Electric Generation and Supply Work Group Meeting
In Support of the
Governor's Task Force on Global Warming

Monday, August 27, 2007
9:00 a.m. – 3:00 p.m.

Public Service Commission of Wisconsin Building
Pecatonica River Conference Room (basement level)
610 North Whitney Way
Madison, WI 53705

There will be a work group meeting from 9:00 a.m. to 3:00 p.m. on Monday, August 27, 2007, at the Public Service Commission of Wisconsin Building, in the Pecatonica River Conference Room, 610 North Whitney Way, Madison, Wisconsin, to discuss policy options, reduction targets, and baseline data in support of the Governor's Task Force on Global Warming. The meeting is open to the public. For more information, or if you need special accommodations to attend this meeting, call Lori Sakk at (608) 266-1383.

Agenda

- Welcome and Review of Agenda
- Updates from Task Force
- Review and Evaluate Policy Summaries
- Break/Lunch
- Additional Policy Summary Review
- Additional Policies to Consider/Reconsider
- Public Input
- Next Meeting Assignments
- Other Items for Discussion--Adjourn

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GOVERNOR'S TASK FORCE 0N GLOBAL WARMING

ELECTRIC GENERATION AND SUPPLY WORK GROUP

AUGUST 27, 2007 MEETING MATERIALS

Wisconsin Global Warming Task Force Workgroup
Template For Presentation Policy Options

1. **Workgroup**: Generation and Delivery (supply side) sub-work group.

2. **Policy Name:** Enhanced Renewable Portfolio Standards (RPS).

3. **Policy Type:** Legislation amending existing RPS, with regulatory implementation and enforcement.

4. **Affected Sectors, Sub-Sectors and/or Entities:**

   Sector: Electric utility

   Sub-Sector: Distribution utilities

5. **Estimated Greenhouse Gas Emissions Reduction Impact:** Based on:

   - the 1,851 pounds per megawatt hour figure that DNR uses for its voluntary emission reduction program,
   - the 66 million megawatts of energy sold in Wisconsin in 2001, and
   - applying a 2% non-compounded annual growth rate of electricity usage,

   in 2020 when a 20% RPS would be in place instead of a 10% RPS, there would be approximately 8.5 million tons in reduced CO_2 emissions. In 2020 when a 25% RPS will be in place instead of a 10% RPS, there would be approximately 13.7 million tons in CO_2 reductions.

Carbon Capture and Storage (CCS)

Draft summary for Wisconsin
Prepared by: Peter Taglia, P.G., Clean Wisconsin, August 2007

Carbon capture and storage (CCS) refers to the process of capturing carbon dioxide from large stationary sources that would otherwise release it to the atmosphere and securely storing, or sequestering, the carbon. CCS is a strategy for reducing anthropogenic emissions of carbon dioxide from fossil fuel use and is one possible "wedge" for reducing the total greenhouse gas emissions from Wisconsin. In this summary, a brief review of several recent estimates of the cost of CCS for new or existing power plants is provided so that this option may be compared with other options available for reducing carbon emissions from the power sector. The opportunities and potential time frames for deploying CCS from Wisconsin's power sector are presented based on the available geological storage in sedimentary deposits in the region.

Additional information about the science and engineering of carbon capture and storage can be found from multiple sources at universities and national laboratories. A thorough overview of CCS was published by the Intergovernmental Panel on Climate Change (IPCC) in 2005. The full environmental impacts of fossil fuel use (e.g., coal mining) and the non-greenhouse gas emission reductions of some CCS technologies (e.g., mercury and sulfur) are not addressed in this summary.

1 Carbon Capture

Carbon dioxide from fossil fuel power plants can be captured either pre- or post-combustion, depending on the type of power plant, and compressed for transport and disposal. Pre-combustion carbon capture involves the chemical modification of syngas from an integrated gasification combined cycle (IGCC) power plant to remove carbon, leaving a stream of hydrogen syngas that is combusted to produce power. Post-combustion capture involves stripping the carbon dioxide from a new or existing power plant flue gas using chemical absorbents or thermochemical processes. Advanced oxy-fuel or chemical cycling power plants have elements of both techniques, concentrating the carbon dioxide in the exhaust stream by operating the power plant on oxygen and recycled exhaust gases. In each case, the capture and compression of carbon dioxide requires additional energy which is supplied by either more fossil fuel consumption or lower electrical output at the power plant.

Presently, no large-scale power plant captures and stores its carbon dioxide emissions, although various components of CCS are deployed at pilot or commercial scales in the energy sector for other purposes (e.g., increasing oil recovery from depleted oil fields). Numerous assumptions about fuel costs, capital costs and the deployment prospects of the various power plant technologies are used to estimate the costs for capturing carbon dioxide from power plants. As a result, the estimates of the costs of CCS are given as a range for each technology and are likely to change with time. In addition, the

construction, fuel, operating, and carbon dioxide transportation costs of a power plant will vary by region and proximity to a carbon dioxide storage project.

The levelized cost of electricity for new power plants with CCS was found to be between $65 and $77 per megawatt hour for IGCC and supercritical pulverized coal (SCPC), respectively, in the MIT Future of Coal report. These numbers are based on design studies in the last seven years, with adjustments for inflation, for plants using Illinois #6 coal but do not reflect the recent escalation in construction costs observed since 2004. The recently published IGCC final report by the Wisconsin Public Service Commission and Wisconsin DNR estimated the costs of CCS at approximately $76 to $78 per megawatt hour for IGCC and SCPC, respectively, burning eastern coal.

2 Carbon Storage

The bulk of research into carbon storage has been devoted to deep ocean storage, geological storage in sedimentary formations, and the crystallization of carbon dioxide into stable minerals. The option with the most promise and relevance for storing carbon dioxide from Wisconsin's electrical sector is geological storage in sedimentary formations. This is also the storage option with the greatest global capacity for carbon dioxide, and the storage option with the greatest characterization and implementation to date. Two of the most detailed multi-disciplinary studies of carbon storage, the IPCC 2005 special report on the subject and the 2007 MIT Future of Coal Report, reviewed the human and environmental risks of carbon storage. The MIT report concluded that geological carbon sequestration “is likely to be safe, effective, and competitive with many other options on an economic basis” but that additional monitoring and verification programs should be implemented before CCS is ready for large-scale deployment.

Three types of sedimentary formations have been investigated for geological storage of carbon dioxide: oil and gas fields, coal beds, and deep saline aquifers. Of these three sedimentary formation types, Wisconsin has one potential candidate for geologic storage: a relatively uncharacterized section of the mid-continent rift that may have deep saline aquifers. In a recent forum of the Wisconsin Public Utilities Institute (WPUI), Jamie Robertson, Wisconsin's State Geologist, concluded that very little is known about the hydrogeology of the mid-continent rift and drilling programs to study it would be expensive. In addition, studies of the geology and potential carbon storage in the mid-continent rift would require greater effort than in other areas due to the block faulting and successive episodes of uplift and subsidence in this feature.

The U.S. Department of Energy has focused research on carbon storage into seven regional sequestration partnerships. Wisconsin is a part of the Plains CO2 Reduction Partnership, which has identified promising geological formations for carbon storage in the Williston Basin (MT and ND), Powder River Basin (WY and MT) and Denver-Julesberg Basins (CO). The carbon disposal opportunities closest to the major baseload power plants in Wisconsin, however, are in the Illinois Basin, part of the Midwest Geological Carbon Sequestration Consortium (MGCSC). The distance from power

plants to the carbon storage formations will be most important early in the deployment of CCS in the U.S. due to the high cost of carbon dioxide pipelines, approximately $800,000 to $1,000,000 per mile.

The hydrogeology of Illinois, in contrast to Wisconsin, includes all three options for carbon storage in sedimentary geological formations (oil and gas fields, coal seams, and deep saline aquifers) in relatively uniform layers across a wide area of Illinois, Indiana, and Kentucky (the Illinois Basin). The characteristics of these formations for carbon storage have also been the subject of millions of dollars worth of research and ongoing tests as part of the MGCSC. The Illinois geology is also promising because of the overlapping geography of the different carbon storage options and the potential for cost-effective development of carbon dioxide transport infrastructure using enhanced oil recovery (EOR). The numerous depleted oil reservoirs in Illinois are prime candidates for EOR, a process of injecting carbon dioxide to recover additional oil that has been used for decades in Texas. The economic benefits of additional oil recovery are planned to help pay for a carbon dioxide pipeline in Illinois that would connect the oil fields with major coal producing and generating areas. The formation with greatest capacity for long-term storage of carbon dioxide in Illinois, the Mount Simon deep saline aquifer, is found thousands of feet beneath the oil fields, and would be accessible from the planned carbon dioxide pipeline. The Mount Simon formation in Illinois has been used since 1959 to store natural gas for Chicago with 137 injection and extraction wells, up to 4,000 feet deep, spread out over 23,000 acres in east-central Illinois (Energy Information Agency).

3 Coal gasification for fuels and chemicals

A final application for CCS is the conversion of high carbon fuels such as coal, petroleum coke (high carbon residue byproduct of oil refineries) to lower carbon fuels such as synthetic transportation fuels and chemicals. In this process, the syngas from a gasifier is converted to liquid fuels, ammonia or methane and the carbon released during the conversion is captured and stored. The conversion of high carbon fuels (e.g., coal and petroleum coke) to methane creates a synthetic or substitute natural gas (SNG) that meets pipeline quality and is distributed in the existing natural gas infrastructure. Production of SNG with CCS and subsequent combustion in a natural gas power plant is one additional option for reducing greenhouse gas emissions from Wisconsin's power sector.

The full fuel-cycle greenhouse gas emissions from SNG production with CCS are comparable to traditional natural gas production, while without CCS the lifecycle emissions of SNG are up to 175% higher than conventional natural gas (MIT Future of Coal, Appendix 3F, 2007). The high efficiency of natural gas combined-cycle (NGCC) power plants and the reduced carbon content of SNG produced with CCS compared to coal results in greenhouse gas emissions approximately 1/2 to 1/3 of those from pulverized coal plants. In Wisconsin, typical greenhouse gas emission rates for pulverized coal plants range from 2,000 pounds/MWh to 2,500 pounds/MWh while NGCC plants range from 800 to 850 pounds/MWh.

The levelized cost of electricity from NGCC can be calculated based on the price of SNG and the cost of construction for NGCC plants. Proposed SNG projects in Illinois have sold SNG through long-term fixed price contracts at around $6/MMBtu. Thus, the levelized cost of electricity from NGCC is likely to be similar to the forecasts of natural gas prices in the Energy Information Agency's Energy Outlook 2007, which show natural gas prices stable at around $6/MMBtu for the next 20 years. The SNG prices, however, would be fixed or only modestly variable compared to the traditional Henry Hub prices for conventional natural gas. The levelized cost of electricity from NGCC plants with natural gas at $6.75/MMBtu were estimated at $68/MWh (compared to $64/MWh for SCPC and $78/MWh for IGCC) by the National Energy Technical Laboratory in May 2007 for the reference cases without CCS (DOE/NETL-2007/1281).

4 CCS Deployment Timeline

The timeline for deploying CCS that would be available to lower greenhouse gas emissions from the electrical sector in Wisconsin is strongly dependent on the pace of carbon storage implementation in Illinois. A summary document prepared by the World Resources Institute for the Illinois Climate Change Advisory Group in May, 2007 provides some detail on the status of CCS in Illinois. The implementation timeline for CCS is also dependent on the technology used. Of the three large-scale ongoing carbon sequestration projects (Sleipner, Norway, 1 $MtCO_2$/year; Weyburn, Canada 850,000 tCO_2/year; In Salah, Algeria, 1 $MtCO_2$/year), two strip carbon dioxide from natural gas fields rich in CO_2 and one, (Weyburn) captures the carbon dioxide from a coal to SNG plant.

The gasification projects that produce liquid fuels, chemicals and SNG are easier to implement with carbon capture because the carbon dioxide is separated as part of the chemical conversion and does not extract a high capital or energy penalty. Direct carbon capture from power plants, both pre- and post-combustion, requires additional equipment and reduces electrical output. Of relevance to Wisconsin is a carbon dioxide capture pilot project at the WE Energies Pleasant Prairie pulverized coal plant which will capture and vent a very small portion of the flue gas to study a new chilled ammonia process for carbon capture. A number of new IGCC power plants with various levels of carbon sequestration are under development in the U.S. and Europe. The construction of a new plant with CCS or the retrofit of an existing plant with CCS in Wisconsin is not likely for at least 5 or more years. Governor Doyle, however, has issued an executive order for the Public Service Commission of Wisconsin to explore the possibility of a multi-utility IGCC plant in Wisconsin.

In Illinois, CCS from a coal or petroleum coke plant to SNG with EOR is possible in as early as two or three years. The SNG from Illinois could be used in existing NGCC plants in Wisconsin to offset coal consumption and reduce carbon dioxide emissions or in a new NGCC facility (Wisconsin has 2,400 MW of recently built NGCC plants, noe with cogeneration, that operate at approximately 30% capacity factors). Because the SNG technology is established and proven (Great Plains Synfuel has produced SNG from

N.Dakota lignite for almost 20 years, with CCS used in Weyburn Canada for EOR since 2000) the deployment is dependant only on the carbon dioxide infrastructure and the construction timeline for the SNG plants. The following projects for SNG are currently under development:

- Secure Energy, Decatur, IL has received an Illinois EPA air permit, has completed contracts with Siemens for 500MWth gasifiers and will produce up to 50 BCF of pipeline quality substitute natural gas beginning in late 2008 or early 2009.
- Two additional SNG projects in Illinois (Madison Power and Power Holdings) have completed front end engineering and design (FEED) studies to develop SNG plants of between 30 and 50 BCF.
- More recently, Peabody Energy and Conoco Philips (E-Gas gasification technology) entered an agreement in July, 2007 to develop SNG facilities in the Midwest with CCS.

5 References for Additional Information

IPCC Special Report on Carbon Dioxide Capture and Storage
http://www.ipcc.ch/activity/srccs/index.htm

Midwest Geological Carbon Sequestration Consortium www.sequestration.org

MIT 2007 "Future of Coal" http://web.mit.edu/coal/

National Energy Technical Laboratory 2007 "Cost and Performance Baseline for Fossil Energy Plants" http://www.netl.doe.gov/energy-analyses/pubs/Bituminous%20Baseline_Final%20Report.pdf

Wisconsin Public Utilities Institute 2007 Power Lunch: Carbon Sequestration
http://wpui.wisc.edu/Past%20Programs/CarbonSequestrationPLPresentations.htm

Wisconsin Global Warming Task Force Workgroup
Template For Presentation Policy Options

1. **Workgroup**: Generation and Delivery (Supply-Side) Subgroup
2. **Policy Name:** Incentives for Combined Heat and Power (CHP) and boiler construction and upgrades.
3. **Policy Type:** Fiscal and regulatory recovery measures to encourage investment in combined heat and power generation and distribution systems.
4. **Affected Sectors, Sub-Sectors and/or Entities:**

   Sector: Electric utility.

   Sub-sectors: Distribution Utilities
5. **Estimated Greenhouse Gas Emissions Reduction Impact:** Estimated reduction in GHG emissions is as follows:

   2020: 1.69 to 4.84 million metric tonnes

   2030: 1.97 to 4.55 million metric tonnes
6. **Estimated Costs:** Estimated electric rate impacts are estimated to be as follows:

   2020: $163 million to $468 million

   2030: -$80 million to $58 million
7. **Specific Description of Policy Proposal:** Develop regulatory recovery mechanisms that encourage the identification and development of combined heat and power facilities through out the State. Emphasis should be on projects that maximize the thermal host in order to maximize efficiencies.
8. **Timetables, Duration and Stringency Option:** Identification and investment to take place over next 20+ years.

9. **Explanation of Rough Estimate of GHG Reductions:** Emission reductions based on EGEAS run with a 500 MW CHP unit installed in 2015 for the lower bound case and a second 500 MW unit installed in 2018 for the upper bound case as compared to base case run.
10. **Rough Estimate of Costs for Selected Years:** Costs are based upon estimated incremental capital costs for a CHP facility less the savings in fuel costs associated with the improved cycle efficiencies. Costs in a particular year are based upon cost of service methodology using EGEAS.
11. **Barriers to Implementation:** Primary barriers are the capital costs associated with a CHP facility, the availability of appropriate thermal host sites to achieve necessary cycle efficiencies, and the risks associated with the long term commercial viability of the thermal host.
12. **Other Factors:**

Wisconsin Global Warming Task Force Workgroup
Template For Presentation Policy Options

1. **Workgroup**: Generation and Delivery (Supply-Side) Subgroup
2. **Policy Name:** Transmission and distribution system upgrades to reduce line losses.
3. **Policy Type:** Capital investment into the transmission and distribution infrastructure to reduce line losses. Possible legislative and regulatory involvement regarding sighting and construction to reduce overall costs.
4. **Affected Sectors, Sub-Sectors and/or Entities:**

   Sector: Electric utility.

   Sub-sectors: Transmission Utilities, Distribution Utilities
5. **Estimated Greenhouse Gas Emissions Reduction Impact:** Estimated reduction in GHG emissions is as follows:

   2020: Distribution – 0.161 to 0.268 million metric tonnes

   Transmission – 0.056 to 0.091 million metric tonnes

   2030 and 2050: Same as above (assumes constant MWh reduction in losses over 37 year regulatory life of Station Equipment)
6. **Estimated Costs:** Estimated electric rate impacts are estimated to be as follows:

   2020: Distribution: $180 million to $263 million

   Transmission: $97 million

   2030: Distribution: $122 million to $166 million

   Transmission: $65 million

   2050: Distribution: $14 million to -$41 million (a.k.a. cost reduction)

   Transmission: -$3 million (a.k.a. cost reduction)

7. **Specific Description of Policy Proposal:** Increase capital expenditures to upgrade transmission and distribution systems to reduce losses. This includes increasing voltage, re-conductoring, etc.
8. **Timetables, Duration and Stringency Option:** Increased expenditures assumed to take place over a ten year period with expenditures returning to normal at that time.
9. **Explanation of Rough Estimate of GHG Reductions:** Distribution estimates are based on reduced distribution losses of 230,800 MWhs to 382,800 MWhs once all distribution projects are completed. Transmission estimates are based on approximately a 6%-10% reduction in transmission losses (80,000 MWhs-130,000 MWhs). Once completed, savings assumed to be constant year-to-year. In order to convert MWh savings into CO2 reductions, a system average emission rate of 0.7 metric tonnes/MWh was used for the conversion.
10. **Rough Estimate of Costs for Selected Years:** Costs are based on an estimated increase in capital expenditures between $1.8 billion and $2.8 billion over a ten year period for distribution improvements and $1 billion for transmission improvements. The rate impacts in a particular year reflect the capitalization costs in that particular year assuming cost of service methodology. Offsetting these costs is the reduction in fuel and capacity purchases required as a result in the reduction in losses. As a result, the impact in 2050 could be a reduction in cost.

11. **Barriers to Implementation:** Primary barriers are the financial cost of the improvements.
12. **Other Factors:**

Wisconsin Global Warming Task Force
Draft Policy Option Template v1

Workgroup: Electric Generation
Policy Name: Carbon Performance Standard
Policy Type: Regulation/Market-Based Mechanism
Estimated 2020 GHG Reductions Compared to BAU: 21 million metric tons of CO2e
Affected sectors, subsectors and/or entities: Major new electric generation units

Description
Require new [and/or existing] electric generation units above [30 MW] to achieve a CO2 emissions rate per MWh equal or less than a nominal combine cycle natural gas rate. For discussion purposes this rate is estimated to be 1100 lbs/MWh. New EGUs could meet the standard by securing qualified emissions offsets, capturing and sequestering CO2, or using low-CO2 fuels such as biomass or natural gas.

Timetables, duration and stringency
Requirements would begin in [2012] and remain constant [pending reevaluation of all state policies].

Rough estimate of GHG reductions from BAU in 2020
Based on forecasts of new EGU builds in Wisconsin between 2012 and 2020, the policy would not result in emission reductions in 2020. New units already coming into service by 2012 are forecast to be adequate to meet demand through 2020. In the 2007 Annual Energy Outlook, no unplanned additions are forecast in the MAIN region between 2012 and 2020. If the policy began earlier, in 2010, several large units could be included perhaps totaling 2,000-4,500 MW.

If the policy applied to all existing EGUs, emissions reductions are estimated to be 23 MMT of CO2e in 2020. This assumes that 2020 baseline emissions are 59 MMT (ref. USEPA multi-pollutant analysis), 95% from coal at a rate of 1750 lbs/MWh, and the performance standard requires controlling or offsetting (1-(1100/1750)) = 37% of these emissions.

In general, for each 1,000 MW included in the policy, emissions could be reduced by about 2.4 MMT of CO2e.

Rough estimate of Costs in 2020
Based on rough estimates of costs for each type of compliance option, using $10/ton for offsets, $50/ton for fuel substitution, and $100/ton for CO2 capture and sequestration, the annual costs of this option would fall into the range of $230 million to $2.3 billion in 2020, with a working estimate of $517 million, assuming that 75% of compliance takes place through offsets, 20% through fuel substitution and 5% through carbon capture and sequestration. Such a portfolio would lead to an average cost of $22.5/ton. This compliance strategy portfolio can be easily changed by the subgroup or Task Force.

These are direct costs of implementation and do not include administrative or macroeconomic costs.

Barriers to implementation

Could be overlapping with GHG caps, other state policies-*coordinate/decide clearly*
Need for qualified offsets at large scale-*tie to state offset policy*
Availability of lower-GHG fuels and the engineering feasibility of co-firing or blending-*R&D*
CO2 capture and sequestration technologies still under development-*R&D*
Cost of policy could be political and competitiveness issue-*put into regional/national context*
If compliance options are not available or clearly set out, could cause investment chill with reliability impacts-*thoughtful regulatory framework*
Even with compliance clearly developed, will raise costs of new capacity and place premium on existing capacity; some potential for GHG increases as secondary impact of less efficient existing capacity being favored over new units-*consider in policy process*

Wisconsin Global Warming Task Force Workgroup Template For Presentation Policy Options

1. **Workgroup**: Electric Generation & Supply Working Group
2. **Policy Name:** Transmission system expansion to support new renewables/low-emitting generation
3. **Policy Type:** Legislation amending existing transmission siting statutes, with regulatory implementation and enforcement. This policy can only impact in-state transmission projects. Coordination with other state and federal regulatory agencies is required to fully implement this policy.
4. **Affected Sectors, Sub-Sectors and/or Entities:**

   Sector: Electric utility - Supply

   Sub-Sector: Transmission owning companies
5. **Estimated Greenhouse Gas Emissions Reduction Impact:** Transmission access enables the use of the following options to reduce CO2:

   Dispatch WI combined cycle units before coal units = 6.8 million metric ton CO2 reduction (as soon as electric and natural gas transmission can accommodate re-dispatch and coal contracts can be adjusted)

   Canadian Hydro (500 Mw) = 2.7 million metric ton CO2 reduction (2020)

   Western Wind (500 Mw @ 40% capacity factor) = 1.3 million metric ton CO2 reduction (2027 – 2037; assumes 20 to 30 years to build network to deliver western wind resources)

   Wisconsin Wind (500 Mw @ 27.5% capacity factor) = 0.9 million metric ton CO2 reduction (2015-2017)

6. **Estimated Costs:** State administrative costs will be negligible. Other material cost impacts include increased electric revenue requirements.

   Dispatch WI combined cycle units before coal units increases fuel and O&M costs by $338.6 million/yr (2007$) (excludes changes in allowance costs, congestion and loss charges). An investment of $XXX to YYY million needs to be made in the existing Wisconsin electric transmission system. An investment of $ZZZ to $AAA million may need to be made in the existing Wisconsin natural gas transmission system in order to allow base load operation on Wisconsin's combined cycle units.

   Canadian hydro cost – may (could be lower based on market conditions) be priced at all in cost (owning and operating) of either a new combined cycle unit or a nuclear unit. The real levelized cost of a combined cycle unit and a nuclear unit is approximately $69.1/Mwh and $77.1/Mwh respectively, whereas the 50/50 coal/combined cycle energy cost is approximately $44.2/Mwh. Compared to the 50/50 coal/combined cycle energy cost, 500 Mw of Canadian hydro would increase annual production costs by $ 92.7 to 122.5 million/year. Approximately $XXX to YYY million needs to be invested in the existing electric transmission system in order to import Canadian hydro into Wisconsin.

   Western Wind – Western wind (40% capacity factor) real levelized capital and O&M cost (includes incremental congestion and losses between the "west" and Wisconsin) is approximately $56.2/Mwh whereas the 50/50 coal/combined cycle energy cost is approximately $44.2/Mwh. Compared to the 50/50 coal/combined

cycle energy cost, 500 Mw of Western wind would increase annual production costs by $21.0 million/year. Assumes adequate transmission is built in the Midwest. Approximately $XXX to YYY million needs to be invested in the existing Midwest electric transmission system in order to import western wind into Wisconsin.

Wisconsin Wind – Wisconsin wind (27.5% capacity factory) real levelized capital and O&M cost is approximately $84.2/Mwh. Compared to the 50/50 coal/combined cycle energy cost, 500 Mw of Wisconsin wind would increase annual production costs by $48.2 million/year. Approximately $XXX to YYY million needs to be invested in the existing Wisconsin electric transmission system in order to significantly increase the use of wind generation in Wisconsin.

These cost estimates exclude:

1. The electric transmission related costs such as allocation of construction costs, congestion and marginal losses. **[This item may be modified to exclude construction costs if construction cost estimates are available]**
2. The construction costs related to investment in new natural gas transmission capacity into and within Wisconsin. **[This item may be removed if cost estimates are available or it is determined not to be an issue]**
3. Changes in fossil allowance costs.

4. The operational impacts associated with control for scenarios with large amounts of wind generation in the region.
5. Capacity cost savings associated with the dependable capacity rating associated with the option.

7. **Specific Description of Policy Proposal:** The Public Service Commission of Wisconsin (PSCW) enforces the current administrative rules that pertain to the site selection and construction of new transmission lines in Wisconsin. Legislation needs to be adopted that will allow for revision to the current rules in order to:
    - Streamline the transmission line permitting process.
    - Allow for acquisition of transmission line right away prior to need (whether it is re-dispatch of existing fossil assets or development of new distributed renewable resources).

   In addition the state needs to continue to work with neighboring states and the federal government to expedite the needed development of the transmission network in the Midwest so that Wisconsin can expand its access to high capacity factor wind resources and/or Canadian hydro generation and at the same time be vigilant that Wisconsin ratepayers do not bear an unfair portion of the development costs.
8. **Timetables, Duration and Stringency Option:** Since this policy has two tiers (intra state and interstate/federal) there are two time tables. For the intra state transmission projects the policy timetable is dependent on the Wisconsin legislative process. The timetable for the interstate/federal tier is very difficult to

estimate and is affected in part by what other states will be doing to comply with existing RPS and climate change initiatives. The duration is until the law is changed. This policy should be regarded as stringent as a result of PSCW enforcement authority, subject to judicial proceedings that may strengthen landowner rights.

9. **Explanation of Rough Estimate of GHG Reductions:** The re-dispatch from coal to combined cycle unit calculations were based on reports developed by the State of Wisconsin and EIA 906/920. Standard estimates of CO2 emission rates (lb/MMBtu) and heat rates (Btu/Kwh) for coal and combined cycle generating technologies were used. The estimate of coal that could be replaced with combined cycle generation assumed at least a 40% minimum load level for coal generation at all times and 12 weeks per year at full output is required 80 hours/week for transmission/generation capacity needs. Canadian hydro, western wind and Wisconsin wind assumed that their output would replace 50% coal and 50% combined cycle output.
10. **Rough Estimate of Costs for Selected Years:** For the material costs associated with the re-dispatch of generation from coal to combined cycle the following costs were assumed:

Parameter	Coal Unit	Combined Cycle Unit
Fuel Cost - $/MMBtu	2.0	8.0
Variable O&M - $/Mwh	2.0	4.0

The following costs were assumed for the development of material costs associated with Canadian hydro (tied to combined cycle and nuclear unit costs) and wind resources:

Parameter	Wind	Combined Cycle	Nuclear
Capital Cost	$2,364/kw Escalated 2010 cost	$818/kw Overnight 2007 cost	$3,760/kw Overnight 2007 cost
Fixed O&M	$28.51/kw-yr 2005$	$8.54/kw-yr 2007$	$115/kw-yr 2007$
Variable O&M	None	$3.6/Mwh 2007$	$11/Mwh 2007$
Heat Rate	None	6.68 MMBtu/Mwh	10.7 MMBtu/Mwh
Fuel Cost	None	$8.0/MMBtu 2007$	$1.022/MMBtu 2014$

The capital cost for the wind project is based on an internal capital cost estimate that reflects current market conditions.

[Basis for the estimated transmission investment costs for the various resource options.]

11. **Barriers to Implementation:** Landowners may strongly oppose this policy change. It could be extremely difficult to coordinate this policy with the policies of neighboring states and the federal government. The material cost impacts could cause financial harm to industries whose rates are impacted by changes in energy costs.

12. **Other Factors:** There could be duplication within the policy options (re-dispatch, Canadian hydro, wind development) mentioned that are impacted by the transmission system expansion option. For instance, the re-dispatch option could change the mix (coal and combined cycle) of the resources that are impacted by the Canadian hydro and wind options (i.e. the lb CO2/Mwh may be lower due to the re-dispatch) resulting in Canadian hydro and wind having less of an impact on CO2 reduction.

Another factor that needs to be considered is the assumption related to what the rest of the world is doing regarding CO2 reduction. If the rest of the world is not reducing CO2, the MISO central dispatch of the Midwest may result in Wisconsin coal generation being reduced and instead of increasing Wisconsin combined cycle generation, other Midwest coal generation could be increased resulting in increased imports into Wisconsin creating higher congestion and marginal loss costs for Wisconsin without the expected reduction in CO2 emissions.

Wisconsin Global Warming Task Force Workgroup
Template For Presentation Policy Options

1. **Workgroup**: Electric Generation and Supply

2. **Policy Name:** Increase nuclear power generation/Repeal nuclear moratorium

3. **Policy Type:** Legislation repealing current nuclear moratorium, with state and federal regulatory implementation and enforcement.

4. **Affected Sectors, Sub-Sectors and/or Entities:**

Sector: Electric utility

Sub-Sector: Distribution utilities

5. **Estimated Greenhouse Gas Emissions Reduction Impact:** Reduction in 2020 of 6.4 million metric tons of CO_2 compared to "business as usual" and each year thereafter with the construction of a single 1400 MW nuclear power plant. *(Source: analysis uses Energy Information Administration (EIA) predicted emissions from Annual Energy Outlook (AEO) 2007).*

6. **Estimated Costs:** Building a new nuclear plant, which will be between 1100 Mw and 1700 MW in size, is estimated to cost between $4-6 billion. Although this number seems large, a new nuclear plant is very large. Estimates show the electricity produced from new nuclear plants will be competitive to that produced by new clean coal plants with carbon capture control technology, renewables, and other projected new construction - even gas. Since the electricity will be competitive, the price should not be higher than the prices already predicted for the future. Price predictions by EIA AEO 2007 for the 7.3 MAIN and 6.3 2005 cents/kWh for MAPP (without mandatory GHG emission reductions). A mandatory GHG emission program in Wisconsin will cause prices to rise, call for more clean generation technology, but not affect the price of power from a new nuclear unit.

7. **Specific Description of Policy Proposal:** Repeal the limits in current law, s. 196.493, on the construction of nuclear power plants. These limits are often referred to as Wisconsin's "nuclear moratorium" law.

Under this statute, s. 196.493, the Public Service Commission (PSC) may not authorize the construction of a nuclear power plant unless it finds that there is a facility with sufficient capacity to receive the spent fuel from all nuclear power plants in Wisconsin and that construction of the power plant is economically advantageous to ratepayers based on specified factors.

Repealing the moratorium is the first step to increasing nuclear generation. Also, policy recommendations to promote nuclear generation should also include legislation to give the PSC authority to consider alternative rate making mechanisms, such as allowing carrying cost of construction work in progress (CWIP), for new nuclear plants or opening up leased generation to nuclear generation [s. 196..52(9)]. The use of alternative rate making principles could be applied to all non- or low- emitting generation technology, including nuclear, renewable, clean coal, etc., to create an incentive for the construction of cleaner plants. Incentives to site new reactors on existing brownfields would also be sensible.

8. **Timetables, Duration and Stringency Option:** It will take a utility about 9-10 years from the time it begins to pursue a new nuclear plant to the time the plant goes into service. [Note: This estimate from the Nuclear Energy Institute may be conservative. For example, it will be 12 years from the time the Oak Creek project was announced to completion.] This includes the time to prepare a license application, for the Nuclear Regulatory Commission to review the application, and for the plant to be constructed. Nuclear plants are initially licensed to run for 40 years and can receive a 20 year license renewal allowing a total of 60 years of operating life.

Wisconsin current portfolio includes 20 percent of its electrical generation capacity from nuclear power. The National Regulatory Commission (NRC) has recently renewed the operating licenses for the two reactors at the Point Beach nuclear power plant. Unit 1's operating license expires in 2030; Unit 2's license expires in 2033. Kewaunee's operating license expires in 2013. Dominion Resources, the owner of the Kewaunee nuclear power plant, has informed the NRC of its intention to apply for a license renewal for this plant in the second quarter of 2008. If approved, it appears the new operating license would expire in 2033.

Replacement planning of these baseload plants will take at least a decade of lead-time. Given the vital contribution of these two plants to our energy portfolio and the projected growth of energy consumption in Wisconsin, it is prudent that we not tie the hands of future PSC Commissioners by limiting their options as they determine how to best replace these decommissioned plants.

9. **Explanation of Rough Estimate of GHG Reductions:** A new 1400 MW nuclear power plant in Wisconsin would reduce CO2 emissions by the power generation sector by approximately 6.4 million metric tons per year in 2020 and each year thereafter. *(Source: analysis uses Energy Information Administration (EIA) predicted emissions from Annual Energy Outlook (AEO) 2007) An estimate of the 2020 emissions rate for the MAIN and MAPP regions was calculated and then the two averaged and applied to the electricity a 1400 MW nuclear plant operating at a 90% capacity factor to calculate the emissions avoided by that nuclear plant. When using the estimated 2030 regional emissions rates, the amount avoided is virtually the same - 6.5 million metric tons. It should be noted that the average capacity factor of the U.S. nuclear fleet today is 90% and this capacity factor is widely believed to be applicable to the new fleet of reactors that will begin to come online in the middle of the next decade and beyond.)*

10. **Rough Estimate of Costs for Selected Years:** *See item #6 "Estimated costs" above.*

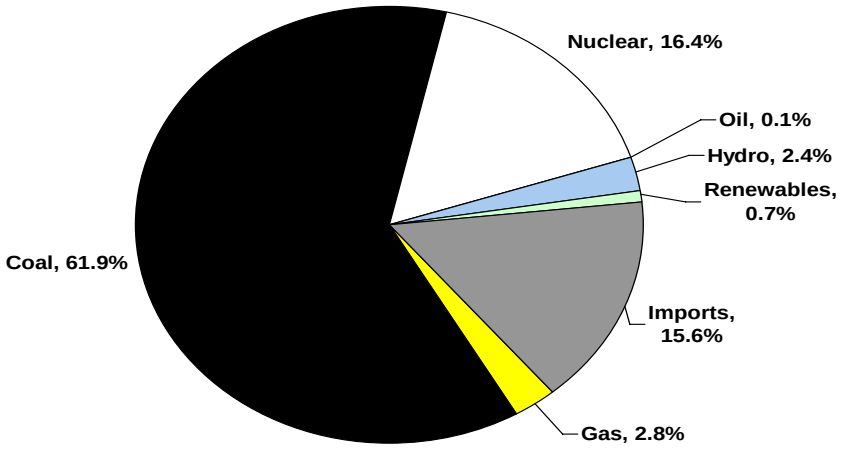
11. **Barriers to Implementation:** The major barrier to implementation of this policy is the need for legislation to repeal the moratorium and implement incentives for construction. Once there is a political appetite to lift the moratorium, there is a long exhaustive approval process at the state and federal level.

Currently nuclear waste is stored on-site in either a pool or dry cask storage. The most optimistic estimates have Yucca Mountain available as a national repository by 2017; however, once Yucca is operational, transportation is an additional consideration until reprocessing technology improves.

NIMBY (not in my back yard) opposition is also a concern with a new reactor on a new site; however, less prevalent when being built next to a reactor currently in operation. In fact, in a recent national survey of 1,100 adults by Bisconti Research, Inc. with Quest Research Group, eighty-two percent of Americans living in close proximity to nuclear power plants favor nuclear energy, and 71 percent are willing to see a new reactor built near them.

12. **Other Factors:** First and foremost, nuclear energy is the only form of baseload power in Wisconsin which produces zero greenhouse gasses.

Current Electric Generation by Plant Type in Wisconsin for 2004*:



**Source: Strategic Energy Assessment – Draft: June 2006*

There are 103 active nuclear power plants in the U.S. and an additional 339 plants worldwide. The U.S. has more nuclear power plants than any other nation, but some other nations rely more heavily on nuclear power than does the U.S. France, for example, relies on nuclear power for 78 percent of its electricity.

No new nuclear generators have been built in the U.S. over the past three decades. The federal government has stepped in with the Energy Policy Act of 2005 to provide investment stimulus for new nuclear power plants, in the form of loan guarantees, production tax credits and federal risk insurance to offset the higher cost of the first new nuclear plant designs. As a result, 12 companies or consortia have expressed interest in building as many as 30 new nuclear plants.

One kilogram of natural uranium contains as much energy as 38.5 tons of coal, but conventional reactors utilize only approximately 3 percent of that energy. Notwithstanding this seemingly inefficient use of nuclear fuel, after more than 30 years of operation, nuclear plants have produced only 54,000 tons of spent fuel, all of which has been safely stored. To put this in perspective, if all used reactor fuel was collected in one location; it would cover a football field to a depth of six feet. Technology is being developed which will allow us to safely reprocess this spent fuel providing us with an almost unlimited supply of nuclear fuel and negating any long-term storage concerns.

Wisconsin Global Warming Task Force Workgroup
Template For Presenting Policy Options

1. **Workgroup**: Utility Generation Workgroup

2. **Policy Name:** Windpower Siting Reform

3. **Policy Type:** Legislation and PSC rulemaking

4. **Affected Sectors, Sub-Sectors and/or Entities:** Public Service Commission, utilities, counties, municipalities and towns, wind energy industry.

5. **Estimated Greenhouse Gas Emissions Reduction Impact:** 1 million tons/yr reduction by 2015, 1.5 million tons/yr reduction by 2020, and 2.0 million tons/yr by 2025.

6. **Estimated Costs:** No cost to utilities. With more project applications to review, an increase in the PSC's workload is likely, which may result in additional administrative expenses. However, siting reform is likely to reduce costs borne by developers in dealing with local opposition, including increases in installation costs caused by permitting delays as well as direct litigation costs.

7. **Specific Description of Policy Proposal:** Legislation would contain the following elements: (1) definitions of large and small wind energy systems; (2) a

requirement on the PSC to draft uniform standards for siting large and small wind energy systems; (3) creation of an optional process for PSC review of projects under 100 MW that have large wind energy systems; (4) a mechanism for allowing parties to appeal a decision rendered by a local jurisdiction to the PSC; (5) extending Chapter 227 judicial review provisions to wind projects permitted by local jurisdictions, including the ability to appeal a decision under 100 MW; and (6) a prohibition on local ordinances restricting meteorological test towers. These provisions would essentially require the PSC to promulgate standards for local review, such as setback distances and sound output, and apply them to both agency-reviewed projects as well as those reviewed by local land use authorities.

8. **Timetables, Duration and Stringency Option:** Once the legislation is enacted, the PSC would have a specified period of time to adopt emergency rules establishing uniform standards for siting wind projects. These standards would apply to PSC-reviewed wind projects as well as those reviewed by local jurisdictions. These rules would remain in effect indefinitely.

9. **Explanation of Rough Estimate of GHG Reductions:** The 2015 estimate is based on the assumption that 440 MW of windpower would be placed in service in Wisconsin that otherwise would not have been built due to restrictive ordinances adopted by local jurisdictions to placate opponents to a specific wind project. Four hundred forty MW of windpower operating at a capacity factor of 26% should produce one million MWH per annum, which in turn should reduce

emissions by one million tons a year. I conservatively estimate that another 440 MW of windpower will be built on Wisconsin land between 2015 and 2025, with half of that to occur by 2020. I am optimistic that additional wind capacity will be built in the waters off Wisconsin. However, it is unclear whether the PSC would have permitting authority over generation projects built in the Great Lakes, so I cannot provide attribute GHG reduction savings from offshore wind development to this policy.

10. **Rough Estimate of Costs for Selected Years:** The savings from reduced preconstruction costs should outweigh any additional costs to the PSC from any increase in the number of wind project applications to review.
11. **Barriers to Implementation:** The only barrier to adoption would be political will, or lack thereof, at the state level.
12. **Other Factors:** The wind energy siting reform proposal tracks closely with the large livestock siting law adopted two years ago.

Wisconsin Global Warming Task Force Workgroup
Template For Presentation Policy Options

1. **Workgroup**: Generation and Delivery (supply side) sub work group.

2. **Policy Name:** Assessment of Off-Shore Wind Potential.

3. **Policy Type:** Development of task force to assess technical and economic potential for wind generation in Great Lakes bordering Wisconsin.

4. **Affected Sectors, Sub-Sectors and/or Entities:**

   Sector: Electric utility

   Sub-Sector: Distribution utilities

5. **Estimated Greenhouse Gas Emissions Reduction Impact:** This policy could ultimately result in the siting of off-shore wind generation. Given the relatively high wind potential in the Great Lakes, this policy could result in increased options for meeting the state's RPS standards. However, previous assessments have indicated that off-shore wind costs are likely substantially higher than on-shore costs. See e.g., "A Study to Evaluate the Impacts of Increasing Wisconsin's Renewable Portfolio Standard," prepared for Department of Administration, October 31, 2003, p. 8.

6. **Estimated Costs:** There would be limited governmental administrative costs associated with this program. These costs would mostly involve the state's

involvement in a task force to evaluate off-shore wind potential. The task force would likely have Department of Natural Resources, Public Service Commission, and Board of Commissioners of Public Lands representatives. In addition, utility, independent power producer, environmental, commercial fishing, commercial shipping, riparian, and other representatives could be invited to join the task force.

7. **Specific Description of Policy Proposal:** The Commission, DNR, and BCPL would be requested to form a task force to evaluate the technical and economic potential for wind generation in the Great Lakes bordering Wisconsin. Among other issues, this task force would evaluate the wind potential in Lake Michigan and Lake Superior, costs of development of wind facilities in the lakes, public trust issues related to wind development in the lake bed, avian impact issues, potential riparian owner concerns, and effective regulatory approaches to addressing siting issues. The task force would also evaluate whether the state should explore a partnership with Michigan regarding the development of off-shore wind facilities in Lake Michigan.

8. **Timetables, Duration and Stringency Option:** The task force would convene by July 1, 2008 and would issue its findings and recommendations by December 31, 2008.

9. **Explanation of Rough Estimate of GHG Reductions:** This policy, standing alone, would not result in any additional GHG reductions. However, if off-shore

wind development is found technically and economically feasible, the findings and recommendations of the task force may assist in the development of off-shore wind projects, which would help the state meet its present and potentially its enhanced RPS standards.

10. **Rough Estimate of Costs for Selected Years:** There would be relatively limited governmental administrative costs with this policy. These governmental costs would mostly involve the time spent by representatives of the Commission, DNR, and BCPL on task force matters.

11. **Barriers to Implementation:** There should not be barriers to convening the off-shore wind task force. There may be legal and other barriers to any recommended actions issued by the task force.

12. **Other Factors:**

mw1363893_1

Wisconsin Global Warming Task Force Workgroup
Template For Presentation Policy Options

1. **Workgroup**: Generation and Delivery (supply side) sub work group.

2. **Policy Name:** Rate Incentives for Renewable Energy – PSC/DNR Award for Cleanest Utilities in State.

3. **Policy Type:** If this policy is limited to CO2 and other emissions associated with utility-owned generation, this policy should not require any legislative or regulatory changes, but just an addition to the PSC's and DNR's web sites to disclose the air emissions associated with each utility and an award for the cleanest utilities. However, if it addresses emissions from non-utility owned generation, regulation and/or legislation may be needed to require utilities to collect and submit that information.

4. **Affected Sectors, Sub-Sectors and/or Entities:**

   Sector: Electric utility

   Sub-Sector: Distribution utilities

5. **Estimated Greenhouse Gas Emissions Reduction Impact:** This policy would encourage utilities to reduce their greenhouse gas and other emission profiles, by providing the cleanest utilities with awards.

6. **Estimated Costs:** There would be limited governmental administrative costs associated with this program. Those costs would mostly involve adding the air emissions inventory data for each utility and placing that information on the PSC's and DNR's web sites.

7. **Specific Description of Policy Proposal:** Under this proposal, the PSC and DNR would collect information regarding the annual emissions of CO_2 and other air contaminants associated with each utility's energy production and energy purchases. The PSC and DNR would then place that information on their respective web sites. They would also provide awards to the cleanest utilities based on the amount of their annual emissions per megawatt hour of energy sold.

8. **Timetables, Duration and Stringency Option:** This policy would take effect as soon as possible and would remain in effect indefinitely.

9. **Explanation of Rough Estimate of GHG Reductions:** This policy option would create incentives for utilities to reduce the CO_2 and other emissions associated with their energy production and purchases by allowing them positive public relations if they are the cleanest utilities in the state.

10. **Rough Estimate of Costs for Selected Years:** There should be limited governmental administrative costs for this policy, due to the collection of CO_2 and other air emission data and presentation of awards for the cleanest utilities. This

policy could also require some additional reporting by the utilities regarding the air emissions associated with energy that they purchase. However, this information would already be required if the carbon cost adder policy is implemented.

11. **Barriers to Implementation:** Regulation and/or legislation may be needed to require the submission of information by the utilities regarding the CO_2 and other emissions associated with the energy that they purchase.

12. **Other Factors:**

mw1363730_1

Wisconsin Global Warming Task Force Workgroup
Template For Presentation Policy Options

1. **Workgroup**: Generation and Delivery (supply side) sub work group.

2. **Policy Name:** Rate Incentives for Renewable Energy – Market-Based Options for Renewable Energy Customers.

3. **Policy Type:** Legislation amending Wis. Stat. §196.192 (market-based compensation, rates and contracts) to allow renewable energy users to receive market benefits and take market risks for their purchase of renewable energy.

4. **Affected Sectors, Sub-Sectors and/or Entities:**

   Sector: Electric utility

   Sub-Sector: Distribution utilities

5. **Estimated Greenhouse Gas Emissions Reduction Impact:** This policy would provide renewable energy users the option of purchasing renewable capacity and energy more directly from providers of that capacity and energy, potentially at rates below present utility green energy pricing. This should encourage the development of additional renewable energy and thereby reduce GHG emissions associated with energy usage in the state. For every increased megawatt hour of renewable energy, 1,851 pounds of CO_2 emissions are avoided.

6. **Estimated Costs:** There would be limited governmental administrative costs associated with this program. Utilities would be required to develop tariffs that allow renewable energy customers to purchase renewable capacity and energy from the providers of that capacity and energy.

7. **Specific Description of Policy Proposal:** Wis. Stat. §196.192 would be revised to require utilities to file with the Commission market-based pricing options and options for individual contracts that allow retail customers to enter into arrangements with renewable energy providers for renewable capacity and energy. Those retail customers would still be required to pay for their fair share of transmission and distribution costs. Sub-section 3(a) of Wis. Stat. §196.192, which requires a determination that the rate will not harm shareholders of the utility or other customers, would not apply to renewable capacity and energy purchases under this policy. Renewable energy and capacity purchased under this policy would not count toward RPS requirements.

8. **Timetables, Duration and Stringency Option:** This policy would take effect as soon as possible and would remain in effect indefinitely. This policy would not require any customers to purchase renewable energy, but would provide opportunities to those who wish to do so.

9. **Explanation of Rough Estimate of GHG Reductions:** This policy would encourage additional renewable energy purchases in Wisconsin. The avoided

emissions from each megawatt hour of renewable energy are estimated at 1,851 pounds of CO_2 based on the figure that DNR uses for its voluntary emission reduction program. See http://www.dnr.state.wi.us/org/aw/air/registry/quantwattcalc.html.

10. **Rough Estimate of Costs for Selected Years:** There would be limited governmental administrative costs for this policy, due to the requirement for the Commission to review and approve the market-based tariffs filed by the utilities. There would be administrative costs for the utilities in the development of the tariffs and work with their customers that wish to enter into arrangements under the tariffs.

11. **Barriers to Implementation:** Legislation would likely be required to implement this program.

12. **Other Factors:**

mw1363804_2

Wisconsin Global Warming Task Force Workgroup
Template For Presentation Policy Options

1. **Workgroup**: Generation and Delivery (supply side) sub work group.

2. **Policy Name:** Rate Incentives for Renewable Energy – Incorporation of CO_2 Costs into Price of Traditional Energy Generation.

3. **Policy Type:** Legislation amending the PSC's rate-making authority to allow it to impose a "carbon-cost adder" based on the CO_2 emissions associated with electrical energy sold in Wisconsin.

4. **Affected Sectors, Sub-Sectors and/or Entities:**

   Sector: Electric utility

   Sub-Sector: Distribution utilities

5. **Estimated Greenhouse Gas Emissions Reduction Impact:** This policy would encourage utilities to adjust their production and purchase of energy to take into account the societal cost of CO_2 associated with the production and purchase of energy. Depending upon the level of the carbon-cost adder, significant reductions in GHG emissions are likely to occur.

6. **Estimated Costs:** There would be limited governmental administrative costs associated with this program. Depending on the level of the carbon-cost adder, there would be increases in the cost of electrical energy with CO_2 emissions.

However, these costs would directly result in the generation of additional revenues, which could be rebated to customers and/or used to help finance the purchase of renewable generation.

7. **Specific Description of Policy Proposal:** The Public Service Commission would be provided authority and required to develop an appropriate carbon-cost adder that would be payable by utilities based on the amount of carbon dioxide emitted from the utility's energy generation and energy purchases. The Commission could base its determination of the appropriate carbon cost adder on the existing CO_2 markets. The Commission would also develop a mechanism to periodically update the appropriate price of the carbon-cost adder. The revenues from the carbon-cost adder would be held by the Commission and returned to customers via rebates and/or used to help finance the purchase of renewable generation.

8. **Timetables, Duration and Stringency Option:** This policy would take effect as soon as possible and would remain in effect until the state implements either a cap-and-trade system or a carbon tax. Because the Commission would be required to develop and impose the carbon-cost adder, this policy would be mandatory.

9. **Explanation of Rough Estimate of GHG Reductions:** The level of GHG reductions would be dependent upon the price of the carbon-cost adder. The higher the carbon-cost adder, the greater incentive that utilities would have to

adjust their production and power purchases to lower carbon emitting sources of electricity. This would occur because after rates are set by the Commission incorporating the carbon-cost adder, utilities could take steps to reduce their costs by utilizing sources of electricity that have a lower carbon profile.

10. **Rough Estimate of Costs for Selected Years:** There should be limited governmental administrative costs for this policy, due to the requirement for the Commission to determine the appropriate carbon-cost adder, to set up a mechanism to collect funds from utilities and monitor utility CO_2 emissions under this program, and to oversee rebates to customers and/or financing of renewable energy purchases. There would be some administrative costs for utilities in monitoring and reporting the CO_2 emissions associated with their generated and purchased electricity and in implementing customer rebates and/or funding renewable energy purchases. There should be limited net costs to customers, if the revenues collected under the carbon-cost adder would be returned to customers through rebates.

11. **Barriers to Implementation:** Legislation would likely be required to implement this program.

12. **Other Factors:**

mw1363520_2

Wisconsin Global Warming Task Force Workgroup
Template For Presentation Policy Options

1. **Workgroup**: Generation and Delivery (supply side) sub work group.

2. **Policy Name:** Rate Incentives for Renewable Energy – Tax Deductibility of Payments Made by Customers.

3. **Policy Type:** Program could be voluntarily employed by utilities or implemented by legislation amending existing or addition to enhanced RPS, with regulatory implementation and enforcement.

4. **Affected Sectors, Sub-Sectors and/or Entities:**

   Sector: Electric utility

   Sub-Sector: Distribution utilities

5. **Estimated Greenhouse Gas Emissions Reduction Impact:** This program would create incentives for additional customers to "sign up" for renewable energy, by making the amounts that they contribute tax deductible, to the extent allowed by law. For each additional megawatt hour of participation by customers, this program would cause the reduction of approximately 1,851 pounds of CO_2 emissions, based on the figures that DNR uses for its voluntary emissions reduction program.

6. **Estimated Costs:** There would be no governmental administrative costs associated with this program. There would be significant cost savings to customers that voluntarily participate in renewable energy programs, since their contributions would be tax deductible. In addition, since there could be significant federal tax savings for Wisconsin residents, there could be substantial financial benefits to the state in general. It should be noted, however, that there would be a reduction in state revenues because contributions would be deductible from state income taxes, but the value of the federal deductions is likely to be approximately four times greater than the amount of the state deduction.

7. **Specific Description of Policy Proposal:** Presently, most renewable energy is purchased by retail customers through green energy rate programs (e.g., Energy for Tomorrow for WE Energies, NatureWise for WPS, Second Nature for Alliant, MGE Windpower for MG&E). However, WPS also has a SolarWise program which allows customers to make a tax deductible donation to WPS' foundation to help support the installation of solar panels on schools. This program also provides educational materials to teachers and students regarding solar power. This policy proposal would call for each of the Wisconsin utilities to provide a similar tax deductible option for supporting renewable energy in the state. However, it would not call for utility programs to invest solely in solar power. The policy would also call for each utility to provide information regarding this tax deductible option regularly in its billing materials to customers and on its web

site. Renewable energy financed under this policy would be separate from and in addition to the RPS requirement.

8. **Timetables, Duration and Stringency Option:** This policy would take effect as soon as possible and would remain in effect indefinitely. The policy would hopefully be implemented via voluntary action by the utilities without regulatory requirements. If not, the task force may need to examine whether the Commission could require that utilities implement this policy. If not, legislative changes may be required.

9. **Explanation of Rough Estimate of GHG Reductions:** The estimated CO_2 reductions per megawatt hour are based on DNR figures from its voluntary emissions reduction program. See http://www.dnr.state.wi.us/org/aw/air/registry/quantwattcalc.html. Although, it is difficult to estimate the projected increase in customer participation from a tax deductible program, it seems logical that many more customers would participate because of both the state and federal tax benefits and the recognition that they are making a donation for the benefit of their community and the state. This appears to be the case with SolarWise, which has about three to four times more participants than WPS' other green energy program, NatureWise.

10. **Rough Estimate of Costs for Selected Years:** There should be no significant governmental administrative costs for this policy. There would be some

administrative costs for utilities and/or their foundations to set up programs under this policy. However, the utilities and their foundations should also receive significant public relations benefits from implementing programs under this policy. There should be reduced costs to customers under this program because of the benefits of federal and state tax deductibility.

11. **Barriers to Implementation:** If the utilities agree to voluntarily develop programs similar to Solarwise, there should be no barriers to the implementation of the policy. If not, barriers could include the need to pass legislation, if the Commission is found not to have regulatory authority to require the utilities to implement the policy.

12. **Other Factors:** The utilities may have concerns that tax deductible green energy programs may discourage customers from participating in their other green energy programs. To that end, it may be appropriate for the Commission to consider examining whether costs for renewable energy required under the RPS be spread among all customers.

mw1363176_2

Wisconsin Global Warming Task Force Workgroup
Template For Presentation Policy Options

1. **Workgroup**: Generation and Delivery (supply side) sub work group.

2. **Policy Name:** Solar Energy Renewable Credit Program.

3. **Policy Type:** Legislation amending existing or adding to enhanced RPS, with regulatory implementation and enforcement.

4. **Affected Sectors, Sub-Sectors and/or Entities:**

   Sector: Electric utility

   Sub-Sector: Distribution utilities

5. **Estimated Greenhouse Gas Emissions Reduction Impact:** To the extent this program requires an overall increase in the RPS standard, it would cause decreases in GHG emissions at a rate of approximately 1,851 pounds per megawatt hour.

6. **Estimated Costs:** Administrative costs would include those associated with establishing a solar renewable energy credit program and a market for the sale and purchase of those credits. The other material costs are potential electric rate impacts. Based on the cost of solar RECs in New Jersey, these costs are likely to range from $150 to $300 per megawatt hour. So long as the additional solar RPS

requirement is relatively low, the increase to electrical rates should be relatively minor.

7. **Specific Description of Policy Proposal:** Wisconsin currently has legislation imposing an RPS that has been implemented by a PSCW rulemaking and is backed by PSCW enforcement authority. This policy recommendation would modify the RPS as specified below. Consistent with New Jersey's solar renewable energy certificate program, this program would provide individuals that produce solar power one credit for each megawatt hour of energy they produce. Utilities would be required to obtain an increasing amount of these credits over time, based on the total amount of energy they sell. In New Jersey, the utilities are required to obtain credits equal to increasing percentages of their total energy sales. These percentages increase from 0.01% in 2004-2005 to 2.12% in 2015-2016. In New Jersey, the solar RECs presently sell for about $200 per megawatt hour unit. There is a cost cap of $300 per megawatt hour unit, since the utilities can pay that amount to the New Jersey Public Utilities Board in lieu of buying solar RECs.

8. **Timetables, Duration and Stringency Option:** If a comparable policy to that of New Jersey is developed, the timetable for this policy recommendation would begin by 2010 **[?]** and the percentage requirements would slowly increase until at least 2020, when they would reach about 2%. This policy should be regarded as stringent as a result of PSC enforcement of this requirement.

9. **Explanation of Rough Estimate of GHG Reductions:** Meeting the new RPS standard would require an estimated 1.85 million MWh of additional renewable energy annually by 2020.

10. **Rough Estimate of Costs for Selected Years:** Incremental administrative costs of the solar REC program would include costs to develop the certification program and to conduct the market for sales of solar RECs to utilities. The other main cost is potential impact on electric rates. This cost is likely to be between $150 and $300 per megawatt hour of solar energy. If similar percentage requirements are enacted to those in the New Jersey solar REC program, the costs would gradually increase from a negligible amount to between $277.5 million and $555 million in 2020.

11. **Barriers to Implementation:** The major barrier to implementation of this policy is the need for legislation to amend to the existing standard. Opposition may come from large electric customers who believe that this requirement will materially increase their electricity costs. To the extent that a significant carbon-adder is perceived as likely, and that the installed costs of solar resources will come down over time compared to new, coal and gas-fired units, as a result of increased manufacturing capacity and technology advances, opposition may lessen. However, opposition may remain because of the relatively high cost of solar power compared to other renewable resources.

12. **Other Factors:** The task force may wish to consider a program similar to the solar REC program but for other, likely more cost-efficient renewables. Also, the task force may wish to consider the REC program in combination with renewable energy feed-in tariffs.

mw1363085_2

Carbon Capture and Storage Background Document
Illinois Climate Change Advisory Group

Compiled by the World Resources Institute
May 2. 2007

The best estimates of when carbon capture and storage (CCS) could be ready at commercial scale

Components of the technologies needed for implementing carbon capture and storage (CCS) largely exist today. However, greater experience is needed in implementing them together as a complete system. Additionally, cost reductions in capture technology are needed to make CCS more economically viable.

The timing of commercial deployment of carbon capture and storage technologies will depend primarily upon 1) the price of carbon and when a carbon policy in enacted, 2) successful demonstration of large scale CCS projects, 3) resolving long term liability issues, and 4) public acceptance. That said, a few commercial projects that enjoy special incentives are currently in the planning stages. BP and Edison Mission Group currently plan to construct a 500MW power plant in Carson, California with CCS. Injection is scheduled for 2011, and the CO_2 will be used for enhanced oil recovery (EOR). This project benefits from low-cost fuel (petroleum coke), tax credits under the Energy Policy Act of 2005, and a revenue stream from CO2 sales for enhanced oil recovery. AEP plans to deploy CCS at its 450MW coal-fired power plant in Oologah, Oklahoma in 2011, although the commercial drivers there are less certain at this point.

It is worth noting that to provide an economic incentive for power producers to deploy CCS, carbon prices will have to be much higher than proposed federal and state policies would initially bring about. The recent MIT study *The Future of Coal* states that a carbon price of $30/tonne of CO_2 will make CCS cost competitive with traditional pulverized coal plants. A 2006 study by the Global Energy Technology Strategy Program provides a clearer picture of carbon prices needed to spur CCS deployment. For ammonia and natural gas processing facilities near EOR opportunities, prices under $20/tonne CO_2 may be sufficient; though they estimate that most coal-fired power plants would require carbon prices around $50/tonne CO_2.

Issues to consider around siting, monitoring and liability

To carry out successful CO_2 geo-sequestration, it is important to ensure that the risks associated with the entire lifecycle of a CCS project (from capturing CO_2 to transport, storage in the geologic formation, closure of the storage site and post closure management) and associated liabilities and financial responsibilities are defined carefully and managed through a robust regulatory framework. The following four issues require proper consideration to minimize the potential risks:

Site Selection and Characterization

The first and most important step is to carefully select and characterize a site for sequestering CO_2. Improper site selection may jeopardize the integrity of CCS projects by increasing the

probability of leakage through surface or sub-surface CO_2 migration, which could have local as well as large-scale environmental and human health impacts.

For proper site selection the geology of the area needs to be studied carefully to determine reservoir specific storage criteria[1]. In Illinois, research on site selection and characterization of possible geologic reservoir candidates, which includes saline aquifers, oil wells and coal seams, is being undertaken as a part of the Midwest Geological Sequestration Consortium (MSGS)[2], one of the seven regional partnerships. The reservoir specific site characterization criteria are being developed to characterize the reservoirs with high, moderate and low CO_2 sequestration potential. The program is now in its second phase of operation (2005-2009) where small field tests are planned to validate the efficacy of carbon sequestration in three types of reservoirs. During the first phase (2003-05), CO_2 capture and transportation options were assessed. In the third phase (2009-2012) DOE plans to include a number of large volume sequestration tests. These tests will be designed to address R&D issues associated with three major steps, namely (1) site selection and characterization; (2) operations and well closure; and (3) post-closure monitoring.

Monitoring, Mitigation and verification (MMV) framework

Monitoring, Mitigation and Verification (MMV) is required to ensure the integrity of a CO_2 storage reservoir, and provide confidence to carbon crediting markets. A robust MMV framework would include a set of site specific tools to measure the amount of CO_2 stored at a sequestration site, monitor the site for leaks or other deterioration of storage integrity over time, and to verify that the CO_2 is stored in a way that is permanent and not harmful to the host ecosystem. A mitigation framework is required to ensure the capability to respond to CO_2 leakage or ecological damage in the unlikely event that it should occur.

Liability

It is crucial to clearly define liability and financial responsibilities to ensure that the potential risks of CCS are properly accounted for and that they are borne by those who share the benefits of CCS. Based on a project's risk profile at various stages of its lifecycle (capture, transport, storage, closure and post closure), potential liabilities may vary, which if not clearly defined may lead to several perverse incentives (e.g. site abandonment). Most project developers are prepared to deal with operational liability in CCS projects, but the question of long-term liability is critical. Most companies believe that transfer of ownership from private to public hands must

[1] The general criteria for selecting a storage site include CO2 storage potential, accessible pore volumes, cap-rock integrity, seismicity, potential leakage pathways but the criteria for selection and characterization may vary for different types for reservoirs.

[2] The Midwest Geological Sequestration Consortium, headed by the University of Illinois - Illinois State Geological Survey, has examined ways of storing CO2 within deep, uneconomic coal seams, numerous mature oil fields and saline reservoirs that lie beneath the 60,000 square mile Illinois Basin, which underlies most of Illinois, western Indiana and western Kentucky. http://sequestration.org/

eventually occur if investment is to take place on a commercial scale. This is currently a priority topic in policy research.

Public acceptability

How the public perceives the risks of geologic CO2 storage is another contributing factor for the success of a CCS project. To ensure public support, it is crucial to develop an effective communication strategy to educate the public about the risks, rewards and trade-offs of CCS. Transparency should be maintained in developing rules for CCS and public involvement in the process will ensure more confidence in the technology. The opposition to a recent California bill by local environmental groups clearly depicts that public support could be a crucial factor in moving forward with CCS.

Current legislative or regulatory measures under consideration in IL

The State of Illinois is contending with Texas as a potential host for FutureGen project. In July 2006, the towns of Mattoon and Tuscola, located in the east-central part of Illinois, were selected as potential sites. Two other candidate sites were announced in Texas. The final selection is expected in September of this year. The state has committed an estimated $80 million package of grants, tax breaks and low-interest loans to attract FutureGen. Specifically, state legislation and clean-coal program funding will provide:

- $17 million direct cash grants from a clean-coal technology fund
- $15 million in sales tax and property tax exemptions
- Up to $50 million in reduced-interest loans
- Public improvement funding
- Reimbursement for employee training costs

To date legislative activity around CCS in Illinois has solely targeted the promotion of FutureGen. There are no legislative proposals under consideration that begin the process of developing a full scale regulatory framework for the deployment of this technology. A discussion of the two FutureGen bills is presented below:

<u>SB 1704- Clean Coal FutureGen for Illinois Act</u>

Introduced by Senator Gary Forby along with six co-sponsors in February 2007, for the purpose of providing the FutureGen Alliance with adequate liability protection, land use rights, and permitting certainty to facilitate the siting of the FutureGen Project in Illinois. The bill contains provisions concerning the transfer of title to sequestered gas and associated liabilities to the State; insurance and indemnification by the State for the Operator for certain liabilities; permits; land use, including condemnation powers; and economic incentives. The Bill amends the Department of Commerce and Economic Opportunity Law concerning financial assistance; the Illinois Enterprise Zone Act concerning high impact businesses; the Court of Claims Act and the State Lawsuit Immunity Act concerning jurisdiction; and the Eminent Domain Act concerning condemnation authority.

The Bill was amended on March 7, noting that locations at Tuscola and Mattoon are the only locations eligible for benefits under the Act. Amendments delete the authority to acquire property by condemnation and makes conforming changes. A sunset date of December 31, 2010 was also added for these incentives unless the FutureGen Project is located at either Tuscola or Mattoon. On March 22 the bill was referred to the Rules Committee.

Similar Legislation was proposed in the House via HB 1777 by Rep. Jay C Hoffman and 6 other co-sponsors. On April 27 the third reading/final action deadline for the bill was extended to May 9.

HB 5825 'Clean-Coal Project Indemnification Act'

HB 5825 was proposed last year in August 2006. The bill would require the Attorney General to appear and defend an operator of a clean-coal project in civil proceedings commenced against the operator arising from the escape or migration of injected carbon dioxide. The bill would require the State to indemnify the operator unless the conduct or inaction that gave rise to the claim or cause of action was intentional, wilful, or wanton misconduct. As of January 2007, the status of bill is 'Sine Die'.

CCS regulatory activity at the federal level

At the federal level, two major bills have been introduced to date. They are described below:

HR 1267 & S 731, these identical bills were introduced in House and Senate by Representative Gordon of Tennessee and Senator Salazar of Colorado. The bill titled 'National Carbon Dioxide Storage Capacity Assessment Act of 2007' requires the Secretary of the Interior, acting through Director of the United States Geological Survey (USGS) to develop a methodology for and complete a national assessment of geological storage capacity for CO_2. The capacity assessment would cover all the 50 states and includes provisions to survey saline formations, unmineable coal seams, oil or gas reservoirs, the injection potential of various storage formations, the potential volumes of oil and gas recoverable by injection and storage of industrial CO2 in storage formations and the risks associated with storage formations. The money allocated to do this assessment amounts to $20,000,000 for the period beginning October 1 of the first full fiscal year after the date of enactment and ending 4 years thereafter.

S 962, was proposed in the Senate on March 23, 2007 by Senator Bingaman of New Mexico. The bill titled 'Department of Energy Carbon Capture and Storage Research, Development and Demonstration Act of 2007' amends the Energy Policy Act of 2005 to reauthorize and improve the carbon capture and storage research, development, and demonstration program coordinated by the Department of Energy. For this purpose the act includes R&D activities under cost sharing requirements of section 988 (b) of EPACT to be considered: $90,000,000 fiscal year 2007, $105,000,000 fiscal year 2008 and $120,000,000 fiscal year 2009.

6. **Estimated Costs:** Administrative costs will be negligible (incremental to existing program). Other material cost is potential electric rate impacts. *A Study to Evaluate the Impacts of Increasing Wisconsin's Renewable Portfolio Standard*, submitted to the Wisconsin Department of Administration, Division of Energy on October 31, 2003 indicates that increasing the RPS to 10% would have a relatively small rate impact. It indicates that the total additional costs would be about $37 million (in 2001 dollars), or about $0.30 per month per residential customer. The cost of both renewable and non-renewable generation have increased substantially since the issuance of the above study. However, it appears that the per-megawatt hour cost of wind (with the federal production tax credit) and coal are relatively similar.

7. **Specific Description of Policy Proposal:** Wisconsin currently has legislation imposing an RPS that has been implemented by a PSCW rulemaking and is backed by PSCW enforcement authority. This policy recommendation would modify the RPS as specified below. The current standard is 10% by 2015. The revised standard would increase by 2% each year until 2020 when it reaches 20% and then by 1% until it reaches 25% in 2025. The current off-ramp for high cost impact would continue. The definition of "renewable source" under current legislation would apply. This is in part because of the significant environmental and cultural costs associated with large hydro projects, and because there is no CO_2 reduction benefit from Wisconsin utilities purchasing power from existing large hydro facilities. Also, to ensure that the actions of customers, including the

state, who agree to pay green pricing rates or make similar donations for renewable energy result in additional renewable generation, green energy associated with those premium purchases and donations will not count toward RPS requirements.

8. **Timetables, Duration and Stringency Option:** The timetable is implicit in this policy recommendation. Duration is until changed by law. This policy should be regarded as stringent as a result of PSC enforcement of the RPS requirements, subject to the possible implementation of high cost impact off-ramp.

9. **Explanation of Rough Estimate of GHG Reductions:** Meeting the new RPS standard would require an estimated 9.2 million MWh of additional renewable energy annually by 2020 (above the 10% standard in existing law) and 14.8 million MWh of additional renewable energy by 2025. Range of GWh reduction estimates assumes displacement of _____ million MWhs of coal generation and _____ million MWhs of gas-fired generation in 2020 and _____ million MWhs of coal generation in 2025 and _____ million MWhs of gas-fired generation in 2025. An average capacity factor for renewable resources of _____% is assumed, requiring an additional _____ MW of renewable capacity above the existing RPS in 2020 and _____ MW in 2025.

10. **Rough Estimate of Costs for Selected Years:** Incremental administrative costs of the revised RPS are estimated to negligible because the PSCW already has in

place the infrastructure for regulating this requirement. The other main cost is potential impact on electric rates. This impact will depend on the projected costs of power and energy from the mix of renewable resources employed to meet this requirement compared with the estimated cost of coal and gas-fired generation that is displaced, including carbon adders. The range of projected carbon adder costs used is $_____ to $_____ per ton of CO_2. Gas prices used range from $_____ per million BTU to $_____ per million BTU in 2020, increased by _____% per year for 2025. Coal prices used range from $_____ per ton to $_____ per ton in 2020, increased by _____% per year for 2025. The mix of renewable resources assumed for both 2020 and 2025 is _____% wind, and _____% biomass, _____% hydro, and _____% solar.

11. **Barriers to Implementation:** The major barrier to implementation of this policy is the need for legislation to amend to the existing standard. Opposition may come from large electric customers who believe that this requirement will materially increase their electricity costs. To the extent that a significant carbon-adder is perceived as likely, and that the installed costs of renewable resources will come down over time compared to new, coal and gas-fired units, as a result of increased manufacturing capacity and technology advances, opposition may lessen.

12. **Other Factors:** It is possible that with a stringent cap-and-trade requirement an RPS may be viewed as unnecessary in that renewables will have to be used in

order to meet the cap. Federal preemption also is possible, as well as substitution of a "clean energy portfolio" standard that includes energy efficiency and other technologies as well as renewables. There will be a potential overlap of impacts if policies related to these matters also are proposed by the Task Force.

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Wisconsin Global Warming Task Force Workgroup
Template For Presenting Policy Options

1. **Workgroup**: Electric Generation Workgroup

2. **Policy Name:** Advanced Renewable Tariffs (10-year fixed price tariffs to stimulate the deployment of renewable generation projects under 15 MW).

3. **Policy Type:** Definitely a PSC proceeding. Authorizing legislation may be necessary.

4. **Affected Sectors, Sub-Sectors and/or Entities:** Public Service Commission, utilities, customer-generators, independent power producers, renewable energy installation contractors and equipment manufacturers.

5. **Estimated Greenhouse Gas Emissions Reduction Impact:** If utilities supplied 2% of their sales with distributed renewable resources by 2020 (above current requirements), and 3% by 2025, this would result in reductions of 1.5 million tons/yr by 2020, and 2.25 million tons/yr by 2025.

6. **Estimated Costs:** Rising from $5 million/yr in 2009, annual costs peak at $33.million/yr in 2018, and decline to $15 million/yr by 2025. At its maximum, the overall rate impact is less than 0.5% of gross utility revenues.

7. **Specific Description of Policy Proposal:** The advanced renewable tariff proposal has two elements: (1) a requirement on utilities to offer advanced renewable tariffs to qualifying generators within their service territories; and (2) a set of goals for increasing the contribution of distributed renewable generation to a utility's system mix. Suggested goals are 2% by 2020 and 3% by 2025. For the purposes of this proposal, advanced renewable tariffs are 10-year fixed-rate tariffs pegged at the generation source's production costs in Year 1. These technology-specific tariffs would be uniform across utility boundaries. Unless the price of conventional fuel declines, the margin between the advanced renewable energy tariff and the utility's avoided cost will narrow during the 10-year period. When the 10-year term ends, the utility can purchase that energy at its avoided-cost based rate. Utilities would have the option of rate-basing these generation sources or reselling some or all of the electricity acquired through these tariffs through their voluntary renewable energy programs, as We Energies' current practice with its special solar tariff.

   Utilities that establish Advanced Renewable Tariffs are purchasing not only the energy from qualifying generators but also the renewable energy credits that are created. A utility may apply generation purchased under these tariffs toward its current Renewable Portfolio Standard or any successor renewable energy obligation, unless the output is resold through a voluntary renewable energy program at retail. After the 10-year fixed rate tariff ends for a particular generator,

a utility may continue to apply that generation toward any successor renewable energy requirement.

8. **Timetables, Duration and Stringency Option:** If the PSC believes it has the authority it has the authority to establish advanced renewable energy tariffs without legislation, it could convene a proceeding at any time to determine the production costs of various distributed renewable resources such as solar, wind, small hydro, landfill gas, biogas, and other biomass sources. To achieve a 2% target by 2020, utilities would, in the aggregate, need to purchase 1.5 billion kWh per year of qualifying generation through these rates by 2020. To achieve a 3% target, the utilities would need to purchase another 750 million kWh/year. Spread out over a 17-year period beginning in 2009, annual increases would average between 100 and 150 million kWh.

9. **Explanation of Rough Estimate of GHG Reductions:** The 2020 estimate assumes the displacement of 1.5 billion kWh/yr of conventional generation with carbon-free or carbon-neutral generation. The 2025 estimate assumes the addition of 750 million kWh/yr on top of the quantity leveraged by the 2020 target. It is assumed that 1 billion kWh of carbon-free or carbon-neutral generation in Wisconsin will result in a reduction of 1 million metric tons of CO_2 from the electrical sector.

10. **Rough Estimate of Costs for Selected Years:** The cost per unit of electricity acquired would be highest in 2009 (Year 1) (approximately 5 cents/kWh). The overall cost per year will increase from Year 1 until it reaches a peak of $33 million/year in 2018 (Year 10). It will then decline each year to $15 million/yr in 2025. In the cost estimate below, it is assumed that the marginal difference between energy purchased through an advanced renewable tariffs and energy purchased through the standard parallel generation rate will decline by 0.25 cents per year. Note: these numbers reflect nominal values and do not take inflation into account.

Year	Amount	Incremental Margin	Annual Cost
2009	100,000,000 kWh	5 cents/kWh	$5,000,000
2010	200,000,000	4.75	$9,500,000
2011	300,000,000	4.50	$13,500,000
2012	400,000,000	4.25	$17,000,000
2013	500,000,000	4.0	$20,000,000
2014	600,000,000	3.75	$22,500,000
2015	750,000,000	3.50	$26,250,000
2016	900,000,000	3.25	$29,250,000
2017	1,050,000,000	3.0	$31,500,000
2018	1,200,000,000	2.75	$33,000,000
2019	1,350,000,000	2.50	$31,250,000
2020	1,500,000,000	2.25	$29,250,000

2021	1,650,000,000	2.00	$27,000,000
2022	1,800,000,000	1.75	$24,500,000
2023	1,950,000,000	1.50	$21,750,000
2024	2,100,000,000	1.25	$18,750,000
2025	2,250,000,000	1.00	$15,000,000

11. **Barriers to Implementation:** It is not clear whether legislation would be required to provided the PSC with the authority to set advanced renewable tariffs and impose targets on utilities.

12. **Other Factors:** The Wisconsin Distributed Resources Collaborative (WIDRC) has spearheaded a voluntary effort to develop a consensus proposal for establishing Advanced Renewable Tariffs. This group has been meeting steadily on this issue since early 2006 to work out various methodological and economic issues associated purchasing renewable electricity from customer-generators. The current proposal before the body recommends a biogas tariff of 10 cents/kWh for systems up to 500 kW, and nine cents/kWh between 500 kW and one megawatt. This initiative has prompted two separate utility proposals this year to establish technology-specific tariffs, and they are both under consideration by the PSC. One, offered by Madison Gas & Electric, would buy back solar-generated electricity from its customers at a rate of 25 cents/kWh. The other, proposed by Xcel-Northern States Power, proposes a biogas rate of 7.3 cents/kWh and a wind energy rate of 6.6 cents/kWh. It is interesting to note that while these proposed

tariffs are higher than the utilities' respective parallel generation rates, they are below the production costs of the technology to be incentivized. Their success in stimulating customer-sited distributed renewable generation wholly depends on other financial support external to the utility tariff, such as federal tax credits and Focus on Energy incentives.