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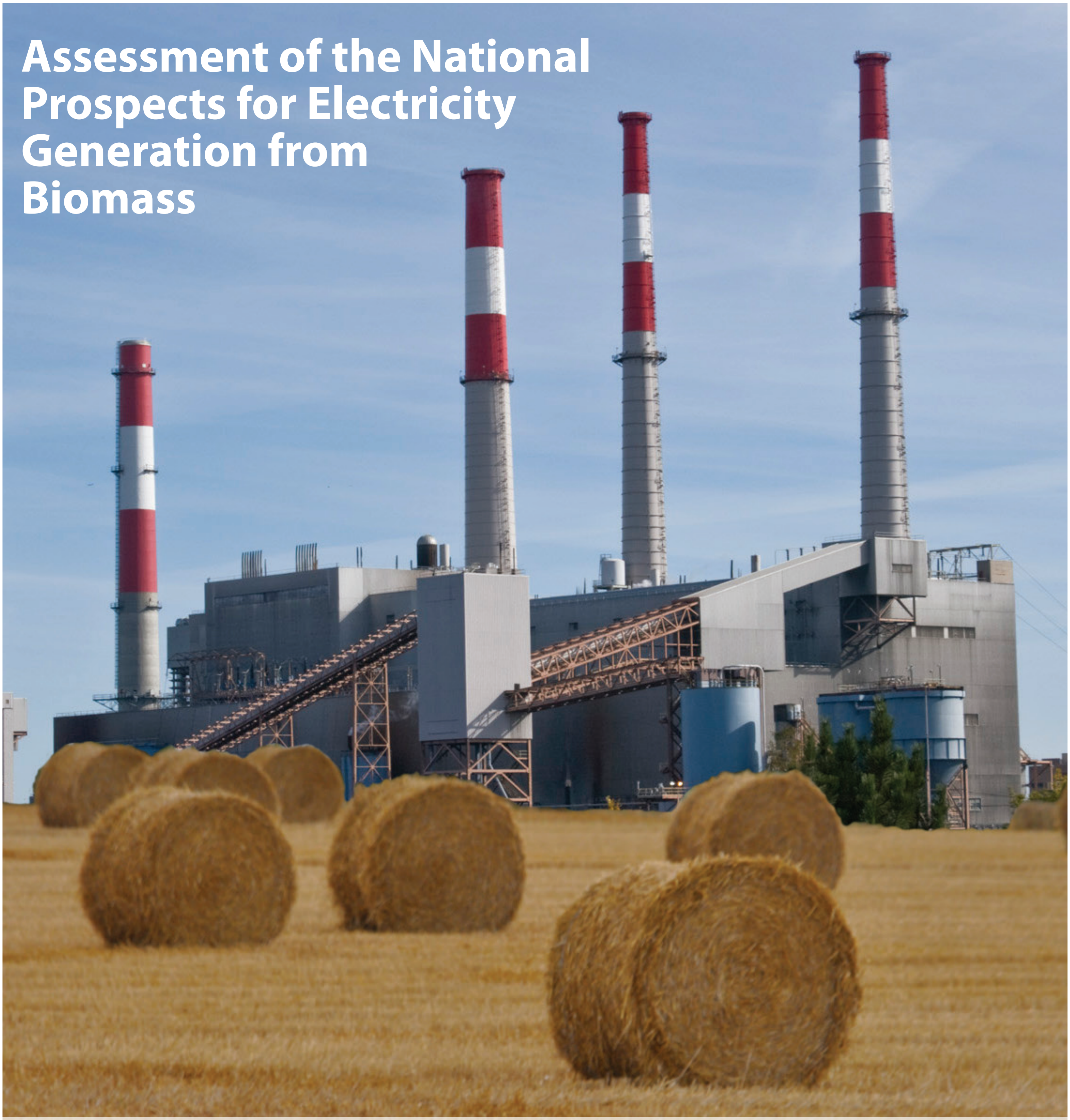
Assessment of the National Prospects for Electricity Generation from Biomass



State Utility Forecasting Group | Energy Center at Discovery Park | Purdue University | West Lafayette, Indiana

Assessment of the National Prospects for Electricity Generation from Biomass[1]

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Introduction

The objective of this study is to assess the national potential for generating electricity using biomass. The assessment is done for the contiguous continental United States and does not include Alaska, Hawaii or U.S. territories. The analysis involves estimating which counties in the contiguous U.S. can economically produce enough biomass annually to sustain an economically sized and operated biopower plant. The determination of whether a county can sustain such a plant is based on three things: the forecasted prevailing price of electricity for the county; the costs of capital, operation and maintenance; and the supply curve for biomass for the county. If the projected electricity price is higher than the projected cost of producing the electricity,[2] then it is deemed that such a plant would be sustainable. The goal is to have an approach to assessment that determines not only the amount of biopower that could be forthcoming for various projected scenarios, but also what regions are likely to see installation of biopower capacity.

The sizing and operation of the biopower plant have important implications for cost per kWh and sustainability. We consider two cases: direct firing, where biomass is the sole fuel used by the generator, and co-firing, where biomass is mixed with coal in the combustion process. For the direct fired case, we assume a 50 megawatt (MW) biopower plant operating at an 85 percent annual capacity factor. (The annual capacity factor is the number of kWh generated during the year divided by the number of kWh that could have been generated during the year if the generator is run at full capacity for the entire year.) This capacity factor is relatively high, reflecting the perspective that because of the nature of this type of generator, biopower is generally most suited for serving base load generating needs. For the co-fired case, we assume a 650 MW biopower plant burning 10 percent biomass and 90 percent coal (by energy content) and operating at an 85 percent annual capacity factor. (Recommended co-firing rates are in the 5 to 10 percent range.) The size and cost characteristics of the power plant, and the cost of transporting biomass to the power plant are based on the economic analysis of biopower done by Allen as part of his 2011 M.S. Thesis [3]. While the biopower plant cost estimates used do not include regional variation in the costs associated with siting and establishing a biopower plant, the projections of electricity prices do reflect regional differences in the electricity supply system and generation portfolio. The price responsive supply of biomass also varies by region.

Because it takes considerable time to plan, site, and build generating capacity, we focus on the year 2022 for our assessment. Regional electricity prices play a critical role in the analysis, and it is important that the forecasted electricity prices reflect changing conditions that may be expected between now and 2022, including demand growth, retirements of some existing generating capacity, installation of some new generating capacity, changes in energy efficiency, etc. For this reason the electricity price forecast is obtained from the U.S. Energy Information Agency (EIA). In particular, the base case regional price forecast is taken from the 2012 Annual Energy Outlook [1].

The potential county level biomass supply at a given price offer is obtained from the U.S. Department of Energy's Bioenergy Knowledge Discovery Framework (DOE-KDF) database [2]. This database is the best source of information regarding the regional availability of biomass at alternative prices. The database provides biomass supply for several types of biomass at alternative prices on a county by county basis for the contiguous United States. The biomass types include: primary forest resources, primary agricultural resources, and secondary residues and waste resources. The database indicates the amount

[2] The cost of producing electricity includes capital and fixed operating and maintenance costs converted to a cost per kilowatt hour (kWh) basis plus variable operating and maintenance costs plus the cost of biomass at the level of annual supply that is sufficient to operate the plant.

of each type of biomass that would be forthcoming from the county for grids of prices with the grid for forest biomass ranging from $10 to $200 in $10 increments and the grid for agricultural biomass ranging from $40 to $80 in $5 increments. It is important that the grid for agricultural biomass starts at $40. For crop residues, this rather high threshold reflects the fact that removal of crop residues creates a nutrient deficit that must be replaced and that agricultural producers will need at least a modest incentive to be enticed to provide biomass supplies. For dedicated energy crops, the $40 threshold reflects the costs of production.

In addition to the base case assessment, two other sets of scenarios are investigated. One set of scenarios tests the effect of variations in the projected production from tight oil and shale gas formations. These scenarios reflect the uncertainty regarding the future availability and pricing of natural gas. Another set of scenarios tests the effect of a national Renewable Energy Portfolio Standard as specified in the proposed Clean Energy Act of 2012 [4]. These scenarios investigate the impact of legislation designed to increase the generation of electricity from renewable energy sources.

The biopower potential being assessed in this report is in addition to the electricity already being generated from biomass, which is included in the EIA Annual Energy Outlook (AEO) forecast from which we obtain the electricity price forecast. According to this EIA forecast the electricity generated from biomass will grow from the 2012 level of 54,247 Gigawatt-hours (GWh) to 122,652 GWh in 2022, and its share of the total U.S. generation from 1.3 to 2.8 percent. The AEO indicates the sources of this biopower as Municipal Waste and Wood and Other Biomass. It is conceivable that some of the forecast generation for 2022 could be based on the feedstocks reflected in the DOE-KDF database. In that event, our estimates of the potential for biopower expansion would be biased upwards.

The conclusion of our assessment is that at most a minor amount of electricity will be generated from biomass above what is included in the EIA forecast under any of the scenarios we modeled. This is because the cost of generating electricity from biomass (either direct fired of co-fired) using the least expensive biomass that is projected to be regionally available by DOE/KDF and including the cost of transporting the biomass to the generator exceeds projected regional electricity prices in every county.

The Methodology

The assessment of the amount of the electricity that can be generated using biomass is done using the following basic steps.

- Obtain a forecast of county-level electricity revenue – this is the generation portion (i.e. excluding costs of transmission and distribution) of the electricity price for the chosen year, 2022, in cents per kilowatt hour (kWh);

- Calculate the total cost that a power plant must recover before it can pay for the biomass feedstock, including capital cost and operating and maintenance (O&M) cost in cents per kWh;

- Calculate the difference between the electricity revenue and the total cost excluding the cost of fuel to represent what a generator in that county can afford to pay for delivered biomass feedstock; and

- Determine the amount of biomass that each county could supply to the biopower plant given the price the power plant can afford to pay. If this annual amount of biomass is sufficient to power the generator for the year, then the plant is considered economically viable.[3]

Electricity Price Forecasts

The electricity price forecasts used in this assessment were obtained from the Energy Information Administration (EIA). A major uncertainty is in regards to the future pricing and availability of natural gas, and one set of scenarios reflects uncertainty about the level of Estimated Ultimate Recovery (EUR) for tight oil and shale gas. These scenarios are based on the 2012 Annual Energy Outlook (AEO) issued by EIA in June 2012 and include cases where the EUR is 50 percent lower (Low EUR) and 50 percent higher (High EUR) than the AEO Reference case. Another set of scenarios is based on the proposed Clean Energy Standard Act of 2012 (CES 2012). The price forecasts for the Clean Energy Standard (CES) based scenarios were obtained from the May 2012 analysis by the EIA of the proposed CES Act. This EIA analysis was in turn based on data from the early release version of the 2012 Annual Energy Outlook. For this reason the results from the CES 2012 scenarios are not directly comparable with the other scenarios presented. An “AEO early release” reference case is provided in this report for the purposes of providing a basis to evaluate the incremental effect of the Clean Energy Standard.

EIA provides electricity price forecasts for the contiguous U.S. in 22 regions as shown in Figure 1. The generation portion of the regional electricity price forecasts for the year 2022 for the six scenarios modeled are shown in Table 1 arranged in descending price order for the base case (e.g. with the highest priced region as the top row). As mentioned earlier this price excludes the transmission and distribution components of the total price of electricity in a region. These prices, like all other costs and prices in this assessment are expressed in real 2010 dollars.

[3] A maximum 50 mile potential supply radius around the biopower plant is assumed. For counties where a 50 mile circle around the centroid of the county does not fit within the county boundaries, the biomass in the neighboring counties within this 50 mile circle is included.

Figure 1: EIA electricity market module regions (Source EIA [5])

The regions in the EIA market module are ordered as follows in Figure 1

1 – Texas Reliability Entity (ERCT), 2 – Florida Reliability Coordinating Council (FRCC), 3 – Midwest Reliability Organization East (MROE), 4 – Midwest Reliability Organization West (MROW), 5 – Northeast Power Coordinating Council New England (NEWE), 6 – Northeast Power Coordinating Council Westchester (NYCW), 7 – Northeast Power Coordinating Council Long Island (NYLI), 8 – Northeast Power Coordinating Council Upstate New York (NYUP), 9 – Reliability First Corporation East (RFCE), 10 – Reliability First Corporation Michigan (RFCM), 11 – Reliability First Corporation West (RFCW), 12 – SERC Reliability Corporation Delta (SRDA), 13 – SERC Reliability Corporation Gateway (SRGW), 14 – SERC Reliability Corporation Southeastern (SRSE), 15 – SERC Reliability Corporation Central (SRCE), 16 – SERC Reliability Corporation Virginia-Carolina (SRVC), 17 – Southwest Power Pool Regional Entity North (SPNO), 18 – Southwest Power Pool Regional Entity South (SPSO), 19 – Western Electricity Coordinating Council Southwest (AZNM), 20 – Western Electricity Coordinating Council California (CAMX), 21 – Western Electricity Coordinating Council Northwestern (NWPP), 22 – Western Electricity Coordinating Council Rockies (RMPA)

	EIA Reference Case[a] (cents/kWh)	Low EUR for Tight Oil and Shale Gas[b] (cents/kWh)	High EUR for Tight Oil and Shale Gas[c] (cents/kWh)	Early AEO Reference Case[d] (cents/kWh)	Clean Energy Standard (CES)[e] (cents/kWh)	CES with Restricted Nuclear Expansion[f] (cents/kWh)
NYLI	9.45	10.17	10.29	10.09	9.42	9.78
FRCC	7.52	7.98	7.19	7.49	8.36	7.67
NYCW	7.32	7.85	7.75	7.69	6.98	7.26
CAMX	7.17	7.43	7.77	7.77	6.57	6.59
RFCW	6.87	6.92	6.94	6.83	6.69	6.96
SRVC	6.57	6.72	6.53	6.51	6.66	6.38
RFCE	6.42	6.72	6.40	6.65	5.82	6.17
NYUP	6.33	6.75	6.86	6.55	5.94	5.96
SRSE	6.00	6.17	5.82	6.01	5.92	5.98
SRDA	5.88	6.27	5.50	5.67	5.58	5.63
RFCM	5.84	5.98	5.88	5.97	5.95	5.99
NEWE	5.67	6.10	5.77	5.68	5.13	5.39
AZNM	5.61	5.82	5.28	5.39	6.18	6.15
SPNO	5.56	6.04	5.53	5.27	6.08	6.19
SPSO	5.56	6.04	5.53	4.78	5.23	5.65
MORE	5.34	5.36	5.44	5.55	5.87	5.93
SRCE	5.24	5.36	5.16	5.27	5.34	5.37
SRGW	5.00	5.10	4.93	5.00	5.01	5.05
ERCT	4.84	5.25	4.33	5.02	6.12	6.65
MROW	4.44	4.52	4.40	4.49	4.58	4.74
NWPP	2.35	2.24	1.64	2.21	2.24	2.13
RMPA	2.35	2.24	1.64	5.02	5.47	5.58

Table 1: Projected 2022 regional wholesale electricity prices in 2010 cents/kWh for six alternative scenarios

[a] Reference case for the EIA 2012 Annual Energy Outlook.
[b] Expected Ultimate Recovery for tight oil and shale gas is only 50 percent of the amount in the EIA Reference Case.
[c] Expected Ultimate Recovery for tight oil and shale gas is 150 percent of the amount in the EIA Reference Case.
[d] Alternative Reference Case from the early release of the 2012 Annual Energy Outlook that serves as a point of comparison for the Clean Energy Standards cases.
[e] Clean Energy Standard Case from the early release of the 2012 Annual Energy Outlook, which reflects the impact of legislation that provides incentives for reduction of carbon emissions.
[f] Clean Energy Standard Case with Restricted Nuclear expansion from the early release of the 2012 Annual Energy Outlook, which reflects the impact of legislation that provides incentives for reduction of carbon emissions plus the restriction that nuclear power generation cannot be expanded beyond planned additions reflected in the Alternative Reference Case from the early release of the 2012 Annual Energy Outlook.

Calculating the Ability of Power Plants to Pay for Biomass

The maximum price a biopower plant can afford to pay for biomass feedstock is the difference between the electricity price at the plant's location and the total non-fuel cost. The total non-fuel cost includes the capital cost and the fixed and variable O&M cost excluding fuel cost (see Table 2). The power plant cost characteristics were obtained from an economic analysis of biopower power plants due to Allen [3]. The power plant cost characteristics used by Allen were in turn based on the 2010 EIA update on generating plant cost estimates [6]. In addition to data for the Direct Fire Biomass and Co-fire Biomass generators, data are also provided for Natural Gas Advanced Combustion Turbine and Advanced Pulverized Coal (without Carbon Capture and Storage) for comparison. Based on a 20 year assumed plant life, a discount factor of 10 percent, and the indicated capacity and annual capacity factor, the fixed costs for capital and fixed O&M are converted to a dollars per kWh basis and indicated as Allocated Fixed Cost. Capacities, Capital Costs, and Fixed and Variable O&M are all sourced from [6] except for the Capital and Fixed and Variable O&M Costs for Co-fire Biomass which were obtained from [3] as indicated in the table footnotes. Annual capacity factors are from the National Energy Technology Laboratory (NETL) [10] for pulverized coal and from the 2010 EIA update [6] for natural gas. Because of the nature of the combustion process, the annual capacity factors for the direct fire and co-fire biomass technologies are assumed to be the same as for pulverized coal. Heat rates are from GREET [8] except for co-fired biomass, which is assumed to have a heat rate equal to the pulverized coal heat rate.

The final row in the table indicates the generation cost excluding the cost of fuel. This is the amount that must be paid for before any fuel expenses can be covered. This is especially relevant for the biomass technologies because when combined with the local price of electricity, it defines how much the generator can afford to pay for delivered biomass. For example, suppose the local generator revenue for electricity is \$0.100/kWh. Direct fire biomass must recover a cost of \$0.079/kWh leaving \$0.021/kWh that can be paid for biomass (delivered to the generator). Ignoring for the moment the cost to transport the biomass, this translates to \$1.976/mmBtu of biomass (=\$0.021/kWh ÷ 0.010629 mmBtu/kWh). Multiplying this by the energy density for forest residues of 13.243 mmBtu/ton (see Table 3) yields an ability to pay for delivered forest residues of \$26.168/ton. Using the same example data for the co-fire biomass technology proceeds as follows. Co-fire biomass can pay \$0.100/kWh – \$0.060/kWh = \$0.040/kWh for fuel after recovering costs. Again ignoring the cost of biomass transport, this gives us a fuel value of \$3.763/mmBtu of biomass (=\$0.040/kWh ÷ 0.010629 mmBtu/kWh), which translates to \$49.833/ton for forest residues (=\$3.763/mmBtu x 13.243 mmBtu/ton) delivered to the co-fired plant.

As shown in Table 1, only two pricing regions in the U.S., the one covering Long Island, New York (NYLI) and one covering Florida Reliability Coordinating Council (FRCC) have prices high enough in any of the scenarios modeled to be able to cover the capital and O&M cost of a direct fire biomass power plant, even before we account for the cost of transporting the biomass to the plant. In addition, the FRCC region's price is only high enough to cover the total costs excluding fuel under the Low EUR for Tight Oil and Shale Gas and the Clean Energy Standard (without restrictions on nuclear expansion) scenarios. This situation is a bit better for co-fire biomass power plants. In addition to Northeast Power Coordinating Council Long Island (NYLI) and Florida Reliability Coordinating Council (FRCC), prices exceed the costs that must be recovered under all scenarios considered for Northeast Power Coordinating Council Westchester (NYCW), Western Electricity Coordinating Council California (CAMX), and Reliability First Corporation West (RFCW) for co-fire biomass generators; and under some of the scenarios prices exceed costs that must be recovered for SERC Reliability Corporation Virginia-Carolina (SRVC), Reliability First Corporation East (RFCE), Northeast Power Coordinating Council Upstate New York (NYUP), SERC

Reliability Corporation Southeastern (SRSE), and SERC Reliability Corporation Delta (SRDA). However, while prices exceed costs that must be recovered for these region/scenario combinations, the analysis now needs to take into account the cost of delivering the biomass to the generator and the amount of biomass available on a county by county basis.

	Direct Fire Biomass	Co-fire 10% Biomass	Natural Gas (Adv. Combustion Turbine)	Pulverized Coal (Adv. w/o Carbon Capture and Storage)
Capacity (MW)	50[a]	650 [a]	210 [a]	650 [a]
Capital Cost ($/kW)	3,860 [a]	3,191 [b]	665 [a]	3,167 [a]
Fixed O&M ($/kW)	100.50 [a]	37.02 [b]	6.70 [a]	35.97 [a]
Capacity Factor (%)	85 [c]	85 [c]	10 [a]	85 [d]
Assumed Plant Life (years)	20	20	20	20
Allocated Fixed Cost ($/kWh) [e]	0.074	0.055	0.030	0.051
Variable O&M excl. fuel ($/kWh)	0.005 [a]	0.005 [f]	0.010 [a]	0.004 [a]
Heat Rate (Btu/kWh)	10,629 [g]	10,006 [h]	10,308 [g]	10,006 [g]
Generation Cost Excluding Fuel Cost ($/kWh)	0.079	0.060	0.040	0.055

Table 2: Plant costs and operating parameters for direct fire and co-fire (10%) biomass electricity generation (natural gas and coal included for comparison)

[a] R.W. Beck [6].
[b] The total capital cost and fixed O&M costs of the biomass processing facility obtained by Allen [3] from the Chariton Valley Biomass Project and from a phone call to an expert (Petro Chem Installation 812-248-9500). This was then added to the cost of the 650 MW coal plant to obtain the total installation $/kW capital cost shown.
[c] Capacity factors for direct fired and co-fired biomass generators is assumed to be the same as for pulverized coal plants reflecting the fact that this type of plant is best used for serving baseload demand.
[d] NETL [10].
[e] This calculation is based on an assumed 10 percent discount rate.
[f] The variable O&M for co-fired plant was obtained from consultation with staff at the Chariton Valley Biomass Project.
[g] GREET [8].
[h] This heat rate is assumed to be equal to the pulverized coal heat rate.

County Level Biomass Supply Curves

The supply of biomass available at a given price is obtained from the U.S. Department of Energy's Bioenergy Knowledge Discovery Framework database (DOE-KDF). The supply functions available in the DOE-KDF database are grouped into three major categories - primary forest resources, primary agricultural resources and secondary residues and waste resources. The supply of forest residue biomass (both primary and secondary) is given for the county level at prices ranging from $10 to $200 per dry ton in $10 increments. The supply of agricultural biomass is given in the price range $40 to $80 per dry ton in $5 increments. While a minimum price of $40 for crop residues may seem high, it reflects a number of costs. In the case of corn stover, it reflects the approximate cost of replacing the nutrients that would be lost due to harvesting of the stover plus a modest margin on the order of 15 percent to provide farmers with incentive to pursue an additional enterprise [9]. In the case of dedicated energy crops, it reflects the costs of production. All of the supplies from the DOE-KDF database are given at the 'farm-gate' or 'forest-gate' as applies so that the cost of transporting the biomass to the generator must also be taken into account.

Table 3 shows the minimum prices at which the various types of biomass will be supplied in the year modeled (2022). The first column of numbers presents the prices in 2022 $/ton as obtained from the DOE-KDF database. The second column of numbers shows the prices converted to equivalent 2010 dollars. The conversion of the prices from 2022 $/ton to the equivalent 2010 $/ton is done assuming a 2.2 percent average inflation rate for the years 2010 to 2018 and zero percent thereafter. (The prices in the DOE-KDF database are in nominal dollars up to 2018 and in real dollars with 2018 as the base year for the years after 2018. The inflation rate assumed for the 2010 to 2018 period of 2.2 percent per year is obtained from the 2010 *USDA Agricultural Projections to 2018* upon which the DOE-KDF biomass prices are based [7].) Thus, all prices employed in the analysis are in 2010 dollars.

The third column of numbers is the heat content of the biomass on a Btu/ton basis, and the fourth column of numbers shows the biomass prices in 2010 cents per unit of electricity. The conversion of the prices from dollars per ton to the equivalent electricity cost in cents per kilowatt-hour assumes the biomass heat content shown in the table and a 32.1 percent power plant energy conversion efficiency, which is consistent with Argonne National Laboratory's GREET model [8]. Assuming a lower efficiency for the biomass plant would result in higher minimum biomass supply prices per unit of electricity.

We see from Table 3 that forest residue is by far the least expensive source of biomass supply per unit of electricity at 0.63 cents per kWh. If we add this minimum cost of biomass to the 6.00 cents per kWh to recover the cost of the biomass co-fire plant plus O&M, we obtain the cost to operate the plant using only the first tier of forest residue (the cheapest source of biomass) of 6.63 cents per kWh before paying for transportation of the biomass to the biopower plant.

	Biomass minimum price from DOE-KDF (2022$/ton)	Biomass minimum price (2010$/ton)	Biomass Heat Content (Btu/ton)[a]	Biomass minimum price (2010 cents/kWh)[b]
Forest residue	10	8.40	13,243,490	0.63
Farm grown trees	40	33.61	16,811,000	2.00
Herbaceous (grasses)	40	33.61	14,797,555	2.27
Agricultural residue	40	33.61	14,075,990	2.39

Table 3: Minimum price for alternative types of biomass per unit of co-fired electricity (excluding transportation)

[a] The heat contents of coal and natural gas are 19,546,300 Btu/ton and 983 Btu per cubic foot (at 32°F and one atmosphere of pressure) from GREET [8], respectively.
[b] The assumed heat rate is 10,629 Btu/kWh, based on a 32.1% efficiency from the GREET model [8]. This is quite a bit higher efficiency than is assumed by EIA (25.3%), and the resulting minimum biomass prices in 2010 cents/kWh would be even higher with the lower efficiency.

Results

Table 4 provides a summary of the number of regions that have a forecast electricity price high enough to cover either the cost of capital plus O&M or the cost of capital plus O&M plus the least expensive source of biomass for each of the scenarios (where both exclude the cost of transporting the biomass to the generator). The first column of numbers indicates the maximum price of electricity across all of the regions. The second column of numbers shows the number of regions that have electricity prices higher than the cost of capital plus O&M, and the third column presents the number of regions with electricity prices higher than capital plus O&M plus the cost of first tier forest residue biomass (excluding the cost of transporting the biomass to the plant).

While several regions under several scenarios have prices high enough to cover the cost of the plant plus the cost of the first tier of the forest residue biomass supply curve, the regional assessment is applied on a county-by-county basis and must also take into account the availability of the alternative types of biomass at the county level and the cost of transporting the biomass from the forest-gate or farm-gate to the generator. When biomass availability (by type of biomass) and the cost of transport are taken into account, biopower is found not to be economically viable in any of the regions under any of the scenarios. (The accounting for transport cost assumes that (a) the biomass is distributed uniformly over the county, and if a 50 mile radius circle around the centroid of the county does not fall within the county, then the biomass in the neighboring county within this 50 mile circle is included; and (b) the biomass is delivered via north-south and east-west roads. This treatment will overstate transport cost in some cases and understate it in others, but should be about right on average.)

Scenario	Maximum regional price forecast (cents/kWh)	Number of regions with price > 6.00 cents/kWh	Number of regions with price > 6.63 cents/kWh
EIA Reference Base Case[a]	9.45	9	8
Low EUR for Tight Oil and Shale Gas[b]	10.17	13	8
High EUR for Tight Oil and Shale Gas[c]	10.29	8	8
Early AEO Reference Case[d]	10.09	9	8
Clean Energy Standard (CES)[e]	9.42	6	6
CES with Restricted Nuclear Expansion[f]	9.78	7	6

Table 4: Summary of biopower generation results for six electricity price forecast scenarios

[a] Reference case for the EIA 2012 Annual Energy Outlook.
[b] Expected Ultimate Recovery for tight oil and shale gas at 50 percent of the EIA Reference Case.
[c] Expected Ultimate Recovery for tight oil and shale gas at 150 percent of the EIA Reference Case.
[d] Alternative Reference Case from the early release of the 2012 Annual Energy Outlook that serves as a point of comparison for the Clean Energy Standards cases.
[e] Clean Energy Standard Case from the early release of the 2012 Annual Energy Outlook, which reflects the impact of legislation that provides incentives for reduction of carbon emissions.
[f] Clean Energy Standard Case with Restricted Nuclear expansion from the early release of the 2012 Annual Energy Outlook, which is like the previous case plus the restriction that nuclear power generation cannot be expanded beyond planned additions reflected in the Alternative Reference Case from the early release of the 2012 Annual Energy Outlook.

Sensitivity to Regional Electricity Prices

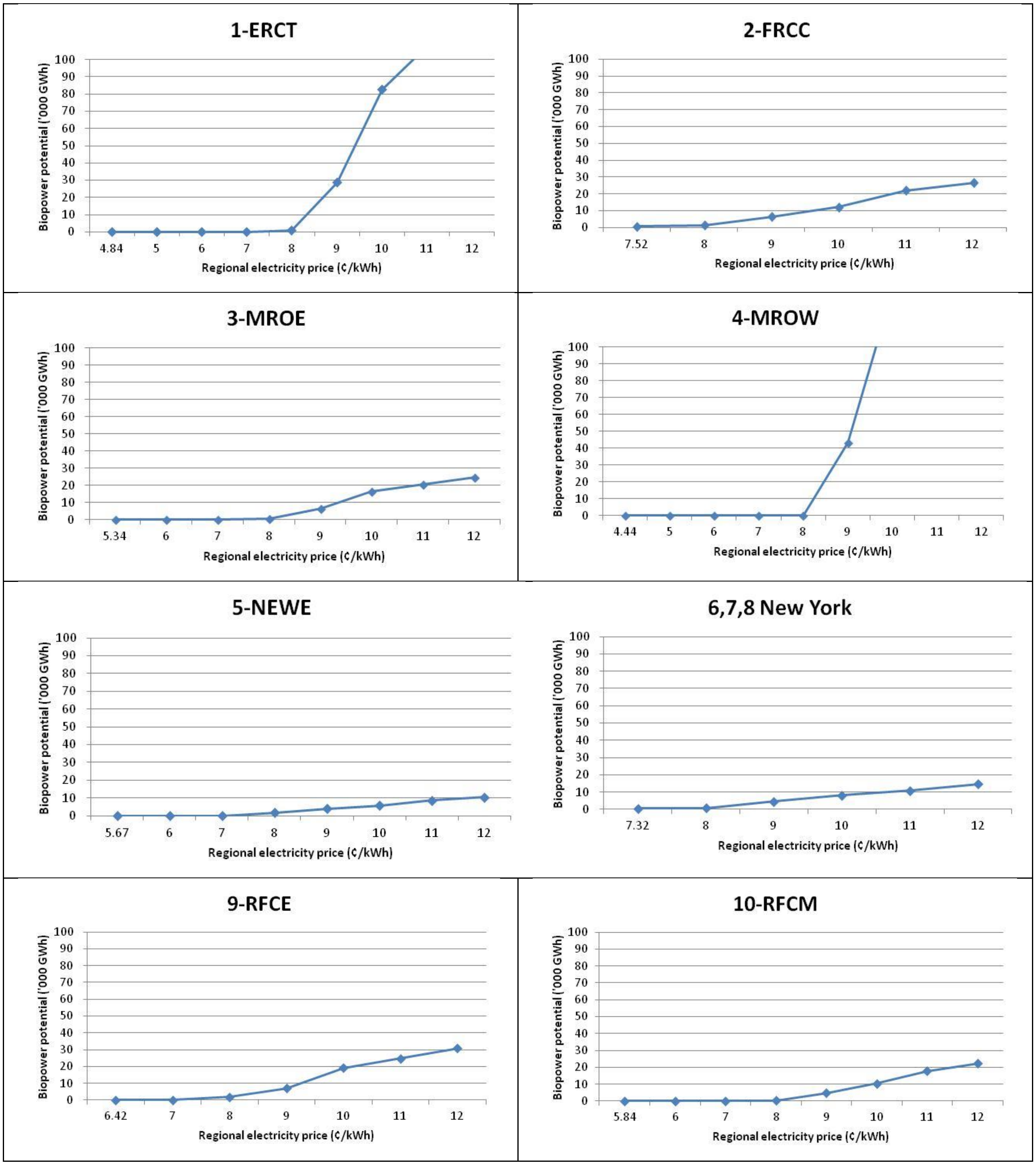
The results for the six electricity price forecast scenarios, give us a sense of the potential biopower supplies under alternative futures reflecting in some cases different outcomes for natural gas markets and in other cases the impacts of incentives for reduction of carbon emissions. One can imagine other more dramatic cases in which either the Federal government or states intensify their efforts to reduce carbon emissions either through carbon taxes or direct controls. The effect of such efforts would likely be reflected in the form of even higher regional prices (e.g. due to restrictions on fossil fuel emissions) or lower costs for biopower (e.g. due to production tax credits, favorable tax treatment of renewable power investments, etc.) than those that were forecast in the scenarios considered. In anticipating these possibilities, we assess the regional responsiveness of biopower generation to increases in the generation portion of regional electricity prices. This sensitivity analysis will give us insight into the magnitude of price increase (or biopower cost decrease) that would be needed to elicit a supply response and the extent of that response.

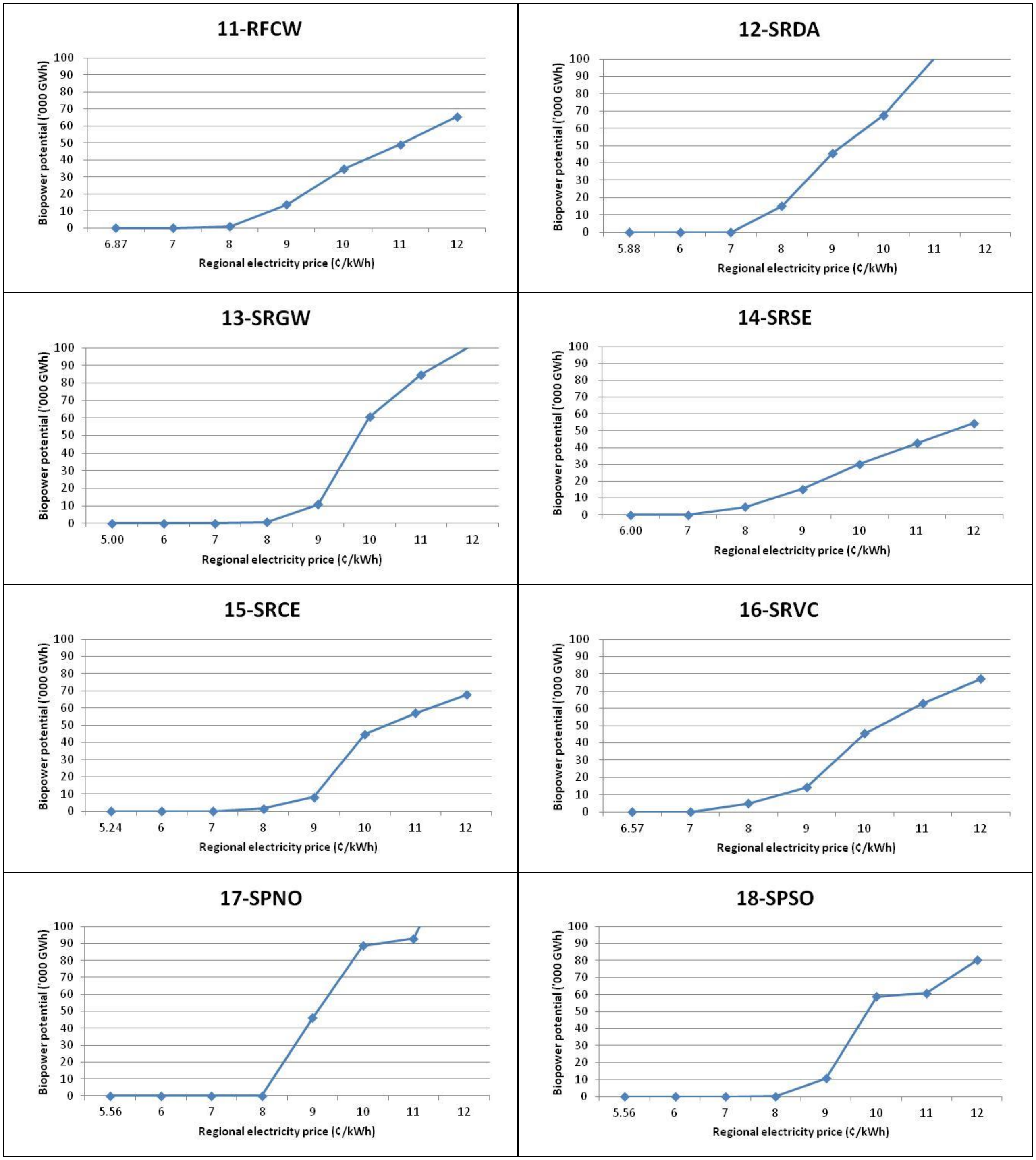
As our point of departure, we begin with the EIA Reference Case. For each of the 22 EIA electricity market module regions, we graph the regional biopower supply response over a range of electricity prices (see Figure 2). The range of prices goes from the forecasted regional electricity price under the EIA Reference Case to $0.12 per kWh. The assessment of the biopower supply is almost identical to the foregoing analysis: given the level of the generation portion of the electricity price, determine how much a biopower plant could afford to pay for delivered biomass, use the supply curves in the DOE-KDF database and estimates of the biomass transportation cost to determine whether a generator (direct-fired or co-fired with coal) would be economically viable on a county by county basis, and sum across counties within the region to obtain the response. The one departure from the procedure for the earlier biomass assessment is that in the cases where the 50 mile region centered at the centroid of the county exceeded the county's boundaries, it is assumed that neighboring counties would have the same biomass density per unit of area as the county being analyzed. This assumption is made to limit the computational burden associated with the sensitivity analysis.

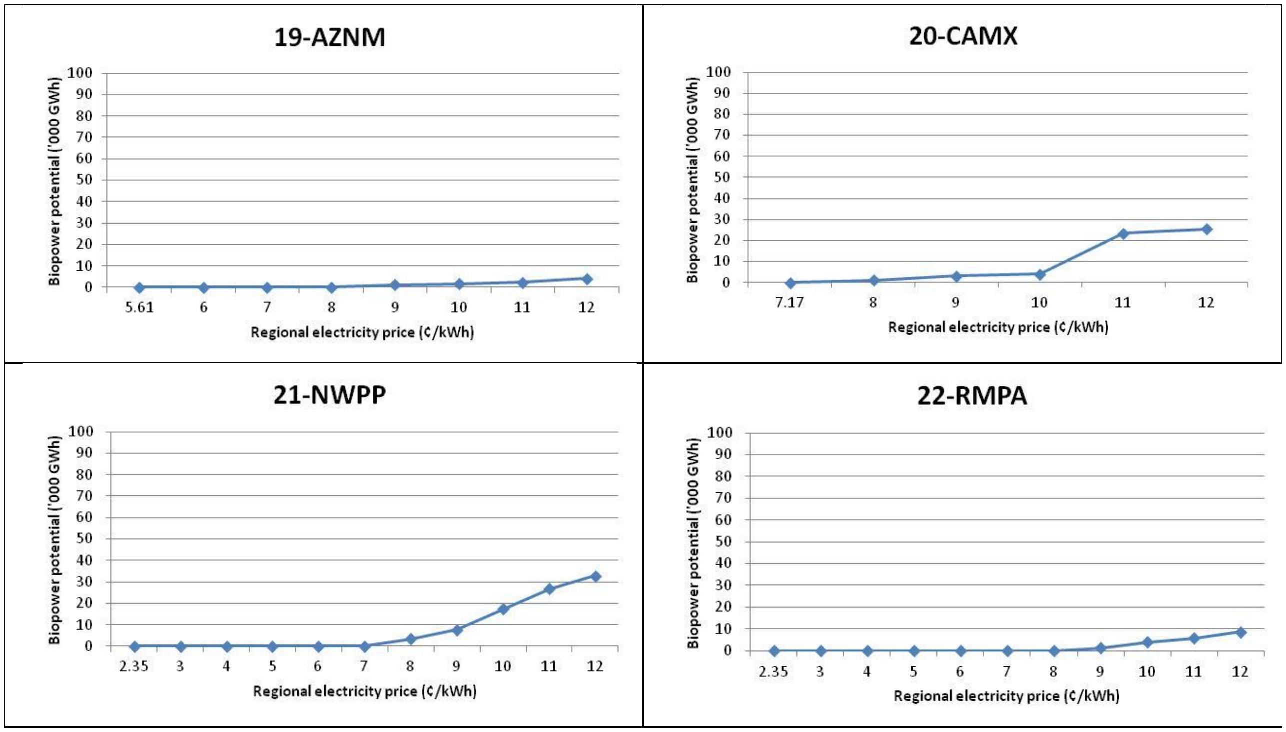
Recalling that the regional supplies of biomass at the EIA Reference Case prices are all zero, one interesting measure of response is how much the regional price has to rise before there is a response of 10,000 GWh from biomass heat (this is on the order of 1.3 GW of direct fired capacity or 13.4 GW of co-fired capacity where the portion of generation that comes from the heat from the coal is not counted). Thus, the generation reflected in Figure 2 is electricity attributable directly to the combustion of biomass. The required regional price increases are the upper numbers in the boxes in Figure 3 (¢/kWh), and the lower numbers in these boxes express these increases as percentages relative to the projected 2022 price of electricity for the EIA Reference Case. No regions have a response as large as 10,000 GWh without a price increase of at least $0.018 per kWh. About a third of the regions (2-FRCC, 9-RFCE, 11-RFCW, 12-SRDA, 14-SRSE, 16-SRVC, and 17-SPNO) obtain a 10,000 GWh response in the $0.018-0.03 range, and about a third of the regions require an increase of $0.03-0.04 to get a response this large. Three regions (5-NEWE, 10-RFCM, and 21-NWPP) need an increase of $0.04-0.07 to get a 10,000 GWh response, and two regions (19-AZNM and 22-RMPA) do not get a response that large until prices increase beyond $0.12 per kWh. (The 22-RMPA region gets a 10,000 GWh response at about a price *increase* in excess of $0.10 per kWh, while the 19-AZNM region does not get a response this large no matter how large the price increase is.)

These increases in the generation portion of the regional electricity prices that are needed to elicit a 10,000 GWh response are also generally large as a percentage of the EIA Reference Case price (see the lower numbers in the boxes in Figure 3). They are all larger than 25 percent and are only less than 30 percent in regions 2-FRCC, corresponding to Florida which has the highest forecasted price of all of the regions, and 11-RFCW, corresponding to the Midwest. The increase is greater than 100 percent in 5-NEWE, corresponding to the northeast, 19-AZNM, corresponding to the region encompassing Arizona and New Mexico, and 22-RMPA encompassing Colorado and parts of several other states in the Rocky Mountain region. The average price increase required to get a regional response of 10,000 GWh is 70%.

Another metric is how much response there is at $0.12 per kWh, the upper end of the examined range for 2022 regional electricity prices in 2010. In more than half of the regions, biopower supply at this price level is still less than 40,000 GWh (about 5.4 GW of capacity). For another five regions, biopower supply at $0.12 per kWh is in the range of 50,000-100,000 GWh (6.7-13.4 GW of capacity). Only five regions supply more than 100,000 GWh at prices up to $0.12 per kWh, and this price level is at least a doubling of the EIA Reference Case forecast price. The regional distribution of biopower generation at $0.12 per kWh is indicated on the map in Figure 4. While substantial supplies of biopower could come at a price of $0.12 per kWh, primarily from the center of the continental lower 48 states, the price increases would amount to more than a doubling of projected 2022 prices.


1-ERCT
Biopower potential ('000 GWh)
4.84 5 6 7 8 9 10 11 12
Regional electricity price (¢/kWh)
2-FRCC
Biopower potential ('000 GWh)
7.52 8 9 10 11 12
Regional electricity price (¢/kWh)
3-MROE
Biopower potential ('000 GWh)
5.34 6 7 8 9 10 11 12
Regional electricity price (¢/kWh)
4-MROW
Biopower potential ('000 GWh)
4.44 5 6 7 8 9 10 11 12
Regional electricity price (¢/kWh)
5-NEWE
Biopower potential ('000 GWh)
5.67 6 7 8 9 10 11 12
Regional electricity price (¢/kWh)
6,7,8 New York
Biopower potential ('000 GWh)
7.32 8 9 10 11 12
Regional electricity price (¢/kWh)
9-RFCE
Biopower potential ('000 GWh)
6.42 7 8 9 10 11 12
Regional electricity price (¢/kWh)
10-RFCM
Biopower potential ('000 GWh)
5.84 6 7 8 9 10 11 12
Regional electricity price (¢/kWh)


11-RFCW
Biopower potential ('000 GWh)
Regional electricity price (¢/kWh)
6.87 7 8 9 10 11 12
12-SRDA
5.88 6 7 8 9 10 11 12
13-SRGW
5.00 6 7 8 9 10 11 12
14-SRSE
6.00 7 8 9 10 11 12
15-SRCE
5.24 6 7 8 9 10 11 12
16-SRVC
6.57 7 8 9 10 11 12
17-SPNO
5.56 6 7 8 9 10 11 12
18-SPSO
5.56 6 7 8 9 10 11 12
0 10 20 30 40 50 60 70 80 90 100



<u>**Figure 2.** Regional electricity from biomass heat in 2022 as a function of regional electricity price in 2010 cents/kWh for the EIA reference case</u>

EIA market modules as follows:

1 – Texas Reliability Entity (ERCT), 2 – Florida Reliability Coordinating Council (FRCC), 3 – Midwest Reliability Organization East (MROE), 4 – Midwest Reliability Organization West (MROW), 5 – Northeast Power Coordinating Council New England (NEWE), 6 – Northeast Power Coordinating Council Westchester (NYCW), 7 – Northeast Power Coordinating Council Long Island (NYLI), 8 – Northeast Power Coordinating Council Upstate New York (NYUP), 9 – Reliability First Corporation East (RFCE), 10 – Reliability First Corporation Michigan (RFCM), 11 – Reliability First Corporation West (RFCW), 12 – SERC Reliability Corporation Delta (SRDA), 13 – SERC Reliability Corporation Gateway (SRGW), 14 – SERC Reliability Corporation Southeastern (SRSE), 15 – SERC Reliability Corporation Central (SRCE), 16 – SERC Reliability Corporation Virginia-Carolina (SRVC), 17 – Southwest Power Pool Regional Entity North (SPNO), 18 – Southwest Power Pool Regional Entity South (SPSO), 19 – Western Electricity Coordinating Council Southwest (AZNM), 20 – Western Electricity Coordinating Council California (CAMX), 21 – Western Electricity Coordinating Council Northwestern (NWPP), 22 – Western Electricity Coordinating Council Rockies (RMPA)

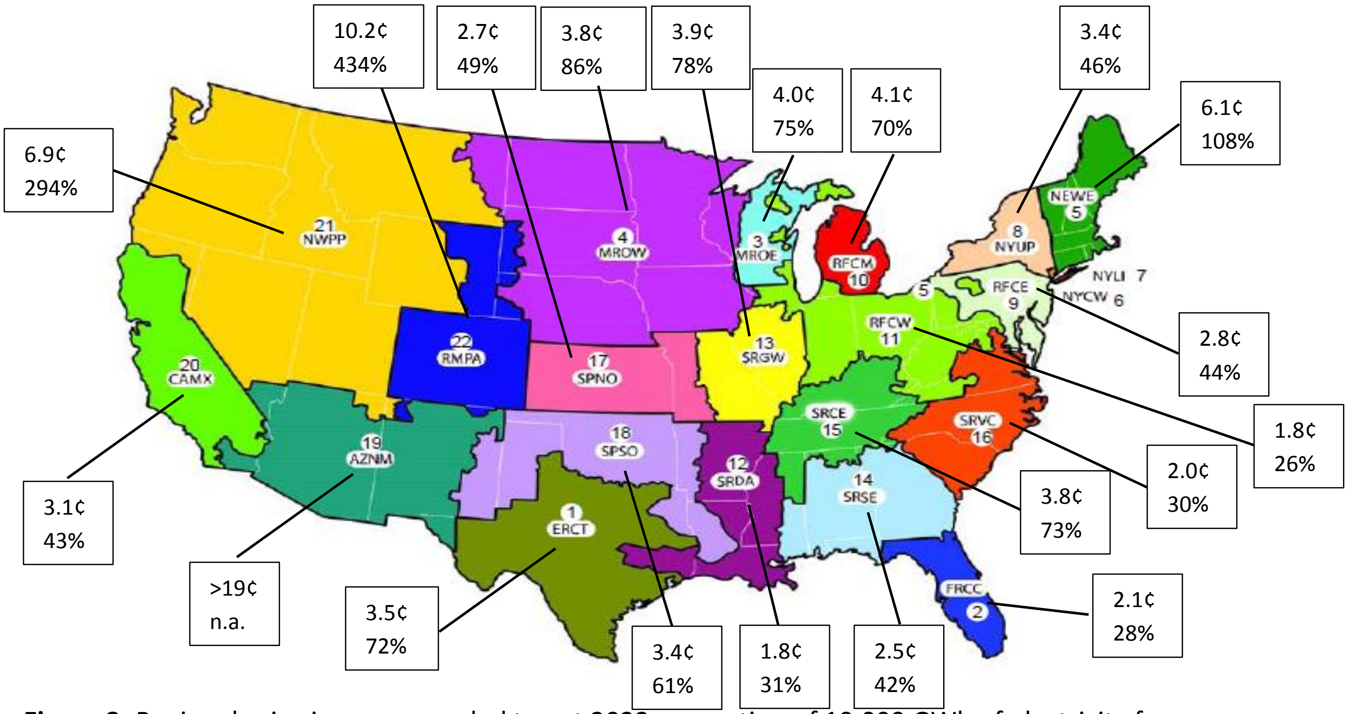


Figure 3: Regional price increase needed to get 2022 generation of 10,000 GWh of electricity from biomass heat in real 2010 dollars (¢/kWh) and as a percent increase from the 2022 forecast price (Source: EIA [5] with annotations)[1,2]

[1] The regions in the EIA market module are ordered as follows in Figure 1: 1 – Texas Reliability Entity (ERCT), 2 – Florida Reliability Coordinating Council (FRCC), 3 – Midwest Reliability Organization East (MROE), 4 – Midwest Reliability Organization West (MROW), 5 – Northeast Power Coordinating Council New England (NEWE), 6 – Northeast Power Coordinating Council Westchester (NYCW), 7 – Northeast Power Coordinating Council Long Island (NYLI), 8 – Northeast Power Coordinating Council Upstate New York (NYUP), 9 – Reliability First Corporation East (RFCE), 10 – Reliability First Corporation Michigan (RFCM), 11 – Reliability First Corporation West (RFCW), 12 – SERC Reliability Corporation Delta (SRDA), 13 – SERC Reliability Corporation Gateway (SRGW), 14 – SERC Reliability Corporation Southeastern (SRSE), 15 – SERC Reliability Corporation Central (SRCE), 16 – SERC Reliability Corporation Virginia-Carolina (SRVC), 17 – Southwest Power Pool Regional Entity North (SPNO), 18 – Southwest Power Pool Regional Entity South (SPSO), 19 – Western Electricity Coordinating Council Southwest (AZNM), 20 – Western Electricity Coordinating Council California (CAMX), 21 – Western Electricity Coordinating Council Northwestern (NWPP), 22 – Western Electricity Coordinating Council Rockies (RMPA).

[2] Regions 6, 7 and 8 are reported in aggregate because they are within the state of New York.

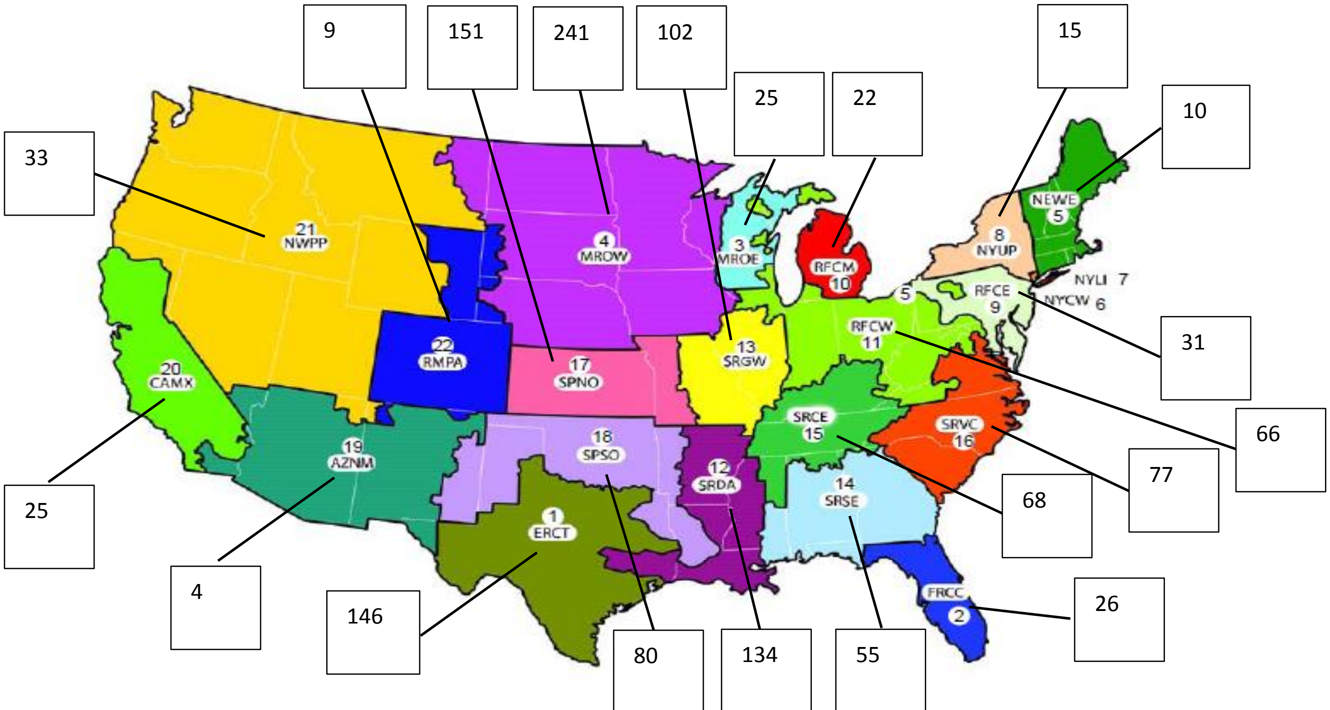


Figure 4: Regional electricity from biomass heat in 2022 at 12¢/kWh in thousands of GWh (Source: EIA [5] with annotations)[1,2]

[1] The regions in the EIA market module are ordered as follows in Figure 1: 1 – Texas Reliability Entity (ERCT), 2 – Florida Reliability Coordinating Council (FRCC), 3 – Midwest Reliability Organization East (MROE), 4 – Midwest Reliability Organization West (MROW), 5 – Northeast Power Coordinating Council New England (NEWE), 6 – Northeast Power Coordinating Council Westchester (NYCW), 7 – Northeast Power Coordinating Council Long Island (NYLI), 8 – Northeast Power Coordinating Council Upstate New York (NYUP), 9 – Reliability First Corporation East (RFCE), 10 – Reliability First Corporation Michigan (RFCM), 11 – Reliability First Corporation West (RFCW), 12 – SERC Reliability Corporation Delta (SRDA), 13 – SERC Reliability Corporation Gateway (SRGW), 14 – SERC Reliability Corporation Southeastern (SRSE), 15 – SERC Reliability Corporation Central (SRCE), 16 – SERC Reliability Corporation Virginia-Carolina (SRVC), 17 – Southwest Power Pool Regional Entity North (SPNO), 18 – Southwest Power Pool Regional Entity South (SPSO), 19 – Western Electricity Coordinating Council Southwest (AZNM), 20 – Western Electricity Coordinating Council California (CAMX), 21 – Western Electricity Coordinating Council Northwestern (NWPP), 22 – Western Electricity Coordinating Council Rockies (RMPA).

[2] The electricity price of 12¢/kWh is in 2010 real dollars. Regions 6, 7 and 8 in aggregate because these are regions within the state of New York.

Conclusions

The results of our assessment indicate that if selling electricity at the market price is the only revenue stream for a biopower plant, the forecast prices of electricity are not adequate to support the establishment of biopower plants under any of the six scenarios modeled. Our assessment indicates that no appreciable stand-alone biopower generation will be forthcoming given current forecasts of regional electricity prices for the 2022 timeframe. It should be noted that our assessment is based on the generator having only one revenue stream, namely the value of electricity sold to the grid. It does not include other value streams such as would accrue to combined heat and power (CHP) plants or the added value of process chemical recovery that occurs in the paper and pulp industry. It also does not include state-level renewable portfolio standards and incentives, such as utility feed-in tariffs, new federal subsidies, tax credits, etc. From our sensitivity analysis, it appears that the value in addition to the electricity sales garnered by a biopower plant would have to be substantial – on the order of at least 25 percent – to begin to elicit a much greater penetration of biopower.

While this assessment reveals dim prospects for biopower, it should be noted that the 2012 EIA Annual Energy Outlook from which our electricity price forecast was obtained models the total U.S. energy industry, including CHP facilities, some of which are now and may in the future be powered by biomass. It also includes the state-level renewable portfolio standards that were in place at the end of 2011. This EIA forecast projects electricity generation from biomass to grow from 54,247 GWh in 2012 to 122,652 GWh in the year 2022 that we modeled, and its share of the total U.S. generation from 1.3 to 2.8 percent. Based on the analysis reported here, one may speculate that those biopower plants will likely be producing additional value in the form of process heat, process chemical recovery, or renewable generation credits against portfolio standards, and may also be collocated with food, fiber, and other processing facilities that produce a stream of waste biomass.

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