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Biomass combustion for electric power: Allocation and plant siting using non-linear modeling and mixed integer optimization

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Electricity generation from the combustion of biomass feedstocks provides low-carbon energy that is not as geographically constricted as other renewable technologies. This study uses non-linear programming to provide policymakers with scenarios of possible sources of biomass for power generation as well as locations and types of electricity generation facilities utilizing biomass. The scenarios are obtained by combining the output from existing agricultural optimization models with a non-linear mathematical program that calculates the least-cost ways of meeting an assumed biomass electricity standard. The non-linear program considers region-specific cultivation and transportation costs of biomass fuels as well as the costs of building and operating both coal plants capable of co-firing biomass and new dedicated biomass combustion power plants. The results of the model provide geographically detailed power plant allocation patterns that minimize the total cost of meeting the generation requirements, which are varying proportions of total U.S. electric power generation, under the assumptions made. The amount of each cost component comprising the objective functions of the various requirements are discussed, and the results show that approximately two-thirds of the total cost of meeting a biomass electricity standard occurs on the farms and forests that produce the biomass. Plant capital costs and biomass transportation costs comprise the largest share of the remaining costs. The most important policy conclusion is that biomass use in power plants will require significant subsidies, perhaps as much as half of their cost, if they are to achieve significant penetrations in U.S. electricity markets. © *2013 AIP Publishing LLC*. [http://dx.doi.org/10.1063/1.4819493]

I. INTRODUCTION

Energy policy has become a concern for many involved in governmental affairs, economics, science, engineering, and central planning. Energy has local, regional, national, and global implications, and oftentimes decision makers within each level do not adequately communicate with local and regional stakeholders when formulating policy since existing models do not provide acceptable levels of geographic detail. Whether a policy takes a top-down or bottom-up approach, integration at each level is key so that appropriate action is taken and all decision makers understand their roles in policy implementation. For example, legislation formulated and approved by the U.S. Congress needs individual farmers to begin growing biomass if the national policy is to be effective.

Optimization techniques in operations research are designed to propose “best” or “optimal” solutions; such a solution is only possible if the focus remains clear and limited. This article seeks to provide clear, accurate, comprehensive optimal solutions for biomass generation by developing a biomass power plant siting model. It is not designed to be an all-encompassing

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capacity expansion model, however. By maintaining an in-depth focus on biomass, this analysis provides comprehensive insights into the consequences of Federal requirements for widespread adaptation of the biomass generation technology.

The modeling assumption that forces the use of biomass in the methodology of this article is a policy constraint requiring a minimum national total of electricity generation from biomass. These targets range from less than 1% of total electricity generation to approximately 17% of total projected generation by 2035.[1] Like much of the data used in this analysis, these projected targets come from the National Energy Modeling System (NEMS),[1] a model developed by the Energy Information Administration (EIA).

The output of a separate, already established agricultural land-use linear programming (LP) model, POLYSYS,[2] will be an input to the model of power plant siting and biomass utilization based on the location of these feedstocks. Results will be useful for the public sector in policy formulation but can be communicated to electricity providers, land developers, and those in the agricultural industry, as these groups enable the policy requirements to become tangible realities. Although the audience for the model is primarily national policy makers, it runs on the regional level with subdivisions corresponding to 305 agricultural statistics districts (ASDs) in order to capture local variations in biomass supply and power market conditions and therefore result in more realistic characterizations of regional and, ultimately, national biomass usage and costs. ASDs have been defined by the U.S. Department of Agriculture (USDA) as groupings of counties with similar climates, geography, and cropping patterns. Using the cropping patterns and resulting biomass supply functions established by the agricultural land-use linear program, the model developed here will run as its own, separate nonlinear program that will optimize co-firing and new power plant siting decisions.

Previous analyses of the economics of biomass supply include both the original and updated version of the Energy Department's so-called "billion ton studies,"[3,4] which were made largely from data provided by Oak Ridge National Laboratory (ORNL). Crop-specific studies on optimal sources of agricultural biomass have been conducted by Khanna *et al*.[5] and Lewandowski *et al*.[6] This analysis seeks to build on these works, and others, to create a national biomass electric power plant allocation map based on potential sources of biomass, dynamic fuel-shipping costs, regional electricity prices, and existing power plant infrastructure. The model results combine biomass supply analyses with electricity data to approximate national optimal solutions based on regional data.

This article is structured as follows: In Sec. II, the data assumptions behind the developed model are presented. In Sec. III, the model is presented followed by a results section and, finally, a section presenting the overall conclusions.

II. DATA ASSUMPTIONS

A. Sources of biomass supply

While most of the biomass data, from perennial energy crops and crop residues, originates from the POLYSYS agricultural land-use LP model, forestry and mill residues are not a direct output of that model, and data for these sources have been developed by ORNL in conjunction with the National Forest Service.[4]

B. POLYSYS

POLYSYS was developed by the Agricultural Policy Analysis Center at the University of Tennessee in the 1990s and is described by De la Torre Ugarte.[2] POLYSYS uses each of the 305 ASDs as a collective area where planting and livestock decisions are made. The model assumes that agricultural enterprises in each ASD seek to maximize their expected net returns through planting and harvesting decisions. POLYSYS has 15 primary crops which are the following: alfalfa hay, other hay, corn, sorghum, oats, barley, wheat, soybeans, cotton, rice, peanuts, switchgrass, sugarcane, sugar beets, and dried beans. It also has a link to the livestock sector. Each crop has various demands from differing sectors and commodity-specific elasticities for supply and demand. Demands for non-energy agricultural commodities are based on macroeconomic growth assumptions. POLYSYS accounts for governmental programs, such as the Conservation Reserve Program, which keeps certain lands off-limits to crop cultivation. The model has a series of cost input assumptions for items including seed, fertilizer, pesticides, machinery services, fuel and lube, labor, and irrigation.

C. Power plant characterizations

1. Dedicated plant technology and size

Biomass can either be combusted in power generation plants constructed exclusively for that fuel type (dedicated facilities), or it can be co-fired in existing coal power plants (co-fired facilities). Existing dedicated generation plants are exclusively direct combustion systems. The efficiency of these systems varies, but a technological assessment performed by the contractor R. W. Beck for EIA[7] suggested that a new plant would have an efficiency of 13 500 BTU/kWh. The representative technology chosen for this estimate is an 80 MW direct combustion system.

2. Co-fired plants

Biomass can be co-fired in existing coal plants to generate electricity. Co-firing is achieved by replacing a portion of coal (as much as 15%) with biomass.[8] Co-fired biomass is a low-cost option to meet State renewable portfolio standard (RPS) goals since it requires a relatively low capital expenditure to retrofit a coal plant to burn biomass.[8] Yet, there is very little co-firing in the U.S. largely due to risk aversion by coal plant owners as well as the uncertainty over the installation costs of this technology. EIA data show only 1.7 billion kWhs of electricity was generated through co-firing in 2011, which has displaced about one-tenth of one percent of total coal generation.[1]

3. Capital cost assumptions

Capital costs for dedicated biomass combustion plants also originate from the R. W. Beck cost report prepared for EIA. The small number of dedicated biomass plant installations and inexperience with the combustion of certain feedstocks makes for a high range of uncertainty for capital cost projections. Since the R. W. Beck report did not examine co-firing costs, an informal survey was conducted in researching the development of this project and a rough average of $500/kW was used. It is assumed that the dedicated plants will generally run near their maximum capacity factor as determined by R. W. Beck. A 90% capacity factor allows plants to run continuously but also allows for isolated maintenance and supply disruptions.[7] The co-firing plants have an 85% capacity factor, in-line with current EIA estimates for a new pulverized coal system. This is a simplifying assumption. Historical capacity factors are available for coal plants, but plants are often run below their potential capacity factors for reasons other than technology performance (see Table I).

TABLE I. Power plant cost and performance assumptions.

Plant type	Efficiency (BTU/kWh)	Capital costs ($2009/kW)	Variable costs ($2009/MWh)	Fixed costs ($2009/MW-year)	Capacity factor
Dedicated biomass combustion	13 500	$3860	$5.00	$100 500	0.9
Biomass co-firing	Plant-specific	$500	$5.00	$36 000	0.85

4. Co-firing sites

Capacity and heat rate data for potential co-firing sites are obtained from the U.S. Energy Information Form EIA-860 "Annual Electric Generation Report." Because not all coal-fired units are candidates for co-firing, a site-specific analysis is needed to determine which units can adopt the fuel-switching practices. Since this was not possible, it was assumed that all coal-fired units with capacities greater than 200 MW are considered eligible to co-fire up to 15%[9] of their nameplate capacity using biomass. According to EIA Form860 data for 2011,[10] there are over 500 of these generators representing over 260 GW of generating capacity. Smaller plants were excluded, since larger plants constitute 85% of total coal capacity, but less than half of the number of plants, limiting the number of decision variables in the model to a reasonable number.

D. Avoided coal use savings and dedicated plant capacity credits

While this model is meant to quantify the total cost from biomass generation and not directly compare its incremental cost relative to other electricity-generating technologies, it is necessary to put both co-firing and dedicated generation technologies on equal footing relative to each other so that unbiased, cost-effective decisions can be made. Co-firing systems directly displace existing coal generation, and so the cost savings of avoided coal use must be calculated as a function of biomass generation and included in the objective function of the plant-siting model. Dedicated capacity has a different advantage, which is that it can displace other types of generating capacity, whose value is reflected in energy and capacity prices in the power market.

1. Coal prices

Plant-delivered coal prices influence which power plants are the best candidates for co-firing, as high coal costs make fuel switching more attractive. EIA projects the average regional delivered coal prices for the electric power sector by the nine U.S. Census Divisions to 2035.

2. Electricity prices

The construction of dedicated capacity offers advantages that co-firing does not, which are most easily seen by constructing a basic capacity expansion model with two load periods, peak and baseload, and a small suite of technologies from which to choose when expanding capacity.[11] Similar to the model developed for this analysis, a mandate for a specific, minimal level of biomass generation is added to this capacity expansion model as a constraint. Additional constraints in this simple model are that both peak and baseload period generation must be met by the sum of generation from all technologies, the generation from co-firing cannot exceed the allowable fraction of total coal generation, the sum of co-firing and coal generation at the coal facility cannot exceed the maximum potential generation of that facility, and the sum of the capacity of each power plant multiplied by the plant-specific capacity factor must exceed the peak period generation by a pre-chosen capacity reserve requirement.

Once the basic capacity model is constructed and the dual variables are viewed, seeing the added value of dedicated plants over co-fired generation becomes easier. If the constraint requiring the sum of all plant capacities to equal or exceed peak load, represented in megawatts, multiplied by a reserve requirement, is binding and has a non-zero dual variable, the value of this variable is the added value of the dedicated plant capacity. In this case, the dual variable represents the cost of adding one more unit of capacity if the constraint is made more stringent. Dedicated biomass capacity is able to contribute to the overall capacity reserve margin, so the plant owner would receive the product of the dual variable and the amount of installed dedicated capacity as revenue. Since co-firing does not increase overall capacity and substitutes coal generation for biomass generation, there is no compensation from expanding the reserve margin constraint.

Further examination of the previously mentioned capacity expansion model allows the other, less obvious value of dedicated capacity to be seen. Even without a capacity reserve constraint, biomass co-firing will still not necessarily be chosen in spite of its lower capital costs and more efficient heat rates compared to dedicated generation. The explanation is found by investigating the two model load constraints which require that both peak and baseload generation be met by the sum of the generation from all technologies. This requirement is very similar to the load constraint formulated for the biomass model (Eq. (3.2)). The dual variables of the load constraints approximate the market value of electricity generation. Since generation is a function of capacity, the construction of a dedicated biomass plant adding to the capacity base allows for an expansion of electricity generation. The market products from this new generation capacity includes sales to the capacity and energy markets, which in the capacity expansion model are quantified as the values of the dual variables for the capacity and load constraints, respectively, and are added revenue for the dedicated plant owner. In addition, the added revenue from increasing the load can more than offset the lower capital costs and fuel usage of co-firing in the basic expansion model.

E. Biomass transportation and interregional utilization

Since spatially precise transportation costs are an essential component to this model, the background behind these assumptions is given in this section. According to the literature,[12] biomass is highly unlikely to be shipped via railroad, unlike coal. The most likely means of biomass transportation will be by truck. This is the exclusive transportation option modeled. Cundiff and Grisso provide an overview of shipping methods. The authors note the challenges of feedstock storage after harvest and baling. According to them, while square baling enables high-density packing in shipping crates, stacks of square bales with too much moisture are vulnerable to spontaneous combustion. They instead use high-density round-bale packing, which permits a truck to carry 32 bales or 12.67 dry tons of material for each load. They assume a shipping distance of 25 miles from the farmgate to the plantgate along with a 20% moisture content. Calculating all loading, transport, and labor costs (including vehicle wear and depreciation), the cost of shipping biomass is approximate to \$7.10 (\$2006) per dry ton. The vast majority of the cost is from the distance shipped, with \$1.25 coming from loading and unloading the materials; biomass shipment costs average \$0.23 per ton-mile. Searcy *et al*.[13] also examined biomass transportation costs in the Canadian market, using straw and woodchips as the representative feedstock. These authors assumed slightly larger loads by truck and calculated a fixed cost component (loading and unloading) of \$4.00 (\$2004) per dry ton and a variable cost of \$.14 per dry ton for each mile traveled. Both estimates are relatively in-line with EIA transportation estimates, which add a flat fee of \$12/dry ton (\$2009).[14] This \$12-estimate generally assumes \$4.00 for loading and unloading and \$8/dry ton for transport distances up to 75 miles.

Intraregional biomass transportation costs are calculated by taking one-half of the distance, in miles, between the geographic center point of any ASD region and the furthermost point along that region's border and multiplying this distance by a shipping cost of \$0.16 per ton-mile, which is the distance-specific EIA estimate.[1] Interregional transportation costs are represented by the product of the cost per ton-mile of shipping (\$0.16)[14] and the distance between the center points of any two ASDs. These distance calculations are readily available using basic functions of GIS-based software. A \$4 fixed cost fee, for material loading and unloading, is added to all biomass prices. This flat fee plus the distance-specific transportation cost added to the original biomass farmgate price equals the total plantgate fuel price.

III. MODELING METHODOLOGY

A. Biomass fuel supply curve derivation using POLYSYS

As noted, the POLYSYS provides supply curves by region for the agricultural biomass feedstocks. The non-energy crops represented in the model all have crop-specific supply and non-energy demand elasticities. The supply elasticities are a reflection of the characteristics of each ASD, such as rainfall patterns, irrigation systems, and soil quality, which will affect cost of production, while the non-energy demand curves are largely exogenous to the model and are national rather than ASD-specific. Non-energy demands include food use (for human and animal consumption) and textile demands. POLYSYS optimizes crop decisions in each ASD for which land-use patterns are projected based on the maximization of present worth of net revenue for landowners while satisfying all demand constraints.

The exogenous shock that causes deviation from the USDA baseline forecast, where no energy crops are produced and crop residues are assumed to hold no value, is in the form of switchgrass development on U.S. agricultural lands spurred by exogenously specified demand prices. The biomass demand prices are entered into a scenario descriptor file within POLYSYS. The demand price represents a uniform national price that will remain in effect throughout the forecasting period: there is no variation among ASD-specific biomass demand prices in the basic POLYSYS model. The period used in this analysis is from 2012 to 2035. POLYSYS has been solved several times with varying biomass demand farmgate prices, in \$5 increments, between \$10 and \$100/dry ton (\$2009); the result is the amount of biomass energy produced for each ASD. These data define points on the agricultural energy biomass supply for that ASD, yielding estimates for 305 such curves.

The power plant siting model's objective function minimizes the total cost of meeting the generation requirement itself rather than a minimization of total expenditures (which would be the product of the market-clearing price and the total quantity demanded). Since the goal of the objective function is cost minimization, the supply curve will be "climbed" in the proper order, with the lowest-cost supplies being exhausted before the next stair-step in the curve is reached.

B. Power plant allocation model structure

Like all mathematical programs, the elements that need to be defined include decision variables, an objective function, and constraints. In words,

Choose the sources of biomass supply, plant types, and locations of these plants in order to minimize total costs, subject to constraints on generation load, plant generation, plant capacity, and fuel supply.

1. Decision variables

$f_{j,k,t}$ is the incremental fraction of co-fired biomass in region j at plant k in year t multiplied by 100%, $0 \le f_{j,k,t} \le 15$, $f_{j,k,t} = \frac{m_{j,k,t}}{E_{j,k,t}} * 100\%$. This decision variable does not appear in the objective function but does appear in the constraints and is used in parameter definitions.

$g_{j,k,t}$ is defined as the actual percent of coal-based generation at co-firing plant k in region j in year t. $g_{j,k,t}$ differs from $(100 - f_{j,k,t})$.since biomass affects the entire boiler efficiency, $(g_{j,k,t} = (1 + 0.0008 * f_{j,k,t}) * (100 - f_{j,k,t}))$. The definition of the parameter is actually the product of two expressions, with each containing the decision variable $f_{j,k,t}$. This relationship causes a nonlinearity within the model and thus classifies it as an NLP rather than an LP.

For decision years beyond the first year, $g_{j,k,t}$ should be a function of $\sum_{t*} f_{j,k,t}$, where t^* is the set of all $\tau \le t$. $(g_{j,k,t} = (1 + 0.0008 * \sum_{t*} f_{j,k,t}) * (100 - \sum_{t*} f_{j,k,t}))$ is the decision variable that determines the incremental fraction of the plant capacity used for co-firing in decision year t, while $\sum_{t*} f_{j,k,t}$ represents the total fraction of plant capacity co-fired in decision year t.

$n_{j,t}$ is defined as the number of dedicated biomass plants constructed within region j in decision year t.

$m_{j,k,t}$ is defined as the total number of megawatts of biomass co-fired capacity retrofitted in region j at coal facility k in decision year t [MW].

$q_{i,s,t}$ is defined as the utilized biomass supply (biomass produced) for electricity production originating in region i during decision year t [MMBTU]. The variable carries the "s" subscript to signify price step s. This biomass is utilized both within the region and transported to all other regions j where it is used for electricity generation.

$t_{i,j,t}$ is the total annual amount of biomass transported from region i to region j during decision year t [MMBTU]. When i and j are equal, $t_{i,j,t}$ is the amount of biomass kept within region i for electricity production.

$x_{j,t}$ is defined as the megawatthour output for dedicated biomass combustion plants in region j during decision year t [MWh].

$y_{j,k,t}$ is defined as the megawatthour output of co-fired capacity in region j at coal facility k during decision year t [MWh]. Since there is assumed to be no incremental variable (or fixed) O&M cost of co-firing biomass relative to coal, this decision variable only appears in the objective function when calculating the fuel savings from displaced coal.

These decision variables as well as the subsequent variables and parameters listed all carry subscripts representing sets to which they belong. The subscript i denotes the set of all biomass-producing ASD regions. The set i contains all integer values from 1 to 305. The subscript j denotes the set of all biomass-consuming ASD regions. That set also contains all integers from 1 to 305. Sets i and j overlap since both represent the same ASDs; however, i can be thought of as the ASD of origin, while j is the ASD to which biomass deliveries are made in order to generate electricity. As noted earlier, when i and j are equal, biomass grown within region i remains within that region for electricity production. Set s is composed of all integer values between 1 and 19, since there are initially 19 different price steps in 5-dollar increments from \$10 to \$100 per ton, which are then converted into \$2009 per MMBTU. Finally, the set t represents all decision years on the forecast horizon. There are 5 elements of set t representing years 2012, 2020, 2025, 2030, and 2035.

2. Objective function

The objective function is given by the following expression:
Minimize

$$\begin{aligned} Z = {} & \sum_{j=1}^{305}\sum_{t=1}^{T} A_{j,t} n_{j,t} + \sum_{j=1}^{305}\sum_{k=1}^{K}\sum_{t=1}^{T} B_{j,t} m_{j,k,t} + L_{j,t}\sum_{j=1}^{305}\sum_{t=1}^{T}(V_{j,t} - R_{j,t}) x_{j,t} \\ & + L_{j,t}\sum_{j=1}^{305}\sum_{t=1}^{T} O_{j,t} n_{j,t} + L_{j,t}\sum_{i=1}^{305}\sum_{s=1}^{S}\sum_{t=1}^{T} C_{i,s,t} * q_{i,s,t} \\ & - L_{j,t}\sum_{j=1}^{305}\sum_{k=1}^{K}\sum_{t=1}^{T} \Xi_{j,t} * y_{j,k,t} + L_{j,t}\sum_{i=1}^{305}\sum_{j=1}^{305}\sum_{t=1}^{T} T_{i,j,t} t_{i,j,t}. \end{aligned} \tag{3.1}$$

The parameters appearing in the objective function are the following:

$A_{j,t}$ is defined as the present-worth capital cost of a dedicated biomass combustion plant installed in decision year t. The dual variable value of the capacity reserve margin constraint from the NEMS model projections are subtracted from each $A_{j,t}$[\$2009]. Although there are no regional variations in the base capital costs, the dual NEMS value does vary for each region, so dedicated capacity will be relatively cheaper in some regions compared to others.

$B_{j,t}$ is defined as the present-worth capital cost per megawatt of biomass capacity in a co-firing system at an existing coal plant in region j for decision year t [\$2009/MW].

$C_{i,s,t}$ is the cultivation cost of the incremental biomass supply provided at price step s [\$2009/MMBTU]. If the quantity of utilized biomass is given on the x axis (MMBTU) and the price at which the material becomes available is given on the y axis, $C_{i,s,t} * q_{i,s,t}$ is an integral function that calculates the product of the width of each non-zero $q_{i,s,t}$ and its corresponding price; it is the area of each separate rectangular piece below the supply curve stair-step function [\$2009].

$L_{j,t}$ is defined as the length of the multi-year time period following decision year t. Generally, $L_{j,t}$ is equal to five, although there are two exceptions: $L_{j,1}$ is equal to eight and $L_{j,5}$ is equal to one.

$O_{j,t}$ is the annual fixed operations and maintenance cost for dedicated plant capacity in region j for year t [$2009/MW/year]. Although a function of plant capacity, O&M costs incur annually.

$R_{j,t}$ is defined as the net value of the expanded generation capacity in region j for year t [$2009/MWh]. Each additional megawatthour generated by new generating capacity from dedicated biomass plants gets credited with the marginal value of electricity production in that region minus the marginal value of transmission expansion.

$T_{i,j,t}$ is defined as the distance-specific transportation cost per ton (ultimately converted into $2009/MMBTU) of biomass from region i to region j during year t [$2009/MMBTU]. It is derived from ton-mile costs of transport [$/ton-mile] (Sec. II E), distance [miles], a fixed loading cost [$/ton], and the energy density [MMBTU/ton]. When i and j are equal, $T_{i,j,t}$ becomes the intraregional transportation cost.

$V_{j,t}$ is defined as the annual variable cost of a dedicated biomass combustion plant for operations and maintenance in region j in year t [$2009/MW/year].

$\Xi_{j,t}$ is the price of coal in region j for year t [$2009/MMBTU]. This price is a fixed output from the NEMS LP.

3. Constraints

Before the constraints are introduced, additional parameters not appearing in the objective function but present in the constraints are defined below:

$E_{j,k,t}$ is the existing coal capacity at coal-fired facility k in region j for year t. Each coal-fired facility is a candidate site for biomass co-firing [MW].

$H_{j,k,t}$ is defined as the effective heat rate of the biomass portion of the co-fired generation to compensate for the overall decrease in boiler efficiency caused by co-firing and the additional coal needed to maintain constant generation [MMBTU/MWh].

$Load_t$ is defined as the total number of megawatthours of generation from biomass [MWh]. It varies with each model run and is specified between 1% and 17% of total U.S. electricity generation as projected by EIA in the *2011 Annual Energy Outlook*.

$Q_{i,s,t}$ is defined as the maximum incremental biomass supply in region i able to be grown during year t at price level s [MMBTU]. This quantity is exogenous to the generation model (Sec. III A) and is determined by the POLYSYS model and ORNL. POLYSYS and ORNL report this value in dry tons, and it is converted into MMBTU so that it can be used in this model.

$\Theta_{j,t}$ is defined as the heat rate of a dedicated combustion system and is constant (13 500 BTU/kWh or 13.5 MMBTU/MWh) [MMBTU/MWh]. It carries a regional subscript to describe a more general situation in which plant efficiency varies regionally and a time-period subscript to accommodate potential future learning-by-doing technological advancement that would decrease heat rates.

$\Lambda_{j,k,t}$ is defined as the initial unit-specific heat rate of coal facility k in region j during year t before co-firing is introduced [MMBTU/MWh].

The constraints of the generation optimization model can now be stated as follows:

$$\sum_{j=1}^{305} x_{j,t} + \sum_{j=1}^{305} \sum_{k=1}^{K} y_{j,k,t} = Load_t \ \forall t, \tag{3.2}$$

$$x_{j,t} \le 8760 * 0.9 * 80MW * n_{j,t} \ \forall j,t, \tag{3.3}$$

$$\sum_{t=1}^{T} m_{j,k,t} = 0.15 * E_{j,k,t} \, \forall j,k,t, \tag{3.4}$$

$$\frac{f_{j,k,t}}{100} \le 0.15 \ \ \forall j,k,t, \tag{3.5}$$

TABLE II. Biomass generation requirements in MWh and percent of total projected electricity generation for the core case.

	25% scenario		50% scenario		75% scenario		100% scenario		Max scenario	
Year	Generation [MWh]	% of total projected generation	Generation [MWh]	% of total projected generation	Generation [MWh]	% of total projected generation	Generation [MWh]	% of total projected generation	Generation [MWh]	% of total Projected generation
2012	2 024 000	0.05	4 048 000	0.11	6 072 000	0.16	8 096 000	0.21	75 600 000	2.00
2020	69 063 000	1.73	138 126 000	3.46	207 190 000	5.18	276 253 000	6.91	399 900 000	10.00
2025	105 989 000	2.56	211 978 000	5.11	317 968 000	7.67	423 957 000	10.23	518 000 000	12.50
2030	150 154 000	3.47	300 308 000	6.95	450 462 000	10.42	600 616 000	13.90	648 000 000	15.00
2035	192 854 000	4.30	385 709 000	8.59	578 563 000	12.89	766 818 000	17.08	768 000 000	17.11

$$y_{j,k,t} \le 8760 * 0.85 * E_{j,k,t} * \left(1 - \frac{g_{j,k,t}}{100}\right) \; \forall k, j, t, \tag{3.6}$$

$$\Theta_{j,t} x_{j,t} + \sum_{k=1}^{K} H_{j,k,t} y_{j,k,t} - \sum_{i=1}^{305} t_{i,j,t} \le 0 \; \forall j, t, \tag{3.7}$$

$$\sum_{j=1}^{305} t_{i,j,t} - \sum_{s=1}^{S} q_{i,s,t} \le 0 \; \forall i, t, \tag{3.8}$$

$$q_{i,s,t} \le Q_{i,s,t} \; \forall i, s, t, \tag{3.9}$$

$$n_{j,t} \in \mathbb{Z}^{+}, \tag{3.10}$$

$$g_{j,k,t} = \left(1 + 0.0008 * \sum_{t*} f_{j,k,t}\right) * \left(100 - \sum_{t*} f_{j,k,t}\right), \tag{3.11}$$

where t^* is the set of all $\tau \le t$ ($n_{j,t}$ represents a discrete number of constructed plants, so $n_{j,t}$ must be a nonnegative integer).

IV. RESULTS

Any generation constraint for a biomass portfolio standard (BPS) is arbitrary since no BPS has ever been proposed, so the Energy Information Administration's *AEO2011* projections for plant retirements and projected electricity generation growth was used as a starting point target. The total amount of generation lost through capacity retirements and the incremental generation needed to meet future demands were combined for each decision year to become the constraint requirement. Since these requirements represented a high amount of biomass electricity generation, three other scenarios were introduced that multiplied the generation totals in each year by 0.25, 0.50, and 0.75. The "100% core case scenario" has the initial calculated generation values. There is also a "core maximum scenario" that increases the stringency of the targets and uses round numbers. All generation targets can be seen in Table II. The max scenario does not significantly increase the 2035 targets over the 100% core case scenario, since nearly all of the biomass resources are utilized in meeting that case's standard, and there is little room for target

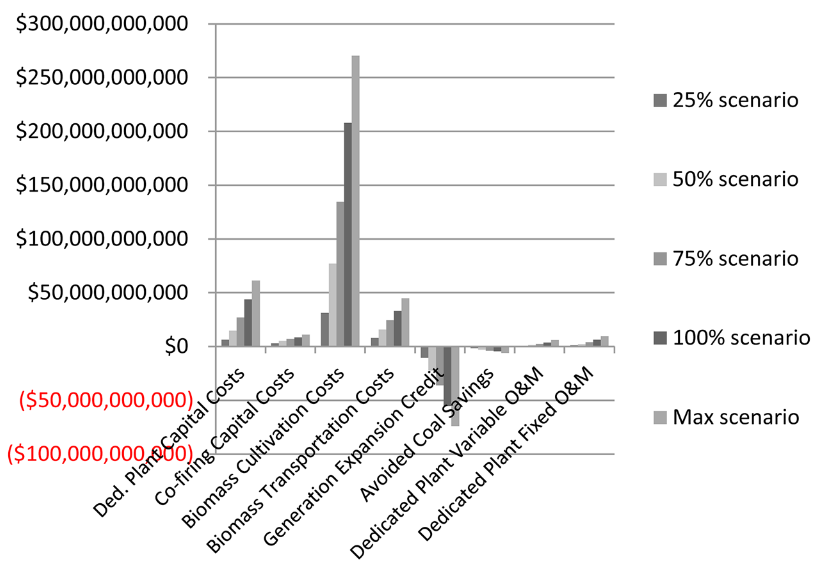

FIG. 1. Costs and avoided costs in the scenarios of the core case.

TABLE III. Objective function values for the core case.

Objective function component	25% scenario	50% scenario	75% scenario	100% scenario	Max scenario
BPS as a percentage of total generation in 2012, 2020, 2025, 2030, and 2035, respectively	0.05	0.11	0.16	0.21	2.00
	1.73	3.46	5.18	6.91	10.00
	2.56	5.11	7.67	10.23	12.50
	3.47	6.95	10.42	13.90	15.00
	4.30	8.59	12.89	17.08	17.11
Dedicated plant capital costs[a]	$6 301 077 142	$14 750 746 900	$27 007 287 560	$43 818 074 770	$61 353 476 630
Co-fired plant capital costs	$2 768 753 940	$5 222 348 065	$7 115 579 954	$8 329 831 108	$10 906 649 530
Dedicated plant variable costs	$551 612 393	$1 312 082 969	$2 224 992 531	$3 628 008 830	$5 906 657 213
Dedicated plant generation expansion credit	$10 245 176 010	$21 991 282 740	$36 116 477 860	$55 298 836 430	$73 877 520 270
Dedicated plant fixed O&M costs	$933 244 847	$2 179 174 431	$3 835 206 387	$6 228 948 768	$9 465 937 616
Biomass fuel cultivation costs	$31 092 773 710	$77 274 490 830	$134 409 629 200	$207 839 873 500	$270 092 601 400
Avoided coal savings	$1 581 125 182	$2 878 600 885	$3 871 654 022	$4 498 038 726	$6 022 735 099
Transportation costs	$7 760 147 200	$15 742 779 320	$24 251 429 550	$33 179 539 380	$44 796 115 380
Total costs	**$49.4 billion**	**$116.5 billion**	**$198.8 billion**	**$303.0 billion**	**$402.5 billion**
Total avoided savings and credits	**$11.8 billion**	**$24.9 billion**	**$40.0 billion**	**$59.8 billion**	**$79.9 billion**
Objective function value	**$37.6 billion**	**$91.6 billion**	**$158.9 billion**	**$243.2 billion**	**$322.6 billion**

[a]Adjusted for the capacity expansion credit.

augmentation. Basing the values on projected retirements and capacity expansion was an arbitrary decision that holds little independent importance. The goal was to provide a wide range of BPS generation requirements that varied from very stringent cases to cases having little impact in order to show a breadth of potential generation scenarios and the associated cost impacts.

In 2035, the 100% core case scenario's target exploits 98.3% of all domestic biomass feedstock. Sensitivity cases, which account for things like cellulosic ethanol production, increased coal plant retirements from air quality measures, and different heat rate assumptions can be found in the full analysis.[13]

Figure 1 and Table III present the overall results from the power plant siting model, showing the costs and avoided costs attributable to each component of the objective function.

Since the objective function subtracts avoided costs from total costs, the objective value dollar amount represents the premium cost, over the cheapest alternative, of generating biomass at the levels specified within each scenario. Table IV, which shows levelized costs, puts the objective function into present-worth $/MWh terms instead of the total present-worth costs listed below. These calculations show how much biomass technology would need to be subsidized if it were to compete in markets with the least-cost alternatives for providing electricity. That is, this is the subsidy necessary for biomass technology to be profitable under NEMS market prices for coal, electric energy, and electricity capacity.

These data support the assertion that as the standards become more stringent, dedicated facilities play a larger role in meeting generation targets as co-firing options are exhausted: co-firing related costs and coal savings account for a larger share of the total in the lower-target scenarios.

The spatial allocation patterns reinforce the conclusions shown earlier which state that co-firing is generally chosen, but not exclusively so, over dedicated generation when low-cost co-firing opportunities exist. Even in the maximum scenario where nearly 100% of nationwide feedstocks are utilized for electricity production, ASD regions with high concentrations of coal plants do not build many dedicated facilities. The main exception is the State of Illinois and the immediate surrounding areas. This area is so rich in biomass feedstocks from agricultural production that it is able to support several gigawatts of co-fired and dedicated capacity. Areas in which coal plants are prevalent, especially Western Pennsylvania and the Lower Ohio Valley, are not chosen for dedicated capacity but hold much of the co-firing contribution to the BPS.

Looking at the allocation patterns also gives insights into the feedstock costs and materials. In the scenarios with lower generation requirements, the area around the State of Iowa is largely left untouched while other areas in the Southeast have large capacity installations. As the requirement becomes more stringent, the dedicated plant allocation patterns move westward, from Illinois into Iowa, Kansas, and Nebraska. The feedstocks from these states ultimately support large amounts of dedicated capacity. These states contain the ASD regions with high amounts of agricultural residues and switchgrass. Generally, forested lands are first exploited since the resource is available at a lower cost. This is why the results show dedicated plants being built along the coasts under the less stringent scenarios, as non-agricultural biomass plays an important role in the lower steps of the biomass supply curve.

TABLE IV. Net levelized cost of biomass generation.

Case	25% scenario	50% scenario	75% scenario	100% scenario	Max scenario
	Net levelized cost [$2009/MWh]	Net levelized cost [$2009/MWh)	Net levelized cost [$2009/MWh]	Net levelized cost [$2009/MWh]	Net levelized cost [$2009/MWh]
Core case	41.5	50.6	58.5	67.2	70.5

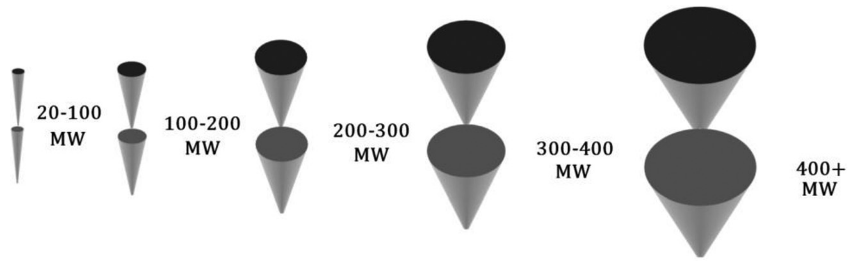

FIG. 2. Legend of capacity installations from co-firing (darker gray) and dedicated (lighter gray) facilities for Figs. 3 and 4 (note: these are relative sizes; absolute sizes are smaller).

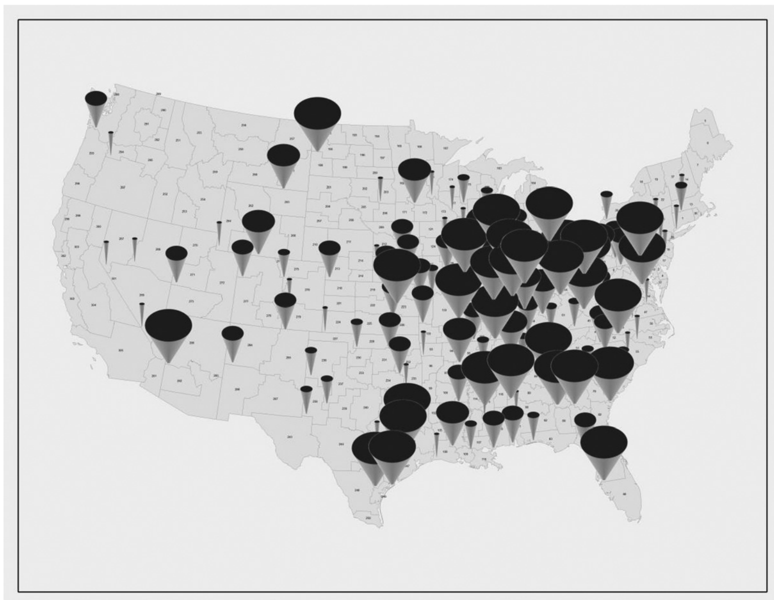

FIG. 3. 2035 co-fired capacity allocated by ASD region in the 75% scenario of the core case.

FIG. 4. 2035 dedicated capacity allocated by ASD region in the 75% scenario of the core case.

V. CONCLUSIONS

The non-linear integer program developed in this analysis simultaneously shows the benefits and shortcomings of biomass as a low-carbon technology. Unlike other renewable sources of generation, biomass generation can be integrated into existing infrastructure when co-fired with coal. Since the results of the model show that large amounts of co-fired capacity are chosen early in the 2012–2035 forecasting period, existing coal plant owners have a viable option to reduce emissions without abandoning their investments or considering other options such changing fuels or operations. Inexpensive biomass is located near existing coal infrastructure. Meanwhile, dedicated biomass plants have geographic versatility that enables their construction in vast areas of the Eastern United States and along the West Coast. Unlike wind resources, which are centered in the Dakotas, West Texas, and the desert Southwest, or solar, which is also concentrated in the desert Southwest, biomass is found where the vast majority of the U.S. population resides. Small dedicated facilities can spring up in these densely populated areas, avoiding some of the transmission constraints associated with other renewable technologies that may require several hundred miles of lines to reach well-populated areas.

While the benefits are apparent, the model also points out some of the shortcomings of biomass technology. Although wind, solar, and geothermal resources are geographically constrained, they are also available without cost. Biomass farmgate costs, however, comprise approximately two-thirds of total objective function costs in all of the scenarios in the core case. In the maximum scenario run in the model, the farmgate fuel costs stand at a whopping \$270 billion. Although the energy content of the biogenic feedstocks is diffuse relative to fossil fuels, transportation costs range from one-fifth of the farmgate costs in the less stringent scenarios to one-seventh of the costs in the maximum scenario. These high fuel costs result from competition in the agricultural sector, a market into which biomass must penetrate to be cultivated. In a world with omnipresent food shortages, the displacement of millions of acres of traditional crops is not achieved without significant costs.

The model allocation patterns and cost results also provide policymakers with areas of focus that can have the potential to decrease costs attributed to a biomass portfolio standard. The plant allocations show the importance of low heat rates. Co-firing is primarily chosen over dedicated generation because it takes advantage of the high efficiency (low heat rates) of large coal-fired power plants, whereas dedicated biomass plants are smaller and less efficient. This was verified with an alternative case in which co-fired generation was assigned the same heat rates as dedicated plants and very little co-fired capacity was constructed.[15] Across all years in the model, dedicated plants were given heat rates of 13 500 BTU/kWh, a very realistic estimate given the current state of the technology and future expectations. Yet if biomass plant efficiency technologies were improved, dramatic cost reductions would be feasible.

One must remain realistic about possible technological developments. The assumptions of the model are supported by the best studies available and show that biomass can have a significant future role in U.S. electricity production, if sufficient subsidies are provided. The physical supply of biomass is available, even if it is uneconomic relative to current projections of natural gas prices. Certainly one could argue that potential complications from a BPS, such as short-term fuel supply restrictions and unforeseen difficulties with cultivating staggering amounts of switchgrass, would add to the costs as calculated by the model. Ultimately, "policy decisions are made by people, not computers, and executives consider analysis as aides, rather than formulas for decisions,"[16] (p. 154). As the United States determines its future energy plan, the goal of the model presented in this article is to provide part of the information needed to assess the costs and benefits of such a plan.

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