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Agriculture, Forestry, and Waste Management Technical Work Group
Summary List of Draft Priorities for Analysis

	Policy Option	GHG Reductions (MMtCO_2e)			Net Present Value 2007–2020 (Million $)	Cost-Effective-ness ($/t$CO_2$e)	Level of Support
		2012	2020	Total 2007 2020			
AFW-1	Agricultural Crop Management	1.2	0.8	11.8	TBD	TBD	TBD
AFW-2	Manure Management and Energy Utilization	0.01	0.32	1.8	66	36	TBD
AFW-3	Reductions in On-Farm Energy Use	0.2	0.71	4.2	TBD	TBD	TBD
AFW-4	Biodiesel Production	0.0	0.2	1.1	156	143	TBD
AFW-5	Ethanol Production	0.2	3.1	15.3	58	3	TBD
AFW-6	Preserve Lands with Carbon Storage Value	TBD	TBD	TBD	TBD	TBD	TBD
AFW-7	Biomass Feedstocks for Energy Production	*Included in AFW-8*					TBD
AFW-8	Forestry Programs to Enhance GHG Benefits	4.2	8.7	80.2	7	0.09	TBD
AFW-9	Source Reduction, Enhanced Recycling and Composting Programs	TBD	TBD	TBD	TBD	TBD	TBD
AFW-10	Landfill Methane Reduction Programs	0.3	1.2	7.5	TBD	TBD	TBD
	Sector Total After Adjusting for Overlaps						
	Reductions From Recent Actions (table to be added below)						
	Sector Total Plus Recent Actions						

Highlights in yellow represent new additions to POD.

Highlights in blue represent matters that need to be addressed by the PWG.

AFW-1. Agricultural Crop Management

Policy Option Description

The amount of carbon stored in the soil can be increased by crop management practices that increase C inputs to soil and/or reduce soil organic matter decomposition rates. Adoption of conservation tillage, in particular no-till, can increase soil C stocks. Reducing mechanical soil disturbance reduces the oxidation of soil carbon compounds and allows more stable aggregates to form. Other benefits of conservation tillage include reduced wind and water erosion, improved soil structure and crop water use, reduced fuel consumption, and improved wildlife habitat. On non-irrigated cropland, increased cropping frequency to reduce or eliminate summer fallow goes hand in hand with adopting no-till practices. Improved nutrient management (i.e., better timing, application rates based on soil test, advanced fertilizer formulations, etc.) of both fertilizer and manure can increase nutrient use efficiency and reduce addition rates, thereby reducing nitrous oxide emissions and potentially fossil fuel use. For some production systems, organic farming practices result in lower net GHG emissions. Application of biochar (i.e., stable organic residues from biomass pyrolysis) to soils is a potential practice to capture and sequester atmospheric CO_2.

Policy Option Design

Goals:

- **No-till goal:** approximately 15% of total annual cropland is currently managed under no-till (most with reduced summer fallow). Achieve 50% no-till by 2020.
- **Nutrient goal:** Increase nitrogen fertilizer efficiency by 20% through the use of best management practices by 2020.

Timing:

- **No-till goal:** 30% no-till on annual croplands by 2012; achieve the full goal by 2020.
- **Nutrient goal:** Increase fertilizer efficiency by 10% by 2012; achieve the full goal by 2020.

Parties Involved: To be determined (TBD).

Other: Current (2005) Colorado cropland: 1,923,000 ha dryland; 924,000 ha CRP; 1,000,000 ha irrigated cropland (~50% as hay).[1]

Implementation Mechanisms

- Increased extension/outreach (a good field-day program for dryland systems, through CSU researchers. has been developed over the past several years—could benefit from more resources). Extension related to nutrient management. ??

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[1] INSERT REFERENCE

- State incentives—e.g., favorable property tax rating for "high conservation management." ?
- R&D support for cropping systems research—e.g., selection/field studies on profitable oil seeds for inclusion in dryland rotation (cross reference to biodiesel incentives).
- Incentives for water conservation/more flexible water allocation could likely play in some way.

Related Policies/Programs in Place

- Federal Conservation Compliance programs (but probably don't specifically award for no-till and reduced summer fallow); possible upcoming provisions in Farm Bill (US or CO?).
- Market-based incentives—e.g., CCX (Chicago Climate Exchange) project with the Rocky Mountain Farmer's Union (RMFU).

Types of GHG Reductions

CO_2: Reducing tillage and soil disturbance slows the breakdown of plant material on the soil surface and in the root zone, accelerating the microbial processes that stabilize carbon and protecting carbon from oxidation, inhibiting the release of carbon back into the atmosphere. Additionally, reducing the amount of nitrogen fertilizer needed will reduce CO_2 emissions that result from the fertilizer manufacturing process.

N_2O: Increasing the efficiency of nitrogen fertilizer application is expected to reduce N_2O emissions.

Improved cultivation methods will reduce all GHG emissions that result from the combustion of distillates and other fossil fuels related to the use of farm equipment. However, this reduction is captured by AFW-3 and will not be quantified under this option.

Estimated GHG Savings and Costs per $MtCO_2e$

Note: The Metric unit "ha" is used in the analysis of this option, rather than the standard unit, acres. The GHG reductions above and costs below do not reflect the organic production incentives elements of this option. Because agricultural soils will only accumulate carbon up to a certain level before tapering off, the GHG benefit related to no-till soil carbon accumulation decreases in the post-2020 period before ceasing in 2025. The remaining benefit, which is permanent, is associated with lower fossil fuel consumption.

GHG reduction potential in 2012, 2020 ($MMtCO_2e$):

- No-till: 1.28, 0.73
- Nitrogen fertilizer efficiency: 0.06, 0.10

Net Cost per $MtCO_2e$:

- No-till: -$11.03
- Nitrogen fertilizer efficiency: TBD

Data Sources:

Quantification of the no-till portion of this option is based upon 2,923,000 hectares of agricultural land in Colorado. This land is comprised of dryland and irrigated land. Using standard unit conversions, the soil carbon accumulation rate of 1.37 $MtCO_2$/ha-yr was calculated from the midpoint of the range provided by Naderman et al.[2] The estimated cost savings ($14.33 per hectare) related to the adoption of no-till farming was derived from an article by Tim McAlvay of Texas A&M.[3] The reduction in fossil diesel fuel use from the adoption of conservation tillage methods is 3.5 gallons/acre.[4] From the CO Inventory & Forecast, the fossil diesel GHG emission factor is 10.07 $MtCO_2e$/1,000 gallons.

The historical quantity of fertilizer used is consistent with the Agriculture module of the CO Draft Inventory & Forecast. This forecast also provides the resulting N_2O emissions and carbon equivalent emissions. Data regarding the cost savings associated with an increase in the efficiency of fertilizer use is taken from an average of the cost of common fertilizers in the spring of 2004.[5] *While the cost savings of this option has been quantified, the net policy implementation costs are to-be-determined, as information regarding the cost of implementation of both no-till farming and nutrient management is still being collected.*

Quantification Methods:

Based on the policy design parameters, the schedule for acres to be put into conservation tillage/no-till cultivation are shown in the table below. The mid-point of the estimated range for carbon sequestration (2.47 tC/ha) in agricultural soils was used to estimate the total amount of carbon to be sequestered. Based on the Naderman et al. study referenced above, it was further assumed that this additional carbon would be sequestered in the soil over a period of six years (after six years no further carbon is stored). The resulting annual carbon accumulation rate was converted into its CO_2 equivalent yielding 1.37 $MtCO_2$/ha-yr.

To estimate carbon stored each year, the annual accumulation rate was multiplied by the number of acres in the policy program each year. After six years, the crop acres that entered the program were assumed to not store additional carbon. Results are shown in the table below.

Additional GHG savings from reduced fossil fuel consumption were estimated by multiplying the fossil diesel emission factor and diesel fuel reduction per acre estimate provided above. Results are shown in the table below along with a total estimated benefit from both carbon sequestration and fossil fuel reductions.

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[2] G. Naderman, B.G. Brock, G.B. Reddy, and C.W. Raczkowski, "Long Term No-Tillage: Effects on Soil Carbon and Soil Density Within the Prime Crop Root Zone," Project Report, January 2006.

[3] Tim McAlavy. AgNews News and Public Affairs: Texas A&M University System Agriculture Program, April 27, 2005, accessed July 11, 2007. Actual estimate is -$5.80 per acre. Converted here to metric units.

[4] Reduction associated with conservation tillage compared to conventional tillage, at www.ctic.purdue.edu/Core4/CT/CRM/Benefits.html, accessed August 2006.

[5] 2004 Fertilizer Use and Cost. Accessed on July 19, 2007 from www.ers.usda.gov/Data/FertilizerUse/Tables/Fert%20Use%20Table%207.xls.

Year	Hectares in Program	Hectares Still Accumulating Carbon	$MMtCO_2e$ Sequestered	Diesel Saved (1,000 gal)	$MMtCO_2e$ From Diesel Avoided	Total $MMtCO_2e$ Saved
2008	526,140	526,140	0.720	4,548	0.0458	0.7663
2009	613,830	613,830	0.841	5,307	0.0534	0.8940
2010	701,520	701,520	0.961	6,065	0.0611	1.0217
2011	789,210	789,210	1.081	6,823	0.0687	1.1494
2012	876,900	876,900	1.201	7,581	0.0763	1.2771
2013	949,975	511,525	0.700	8,213	0.0827	0.7832
2014	1,023,050	496,910	0.680	8,844	0.0891	0.7695
2015	1,096,125	482,295	0.660	9,476	0.0954	0.7559
2016	1,169,200	467,680	0.640	10,108	0.1018	0.7422
2017	1,242,275	453,065	0.620	10,739	0.1081	0.7286
2018	1,315,350	438,450	0.600	11,371	0.1145	0.7149
2019	1,388,425	438,450	0.600	12,003	0.1209	0.7213
2020	1,461,500	438,450	0.600	12,635	0.1272	0.7276

Costs savings were estimated by multiplying the estimated savings per acre cited above ($14.33) by the number of acres in the program each year. The effects of other existing incentive programs were not taken into account in these estimates. The resulting cost effectiveness of no-till cultivation is a cost savings of $11.03/MtCO$_2$e.

The projected business as usual (BAU) fertilizer use is determined by extrapolating the trend in historical fertilizer use (1990-2002) with Excel's projection tool. The application of this tool results in a projected moderate annual growth in fertilizer use in Colorado. The target efficiency improvements laid out in this policy are applied to the BAU fertilizer use projection to determine how much fertilizer use will be avoided for the years 2007-2020.

The life-cycle emission factor of fertilizer use is calculated by multiplying the carbon equivalent emissions in the CO Draft I&F by the standard C to CO_2 conversion of 44/12. Then, the CO_2-equivalent emission factors for the years 1990-2002 are averaged to provide an estimated emission factor (5.47×10^{-9} $MMtCO_2e$/kg N) that is used to calculate the avoided GHG emissions from the proposed increase in fertilizer efficiency. The results of the calculations detailed in the preceding discussion are displayed in the table below:

Year	Total BAU Fertilizer Use (kg N)	Policy Target	Target Fertilizer Reduction (kg N)	Avoided GHG Emissions (MMtCO$_2$e)
2007	117,844,490	0%	-	-
2008	115,837,438	2%	2,316,749	0.01
2009	113,830,386	4%	4,553,215	0.02
2010	111,823,334	6%	6,709,400	0.04
2011	109,816,282	8%	8,785,303	0.05
2012	107,809,230	10%	10,780,923	0.06
2013	105,802,178	11%	11,902,745	0.07
2014	103,795,127	13%	12,974,391	0.07
2015	101,788,075	14%	13,995,860	0.08
2016	99,781,023	15%	14,967,153	0.08
2017	97,773,971	16%	15,888,270	0.09
2018	95,766,919	18%	16,759,211	0.09
2019	93,759,867	19%	17,579,975	0.10
2020	91,752,815	20%	18,350,563	0.10

The cost savings associated with using less fertilizer is calculated by multiplying the Total Fertilizer Reduction in each year by the average cost of fertilizer in the spring of 2004.[6] The non-discounted cost savings from 2007 to 2020 of this option is $40 million.

Key Assumptions: C maintenance (i.e., "permanence" issue)

Key Uncertainties

- Data on N_2O emissions is still sparse.
- Need for low-intensity "in field" soil C monitoring to decrease uncertainty (i.e., benchmark sites) in soil C sequestration estimates.

Additional Benefits and Costs

- Rocky Mountain National Park N-Deposition MOU
- Erosion reduction, air and water quality, wildlife habitat, increased net returns.

Feasibility Issues

TBD

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[6] 2004 Fertilizer Use and Cost. Accessed on July 19, 2007, from www.ers.usda.gov/Data/FertilizerUse/Tables/Fert%20Use%20Table%207.xls.

Status of Group Approval

TBD

Level of Group Support

TBD

Barriers to Consensus

TBD

AFW-2. Manure Management and Energy Programs

Policy Option Description

The methane emissions inherent from the anaerobic decomposition process of manure and other wastes may be captured and used as an energy source. Methane and nitrous oxide emissions can occur at several different places in the manure management process. Management techniques can also reduce GHG emissions and, with energy recovery, offset fossil-based energy. This option covers producer incentives to adopt programs to increase the number of methane capture and energy recovery projects or other manure management techniques that reduce methane and nitrous oxide emissions.

Policy Option Design

Goals: Implement manure management and energy programs (where feasible for adoption by the facility) on 80% of animal feeding operations (AFOs) by 2020.

Timing: Implement programs on 10 AFOs by 2012; achieve the full goal by 2020.

Parties Involved: TBD

Other: Currently, one housed commercial swine feeding operation utilizes a methane digester to produce power for facility use and one additional AFO is developing a manure energy recovery strategy.

Implementation Mechanisms

Work with the Colorado Office of Energy to develop a pilot program to help fund manure energy recovery systems that are specific to the site and the operation. The pilot program would include a CAFO, a dairy and a swine operation.

Related Policies/Programs in Place

- CDPHE, EPA and the NPS are participating in developing a Rocky Mountain National Park Nitrogen Deposition Reduction Plan. Part of the plan utilizes current Best Management Practices (BMPs), as well as on-going research into additional BMPs that can be used to reduce nitrogen emissions from livestock operations.
- Recent state legislation that requires local cooperatives to purchase power generated from renewable resources could provide markets for energy generated from AFOs.

Types of GHG Reductions

CH_4: methane is captured and typically combusted in an energy recovery system or flare. Small amounts of N_2O and CH_4 are emitted from the combustion process.

CO_2: carbon dioxide is reduced when the methane is converted to energy and that energy is used to offset fossil-based energy (e.g., electricity, natural gas, etc.). Small amounts of N_2O and CH_4 are also reduced from the fossil-based energy that is offset.

Estimated GHG Savings and Costs per $MtCO_2e$

- GHG reduction potential in 2012, 2020 ($MMtCO_2e$): 0.01, 0.32
- Net Cost per $MtCO_2e$: $36

The cost per ton is the weighted average for dairy ($25) and swine ($58). For beef feedlots, the cost effectiveness estimate is much higher ($1,500; due to much lower methane emissions/head), so the Policy Work Group (PWG) does not recommend adopting this policy to address feedlots. These cost estimates include the effects of grants for renewable energy projects from the Federal Farm Bill but do not include the effects of other existing federal and state tax incentives.

Data Sources: CO GHG Inventory & Forecast (I&F data), digester and engine generator set cost data from EPA and the literature, assume 75% of methane generated at AFO is collected, value of generated electricity ($0.05/kW-hr). The total number of animal feeding operations for dairy, beef feedlots, and swine were provided by the Colorado Livestock Association.7 In 2005, there were 660 dairy operations, 260 beef feedlots, and 700 swine AFOs.

Quantification Methods:

GHG Benefit

Methane emissions data from the Draft CO I&F was used as the starting point to estimate the GHG benefits of capturing and controlling the volumes of methane targeted by the policy and to add in the additional benefit of electricity generation using this captured methane (through offsetting fossil-based generation). For 2012 and 2020, the GHG benefit for capturing methane was estimated by multiplying the methane emissions from dairy, feedlot, and swine operations by the applicable goal and then by an assumed collection efficiency of 75%,8 and converting to CO2e. The goal was expressed as a fraction of the population, based on the average number of livestock in each category of AFO (dairy, feedlot, or swine).

The second portion of the GHG benefit for offsetting fossil-based electricity generation was estimated by converting the methane captured in each year to its heat content (in BTUs) and then multiplying by an energy recovery factor of 17,100 BTU/kW-hr to estimate the electricity produced (assumes a 25% efficiency for conversion to electricity in an engine and generator set). The CO_2e associated with this amount of electricity in each year was estimated by converting the

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[7] Livestock Industry Practices. A presentation to the RMNP Subcommittee Meeting. Provided via personal communication (e-mail) by M. Collins to B. Strode on July 19, 2007.

[8] The collection efficiency is an assumed value based on engineering judgment. No applicable studies were identified that provided information on methane collection efficiencies achieved using manure digesters (as it relates to collection of entire farm-level emissions).

kW-hrs to MW-hrs and then multiplying this value by the CO-specific emission factor for electricity production from EIA data (0.877 Mt/MW-hr).[9]

The total GHG benefit was estimated as the sum of both portions of the benefit described above.

Costs

For swine, costs were estimated using annualized costs for the Barham Farm study, which was part of the North Carolina State University (NCSU) technology determinations referenced in the footnote below. Data from this study indicate a range of annualized costs from $18 to $45/head to cover installation and operation of a digester and an engine-generator set/flare. Annual operations and maintenance costs from this study were $8/head. These costs provide an estimate for the implementation of digester and energy projects at swine farms toward the upper end of the range for U.S. projects with documented costs.[10] Capital costs per head were about $72 for Barham Farm compared to an average of $52/head for seven U.S. swine digester to energy projects.

For dairies and feedlots, data from the EPA methane to markets report and Gallo Farms studies referenced below provided an average cost of $450/head for digesters and engine-generator sets (dairies >1,000 head). From the New Mexico Dairy Producers report, capital costs for regional digesters (those serving multiple nearby operations) were estimated to be $190/head. It is not clear based on available data how well regional digesters could be implemented in CO as they require several dairies in close proximity. Therefore, the average of $450/head was used.

CCS assumed that the 25% Farm Bill grant would be available to each project initiated as a result of this policy.[11] After adjustment of the capital costs, annualized costs per head were estimated assuming a 5% interest rate and a 15-year project life, annual operations and maintenance costs of $38/head were taken from the Gallo Farms Study, and the value of the electricity produced was assumed to be $0.05/kW-hr. Additional incentives to the farmer from the Renewable Energy Production Incentives were not included but could have a small effect on the estimated costs (about $1/MtCO$_2$e reduced). The annualized per head cost estimates were multiplied by the head of livestock to be controlled in each year to estimate total costs.

Key Assumptions: That the cost data for the studies cited is representative of actual costs; 75% collection efficiency for farm-level methane emissions for the digester. Farm Bill grant will be available to all projects in subsequent cycles of the Farm Bill through 2020. The $0.05/kWh is the assumed value to the farmer for the electricity produced (either to offset on-farm use or to sell back to the grid); this is a conservative estimate. Higher values for this electricity would translate into a lower cost effectiveness estimate and a faster return on investment for the farmer.

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[9] Emission factor derived from "2002 Voluntary Greenhouse Gas Reporting Program"; accessed July 24, 2007, from www.eia.doe.gov/oiaf/1605/e-factor.html.

[10] M. Moser, "A Dozen Successful Swine Waste Digesters", RCM Digesters, Inc., accessed February 2007 at: http://rcmdigesters.com/images/PDF/ADozenSuccessfulSwineWasteDigesters.pdf.

[11] More information on the program is also available at www.rurdev.usda.gov/rbs/farmbill/index.html. The application of this grant incentive was considered a reasonable assumption based on CCS discussions with EPA AgSTAR Program staff; Kurt Roos, personal communication with S. Roe, CCS, March 2007.

Key Uncertainties

- The minimum cost for developing a manure energy recovery system on an AFO facility is one million dollars. Without significant federal or state government assistance (50%–100%) in developing the generation infrastructure, developing an energy recovery system for an AFO is not feasible for most operators.
- The operator needs to have a buyer for the power generated or needs to receive a price per kilowatt for the power generated that provides an reasonable rate of return on the investment.

Additional Benefits and Costs

TBD

Feasibility Issues

TBD

Status of Group Approval

TBD

Level of Group Support

TBD

Barriers to Consensus

TBD

AFW-3. Reductions in On-Farm Fossil Energy Use

Policy Option Description

This option seeks to develop and implement cost effective programs for renewable energy (biofuels, renewable electricity generation) and energy efficiency technologies for farmers and ranchers. Reductions in fossil fuel consumption reduce emissions of carbon dioxide, methane, nitrous oxide, and black carbon.

Policy Option Design

Goals:

- **Fossil fuel reduction goal:** 20% reduction in petro-diesel use by 2020.
- **Electricity reduction goal:** 40% includes reductions from electricity efficiency and on-site generation using renewable energy (solar, wind, hydro).

Timing:

- **Fossil fuel reduction goal:** Achieve 5% reduce consumption by 2012. Achieve the full policy goal by 2020.
- **Electricity reduction goal:** Achieve 10% reduce consumption by 2012. Achieve the full policy goal by 2020.

Parties Involved: Colorado Rural Electric Associations, State Agriculture Organizations, Governors Office of Energy Management and Conservation, Colorado Department of Agriculture, Businesses providing energy efficiency and renewable energy equipment.

Other: As needed, identify incentives that encourage the growing and supply of feedstocks, and the utilization of ethanol in transportation markets across the state.

Implementation Mechanisms

Colorado state government and others should work with rural electric associations in developing programs or businesses for services and products to increase energy efficiency and conservation. Develop group purchasing options and coordinate installation of products to lower costs.

Develop state standards for ownership renewable energy credits (RECs) to be utilized by rural electric associations for upfront incentives in the form of rebates (e.g., $2 per watt of installed renewable energy generation on a farm or ranch). The REA's ownership of RECs would allow REAs to count the production over the life of the project toward the 10% renewable energy standard under HB 1281.

Develop 3-4 case studies of energy efficiency measures taken on various agriculture operations (farm, ranch, feedlot, dairy, etc) to present around the state.

Colorado state government should create incentives to upgrade REA distribution systems to "smart grid" technologies that can better take advantage of the benefits of distributed generation installed on farms and more sophisticated energy tracking devices on farms and businesses.

REAs, Tri-State, and Colorado state government should consider and develop net metering standards above 25 kW in capacity that insures the economic viability of REAs.

Related Policies/Programs in Place

- Colorado Department of Agriculture's Renewable Energy Grant Program under the Colorado Agriculture Development Authority. Provides grants to agriculture producers for on-farm renewable energy production. Includes grants for implementation up to $100,000 and feasibility study grants up to $25,000.
- USDA Farm Bill 9006 Renewable Energy/Energy Efficiency Grant and Guaranteed Loan Program. Provide grants up to 25% of the cost for renewable energy, biofuels production, and energy efficiency products.
- Chicago Climate Exchange Methane Offset allows producers with anaerobic digester generating power to receive income from sell of credits based on MTCO2 Equivalent for Methane trapping and combustion. Metric ton of methane valued at 18 mtCO2. At current price of a mtCO2 on the exchange at $3.30, a metric ton of methane would sell for more than $59.
- Net metering up to 25 kW with REA service territories and new interconnection standards for all 22 REAs from HB07-1169.

Types of GHG Reductions

CO_2: GHG reductions that occur as a result of a decline in on-farm energy use are largely comprised of CO_2, which is the byproduct of combustion of diesel fuel to run farm equipment, such as tractors, and the indirect byproduct of the generation of electricity that is used for irrigation pumps, lighting, food processing, and other agricultural processes.

CH_4 and N_2O: These gases are also emitted through the different forms of combustion that create energy for use on farms. The greenhouse effects of these gases are normalized and included in the GHG reduction potential calculations that are expressed as units of CO_2e (carbon dioxide equivalent).

Estimated GHG Savings and Costs per $MtCO_2e$

- GHG reduction potential in 2012, 2020 ($MMtCO_2e$): 0.16, 0.71
- Net Cost per $MtCO_2e$: TBD

Data Sources: Consumption of Distillate fuel by the agriculture sector in Colorado was projected from historical data found at www.eia.doe.gov. The petro-diesel emissions factor used is consistent with the Colorado I&F. Agricultural sector electricity consumption from in-state source (check with RCI PWG)?, CO grid electricity consumption emission factors for 2012 and 2020 was derived from data found in the 1997 and 2002 USDA Agriculture Censes and EIA data;[12] fuel reductions and capital costs for energy efficiency technologies from the literature (most likely studies conducted by the ACEEE).

Quantification Methods:

The business as usual (BAU) distillate fuel use for the CO agricultural sector was projected from historical (1984-2005) data retrieved from the EIA. Based upon the projected BAU distillate use, the target distillate reduction was calculated. Multiplying this reduction by the lifecycle GHG emissions factor for distillate fuel yielded the incremental GHG benefit from a reduction in the use of distillate fuel.

Agriculture sector-specific data regarding end-use electricity sales were not found, although an extensive research was conducted. The projected BAU on-farm electricity use, therefore, was estimated based on information found in the 1997 and 2002 USDA Agriculture Censes. In 1997, the census conducted a survey of farm expenditures on electricity. However, in 2002, these expenditures included all utilities. Therefore, the total electricity use by the agricultural sector was derived through the following method: 1) identify the total electricity consumption for the agricultural sector in 1997 by dividing the total expenditure by the price of electricity in that year; 2) divide the total electricity consumption by the total number of farms reporting in 1997; 3) take the product of this per-farm electricity use figure and the total number of farms in 2002; 4) based on CO I&F projections of total CO electricity use, project future BAU on-farm energy use, assuming that the electricity used by the agricultural sector will grow at the same rate as the total electricity consumption.

The CO electricity emission factor is calculated using the same methods as AFW-2. This EF is multiplied by the target electricity reduction (the product of the target efficiency increase and BAU electricity consumption) to determine the incremental GHG benefit.

The results of these analyses are displayed in the table below:

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[12] Links to these data sources are www.nass.usda.gov/Census/Pull_Data_Census, http://agcensus.mannlib.cornell.edu/show2.php, www.eia.doe.gov/cneaf/electricity/page/sales_revenue.xls.

Year	BAU Distillate Use (1000 gal)	Target Distillate Reduction	Incremental GHG Benefit from Distillate Reduction (MMtCO$_2$e)	BAU Electricity Consumption (MWh)	Target Electricity Reduction	Incremental GHG Benefit from Electricity Reduction (MMtCO$_2$e)
2007	49,047	0	0.000	1,368,905	-	-
2008	48,135	445	0.004	1,402,683	30,756	0.027
2009	47,222	890	0.009	1,436,460	61,512	0.054
2010	46,310	1,335	0.013	1,470,238	92,268	0.081
2011	45,397	1,779	0.018	1,504,015	123,023	0.108
2012	44,485	2,224	0.022	1,537,793	153,779	0.135
2013	43,572	2,876	0.029	1,571,571	224,958	0.197
2014	42,660	3,527	0.036	1,605,348	296,136	0.260
2015	41,747	4,179	0.042	1,639,126	367,314	0.322
2016	40,835	4,831	0.049	1,672,903	438,492	0.385
2017	39,922	5,482	0.055	1,706,681	509,671	0.447
2018	39,010	6,134	0.062	1,740,459	580,849	0.510
2019	38,098	6,785	0.068	1,774,236	652,027	0.572
2020	37,185	7,437	0.075	1,808,014	723,205	0.634

The following tasks will be performed to estimate the cost effectiveness of this policy option:

- Identify energy efficiency technologies to be applied to meet policy goals;
- Estimate annualized costs based on energy efficiency technologies applied (for both petro-diesel and electricity);
- Determine net costs based on annualized capital costs and savings from reduced energy consumption;
- Determine cost effectiveness from GHG reductions and annualized costs in each year.

Key Assumptions: TBD

Key Uncertainties

TBD

Additional Benefits and Costs

TBD

Feasibility Issues

TBD

Status of Group Approval

TBD

Level of Group Support

TBD

Barriers to Consensus

TBD

AFW-4. Biodiesel Production

Policy Option Description

Provide incentives for the production of biodiesel from oilseed crops, waste vegetable oil, or other sources. Biodiesel use will offset diesel fuel derived from petroleum and will lead to decreased fossil fuel-based CO_2 emissions.

Policy Option Design

Goals: Produce enough biodiesel fuel to offset 20% of the state diesel fuel demand by 2020 using GHG-superior feedstocks.

Timing: Produce enough in-state biodiesel to offset 2% of Colorado's petro-diesel consumption by 2012 and 20% by 2020.

Parties Involved: Governor's Office of Energy Management and Conservation, Colorado Dept. of Agriculture, Rocky Mountain Farmers Union, Colorado Farm Bureau, Colorado Livestock Association.

Other: Colorado's distillate fuel usage in 2002 was 0.73 billion gallons and is projected to be 1.25 billion gallons by 2020 (transportation diesel use was 0.57 billion gallons in 2002; 1.0 billion gallons by 2020).

Implementation Mechanisms

Colorado agriculture producers and private industry should be encouraged to build and operate biodiesel facilities within Colorado using local resources and providing locally-available product.

Colorado state government should actively evaluate the benefits and costs of incentive programs for new businesses entering the state for biodiesel production [For example, a particular plant may plan to use soybean oil not produced in the state and would likely need to be transported 1,000 miles or more to the site]. The costs should include the impacts to the environment as a whole as the fuel production cycles change, also the impacts to local and regional agricultural businesses (farming, feedlots, dairies) as the demand for feedstock crops increase and additional meal cake for livestock is available. In short, biodiesel production incentives should be established with consideration for the life-cycle of the fuel source in economic and environmental terms.

Colorado state government should consider a Renewable Fuels Standard by volume of retail sales beginning at 2% and escalating to 5% in the short term. Increases in the RFS could be based upon local production levels.

Colorado state government should consider a retail tax credit for sale of B20 fuel. The tax credit value could increase with great retail volume sold [similar to Iowa retail incentive]

Implementation will likely require that oilseed crops be produced on land already in cultivation. Some conversion of idle land to new cropland could also occur which could decrease the overall carbon benefit to be gained from producing biodiesel [as soil organic carbon and soil nitrogen (as N2O), both GHG sources, will be lost to the atmosphere when the land is converted to new cultivation].

Related Policies/Programs in Place

- Colorado Department of Agriculture's Renewable Energy Grant Program under the Colorado Agriculture Development Authority for grants up to $100,000 for new biodiesel production facilities; $25,000 for biodiesel feasibility studies; and $50,000 for research. grants funded through 2009.
- The Colorado Clean Energy Fund under the Governor's Energy Office with [$7 million in annual revenue?] for project development.
- The renewable fuels standard from the Energy Policy Act of 2005 requires 7.5 billion gallons of renewable fuel in the U.S. by 2012, including biodiesel.
- USDA Farm Bill grant and guaranteed loan program for biodiesel facilities and research.

Types of GHG Reductions

CO_2: Lifecycle emissions are reduced to the extent that biodiesel is produced with lower embedded fossil-based carbon than conventional (fossil) diesel fuel. Feedstocks used for producing biodiesel can be made from crops, which contain carbon sequestered during photosynthesis (e.g., biogenic or short-term carbon). The primary feedstocks are vegetable oils (soy, canola, sunflower, algal, etc.) and alcohols (either methanol or ethanol). From a recent report (Hill et al. 2006),[13] biodiesel from soybeans contains 93% more useable energy than its petroleum equivalent and reduces lifecycle GHG emissions by as much as 41%. Higher oil production potential of different feedstocks (e.g., other oil crops, algae) will likely adjust the lifecycle GHG emissions further downward as they are developed as biodiesel sources. Local production of biodiesel also decreases the embedded CO_2e of biodiesel compared to importation of out of state vegetable oil supplies.

Estimated GHG Savings and Costs per $MtCO_2e$

- GHG reduction potential in 2012, 2020 ($MMtCO_2e$): 0.02, 0.22
- Net Cost per $MtCO_2e$: $143

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[13] Hill et al, "Environmental, Economic, and Energetic Costs and Benefits of Biodiesel and Ethanol Biofuels," *Proceedings of the National Academy of Sciences*, Vol. 103, pp. 11206–10, July 25, 2006.

Data Sources:

Data from the CO Draft Inventory & Forecast were the starting point for quantifying the benefits of offsetting fossil diesel consumption with biodiesel produced within the state (these do not incorporate future reductions in consumption due to TLU options). Fossil diesel consumption estimates are (under business as usual):

Year	Diesel Consumption (MMgal/yr)
2012	828
2020	1,009

The policy design calls for 2% of the fossil diesel consumption to be offset by 2012 from in-state production and 20% offset by 2020. In-state BAU production is estimated to be 6 MMgal/yr in 2012 and 9.5 MMgal/yr in 2020 (see below). Therefore, incremental in-state biodiesel production targets are:

Year	Biodiesel Production Needed (MMgal/yr)
2012	0.02*828 – 6
2020	0.20*1009 – 9.5

The BAU biodiesel production is based upon the current and planned biodiesel capacity of CO. A capacity factor of 50% is assumed. See the table below for the existing and planned facilities in CO:[14]

Facility Name	Status	Capacity (1000 gal)	Feedstock
American Agri-Diesel	In-production	6000	O-S Soy
Bio Energy of America	In-production	10000	O-S Soy
Bio Energy of America	In-production	8000	O-S Soy
San Juan Biodiesel	Planned	5000	Veg Oil (Sunflower)
San Luis Valley	Planned	1000	Veg Oil (Canola)
Kiowa County	Planned	1000	Veg Oil, I-S Soy
Rocky Mountain Sustainable Enterprises	Planned	5000	Waste Grease, I-S Soy
Holyoke Community Biodiesel	Planned	2000	I-S Soy

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[14] Personal communication from T. Frank to B. Strode. E-mail sent on July 24, 2007.

The CO_2e emission factor for fossil diesel used in the inventory and forecast is 10.04 Mt/1,000 gallons. The lifecycle fossil diesel emission factor is 12.3 Mt/1,000 gallons.[15]

Quantification Methods:

GHG Reductions

A new study on lifecycle GHG benefits for biodiesel production and use was used to estimate the CO_2e reductions for this option.[16] This study covered biodiesel production from soybean production, which is currently the predominant feedstock source for biodiesel production in the US and is assumed to remain that way for the purposes of this analysis (it is also the predominant feedstock of biodiesel production in CO). Lifecycle CO_2e reductions (via displacement of fossil diesel with soybean-derived biodiesel) were estimated by Hill et al. to be 41%. This value is being used by the TLU TWG to estimate the benefit of the biodiesel component of the TLU biofuels option. Hence, this analysis focuses on incremental benefits of in-state feedstocks production with the focus on vegetable oils.

For this option, the incremental benefit of in-state production is derived from the lower embedded GHG content of biodiesel feedstocks (vegetable oil) avoided from having to transport the feedstocks from their likely source region. For this assessment, the likely source regions for soybean or canola oil are the U.S. mid-west or northern plains regions. Using South Dakota as a potential source region, rail transport would require shipments to central North Carolina of about 650 miles.[17] Rail fuel consumption is about 400 ton-miles/gallon.[18] The density of vegetable oil is about 3,700 tons/MMgal. From these inputs, a GHG emission rate of 130 $MtCO_2$/MMgal oil was calculated.

When combined with the other feedstocks needed to produce biodiesel (e.g., either methanol or ethanol),[19] a gallon of vegetable oil will produce slightly more than one gallon of biodiesel. For the purposes of this estimate, each gallon is assumed to produce one gallon of biodiesel.

In addition to soybean oil, other oil feedstocks included in this analysis include animal oils (yellow grease, poultry fat, lard, and tallow), canola, and algal oils. It is assumed that technology advances will occur during the policy period that will allow for commercial scale production of algal oil to make up the shortfall (e.g., in the post-2015 period). With sufficient technology advancement, another option could be Fischer-Tropsch biodiesel from cellulose.

For oil sources other than soybean oil, the benefit for substituting in-state biodiesel for fossil diesel is estimated starting with the lifecycle soybean emission factor (7,261 $MtCO_2e$/MMgal from the Hill et al. study). As mentioned previously, the benefits of the biodiesel component of the TLU biofuels option is based on displacement with soybean-based biodiesel. Hence, this

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[15] Hill et al 2006.

[16] Ibid.

[17] Mapquest directions, North Dakota to Colorado; www.mapquest.com.

[18] U.S. National Atlas, at http://nationalatlas.gov/articles/transportation/a_freightrr.html.

[19] While the analysis here focuses on the primary feedstock for biodiesel, vegetable oil, the policy should also promote the production and use of alcohol feedstocks produced from renewable resources (e.g., starch or cellulosic ethanol, renewable methane to methanol).

analysis was designed to only account for the incremental benefit of in-state feedstock (oil) production using GHG preferential feedstocks. These include vegetable oils that produce greater volumes of oil per unit of energy input (e.g., canola), animal fats, and, in the future, algal oils.

Canola produces 127 gallons of oil per acre compared to soybeans at 48 gallons/acre. Assuming canola production energy inputs are not significantly greater than soy, the lifecycle emission rate for canola would be 7,261 x 48/127 or 2,744 $MtCO_2e$/MMgal. So the incremental benefit of canola over soy is 7,261–2,744 = 4,517 $MtCO_2e$/MMgal.

For animal fats and algal oils, CCS assumes that these have negligible embedded energy. So the incremental benefit over soy equals the lifecycle fossil diesel EF (12,306 $MtCO_2e$/MMgal) minus the soybean based EF (7,261 $MtCO_2e$/MMgal), which is 5,045 $MtCO_2e$/MMgal.

To meet the in-state production goals for 2012 and 2020, the table below provides the mix of oil feedstocks assumed in this analysis. The assumed mix relies heavily on new technologies (e.g., algal oil) to produce feedstocks in the post-2012 period.

Year	Oil Feedstock	Fraction of New Production	MMgal/yr Needed
2012	Soy (out-of-state)	0.63	10.2
2012	Soy	0.13	2.1
2012	Canola	0.17	2.8
2012	Animal	0.07	1.1
2012	Algal	0	0
2012 Total			**16**
2020	Soy (out-of-state)	0	0
2020	Soy	0.35	69.3
2020	Canola	0.20	39.6
2020	Animal	0.20	39.6
2020	Algal	0.25	49.5
2020 Total			**198**

Excludes BAU production estimated to be 6000 MMgal/yr in 2012 and 9500 MMgal/yr in 2020.

GHG reductions were estimated by multiplying the production of each oil feedstock by the applicable incremental benefit (e.g., by oil type). Total reductions in each year were estimated by summing the incremental benefit for each oil type.

Costs

Costs were estimated using information from an analysis of biodiesel production costs from the US DOE.[20] The value of incentives needed is assumed to be equivalent to the difference in the

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[20] See www.eia.doe.gov/oiaf/analysispaper/biodiesel/index.html; accessed January 2007.

costs of producing fossil diesel and soy-based biodiesel ($0.34/gallon). This value is very close to the incentive offered in a State of Missouri incentives program.[21] This program offers production incentives of $0.30/gallon to producers up to 15 million gallons of production/yr. The incentive grants last for five years.

CCS assumed a similar incentive structure and that these would cover the costs of all grants or tax incentives associated with this policy (all other implementation mechanisms are assumed to be achieved within existing programs). The cost estimates are based on multiplying the amount of biodiesel produced in each year by the production incentive. This assumes that all production occurs at production facilities of less than 15 million gallons/yr. The production incentive runs out after five years of production.

Key Assumptions: Life-cycle GHG emission factors utilized/derived for this analysis are representative for each feedstock and for fossil diesel. Production incentives offered by this option are sufficient to drive production of GHG-superior feedstocks (e.g., superior to soybeans) and to increase the level of research and development needed for non-crop based feedstocks (e.g., algal biodiesel, Fischer-Tropsch biodiesel).

Key Uncertainties

TBD

Additional Benefits and Costs

TBD

Feasibility Issues

TBD

Status of Group Approval

TBD

Level of Group Support

TBD

Barriers to Consensus

TBD

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[21] Information on the Missouri Program from www.newrules.org/agri/mobiofuels.html#biodiesel, accessed January 2007.

AFW-5. Ethanol Production

Policy Option Description

Trees, crops and other plants convert atmospheric carbon to carbohydrate or fiber stocks that can be converted to liquid fuels, such ethanol. The use of these renewable, biological fuels can offset fossil fuel use and reduce associated net carbon dioxide emissions. Production incentives for the conversion of crops, forest sources, animal waste and other sources to ethanol through existing or new technologies can increase the level of ethanol use in future markets. In-state production of ethanol using GHG-superior feedstocks and processes (e.g., cellulosic technologies) offer the highest GHG benefits and complement policies to increase ethanol consumption (e.g., TLU-5).

Policy Option Design

Goals: Increase in-state ethanol production using GHG-superior feedstocks and production methods to 400 million gallons per year above BAU by 2020.

Timing: Add additional ethanol production capacity of 50 million gallons/yr by 2012 and achieve the full policy goal by 2020.

Parties Involved: Suppliers of feedstocks, ethanol producers and distributors.

Other: Colorado's gasoline consumption was 1.9 billion gallons in 2002 and is projected to be 2.2 billion gallons by 2020.

Implementation Mechanisms

TBD

Related Policies/Programs in Place

TBD

Types of GHG Reductions

CO_2: Lifecycle emissions are reduced to the extent that ethanol is produced with lower embedded fossil-based carbon than conventional (fossil) gasoline. Feedstocks used for producing ethanol can be made from crops or other biomass, which contain carbon sequestered during photosynthesis (i.e., biogenic or short-term carbon). There are two different methods for producing ethanol based on two different feedstocks. Starch-based ethanol is derived from corn or other starch/sugar crops. Cellulosic ethanol is made from the cellulose contained in a wide variety of biomass feedstocks, including agricultural residue (e.g., corn stover), forestry waste, purpose grown crops (e.g., switchgrass), and municipal solid waste. Local production of ethanol also decreases the embedded CO_2e of ethanol compared to importation from the current U.S. primary ethanol producing regions. Current research indicates cellulose-based ethanol production provides up to 72-85% reduction in GHGs compared to gasoline, whereas an 18-29% reduction is measured from starch-based ethanol production compared to gasoline.[22]

Estimated GHG Savings and Costs per MtCO$_2$e

- GHG reduction potential in 2010, 2020 (MMtCO$_2$e): 0.2, 3.1
- Net Cost per MtCO$_2$e: $3

Data Sources: The target for ethanol production requires a fixed quantity of production above BAU, rather than a percentage increase. Therefore, it is not necessary to project the BAU ethanol production in Colorado to quantify the cost effectiveness and GHG reduction potential of AFW-5. The targets set forth in this option (50 MMgal/yr by 2012, 400 MMgal/yr by 2020) are reached by increasing the quantity of ethanol produced in CO by equal increments in the years leading up to the target years. The in-state production targets are shown in the table below.

Assumed Ethanol Production Schedule (MMgal/yr)	
2007	-
2008	10
2009	20
2010	30
2011	40
2012	50
2013	75
2014	100
2015	150
2016	200
2017	250
2018	300
2019	350
2020	400

Emission factors from gasoline, starch-based ethanol and cellulosic ethanol are based on the ANL Greet Model.[23] The production cost differential for cellulosic versus starch-based ethanol is derived from analysis completed by the Energy Information Administration (EIA).[24]

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22 *Well-to-Wheels Analysis of Advanced Fuel/Vehicle Systems—A North American Study of Energy Use, Greenhouse Gas Emissions, and Criteria Pollutant Emissions*, General Motors, Argonne National Lab, and Air Improvement Resource, Inc., May 2005.

[23] Ibid.

[24] DOE EIA analysis can be found at www.eia.doe.gov/oiaf/analysispaper/biomass.html, accessed January 2007.

Quantification Methods:

GHG Reductions

The benefits for this option are dependent on developing in-state production capacity that achieves benefits above the levels of existing and planned (BAU) starch-based production in the U.S. (the benefits of using ethanol from starch-based production are already accounted for under TLU Option 5). Emission factors for reformulated gasoline, starch-based ethanol, and cellulosic ethanol were taken from a General Motors/Argonne National Lab study.[25] These emission factors incorporate the GHG emissions during the entire life-cycle of fuel production (e.g., for gasoline: extraction, transport, refining, distribution, and consumption; for ethanol: crop production, feedstock transport, processing, distribution, and consumption). These life-cycle emission factors are referred to as "well-to-wheels" emission factors:

Fuel	Emission Factor (grams CO_2e/mi)
Reformulated gasoline	552
Starch-based ethanol	451
Cellulosic ethanol	154

In addition to cellulosic ethanol production, the other types of ethanol production processes targeted by this option include starch-based processes that achieve similar levels of life-cycle GHG reductions to cellulosic ethanol. These would be starch-based plants that use renewable fuels, such as biomass, biogas, landfill gas, or other renewable fuels. While CCS is not aware of any lifecycle emission factors for these types of plants (although several have been proposed in the U.S.), CCS assumes that reductions similar to cellulosic ethanol can be achieved.

Based on the emission factors shown above, the incremental benefit of the production targeted by this policy over conventional starch-based ethanol is 66% (reduction of CO_2e by offsetting gasoline consumption). This value was used along with the lifecycle emission factor for gasoline[26] and the production in each year to estimate GHG reductions.

Costs

Costs for the incentives needed by this policy option are based on the difference in estimated production costs between conventional starch-based ethanol and cellulosic ethanol. The DOE EIA estimated that the cost to produce starch-based ethanol is $1.10/gal compared to $1.29/gal, or a difference of $0.19/gal (in $1998).[27] In 2006 dollars, the difference is $0.23/gal. These incentives are considered necessary in the near term (up to 2015) to help commercialize technologies that produce ethanol from cellulose or produce starch-based ethanol using renewable fuels. The incentives should also help to establish the infrastructure to deliver biomass

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[25] *Well-to-Wheels Analysis*.

[26] In the study mentioned above, the average fuel economy used was 21.3 miles/gallon or 100 miles/4.7 gallons. Multiplying this value by the emission factor of 552 grams/mile yields 11,745 grams/gallon.

[27] DOE EIA analysis can be found at www.eia.doe.gov/oiaf/analysispaper/biomass.html, accessed January 2007.

to biorefineries, since producers will seek the local feedstocks or renewable fuels for their operations.

By 2015, it is assumed that advances in cellulosic ethanol production (e.g., enzyme costs, production processes) will make cellulosic ethanol production cost competitive with starch-based production. Hence, the incentives are discontinued beginning in 2015. Note that there is currently federal legislative proposal to offer cellulose an incentive of \$0.765/gallon compared to the \$0.51/gallon currently offered for ethanol production.[28] If enacted, this \$0.255/gallon premium could cover the additional incentives that are assumed to be needed by the State of Colorado. Obviously, the federal incentives do not assure that production facilities would locate in CO. These federal incentives have not been factored into the cost estimates for this option.

The costs for this option were estimated using the \$0.23/gal incentive multiplied by the production needed in each year. By 2015, it is assumed that these incentives will no longer be needed as cellulosic ethanol technologies become fully commercialized. Below is the assumed schedule for these incentives:

Year	New Capacity (MMgal)	Incentives Cost (MM 2006$)	GHG Benefit (MMtCO$_2$e)
2007	-	$0.00	0
2008	10	$2.3	0.08
2009	20	$4.6	0.15
2010	30	$6.9	0.23
2011	40	$9.2	0.31
2012	50	$11.5	0.39
2013	75	$17.3	0.58
2014	100	$23.0	0.77
2015	150	$0.0	1.16
2016	200	$0.0	1.55
2017	250	$0.0	1.93
2018	300	$0.0	2.32
2019	350	$0.0	2.71
2020	400	$0.0	3.09

After discounting and leveling the costs from 2007-2020, the cost effectiveness is just under \$3.50/MtCO$_2$e and the net present value of the 2007-2020 costs are \$58 million.

Key Assumptions: Starch-based ethanol production using renewable fuels achieves equivalent GHG lifecycle benefits as cellulosic ethanol; cellulosic production or starch-based production

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[28] D. Morris, *Making Cellulosic Ethanol Happen: Good and Not So Good Public Policy*, Institute for Local Self-Reliance, January 2007, at www.newrules.org/agri/cellulosicethanol.pdf, accessed January 2007.

with renewable fuels can achieve the production levels in the near term (2014 production of 310 MMgal/yr) required by this policy option; Federal tax incentives do not preclude the need for the additional state incentives assumed for the cost estimate.

Key Uncertainties

TBD

Additional Benefits and Costs

TBD

Feasibility Issues

TBD

Status of Group Approval

TBD

Level of Group Support

TBD

Barriers to Consensus

TBD

AFW-6. Preserve Lands with Carbon Storage Value

Policy Option Description

Reduce the rate at which existing crop/pasture and forested lands are converted to developed uses. The carbon stored in soils and aboveground biomass is typically higher in these lands than in developed land uses. Each year, developed areas also typically sequester less carbon dioxide than forested areas. Policies are needed to protect working farms and forests from unwise and unplanned development. Indirectly, this option also supports important policies in the transportation and land use sector by promoting more efficient development patterns (e.g., TLU-1).

Reduce the rate at which permanent grassland in the USDA Conservation Reserve Program is converted to cultivated cropland. Soil carbon stored in retired agricultural land that has been maintained as grassland is reversed when lands are put back to cultivation, resulting in net carbon emissions.

Policy Option Design

The rate of land conversion (from undeveloped to developed) in Colorado is estimated to be at least 100,000 acres per year. These lands include a mix of former cropland, untilled grassland, forests, and western slope shrublands. Land conservation strategies alone (absent significant growth management policy) are unlikely to alter the general rate of land conversion, but can play a role in determining which lands are protected from conversion. Further, land conservation is a generally expensive means of preventing carbon emissions, unless targeted toward highest return strategies. Colorado has an advanced program of land protection with a system of transferable tax credits for land-owners, dedicated public funding, and numerous local and statewide private land trusts. At present, the carbon storage value of lands protected is an uncompensated additional benefit that comes with the open space and wildlife habitat protection values of protecting lands. Additional incentives targeted toward the carbon storage value of land, over and above existing compensation for retiring development rights, would in theory drive more land protection toward high carbon vale lands, and compensate landowners for the additional societal benefit of avoided carbon emissions. This policy would create a program to provide additional tax incentives for landowners donating development rights as part of an easement transaction for the carbon storage value of their land. In all likelihood this policy would focus on protecting forest lands from conversion, but some more mesic untilled grasslands might also qualify.

Colorado currently has 2,469,041 acres of land under CRP contract. 1,690,190 acres of those contracts are due to expire by 2011. Some percentage of these lands will be ineligible for a new contract (due to new rules and limits at the national level for CRP) or will have an economic incentive to re-convert to dry-land crops rather than re-enroll in CRP (particularly if dry-land biofuel crops become a feasible land use in Colorado). The cost of paying landowners to maintain permanent grass cover, particularly if grazing is permitted as a land use providing some economic return, is likely to be low, with demonstrable carbon benefits. This policy would create a program to target either permanent or long-term contracts to maintain expired CRP acres in grass cover either with or without use as grazing lands.

Goals:

- Protect 3,500,000 acres of lands in natural cover that would have been converted by 2030.
- Increase the amount of high carbon value lands in land protection programs by 10% by 2020
- Maintain X acres of CRP land in permanent grassland cover by 2020.

Timing: By 2015, protect 2,000,000 acres of lands that would have been converted (protect 1,500,000 by 2012); achieve the full goal by 2030.

Parties Involved: TBD

Other: Data from the Natural Resources Conservation Service (NRCS) National Resources Inventory (NRI) show the following losses of lands between 1982 and 1997 to the "urban built-up" and "rural transportation" categories[29]:

Land Cover/Use	10^3 Acres Lost 1982-1997	Annual Average Loss (10^3 acres)
Cultivated cropland	89.9	6.0
Non-cultivated cropland	36.1	2.4
Pastureland	46.9	3.1
Rangeland	176.9	11.8
Forest land	66.6	4.4
Totals	416	27.7

Implementation Mechanisms

Establish a fund to provide additional incentives (likely tax credits) above those currently granted for donated portions of easements, based on the avoided carbon emissions potential of the development rights being retired. Easement transactions include an appraisal of the value of the development rights forgone. Based on the amount of land disturbance associated with those rights, and the carbon storage value of the land in question (would need a simple method for

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[29] See www.co.nrcs.usda.gov/technical/nri/tables/table5.pdf for conversion rates between 1982 and 1997. The NRI annual acreage lost to development can be compared to an estimate from David Theobald of CSU of 33,700 acres/yr on average from 2000 to 2030.

evaluating carbon storage value based on existing land cover and condition), an avoided carbon emission value can be calculated. The fund would provide additional incentives based on the amount of avoided emissions associated with the transaction, thus rewarding landowners who protect the highest amount of carbon (or avoid highest potential carbon emissions) The value of the incentive can be set based on a portion of the value of a ton of avoided carbon emissions based on current markets for offsets (only a portion is appropriate since landowner has already been compensated for a portion of their donation of an easement from existing sources).

Establish a fund to pay for contracts with landowners who are not able to get expiring CRP acres back in to the system to maintain grass cover on their expired CRP acres. Least-cost policy mechanism would be for a bid-in process with contracts awarded in terms of CO_2-equivalent cost-benefit (presuming some lands have higher carbon values associated with maintenance of grass cover). If there is not significant difference in carbon value, contracts would be evaluated solely on basis of cost and length of contract.

Ramping up the pace of land protection by increasing funding sources, combined with coordinated growth management strategies, could significantly reduce the pace of land conversion in the state. Land conservation organizations in Colorado have identified an additional 3 million acres of land as priorities for protection in the next ten years. Meeting this goal would require additional funding above existing sources. Targeting these acres in ways that maximized both the conservation values (open space, wildlife habitat, etc.) and growth management strategies (maintaining buffers between communities, protecting untilled landscapes on urban fringe, consolidating public lands holdings, etc.) would change baseline projections of land conversion associated with future population growth.

In conjunction with growth management strategies developed as part of a climate strategy, identify priorities for land protection that would help implement those strategies. Direct a significant portion of new resources to those priorities, by making climate mitigation and growth management priorities of state funding sources.

Related Policies/Programs in Place

TBD

Types of GHG Reductions

- Avoided emissions from land use change
- Maintenance of annual carbon sequestration potential

Estimated GHG Savings and Costs per $MtCO_2e$

TBD

Data Sources: Natural Resources Conservation Service data on Conservation Reserve Program acres expiring during the policy period, NRI data on agricultural/range/forest land lost to urban development, data on above and below ground soil carbon levels from CSU, USFS, and the scientific literature, costs for conservation easements on ag/range/forest land in CO.

Quantification Methods: Description of Approach (data collection and analysis in progress)

A. Maintaining CRP Land

CSU NREL has been conducting studies to evaluate differences in carbon storage value of alternative uses of CRP lands. If data are available, calculate average carbon storage value of formerly tilled lands with 15 years of grass cover (the length of a CRP contract) minus average carbon value of CRP lands returned to dry-land cropping. Assume cost to maintain land in that cover is average rental rate of dryland agriculture at a county level (that is what a CRP contract pays and this rate was sufficient to entice enrollment in the first place). Total amount of land likely to be available for this policy option would be the number of retiring CRP acres not likely to qualify under new CRP rules. Note that emissions from CRP acreage returning to cultivation are not currently included in the forecast projections of the I&F.

The cost-benefit value of carbon with the evaluation method outlined above is likely at the high end for two reasons: 1) CRP lands 15 years after initial grass planting are likely continuing to accumulate carbon, but this approach would only value them for current carbon storage value: 2) some percentage (perhaps quite high) of farmers ineligible to re-enroll their lands in CRP are likely to be willing to continue to rent their lands for a much lower rate (since the costs of re-starting an ag operation are high and because most of these lands are very marginal compared to average dryland opportunities in a county). The costs estimated by using current rental rates would be on the low side only if there is some large increase in demand for dryland crops that would raise the bid-in rental price. The additional carbon benefits of this policy could be over-estimated if the baseline scenario for many of these lands would be for them to remain as grass as it would be uneconomical to put them back into cropland.

B. Protecting High Carbon Value Lands Through Land Preservation

For assessment purposes, we could calculate the carbon storage value of certain classes of land use (e.g., forest land, grassland, other?); calculate the current rate of land protection in those types of land, assume some percentage increase in that rate, and use a modest increase in the cost of those easements from new incentives (say 10%). Presumably, it would be cost-effective, since the value of the avoided emissions incentive can be set at a level gets the most value. The additional incentives presumably will both result in more easement transactions and will skew transactions towards more carbon valuable lands.

This type of approach should in theory avoid some of the problems of additionality and leakage that generally plague efforts to establish rigorous offset programs based on avoided emissions through land protection. Additionality is addressed through the fact that you aren’t paying for the entire easement, but only a portion of the actual carbon storage value associated with it. So the program is creating an incentive for different transactions that might not otherwise have happened, based solely on carbon value. It is certainly likely that some landowners would have done the easement transaction without the added carbon incentive, and that causes some problems with additionality. Further, the calculation of the carbon incentive is based on the amount of development that could have occurred without the easement, there is again a chance that such development would not have occurred, absent the easement, but the appraised value is lower in cases of less likelihood of development. As with any land protection scheme, it is very difficult to assess the leakage issues; whether the protection of one piece of property just moved the development to another parcel. Since the program here is focused on the retirement of specific development rights, it is likely that there is an actual reduction in the amount and pace of such development, particularly in higher carbon value lands.

Background Data on Land Use Conversion Rates:

- Acres converted to development annually: ~33,703 acres per year (Dr. David Theobald of CSU projects that 1,011,090 acres will be converted to developed uses from 2000-2030)
- Approximately 22,286 acres of forest converted to other uses annually, based on historical forest losses calculated from NRI data (1982-2003) for CO. NRI does not include Federal land. See table below.
- Approx. 4,400 acres of forest converted to developed uses per year (1982-1997 NRI), see Other section above
- Approximately 137,081 acres/yr of cultivated cropland enrolled in the CRP program

Land Use	Area 1982 (acres)	Area 2003 (acres)	Annual Change (acres/yr)	Annual Change (% of land use/yr)	Annual Change (% of total/yr)
Cropland	10,603,500	8,348,000	-107,405	-1.01%	-0.26%
CRP land	0	2,193,300	137,081	--	0.33%
Pastureland	1,164,700	1,001,800	-7,757	-0.67%	-0.02%
Rangeland	25,053,600	24,790,600	-12,524	-0.05%	-0.03%
Forest land	3,757,000	3,289,000	-22,286	-0.59%	-0.05%
Other rural land	876,000	1,006,000	6,190	0.71%	0.01%
Total	41,454,800	40,628,700	-39,338		-0.09%

Key Assumptions: TBD

Key Uncertainties

TBD

Additional Benefits and Costs

TBD

Feasibility Issues

TBD

Status of Group Approval

TBD

Level of Group Support

TBD

Barriers to Consensus

TBD

AFW-7. Biomass Feedstocks for Energy Production

Policy Option Description

The goals of this option are to increase the use of low value wood material (including logging and mill residues), agricultural residues, and municipal solid waste fiber by appropriate processing centers for energy purposes (electricity, heating, liquid fuels). Offsetting fossil fuel use with biomass for energy, in applications such as distributed generation, combined heat and power and community energy systems will yield additional GHG emissions reduction benefits.

Policy Option Design

Goals: Increase production and use of biomass energy feedstocks by a factor of 10 by 2020 through sustainable harvesting and recovery practices.

Timing: Achieve an increase in consumption of biomass energy feedstocks of a factor of 3 by 2012; achieve the full goal by 2020.

Parties Involved: TBD

Other: Current levels of biomass energy production are low in CO. There is no biomass utilized to produce electricity and there is one known biomass heating system in Boulder County, which consumes about 850-1000 tons of biomass per year. Additional biomass heating systems are planned for CSU, NREL and Gilpin County for this winter. On other project in progress is in Jackson County/Walden that might produce some electricity as well as heat when it becomes operational.

Implementation Mechanisms

Forest treatment under AFW-8 will produce a significant amount of woody biomass suitable for energy production.

Related Policies/Programs in Place

TBD

Types of GHG Reductions

Displaces emissions from fossil fuel combustion

Estimated GHG Savings and Costs per MtCO$_2$e

Under AFW-8, forest biomass thinning treatments are implemented above current planned levels of treatment in order to reduce fire risk in the Lower Montane Forests of Colorado. The additional biomass removed from the Lower Montane Forests is used to produce biomass energy, and would more than exceed the goals levels above. Under implementation at goal levels, AFW-8 yields an additional 617,487 dry tons of biomass in 2012 and 1,175,431 dry tons of biomass in

2020 (see Table 8 of AFW-8). The cumulative increase in biomass feedstocks from AFW-8 would be about 11.5 million dry tons of biomass. Reduction of 5.2 MMtCO2e in 2012, 9.8 MMtCO2e in 2020, and 96.2 MMtCO2e cumulatively from 2008-2020 are estimated under AFW-8 for the avoided fossil fuel emissions associated with the additional volume of biomass feedstocks.

It is possible that the ES/RCI TWG will quantify GHG reductions associated with the consumption of renewable fuels in place of fossil fuels, which would take into account some or all of the GHG benefits of using biomass energy produced from feedstock envisioned under this option. Final cumulative totals will take this overlap into account.

Data Sources: See AFW-8.

Quantification Methods: See AFW-8.

Key Assumptions: See AFW-8.

Key Uncertainties

TBD

Additional Benefits and Costs

TBD

Feasibility Issues

TBD

Status of Group Approval

TBD

Level of Group Support

TBD

Barriers to Consensus

TBD

AFW-8. Forestry Programs to Enhance GHG Benefits

Policy Option Description

Carbon dioxide is captured and stored in trees, soil and other forest biomass. Any forest management activity that promotes forest productivity will increase carbon dioxide sequestration rates and enhance GHG benefits. Retaining forest management where it is being done and expanding the area covered by management plans would stimulate the rate of carbon sequestration. Use of biomass waste from forestry programs for energy purposes is covered under AFW-7. This option focuses on forest management methods to decrease the potential for catastrophic wildfires that result in large carbon losses and losses of near-term sequestration potential.

Policy Option Design

Goals: Treat 10% of Lower Montane forests to reduce the risk of stand replacement fires and increase productivity by 2020.

Timing: Increase productivity by 2% by 2012 and achieve the full goal by 2020.

Parties Involved: TBD

Other: Focus is on the lower elevation forest systems in the state.

Implementation Mechanisms

TBD

Related Policies/Programs in Place

TBD

Types of GHG Reductions

- Net balance of avoided CO_2, CH_4, and N_2O emissions from reduced rate of stand replacement fires and increase carbon removals from forest thinning.
- Biomass energy produced with biomass from forest thinning displaces fossil fuel use

Estimated GHG Savings and Costs per $MtCO_2e$

Data Sources: Forest Inventory Analysis 2005, USFS GTR NE-343; Front Range Fuels Treatment Partnership Final Report 2006, Forest Biomass Removals for Fossil Fuel Offsets, Nelson, Kashian, and Ryan, unpublished report 2007. Michael Ryan, USDA FS, personal communications.

Quantification Methods:

The policy scenario is based on implementation of increased forest thinning to reduce the risk of catastrophic wildfires in the Lower Montane Forests of Colorado. The policy scenario is compared to a baseline case of limited thinning and more extensive catastrophic fires in the Lower Montane Forests. In both cases, biomass from the thinning treatments is used to produce bioenergy and offset the use of fossils fuels. There are two parts to the analysis of this option. The first compares the net change in carbon stocks and trace gas emissions (CH_4 and N_2O) in the Lower Montane Forests under the policy and baseline cases. The second estimates the avoided fossil fuel emissions of each scenario due to the use of the biomass from the forest thinning treatment to produce biofuels.

Lower Montane Forests (LMF) were roughly identified as Ponderosa Pine and Douglas Fir forest types in the elevation range from 5,000 to 8,000 feet based on consultation with experts and findings in the Front Range Fuels Treatment Partnership Final Report. The area of LMF was estimated with data published in the 2005 USFS Forest Inventory Analysis (FIA) by forest type and elevation for Colorado. FIA data indicate approximately 801,457 acres of Ponderosa Pine and 311,859 acres of Douglas Fir in this elevation range in CO.

The same general processes are modeled in the baseline and policy scenarios with different levels of thinning treatment essentially driving the net changes in carbon stocks and trace gas emissions in the forest. The analysis assumes that 5% of the untreated forest area (forests that have not been thinned) is burned each year and that 50% of those burns are catastrophic, resulting in a permanent conversion to non-forest cover (e.g., grasslands) and a complete (100%) loss of carbon in forest biomass as a result of combustion and mortality. In addition, the combusted biomass causes CH_4 and N_2O emissions. Soil carbon stocks are assumed unchanged by fires.

Thinning treatments are assumed to result in the removal of 45% of biomass carbon (based on a range of 30-60% from Nelson et al.) and are considered a net loss of biomass carbon from the forest ecosystem (i.e., treated as an emission). Both the carbon losses from fire and thinning are in part offset by carbon sequestration due to annual growth on the portion of the forest that is not burned.

The baseline and policy scenarios differ in the extent to which forest thinning occurs. The baseline assumes that 14,000 acres of Ponderosa Pine and 6,000 acres of Douglas Fir forests will be treated with thinning each year, based on current plans for forest thinning treatments in Colorado (Michael Ryan, personal communication). The policy scenario increases this level of treatment, in accordance with stated goal levels for this option, to include an additional 2% of the untreated forest area in 2012 and an additional 10% of the untreated forest area in 2020, with incremental increases in between as shown in Table 1.

Table 1. Policy Scenario Targets for Thinning Treatments Over Baseline Levels

	Proportion of Untreated Forest That Is Thinned (in addition to baseline levels)
2008	0.004
2009	0.008
2010	0.012
2011	0.016
2012	0.02
2013	0.03
2014	0.04
2015	0.05
2016	0.06
2017	0.07
2018	0.08
2019	0.09
2020	0.1

The total area of forests at the start of each year, and the amount burned with catastrophic fires and thinned during each year was modeled separately for Ponderosa Pine and Douglas Fir forests for both the baseline and policy scenarios using the assumptions stated above. The baseline and policy scenario results from Ponderosa Pine and Douglas Fir are shown in Tables 2 and 3 below. In both cases, the number of acres burned with catastrophic fires is slightly lower and the number of acres treated with thinning is substantially higher in the policy scenario compared to the baseline.

Table 2. Baseline and Policy Scenario Area Data for Ponderosa Pine

Baseline	Acres	Untreated Acres at Start of Year	Acres w/ Catastrophic Burn	Acres Treated with Thinning	Cumulative Acres Treated	Untreated Acres Remaining Forest at the End of the Year
2008	801,457	801,457	4,007	14,000	14,000	783,450
2009	797,450	783,450	3,917	14,000	28,000	765,533
2010	793,533	765,533	3,828	14,000	42,000	747,705
2011	789,705	747,705	3,739	14,000	56,000	729,966
2012	785,966	729,966	3,650	14,000	70,000	712,317
2013	782,317	712,317	3,562	14,000	84,000	694,755
2014	778,755	694,755	3,474	14,000	98,000	677,281
2015	775,281	677,281	3,386	14,000	112,000	659,895

Baseline	Acres	Untreated Acres at Start of Year	Acres w/ Catastrophic Burn	Acres Treated with Thinning	Cumulative Acres Treated	Untreated Acres Remaining Forest at the End of the Year
2016	771,895	659,895	3,299	14,000	126,000	642,595
2017	768,595	642,595	3,213	14,000	140,000	625,382
2018	765,382	625,382	3,127	14,000	154,000	608,255
2019	762,255	608,255	3,041	14,000	168,000	591,214
2020	759,214	591,214	2,956	14,000	182,000	574,258
Policy Scenario						
2008	801,457	801,457	4,007	17,206	17,206	780,244
2009	797,450	780,244	3,901	20,242	37,448	756,101
2010	793,549	756,101	3,781	23,073	60,521	729,247
2011	789,768	729,247	3,646	25,668	86,189	699,933
2012	786,122	699,933	3,500	27,999	114,188	668,435
2013	782,622	668,435	3,342	34,053	148,241	631,039
2014	779,280	631,039	3,155	39,242	187,482	588,643
2015	776,125	588,643	2,943	43,432	230,914	542,267
2016	773,182	542,267	2,711	46,536	277,450	493,020
2017	770,470	493,020	2,465	48,511	325,962	442,043
2018	768,005	442,043	2,210	49,363	375,325	390,470
2019	765,795	390,470	1,952	49,142	424,468	339,375
2020	763,843	339,375	1,697	47,938	472,405	289,741

Table 3. Baseline and Policy Scenario Area Data for Douglas Fir

Baseline	Acres	Untreated Acres at Start of Year	Acres w/ Catastrophic Burn	Acres Treated with Thinning	Cumulative Acres Treated	Untreated Acres Remaining Forest at the End of the Year
2008	311,859	311,859	1,559	6,000	6,000	304,300
2009	310,300	304,300	1,522	6,000	12,000	296,779
2010	308,779	296,779	1,484	6,000	18,000	289,295
2011	307,295	289,295	1,446	6,000	24,000	281,848
2012	305,848	281,848	1,409	6,000	30,000	274,439
2013	304,439	274,439	1,372	6,000	36,000	267,067
2014	303,067	267,067	1,335	6,000	42,000	259,732
2015	301,732	259,732	1,299	6,000	48,000	252,433

Baseline	Acres	Untreated Acres at Start of Year	Acres w/ Catastrophic Burn	Acres Treated with Thinning	Cumulative Acres Treated	Untreated Acres Remaining Forest at the End of the Year
2016	300,433	252,433	1,262	6,000	54,000	245,171
2017	299,171	245,171	1,226	6,000	60,000	237,945
2018	297,945	237,945	1,190	6,000	66,000	230,755
2019	296,755	230,755	1,154	6,000	72,000	223,601
2020	295,601	223,601	1,118	6,000	78,000	216,483
Policy Scenario						
2008	311,859	311,859	1,559	7,247	7,247	303,053
2009	310,300	303,053	1,515	8,424	15,672	293,113
2010	308,785	293,113	1,466	9,517	25,189	282,130
2011	307,319	282,130	1,411	10,514	35,703	270,205
2012	305,909	270,205	1,351	11,404	47,107	257,450
2013	304,558	257,450	1,287	13,724	60,831	242,440
2014	303,270	242,440	1,212	15,698	76,528	225,530
2015	302,058	225,530	1,128	17,276	93,805	207,126
2016	300,931	207,126	1,036	18,428	112,233	187,662
2017	299,895	187,662	938	19,136	131,369	167,588
2018	298,957	167,588	838	19,407	150,776	147,343
2019	298,119	147,343	737	19,261	170,037	127,345
2020	297,382	127,345	637	18,735	188,771	107,974

Published average carbon stocks (tons carbon per acre), by stand age, for Ponderosa Pine and Douglas Fir forests in the Southern Rocky Mountain Region were used to calculate forest carbon stocks, the amount of carbon removed from thinning and the amount of carbon lost through burning. Carbon stock values of 65 yr old stands were chosen to represent the average for these forest types. In addition, an annual carbon stock change (or carbon sequestration) value was calculated from the carbon stock data (by subtracting carbon stocks in 65 year old stands from carbon stocks in new stands and diving by 65) and used to calculate carbon sequestration due to forest growth. Carbon stocks and carbon sequestration rates used in the analysis are shown in Table 4.

Non-CO_2 fire emissions (CH_4 and N_2O) were calculated with default emission factors published by the Intergovernmental Panel on Climate Change (IPCC 2006) to estimate trace gas emissions from the burned biomass (Table 5).

Table 4. Carbon Stocks and Carbon Sequestration Rates for Lower Montane Forests

Carbon Stocks/Sequestration Rates	Ton Carbon (per acre, or per acre per year)
Ponderosa Pine	
Biomass Carbon Stocks (65-yr old stand), tons C/ac	31.7
Annual sequestration in biomass, tons C/ac/yr	0.25
Douglas Fir	
Biomass carbon stocks (65-yr old stand), tons C/ac	56.3
Annual sequestration in biomass, tons C/ac/yr	0.50

Table 5. IPCC Emissions Factors for CH_4 and N_2O Emissions From Forest Fires

	Default factor
IPCC default combustion factor (dimensionless, proportion of biomass fuel that is combusted)	0.45
IPCC default emission factor CH4 (g/kg dry matter burned)	4.70
IPCC default emission factor N2O (g/kg dry matter burned)	0.26

Area data in Tables 2 and 3 were used to calculate forest carbon stocks at the start of each year by multiplying the forest area by the carbon coefficients in Table 4. Carbon removals and sequestration were calculated each year due to fires, thinning, and growth, using the appropriate area data, coefficients, and assumptions. Carbon stocks at the end of each year were calculated by subtracting emissions and removals, and adding sequestration to the initial carbon stock. The net change in carbon stocks was calculated each year by subtracting carbon stocks at the end of the year from carbon stocks at the start of the year. In all cases (baseline and policy for Ponderosa Pine and Douglas fir) net emissions of CO_2 occurred each year because fire and thinning losses were greater than carbon gains from sequestration. In addition, emissions increase in the policy scenario relative to the baseline because increased removals of CO_2 from thinning are only slightly offset by reduced fire emissions.

Table 6 shows the complete results for the baseline case, policy scenario, and the difference between the two, for Ponderosa Pine only. Negative values indicate emissions and positive values indicate sequestration. Carbon stock data were initially calculated in units of tons of carbon, and then converted to million metric tons of CO_2 equivalents (MMtCO2e). CH_4 and N_2O emissions are also expressed in MMtCO2e, permitting direct comparison for a total emission value each year. The complete results for the Douglas Fir analysis are not shown here due to limited space. However, Table 7 shows the summary results for Ponderosa Pine and Douglas Fir.

Table 6. Complete Carbon Stock, Sequestration, and Non-CO_2 Emissions Results for Ponderosa Pine

Baseline	Forest Carbon Stock at Start of Year (tC)	CO2 emissions from fire (tC)	CO2 Removed From Thinning (tC)	Carbon Sequestered in Biomass of Unburned Forests (tC)	Forest Carbon Stock at End of Year (tC)	Net CO2 Flux (MMtCO2e)	CH_4 Emissions From fire (MMt CO_2e)	N2O Emissions From Fire (MMtCO_2e)	Total Emissions (MMtCO_2e)
2008	25,406,192	-635,155	-199,710	194,754	24,766,081	-2.35	-0.0564	-0.0461	-2.4496
2009	24,766,081	-608,181	-199,710	189,972	24,148,163	-2.27	-0.0540	-0.0441	-2.3638
2010	24,148,163	-581,881	-199,710	185,398	23,551,969	-2.19	-0.0517	-0.0422	-2.2799
2011	23,551,969	-556,239	-199,710	181,024	22,977,044	-2.11	-0.0494	-0.0403	-2.1978
2012	22,977,044	-531,238	-199,710	176,848	22,422,943	-2.03	-0.0472	-0.0385	-2.1174
2013	22,422,943	-506,862	-199,710	172,863	21,889,234	-1.96	-0.0450	-0.0368	-2.0387
2014	21,889,234	-483,096	-199,710	169,064	21,375,492	-1.88	-0.0429	-0.0350	-1.9617
2015	21,375,492	-459,923	-199,710	165,448	20,881,307	-1.81	-0.0409	-0.0334	-1.8862
2016	20,881,307	-437,330	-199,710	162,010	20,406,277	-1.74	-0.0388	-0.0317	-1.8123
2017	20,406,277	-415,302	-199,710	158,745	19,950,010	-1.67	-0.0369	-0.0301	-1.7400
2018	19,950,010	-393,825	-199,710	155,649	19,512,124	-1.61	-0.0350	-0.0286	-1.6691
2019	19,512,124	-372,884	-199,710	152,717	19,092,247	-1.54	-0.0331	-0.0270	-1.5997
2020	19,092,247	-352,467	-199,710	149,946	18,690,016	-1.47	-0.0313	-0.0256	-1.5317
Policy Scenario									
2008	25,406,192	-635,155	-245,441	194,754	24,720,350	-2.51	-0.0564	-0.0461	-2.6172
2009	24,720,350	-605,640	-286,922	189,992	24,017,780	-2.58	-0.0538	-0.0439	-2.6738
2010	24,017,780	-574,559	-323,815	185,475	23,304,881	-2.61	-0.0510	-0.0417	-2.7067
2011	23,304,881	-542,205	-355,865	181,212	22,588,023	-2.63	-0.0482	-0.0393	-2.7160
2012	22,588,023	-508,880	-382,907	177,211	21,873,447	-2.62	-0.0452	-0.0369	-2.7022
2013	21,873,447	-474,885	-456,148	173,478	21,115,891	-2.78	-0.0422	-0.0344	-2.8543
2014	21,115,891	-437,672	-514,834	170,037	20,333,423	-2.87	-0.0389	-0.0317	-2.9397
2015	20,333,423	-398,128	-558,025	166,907	19,544,176	-2.89	-0.0354	-0.0289	-2.9582
2016	19,544,176	-357,173	-585,457	164,098	18,765,643	-2.85	-0.0317	-0.0259	-2.9123
2017	18,765,643	-315,719	-597,516	161,616	18,014,025	-2.76	-0.0280	-0.0229	-2.8069
2018	18,014,025	-274,630	-595,178	159,457	17,303,674	-2.60	-0.0244	-0.0199	-2.6489
2019	17,303,674	-234,699	-579,923	157,612	16,646,663	-2.41	-0.0208	-0.0170	-2.4469
2020	16,646,663	-196,614	-553,615	156,066	16,052,500	-2.18	-0.0175	-0.0143	-2.2103

Difference between policy scenario and baseline	Forest Carbon Stock at Start of Year (tC)	CO2 emissions from fire (tC)	CO2 removed from thinning (tC)	Carbon sequestered in biomass of un-burned forests (tC)	Forest Carbon Stock at End of Year (tC)	Net CO2 Flux (MMtCO2e)	CH4 emissions from fire (MMt CO2e)	N2O emissions from fire (MMtCO2e)	Total Emissions (MMtCO2e)
2008	0	0	-45,731	0	-45,731	-0.1677	0.0000	0.0000	-0.1677
2009	-45,731	2,541	-87,212	20	-130,383	-0.3104	0.0002	0.0002	-0.3100
2010	-130,383	7,322	-124,105	78	-247,088	-0.4279	0.0007	0.0005	-0.4267
2011	-247,088	14,034	-156,155	188	-389,021	-0.5204	0.0012	0.0010	-0.5182
2012	-389,021	22,358	-183,197	364	-549,496	-0.5884	0.0020	0.0016	-0.5848
2013	-549,496	31,977	-256,438	615	-773,342	-0.8208	0.0028	0.0023	-0.8156
2014	-773,342	45,424	-315,124	972	-1,042,069	-0.9853	0.0040	0.0033	-0.9780
2015	-1,042,069	61,795	-358,315	1,458	-1,337,131	-1.0819	0.0055	0.0045	-1.0719
2016	-1,337,131	80,157	-385,747	2,088	-1,640,634	-1.1128	0.0071	0.0058	-1.0999
2017	-1,640,634	99,583	-397,806	2,871	-1,935,985	-1.0830	0.0088	0.0072	-1.0669
2018	-1,935,985	119,194	-395,468	3,808	-2,208,450	-0.9990	0.0106	0.0086	-0.9798
2019	-2,208,450	138,185	-380,213	4,895	-2,445,583	-0.8695	0.0123	0.0100	-0.8472
2020	-2,445,583	155,853	-353,905	6,120	-2,637,515	-0.7038	0.0138	0.0113	-0.6786
Total			-3,439,416			-9.6709	0.0691	0.0565	-9.5453

The net impact of this policy on the forest carbon balance is an increase in emissions each year relative to the baseline case, as shown in Table 7. Note that a negative value indicates an increase in emissions (net reductions would yield positive values). The forest treatment actually increases the net loss of carbon from forests because of the significant amount of biomass removed from thinning. This biomass is ultimately combusted and results in CO_2 emissions to the atmosphere, the magnitude of which are accounted for here as carbon removals from the forest[30]. As shown below, forest treatment forms a crucial input to the next part of the analysis, i.e., increased biomass feedstocks for bioenergy production. The biomass energy reductions far exceed the increased emissions estimated for Lower Montane Forest ecosystem.

Table 7. Summary of GHG Impacts of This Policy in the Lower Montane Forest

Year	Ponderosa Pine ($MMtCO_2e$)	Douglas Fir ($MMtCO_2e$)	Total ($MMtCO_2e$)
2008	-0.17	-0.12	-0.28
2009	-0.31	-0.21	-0.52
2010	-0.43	-0.29	-0.72
2011	-0.52	-0.36	-0.87
2012	-0.58	-0.40	-0.99
2013	-0.82	-0.56	-1.37
2014	-0.98	-0.67	-1.65
2015	-1.07	-0.73	-1.80
2016	-1.10	-0.75	-1.85
2017	-1.07	-0.72	-1.79
2018	-0.98	-0.66	-1.64
2019	-0.85	-0.56	-1.41
2020	-0.68	-0.44	-1.12
Cumulative	-9.55	-6.46	-16.01

The second part of the analysis accounts for the avoided emissions as a result of using biomass from the thinning treatments to produce energy in place of fossil fuels. The tons of carbon removed from forest thinning as modeled above, translates into net annual gains in biomass feedstocks for energy productionas shown in Table 8. The tons carbon in biomass from forest thinning is converted to biomass feedstocks by assuming a 50% carbon content of biomass (i.e., tons carbon is multiplied by 2 to yield tons biomass and the sign is reversed to a positive value). Cumulatively the forest thinning yields over 11.5 million tons of biomass feedstocks. The energy content of biomass was calculated using a conversion factor of 16.4 MBtu/ton biomass. Emission

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[30] Because forest management under this option seeks to maintain a lower biomass density for fire risk purposes, the thinned biomass will not be replaced in the future by regrowth and thus the emissions are accounted for. In other circumstances where biomass volume is replaced by future regrowth, emissions can be considered biogenic and do not result in a net increase in CO_2 emissions to the atmosphere.

reductions were calculated using the difference between biomass energy and natural gas emissions based on the following emission factors: biomass energy yields 14.96 lbs CO2e/MBtu, natural gas yields 116.7 lbs CO2e/MBtu (Note: emission factors are based in NM analysis, further development of emission factors should be considered, NM values were used as defaults for this initial analysis). The relative emissions avoided are shown below, converted to units of MMtCO2e.

Table 8. Additional Biomass Feedstocks From Policy Implementation and Corresponding Emission Reductions From Avoided Emissions

Year	Ponderosa Pine (tons biomass)	Douglas Fir (tons biomass)	Total (tons biomass)	MMBtu	Emission Reductions (MMtCO2e)
2008	91,462	63,208	154,670	2,536,587	1.29
2009	174,424	120,317	294,742	4,833,762	2.46
2010	248,210	170,872	419,081	6,872,934	3.50
2011	312,310	214,535	526,845	8,640,265	4.40
2012	366,394	251,093	617,487	10,126,789	5.15
2013	512,876	350,571	863,447	14,160,533	7.20
2014	630,247	429,558	1,059,806	17,380,815	8.84
2015	716,631	486,845	1,203,476	19,737,007	10.04
2016	771,495	522,157	1,293,652	21,215,892	10.79
2017	795,611	536,121	1,331,733	21,840,416	11.11
2018	790,936	530,181	1,321,117	21,666,317	11.02
2019	760,426	506,464	1,266,890	20,776,995	10.57
2020	707,810	467,621	1,175,431	19,277,071	9.81
Cumulative	6,878,832	4,649,545	11,528,377	189,065,383	96.18

The net impact of this policy on GHG emissions takes into account increases in emissions within the forest ecosystem (final column of Table 7) and avoided emissions from the use of biofuels (final column of Table 8) and is estimated to yield total cumulative reductions of 80.17 MMtCO2e.

The net costs of this option take into account both the direct costs of forest thinning treatments and cost savings from avoided fires and wood utilization. Per acre costs and cost savings for these three variables were taken from the Front Range Fuels Treatment Partnership Roundtable Report, which included a cost assessment for meeting fuel reduction targets in Lower Montane Forests in the Front Range. Estimate costs and cost savings are shown in Table 9.

Table 9. Estimated per Acre Costs and Cost Savings From This Option

	Total Cost	Acres	Cost per acre	Notes
Cost of forest treatment	$600,000,000	1,500,000	$400	Cost assumes $15 million needed annually over 40 years to treat 1.5 million acres with fuel reduction treatments
Cost of forest fires	$237,800,000	140,000	$1,699	Based on costs of the Hayman fire; includes costs of fire fighting, immediate and long-term rehabilitation, and indirect economic losses.
Cost savings from wood utilization			$210	Based on an increase in utilization from 0 to 50%, which may be conservative for this option which assumes 100% utilization

To assess the incremental cost impact of the policy scenario compared to the baseline case, the total number of additional acres treated with thinning in the policy scenario (with respect to the baseline case) was multiplied by the cost of forest treatment (Table 10). Under policy implementation, fewer acres are burned each year relative to the baseline and this decrease in acres was multiplied by the cost of forest fires to yield annual cost savings from avoiding forest fires. Finally, the cost savings from wood utilization was calculated by multiplying the additional acres treated with thinning in the policy scenario by the anticipated cost savings from wood utilization (the value is recorded as negative to denote cost savings). Net costs were calculated as the sum of these three cost/cost savings variables.

Annual discounted costs were estimated using a 5% interest rate. The sum of annual discounted costs yields an estimated net present value (NPV) of this option on the order of $7 million dollars. The NPV divided by cumulative GHG reductions gives and overall assessment of the cumulative cost effectiveness of the option in dollars per ton. In this case, the option is estimated to cost about $0.09/ton (note the GHG reductions in Table 10 are converted to metric tons from million metric tons before diving into the NPV).

Table 10. Calculation of Net Costs, Net Present Value, and Cumulative Cost Effectiveness

Year	Reduced Acres w/ Cata-strophic Burn	Increased Acres Treated With Thinning	Avoided Costs From Fire ($)	Cost of Treatment ($)	Cost Savings From Wood Utilization ($)	Net Costs ($)	Discounted Costs ($)	Net GHG Reductions (MMtCO$_2$e)
2008	0	4,453	$0	$1,781,307	-$935,186	$846,121	$846,121	1.01
2009	-111	8,488	-$189,105	$3,395,297	-$1,782,531	$1,423,661	$1,355,868	1.94
2010	-321	12,072	-$544,824	$4,828,879	-$2,535,161	$1,748,893	$1,586,298	2.78
2011	-615	15,181	-$1,043,841	$6,072,281	-$3,187,947	$1,840,492	$1,589,886	3.52
2012	-979	17,798	-$1,662,383	$7,119,146	-$3,737,552	$1,719,212	$1,414,400	4.17
2013	-1,399	24,895	-$2,376,597	$9,958,177	-$5,228,043	$2,353,537	$1,844,058	5.83
2014	-1,987	30,568	-$3,374,349	$12,227,303	-$6,419,334	$2,433,620	$1,816,005	7.20
2015	-2,701	34,727	-$4,588,049	$13,890,661	-$7,292,597	$2,010,014	$1,428,480	8.24
2016	-3,502	37,347	-$5,947,991	$14,938,633	-$7,842,782	$1,147,860	$776,917	8.95
2017	-4,348	38,467	-$7,385,187	$15,386,991	-$8,078,170	-$76,366	-$49,226	9.32
2018	-5,201	38,186	-$8,834,051	$15,274,545	-$8,019,136	-$1,578,642	-$969,149	9.39
2019	-6,026	36,649	-$10,234,756	$14,659,557	-$7,696,268	-$3,271,467	-$1,912,759	9.16
2020	-6,791	34,038	-$11,535,157	$13,615,231	-$7,147,996	-$5,067,922	-$2,822,008	8.68
Total							**$6,904,889**	**80.17**

Key Assumptions:

Baseline Assumptions:	
Proportion of untreated forest land burned annually	0.05
Proportion of burn that is catastrophic	0.5
Proportion of biomass emitted from burning and subsequent death/decay	1
Number of Ponderosa Pine acres treated with thinning annually	14,000
Number of Douglas Fir acres treated with thinning annually	6,000
Proportion of biomass removed during thinning	0.45
Policy Scenario Assumptions:	
Proportion of untreated acres burned annually	0.05
Proportion of burn that is catastrophic	0.5
Proportion of biomass emitted from burning and subsequent death/decay	1
Proportion of acres treated with thinning by 2012, in addition to baseline	0.02
Proportion of acres treated with thinning by 2020, in addition to baseline	0.1
Proportion of biomass removed during thinning	0.45

See Table 9 above for cost assumptions.

Key Uncertainties

The analysis is highly sensitive to assumptions about fire extent. If a higher proportion is assumed for the amount of untreated land burned annually (e.g., 15%), emissions under policy implementation increase to a much lesser degree in the forest ecosystem. (e.g., -3.44 MMtCO2e). However, less biomass feedstocks are produced because more land burns before it can be treated with thinning (e.g., 7 million tons of biomass feedstocks are generated) and net emissions reductions, taking into account forest carbon and fossil fuel reductions are lower (e.g., 56.4 MMtCO2e)

The analysis does not take into account fuel-related GHG emissions associated with forest treatment, which would entail heavy machinery. GHG emissions and costs associated with transportation of biomass feedstocks are also not taken into account.

The analysis does not estimate the amount of carbon that might accumulate on previously forested sites after catastrophic burns. If this is factored in, net GHG reductions could be slightly lower.

Additional Benefits and Costs

TBD

Feasibility Issues

TBD

Status of Group Approval

TBD

Level of Group Support

TBD

Barriers to Consensus

TBD

AFW-9. Source Reduction, Enhanced Recycling and Composting Programs

Policy Option Description

Solid waste that is normally buried in landfills generates methane through decomposition processes. By preventing this source of methane, GHG emissions are reduced. Waste can be diverted through a variety of actions including composting, source reduction, recycling, and re-use. Alternatives to landfilling unprocessed organic material (food wastes, agricultural wastes, biosolids, lawn & garden wastes, or other organic materials) include composting and anaerobic digestion. Both alternatives reduce net GHG emissions and anaerobic digestion can also provide a source of renewable energy (methane). Source reduction and recycling also reduce product life cycle GHG emissions, including extraction and processing of raw materials, product manufacture, transport, and final disposal.

Policy Option Design

Goals: Divert 75% of wastes from landfilling by source reduction, recycling and composting.

Timing: Divert 25% by 2012; achieve the full goal by 2020.

Parties Involved: TBD

Other: Not applicable.

Implementation Mechanisms

Colorado will explore all reasonable options that increase the recovery of waste materials and put them to beneficial use. Opportunities may be implemented through:

- Education and public involvement
  - Colorado Association for Recycling may play an important role
  - Other non-profits can also be relied upon for advocacy/outreach
  - Leverage public desire to protect the natural beauty of Colorado
- Economic support
  - Target job development
  - Improve Colorado’s processing infrastructure
  - Public/private partnerships will be encouraged that lead to development and construction of new recycling and composting processing facilities.

    Mechanisms that have proved successful in other states will be evaluated for use in Colorado, such as low-interest financing packages; long-term contracts; guaranteed supplies of materials (e.g., from “clean stream” collection processes).

  - Landfill surcharges are the financial bridge to transition us away from a dominant landfill system to a 75% recovery system; therefore, additional surcharges on tipping fees will be evaluated for appropriate levels to achieve programmatic goals.
    - This approach is used across the country, going as high as $6/yard at a landfill in California. For perspective, Colorado recently created its first recycling surcharge of ten cents/yard.
- Technical research and assistance
  - Evaluate state and local resources (data based)
- Relationship to transportation-reduction goals and policies
  - Evaluate ways to improve trash collection efficiencies
  - Apply purchasing guidelines
    - Local product procurement objectives
    - Source reduction limitations to discourage excessive packaging
- Legislative actions
  - Review successful programs that have helped other states increase diversion
  - Leverage grant opportunities from landfill surcharges
  - Adopt bans on landfill disposal for certain materials
  - Increase number of communities that apply pay-as-you-throw trash rates
  - When communities reach urban population thresholds of 50,000 or more, the state will require comprehensive discards collection plans that require Clean Stream (i.e., three separated materials modeled after San Francisco's Fantastic Three program) technology to be used.
- State agencies will lead by example

Related Policies/Programs in Place

- Adopted in 2007, the Sustainable Resource Economic Opportunity Bill establishes a 7-10 cent surcharge per ton of landfilled trash, which will create a source of funding to: provide grants for the sustainable use and economic development of discarded resources; pay for additional staff at the Colorado Department of Public Health & Environment to implement solid waste reduction programs; and offer financial rewards to communities that divert more waste.
- Also adopted in 2007, the Environmentally Preferable Products Act enables state agencies to award contracts to bidders who offer environmentally preferable products or services that may exceed the price of the lowest bid. In 2005, SB 141 was passed making it illegal to dispose of used oil, tires, and batteries in Colorado landfills.

Types of GHG Reductions

TBD

Estimated GHG Savings and Costs per MtCO$_2$e

GHG Reductions (MMtCO$_2$e) in 2012, 2020: TBD, TBD

Costs ($/Mt): TBD

Data Sources: State-level data on current (BAU) recycling levels from the Colorado Department of Public Health and the Environment;[31] CO State or TWG estimates of waste reduction opportunities by WARM waste category (possibly from existing municipal programs like Fort Collins); current landfilling rates from CO I&F; data from CO municipalities or the literature on the capital and annual costs for source reduction, recycling, and composting programs.

Quantification Methods:

WARM provides estimates of the lifecycle GHG emissions avoided via source reduction, recycling, and composting. The 2005 CO waste generation rate was 52,536,631 tons. Waste composition data from the CDPHE study cited above were used to provide inputs to the WARM model.

The WARM model is run three times: one for a 2005 reference case, one for a 2012 policy scenario, and one for a 2020 policy scenario. The total GHG reductions for 2012 and 2020 are found by subtracting the GHG benefit output from WARM in the corresponding year from the 2005 reference case.

Due to the limited availability of data regarding current recycling and composting rates, CCS assumed first that the CDPHE study was a comprehensive data source for recycling, and that the current rate of composting is zero. In order to achieve the 75% by 2020 waste diversion, a multiplier was used for each year that scaled up the targeted diversion due to recycling, composting, and source reduction annually.

The resulting GHG reductions were found to be quite high, likely due to the large diversion prescribed by this policy. The estimated GHG reduction for 2012 is 51.93 MMtCO$_2$e/year and 182.19 MMtCO$_2$e/year in 2020.

Going forward, CCS will work with the TWG to apply the implementation strategies to achieve cost estimates for this option. The paragraph below describes likely steps that will be taken to accomplish this goal:

To establish how much money it costs to implement AFW-9, we need to establish the costs for implementing waste separation programs. To accomplish successful trash separation, materials need to be collected in independent streams free of trash or other materials; the term “clean stream” is sometimes used for this type of system. It is being modeled in communities in California such as San Francisco, Los Angeles, and San Diego where public programs offer three different containers for customers community-wide to use; a bin for organic materials, including

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[31] Colorado Department of Public Health and Environment, “Annual Reporting Data Received—What We’ve Learned,” 2005, accessed July 11, 2007, at www.cdphe.state.co.us/hm/recycling2006rpt.pdf.

kitchen waste; a bin for conventional recyclable materials such as paper, cardboard, plastic, and metal containers; and a bin for trash. San Francisco calls their program "the Fantastic Three".

A general rule of thumb in California has been that the monthly costs for a three-bin system average $25 per household. The current monthly costs in Colorado for waste collection average $12.50 per household; therefore, the increase for Colorado households to implement a comprehensive waste diversion program would cost about $12.50 per month, or $150 per year, per household.

For businesses, the Fantastic Three system is estimated to cost about $40 per month above and beyond their current waste collection costs; therefore the average annual cost for businesses could be estimated to be $480.

Key Assumptions: TBD

Key Uncertainties

TBD

Additional Benefits and Costs

TBD

Feasibility Issues

The State legislature needs to pass a resolution that sets waste diversion goals for Colorado. The newly elected governor has already showed leadership on environmental issues. The state's reputation as an incubator for renewable energy policies and technology is growing, and greater amounts of recycling will further enhance Colorado's identity as a "green" state.

Composting, recycling and waste reduction are important tools for citizens because they can take personal action to reduce global warming at the household level—and in their workplaces and schools. The public is receptive and eager to reduce/reuse/recycle. Demonstrated success at reducing volumes of trash at landfills is relatively attainable and provides motivation/encourages people to strive for even greater attempts to contribute to climate protection.

Nationally, Colorado ranks among the lowest in costs for landfill disposal (between $10–18 per ton, compared with $60–90 in many other parts of the country); the public would be likely to absorb new increases in landfill fees if revenues were used to provide greater opportunities to recycle and compost waste materials.

Status of Group Approval

TBD

Level of Group Support

TBD

Barriers to Consensus

TBD

AFW-10. Landfill Methane Reduction Programs

Policy Option Description

Provide incentives that will result in an increase in the recovery of landfill methane for use as an energy source. Increasing the recovery of landfill methane will reduce emissions of this GHG and will offset the use of fossil fuels for commercial/industrial heat/steam generation or electricity production.

Policy Option Design

Goals: Implement controls or waste management options at municipal solid waste landfills such that 50% of the methane emissions that would be generated under business as usual conditions are avoided by 2020. This can be done through development of additional landfill gas to energy (LFGTE) projects, flaring, reducing the amount of biodegradable waste being landfilled, or possibly other methods.

Timing: By 2012, implement controls or management strategies at 12 sites not currently using these technologies; by 2020, achieve full implementation of the policy (50% coverage of generated methane).

Parties Involved: TBD

Other: This policy is meant to cover sites that would not be expected to trigger the Federal New Source Performance Standards/Emission Guidelines (NSPS/EG) for landfills (and would be required to capture and control methane). Per the Colorado GHG Inventory & Forecast, the following landfills currently employ LFG controls:

Site Name	County	Control
County Line LF	Arapahoe	Flare
Fountain LF	El Paso	Flare
Foothills LF	Jefferson	Flare
Denver Regional North LF	Weld	Flare
Denver Regional South LF	Weld	Flare
Tower LF	Adams	Flare
Denver – Arapahoe	Arapahoe	LFGTE
Boulder LF	Boulder	Flare
Larimer County LF	Larimer County	Flare

Implementation Mechanisms

Colorado will explore all reasonable options that will decrease the amount of biodegradable waste sent to landfill, as well as increase the recovery of "bio" waste materials and put them to beneficial use. Opportunities may be implemented through:

- Education and public involvement
    - The State would provide good education about the need for waste separation systems so that "clean streams" of materials are available for reuse/recycling/composting.
- Economic support
    - Improve Colorado's processing infrastructure for discarded materials. The private sector is likely to come in and build facilities if State and local government sets the direction for how materials will be separately collected.
- Technical research and assistance
    - Evaluate state and local resources (data based)
- Relationship to transportation reduction goals and policies
    - Apply government purchasing guidelines
- Legislative actions
    - Review successful programs that have helped other states increase diversion
    - Leverage grant opportunities from landfill surcharges
    - Adopt bans on landfill disposal for certain materials
    - Increase number of communities that apply pay-as-you-throw trash rates
    - State agencies will lead by example
    - Every landfill in the state will be required to develop a methane reduction and mitigation program by end of 2008, with financial assistance available from the State for planning purposes
        - Funds will be created to assist landfill planning using new surcharges that will be applied to solid waste disposal in landfills
        - The State will provide financial assistance to small landfills to install methane flaring systems.
- Large landfills that meet the EPA's Federal New Source Performance Standards/Emissions Guidelines NSPS/EG) are required to install methane collection systems.

Related Policies/Programs in Place

- Federal New Source Performance Standards/Emission Guidelines for municipal solid waste landfills (require landfill collection and control for landfills of specific sizes and pollutant emission levels).

- Adopted in 2007, the Sustainable Resource Economic Opportunity Bill establishes a 7-10 cent surcharge per ton of landfilled trash, which will create a source of funding to: provide grants for the sustainable use and economic development of discarded resources; pay for additional staff at the Colorado Department of Public Health & Environment to implement solid waste reduction programs; and offer financial rewards to communities that divert more waste.
- Also adopted in 2007, the Environmentally Preferable Products Act enables state agencies to award contracts to bidders who offer environmentally preferable products or services that may exceed the price of the lowest bid. In 2005, SB 141 was passed making it illegal to dispose of used oil, tires, and batteries in Colorado landfills.

Types of GHG Reductions

- Methane reductions via collection and control (via flaring, or preferentially via energy utilization).
- Reduction of fossil fuels and associated GHGs through the use of landfill methane.

Estimated GHG Savings and Costs per MtCO$_2$e

GHG Reductions (MMtCO$_2$e) in 2012, 2020: 0.3, 1.2

Costs ($/Mt): TBD

Data Sources:

GHG reductions. Information on current and forecast landfill emissions levels comes from the CO GHG I&F for both flared and uncontrolled landfill categories. An lifecycle emission factor for natural gas consumption (120.2 lb CO$_2$e/MMBtu) was calculated from the I&F emission factor for natural gas combustion (116.7 lb CO$_2$e/MMBtu) plus an estimated emission factor that covered natural gas extraction, processing, transmission and distribution using estimates in EPA's 2001 national emission estimates for that sector (3.5 lb CO$_2$e/MMBtu);

Costs. EPA model LFGcost-Web, which estimates the costs to implement different types of landfill gas controls (including LFG to energy); assumptions on the types of controls to be applied (flare, LFGTE plant type) to estimate costs.

Quantification Methods:

GHG reductions come from two components—landfill methane controlled through this option and fossil fuel offset with the use of collected landfill methane. The methane controlled was calculated from the uncontrolled landfill category in each year of the policy period. In 2012, 20% of the generated methane is to be collected and used for energy purposes. In 2020, 50% is to be collected and used.

The CO$_2$e emissions reductions achieved from collecting and using this methane were added to the emissions from fossil fuel that would be avoided from using the energy in the collected landfill methane. The methane to be collected from both flared and uncontrolled sites was added in each year and then converted to MMBtu. Then, the lifecycle natural gas emission factor provided above was applied to estimate GHG reductions from avoided natural gas use.

- CCS will use EPA's LFGcost-Web model to estimate a range of costs for implementing LFG controls based on different technologies; this model handles large or small engine/gen sets, direct LFG use, turbines, combined heat and power turbines or engines, and leachate evaporators. TWG provides input on 2 or 3 of these technologies to be applied.
- From LFGcost-Web results of annualized costs, statewide total costs in each year will be estimated.
- Initial GHG reduction estimates above may be refined based on the results from LFGcost-Web results of the electricity/methane produced: CCS will calculate emissions offset from fossil fuel consumption (assume natural gas lifecycle emissions for any direct use of natural gas) or electricity offset (use BAU CO grid emission factors for each year from the ES TWG). Add the emission reductions here to those calculated for methane reductions above (note that the ES or RCI TWG may claim overlapping reductions for the use of renewable fuels in their options; we'll need to adjust as needed).
- Estimate cost effectiveness from total annualized costs in each year and emissions reduced in each year.

To establish how much money it costs to implement AFW-10, we need to establish the costs for implementing waste separation programs. To accomplish successful trash separation, materials need to be collected in independent streams free of trash or other materials; the term "clean stream" is sometimes used for this type of system. It is being modeled in communities in California such as San Francisco, Los Angeles, and San Diego where public programs offer three different containers for customers community-wide to use; a bin for organic materials, including kitchen waste; a bin for conventional recyclable materials such as paper, cardboard, plastic, and metal containers; and a bin for trash. San Francisco calls their program "the Fantastic Three".

A general rule of thumb in California has been that the monthly costs for a three-bin system average $25 per household. The current monthly costs in Colorado for waste collection average $12.50 per household; therefore, the increase for Colorado households to implement a comprehensive waste diversion program would cost about $12.50 per month, or $150 per year, per household.

For businesses, the Fantastic Three system is estimated to cost about $40 per month above and beyond their current waste collection costs; therefore the average annual cost for businesses could be estimated to be $480.

Key Assumptions: Current reduction estimates include benefits of offset natural gas consumption. To the extent that other higher carbon fossil fuels are offset, the benefit could be greater. The refined analysis will incorporate reductions associated with electricity produced using landfill gas, since that is the most likely and common use for this energy source.

Key Uncertainties

TBD

Additional Benefits and Costs

TBD

Feasibility Issues

The State legislature needs to pass a resolution that sets landfill methane reduction goals for Colorado. The newly elected governor (Governor Bill Ritter) has already shown leadership on environmental issues. The state's reputation as an incubator for renewable energy policies and technology is growing, and greater amounts of recycling will further enhance Colorado's identity as a "green" state.

Composting, recycling and waste reduction are important tools for citizens because they can take personal action to reduce global warming at the household level—and in their workplaces and schools. The public is receptive and eager to reduce/reuse/recycle. Demonstrated success at reducing volumes of trash at landfills is relatively attainable and provides motivation/encourages people to strive for even greater attempts to contribute to climate protection.

Nationally, Colorado ranks among the lowest states in costs for landfill disposal (between $10-18 per ton, compared with $60-90 in many other parts of the country); the public would be likely to absorb new increases in landfill fees if revenues were used to provide greater opportunities to recycle and compost waste materials.

Status of Group Approval

TBD

Level of Group Support

TBD

Barriers to Consensus

TBD