843,428
California	6,755,094	5,830,390	15,926,886	28,512,369	3,514,483	578,054	32,604,906
Colorado	1,602,845	443,542	839,439	2,885,826	657,353	73,405	3,616,584
Hawaii	419,291	0	295,375	714,665	53,991	20,676	789,332
Idaho	3,998,434	2,062,503	173,832	6,234,769	10,604	22,083	6,267,455
Kansas	1,016,945	24,144	750,958	1,792,047	184,756	45,881	2,022,684
Montana	886,395	1,845,648	208,204	2,940,247	44,220	15,397	2,999,864
Nebraska	1,170,224	52,896	383,894	1,607,014	74,665	29,204	1,710,884
Nevada	74,655	9,264	576,737	660,657	183,576	34,102	878,335
New Mexico	462,768	309,257	346,039	1,118,064	47,717	31,044	1,196,825
North Dakota	288,916	1,633	103,806	394,355	14,492	10,960	419,806
Oregon	1,842,183	1,522,417	705,734	4,070,334	185,689	58,390	4,314,413
South Dakota	697,052	123,190	92,164	912,406	28,931	12,882	954,219
Texas	2,414,706	1,397,838	4,882,817	8,695,361	1,407,774	355,858	10,458,993
Utah	447,626	162,918	416,142	1,026,686	136,189	38,111	1,200,987
Washington	5,781,363	1,550,386	1,459,847	8,791,596	366,631	100,589	9,258,816
Wyoming	204,426	231,777	112,338	548,541	14,807	8,427	571,775

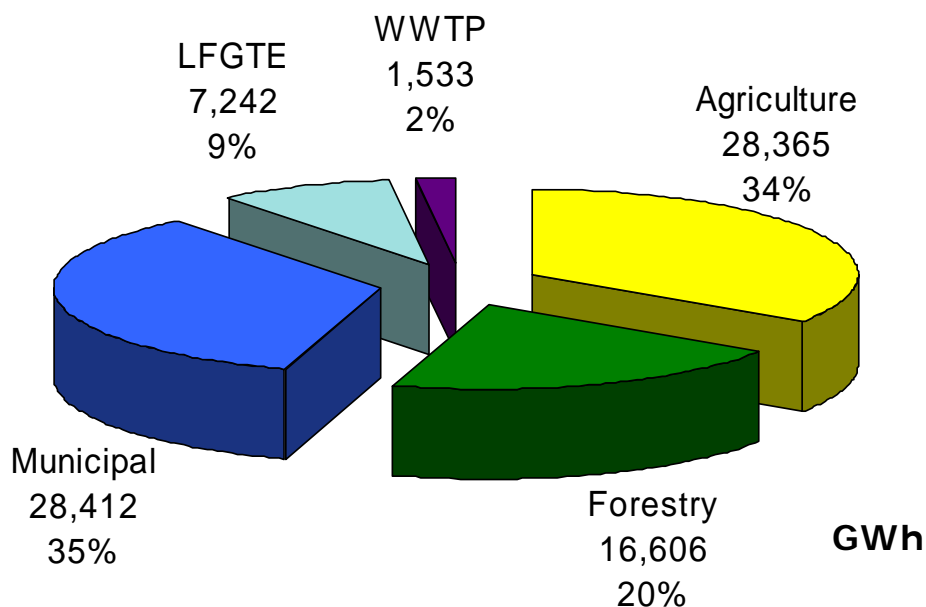


Figure 2. Potential annual electrical energy (GWh) from biomass allocated in the WGA region.

Exhibit 1-3 Potential generating capacity (MW_e) from biomass in the WGA region.

State	Generating Capacity Totals (MW _e)						Total Generating Capacity (MW _e)
	Annual Solids				Landfilled MSW	Waste- water Treatment	
	Agriculture	Forestry	Total Biomass in Municipal Wastes	Total Annual Solids	Landfill Waste in Place	WWTP Influent	
Total Allocated	3,809	2,230	3,816	9,855	973	206	11,034
Alaska	0	114	23	137	2	1	141
Arizona	40	25	130	195	40	12	248
California	907	783	2,139	3,829	472	78	4,379
Colorado	215	60	113	388	88	10	486
Hawaii	56	0	40	96	7	3	106
Idaho	537	277	23	837	1	3	842
Kansas	137	3	101	241	25	6	272
Montana	119	248	28	395	6	2	403
Nebraska	157	7	52	216	10	4	230
Nevada	10	1	77	89	25	5	118
New Mexico	62	42	46	150	6	4	161
North Dakota	39	0	14	53	2	1	56
Oregon	247	204	95	547	25	8	579
South Dakota	94	17	12	123	4	2	128
Texas	324	188	656	1,168	189	48	1,405
Utah	60	22	56	138	18	5	161
Washington	776	208	196	1,181	49	14	1,243
Wyoming	27	31	15	74	2	1	77

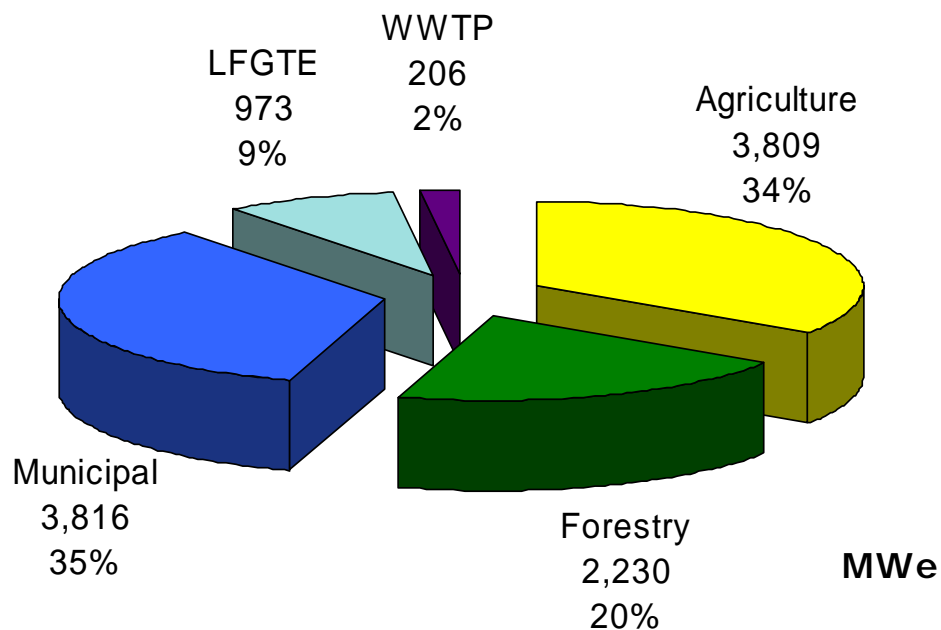


Figure 3. Potential generating capacity (MW_e) from biomass allocated in the WGA region.

1.3 Overlaying Advances in Resource Recovery

The working group will address growth in productivity of the resource and advances in resource recovery with time. This includes everything from advances in harvesting technology to improvements in source separation and treatment of municipal sources of biomass that all make more biomass available at lower cost.

2. Biomass Transportation Infrastructure

2.1 Current Transportation Infrastructure

For solid fuels truck transport is the dominant method of feedstock transport. Barge and train transport are used only in a very few instances currently. Basic truck transport cost functions are well known from an earlier report by Antares is reported here to illustrate the methodology for determining transport costs.²⁹ Based on the data in the Statistical Abstract of the United States (1997), the total outlay for local transportation was \$122 billion in 1996. Local trucking (non-intercity) ton-miles logged was 506 billion in 1996. This implies a national average local freight charge per ton mile of approximately \$0.2411. As a counterpoint, Antares work in developing supplies for many private clients suggests that in rural areas contracts with independent transporters for biomass materials are more typically in the range of \$0.10 to \$0.15 per ton-mile. The recent USDA and DOE report on biomass supply suggested a range of transportation costs associated with forest biomass removal to be \$0.20-0.60/dry ton-mile. This equates to \$0.10 to \$0.30 per green ton-mile. For the base case we are recommending a value of \$0.20 per ton-mile as received.

To convert the national average to state averages, specific transportation price indices for different geographical areas were used. The national average was turned into a state average by multiplying the national average freight charge by the appropriate state specific transportation index. For pallets and construction and demolition materials, a particular state's major city based transportation indices were used. For primary mill wastes, the state's lowest transportation index was used to reflect the more rural nature of the location of the wood processing centers. The price per ton of residues would be a function of the transportation charge, preprocessing costs, tipping fees and distance. Included in the transportation charges are the costs of handling, loading and unloading trucks, variable transportation expenses related to distance (such as fuel, oil), truck maintenance, and return on investment. The estimate Antares reported is close to the value used by Morrison and Larson³⁰ (\$0.23 estimated for 100 mile hauls) and falls within the range of values estimated by Hughes and Wiltsee³¹ (\$0.25 to \$0.21 for 100 mile hauls).

2.2 Overlaying Advances in Transport Infrastructure.

There are potential changes in transport infrastructure that could change the delivery cost element of the equation. It is possible that by 2015/2025 biomass could be transported in a densified form at less cost per MMBTU-mile as unrefined biomass oils or pelletized biomass.

²⁹ Antares Group Incorporated (1999), "Biomass Residue Supply Curves for the United States", National Renewable Energy Laboratory, Task No. ACG-7-17078-07, Contract No. ACG-7-17078

³⁰ Morrison, Christopher, I., and Larson, Eric, D., (1996). "Cost Versus Scale for Advanced Plantation-Based Biomass Energy Systems in the USA and Brazil." Published in the 2nd Biomass Conference for the Americas Papers p.1274.

³¹ Hughes, Evan, E., and Wiltsee, George, A., Jr., (1996). "Comparative Evaluation of Fuel Costs from Energy Crops." Published in the 2nd Biomass Conference for the Americas Papers p.1300

With transportation fuel prices heading in an upward trajectory it is expected that current delivery costs will increase over time.

3. Bioconversion Technology and Applications – Current and Future (2015 and 2025)

3.1 Conversion Technologies and Applications Introduction.

This section discusses the technologies available for conversion of biomass materials into electricity. It also provides information on the conversion efficiencies, capital costs, and operating and maintenance costs. An overarching view of biopower production can be organized into a primary conversion process that converts the biomass into an intermediate product that is then converted into electricity. Exhibit 3-1 illustrates the different pathways and identifies those that will be developed in more detail. The cells with an “X” indicate an available process and the shaded cells are those we have developed efficiency and cost data. Combined heat and power applications at industrial or institutional sites can benefit from the high overall efficiency achievable. When the industry also produces a portion or all of its fuel as a byproduct, this application is very economical.

Exhibit 3-1 Conversion Technologies Evaluated

Primary Conversion					Intermediate Products	Electrical Conversion				
Stoker and Fluid Bed Combustors	Gasification	Pyrolysis	Anaerobic Digestion	Fermentation		Stirling Engine	Internal Combustion Engine	Steam turbine	Gas turbine	Fuel Cell
X	X				Heat	X				
X	X				Steam			X		
	X	X	X	X	Combustible Gas	X	X	X	X	X
	X	X		X	Combustible Liquid	X			X	X

3.1.1 Primary Conversion Technologies

Primary conversions can be classified into thermochemical and biochemical conversions. Thermochemical conversions are further divided into direct combustion, pyrolysis, and gasification. The major differences are the amount of oxygen used by the process and the intermediate products produced.

Direct combustion is the oldest conversion technology. Sustainable and optimum combustion requires using a quantity of air (oxygen) greater than the stoichiometric³² amount required for complete combustion. Complete conversion assumes all the carbon contained in the biomass is converted into carbon dioxide and all the hydrogen into water. The technologies used for direct conversion include pile burners, stoker boilers, and fluidized bed boilers. These all produce heat

³² the stoichiometric mixture is the 'ideal' mixture that will allow complete combustion

that can then be used directly, or more often, converted into steam as the intermediate product. There are many variations for stokers including the method of spreading the fuel onto the grate system and the type of grates, e.g. vibrating, sloping, water cooled. Fluidized bed boilers also have several variations including circulating bed, bubbling bed, and entrained bed.

Gasifiers are used to convert biomass into a combustible gas and they use less than stoichiometric amounts of air (air-starved environment). The biomass can be gasified using the heat generated from combustion of a portion of the biomass or from heat generated externally to the gasifier. The heat content and chemical composition of the gas depends on the gasification conditions including gasifier operating pressures, the heating method and gasification medium³³. The gas can be burned to produce heat or steam or it can be converted into liquid fuels such as methanol or diesel.

Pyrolysis involves heating the biomass in the absence of any oxygen and producing a mixture of gases, liquids, and solids. The composition and proportion of these intermediate products depends on the pyrolysis conditions and technology. The variables include the temperatures employed and the residence time of the biomass at the various temperatures. The product gases can be burned and the liquids are generally of the heavy oil type that can be further processed or burned. The solids (usually a process char) are often recycled into the pyrolysis conversion system.

Biochemical conversions include anaerobic digestion and fermentations. Anaerobic digestion is the current method for biomass resources that have high moisture contents such as animal manures. The process includes biological processes to break the carbohydrates and proteins into simple organic acids that are then converted by bacteria into methane and carbon dioxide. The process is done in the absence of air and thus called anaerobic. Fermentation involves the selective conversion of biomass materials into desired products through the selection of specific biological organisms. Most fermentation work today is focused on converting biomass into ethanol fuel.

3.1.2 Electrical Conversion Technologies

There are a variety of technologies that can produce electricity from the intermediate products produced from the primary biomass conversion technologies. All the technologies, with the exception of fuel cells, produce electricity from an electrical generator and the generator is turned by some form of mechanical driving action provided by the prime mover. The most common and technologically mature prime movers are internal combustion engines, steam turbines, and gas turbines. Stirling engines are externally heated engines that are in the early stages of development.

Fuel cells operate on electrochemical principals and their conversion efficiency is not limited by the same thermodynamic constraints that limit heat driven conversion devices. There are several variations of fuel cells depending on the electrochemical environment used. These include

³³ Air, steam, and oxygen can all be used in gasification processes

alkaline, proton exchange membrane, phosphoric acid, molten carbonate, and solid oxide. Most are in the demonstration phase of their development cycle and have high capital and operating and maintenance costs.

3.2 Commercially Accepted Conversion Technologies

This section presents the technical and economic data representative of technologies commercially accepted in the United States today. The data includes electric capacity (MW), capacity factor (%), net heat rate (Btu/kWh), capital cost (2004\$/kW), fixed operating and maintenance cost (2004\$/kW-yr), variable (non-fuel) O&M, the source of the data, and regression equations. The data will be used to determine the cost of electricity when combined with the feedstock costs, and financing assumptions. The regression equations are intended to provide reasonable cost estimates within the plant capacity ranges provided and the reader is cautioned about extrapolating to different scales. The section is subdivided into technologies using solid fuels (e.g. woody materials and agricultural field residues) and those that use biogas from animal manures, wastewater treatment plants, or landfill gas. Exhibit 3-2 shows the technologies that are most representative of those widely used today.

Exhibit 3-2 Representative Technologies

Fuel Type	Technology	Sizes, MW
Solid Fuels	Direct fired/steam turbine	5,10,25,50, 100
	Direct co-fire with coal*	7.5, 15, 30
Biogas/Manure	IC-engine	65kW, 130kW, 650 kW
Biogas/Landfill	IC-engine	1, 5

* Biomass Capacity at 10% of boiler heat input

3.2.1 Stoker and Fluidized Bed-Steam Turbines

Stoker and fluidized bed boilers combined with steam turbines represent the most widely used biomass power technology combination in the United States. They are both mature technologies. The heat rates are mainly determined by the fuel moisture content and steam pressure and temperature. The added cost for higher-pressure boilers must be compensated by the improved efficiency and this is mainly implemented in larger facilities. The data derived by NREL³⁴ show lower heat rates than that derived by EPRI³⁵ that served as the basis for the NREL study. The NREL study was completed four years after the EPRI study assumed that a fuel dryer was part of the system resulting in a greatly reduced heat rate. The data for the smaller sized facilities were from TSS³⁶ and Antares.³⁷ Exhibit 3-3 shows the data we chose to represent these technology

³⁴ R.L. Bain, W.A. Amos, M. Downing, and R.L. Perlack, Biopower Technical Assessment: State of the Industry and Technology, National Renewable Energy Laboratory, Golden, CO, NREL/TP-510-33123, March 2003

³⁵ Department of Energy Office of Utility Technologies and Electric Power Institute, Renewable Energy Technology Characterizations, EPRI, TR-109496, December 1997

³⁶ TSS Consultants, Preliminary Feasibility Study for a Biomass Gasification Facility in the Tusayan-Grand Canyon Area, The Tusayan-Grand Canyon Sustainable Energy Project Committee, Tusayan, AZ, December 2004

choices. Fluidized bed systems have similar efficiencies but tend to cost 15 to 20 percent more than stoker units. The choice of technology for a specific project depends on local conditions including the permitting requirements and the type of fuel or fuels available. Exhibit 3-4 shows the heat rates for several existing power plants taken from a report by Wiltsee.³⁸ Exhibits 3-5 show the relations between capital cost and capacity and a power curve regression equation. The regression equation for capital cost is Capital cost (\$/kW) = 5,459.5 x Capacity (MW)^{-0.2488}. Exhibit 3-6 shows the heat rates for these systems, a regression curve, and heat rates for some existing facilities. The regression equation is Heat rate (Btu/kWh) = 42,937 x Capacity (MW)^{-0.2896}.

Exhibit 3-3 Direct Combustion-Steam Turbine Operating and Economic Characteristics

Plant Size	MW	3.4	10	10	15	15	25
Capacity factor	Percent	90	90	90	90	90	90
Net heat rate	Btu/kWh	20,400	26,686	26,686	26,508	26,508	11,373
Total Capital	2004\$/kW	3,735	2,875	3,570	2,476	3,116	2,540
Fixed Operating	2004\$/kW-yr	262	270	300	219	254	89
Variable operating	2004 C/kW-hr	0.00	0.00	0.00	0.00	0.00	0.58
Technology		Pile	Stoker	Fluidized bed	Stoker	Fluidized bed	Stoker
Data Source		TSS	Antares	Antares	Antares	Antares	NREL
Plant Size	MW	50	50	60	75	100	100
Capacity factor	Percent	80	90	80	90	80	90
Net heat rate	Btu/kWh	14,486	11,373	12,325	11,373	12,325	11,373
Total Capital	2004\$/kW	2,191	2,062	1,946	1,829	1,684	1,681
Fixed Operating	2004\$/kW-yr	81	80	67	77	67	75
Variable operating	2004 C/kW-hr	0.95	0.58	0.78	0.58	0.78	0.58
Technology		Stoker	Stoker	Stoker	Stoker	Stoker	Stoker
Data Source		EPRI	NREL	EPRI	NREL	EPRI	NREL

Exhibit 3-4 Heat Rates of Existing Typical Biomass Power Plants

Plant Size (MW)	46	49	66	25	50	36	10	50
Net heat rate (Btu/kWh)	14,100	12,400	13,700	20,000	14,000	13,600	20,000	17,200
			Williams					
Facility Name	Kettle Falls	Colmac	Lake	Madera	McNeil	Grayling	Chowchilla	Shasta
Data Source	Wiltsee	Wiltsee	Wiltsee	Wiltsee	Wiltsee	Wiltsee	Wiltsee	Wiltsee

³⁷ Antares Group, Assessment of Power Production at Rural Utilities Using Forest Thinnings and Commercially Available Biomass Power Technologies, for USDA, DOE, and NREL, September 2003

³⁸ G. Wiltsee, Lessons Learned from Existing Biomass Power Plants, National Renewable Energy Laboratory, Golden, CO, NREL/SR-570-26946, February 2000

Exhibit 3-5 Relationship of Capital Cost and Facility Size

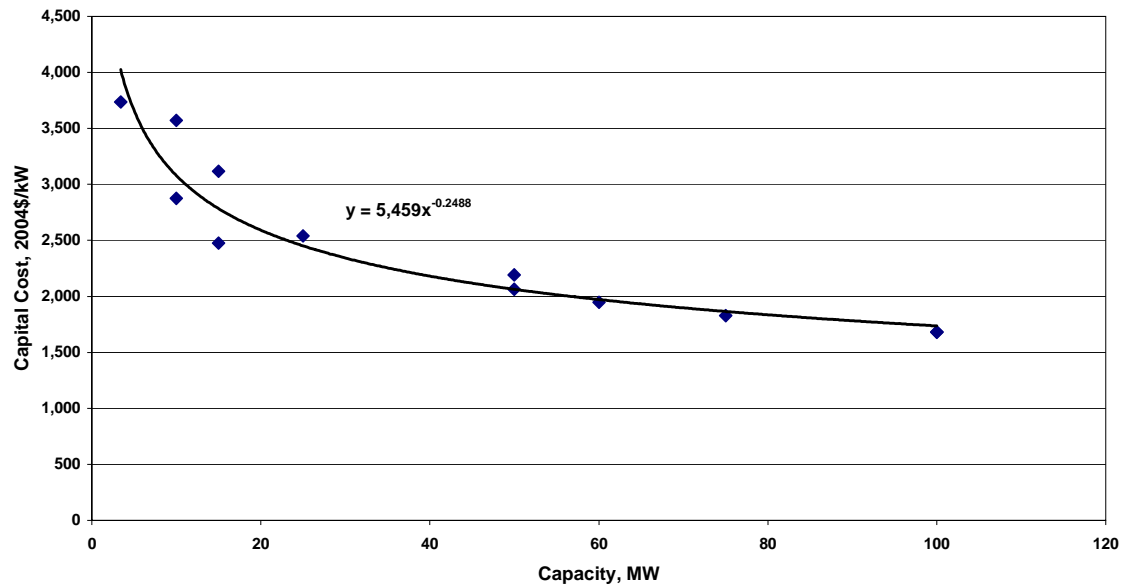
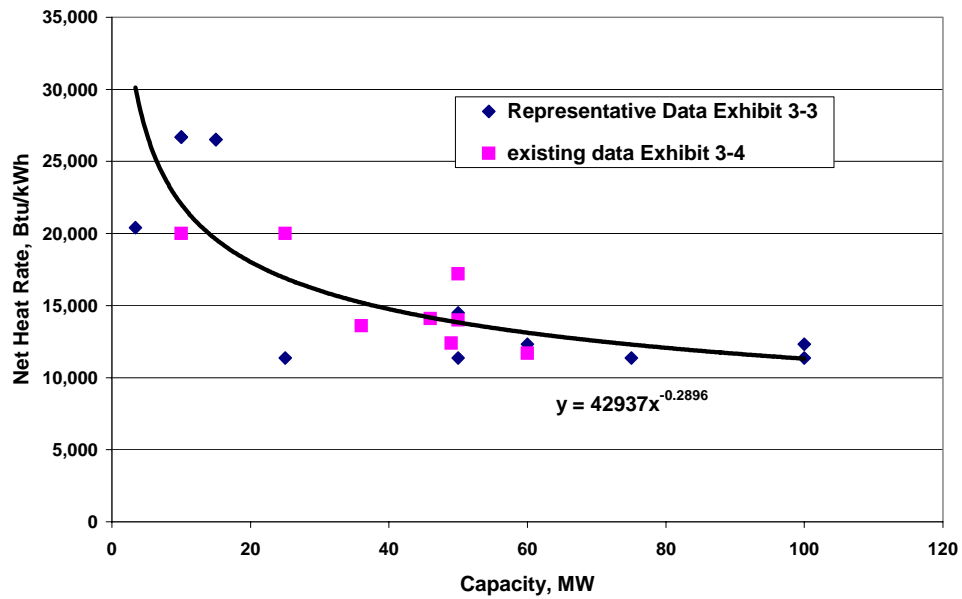


Exhibit 3-6 Heat Rates for Representative and Existing Facilities



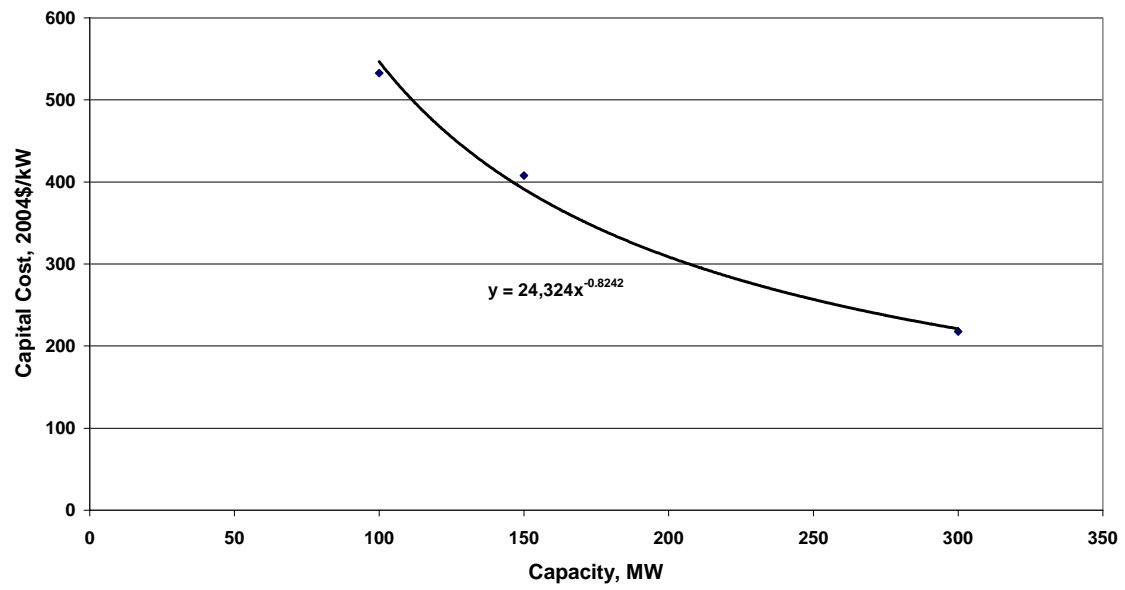
3.2.2 Direct Co-firing with Coal

Biomass can be co-fired in existing coal-fired boilers and is in commercial use at several facilities. Most co-firing involves direct introduction of a solid biomass fuel into the combustor, either blended with the coal or introduced separately. Biomass can also be gasified and the combustible gas then co-fired in the coal boiler but this option is not currently used in the United States. Exhibit 3-7 shows the operating and economic characteristics for three different sized facilities based on their coal generating capacity. The systems characterized by Antares were for automated systems that require new equipment for receiving, processing, storage, and metering. The heat rate is determined by the basic characteristics of the coal-fired unit. Exhibit 3-8 shows the relationship between capital costs and facility size along with the power curve correlation. The regression equation is Capital cost (\$/kW) = 24,324 x Capacity (MW)^{-0.8242}.

Exhibit 3-7 Characteristics for Direct Co-firing Facilities

Plant Size	MW	100	150	300
Capacity factor	percent	90	90	90
Net heat rate	Btu/kWh	14,400	14,400	10,377
Total Capital	2004\$/kW	533	408	218
Fixed Operating	2004\$/kW-yr	45	31	10
Variable operating	cents/kWh	1.07	1.07	0.19
Co-firing rate	% heat	10	10	15
Data source		Antares	Antares	NREL

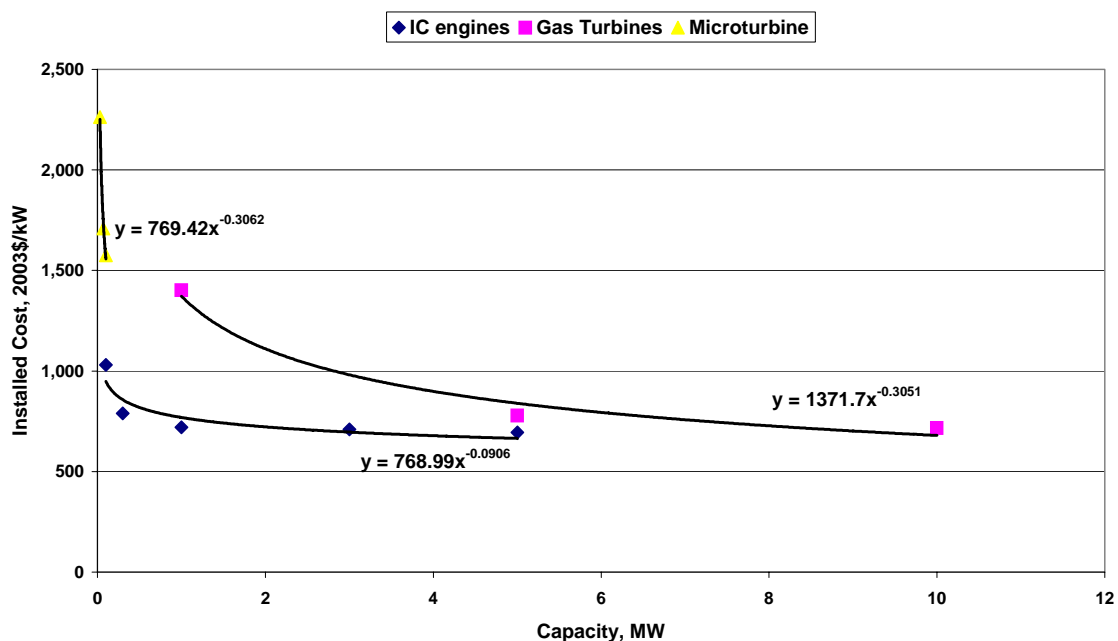
Exhibit 3-8 Direct Co-firing Relationship Between Capital Cost and Capacity



3.2.3 Biogas

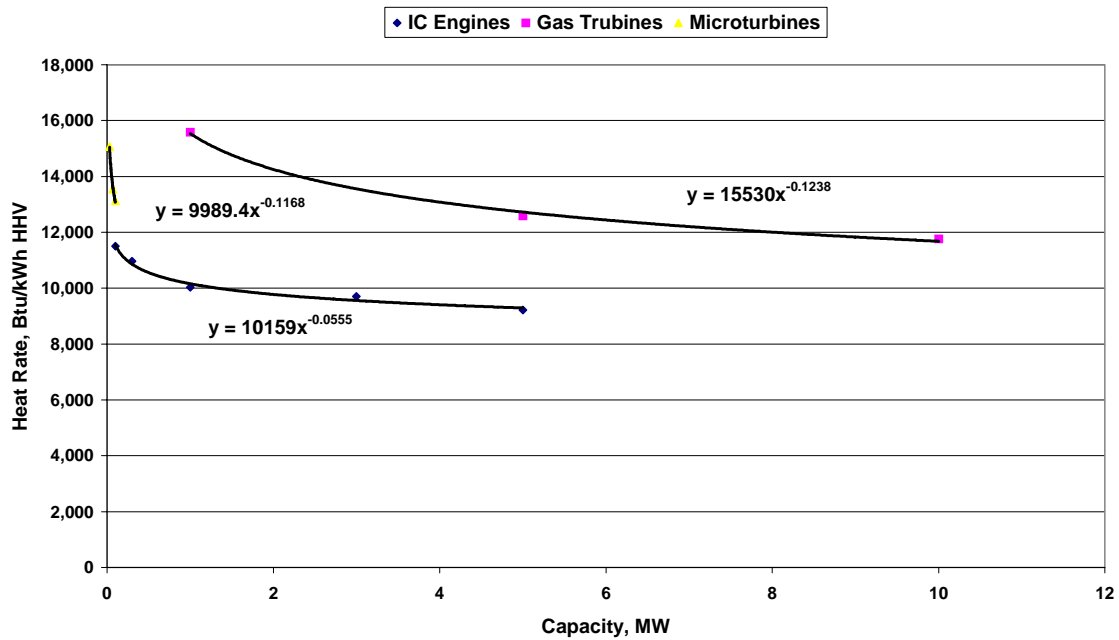
The organic portion of municipal solid waste and wastewater, industrial wastewater, and animal manures, decomposes under anaerobic conditions into biogas, a mixture of methane and carbon dioxide with some trace contaminants. Today, the most widely used technologies for producing electricity from biogas are internal combustion engines, gas turbines, and microturbines. Facilities generating biogas are generally of a relatively small size, ranging from 60 kW from animal manures to 20 MW from landfills. Exhibit 3-9 and 3-10 show the installed capital costs and heat rates for the prime movers for these smaller sized units. The data come from a recent study on natural gas fired distributed energy technologies.³⁹ Since biogas has a lower heat content than natural gas there will be some derating of the prime movers. Internal combustion engines have both lower capital costs and heat rates which account for their predominant use for biogas projects.

Exhibit 3-9 Capital Costs for Small Gas-Fired Electric Generating Technologies



³⁹ L.Goldstein, B. Hedman, D. Knowles, S. Freedman, R. Woods, and T. Schweizer, Gas-Fired Distributed Energy Resource Technology Characterization, NREL, Golden, CO, November 2003, NREL/TP-620-34783.

Exhibit 3-10 Heat rate (HHV) for Small Gas-Fired Electric Generating Technologies



3.2.3.1 Landfill Gas

Most states require the biogas from landfills be collected and either flared or used for a beneficial purpose. There are over 350 landfills that convert the collected biogas into electricity. Internal combustion engines are the predominant (75%) conversion technology with a scattering of steam turbines, microturbines, and gas turbines. Fuel cells have been demonstrated, mainly to gain experience with the gas clean-up required before using the gas in a fuel cell. Landfill electricity capacity depends on the quantity of biogas collected, the energy content of the gas, and the technology used to convert the biogas into electricity. Biogas has a lower heating value of about 450 Btu/scf.

A recent report⁴⁰ prepared by SCS Engineers for the California Energy Commission has data on operating characteristics and costs for the most commonly used conversion systems and Exhibit 3-11 shows the cost and performance data for landfill gas projects. The capital costs are for the electrical generating equipment, any compressors that may be needed and the cost of cleaning the biogas, collection costs are assumed to be part of the landfill operating costs.

⁴⁰ SCS Engineers, Economic and Financial Aspects of Landfill Gas to Energy Project Development in California, Consultant Report, # 500-02-020F, California Energy Commission, April 2002, Sacramento, CA

Exhibit 3-11 Characteristics for Landfill Gas Conversion Technologies

Technology		IC engine	Gas turbine	Microturbine
Typical size	MW	0.8-3	3-10	0.03-0.6
Net heat rate	Btu /kWh LHV	10,600	13,700	16,350
Capital Cost	2004\$/kW	1,300-1,100	1,200-1,000	2,400-1,950
O&M Cost	2004 C/kW-hr	1.6-2.0	1.4-1.8	2.2-1.8
Data Source		CEC	CEC	CEC

3.2.3.2 Animal Manure Biogas

Animal manures represent a potential source of electricity when they are processed in an anaerobic digester that generates biogas that can then be converted to electricity in an internal combustion engine. Other prime movers could be used but today IC engines are the industry standard. There are currently a limited number of facilities producing electric power from animal manure. The quantity of biogas produced from manure depends on many factors including the type of animal manure, the feeding ration given to the animal, the percent of manure that is collected, the presence of any contaminants, and the technology used to convert the manure to biogas.

A common method for estimating electric production from animal manure is to make reasonable assumptions for the amount of manure collected, the volatile solids (VS) composition of the manure, the volatile solids conversion efficiency, and a heat rate for the engine-generator. Exhibit 3-12 shows typical values for the energy content of the biogas produced from anaerobic digestion of animal manures using animal size and volatile solids production from an ASAE [8] report and the following assumptions: 5.6 ft³ CH₄ per pound of VS destroyed and 912 Btu/ft³ CH₄, lower heating value at 60° F.

Exhibit 3-12 Energy Content of Gas Produced from Anaerobic Digestion by Animal Type per Day

Animal Type	lb VS/animal-day	% VS destroyed	Btu/animal-day LHV
Dairy Cow	14.0	45	32,175
Beef Cow	5.7	45	13,238
Swine	1.15	73	4,278
Layer	0.048	76	186
Broiler	0.034	76	132

Exhibits 3- 13 and 3-14 shows capital cost data for dairy anaerobic digesters from the EPA AgStar program⁴¹ and the California Dairy Power Production Program⁴² for facilities built or under construction since 1998. The cost per kW was calculated assuming 0.13 kW per cow. The spread in costs is typical for anaerobic digesters systems since they depend on site specific conditions. There is insufficient data for other animal types to develop similar curves.

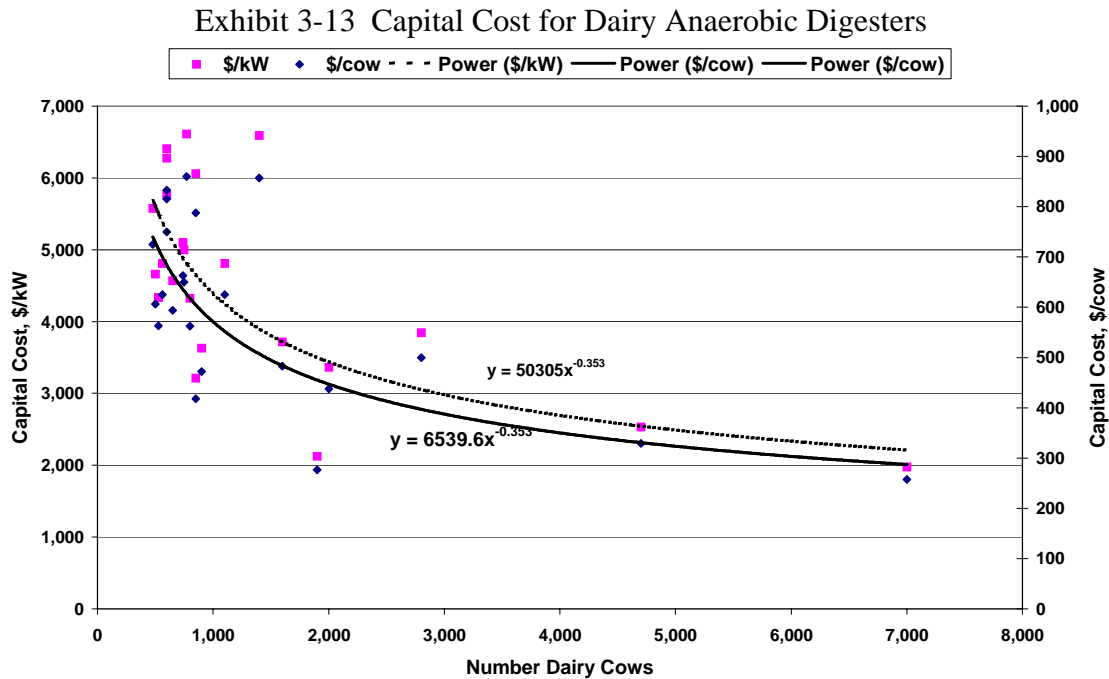


Exhibit 3-14 Capital and O&M Costs for Dairy Facilities

	Number of Dairy Cow		
	500	1,000	5,000
Capacity, kW	65	130	650
Capital cost,\$/cow	729	571	323
Capital cost \$/kW	5,600	4,400	2,500
Capacity factor, %	70	70	70
O& M Cost, \$/kWh	0.015	0.015	0.015

⁴¹ American Society of Agricultural Engineers, Manure Production and Characteristics, ASAE D384.1 Dec 99, St. Joseph, MI

⁴² Zhang, Z, Biogas Renewable Energy Projects Under the Public Interest Energy Research Program, presented at Fourth Annual Renewable Energy from Organics Recycling Conference, November 2004, Des Moines, IA, http://www.energy.ca.gov/pier/renewable/documents/2004-11-04_ZHANG_BIOGAS.PDF

3.3 Characteristics for Technologies in 2015-2025

New and improved commercially accepted technologies are expected in the coming years. Gasification is moving toward commercialization, although at a slower pace than expected. Gasification will permit the use of more efficient and lower cost electric conversion technologies including internal combustion engines and combined cycle systems. There have been several projections of future costs for these technologies as well as cost estimates for units installed today but very few, if any, have operating experience. Exhibit 3-15 shows the technologies selected as being commercially accepted in the 2015-2025 time frames. A combined heat and power case is also included based on a gasifier – gas turbine combination.

Costs are expected to decrease due to research and development, economies of scale, and project experience. Cost improvements achieved through project development and operational experience (i.e. learning) has been documented for other technologies.

Exhibit 3-15 Technologies Expected to be in Use in 2010-2025

Fuel Type	Technology	Sizes, MW
Solid	Direct Fired/Steam Turbine	25 to 80
Solid	Gasifier/IC Engine	3, 8, 15
Solid	Gasifier/Combined Cycle	13 to 110
Solid	Gasifier/Gas turbine cogeneration	6 to 25
Spent Liquor	Gasifier/Combined Cycle	150
Biogas/Landfill	IC Engines	0.5 to 10
Biogas/Manure	IC Engines and Microturbines	0.1 to 1

3.3.1 Stoker and Fluidized Bed-Steam Turbine

EPRI investigated the cost and operating characteristics for stoker fired facilities that would be built in the years 2010 to 2030. The capital costs were assumed to follow an 0.7 scaling factor with increasing size, thus indicating no cost reductions because of technology change until the year 2020 when costs dropped because of the assumed increase in efficiency through more severe steam turbine cycle conditions. Exhibit 3-16 shows the operating and capital costs developed by EPRI.

Exhibit 3-16 Projected Cost and Operating Characteristics for Stoker-Turbine

	Projected yr	2000	2005	2010	2020
Plant Size	MW	60	100	150	184
Capacity factor	Percent	80	80	80	80
Net heat rate	Btu/kWh	12,325	12,325	12,325	10,068
Total Capital	2004\$/kW	1,946	1,684	1,501	1,243
Fixed Operating	2004\$/kW-yr	67	67	67	55
Variable operating	2004 C/kW-hr	0.78	0.78	0.78	0.64

3.3.2 Gasifier-Combined Cycle Technology

The combination of a gasifier with a combined cycle electric conversion system is viewed by many as one of the more promising technology combinations for future generation of electricity and/or heat and power (CHP.) At larger scales, the advances being made in gas turbine technologies offer substantial potential for more efficient electrical generation than other prime movers.

Plant Size	MW	13	27	44	110
Capacity factor	percent	90	90	90	80
Net heat rate	Btu/kWh	10,464	9,448	9,126	8,220
Total Capital	2004\$/kW	2,2308	2,116	1,802	1,403

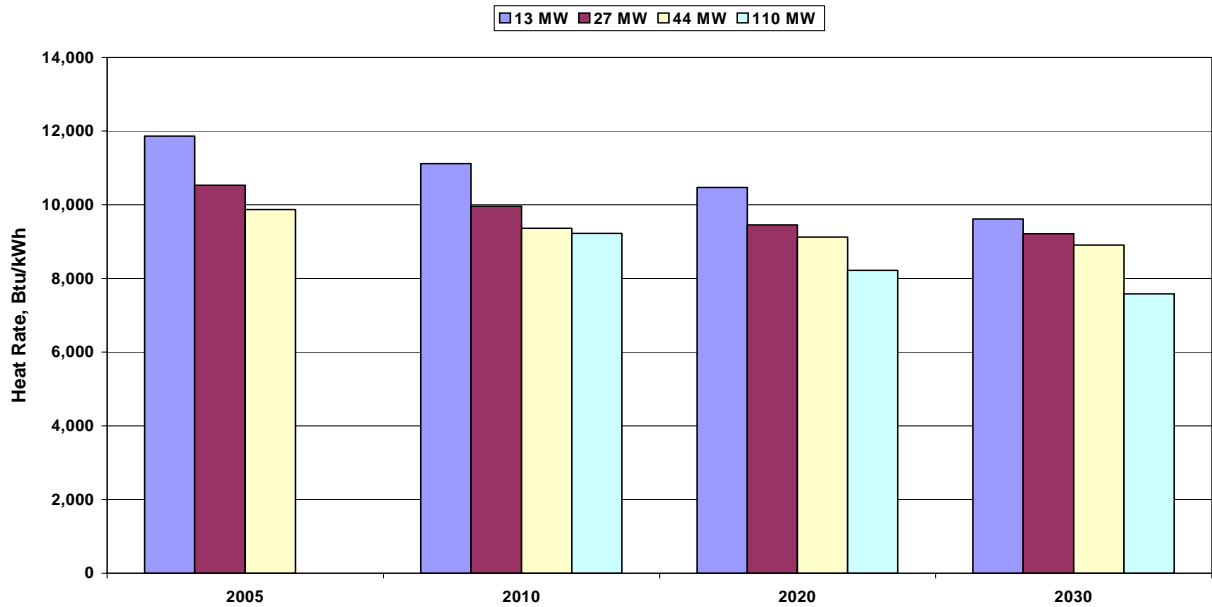
Fixed Operating	2004\$/kW-yr	151	122	109	48	EPRI has projected cost and
Variable operating	2004 C/kW-hr	.46	.46	.46	0.58	
Data source		Antares	Antares	Antares	EPRI	

performance characteristics for large (110 MW) systems for the years 2010, 2020 and 2030. Antares⁴³ estimated cost and performance data for 13, 27, and 44 MW systems for the years 2005, 2010, 2020, and 2030. Their data is based on recent studies they had completed for gasifiers and they used recent gas turbine data projected for future years. Exhibit 3-17 shows the capital cost projections over time for four system sizes. We can see the effect of economies of scale and of lower costs over time as more systems are built and run. Exhibit 3-18 shows the heat rates developed by EPRI and Antares over time and for different sized systems.

Exhibit 3-17 Projected Cost and Operating Characteristics for Gasifier-Combined Cycle

⁴³ Antares Group, Based on Model Developed for Connecticut Clean Energy Fund, Connecticut Innovations, Biomass Conversion Technology Characterization Study, February 2005

Exhibit 3-18 Heat rate for Gasifier-Combined Cycle Systems



For use in the integrating model we chose data for 2020 as representative of the future costs and heat rates. Exhibit 3-19 and 3-20 show the relationship between capital costs and facility size along with the power curve correlation. The regression equation for capital costs is $\text{Capital Cost} = 4,421.7 \times \text{Capacity (MW)}^{-0.2397}$. The regression equation for heat rate is $\text{Heat Rate} = 13,788 \times \text{Capacity (MW)}^{-0.1104}$.

Exhibit 3-19 Projected Cost and Performance Data for Gasifier-Combined Cycle Systems in the Year 2020

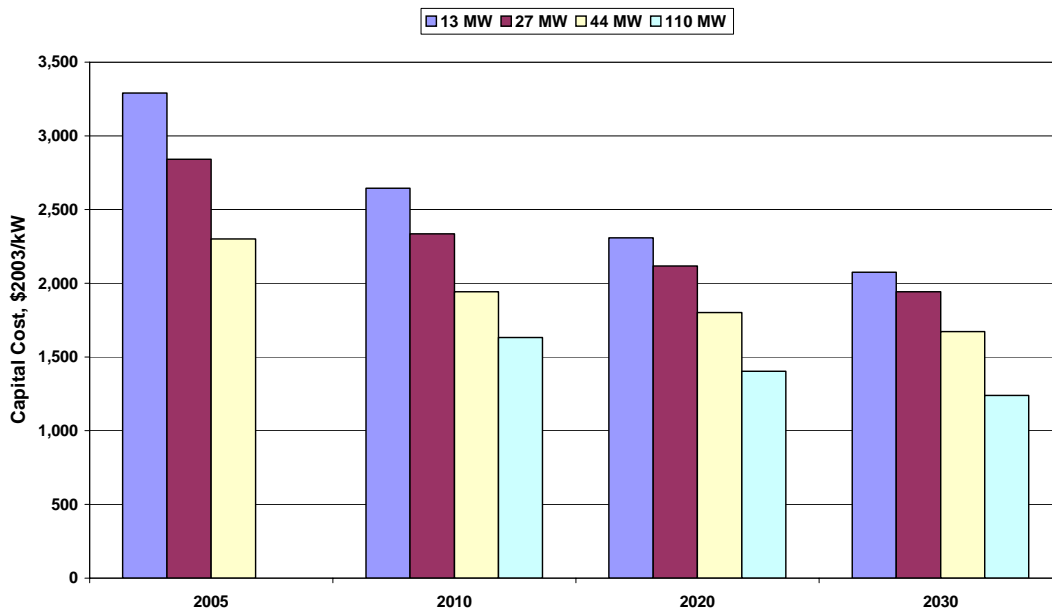
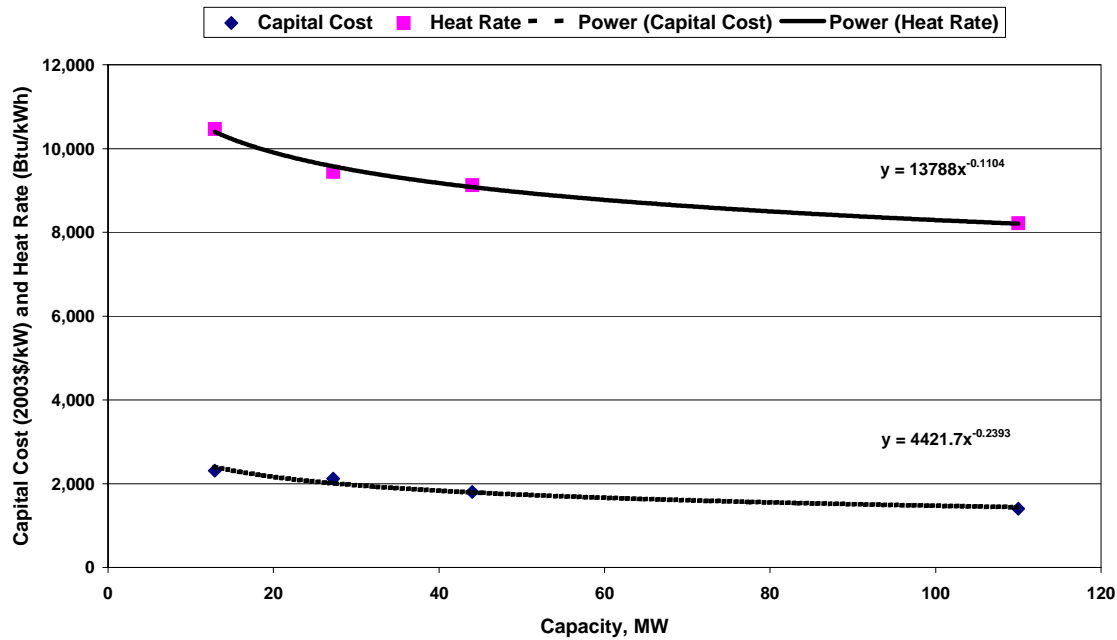


Exhibit 3-20 Capital Cost and Heat Rates for Gasifier-Combined Cycle System in the Year 2020



3.3.3 Gasifier-Gas Turbine Cogeneration

Combined heat and power applications for industry or large institutions can substantially reduce the cost of generation for any fuel. Low grade heat rejected in the power generation process and sent to a sink such as a condenser can instead be used to provide process heat to industrial applications. One way to capture this benefit quantitatively is by applying an adjusted net heat rate to the production of electricity in the cost of electricity calculations. The method assumes that the steam produced for heating is produced at typical boiler efficiencies. The heat input calculated for thermal loads is subtracted from total heat input and the adjusted net heat rate for power production can be calculated. This is a rational assignment of heat inputs to two services and permits an alternative supply curve to be produced that represents a given level of CHP penetration in the biomass generation market.

Exhibit 3-21 Cost and Operating Characteristics for Gasifier-Gas Turbine Cogeneration System - 2020

Plant Size	MW	6	15	25
Capacity factor	percent	90	90	90
Net heat rate a	Btu/kWh	5,402	4,995	4,987
Total Capital b	2004\$/kW	3,921	2,952	2,421
Fixed Operating	2004\$/kW-yr	157	127	112
Variable operating	2004 C/kW-hr	.46	.46	.46
Data source		Antares	Antares	Antares

- a. Heat rate includes useful steam energy
- b. \$/kW based on plant electrical output

3.3.4 Gasifier-Internal Combustion Engine

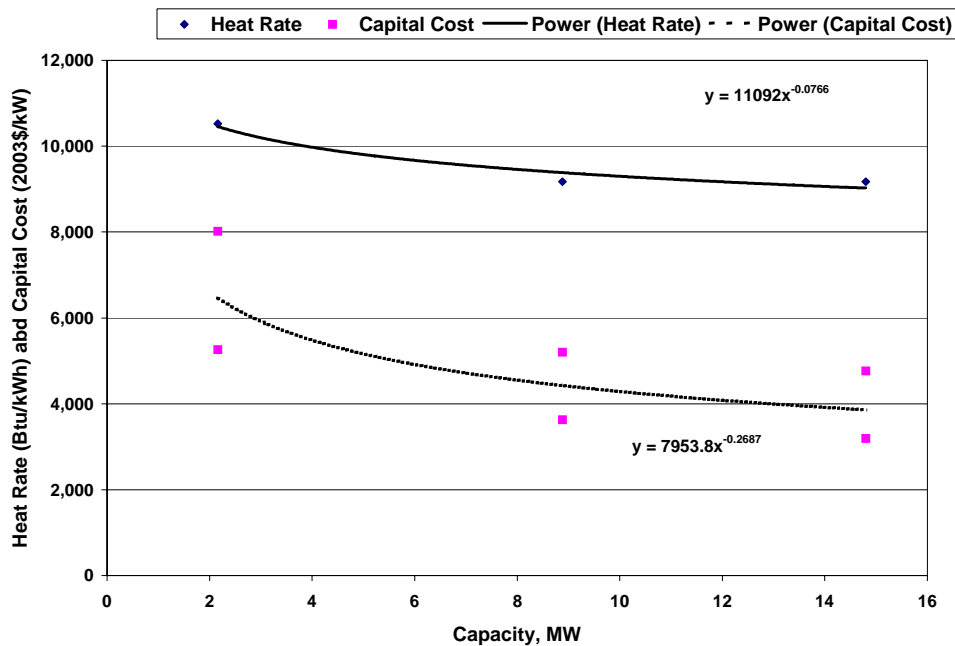
Gasifiers combined with internal combustion engines will most likely be used for smaller biomass facilities. The most consistent data set available for this report is from Antares. They developed cost and efficiency data for units, if built, with sizes from 2 to 15 MW for both a fixed bed gasifier (Lurgi) and a fluidized bed gasifier (Energy Products of Idaho). The fluidized bed systems are substantially (30-40%) more expensive. These technology combinations are currently not in commercial use in the United States. We would expect to see the costs decrease if they are produced as packaged units by achieving an economy of production. This will only occur if the demand for such units is great enough to justify the production facilities. Exhibit 3-22 shows the operating costs and characteristics for units that could be built today. A conservative projection is that these costs and efficiencies will apply to units built in the 2010 to 2020 time frame.

Exhibit 3-22 Cost and Operating Characteristics for Gasifier-Internal Combustion Engine System

Plant Size	MW	2.16	2.16	8.88	8.88	14.8	14.8
Capacity factor	percent	90	90	90	90	90	90
Net heat rate	Btu/kWh	10,520	10,520	9,175	9,175	9,175	9,175
Total Capital	2004\$/kW	5,263	8,020	3,631	5,204	3,197	4,770
Fixed Operating	2004\$/kW-yr	410	507	144	171	93	111
Variable operating	2004 C/kW-hr	1.07	1.07	1.07	1.07	1.07	1.07
Technology		Lurgi	EPI	Lurgi	EPI	Lurgi	EPI
Data source		Antares	Antares	Antares	Antares	Antares	Antares

Exhibit 3-23 shows the relationship between capital costs and heat rates for gasifier-internal combustion systems ranging from 2 to 15 MW. The power curve regression relationship for capital costs is $\text{Capital Cost} = 7,953.8 \times \text{Capacity (MW)}^{-0.2887}$. The regression curve for heat rates is $\text{Heat Rate} = 11,092 \times \text{Capacity (MW)}^{-0.0788}$.

Exhibit 3-23 Capital Costs and Heat Rates for Gasifier-Internal Combustion Engine Systems



3.3.5 Spent Pulping Liquor Gasification-Combined Cycle

The pulp and paper industry currently uses chemical recovery boilers developed over 40 years ago to recover pulping chemicals for reuse and also for the production of steam and sometimes electricity. These boilers are reaching the end of their useful life and the pulp industry is interested in developing technologies that would be safer to operate and also able to generate more electricity per ton of spent pulping liquor. There are several technology options being investigated but all are based on gasification of the pulping liquor, and producing electricity in a combined cycle operation.

Princeton University, in collaboration with Politecnico di Milano and Navigant Consulting, prepared a report on the costs for nth recovery boiler using gasification-combined cycle technology.⁴⁴ They developed costs and production capacities for a typical pulp mill in Southeastern United States. It is not a straightforward exercise to determine electric capacity and costs for facilities located in the Western Governors Association area. The model used by Princeton included some changes in the pulping process, #6 oil use for the lime kilns, NG for duct burners, and hog fuel boilers for

⁴⁴ Larson, E. D., S. Consonni, and R. Katofsky, A Cost-Benefit Assessment of Biomass Gasification Power Generation in the Pulp and Paper Industry, Princeton University, October 2003, http://www.princeton.edu/~energy/publications/pdf/2003/BLGCC_FINAL_REPORT_8_OCT_2003.pdf, accessed 5/8/2005

achieving the heat balance. Nevertheless, as a first estimate, we derived the electric production capacity based on tons of spent pulping liquor and capital and operating costs. Exhibit 3-24 gives the heat balance for the model facility and Exhibit 3-25 gives the cost data for the mill that was modeled.

Exhibit 3-24 Heat Balance for Chemical Recovery Boiler System

Heat Balance	MWt
BL to gasifier	391.1
Mill hog fuel	66.6
Purchased hog	33.4
NG to duct burner	14.3
#6 oil to lime kiln	38.2
Total input	543.6
Process Steam	200.2
Net electric	114.7
Total output	314.9
Electric efficiency	0.21
Co-gen efficiency	0.58

Exhibit 3-25 Cost and Electric Capacity Estimates for Chemical Recovery Boiler System

Plant Size	MW	115
Capacity Factor	Percent	95
Net Heat Rate	Btu/kWh	16175
Total Plant Cost	2004\$/kW	1,755
Total Capital Cost	2004\$/kW	1,778
Fixed Operating Cost	\$/kW-yr	93
Electricity from liquor	kW/ton/day	42.5
Data Source		Princeton

3.3.6 Landfill Gas

Landfill gas will continue to be used for generation of electricity. New landfills are larger in size and accept waste from a wider geographical area than in the past. Environmental regulations require collection and disposal of the biogas that is generated. As cells within a landfill are developed, the biogas is converted into electricity using a variety of prime movers.

We expect to see internal combustion engines be the most widely used prime mover through 2025. If microturbines can prove their promise of lower capital costs with

increased production and of lower maintenance costs, they may find an increasing market share. If fuel cell prices are reduced, they may also find a market as a prime mover for landfill gas applications. We suggest using existing cost and performance data from sections 3.2.3.1 for systems built through 2020 until a fully documented case is presented for using different values.

3.3.7 Animal Manures

It would only be guessing what the cost of anaerobic digesters will be in the future and what their manure to methane conversion efficiencies will be. Here again, microturbines may become more cost effective than IC engines. We do expect to see the trend towards larger facilities that would offer some economies of scale. However, as with landfill gas, we suggest using existing cost and performance data from section 3.2.2.2 for systems built through 2020.

4. Spatial Analysis and Supply Curve Development

4.1 *Developing Supply Cost Curves*

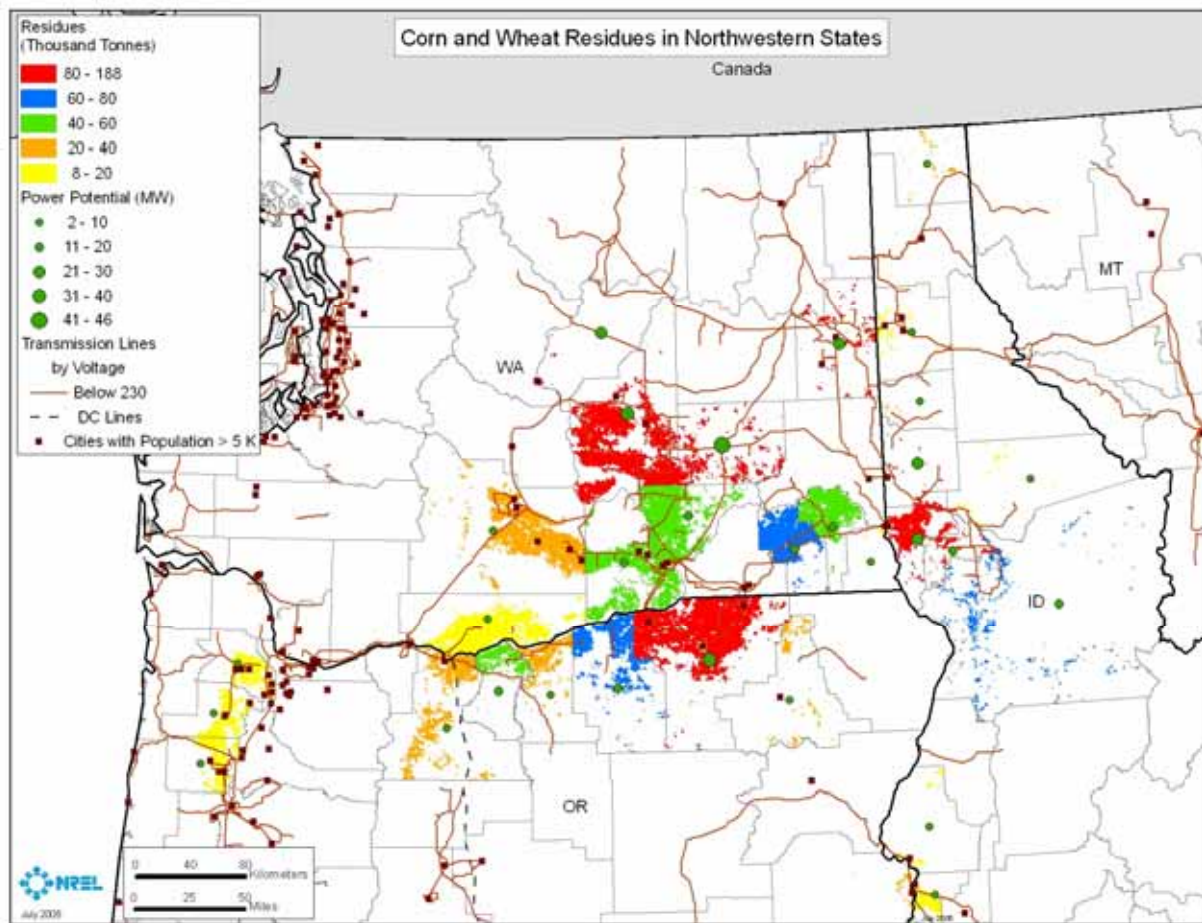
Building supply cost estimates for the WGA region requires an analysis of the spatial relationships between the biomass resources, the energy conversion facilities and the electric grid system. Considering the fairly short time horizon for the analysis the working group has developed a balanced approach to coupling resources, conversion systems and grid entry points, including the customer side of the equation.

4.1.1 Biomass is a Distributed Generation Resource

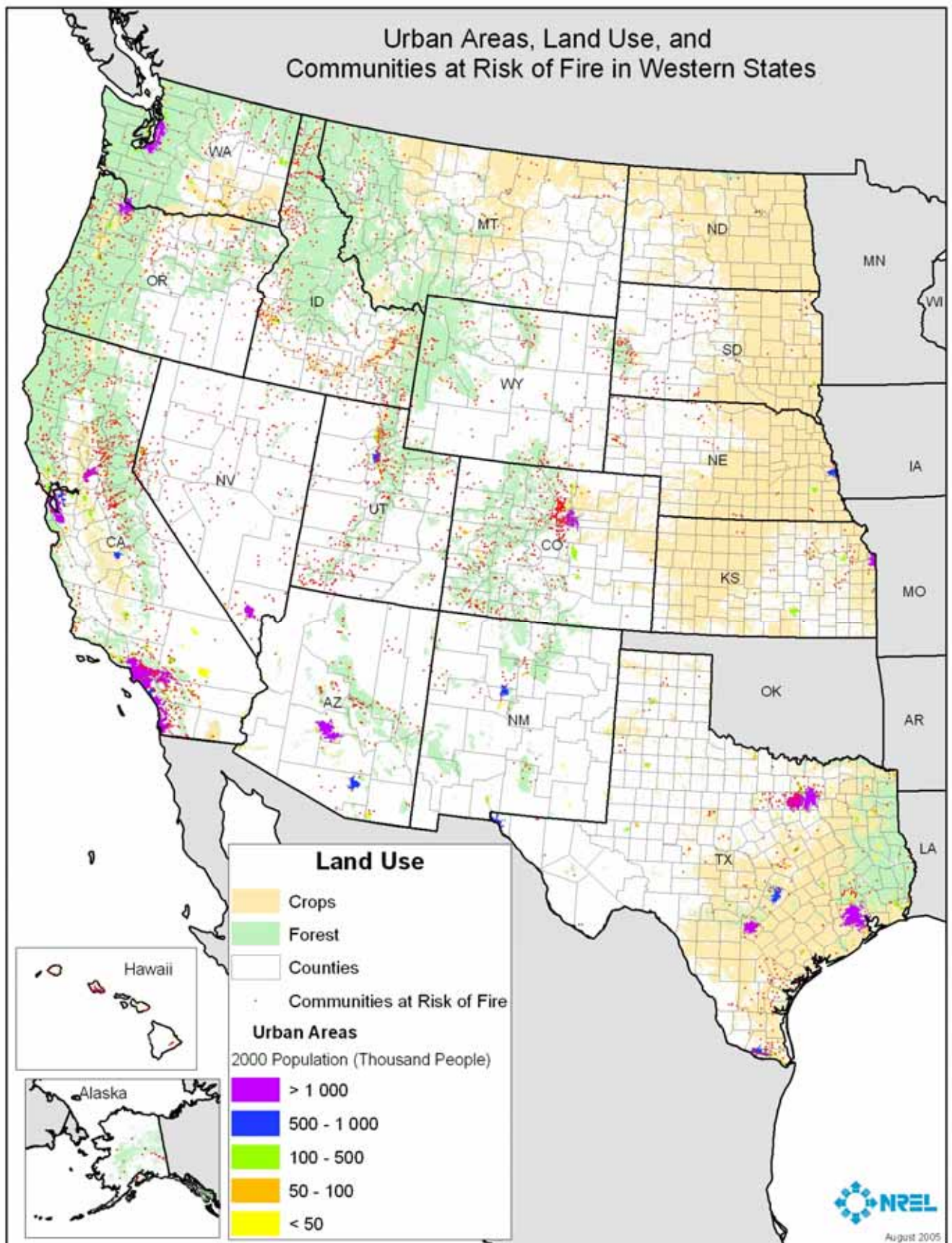
Biomass is a widely distributed resource. Fuel competition and transportation costs virtually preclude the construction of power plants of greater than 50 MW capacities. Most future solid fueled plants are likely to be in the range of 15 to 30 MW. Systems built for biogas generated from landfills and manure will typically be under 10 MW. Biomass facilities for the most part are sited to interconnect at a subtransmission voltage of 69KV or less, at a substation that feeds the distribution system or at an industrial site in a cogen application. The Biomass Task force therefore believes that biomass plants will more often provide grid support rather than strain grid capacity by serving loads at the end of the transmission line. At this stage in the analysis we do not believe that new lines or line upgrades to transmission will be required for wide biomass utilization and that biomass facilities should generally be treated as distributed generation projects. In addition, small biomass plants should not be charged with energy losses to remote load centers, but instead credited with improvements to system voltage and reliability. The task force agreed that a simplified GIS analysis is appropriate. In the analysis, the transmission grid and the location of towns and urban centers will be overlaid with biomass resource estimates to evaluate the potential to serve load centers. Areas of “stranded biomass” are not expected to be a significant portion of the resource.

Exhibit 4-1 illustrates the principles above for one important segment of the resource: potential crop residues in the Northwest. The green pins on the chart are the loci of supply sheds for crop residue supplies and not the proposed location of the plants. In nearly every instance the plants can be sited near the towns (representing load centers) and electric utility lines with carrying capacity less than 230 KV. In some cases the fuel supply will support cogeneration facilities for industries near those towns.

Exhibit 4-1 Crop Residue Supplies in Relation to Communities and Subtransmission lines.



While the analysis being performed by the National Renewable Energy Laboratory (NREL) is incomplete at this stage, we expect similar results for the forest biomass resources. This is illustrated by the proximity of potential forest resources to population centers and more importantly to communities at risk for forest fires - Exhibit 4-2 "Forest Resources in Proximity to Communities." If efforts to reduce forest fuels gain increasing community and government support, these are the sites that will likely seek to use forest resources for biomass power and other products. Greenfield plants will be added close to resources and load centers to fully utilize the potential supply.



4.1.2 Biomass Generation Supply Curves

For this analysis, NREL has combined the spatial distribution of resources, harvesting/collection costs, and a transportation cost function to determine the delivered biomass fuel cost to representative plant sites. For analytical simplicity and given that most of the resources fell within counties with nearby load centers, representative plant sites are assumed to be located at the geographic center of counties central to each biomass supply shed. Actual plant sites will be close to load centers or subtransmission lines to minimize grid connection costs.

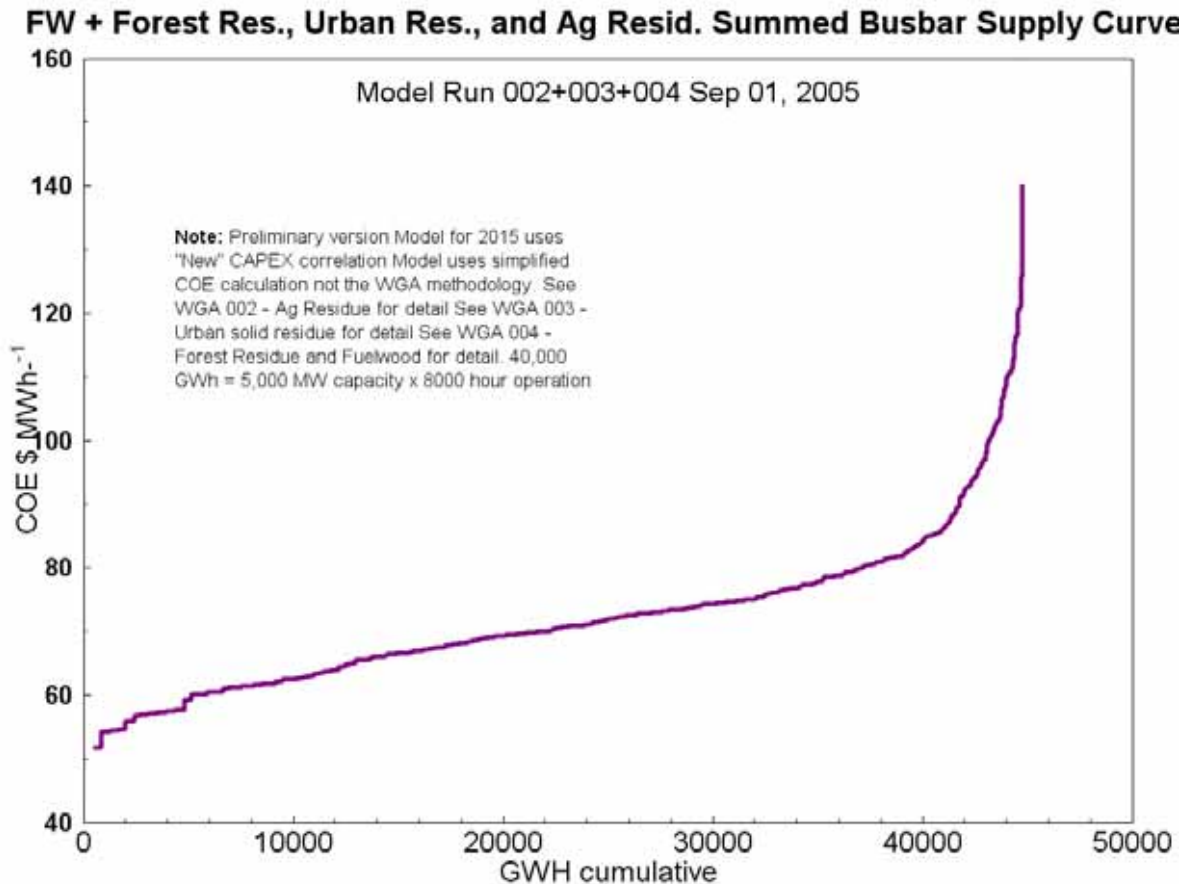
For each representative plant site NREL calculated the busbar cost of electricity using the fuel costs specific to the surrounding supply shed coupled with the conversion technology characteristic curves provided in this report. Production costs for all sites are aggregated beginning with the lowest cost resources to build a power production supply curve for the entire region. The preliminary supply curves below represent busbar costs and do not include interconnection costs. However, the analysis team believes that these costs will be partially offset by capacity credits. These credits would accrue given the likely geographic distribution of the potential sites which supports the biomass task force's contention that biomass plants will reduce the strain on the transmission system.

Exhibit 4-3 represents the preliminary aggregate supply curve prepared by NREL for biomass generated electricity in the Western States in the 2015 time frame. The cost of electricity calculation is based on the data on feedstocks and conversion technologies provided in the report with some important exceptions. Four components of supply should be added in the final version of the report to complete the picture:

- Landfill gas resources have not yet been included. This important segment of supply contributes to the lowest cost portion of the supply curve and could add several GWe of additional power supply all in urban locations. By 2015 there will be increasing competition for the use of the biomass that would be headed for the landfill in today's circumstances. That effect will be accounted for in the final supply calculation.
- Animal manure resources have not been included. Conversion of decomposing animal manures into useful energy is already making good strides and by 2015 will likely be included in best management practices for dairy, swine and cattle operation. Like landfill gas these resources contribute to the lower cost end of the supply curve.
- Pulp and paper industry byproducts (bark, pulping liquors, and paper sludges) have not been included. The readily available data for this segment of the resource was too old to include in the supply data. If a verifiable and recent source of data for this unique component of the supply can be found it should be added to the curve.
- Wastewater treatment plant sludges and biosolids have not been included. Technologies for recovering energy from these wet biomass supplies may be economic by 2015. A rough projection of their contribution to supply should be included.

Once added, these resources could add an additional 3-4 GW of dispatchable power to the curve and would represent a more complete use of the total resource potential. Exhibit NN suggests that the bulk of the biomass power generation will be produced in the gradually upward sloping portion of the regional supply curve up to a cumulative production cost of \$80/MWh. This portion of the curve represents the conversion of available fuels in areas of sufficient feedstock density for power production. The portion of the curve that moves sharply upwards is consistent with the costs of converting “stranded biomass.” That is biomass that is too widely distributed or too costly to harvest to be easily converted to power. However, some portion of this stranded biomass may be an artifact of the modeling scheme which does not attempt to treat generation facilities under one megawatt. Further, the model does not currently aggregate different types of resources in the same area, for example combining agricultural and forest supplies to fuel a plant.

Exhibit 4-3 Preliminary Aggregate Biomass Power Production Curve



The following exhibits (4-4 to 4-6) display the resource model results by feedstock category. These individual curves all share the same characteristic shape with the obvious difference that the urban resources start at a much lower cost and span across a wider range.

Exhibit 4-4 Forest Resources Supply Curve

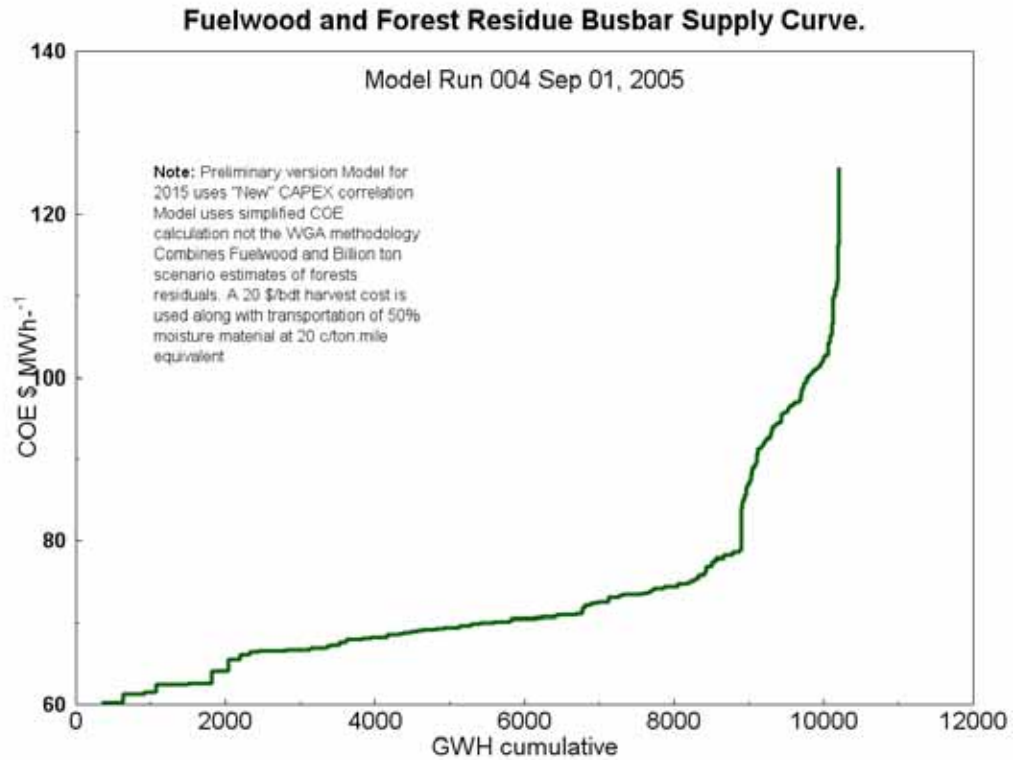


Exhibit 4-5 Agricultural Crop Resources Supply Curve

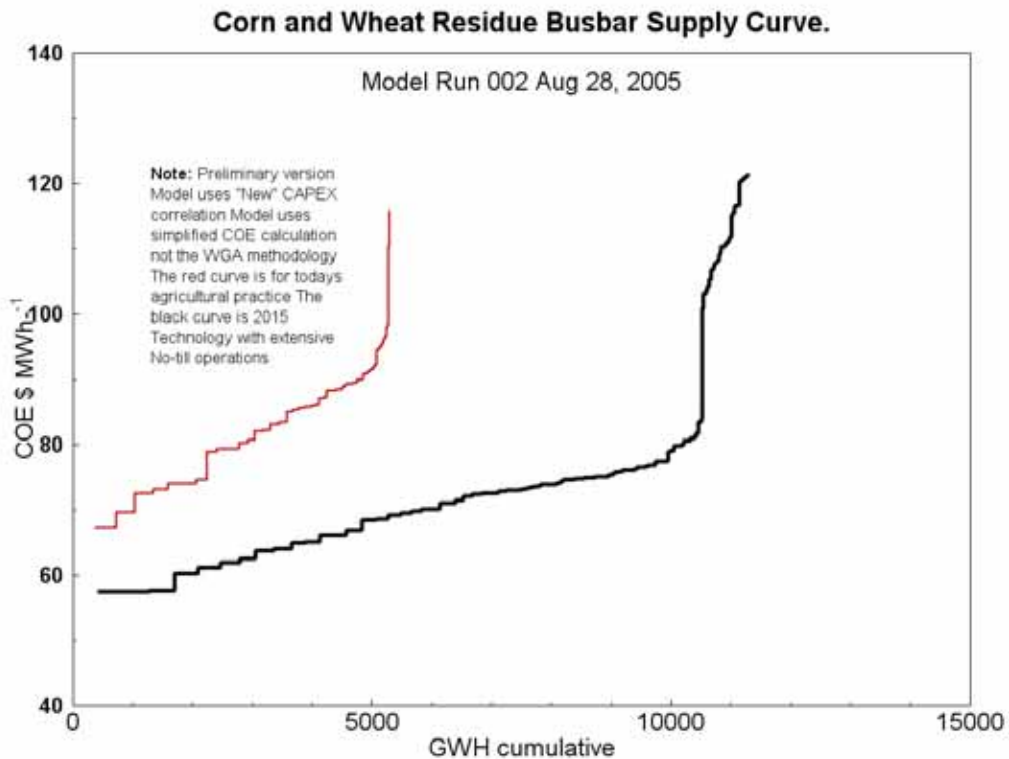
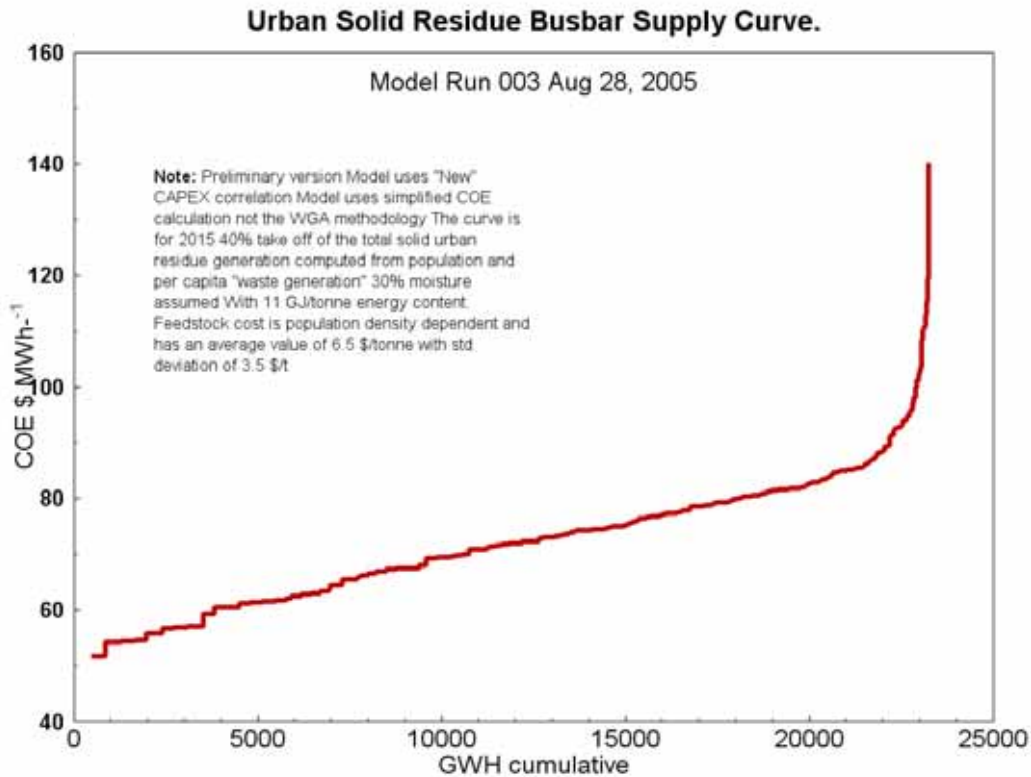


Exhibit 4-6 Urban Solid biomass Resources



4.2 Overlaying Alternative Cases and Other Considerations

To build the base case for biomass deployment some simplifying assumptions about technology choices and the relationships between the grid, plant and resource are made. In reality developers will expend considerable resources choosing plant sites and markets that will afford the best economics. To capture some of these variables the biomass task force has asked NREL to run selected alternative cases:

- Alternate agricultural field management case - increased use of reduced and/or no-till practices that can potentially increase availability of crop residues
- Technology improvements case – lower heat rates and lower production costs are projected for biomass power generation technologies
- Retail side generation (CHP) case – improved economics result when a both heat and power can be put to use in an industrial application and power is used locally
- High and low fuel transport cases - 10 cents a ton mile representing the lower end of the commercial spectrum and 30 cents per ton mile reflecting the potential effects higher transportation fuels costs (as received tons range from 15% to 50% moisture content by weight depending on the type of type of resource)
- Monetized societal benefits case – based on calculated value of environmental and fire prevention benefits assigned to specific biomass generation resources

- Monetized electric grid benefits – benefits that produce value to the grid including reduced congestion, voltage support
- Cooperative development of the biomass resource for both transportation and power generation fuels will increase fuel availability and improve economics for all uses

Only two cases have been evaluated thus far. The base case presented in this chapter is the 2015 case for technology cost and performance characteristics. Thus technology improvements have already been taken into account. The alternative field management case is shown in Exhibit 4-5. This case markedly increases the supply of this resource category and this case was incorporated into the aggregate supply curve.

4.2.1 Alternate agricultural field management

The Biomass task force will examine the effects of a realistic, but yet unrealized level of conservation tillage on the price of crop residues. The primary impact is expected to come through changes in crop yield.

4.2.2 Overlaying technology advances

An important alternative case is to account for the projected technological changes over time in each component of production costs. Technologies that make it possible for biomass to take advantage of higher efficiency prime movers including advanced cogeneration cycles can increase the energy produced from the base of resources. The conversion section of this report details the expected future technology characteristics that will be used in this analysis.

4.2.3 Retail Side Generation Case

Retail generation with biomass is possible anywhere that biomass resources and industrial heat and power demands coincide. Opportunities for success increase greatly when either the facility generates its own biomass resources or the facility is located in an area of constrained grid capacity or congestion. From a system perspective biomass generation in areas of constrained transmission capacity can generate important benefits for the electricity system as a whole and the customers served by the system. When the industrial facility generates biomass byproducts the owner can reap the dual benefits of reduced electricity consumption and productive use of processing/manufacturing wastes. This benefit will be enhanced in situations where combined heat and power applications are practical. The biomass task force is projecting the potential for retail side biomass generation as an alternative case to indicate the positive effects on the regional supply curve.

This alternative case may be evaluated two ways:

- Identifying the industries within the supply sheds developed in the base case and applying the CHP model to those resources
- Assuming a reasonable overall level of CHP development within the mix of conversion technologies

The effort to acquire data on the location and loads of the industrial facilities and the work to perform the site by site analysis would take more resources than the task force has available. Therefore the CHP case will be run assuming a fixed proportion of the sites will be amenable to CHP. Since this is one of the principal means by which biomass has been developed in the past we are running a 30% CHP development mix. In those cases approximately half of the resources used will be byproducts of the business.

In addition we will summarize the results of the recent CEC study examining the benefits of distributed biomass generation development in capacity constrained urban areas of the state. These benefits can be derived from independent generators and CHP projects in the areas of congestion. In this case we will attempt to indicate the value of these benefits to the Western Grid system but will not run a full deployment case.

4.2.4 High and low feedstock Transportation costs

This is a straightforward sensitivity case that permits the Task force and CDEAC to assess the impact of this cost element on the cost of development of the resource. Given the recent spike in fuel costs and the level to which these costs affect trucking, this sensitivity seems especially relevant.

4.2.5 Monetizing the Benefits of Biomass to Communities in the West

The benefits section of the Biomass Task Force report delineates the environmental and fire protection benefits that are generated by biomass energy projects. In this section we will apply the monetary values assigned to those benefits to calculate a net benefits supply curve.

4.2.6 Cooperative Development of Biomass Feedstocks for Power and Transportation

Competition between the use of lignocellulosic biomass for electricity production and transportation fuels could increase over the proposed timeframe for the WGA study. The biomass task force believes that cooperative development of the resource for both uses could significantly enhance the economics for all uses. While the working group will not be able to treat that cooperative development in a thorough analytical fashion, scenarios will be suggested and the implications for projected electricity production capacity and cost will be discussed.