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Project Title: Biomass Electricity Generation at Ethanol Plants - Achieving Maximum Impact

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Minnesota fourth (UofM Bioproducts and Biosystems Engineering)

Executive Summary

- Updated project web site www.biomassCHPethanol.umn.edu to make recent results more readily available to the public.
- Developed comparisons of biomass integrated gasification combined cycle (BIGCC) power production at corn ethanol plants for a range of system configurations. Key results include: 1) systems using steam tube drying provided more power to the grid than those using superheated steam drying, 2) 10 bar gas compression provided better performance than 20 bar gas compression, 3) discharging steam tube dryer exhaust to the gas turbine provided more power to the grid than discharging to a duct burner after the gas turbine, and 4) corn stover alone or syrup and corn stover fuels provided about the same performance in terms of electricity sent to the grid.
- Developed detailed capital cost estimates for BIGCC systems and compared them to previously developed capital cost estimates for steam turbine combined heat and power (CHP) systems at ethanol plants.
- Presented a detailed analysis of integrated resource plans developed by several utilities to determine how electricity generated at ethanol plants might fit in future power generation systems.
- Continued to update life-cycle greenhouse gas emission estimates for corn ethanol produced with biomass fuel compared to conventional natural gas systems. Documenting life-cycle greenhouse gas emission reductions for producing ethanol and generating renewable electricity will be an important consideration in policy and economic decisions related to investments in alternative energy. This information will be critical to investors and their bankers when firms consider adopting these new renewable technologies.
- Formulated plans for additional financial analysis from the standpoint of a business model involving a “power island” at the ethanol plant that would be owned by another

entity. This type of analysis should be of interest to outside investors and the bankers they use.

- Developed plans to hold three conferences related to our work: March 29 in Owatonna, MN, March 31 in Lamberton, MN, and July 11 in St. Paul, MN (St. Paul Campus of the University of Minnesota). The website for registration is http://www.cce.umn.edu/Using-Corn-Stover-for-Energy-at-Ethanol-Plants/index.html
- Communicated about project activities, carried out project management, accounting, and reporting functions.

Project funding provided by customers of Xcel Energy through a grant from the Renewable Development Fund.

Technical Progress

Prepared by

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Summary of Tasks Listed under Milestone 7

1A. Integrated gasification combined cycle analysis

- Complete rate of return study
- Continue specification of policies and rates to make biomass generated electricity attractive

We have continued to model BIGCC systems in Aspen Plus for a range of fuels, dryer types, dryer exhaust configurations, and compression levels for the gas turbine. All systems are designed to meet the process energy and electricity needs of a 190 million liter per year (50 million gallon per year) ethanol plant, plus send as much electricity to the grid as possible. We also are modeling natural gas combined cycle systems (NGCC) to provide a basis for comparison to the BIGCC systems.

Performances of all of these systems with an emphasis on electricity supplied to the grid are summarized for corn stover, corn stover and syrup, and natural gas fuels in Tables 1 through 3, respectively. Several general conclusions can be drawn:

1. Steam tube drying has more potential for maximizing electricity production than superheated steam drying because it provides a greater sink for process heat, and therefore, potential for discarding waste heat from the electricity generation process. In addition, steam tube drying requires less power to operate than superheated steam drying further increasing power available to the grid.

2. Systems utilizing steam tube drying provide more power to the grid with 10 bar gas compression than 20 bar gas compression. This relationship is reversed for superheated steam drying.

3. Discharging steam tube dryer exhaust to the gas turbine provides more electricity to the grid than discharging to a duct burner after the gas turbine or to the biomass combustor. Discharging dryer exhaust to the biomass combustor is the poorest option of the three. Potential dryer exhaust air clean-up issues may limit the opportunity to discharge to the gas turbine.

4. Corn stover alone or syrup and corn stover fuels provide about the same performance in terms of electricity sent to the grid. Natural gas provides greater levels of electricity sent to the grid than the biomass systems for the same level of energy input because there is much less parasitic power loss for gas compression for the natural gas systems versus the biomass systems.

Table 1. System performance for a 190 million liter per year (50 million gallon per year) ethanol plant with syrup and corn stover fuel at 110 MW_{th} input rate (all fuel to gasifier)[a].

	Steam Tube Dryer						Superheated Steam Dryer	
Exhaust treatment methods	**Exhaust to Combustor**		**Exhaust to Gas Turbine**		**Exhaust to Duct burner**			
Syngas compression	**10 bar (2 stage)**	**20 bar (3 stage)**	**10 bar (2 stage)**	**20 bar (3 stage)**	**10 bar (2 stage)**	**20 bar (3 stage)**	**10 bar (2 stage)**	**20 bar (3 stage)**
Generation Efficiency	27.1%	27.5%	30.6%	29.4%	28.1%	25.5%	31.0%	33.7%
Thermal Efficiency[b]	70.0%	69.8%	73.3%	71.6%	71.4%	68.7%	50.0%	51.4%
Power Generation, MW								
Total power by gas turbine	36.9	48.7	49.6	64.2	38.9	42.9	54.8	78.4
Shaft power	18.6	30.0	27.6	43.4	19.7	26.4	27.6	48.3
Gas turbine[c]	18.3	18.7	22.0	20.8	19.3	16.5	27.2	30.1
Steam turbine	11.6	11.6	11.6	11.6	11.6	11.6	7.0	7.0
Power Use, MW								
Ethanol process	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7
Dryers[d]	0	0	0	0	0	0	4.5	4.5
Parasitic BIGCC[d,e]	4.1	4.6	4.3	4.8	3.6	3.6	4.7	6.2
To Grid	21.1	21.0	24.7	22.9	22.5	19.7	20.2	21.7
Total	29.9	30.3	33.6	32.4	30.9	28.1	34.1	37.1
Process Heat, MW_{th}								
Ethanol process	27.9	27.9	27.9	27.9	27.9	27.9	27.9	27.9
Dryers	23.3	23.3	23.3	23.3	23.3	23.3	2.3	2.3
Total	51.2	51.2	51.2	51.2	51.2	51.2	30.2	30.2
Synthesis Gas Split, MW_{th}								
Combustor	39.3	39.4	8.1	8.1	8.1	7.5	5.5	5.5
Turbine	69.6	64.3	89.9	78.9	73.4	56.7	103.4	103.4
Duct burner	0	5.2	10.9	21.9	27.4	44.7	--	--
Combustor Input, MW_{th}								
Char	17.1	17.1	17.1	17.1	17.1	17.1	17.1	17.1
Syngas	39.3	39.4	8.1	8.1	8.1	7.5	5.5	5.5
Total	56.4	56.5	25.2	25.2	25.2	24.6	22.6	22.6
Combustor Output, MW_{th}								
Gasifier heat duty	16.0	16.0	16.0	16.0	16.0	16.0	15.9	15.8
Combustion exhaust	40.4	40.5	9.2	9.2	9.2	8.6	6.7	6.8
Total	56.4	56.5	25.2	25.2	25.2	24.6	22.6	22.6

[a]All energy and power values are based on the fuel higher heating value (HHV). Syrup: 38.6 MW_{th}, 509 t/day at 66.8% moisture; Stover: 71.4 MW_{th}, 396 t/day at 13% moisture.
[b]Thermal efficiency of converting fuel energy into other useful forms of energy (process heat and electricity), excludes BIGCC parasitic load.
[c]Isentropic efficiency of gas turbine: 0.90, mechanical efficiency of gas turbine: 0.98.
[d]Power use for superheated steam dryers and parasitic BIGCC based on calculated power requirement for equipment (compressors, fans, pumps) and an electric motor efficiency of 95%.
[e]Isentropic efficiency of air compressor: 0.85, mechanical efficiency of air compressor: 0.97.

Table 2. System performance for a 190 million liter per year (50 million gallon per year) ethanol plant with corn stover fuel at 110 MW_{th} input rate (all fuel to gasifier)[a].

	Steam Tube Dryer						Superheated Steam Dryer	
Exhaust treatment methods	Exhaust to Combustor		Exhaust to Gas Turbine		Exhaust to Duct burner			
Syngas compression	10 bar (2 stage)	20 bar (3 stage)	10 bar (2 stage)	20 bar (3 stage)	10 bar (2 stage)	20 bar (3 stage)	10 bar (2 stage)	20 bar (3 stage)
Generation Efficiency	26.8%	27.2%	30.6%	29.2%	28.2%	27.7%	30.4%	33.0%
Thermal Efficiency[b]	68.9%	68.8%	72.6%	70.7%	70.7%	69.7%	49.3%	50.7%
Power Generation, MW								
Total power by gas turbine	36.0	47.6	50.3	63.0	39.2	47.5	53.0	75.8
Shaft power	18.0	29.2	28.1	42.4	19.7	28.5	26.6	46.5
Gas turbine[c]	18.0	18.4	22.2	20.6	19.5	19.0	26.4	29.3
Steam turbine	11.5	11.5	11.5	11.5	11.5	11.5	7.0	7.0
Power Use, MW								
Ethanol process	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7
Dryer[d]	0	0	0	0	0	0	4.4	4.4
Parasitic BIGCC[d,e]	4.1	4.7	4.4	4.8	3.8	4.3	4.8	6.2
To Grid	20.6	20.5	24.6	22.6	22.5	21.5	19.5	21.0
Total	29.4	29.9	33.7	32.1	31.0	30.5	33.4	36.3
Process Heat, MW_{th}								
Ethanol process	27.9	27.9	27.9	27.9	27.9	27.9	27.9	27.9
Dryer	22.6	22.6	22.6	22.6	22.6	22.6	2.2	2.2
Total	50.5	50.5	50.5	50.5	50.5	50.5	30.1	30.1
Synthesis Gas Split, MW_{th}								
Combustor	42.1	41.7	11.2	11.0	11.2	11.0	9.9	9.9
Turbine	68.1	63.0	90.7	77.7	74.0	64.3	100.3	100.3
Duct burner	0	5.5	8.3	21.5	25.0	34.9	--	--
Combustor Input, MW_{th}								
Char	18.0	18.0	18.0	18.0	18.0	18.0	18.0	18.0
Syngas	42.1	41.7	11.2	11.0	11.2	11.0	9.9	9.9
Total	60.1	59.7	29.2	29.0	29.2	29.0	27.9	27.9
Combustor Output, MW_{th}								
Gasifier heat duty	18.2	18.2	18.2	18.2	18.2	18.2	18.2	18.2
Combustion exhaust	41.9	41.5	11.0	10.8	11.0	10.8	9.7	9.7
Total	60.1	59.7	29.2	29.0	29.2	29.0	27.9	27.9

[a]All energy and power values are based on the fuel higher heating value (HHV). Stover: 110 MW_{th}, 637 t/day at 13% moisture.
[b]Thermal efficiency of converting fuel energy into other useful forms of energy (process heat and electricity), excludes BIGCC parasitic load.
[c] Isentropic efficiency of gas turbine: 0.90, mechanical efficiency of gas turbine: 0.98.
[d] Power use for superheated steam dryers and parasitic BIGCC based on calculated power requirement for equipment (compressors, fans, pumps) and an electric motor efficiency of 95%.
[e]Isentropic efficiency of air compressor: 0.85, mechanical efficiency of air compressor: 0.97.

Table 3. System performances of natural gas for a 190 million liter per year (50 million gallon per year) ethanol plant (natural gas input rate is 110 MW; steam tube drying)[a] .

Exhaust treatment methods	**Exhaust to Gas Turbine**		**Exhaust to Duct Burner**	
Natural gas compression	**10 bar**	**20 bar**	**10bar**	**20bar**
Generation efficiency	32.0%	30.0%	29.6%	28.5%
Thermal efficiency[b]	77.7%	75.6%	75.3%	74.1%
Power Generation, MW				
Gas turbine net power[c]	24.4	22.2	21.8	20.0
Steam turbine	10.8	10.8	10.8	10.8
Total	35.2	33.0	32.6	31.3
Power Use, MW				
Ethanol process	4.7	4.7	4.7	4.7
Parasitic BIGCC[d,e]	0.2	0.4	0.2	0.4
To Grid	30.3	27.9	27.7	26.2
Process Heat, MWth				
Ethanol process	27.9	27.9	27.9	27.9
Dryer	22.6	22.6	22.6	22.6
Total	50.5	50.5	50.5	50.5
Synthesis Gas Split, MWth				
Turbine	91.6	78.1	76.0	65.2
After turbine	18.4	31.9	34.0	44.8

[a]All energy and power values are based on the fuel higher heating value (HHV).
[b]Thermal efficiency of converting fuel energy into other useful forms of energy (process heat and electricity), excludes BIGCC parasitic load.
[c]Isentropic efficiency of gas turbine: 0.90, mechanical efficiency of gas turbine: 0.98.
[d]Power use for parasitic BIGCC based on calculated power requirement for equipment (compressors, fans, pumps) and an electric motor efficiency of 95%.
[e]Isentropic efficiency of air compressor: 0.85, mechanical efficiency of air compressor: 0.97.

Life-Cycle Greenhouse Gas (GHG) Emissions

Life-cycle GHG emissions analyses and results for the systems described in Tables 1 through 3 are summarized in Tables 4 through 6. BIGCC systems result in GHG emission reductions in the range of 105 to 125% for corn ethanol compared to gasoline depending on gas compression, dryer type, and location of exhaust discharge for the steam tube dryer. The significant reductions for ethanol compared to gasoline are primarily due to power produced and sent to the grid to replace goal generated electricity.

Natural gas combined cycle systems result in GHG emissions reductions of 85 to 95% for corn ethanol compared to gasoline depending on the system configuration. Even though biomass is not used for fuel, significant reductions are possible for ethanol compared to gasoline primarily due to power produced and sent to the grid to replace coal generated electricity.

Table 4. Technical data for various BIGCC and NGCC systems integrated with a 190 million liter per year (50 million gallon per year) dry-grind corn ethanol plant. [a]

Combined cycle system configuration			Chemicals used for emissions control ($g\ dm^{-3}$ of denatured ethanol)			Power to grid (MW)	Ash produced ($Mg\ d^{-1}$)
Co-product dryer type	**Gas compression pressure (bar)**	**Dryer exhaust VOCs destructor**	**Limestone (Combustor/Gasifier)**	**Ammonia (Boiler/HRSG)**	**Quicklime (Dry-scrubber)**		
BIGCC with stover fuel (Stover dry matter used = 0.925 $kg\ dm^{-3}$ of denatured ethanol [b]; Total fuel energy input rate = 102.6 MW [c]; Co-product DDGS at 10% w.b. moisture content to be sold = 459 $Mg\ d^{-1}$)							
Steam tube dryer	10	Fluidized bed combustor	1.27	0.18	0.51	20.6	36.5
Steam tube dryer	20	Fluidized bed combustor	1.27	0.09	0.55	20.5	36.6
Steam tube dryer	10	Gas turbine	1.27	0.11	0.22	24.6	36.2
Steam tube dryer	20	Gas turbine	1.27	0.11	0.37	22.6	36.4
Steam tube dryer	10	Duct burner/HRSG	1.27	0.10	0.40	22.5	36.4
Steam tube dryer	20	Duct burner/HRSG	1.27	0.11	0.52	21.5	36.5
Superheated steam dryer	10	NA	1.27	0.06	0.10	19.5	36.2
Superheated steam dryer	20	NA	1.27	0.01	0.10	21.0	36.2
BIGCC with syrup and stover fuel (Stover dry matter used = 0.600 $kg\ dm^{-3}$ of denatured ethanol [b]; Syrup dry matter used = 0.295 $kg\ dm^{-3}$ of denatured ethanol [b]; Total fuel energy input rate = 102.2 MW [c]; Co-product DDG at 10% w.b. moisture content to be sold = 271 $Mg\ d^{-1}$)							
Steam tube dryer	10	Fluidized bed combustor	10.50	0.18	1.51	21.1	39.9
Steam tube dryer	20	Fluidized bed combustor	10.50	0.08	1.36	21.0	39.7
Steam tube dryer	10	Gas turbine	10.50	0.13	0.62	24.7	38.9
Steam tube dryer	20	Gas turbine	10.50	0.01	0.86	22.9	39.2
Steam tube dryer	10	Duct burner/HRSG	10.50	0.11	1.01	22.5	39.3
Steam tube dryer	20	Duct burner/HRSG	10.50	0.20	2.11	19.7	40.5
Superheated steam dryer	10	NA	10.50	0.05	0.13	20.2	38.4
Superheated steam dryer	20	NA	10.50	0.01	0.10	21.7	38.4
NGCC with natural gas fuel (Natural gas used = 0.313 $kg\ dm^{-3}$ of denatured ethanol; Total fuel energy input rate = 99.8 MW [c]; Co-product DDGS at 10% w.b. moisture content to be sold = 459 $Mg\ d^{-1}$)							
Steam tube dryer	10	Gas turbine	NA	0.16	NA	30.3	NA
Steam tube dryer	20	Gas turbine	NA	0.13	NA	27.9	NA
Steam tube dryer	10	Duct burner/HRSG	NA	0.13	NA	27.7	NA
Steam tube dryer	20	Duct burner/HRSG	NA	0.12	NA	26.2	NA

Note: BIGCC = biomass integrated gasification combined cycle; DDG = dried distillers grains; DDGS = dried distillers grains with solubles; HRSG = heat recovery steam generator; NA = not applicable; NGCC = natural gas combined cycle; VOCs = volatile organic compounds.

[a] The yield of denatured ethanol is 0.412 $dm^3\ kg^{-1}$ of corn. The 0.19 $hm^3\ y^{-1}$ corn ethanol plant produces 23,888 $dm^3\ h^{-1}$ of denatured ethanol, and the ethanol plant operates 7920 $h\ y^{-1}$. Excess power is exported to the grid from the ethanol plant after meeting the plant's all of the electricity demand.

[b] Moisture contents (w.b.) of corn stover and syrup are 13% and 67%, respectively.

[c] All fuel energy values are based on the lower heating value (LHV) of the fuel dry matter.

Table 5. Greenhouse gas (GHG) emissions (g MJ^{-1} carbon dioxide equivalent of denatured ethanol) inventory for corn-ethanol life cycle for a Midwest dry-grind corn ethanol plant integrated with BIGCC and NGCC systems. (Co-product dryer = steam tube dryer; Gas compression pressure = 10 bar; Dryer exhaust VOCs destructor = gas turbine)

GHG emission category	g MJ^{-1} for base case with natural gas	g MJ^{-1} for combined cycle systems with different fuels		
		BIGCC with stover	BIGCC with syrup and stover	NGCC with natural gas
Input				
Corn and biomass production				
Corn production	36.2	36.2	36.2	36.2
Biomass (stover) production	NA	2.35	1.52	NA
Biorefinery				
Corn transportation	2.05	2.05	2.05	2.05
Biomass processing/transportation	NA	1.15	0.74	NA
Natural gas input	23.6	NA	NA	46.4
Electricity import	8.33	NA	NA	NA
Denaturant contribution	2.80	2.80	2.80	2.80
Limestone (Combustor/Gasifier)	NA	0.06	0.52	NA
Ammonia (Boiler/HRSG)	NA	0.01	0.01	0.02
Quicklime (Dry-scrubber)	NA	0.01	0.04	NA
Biomass conversion (CH_4 and N_2O)	NA	2.25	2.24	NA
Depreciable capital	0.45	0.89	0.89	0.89
Ethanol transport to blend/sell	1.40	1.40	1.40	1.40
Output				
Ethanol (anhydrous) combustion	1.0	1.0	1.0	1.0
Co-product (DDGS/DDG) feed credit [a]	-19.4	-19.4	-11.5	-19.4
Electricity exported to grid credit	NA	-53.0	-53.2	-65.3
Net (i.e., input + output)				
Life-cycle net GHG emissions for ethanol (g MJ^{-1})	56.4	-22.2	-15.3	6.1
GHG reduction relative to gasoline (%) [b]	38.9%	124.1%	116.5%	93.4%

Note: BIGCC = biomass integrated gasification combined cycle; CH_4 = methane; DDG = dried distillers grains; DDGS = dried distillers grains with solubles; HRSG = heat recovery steam generator; NA = not applicable; NGCC = natural gas combined cycle; N_2O = nitrous oxide; VOCs = volatile organic compounds.

[a] The co-product is DDGS when the fuel is natural gas (base case, and IGCC case) or stover. The co-product is DDG when the fuel is syrup and stover.

[b] The life-cycle GHG emission of gasoline is 92.3 g MJ^{-1} carbon dioxide equivalent of gasoline.

Table 6. Greenhouse gas (GHG) emissions (g MJ^{-1} carbon dioxide equivalent of denatured ethanol) reduction for corn-ethanol life cycle for a Midwest dry-grind corn ethanol plant integrated with various BIGCC and NGCC system configurations.

BIGCC and NGCC system configuration			Electricity exported to grid credit (g MJ^{-1})	Life-cycle net GHG emissions for corn ethanol (g MJ^{-1})	Life-cycle net GHG emissions reduction for corn ethanol relative to gasoline (%) [a]
Co-product dryer type	**Gas compression pressure (bar)**	**Dryer exhaust VOCs destructor**			
BIGCC with stover fuel					
Steam tube dryer	10	Fluidized bed combustor	-44.4	-13.6	114.7%
Steam tube dryer	20	Fluidized bed combustor	-44.2	-13.4	114.5%
Steam tube dryer	10	Gas turbine	-53.0	-22.2	124.1%
Steam tube dryer	20	Gas turbine	-48.7	-17.9	119.4%
Steam tube dryer	10	Duct burner/HRSG	-48.5	-17.7	119.2%
Steam tube dryer	20	Duct burner/HRSG	-46.3	-15.5	116.8%
Superheated steam dryer	10	NA	-42.0	-11.3	112.2%
Superheated steam dryer	20	NA	-45.2	-14.5	115.7%
BIGCC with syrup and stover fuel					
Steam tube dryer	10	Fluidized bed combustor	-45.4	-7.4	108.1%
Steam tube dryer	20	Fluidized bed combustor	-45.2	-7.2	107.9%
Steam tube dryer	10	Gas turbine	-53.2	-15.3	116.5%
Steam tube dryer	20	Gas turbine	-49.3	-11.4	112.3%
Steam tube dryer	10	Duct burner/HRSG	-48.5	-10.5	111.4%
Steam tube dryer	20	Duct burner/HRSG	-42.4	-4.4	104.8%
Superheated steam dryer	10	NA	-43.5	-5.6	106.1%
Superheated steam dryer	20	NA	-46.7	-8.8	109.6%
NGCC with natural gas fuel					
Steam tube dryer	10	Gas turbine	-65.0	6.3	93.4%
Steam tube dryer	20	Gas turbine	-60.1	11.3	87.8%
Steam tube dryer	10	Duct burner/HRSG	-59.4	11.9	87.3%
Steam tube dryer	20	Duct burner/HRSG	-56.4	14.9	83.8%

Note: BIGCC = biomass integrated gasification combined cycle; HRSG = heat recovery steam generator; NA = not applicable; NGCC = natural gas combined cycle.
[a] The life-cycle GHG emission of gasoline is 92.3 g MJ^{-1} carbon dioxide equivalent of gasoline.

Economic Analysis of BIGCC and NGCC Systems

We worked with our subcontractor AMEC E&C Services to develop capital cost estimates for the most promising BIGCC and NGCC systems based on our modeling efforts. Those results are summarized in Table 7. Capital costs for all BIGCC systems, corn stover and syrup and corn stover fuels, are similar. Capital costs for the NGCC systems are approximately two-thirds of those for the BIGCC systems. Biomass gasification, gas cleanup, and syngas compression account for the additional costs for BIGCC systems compared to NGCC systems.

Capital costs for the nine biomass fuel/technology combinations developed in the previous Xcel RDF project (RD-56) are presented in Table 8. These costs have been adjusted to reflect the decrease in costs of conventional ethanol plants that have occurred in the last three years.

Using performance data for the systems based on the results of Tables 1 through 3, GHG emission reductions estimated in Tables 4 through 6, and capital cost data for the systems display in Tables 7 and 8, we will be able to evaluate rates of return for a range of fuel cost, renewable fuel and carbon policies, and investment strategies. Those analyses are underway.

Table 7. Total project costs for 190 million liter per year (50 million gallon per year) ethanol plants integrated with BIGCC/NGCC systems. (Gas compression pressure = 10 bar)

Component/System		Dryer Exhaust to Gas Turbine			Dryer Exhaust to HRSG Burner		
		FOB Equip. Cost	% New	Total Project Cost	FOB Equip. Cost	% New	Total Project Cost
BIGCC with Syrup and Corn Stover Fuel							
Biomass fuel handling	New	$1,750,000	4		$1,750,000	4	
Gasification & syngas cleanup	New	$11,636,000	24		$11,457,000	24	
Ash handling	New	$650,000	1		$650,000	1	
Emissions control	New	$2,352,000	5		$2,509,000	5	
HRSG & steam system	New	$6,433,600	13		$6,824,600	14	
Gas compression & gas turbine gen.	New	$13,075,000	27		$12,143,000	25	
Steam turbine gen.	New	$5,000,000	10		$5,000,000	10	
Total cost: power island		$40,896,600	84	$127,696,000	$40,333,600	83	$125,991,000
Typical conventional ethanol plant cost	Baseline			$75,000,000			$75,000,000
Natural gas dryer & thermal oxidizer	Avoided	($6,000,000)	-12	($20,287,000)	($6,000,000)	-12	($20,287,000)
Steam tube dryers [#]	New	$8,000,000	16	$24,979,000	$8,000,000	17	$24,990,000
Ethanol plant with BIGCC grand total (new items + baseline - avoided):				$207,388,000			$205,694,000
BIGCC with Corn Stover Fuel							
Biomass fuel handling	New	$2,188,000	4		$2,188,000	5	
Gasification & syngas cleanup	New	$12,422,000	26		$12,235,000	25	
Ash handling	New	$780,000	2		$780,000	2	
Emissions control	New	$2,389,000	5		$2,545,000	5	
HRSG & steam system	New	$6,593,600	14		$6,897,600	14	
Gas compression & gas turbine gen.	New	$13,075,000	27		$12,142,000	25	
Steam turbine gen.	New	$5,000,000	10		$5,000,000	10	
Total cost: power island		$42,447,600	87	$132,637,000	$41,787,600	87	$130,642,000
Typical conventional ethanol plant cost	Baseline			$75,000,000			$75,000,000
Natural gas dryer & thermal oxidizer	Avoided	($6,000,000)	-12	($20,287,000)	($6,000,000)	-13	($20,287,000)
Steam tube dryer	New	$6,200,000	13	$19,373,000	$6,200,000	13	$19,383,000
Ethanol plant with BIGCC grand total (new items + baseline - avoided):				$206,723,000			$204,738,000
NGCC with Natural Gas Fuel							
Biomass fuel handling	New	$0	0		$0	0	
Gasification & syngas cleanup	New	$0	0		$0	0	
Ash handling	New	$0	0		$0	0	
Emissions control	New	$0	0		$0	0	
HRSG & steam system	New	$6,918,600	24		$7,043,600	25	
Gas compression & gas turbine gen.	New	$10,575,000	37		$10,000,000	36	
Steam turbine gen.	New	$4,750,000	17		$4,750,000	17	
Total cost: power island		$22,243,600	78	$67,907,000	$21,793,600	78	$66,581,000
Typical conventional ethanol plant cost	Baseline			$75,000,000			$75,000,000
Natural gas dryer & thermal oxidizer	Avoided	($6,000,000)	-21	($20,287,000)	($6,000,000)	-21	($20,287,000)
Steam tube dryer	New	$6,200,000	22	$18,928,000	$6,200,000	22	$18,942,000
Ethanol plant with NGCC grand total (new items + baseline - avoided):				$141,548,000			$140,236,000

Note: BIGCC = biomass integrated gasification combined cycle; DDG = dried distillers grains; HRSG = heat recovery steam generator; NGCC = natural gas combined cycle.

[#] The FOB equipment cost for steam tube dryers ($8,000,000) is the sum of costs for DDG dryer with product-cooler ($4,300,000) and for syrup and stover fuel dryer without product-cooler ($3,700,000).

Table 8. Total project costs for 190 million liter per year (50 million gallon per year) ethanol plants for nine biomass fuel/technology combinations.

Component/System		Process Heat Only			Combined Heat and Power (CHP)			CHP plus Electricity to the Grid		
		FOB Equip. Cost	% New	Total Project Cost	FOB Equip. Cost	% New	Total Project Cost	FOB Equip. Cost	% New	Total Project Cost
Syrup and Corn Stover Combustion										
Biomass fuel handling	New	$1,275,000	7		$1,400,000	6		$1,750,000	6	
Fluidized bed boiler & steam system	New	$9,264,000	52		$11,731,000	51		$13,867,000	48	
Ash handling	New	$650,000	4		$650,000	3		$650,000	2	
Emissions control	New	$2,481,000	14		$2,517,000	11		$2,565,000	9	
Steam turbine gen.	New	$0	0		$2,600,000	11		$5,497,000	19	
Total cost: power island		$13,670,000	76	$45,589,000	$18,898,000	81	$62,803,000	$24,329,000	85	$80,674,000
Typical conventional ethanol plant cost	Baseline			$75,000,000			$75,000,000			$75,000,000
Natural gas dryer & thermal oxidizer	Avoided	($6,000,000)	-33	($20,287,000)	($6,000,000)	-26	($20,287,000)	($6,000,000)	-21	($20,287,000)
Steam tube dryer	New	$4,300,000	24	$14,340,000	$4,300,000	19	$14,290,000	$4,300,000	15	$14,259,000
Biomass powered ethanol plant grand total (new items + baseline - avoided):				$114,642,000			$131,806,000			$149,646,000
Corn Stover Combustion										
Biomass fuel handling	New	$1,275,000	6		$1,400,000	5		$1,750,000	5	
Fluidized bed boiler & steam system	New	$10,394,000	49		$13,203,000	49		$15,314,000	47	
Ash handling	New	$650,000	3		$650,000	2		$650,000	2	
Emissions control	New	$2,520,000	12		$2,575,000	10		$2,950,000	9	
Steam turbine gen.	New	$0	0		$2,900,000	11		$5,556,000	17	
Total cost: power island		$14,839,000	71	$49,361,000	$20,728,000	77	$68,759,000	$26,220,000	81	$86,836,000
Typical conventional ethanol plant cost	Baseline			$75,000,000			$75,000,000			$75,000,000
Natural gas dryer & thermal oxidizer	Avoided	($6,000,000)	-29	($20,287,000)	($6,000,000)	-22	($20,287,000)	($6,000,000)	-19	($20,287,000)
Steam tube dryer	New	$6,200,000	29	$20,624,000	$6,200,000	23	$20,567,000	$6,200,000	19	$20,533,000
Biomass powered ethanol plant grand total (new items + baseline - avoided):				$124,698,000			$144,039,000			$162,082,000
DDGS Gasification										
Biomass fuel handling	New	$790,000	4		$890,000	4		$990,000	4	
Fluidized bed gasifier & steam system	New	$9,054,000	48		$10,586,000	45		$12,216,000	44	
Ash handling	New	$350,000	2		$350,000	2		$350,000	1	
Emissions control	New	$2,300,000	12		$2,414,000	10		$2,673,000	10	
Steam turbine gen.	New	$0	0		$2,870,000	12		$5,556,000	20	
Total cost: power island		$12,494,000	67	$41,625,000	$17,110,000	73	$56,842,000	$21,785,000	78	$72,239,000
Typical conventional ethanol plant cost	Baseline			$75,000,000			$75,000,000			$75,000,000
Natural gas dryer & thermal oxidizer	Avoided	($6,000,000)	-32	($20,287,000)	($6,000,000)	-26	($20,287,000)	($6,000,000)	-21	($20,287,000)
Steam tube dryer	New	$6,200,000	33	$20,656,000	$6,200,000	27	$20,597,000	$6,200,000	22	$20,559,000
Biomass powered ethanol plant grand total (new items + baseline - avoided):				$116,994,000			$132,152,000			$147,511,000

1C. Integration of superheated steam dryer technology

- Complete evaluation of rate of return

System performance comparisons for BIGCC systems involving superheated steam drying are included in Tables 1 and 2. Greenhouse gas (GHG) emission comparisons for the corresponding BIGCC systems involving superheated steam drying are shown in Table 6. Because less electricity is sent to the grid for BIGCC systems involving superheated steam drying compared to steam tube drying, overall performance and GHG emission estimates are lower. Therefore, we have focused the economic analysis and rate of return analysis on systems which use steam tube drying.

2. Develop and test business model

- Begin development of recommendations for investment structure

We have had several important meetings during this period which have guided our thinking about how to complete the economic analysis on this project. Our meeting with Dr. Ian Purtle of Cargill was significant due to the interest he expressed in the use of biomass at ethanol facilities and other types of facilities operated by Cargill around the world. Dr. Purtle was interested in the range of technologies that our existing models were capable of comparing with respect to the engineering and environmental performance. However, he was interested in more information regarding the financial performance of the power generating assets when those could be owned by a party other than the ethanol plant.

Our project's website (www.biomassCHPethanol.umn.edu) attracted an inquiry from Mr. Anshuman Roy who has negotiated a number of relationships between investors and the pulp and paper firms of the Pacific Northwest involving sale of electricity to the grid. He was very interested in the details that we presented concerning the economic performance of ethanol plants. Like Mr. Purtle, Mr. Roy was very interested in the technical performance of the different CHP options; however, he was even more interested in parsing out the returns that would accrue to outside investors of power generation assets associated with ethanol plants.

The combination of these two meetings in recent months has prompted our team to embark on a more involved level of financial modeling in order to report results of rates of return from the point of view of an outside firm. We are embarking on additional modeling to portray the situation of a separate party that would be buying and then combusting or gasifying biomass before selling electricity to the grid and steam to the ethanol plant. We intend to report our enhanced financial analysis to offer technology comparisons as in the past from the standpoint of the ethanol plant but also from the standpoint of the "power island." We believe that results reported in this fashion will be of greater interest to outside investors with the ability to utilize provisions in the federal Tax Code and the Recovery Act.

We have hired a graduate student in the Department of Applied Economics to help perform additional financial analysis and also develop pertinent financial ratios that should be of interest to outside investors and the bankers they use. In addition to further analysis of financials from the standpoint of a modeled "power island," our research team is planning to present our conclusions in three conferences, with two in March and one in July. The schedule of topics, agenda, and speakers for the events that we are planning are described under task 4 of this report.

We have also evaluated market outlook changes for four investor owned utilities operating in Minnesota based on Integrated Resource Plans (IRP's) that they file with the Minnesota Public Utilities Commission (MPUC). This analysis was prepared by Larry L. Schedin, LLS Resources, LLC and his colleague William Glahn and is included on the following pages. Most of this analysis is new but two or three figures or tables are repeated from the Milestone 6 report.

Review of Four Integrated Resource Plans (IRP's)

This report contains summaries of four Integrated Resource Plans (IRP's) on file with the Minnesota Public Utilities Commission (MPUC). The utilities surveyed include the state's four investor-owned electric utilities, listed in descending order of their Minnesota electrical load: Xcel Energy, Minnesota Power, Otter Tail Power, and Interstate Power and Light. In reviewing each plan, an emphasis was placed on information regarding renewable energy and, specifically, biomass energy.

The report begins with brief descriptions of the IRP process and the related Renewable Energy Objective/Renewable Energy Standard that impacts each utility. Next, a series of charts is presented, taken from each utility's respective IRP, showing in graphical form the preferred plan for each company for the period 2010-2025. Next, two tables are included which provide side-by-side, year-by-year comparisons of how each utility proposes to satisfy both RES and IRP requirements during the study period. Finally, a narrative describing each utility's current IRP filing concludes this report.

(Please note that the numbering of figures and tables may create some confusion: some items were copied directly from utility IRP's while other charts were created for this report.)

Integrated Resource Planning—Overview

Electric utilities doing business in Minnesota—with generating capacities greater than 100 MW and serving more than 10,000 retail customers—must submit Resource Plans to the Minnesota Public Utilities Commission (MPUC).

Simply put, the Resource Plans explain how the utility intends to serve the needs of its customers for the next fifteen years. The "integrated" part of the name refers to the integration of both supply-side resources (new or upgraded power plants) and demand-side resources (conservation or energy efficiency) within a single plan. Under Commission Rule, plans are supposed to be filed every two years. However, in practice, three to four years frequently elapse between filings, as the Commission is generous with waivers and delays. Any interested person or group can comment on a utility's proposed plan. However, an interested participant would need to be granted "party" or "intervener" status to fully participate in a case.

Resources that are included in approved Plans hold an advantage in the regulatory process. Under law, a facility that is vetted through the Resource Planning process can skip the "Certificate of Need" process required of all power plants greater than 50 MW in size. Renewable power and energy efficiency are given preferred status in the resource planning process. However, a number of different definitions of "renewable energy" appear in statute. The definition used in resource planning does not use the word "biomass", but rather "trees, or other vegetation."

In filing a plan, the utility submits a load forecast, describing how much energy and peak load the utility expects to supply, annually, over the study period. Along with the forecast, the utility enters a number of assumptions into a sophisticated computer model, which chooses from among a menu of supply-side and demand-side resources to find the combination which minimizes the total cost of operating the utility system. Of course, a number of constraints are also built into the model, including compliance with various environmental mandates, and accounting for environmental “externalities.”

Renewable Energy Objective/Renewable Energy Standard—Overview

Dating back to 2001, Minnesota applies a Renewable Energy Objective (REO) to the electric utilities doing business in the state.[1] Utilities subject to the REO include investor-owned utilities, municipal power agencies, and generation and transmission (G&T) cooperatives. By 2015, utilities were to provide 10 percent of their energy requirements from qualifying resources. Biomass, wind, solar, and other technologies are listed among the eligible. Biomass was singled out as a technology that each utility must acquire to account for at least one (1) percent of the total under the REO.

Xcel Energy had additional wind power requirements included in its Objective. All four investor-owned utilities report compliance with the Objective through 2009. However, there were no clear penalty provisions put in place to apply to a utility that is not in compliance with the REO.

In 2007, the Legislature amended the Objective to incorporate the Renewable Energy Standard (RES). The REO remains in place, for years prior to 2012. However, the language specifying a one percent share for biomass power is no longer included.

For utilities subject to the REO, now RES, 25 percent of total energy must be supplied by eligible technologies by 2025. Lower standards are in place for interim years. Xcel’s standard is set at 30 percent by 2020, with lower standards for interim years, including 15 percent for 2010.

In addition, the Public Utilities Commission now has some ability to modify or delay implementation of the standard, under certain conditions. Further, the Commission has some enforcement powers under the RES for utilities not in compliance.

[1] Minnesota Statutes § 216B.1691.

Utility Resource Plans in Graphical Form

Figure 1.
Xcel Energy Peak Requirements and Existing Resources, Before Additions

Figure 3.10
Requirements and Resources 2011-2024

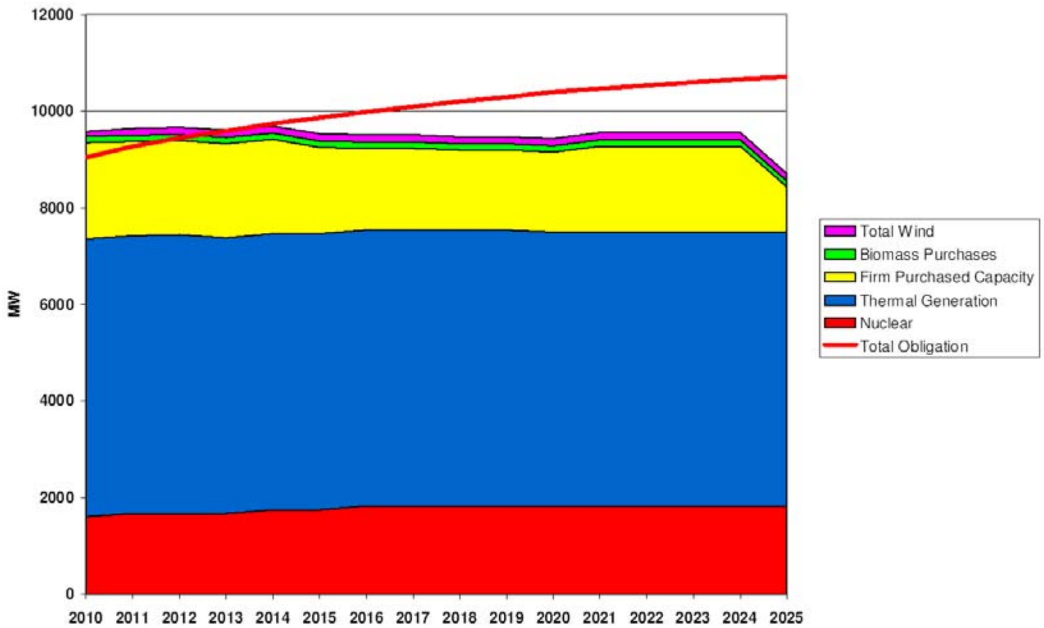


Figure 2
Xcel Energy Proposed Energy Mix, 2025

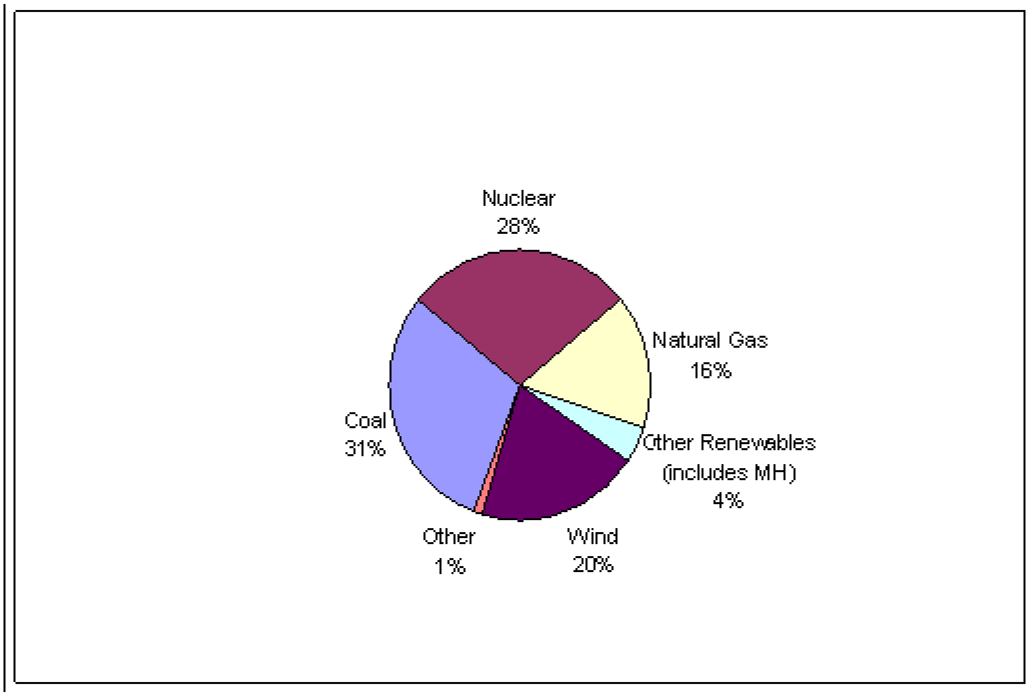


Figure 3
Minnesota Power's Planned Resources, Including Additions, 2010-2024

FIGURE 14
Reference Case Scenario Energy Sources

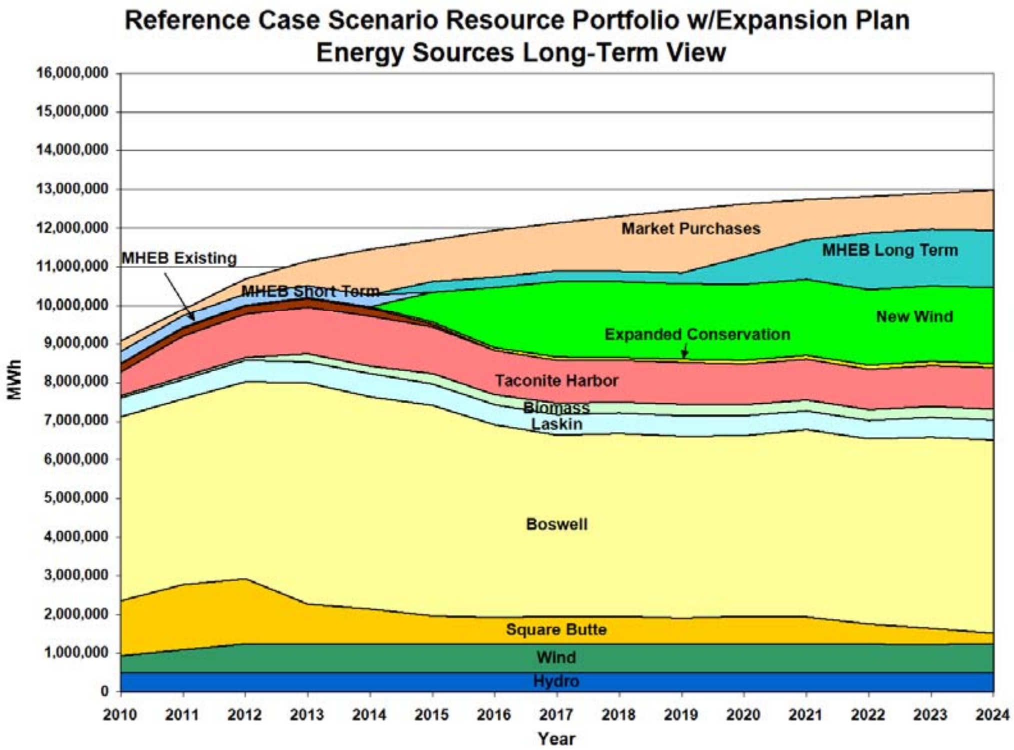


Figure 4
Otter Tail Power Proposed Resource Additions, 2025

Figure 2-1: Preferred Plan by Resource Selection, Summer Capacity (MW), and Percent of Total in 2025
(Wind is shown as installed capacity. Accredited capacity for wind was assumed to be 3%.)

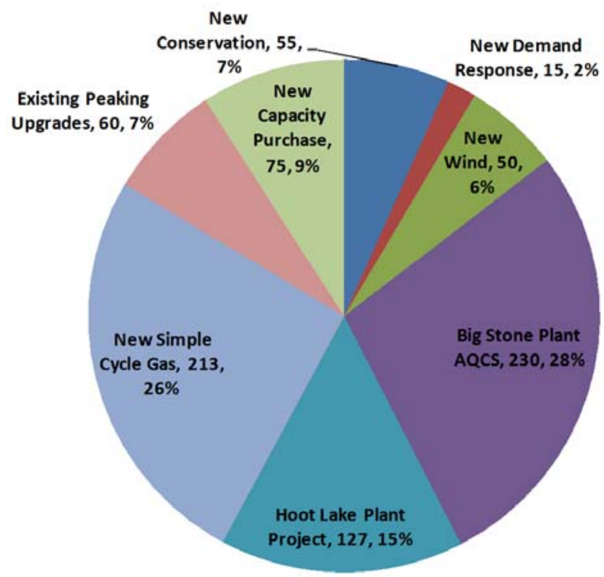


Figure 5
Otter Tail Proposed Plan Load and Capabilities, With New Additions, 2010-2025

Figure 2-2: Preferred Plan Capacity Resources and Reserve Obligation 2010-2025 (MW)

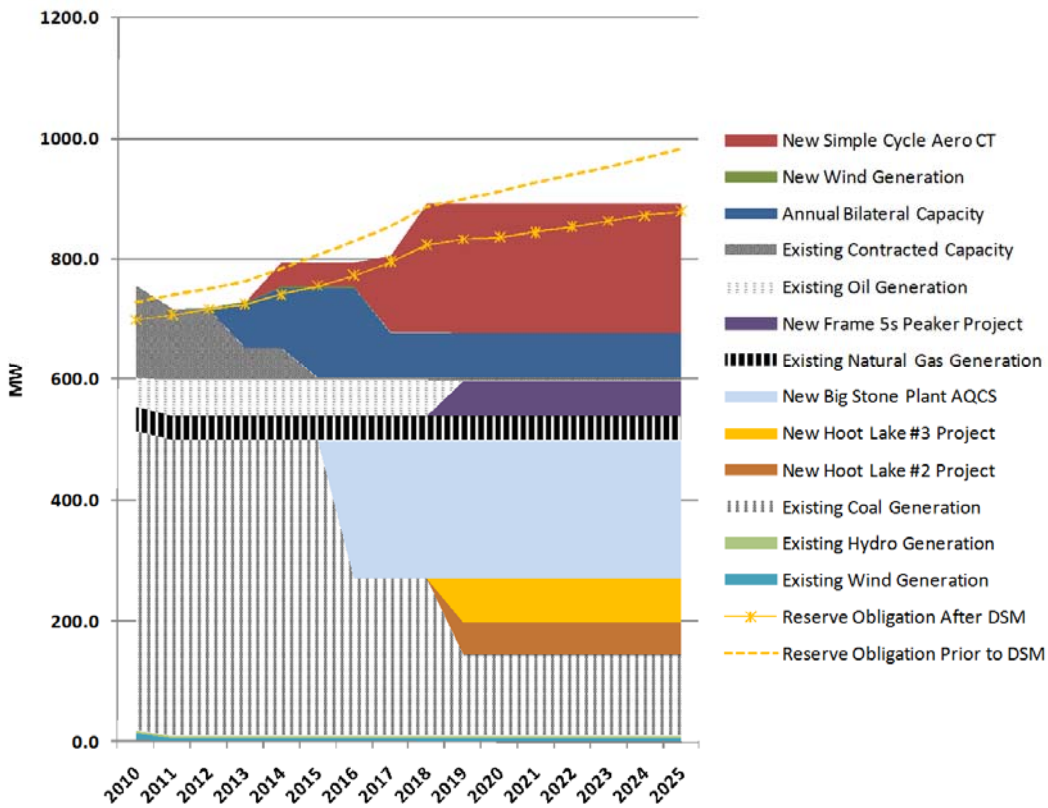
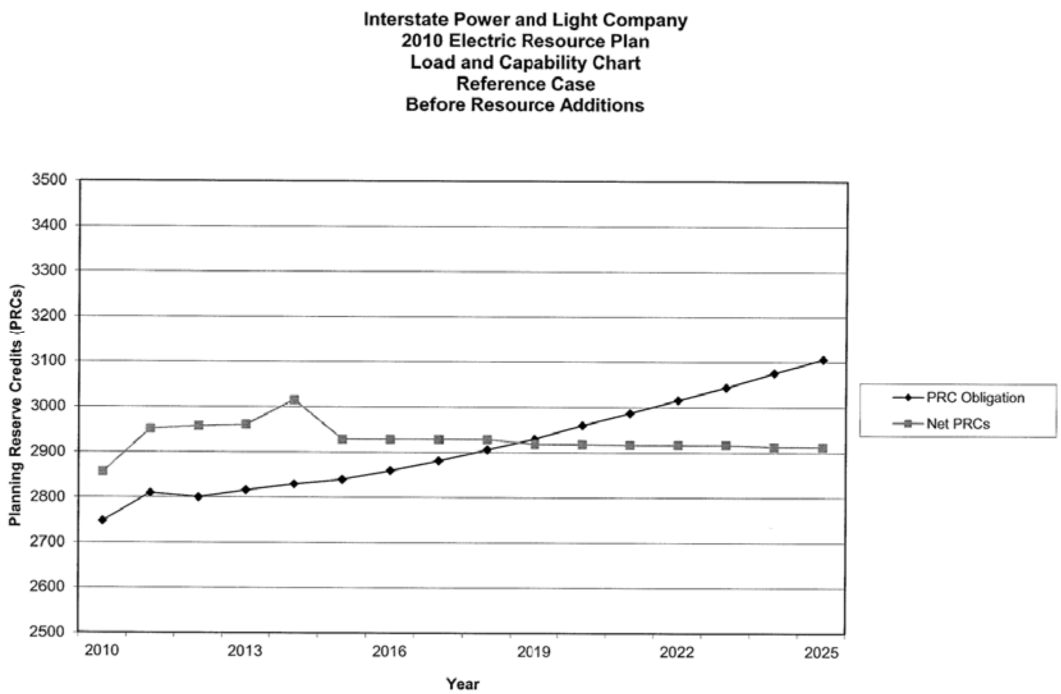


Figure 6
Interstate Power and Light Co.
Load and Capabilities Before Resource Additions, 2010-2025



Resource Plans and RES Compliance

In each resource plan on file with the MPUC, the utility must specify how it intends to comply with the Renewable Energy Standard and supply the remaining requirements of its customer base.

The following table summarizes how each of the state’s four investor-owned utilities proposes to comply with the RES, showing the years in which new resources are to be added.

Table 1
RES Resource Additions

<table>
<tr><th>Years</th><th>Interstate P&L</th><th>Minnesota Power</th><th>Otter Tail Power</th><th>Xcel Energy</th></tr>
<tr><td>2011</td><td></td><td></td><td></td><td>Wind added</td></tr>
<tr><td>2012</td><td></td><td></td><td>Wind added</td><td>Wind added</td></tr>
<tr><td>2013</td><td rowspan="11">Use of Iowa Renewable Energy Credits (REC’s)</td><td></td><td></td><td>Wind added</td></tr>
<tr><td>2014</td><td>Wind added</td><td></td><td>Wind added</td></tr>
<tr><td>2015</td><td></td><td></td><td>Wind added</td></tr>
<tr><td>2016</td><td></td><td></td><td>Wind added</td></tr>
<tr><td>2017</td><td></td><td></td><td>Wind added</td></tr>
<tr><td>2018</td><td></td><td></td><td>Wind added</td></tr>
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<tr><td>2020</td><td></td><td></td><td>Wind added</td></tr>
<tr><td>2021</td><td></td><td></td><td></td></tr>
<tr><td>2022</td><td></td><td></td><td>Wind added</td></tr>
<tr><td>2023</td><td></td><td></td><td></td></tr>
<tr><td>2024</td><td>Wind added</td><td>Wind added</td><td></td><td>Wind added</td></tr>
<tr><td>2025</td><td>Wind added</td><td></td><td></td><td>Wind added</td></tr>
</table>

The next table summarizes how each utility intends to supply requirements to customers beyond the resources acquired in complying with the renewable energy standard.

Table 2
Other Resource Additions

Years	Interstate P&L	Minnesota Power	Otter Tail Power	Xcel Energy
2011				Coal upgrade
2012				Nuclear upgrade
2013				
2014			Simple cycle CT	Nuclear upgrade
2015		Purchases		Purchase, nuclear upgrade
2016		Purchases	Coal upgrade	Combined cycle CT
2017		Purchases	Simple cycle CT	
2018		Purchases	Simple cycle CT	
2019	Purchases	Purchases	Simple cycle CT, coal upgrade	
2020	Purchases	Purchases		Simple Cycle CT
2021	Purchases	Purchases		Purchase
2022	Purchases	Purchases		Simple Cycle CT
2023	Purchases	Purchases		
2024	Purchases	Purchases		Simple cycle CT
2025	Simple cycle CT	Purchases		Combined cycle CT, simple cycle CT

Xcel's 2010 Integrated Resource Plan

Xcel filed its IRP with the Minnesota Public Utilities Commission on August 2, 2010, under Docket No. E-017/RP-10-825. This filing is submitted pursuant to MN Statutes §216B.2422 and Minnesota Rule 7843. Xcel is seeking MPUC approval of the 2011-2025 Resource Plan. Xcel files this same plan in WI, ND and SD, Minnesota's Integrated Resource Plan is the most thoroughly reviewed, modified, and is what Xcel follows. This is notable since Minnesota has the highest environmental mandates, as well as typically the most involvement from environmental groups.

Summary

Of the state's utilities, Xcel has by far the greatest experience with biomass fueled resources. With 290 MW already in operation on its utility system, Xcel has gained a breadth of experience with differing fuels, technologies, sizes, and geographic locations. However, the utility plans to rely exclusively on wind and natural gas-fired conventional generation in meeting its considerable resource requirements in the next fifteen years.

Resource Planning

As the state's largest utility, Xcel Energy garners the most attention of any utility in the Resource Planning process. A coalition of environmental groups—including the Izaak Walton League's Midwest Office, Fresh Energy, Wind on the Wires, and the Minnesota Center for Environmental Advocacy—has participated in this case. The Minnesota Chamber of Commerce has intervened on behalf of Xcel's business customers. The Prairie Island Indian Community—whose reservation borders one of the utility's nuclear plants—has also indicated that they will participate in the process.

The PUC will accept comments from any interested persons or groups on the Xcel plan through April 1, 2011. Reply comments will be accepted through May 31, 2011.

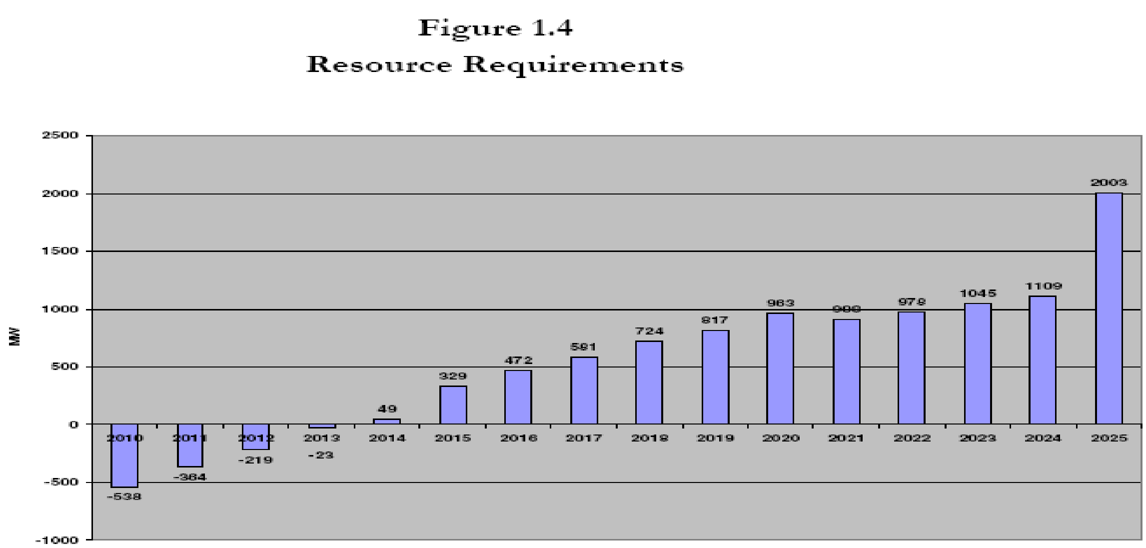
Xcel's last Resource Plan was filed in 2007.[2] All of Xcel's recent expansion, improvements/retrofits and wind resources have been added under this approved resource plan. The resource plan guides a utility's future investments and resource growth. If approved in the resource plan, Xcel's growth and investments will enjoy a presumption of prudence despite review in Certificate of Need review on major projects.

Current annual MWh sales are 46,000,000 and peak demand is 9,300 MW. For perspective Otter Tail's are 4,500,000 MWh and 700 MW. Xcel's largest facility is Sherco (3 units), 1900 MW and then Prairie Isle at 1100 MW and produces 9,000,000 MWh annually.

Xcel anticipates a shortage of capacity in 2014 – the following graph shows their anticipated need.

Figure 7

Xcel Resource Requirements, 2010-2025



This growth is not only due to customer growth but also due to expiring purchase contracts and likely retirement and re-rating of generation facilities. This IRP will be used by Xcel as its blueprint for adding substantial amounts of improvements, intermediate generation and wind-powered generation.

[2] MPUC Docket No. E-017/RP-07-1572. Initial filing made on December 14, 2007. Commission approval occurred in August 2009.

The following table shows how they propose to meet that need.

Table 3

Xcel Proposed Resource Additions, 2011-2025

Table 1.1
2010 Proposed plan

Year	Planned Additions	Combined Cycle	Combustion Turbine	Wind
2011	Merricourt Wind 150 MW Sherco 3 13 MW			
2012	Monticello 71 MW			250 MW
2013				100 MW
2014	PI Unit 1 82 MW			100 MW
2015	MH 725 MW extension PI Unit 2 EPU 82 MW			100 MW
2016	Black Dog 680 MW CC Retire BD units 3&4 270 MW			100 MW
2017				100 MW
2018				100 MW
2019				100 MW
2020			390 MW	200 MW
2021	MH 125 MW			
2022			195 MW	200 MW
2023				
2024			195 MW	200 MW
2025		730 MW	585 MW	200 MW

The following table shows their anticipated cost increases under this plan.

Table 4

Xcel Energy, Relative Cost of Alternative Scenarios

Table 4.12
Relative cost increases by scenario for selected years ($2010/kwh)

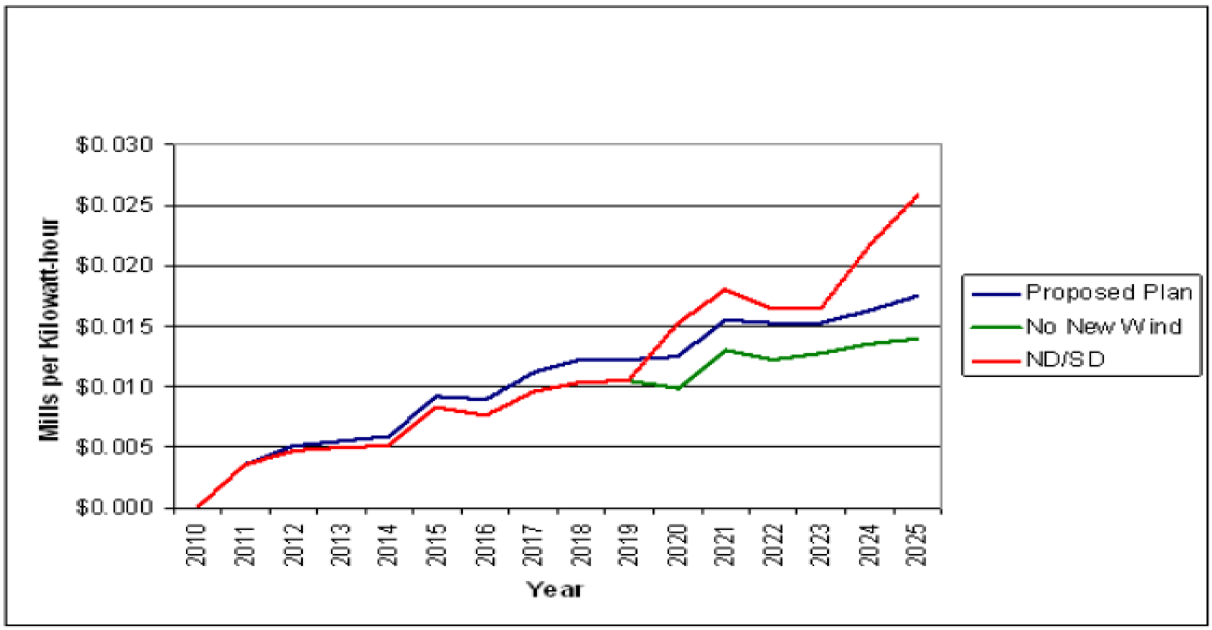
	2015 Increase over 2010	2020 Increase over 2010	2025 Increase over 2010
Proposed plan	$0.009	$0.013	$0.017
No New Wind	$0.008	$0.010	$0.014
ND/SD w/ DSM	$0.008	$0.015	$0.026

Their proposed plan is not "least cost", it is the plan which allows them to satisfy the RES requirements. They have chosen not to test the "off ramp" provision in statute. The following chart shows the relationship of the preferred plan and least cost plan.

Figure 8

Xcel Costs, by Scenario

Figure 4.6
Relative Cost Increases by Scenario 2010-2025



The data behind the differences are in the following table.

Table 5
Present Value Differences Between Scenarios

Table 4.9
PVRR Differences Between Proposed Plan and No New Wind Scenario

PVRR ($000s)	Proposed plan	No New Wind	Difference
Base	$90,702,859	$89,302,895	-$1,399,963
High Gas	$92,184,890	$91,445,271	-$739,619
Low Gas	$89,192,022	$87,195,101	-$1,996,921
High CO2	$96,328,301	$95,746,824	-$581,477
Low CO2	$88,058,510	$86,279,304	-$1,779,205
Late CO2	$88,445,801	$86,856,079	-$1,589,722
No CO2	$85,087,884	$82,875,738	-$2,212,145
High Load	$96,466,131	$94,538,706	-$1,927,425
Low Load	$86,582,937	$84,459,291	-$2,123,647

Xcel is not selecting its least cost plan due to forcing wind selection. This is demonstrated by the above chart and discussions with Xcel that indicate, even assuming all externalities and DSM requirements, departure from wind RES would result in savings. This presents a question of timing on when to test the “off ramp” built into statute.

Use of Strategist™ Model
Along with other utilities in Minnesota, Xcel Energy utilizes the Strategist™ Resource Planning and analytics software package sold by a unit of ABB, the European energy equipment company. Biomass was not one of the generation resources considered for inclusion in the Strategist model: only wind, coal, and natural gas resources were included.

Xcel and the Minnesota Renewable Energy Standard
As are other Minnesota Utilities, Xcel Energy is subject to the state’s Renewable Energy Standard, for that portion of the company’s load located within Minnesota. Unlike other utilities, Xcel is required to, by 2020, obtain 30 percent of its total electrical energy requirements from qualifying renewable resources, of which at least 25 percent must be wind power. Xcel’s standard is set higher and sooner, reflecting its early adoption of wind power in its supply portfolio.

In its Plan, the utility acknowledges that biomass, solar, and certain other technologies are eligible for use in meeting the RES. However, of the eligible technologies, only wind power was included in the Strategist model.

Xcel estimates that it will need an additional 1,150 MW of nameplate wind capacity to meet the state's 30 percent mandate by 2020.[3] Xcel intends to acquire renewable resources through utility's developed projects, community-based projects, and independent power producer (IPP) developed projects, in roughly equal proportions. All renewable resources acquired, going forward, are expected to be wind, with small amounts of solar power included.

As for biomass, Xcel notes that the utility currently has 290 MW of biomass generation in its portfolio.[4] Xcel lists off of these facilities and their primary fuel supply.[5] None is associated with an ethanol plant or similar facility.

Minnesota Power's 2009 Integrated Resource Plan

Minnesota Power (MP) filed its IRP with the Minnesota Public Utilities Commission on October 5, 2009, under Docket No. E-015/RP-09-1088. This filing is submitted pursuant to MN Statutes §216B.2422 and MPUC Rules Chapter 7843.

<u>Summary</u>
Minnesota Power already has considerable experience in partnering with some of its largest customers to produce biomass-fueled combined heat and power. Three paper mill customers in its territory (located in Grand Rapids, Cloquet, and Duluth) utilize wood waste to co-generate electricity and steam at on-site facilities. MP's direct experience with customer-sited, biomass-fueled cogeneration would suggest that new projects may receive a favorable reception.

Predicting future resource requirements for this utility is difficult, given the large share of volatile, industrial load on the system. The utility is planning for a range of outcomes, from adding virtually no new resources, to a need for up to 600 MW of additional generation in the next fifteen years.

<u>Regulatory Process</u>
MP seeks approval from the MPUC of its 2010-2024 Resource Plan. The utility serves 144,000 retail electric customers in central and northeastern Minnesota.[6] Minnesota Power is a division of ALLETE, which also owns the small utility Superior Water, Light and Power, which serves 15,000 customers in northwestern Wisconsin.

In addition to Interstate, the Office of Energy Security, a Division of the Minnesota Department of Commerce, is a party to the case. A group of environmental organizations—including the Izaak Walton League's Midwest Office, Fresh Energy, and the Minnesota Center for Environmental Advocacy—has participated in this case. Of these groups, the Minnesota Center

[3] Resource Plan, Page 1-16.
[4] Resource Plan, Page 5-1.
[5] Resource Plan, Pages 5-8 to 5-10.
[6] Resource Plan, page 1.

for Environmental Advocacy has issued a number of data requests of Minnesota Power. This group has submitted comments challenging the continued operation and upgrades to existing coal facilities operated by the utility. Another group, representing the utility's largest customers and styled "Large Power Interveners" has also participated in the case.

The PUC accepted comments on the MP plan beginning September 2010. Reply comments were accepted in November 2010. No action has taken place in this case in 2011.

Minnesota Power has filed some material in this Docket under the protection of "Trade Secret" status. Data filed under Trade Secret status were not reviewed in assembling this summary.

Minnesota Power's last resource plan was originally filed in 2004 and approved by the MPUC in May 2006.[7] Minnesota Power filed a new Resource Plan in 2007 but the utility was allowed in 2008 to withdraw the filing and resubmit in 2009.

The resource plan guides a utility's future investments to meet growth. If approved in the resource plan, MP's growth and investments will enjoy a presumption of prudence despite review in Certificate of Need proceedings on major projects. This IRP will be used by MP as its blueprint for adding new resources, if any, until the next plan is filed a few years hence.

Resource Requirements

In trying to gauge Minnesota Power's future supply requirements, the biggest factor will be the success of its heavy industrial base. Dependent on a handful of customers, MP's sales have been on a boom and bust cycle in recent years, depending upon the fortunes of the iron, pulp and paper, and pipeline and refinery economies. Should planned additions to the taconite, iron, and mining industries occur in the next few years, MP will have an urgent need for significant new resources. Should the bust cycle experienced in 2009 recur, the utility will have need for little more than adding additional renewables and refurbishing existing equipment during the study period.

Minnesota Power's current (2010) annual sales are estimated at approximately 12,000,000 MWh of energy and the utility estimates that its peak summer demand in 2012 will be 1,577 MW. For perspective, Xcel's Energy's current annual MWh sales are 46,000,000 and its peak demand is 9,300 MW. Minnesota Power expects its underlying (non-industrial) load to grow at approximately 17 MW per year.

Minnesota Power has perhaps the largest share of industrial load among its customers than any utility in the nation, as most of the utility's sales are to its 12 largest customers. This large share of round-the-clock usage gives the utility a high overall load factor, leaving it needing relatively little in the way of peaking or intermediate-load resources, and more heavily dependent on its baseload, coal-fired plants than other utilities.

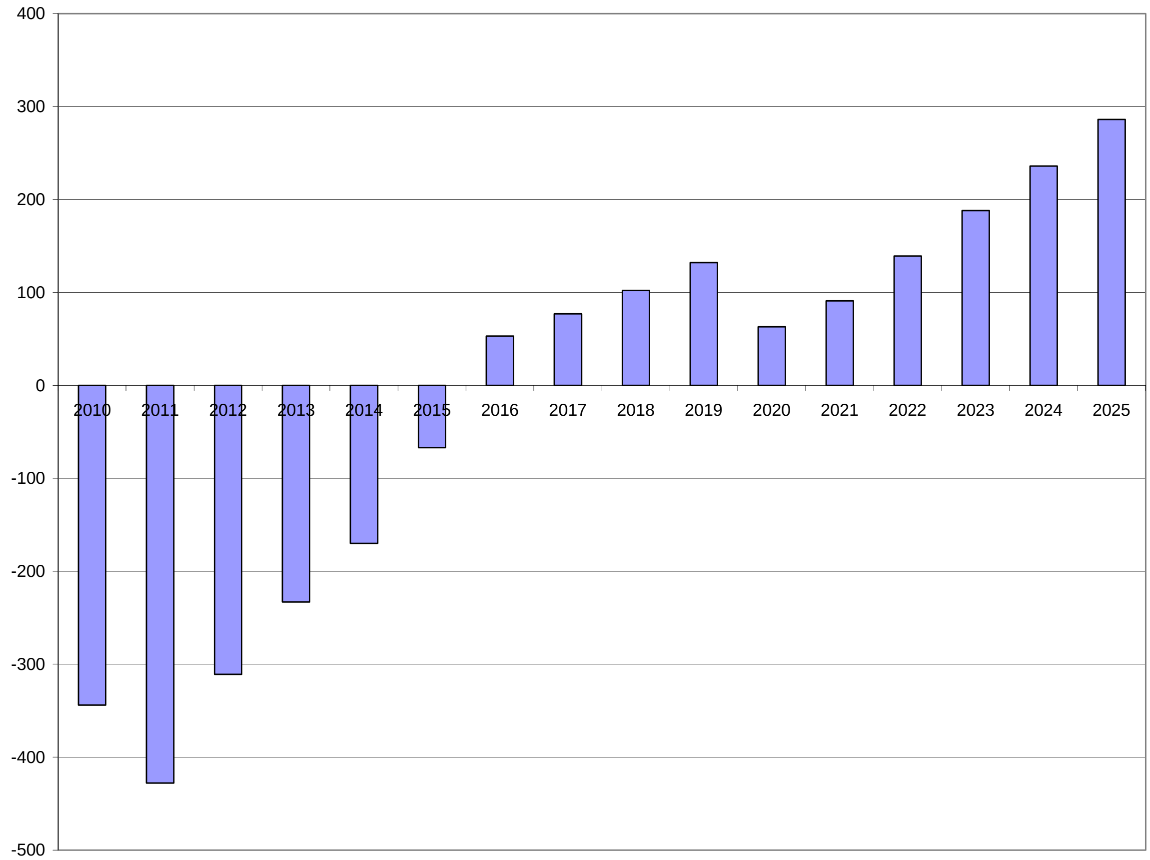
According to its resource plan, Minnesota Power anticipates experiencing significant surpluses of generating capacity through 2015. After that point, a modest deficit is expected, growing to approximately 300 MW by 2025, as shown in the figure below.

[7] Docket No. E-015/RP-04-865.

Figure 9

MP Resource Requirements (Before Resource Additions)

2010-2025, In MW, Summer Season



MP's future resource requirement needs are due to a combination of customer growth and expiring purchase contracts. The above figure represents what would happen if MP added no additional resources in the next fifteen years.

As outlined in Appendix J of the MP's Resource Plan, the utility expected to meet the bulk of its future requirements through a 250 MW purchase agreement with the Canadian utility Manitoba Hydro. The agreement would begin at 50 MW in 2020 and represents an extension and expansion of an existing purchase agreement with Manitoba Hydro. Other resources would be obtained through meeting the Minnesota Renewable Energy Standard, as discussed below.

<u>Rate Impact of Proposed Plan</u>

Minnesota Power estimates that the utility's preferred plan would result in rates approximately 50 percent higher in 2025 than current levels. In assembling its preferred plan, MP reviewed a number of different scenarios, with differing assumptions and sensitivities to a number of variables, including environmental policies and economic climate. Regarding rate impact, the proposed plan (Reference Case) performs near the mid-point of impacts from the range of scenarios considered.

2007 Plan

As noted above, Minnesota Power's previously filed a Resource on October 31, 2007.[8] The 2007 legislative session in Minnesota saw the passage of numerous clean energy mandates, which the utility addresses in the updated plan, typically by including additional wind resources. As a result, in October 2008, Minnesota Power was allowed to withdraw its 2007 plan and refile in 2009 to address the changes made to the state's energy policy.

Prior to the 2007 filing, MP's previous Resource Plan had been filed in September 2004 and approved by the MPUC in May 2006.

The 2009 resource plan will guide the utility's future investments and resource growth. Rules on construction of facilities require any investments above 50 MW in Minnesota to go through a prudence review. Assets added in Iowa follow a different process, where prudence is determined prior to construction in an "Advance Determination of Prudence" proceeding.

Additions Included in 2009 Plan

In determining its future resource requirements, in the face of regulatory and economic uncertainty, Minnesota Power examined three separate growth scenarios. The requirements shown in Figure 1, reflect the Reference Case selected by MP and corresponds to the utility's "Green Growth, Slow Business" scenario. Under its "Back to Business" scenario, Minnesota Power would require significantly more resources, with a deficit appearing in 2013 and a total of 595 MW needed by 2025. The third scenario, "Green Focus", would see no additions made until 2025, and then only a modest 23 MW.

In the "Back to Business" scenario, MP plans for the addition of 150 MW of natural gas- fired combined cycle generation, in addition to the Manitoba Hydro purchased discussed above, and the renewable energy additions, discussed below.

Use of Strategist™ and RTSim Models

Along with other utilities in Minnesota, MP utilizes the Strategist™ energy planning and analytics software package sold by a unit of ABB, the European energy equipment company. In addition, MP ran the RTSim modeling package, also used by the utility in developing its 2004 Resource Plan.

Assumptions and characteristics of potential supply and demand-side resources are entered into these models, which optimize the combined supply and demand portfolio to minimize the costs of serving load, while meeting regulatory mandates.

Biomass

Biomass and wind power, were the renewable generation alternatives included in the Strategist and RTSim model.

[8] MPUC Docket No. E-015/RP-07-1357.

Regarding biomass, MP states,

> "Minnesota Power will boost use of biomass, such as wood waste, to help meet renewable energy goals."[9]

MP discusses biomass in the context of existing facilities, either owned by its pulp and paper industrials, or at Duluth's Hibbard Energy Center, recently purchased from the City. MP writes, "Any additional development will continue to focus on utilizing existing infrastructure to find competitively priced projects."

> In modeling a biomass alternative, MP incorporated the following resource, "For the purposes of this estimate, untreated wood products such as mill and forest residue are assumed as fuel. Wood-fired boilers are typically a derivative of older stoker type designs, or the newer bubbling fluidized bed design, and range in size from 10 to 50MW."[10]

The resource plan contains significant detail regarding the assumptions made and characteristics modeled for each of the resources types included for consideration.

<u>MP and the Minnesota Renewable Energy Standard</u>
As are other Minnesota utilities, MP is subject to the state's Renewable Energy Standard, for that portion of the company's load located within Minnesota. MP is required to, by 2025, obtain 25 percent of its total electrical energy requirements from qualifying renewable resources. In its Plan, the utility outlines the additional steps it plans to take to achieve the RES, including the following,[11]

- An increase in biomass-fueled production at the Hibbard Energy Center in Duluth by 140,000 MWH per year, for completion in 2012-2013.
- Development of 375 MW of wind near Center, ND. This resource would be developed in phases through the planning period.

[9] IRP, Appendix E-2, Page 34.
[10] Appendix D, Page 11.
[11] Appendix G, Pages 2-3.

Otter Tail Power's 2010 Integrated Resource Plan

Otter Tail Power Company (OTP) filed its IRP with the Minnesota Public Utilities Commission on June 26, 2010, under Docket No. E-017/RP-10-623. This filing is submitted pursuant to MN Statutes §216B.2422. Otter Tail seeks approval of the 2011-2025 Resource Plan. Otter Tail files this same plan in North Dakota and South Dakota. Since the utility has 50 percent of its total load within Minnesota, located in the western part of the state, MN's Integrated Resource Plan is the controlling one. This is notable since Minnesota has greater environmental mandates, as well as typically the more involvement from environmental groups, than the processes undertaken by the other states.

In addition to Otter Tail, parties to the case include the Office of Energy Security, a Division of the Minnesota Department of Commerce. A group of environmental organizations—including the Izaak Walton League's Midwest Office, Fresh Energy, and the Minnesota Center for Environmental Advocacy—has participated in this case. Of these groups, the Minnesota Center for Environmental Advocacy has issued a number of data requests of Otter Tail. This group has made it known that they will challenge continued operation and upgrades to existing coal facilities operated by the utility. A number of private citizens and groups have submitted comments on the Resource Plan.

The PUC will accept additional comments on the Otter Tail plan through April 1, 2011. Reply comments will be accepted through May 2, 2011.

Otter Tail has filed some material in this Docket under the protection of "Trade Secret" status. Data filed under Trade Secret status were not reviewed in assembling this summary.

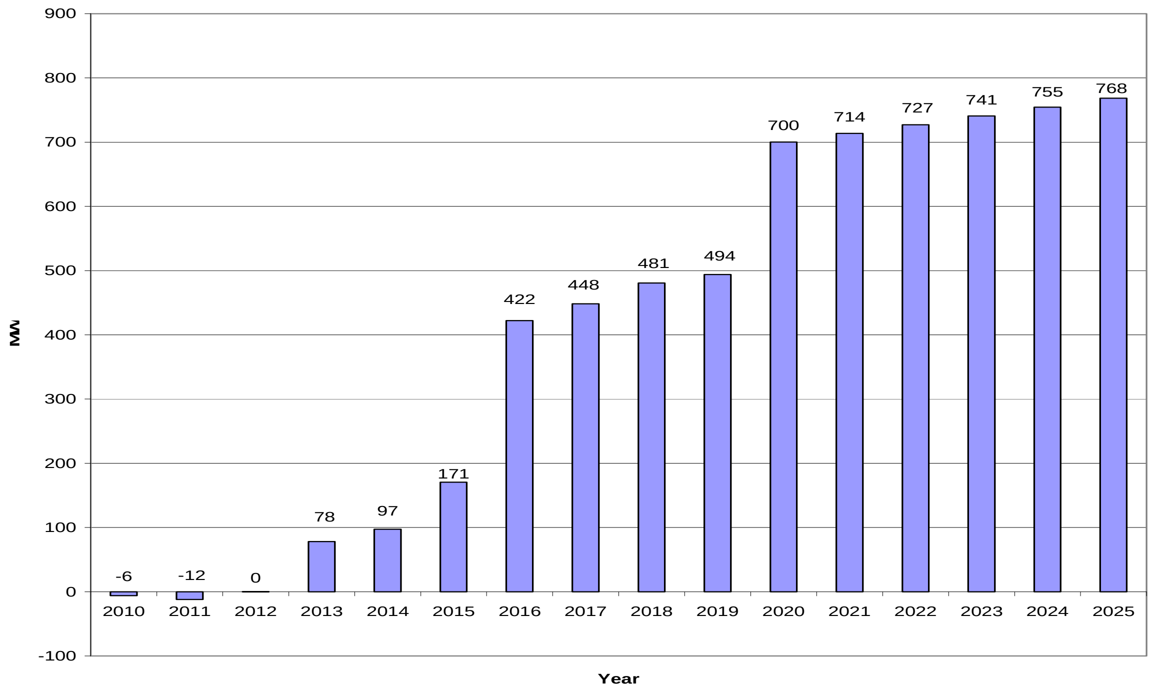
OTP's last Resource Plan was filed in 2005. All of OTP's recent expansion, improvements/retrofits and wind resources have been added under this approved resource plan. The resource plan guides a utility's future investments and resource growth. If approved in the resource plan, OTP's growth and investments will enjoy a presumption of prudence despite review in Certificate of Need review on major projects. This IRP will be used by Otter Tail as its blueprint for adding substantial amounts of improvements, intermediate generation and wind-powered generation.

Otter Tail's current annual sales are 4,500,000 MWh and 700 MW at peak. For perspective, Xcel's Energy's current annual MWh sales are 46,000,000 and its peak demand is 9,300 MW.

Otter Tail anticipates a shortage of capacity beginning in 2013 – the following graph shows their anticipated need.

Figure 10

Otter Tail's Resource Requirements (Summer, in MW), 2010-2025



Otter Tail's future resource requirements are due in part to customer growth, but are largely driven by expiring purchase contracts and likely retirements of existing generation facilities. The above Figure represents what would happen if Otter Tail took no actions in the next fifteen years. The following table shows how they propose to meet that need:

Table 6

Otter Tail Power: Proposed Resource Plan 2010-2025

Year	Planned Upgrades	Combined Cycle	Simple Cycle CT	Wind
2010				
2011				
2012				50 MW
2013				
2014			40 MW	
2015				
2016	230 MW at Big Stone			
2017			87 MW	
2018			87 MW	
2019	127 MW at Hoot Lake		60 MW	
2020				
2021				
2022				
2023				
2024				
2025				

The above capacity additions do not add up to the 700+ MW deficit. Not included in these totals are short-term market purchases of capacity.

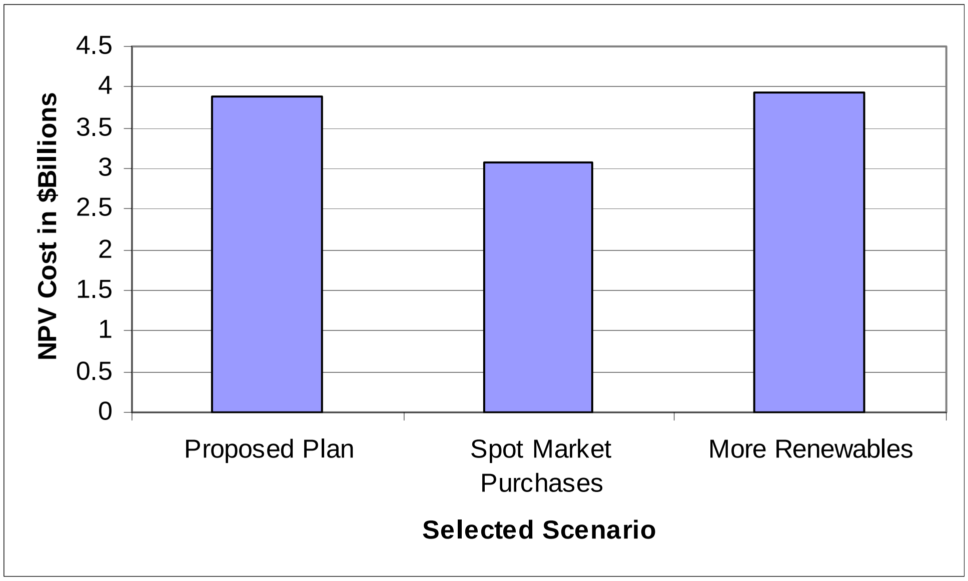
Otter Tail estimates that their preferred plan would result in rate increases of roughly 2 cents per kWh, increasing from the current level of approximately 8 cents per kWh to above 10 cents per kWh in 2019, and falling back to below 10 cents per kWh through 2025 (all amounts in 2010 dollars).

Otter Tail's proposed plan is not "least cost", it is the plan which allows the utility to satisfy RES and energy efficiency requirements at a minimal cost. Rather than test the "off ramp" provisions in statute, the utility has proposed to meet the clean energy requirements at a higher cost. The following chart shows the relationship of the preferred plan and other lower cost plans.

Figure 11

Otter Tail Power

Net Present Value (NPV) of Revenue Requirements for Selected Scenarios



In assembling its Resource Plan, Otter Tail reviewed a number of different scenarios, with differing a assumptions and sensitivities to a number of variables, including natural gas and coal prices, capital costs, CO_2 targets, Federal policies, load growth, and other items. Depending on the variable, the proposed plan either performs better or worse than alternative scenarios. Commenting on its selection or resources, Otter Tail states,

> "New resources have been selected that will meet the Company's needs while maintaining flexibility and limiting the risk of exposure to changes in financial, social, and technological factors beyond its control."[12]

<u>2005 Plan</u>

As noted above, Otter Tail's previous Resource Plan was filed in 2005. Following the 2007 legislative session in Minnesota, and the passage of numerous clean energy mandates, the utility provided an updated plan, adding additional wind resources. All of OTP's recent wind resources have been added under this approved, amended resource plan. The resource plan guides a utility's future investments and resource growth. Rules on construction of facilities require any investments above 50 MW in Minnesota to go through a prudence review, but wind facilities in ND have a presumption of prudence. OTP has avoided the prudence review on its existing wind farms by building them in ND and making them smaller than 50 MW.

<u>Additions Included in 2010 Plan</u>

That Otter Tail appears to have such a large and growing capacity deficit is not an indication of significant growth in native load, but rather expectations for retirements at some of its oldest and

[12] IRP, Page 25.

largest coal-fired power plants. Notably, the bulk of future resource additions is planned to occur at Otter Tail's Big Stone plant in 2016 and the upgrades of its Hoot Lake plant in 2019.

OTP's recently filed IRP shows total system capacity deficiencies beginning in 2012 with a big deficiency jump to about 80 MW in 2013 with significant deficiency increases beyond. This growth is not only due to customer growth but also due to expiring purchase contracts and likely retirement and re-rating of generation facilities. Depending upon Commission review, this IRP will be used by OTP as its blueprint for adding substantial amounts of natural gas fired and wind-powered generation.

Use of Strategist™ Model

Along with other utilities in Minnesota, Otter Tail Power utilizes the Strategist™ energy planning and analytics software package sold by a unit of ABB, the European energy equipment company. Biomass was one of a number of generation resources considered for inclusion in the Strategist model, but ultimately left off the list.

> As Otter Tail explains,
>
> "[I]t is important to note that any resource used as a potential future addition in the Strategist model was intended to be generic and representative of the Company's needs. In no way do the alternatives selected for modeling purposes exclude future consideration of competing options in similar generation categories."[13]

However, Otter Tail specifically addresses biomass as a resource later in the Plan. For the most part, Otter Tail considered the use of biomass primarily as a fuel to be co-fired with coal in its baseload power plants. As for stand-alone projects,

> "Otter Tail did not include any other additional biomass alternatives in the model. As the cost of fossil fuels increases, other markets develop for biomass fuels such as wood waste. In many cases, the wood products companies that create the waste fuel use it as fuel in their own process. Otter Tail has worked with customers on potential wood waste-fired biomass facility investigations. The fuel supply is limited and the costs of such facilities are high. The development potential of these facilities is limited and very site specific. To date, Otter Tail has not found other opportunities for development of such facilities with costs being close to economic."[14]

Cogeneration and Ethanol

As for cogeneration, or combined heat and power (CHP) technologies more broadly, Otter Tail mentions the proximity of its Big Stone facility to POET's ethanol plant and the fact that Otter Tail supplies steam to POET.[15] However, this reference comes in the context of Otter Tail as the

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[13] Page 179.
[14] Footnote.
[15] Page 163.

supplier of thermal energy, not the purchaser of electrical energy from a customer-owned facility.

Other references to ethanol describe ethanol plants as an important customer segment of Otter Tail's. No specific mention is made regarding ethanol as a potential source for customer-generated power. Otter Tail writes that,

> "A key uncertainly to with the large commercial portion of the [demand] forecast relates to the construction of ethanol plants. The forecast includes new ethanol plant loads in the near term for which Otter Tail has information."[16]

Otter Tail and the Minnesota Renewable Energy Standard

As are other Minnesota Utilities, Otter Tail Power is subject to the state's Renewable Energy Standard, for that portion of the company's load located within Minnesota. Otter Tail is required to, by 2025, obtain 25 percent of its total electrical energy requirements from qualifying renewable resources. In its Plan, the utility acknowledges that biomass, solar, and certain other technologies are eligible for use in meeting the RES. However, of the eligible technologies, only wind power was included in the Strategist model. A total of 50 MW of new wind power was included in the utility's preferred Resource Plan as being an "economic" resource. With this and other planned wind additions, the utility reports that it will have sufficient renewable energy resources to comply with requirements through 2024.

Interstate Power and Light's 2010 Integrated Resource Plan

Interstate Power and Light Company (IPL) filed its IRP with the Minnesota Public Utilities Commission on November 1, 2010, under Docket No. E-001/RP-08-673. This filing is submitted pursuant to MN Statutes §216B.2422 and MPUC Rules Chapter 7843.

Summary

Interstate appears open to biomass and bio-gas fueled generation, cogeneration and combined heat and power, and customer supplied distributed generation as supply options to meet the requirements of its customer base. The utility is experiencing modest but significant growth in its customer load. However, its Minnesota operations represent only a small fraction of its overall activities. Further, no additional supply resources are projected to be needed until late in the 15-year study period.

Regulatory Process

IPL seeks approval from the MPUC of its 2010-2025 Resource Plan. Interstate files this same plan in Iowa. IPL, a unit of Madison, Wisconsin's Alliant Energy, also provides power to a utility in the state of Illinois, a deregulated state, as a wholesale supplier. The utility has only 8 percent of its total load within Minnesota, in the southern tier of the state. With 92 percent of its load in Iowa, the Minnesota Commission has relatively less involvement in the utility's operations, compared to the Iowa Utilities Board.

In addition to Interstate, the Office of Energy Security, a Division of the Minnesota Department of Commerce is a party to the case. No other entities have participated in this case, to date.

[16] Page 151.

The PUC will accept comments on the Interstate plan through March 1, 2011. Reply comments will be accepted through May 2, 2011.

Interstate has filed some material in this Docket under the protection of "Trade Secret" status. Data filed under Trade Secret status were not reviewed in assembling this summary.

Interstate's last resource plan was originally filed in 2005 and approved by the MPUC in April 2007.[17] IPL was to have filed a new Resource Plan in 2008 but had the deadline extended into 2009. In 2009, the utility filed a Notice of Changed Circumstances to inform the MPUC that the utility was canceling its proposed 630-MW Sutherland Generating Station Unit 4, a coal-fired power plant project that was to have been built in Marshalltown, Iowa. The Sutherland project was to have fulfilled a large portion of the utility's future resource requirements. In July, 2009, the MPUC allowed Interstate to withdraw its Resource Plan and refile in November 2010.

The resource plan guides a utility's future investments to meet growth. If approved in the resource plan, IPL's growth and investments will enjoy a presumption of prudence despite review in Certificate of Need proceedings on major projects. This IRP will be used by Interstate as its blueprint for adding new resources, if any, until the next plan is filed a few years hence.

Resource Requirements

Interstate's current (2010) annual sales are estimated at 16,300,000 MWh of energy and 2,629 MW of peak demand. For perspective, Xcel's Energy's current annual MWh sales are 46,000,000 and its peak demand is 9,300 MW. IPL expects its load to grow at 25 MW per year. The utility presents a forecast load for the whole utility, not one specific to its Minnesota operations.

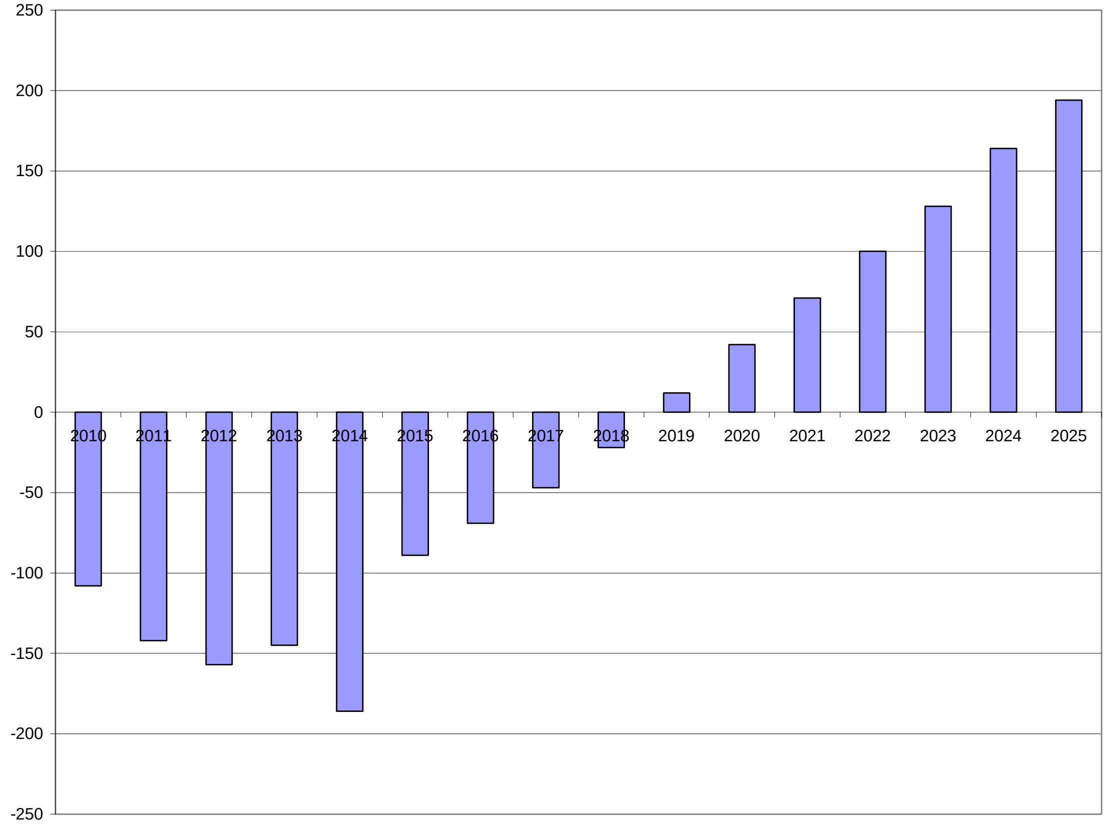
According to its resource plan, Interstate anticipates experiencing a shortage of generating capacity beginning in 2019 and increasing to approximately 200 MW by 2025, as shown in the figure below.

[17] Docket No. E-001/RP-05-2029.

Figure 12

IPL Resource Requirements (Before Resource Additions)

2011-2025, In MW



IPL's future resource requirement needs are due to a combination of customer growth and expiring purchase contracts. The above figure represents what would happen if IPL added no additional resources in the next fifteen years. The following table shows how they propose to meet that need:

Table 7

Interstate Power and Light: Proposed Resource Plan 2010-2025

Year	Purchased Power	Combined Cycle	Simple Cycle CT	Wind
2010				
2011				
2012				
2013				
2014				
2015				
2016				
2017				
2018				
2019	50 MW			
2020	50 MW			
2021	100 MW			
2022	100 MW			
2023	150 MW			
2024	150 MW			100 MW
2025			189 MW	200 MW

As you can see above, no planned capacity additions occur before 2019 and no new construction appears until the last two years of the study period.

Rate Impact of Proposed Plan

Interstate estimates that the utility's preferred plan would result in rate increases of roughly 4.9 percent per year, throughout the study period. This amount would be well above the assumed inflation rate of 2.7 percent per year.

In assembling its preferred plan, Interstate reviewed a number of different scenarios, with differing a assumptions and sensitivities to a number of variables, including natural gas and coal prices, capital costs, CO_2 targets, Federal policies, load growth, and other items. Depending on the variable, the proposed plan either performs better or worse than alternative scenarios.

2005 Plan

As noted above, Interstate's previous Resource Plan was filed in 2005. The 2007 legislative session in Minnesota saw the passage of numerous clean energy mandates, which the utility addresses in the updated plan, typically by including additional wind resources. All of IPL's recent wind resources have been added in Iowa.

The 2010 resource plan guides a utility's future investments and resource growth. Rules on construction of facilities require any investments above 50 MW in Minnesota to go through a prudence review. Assets added in Iowa follow a different process, where prudence is determined prior to construction in an "Advance Determination of Prudence" proceeding.

Additions Included in 2010 Plan

As shown in the figure above, IPL appears to have a large and growing capacity surplus in the first few years of the period, declining into a modest deficit by 2025. Attributing 8 percent of the 194 MW deficit in 2025 to Minnesota results in a resource requirement of less than 16 MW. As IPL points out,

> "The proposed resource plan calls for very little new generation to be added over the study period and most, if not all, being added in the back half of the study period."[18]

Use of EGEAS™ Model

In contrast to the other utilities in Minnesota, Interstate utilizes the Electric Generation Expansion Analysis System (EGEAS™) energy planning and analytics software package developed by the Electric Power Research Institute (EPRI) industry group. Assumptions and characteristics of potential supply and demand-side resources are entered into this model, which optimizes the combined supply and demand portfolio to minimize the costs of serving load, while meeting regulatory mandates.

Biomass and Cogeneration

Biomass and bio-gas (including anaerobic digestion and landfill) generation alternatives were among the potential supply resources included in the EGEAS model. Also considered for the Plan under the "purchases" category were cogeneration and customer-provided distributed generation alternatives.

Regarding biomass, IPL states,

> "There is reasonable potential for power production from biomass combustion in IPL's service territory. Fuel stream limitations and higher capital costs make this option less attractive; however, biomass was modeled as an option in the EGEAS analysis for this resource plan."[19]

Regarding Cogeneration, Interstate has this to say,

[18] Integrated Resource Plan, Page 9-7.
[19] IRP, Page 5-4.

> "There are a couple of potential cogeneration candidates within the regulated service territory of IPL. Cogeneration will be considered, if feasible."[20]

<u>Distributed Generation</u>

In its Resource Plan, IPL specifically considers the installation of distributed generation (DG) on its system, as an update to a series of reports on the subject, dating back to 2001 and updated in 2003. The report specifically considers small-scale combined heat and power (CHP, cogeneration) and bio-gas and biodiesel-fired generating units. However, Interstate does not specifically discuss ethanol facilities as a site for such customer-installed generation.

> IPL concludes,
> "Consequently, factors such as greater state and federal subsidies, the emergence of new technologies and a heightened customer interest and awareness of DG suggests a higher DG potential. However, IPL sees little evidence of material DG capabilities being installed. In contrast, IPL does see evidence that the costs of installing and operating DG have risen considerably since 2003."

The resource plan contains significant detail regarding the assumptions made and characteristics modeled for each of the resources types included for consideration.

<u>Interstate and the Minnesota Renewable Energy Standard</u>

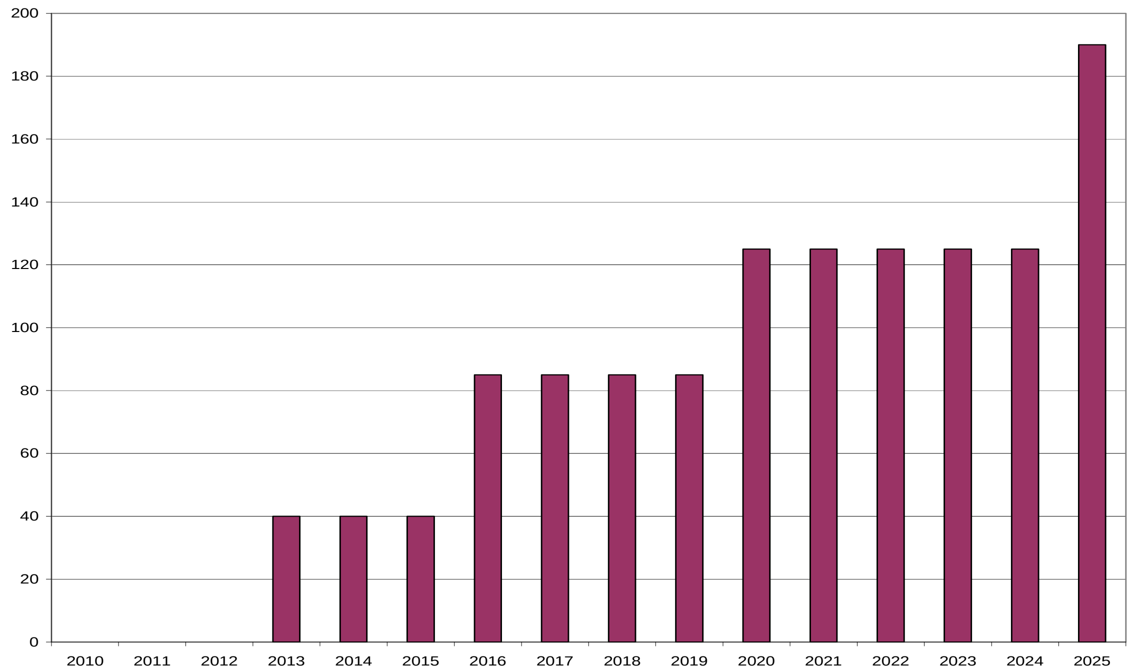
As are other Minnesota utilities, Interstate is subject to the state's Renewable Energy Standard, for that portion of the company's load located within Minnesota (8 percent of the total). IPL is required to, by 2025, obtain 25 percent of its total electrical energy requirements from qualifying renewable resources. In its Plan, the utility acknowledges that the Minnesota portion of its joint operations will fall short of Minnesota's Renewable Energy Standard for most years during the study period. This shortfall is illustrated in the figure below.

[20] IRP, Page 5-9.

Figure 13

IPL's Minnesota Shortfall of Renewable Energy Credits (REC's), by Year

In Thousands (MWH Equivalent)



IPL plans to use its surplus of renewable energy in Iowa to meet the shortfall in Minnesota requirements, assuming the standard required in Iowa does not increase during this period. However, even a shortfall of 190,000 MWH per year translates into a modestly-sized wind farm of 75 MW, assuming a 30 percent capacity factor.

Predating the Renewable Energy Standard, the state of Minnesota has had in place a Renewable Energy Objective (REO) since 2001. The REO remains in effect, alongside the RES, and would have utilities reach 10 percent of total energy from eligible technologies by 2015. Of the 10 percent, "not less than 0.5 percent of the energy must be generated by biomass energy technologies."[21] To date, IPL has no resource in its mix that meets the definition of qualifying biomass. But neither the MPUC nor the OES has sought to enforce this provision, citing the "good faith effort" part of the statute.

[21] Minnesota Statutes 216B.1692 Subd. 2(3)(b).

3. Analysis of a biomass procurement system

- Complete specification of equipment and determination of capital and operating costs
- Continue rate of return on investment study
- Begin study of organizational structures

Economic and greenhouse gas (GHG) emission analyses for biomass logistics systems have been presented in previous Milestone reports. The cost and GHG emission information developed previously is reflected in the rate of return and investment analyses currently underway.

4. Outreach and education for investors, policy makers, utilities and the public

- Update web site
- Continue development of models, spreadsheets and other decision aids
- Continue workshops or presentations at conferences
- Continue presentation of papers
- Identify and document policy issues

We continue to update the web site to reflect the most recent project results. We are continuing to improve new sections on biomass logistics and biomass densification.

Outreach Workshops/Meetings

We are planning three conferences to discuss the results of our work. They will be held on March 29 in Owatonna, MN, March 31 in Lamberton, MN, and July 11 in St. Paul, MN (St. Paul Campus of the University of Minnesota). The website for registration is

http://www.cce.umn.edu/Using-Corn-Stover-for-Energy-at-Ethanol-Plants/index.html

We hope to get farmers to attend the first two meetings so we wanted to get them scheduled before spring field work. The July conference will be targeted more for Twin Cities attendees and the investment community. The conference schedule for each of the three days is listed below.

Conference Schedule

8:30 a.m.	Registration
9:00	Welcome, *Doug Tiffany*, University of Minnesota
9:10	Corn Stover Logistics and Densification, *Vance Morey*, University of Minnesota
9:40	Corn Stover Removal Rates, *Jeff Coulter* or *Jane Johnson*, University of Minnesota
10:05	Experiences and Perspectives on Stover Harvest, *Eric Woodford*, Woodford Equipment
10:30	Break
10:45	Cob Harvest and Gasification Plans at Chippewa Valley Ethanol, *Andrew Zum*, Chippewa Valley Ethanol
11:15	Using Biomass at Ethanol Plants for CHP, *Vance Morey*, University of Minnesota
11:45	Harvest Logistics and Using Biomass at Ethanol Plants, *Morning Panel*
12:10 p.m.	Lunch
12:55	Electricity Markets and Steam Contracts, *Larry Schedin*, LSS Resources
1:25	Economics of Biomass Use at Ethanol Plants, *Doug Tiffany*, University of Minnesota
1:55	Break
2:10	Investor Perspectives - Investor Objectives and Fears, *Dan O'Neil*, Northland Securities
2:35	Legal Issues: Contracting Biomass, Selling Steam and Electricity, *Mark Hanson* or *Greg Jenner*, Stoel Rives Law Firm
3:05	Organizational, Economic and Legal Issues of CHP and Biomass, *Afternoon Panel*
3:30	Adjourn

Conference Presenters

Douglas Tiffany is an Assistant Extension Professor at the University of Minnesota focusing on renewable energy economics. Doug has analyzed many technologies that can produce biofuels and bioenergy including integrated systems at ethanol plants using biomass. Doug holds B.S. and M.S. degrees in Agricultural Economics from the University of Minnesota.

Vance Morey is a Professor in the Department of Bioproducts and Biosystems Engineering. He is well known for research work in grain drying and energy usage in agriculture and agricultural processing industries. Vance holds a B.S. in Agricultural Engineering from Michigan State University and a PhD from Purdue University.

Jeff Coulter is an Assistant Professor in the Department of Agronomy and Plant Genetics at the University of Minnesota. Jeff specializes in research and Extension programming related to corn production and is based in St. Paul. He holds a PH. D from the University of Illinois.

Jane Johnson is a Research Soil Scientist with the USDA Agricultural Research Service at the North Central Soil Conservation Research Laboratory in Morris, Minnesota. She has publications discussing preservation of soil organic carbon and ongoing research to develop tools to guide producers on appropriate removal rates of biomass. Jane holds a MS and Ph. D. from the University of Minnesota.

Eric Woodford owns a dealership that specializes in forage harvesting equipment at Emmetsburg, Iowa. Before moving to Iowa, Eric operated a custom harvesting business near Redwood Falls, MN, with annual harvests of as many as 20,000 round bales per year and substantial tonnage of hay. Eric holds several patents on baler design and has participated in biomass harvest trials sponsored by universities, government agencies, and businesses.

Andrew Zurn is the plant engineer at Chippewa Valley Ethanol in Benson, MN. Andy has over 20 years of design engineering and project management experience in a variety of industries including electric power generation, geotechnical, iron ore processing, agriculture equipment and ethanol production. Mr. Zurn earned a B.S. in Mechanical Engineering from the University of Minnesota.

Larry Schedin is an electrical engineer with vast experience in the power utility industry. Larry owns LLS Consulting, and performs contracted research on engineering projects and regulatory matters. Larry is frequently an expert witness on electrical rate cases. Larry holds a B.S. degree in electrical engineering from the University of Minnesota and a Masters of Engineering Management from Massachusetts Institute of Technology. He worked for Northern States Power Company from 1960 to 1979, before starting Schedin & Associates.

Dan O'Neill is the Senior Vice President of Public Finance at Northland Securities in Minneapolis. In this capacity he organizes offerings of debt on a variety of energy production projects. He assists clients in the areas of infrastructure and environmental project finance with extensive work in the area of alternative energy and renewable fuels. Dan has also worked on several professional sports venues, and recently served as banker to the Minnesota Twins.

Mark Hanson is a Partner in the Stoel Rives law firm and is based in the Minneapolis office. He has assisted in the organization of numerous ethanol plants and wind energy projects in Minnesota and neighboring states. Mark received his law degree from William Mitchell College of Law.

Greg Jenner is a Partner in the Tax Practice of Stoel Rives law firm and specializes in energy tax law at the Minneapolis office. In addition to his employment at Stoel, Greg worked in Washington, D.C., as Acting Assistant Secretary of the U.S. Treasury for Tax Policy. Greg received his law degree from New York University School of Law.

Sponsors

Research results presented at this conference includes research sponsored by the Xcel Renewable Energy Development Fund and the University of Minnesota Agricultural Research Station.

Publications

Morey, R. V., N. Kaliyan, D. G. Tiffany, and D. R. Schmidt. 2010. A corn stover supply logistics system. Applied Engineering in Agriculture 26(3): 455-461.

Kaliyan, N., R. V. Morey, and D. G. Tiffany. 2011. Reducing life cycle greenhouse gas emissions of corn ethanol by integrating biomass to produce heat and power at ethanol plants. Biomass and Bioenergy 35(3): 1103-1113.

Invited Lectures, Poster Presentations and Other Outreach Activities by Project Personnel

Sept. 29	Doug Tiffany presented BIGCC results using corn stover and syrup to class of Bill Easter of Applied Econ. (30 in class)
Oct. 12	Doug Tiffany presented BIGCC results at class for Dr. Lanny Schmidt of Chemical Engineering (35 in class)
Nov. 1	Meeting at Highwater Ethanol Plant at Lamberton, MN, to discuss torrefaction of biomass. Doug Tiffany discussed how volatile gases of torrefaction could be converted to steam and sold to adjacent ethanol plant
Nov. 4	Doug Tiffany presented lecture on biomass use at ethanol plants to produce combined heat and power and also discussed economics of torrefaction for Dr. Ford Runge's class. (25 in class)
Nov. 16	Doug Tiffany presentation entitled, "Economics of Torrefied Biomass: Costs of Production and Prices that Could Be Paid by Power Utilities," at Midwest Regional Biomass Conference in Dubuque, IA. (30 in audience, presentation posted on web)
Nov. 30	Corn Stover Logistics Poster was displayed at E3 Conference, River Centre, St. Paul, MN. This poster documented costs, energy usage, and GHG emissions associated with use of corn stover as a fuel at ethanol plants. The poster used a graph to show how the use of corn stover results in approximately 1/9 of the emissions of GHG per Megajoule versus natural gas. This conference attracted approximately 600 people.
Dec. 3	Doug Tiffany gave an invited presentation to the Sibley-Nicollet Corn Growers at Lafayette, MN, that discussed harvest of corn stover and its utilization to produce process heat and electricity at ethanol plants as well as the process of torrefaction to produce biocoal. (25 were in the audience)
Dec. 6	Doug Tiffany gave an invited lecture to retired College of Food Agriculture and Natural Resource Sciences (CFANS). Among the topics discussed was the use of biomass to produce combined heat and power at fuel ethanol plants, using the research developed on this project.
Dec. 7	Doug Tiffany gave an invited lecture at a conference sponsored by the Natural Resources Research Institute in Duluth to an audience including power utilities and forest products managers and staff. In addition employees of NRRI conducting research on torrefaction and the company Torrsys made presentations. (35 were in attendance)
Dec. 14	Doug Tiffany gave an interview on the topic of torrefaction to staff from Bryan and Bryan International to help them promote the Pacific West Biomass Conference at Seattle, Washington.

Dec. 17	Doug Tiffany, Nalladurai Kaliyan, Vance Morey, and David Schmidt made presentations and discussed the BIGCC project and previous conclusions about use of biomass to product process heat at ethanol plants with Dr. Ian Purtle of Cargill. Dr. Purtle offered perspectives on our conclusions and offered some ideas about approaches that Cargill had considered in a variety of locations. Dr. Ian Purtle expressed interest in applying additional financial analysis to the cases that had previously been analyzed.
Jan. 8	Doug Tiffany presented a lecture to the University of Minnesota Alumni Chapter of Puget Sound, Washington, including information on the use of biomass to produce combined heat and power at fuel ethanol plants. (20 in audience)
Jan. 12	Doug Tiffany presented a lecture entitled, "Torrefied Biomass: Production Costs and Value to Power Utilities" at the Pacific West Biomass Conference, sponsored by BBI in Seattle. (60 in audience)
Jan. 17	Doug Tiffany presented a poster entitled, "A Biomass Logistics System," containing information developed in an earlier phase of this project at Ag. Expo, which is an event co-sponsored by the Minnesota corn and soybean grower organizations. This event attracted approximately 400 farmers, venders, and educators and was held at Jackpot Junction, near Redwood Falls, MN.

Project Status

Overall we continue to make good progress. We have continued to revise the BIGCC system models to obtain maximum electricity to the grid consistent with technology suggestions made by our subcontractor, AMEC E&C Services. We have received detailed cost estimates, which have allowed us to make preliminary estimates of rates of return for BIGCC systems. More in depth analysis of rates of return is underway.

We have worked with our subcontractor, Larry Schedin, LLS Resources, to discuss various incentive programs and business models. He has reviewed integrated resource plans developed by several utilities to help us better understand how electricity generated at ethanol plants might fit in their power generation systems. He has set up several meetings with potential users of the technology. These meetings have helped focus our analysis on more detailed financial modeling in order to report results of rates of return from the point of view of an outside firm. We have hired a graduate student in the Department of Applied Economics to help perform additional financial analysis and also develop pertinent financial ratios that should be of interest to outside investors and the bankers they use. In addition to further analysis of financials from the standpoint of a modeled "power island," our research team is planning to present our conclusions in three conferences, with two in March and one in July described above.

In addition to the three conferences that are planned, we continue to participate in extension and outreach activities related to the project, primarily through the work of Doug Tiffany.

To allow us time to complete the more sophisticated financial analysis and to conduct the three conferences, we are requesting a three month no-cost extension of the project (Milestone 8) until August 21, 2011. This will allow us time to complete all of the objectives that we envisioned at the start of the project.