Powering the Plains:
Energy Transition Roadmap

Great Plains Institute
Working on tomorrow's solutions with today's leaders

Our future prosperity depends on clean and ultimately inexhaustible energy supplies. Yet rising energy prices, growing dependence on unstable regions of the world, continuing high growth in energy use and widespread concern over climate change have converged to place our collective energy future in doubt. For these and other reasons, energy has climbed to the top of the agenda around the world and across our region. Responding effectively to these new realities is among the most urgent and important challenges of our time.

In 2001 the non-profit Great Plains Institute (GPI) convened a diverse group of stakeholders and launched its Powering the Plains (PTP[1]) program. From the beginning, PTP turned the energy and climate debate on its head. Instead of focusing primarily on costs, PTP stakeholders[2] also devoted attention to how the Upper Midwest can maximize its economic *opportunities* in energy and agriculture in a carbon-constrained world.

This roadmap represents the collective thinking by these stakeholders in meeting this challenge. What may distinguish this document most from similar roadmap efforts elsewhere is *who* developed this one and *how* it came about (see graphic below). It is rare to have a forum in which widely diverse interests can speak candidly about difficult issues. While consensus cannot solve all disputes, in this case the PTP process allowed participants to develop a shared understanding of key energy and climate issues and to reach agreement on how this region might respond.

Purpose of this Roadmap

This Roadmap seeks to position the region for prosperity under several possible energy development scenarios over the next 50 years. Succeeding at this task means identifying and encouraging policy and technology pathways that appear to be wise under a wide range of future circumstances.

How this Energy Roadmap is Different

Traditional Policy Approach → Each interest group attempts to build the most political support. → This can lead to good outcomes, but often creates divisions among factions, which can undermine implementation of the policy.

Powering the Plains Approach → Key interests met over five years to educate themselves on energy and climate issues and discuss regional challenges and opportunities. → Has led to consensus on a multi-pronged approach to energy development and CO_2 reduction.

More importantly: commitment to implementation over the long-term.

1 PTP has been generously supported by the Bush Foundation, Joyce Foundation and its participant institutions.
2 See the Overview for list of PTP stakeholders.

The consensus represented in these pages is one that PTP participants hope will be embraced and acted upon by policymakers and others in leadership positions across the region. A cross-section of society as diverse as the PTP stakeholders themselves will need to act boldly and in unison for the roadmap to become reality. This includes governors, legislators, regulators, industry executives, agricultural leaders and environmental advocates among others.

PTP's development of this 50-year energy transition roadmap for the region responds to a request from the International Legislators Forum, a bipartisan coalition of 32 legislative leaders from Manitoba, Minnesota, North Dakota and South Dakota who meet annually to develop policy consensus on key regional issues.

In 2004 the Legislators Forum delegates passed a resolution calling on PTP to develop an energy transition strategy that "relies on clean energy production and carbon sequestration" and that maximizes the Upper Midwest's comparative advantages in:

- Renewable resources such as wind, biofuels, biomass and hydropower;
- Experience with coal gasification and geologic storage of the CO_2;
- Hydrogen production from renewable energy and the gasification of coal;
- Sequestration of atmospheric carbon in soils, wetlands and woodlands; and
- The marketing of renewable energy and carbon credits.

Further, the legislators asked PTP to:

1. "Prepare preliminary scenarios, goals and measurable targets outlining a potential regional energy transition; and,
2. Identify legislative measures and institutional arrangements needed to implement such a transition roadmap inter-jurisdictionally over time."

This resolution reflects the fact that leaders of all political stripes in both public and private sectors increasingly recognize that carbon regulation is imminent even while they may disagree on what form that regulation will or should take.

The diverse stakeholders behind this roadmap also agree that it is responsible and prudent for the region to prepare for an eventual policy in the United States that constrains CO_2 emissions and to take steps now so that our energy and agriculture sectors have the technologies, policies, infrastructure and institutional mechanisms in place to do well under such a policy. In addition, the abundance of renewable energy resources and carbon-neutral energy options in the region presents an opportunity to stimulate new rural economic development and growth.

Why a 50-year Roadmap?

Like turning a large oil tanker, it takes a long time to influence the overall direction of the energy system. Power plants, refineries, wind farms and other energy production facilities and infrastructure require major investments that can last 25 to 50 years or more. Influencing the nature and timing of these investments must happen incrementally, year after year, and over a long period of time to have any hope of arriving at the desired destination. Having policies and regulations in place that encourage innovation and reinvention at those critical moments when energy infrastructure is replaced, upgraded or expanded can make the difference between advancing new technologies and practices or being stuck with last century's inventions and suffering unnecessary economic harm as a result.

This document aims at nothing less than fostering—as quickly as possible—an economically advantageous transition to a renewable and carbon-neutral energy system by 2055 based on the native energy resources of the Upper Midwest.

To help navigate this transition, University of Minnesota researchers and GPI staff, in consultation with PTP stakeholders, developed a transparent and flexible computer modeling tool that allows users to develop plausible scenarios, rooted in the specifics of the region's energy sector, for meeting future electric demand at reasonable cost while significantly reducing CO_2 emissions.

In order to avoid fruitless debates over what may or may not happen over the course of 50 years, the model includes only known costs for commercial technologies available today. In other words, it assumes that even with no technological advancements (unheard of in human history) it is still possible to meet projected electrical demand and reduce greenhouse gases.

PTP participants agreed to run four different representative scenarios for the region—business as usual, high energy efficiency, high renewables and high coal with carbon capture and storage (CCS)—to see how costs and resources would vary under different carbon-constrained worlds relative to business as usual. The model's conservative assumptions combined with compelling cost results for all three scenarios that limit CO_2 emissions helped PTP stakeholders reach consensus on three key points:

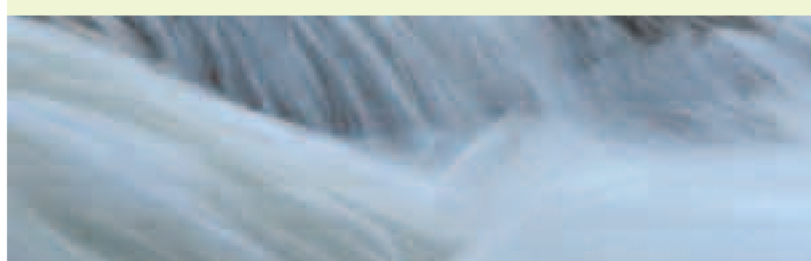
1. It is possible to achieve as much as an 80 percent reduction in power sector CO_2 emissions from 1990 levels by 2055 if we begin now;
2. Doing so will *not* be significantly more expensive than business as usual; and
3. The path forward with the lowest long-term cost relies on heavy investments in energy efficiency and a portfolio of energy options and technology combinations including: wind, biomass, hydro, existing nuclear and advanced coal technologies with the capture and storage of the resulting CO_2.

Roadmap Proposes Seven Key Strategies for Energy Investment

The scenario analysis that informs this roadmap suggests that many different combinations of resources and technologies can not only meet future energy demand at moderate additional cost but can also lead to an 80 percent reduction of CO_2 emissions from the electric sector by mid-century.

No one energy resource must necessarily decline in favor of another during the transition since the region's entire portfolio of low- and zero-carbon energy options must increase dramatically if we are to meet projected energy demand and significantly reduce emissions. The following seven key strategies require significant new investment:

1. **Invest in energy efficiency** until investment in other energy options would be less expensive;
2. **Accelerate commercialization of advanced coal technologies** with the capture and geologic storage of CO_2 emissions;
3. **Maximize economic and reliable integration of wind energy** onto the electrical grid and harness the region's wind energy resource for additional uses;
4. **Launch a biorefinery industry** that produces liquid fuels, biogas, electricity and bio-products from cellulosic biomass;
5. **Advance new low-impact hydropower development** as part of a broader portfolio of energy options;
6. **Build a hydrogen and fuel cell industry** based on regional renewable and carbon-neutral energy resources; and
7. **Expand electric transmission and energy delivery capacity** to accommodate the substantial increases needed in low- and zero-carbon energy production.



Once in agreement on these core points, PTP participants agreed on specific objectives, milestones and recommendations for:

1. Energy efficiency,
2. Coal with CO_2 capture and permanent storage,
3. Wind,
4. Hydropower,
5. Nuclear power,
6. Biomass, and
7. Hydrogen, fuel cells and related technologies.

With a draft roadmap in hand, Great Plains Institute staff held five Town Hall Meetings across the region to solicit public input on the document's initial recommendations. These public meetings were held in Washburn, ND; Brookings, SD; St. Cloud, MN; Eau Claire, WI; and Storm Lake, IA. In some cases citizen feedback confirmed the roadmap's content; in others it informed subsequent changes. The hundreds of citizens that joined us for these meetings also brought forth many exciting and entrepreneurial ideas for the region, as well as some criticisms, that we were unable to reflect in the final version of the roadmap. A compendium of these ideas as well as a complete summary of citizen input can be found at **www.poweringtheplains.org**.

History is littered with strategic plans and roadmaps that collect dust on shelves. For this document to remain relevant, people from many walks of life will need to help with its implementation and contribute to updating its contents as technology and markets change. In other words, the roadmap is not intended as a static document prescribing a single path forward or a quick fix. Instead it offers a menu of policy options and a multi-pronged approach—already vetted by many of those with a stake in the transition—for reconciling energy production and use with climate stewardship.

The good news is that harnessing the region's energy sources and ingenuity *can* reduce our dependence on uncertain sources of energy, stimulate jobs and economic development, and offer a prudent hedge against volatile energy prices and the risks of climate change. Rising to the challenge is one of the most daunting and exciting prospects our society will face in this new century.

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With generous support from
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Introduction

Most people in North America do not give much thought to where their energy comes from. They just know that when it's dark, cold or hot, they want light, heat and cooling. The engineering marvel that is today's electric grid has delivered all those things and more, so well that most of us now take them entirely for granted. Unfortunately, that same electric system also faces serious problems that suggest that over the next half century we must dramatically change the way we produce, distribute and use energy. How we make this energy transition is as much a social and political decision as it is a technological and economic one. This roadmap summarizes years of stakeholder negotiation about how the Upper Midwest can best position its energy and agriculture sectors to thrive in the future. It represents a consensus among leaders from Iowa, Manitoba, Minnesota, North Dakota and South Dakota on how best to meet this challenge.

For nearly five years, more than 20 representatives from the energy industry, agriculture, government and environmental organizations worked together through the Great Plains Institute's (GPI) voluntary public/private Powering the Plains program (PTP). They explored fundamental energy and climate challenges and opportunities facing the Upper Midwest and found common ground on key issues and potential solutions. This 50-year regional energy transition roadmap outlines the milestones, objectives and specific recommendations negotiated by this group over time for the transitioning to a low-carbon energy economy by mid-century.

Legislators

- **Ellen Anderson (D)**, Chair, Environment, Energy, and Natural Resources Budget Division, Finance Committee, Minnesota Senate, St. Paul, MN
- **Jon Nelson (R)**, Farmer and State Representative, Wolford, ND

Utility Regulators

- **Jim Burg (D)**, Farmer and former South Dakota Utilities Commissioner, Wessington Springs, SD
- **Phyllis Reha**, Commissioner, Minnesota Public Utilities Commission, St. Paul, MN

State and Provincial Officials

- **Kim Christianson**, Energy Program Manager, North Dakota Department of Commerce, Bismarck, ND
- **Kurt Simonsen**, Manager, Utilities and Energy Issues, Manitoba Energy Development Initiative, Winnipeg, MB

Utility Industry Executives

- **Garry Connett**, Director, Environmental Stewardship, Great River Energy, Elk River, MN
- **Mike Eggl**, Senior Vice President, External Affairs and Communications, Basin Electric Power Cooperative, Bismarck, ND
- **William Hamlin**, Manager, Energy Policy and Emission Trading, Manitoba Hydro, Winnipeg, MB
- **Brian Zelenak**, Manager, Regulatory Administration, Xcel Energy, Minneapolis, MN

Agricultural Producers

- **Larry Diedrich (R)**, Farmer, former State Senator and Past President, American Soybean Growers, Elkton, SD
- **Dave Miller**, Farmer and Director, Commodity Services, Iowa Farm Bureau, Des Moines, IA
- **John Sellers, Jr.**, Farmer and Forages Coordinator, Leopold Center for Sustainable Agriculture, Corydon, IA
- **Paul Symens (D)**, Farmer, Feedlot Owner and Former State Senator, Amherst, SD

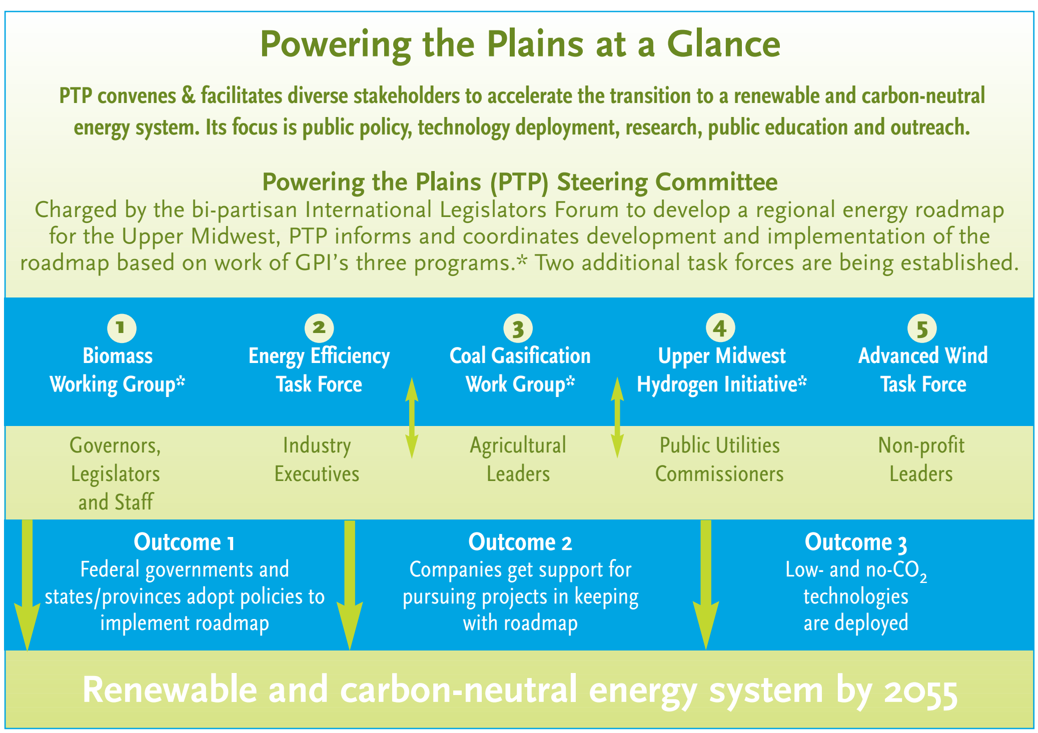
Environmental Advocates

- **Bill Grant**, Midwest Director, Izaak Walton League of America, St. Paul, MN
- **Michael Noble**, Executive Director, Fresh Energy, St. Paul, MN
- **Lola Schoenrich**, Senior Program Director, The Minnesota Project, St Paul, MN
- **Beth Soholt**, Director, Wind on the Wires Project, St. Paul, MN
- **Patrick Spears**, President, Intertribal Council on Utility Policy, Ft. Pierre, SD
- **Ed Woolsey**, Consultant, Iowa Renewable Energy Association, Prole, IA

The following individuals contributed significantly to the development of this roadmap but no longer formally participate in PTP:

- **Steve Brick**, Manager of Environmental Programs, The Joyce Foundation and formerly of the Energy Center of Wisconsin, Madison, WI.
- **Betsy Engelking**, Manager, Resource Planning and Bidding, Xcel Energy and formerly of Great River Energy, Minneapolis, MN
- **Michelle Swanson**, Former Manager, Policy Development, Xcel Energy, Minneapolis, MN

In addition, a wide range of leaders from the GPI's other work groups have contributed to this roadmap (see Appendix A).



Goals for the Region's Energy System

In developing a vision for our region's energy future, PTP participants sought input from a range of experts, used computer modeling to explore various energy options, organized site visits to energy facilities in the region, and participated in an energy technology and policy delegation to Northern Europe. Drawing on this input and their own experiences and deliberations with one another, PTP participants outlined a vision for our region's future energy system based on the following goals:

1. Achieve ever greater levels of energy efficiency;
2. Be based on an affordable, reliable and diversified portfolio of regional energy resources;
3. Enhance the region's economy and further develop its energy, agriculture and other key economic sectors; and
4. Avoid, reduce and offset emissions of CO_2 and other negative environmental impacts.

Region Covered by this Roadmap

The PTP region—and the focus of the recommendations in this roadmap—includes Iowa, Minnesota, North Dakota, South Dakota, Wisconsin and the province of Manitoba. This region was chosen because the jurisdictions share a common electric transmission system, regularly exchange power and exemplify both the challenges and opportunities presented by a carbon-constrained future.

For the purposes of the broader regional CO_2 scenario analysis that informs this energy roadmap (described in more detail later in this overview), PTP participants also added the states of Illinois, Montana and Wyoming to avoid distorting the results of the modeling—Illinois because it represents a major energy consuming state and Wyoming and Montana because they supply coal to the region's power sector and have enormous proven reserves. While clearly pivotal in our region's energy system, these states are not included in the roadmap recommendations, nor were these jurisdictions represented within PTP itself.[1]

1. The only exception is the coal chapter where an additional set of stakeholders from the states further west (see Coal Gasification Working Group list) contributed to the creation of this document.

One of the key lessons from the PTP delegation to European was the political and economic value of establishing consensus on a long-range energy vision and measurable targets for achieving that vision, regardless of which political party holds power.

Why a Roadmap at All?

In 2003 GPI led a delegation of PTP and other regional stakeholders to Denmark, Germany, the Netherlands and Iceland to better understand how those countries are approaching renewable energy development, climate change and the growth of an early hydrogen industry and infrastructure. Each country offered striking examples of what is possible when there is broad agreement across society on a long-term energy vision and strategy.

The trip proved a turning point for PTP participants and their work together by reinforcing the fact that an energy technology and policy agenda that responds proactively to the challenge of global warming and reducing greenhouse gas emissions can, in some cases, actually generate economic advantages and new markets for industry and agriculture.

One PTP participant likened the approach of these European countries to that of turning a large oil tanker. It takes a long time to influence the overall direction of the energy system. Power plants, refineries, wind farms and other energy production facilities and infrastructure require major investments that can last 25 to 50 years or longer. Influencing the nature and timing of these investments must happen incrementally, year after year, over a long period of time to have any hope of arriving at the desired destination. **Having policies and regulations in place that encourage innovation and reinvention at those critical moments when energy infrastructure is replaced, upgraded or expanded can make the difference between advancing new technologies and practices or being stuck with the last century's inventions and suffering unnecessary economic harm as a result.**

The events of the ensuing three years since PTP's delegation to Europe underscore the potentially high costs of being unprepared for change: greater economic uncertainty from volatile energy markets, strategic risks from growing dependence on imported energy, worsening effects of rising greenhouse gas emissions and, ultimately, greater economic burdens on local businesses and consumers. Those factors have already begun to influence policy-makers and the private sector in our region as evidenced by the accelerating development of wind farms and ethanol and bio-diesel plants, as well as early steps toward demonstrating and commercializing renewable hydrogen and low-carbon coal technologies.

The challenge is to build on these encouraging energy trends and act *now* to pursue strategies that will yield benefits for years, decades and even generations to come.

What the Roadmap is *Not*

A "roadmap" is a useful metaphor, but it runs the danger of suggesting to its readers that there is only *one* right way to move forward, and that the authors of the roadmap have discovered that optimal path. By contrast, this roadmap does not lay out one "right" energy future but rather a selection of possible futures. **The point is not to pick one of the four scenarios presented here, but instead to understand that multiple roads could lead to a renewable and carbon-neutral energy system as long as we begin *today*.**

Similarly, the roadmap itself is not meant to be interpreted as a definitive and final guide for reducing our region's CO_2 emissions. As mentioned earlier, it does not sufficiently address other important sectors, such as:

1. **Oil dependence and the transportation system in general**, except for the potential for biofuels and hydrogen;
2. **Land-use planning and public transportation** policy and investments that could minimize energy use;
3. **Oil and natural gas industry** and its role in the electric system; and
4. **Environmental concerns beyond CO_2 emissions**, including mercury, emissions of other greenhouse gasses and air pollutants, water quality and quantity, etc. (environmental outcomes generally would likely improve assuming implementation of roadmap recommendations, with possible exceptions such as NO_x emissions from biomass use).

PTP participants have already agreed to include the production and use of fuels in the transportation sector in a future version of the roadmap. These gaps, recognized by PTP participants from the outset, and others identified by citizens throughout the region in five Town Hall Meetings will be considered when the roadmap is updated and revised.

Finally, and perhaps most importantly, the roadmap details consensus agreements reached in PTP, which is inherently a negotiated process among diverse interests about policy and priorities, NOT primarily an analytical exercise that draws scientific and technical conclusions. While the roadmap is informed by energy modeling and other credible technical information available to the group, the roadmap recommendations represent what a broad group of public, private and nongovernmental stakeholders have found themselves able to agree on at this time. That is why, for example, the roadmap does not recommend strategies for nuclear, except to maintain current generation (see a more detailed explanation on nuclear in the strategies for policymakers section of this overview and in the nuclear chapter). Thus, it is this consensus aspect of the roadmap that is truly unique and will hopefully lead to real change that a purely analytical exercise could never produce. This roadmap recognizes that, in the end, the energy technologies that society adopts will be driven as much or more by what people can agree on as by what is technically possible.

International Legislators Forum delegates requested that PTP stakeholders:

1. "Prepare preliminary scenarios, goals and measurable targets outlining a potential regional energy transition; and

2. Identify legislative measures and institutional arrangements needed to implement such a transition roadmap inter-jurisdictionally over time."

Who Asked for this Roadmap?

In 2004, in response to presentations on PTP's early conclusions (including those drawn from its delegation to northern Europe), the bipartisan International Legislators Forum[2] passed a resolution stating that **this region has "comparative advantages to lead a long-term energy transition in North America that relies on clean energy production and sequestration of carbon dioxide."** In their resolution, the legislators articulated the region's comparative energy advantages as follows:

- Renewable resources, such as wind, biofuels, biomass and hydropower;
- Experience with coal gasification and geologic storage of the CO_2;
- Hydrogen production from renewable energy and the gasification of coal;
- Sequestration of atmospheric carbon in soils, wetlands and woodlands; and
- Marketing of renewable energy and carbon credits.

Who Funded this Roadmap?

PTP has been generously supported by the Bush Foundation, based in St. Paul, Minnesota; the Joyce Foundation, based in Chicago, Illinois; and many of the PTP stakeholder institutions themselves.

In addition, financial and technical support for the CO_2 scenario modeling tool was provided by the University of Minnesota's Initiative for Renewable Energy and the Environment. Fresh Energy, the Izaak Walton League of America (Midwest Office) and the Energy Center of Wisconsin also contributed financially to the University of Minnesota's development of the CO_2 scenario model.

The citizen input to this roadmap was made possible through a series of townhall meetings, which were generously supported by the Otto Bremer Foundation, Great River Energy, Xcel Energy, the Iowa Farm Bureau and in-kind support from several community hosts.

2. Comprised of 32 legislators representing all political parties from the Dakotas, Manitoba and Minnesota, the Legislators Forum began after the devastating 1997 floods in the Red River Valley and now meets annually on issues of regional concern. The Legislators Forum has been facilitated and staffed since its inception in 2000 by the Consensus Council of Bismarck, ND.

The Roadmap's Technical Basis: Regional CO_2 Scenario Analysis

As PTP participants began to tackle the challenge of building a long-range energy vision, it became clear that they needed to develop a common understanding of the region's current energy system and what our energy resources could potentially deliver in the future.

PTP participants and GPI staff worked with faculty at the University of Minnesota to establish a research team and secure funding to develop a computer model that could help answer substantial "what if?" questions about energy technologies, costs and the impacts of different choices over the next 50 years. Together the team assembled specific regional data[3] and built a flexible and transparent computer model capable of answering these questions in real time.

The PTP stakeholders agreed that, for analytical purposes only, the project team should run scenarios based on the objective of reducing CO_2 emissions by 80 percent from 1990 levels by 2055 in the region's power sector. According to scenarios developed by the Intergovernmental Panel on Climate Change, 50 to 80 percent reductions in total global CO_2 emissions will be necessary to stabilize atmospheric CO_2 and avoid the worst consequences of climate change. This regional analysis deals only with CO_2 emissions from electricity production in our region. Reductions from other sources, and of other greenhouse gases, will be necessary to stabilize total greenhouse gas emissions.

Neither PTP stakeholders nor the research team have formally endorsed this 80 percent numeric target as a recommendation to policy-makers. However, were policy-makers to establish such a goal, the model demonstrates that a reduction on this scale in the power sector is possible at modest additional cost if incremental progress on emissions reductions begins early in the 50-year period and is sustained throughout.

The scenario analysis undertaken for this roadmap is inherently conservative because the research and modeling is based on existing technologies and costs only. In reality, the next few decades will bring remarkable technological advancements—including reduced costs, greater efficiencies and entirely new approaches—many of which cannot even be imagined at this time.

3. The team relied heavily on the USDOE's Energy Information Agency's (EIA) Form Data and assumptions in the EIA's 2005 Annual Energy Outlook in order to maintain a consistent data source. More on the model's data and underlying assumptions can be found on the public website: http://forio.com/simulation/co2tracker/index.htm?FD_rand=6217.

Thus, the roadmap should not be interpreted as comprehensive. As already noted, the roadmap covers a few topics outside of the electricity sector (e.g., use of biofuels and hydrogen in the transportation sector), yet it focuses on electric power. Future work will expand the analysis to encompass the co-evolution of vehicles and fuels in the transportation sector, including advanced fuels, efficiency improvements and the steady electrification of vehicles. This is precisely what the International Legislators Forum has asked PTP to do next in its next phase of work.

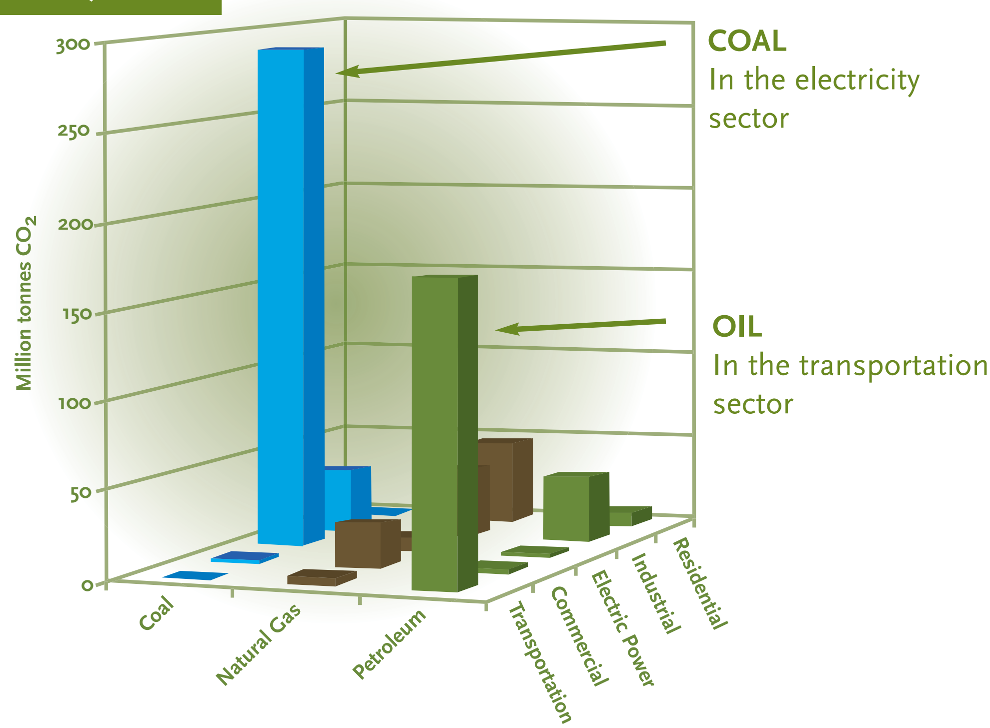
Finally, to appreciate what the scenario model and roadmap can and cannot do, it is important to briefly discuss the idea of **managing risk over a 50-year timeframe**. Each of the technologies covered in this roadmap has inherent risks and benefits. At the scale of energy development envisioned in this roadmap, even something as seemingly benign as wind power has significant implications for the visual landscape and for land use in general. Such issues fall well outside this roadmap exercise but will need to be considered carefully by the people, communities and institutions involved in and impacted by the development. Thus, the roadmap and the scenario modeling that underlies it do not eliminate risk, but instead help inform policy-makers and the public's judgments about what is technically and economically practical in our region.

CO_2 Scenario Analysis Suggests Four Key "Compass Headings"

The following may seem obvious, particularly given the bar chart below, but achieving the four broad goals below will be far from simple:

1. Significantly increase the efficiency of electricity production and use;
2. Build new and re-power existing electric generation with low- and zero-CO_2 technologies;
3. Implement geologic and terrestrial carbon sequestration on a large scale; and
4. Deploy low- and zero-carbon fuels and technologies in the transportation sector.

2005 CO_2 Emissions by Sector



Maximizing energy efficiency is the lowest long-term cost scenario

	Total Cost (US$ billions)	Unit Cost (US$/MWh)	Achieves 80% Reduction in CO_2
Business as Usual	$771	$42	NO
High Efficiency	**$743**	$51	YES
High Renewables	$775	$49	YES
High Coal (IGCC w/CCS)	$779	$51	YES

* While the unit costs of electricity per MWh are relatively similar under any of the CO_2 reduction scenarios, greater deployment of energy efficiency significantly reduces demand and thus total regional expenditure for electricity.

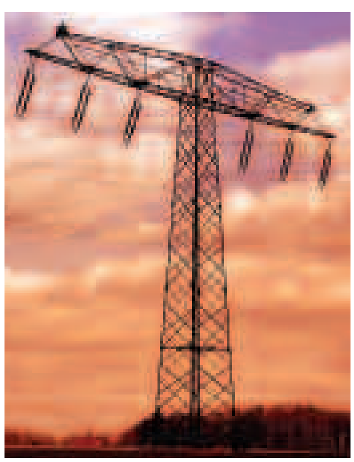
Within the electricity sector in particular, as presented in the box above, significant new investments in energy efficiency are not only required but also yield the lowest long-term costs for society. The box above captures key findings from each of the four scenarios run with the modeling tool: business as usual, high efficiency, high renewables, and high coal with carbon capture and storage. In short, there are multiple paths for our region to dramatically reduce CO_2 emissions from the electricity sector. While any of the CO_2 reducing scenarios may add modestly to the cost of electricity on a per unit basis, additional cost across the economy is either relatively nominal or reduced (in the case of the energy efficiency scenario). More on the model and scenario assumptions and key findings can be found in Appendix B.

Strategies for Policy-Makers and Others to Consider

PTP participants recommend the following policy and technology deployment options for consideration. These are covered in more detail in the roadmap's respective chapters:

A Strategies Relevant to Multiple Energy Sectors

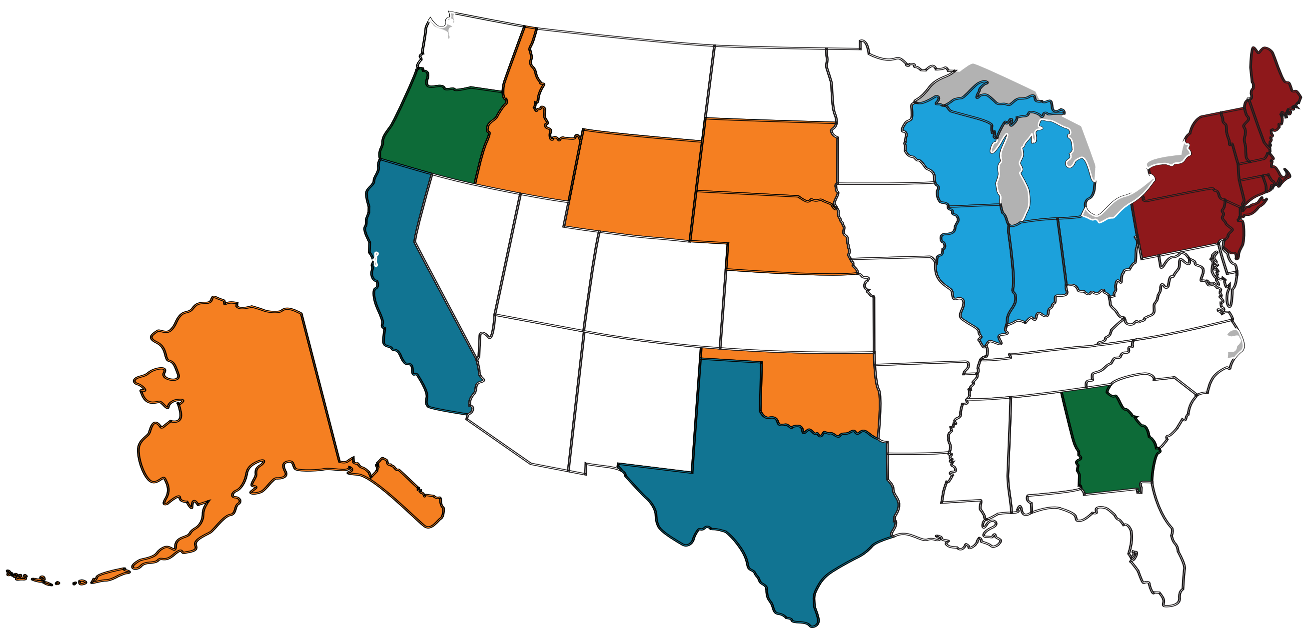
1. Establish quantifiable goals in each jurisdiction for energy efficiency and specific generation resources.
2. Establish a regional registry for greenhouse gas (GHG) emissions. Registries allow industry to document early action on CO_2 and other greenhouse gases and, eventually, to receive credit for those actions when the government begins regulating those emissions. See map at right.
3. Complete the design and implementation of the Midwest Renewable Energy Tracking System (M-RETS) to facilitate the trading of renewable electricity credits.
4. Support and expand collaborative regional transmission planning to explore the potential for shared transmission corridors that benefit the entire region's renewable and low- and zero-carbon generation resources.
5. Define and support a large-scale, multi-jurisdictional wind energy project that incorporates synergies with other low-carbon generation options. Elements to consider include, but are not limited to:



   a. Common transmission corridor serving several jurisdictions (upgrade of an existing corridor or a new one or both);
   b. Multiple wind farms in participating jurisdictions, including some projects with local ownership components;
   c. Wind-hydro, wind-biofuels, and wind-compressed air demonstrations with the potential to qualify for 65 percent "firm" capacity payments (FERC[4] tariff for renewable generators);
   d. Commercial-scale baseload IGCC[4] or advanced combustion coal plant with CCS[4]; and
   e. Associated hydrogen and fertilizer production applications using wind, IGCC coal and possibly biomass or bio-fuels as energy sources.

4. FERC: Federal Energy Regulatory Commission; IGCC: Integrated Gasification Combined Cycle; CCS: Carbon Capture and Storage

States already organizing GHG registries



Lake Michigan Air Directors Consortium (LADCO)

Eastern Climate Registry

Carbon Sequestration Registries in Development

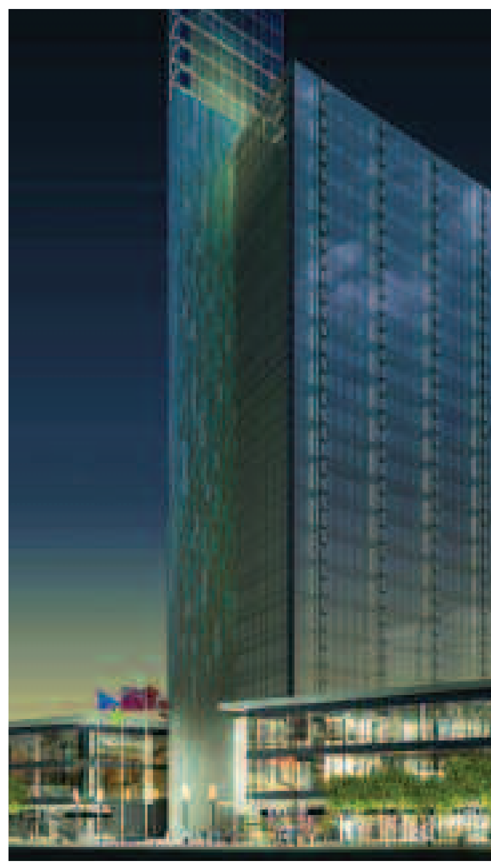
Voluntary Registries in Operation

Carbon Sequestration Boards Investigating Creating Registries

Information courtesy of the Pew Center for Climate Change

B Energy Efficiency Strategies

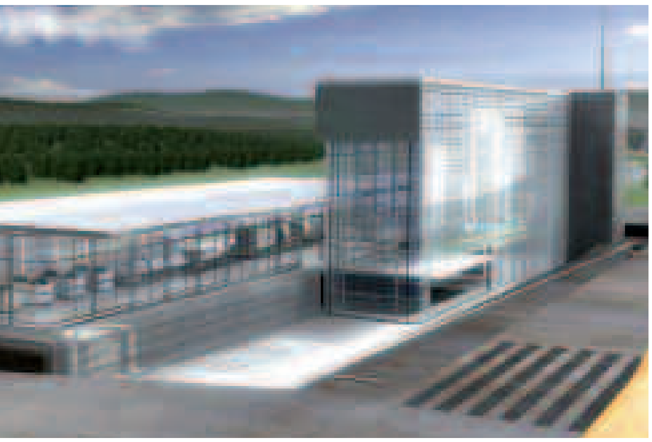
1. Strengthen existing state/provincial and federal energy efficiency programs.
2. Support utility efforts to undertake energy efficiency/conservation potential assessments that quantify the amount of energy efficiency that would cost less per kilowatt hour than the next most expensive energy source.
3. Establish quantifiable goals for energy efficiency.
4. Require utilities to make energy efficiency a priority and to include it as a standard part of their integrated resource plans.
5. Decouple utility revenues from sales for investor-owned utilities so that utilities can make money without necessarily selling more electricity.
6. Encourage utilities to adopt creative rate design that promotes energy efficiency.
7. Adopt more aggressive building codes and appliance standards.
8. Have the public sector lead by example.
9. Strengthen efforts to encourage adoption of energy efficiency technologies by consumers.



Manitoba Hydro's proposed new LEED gold certified headquarters.

C Coal Strategies

1. Support the development of commercial scale advanced coal plants with CCS in the region including:
   a. IGCC using western sub-bituminous coal;
   b. IGCC with co-product production using lignite (and straight lignite IGCC if feasible);
   c. Advanced combustion technology with post-combustion CO_2 capture using both sub-bituminous and lignite coals; and
   d. The pairing of advanced coal technologies with wind power, hydrogen production and biomass co-gasification/co-firing.
2. Lay a foundation for CO_2 management through:
   a. Development of the legal and regulatory framework needed for geologic storage of CO_2;
   b. Comprehensive assessments of geologic reservoirs at state and federal levels to determine CO_2 storage potential and feasibility;
   c. Sufficient large-scale geologic sequestration tests to prepare for future sequestration on a widespread commercial basis;
   d. Feasibility assessment of CO_2 transport and "advanced sequestration" options for jurisdictions with no documented geologic sequestration potential, such as Minnesota and Wisconsin;
   e. Tax incentives for CCS, including CO_2's use in enhanced oil recovery (EOR); and
   f. EOR project development assistance.



Department of Energy's FutureGen project aimed at producing zero emission electricity and hydrogen from coal.

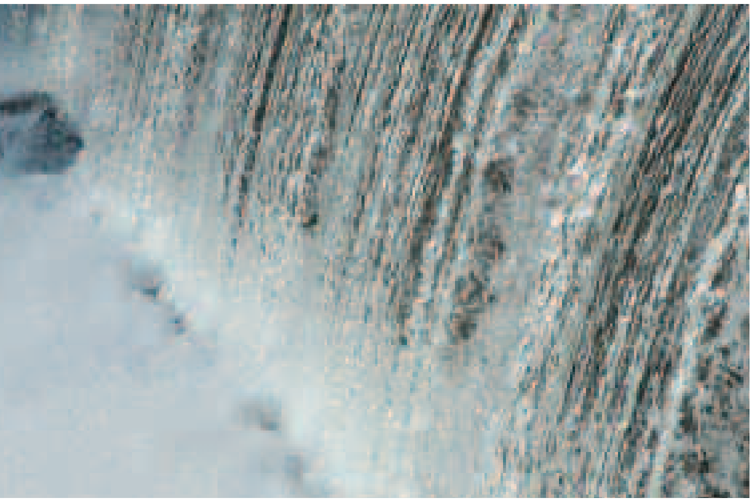
3. Provide incentives to get commercial and low CO_2 projects built through:
   a. Support for front-end engineering and design or FEED packages (FEED studies provide good cost estimates for power plant projects and are essential to securing private investment, especially with newer technologies);
   b. Direct state financial incentives (tax credits, loan guarantees and performance coverage for engineering/procurement/construction);
   c. Allowing regulated utilities cost recovery for appropriate demonstration projects;
   d. Improved policies on integrated resource planning policies to encourage low-CO_2 coal technologies; and
   e. Opportunities for state policies and regulatory programs to favor IGCC and advanced combustion technologies over conventional pulverized coal combustion technologies (could include low-carbon electricity portfolio standards or objectives; long-term power purchase agreements to provide developers with higher rates of return and reduced risk for ratepayers; and market-based regulatory programs to provide incentives to invest in low-emission technologies).
4. Update workforce training and research and development programs and investments, with a focus on developing the gasification and carbon sequestration industries.

D Wind Strategies

1. Support a long-term extension of the U.S. federal production tax credit or comparable new long-term federal incentive.
2. Consider new policy approaches to wind energy development in states which currently lack renewable energy standards or objectives.
3. Incorporate transmission development requirements into existing state and provincial renewable energy objectives and standards.
4. Encourage a diversity of approaches to wind development, including projects that have significant components of local ownership.
5. Expand collaborative regional transmission planning efforts to help develop the infrastructure for future wind energy development.
6. Consider a significant multi-state transmission initiative to facilitate construction and delivery to market of a large amount of new wind power in partnership with energy from other low-carbon generation facilities.
7. Define and support a large-scale, multi-jurisdictional wind energy project that incorporates synergies with other low-carbon generation options.
8. Demonstrate technology and engineering strategies for achieving greater than 20 percent of total electricity generation from wind.
9. Develop policies to attract wind energy component manufacturers and service providers to locate their operations within the region.

E Hydro Strategies

1. Explore potential synergies among hydro, wind and other renewable and near-zero emission energy technologies, including their ability to share new transmission capacity (reaching consensus about what goes on the wires will facilitate the siting, permitting and construction of those wires).



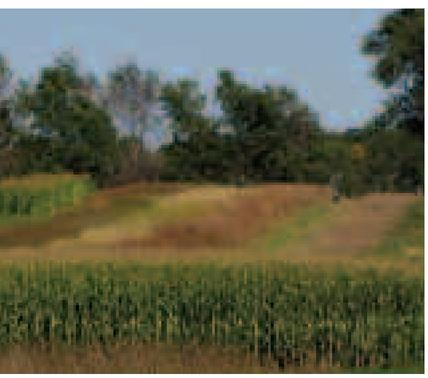
2. If a market evolves for the tracking and trading of CO_2 emissions, allocate emission reduction credits to new hydro generation.
3. Consider including new hydropower production in any regional, state and provincial renewable energy standards or objectives.
4. Include new hydro generation in any incentives established or revised for other zero-CO_2 energy production.

F Nuclear Strategies (None at this Time)

Nuclear generation currently provides the largest current contribution of emissions-free electricity production in the region today. In the context of future federal regulation of CO_2 emissions, nuclear has the potential to become an even greater source of zero-carbon generation. Indeed, in the scenario modeling undertaken by GPI and the University of Minnesota for PTP, nuclear would likely become the dominant source of new generation—unless constrained in the model at present levels (the approach taken at the decision of PTP participants for the scenarios presented here).[5]

While the roadmap's underlying analysis suggests the potential for future growth in nuclear power, the roadmap itself does not include any specific strategies for encouraging or discouraging such an outcome. PTP participants could not reach consensus on strategies to recommend for several reasons: unresolved concerns over nuclear waste, weapons proliferation and vulnerability of plants to security threats; need for regulatory approval in the United States for new, efficient plant designs; and the absence of any current firm plans by the region's utilities for new nuclear generation capacity (only seeking relicensing of existing facilities). Instead, the nuclear chapter sheds light on issues to be addressed and resolved for nuclear power to play a larger future role in the region.

G Biomass Strategies



South Dakota State University energy crop research plots.

1. Support demonstration and commercialization of advanced biomass technologies by:
   a. Providing capital through cost share, loan guarantees, revolving loan funds and bonds;
   b. Production and purchase incentives for bio-based energy;
   c. Reduction of regulatory barriers through streamlining and new permitting rules and other procedures for emerging technologies; and
   d. Supporting local ownership while recognizing the role that outside investment will play in the industry.
2. Develop a perennial biomass supply through a range of incentives and programs.
3. Establish bio-based product procurement rules in each state and province of the region that are consistent across the region.
4. Implement policies that help increase the penetration of biofuels in the marketplace such as renewable fuels standards (including for cellulosic biofuels), promotion of biofuel powered vehicles, state purchasing and retail tax incentives.
5. Provide technical assistance and support through state and provincial funding of FEED studies, business planning and assistance, and expansion of technical assistance capabilities and services.
6. Help the industry overcome the difficulties with feedstock logistics by funding necessary assessments and research, using public university and state resources to provide technical assistance, providing financial incentives for the equipment to manage and harvest biomass crops, and leading energy crop pilot projects.
7. Support basic and applied research on energy crops and conversion technologies.
8. Expand state/provincial workforce development programs and cooperation with the private sector to ensure a new generation of trained personnel to build and operate the facilities that will make up the new bio-economy.
9. Increase public education about the bio-economy through schools, government agencies and private organizations.

5. PTP participants felt that new nuclear generation would require the region to settle on different waste disposal methods than are currently used, and that cost numbers for those methods would not be possible to estimate at this time. There is further uncertainty regarding the future costs and difficulties of permitting nuclear.

Hydrogen dispenser made by Winnipeg-based Kraus Global, Inc.

10. Establish a regional entity to foster collaboration among state departments of agriculture, land grant universities and extension systems to advance bio-economy goals, policies and initiatives.
11. Facilitate the trading of carbon and water credits associated with biomass production.

H Strategies for Hydrogen, Fuel Cells and Related Technologies

1. Develop a hydrogen roadmap in each state and province that capitalizes on each jurisdiction's strengths and describes the role of hydrogen and fuel cells in the energy system.
2. Launch, participate in and/or endorse public-private partnerships aimed at accelerating the commercialization of renewable and low-carbon hydrogen production, fuel cells and related technologies.
3. Support publicly-funded basic and applied research on hydrogen technologies at the region's respective research institutions.
4. Provide matching funds and policy support for strategically important early deployment projects.
5. Explore hydrogen's potential for bringing renewable energy sources to market (e.g., ammonia production from wind-powered water electrolysis).
6. Establish a "Refueling Infrastructure Transition Fund" (RIT Fund). The revolving fund would help finance the shift away from a petroleum-only refueling network toward one that supports multiple domestic low- or zero-carbon fuels.
7. Allow owners of hydrogen-fueled vehicles for a defined amount of time to:
   a. Use High Occupancy Vehicle (HOV) lanes (where applicable);
   b. Use toll roads free of charge (where applicable);
   c. Pay no annual vehicle registration fees;
   d. Pay no highway use tax;
   e. Park free in high-demand areas (e.g., downtowns). This option may require developing hydrogen standards for parking garages; and
   f. Establish additional tax credits for the purchase of these vehicles.
8. Implement other policies and incentives to accelerate the commercialization of hydrogen technologies:
   a. Establish a hydrogen production incentive for renewable and carbon-neutral hydrogen production and use (i.e., similar to the production tax credit for wind);
   b. Establish a renewable and carbon-neutral hydrogen production standard or objective and allow such renewable hydrogen production to qualify under existing standards or objectives.
   c. Incorporate hydrogen technologies into government and other public purchasing guidelines and contracts;
   d. Adopt uniform codes and standards and siting requirements for hydrogen-related infrastructure;
   e. Appropriate funds for education and outreach to key audiences on hydrogen, fuel cells and related technologies, and their role in the future energy mix; and
   f. Ask the Public Utilities Commission (or its equivalent) to study cost recovery mechanisms that would support hydrogen-related utility investments.

What do Citizens in our Region Want in their Energy Future?

Great Plains Institute staff held five Town Hall Meetings[6] across the region between December 2006 and February 2007 to solicit public input on the document's initial recommendations. These public meetings were held in: Washburn, ND; Brookings, SD; St. Cloud, MN; Eau Claire, WI and Storm Lake, IA.

Citizens were first asked to describe what they like and don't like about the current energy system, and attitudes were remarkably similar across all five Town Hall Meetings. Citizens liked the current energy system's reliability, affordability and its role in supporting a high quality of life and a strong economy. Criticisms of the existing system include: pollutants, such as mercury, SO_2 and NO_x, greenhouse gas emissions (mainly CO_2), the potential for rising costs, dependence on too few resources and the vulnerability of the grid to disruption and blackouts.

The primary task for citizens at the Town Hall Meetings, however, was to respond directly to the objectives, milestones and recommendations in this roadmap. In many cases, citizen feedback confirmed the roadmap's content or made it stronger; in others it informed subsequent changes. The hundreds of citizens that joined us for these meetings also brought forth many exciting and entrepreneurial ideas for the region, as well as some criticisms of the roadmap, that are not reflected in the final version. A compendium of these ideas, as well as a complete summary of citizen input, is available at **www.poweringtheplains.org**.

Citizen feedback also highlighted a number of important issues that this first edition of the roadmap does not address in great detail or, in some cases, at all. These include:

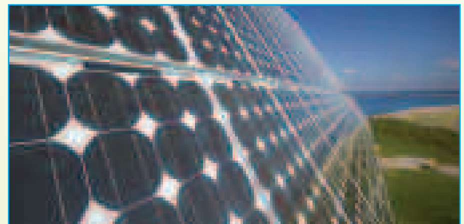
1. **The potential contribution of solar power (see opposite page)** to the region's energy system if anticipated technical breakthroughs bring down its cost. Many citizens were critical of the absence of solar energy in the roadmap. PTP stakeholders decided not to focus on solar in favor of a more detailed treatment of our region's abundant wind resources and already cost-competitive wind generation technology. Substantial solar cost reductions would change that prioritization. As with transportation fuels, solar will be included when this roadmap is expanded.
2. **Full-cost pricing**, sometimes called true-cost or lifecycle cost, is grounded in conventional economics. It stipulates that the price of any good or service should reflect the full cost to society of producing it, including environmental costs. Many citizens

6. Generous support from the Otto Bremer Foundation, Great River Energy, Xcel Energy and the Iowa Farm Bureau helped make these meetings possible.

The Potential Contribution of Solar

Of the renewable resources able to contribute to our long-term carbon-neutral energy future, solar power has the largest potential but the highest current cost. Roughly 10,000 times the average power consumed by humans hits the earth in the form of sunlight at any given time. The resource tends to be best in our region when other renewable resources are less available and energy needs are up (hot, sunny summer days with little wind), and thereby would provide a nice addition to our energy mix. Unlike other renewable energy options, solar photovoltaic systems (PV) also have the potential to be physically integrated into many materials that make up the built environment (facades of buildings, roofing tiles, etc.) and used in a highly distributed fashion nearly anywhere.

The Achilles heel of solar power (PV in particular) has simply been its cost. It is currently several times more expensive than the lowest cost new energy source, despite decades of development. While some have argued that solar PV could be cost competitive today if manufactured at a massive scale, no company has yet proved that to be true. Other solar technologies like concentrating solar appear increasingly promising from a cost perspective but have yet to be seriously considered for our region. For solar electricity to play a much larger role in our electric system, the costs of installed capacity will have to come down considerably. This is amplified in our region by the fact that other renewable resources, namely wind, are abundant and cost-competitive today.



Estimated Total Global Capacity

(in Terawatts or Million Megawatts)[1]

Solar	7,500
Wind	14
Hydro	1

In the near-term, however, solar heat is a practical and cost-effective way to heat water and buildings, and solar lighting can significantly reduce electrical power needs in buildings. Some of these strategies should be strongly considered as part of the energy-efficiency recommendations aimed at improving building codes and standards.

Solar Technology Applications[2]

Solar Photovoltaic Systems (PV): PV systems use semiconductor materials that convert sunlight directly to electricity. Such systems are scalable and currently used in many off-grid applications where installing a new transmission line would be cost prohibitive.

Solar Lighting: While a combination of mirrors and skylights can be used to increase natural lighting in buildings, recent technology collects sunlight and routs it through optical fibers into buildings where it is combined with electric light in "hybrid" light fixtures.

Solar heat: These simple systems use the sun's energy to heat up water (or fluid) or air. The warmed air is transferred directly to heat buildings or water for hot water usage. With high natural gas prices, solar hot water heating has become increasingly attractive.

Concentrating solar: The large-scale solar thermal technology known as concentrating solar power (CSP) uses different kinds of mirror configurations to convert the sun's energy into high-temperature heat. That heat is then used in a steam generator to turn a turbine and generate electricity. The technology's ability to deliver power on-demand or for peak power production makes it an especially attractive nearer term option.

1. Nelson, Sandia National Labs: http://www.hydrogenassociation.org/renewablesForum/pdf/solar_nelson.pdf
2. Technology descriptions modified from the USDOE Solar Energy Technology Program. More on each technology can be found at http://www1.eere.energy.gov/solar/

called for a tax and regulatory environment that discourages activities that impose harm or cost on society—inefficiency, environmental damage and reliance on outside energy sources—and instead encourages greater investment in low-CO_2 energy technologies, jobs and economic development from local resources, more distributed energy production, and greater transparency for consumers to understand the connection between their energy use and what they pay.

3. **Transmission system issues beyond just capacity expansion**, including the age and integrity of the existing grid system, implications of having energy production more geographically dispersed across the landscape (i.e., distributed generation), and the emergence of so-called "micro-grids."
4. **Ground source heating and cooling** and its significant potential for increasing energy efficiency, particularly in new construction.
5. **Opportunity cost of NOT maximizing efficiency and low- and zero-CO_2 energy options**, or an attempt to quantify what the region will give up economically if it sticks with business as usual.
6. **Local ownership of energy production** and the social, economic and environmental costs and benefits.
7. **Value of producing multiple products at energy facilities.** For example, wind power can produce electricity for the grid, hydrogen for use in vehicles and stationary fuel cells, and perhaps anhydrous ammonia (NH_3) fertilizer for farmers by harvesting hydrogen from water and nitrogen from the air.
8. **Education and workforce training** that prepares the region's population to participate in and benefit from innovative energy development over the next 50 years.

Implementing the Roadmap and Future Work

Implementing the roadmap is, of course, when the real work begins. PTP participants and GPI staff will be working with a wide range of additional stakeholders to make the ideas in these pages become reality. The most immediate next steps are to:

1. Expand the roadmap and scenario model to include transportation fuels. This will not include tackling the broader transportation system challenges such as land use, transit and the like.
2. Engage governors, legislators, regulators, business leaders and others in implementing the roadmap's strategies and recommendations. This will be the heart of what PTP does in its next phase.
3. Encourage strategic demonstration projects that give our region's engineers and system operators experience with new technologies and with the integration of those technologies in ways that maximize synergies among our region's native energy resources.

Of course, the rest of the world will not sit still while we implement this roadmap. Growing numbers of states and provinces across North America already have similar action plans and energy roadmaps either underway or planned. Likewise, we view this roadmap as a "living" document that will continue to evolve as markets change and new technology breakthroughs, information and opportunities surface.

Final Thoughts

Today, the Upper Midwest is the region of North America most heavily dependent on electricity from traditional combustion coal plants. Moreover, like other parts of the nation, we rely almost entirely on petroleum to fuel our agricultural and transportation sectors. Transitioning these sectors to low-carbon and renewable energy use over the long term will require significant and sustained political commitment, financial and regulatory incentives, and public and private investment.

At the same time, this region has resource advantages over other regions of North America such as world-class wind and biomass potential and large geologic reservoirs suitable for permanent storage of CO_2 that are located in close proximity to regional coal reserves. Add to this our regional congressional delegation's pivotal role in the nation's policy debate on energy, agriculture and climate, and our energy future looks very bright.

What to Expect from the Full Chapters

While this overview is meant to detail the roadmap's broad themes and over-arching ideas, seven full chapters—each dedicated to a particular energy option—can be found at **www.poweringtheplains.org**. The chapters represent the real heart of the PTP stakeholder consensus on objectives, milestones and recommendations. Each chapter includes:

1. Background on the specific energy option or resource;
2. Key objectives for the option or resource in the region;
3. Regional potential for the resource or option;
4. Measurable milestones for development of the resource and associated technologies;
5. Challenges and barriers to development; and
6. Specific policy recommendations for action.

Although each chapter is comprised of these common elements, they differ markedly in breadth and length depending on when work on particular chapters began within PTP and the process for developing them. For example, the opportunity for our region to lead in the renewable and low-carbon hydrogen development was one of the first strategic action areas where the PTP stakeholders reached consensus. PTP even launched a work group specifically dedicated to hydrogen called the Upper Midwest Hydrogen Initiative. This chapter has been carefully crafted by not only PTP members but also by a wider set of stakeholders with considerably more experience in hydrogen technologies.

The coal and biomass chapters also benefited from detailed input from separate work groups created by PTP. The development of the coal chapter actually became an important tool as the Coal Gasification Work Group reached a broad regional consensus on its vision for future low-carbon coal use in the Upper Midwest and Northern Plains. For that reason, it is one the longest and most detailed chapters in the roadmap.

Other chapters vary in length or detail based on their relative potential contribution to achieving CO_2 emissions reductions in the region. Thus, given that every jurisdiction in our region has an enormous and largely untapped wind resource potential, the wind chapter is quite extensive. By contrast, the hydropower chapter is more concise because new hydro development potential in the region is primarily limited to northern Manitoba.

The lessons this roadmap offers are straightforward:

1. Energy efficiency offers the best return on investment and makes any broader energy transition affordable for society.
2. Meeting the energy and climate challenge in our region will require dramatic scale-up of multiple low- and zero-carbon energy technologies.
3. Many combinations of our region's resources could successfully meet the region's power needs while dramatically reducing CO_2 emissions and keeping energy costs affordable.
4. Most importantly, the necessary transition is technically feasible, economically affordable and politically achievable—but only if we begin taking action now.

Appendix A

Additional Contributors to This Roadmap

The following people participate in additional work groups run by the Great Plains Institute. The following three work groups made substantive contributions to a particular chapter of this roadmap.

Biomass Working Group

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Gretchen Bonfert, McKnight Foundation

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Ronald Cox, Center for Industrial Research and Service, Iowa State University

Dean Current, Center for Integrated Natural Resources and Agriculture Management, University of Minnesota

Dave DeGeus, The Nature Conservancy

Chris Deisinger, Energy Foundation/ Union of Concerned Scientists

Steve Devlin, Center for Industrial Research and Service, Iowa State University

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Patrick Girouard, Iogen

Kate Gordon, Center on Wisconsin Strategy

Nathanael Greene, Natural Resources Defense Council

Mindi Grieve, North Dakota Farmers Union

Robert Gronski, National Catholic Rural Life

Ralph Groschen, MN Department of Agriculture

Chad Hart, CARD, Iowa State University

Ken Hellevang, North Dakota State University Extension

Jennifer Hermans, GDS Associates

Jack Huggins, The Nature Conservancy/ethanol plant board member

Michael Jerstad, PraireGold Venture Partners

Stanley Johnson, University of Nevada - Reno

Dennis Keeney, Institute for Agriculture and Trade Policy

Jim Kleinschmidt, Institute for Agriculture and Trade Policy

Arnold Kruse, North Dakota Natural Resources Trust

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Rich Leopold, Iowa Environmental Council

Mark Lindquist, MN Project/Midwest AgEnergy Network

Deron Lovaas, Natural Resources Defense Council

Scott McLeod, Ducks Unlimited

Russ Meier, ePowerSynergies

Dave Miller, Iowa Farm Bureau

Jeff Moore, Virent

Bob Mulqueen, Iowa Environmental Council

Jeri Neal, Leopold Center for Sustainable Development

Katie Nekola, Clean Wisconsin

Jon Nelson, North Dakota State Senator

Andy Olsen, Environmental Law and Policy Center

Ben Paulos, Energy Foundation

Gary Radloff, WI Department of Agriculture, Trade, and Consumer Protection

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Jerod Smeenk, Frontline Bioenergy

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Robert Goff, R4Energy

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John Howard, Distributed Generation Solutions, Inc.

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Jim Kubiak, Great Plains Institute

Robert Lindstrom, FreedomField (Illinois)

Dave Mulder, Donaldson Company

Frank Novachek, Xcel Energy

Jeff Moore, Virent Energy Systems, Inc.

Robert Parsons, MBA, P.Eng., Manitoba Energy Development Initiative

Nancy Pellowski, Xcel Energy

Andy Polzin, Barr Engineering

Mike Reese, West Central Research & Outreach Center, University of Minnesota

Lanny Schmidt, University of Minnesota Initiative on Renewable Energy and the Environment

Yvonne Simon, Minnesota Corn Growers Association

Robert Swenson, Moorhead Public Service

Scott Tolbert, University of North Dakota

Steve Tweed, Wisconsin Power Control

Sean Weitner, Energy Center of Wisconsin

Bruce Wood, ePower Synergies, Inc.

Paul Zanetel, New Flyer Industries

Coal Gasification Work Group

Ian Andrews, PacifiCorp Energy

Steve Brick, The Joyce Foundation

Charles Bullinger, Great River Energy

Betsy Engelking, Xcel Energy

Bill Grant, Izaak Walton League of America

Gary Hanson (R), South Dakota Utilities Commissioner

Roger Johnson (D), North Dakota Agriculture Commissioner

Dave Klemp, Montana Department of Environmental Quality

Dennis Koepke, Public Service Commission of Wisconsin (observer)

Mark Meyer, Commissioner, Public Service Commission of Wisconsin (observer)

John Nielsen, Western Resource Advocates

Bob Raney (D), Montana Public Service Commissioner

Mark Redsten, Clean Wisconsin

Glen Skarbakka, Great River Energy

Beth Soholt, Wind on the Wires

Wayne Stenehjem (R), North Dakota Attorney General (observer)

John Thompson, Clean Air Task Force

Bonnie Turner, Westmoreland Coal Company

Kevin Vesperman, Alliant Energy

Appendix B

Additional Background on the CO_2 Scenarios

The following tables and charts describe key assumptions and outcomes of the CO_2 scenario model referenced in this roadmap.

Assumptions for Scenarios

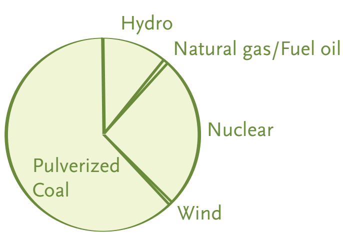
	2005	Business as Usual	Scenario 1 High Efficiency Modest Coal & Renewables	Scenario 2 High Renewables Modest Coal & Efficiency	Scenario 3 High Coal Modest Renewables & Efficiency
Reduces CO2 80% from 1990 levels?	NO	NO	YES	YES	YES
Regional demand management (US$ Million annually)	–	$96	$500	$250	$250
Cost of Demand management ($/MWh avoided)	$10	$10	$10	$10	$10
CO_2 maximum (tons CO_2/MWh)	No max.	No max.	0.2	0.2	0.2
Maximum Technology Penetration					
Hydro	–	10%	14%	16%	13%
Wind	–	–	26%	30%	20%
Nuclear	–	Held constant	Held constant	Held constant	Held constant
Minimum Technology Penetration					
Biomass IGCC*	–	–	–	10%	–
Coal IGCC with CCS*	–	–	–	10%	50%
Natural Gas	–	2%	2%	2%	2%
1.9 cent/kWh production tax credit applied for	Biomass, Waste Biomass, wind, PV	Biomass, Waste Biomass, wind, PV	Biomass, Waste Biomass, wind, PV Coal IGCC w/CCS	Biomass, Waste Biomass, wind, PV Coal IGCC w/CCS	Biomass, Waste Biomass, wind, PV Coal IGCC w/CCS

* IGCC stands for “Integrated Gasification Combined Cycle” and CCS stands for “carbon capture and sequestration.” IGCC power generation technology can utilize a wide range of carbon-rich fuel sources.

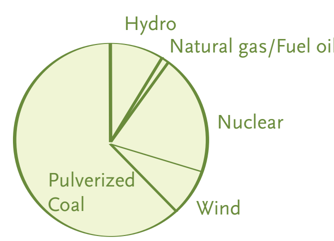
Characteristics of Scenarios

	2005	Business as Usual	Scenario 1 High Efficiency Modest Coal & Renewables	Scenario 2 High Renewables Modest Coal & Efficiency	Scenario 3 High Coal Modest Renewables & Efficiency
Demand in 2055 (Million MWh)	–	521	439	471	462
Cumulative 50 yr. power cost (US$ Billions)	–	$771	$743	$775	$779
Percent change in cumulative cost over BAU	–	–	4% **decrease**	1% increase	1% increase
Avg. power cost in 2055 (US$/MWh)	–	$42	$51	$49	$51
Percent increase in electricity cost over BAU (on a per unit basis)	–	–	18%	14%	18%
Percent increase in electricity cost over 2005 costs (on a per unit basis)	–	31%	43%	41%	43%

High Carbon Scenarios

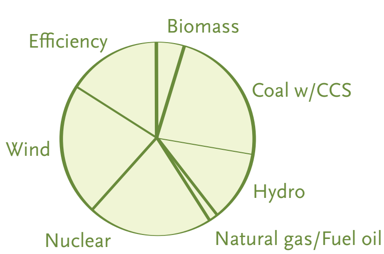


2005

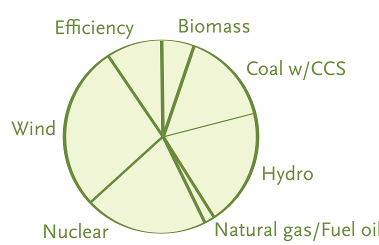


Business as Usual

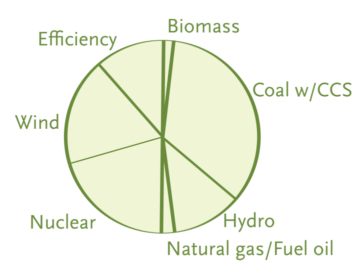
Low Carbon Scenarios



Energy Efficiency



Renewable



Coal

Powering the Plains:
Energy Transition Roadmap
Milestones

Great Plains Institute
Working on tomorrow's solutions with today's leaders

The following milestones were developed by the Powering the Plains (PTP) stakeholders as part of a comprehensive roadmap aimed at transitioning to a renewable and carbon-neutral energy system in the Upper Midwest by mid-century. The numeric targets and milestones itemized below are meant to serve as indicators of progress in meeting this challenge in the short, medium and long-term. More information, including more detailed background and strategies for each resource mentioned below, can be found in the full Energy Transition Roadmap chapters available at www.poweringtheplains.org.

Energy Efficiency Milestones

Efficiency will need to be a cornerstone of the region's energy system for both cost and environmental reasons. While electricity use in our region is expected to grow considerably each year, reducing that energy use—especially in the early years—will reap substantial benefits from avoided new generation costs and reduced resource use and pollution.

The PTP stakeholders recommend that each jurisdiction evaluate how much energy efficiency and conservation is possible and desirable, then set measurable energy efficiency targets for 2015, 2030 and 2055 to achieve that potential. These milestones should be re-evaluated and adjusted, if necessary, every 2–5 years. As policy makers in each jurisdiction set their own targets, the PTP stakeholders recommend that the sum total of these milestones collectively aim to achieve the following regional outcomes:

By 2015:
Regional electrical demand has slowed to 1% on an annual basis.

By 2030:
Regional energy demand has slowed to under 1% annual growth.

By 2055:
Regional energy demand has slowed to 0% annual growth.

Coal Milestones

The following regional coal milestones are proposed by PTP stakeholders for policy-makers' consideration:

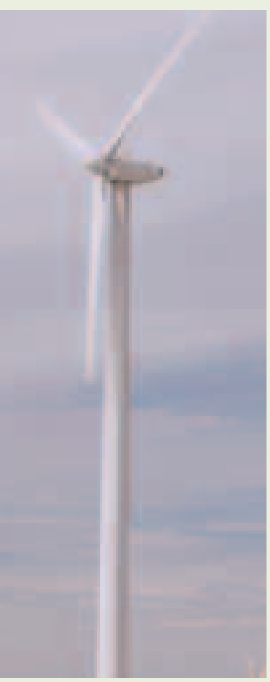
- **By 2015**, the region should strive to have at least two IGCC[1] projects with CCS[2] through design, construction and into full operation, including at least one project using sub-bituminous coal and another using lignite.
- **By 2015**, the region should demonstrate commercial scale post-combustion capture of CO_2 at a pulverized coal plant.
- **By 2020**, the region will have operating at commercial scale multiple IGCC and/or pulverized coal combustion plants with CCS.
- **By 2055**, the region will generate 80 percent of its coal-based electric power from plants that eliminate or capture CO_2 emissions.

In order to know whether or not the region is achieving its long-term vision for coal use, each jurisdiction should also track the following:

1. Percentage of total CO_2 from coal use captured and permanently stored underground or used for EOR[3];
2. Percentage of total sulfur dioxide, nitrogen oxide, mercury emissions and fine particles avoided;
3. Increase in average efficiency of coal fleet due to technology retrofits or new coal plants; and
4. Percent of new coal plant capacity installed with low-carbon technology and CCS.

Wind Energy Milestones

The following regional wind energy milestones are proposed by PTP stakeholders for policy-makers' consideration[4]:



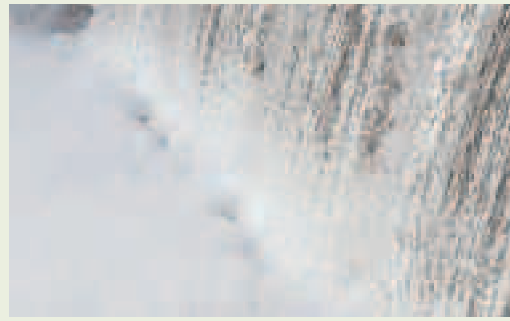
- **By 2015**, 13,000 MW of installed capacity or 10 percent of electricity consumed in the region.
- **By 2020**, 30,000 MW of installed capacity or 20 percent of electricity consumed in the region.
- **By 2030**, 50,000 MW of installed capacity or 30 percent of electricity consumed in the region, assuming technical feasibility and reliability.
- **By 2040**, one third of all energy consumed in the region will be derived from wind power, including electric generation for the grid and non-grid applications.

The targets for 2015, 2020 and 2030 could be revised upward over time depending on the scope of policy incentives and transmission development.

As for the 2040 target, achieving 30 percent of total regional energy production from wind by 2040—rather than just 30 percent of electricity production—will require significant policy changes; the demonstration and commercialization of wind energy paired with other energy resources and technologies; storing wind energy; and harnessing wind for uses other than just electric power.

1. Integrated Gasification Combined Cycle.
2. Carbon Capture and Storage.
3. Enhanced Oil Recovery.
4. The first three milestones assume annual average growth in electricity demand of 1.5 percent and an average wind turbine capacity factor of 40 percent.

Hydro Milestones



Even with significant new investments in energy efficiency between now and 2055, the region will need a large amount of electricity production that emits little or no CO_2. Thus, the following regional hydropower milestones are proposed by PTP stakeholders for policy-makers' consideration, provided the objectives described in the hydropower chapter of this roadmap are also met:

- **By 2025**, 2000 new MW of hydro power added to the region's electricity system.
- **By 2055**, 5000 new MW of hydro power added to the region's electricity system.

Nuclear Power Milestones

While the roadmap's underlying analysis suggests the potential for significant growth in nuclear power in a future carbon-constrained world, the roadmap itself does not include any specific strategies, numeric targets or milestones for nuclear power. PTP participants could not reach consensus on nuclear recommendations for several reasons: unresolved concerns over nuclear waste, weapons proliferation and vulnerability of plants to security threats; the need for regulatory approval in the U.S. for new, efficient plant designs; and the absence of any current firm plans by the region's utilities for new nuclear generation capacity (only seeking relicensing of existing facilities). Instead, the nuclear chapter sheds light on issues to be addressed and resolved for nuclear power to play a larger future role in the region.

Biomass Milestones

The following regional biomass energy milestones are proposed by PTP stakeholders for policy-makers' consideration:

By 2015:

1. Biomass is 10% of total regional energy consumption, including:
   - Twenty-five percent of vehicle fuels from biofuels;
   - Commercialization of advanced cellulosic biofuel technologies; and
   - Greater penetration of biomass into natural gas and electricity markets.
2. Twenty-five percent of gas stations offer biofuels at high blends (E85 and B20).
3. The jurisdictions in the region have established an efficient bio-based product procurement system.
4. Technologies that convert biomass to energy, fuels and products have been demonstrated on a variety of our region's most promising feedstocks (e.g. native perennial grasses and agricultural residues) including the following:
   - Biomass combined heat and power systems;
   - Direct biomass gasification and co-gasifying biomass with coal;
   - Cellulosic biofuels development through both thermo-chemical and bio-chemical processes;
   - Pipeline quality natural gas produced from biomass and integrated into the existing natural gas system; and
   - Pyrolysis as a source of fuel and products.

By 2025:

1. Biomass is 25% of total energy consumption, including:
   - Twenty-five percent of vehicle fuels; and
   - Significant use of biomass to replace natural gas and produce electricity.
2. Fifty percent of gas stations offer biofuels in high blends.

By 2055:

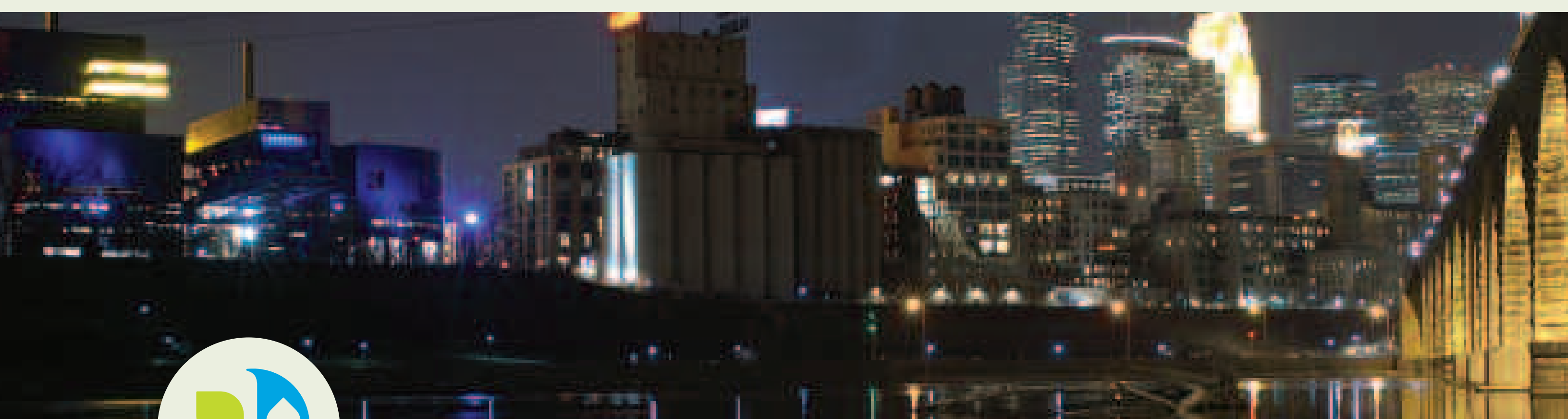
1. Replacement of 25% of total regional energy consumption with biomass.
2. All gas stations offer biofuels in high blends.

Hydrogen Milestones

Hydrogen, fuel cells and related technologies were not included in the CO_2 Scenario model that has informed this roadmap. As a result, Powering the Plains stakeholders have not developed cost and technology milestones specific to this region, but instead recommend strategies (outlined in the full chapter) that will help this region contribute to the measurable milestones already developed by industry in coordination with the federal government. A more detailed list of milestones developed by the United States Department of Energy can be found in the full hydrogen chapter.

Summary of Hydrogen Targets

1. Make hydrogen competitive with gasoline on a cost per mile basis.
2. Increase the efficiency of hydrogen production using renewable and carbon-neutral methods.
3. Increase material and system durability for fuel cells.
4. Increase hydrogen storage and hydrogen vehicle range.
5. Improve integration with existing power delivery systems.
6. Minimize lifecycle environmental emissions and impacts.



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Energy Efficiency

Great River Energy's proposed new LEED platinium certified headquarters

"Adopting a comprehensive set of policies for advancing energy efficiency could lower national energy use by 18 percent in 2010 and 33 percent in 2020…(this) could dramatically lower U.S. carbon dioxide emissions while saving consumers and business $500 billion net during 2000–2020."
Source: American Council for an Energy-Efficient Economy

Energy efficiency is often the cheapest form of new electric "generation" and critical to any integrated resource plan.

1.0 Introduction

The steady march of industrial progress, helped along by government policy, has yielded impressive efficiency gains over the past 25 years. According to the American Council for an Energy Efficient Economy (ACEEE), the amount of energy used per unit of GDP fell 42 percent between 1973 and 2000, and roughly three-quarters of this decline is attributable to real energy efficiency improvements (the rest due to structural changes in the economy and fuel switching). Yet nearly everyone agrees that much more could and must be done, not least of all because greater energy efficiency will save the most money in the long run.

ACEEE estimates that adopting a comprehensive set of policies for advancing energy efficiency could lower national energy use by 18 percent in 2010 and 33 percent in 2020. These policies, along with policies to advance renewable energy, could dramatically lower U.S. carbon dioxide emissions while saving consumers and business $500 billion net during 2000–2020.[1]

Rising energy prices, concern over energy dependence on foreign sources and mounting evidence of global climate change have all brought new urgency and interest to harnessing the economic and environmental gains that greater efficiency brings. Reducing demand through increased energy efficiency often costs less than building new energy facilities and is a prerequisite to meeting the region's growing energy needs at the lowest long-term cost. In fact, because efficiency investments can reduce the need to build new power plants and the associated regulatory burden those impose, greater efficiency reduces costs for utilities, governments and consumers alike.

Leadership from state and national groups is starting to refocus our planning on energy efficiency. The National Action Plan for Energy Efficiency Leadership group, co-chaired by Diane Munns (Iowa Utilities Board and President NARUC) and Jim Rogers (President and CEO of Duke Energy) have developed the National Action Plan for Energy Efficiency Report which:

- Identifies key barriers limiting greater investment in energy efficiency;
- Reviews sound business practices for removing these barriers and improving the acceptance and use of energy efficiency relative to energy supply options; and
- Outlines recommendations and options for overcoming these barriers.

Detailed recommendations are contained in the report which is available at www.epa.gov/cleanenergy/eeactionplan, but the summary recommendations are as follows:

- Recognize energy efficiency as a high priority energy resource.
- Make a strong, long-term commitment to implement cost-effective energy efficiency as a resource.
- Broadly communicate the benefits of and opportunities for energy efficiency.
- Provide sufficient, timely and stable program funding to deliver energy efficiency where cost-effective.
- Modify policies to align utility incentives with the delivery of cost-effective energy efficiency and modify ratemaking practices to promote energy efficiency investments.

For each recommendation, a number of options are available to be pursued based on regional, state and utility circumstances. The leadership group met on March 29th, 2007 to adopt the second year action plan which can be found on the website listed above.

Several states and the province of Manitoba have taken the energy efficiency challenge seriously and are projecting large cost savings and emissions reductions as a result. The examples below highlight the value of utilities including energy efficiency as a real resource in their integrated resource planning and underscore the economic justification for significantly higher levels of investment by utilities and government in energy efficiency programs:

1.1 California. As part of the governor's climate initiative, the California Public Utilities Commission (CPUC) initiated the largest energy efficiency program in the United States. CPUC has approved budgets of nearly $2 billion over three years (2006–2008) for the four largest electric and gas utilities in California. Projected savings are over 7.3 billion kilowatt-hours (kWh).[2]

California's estimated savings are $2.7 billion over the initial efficiency investment and will avoid the building of three large power plants.

1.2 Minnesota. The Minnesota Department of Commerce promotes energy efficiency programs such as conservation, demand side management and peak demand reduction programs through their Conservation Investment Program (CIP). In addition, the Minnesota Public Utilities Commission has required utilities to include energy efficiency as a resource in their integrated resource plans. Xcel Energy currently invests 2% of revenues in energy efficiency programs and other regulated utilities in the state are required to invest 1.5%. Natural gas utilities are required to invest 0.5%. In 2002 rural electric co-ops and municipal utilities agreed to invest 1.5% for electric and 0.5% for gas revenues in CIP programs. Even higher program goals and investments are being considered in the 2007 legislative session as

Xcel Energy, during the period 2000–2004, saved over 580 MW of demand and 1.2 billion kWh of energy.

part of the governor's and legislature's plans to reduce the carbon emissions from Minnesota.[3]

In 2005 Wisconsin's *Focus on Energy* projects saved over 38 MW, 221 million kWh and 10 million therms.

1.3 Wisconsin. The Wisconsin Public Service Commission set up a public benefits program in 2000 called *Focus on Energy*. Utilities collect a surcharge from customers and pay those dollars to the Department of Administration which, in turn, funds the *Focus on Energy* program and the *Home Energy Plus* program to provide weatherization services for low-income customers. Focus on Energy projected that for every dollar ratepayers put into the program, 5.7 dollars are returned in energy, environmental and economic benefits.

The Energy Center of Wisconsin recently completed a study on *Energy Efficiency and Customer-Site Renewable Energy: Achievable Potential in Wisconsin 2006–2015*. They concluded that an average of $75 to $121 million per year could be spent cost effectively on statewide programs to improve energy efficiency in Wisconsin. In fiscal year 2005, the spending level was $38 million.[4]

1.4 Manitoba. Manitobans spend roughly $2 billion (CAD) every year on imported energy purchases. *Efficiency Manitoba* is the working title for a new agency created by the Province of Manitoba provides a one-stop-shop for all efficiency-related expertise and information. The agency's goal goes beyond just electricity and aims to help Manitobans cut their energy and water bills and decrease the amount of waste destined for landfills. It will also promote transportation demand side management, and small-scale renewable energy technologies, such as ground source heat pumps. The agency's efforts are expected to defer or eliminate the need for expensive new public infrastructure.

Primary Objectives

1. Increase the overall role of efficiency.
2. Attempt to grow the economy without growing energy consumption.
3. Pursue efficiency until other options are less expensive.

For its part, Manitoba Hydro's *Power Smart* program has yielded significant savings since its launch in 1991. Its efficiency programs for residential, commercial and industrial customers have saved the same amount of energy that the town of Selkirk, Manitoba uses in an entire year. Put another way, the Power Smart program has saved the same amount of energy as is provided by the McArthur Falls Generating Station (see photo at left), which generates an average of 380 million kWh/year, enough to power roughly 36,000 homes.* Manitoba Hydro was also named the leading utility in Canada on energy efficiency by the Canadian Energy Efficiency Alliance for 2006.[5]

* The average U.S. household used 10,654 kWh a year in 2001

2.0 Objectives for energy efficiency

The main goals of pursuing additional energy efficiency in the Upper Midwest are to reduce energy costs over the long-term by reducing the rate of growth in energy use; while also reducing our region's carbon footprint. This will also simultaneously reduce other air pollutants and the amount of energy resources such as coal and natural gas used in our region.

If policy makers plan to utilize energy efficiency programs as a part of an overall regional energy transition, they should consider several objectives:

2.1 Decide how much more energy efficiency to pursue. Through an energy efficiency/conservation potential assessment, determine how much cost effective potential exists. This should be complemented with an evaluation broken down into technical potential, economic potential and the "achievable" savings laid out over a specific time period. The energy efficiency scenarios presented in the next section are only meant to suggest possible pathways forward. Each jurisdiction will need to decide on its own numeric targets for energy efficiency based on the results of its energy efficiency/conservation potential assessment.

Most current programs are saving electricity at a total cost of only 2–3 cents per kWh.

2.2 If none exists, design the energy efficiency program that best fits your jurisdiction. Once states and provinces have decided how much efficiency they would like to see as part of the energy mix, they should figure out the best methods for achieving those targets. There are several approaches to energy efficiency program funding that can work. Wisconsin, as noted above, uses a public benefits fund whose money comes from a surcharge on electricity sales. Minnesota requires a certain percentage of revenues for each utility to be spent on energy efficiency and load management programs along with goals for demand and energy reductions. Other regional groups such as the Center for Energy and the Environment in Minnesota have significant experience in designing efficiency programs, performing recommissioning for existing commercial properties, and prioritizing the most attractive opportunities (e.g., rental housing and government buildings).

2.3 Measure annual progress and the cost/benefit of efficiency investments. The agency or department already responsible for energy-related matters in each jurisdiction could be asked to track progress toward efficiency targets and periodically calculate the costs and savings of efficiency investments. Doing so will give states and provinces hard data on which to base policy and funding adjustments .

Efficiency in Canada

Energy efficiency options are treated as a full-fledged energy resource. Energy efficiency options are undertaken if:

1. Their cost is less than the marginal cost of new generating facilities;
2. Customers benefit; and
3. The country wouldn't make more money exporting the energy than saving it.

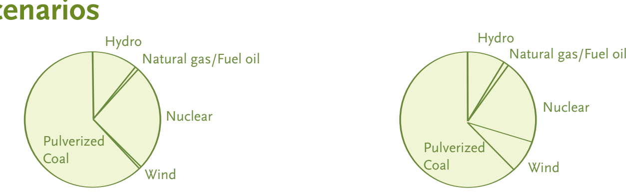
3.0 Potential contribution of new energy efficiency programs to the region's energy sector by 2055

It is both technically and economically possible, even attractive, to reduce growth in energy demand. The region's consumers, businesses and governments would save money while reducing pollution and CO_2 emissions. It is estimated that implementation of a "best practices" energy efficiency scenario could reduce our current 1.9% annual electrical growth rate to well below 1%.

The Western Governors Association Energy Efficiency Task Force and the Energy Center of Wisconsin have both estimated that investments of 2% of revenues by electric utilities in energy efficiency and load management programs can reduce growth by 0.8–1.0% per year and still be cost effective.

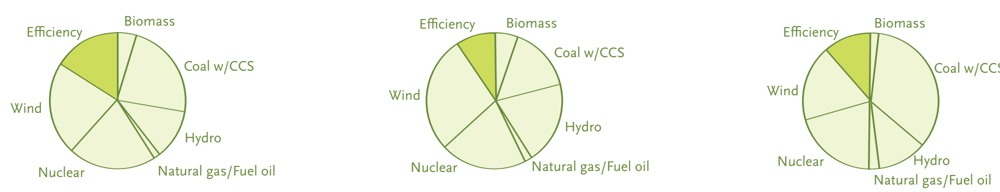
If policy-makers were to commit to reducing CO_2 emissions 80 percent from 1990 levels by 2055, energy efficiency makes the following contributions under four 50-year scenarios for the region's electricity sector: business as usual (BAU), high energy efficiency (EE), high renewable (Renewable) and high coal with carbon capture and storage (Coal). These scenarios are based on modeling done by the University of Minnesota and GPI in partnership with PTP participants.

High Carbon Scenarios



2005 Business as Usual

Low Carbon Scenarios



Energy Efficiency Renewable Coal

	2005	BAU	EE	Renewable	Coal
2055 Total Electricity (million mWh)	374	521	439	471	462
Cost per mWh	$30	$42	$51	$49	$51
Cumulative 50-year spending on Electricity ($ billion)		$771	$743	$775	$779

History proves value of efficiency

If the United States had not dramatically reduced its energy intensity over the past 27 years, energy use in 2000 would have equaled about 171 quadrillion Btus instead of the 99 quadrillion Btus actually consumed. **Consumers and businesses would have spent at least $430 billion more on energy purchases in 2000 had this 72 quadrillion Btus of savings not occurred.**

Source: American Council for an Energy Efficient Economy

The value of this modeling exercise is to highlight how much future energy demand could be met just with greater efficiency, regardless of what new electric generation facilities (or how many) may be built. In all three scenarios that focused on meeting an 80% CO_2 reduction, energy efficiency contributed (or saved) the equivalent of 60 to 80 trillion kWh of electric power compared to the BAU case. This is among the most substantial contribution to our future energy economy of any of the resources outlined in this roadmap.

Another way to estimate the potential contributions of energy efficiency programs in the Upper Midwest is to look at the results of successful programs elsewhere. For example, the California initiative over the past decade has provided net benefits of approximately $3.4 billion dollars and cut demand by almost 5,000 MW (equal to 8–10 conventional power plants).

A significant advantage of energy efficiency programs in our region is that the slower rate of growth in energy demand delays even longer the need for additional base load power plants and buys more time for new renewable, energy storage and carbon-neutral technologies to become commercially viable.

4.0 Measurable Milestones

Efficiency will need to be a cornerstone of the region's energy system for both economic and environmental reasons. The magnitude of its role depends on the overall energy mix that the region's decision makers agree to pursue. Currently our region's electric energy use each year is estimated to grow an average of 1.9%.[6] For some companies, such as Great River Energy, the growth rate of their electric system is closer to 6%, which magnifies the need for effective conservation and energy efficiency programs now. As noted elsewhere, if we can reduce that energy use more in the early years, we will reap benefits forever on reduced resource use and pollution.

We should note that technological advancements in other sectors, notably the transportation sector, promise to increase the total services provided by the electric sector. Plug-in hybrid vehicles and electrolyzed hydrogen are two examples in which electric power may be used to power our future vehicles. Targets over this 50 year planning period should reflect the need for greater efficiency, while also planning to power additional parts of our economy.

The PTP stakeholders recommend that each jurisdiction set numeric milestones for 2015, 2030 and 2055 to achieve the potential identified in the efficiency and conservation assessment noted in the objectives section (2.0) of this report. These milestones should then be re-evaluated and adjusted if necessary every two to five years. As policy-makers in each jurisdiction set their milestones based on the analysis mentioned above, the PTP stakeholders recommend that the sum total of these milestones collectively aim to achieve the following regional milestones:

By 2015:
Regional electrical demand has slowed to 1% annual growth.

By 2030:
Regional energy demand has slowed to under 1% annual growth.

By 2055:
Regional energy demand has slowed to 0% annual growth while maintaining a thriving economy.

Large efficiency gains possible through combined heat and power (CHP)

Cogeneration (or combined heat and power) captures the heat created by electricity generation and either distributes the heat to nearby buildings or generates more electricity via a steam turbine or other means. Capturing and using this otherwise wasted heat can make these installations 85% efficient or better.

The **Northern Border Pipeline**, which extends from Montana through the Midwest, has proposed four CHP projects along its length, each projected to generate 5.5 MW of power. The excess heat produced at these four compressor stations will pass through heat exchangers, and the captured energy will drive turbines directly connected with a generator.

In another example, District Energy provides most of downtown St. Paul, MN with steam heat by burning waste wood.

5.0 Key challenges and barriers

The obvious goal of energy efficiency programs is to reduce end-users' demand for electricity. This means implementing more efficient technologies, improving practices and eliminating unnecessary uses, while maintaining a sufficient energy supply to ensure an economically prosperous region.

This sounds relatively straightforward but has proven to be an elusive goal. What appears to be a natural human instinct for invention and development has traditionally led to greater resource use and an unwillingness to use less. While the economy overall has succeeded in producing more value for a given level of energy use, absolute energy demand continues to climb.

Consumers do not often believe that the savings from energy efficiency are worth the effort because, for many, energy represents a relatively small percentage of their overall expenses.

The public's apparent disaffection for using less energy is one of the reasons why those responsible for energy efficiency efforts have moved away from calling them "conservation programs" and are instead advocating smart use of technology, lean manufacturing and intelligent building practices that happen to save energy but are also attractive economically. No matter what the strategies are called, however, these initiatives result in lower energy use per capita and power plants that are more efficient and more environmentally sound.

The following are some of the most significant challenges to greater reductions in energy use:

5.1 Utility business models encourage energy sales rather than energy efficiency. Utilities make money by selling more electricity rather than less. In order for efficiency to become a larger share of the energy mix, utilities will need to enjoy financial success from selling less energy. This will only happen if jurisdictions can successfully "decouple", or separate, profits in the energy sector from the volume sale of electricity. A recent study by the Regulatory Assistance Project found that a 5% decrease in sales can lead to a 25% decrease in net profit for an integrated utility.[7] For a stand-alone distribution utility, the loss to net profit can roughly double the impact. This is even more of a problem in states which have retail competition such as Illinois and Texas and there is no regulatory mechanism to force competitive energy providers to pay for conservation programs with their customers.

5.2 Utilities often do not consider energy efficiency as an energy "resource" in their planning. Since selling more electricity is how utilities make money, they and their customers tend to focus on the supply side of the energy equation. When demand goes up, plans get underway to build more power plants, even when the same demand might be met at a lower societal cost, at least in part, through greater efficiency investments.

5.3 Lack of incentives for municipal and cooperative power agencies to focus on efficiency. Unlike regulated Investor-Owned Utilities (IOUs), municipal and cooperative utilities have very few drivers pointing them toward greater investments in efficiency, particularly since their members benefit from selling more electricity rather than less. In short, states and provinces have not provided much support for municipal and cooperative power agencies to maximize cost-effective energy efficiency programs in their resource planning and work with customers. Some states like Wisconsin make their energy efficiency training and programs available to municipal and cooperative utilities at a reasonable cost to ensure the maximum participation by these public energy groups.

5.4 Lack of state support for high efficiency building codes along with the training and enforcement needed to make the building codes effective. This is especially true in rural areas where resources are scarce and enforcement is much more difficult. The technologies and practices necessary for high performance building design have matured significantly, making it possible to dramatically lower the lifetime operating costs of built structures. But codes, by their nature, represent the “floor” in terms of building performance (i.e., doing anything less is against the law). As such decision-makers have had a hard time keeping up with advances in technology and building practices and deciding what should represent this floor.

5.5 The upfront expense of many energy efficiency investments deters consumers even when those investments would yield significant long-term savings. For example, new construction for residential consumers often comes down to choices about “how much house” for the money. As those choices are made, long term energy efficient choices like ground source heat pumps and top-efficiency air conditioning must compete against other desirable features. Consumers face few incentives to choose energy efficiency over other amenities. Without enforceable regulations in place for appliance and building codes, many buyers of residential and even commercial buildings will not make the extra investment based on the length of the payback. The same is true for owners of existing homes contemplating new appliances or energy retrofits.

5.6 A disconnect between who pays for energy efficiency investments and who benefits. In rental housing, for example, renters would have a natural interest in lowering their heating and electric use if they reaped the economic benefits, but it is often landlords who have control over efficiency investments. Yet landlords often do not see great value in lower utility bills because they simply pass costs along to their tenants.

6.0 Strategies for achieving greater energy efficiency

Highly successful energy efficiency policies and programs already exist within the region and could be broadly applied without reinventing the wheel. Building on this success, states and provinces may consider the following additional strategies for accelerating and improving the effectiveness of energy efficiency investments:

6.1 Strengthen existing state and federal energy efficiency programs with more funding for research on technology to support higher appliance and building energy efficiency standards.

6.2 Support utility efforts to undertake energy efficiency/conservation potential assessments that quantify the amount of energy efficiency that would cost less per kilowatt-hour than the next most expensive energy source. This analysis should include costs and benefits of pursuing this amount of efficiency.

6.2 Establish quantifiable goals for energy efficiency. Policy-makers need to determine what level of efficiency improvement is realistic and desirable for their jurisdiction, and what level of spending will be required to accomplish it. If each state and province identified targets for: 1) energy efficiency spending; 2) total megawatts avoided; and 3) megawatt-hours saved for the years 2015, 2035 and 2055, it would be possible to determine what role each state and province may play in achieving the region's overall energy efficiency objectives. Progress towards goals should be continually measured and evaluated and adjustments made as necessary.

6.3 Require utilities to make energy efficiency a priority and to include it as a standard part of their integrated resource plans. Utility energy plans should begin with energy efficiency goals, targets and strategies before any discussion of other resource needs. This would assure customers and regulators that all cost-effective energy efficiency investments are being made before considering new generation.

6.4 Decouple utility revenues from sales for Investor-Owned Utilities. Loss of sales from successful energy efficiency can significantly lower regulated utility profitability. Several groups such as The Regulatory Assistance Project in Gardiner, Maine and ACEEE have extensive reports on regulatory policies and methods for successful decoupling methods for regulatory commissions and utilities.[8] Decoupling has been done successfully in Oregon, Connecticut and California. There are also numerous studies and efforts in states such as California, Minnesota and the northeast that suggest implementing "decoupling" rates could help utilities make the investments necessary to significantly increase energy efficiency but still provide an agreed-upon rate of return on their investments. Even without decoupling, there is a threshold under which energy efficiency spending by utilities is cost-effective.

State-of-the-art Building in Our Region

Good examples of energy efficient new buildings in our region include the new corporate headquarters for Manitoba Hydro and Great River Energy (GRE). GRE is designing their headquarters to qualify for LEED (Leadership in Energy and Environmental Design) platinum certification. The building will feature the latest in energy efficiency technology, including a geothermal heating and cooling system, extensive use of daylight to provide working light, and on-site renewable energy sources such as solar panels and a wind turbine. Manitoba Hydro is building a state of the art corporate headquarters in downtown Winnipeg which aims to be LEED gold certified. The building will feature a double façade high performance envelope to reduce heating load, a living green roof, and a geothermal heat pump system to heat and cool the building.

6.5 Adopt more aggressive building codes and appliance standards. The experience of other countries and regions in developing aggressive codes and standards could be a model for this region. For example, leading states have adopted a recent version of the International Energy Conservation Code (IECC) to assure that state building codes are keeping up with technology advancements. Other options for improving energy efficiency include:

- Adapt effective, market-based programs, such as Energy Star, to buildings and appliances not now covered, so that energy efficiency becomes a visible selling point for a wider array of products.
- Regularly update building codes so that they reflect the latest in proven conservation and building technology.
- Invest in the training of architects, builders and local code officials in how to comply with new codes in order to reap the full benefits of new building codes.
- Establish incentives to exceed the building code. For example, if developers build an "Energy Star structure," they might qualify for preferential and/or lower-interest financing.

6.6 Have the public sector lead by example. The federal government and several states have taken the lead in establishing challenging energy use reduction goals for state and federal buildings. These programs provide leadership and set an example for the private sector. Public initiatives also represent opportunities for testing more effective energy management programs, shared savings contracts and other technical and programmatic plans that can help show the private sector how these programs can work and reduce per capita energy use. Recommissioning existing commercial properties is a good example where the public sector can initiate these programs on public buildings and monitor the results to show the payback for the private sector. Good information on recommissioning, along with several project summaries, is available at the Center for Energy and Environment website, www.mncee.org.

6.7 Strengthen efforts to encourage adoption of energy efficiency technologies by consumers. This could start with using the government's "bully pulpit" by developing an education campaign (e.g., public service announcements), but could also entail changing local government aid to reward communities with specific energy efficiency goals. A great deal of progress could be made by building capacity to conduct more residential and industrial energy efficiency audits and assessments. Whatever combination of "carrots and sticks" policy-makers use to encourage greater efficiency, low-income customers will need programs to assist them with the front-end costs of efficiency improvements.

6.8 Encourage utilities to adopt creative rate design that promotes energy efficiency. Certain rate rules may unintentionally be a barrier to efficiency investments. For example, when there is a disconnect between who pays for the efficiency investment and who benefits, it may be possible to design rates so that a company getting some level of public financing for its efficiency investments would then share the benefit of those savings between the company and the customer.

Additional Sources of Information

> "National Action Plan for Energy Efficiency" Environmental Protection Agency. www.epa.gov/cleanenergy/eeactionplan

> American Council for an Energy-Efficient Economy. www.aceee.org.

> Center for Energy and Environment (CEE). www.mncee.org

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Coal

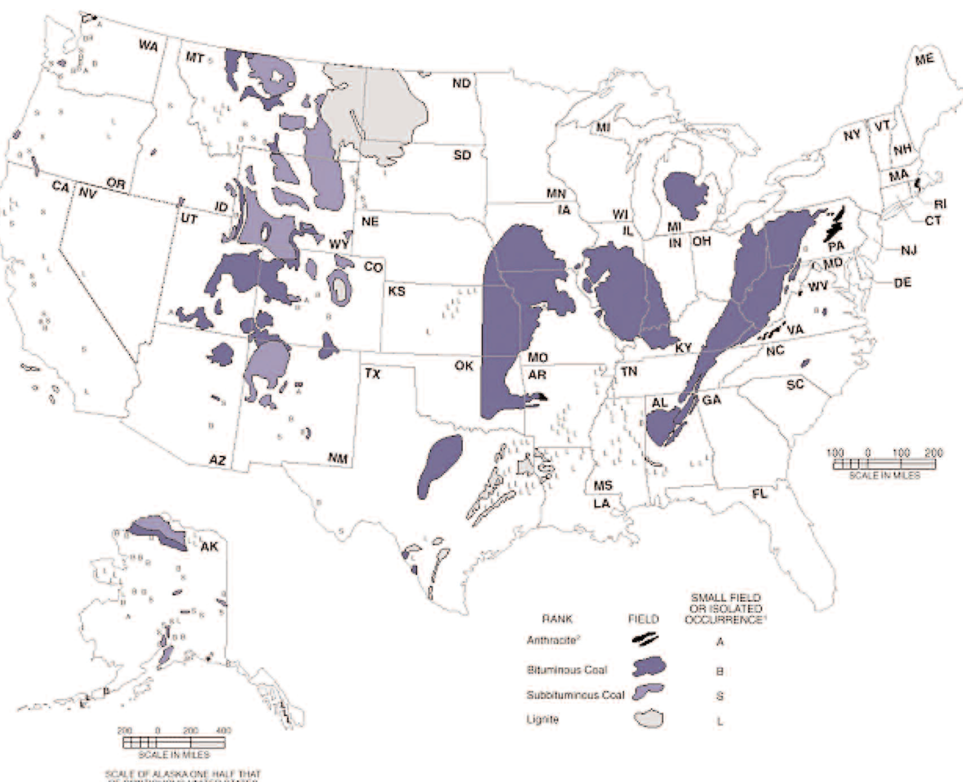
1.0 Introduction

Coal provides two thirds of this region's electricity today, 50 percent nationwide, and it is the largest source of energy for electric power generation worldwide. The United States has an estimated 250-year supply of coal. A majority of the nation's proven coal reserves are found in our region; indeed, one third of coal mined in the United States today comes from a single county in Wyoming.[1]

Because of its abundance and high energy value relative to cost, coal will continue to play a significant role in the energy system of the future. For economic and energy security reasons, many expect the amount of electricity generated from coal, especially worldwide, to grow substantially between now and mid-century. Domestically, if natural gas prices remain high, pressure will grow to tap the nation's coal reserves to produce electricity and synthetic natural gas, among other things.

Although coal use is predicted to rise in the United States and globally, the resource has significant environmental challenges to overcome, most notably mercury control and the reduction of carbon dioxide (CO_2) emissions. An array of advanced coal technologies in various stages of commercialization around the world offers a much-needed path forward for coal-based energy in a future carbon-constrained world. This will require public and private leadership and policies that provide financial incentives and regulatory support to accelerate the deployment of low-CO_2 coal technologies and practices like those described in this chapter.

U.S. Coal Deposits by Type



Source: Luca Technologies

1.1 Region's coal resource. Coal reserves in our region are predominately sub-bituminous in Montana and Wyoming and lignite in North Dakota and Montana. Bituminous coals predominate in the Illinois Basin to the east (see U.S. Geological Survey map above). Sub-bituminous and lignite are low-rank coals, meaning that they are lower in energy value and higher in moisture content than bituminous and anthracite coals.

Sub-bituminous coal has 35–45 percent carbon content and a heat value between 8,300 and 10,000 BTUs per pound. Reserves are located mainly in a half-dozen Western states and Alaska. Although its heat value is lower, this coal generally has a lower sulfur content than other types, which makes it attractive because, under existing regulations, it can be burned in today's coal plants to achieve the required sulfur emissions without "scrubbing."

Lignite is the youngest coal geologically and has the lowest carbon content, 25–35 percent. Its heat value ranges between 4,000 and 8,300 BTUs per pound. Sometimes called brown coal, it can be up to 60 percent water and requires larger boilers and ancillary equipment to produce the same output as other coals. Lignite-burning power plants are usually sited at the mine mouth so that the coal does not have to be transported very far. Because of lignite's high water content, there are several projects to improve the plant efficiency by using the waste heat from the coal plant to pre-dry the lignite before combustion to improve its burn efficiency.

1.2 Diversity of energy and chemical products from coal. In addition to combustion of coal for electric power production, the use of gasification technology allows many additional energy and chemical products to be produced from coal, increasing its value as a resource. Table 1 describes the range of products—from electricity, syngas and transportation fuels to fertilizer and construction materials—that can be derived from coal. Other parts of this chapter will describe certain low-CO_2 technologies available around the world to help develop these products from coal without significant impact to our environment.

TABLE 1: What Coal Has to Offer

Electricity				
Base load power	Co-firing with biomass	Combined heat and power (CHP)	Serve as Non-Utility Steam Hosts (NUSH)	Pairing with wind or other renewables
Tranportation Fuels				
Electricity	Dimethyl ether (DME)	Fisher-Tropsch diesel	Hydrogen	
Chemical byproducts				
Ammonia fertilizer	Carbon dioxide (CO_2)	Sulfur	Phenols	
Other Uses				
Synthetic natural gas	Enhanced oil recover (EOR) using the CO_2 from coal gasification	Construction and industrial materials from coal residuals: Fly ash, Bottom ash, Scrubber sledge, Frit		

2.0 Objectives for any coal transition

The following objectives are critical for accomplishing the transition from conventional coal use to low-CO_2 coal use:

2.1 Support large-scale geologic carbon sequestration projects. Low-CO_2 coal technologies involve capturing and injecting CO_2 into geologic formations deep underground, where it remains permanently trapped, a process known as carbon capture and storage (CCS). Scaling up these technologies will require the ability to carry out CCS on a large scale in order to manage effectively the significant volumes of CO_2 that will be captured. Today's available science and established commercial experience suggest that safe and permanent underground storage of CO_2 in oil and gas formations works well. Science also suggests that CCS in other geologic formations such as deep saline aquifers will also prove effective. However, tests that inject much larger amounts of CO_2 annually are critical to ensuring confidence in widespread deployment of CCS and to establishing an appropriate legal and regulatory framework.

2.2 Begin now to develop the considerable CO_2 management infrastructure needed to permanently sequester carbon dioxide on a large scale, both geologically and terrestrially. If CCS is a prerequisite to low-CO_2 coal use, then work must begin today on establishing the significant network of pipelines and other means of transporting CO_2 that will be necessary. Most of the current CO_2 pipeline infrastructure exists for enhanced oil recovery (EOR), in which captured CO_2 is injected into aging oil and gas fields to pressurize them and extract additional petroleum, while storing the CO_2 deep underground. EOR is currently practiced and commercial in the Permian Basin in Texas and in the Northern Plains where CO_2 from lignite coal is captured at the Dakota Gasification plant and piped to an oil field in Weyburn, Saskatchewan.

2.3 Support demonstration and commercialization of carbon capture technologies at existing coal combustion plants and repowering of existing facilities, where appropriate, to increase efficiency and reduce CO_2 emissions. Given the scale of today's fleet of conventional coal-fired power plants and its rapid growth worldwide, reducing CO_2 emissions at existing facilities will be as important long-term as commercialization of low-CO_2 coal technologies for new power plants.

2.4 Create a policy and regulatory environment that provides incentives for building coal plants that enable permanent CCS. This policy framework should help speed development of commercial-scale advanced coal technologies, with a particular priority toward projects that commit to up-front carbon capture. Financial and regulatory incentives should help make these projects competitive with new pulverized coal plants and reward early adopters of low-CO_2 coal technologies.

2.5 Support state public service commission use of integrated resource planning (IRP) to maximize the cost-effective use of energy efficiency, load management programs and renewable energy in order to buy time for advanced coal technologies with CCS to be demonstrated commercially. State regulatory agencies should pursue energy efficiency programs and renewable energy as a first resource option over the next five to seven years. This will give utilities more time to develop advanced coal technology projects and expertise (especially using the region's low-rank coals) while also avoiding interim investment in conventional generation technologies that are not well equipped to capture CO_2 and that risk creating long-term carbon liabilities under future federal CO_2 regulation.

2.6 Accelerate renewable energy development by pairing advanced coal power projects and CCS with large-scale wind energy development and by demonstrating the co-gasification of biomass and coal with CCS. Integrated gasification-combined cycle (IGCC) and other advanced coal generation technologies with CCS can be combined with wind energy development and offer the possibility of providing electric power with very low CO_2 and mercury emissions to urban load centers in the Upper and Lower Midwest. These technologies can help address key environmental concerns over new traditional coal plants and associated transmission expansion, making it easier to build public support for the additional transmission capacity needed for further wind development. In addition, co-gasifying or co-firing biomass in a plant equipped with CCS can help improve the CO_2 emissions profile of a coal plant significantly beyond simply pairing advanced coal technologies with wind power alone. In addition, incorporating biomass into a coal facility creates a major biomass market for our region's agricultural producers.

3.0 Potential for low-Co_2 coal as an energy source over the next 50 years

Given the significant role coal is expected play in the region's energy system over the next half century, key technologies will be critical to making low-CO_2 coal utilization a reality. As noted in Table 2, it is more difficult and expensive to capture CO_2 from today's conventional pulverized coal technologies than from currently available commercial gasification technologies. Emerging post-combustion technologies may allow for more cost-effective CO_2 capture in the future, but they have yet to be commercially demonstrated.

A number of very detailed studies and technology roadmaps for coal already exist. For example, under the auspices of the Western Governors Association's Clean and Diversified Energy Advisory Committee (CDEAC), a Technology Working Group put together a report on advanced coal options that may be found at: www.westgov.org/wga/initiatives/cdeac/coal.htm.

Therefore, this chapter does not attempt duplicate existing work, but rather to provide policy-makers enough information about each technology option to appreciate its potential and the role it may or may not play in the region's energy system.

TABLE 2: Coal Options*

Combustion (difficult to capture CO_2 cost effectively)	**Gasification** (easier to capture CO_2 cost effectively)
Pulverized Coal • Supercritical steam cycles • Ultra-supercritical steam cycles	**Gasifier technology types** • Entrained flow gasifier • Fluidized bed gasifier • Moving bed gasifier
Fluidized Bed Combustion • Atmospheric combustion • Pressurized combustion	**Integrated gasification-combined cycle for electric power generation**
	Polygneration or co-production of electricity, fuels and chemicals (process preferred by most European utilities for production and earnings flexibility)

* Adapted from "Canada's Clean Coal Technology Roadmap" www.cleancoaltrm.gc.ca

3.1 Coal combustion technologies. More than 90 percent of coal plants worldwide make electricity by burning coal in "pulverized coal" or PC plants. Most of these plants use what is called a sub-critical steam cycle, which is very reliable but not particularly efficient (roughly 36 percent efficiency*). Improvements in materials and technology are leading to higher efficiency combustion options, including the following:

Supercritical Coal Plant

- Supercritical pulverized coal combustion at higher pressure (3500 psi versus 2400 psi) and temperature (1050° F versus 1000° F) than conventional PC plants.
- This is the technology of choice in the United States today for new PC plants.
- While supercritical coal plants emit somewhat fewer emissions per unit of electricity produced, it is difficult and expensive to remove CO_2 from the flue gas, and there are no units with commercial-scale carbon capture in operation in the world today.

The focus here is on providing policy makers enough information about each technology option to appreciate its potential and the role it may or may not play in the region's energy system.

Ultra-supercritical Coal Plants

- Advanced boilers using steam at even higher pressure and temperature (4500 psi and 1100° F).
- This technology is potentially commercially available before 2015 and is currently under development in Japan.
- Ultra-supercritical coal plants potentially increase efficiency over supercritical plants, but no simple, cost-effective way to remove CO_2 has been commercially demonstrated for this technology.

Circulating Fluidized Bed Combustion

- The boiler operates by mixing limestone with coal in a floating bed which allows lower operating temperature and reduces nitrogen oxide (NOx) emissions.
- CFB is utilized where multiple fuels with lower quality and consistency are being considered as a fuel source.
- It currently offers no advantages for removal of CO_2 and increases nitrous oxide (N_2O) emissions, a potent greenhouse gas.

3.2 Gasification of coal. Instead of simply burning coal in a boiler, gasification subjects coal to high temperatures in the presence of oxygen to *chemically* convert coal to a synthetic gas. This technology is widely commercial in the chemical and refining industries.

3.2.1 Gasification for electric power generation. For the generation of electric power, the syngas produced from the gasification of coal or other carbon-rich feedstocks is burned in a modified gas turbine to produce both heat and electricity in a process known as integrated gasification-combined cycle (IGCC). It is called "combined cycle" because, in addition to producing the synthetic gas, the process produces steam that in turn powers a steam turbine to produce more electricity.

* Based on higher heating value (HHV).

There are a number of successful commercial gasification plants producing electric power worldwide today. While the United States has larger-scale demonstration plants, no IGCC facility has yet been built in the United States on a fully commercial basis. Moreover, until recently gasification vendors in the United States have not focused on our region's low-rank sub-bituminous and lignite coals, despite IGCC experience using low rank coals in China, India and Europe. Vendors here have initially prioritized higher-rank bituminous coal for early projects; however, this emphasis is changing because low-rank coals make up more than half of U.S. reserves.

While IGCC remains less familiar to the utility industry in the United States, it offers certain advantages in power production:

- **Higher efficiency.** The conversion of coal to a syngas allows for the use of a combined-cycle gas turbine. In addition to combusting the syngas, the process also utilizes waste steam to produce electricity, thus making the whole process more efficient than a conventional coal combustion plant.
- **Prospects for near CO_2-neutral operation.** Because they produce a concentrated stream of CO_2, gasification technologies such as IGCC presently provide the best option to capture CO_2 at higher levels and lower cost. Close to 95 percent of the CO_2 can potentially be captured and permanently stored in geologic formations deep underground.
- **Better environmental profile.** Sulfur dioxide (SO_2) and nitrogen oxide (NOx) emissions from an IGCC process are comparable to a combined cycle natural gas plant. In fact, the syngas cleanup process can yield elemental sulfur that is pure enough to be sold as a byproduct. Mercury emissions from coal gasification can be dramatically lower than from combustion technologies; a carbon bed filtration process can easily remove more than 90 percent of the mercury. IGCC facilities require roughly half the water use of a conventional pulverized coal plant. Finally, they produce significantly less solid waste, and that waste comes in the form of a stable, vitrified slag that can be reused in construction and road building.

3.2.1.1 Proposed commercial IGCC projects. In Europe, new commercial IGCC projects are emerging to join a half-dozen commercial facilities already operational. Within the next six years, Dutch utility Nuon plans to build a 1,200 MW plant in the Netherlands, 750 MW of which will be IGCC, and RWE in Germany has announced its plans for a 400 MW lignite IGCC plant with CCS.

In the United States, proposals for IGCC plants in the lower Midwest are furthest along given that the higher energy value and lower moisture content of higher-rank bituminous coals presents fewer engineering and financial challenges. Commercial plants are anticipated first in Ohio and Indiana.

Projects using low-rank coal are also in the works. Excelsior Energy's IGCC project proposed for northern Minnesota would use low-rank coals in combination with other feedstocks. This project, together with the lower Midwest IGCC projects, are currently conceived as carbon-capture ready, meaning that they would have the capability to install equipment in the future to capture CO_2 but would not do so initially.

There are two proposed projects that would capture CO_2 immediately and use low-rank coals as their feedstock. Xcel Energy is pursuing development of a commercial scale IGCC plant in Colorado that will use low-rank western coals, especially Powder River Basin sub-bituminous, and capture and store CO_2 through EOR. Great River Energy and Headwaters in North Dakota are pursuing a large-scale lignite gasification plant that will produce both electricity and liquid fuels, while capturing CO_2 for use in EOR.

3.2.2 IGCC with co-production of fuels and chemicals. Co-production begins with coal gasification, then converts a portion of the syngas to other high-value products. The remaining syngas is then used to produce electricity. Co-production, also referred to as poly-generation, has gained industry attention and focus due to high oil and natural gas prices. The U.S. Department of Defense also has an interest in development of coal-to-liquids facilities for national security reasons. Co-production can yield hydrogen and hydrogen-rich liquids, and a wide range of chemicals such as ammonia, jet fuel and cleaner diesel fuel.

Producing liquid fuels from coal actually increases net CO_2 emissions unless the gasification portion of the process incorporates CCS. Since the coal-to-liquids process creates a concentrated stream of CO_2 anyway, the economics of capturing and selling that CO_2 for use in EOR—and thereby permanently sequestering it underground—looks highly favorable. Thus, an important priority must be to help ensure that these first coal-to-liquids projects include CCS. Otherwise, CO_2 emissions produced from transportation fuels derived from coal will be worse than emissions associated with transportation fuels derived from the refining of petroleum.

The best example of co-production in North America is Dakota Gasification Co., which converts lignite to pipeline quality syngas using an older Lurgi gasifier technology. It captures roughly half of its CO_2 for use as a marketable product, compresses it and pipes it to southern Saskatchewan for EOR. The facility also produces an array of other marketable products from lignite, including commercial fertilizer. Co-production could become a significant use of coal if oil and natural gas prices stay high and as national security concerns grow over U.S. dependence on imported oil.

3.2.2.1 Proposed commercial IGCC co-production projects. In addition to the Great River Energy-Headwaters lignite IGCC co-production project slated for North Dakota, several commercial gasification projects are at various stages of development in Illinois that incorporate a co-production strategy. There are also other co-production projects with a narrower liquid fuels focus proposed in Illinois, Montana and Pennsylvania.

3.2.3 Co-gasification of biomass with coal. The Dutch utility Nuon is currently using Shell technology to gasify up to 30 percent biomass with coal at their 250 MW Buggenum facility. The utility plans to reach 50 percent biomass by weight by 2008, which would require roughly 300,000 tons of biomass annually to produce 50 MW equivalent of energy. Nuon will also utilize a significant biomass feedstock stream in its planned 1200 MW Magnum plant. which, in addition to electric power, will produce diesel fuel. The proportion of the diesel that comes from biomass feedstocks will qualify for European Union biodiesel credits because of its biomass origin.

Biomass co-gasification holds promise as a way to reduce CO_2 emissions even more than would be possible from the gasification of coal alone, and it is emerging as an important component of a broader European carbon management strategy. With the right policy incentives, biomass could one day provide an important feedstock complement to coal in the United States as well. In a gasification plant equipped with CO_2 capture, carbon accrued in the plant material during its lifecycle would not be re-released into the atmosphere. A facility using sufficient biomass with coal creates the possibility of a net carbon-negative power plant that actually "harvests" CO_2 from the atmosphere.

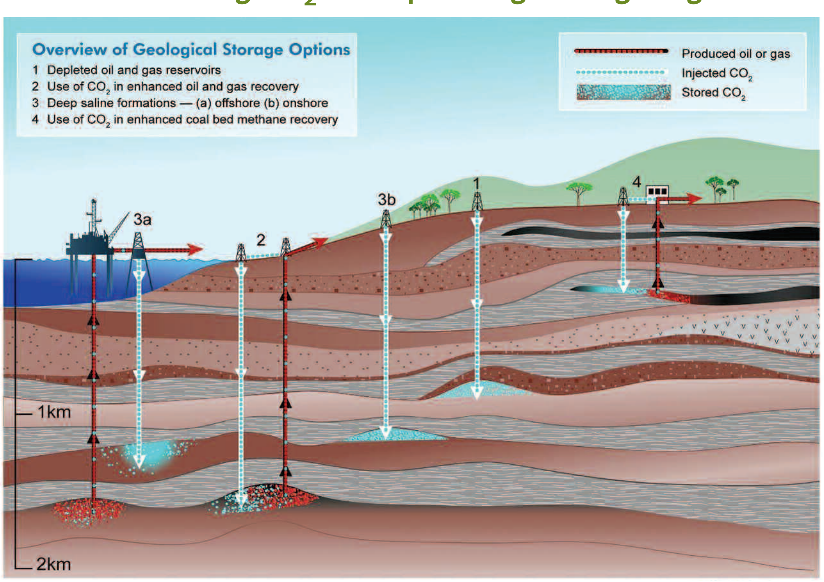
3.3 Advanced combustion technologies and post-combustion CO_2 capture.

Oxy-combustion refers to the burning of coal in an oxygen-rich atmosphere (as opposed to ambient air, which is nearly four-fifths nitrogen) with a smaller supercritical pulverized coal (SCPC) boiler to produce a purer stream of CO_2. This form of coal combustion is the subject of growing interest and investment because it could produce a more concentrated and, therefore, more easily captured exhaust stream of CO_2. The technology would be of particular importance if it can be demonstrated as a viable option for retrofitting existing pulverized coal plants that currently lack an economically viable method for carbon capture.

3.3.1 Proposed oxyfuel combustion demonstration and commercial projects. Vattenfall of Germany is probably the leading utility worldwide pursuing the demonstration of oxyfuel combustion. The company is building a 30MW demonstration project at an existing lignite power plant in Germany but does not expect to have a commercial unit until 2020, at the earliest.[2] In Canada, SaskPower of Saskatchewan is pursuing a 300 MW oxyfuel combustion project in Saskatchewan with Babcock &Wilcox and Air Liquide as partners. They are planning for 90 percent carbon capture and sequestration for EOR. Pending a decision to proceed, the plant could be operational within five years.[3]

3.3.2 Proposed retrofits of existing coal plants for advanced combustion and CO_2 capture. American Electric Power (AEP) recently announced its commitment to partner with Babcock and Wilcox, Air Liquide and Alstom to demonstrate oxyfuel combustion and post-combustion CO_2 capture retrofits. AEP will use Alstom's experimental chilled ammonia process for capturing CO_2 from power plant flue gas. In a phased approach that will proceed from demonstration to commercial scale, AEP plans to be the first company to retrofit an existing conventional coal-fired powerplant for large-scale CO_2 capture. If successful, the company would capture an estimated 1.2 million tons of CO_2 annually at a plant in Oklahoma by 2011.[4] A test project with Alstom, WE Energies and EPRI at the Pleasant

Methods for storing CO_2 in deep underground geological formations



Source: Intergovernmental Panel on Climate Change

Prairie Power Plant in Kenosha, WI is scheduled to be in service in 2008 and will test innovative CO_2 removal technologies with a flue gas slipstream from one boiler.[5]

3.4 Carbon capture and geologic sequestration. Public policy in the future will demand significant reductions in the amount of CO_2 produced in the conversion of coal to electricity, fuels and chemicals. Keeping the CO_2 out of the atmosphere, in turn, will require the cost-effective capture of CO_2 released by coal and its permanent storage.

Prospects for CCS look promising given that annual CO_2 emissions from the U.S. power sector are similar in volume and scale to other gases and fluids already injected and stored underground. The two main options in this region are permanent storage (or sequestration) of coal's CO_2 emissions geologically (see graphic) and offsetting CO_2 emissions by sequestering atmospheric carbon terrestrially in soils, wetlands and woodlands. This chapter addresses geologic sequestration only, which requires capturing and compressing the CO_2 in oil and gas reservoirs, deep brine formations, unmineable coal seams and other geologic formations.

This region has the double benefit of extensive coal resources and extensive geologic sinks appropriate for permanent underground storage of compressed CO_2. While Minnesota and Wisconsin lack identified and adequately characterized geologic reservoirs and therefore uncertain sequestration potential, other states in the region have known oil and gas fields known to be suitable for EOR and vast but less well understood formations of limestone, sandstone and coal with potentially much larger storage capacity. These formations extend, in some cases, over thousands of square miles, often in close proximity to the coal fields themselves that supply the region's power plant fleet.

At this early stage in developing large-scale CCS, the use of CO_2 for EOR represents a well-known commercial practice and large economic opportunity that can make coal gasification projects more attractive. For example, Texas has used EOR for 30 years to recover oil economically from aging and depleted fields. There is already an extensive network of CO_2 pipelines and naturally-occurring CO_2 mined for use in EOR at more than 70 sites.

In our region, Dakota Gasification Co. (DGC) has pioneered the development of an EOR-based CO_2 management infrastructure (see 3.2.2). The plant in Beulah, ND is the only coal-based energy facility in the world that captures CO_2 at commercial scale and sequesters it underground. Other than the Permian Basin EOR operations in Texas, DGC is rivaled in scale only by two other million-ton/year scale

Scale of the carbon capture and storage challenge

- Today, fossil sources account for 80 percent of global energy produced, of which 25 percent comes from coal.
- Fifty percent of U.S. electricity comes from coal.
- The U.S. current coal capacity is the equivalent of five hundred, 500 MW conventional combustion coal power plants with an average age of 35 years.
- China builds the equivalent of two 500 MW conventional coal plants per week and annually builds the new capacity equivalent of Great Britain's entire electricity grid.
- One 500 MW combustion coal plant produces roughly 3 million tons of CO2 annually.
- U.S. combustion coal plants produce approximately 1.5 billion tons of CO2 per year.
- This volume of CO2, transported for sequestration, would be three times the weight and one-third the volume of all natural gas transported annually in U.S. pipelines.
- Sixty percent of this CO2 captured from U.S. combustion coal plants, compressed to a liquid state and sequestered geologically, would roughly equal the total volume of U.S. oil consumption.

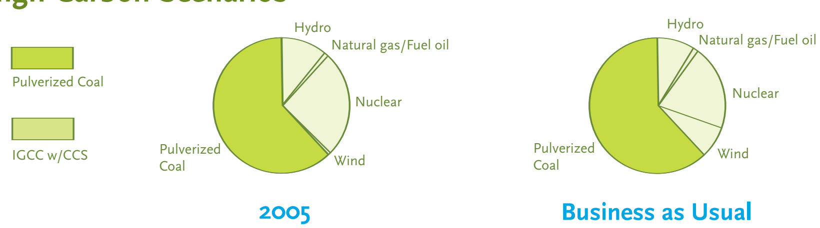
Source: The Future of Coal: Summary Report, MIT, 2007.

sequestration projects, both of which capture CO_2 found in natural gas: Norway's Statoil in the Sleipner field of the North Sea and British Petroleum's In Salah project in Algeria. DGC's achievement underscores our region's leadership potential in this area.[6]

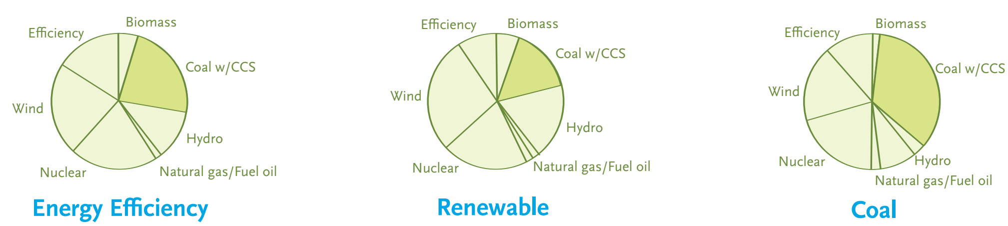
As the box below reveals, the scale of the CCS task before us is immense. While we still need research and practical demonstration to confirm the potential and reliability of CCS in non-oil and gas bearing formations, the technology and experience needed for the first phase—capturing and selling CO_2 for EOR—are in current commercial operation. We need to integrate this technology with gasification and other advanced coal combustion technologies in power generation and gain enough commercial experience in the energy sector to determine the true cost and benefits of CCS on a scale large enough to make a meaningful contribution to CO_2 emissions reductions.

3.5 Potential contribution of IGCC with CCS to regional CO_2 emissions reductions. If policy-makers were to commit to reducing CO_2 emissions 80 percent from 1990 levels by 2055, coal gasification in the form of IGCC for power production, combined with carbon capture and storage, makes the following contributions under four 50-year scenarios for the region's electricity sector: business as usual (BAU), high energy efficiency (EE), high renewable (Renewable) and high coal with carbon capture and storage (Coal). These scenarios are based on modeling done by the University of Minnesota and the Great Plains Institute in partnership with PTP participants.

High Carbon Scenarios



Low Carbon Scenarios



	2005	BAU	EE	Renewable	Coal
2055 Total Electricity (million mWh)					
	374	521	439	471	462
Cost per mWh					
	$30	$42	$51	$49	$51
Cumulative 50-year spending on Electricity ($ billion)					
		$771	$743	$775	$779

4.0 Measurable milestones

The following regional coal milestones are proposed by PTP stakeholders for policymakers' consideration:

- By 2015, the region should strive to have at least two IGCC projects with CCS through design, construction and into full operation, including at least one project using subbituminous coal and another using lignite.
- By 2015 the region should demonstrate commercial scale post-combustion capture of CO_2 at a pulverized coal plant.
- By 2020 the region will have operating at commercial scale multiple IGCC and/or pulverized coal combustion plants with CCS.
- By 2055, the region will generate 80 percent of its coal-based electric power from plants that eliminate or capture CO_2 emissions.

Vision of future coal use

- For coal to play a significant role in the future energy system, its overall environmental profile must improve and come as close to producing zero harmful emissions and CO2 as possible. More specifically, this means that coal use in the future must:
- As quickly as possible become low-CO2, adding little or no additional carbon dioxide to the atmosphere;
- Produce low or no emissions of other pollutants, such as sulfur dioxide, nitrogen oxide, mercury and fine particulates;
- Be part of an energy infrastructure that significantly expands and complements additional renewable resources;
- Promote local and regional economic development and security;
- Produce electricity that is affordable and reliable for ratepayers; and
- Produce multiple useful products rather than just electricity (often called co-production or poly-generation).

In order to know whether or not the region is achieving its long-term vision for coal use, each jurisdiction should track the following:

1. Percentage of total CO_2 from coal use captured and permanently stored underground or used for EOR;
2. Percentage of total sulfur dioxide, nitrogen oxide, mercury emissions and fine particles avoided;
3. Increase in average efficiency of coal fleet due to technology retrofits or new coal plants; and
4. Percent of new coal plant capacity installed with low-carbon technology and CCS.

5.0 Key challenges and barriers

If paired with CCS, coal gasification holds great promise as part of the region's energy mix, but fulfilling that promise has some significant challenges. Below are some of the most important:

5.1 Barriers to CCS.

5.1.1 Identified carbon sequestration sites in the region have not been tested and verified. In our region, only the Weyburn oil fields in Canada are documented, tested and doing CO_2 injection for EOR. More testing is needed to verify capacity and availability of geologic reservoirs, especially non-oil and gas bearing formations such as saline aquifers that are less well studied but critical to ensuring sufficient CO_2 storage capacity long-term.

5.1.2 EOR experience is geographically limited. Most experience with CCS is limited to the Permian Basin, a region of the Texas panhandle where naturally-occurring CO_2 is mined and transported to oil fields for EOR. Another important center of experience is found in our region, where the Dakota Gasification Plant in Beulah, ND captures CO_2 from the gasification of coal, compresses it on site and transports it via pipeline over 200 miles to an oil field at Weyburn, Saskatchewan.

5.1.3 Significant legal and regulatory questions remain unanswered. There is also a need to establish a legal and regulatory framework for large-scale implementation of CCS to address questions such as who owns the CO_2, who holds liability, and how to regulate CCS activities and monitoring. This issue has also become prominent in the federal government's FutureGen project.

5.2 Barriers to coal gasification technologies with CO_2 capture capability.

5.2.1 High capital cost. Capital costs for IGCC facilities are estimated to be 15 to 25 percent higher than conventional SCPC units. Just the necessary front-end engineering and design (FEED) studies can cost between \$8 and \$20 million depending on the detailed engineering, procurement and construction estimates done for the project. Until several units have gone through detailed design, engineering and construction in the United States, it will be difficult to build utilities' confidence in the cost and viability of IGCC. There is also no competitive bidding for IGCC projects as compared to conventional coal projects, where multiple bidders exist for boilers, air quality control systems and other major plant components. The regulatory process does not currently place a dollar value on IGCC's potential to reduce air emissions and meet future CO_2 limits.

5.2.2 Lack of industry experience and confidence in the technology. Gasification is an old technology in the refinery and chemical industries but is relatively new to the power sector. Utilities do not have the same level of experience with IGCC that they have with PC units. IGCC's higher capital cost, along with utilities' perception that vendor guarantees are inadequate, only lends to industry uncertainty. The necessary engineering expertise for IGCC is just starting to mature and does not generally exist in utility engineering groups, which utilities rely on in making technology choices and developing projects.

5.2.3 Lack of standardization and vendor familiarity. The engineering and construction personnel of electric utilities are only familiar with companies and consulting firms that design and build PC units and gas/steam turbines. They have little experience with the companies in the IGCC world. A small number of IGCC units are operating in the United States, and there is good operational experience in Europe, but each U.S. plant has required a new design process and received significant federal subsidy. This one-off approach has made the technology more expensive. This should lessen once the vendor groups have designed and built several commercial-sized reference projects.

5.2.4 State regulatory and permitting regulations. Public utility commissioners are often legally unable to allow IGCC and other low-CO_2 coal projects to compete directly with conventional SCPC plants in delivering baseload electricity to the grid. The current approach to "least cost" resource planning tends to favor conventional technologies by not accounting for such things as fuel price fluctuation, carbon constraints, new emission limits on criteria pollutants and mercury, and technology uncertainty. In addition, advanced coal technologies and CCS may not receive preference or credit in the air quality permitting process for delivering lower emissions of SOx, NOx, CO_2 and mercury. In short, electric utilities will need help and direction from state regulatory and legislative bodies to take on risks and financial costs associated with IGCC and CCS. California, Illinois, Indiana, Ohio and Pennsylvania have begun moving in this direction.

5.2.5 Financing risk. IGCC with CCS will be more expensive than current SCPC projects that only address conventional air pollutants. Despite widespread agreement that carbon limits are inevitable, most companies are waiting for national legislation to set the bar and impose some type of limit and dollar value on CO_2 emissions. The Energy Policy Act of 2005 authorizes grants, loan guarantees, and tax credits for coal gasification projects, but many provisions in the legislation are poorly funded and still others not at all. More incentives are needed on the state level to help utilities embrace gasification technology more broadly and quickly.[8]

6.0 Strategies for reconciling coal, climate and energy security

In order to hasten the transition to low-carbon coal technologies and practices, states and the federal government must support their early demonstration and deployment. This will involve governments sharing risk with companies willing to be early adopters. It also means that governments must develop and implement policies that support a long-term transition toward low-carbon coal use as the industry norm.

6.1 Establish a regional infrastructure for CO_2 management. There is a geographical mismatch between urban load centers and the power plants that serve them, and confirmed geologic sequestration sites. Therefore, our region must lay the groundwork for a new infrastructure of CO_2 management and electric transmission over time. If IGCC and other gasification plants with CCS are built far from sequestration sites but close to load centers, they may require long-distance pipeline infrastructure for transporting the compressed CO_2 for sequestration. Conversely, if new CCS-equipped facilities are constructed near suitable sequestration sites but distant from load centers, new transmission capacity will be needed to get the electric power to market. These kinds of infrastructure investments will benefit the region's future energy system as a whole and will need to be paid for accordingly.

While siting and building transmission and pipeline infrastructure is challenging, much of the opposition underlying such projects, especially power lines, stems from a lack of public agreement over how baseload electricity should be produced, many in consuming states fear that transmission expansion will merely allow more conventional coal-based power generation to be built. The potential for new infrastructure to serve low-carbon advanced gasification plants with CCS, especially when paired with wind and other renewables, has the prospect of reducing opposition and even building support for transmission and pipeline development.

6.2 Technology demonstrations. An urgent priority is to demonstrate at commercial scale advanced coal technologies with CCS that use our region's low-rank coals for electric power generation. These facilities should be operational no later than 2015 and sooner where possible. In particular, it will be important to demonstrate:

- IGCC using western sub-bituminous coal;
- IGCC with co-product production using lignite (and straight IGCC with lignite if feasible);
- State of the art combustion technology with post-combustion CO_2 capture; and
- Pairing of advanced coal technologies with wind power, hydrogen production and biomass co-gasification/co-firing.

6.3 State and provincial "toolbox" for accelerating commercialization. In addition to demonstrating that low-carbon coal technologies and practices are commercially ready, public policies and regulatory changes can help make them cost-competitive by recognizing their contribution to cleaner air and a more stable climate.

There have been a number of innovative policy and financial incentive packages developed in different states to foster IGCC and other advanced coal project development, including Illinois, Indiana, Ohio, Texas and Pennsylvania.

Advanced coal projects can be grouped into three categories depending upon their development in the marketplace.

1) Prototypes (pre-commercial). These projects incorporate a significant amount of novel technology and are meant to prove that technology and/or demonstrate cost-effective performance. Often these projects have the potential to be "breakthrough" technologies that could reshape the industry. Prototypes are typically small scale and under 50 MW. Examples in this category include amine scrubbing of CO_2 emissions, oxy-combustion, coal drying and other pretreatments, and "next generation" gasification technologies that utilize novel gasification methods.

2) First-of-a-kind commercial demonstration projects. These are projects that have been demonstrated at prototype stage and are ready to be demonstrated for the first time at a commercial scale (~250 MW). Examples include FutureGen, the USDOE and industry-sponsored effort to build a near zero-emission advanced coal gasification facility and Southern Company's demonstration of transport reactor gasification technology in Florida, which may have promise for low rank coals.[9]

3) Commercial technology that could be deployed at an accelerated rate. These projects are ones that have been demonstrated at least once at a commercial scale and whose deployment in the market could be accelerated with favorable public policies. Examples in 2006 that would fit this category would include coal gasification systems marketed by major companies such as GE, ConocoPhillips, Siemens/Future Energy or Shell. CCS might also fit in this category depending on the specific project.

Each of these three categories of projects benefit from different public policies. The table below identifies some of these key policies. Also shown are some examples of the types of projects that would advance the coal transition:

Key Policies and Projects

Prototypes (pre-commercial)	First-of-Kind Commercial Demonstrations	Accelerated Deployment of Proven Commercial Technologies
Grants	Grants	Front-End Engineering and Design (FEED) packages
Tax credits and other incentives for R&D spending; state pension fund investments as venture capital.	Loan guarantees; low interest and tax exempt financing; investment tax credits; state pension fund investments.	Direct financial incentives (tax credits, tax exemptions, loans, wrap financing)
Economic development incentives to help attract innovative coal technologies to state	Regulatory pilot programs, waivers, indemnification and other special provisions	Established regulatory framework and incentives, including integrated resource planning incentives and/or supportive commission rules where appropriate
	EOR development assistance, tax and other incentives	EOR development assistance, tax and other incentives
	Grants, development assistance, tax incentives for non-EOR sequestration if applicable	Development assistance, tax and other incentives for non-EOR sequestration if applicable

Examples of projects that could usefully be done in each category

Prototypes (pre-commercial)

1. Coal combustion and gasification using next generation technologies that improve efficiency and reduce emissions of CO_2, mercury and other pollutants.
2. Amine scrubbing.
3. Oxy-combustion.
4. Other pre-combustion coal treatment technologies.
5. Retrofit oxyfuel combustion and post-combustion pilots on existing coal plants.
6. Geologic sequestration in non-oil and gas bearing formations.

First-of-Kind Commercial Demonstrations

1. Certain European gasification technologies that have been used at smaller scale on lignite and sub-bituminous coals.
2. RWE's planned 400 MW lignite IGCC unit in Germany that will incorporate CCS up front.
3. Nuon's 1,200 MW combined IGCC and natural gas-fired power plant planned for 1012 that will co-gasify biomass.
4. Australia's HRL Ltd. and China's Harbin Power planned 400-MW lignite IGCC plant with CCS slated for 2009.
5. AEP's proposed commercial-scale oxyfuel and post-combustion capture retrofits.

Accelerated Deployment of Proven Commercial Technologies

1. Fischer-Tropsch and Synthetic Natural Gas technologies.
2. IGCC offerings from major companies.
3. CCS projects in oil and gas-bearing formations.

Different incentives benefit various kinds of project developers and utilities differently. Investor owned utilities (IOUs), merchant power producers (MPPs), independent power producers (IPPs) and public power companies will receive different levels of benefit from the various financial incentives being offered at the federal and state level. Generally, IOUs will benefit most from tax incentives, MPPs and IPPs will benefit from credit-based incentives due to lower interest rates, and public power entities will benefit from direct grants given their low cost of financing and tax free status.*

6.3.1 CCS policies: laying the foundation for CO_2 management.
6.3.1.1 Require development of a legal and regulatory framework for geologic storage of CO_2. In order to set the stage for geologic sequestration projects to move forward in a 5- to 10-year timeframe, we need to establish the necessary legal and regulatory framework to provide answers to core questions that currently pose barriers to significant development. For example, who owns the CO_2 once underground? Who is liable and how will firms be indemnified or insured? How and for how long will sites be monitored and who will be responsible? These legal questions need resolution before coal gasification and CO_2 sequestration become the norm for new coal plants. State agencies should also begin to develop the necessary permitting processes for geologic sequestration, including guidance on pipelines, drilling, storage, measurement, monitoring, verification and long-term liability.

6.3.1.2 Support comprehensive assessments of geologic reservoirs at state and federal levels to determine CO_2 storage potential and feasibility. State and federal governments should build on work of the USDOE-funded regional sequestration partnerships to complete comprehensive, basin-level geologic assessments of storage potential and CO_2 injection rates (i.e., how much CO_2 can be stored annually) according to common and accepted standards and methodologies. Regions with a history of oil and gas exploration tend to have better data available on geologic formations, making such assessments easier and less expensive. Detailed, accurate mapping of less well-known potential reservoirs for CCS will require continued federal and state investment.

6.3.1.3 Fund sufficient large-scale geologic sequestration tests to prepare for future sequestration on a widespread commercial basis. The region's congressional delegation should provide sufficient funding to the USDOE to ensure a robust program of large-scale sequestration tests in order to demonstrate to the private sector, policy-makers and the public the viability, efficacy and safety of widespread commercial geologic sequestration of CO_2. These tests should focus on a variety of geologic formation types, including reservoirs other than oil and gas bearing formations, and produce guidelines for appropriate measuring, monitoring and verification.

* A complete review of financial incentives and considerations can be found on the Public Service Commission of Wisconsin website http://psc.wi.gov/cleancoal/meetings.html under the April 6, 2006 presentation by Scully Capital Financing Group.

6.3.1.4 Evaluate the feasibility of CO_2 transport and "advanced sequestration" options for jurisdictions with no documented geologic sequestration potential, such as Minnesota and Wisconsin. This could include evaluating the cost and feasibility of CO_2 pipelines to geologically appropriate areas, of nontraditional geologic formations and of advanced sequestration options, such as mineralization, the use of carbon nano-fibers or algae.

6.3.1.5 Provide tax incentives for CCS, including CO_2's use in EOR. For example, Illinois has proposed financial support for construction of pipelines to get CO_2 from a gasification project to the oil fields for EOR.

6.3.1.6 Provide EOR project development assistance. In parts of the Upper Midwest there are many small oil and gas producers who have not traditionally used EOR, in part because they are not large enough to develop a cost-effective project. State governments, companies, trade associations and NGOs can play a useful role in helping to identify the specific mechanisms by which producers can band together to leverage a cost-effective project. Issues that would need to be addressed in such a project include, but are not limited to, pipeline siting, well capping and monitoring.

6.3.2 Project incentives: getting commercial projects built.

6.3.2.1 Provide support for FEED packages. FEED packages are the upfront studies needed to provide good cost estimates for power plant projects. Utilities are reluctant to fully fund these initial studies on their own when the entire industry, and ultimately the public, will benefit from the information they yield. Therefore, establishing state programs that offset some of the cost of these FEED packages would allow utilities and developers to recoup their initial engineering costs through state tax credits or grants that would be applicable during the first 10 years of the facility's life. Wyoming and North Dakota are using this approach. State-supported FEED packages have also been critical in Illinois, and they are being pursued in Ohio and West Virginia.

6.3.2.2 Provide direct state financial incentives (grants, tax credits, loan guarantees and performance wrap engineering/procurement/construction (EPC) coverage). States should establish the same or complementary incentives to those in the federal EPACT 2005 program to help reduce the financial cost of the overall project once engineering and cost studies are completed.

6.3.2.3 Allow regulated utilities cost recovery for appropriate demonstration projects. Utilities committed to developing advanced technology coal plants that capture and sequester CO_2 (or would be able to do so cost-effectively in the near future) should be ensured cost recovery, including construction work in progress, as long as they meet the standards of the state commission on proper spending decisions. States should also consider some comparable process for MPP and IPP developers involved in an RFP bidding process.

6.3.2.4 Enhance Integrated Resource Planning (IRP) policies by using them to encourage low-CO_2 coal technologies. States and provinces should adopt well-designed IRP rules to weigh the full costs, benefits and risk characteristics of various resource options. Future risks to be factored in should include fuel price fluctuation, carbon constraints, emission limits of criteria pollutants and mercury, and technology uncertainty. Doing so would improve the accuracy of "least cost" planning for generation options, which does not fully address future regulatory and environmental costs. Some European utilities are pursuing IGCC precisely because they believe it will provide them flexibility in meeting any future emission standards or credit systems within the European Union.

6.3.2.5 Identify opportunities for state policies and regulatory programs to favor IGCC and other advanced carbon limiting technologies over conventional pulverized coal units. These could include:

- Low-carbon electricity portfolio standard or objective that combine fossil electricity generation resources (such as IGCC with CCS) with traditional renewable resources;
- Innovative, long-term power purchase agreements to provide developers with higher rates of return and reduced risk in exchange for price stability that allows regulators to demonstrate a direct benefit to residents (more stable prices qualifying as such a benefit);
- Market-based environmental regulatory programs to provide incentives to invest in low emission technologies with flexibility and certainty for achieving reductions; and
- Three-party covenants in which the federal government provides credit, the state regulatory commission provides an assured revenue stream from the syngas to protect the federal credit, and a project developer provides equity and initiative to build the project. This process is being proposed for a pipeline quality syngas plant in Indiana where the state is allowing the three major gas utilities in the state to sign long term off-take contracts with the developer, giving the developer the purchase agreements necessary for project financing.[10]

6.3.2.6 Update workforce training and research and development programs and investments, with a focus on developing the gasification and carbon sequestration industries.

6.3.3 Existing Model State Policies and Statutes. A comprehensive overview of existing state policies that provide regulatory certainty, financial incentives and indemnification for advanced gasification and CCS projects has been prepared by Paul Loeffelman, Director of State Policy, and his staff at American Electric Power. The report also includes an appendix with actual state statutes and links to access electronic versions. The March 14, 2007 draft of the AEP report is available at www.poweringtheplains.org.

Additional Sources of Information

> Canadian Clean Coal Technology Roadmap: http://www.nrcan-rncan.gc.ca/es/etb/cetc/combustion/cctrm/htmldocs/overview_e.html
> Wisconsin Governors IGCC task force: http://psc.wi.gov/CleanCoal/index-cleanCoal.htm
> Western Governors Association Advanced Coal Task Force Report: www.westgov.org
> MIT, The Future of Coal, An Interdisciplinary MIT Study, 2007. http://web.mit.edu/coal

1. EIA. 2005 annual statistics. www.eia.doe.gov/fuelcoal.html
2. "Germany Plans CO2-free power plant" www.news.bbc.co.uk/.2/hi/europe/4642837.stm
3. SaskPower. www.saskpower.com/cleancoal
4. American Electric Power. March 15, 2007. "AEP to install carbon capture on two existing power plants". www.aep.com/newsroom/newsreleases
5. We Energies "Carbon Capture Project" www.we-energies.com/home/carboncapture.htm
6. The Future of Coal: An Interdisciplinary MIT Study: Chapter 4- Geological Carbon Sequestration, 2007
7. Fitzpatrick, Eileen. "The Weyburn Project: A Model for International Collaboration" www.netl.doe.gov/publications/carbon_seq/mediarelease/mr-101102.pdf
8. Tucker, Sherry. March 14, 2007 "Federal Incentives- Where Are They Now?" Gasification Technology Council, Denver, CO Workshop. www.gasification.org/Docs/Workshops/2007/Denver
9. US Dept. of Energy- Fossil Energy-Clean Coal and Natural Gas Power Development www.fossil.energy.gov/programs/powersystems
10. Indiana Statute IC 8-1-8.8 Utility Generation and Clean Coal Technology

Wind Power

1.0 Introduction

2.0 Objectives for wind development in the region

3.0 Potential contribution of wind power to the region's energy sector by 2055

4.0 Measurable milestones for wind power

5.0 Key challenges and barriers

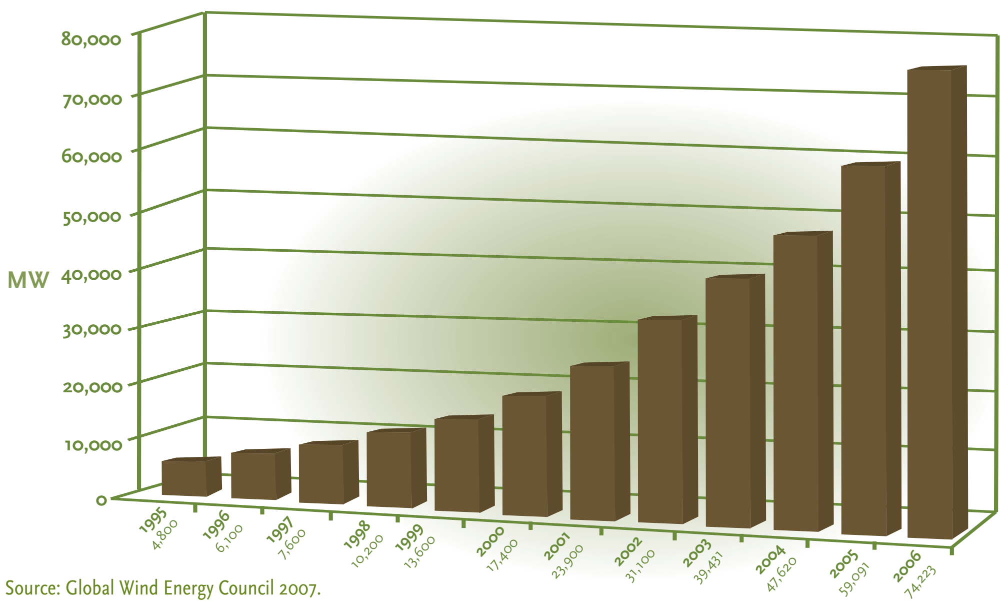
6.0 Strategies

1.0 Introduction

Wind energy represents the fastest growing energy sector today in the United States and worldwide. Wind generation technology has improved dramatically over the past twenty years, as has understanding of how to manage wind energy reliably and affordably as part of a broader power production portfolio. During that time period, the unsubsidized cost of wind power had declined from $0.15–0.20 per kWh to $0.04–0.6 per kWh, making it in certain places the lowest-cost source of new electric generation today.

While wind energy starts from a very small base of production, annual capacity growth has exceeded 20 percent for a number of years. According to the Global Wind Energy Council, total installed wind power capacity stood at 74,223 MW worldwide at the end of 2006, an increase of 32 percent over 2005.[1] The wind energy sector is now an important player in energy markets, with the total value of new generating equipment installed in 2006 reaching $23 billion.

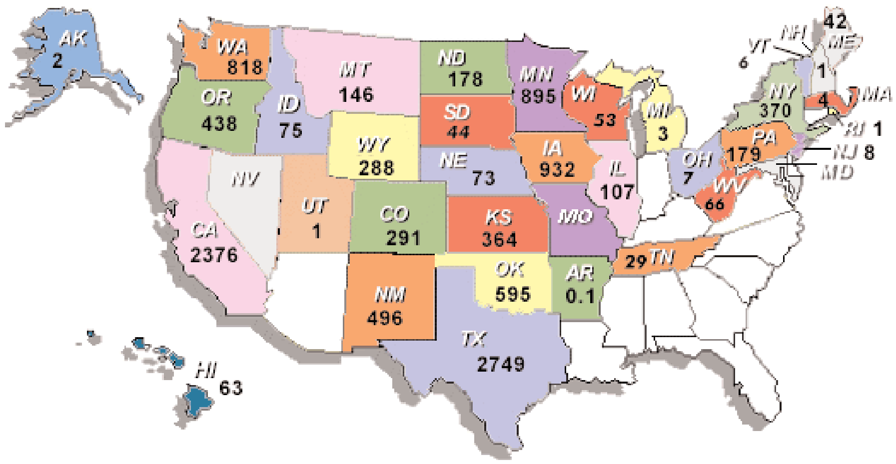
Global Cumulative Installed Capacity 1995–2006



Source: Global Wind Energy Council 2007.

The American Wind Energy Association (AWEA) reports that total U.S. wind generation capacity reached 11,603 MW as of the end of 2006. This compares to roughly 48,545 MW of capacity in the Europe or 65 percent of the world's total. In 2005 the European Union achieved its 40,000 MW target for 2010, five years ahead of schedule. After long lagging behind Europe, the United States led the world in new development during 2006 by adding 2,454 MW of new capacity, or a 27 percent increase over 2005. AWEA estimates that U.S. wind power capacity will grow an additional 25 percent in 2007.[2]

U.S. Wind Capacity by State



Source: AWEA

In our region, Iowa and Minnesota secured top-five rankings nationally in wind development, with Iowa achieving third place at 936 MW of installed capacity and Minnesota in fourth place at 895 MW.[3] Manitoba is poised to become a wind energy leader in Canada, with 99 MW now operational and an official provincial commitment to implement 1,000 MW within a decade.*

State and provincial renewable energy standards (RES) and renewable energy objectives (REO) have acted as the biggest drivers of wind development. An RES establishes a legal requirement, whereas an REO takes the form of a good faith obligation. Both stipulate that utilities obtain a certain percentage of their electricity sales—or, in some cases, a specified amount of installed capacity—from renewable sources by a particular date.

Currently, 21 states and Washington D.C. have RES or REO policies in place, and all ten Canadian provinces have some sort of policy such as an RES or an official target. All but a handful of these policies address a broad range of renewable sources, although they typically restrict the amount of hydropower and types of hydro projects that may qualify. Because of our region's superior wind resource, utilities have responded to RES and REO policies primarily with the development of wind projects unless mandated to develop other renewable energy sources as well.

Wind power as a generation resource will continue to grow for environmental, economic and technical reasons. Other than the energy required to produce the steel and to manufacture, transport and construct the turbines and components, electricity generated from wind produces no emissions. While the costs of building wind farms has risen considerably in recent years along with other electricity generation technologies, wind power has no fuel cost, an increasingly valuable attribute at a time of increasing price volatility and a trend toward rising fossil energy costs, especially natural gas. And the improved technical performance of modern, commercial-scale wind turbines means that wind power has become one of the most reliable forms of power generation as well. Finally, there have been a number of advances in understanding how to integrate large amounts of wind into the electrical grid.

Summary of wind objectives

1. Maximize economical and reliable integration of wind power into the electrical grid.
2. Expand transmission capacity to accommodate substantial new wind generated electricity.
3. Encourage greater local equity participation in wind farm projects to increase our region's economic returns from wind development.
4. Demonstrate new technologies to enable very large-scale utilization of our region's wind resource beyond what integration of variable wind power onto the electrical grid would allow.

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* Thirteen countries, including Canada and France, reached the milestone of 1000 MW of installed wind capacity in 2006.

2.0 Objectives for wind energy development

Several key objectives should guide policy-makers' efforts to maximize the development of our region's enormous wind energy potential over time.

2.1 Maximize wind power integration on the grid. Until recently, wind energy faced considerable skepticism. Conventional wisdom suggested that, because wind turbines generate electricity only when the wind blows, every increment of new wind generation needed to be backed up by an equivalent amount of new dispatchable generation from a conventional power plant. Fortunately, extensive experience in Europe (and increasingly in the United States) and a number of recent engineering studies have improved our understanding of how greater levels of wind generation can be affordably and reliably integrated and managed on the grid as part of a broader portfolio of generation resources.

Wind power as a variable resource does not eliminate the need for other generation capacity sufficient to meet peak demand, nor does it avoid the costs to the system of building and maintaining those assets. However, a consensus is emerging in the engineering community and power industry that much greater levels of wind power can be managed on the grid without significantly increasing costs and, importantly, without reducing system reliability. For example, in May 2006 the Utility Wind Integration Group, American Public Power Association, Edison Electric Institute, and the National Rural Electric Cooperative Association issued a consensus determination that there are no fundamental technical barriers at the present time to wind penetrations of up to 20 percent of system peak demand.[5] By comparison, current wind power penetration in our region only averages about three percent.

Europe has the greatest experience with high wind integration. Denmark, for example, produces over 20 percent of its electricity from wind power right now and, during off-peak periods, wind sometimes fully meets Danish demand. Balancing generation and load so far has been manageable; about 50 percent of the time in Denmark wind power output does not vary over 15-minute intervals. Germany also has high levels of wind penetration on the grid and expects to reach 14 percent nationwide by 2015.

Given greater distances between wind generation and load centers, our region will face somewhat different challenges in ensuring stability and reliability and in financing transmission. Nevertheless, recent U.S. utility and state-sponsored engineering studies in our region and others conclude that wind penetration of 10-20 percent or higher can be integrated and managed reliably at low average costs to the system—three to five tenths of a cent per kilowatt hour (US $), or about 10 percent of the average wholesale value of the wind energy produced.* Specific regional or utility-based study variables could provide different integration costs.**

Costs and other barriers to increased wind integration will vary on a local, case-by-case basis. Thus, it will be important to reach agreement on a desired overall level of wind integration and any accompanying build-out of the transmission grid infrastructure. It will also be important to build agreement on public policy and other measures needed to achieve both on a regional scale.

Engineering Studies of Wind Integration on System Operating Costs

Date	Study	Wind Capacity Penetration (%)	Total Operating Cost Impact ($/MWh)
2003	We Energies	29	2.92
2004	Xcel Energy-MN Dept of Commerce	15	4.60
2005	PacifiCorp	20	4.60
2006	Xcel-PSCo	10	3.72
2006	Xcel-PSCo	15	4.97
2006	MN/MISO	35–40 (25% energy)	4.41

Source: Charlie Smith. Power Point Presentation. February 2007. Utility Wind Integration Group. Reston, VA.

2.2 Expand transmission capacity to accommodate more wind energy. Although our ability to *manage* higher levels of wind power on the grid has improved markedly, the actual *capacity* of the grid to handle additional wind-generated electricity remains severely constrained. While limitations in the region's grid affect all new electric generation, wind development faces particular obstacles because the region's best wind resources tend to be located in sparsely-populated rural areas where grid infrastructure is weakest. Without substantial additional investments in transmission upgrades and expansion, potential for further wind development will be limited.

* There are several reasons for costs being lower than anticipated. Over larger control areas on the grid, generation units continuously vary output and come on- and off-line anyway, whether they are conventional fossil or wind generation units. Power plant managers and grid system operators are learning through experience, improved wind forecasting, and evolving rules and protocols to manage wind's variability as part of the larger variability of the whole system. Further, wind power output does not suddenly stop and disrupt system stability as commonly imagined. Constant variations in windspeed affecting individual turbines are moderated by the dispersion of those turbines across the wider area of a wind farm. As more and more wind development occurs, wind farms themselves have become spatially distributed across a much wider geographic area, further smoothing generation output into the grid.

** These regional or utility-based study variables include: generation resource composition (size, availability, and fuel type); market or control area size; transmission import capabilities; wind resource generation profile; control area load profile; quick start or regulation support capability; future generation resource acquisition (fuel type and size); gas supply/storage availability; and fuel price assumptions.

2.3 Reduce capital and other costs of wind development. As with conventional power plants, the rising costs of steel and other commodities, a shortage of skilled labor and a three-year backlog for new wind turbines have helped drive increases of roughly 60 percent in the cost of wind farm construction over the past four years. Uncertainty over the fate of the U.S. federal production tax credit for wind energy exacerbates this underlying trend by disrupting the long-term planning and investments of utilities purchasing the power, wind farm developers and their service providers that build the projects, and the turbine and component manufacturers who supply them. To slow and perhaps reverse these increasing costs, expanded efforts by jurisdictions in the region are needed to attract and support domestic industry development. This should include: manufacturing of turbines and components; augmenting work force training for manufacturing, construction and maintenance trades; and building support for stability and predictability in the federal production tax credit to avoid needless industry dislocation. In our region, Iowa stands out as a state that has attracted wind manufacturing and component part suppliers. To date, Clipper Wind, Siemens and Acciona have existing or committed future facilities located in Iowa.

Wind potential

The wind resource in the United States could theoretically supply more than one and a half times the electricity consumed in the 48 contiguous states in 1990.

2.4 Encourage greater local equity participation in wind farms. In addition to its environmental benefits, wind energy development can also serve as an engine of rural economic development in parts of our region that have long suffered from low wages, out-migration of youth and a rapidly aging population. The experience of local ownership of wind farms in Minnesota, and of ethanol plants throughout the region, shows that when farmers, ranchers and other rural residents have equity stakes as full or partial owners in projects, more of the economic benefits of those projects are retained and circulate locally. As a result, a number of wind farm project models have emerged in the region, including partnerships between farmer-landowner groups and larger wind development companies. However, rigorous study (rather than anecdotal information) is needed to document that locally-owned projects actually result in greater local retention of economic benefits.

2.5 Demonstrate new technologies for very large-scale wind energy development. Because the wind resource potential in our region is so high, even significantly higher penetration of wind in our electric transmission system than anything planned today would not begin to approach that resource potential. Thus, over the 50-year timeframe of this roadmap, our region has the opportunity to play a leadership role in helping to demonstrate new technology applications that can make very large-scale wind energy development possible.

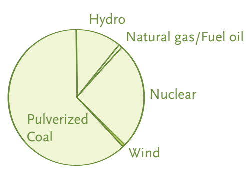
Emerging technologies and approaches have the potential to improve the schedulability of wind power and therefore its economic value in the marketplace, for example by deploying hybrid generation systems paired with other renewable energy resources or using compressed air or other forms of energy storage. This could then increase the availability or capacity factor of wind energy and the ability to dispatch wind power on the grid when its market value is highest. Other technologies will permit the use of wind energy to produce ammonia for fertilizer and other energy-intensive purposes that do not require additional transmission infrastructure.

3.0 Potential contribution of wind energy to the region's energy sector by 2055

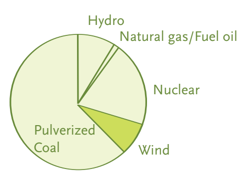
Regardless of the specific mix of options chosen over time for reducing greenhouse gas emissions in the Upper Midwest, wind energy will play a central role given the region's world class wind resource. It could well play the dominant role if progress is made toward overcoming key barriers to wind energy development.

3.1 Potential contributions of wind under various CO_2-reduction scenarios. If policy-makers were to commit to reducing CO_2 emissions 80 percent from 1990 levels by 2055, wind makes the following contributions under four 50-year scenarios for the region's electricity sector: business as usual (BAU), high energy efficiency (EE), high renewable (Renewable) and high coal with carbon capture and storage (Coal). These scenarios are based on modeling done by the University of Minnesota and GPI in partnership with PTP participants.

High Carbon Scenarios

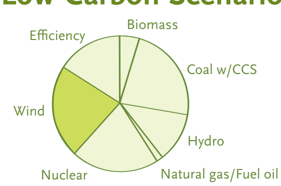


2005

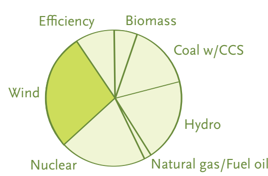


Business as Usual

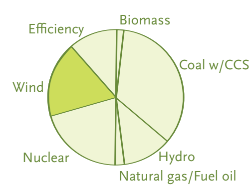
Low Carbon Scenarios



Energy Efficiency



Renewable



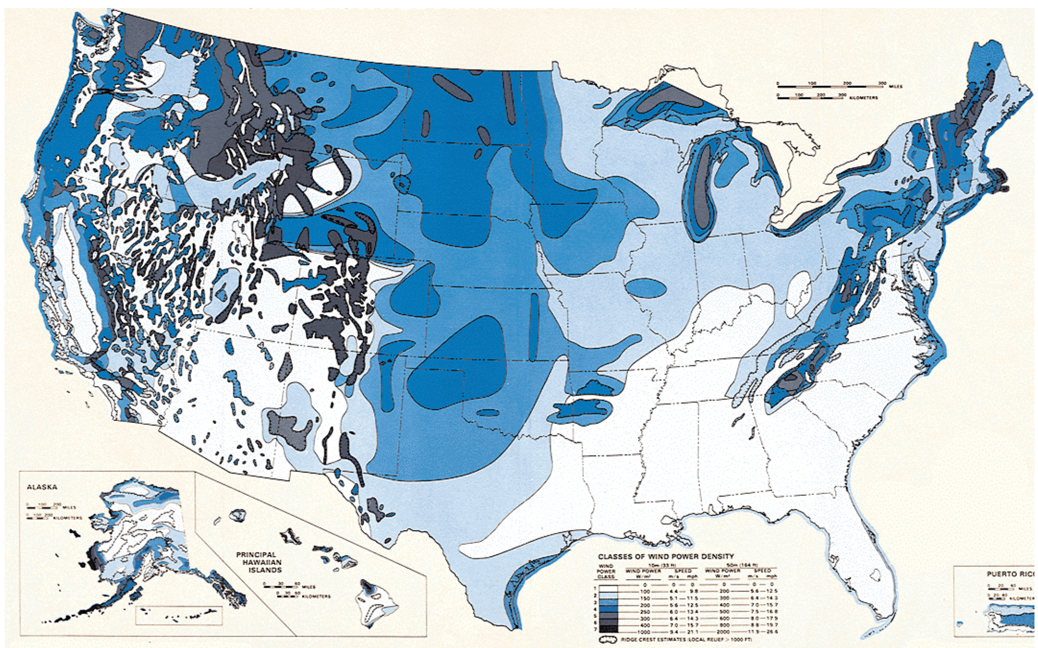
Coal

	2005	BAU	EE	Renewable	Coal
2055 Total Electricity (million mWh)					
	374	521	439	471	462
Cost per mWh					
	$30	$42	$51	$49	$51
Cumulative 50-year spending on Electricity ($ billion)					
		$771	$743	$775	$779

3.2 Scale of the Northern Plains' wind resource. The Northern Plains area has the wind resource potential to achieve the levels of wind energy development in any of the scenarios described in this roadmap and much more. Pacific Northwest Laboratory (PNL) conducted comprehensive assessments of U.S. wind resources and determined that good wind potential and developable sites cover 6 percent of the country's land area. The PNL assessment concluded that the nation's wind resource could theoretically supply more than one and a half times the electricity consumed in the 48 contiguous United States in 1990.[7] In Canada, Manitoba's efforts to assess its potential are revealing impressive Class 5 and 6 wind resources in the southwestern region of the province, similar to what one finds across the border in North Dakota.

PNL's further calculation of each state's share of the wind resource is even more dramatic: the six Northern Plains states of North Dakota, South Dakota, Montana, Wyoming, Minnesota and Iowa have the theoretical potential to produce the equivalent of 109 percent of total power consumed in 1990 by the 48 contiguous United States. The Dakotas alone could have supplied 70 percent of that demand.[8] Since PNL's early assessments two decades ago, some states have reassessed their wind resource. Minnesota, for example, hired WindLogics to update its state wind resource map. The further refinement of wind resource data—measuring wind speed at taller heights (80 meters rather than 50 meters)—has increased estimated wind resource potential and has yielded additional economically viable wind potential across a broader geographic area.

Estimated U.S. Wind Resources



Source: National Renewable Energy Laboratory. http://rredc.nrel.gov/wind/pubs/atlas/maps/chap2/2-01m.html

3.3 Having a good wind resource is not enough. Theoretical potential and actual development are very different things, and this distinction highlights the challenges our region faces in achieving a level of wind energy development commensurate with its resource potential. For example, California had the second highest installed wind capacity with 2,361 MW by the end of 2006. By contrast, North Dakota—with roughly 138,400 MW or 36 times California's developable wind resource—ranked 14th with 178 MW installed at the end of 2006. Similarly, of the six Northern Plains states cited above, Minnesota and Iowa have the smallest resource potential in the region, yet enjoy the greatest share of actual wind development with 895 MW and 936 MW respectively. To date, public policy incentives, transmission capacity and distances between generation and load have acted as much more important drivers of wind development than has actual resource potential.

4.0 Measurable milestones for wind energy development

The following regional wind energy milestones are proposed by PTP stakeholders for policy-makers' consideration:*

- By 2015, 13,000 MW of installed capacity or 10 percent of electricity consumed in the region.
- By 2020, 30,000 MW of installed capacity or 20 percent of electricity consumed in the region.
- By 2030, 50,000 MW of installed capacity or 30 percent of electricity consumed in the region, assuming technical feasibility and reliability.
- By 2040, one third of all energy consumed in the region will be derived from wind power, including electric generation for the grid and non-grid applications.

Depending on the pace and scope of implementation of state, provincial and federal policy incentives and of transmission development, the targets for 2015, 2020 and 2030 could be revised upward over time. Achieving 30 percent of total regional energy production from wind by 2040—rather than just 30 percent of electricity production—will require policy changes, the demonstration and commercialization of emerging technologies and processes for pairing wind energy with other energy resources and technologies, storing wind energy, and harnessing wind-generated electricity for energy-intensive applications beyond electric power production for bulk transmission on the grid.

* The first three milestones assume annual average growth in electricity demand of 1.5 percent and an average wind turbine capacity factor of 40 percent.

5.0 Key challenges and barriers

5.1 Current transmission capacity in the region cannot accommodate existing demand for new wind development. Significant transmission bottlenecks in the region prevent robust development of additional wind generation capacity in the region. These bottlenecks are worst where wind resources are the best and where wind power can be produced at lowest cost. In the Dakotas, for example, no more than a few hundred megawatts of capacity remain to accommodate new wind farm development, and much of that capacity will be used by current projects in various stages of development. Important progress has been made in Minnesota to upgrade key transmission lines in the southwest part of the state, and significant state and regional planning initiatives are underway that should help shape the region's future transmission build-out. However, much work remains to be done on transmission both in the planning and regulatory areas.

Regional transmission planning efforts underway

2006 Minnesota Wind Integration Study evaluated the impacts on reliability and the costs associated with increasing wind capacity to 15, 20, and 25 percent of Minnesota retail electric energy sales by 2020. The study utilized a Technical Review Committee comprised of utilities, the Midwest Independent System Operator (MISO), wind interests and national experts. The study concluded that up to 25 percent wind can be incorporated reliably into the electric power system given: 1) the wind operating in the MISO service area; 2) control area consolidation (currently underway in MISO); 3) geographic diversity of the wind power; and 4) adequate transmission.

Buffalo Ridge Incremental Generation Outlet (BRIGO) was initiated to identify several lower voltage transmission lines for the next 300–500 MW of wind (above 825 MW). Xcel Energy is currently in the regulatory process to obtain a Certificate of Need for the three 115 kV lines identified as needed. The new facilities are scheduled to be in service in 2009.

Southwestern Minnesota to Twin Cities 345 kV line. In November 2005 Xcel Energy completed a study of a new 345 kV line from southwestern Minnesota to the Twin Cities. The recommended plan will increase generation outlet capability in southwestern Minnesota/eastern South Dakota to nearly 2,000 MW. The recommendation includes a number of new key facilities: White-Lyons 345 kV, Lyons-Twin Cities double circuit 345 kV, Yankee-Brookings 115 kV (2nd circuit), and Brookings-Toronto 115 kV. A Certificate of Need is expected to be filed in 2nd quarter of 2007

Community-Based Energy Development (C-BED). and the Big Stone II partners are analyzing connection of large amounts (hundreds of megawatts) of wind power to substations in the West Central Minnesota Planning Zone. This study covers only steady state thermal analysis and impacts to the bulk power system.

CapX 2020 Group I Transmission Projects. CapX 2020 comprises Minnesota's largest transmission owning utilities who are studying required transmission infrastructure needed to meet growing demand in Minnesota and surrounding regions over the next 15 years. CapX estimates that some 6,300 MW of new generation will be needed to serve growing load by 2020. The study includes 2,400 MW of new wind power to meet Minnesota's Renewable Energy Objective. CapX utilities will file Certificates of Need for several major transmission lines in the 2nd quarter of 2007: Buffalo Ridge-Metro 345 kV line, Boswell-Wilton 230 kV line, and Prairie Island-Rochester-LaCrosse 345 kV line.

Midwest Independent System Operator (MISO) Transmission Expansion Plan '06 (MTEP '06). MISO continues to work on MTEP '06, including refining several exploratory transmission scenarios (Northwest Exploratory Plan, Iowa/Minnesota/Wisconsin Exploratory Plan) that would enable the delivery of thousands of megawatts of wind power. While these transmission scenarios are longer-range in nature, they set the framework for discussion of transmission needed to deliver wind under state/provincial RES and REO policies. Currently MISO is also studying transmission needed to implement a 10 percent RES across the MISO footprint (approximately 15,000–20,000 MW of wind power).

Source: Beth Soholt, April 2007. Wind on the Wires, St. Paul, MN.

5.2 The short timeframe for development of wind farms outpaces traditional transmission planning and construction. The planning, siting and construction of a wind farm can be accomplished within one calendar year under optimal circumstances. By contrast, the planning, siting and construction of upgrades to existing transmission infrastructure or of new transmission lines can take several years for lower voltage (115 kV) lines or 5 to 7 years for higher voltage (345 kV) lines. The combination of growing market opportunities associated with wind energy and utility companies' need to comply with renewable energy requirements has generated a flood of individual applications for transmission access. The Midwest Independent System Operator (MISO), the region's grid operator, has developed a study process that combines multiple wind projects together to determine transmission requirements for the group of projects, rather than processing projects one at a time.

5.3 Transmission access and transmission financing are significant issues for wind projects and can hinder development. Applying for and securing access to the transmission grid is a complex, lengthy, and expensive process. The generator interconnection and transmission service rules were developed mainly with large conventional (thermal) power plants in mind rather than for wind power. Study methodologies must be adapted for the characteristics of wind power (primarily an energy resource) versus conventional power plants that serve both as a capacity and energy resource. In addition, the cost of interconnection studies can be prohibitive for smaller wind projects and a significant financial commitment for larger wind projects.

The American Wind Energy Association, the Utility Wind Integration Group, and other stakeholders are working in partnership with Regional Transmission Organizations such as MISO and the U.S. Federal Energy Regulatory Commission (FERC) to recommend changes to interconnection, transmission and market rules that can expedite and reduce the barriers to developing wind projects.

Finally, how we finance transmission will ultimately have a significant impact on wind development. Generator or participant-funded transmission places an additional large burden on wind projects that are already very capital-intensive. Due to the way the MISO interconnection and transmission queues work, the last new generator that triggers a transmission upgrade may incur an enormous transmission bill that the single wind project alone must fund. Current MISO rules require new generators to fund up front 100% of the transmission upgrade costs and only be reimbursed by the Transmission Provider for 50%. Developers seeking the best wind resources often site their projects in precisely those rural areas where the greatest transmission investments are needed. "Rolling in" transmission costs (or a significant portion of them) and spreading them across all electricity customers offers a more conducive environment to the development of new wind projects.

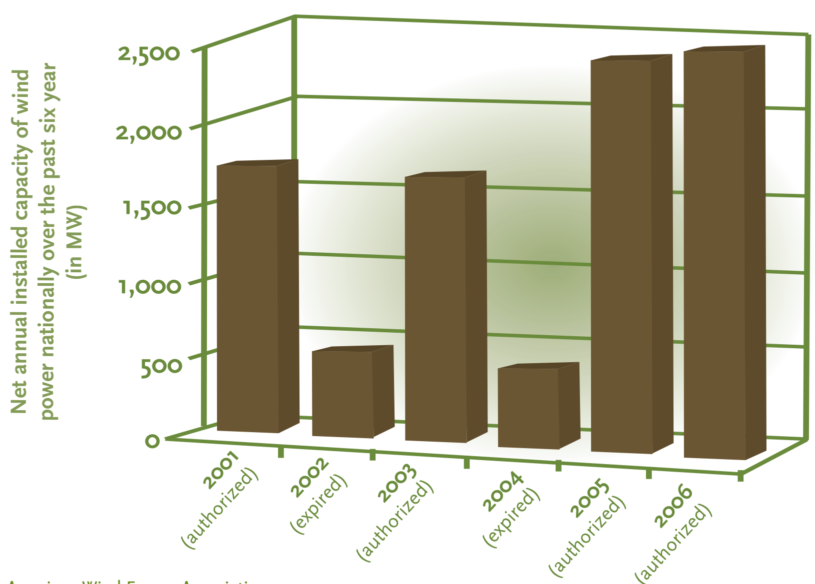
5.4 Lack of consensus over new baseload coal generation hinders approval of major transmission projects that would also benefit wind energy. Perhaps the single greatest barrier to major new transmission development in the region today stems from growing opposition to conventional coal-fired power plants because of public concerns about the CO_2 and mercury emissions associated with them.

Fortunately, as detailed in the accompanying chapter on advanced coal technologies, our region has the opportunity to pursue new advanced coal generation technologies such as integrated gasification-combined cycle (IGCC) that can dramatically reduce mercury emissions and capture and sequester the resulting CO_2 emissions (IGCC with CCS).

The recent successes in studying, approving and constructing new transmission in southwest Minnesota for 825 MW of wind generation outlet shows that transmission can be built without pairing wind with baseload power plants. However, pairing wind power with IGCC with CCS could increase public support for transmission expansion, allow wind and coal-based generation to share transmission costs, and accelerate approval of transmission that also benefits wind power.

5.5 Uncertainty of the U.S. federal production tax credit disrupts the financing and construction of wind farms and ultimately constrains development. The federal production tax credit (PTC) represents the single most important incentive in the United States for wind energy development, yet it has proven both a blessing and a curse. Congress has not reliably renewed the credit over time, leading to its periodic expiration and then reauthorization for relatively short periods of time.

Boom-and-Bust of Production Tax Credit has Hurt Wind



Source: American Wind Energy Association

It is hard to overstate the negative consequences of this uncertainty on wind development. Wind energy development has alternated between rapid expansion and tepid growth from year to year, depending upon the availability of the credit. This has created a boom and bust cycle in the industry, often grinding the planning, financing and construction of wind farms to a halt. It has also forced wind turbine and components manufacturers to slow production lines and lay off employees when the credit expires and then ramp up production when it is renewed to meet sudden demand. This creates supply bottlenecks for turbines, blades and towers and increases their cost. By making long-term planning and investment uncertain, the episodic nature of the PTC has reduced wind energy development and unnecessarily increased its capital and other costs.

The latest congressional reauthorization of the PTC continues through 2008. Another expiration risks stalling this latest boom in wind energy development. Discussion is already underway in and outside of Congress about the elements of a longer-term (perhaps five year) extension of the PTC for 2009 and beyond. A multi-year extension would help to restore greater certainty to the industry and assure robust and stable growth.

5.6 Backlogs for turbines and other components and a shortage of skilled labor and service providers delay wind projects and increase costs. The boom in new wind farm construction since reauthorization of the PTC, coupled with an increasing global demand for steel and other commodities and for trained professionals and tradespersons to work large construction projects, has led to three mini boom and bust cycles in the construction of wind turbines and other components and to increases in construction costs of over 50 percent. While this affects all new construction in the power sector, the associated costs and delays could be mitigated somewhat by governments, industry and higher education helping scale up the manufacturing and service sectors based in the region to support expanded wind development.

The components of wind farm construction are already being manufactured in this region. DMI Industries and LM Glasfiber manufacture turbine towers and blades in West Fargo and Grand Forks, ND respectively. Clipper Windpower has a manufacturing facility in Iowa. Suzlon assembles turbines in Minnesota. And Knight & Carver Wind Blade Division opened a manufacturing and repair facility in Howard, SD in the summer of 2006. If we build upon this base, we could contribute to the economic development of the region by creating new jobs and reducing the costs of new wind farm construction.

5.7 Some jurisdictions lack policy incentives that create a market for wind development and encourage local equity participation in wind projects. All jurisdictions in the region have at least some incentives in place to encourage the development of wind energy, although policies by jurisdiction differ greatly in terms of their scope and impact. The greatest differences emerge with regards to policies in two areas:

- Portfolio standards or objectives establishing requirements or good-faith commitments for utilities to deliver electricity from renewable sources to their customers (or to purchase renewable energy credits in lieu of actual generation); and
- Incentives that foster local ownership of wind projects.

In the Upper Midwest region, Illinois, Iowa, Manitoba, Minnesota, North Dakota and Wisconsin already have or are implementing RES or REO-type portfolio policies. By contrast, South Dakota lacks any such policy.

In addition to REO and RES policies, the Midwest Renewable Energy Tracking System (M-RETS) will further build the market for wind and other renewable sources of electric power in the region. With the support and participation of PTP stakeholders, the Izaak Walton League, Great Plains Institute and Center for Resource Solutions collaborated and partnered with the region's regulators, utilities and other stakeholders to design M-RETS. Slated to become operational in six states and one province by mid-2007 (IA, IL, MB, MN, ND, SD, and WI), M-RETS will serve as a regional accounting system for the generation, exchange and retirement of renewable energy credits.

Renewable Energy Standards or Objectives by Jurisdiction

Jurisdiction	Policy	Target	Date
Illinois (pending)	Renewable Energy Standard	8%	2013
Iowa	Renewable Energy Standard	2%	1999
Iowa	Renewable Energy Objective	1,000 MW	2010
Manitoba	Wind Development Objective	1,000 MW	2015
Minnesota	Renewable Energy Standard	25%	2025
Minnesota (Xcel Energy)	Renewable Energy Standard	30%	2020
Montana	Renewable Energy Standard	15%	2015
Wisconsin	Renewable Energy Standard	10%	2015
North Dakota	Renewable Energy Objective	10%	2015
South Dakota	None	NA	NA
Wyoming	None	NA	NA

Like many market-based systems, renewable energy credit tracking, and the consequent trading of credits, will help reduce the costs of developing renewable energy and encourage development in resource-rich areas such as the Northern Plains states and prairie provinces. By facilitating credit trading, M-RETS will allow generators to capture extra value for renewable energy produced our region, whether or not transmission exists to export the actual power to distant markets.

In terms of fostering local ownership of wind projects, clear policy differences exist among the region's jurisdictions as well. Minnesota pioneered using state policy to increase local equity participation in wind development. Its legislature enacted a state production payment of 1.5 cents/kWh applied to projects of 2 MW or smaller. This policy led to the development of many locally-owned wind projects amounting to 200 MW of capacity.

In Iowa, the legislature approved last year a comparable incentive for up to 90 MW of locally-owned wind projects. The state received a flood of applications from interested developers working in partnership with local landowners and other interests, and the program was oversubscribed in seven days.

Because of the support and interest for local equity participation in wind projects, these incentive policies may well prove too costly for other jurisdictions to emulate. Recognizing that a new funding approach was needed, the Minnesota legislature last year passed legislation granting the Minnesota Public Utilities Commission the authority to develop the Community-Based Energy Development tariff, or C-BED. Using a present value calculation, the C-BED tariff will allow utilities to rate-base increased payments to developers of locally-owned projects on the front end of a 20-year power purchase agreement, while decreasing those payments in later years. It is too early to determine the effectiveness of C-BED and its desirability as a model for other jurisdictions to adopt.

To date, no other jurisdiction in the region other than Minnesota and Iowa have policies in place to support local ownership of wind projects.

6.0 Strategies for developing the region's wind potential

6.1 Support a long-term extension of the U.S. federal production tax credit. The region's congressional delegation should continue their strong support for the PTC and seek a multi-year extension of up to eight years, effective once the current two-year extension expires on December 31st 2008. A longer extension will bring needed confidence and stability to the industry and help to achieve more wind development than would otherwise be possible under the current pattern of repeated short-term extensions. Governors and legislatures in the region should communicate to the region's congressional delegation the importance of securing such a multi-year extension in 2008.

6.2 Consider new policy approaches to encouraging wind energy development in South Dakota, which currently lacks a renewable energy standard or objective. Consensus on renewable energy standards and objectives has proven elusive in some jurisdictions. With North Dakota's passage of an REO in 2007, South Dakota remains the only jurisdiction in the Upper Midwest without an established standard or objective for renewable electricity. South Dakota legislators should work with utilities and other stakeholders to establish a policy that establishes clear targets and timeframes for development of renewable energy generation capacity or for sales of renewable electricity at retail.

6.3 Incorporate transmission development requirements into existing state and provincial renewable energy objectives and standards. Given the timing mismatch between rapid wind farm development and the much longer time required to study, approve and construct transmission, the requirement to provide for transmission needs to go hand in hand with state and provincial renewable energy standards and objectives. State and provincial RES and REO policies should require utilities to identify additional transmission capacity needed to meet their renewable energy obligations, seek approval through the utility regulatory process, and construct transmission. For their part, regulators, other policy-makers and stakeholders should actively support utilities in securing needed transmission expansion. Recent filings by Xcel Energy before the Minnesota Public Utilities Commission requesting approval for transmission needed to meet that state's REO constitutes a positive example of this approach, as does the planning CapX 2020 has done for transmission for renewables in the region.

6.4 Encourage a diversity of approaches to wind development, including projects that have significant components of local ownership. Policy-makers in all jurisdictions should evaluate the emerging experience with local ownership incentives in Minnesota and Iowa and consider further measures that might foster local equity participation in wind projects as a way to enhance further economic returns in the region. However, policy-makers should continue to support a diversity of ownership structures in the marketplace and avoid creating unanticipated barriers to achieving significant levels of wind development and associated transmission expansion. PTP stakeholders support all forms of wind development in the region, including both wind farms constructed and owned by major national and multi-national companies, as well as projects that feature full or partial local ownership.

6.5 Expand collaborative regional transmission planning efforts to help develop the infrastructure for future wind energy development. Collaborative, inter-jurisdictional transmission planning efforts must be continued and strengthened in order to optimize future investments in transmission and ensure that the region's future grid infrastructure meets the wind energy and other objectives identified in this roadmap. These efforts need to involve utilities, regulators, transmission planners, wind developers and advocates, and other stakeholders. Governors/premiers, legislators, regulators and other policy-makers can play an important role in bringing more focused political and policy support to such efforts. In particular, they can encourage planning on a genuinely inter-jurisdictional basis and at an appropriate regional scale and help bring key parties needed to the table to achieve results.

6.6 Consider a significant multi-state transmission initiative to facilitate construction and delivery to market of a large amount of new wind power in partnership with energy from other low-carbon generation facilities. Utility transmission planners have long identified bottlenecks in the transmission system in the Upper Midwest that must be fixed in order to deliver large amounts of new wind energy as well as low carbon energy to market.* Policy-makers in all jurisdictions, together with other stakeholders, need to identify components of a multi-state transmission and generation initiative and move them forward in a study process.

6.7 Define and support a large-scale, multi-jurisdictional wind energy project that incorporates synergies with other low-carbon generation options. PTP participants invite governors/premiers, legislators and other policy-makers to join them in convening regional workshop sessions to explore the design and implementation of a collaborative, multi-jurisdictional project(s) to demonstrate how various elements of this regional energy roadmap could be implemented synergistically. Elements to consider include, but are not limited to:

- **Common transmission corridor** serving several jurisdictions (upgrade of an existing corridor or a new one or both);
- **Multiple wind farms in participating jurisdictions**, including some projects with local ownership components;
- **Wind-hydro, wind-biofuels, and wind-compressed air demonstrations** with the potential to qualify for 65 percent "firm" capacity payments (FERC tariff for renewable generators);
- **Demonstration baseload IGCC coal plant** with carbon capture and storage; and
- **Associated hydrogen and fertilizer production** applications using wind, IGCC coal and possibly biomass or bio-fuels as energy sources.

* In August 2006, the USDOE released the National Electric Transmission Congestion Study in response to Section 1221 (a) of the Energy Policy Act of 2005. The study identified the Dakotas to Minnesota geographic area as a "Conditional Congestion Area," meaning that there is some transmission congestion present, but significant congestion would result if large amounts of new generation were developed without additional transmission capacity. The USDOE concluded that "affirmative government and industry decisions will be needed in the next few years to begin development of some of these generation resources and the associated transmission facilities."" USDOE. August 2006. *National Electric Transmission Congestion Study*. Washington, DC. http://nietc.anl.gov/documents/docs/Congestion_Study_2006-9MB.pdf

Examples of new wind opportunities

Advanced Wind Forecasting

Better forecasting of wind conditions improves utility and grid operators' ability to schedule and manage wind power with other generation sources on the grid. With funding from the Xcel Renewable Energy Development Fund (RDF), WindLogics and Xcel Energy are working to integrate sophisticated, real time wind forecasts with utility control center energy management systems. This promising application of advanced forecasting capabilities can serve as a model for other utilities.

Pairing Wind and Bio-Fuels

Research by Doug Tiffany of the University of Minnesota concludes that pairing conventional wind generation with biodiesel-powered generators can produce favorable project returns and provide a renewable source of electricity generation capable of qualifying for higher capacity payments under a 65 percent "firm" FERC tariff applied to qualified facilities supplying power during peak demand periods.[9] Additional research has been proposed to determine the feasibility of pairing wind generation with generators fueled by bio-oil derived from native grasses.

Wind Energy Storage

Projects underway or under consideration have the potential to demonstrate the use of wind power to compress air and store that energy. The compressed air would then be deployed to generate electricity when it is most needed on the grid and, therefore, of highest value in power markets.

Conventional Compressed Air Energy Storage (CAES). The Iowa Stored Energy Park or ISEP may well offer the first demonstration of CAES with wind in the region. A project of the Iowa Association of Municipal Utilities, with support from municipal utilities in Iowa, Minnesota and the Dakotas, ISEP envisions a 268 MW system in operation by 2011 that will rely on 75–100 MW of wind power combined with natural gas generation to store compressed air in an underground sandstone formation and generate power for the grid during periods of peak demand. With the final site selected, the USDOE will invest several million in remaining design work for a project with a cost of power estimated at $65 per megawatt hour.[10] If successful, our region has ample geologic reservoirs for further CAES facilities.

Wind Turbine-Integrated CAES. General Compression is pursuing prototype development CAES that integrates air compression within the wind turbine itself. This approach to CAES could utilize geologic reservoirs, conventional pipelines and possibly turbine towers themselves as storage vessels. Direct-drive powering of the compressor by the turbine blades at variable speeds would eliminate the need for a gearbox, generator and other turbine components, reducing capital costs. The resulting reduction in turbine weight would permit taller turbine towers, improving the wind resource and energy output. Finally, the compressed air expansion phase to generate electricity for sale to the grid could incorporate useful synergies with waste heat from conventional coal-fired power plants or from heat produced from renewable biomass sources, increasing both the energy efficiency and scale of the system's power output.[11]

Vanadium Redox or Flow Batteries. VRB Power Systems of Canada announced in August 2006 a US $6.3 million project to deploy 12 MWh of storage at a 39 MW wind farm in Ireland, where high and increasing levels of wind penetration on the grid are raising stability concerns.[12] The company's technology relies on a PEM fuel cell to convert electrical energy into chemical energy and vice versa. The electrical energy is stored in different ionic solutions of vanadium in a sulphuric acid electrolyte solution. According to the company, the technology is readily scalable by increasing the size of the electrolyte storage tanks and can be fully charged and discharged over 10,000 times without degrading capabilities. The electrolyte also lacks the harmful chemicals and environmental impacts of more conventional battery storage.[13]

Wind Power to Hydrogen to Ammonia Production

Most ammonia today is used in fertilizer, and 90 percent of its cost comes from the natural gas feedstock. Skyrocketing natural gas prices have shut down nearly a third of the U.S. domestic fertilizer industry, forcing the importation of ammonia to meet about half of the country's fertilizer needs. With funding from the state of Minnesota, the University of Minnesota's West Central Research and Outreach Center is partnering with Norsk Hydro to demonstrate using our region's low-cost wind power to harvest hydrogen from water and combine it with ambient air to produce affordable domestic ammonia for use in fertilizer.

Successful demonstration of this process in our region would yield multiple benefits: lower-cost fertilizer for farmers and reduced imports; substitution of zero-emissions wind energy for fossil natural gas; and a potentially enormous market for wind energy that requires no additional high voltage transmission and no power purchase agreements from utilities. Analysis done for the University of Minnesota by Sebesta Blomburg estimates that satisfying Minnesota's commercial fertilizer needs alone would require 2,000 MW of wind generation, nearly three times the state's current installed capacity. Under such a scenario, farmers would benefit twice—through reduced costs of fertilizer and through lease payments from new wind development.

The potential for many positive synergies exists among our region's various energy generation resources, and future upgrades to the region's transmission system should be encouraged that benefit multiple low- and zero-carbon energy resources and jurisdictions at once. Demonstration of technology synergies, and of how states and provinces can regionally share together in the benefits, will be important for building public and political support for needed policies and investments over time.

6.8 Demonstrate technology, engineering and operating strategies for achieving greater than 20 percent of total electricity generation from wind. Policy-makers should support research and practical demonstrations of strategies and technologies with the medium to long-term potential to expand wind energy's contribution beyond 20 percent of the region's electric power generation. Such efforts should focus on:

- Applying and building upon findings in wind integration studies, such as the conclusions of the 2006 Minnesota Wind Integration Study. These include the finding that up to 25 percent wind can be incorporated reliably into the electric power system given: 1) the wind operating in the MISO service area; 2) control area consolidation (currently underway in MISO); 3) geographic diversity of the wind power; and 4) adequate transmission.
- Developing new uses of wind energy that do not need the construction of bulk transmission and can readily substitute for existing CO_2-emitting fossil energy sources, especially increasingly costly natural gas.
- Increasing the market value of wind by improving the dispatchability or schedulability of the resource on the grid, and thereby achieving higher prices for wind power and accelerating its market penetration.

6.9 Develop policies to attract wind energy component manufacturers and service providers to locate their operations within the region. Policy-makers should take concrete steps to integrate economic development programs incentives into state and provincial wind energy development policies and strategies with the goal of attracting manufacturers and service providers to the region for its economic development benefits and to reduce the cost of future wind energy development. The Northern Plains already benefits from the presence of major wind turbine blade and tower manufacturers, turbine assembly operations, engineering and wind farm construction firms, and operations and maintenance providers whose commercial success extend well beyond the region. As previously mentioned, Iowa has recently been very successful in attracting wind manufacturing facilities to its state, and other states should follow Iowa's lead.

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Hydroelectric Power

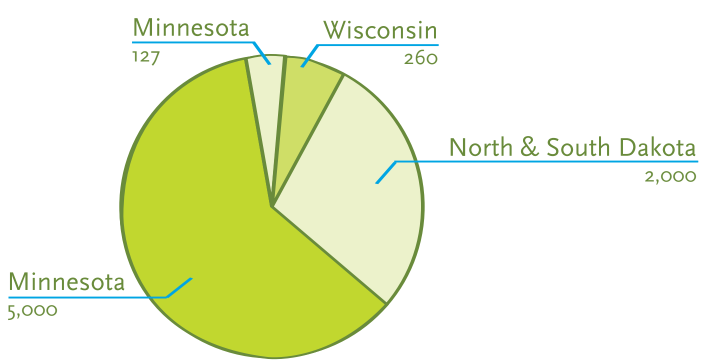
McArthur Generating Station, Manitoba

1.0 Introduction

Hydroelectric power production in the Upper Midwest region has been a part of the region's energy supply picture for decades. As illustrated in the pie chart below, Manitoba Hydro is the largest hydropower producer in the region by far, with roughly 5,000 MW spread among 14 hydro stations within the province.

North Dakota and South Dakota have hydropower facilities operated by the U.S. Army Corp of Engineers. The Missouri River District generates roughly 2,000 MW of electricity, which the Western Area Power Administration distributes. Minnesota and Wisconsin have a relatively small amount of hydropower production supplied by Xcel Energy's Hennepin Island plant in Minneapolis (12 MW) and 19 plants in Wisconsin (260 MW). Minnesota Power has 11 plants in northern Minnesota that total 115 MW.

Current hydropower generation in the Midwest (in mW)



As a Crown corporation, Manitoba Hydro serves Manitoba customers first and then sells surplus energy to Xcel Energy, Minnesota Power, Otter Tail Power, Great River Energy and Minnkota Power Cooperative in the United States. Xcel Energy purchases the most; during the peak summer season in normal water years, Xcel's Northern States Power subsidiary purchases about four percent of its electric energy from Manitoba Hydro. During low water years, Manitoba Hydro can benefit from imported power from the United States to meet its local demands in the winter. Hydropower contributes to a diversified energy system, which in turn leads to increased reliability for the region as a whole.

Although the region has benefited from renewable, zero-emission hydropower, very large hydro projects developed in a previous era have also had significant impacts on the environment and on local communities. These facilities were built at a time when environmental knowledge and society's views of what constitutes acceptable development were vastly different than today. Future projects are being pursued in a much more progressive fashion. If the region is to meet energy demand and significantly reduce CO_2 emissions, it will need low-impact hydro power as part of the mix.

2.0 Objectives for new hydropower development

Additional hydropower ought to proceed with several objectives in mind:

2.1 Pursue environmentally responsible development of hydropower projects for both new and upgraded facilities.

2.2 Develop new hydropower projects with the involvement of locally affected peoples. Development of all projects can result in positive and negative implications for local peoples. Projects should provide meaningful involvement for affected peoples. For example, Manitoba Hydro and the province of Manitoba have worked on a plan to provide partnership agreements with affected First Nations for such projects. The Wuskwatim Project Development Agreement between Nisichawayasihk Cree Nation and Manitoba Hydro will be the first test of this approach. The Wuskwatim 200 MW hydropower project would be the first of three projects proposed by Manitoba Hydro over the next 15 to 20 years.

2.3 The timing and delivery of new hydro power must be coordinated with a broader regional energy strategy so that the necessary transmission infrastructure is in place if and when it is needed. If additional hydropower is to be part of the region's future energy portfolio, policy makers and resource planners must consider the timeline requirements for new hydropower and transmission projects to provide electric energy to this region. Manitoba Hydro and U.S. customers will determine what portion of any new hydropower development will be delivered to the U.S. market. If Manitoba Hydro's new resources are to help meet electric power supply requirements in the United States, new transmission from Manitoba into the United States will be required. This requires planning with the Midwest Independent System Operator (MISO), the North Dakota Transmission Authority, the province of Manitoba and any affected electric utilities.

2.4 Hydropower expansion in the region should, wherever possible, complement the development and delivery of other low- and zero-CO_2 energy resources in the region. Hydropower projects, because of their storage capabilities in the watershed, may lend themselves well to pairing with variable renewable resources such as wind power. There is also real potential to pair hydro power with advanced hybrid wind systems that include flow batteries, compressed air, hydrogen and other storage technologies. This would allow on-demand electric production and generation of hydrogen (either for vehicle fueling or to produce local ammonia fertilizer) from a wind-hydro resource combination.

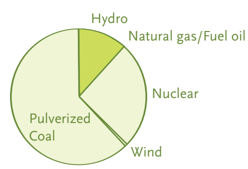
3.0 Potential contribution of new hydropower projects to the region's energy sector by 2055

Hydropower's exact role in the Upper Midwest's energy system will be influenced by a wide range of factors, including growing concern over air quality and greenhouse gas emissions, the potential trading of CO_2 emission credits, the fate of renewable or low-CO_2 energy portfolio standards, and on-going resolution of issues stemming from hydro development.

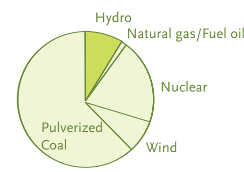
Hydro Potential
Most of the potential for additional hydropower in the region exists in the province of Manitoba.

If policy-makers were to commit to reducing CO_2 emissions 80 percent from 1990 levels by 2055, hydropower makes the following contributions under four 50-year scenarios for the region's electricity sector: business as usual (BAU), high energy efficiency (EE), high renewable (Renewable) and high coal with carbon capture and storage (Coal). These scenarios are based on modeling done by the University of Minnesota and GPI in partnership with PTP participants.

High Carbon Scenarios

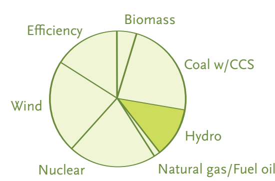


2005

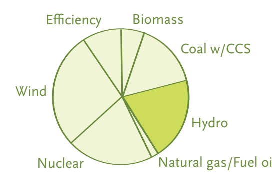


Business as Usual

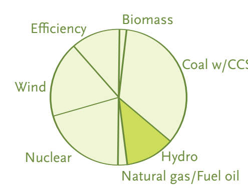
Low Carbon Scenarios



Energy Efficiency



Renewable



Coal

	2005	BAU	EE	Renewable	Coal
2055 Total Electricity (million mWh)					
	374	521	439	471	462
Cost per mWh					
	$30	$42	$51	$49	$51
Cumulative 50-year spending on Electricity ($ billion)					
		$771	$743	$775	$779

There are several small hydropower expansions under consideration in the United States, but Manitoba Hydro has estimated a long term potential of 5,000 MW of additional hydropower production and has (along with the province itself) proposed plans to develop the first 2,310 MW of that over the next 15 years. Three major hydropower projects make up the 2,310 MW proposed by Manitoba Hydro:

3.1 Wuskwatim Generating Station: A 200 MW station with three generator units is planned on the Burntwood River near Thompson, Manitoba. Members of the Nisichawayasihk Cree Nation voted to approve the partnership agreement with Manitoba Hydro. The facility is under construction with a projected in-service date of 2012.

3.2 Keeyask Generating Station (formerly known as Gull): A 630 MW station is planned at a site on the Nelson River, 30 km west of Gillam. Manitoba Hydro is involved in ongoing discussions with all of the locally affected First Nations to plan for and design the facility, avoid and mitigate impacts, deliver pre-project training initiatives, and explore partnership opportunities. The earliest possible in-service date for the project is 2017. The Keeyask Generating Station Project would require associated transmission facilities.

3.3 Conawapa Generating Station: A 1380 MW station is planned at a site on the Lower Nelson River, 28 km downstream of Limestone Generating Station, and 90 km downstream of Gillam. The projected in-service date is 2019. The project would require major transmission facilities associated with the export interconnection project. No final design development or construction decisions have been made nor have the routes of power lines, long distance HVDC lines, or the location of converter stations been determined.

These projects deserve primary attention from policy-makers considering the role of additional hydropower as part of a long-term CO_2 emissions reduction strategy for the Upper Midwest. As an example of the potential importance of hydro power in a carbon-constrained world, a study by the Pembina Institute for Appropriate Development—a leading Canadian environmental think-tank—documents that the Wuskwatim hydro project will have a greenhouse gas impact 290 times less than a similarly-sized conventional coal plant and 130 times less than the most efficient natural gas generation technology. More generally, Manitoba Hydro calculates that hydro exports to the United States since 1970 have displaced over 171 million tons of greenhouse gases from U.S. generating stations.

Careful and respectful development of Manitoba's renewable hydropower resources can make a significant contribution to the region's energy and climate goals.

4.0 Measurable Milestones

Even with significant new investments in energy efficiency between now and 2055, the region will need a large amount of electricity production that emits little or no CO_2. Thus, PTP stakeholders support the following milestones for hydro development as long as the objectives described in section 2.0 of this chapter are met:

- By 2025, 2000 new MW of hydro power added to the region's electricity system.
- By 2025, 5000 new MW of hydro power added to the region's electricity system.

5.0 Key challenges and barriers

Key challenges and barriers

1. Environmental and regulatory issues.

2. Future power supply agreements between Manitoba Hydro and U.S. customers.

3. The timing and development of transmission lines to bring new hydro power to market.

New hydropower expansion in the Upper Midwest would provide an important carbon-neutral contribution to the region's electric energy supply, in contrast to the primarily fossil-based electricity that states in the Upper Midwest rely on today.

At the same time, hydropower plants, like any other generating facility, have site-specific impacts on the local ecosystem and surrounding communities that must be minimized. Whatever impacts hydro has should be weighed against the various impacts of other energy alternatives.

The hydropower now under consideration and development within the region is predominantly low-impact that does not significantly modify a river's flow. Projects in Manitoba have been designed to minimize the associated flooding. While low-flooding designs reduce the environmental impacts of a dam significantly, they can also reduce electrical energy output and exclude opportunities to store water over longer periods to maximize the market value of the electric energy.

Finally, new hydropower development in Manitoba will also require new high voltage DC transmission lines and converter stations from the northern generating stations to Winnipeg. Any new hydropower supply contracts with U.S. utilities may require the construction of additional transmission to serve markets in the United States. Planning these facilities in conjunction with other U.S. transmission planning activities will require significant coordination.

Today's comprehensive regulatory processes for new hydropower projects create challenges for new development, but they also ensure that all of the economic, environmental, social and technical implications are carefully considered, and that the majority of potential negative implications are avoided, mitigated and/or compensated for.

6.0 Recommendations

There is potential for development of additional hydropower within the Upper Midwest jurisdictions of the United States and Canada. The recommendations that follow are meant to assist policy makers and other interests in the region in realizing this potential:

6.1 Explore potential synergies among hydro, wind and other renewable and near-zero emission energy technologies, including their ability to share transmission development (getting agreement about what goes *on* the wires may help the siting, permitting and construction of those wires);

6.2 If a market evolves for the tracking and trading of CO_2 emissions, allocate emission reduction credits to new hydro generation. One of the challenges for new hydro power (as with other low- and zero-CO_2 energy production) is competing with conventional fossil-based power in a policy and regulatory environment that does not put a price on CO_2 emissions. If policymakers at the state or federal level develop emission trading systems, then new hydro power should be recognized for its low-CO_2 profile.

6.3 Consider including new hydropower production in any regional, state and provincial renewable energy standards or objectives. This would recognize large hydro power as an eligible renewable form of energy production.

6.4 Include new hydro generation in any incentives established or revised for other zero-CO_2 energy production. This would ensure an even playing field for hydro as part of the region's portfolio of low- and no-CO_2 energy options.

Nuclear Power

1.0 Introduction

Nuclear power has been the subject of great optimism and skepticism over the past 40 years. Today over 100 nuclear power plants in the United States provide about 20% of the country's energy (that figure is 17% worldwide). The obvious benefit of nuclear power is that it produces no CO_2 emissions or other air pollution. The Nuclear Energy Institute estimates that without nuclear power, the United States would emit an additional 190 million metric tons of carbon each year.[1]

The technology's main stumbling block as a next generation energy source has been a lack of consensus on disposal of the nuclear waste that is generated in the process of making electricity. Restarting an industry that has gone dormant (at least in terms of new construction), has also proven challenging. Despite the billions of dollars that have been spent by the federal government since 1982 to study and prepare a long-term repository for the waste at Nevada's Yucca Mountain, the waste issue remains unsolved. In addition, several states have made nuclear waste *transportation* an issue that will also need to be resolved if a permanent waste disposal site can be used by nuclear power plants and utilities.

Prairie Island plant in southern Minnesota

Even if consensus could be reached on Yucca Mountain as a long-term storage site, it would not be able to hold all the expected waste from the nation's existing nuclear plants. According to a Minnesota Environmental Quality Board Report,

> The Yucca Mountain project would construct a series of tunnels 1000 feet into the earth, where up to 77,000 metric tons of high level radioactive wastes would be stored. The amount of waste that is expected to be generated by operating nuclear power plants during their operating lives, considering re-licensing efforts, is about 105,000 metric tons. Therefore, Yucca Mountain as presently authorized cannot hold all the waste that is expected to be generated.[2]

The Upper Midwest is host to several nuclear reactors, each of which must manage its own waste:

> Prairie Island Units 1 and 2 (MN), 1,050 MW, 8.4 million MWh in 2005

> Monticello (MN), 560 MW, 4.5 million MWh in 2005

> Duane Arnold (IO), 560 MW, 4.5 million MWh in 2005

> Kewaunee (WI), 560 MW, 3 million MWh in 2005

> Point Beach Units 1 and 2 (WI), 1,025 MW, 6.9 million MWh in 2005[3]

The PTP region currently generates approximately 15% of all electricity from nuclear power plants.*

Although nuclear power has come to play a significant role in the region's and nation's energy supply, no new nuclear power plants have been built in the United States in the last 30 years.

* The broader region that includes Illinois and was used for the CO2 scenario model, generates substantially more electricity from nuclear power.

2.0 Objectives for any new nuclear development in the region

New nuclear power development is unlikely in the Upper Midwest unless we resolve several issues first:

2.1 There would need to be agreement on a safe and permanent storage option for nuclear waste. Permanent disposal of nuclear waste is a prerequisite to any additional nuclear power plant development since there is wide agreement that today's temporary waste storage sites at the various nuclear plants are an insufficient long-term solution. As noted in the introduction, even if Yucca Mountain suddenly became available as a national repository, it cannot hold all the expected waste from existing plants. Additional nuclear plants would exacerbate this problem. Nuclear proponents believe that if spent fuel were fully reprocessed, the relatively small volume of waste remaining would be manageable.

Explore safe, secure and cost-effective waste management and fuel reprocessing options that enable future use of nuclear power as a carbon-free energy source.

2.2 Concerns over terrorism and nuclear proliferation would need to be adequately addressed. The U.S. Nuclear Regulatory Commission has issued a number of new security orders since the terrorist attacks of September 11, 2001, but concerns remain over how secure nuclear facilities are or can be against future terrorist attempts. In addition, the risk of nuclear proliferation would have to be made acceptably small in order for nuclear power to expand.

2.3 New, simpler and more efficient power plant designs also need to be approved by regulators with good cost estimates on construction of these next generation nuclear power plants. Next generation nuclear power plants have simpler, more inherent safety features than today's nuclear plants. Several features of the 2005 Energy Policy Act (EPACT) have licensing, insurance and cost incentives for new nuclear plants, but federal regulatory agencies have not yet reviewed, approved or priced out any new nuclear power plants. According to the Nuclear Energy Institute, there are 19 project proposals in the process of early site permitting and construction/operating license submittal awaiting federal design approval to move ahead with state licensing.[4] As of April 1, 2007 two projects have received early site approval from the Nuclear Regulatory Commission.

2.4 Nuclear power would need to out-compete energy options with a natural advantage in the region. Other than as a response to new carbon emissions caps or other plans to reduce CO_2, new nuclear power plants do not offer the region energy independence from outside sources since we have no local uranium production facilities. Therefore, nuclear power must compete with energy options that are native to the region.

3.0 Potential contribution of nuclear power to the region's energy sector by 2055

The fact that nuclear power produces no CO_2 emissions has prompted serious and renewed discussion among some in the environmental and technical community about its potential role in a carbon-constrained world. Still, there is also great skepticism that issues such as permanent waste disposal, cost, licensing risk and nuclear proliferation can be overcome.

Nuclear power's potential contribution to the region's energy mix is nearly impossible to estimate since it is constrained more by waste, safety, proliferation and political issues than it is by a lack of the necessary natural resources globally. In other words, "How much nuclear power could we have?" remains more of a political, economic and social question than a technical one.

At the national level, the new EPACT of 2005 contains significant financial and regulatory incentives for developers of new nuclear power plants. The Nuclear Energy Institute estimates that up to 15 new nuclear plant projects may be proposed in the next several years, mostly in the southeastern part of the United States. Both General Electric and Westinghouse are working on next-generation designs of nuclear reactors and the French company Areva has teamed up with Constellation Energy in the United States to sell their nuclear power plant design. Formal applications for the new designs are expected by 2008.

Given the lack of consensus on the future of nuclear power development in the region, GPI and PTP participants have adopted the planning assumption of holding nuclear power constant for each of the three 50-year energy transition scenarios.

This assumption is complicated by the fact that current nuclear power plants are being relicensed for 20 years with no plans for what should be done after that time period. This issue has not been accounted for in our planning estimates. Nuclear industry experts explain that current nuclear power plants should be able to be life-extended for the subsequent 20 years as well by replacing the "active components" that are monitored and measured on an ongoing basis depending on what approach the Nuclear Regulatory Commission decides to take at the end of the current relicensing period for the existing nuclear power plants.

The passive components, such as reactor vessel containments, that might need to be replaced after the next 20 years, pose a much more serious decision point on the cost of replacement of those fixed, passive components versus replacement with next generation nuclear power plants or some other energy source.

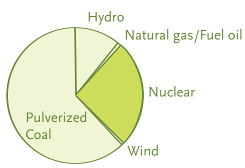
The current licensing status of the regional nuclear power plants is:

- Prairie Island Units 1 and 2—Application for 20 year license renewal expected October, 2008
- Monticello—20-year license extension granted in November, 2006
- Duane Arnold—Application for 20-year license renewal expected October, 2008
- Kewaunee—Application for 20-year license renewal expected April, 2008
- Point Beach Units 1 & 2—20-year license extension granted December 2005

As noted above, each nuclear power plant will undergo another evaluation at the end of the 20 year license extension as to whether another life extension makes sense technically and economically or whether next generation nuclear plants or other energy sources may be better options. The federal Nuclear Regulatory Commission will also have to start providing direction on this issue in the next 15 years.

If policy-makers were to commit to reducing CO_2 emissions 80 percent from 1990 levels by 2055, current nuclear capacity makes the following contributions under four 50-year scenarios for the region's electricity sector: business as usual (BAU), high energy efficiency (EE), high renewable (Renewable) and high coal with carbon capture and storage (Coal). Based on a PTP stakeholder decision, nuclear energy was held constant in all four scenarios done by the University of Minnesota and represented here.

High Carbon Scenarios



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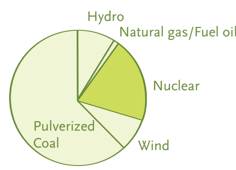
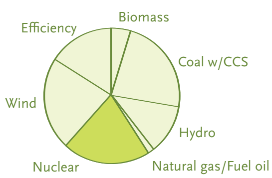
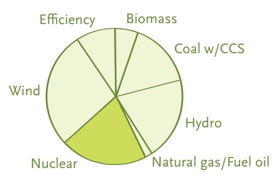


Business as Usual

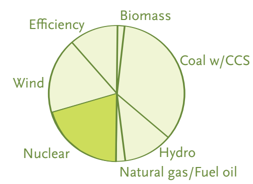
Low Carbon Scenarios



Energy Efficiency



Renewable



Coal

	2005	BAU	EE	Renewable	Coal
2055 Total Electricity (million mWh)					
	374	521	439	471	462
Cost per mWh					
	$30	$42	$51	$49	$51
Cumulative 50-year spending on Electricity ($ billion)					
		$771	$743	$775	$779

4.0 Measurable milestones for nuclear power

There are no specific numeric targets or milestones identified at this time for developing additional nuclear power in the region.

5.0 Key challenges and barriers

According to a 2003 interdisciplinary study by MIT, nuclear power faces the following challenges:[5]

5.1 Cost. In deregulated markets, new nuclear power is not now cost competitive with coal and natural gas. The energy model suggests that if cost were the only factor considered, nuclear power appears to be slightly less expensive than coal gasification with carbon capture at $47.55 /MWh vs. $49.49/MWh (the model uses Energy Information Administration estimates).[6]

Compared to a new super-critical pulverized coal plant, a new nuclear power plant is estimated to be at least twice as capital intensive, although cost estimates for the new generation of nuclear plants have not been completed. However, plausible reductions by industry in capital cost, operation and maintenance costs, and construction time could reduce the gap. Carbon emission credits, if enacted by government, can also reduce the cost difference for nuclear power.

5.2 Safety. Modern reactor designs may be able to achieve very low risk of serious accidents, but "best practices" and standardization in construction and operation are essential.

5.3 Waste. Geological disposal is technically feasible but execution is yet to be demonstrated or certain. A convincing case has not been made that the long-term waste management benefits of advanced, closed fuel cycles involving reprocessing of spent fuel outweigh the nuclear proliferation risks and costs. Improvement in the open, once-through fuel cycle may offer future waste management benefits as large as those claimed for the more expensive closed fuel cycles. Until a depository is licensed, improvements will not be developed.

5.4 Negative public perceptions of nuclear power. A survey conducted by MIT as part of its 2003 Study on the *Future of Nuclear Power* concluded that "a majority of Americans and Europeans oppose building new nuclear power plants to meet future energy needs." Additional survey research by MIT revealed that opposition by the public is based mainly on concerns about nuclear power's waste, safety and cost.

6.0 Strategies

GPI and PTP participants have not devoted much time to the subject of nuclear power for several reasons: the challenges faced by the technology and the industry generally require action at the federal level; states such as Minnesota have a moratorium on new nuclear power plants; the region's utilities have not identified new nuclear generation capacity as a short- to medium-term option (only seeking relicensing of existing facilities); and it does not appear that we could obtain consensus in the region on new nuclear power today. Citizens at several of our town hall meetings identified new nuclear power as an issue that needs to be addressed over the next several years so that our region's decision-makers know whether nuclear energy should be an option in a future carbon-constrained world.

Thus, this roadmap does not include any specific strategies for encouraging or discouraging additional nuclear power. Instead, this chapter attempts to shed light on those issues that need to be addressed and resolved in order for nuclear power to play any larger role than it currently does in the region's energy mix.

Additional Sources of Information

> U.S. Nuclear Regulatory Commission: http://www.nrc.gov/

> United States Department of Energy, Office of Civilian Radioactive Waste Management: http://www.ocrwm.doe.gov

1. Nuclear Energy Institute. http://www.nei.org.
2. *2004 Annual Report, Federal Program for the Management of High-Level Radioactive Waste.* Minnesota Environmental Quality Board. http://www.eqb.state.mn.us.
3. Nuclear Energy Institute. http://www.nei.org.
4. Nuclear Energy Institute. http://www.nei.org.
5. 2003. *The Future of Nuclear Power.* Massachusetts Institute of Technology. http://web.mit.edu/nuclearpower/.
6. Energy Information Administration. http://www.eia.doe.gov/cneaf/nuclear/page/nuc_reactors/reactsum.html.

Biomass

Biomass: Organic matter available on a renewable basis. Biomass includes forest and mill residues, agricultural crops and wastes, wood and wood wastes, animal wastes, livestock operation residues, aquatic plants, fast-growing trees and plants, and municipal and industrial wastes.

1.0 Introduction

Prior to the widespread adoption of coal as a source of energy during the industrial revolution, the majority of our energy supply came from of biomass. Animals, powered by the plants they ate, transported us and performed farm labor now done by diesel-powered tractors. Our homes were heated by wood and other organic matter.

Until very recently, the modern world relied on oil and other fossil fuels as the chemical "toolkit" for producing most of our energy and a vast array of goods. At their simplest, these fossil fuels are very old, fossilized plant matter. They formed from the remains of plants and animals deposited millions of years ago. Once buried, compressed and heated by geologic processes, this plant matter changed physically and chemically to yield today's carbon-based oil, coal and natural gas.

Today, policy-makers, entrepreneurs and researchers alike are looking to above-ground plants as a renewable, potentially CO_2-neutral (or even CO_2 reducing) alternative that is domestic, secure and environmentally superior. In fact, there is more consumption today of energy in the United States from biomass than from any other source of renewable energy. The largest uses of biomass today are:

- residential, commercial and industrial heat, mostly from burning wood and wood waste;
- ethanol production from corn, typically blended with gasoline; and
- electricity production, mostly from wood and wood waste.

In the near future native grasses and other forms of biomass could eventually serve as the raw material for "biorefineries" that, like petroleum refineries today, produce a range of energy products, chemicals and materials. Policy makers in agricultural regions like the Upper Midwest have an enormous opportunity to help farmers add these to the list of valuable products they deliver to society.

2.0 Objectives for a biomass transition

Although it appears unlikely that the main contribution of biomass will be in the electric power sector, biomass holds great potential as part of a comprehensive regional energy transition toward renewable and low- or zero-carbon options. Below are five objectives that should guide increased reliance on biomass for energy and products:

2.1 Maximize the economic and environmentally sustainable uses of biomass.

2.2 Reduce the energy, carbon and water-use intensity of biomass production and conversion.

2.3 Demonstrate and commercialize a wide range of biomass technologies to allow biomass to compete with fossil fuels in multiple markets.

2.4 Facilitate increased use of terrestrial carbon sequestration through research, demonstration projects, and establishment of market rules and policy incentives.

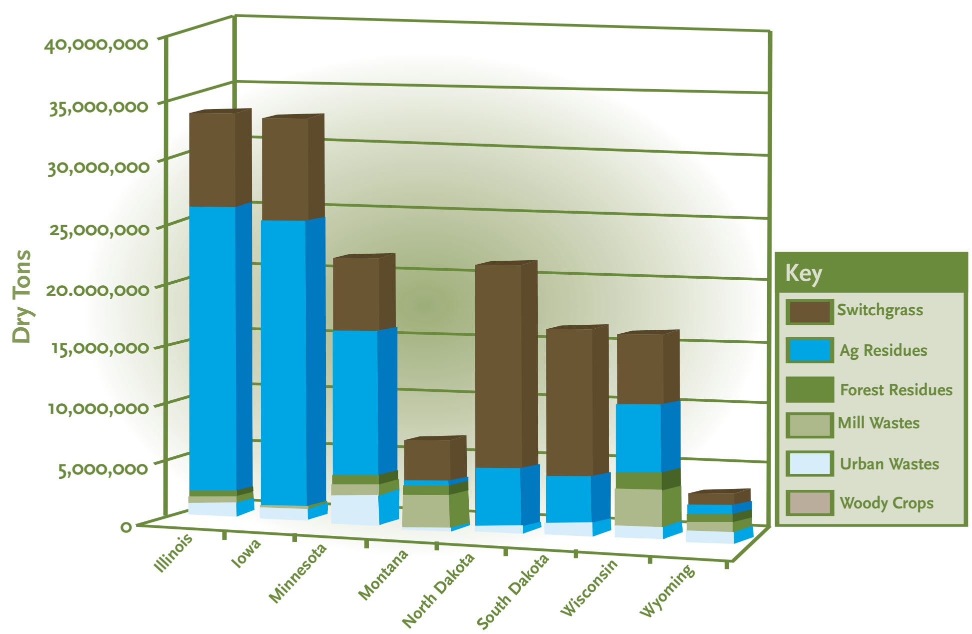
2.5 Become a net exporter of bioenergy and bioproducts.

3.0 Potential Contribution of biomass to the region's energy sector by 2055

Biomass is an abundant resource that is relatively flexible in its application. It can be used to replace energy in the form of liquid fuels, natural gas, or electricity, or to replace chemicals currently made from petroleum. The relative proportions of biomass that will replace the various energy carriers or chemicals will depend on economics and technology, but it is likely that biomass will play a role in all sectors.

3.1 Overall Biomass Resource. A 1999 paper by Marie Walsh summarizes the efforts of researchers around the country to estimate biomass supply from various materials. The researchers at the time estimated that the United States could supply more then 500 million tons of biomass per year, and more than 120 million tons could come from the Northern Great Plains (see Figure 1). A 2005 study, dubbed the Billion Ton Study, conducted by the U.S. Departments of Energy and Agriculture found that the annual supply could feasibly approach 1.3 billion without significantly disrupting food production and other agricultural uses of land. The numbers in Figure 1 are therefore a conservative estimate of total biomass potential in the region.

FIGURE 1: Annual supply of biomass at $50 per ton or less from forest residue, mill residues, agricultural residues, energy crops, and urban wood waste by state, in dry tons.[1]



3.2 Electricity. Biomass, with the right technology, can replace any type of fossil fuel. To replace coal, biomass can be burned or gasified. Burning biomass is its most common use today, primarily for home heating, but also for electricity. For instance, the wood and paper products industry burns waste wood to produce electricity and process heat. Biomass can be mixed with coal and burned in a power plant, a process called "co-firing." The Chariton Valley Biomass Project in southern Iowa is a demonstration project that co-fires switchgrass and coal. Other countries are co-firing biomass and coal in more advanced coal facilities that gasify the feedstocks and burning the resulting "syn-gas" to turn turbines and produce electricity. Some researchers at Princeton University estimate that, with carbon capture and storage, a certain percentage of biomass (somewhere over 20–25%) blended with coal could produce energy with net negative carbon emissions.

3.3 Liquid Fuels. Corn ethanol is a rapidly growing liquid fuel. Production in 2005 was more than 4 billion gallons,[2] enough to replace about 15% of regional gasoline and diesel use,[3] and using about 26% of the regional corn crop.[4] At current rates of growth, the ethanol industry will double by 2010,[5] presumably producing more than 8 billion gallons of ethanol and using more than half of the region's corn supply. Federal incentives, a federal Renewable Fuels Standard and state policies all encourage corn ethanol production.

Technical and economic limits exist to the supply of corn ethanol, and we clearly cannot satisfy our liquid fuel demand from corn ethanol alone. Cellulosic biomass—feedstocks from the woody part of the plant rather than the seeds—has the potential to greatly increase the supply of renewable liquid fuels. If all of the biomass estimated in the analysis in Figure 1 were used to produce cellulosic ethanol, it would produce more than twice current corn ethanol production and supply half of current regional liquid transportation fuel consumption

3.4 Natural gas and heat. Biomass can also replace natural gas through a technology called gasification. Gasification is a thermo-chemical process that converts biomass into carbon monoxide and hydrogen. This gas can be transformed into a natural gas substitute, or used as the precursor to other chemicals, including synthetic diesel and alcohols like ethanol. Two ethanol plants in Minnesota that rely heavily on natural gas are installing biomass gasifiers that will eventually replace much of their natural gas consumption.

Biogas, a product of anaerobic digestion of manure, can be a source of heat, electricity, and hydrogen for use on the farm. For example, the Haubenschild Farm in Princeton, MN[6] uses manure from a 1,000 cow operation to produce methane that fuels a Caterpillar diesel engine, which in turn provides heat and power for the entire dairy operation while selling electricity to East Central Energy.[7] In addition to displacing fossil heat and power, digesters can play an important role in manure and odor management systems.

Biomass is currently widely used as a source of heat in residential applications such as fireplaces and woodstoves and as a source of industrial heat, particularly in the wood and paper products industry. Biomass could be used for heat in other applications as well and could be used more efficiently where it is now used. The use of biomass pellets could further improve efficiency by improving the transportation economics of biomass distribution and also allowing for the use of high-efficiency pellet stoves.

3.5 Bio-based Products. Biomass can replace a multitude of chemicals, plastics and other non-energy products that are currently manufactured from petroleum. Wal-Mart's decision to begin using only plastic bags manufactured from corn-derived PLA (poly-lactic acid) plastic represents a high-profile example of this trend and its future potential in the marketplace.

3.6 Biomass contribution to CO_2 reduction and other environmental goals. The extent to which biomass helps achieve broader environmental goals depends to a large degree on how it is produced. Biomass can be produced in a way that degrades soil, decreases wildlife habitat and causes water pollution. It can also be produced in a way that improves soil, increases wildlife habitat and improves water quality. Replacing the equivalent of one third of current petroleum consumption with biomass will mean placing many tens of millions of acres of land into production of biomass crops. Whatever positive or negative impacts the production methods have, they will be magnified over many millions of additional acres. It is crucially important that any strategy for increasing the use of biomass assures that the biomass is produced in a way that enhances soil health, maintains wildlife habitat and recreational opportunities, and improves water quality.

Biomass can have an impact on greenhouse gas (GHG) emissions in two ways. The first is by replacing fossil fuels. Biomass is plant material and grows by capturing carbon dioxide from the air and transforming it into plant tissue through photosynthesis. When biomass is burned, that carbon dioxide is released back into the atmosphere. Biomass used for energy is said to have near zero net emissions of carbon dioxide, because it only re-releases carbon dioxide it initially captured during its growth cycle. When biomass energy replaces fossil energy, it replaces a net-carbon-emitting resource with a non-net-carbon-emitting resource.

Biomass can also reduce GHG emissions through terrestrial sequestration, a process in which plants store carbon underground in the form of roots, degraded plant material and soil. Typically not all of an energy crop is harvested. Crops such as switchgrass, big blue-stem or other grasses have extensive root systems. Although part of the plant is harvested, the root system continues to grow, capturing carbon from the air and storing it underground. This could help mitigate climate change by removing carbon from the atmosphere.

Various land management practices can play a role in sequestering atmospheric carbon dioxide and thereby reduce overall emissions. Ruttan Lal of Ohio State University argues that adoption of recommended management practices (RMPs) on soils of agricultural, grazing, and forestry ecosystems, and conversion of degraded soils and drastically disturbed lands to restorative land use, could lead to sequestration at an annual rate of 158–317 million tons of carbon per year,[8] or 582–1164 million tons of CO_2 equivalent. Since the United States emitted around 7,800 million tons of CO_2 equivalent in total GHG emissions in 2004, RMPs could offset 7–15% of U.S. emissions.

The same management practices that result in carbon sequestration are often associated with other benefits. No-till and reduced-tillage agriculture, for example, are associated with improved crop yields, better soil health and reduced soil erosion and run-off. It also reduces on-farm energy use and saves money for farmers.

Land management and biomass production can be paired together to increase the agricultural sector's total potential contribution to energy and climate solutions. Increased production of switchgrass, for example, would result in increased soil sequestration of carbon while replacing fossil fuels with renewable biomass.

In summary, biomass could replace one fourth of the region's total energy consumption without any advances in crop yields if all of the estimated supply were used. The economics of biomass are such that it can likely compete with fossil fuel under various circumstances. Many factors will determine whether biomass is used primarily to replace natural gas, electricity from coal, or petroleum. It will likely replace all of these conventional energy resources to varying degrees, depending on the relative costs of these resources compared to biomass feedstock alternatives and on the nature and pace of commercialization of biomass technologies.

Soil sequestration can displace a significant proportion of regional CO_2 emissions, although precisely how much is unclear. Given that the upper Midwest has a higher than average proportion of the nation's crop land and relatively less industry than other regions of the country, it is likely that terrestrial sequestration could offset more than 7-15% of current regional GHG emissions.

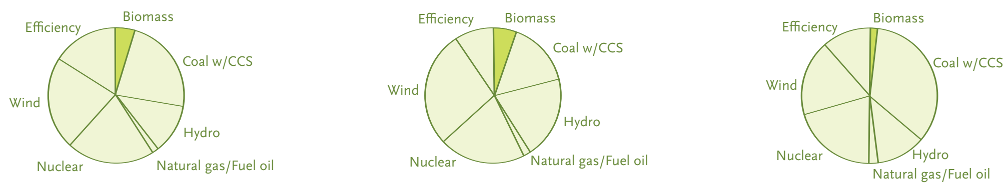
If policy-makers were to commit to reducing CO_2 emissions 80 percent from 1990 levels by 2055, biomass makes the following contributions under four 50-year scenarios for the region's electricity sector: business as usual (BAU), high energy efficiency (EE), high renewable (Renewable) and high coal with carbon capture and storage (Coal). These scenarios are based on modeling done by the University of Minnesota and GPI in partnership with PTP participants.

Since this scenario research deals only with the electricity sector, and the economics of biomass favor its use in the liquid fuels and gas sectors rather than the electricity sector, these scenarios represent only a small proportion of the region's biomass resource.

High Carbon Scenarios

2005 **Business as Usual**

Low Carbon Scenarios



Energy Efficiency **Renewable** **Coal**

	2005	BAU	EE	Renewable	Coal
2055 Total Electricity (million mWh)	374	521	439	471	462
Cost per mWh	$30	$42	$51	$49	$51
Cumulative 50-year spending on Electricity ($ billion)		$771	$743	$775	$779

4.0 Measurable Milestones

The following regional biomass energy milestones are proposed by PTP stakeholders for policy-makers' consideration:

By 2015:

- Biomass is 10% of total regional energy consumption:
  - > Twenty-five percent of vehicle fuels from biofuels;
  - > Commercialization of advanced cellulosic biofuel technologies; and
  - > Greater penetration of biomass into natural gas and electricity markets.
- Twenty-five percent of gas stations offer biofuels at high blends (E85 and B20)
- The region has established an efficient bio-based product procurement system for state governments.
- Biomass conversion technologies have been demonstrated on a variety of our region's most promising feedstocks.
- Commercial demonstrations of key biomass technologies in the region for a variety of biomass feedstocks, including the following:
  - > **Biomass combined heat and power systems:** When biomass is used to produce electricity, heat is typically a waste product. Utilization of waste heat can more than double the efficiency and can displace heat which is typically produced from natural gas.
  - > **Biomass IGCC:** Integrated Gasification Combined Cycle (IGCC) is the most efficient power production technology for biomass and can produce power more cheaply than other biomass technologies at large scale (greater than 50 MW). Biomass could be co-gasified with coal at various proportions as a way to displace coal use and reduce carbon dioxide emissions.
  - > **Cellulosic biofuels:** Where ethanol is currently made from corn, there are opportunities to use corn stalks, wood chips, switchgrass and other materials to greatly expand biofuels production.
  - > **Pipeline-quality natural gas** produced from biomass—particularly manure through anaerobic digestion—and integrated into the existing natural gas system. Also develop peak-load power generation from methane and other high-value products.
  - > **Pyrolysis** developed as a source of fuel and products. Pyrolysis can produce a low-quality liquid fuel that is a suitable and cost-competitive replacement for low-quality fuel-oil which is commonly used for home heating and power production. This oil may also become the feedstock for a bio-refinery which produces a number of higher-valued distillate products and/or a bio-char that is a good soil enhancement.

By 2025:

- Biomass is 25% of total energy consumption in the region:
  - > Twenty-five percent of vehicle fuels; and
  - > Significant use of biomass to replace natural gas and produce electricity.
- Fifty percent of gas stations offer biofuels in high blends.

By 2055:

- Replacement of 25% of total regional energy consumption with biomass.
- All gas stations offer biofuels in high blends.

5.0 Key Challenges and Barriers

A variety of barriers stand in the way of biomass replacing a significant portion of current energy consumption. These barriers include the relatively lower price of conventional fuels (the price of which does not include environmental damage or climate risk), immature technology (which translates into investment risk) and infrastructure and logistics issues (moving, storing and managing large volumes of bulky biomass).

5.1 Demonstration, commercialization and widespread adoption. Despite many years of research by the USDOE and others, many applications of biomass have not yet reached the demonstration or commercialization phase, or have not been adopted throughout the energy system.

5.2 Real and perceived investment risk. Many bio-energy technologies are near commercialization but still represent an unacceptable risk for many investors. Many technologies in the early stages of their development will have learning costs that do not exist for more mature technologies. The immature nature of bio-energy technologies presents a serious barrier to their widespread use. Until investors see "on the ground" demonstrations of technologies in the region, they will be unlikely to use that technology no matter how great the potential return.

5.3 Lack of infrastructure. There are a variety of infrastructure challenges for biomass:

- There isn't adequate E85 fueling infrastructure to provide E85 to the growing number of flex-fuel vehicles on the road.
- Infrastructure is needed for integrating biogas into natural gas systems, and bio-oil into fuel oil distribution systems.

5.4 Lack of experience with feedstock logistics. There are challenges with feedstock logistics all along the supply chain, including establishing, growing, harvesting, densifying, collecting, transporting, storing and pre-processing biomass.

5.5 Regulatory hurdles. Biomass technologies, despite their promise of improvements in a variety of environmental goals, are unknown to regulatory agencies. New projects will face regulatory challenges, and regulators will be challenged to keep up with new technologies.

5.6 The need for research. More research is needed to develop and refine advanced processing technologies for producing energy and products from biomass, to develop new crops and improved crops, to develop BMPs for energy crop systems, and to integrate biomass production with other environmental goals.

5.7 Public Acceptance. The public must be satisfied that development of the region's bioeconomy is beneficial for the economy and the environment.

6.0 Strategies for increasing the use of biomass in the economy

Our region has already claimed the leadership role in bio-fuels development based on corn-ethanol and soy-diesel. Building on this success, states and provinces may consider the following additional strategies for accelerating and improving the effectiveness of energy efficiency investments.

6.1 Demonstration and Commercialization of Advanced Biomass Technologies. The most important step in taking full advantage of our biomass resources is helping processing and conversion technologies become commercial. Many technologies are near commercialization but pose too high a risk for the investment community. State and provincial policies could help mitigate risk and bring the next generation of advanced biofuels to market. Long-term support for projects should be encouraged until projects are profitable on their own. Incentives should be phased out when they are no longer needed.

6.1.1 Qualifying projects: In seeking to assist in the commercialization of advanced biomass projects, governments should provide funding or incentives to projects meeting one or more of the following criteria:

- Projects using technologies and practices that are not already commercial technologies or well-established practices.
- Projects using cellulosic biomass in novel ways to produce energy in any form—liquid fuels, gas, heat, or electricity—or new biobased products.
- Projects that expand the range of valued added products from conventional facilities, including producing new types of fuels in conventional biofuels plants.
- Projects that otherwise seek to demonstrate or commercialize a new use of any biomass material to produce energy or high value products.
- Projects that allow innovative pairings with other renewable energy resources.
- Where possible, public financing should go to projects that have a local ownership stake and include some promise of local hire, improved local wages and a commitment to worker training.

6.1.2 Capital: Governments and local economic development agencies should provide assistance in the form of capital cost share, loan guarantees, revolving loan funds and Industrial Development Bonds to projects qualifying as advanced or cellulosic biofuels. This assistance could be structured as a revolving fund or multi-year production incentive.

- State and provincial governments should not provide all project funding, assuring that investors share the risk.
- Industrial Development Bonds could also be granted for projects meeting advanced and cellulosic biomass project criteria.
- Governments and local agencies should look for ways for the farm credit system to get more involved in biomass projects.

6.1.3 Subordinated Debt: Governments should offer subordinated debt in order to lower risk to advanced and cellulosic biomass projects.

6.1.4 Incentives: State and provincial governments should provide incentives for the production or purchase of advanced or cellulosic biofuels by all consumers, or for the production or purchase of cellulosic biomass by various energy users, for instance:

- Extending existing incentives to advanced biofuels;
- Considering shifting corn ethanol incentives to cellulosic ethanol;
- Applying incentives broadly to promote the use of cellulosic biomass to replace liquid fuels, natural gas, heat, and electricity; and/or
- Tying existing tax exemptions for manufacturers' energy bills specifically to their use of biomass.

6.1.5 Regulatory barriers: New technologies can deliver environmental benefits but often do not fit neatly into regulatory categories. Many demonstration projects have been delayed because regulatory agencies lack familiarity with new technologies, fuels and production systems. Governments and local regulatory agencies can help by:

- Developing permitting rules for emerging technologies. Permitting authorities should be educated about types of projects, including obtaining and standardizing data.
- Finding ways to exempt or streamline novel demonstration projects from the conventional regulatory process to allow experimentation without creating a dangerous precedent. In order to avoid dangerous precedent, this should be developed such that:
    - > Only qualifying projects should receive exemptions, and only if they are the first project of their type in the state;
    - > State regulatory agencies have the authority to grant or deny such exemptions; and
    - > Regulatory exemptions are structured as limited-time grace periods to get projects started. They may also only allow exceptions for projects below a certain size.
- Making the Power Purchase Agreement process more consistent and transparent.
- Promoting innovative pollution control strategies that improve the overall environmental characteristics of the plant—including energy, fossil, and materials balance.
- Seeking to create regional consistency in the regulation of advanced biofuels facilities.

6.1.6 Local Ownership: Recognizing that outside money will play a role in the development of a new generation of advanced biofuels, efforts should be made to ensure that the benefits of these facilities accrue to public and private entities in the communities containing them. For example, governments and local regulatory agencies can:

- Provide loans for equity capital similar to the Minnesota Stock Loan Program or other agricultural bond programs.
- Allow co-ops, municipal utilities, and other local and community-owned entities to have bonding authority to fund biomass projects.
- Include a preference for the highest level of local ownership practicable when public investments are used.

- Develop structures that make it easier to have many small investors so that the regulatory costs associated with securities filing are less burdensome for small projects.

6.2 Developing a Perennial Biomass Supply. Of all potential sources of cellulosic biomass, perennials crops such as switchgrass and other native grass mixtures, as well as short rotation woody crops such as hybrid poplar and willow, represent the biggest opportunity to improve soil, water, wildlife and agricultural energy efficiency benefits while generating a potentially significant biomass resource. Because of the synergies between farm economics, biofuel production and environmental objectives, any biofuels policy should encourage the development of a perennial biomass supply. State and provincial decision-makers should consider:

- Providing producer incentives for the production of perennial energy crops.
- Expanding programs that pay landowners for planting perennial grasses for water quality and wildlife purposes to include perennial biomass development so long as it doesn't take away from other program objectives.
- Recruiting energy crop acreage based on proximity to a proposed or existing plant.
- Accompanying perennial biomass demonstration projects with research evaluating the impact of these projects on farmer income, wildlife, soil, water and GHG flux. Projects should seek to maximize benefits in these areas.
- Creating programs to offer crop insurance to producers that want to grow perennial energy crops that are not covered by current crop insurance programs.
- Leading collaborative efforts to develop and implement energy crop demonstration programs.

6.3 Bio-based Product Procurement. As part of the 2002 Farm Security and Rural Investment Act, the USDA was required to create a comprehensive program for designating bio-based products. In addition to creating a list of products, federal agencies are required to purchase bio-based product provided that they are available and near cost-competitive with their fossil-based equivalent. This program can play a crucial role in raising awareness about, and developing markets for, new bio-based products. High value non-energy products can play a key role in improving the profitability of plants producing bio-fuel, just as the sale of bulk chemicals improve the profitability of oil refineries. State and provincial decision-makers should consider:

- Adopting bio-based product procurement rules at the state level. They may decide to simply adopt the federal rules and the federal list of bio-based products.
- Requiring state/provincial agencies, as with federal rules, to procure bio-based products provided that they are available and cost-competitive relative to the fossil-based equivalent.
- Making rules consistent across the region.
- Expanding the program further by creating a regional bio-based product certification program and promoting it through education and incentives for business participation.

6.4 Bringing Biofuels to Market. State and provincial governments can take various steps to ensure that there is market pull for biofuel facilities. Decision-makers should consider:

- Promoting renewable fuels standards that include specific carve-outs for advanced and cellulosic biofuels.
- Promoting development and production of highly efficient bio-fuel-powered vehicles.
- Creating market pull by expanding state government use of biofuels, including:
  - > Directing agencies to purchase high blend biofuels, such as E-85 and B-20 where available and appropriate;
  - > Creating interagency strategies to educate fleet managers and drivers about the goals, options and priorities pertaining to biofuel use;
  - > Establishing biofuels goals and measures for state agencies; and
  - > Developing and funding investment plans for appropriate state fleet infrastructure (i.e., E-85 and B-20 tanks where fleets have dedicated fueling stations).
- Considering retail tax incentives that encourage retailers to sell biofuels and bio-based products.
- Providing incentives or standards that increase the number of gas stations selling biofuels, particularly high blends such as E85 and B20.

6.5 Technical Assistance. Adopting new technologies will be challenging, but governments can assist in many ways. States and provincial decision-makers should consider:

- Providing funding for Front End Engineering and Design (FEED) studies, and other feasibility studies for advanced biomass projects.
- Providing business planning assistance and mentoring.
- Expanding technical assistance capabilities and funding in the following areas at the state and regional level, including: Cooperative Development Centers, State Departments of Agriculture, Universities (including Extension and RC&Ds) and State Energy Offices.

6.6 Overcoming the Difficulty of Feedstock Logistics. Although there is an enormous potential supply of biomass in the Midwest, there will be tremendous challenges in growing, harvesting, collecting, transporting, storing and processing it. Overcoming logistical challenges will be a precursor to the development of a prosperous bioeconomy. As we move forward, both producers and commercial and custom harvesters will need to develop experience in developing a feedstock supply. States and provincial decision-makers should consider:

- Funding a detailed state-level resource assessment evaluating the availability, location and likely cost of various types of biomass.
- Developing plans for maintaining a supply of biomass in the event of droughts or crop failures.

- Using Extension Service, Resource Conservation and Development Districts (RC&Ds), Soil and Water Conservation Districts, and Agronomic Co-ops to provide technical assistance for feedstock logistics.
- Providing dedicated funding to demonstration projects as they seek to develop a sustainable biomass supply, including providing funding and assistance to local governments and communities that want to do a biomass resource assessment.
- Providing incentives (grants, tax exemptions, low interest loans) for the purchase of harvesting equipment for biomass crops, equipment for switching to conservation tillage for conventional crops, and other equipment for harvesting and collection of biomass.
- Funding research evaluating the sustainability of crop and forestry residue removal and developing BMPs for sustainable residue removal. Guidelines must be created to assure that soil and water health are protected.
- Funding applied research on feedstock logistics from field to plant in order to develop more efficient methods.
- Leading energy crop pilot projects using existing boilers to build practical, on-the-ground experience using local energy crops.

6.7 Basic and Applied Research on Crops and Conversion Technologies. There are currently technologies that are near commercialization or already commercial, and appropriate biomass crops that could be better utilized, yet we have only caught a glimpse of the bioeconomy's potential to deliver energy, products, and various ecosystem services. We have the knowledge to create energy from some biomass crops, but there is research that still needs to be done. State and provincial decision-makers should consider:

- Emphasizing collaborative on-farm research and demonstration projects.
- Working with state universities to form interdisciplinary centers on the bioeconomy and developing strategic plans to target university resources to this challenge.
- Funding basic and applied research on biomass crops, germplasm development and conversion technologies.
- Funding research on advanced cropping systems, including native grass mixtures, and long-term studies on the impact of biomass crops on soil, water quality and wildlife. Studies should also evaluate the long term impact of crop and forestry residue removal on soil, water quality and wildlife
- Accelerating research on utilization of by-products from the existing biofuels industry.
- Conducting studies to evaluate the appropriateness of feedstocks for various climates, soil types and inputs.
- Supporting lifecycle assessments of various technology and product options.

6.8 Workforce Development. A new generation of workers must be trained to build and operate the new bioeconomy. This will require skilled workers in nearly every imaginable field being engaged in this challenge. State and provincial decision-makers should consider:

- Creating workforce development programs that create collaboration between industry, state/provincial government, and educational institutions. Subsidies and incentives should be targeted to companies dedicated to participation in these programs.
- Evaluating state universities, technical and community colleges, high schools, and other secondary and post-secondary institutions curricula and making and implementing recommendations for incorporating the bioeconomy into their curricula.
- Encouraging Extension, RC&Ds, Agronomic Co-ops, soil and Water Conservation Districts, agribusiness providers and other institutions to play a strong role in providing information and training to the agricultural industry interesting in producing, selling and marketing bioenergy crops.
- Educating local financial institutions about potential biomass technologies.

6.9 Public Education. We need to educate public leaders, farmers and the general public about the benefits and realities of the bioeconomy. As state and provincial decision-makers construct a public education campaign to sell the bioeconomy to the public, they should consider:

- Educating legislators, government officials and their staff about process technologies and feedstocks.
- Developing a curriculum on the bioeconomy and conducting teacher workshops to get teachers at all levels familiar with the bioeconomy.
- Promoting biofuels through radio, TV, internet, and newspaper coverage and through paid advertisements in these venues.
- Making grants available that allow organizations to do public education and promote state goals with respect to bioeconomy development.
- Encouraging extension, youth programs like 4H and FFA, primary and secondary institutions, and other state institutions to provide education about the bioeconomy.

6.10 Regional Recommendations. Many of the recommendations included here should be done regionally to ensure a level playing field for business throughout the region and to learn from the successes and mistakes of others.

- Departments of Agriculture and Land Grant Institutions should establish a vehicle for collaborating on bioeconomy goals throughout the Midwest.
- There should be a regional catalog of available resources for those interested in beginning projects. This should include resources from Extension, federal laboratories, Departments of Agriculture, private industry, utilities, RC&Ds and international sources of information.
- Regional governments and institutions should collaborate to develop consistent regional “asks” for federal policy and funding.

- Regional regulators (including Departments of Natural Resources and Pollution Control Agencies) need a venue to discuss innovative models and regulatory needs.

6.11 Greenhouse Gas (GHG) and Water Credit Trading. There are opportunities to create increased income for land-owners through the sale of carbon, renewable energy and water credits. This system in turn encourages biofuels production and use and has the potential for significant reductions in regional greenhouse gas emissions and improvement in water quality. The region should take the following steps to assure that the region has opportunities for additional revenue through the development of systems for environmental credit trading:

- No policies recommended in this document should prevent landowners from selling permits or credits for legitimate, demonstrated sequestration of carbon in soils or for improvement in water quality.
- States should facilitate the trading of carbon, renewable energy and water credits.
- There should be a regional program to evaluate the potential for agricultural and forestry sequestration.
- There should be a regional carbon credit registry system.
- The region should strive for continuous reductions in the GHG profile of biofuels.
- Research should be performed to better understand the GHG impact of various biofuels technologies and biomass crop production systems.

Additional Sources of Information

> National Renewable Energy Lab. http://www.nrel.gov/biomass/

> Oak Ridge National Lab. http://www.ornl.gov/

> United States Department of Energy, Office of Energy Efficiency and Renewable Energy, Biomass Program. http://www1.eere.energy.gov/biomass/

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Hydrogen, Fuel Cells and Related Technolgies

1.0 Introduction

Hydrogen is widely considered to be the ultimate zero-carbon replacement for oil and gas in a global economy increasingly hungry for more energy of all kinds.

Photograph courtesy of Manitoba Energy Development Initiative.

Hydrogen hybrid ICE-electric bus cold-weather tested in Winnipeg, Winter 2005.

Growing concerns over energy security, economic stability and the air and climate impacts of conventional fossil fuels have led companies and governments around the world to invest billions of dollars in pursuit of an energy system in which electricity and hydrogen are two of society's main ways of storing and moving energy.

Indeed, hydrogen represents what many see as the logical conclusion of an energy evolution in which people have gone from using carbon-rich fuels such as wood and coal to less carbon-dense energy sources such as oil and natural gas. Since hydrogen contains no carbon, say proponents, it is the final destination along this evolutionary path, particularly in a world increasingly concerned over the CO_2 released from conventional fossil fuels.

Hydrogen (H_2) molecules are thought to make up 70 to 90 percent of the universe and can offer an inexhaustible supply of fuel for everything from vehicles and buildings to laptops and cell phones, once it is released from substances such as water, biomass or other hydrocarbons such as coal. Indeed, it is fitting that hydrogen makes up the final chapter of this roadmap because it can be produced using any of the other energy sources discussed.

The debate about hydrogen

Is hydrogen the best way to replace foreign oil and reduce greenhouse gas emissions, or is it an expensive distraction from higher priority investments in greater energy efficiency, more renewables on the grid, biofuels and plug-in hybrid vehicles? This is the debate in which hydrogen finds itself.

A report from researchers at UC Davis notes that depending on how hydrogen is produced and delivered, greenhouse gas emissions could either become 80 percent worse or 100 percent better than today[1]. This underscores that hydrogen is only as clean as its production method and source, and today 95% percent of it in the United States is made from natural gas. Natural gas-derived hydrogen may be a sensible bridging strategy, but hydrogen will only be worth pursuing if it permanently resolves concerns over air pollution and CO_2 emissions, which the right combination of renewable and carbon-neutral hydrogen production can.

But if hydrogen is ever to play a significant role in the energy system, then work on the transition must begin now, alongside aggressive deployment of other low- and zero-carbon options. Greater efficiency, more renewable electricity, flexible-fuel vehicles, biofuels and plug-in hybrids can all work together with hydrogen and fuel cells. Instead of viewing particular low- and zero-carbon options as competitors, we need to see them as critical and complementary technological steps on the path toward a cleaner, more secure energy system.

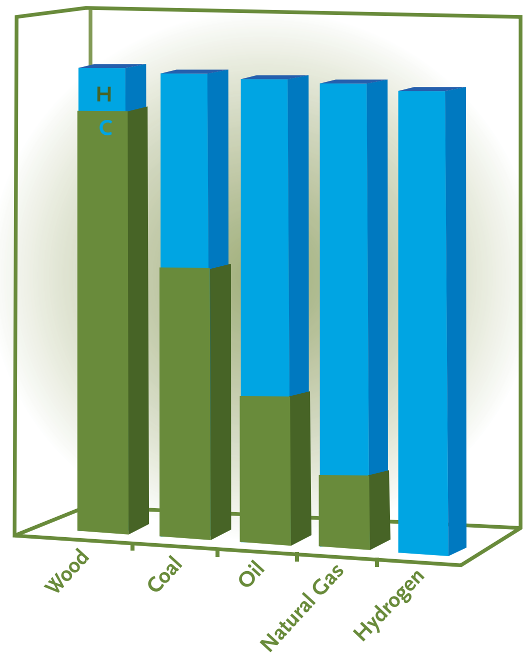
If the nation is to achieve a reliable and inexhaustible domestic energy system—in which electricity and hydrogen are main energy carriers—then renewable and carbon-neutral energy *sources* are a prerequisite.

Although it is abundant, hydrogen is nearly always bound with something else and does not occur naturally in its elemental form. For this reason, hydrogen is considered an energy "carrier" rather than a direct source of energy. Like electricity, hydrogen is a way of storing energy and then using it when and where you want to. And, like electricity, one might think of it as a form of energy currency or a medium of energy exchange. In fact, hydrogen and electricity are considered interchangeable because you can produce one with the other: electricity can be used in a process called electrolysis to split water into its constituent parts, hydrogen and oxygen; hydrogen can, in turn, be used in a fuel cell or generator to produce electricity.

To understand why hydrogen is a "carrier" of energy and not a primary source of it, imagine how difficult it would be to mount a wind turbine on your car as its power source. But you *could* use the electricity generated by a wind turbine to separate water into hydrogen and oxygen and then use that hydrogen to power your car. Hydrogen becomes the "carrier" of wind energy, and wind *indirectly* powers your vehicle.

Fuel cells unlock hydrogen's potential. Fuel cells are a key enabling technology for turning hydrogen into useful electricity and heat. They essentially run the process of electrolysis in reverse by combining oxygen and hydrogen to produce electricity, heat and water vapor (see diagram at right).* Fuel cells are like batteries in that they produce power through a chemical reaction rather than by combustion, which makes them roughly twice as efficient as combustion engines. As long as fuel is supplied, the fuel cell will continue to generate electricity.

Ratio of Carbon to Hydrogen Atoms



Carbon content of fuels has been steadily decreasing. Graphic shows ratio of carbon to hydrogen atoms.
Source: www.sustainability.ca

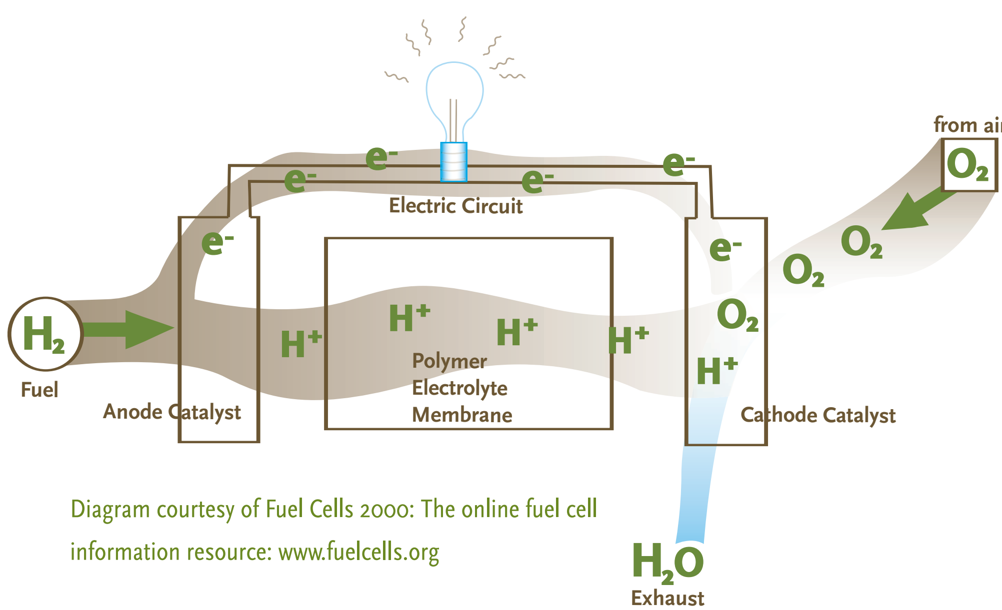


Diagram courtesy of Fuel Cells 2000: The online fuel cell information resource: www.fuelcells.org

*. According to the U.S. Department of Energy (USDOE), hydrogen fuel cell vehicles emit approximately the same amount of water per mile as conventional vehicles powered by internal combustion engines.

Why hydrogen?

- It is domestic and essentially inexhaustible since it's found in water and organic matter.
- Promises potential "peace dividend" since every nation could produce its own.
- Essentially pollution-free if produced with renewable and climate-friendly methods.
- Colorless, odorless, non-toxic and as safe or safer than conventional fuels in most situations.
- Can be used like conventional fuels are today and produces only heat, electricity and water vapor when used in battery-like fuel cells.
- Could replace essentially all gasoline and eliminate almost all CO_2 emissions from the transportation sector.

Hydrogen works well in conventional engines too[2]

Burning hydrogen is nearly pollution-free and vastly cleaner than burning traditional fossil fuels. Hydrogen burns up to 25 percent more efficiently in internal combustion engines than gasoline. Engines burning pure hydrogen produce only water, very low quantities of nitrogen oxides and trace amounts of carbon monoxide and volatile organic compounds from the engine oil. There are no carbon dioxide emissions. A number of automakers, including Toyota, Ford and BMW, have demonstration vehicles that burn pure hydrogen in internal combustion engines. BMW plans to start production of such vehicles in limited numbers by 2008.

2.0 Objectives for hydrogen-related development in the region

Hydrogen, fuel cells and related technologies hold enormous promise for the Upper Midwest, but realizing this promise will require public and private commitment over an extended period of time. To ensure that hydrogen development proceeds as quickly and sensibly as possible, the region should pursue the following key objectives:

2.1 Identify and capitalize on early niche markets for hydrogen, fuel cells and related technologies. For fuel cells this means supporting early deployment in the most promising markets, such as transit and airport vehicles, fork lifts, grounds-keeping and other off-road vehicles, as well as for emergency and back-up power. For hydrogen this means identifying the most commercially viable hydrogen production options and end-uses in each jurisdiction and supporting research, development and deployment of those technologies. The characteristics of these early market opportunities are that hydrogen and/or fuel cells fit easily into existing business models and solve problems for companies. For example, fuel cells that fit into the same space on a fork lift now occupied by lead-acid batteries, but deliver better performance and less down time. Or an integrated hydrogen and fuel cell package that out-competes the heavy "brick" batteries used by professional camera crews.

Does hydrogen production take more energy than it yields?

The short answer is yes, but the same is true for all fuels. The real question is whether or not the energy loss is worth it. To get the answer, it's instructive to look at electricity for a comparison:

We have to spend energy to produce electricity (approximately three units of fossil fuels to produce one unit of electricity) and there are additional losses in transmission and distribution.

Yet we use electricity because it is convenient, clean and relatively safe at the point of use, and can do things other forms of energy cannot (e.g., transmit energy and carry information without moving matter). As Chauncey Starr, founder of the Electric Power Research Institute, has put it, "**hydrogen's energy cost is secondary when its end-use is socially valuable enough to justify its cost.**"

For its part, hydrogen can be stored more easily than electricity, and can be used as a fuel and a chemical feedstock for many uses.

Both electricity and hydrogen:
- Can be produced from renewable and carbon-neutral energy sources;
- Provide a means of storing and moving these energy sources;
- Can be used in a wide variety of applications; and
- Are efficient and clean at the point of use.

As "carriers" of energy, hydrogen and electricity together could enable a permanent and inexhaustible energy system. Thus, whatever losses are incurred in their production must be weighed against the benefits of their use.

2.2 Establish hydrogen infrastructure to support those markets, based on each jurisdiction's hydrogen production strengths. Hydrogen by nature is expensive to move more than about 200 miles, so it will be important for each jurisdiction to evaluate and develop its local strengths in hydrogen production, whether from wind, biomass, solar, hydro-power, coal gasification (with capture and storage of the resulting CO_2) or some combination. This means encouraging the scale-up and testing of multiple hydrogen production options, and cross-jurisdictional cooperation on shifting away from a petroleum-only refueling infrastructure (see section 3.4.3).

2.3 Stimulate consumer demand through early education and outreach. Consumer acceptance of hydrogen technologies hinges on dispelling myths about them and effectively communicating how they fit in the larger energy system. Iceland's experience in building its first hydrogen refueling station underscores the value of early educational efforts. People welcomed the first hydrogen station there because they had already been well-educated on the pros and cons of hydrogen and fuel cells. Shell Hydrogen's experience in Washington D.C. offers a cautionary tale on the importance of early public education. Neighbors surrounding the D.C. hydrogen station were not well informed in advance and fought the project initially.

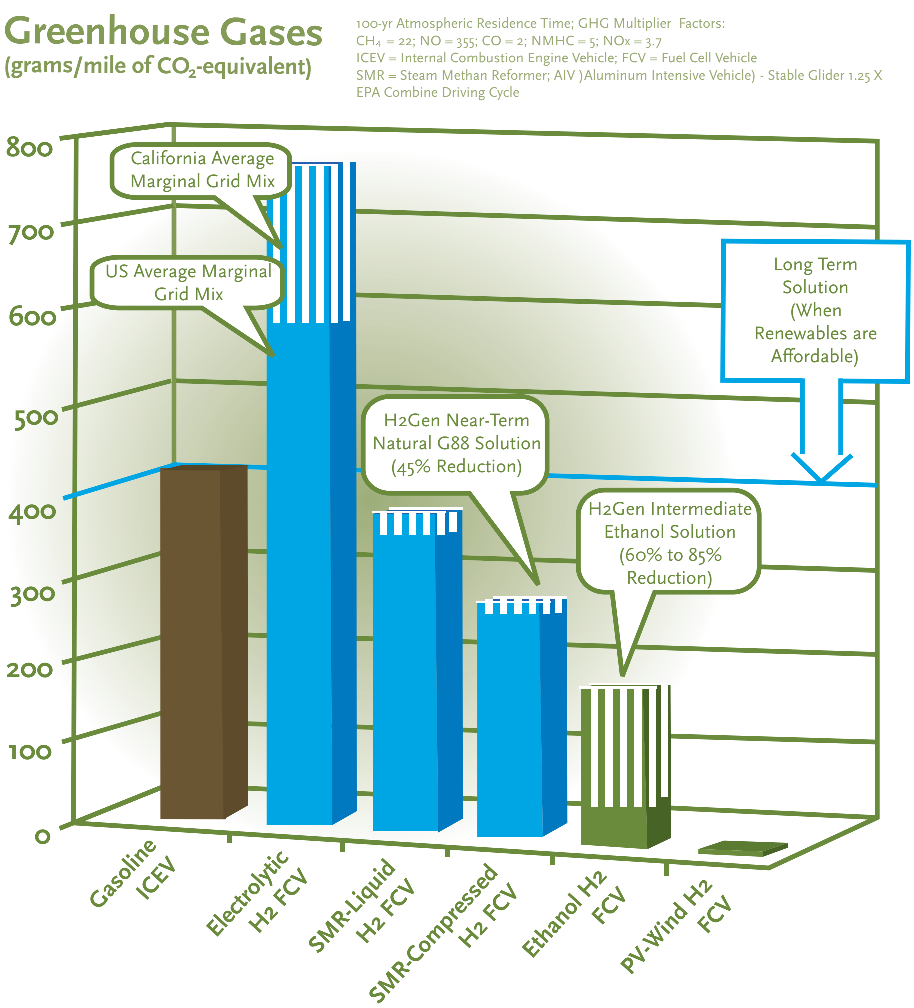
2.4 Expand the region's industrial base in hydrogen technologies. Minnesota has a small cluster of fuel cell components manufacturers and firms, such as Toro Company, beginning to incorporate hydrogen and fuel cells into their grounds-keeping vehicles. North America's largest bus manufacturer, Manitoba's New Flyer Industries, is participating in a number of hydrogen bus projects. North Dakota has one of the nation's first wind-to-hydrogen projects. Wisconsin has companies selling and installing fuel cells and developing novel hydrogen production technologies using inexpensive biomass feedstocks. Indeed, nearly every jurisdiction in the region has research and deployment efforts that could lead to an expansion of hydrogen technologies. These must be encouraged and supported at this formative stage of the industry, or we risk losing the economic development potential to other states, provinces and nations.

2.5 Explore hydrogen's potential for bringing additional renewable energy sources to market, either as electricity or as other products. This means everything from exploring hydrogen's potential to "store" wind power (as Xcel Energy and the National Renewable Energy Laboratory are doing in Colorado), to demonstrating the potential for making local anhydrous ammonia fertilizer using wind-generated hydrogen (via electrolysis of water) and nitrogen from the air, as the University of Minnesota is doing at its West Central Research and Outreach Center.

3.0 Potential contribution of hydrogen and fuel cells to the region's energy sector by 2055

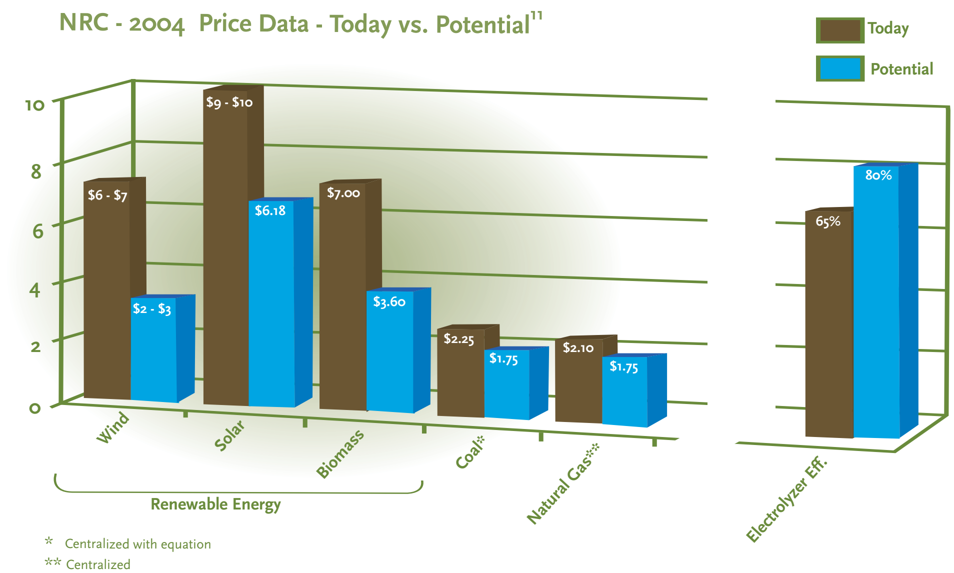
Hydrogen could provide electricity, heat and transportation fuel throughout the economy and can be used in virtually the same ways that conventional fuels are used today. But hydrogen will only make a meaningful contribution to improved public health and reduced CO_2 and other greenhouse gas emissions if the hydrogen is produced with and from renewable and carbon-neutral energy sources. As noted earlier, a report from researchers at UC Davis underscores that depending on how hydrogen is produced and delivered, greenhouse gas emissions could either become 80 percent worse or 100 percent better than today.[1]

The CO_2 Scenario Model that provides the analytical underpinnings of this roadmap does not include hydrogen and fuel cells (or any other novel technologies). The model includes only known costs for fully commercial technologies available today. Therefore, how large or small a contribution hydrogen, fuel cells and related technologies make to the region's energy system by mid-century is as much a matter of political will as technology or economics. That said, below is a brief overview of some of the ways that hydrogen and hydrogen technologies *could* contribute to a secure, sustainable and affordable energy system.



Estimated greenhouse gas emissions per vehicle for an advanced ICEV and an advanced FCV with five different sources of hydrogen. Source: C. E. (Sandy) Thomas, "An Affordable Hydrogen Entry Pathway, revised July 2005. ICEV means "Internal Combustion Engine Vehicle" and FCV means "Fuel Cell Vehicle"

Goal is Hydrogen Made From Renewable & Carbon-neutral Energy Sources



3.1 How is hydrogen used today? Hydrogen has been used since the late 19th century, when people burned a mixture of hydrogen and carbon monoxide called "town gas." Today, the United States produces roughly 9 million tons of pure hydrogen per year, all but 5% of which is used on-site for oil refining or fertilizer production. In its super-cold liquid form, hydrogen powers unmanned rockets and the space shuttle. It is also used onboard the space shuttle in alkaline fuel cells that provide astronauts with electricity and potable water.

3.2 What can hydrogen be derived from? Hydrogen can be derived from water, biomass, or from fossil fuels. Indeed, one of hydrogen's key strengths is that is can be produced from so many different sources in so many ways, and at a variety of scales, from large centralized plants and regional depots to corner filling stations.

Assuming that hydrogen joins electricity as one of the world's premier energy carriers, there is near-universal agreement that it must eventually be produced using renewable and carbon-neutral energy sources. Below is a brief survey of some of the most promising options.

3.2.1 Hydrogen from biomass. Hydrogen can be derived from a wide range of plant matter and other organic wastes, commonly called "biomass." Gasifying biomass produces a synthetic gas of mostly carbon monoxide and hydrogen. When reacted with steam the process converts the carbon monoxide to carbon dioxide and produces even more hydrogen from the steam.

Biomass can also be made into liquid fuels, such as ethanol, biodiesel or bio-oil. These fuels can be more easily stored and transported than hydrogen and reacted with high-temperature steam to produce hydrogen at or near the point of use.

Another source of bio-hydrogen is the methane produced by anaerobic digestion of manure and at landfills and wastewater treatment facilities. Fuel cells have been installed at many such sites to take advantage of the methane they produce.

Wisconsin-based Virent Energy System, Inc. has developed a unique Aqueous Phase Reforming (APR) process that may prove to be a cost effective method for low temperature production of hydrogen and/or fuel gas from a wide range of waste biomass. The APR systems can be designed to deliver predominantly hydrogen or alkanes (i.e., methane, ethane, butane and propane) or a customized blend of these fuels. Virent's initial system design is suitable for a number of applications, ranging from stationary power, industrial hydrogen, renewable fuel stations or, in the longer term, mobile applications.

Finally, the natural photosynthetic activity of bacteria and green algae also produces hydrogen, as does the fermentation of sugars. These processes are longer-term options.

3.2.2 Hydrogen from fossil fuels. As noted earlier, roughly 95 percent of the hydrogen produced in the United States is produced from methane, the largest component of natural gas. A "steam methane reforming" process uses catalytic surfaces and steam at temperatures of 392°F or higher to harvest the hydrogen. Another process called partial oxidation involves reacting natural gas with a limited supply of pure oxygen. Both of these processes yield a synthetic gas similar to that derived from biomass. The "syngas" is then reacted with water to produce more hydrogen for purification and use.

Steam reforming of natural gas does produce carbon dioxide, a key greenhouse gas, but according to the USDOE, "…fuel cell vehicles running on hydrogen produced from natural gas would use less energy and emit less carbon than both gasoline hybrid electric vehicles and conventional internal combustion engine vehicles."[3] Steam reforming is also the most energy efficient commercialized technology at present, though many promising technologies are emerging.

In addition to natural gas, large amounts of hydrogen could be produced by gasifying coal. The most promising coal gasification technology is Integrated Gasification Combined Cycle (IGCC). As with gasifying biomass, coal gasification produces a synthetic gas that is largely made up of carbon monoxide and hydrogen. Coal's potential to be a low-carbon source of hydrogen rests on the ability to capture and permanently store the resulting CO_2 geologically.

3.2.3 Hydrogen from electrolysis of water. Hydrogen can be separated from the oxygen in water by running an electric current through it in a process called electrolysis. Electrolysis can be made even more efficient by heating the water either via nuclear power or the concentration of direct solar power. When the water is heated, it takes less electricity to split apart the oxygen and hydrogen atoms. The heat generated by nuclear or solar power can also be used to fuel a series of chemical reactions that split water into hydrogen and oxygen, with the chemicals being recycled as part of those processes.

Natural gas could bridge hydrogen transition

U.S. Department of Energy estimates that using natural gas to produce hydrogen for the near-term transition to a hydrogen economy would increase overall U.S. natural gas consumption by less than three percent.[21]

USDOE Hydrogen Production Fact Sheet
www.hydrogen.energy.gov

Of these options, electrolysis is the most mature technology and has been used for decades. A piece of equipment called an electrolyzer uses electricity to separate water into its constituent parts, oxygen and hydrogen. The electricity used by the electrolyzer can come from renewable sources (e.g., wind, hydro, solar, biomass), from nuclear power or from coal if the CO_2 were captured and sequestered.

Making hydrogen via electrolysis of water currently costs more than reforming it from natural gas, but could become cost competitive where low-cost power is available (around 1 to 2 cents per kilowatt hour) or if electrolyzers become cheaper. For example, at least one firm expects to soon produce electrolyzers at $164/kW compared to the typical 2006 cost of $2,000–$3,000/kW. The energy losses of making hydrogen via electrolysis are not nearly as important as whether or not the hydrogen can be produced at a lower cost than competing fuels. Thus, the production of hydrogen from water is less a question of physics than economics.

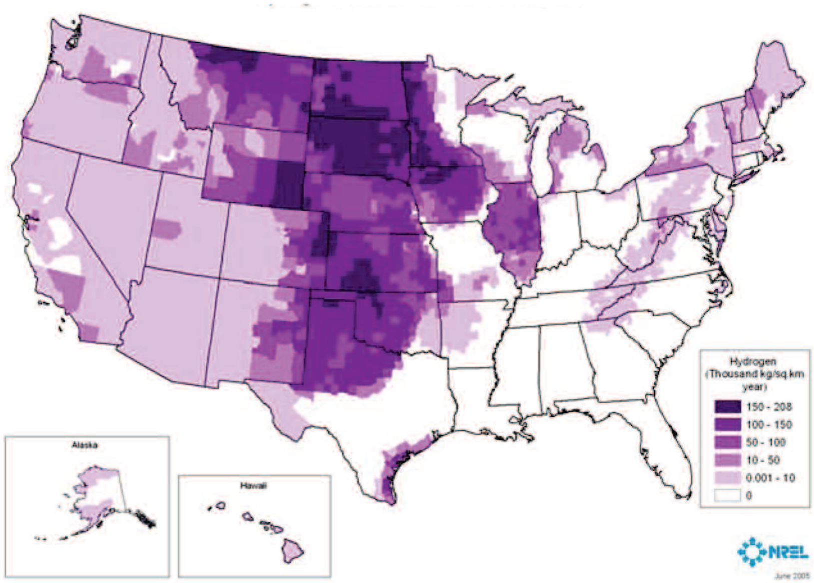
3.2.3.1 Renewable energy-to-hydrogen. While solar and hydro power could similarly produce energy for the electrolysis of water, using wind power to harvest the hydrogen from water is among the most promising near-term renewable hydrogen options. Wind is abundant and continues to decline in cost. As noted by the Rocky Mountain Institute, just North and South Dakota have sufficient class 3 and above wind potential to make enough hydrogen to displace all the gasoline used by highway vehicles in the United States, assuming readily available water and the ability to get the hydrogen to market.[4]

Producing hydrogen from water at the rate of 40 kWh/kg of hydrogen with electrolyzers operating at roughly 70% efficiency yields an electricity cost for wind-hydrogen of some $2–3/kg, according to ISE Corporation's Chief Science Office, Paul Scott. He goes on to note that "the investment in electrolyzers and gas compression is substantial, however, and probably similar in magnitude to the investment in the wind turbine. This suggests that the price of hydrogen from wind will be in the range of $4–6/kg depending on amortization, operations and maintenance costs."[5] A kilogram of hydrogen is roughly equivalent to a gallon of gasoline in terms of energy content, and, if that hydrogen is used in a fuel cell vehicle, one could travel twice as far at the same cost.

Stanford researchers have come to similar conclusions regarding the cost of hydrogen from wind, noting that "converting all the current vehicles to fuel cell vehicles powered by wind would save 4,000 to 6,000 lives in the United States annually and could be done at a fuel cost that's comparable to the cost of gasoline, and less than the cost of gasoline when you consider the health effects of gasoline."[6]

Putting aside the issue of cost, National Renewable Energy Laboratory (NREL) research shows that there are more than enough solar and wind energy resources to meet hydrogen needs at the state level, even if some individual counties may have too little resources or too many people (see map below). NREL analysis also suggests that where wind resources are located close to transportation fuel markets, it may make the most sense to place electrolyzers at wind farms and transport the hydrogen. Yet wind's greatest contribution to a hydrogen economy may simply be having more of it contributing to our electrical grid to be used for electrolysis of water at the filling station.

Hydrogen Potential from Wind Resources



3.2.3.2 Nuclear-to-hydrogen. The Nuclear Energy Institute estimates that without nuclear power the United States would emit an additional 190 million metric tons of carbon each year. The technology's main stumbling block has been getting consensus on what to do with the nuclear waste that is generated in the process of making electricity. If nuclear power can resolve issues surrounding permanent waste storage, cost, nuclear proliferation and safety, it offers a carbon-free source of energy to produce hydrogen on a large scale either via electrolysis of water, thermochemical splitting of water, electrolysis of high-temperature steam or as the source of heat for steam methane reforming.

3.3 Hydrogen storage, distribution and delivery

Once produced, hydrogen needs to be stored. If it is produced a significant distance from where it will be used, it needs to be transported and distributed as well. Hydrogen is already stored and shipped regularly, both as a gas and as a liquid, using pipelines, tanker trucks and cryogenic tube trailers.

Once there is a mature market for hydrogen and demand is sufficiently high, pipelines will likely be the cheapest way of moving large amounts of hydrogen to market, but only about 700 miles of hydrogen pipeline exist today near large refineries and chemical plants in Illinois, California and the Gulf Coast (compared to more than a million miles of natural gas pipeline).

Hydrogen is known to cause embrittlement of conventional steel pipelines and, because of its small molecular size, is prone to leakage. But researchers at Rocky Mountain Institute believe that if and when pipelines are justified, the existing network could be retrofitted "by adding polymer-composite liners, similar to those now used to renovate old water and sewer pipes, plus a hydrogen-blocking metallized coating or liner (analogous to those used in composite hydrogen tanks), and by converting the compressors" used on pipelines today.[4]

Research directions for H_2 distribution and delivery

- Lower-cost, more reliable hydrogen compression technology;
- More cost-effective bulk hydrogen storage technology;
- New materials for lower-cost hydrogen pipelines;
- More energy-efficient and lower-cost hydrogen liquefaction processes; and
- Integrated production, delivery and end-use technologies.[21]

Source: USDOE Fact Sheet, March 2006

Beyond getting hydrogen to the end user, suitable storage technologies are needed for on-board vehicles, at hydrogen production and distribution sites, and at filling stations.

Hydrogen has the highest energy content by weight of any fuel (about three times more than gasoline), making it a great fuel where weight is important, such as on airplanes. But it also has among the lowest energy density by volume (roughly four times less than gasoline), so fitting very much hydrogen in a given space is a challenge. Compared to storing large amounts of electricity, though, storing hydrogen is relatively easy, even though each storage option comes with challenges.

Hydrogen storage options

- High pressure tanks holding compressed hydrogen gas at 5,000 and 10,000 psi
- Super insulated thermos-like tanks holding liquid hydrogen (at -423° F)
- Storage of hydrogen in advanced materials such as metal hydrides, carbon-nanotubes and chemical hydrides
- The use of hydrogen-rich liquids as a means of storing and moving hydrogen (e.g., ethanol or ammonia)[21]

Source: USDOE Fact Sheet, October 2006[7]

3.3.1 Hydrogen in gas form. High pressure storage in ultra-strong, carbon-fiber gas tanks is the most advanced storage technology today, able to store hydrogen at 5,000 and 10,000 pounds per square inch (psi).

According to the USDOE, "a light duty vehicle must carry approximately 5–13 kilograms of hydrogen on-board (depending on the size and type of the vehicle) to allow a driving range of more than 300 miles."[7] Carrying this amount of compressed gaseous hydrogen on today's average conventional vehicle would require a tank larger than the average trunk.*

But according to the Rocky Mountain Institute's Amory Lovins, if the auto industry first concentrated on making lighter, more aerodynamic cars, then there is no volume or safety reason not to use today's high pressure tanks. "Further R&D on hydrogen storage is…desirable but not essential," argues Lovins.[4] Indeed, GM's latest fuel cell vehicle, the Sequel, already has a 300+ mile range running on compressed hydrogen gas using today's high compression tanks. In addition, researchers are working on developing strong, light-weight, conformable tanks from composite materials that could be smaller, packaged more easily in a vehicle and hold more hydrogen.

Beyond on-board storage for vehicles, large amounts of hydrogen gas could be stored in pipelines, underground caverns, gas fields and mines, then piped to individual homes and businesses the way that natural gas is today.

3.3.2 Hydrogen as a liquid. Turning hydrogen into its liquid form allows more storage and greater energy density in a given amount of space, but it also means cooling the hydrogen to -423° F, which requires 35 to 40 percent of its total energy content. Liquid hydrogen evaporates under low pressure and can only be kept in liquid form at extremely low temperatures inside cryogenic containers. Researchers are working on developing hybrid tanks that are both pressurized and cooled to only -248° to -385° F.

Even with these challenges, at least one automaker, BMW, is introducing a sedan in 2008 that will run on gasoline or liquid hydrogen with the press of a button on the steering wheel. With a 170-liter liquid hydrogen tank storing about 8 kg of hydrogen, the car has a hydrogen-fueled range of 200 to 300 kilometers (125 to 185

* "That factor shrinks still further—making the hydrogen tank only modestly bigger than a same range gasoline tank in today's cars, but far lighter—when cars are designed to use two-thirds less power to move them, hence two-thirds less stored hydrogen for the same driving range."[4]

miles). On gasoline, the car has a range up to 500 kilometers (310 miles). If sufficient hydrogen refueling infrastructure existed, this vehicle could be mass-produced today.

3.3.3 Hydrogen held in solid materials. There is great interest in finding ways of safely storing more hydrogen in a given amount of space using metal or chemical hydrides. These allow storage and use of hydrogen at or near room temperature and pressure. Hydrides are metal or chemical compounds that chemically bond hydrogen to them and require heat to release it, such as the waste heat from fuel cells or combustion engines.

The two main benefits of this approach are safety and space. Hydrides are not explosive and metal hydrides can hold more hydrogen in a given amount of space than a high-pressure tank. Honda has combined these technologies by marrying hydrogen-absorbing materials with high-pressure tanks to achieve what they believe is sufficient storage for their next-generation fuel cell vehicle.

Research is also underway on methods of storing hydrogen chemically in tiny carbon structures called nanotubes, but this technique is in the early stages of development.

In the future, there will likely be a wide variety of cost competitive storage devices, from pocket-sized containers for laptops and other portable devices, medium-sized containers for vehicles and on-site power systems, and industrial-sized storage technologies for community power parks and utility-scale systems.

3.3.4 Storage and distribution of hydrogen in hydrogen-rich liquids (such as ethanol or ammonia). In order for hydrogen to be widely used as a fuel, it must be as accessible as today's fuels. Hydrogen's low energy density (by volume) means it is cost-prohibitive to move compressed hydrogen very far. For this reason, many are evaluating the use of stable, hydrogen-rich liquids that could, in effect, be the carrier for hydrogen and provide a less expensive way of moving it around.

For example, ethanol already has a significant production and distribution network and may be an attractive vehicle for first storing and distributing hydrogen and then reforming ethanol into hydrogen on-site as needed. According to C.E. (Sandy) Thomas of H2Gen Innovations, Inc., ethanol will be the lowest cost source for renewable hydrogen for the foreseeable future.[8] At least five different organizations are developing ethanol-to-hydrogen technologies:

- The University of Minnesota
- The Gas Technology Institute
- Hyradix Corporation
- Energy and Environmental Research Center (EERC) at the University of North Dakota
- H2Gen, Inc.

Wind-powered ammonia production could speed wind and hydrogen development

There is a potentially significant synergy among wind power, hydrogen and ammonia production. First, research by the Iowa Energy Center and others suggests that ammonia may deserve serious reconsideration as a fuel in its own right and as a premier hydrogen carrier, particularly where it is already widely distributed and used, such as in the Upper Midwest.[9]

Second, most of the ammonia produced today is used for fertilizer. Unfortunately for the farming community, the vast majority of that ammonia is produced from natural gas, making its price tied to a volatile and increasingly scarce fossil commodity. Ninety percent of the cost of ammonia today is due to the natural gas used in its production. Consequently over one quarter of the U.S. nitrogen fertilizer industry has shut down and the United States now imports 50 percent of its fertilizer.

This crisis for farmers may spell opportunity for both hydrogen and wind, suggesting that the path toward a renewable hydrogen economy may not be just about fuel. An attractive option may be to use low-cost wind power to harvest hydrogen from water and combine it with nitrogen stripped from the ambient air to produce affordable, domestic ammonia (NH_3). The Norwegian company Norsk Hydro has a rich history of doing just that using hydropower. Today, the University of Minnesota West Central Research and Outreach Center near Morris, MN intends to scale up and test this same process using wind power.

If such ammonia production were proven economical, it could jump-start wind development (no transmission lines or power purchase agreements needed) and thereby renewable hydrogen production. One estimate done for the University of Minnesota by Sebesta Blomburg suggests that meeting all of Minnesota's fertilizer needs would require 2,000 MW of nameplate wind energy.[10] Farmers and landowners could benefit from both wind leases and reduced input costs.

Whether the hydrogen is produced at existing E-85* stations or at ethanol production facilities, this hydrogen pathway faces some challenges. On the one hand, the most cost-competitive option for producing hydrogen from ethanol may be to do so at existing ethanol plants. This method has the advantage of saving both energy and money because less water must be removed from the ethanol (fuel grade ethanol must have virtually all water removed). The Energy and Environmental Research Center at the University of North Dakota is leading a project to demonstrate the production of hydrogen at existing and future ethanol facilities in a unique, economical way, providing a near-term path toward a hydrogen economy. The hydrogen produced could be used on-site in fuel cells to provide additional power for the plant or as fuel for hydrogen vehicles. This centralized approach may produce the cheapest hydrogen, but the need to transport the hydrogen to distant markets may nullify the cost advantages of not drying the ethanol.

The other option is to use the existing distribution network of E-85 stations as a starter-kit for a hydrogen network and rely on the fuel-grade ethanol that is already shipped to those sites. This takes advantage of the ethanol infrastructure that already

* E-85 is a blend of 85% ethanol and 15% gasoline. So-called "flex-fuel" vehicles on the road today can run on any proportion of regular gasoline and E-85.

exists, but suffers from using the more expensive fuel-grade ethanol that has all the water removed as the hydrogen source.

The best of both worlds may be to ship a lower grade (wetter) ethanol to refueling stations where it could be reformed on-site into hydrogen *and/or* used as a gasoline additive. Research is underway to analyze various grades of ethanol to see how far the distillation/drying steps can be scaled back and still be able to deliver a grade of ethanol suitable for reforming into hydrogen or blending with gasoline. A demonstration ethanol-to-hydrogen refueling station is underway in Chicago.

Another option for storing and distributing hydrogen is to use ammonia, particularly in the nation's farming communities. Ammonia (NH_3) is made up of nitrogen and hydrogen and is an inexpensive commodity chemical. Ammonia could be stored in large tanks at the filling station and used directly as a fuel in combustion engines or fuel cells, or reformed into gaseous hydrogen on demand.

Ammonia offers a number of advantages as a carrier and source for hydrogen. It has by far the highest hydrogen energy density of any other readily available hydrogen carrier, including methanol, ethanol, compressed natural gas or even liquid hydrogen.

Despite ammonia's real and perceived health hazards, research by the Iowa Energy Center and others suggests that it may deserve serious reconsideration as a fuel in its own right and as a premier hydrogen carrier, particularly where it is already widely distributed and used, such as in the Upper Midwest.* The Iowa Energy Center asserts that ammonia could meet the federal government's 2015 Freedom Car cost

Fuel cell commercialization timeline

Today

- Fork lifts, ice refinishers, grounds-keeping vehicles, airport tugs, buses and other fleet vehicles
- Backup and emergency power (e.g., telecommunications sites)
- Military applications
- Controlled fleet demonstrations of small numbers of vehicles
- Some portable power applications

By 2010

- More portable applications (cell phones, laptops, etc.)
- Uninterrupted Power Supply
- Niche commercial and industrial stationary power applications
- Auxiliary power for vehicles
- More fleet vehicles, scooters and utility vehicles

2010 to 2020

- Initial distributed power for residential market
- More transit buses and other fleet vehicles
- First wave of light-duty cars and trucks

* Danish researchers concluded that when used as a transportation fuel, ammonia would not pose any greater risk than current transportation fuels (see http://www.risoe.dk/rispubl/SYS/syspdf/ris-r-1504.pdf.

and performance targets today and could provide a seamless transition to pure hydrogen, arguing that hydrogen and ammonia are the only transportation fuel candidates that can be made from domestic energy sources.[9]

Another potential liquid carrier for hydrogen is dimethyl ether (DME), which is made today from natural gas-derived methanol but can also be made from coal or biomass. DME is non-toxic and its main use today is as an aerosol propellant in the cosmetic industry to replace CFC propellants. If produced in large quantities, DME could be burned in gas turbines for power generation, used for household cooking and heating, as a vehicle fuel, and also as a hydrogen source for fuel cells.

In the end, hydrogen production is likely to be both centralized and highly distributed (particularly in more rural settings), and the storage, transportation and delivery of hydrogen is likely to be different in each region, based on local strengths and economics.

3.4 Conversion technologies and ways to use hydrogen. Hydrogen can be used in the same ways that fossil fuels are. It can be burned like gasoline or natural gas in internal combustion engines, blended with conventional fuels, or it can be combined with oxygen in a fuel cell to produce heat and electricity.

3.4.1 Burning hydrogen. As noted earlier, burning hydrogen is nearly pollution-free and vastly cleaner than burning traditional fossil fuels since water is the main byproduct. In fact, a promising option for building early hydrogen demand is to blend it with conventional fuels as a transition to 100 percent hydrogen use. Adding just 5 percent hydrogen to a tank of gasoline increases its energy content and reduces nitrogen oxide emissions by 30 to 40 percent.

3.4.2 Using hydrogen in fuel cells. Fuel cells create energy through an electrochemical reaction between hydrogen, oxygen and a catalyst. There are half a dozen main types of fuel cells, each characterized by the electrolyte they use, their operating temperature and the purity of hydrogen they require. These differences make some types better for certain uses than others.

Fuel cells have no moving parts and are nearly silent. They are roughly twice as efficient as traditional internal combustion engines running on gasoline. This is because electrochemical processes are inherently more efficient than combustion at capturing the energy in hydrogen. Fuel cells are between 35 and 50 percent efficient and are better than 85 percent efficient when used in situations where both the fuel cell's heat and electric power are used.

Most of the attention that fuel cells have gotten in the media has focused on their role in powering passenger vehicles. This is in large part because displacing foreign oil use and eliminating CO_2 emissions in the transportation sector are among the largest drivers propelling the hydrogen transition. But many other off-road vehicles and applications are nearer a commercialization tipping point, and public investment could make the difference in several niche markets including fork lifts, airport vehicles, shuttle buses, ice refinishers, fuel cells for emergency and backup power, and grounds-keeping equipment (see timeline on page 15).

Benefits of fuel cells

- For vehicles, over 50% reduction in fuel consumption compared to a conventional gasoline vehicle
- Increased reliability of the electric grid by reducing system loads and bottlenecks
- Increased co-generation of energy in combined heat and power applications for buildings
- Zero to near-zero levels of harmful emissions from vehicles and power plants
- Wide range of applications (can be scaled to many sizes)
- Silent operation
- No moving parts
- Reliable, high quality power

3.4.3 Hydrogen-powered vehicles and hydrogen refueling infrastructure. Alternatives to gasoline are limited. The main options appear to be biofuels, such as ethanol and biodiesel, Fischer-Tropsch liquids, dimethyl ether (DME), electricity and hydrogen. Automakers have largely abandoned pure battery-electric vehicles, and methanol and natural gas have never taken off in the mass market.

Yet for hydrogen-powered vehicles to make the transition from prototype demonstrations to commercial production, there will need to be a sufficient number of refueling sites. In its 2004 report to Congress, the National Research Council wrote:

> Since it will be difficult to stimulate investment in large centralized hydrogen production and distribution systems without proven demand, the committee strongly suggests that the transition be progressed with small, on-site hydrogen production systems at the filling station… A transition based on distributed hydrogen production will allow time for the development of new technologies and concepts needed for the eventual widespread use of hydrogen.[11]

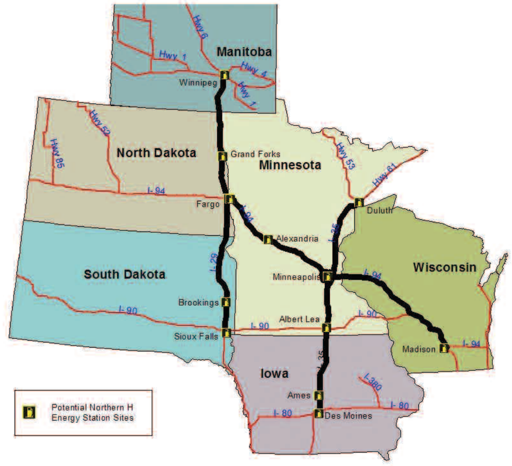
In keeping with this advice, members of the Great Plains Institute's Upper Midwest Hydrogen Initiative have developed a plan for the Northern Hydrogen Corridors Network (Northern H) [see map on page 18]. It would establish 10–12 flexible-fuel Energy Stations along key trade corridors across the Northern Plains by 2015,* spanning Manitoba, North Dakota, South Dakota, Minnesota, Iowa, Wisconsin and Illinois (not yet pictured in the map), ultimately linking with other regional refueling networks, like that being considered by the Western Governors Association. The goals of the Northern H network are to:

1. Identify how best to establish transitional hydrogen infrastructure in rural areas and smaller metropolitan markets;
2. Test a variety of renewable and carbon-neutral hydrogen production options and better understand what it will take to make them commercially viable;
3. Support nearby on- and off-road fleet vehicles (e.g., at farms, airports, materials handling and distribution centers);
4. Encourage a multi-fuel approach to infrastructure development that takes advantage of superior transportation technologies available today, such as flexible-fuel and hybrid-electric vehicles;
5. Introduce consumers to hydrogen as a fleet vehicle fuel well before offering it as a fuel for private vehicles;
6. Support hydrogen-powered fuel cell vehicles as they become ready;
7. Eventually link major cities and other "Hydrogen Highway" efforts; and
8. Demonstrate seamless Canadian-U.S. infrastructure integration.

What would accelerate commercialization of hydrogen vehicles?

- Public access to existing stations
- Expedient station approval process
- Gasoline-like liability treatment
- Vocal support from policymakers and compelling incentives for automakers, suppliers, infrastructure developers and consumers.
- Early use by government vehicles
- Retail-like refueling stations with 700 bar (10,000 psi) fast-fill refueling[22]

* It is not expected that hydrogen-fueled passenger vehicles will be widely deployed in this region by 2015, but rather that Northern H stations would serve a dedicated fleet use (transit buses, delivery vehicles, etc.).



A growing number of "hydrogen highway" efforts have emerged across the continent and around the world aimed at establishing initial hydrogen infrastructure. The National Hydrogen Association maintains an interactive database of such efforts in the United States and Canada that documents 72 stations operating or underway in North America to date. There is also a global database of hydrogen stations that lists more than 200 existing and planned hydrogen stations worldwide.

This early investment in hydrogen infrastructure around the world signifies the urgency of finding non-petroleum options in the transportation sector. In June 2006 the Western Governors Association passed a resolution committing to development of policies that encourage:

> simultaneous production and consumption of hydrogen and ethanol fuels; rapid market growth of hydrogen and agriculturally-fueled vehicles; and creation of Western highway networks capable of supporting public and private alternative fuel vehicle travel, rapidly leading to a national alternative fuels highway network.[12]

While there are significant infrastructure challenges for hydrogen, several studies have suggested that the cost would not be as great as first imagined. For example, General Motors has estimated that putting hydrogen refueling stations within reach of 70% of the U.S. population in the 100 largest cities would not cost a great deal in relative terms. According to Larry Burns, GM's vice president of research and development and strategic planning, "even if every station cost $1 million for hydrogen, that's $12 billion. The Alaskan Pipeline today would cost $25 billion. So for half the cost of the Alaskan Pipeline, you could have stations for 70 percent of the population."[13]

3.4.3.1 Co-evolution of vehicles and fuels. Most automakers have two main goals for meeting the economic, environmental and social challenges that vehicles face:

- Diversify the types of fuels that vehicles can run on; and,
- Electrify the automobile with the ultimate goal of zero emissions. General Motors, among others, sees a combination of batteries, electricity and hydrogen as the ultimate zero-emissions solution (with other fuels contributing along the way).

Fuel cells in portable products

The first fuel cells that consumers are likely to encounter will be used to power cell phones, laptops, personal digital assistants and other portable electronics. For example, several companies are working on producing small methanol cartridges that would give laptop computers a run-time of nine hours. As with fuel cells generally, mass producing these cartridges at a low enough cost is the largest remaining barrier to widespread use.

Jadoo Power Systems has already developed a commercial product that replaces the heavy "brick"-style batteries that professional camera crews use.

Today's hybrid and flex-fuel vehicles are steps toward meeting these two goals. Still to come are vehicles like the Ford Edge and the Chevy Volt which represent flexible vehicle platforms that allow the use of a variety of fuels and propulsion technologies. In other words, what will change over time is the fuels that power these hybrid vehicles, whether or not they can be plugged into the electric grid, and the type of engine they use (an internal combustion engine today and a fuel cell when it becomes cost competitive).

3.4.4 Stationary fuel cells. While not yet ready for passenger vehicles, fuel cells are beginning to commercialize for some stationary applications. According to FuelCells2000, more than 2,500 fuel cells have been installed around the world since the early 1980s, powering everything from hospitals and military bases to police stations and banks.[14] The main stationary markets today are in emergency and back-up power for telecommunications sites, and for industries that are prepared to pay a premium for secure, uninterruptible power.

Distributed electric generation technologies, including fuel cells, can be used for base-load power, peaking and backup power, remote power, and heating and cooling.

A fuel cell review by the American Council for an Energy Efficient Economy (ACEEE) notes that the eligible market base for fuel cells far exceeds the current manufacturing capacity of the industry and may continue to exceed capacity for the next 10 years. Yet the report also notes that "strictly speaking, close to 100% of the small-scale (under 1 MW) distributed generation market could technically be served by fuel cells."[15] This suggests that farms and other remote sites, such as rural post offices, may be logical early deployment opportunities for fuel cells.

However, fuel cells are roughly four times more expensive to install than the most commonly installed distributed generation technology and twice as expensive as micro-turbines. Indeed, the ACEEE authors believe that "market penetration in the near future will be heavily dependent on programmatic intervention from federal and state agencies."[15] Thus, it will take public-private collaboration to boost fuel cell demand and production volumes to bring down costs. This has been true for other technologies as well.

Summary of hydrogen targets

- Make hydrogen competitive with gasoline on a cost per mile basis
- Increase the efficiency of hydrogen production using renewable and carbon-neutral methods
- Increase material and system durability for fuel cells
- Increase hydrogen storage and hydrogen vehicle range
- Improve integration with existing power delivery systems
- Minimize lifecycle environmental emissions and impacts

4.0 Measurable milestones for hydrogen and related technologies

As noted earlier, hydrogen, fuel cells and related technologies were not included in the CO_2 Scenario model that has informed this roadmap. As a result, PTP stakeholders have not developed cost and technology milestones specific to this region but have instead recommended strategies (outlined in the next section) that will help this region contribute to the measurable milestones already developed by the industry in coordination with the federal government.

The milestones on the next page are excerpted from USDOE's December 2006 *Hydrogen Posture Plan*.[16]

PRODUCTION MILESTONES

Distributed Natural Gas and Electrolysis Central

1. 2010: Develop technology to produce hydrogen from natural gas at a refueling station that projects to a cost of $2.50/gge for hydrogen. [At the pump, untaxed, at 5,000 psig]

2. 2015–2017: Develop technology to produce hydrogenutilizing distributed electrolysis that projects to a cost of <$3.00/gge. [At the pump, untaxed, at 10,000 psig]

Coal [c, d]

3. 2010–2011: Develop pre-engineering membrane separation modules and reactors for hydrogen production that meet membrane cost target of $150-200/ft

4. 2015: Demonstrate a near-zero atmospheric emission coal plant producing hydrogen and power with carbon capture and sequestration at a 25% cost reduction that projects to $0.80/gge at the plant gate (ultimate target: $1.80/ggedelivered)

Renewable Resources [e]

5. 2015–2017: Develop technology to produce hydrogenthrough distributed reforming of renewable liquid fuels at a refueling station that projects to a cost of <$3.00/gge for hydrogen [At the pump, untaxed, at 10,000 psig]

6. 2015–2017: Develop technology for central hydrogen production integrating wind electricity production and electrolysis that projects to a cost of <$2.00/gge at the plant gate (<$3.00/gge delivered)

7. 2015–2018: Demonstrate laboratory-scale photobiological water splitting system to produce hydrogen at an energy efficiency of 5% (solar-to-hydrogen). Demonstrate laboratory-scale photoelectrochemical water splitting system to produce hydrogen at an energy efficiencyof 10% (solar-to-hydrogen)

8. 2007–2008: Operate laboratory-scale thermochemical and electrolytic processes to determine the feasibility of coupling them with a nuclear reactor

9. 2010–2012: Laboratory-scale demonstration of solar-driven high-temperature thermochemical hydrogen production that projects to a cost $6.00/gge (ultimate target: $7.00/gge delivered)

10. 2011–2014: Pilot-scale demonstration of thermochemical hydrogen production system for use with nuclear reactors that projects to a cost of $2.50/gge(ultimate target: $3.50/gge delivered)

11. 2017–2020: Engineering-scale demonstration of thermochemical hydrogen production system for use with nuclear reactors that projects to a cost less than $2.00/gge($3.00/gge delivered)

STORAGE MILESTONES

1. 2007: Downselect hydrogen storage options with potential to meet 2010 targets

2. 2010: Develop and verify on-board storage systems achieving:6% by weight capacity and 1,500 watt hours/liter energy density at a cost of $4.00/kWh of stored energy

3. 2015: Develop and verify on-board storage systems achieving:9% by weight capacity, 2,700 watt hours/ liter, and $2.00/kWh

VALIDATION MILESTONES

1. 2008: Validate stationary fuel cell system that co-produces hydrogen and electricity at 20,000 hours durability with 40% efficiency at a cost of $1500/kW or less

2. 2009: Validate polymerelectrolyte membrane fuel cell vehicles at multiple sites, achieving 2,000 hours durability, a 250-mile range, and $3.00/ggeof hydrogen

3. 2014: Validate stationary fuel cell system that co-produces hydrogen and electricity at 40,000 hours durability with 40% efficiency at a cost of $750/kW or less

4. 2015: Validate PEM fuel cells on operational vehicles in different climatic conditions that can be produced for $45/kW when produced in quantities of 500,000

5. 2015: Validate polymerelectrolyte membrane fuel cell vehicles achieving 5,000 hours durability (service life of vehicle) and a 300-mile range Validation Milestones Validation Milestones

CONVERSION MILESTONES [e]

1. 2004: Decision to discontinue on-board fuel processing R&D based on inability to achieve 78% efficiency and <0.5 minute start time

2. 2010–2011: Distributed stationary generation natural gas/propane 5–250 kW fuel cell go/no-go decision based on ability to achieve: 40% electrical efficiency, 40,000 hours durability(equivalent to service life between major overhauls), at a cost of less than $400-$750/kW (depending on application)

3. 2010: Develop direct hydrogenpolymer electrolyte membrane automotive fuel cell operating at 60% peak efficiency, 220 W/L density, 325 W/kg specific power at a cost of $45/kW (automotive production quantity)

4. 2015: Polymer electrolytemembrane automotive fuel cell meets cost of $30/kW

5. 2015: Fuel cell/turbine hybridoperating on coal developed at a cost of $400/kW with a HHV efficiency of 50% with carbon sequestration

EDUCATION, SAFETY, CODES AND STANDARDS MILESTONES [e]

1. 2006–2007: Facilitate publishing domestic and international hydrogenquality standards and publish initial set of basic safety training materials

2. 2007–2008: Publish initial Best Practices manual for hydrogen safety

3. 2007–2009: Education program for safety and code officials in place

4. 2010–2012: Initial set of technical codes and standards in place to supportdemonstrations, commercialization decisions and regulatory standards

CENTRALIZED DELIVERY MILESTONES [e]

1. 2007: Define the criteria for a cost-effective hydrogen fuel deliveryinfrastructure for supporting the introduction and long-term use of hydrogen for transportation and stationary power

2. 2010–2012: Develop technologies to reduce the cost of hydrogen fuel delivery from the point of production to the point of use in vehicles or stationary power units to <$1.70/gge of hydrogen

3. 2015–2017: Develop technologies to reduce the cost of hydrogen fuel delivery from the point of production to the point of use in vehicles or stationary power units to <$1.00/gge of hydrogen

SYSTEMS ANALYSIS MILESTONES [e]

1. 2007: Complete technoeconomic analysis of current production technologies

2. 2008: Develop a macro-system model of the hydrogen fuel infrastructure to support the transportation system

3. 2009–2010: Complete assessment of hydrogen quality requirements for production, delivery, storage and fuel cell pathway

4. 2010–2011: Develop electricity infrastructure module for the macro-system model

a. Achieving the milestones is dependent on requesting and receiving funding at the Hydrogen Program planninglevels for each office.

b. The hydrogen cost milestones are not yet normalized across the Hydrogen Program. The Program is in the process of normalizing the criteria used to determine the Hydrogen Program cost goals using the recently-developed “H2A” modeling tool.The assumed feedstock cost for coal is $2 .00/short ton.

c. The assumed feedstock cost for coal is $29.00/short ton.

d. Milestone delay due to changes in Fossil Energy program planning.

e. Milestone delays are due to shortfalls in appropriations.

f. Milestone delays are due to changes in the DOE budget planning profile.

5.0 Key challenges and barriers*

The integration of hydrogen, fuel cells and related technologies into the energy system faces a number of challenges. Below is a summary of those that are most critical to overcome:

5.1 Improving the efficiency and cost of hydrogen production and delivery to consumers at prices that are competitive with other fuels. In addition to reducing the cost of renewable and carbon-neutral hydrogen production (including on-site production technologies), hydrogen faces some delivery challenges. These include the need for lower-cost transport technologies, uniform codes and standards, potential new right-of-ways for new delivery systems, and the initially high investment risk of developing a hydrogen delivery infrastructure.

5.2 Lack of a consistent energy policy. Changing priorities for energy research and development have led to delays and setbacks in pursuing a coherent strategy on hydrogen technologies. In the absence of consistent public policy, private firms are more hesitant to make significant investments.

5.3 The absence and cost of a hydrogen infrastructure. Introducing a new fuel like hydrogen is challenging given the extensive infrastructure that supports today's fossil fuels, the economies of scale that those mature industries have achieved, and the largely un-priced costs of pollution and greenhouse gases. In addition, adding hydrogen to our energy system would require significant new investment on the order of $5 to $25 billion over the next 40 years.[17] Yet the International Energy Agency estimates that maintaining and expanding the oil industry worldwide will cost $4.3 trillion between 2005 and 2030; and $3.9 trillion in the gas sector.[18]

5.4 Better methods for storing hydrogen. Hydrogen will need to be stored and used as easily as gasoline or propane if it is to be widely adopted as a fuel. While several hydrogen storage technologies are already in use, there is still a need for low cost, high capacity, lightweight and low volume hydrogen storage systems.

5.5 Safety and perceived safety risk. Hydrogen poses roughly the same risks as existing fuels. In fact, it is actually a safer fuel than gasoline and natural gas in many ways. But when people think of hydrogen they often think of the Hindenburg dirigible that burst into flames. It turns out that hydrogen was not to blame for the Hindenburg's demise. According to research by NASA scientist Addison Bain, the ship's shell was coated with a close cousin of rocket fuel which ignited and caused the fire. The hydrogen did burn, but, because it is so light, it quickly dispersed.[19]

Misperceptions about the safety of hydrogen will need to be overcome if there is to be widespread public acceptance of it. The same fears arose when light bulbs and natural gas were first introduced. The development of public education campaigns, codes and safety standards, field tests and demonstrations will influence public confidence in this technology as they have for previous innovations.

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* A more detailed list of barriers and the targets to overcome them are available in the federal hydrogen program's *Multi-Year Research, Development, and Demonstration Plan*: http://www.eere.energy.gov/hydrogenandfuelcells/mypp/

5.6 Fuel cells that are lower cost, more durable and reliable, and can be mass-produced. Fuel cells are already competitive in some niche markets, and government and industry together have made significant progress toward commercializing fuel cells for vehicle use, achieving the 2006 USDOE cost target of $110/kW, a decrease from $275/kW in 2002. But more research will be required to achieve the $30/kW goal for automotive use.

5.7 The need for real-world technology validation. Hydrogen technologies must clearly prove themselves in real-world situations before being introduced commercially to the mass market. Thus, while continued basic research is important, industry often learns the most once new technologies are in the hands of everyday users. This is a key reason why GM, Honda, BMW and others, for example, are putting hydrogen vehicles in the hands of real people, and why transit agencies around the world are deploying hydrogen buses. Getting such "learning demonstrations" done requires cost-sharing between the public and private sectors.

5.8 Incomplete safety codes & standards. There are a significant number of codes and standards already developed for hydrogen technologies (a list of current and emerging codes and standards is at: http://www.fuelcellstandards.com), but there is still a need for model building codes that local jurisdictions could adopt. The fuel gas code needs to include hydrogen, and there needs to be uniform safety standards for certifying hydrogen vehicles, stationary power facilities and portable devices. In addition to the challenge of completing the codes and standards themselves, there are a large and diverse number of jurisdictions in North America and limited funds for training all the relevant officials.

5.9 The need for widespread education about the potential for hydrogen, fuel cells and related technologies. There is a general lack of understanding and awareness about hydrogen and hydrogen technologies. This must change if consumers are to begin demanding these technologies. In an effort to begin educating first responders and other local officials, the USDOE has developed a free on-line training course. It should be useful to anyone interested in hydrogen: http://www.ehammertraining.us/energy/h2_login/login.cfm

5.10 Liability and insurability issues. Hydrogen technologies need to achieve the same level of insurability as other fuels. Lawsuits and insurability are serious concerns that could affect the commercialization of hydrogen technologies. New technologies not yet recognized in codes and standards will have difficulty in obtaining reasonable insurance and may not be approved in some cases.

6.0 Sample strategies for hydrogen development

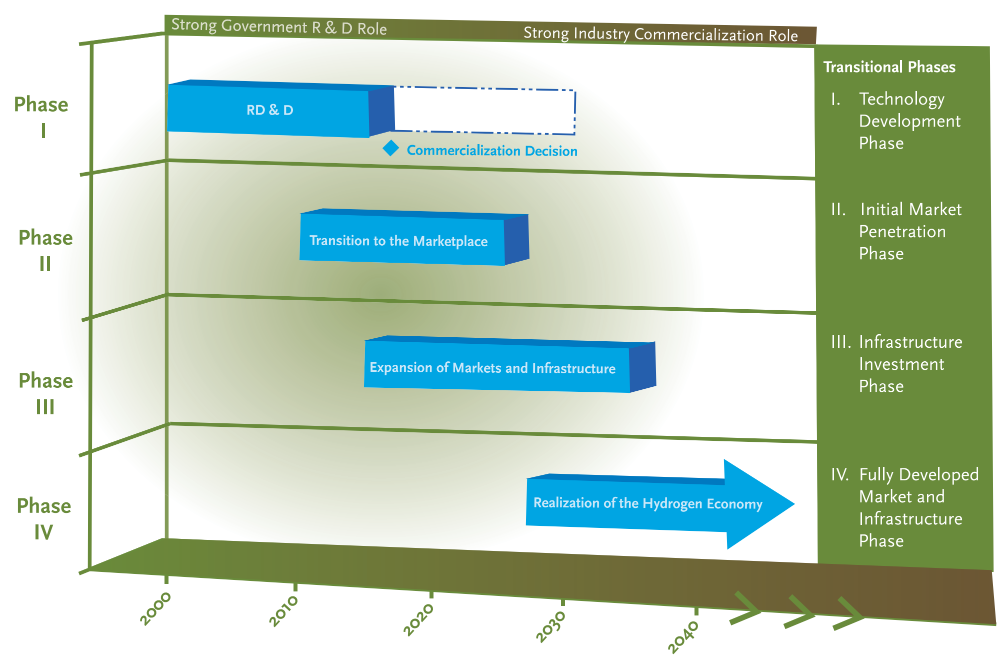
In 1976 Stanford University researchers conducted a comprehensive study: *The Hydrogen Economy, A Preliminary Technology Assessment*.[20] In it, the authors argue that because of the enormous investment and long lead times required to make a shift in energy infrastructure, those decisions should not be left entirely to the marketplace with its inherent bias toward the near term.

Today's energy and transportation systems would not have evolved without significant governmental initiative. The railroads, the interstate highway system and the electrical grid all exist in large part because of government investment on the public's behalf.

Markets are generally effective in allocating resources among competing interests in the present, but, because of their inherent short-term focus, they are less effective in helping society get to a planned, long-term destination, such as a hydrogen economy. This is where consistent, thoughtful public policies can play a critical role. Below is a menu of options for policymakers to consider:

> **6.1 Develop a hydrogen roadmap.** The Province of Manitoba has already taken this step* (as have many U.S. states), but the first order of business may be for each jurisdiction to consider convening a broad range of stakeholders to develop a roadmap that details its hydrogen vision, goals, objectives, measurable targets and general timeline for a hydrogen transition. A hydrogen roadmap would establish a consistent, predictable and prudent investment environment for the private sector so that firms feel comfortable making the significant investments needed.

USDOE's Hydrogen Timeline



* http://www.gov.mb.ca/est/energy/hydrogen/hy_comite.html

Each jurisdiction will likely want to:

6.1.1 Identify the renewable and low-carbon hydrogen production capacity within its region;
6.1.2 Quantify hydrogen demand at different market penetration rates for both rural and urban communities; and
6.1.3 Identify the optimal infrastructure design and build-out for different market penetration scenarios. Decisions about what constitutes "optimal" should be based on the cost, emissions, and overall energy efficiency of various hydrogen production and distribution pathways.

6.2 Foster a public-private approach. The task of moving to hydrogen is large enough that no single sector of society can do it alone. Indeed, current progress around the world has been almost universally the product of serious coordination and cooperation among business, government, academic and nonprofit interests. States and provinces could help launch, participate in, and/or endorse such public-private partnerships.

6.3 Consider a range of policy reforms, including:

6.3.1 Provide public matching funds for strategically important, early deployment projects. State Energy Offices (and their provincial equivalents) should use a competitive process to test multiple hydrogen technology applications to maximize research and development results. The funds should be focused on those projects with the greatest potential to lead to eventual economic viability and commercialization. Each funded project should be required to have a strong education and awareness-raising component. The projects would be cost-shared 50/50 with private and non-state sources (with an exception for public institutions, such as institutions of higher learning). In addition to strong prospects for commercialization and economic viability, demonstrations should focus on key technical objectives including:

- Reducing costs;
- Increasing material and system durability;
- Increasing the efficiency of hydrogen production;
- Increasing hydrogen storage and hydrogen vehicle range;
- Improving integration with existing power delivery systems; and
- Minimizing lifecycle environmental emissions and impacts.

6.3.2 Hydrogen production incentive. Considering the significant role that financial incentives have played in stimulating the wind, ethanol and biodiesel industries, hydrogen and hydrogen technologies would benefit from similar treatment. For renewable and carbon-neutral hydrogen, the incentive payment could be based on the number of barrels-of-oil equivalent of hydrogen generated and used for transportation fuel, electricity, heating, cooling, fertilizer production or other commercially productive end use. The total amount available from this incentive could be capped.

6.3.3 Renewable or carbon-neutral hydrogen production standard or objective. This would be another way to help create an initial market incentive for hydrogen produced with renewable and carbon-neutral methods. It would function much like the Renewable Energy and Fuels Standards and Objectives that many states have adopted to stimulate the wind and biofuels markets.

6.3.4 Incorporate hydrogen technologies into government and other public purchasing guidelines and contracts. Early government purchases and demonstrations have been critical to the commercialization of beneficial technologies in the past and will be equally important to advancing hydrogen and fuel cell technology. By becoming an early market participant, states or provinces can:

- Provide objective performance data to the marketplace;
- Boost demand for hydrogen, fuel cells and related technologies and thereby bring down their costs;
- Identify infrastructure needs;
- Identify code and regulatory issues to be resolved;
- Foster new capital investment by the private sector;
- Advance critical research; and
- Lead by example.

States, local governments and other public institutions (such as universities) should develop a hydrogen technology section in their purchasing guidelines and contracts to streamline and accelerate procurement of hydrogen, fuel cells and related technologies. States or provinces could underwrite the additional marginal cost of these technologies and provide training for those who will need to maintain them. In the United States, this provision could include purchasing targets compatible with the federal Energy Policy Act of 2005.

6.3.5 Adopt uniform codes, standards and siting requirements for hydrogen technologies. This provision would standardize and streamline fire, safety and building codes so that all regulatory jurisdictions (preferably throughout the entire region) operate within the same standards established by the National Fire Protection Association. This should include funding to educate code officials and should establish a referral service for “authorities in charge” of hydrogen developments. This should also include any necessary changes to environmental and other permitting processes and allow the development of initial infrastructure guidelines by educational institutions (e.g., research universities).

6.3.6 Appropriate funds for education and outreach to key audiences on hydrogen, fuel cells and related technologies and their role in the future energy mix. Audiences would include fire, safety and building code officials, transit officials, elected officials, financial institutions and others deemed critical to early deployment. The funds would be appropriated to state energy offices (or provincial equivalents) for disbursement via a competitive process. Activities eligible for funding would include outreach to potential early users of hydrogen technologies.

6.3.7 Ask the Public Service Commission (or its equivalent) to study cost recovery mechanisms that would support hydrogen-related utility investments. This could be tied to existing incentives for renewable and carbon-neutral energy production.

6.3.8 Support publicly-funded basic and applied research at the region's respective research institutions. Funds appropriated for public research would be designed to complement federal and industry research efforts and would be aimed at both fundamental science and near-term priorities that build on a given jurisdiction's strengths.

6.3.9 Establish a "Refueling Infrastructure Transition Fund" (RIT fund). The fund would help finance the shift away from a petroleum-only refueling network toward one that offers a range of domestically-produced low- and zero-carbon fuels as demand dictates.

6.3.10 Allow owners of hydrogen-fueled vehicles to:

- Use High Occupancy Vehicle (HOV) lanes;
- Use toll roads free of charge;
- Pay no annual vehicle tag registration fees;
- Pay no highway use tax;
- Park free in high-demand areas (e.g., downtown), which may require developing hydrogen standards for parking garages; and/or
- Establish additional tax credits for the purchase of these vehicles

These reforms may seem premature given the limited availability and high cost of hydrogen vehicles but, for the same reasons, may also represent an "easy win" for states or provinces at little cost today.

6.3.11 At the local level:
Local governments will need to work out permitting, siting, and other zoning issues raised by the production, distribution and dispensing of hydrogen.

This might include adopting standards being developed by the National Hydrogen Association and integrating information and procedures from the *Sourcebook for Hydrogen Applications* into local codes and ordinances: http://www.tisec.com/products/hydrogen_sourcebook/hydrogen_sourcebook.htm. More specifically, local governments will need to:

- Put in place zoning ordinances that allow for a hydrogen infrastructure;
- Define siting and permitting standards and processes;
- Work out maintenance, operations and safety issues, including emergency response procedures among fire, police, cities and counties; and
- Support the emergence of hydrogen vehicles through local government vehicle fleets and perhaps through local cost-sharing.

Additional Sources of Information

> European Hydrogen and Fuel Cell Platform

> Fuel Cells Canada

> Fuel Cell 2000 (a comprehensive on-line resource)

> Hydrogen and Fuel Cells Canada

> National Hydrogen Association

> National Renewable Energy Laboratory

> Upper Midwest Hydrogen Initiative www.umhi.org

> U.S. Fuel Cell Council

> U.S. Department of Energy Hydrogen Program

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