Exhibit GAC # 20-2

Volume 1 - Green Action Centre Book of Documents

NFAT Review
Subject: Alternatives Panel

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NREL
NATIONAL RENEWABLE ENERGY LABORATORY

Wind Resource Assessment Report: Mille Lacs Indian Reservation, Minnesota

Antonio C. Jimenez

Produced under direction of the U.S. Environmental Protection Agency (EPA) by the National Renewable Energy Laboratory (NREL) under Interagency Agreement IAG-08-1719 and Task No. WFD3.1000.

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Technical Report
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December 2013

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7.6.2.2 Operations and Maintenance

O&M costs, as shown in Table 7-1, are cited at $35/kW/yr in the *2011 Cost of Wind Energy Review*.[13] This represents a $7/kW/yr decline from the 2010 O&M average. There are substantial research and development investments currently being made by both the private and public sector aimed at reducing O&M costs. The trend shown is indicative of the success of these efforts.

Because the O&M figures cited are aggregated from wind farm-sized projects, it is assumed these costs will be higher for single turbine projects. These costs are site specific and are negotiable with the O&M providers. A cost 20% higher than the wind farm rate, at $42/kW/yr or $67,200/yr, was assumed over the life of the project. It increases at the rate of inflation.

7.6.2.3 Project Life

The project life is assumed to be 20 years. Wind turbine design life is typically at least 20 years. There have been extensive research and development efforts in the past 15–20 years focused on improving component design throughout the entire wind system and reducing O&M costs. The wind turbine useful life is estimated to be 20–30 years, depending on actual O&M practices and environmental conditions.

7.6.2.4 Salvage Value

The actual value of wind turbines at the end of their useful life is a figure commonly estimated at 5%–10% of turbine purchase cost, though actual salvage value data is difficult to find. This analysis assumes that the salvage value of the turbine is equal to the decommissioning costs.

7.6.3 Regulatory and Market Factors

There are a number of market and regulatory factors that impact the overall economic analysis. These are described below.

7.6.3.1 Production Tax Credit and Investment Tax Credit

The federal renewable electricity PTC is a per-kilowatt-hour tax credit for electricity generated by qualified energy resources and sold by the taxpayer to an unrelated person during the taxable year.[14] The current value of the PTC is $0.023/kWh for electricity produced during the first 10 years of operation from a wind turbine.

In lieu of the PTC, turbine project owners can take an investment tax credit (ITC)[15] equal to 30% of the project cost. In this case, where the site has a modest wind resource, the ITC may be more valuable.

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[13] Tegen, S.; Lantz, E.; Hand, M.; Maples, B.; Smith, A.; Schwabe, P. *2011 Cost of Wind Energy Review*, National Renewable Energy Laboratory, Technical Report NREL/TP-5000-56266, March 2013. Accessed March 2013: http://www.nrel.gov/publications/recent_publications.html.

[14] Database of State Incentives for Renewables & Efficiency. "Renewable Electricity Production Tax Credit." Accessed August 30, 2013: http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=US13F&re=1&ee=1.

[15] Database of State Incentives for Renewables & Efficiency. "Renewable Electricity Investment Tax Credit." Accessed August 30, 2013: http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=US02F&re=0&ee=0.

Tab 2

WP2

IEA Wind Task 26

The Past and Future Cost of Wind Energy

Leading Authors

Eric Lantz: National Renewable Energy Laboratory
Ryan Wiser: Lawrence Berkeley National Laboratory
Maureen Hand: National Renewable Energy Laboratory

iea wind

5 Conclusions

Over the past 30 years, the wind industry has become a mainstream source of electricity generation around the world. The industry has observed significant cost of energy reductions. However, from roughly 2004 to 2009, the cost of wind energy increased. Historically, cost reductions have resulted from both capital cost reductions and increased performance. From 2004 to 2009, however, continued performance increases were not enough to offset the sizable increase in capital costs that were driven by turbine upscaling, increases in materials prices, energy prices, labor costs, manufacturer profitability, and—in some markets—exchange rate movements. Nevertheless, as capital costs have moderated from their 2009–2010 levels, the cost of wind energy has fallen and is now at an all-time low within fixed wind resource classes.

Looking forward, the LCOE of wind energy is expected to continue to fall, at least on a long-term global basis and within fixed wind resource classes. Performance improvements associated with continued turbine upscaling and design advancements are anticipated, and lower capital costs may also be achievable. The magnitude of future cost reductions, however, remains highly uncertain, although most recent estimates project that the LCOE of onshore wind could fall by 20%–30% over the next two decades.

As the industry continues to mature and future technology advancement opportunities become increasingly incremental, however, LCOE reductions can be anticipated to slow. Moreover, continued movement towards lower wind speed sites may invariably increase industry-wide LCOE, despite technological improvements that would otherwise yield a lower LCOE. Other local factors such as transmission needs may also push towards higher costs. With these factors in mind, it is of important to consider the interdependence of capital costs and performance, and to evaluate the future cost of wind energy on an LCOE basis. Moreover, such evaluations must consider trends in the quality of the wind resource in which projects are located, as well as development, transmission, integration, and other cost elements that may also change (and increase) with time and deployment levels, but are sometimes ignored in traditional LCOE analyses (e.g., Dinica 2011).

Estimates of the future cost of wind energy conducted to date have often been the result of an iterative process that incorporates some combination of historical trends, learning curve analysis, expert elicitation, and engineering modeling. Theoretically, each of these approaches could independently provide an estimate of the future cost of energy; however, it has often been recognized that it is a combination of these different methodologies that is likely to yield the most accurate results. The individual strengths and weaknesses of each approach are in some ways complementary, so future projections are also expected to employ various combinations of these methods.

Further improving our understanding of possible future cost trends will require additional data gathering and improved modeling capability. Robust data collection is needed across the array of variables that must be factored into estimating LCOE (e.g., capital cost, capacity factor, O&M costs, component replacement rates and costs, and financing costs) and in each of the wind energy markets around the globe. Also needed are data on the many contextual factors that impact the overall cost of wind energy and that may also vary with time, such as interconnection costs, permitting costs, and the average wind speed of installed wind projects. Such data would

Tab 3

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IRENA WORKING PAPER

IRENA
International Renewable Energy Agency

RENEWABLE ENERGY TECHNOLOGIES: COST ANALYSIS SERIES

Volume 1: Power Sector

Issue 5/5

Wind Power

June 2012

5. Wind power cost reduction potentials

The recent increases in wind turbine prices makes projecting cost reductions for wind power projects in the short-term challenging. However, estimating cost reductions is important if policy makers, energy companies and project developers are to have robust information in order to compare between renewable power generation projects and conventional power generation technologies.

Numerous studies have looked at where cost reductions could be achieved and how large these savings might be. Most analysis has looked at quantitative estimates of cost reduction possibilities for onshore wind, but there is an increasing number of studies that have done this for offshore wind. Most of these studies focus on cost reductions caused by improved designs of wind farms. However, other factors (e.g. learning-by-doing, standardization and economies of scale) may also contribute significantly to cost reductions. The improved performance of wind turbines and their location in higher average wind speed locations will also help to reduce the LCOE of wind by improving the average capacity factor.

For offshore wind, cost reductions in other industries, such as the offshore oil and gas sector and offshore cable laying, will also have benefits for wind. At the same time, developments in commodity prices, particularly steel, copper and cement, will also influence wind power cost reduction potentials depending on how they evolve over time.

For onshore and offshore wind power projects the key cost components, and hence areas for cost reduction, are:

- Wind turbines;
- Foundations;
- Grid connection/cabling;
- Installation; and
- Project planning and development.

To achieve significant reductions in the LCOE of wind will require efforts to reduce the costs of each of these components of a wind power project. At the same time, efforts to improve the yield of wind farms (i.e. the capacity factor) will also need to be pursued.

Historical learning rates for wind power were around 10% prior to 2004, when wind turbine prices grew strongly. Solar photovoltaic experienced a similar divergence from its historical learning curve due to supply chain bottlenecks, but once these were overcome, prices returned to their historical trend. It is not yet clear whether or not the installed cost of wind power will return to the trend seen between the 1980s and 2004. Current projections by the IEA and GWEC are based on a learning rate of 7%, but lower values may also be possible. Increased competition, particularly from emerging market manufacturers will help keep costs down and will likely lead to a consolidation among wind manufacturers, helping to increase economies of scale.

An alternative approach is to look at the cost reduction potential from a bottom-up perspective, although these are often informed by learning rates as well. Recent analysis for the United Kingdom suggests that onshore wind farm costs could be 12% lower by 2020 than they are in 2011 and 23% lower by 2040. The largest percentage and absolute cost reductions come from the wind turbines. Wind turbines are projected to be 15% cheaper in 2020 than in 2011 and 28% cheaper in 2040. The sections that follow discuss these cost reduction potentials in more detail.

5.1 COST REDUCTION POTENTIAL BY SOURCE

Wind turbine cost reductions in the last two decades, for both onshore and offshore wind turbines, have been achieved by economies of scale and learning effects as installed capacity has grown. The LCOE of wind has been further reduced as the result of higher capacity factors that have come from increasing turbine height and rotor diameter. Onshore, wind turbines are typically in the 2

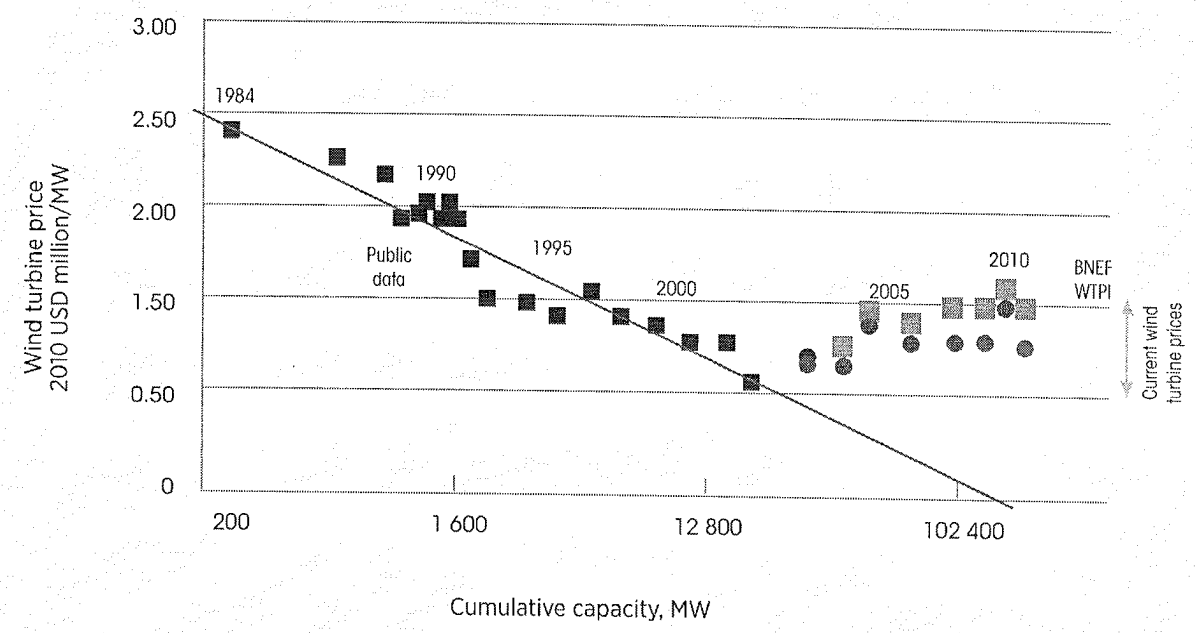

FIGURE 5.1: HISTORICAL LEARNING RATE FOR WIND TURBINES, 1984 TO 2010

Note: WTPI = Wind turbine price index

Source: BNEF, 2011b.

TABLE 5.1: PROJECTED CAPITAL COSTS FOR SMALL-SCALE WIND FARMS (16 MW) WITH 2 MW TURBINES IN THE UNITED KINGDOM, 2011 TO 2040

	2011	2020	2040	% of 2011 cost in 2020	% of 2011 cost in 2040
Development	100	98	93	98%	93%
Turbine	870	737	630	85%	72%
Foundation	170	159	144	93%	84%
Electrical	100	91	83	91%	83%
Insurance	40	37	34	93%	84%
Contingencies	70	65	59	93%	84%
Total	1 350	1 187	1 042	88%	77%

Source: Mott MacDonald, 2011.

MW to 3 MW size range, while offshore the average is higher at around 3.4 MW per turbine for projects in 2011 (EWEA, 2011b). This compares to less than one megawatt in 2000 (EWEA, 2011b). The growth in the average size of onshore turbines will slow as increasing wind farm heights on land will become increasingly difficult. The increase in the average size of offshore wind turbines will continue as increased rotor height and diameter allow greater energy yields.

The reason for this growth is simple; the LCOE of wind energy can be reduced significantly by having larger rotors and higher hub heights. This is because, all other things being equal, the energy yield of a turbine is roughly proportional to the swept area of the rotors. Similarly, all other things being equal, the energy yield is roughly proportional to the square root of the hub height due to higher wind speeds at greater heights (although surrounding terrain can affect this).

However, the increase in the size of turbines and blades also increases their weight, increasing the cost of towers and the foundations. Historically the increase in the weight of turbines has been limited by the utilisation of lighter materials and the optimisation of design, although it is not clear if this trend can continue. As a result, there appears to be relatively small economies of scale from larger turbines, their main benefit being the increased energy yield and scale given to wind farms.

Recent trends in wind turbine prices suggest that wind turbine prices have peaked. It is difficult to predict the evolution of wind turbine prices, but increasing competition among manufacturers and the emergence of large-scale wind turbine manufacturing bases in China and other emerging economies is likely to put continued downward pressure on wind turbine prices in the short- to medium-term. The current global manufacturing surplus in all major components of wind turbines also suggests that there are no major supply chain bottlenecks that could disrupt this trend in the next few years (MAKE Consulting, 2011a).

The largest cost reductions will therefore come from learning effects in wind turbine manufacturing, with smaller, but important contributions from the remaining areas. By 2020, wind turbine costs may decline by 15% compared to 2011 levels (Mott Macdonald, 2011) and perhaps by more than this if oversupply pushes down manufacturers' margins, or emerging market manufacturers gain larger shares of the European and North American markets.

The key cost reduction areas for wind turbines (Douglas-Westwood, 2010) are:

- **Towers:** These are an important part of the wind turbine cost (up to one-quarter), but are a relatively mature component. Most are rolled steel, with costs being driven by steel prices. However, increased competition, the integration of lightweight materials and the more distributed location of manufacturers that will be possible as markets expand means tower costs may come down, perhaps by 15% to 20% by 2030.

- **Blades:** Wind turbine rotor blades can account for one-fifth of turbine costs. The key driver behind blade design evolution is weight minimisation as this reduces loads and helps improve efficiency. Using more carbon fibre in blades, as well as improving the design of blades (with production efficiency and aerodynamic efficiency in mind) can help reduce weight and costs, although the high cost of carbon fibre is a problem. Cost reductions of 10% to 20% could be possible by 2020.

- **Gearboxes:** Typically represent 13% to 15% of wind turbine costs The R&D focus for gearboxes is to improve reliability and reduce costs. Vertical integration of gearbox manufacturing by wind turbine suppliers should help reduce costs. Cost reductions may also stem from the increasing share of gearless drive generators using permanent magnet synchronous motors. Overall, cost reductions could reach 15% by 2020.

- **Other components:**[22] The most significant remaining components are

[22] *See Figure 4.4.*

the generator, control systems (including pitch and yaw systems), transformer and power converter. These components, as well as the other miscellaneous components of the turbine, all have opportunities for cost reductions through increased manufacturing efficiency and R&D efforts. These components could see cost reductions of 10% to 15% by 2020.

The cost reduction potentials in percentage terms are likely to be similar for onshore and offshore wind turbines, as the technology improves and designs become further standardised. Significant savings are expected to be realised through the mass production of wind turbines, the vertical integration of turbine manufacturers as they bring more components "in-house" and learning effects. The absolute reduction in costs for offshore wind turbines will be somewhat higher than for onshore turbines (on a per kW basis) given their higher overall cost.

One area where offshore wind farms will have a cost advantage is through scale. Offshore wind projects have the possibility to be very large compared to onshore wind farms and this will allow very competitive prices for large wind turbine orders.

Cost reductions for grid connections

The cost of grid connection is not likely to decline significantly for onshore wind farms. However, offshore developments can expect to see cost reductions as the scale of wind farms developed increases and as the industry capacity increases. The cost of long distance grid connections for wind farms far from shore could be reduced by using HVDC (high-voltage direct current) connections. Costs are coming down for these connections and lower losses could make them more economical overall, even taking into account the cost of converting the DC to AC onshore. The costs for the internal grid connection are estimated to be constant and only contribute a minor share of the investment costs associated with an offshore wind farm.

Cost reductions for foundations

The foundations can account for 7-10% of onshore wind farm costs and 15% to 20% (EWEA, 2009) or more for offshore wind farms. The largest cost components of foundations are cement and steel. Actual foundation costs will therefore be strongly influenced by these commodity prices. However, some cost reductions are still possible as costs will increase somewhat less proportionately than the increase in swept rotor area, so larger turbines will help reduce specific installation costs somewhat (EWEA, 2009). Other cost reductions can come from economies of scale, reduced material consumption (through more efficient designs) and reduced materials cost (materials substitution). It has been estimated that if steel costs decline by 1-2%/year and can result in a 5-10% reduction in overall foundation costs (Junginger, 2004).

The potential for reducing the cost of offshore wind turbine foundations is higher than for onshore. Offshore foundations are typically at least 2.5 times more expensive than onshore ones (EWEA, 2009). The trend to larger wind turbines, improved designs, reduced installation times and larger production lines for foundations will help reduce costs.

However, for shallow, fixed foundations (predominantly monopiles), cost reductions will be modest. For deeper offshore foundations the dynamics are more complicated. Fixed seabed foundations in greater than 20 m of water become increasingly expensive as deeper piles are required and wave and current forces can be greater. Significant cost reductions are therefore not obvious. It is likely that fixed seabed foundations will be uneconomic beyond a depth of around 40 m and floating foundations will be required.

Floating foundations are more expensive than shallow monopole foundations, but cost reduction potentials are significantly larger, as a range of innovative designs are being explored. Today's floating foundations are predominantly demonstrator projects. As experience is gained and R&D advances, designers will be able to identify foundation types with the greatest potential. The costs of floating foundations could decline by 50% by 2030 (Douglas-Westwood, 2010), although they are still likely to be a third more expensive than shallow water monopole foundations.

Other cost reductions

The remaining project costs for onshore wind farms are typically in the range of 8% to 18%, with 10% typical for wind farm based on 2 MW wind turbines (EWEA, 2009). Offshore, this proportion is higher and likely to be in the range of 25% to 35%. Modest cost reductions can be expected for the remaining electrical installation, controls,

civil works, consultancy and projects costs onshore, but the potentials offshore are larger as the industry learns from experience. Costs could be reduced by between 20% and 30% by 2030 (Douglas-Westwood, 2010).

Installation and commissioning costs, particularly for offshore wind farms, could be reduced, despite the increasing size and weight of turbines making this process more difficult. Specialised installation vessels will provide reduced installation times.

However, the largest cost reduction possibility is the so-called "all in one" installation, where the wind turbine is fully assembled onshore, transported to the already installed foundation and installed in one piece. This technique is just beginning to be evaluated, with two projects to date having used this method: the Beatrice Demonstrator in Scotland and the Shanghai Bridge project in China. Turbine installation costs offshore could be reduced by as much as 30% by 2030 (Douglas-Westwood, 2010).

Speeding up the installation process and electrical installations should help reduce commissioning time significantly, reducing working capital requirements and bringing forward the date when first revenue from electricity sales occurs.

Cost reductions due to increased efficiency

The capacity factor for a wind farm is determined by the average wind speed at the location and the hub height. The energy that can be harvested is also a function of the swept rotor area. Thus, tall turbines with larger rotor areas in high average mean wind speed areas will have the highest capacity factors and energy yields. One of the main advantages of offshore wind power is its ability to obtain increased capacity factors compared to equivalent capacity onshore installations. This is due in part to opportunities to place the wind farms in high average wind speed environments, but also because objections to very tall wind turbines are sometimes less of an issue.

Considerable information on wind resource mapping across Europe and the USA has been accumulated and it is extending to other areas of the world, where the development of wind power has the potential to contribute to the energy mix. Increased access to wind mapping information will have a significant impact on maximising yield and minimising generation cost by reducing the information barrier to identifying the best sights for wind farm development.

Continuing improvements in the ability to model turbulence with computational fluid dynamics (CFD) can help improve designs and increase the responsiveness of machines in turbulent conditions. At the same time, the use of a radar on top of the nacelle to "read" the wind 200 to 400 metres in front of the turbine can allow appropriate yaw and pitch adjustments in anticipation of shifts or changes in the wind. It is thought that these improvements will both increase efficiency and reduce wear and tear on the machine by reducing the frequency and amplitude of shear loads on the rotor.

Cost reductions in offshore wind power: A summary

Currently, the capital cost of offshore wind is around two times higher than onshore wind. If offshore wind is to become truly competitive, capital and O&M costs need to be reduced. The outlook for cost reductions is good and when combined with the ability to achieve higher capacity factors than onshore, it means that the LCOE of offshore wind could come down significantly in the long term.

The main drivers for cost reductions will be continued design improvements, the upscaling of wind turbines, the continuing growth of offshore wind capacity (learning effects) and the development and high utilization rates of purpose-built installation vessels. Other factors that will help reduce costs are stable commodity prices, technological development of HVDC converter stations and cables, standardisation of turbine and foundation design, and economies of scale for wind turbine production. An overview of key factors influencing cost reductions for offshore wind farms is presented in Table 5.2.

It is expected that offshore wind power installations will move further offshore in order to maximise electricity generating capability through the utilisation of stronger and more consistent winds. In some cases, this shift is in order to site the wind farm closer to main consumption centres (e.g. London Array), and to provide reduced impact from visual obstruction and noise-related issues.

Shifting to further offshore and deeper water environments with more extreme offshore weather conditions that are unfamiliar and unpredictable can result in significantly higher costs for all components

TABLE 5.2: SUMMARY OF COST REDUCTION OPPORTUNITIES FOR OFFSHORE WIND

	Specific offshore wind developments	Exogenous development
Wind turbine	Upscaling Improved design Standardisation Economies of scale	Further development of onshore turbines Steel price
Grid Connection	Standardising the design of HVDC cables Applicability of XLPE insulation to HVDC cables Advances in valve technology and power electronics	Further development and diffusion of submarine HVDC interconnectors
Foundation	Standardisation Economies of scale	Steel price
Installation	Learning-by-doing Development and structural purpose-built ships Optimisation of ship use Standardisation of turbines and equipment	Oil price

Source: Junginger, 2004.

TABLE 5.3: DIFFERENT ESTIMATES OF THE POTENTIAL FOR COST REDUCTIONS IN THE INSTALLED COST OF ONSHORE WIND, 2011 TO 2050

	2015	2020	2025	2030	2035	2040	2045	2050
				(%)				
IEA				-18				-23
EWEA	-11	-22	-28	-29				
GWEC	-5 to -6	-9 to -12		-16 to -18				
Mott MacDonald		-12				-23		
US DOE				-10				

Sources: DOE, 2008; GWEC and Greenpeace, 2010; EWEA, 2011c; IEA, 2009 and Mott MacDonald, 2011

of offshore wind power due to the associated risk; high prices will continue until adequate experience is gained.

5.2 OVERALL COST REDUCTION POTENTIALS

There are currently no major supply bottlenecks in the wind turbine industry, at least globally, as the result of the rapid expansion of manufacturing capacity in all critical areas. It is projected that wind turbine prices will decline in the coming years as a result, but to what extent is difficult to gauge and depends on the impact of turbine manufacturers based in emerging economies on OECD markets.

It is thus possible, perhaps even likely, that wind turbine costs will revert to a trend similar to the one evident between the 1980s and 2004. The IEA and GWEC assume that the learning rate will be slightly lower than this historical average at 7% (IEA, 2009 and GWEC, 2011). Table 5.3 presents projections of the cost reductions for total installed wind farm costs between now and 2050 from a variety of sources. Projected cost reductions vary depending on the base year of the analysis, with recent studies using base years of 2009, 2010 or 2011 but also due to different assumptions about engineering costs, learning rates, and global deployment of wind in the future. Cost reductions to 2015 are in the range of 5% to 11%, while by 2020 the estimated cost reduction range widens to 9% to 22%.

Estimates of the cost reduction potential for offshore wind are quite uncertain given the fact that the offshore wind industry is just at the beginning of its development. Recent analysis has identified cost reduction potentials of 11% to 30% by 2030, depending on how rapidly the industry expands (Douglas-Westwood, 2010). The key to reducing costs will be through learning effects, more R&D, wind turbine capacity increases, expansion of the supply chain, greater dedicated installation capacity (to reduce reliance on offshore oil and gas industry) and more competition.

However, cost reduction potentials could be higher, as supply chain constraints and lack of competition have been estimated to have inflated installed costs by around 15% (Mott MacDonald, 2011). In this scenario, learning effects, moving to larger wind farms with larger turbines, increased supply chain development, and greater competition – as well as potential breakthroughs from novel wind turbine designs and foundations – could see costs fall by 28% by 2020 and by 43% by 2040. However, these reductions remain highly uncertain and variations of plus or minus 20% in 2040 are possible. Taking into account the increased capacity factors achieved by offshore wind turbines as they get continually larger means that capital costs (undiscounted) per MWh generated could drop by 55% by 2040 (Mott MacDonald, 2011).

Tab 4

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NREL
NATIONAL RENEWABLE ENERGY LABORATORY

2011 Cost of Wind Energy Review

S. Tegen, E. Lantz, M. Hand, B. Maples, A. Smith, and P. Schwabe
National Renewable Energy Laboratory

NREL is a national laboratory of the U.S. Department of Energy, Office of Energy Efficiency & Renewable Energy, operated by the Alliance for Sustainable Energy, LLC.

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NREL
NATIONAL RENEWABLE ENERGY LABORATORY

2011 Cost of Wind Energy Review

S. Tegen, E. Lantz, M. Hand, B. Maples, A. Smith, and P. Schwabe
National Renewable Energy Laboratory

Prepared under Task No. WE11.1201

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Although the ranges provided here for the selected variables are grounded in actual 2011 plant costs and performance data, the high and low LCOE ranges should not be taken as absolute. These variables are generally not independent, and it is unlikely for changes to only occur in a single variable. Moreover, each individual wind project has a unique set of characteristics. Accordingly, the sensitivities shown here are not universal.

3.7 Example Cost Reduction Scenarios

For the 2011 reference project installations, two additional scenarios were modeled: 1) decreased installed capital cost, and 2) increased annual average wind speed. Similar to the other sensitivities, this analysis was performed by holding all reference project assumptions constant and changing only one variable at a time.

3.7.1 Decreased Capital Cost

Wiser and Bolinger (2012) suggested that 2009/2010 represented a likely peak in installed capital cost based on 2011's slightly lower averages and estimates for 20 projects in 2012 that were reported to be even lower. With turbine prices peaking in 2008/2009 and continuing in a downward trend, it is reasonable to expect that installed capital cost would continue in a downward trend as well, because of the lag time between negotiations of turbine supply contracts, power purchase agreements, and project commissioning. If installed capital costs continue downward and match the initial 2012 estimated average reported by Wiser and Bolinger (2012) in midyear (approximately $1,750/kW), the reference project LCOE would be expected to fall to $62/kWh (Table 7).

3.7.2 Increased Annual Average Wind Speed

A number of factors, such as policy influences, siting impacts, and technology changes, have led to the recent trend in siting wind projects in areas of reduced wind resource quality (Wiser and Bolinger 2012). There is still a surplus of high-quality wind resource project sites that are undeveloped in the United States, and an effort to place more projects in these areas could lower LCOE. Table 7 presents the change in LCOE that is a direct result of switching from a Class 4 wind resource (annual average hub-height wind speed of 7.75 m/s) to a Class 5 wind resource (annual average hub-height wind speed of 8.29 m/s). It is important to note that the decrease in LCOE resulting from the better wind resource may also be achieved with a taller tower or a larger rotor for the same turbine power rating. If these technological advances can be implemented without a concurrent increase in either ICC or AOE (using advanced controls or design innovations), the net effect could be similar.

Table 7. Example Land-Based LCOE Reduction Scenarios

	Reference Project	Reduced ICC	Higher Annual Wind Speed
Installed capital cost ($/kW)	$2,098	$1,750	$2,098
AOE ($/kW/yr)	$35	$35	$35
Net annual energy production (MWh/MW/yr)	3,263	3,263	3,578
LCOE ($/MWh)	**$72**	**$62**	**$65**

4 Offshore Wind

Although there is much enthusiasm about the potential of offshore wind development in policy circles, no projects have been installed in U.S. waters to date. The lack of domestic experience with offshore wind technology has contributed to considerable uncertainty in estimates of the potential cost of offshore wind energy in the United States. The *2010 Cost of Wind Energy Review* (Tegen et al. 2012) offers a detailed analysis of offshore wind cost trends in Europe as well as projections for the United States to develop input assumptions for a reference project based on commercial-scale fixed-bottom offshore wind technology.

This report provides an update to the 2010 report including trends in capital costs observed outside of the United States as well as recent market conditions. However, as no major differences in offshore costs have been observed for projects under development in the United States, the cost estimates are consistent with those reported in the 2010 report (Tegen et al. 2012) (Table 8). Although information on floating offshore wind projects is not included here, it will be covered in future iterations of this report.

Table 8. Summary of Inputs and Results for the Fixed-Bottom Offshore Wind Project

Data Source		3.6-MW Offshore $/kW	3.6-MW Offshore $/MWh
Literature	Turbine capital cost	1,789	62
Market	Balance-of-station costs	2,918	101
Literature	Soft costs	893	31
Market	**INSTALLED CAPITAL COST**	**5,600**	**194**
Market	Annual operating expenses ($/kW/yr)	136	40
Market	Fixed charge rate (%)	11.8	
Model	Net annual energy production (MWh/MW/yr)	3,406	
Model	Capacity factor (%)	39	
	TOTAL LCOE ($/MWh)	**225**	

4.1 2011 Market Developments

In 2011, 966 MW of offshore wind capacity were installed worldwide (GWEC 2012). To date, offshore wind development has been highly concentrated, with over 93% of cumulative capacity installed in Europe (GWEC 2012). Installations in Asia are starting to accelerate, with two commercial-scale projects installed in China and three demonstration projects installed in South Korea and Japan. Global markets are poised for growth with aggressive goals in both Europe and Asia. However, deployments have been affected by uncertainty in the form and value of incentives (United Kingdom), delays in grid development (Germany), and local and national

Tab 5

COST REPORT

COST AND PERFORMANCE DATA FOR POWER GENERATION TECHNOLOGIES

Prepared for the
National Renewable Energy Laboratory

FEBRUARY 2012

BLACK & VEATCH
Building a world of difference.

1 Introduction

Black & Veatch contracted with the National Renewable Energy Laboratory (NREL) in 2009 to provide the power generating technology cost and performance estimates that are described in this report. These data were synthesized from various sources in late 2009 and early 2010 and therefore reflect the environment and thinking at that time or somewhat earlier, and not of the present day.

Many factors drive the cost and price of a given technology. Mature technologies generally have a smaller band of uncertainty around their costs because demand/supply is more stable and technology variations are fewer. For mature plants, the primary uncertainty is associated with the owner-defined scope that is required to implement the technology and with the site-specific variable costs. These are site-specific items (such as labor rates, indoor versus outdoor plant, water supply, access roads, labor camps, permitting and licensing, or lay-down areas) and owner-specific items (such as sales taxes, financing costs, or legal costs). Mature power plant costs are generally expected to follow the overall general inflation rate over the long term.

Over the last ten years, there has been doubling in the nominal cost of all power generation technologies and an even steeper increase in coal and nuclear because the price of commodities such as iron, steel, concrete, copper, nickel, zinc, and aluminum have risen at a rate much greater than general inflation; construction costs peak in 2009 for all types of new power plants. Even the cost of engineers and constructors has increased faster than general inflation has. With the recent economic recession, there has been a decrease in commodity costs; some degree of leveling off is expected as the United States completes economic recovery.

It is not possible to reasonably forecast whether future commodity prices will increase, decrease, or remain the same. Although the costs in 2009 are much higher than earlier in the decade, for modeling purposes, the costs presented here do not anticipate dramatic increases or decreases in basic commodity prices through 2050. Cost trajectories were assumed to be based on technology maturity levels and expected performance improvements due to learning, normal evolutionary development, deployment incentives, etc.

Black & Veatch does not encourage universal use solely of learning curve effects, which give a cost reduction with each doubling in implementation dependent on an assumed deployment policy. Many factors influence rates of deployment and the resulting cost reduction, and in contrast to learning curves, a linear improvement was modeled to the extent possible.

1.1 ASSUMPTIONS

The cost estimates presented in this report are based on the following set of common of assumptions:

1. Unless otherwise noted in the text, costs are presented in 2009 dollars.
2. Unless otherwise noted in the text, the estimates were based on on-site construction in the Midwestern United States.
3. Plants were assumed to be constructed on "greenfield" sites. The sites were assumed to be reasonably level and clear, with no hazardous materials, no standing timber, no wetlands, and no endangered species.
4. Budgetary quotations were not requested for this activity. Values from the Black &Veatch proprietary database of estimate templates were used.
5. The concept screening level cost estimates were developed based on experience and estimating factors. The estimates reflect an overnight, turnkey Engineering Procurement Construction, direct-hire, open/merit shop, contracting philosophy.

Tab 6

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Independent Statistics & Analysis
U.S. Energy Information Administration

Updated Capital Cost Estimates for Utility Scale Electricity Generating Plants

April 2013

Independent Statistics & Analysis
www.eia.gov

U.S. Department of Energy
Washington, DC 20585

Technology:	**WN**	
Nominal Capacity (ISO):	**100,000 kW**	
Nominal Heat Rate (ISO):	**N/A Btu/kWh-HHV**	
Total Project Cost (excluding project finance)	**/ kW**	**2,213**

(1) Includes engineering, distributable costs, scaffolding, construction management, and start-up.

For this type of technology and power plant configuration, our regional adjustments took into consideration the following: seismic design differences, remote location issues, labor wage and productivity differences, location adjustments, and owner cost differences and the increase in overheads associated with these five adjustments.

Seismic design differences among the various locations were based on U.S. seismic map information that detailed the various seismic zones throughout the U.S. No cost increases were associated with seismic Zone 0 and cost step increases were considered for Zones 1, 2, 3 and 4.

Remote location issues are related to geographic areas that typically require installation of man camps, higher craft incentives, and higher per diems are generally required with respect to construction, due to the fact that such areas are long distances from urban areas, where labor is generally abundant. Remote location designations were also considered in locations where higher equipment freight costs are typically incurred, which for example are regions not near established rail or highway access. Remote locations related to the WN Facility include Fairbanks, Alaska; Honolulu, Hawaii; Albuquerque, New Mexico; Cheyenne, Wyoming; and Cayey, Puerto Rico.

Labor wage and productivity differences were handled as discussed in Section 2.5.1, taking into consideration the amount of labor we estimated for the WN Facility.

Location adjustments were made to locations where higher cost of living levels are incurred and/or where population density generally correlates to higher construction costs for power and other infrastructure projects. These locations include, but are not limited to, Alaska, California, Connecticut, Delaware, District of Columbia, Hawaii, Illinois, Maine, Maryland, Massachusetts, Michigan, Minnesota, New York, Ohio, and Wisconsin.

Owner costs were reviewed based on the need for utility upgrades and/or infrastructure costs such as new facility transmission lines to tie to existing utility transmission substations or existing transmission lines.

Table 21-2 in the Appendix presents the WN Facility capital cost variations for alternative U.S. plant locations.

21.5 O&M ESTIMATE

In addition to the general items discussed in the section of the report entitled O&M Estimate, the major areas for O&M for an Onshore Wind Facility include periodic gearbox, WTG, electric generator, and associated electric conversion (e.g., GSU) technology repairs and replacement. These devices typically undergo major maintenance every five to seven years. Based on recent experience, most WN operators do not treat O&M on a variable basis, and consequently, all O&M expenses are shown below on a fixed basis. Table 21-3 presents the O&M expenses for the WN Facility.

Tab 7

REFERENCE: Appendix 7.2 Range of Resource Options; Page No.: 334

PREAMBLE: Appendix 7.2 indicates that "REC Premium Marketability" for On-Shore Wind Projects is "Very High"

QUESTION:

Does Manitoba Hydro realize any Class I REC value for the sale output of the St. Leon and St. Joseph wind projects in US export markets? If not, please discuss why not.

RESPONSE:

Manitoba Hydro does not realize any Class I REC value for the sale output of the St. Leon and St. Joseph wind projects. The St. Leon and St. Joseph wind farm output does not qualify under U.S. state renewable portfolio standards as Class I RECs because the generation is external to the U.S.

REFERENCE: Chapter 8: Determination and Description of Development Plans; Recent PRP(s)

QUESTION:

Please provide an updated history of MH's purchased wind energy (MW/GWh/year) and discuss the potential for more Manitoba wind energy capacity while employing Lake Winnipeg and other reservoir storage to optimize the wind energy value.

RESPONSE:

Manitoba Hydro is unable to provide wind farm specific production information as it is commercially sensitive and confidential. Therefore any wind generation data prior to April, 2011, when only one wind farm was in production, has not been provided.

Total wind generation data for both St Leon and St Joseph since April, 2011 is as follows:

Year	MWh
2011/12	908267
2012/13	851139

Additional Manitoba wind development is considered as an energy resource option as described in Chapter 8 of the submission. However in order to ensure that load can be met, wind resources must be combined with firm capacity resources over time such as natural gas-fired generation in order that Manitoba Hydro can meet the capacity needs of customers in Manitoba.

Under today's market and regulatory environment it is not viable to develop additional wind energy in Manitoba using existing reservoir storage and transmission line capacity to provide that firm power to US customers for the following reasons:

a) Information provided from potential Manitoba wind developers indicates that the cost of new wind power projects far exceeds the current market energy price in the US market. Developers are unwilling to assume any future market price risk.
b) US customers have access to relatively inexpensive wind energy because of US federal subsidies.
c) Wind energy from Manitoba may technically qualify for meeting US Renewable Portfolio Standards (RPS) in some jurisdictions but Manitoba Hydro's US customers are not interested in purchasing wind energy from Manitoba to meet state RPS requirements.
d) New wind generation development in Manitoba would not enable the construction of new transmission for Manitoba's benefit in the US. As indicated in the MISO Wind Synergy Study, only new hydro generation provides dispatchable capacity and storage services which are needed in the MISO market to accommodate US wind integration. New Manitoba wind generation for export would exacerbate the issues associated with developing US wind resources and would result in increased integration costs rather than lower costs. To the extent US utilities invest in new transmission for wind, it will be to support the development of local wind resources that qualify for RPS recognition.

In summary, US customers and regulators have shown no interest in wind energy from Manitoba and are unwilling to enter into contracts for such energy. It would be uneconomic for Manitoba Hydro to develop additional wind energy in Manitoba for export purposes.

Tab 8

SUBJECT: Wind LCOE

REFERENCE: Chapter 7: Screening of Manitoba Resource Options; Section: 7.3; Page No.: 39

QUESTION REFERENCE: GAC/MH I-001c

PREAMBLE: Table 7.6 gives the Levelized Cost of Energy (LCOE) of wind as $86/MWh in 2014 dollars. Manitoba Hydro's response to GAC/MH I-001c states "The levelized cost for a 100 MW on-shore wind project at the reference capital cost of$2100/kW without transmission is $75/MWh. ... after the submission of the NFAT filing it was identified that the capital cost for the wind resource option used throughout the filing was approximately 5% higher than it should have been."

QUESTION:

Please confirm that the new LCOE of $75/MWh is in 2014 dollars, and is inclusive of all costs that should be considered in screening resource options, and thus is directly comparable to the $86/MWh amount shown in Table 7.6. If so, please explain how a 5% change in capital costs translates into a 13% change in total costs. If not, please explain what further adjustments need to be made either to the $75/MWh amount or to the $86/MWh amount to make them directly comparable to the LCOEs shown in Table 7.6 for Keeyask and Conawapa of $60/MWh and $67/MWh respectively.

RESPONSE:

Not confirmed.

The LCOE of $75/MWh quoted in the response to GAC/MH I-001c does not include a transmission component and is provided in 2012 dollars. This value therefore cannot be compared to the LCOE values presented in Table 7.6 as the values in this table include transmission and are provided in 2014 dollars.

The levelized cost of a 65 MW wind farm has been revised from $86/MW.h to $84/MW.h (2014 dollars including transmission) and is directly comparable to the LCOE values listed in table 7.6 for Keeyask and Conawapa. Refer to tab 22 of LCA-MH I-308 Att 1.xlsx which is an attachment to IR LCA/MH I-308 for inputs, assumptions and calculations used to derive the $84/MW.h levelized cost.

Tab 9

Power Generation Flexibility:

- **Fuel Type:** Renewable - Wind Energy
- **Mode of Operation:** Must-take generation
- **Dispatch & Deployment Speed:** Non-Dispatchable
- **Intermittency:** Intermittent - wind speed variability
- **Seasonality:** Some seasonality affect

Maturity of Technology: Well-Established

System Integration Considerations: Intermittency diffcult to forecast contibuting to higher integration costs.

Technical Challenges: No major impediments

Project Lead Time:

Planning Phase: Investigations, Development Arrangements, Preliminary Design & Approvals *(years)*	1-2
Construction Phase: Final Design, Procurement & Construction *(years)*	2-3
Minimum Time to Earliest ISD *(years)*	3-5

Typical Asset Life: 20 years

Economic Characteristics

Generic On-Shore Wind (100 MW)

Levelized Cost (*P_{50} Estimate*):

With Transmission - $67 to $108 CAD (2012$)/MW.h @ 5.05%

Without Transmission ≈ $62 to $99 CAD (2012$)/MW.h @ 5.05%

Base Estimate (*P_{50} Estimate*):

Without Transmission - $160 to $300 million CAD (2012$)

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Expected Accuracy Range of Cost Estimate: -50% to +100%

Overnight Capital Cost ($/kW): $1600 to $3000 CAD (2012$)/kw

Estimate Classification:

Manitoba Hydro Planning Stage	Stage 1 - Inventory
AACEI Estimate Classification	Class 5

Estimating Technique: Analogy

Year of Current Estimate: 2012

Average Lifetime Operations and Maintenance Costs:

Fixed O&M Costs	$39.55 CAD (2012$)/kW/year
Variable Non-fuel O&M Costs	$0.00 CAD (2012$)/MW.h/year

Fuel Supply Description:

- **Source:** Locally-sourced fuel
- **Quality:** Very Good: Southern Manitoba has Wind Power Class ranking of Class 3 to 4 . (NREL Wind Power Classification)
- **Supply Risk:** None
- **Commodity Pricing Trends:** Post-2001 Fuel Price Volatility - None
- **Transportation Pricing Trends:** None
- **Price Forecast:** None

REC Premium Marketability: Very High

Overnight Capital Cost ($/kW): $2400 CAD (2012$)/kw

Estimate Classification:

Manitoba Hydro Planning Stage	Stage 1 - Inventory
AACEI Estimate Classification	Class 5

Estimating Technique: Analogy

Year of Current Estimate: 2012

Average Lifetime Operations and Maintenance Costs:

Fixed O&M Costs	$39.55 CAD (2012$)/kW/year
Variable Non-fuel O&M Costs	$0.00 CAD (2012$)/MW.h/year

Fuel Supply Description:

- **Source:** Locally-sourced fuel
- **Quality:** Very Good: Southern Manitoba has Wind Power Class ranking of Class 3 to 4 . (NREL Wind Power Classification)
- **Supply Risk:** None
- **Commodity Pricing Trends:** Post-2001 Fuel Price Volatility - None
- **Transportation Pricing Trends:** None
- **Price Forecast:** None

REC Premium Marketability: Very High

Tab 10

The incremental costs for the 500 MW wind capacity in relation to the EEB case are summarized in Table 5.3 and Table 5.4 of the Synexus Global report for the base case as well as the sensitivity to reserve case.

Synexus Global Table 5.3 500 MW - Incremental Costs, Millions of U.S. Dollars

Hydrology	Wind	Sensitivity[1]
Low	4.8	3.1
Median	5.6	3.6
High	6.7	1.8

1- Due only to variability as there is no additional reserves defined.

Synexus Global Table 5.4 1000 MW - Incremental Costs, Millions of U.S. Dollars

Hydrology	Wind	Sensitivity[1]
Low	9.1	4.5
Median	11.3	6.9
High	19.7	4.8

1- Due only to variability as there is no additional reserves defined.

The above wind integration costs were flow weighted and then the total divided by the average annual wind generation to produce the unit wind integration costs as follows:

- 500 MW of wind generation: $4.22/ MWh (2005 dollars)
- 1000 MW of wind generation: $4.99/ MWh (2005 dollars)

The unit wind integration costs are expressed on a marginal basis for each 100 MW increment of wind, and scaled to the current long-term export price forecast using the ratio of the current long-term price forecast divided by the 2005 price forecast.

Tab 11

assumption, noting recent projects in the region with an average capacity factor of 42%, and assuming a 43% capacity factor in its sensitivity analysis." [57,58]. Manitoba Hydro does not agree that capacity factors in excess of 40% are achievable for all future wind projects. Manitoba Hydro maintains that using a representative capacity factor of 40% is reasonable and appropriate.

A study[59] undertaken for Manitoba Hydro and completed in 2005 examined the wind performance characteristics of 7 sites throughout southern and central Manitoba. The following table summarizes the findings of this study demonstrating the variability of the wind resource at locations across Manitoba.

Table 1: Estimated Capacity Factors at 7 Manitoba Sites

Site Location	Average Wind Speed @80 m AGL (m/s)	Wind Class	Capacity Factor @80 m AGL (%)
Lizard Lake – (within St. Leon Wind Farm area)	8.3	5	38.2
Boissevain	7.9	4	35.3
Letellier - (approximately 8 km from St. Joseph Wind Farm)	7.6	4	33.0
Minnedosa	7.1	3	27.7
Grandview	6.9	3	27.3
Lake Manitoba Narrows	6.6	2	24.6
PTH 60 near Cedar Lake	6.5	2	22.8

[57] La Capra Technical Appendix 3A – Page 3A-28, Section VI – B. Wind cost assumption analysis
[58] Green Action Centre Evidence on Fuel Switching, DSM and Wind – Page 4-7, Section 4.2.3.1 Capacity Factor
[59] Helimax Energy Inc. (2005), Wind Monitoring Program Final Report (2003-2004) Manitoba Hydro

Tab 12

REFERENCE: Appendix 7.2 Range of Resource Options; Section: 1.2; Page No.: 9

PREAMBLE: Table 7.2.2 specifies a 40% lifetime capacity factor for on-shore wind.

QUESTION:

Please provide the work papers and assumptions that were used to derive this 40% capacity factor value.

RESPONSE:

The 40% lifetime capacity factor assumption for on-shore wind in Manitoba was derived from actual experience from the two wind farms in Manitoba. Manitoba Hydro's 2012/13 Annual Report at page 101 states wind purchases of 0.9 billion kWh. Based on installed capacities of St. Leon at 120.5 MW and St. Joseph at 138 MW, the calculation results in a capacity factor (CF) of 39.72% (40% rounded up) for purchased wind energy.

Capacity Factor = (900,000,000 kW.h/year/ (258,500 kW x 24 hours/day x 365.25 days/year)) x 100% = 39.72%

Table Appendix 7.2-2. **LCOE SUMMARY OF NON-DISPATCHABLE RESOURCE OPTIONS (2012$)**

Resource Options	Category	Rated Capacity	Net System Capacity	Lifetime Capacity Factor	Levelized Cost without Transmission (CAD 2012$ at 5.05%)	Levelized Cost with Transmission (CAD 2012$ at 5.05%)
NON-DISPATCHABLE RESOURCES						
Solar Photovoltaics - Fixed Tilt	Renewable - Solar	20 MW	0 MW	≈20%	≈$203/MW.h	
Solar Photovoltaics - Single Axis Tracking	Renewable - Solar	20 MW	0 MW	≈26%	≈$187/MW.h	
Solar Photovoltaics - Dual Axis Tracking	Renewable - Solar	20 MW	0 MW	≈28%	≈$193/MW.h	
Solar Parabolic Trough (No Thermal Storage)	Renewable - Solar	50 MW	0 MW	≈26%		
Low Capital Cost Case					$140/MW.h	
High Capital Cost Case					$187/MW.h	
Solar Parabolic Trough (6-hour Thermal Storage)	Renewable - Solar	50 MW	0 MW	≈40%		
Low Capital Cost Case					$144/MW.h	
High Capital Cost Case					$175/MW.h	
Generic On-Shore Wind (100 MW)	Renewable - Wind	100 MW	0 MW	≈40%		
Low Capital Cost Case					$62/MW.h	$67/MW.h
High Capital Cost Case					$99/MW.h	$108/MW.h
Generic On-Shore Wind (65 MW)	Renewable - Wind	65 MW	0 MW	≈40%	$78/MW.h	$83/MW.h
Generic In-Lake Wind	Renewable - Wind	100 MW	0 MW	≈43%		
Low Capital Cost Case					$132/MW.h	$140/MW.h
High Capital Cost Case					$225/MW.h	$233/MW.h

1.3 NFAT PREFERRED RESOURCE OPTIONS - SUMMARY OF CHARACTERISTICS

Following a general review of resource options conducted annually for the resource planning process and a more comprehensive screening exercise undertaken for the NFAT process, 16 resource options were recognized and chosen for additional study. The 16 resource options include 12 hydroelectric options, three thermal options and a wind resource option. Table Appendix 7.2-3, Table Appendix 7.2-4, and Table Appendix 7.2-5 respectively summarize important characteristics for these resources. LCOE values in these tables are reported in 2014$ as required for NFAT analysis purposes while LCOE values contained in the resource option summary sheets are reported in 2012$.

Tab 13

Levelized Cost of Energy
Keeyask Generating Station

Current Dollar Year:	2012	
Discount Rate:	5.05	%
Service Life:	67	yrs
Time to First Power:	7	yrs
Nominal Capacity:	695	MW
Net Summer Capacity:	630	MW
Net Winter Capacity:	630	MW
Capacity Factor:	60	%
Auxiliary Power:	0	%
N to S Trans. Adjustment:	10	%
Capital Tax:	0.5	%
Water Rental Rate:	3.3426	$/MW.h
Heat Rate:	N/A	Btu/kW.h

With Transmission	2012$	2014$	
Base Estimate:	3324	3452	$Million
Overnight Capital Cost:	4783	4967	$/kW
LCOE@Gen.:	52.71	54.74	$/MW.h
LCOE@Load:	57.98	60.21	$/MW.h

Without Transmission	2012$	2014$	
Base Estimate:	3168	3289	$Million
Overnight Capital Cost:	4558	4733	$/kW
LCOE@Gen.:	50.32	52.25	$/MW.h
LCOE@Load:	55.35	57.48	$/MW.h

			Generation (Millions of $CDN)							
Fiscal Year	Years to Earliest ISD	Average Net Energy (GW.h)	Generating Station	Trans. Station	Trans. Line	Capital Tax on GS	Capital Tax on TL & TS	Water Rentals	Fixed O&M	TOTAL COST
2012/13	-7	0	0.00	0.07	1.83	0.00	0.01	0.00	0.00	1.91
2013/14	-6	0	0.00	0.41	0.73	0.00	0.02	0.00	0.00	1.15
2014/15	-5	0	213.21	1.17	17.60	1.07	0.11	0.00	0.00	233.15
2015/16	-4	0	467.85	0.39	8.33	3.41	0.15	0.00	0.00	480.13
2016/17	-3	0	619.50	14.43	1.00	6.50	0.23	0.00	0.00	641.67
2017/18	-2	0	750.79	18.30	8.68	10.26	0.36	0.00	0.00	788.39
2018/19	-1	0	529.39	19.78	18.57	12.90	0.56	0.00	0.00	581.20
2019/20	0	1371	378.63	16.14	29.30	14.80	0.78	3.93	12.53	456.11
2020/21	1	3955	154.61	0.00	0.01	15.57	0.78	11.13	12.73	194.84
2021/22	2	4430	53.65	0.00		15.84	0.78	12.23	12.45	94.96
2022/23	3	4430		0.00		15.84	0.78	12.00	12.66	41.29
2023/24	4	4430		0.00		15.84	0.78	11.78	12.49	40.90
2024/25	5	4430		0.00		15.84	0.78	11.56	12.45	40.63
2025/26	6	4430		0.00		15.84	0.78	11.34	12.22	40.18
2026/27	7	4430		0.00		15.84	0.78	11.13	11.80	39.56
2027/28	8	4430		0.00		15.84	0.78	10.93	11.80	39.35
2028/29	9	4430		0.00		15.84	0.78	10.72	11.84	39.19
2029/30	10	4430		0.00		15.84	0.78	10.52	14.44	41.58
2030/31	11	4430		0.00		15.84	0.78	10.33	10.65	37.60
2031/32	12	4430		0.00		15.84	0.78	10.13	10.65	37.41
2032/33	13	4430		0.00		15.84	0.78	9.94	10.65	37.22
2033/34	14	4430		0.00		15.84	0.78	9.76	10.65	37.03
2034/35	15	4430		0.00		15.84	0.78	9.58	10.65	36.85
2035/36	16	4430		0.00		15.84	0.78	9.40	10.02	36.04
2036/37	17	4430		0.00		15.84	0.78	9.22	10.02	35.86
2037/38	18	4430		0.00		15.84	0.78	9.05	10.02	35.69
2038/39	19	4430		0.00		15.84	0.78	8.88	10.02	35.52
2039/40	20	4430		0.00		15.84	0.78	8.72	12.81	38.14
2040/41	21	4430		0.00		15.84	0.78	8.55	10.02	35.19
2041/42	22	4430		0.00		15.84	0.78	8.39	10.02	35.03
2042/43	23	4430		0.00		15.84	0.78	8.24	10.02	34.88
2043/44	24	4430		0.00		15.84	0.78	8.08	10.02	34.72
2044/45	25	4430		0.00		15.84	0.78	7.93	11.69	36.24
2045/46	26	4430		0.00		15.84	0.78	7.79	11.69	36.10
2046/47	27	4430		0.00		15.84	0.78	7.64	11.69	35.95
2047/48	28	4430		0.07		15.84	0.78	7.50	10.85	35.04
2048/49	29	4430		0.41		15.84	0.79	7.36	10.02	34.41
2049/50	30	4430		1.17		15.84	0.79	7.22	12.81	37.83
2050/51	31	4430		0.39		15.84	0.79	7.09	10.02	34.13
2051/52	32	4430		14.43		15.84	0.87	6.95	10.02	48.10
2052/53	33	4430		18.30		15.84	0.96	6.82	10.02	51.94
2053/54	34	4430		19.78		15.84	1.06	6.70	10.02	53.39
2054/55	35	4430		16.14		15.84	1.14	6.57	10.02	49.70
2055/56	36	4430		0.00		15.84	1.14	6.45	10.02	33.44
2056/57	37	4430				15.84	1.14	6.33	24.94	48.24
2057/58	38	4430				15.84	1.14	6.21	10.02	33.20
2058/59	39	4430				15.84	1.14	6.10	24.94	48.01
2059/60	40	4430				15.84	1.14	5.98	12.81	35.76
2060/61	41	4430				15.84	1.14	5.87	24.94	47.78
2061/62	42	4430				15.84	1.14	5.76	10.02	32.75
2062/63	43	4430				15.84	1.14	5.65	24.94	47.57
2063/64	44	4430				15.84	1.14	5.55	10.02	32.54
2064/65	45	4430				15.84	1.14	5.44	24.94	47.36
2065/66	46	4430				15.84	1.14	5.34	10.02	32.33
2066/67	47	4430				15.84	1.14	5.24	24.94	47.16
2067/68	48	4430				15.84	1.14	5.15	10.02	32.14
2068/69	49	4430				15.84	1.14	5.05	24.94	46.96
2069/70	50	4430				15.84	1.14	4.96	12.81	34.74
2070/71	51	4430				15.84	1.14	4.86	11.69	33.53
2071/72	52	4430				15.84	1.14	4.77	11.69	33.44
2072/73	53	4430				15.84	1.14	4.68	11.69	33.35
2073/74	54	4430				15.84	1.14	4.60	10.85	32.42
2074/75	55	4430				15.84	1.14	4.51	10.02	31.50
2075/76	56	4430				15.84	1.14	4.43	10.02	31.42
2076/77	57	4430				15.84	1.14	4.34	10.02	31.34
2077/78	58	4430				15.84	1.14	4.26	10.02	31.25
2078/79	59	4430				15.84	1.14	4.18	10.02	31.18
2079/80	60	4430				15.84	1.14	4.11	12.81	33.89
2080/81	61	4430				15.84	1.14	4.03	10.02	31.02
2081/82	62	4430				15.84	1.14	3.95	10.02	30.95
2082/83	63	4430				15.84	1.14	3.88	10.02	30.87
2083/84	64	4430				15.84	1.14	3.81	10.02	30.80
2084/85	65	4430				15.84	1.14	3.74	10.02	30.73
2085/86	66	4430				15.84	1.14	3.67	10.02	30.66
2086/87	67	3059						2.48		0.38
2087/88	68	475						0.38		0.00
2088/89	69									
2089/90	70									
2090/91	71									
2091/92	72									
2092/93	73									
2093/94	74									
PV =		60473	2493.13	63.82	67.83	250.71	13.08	128.21	170.82	3187.52
LCOE@Gen. ($/MW.h) =			41.23	1.06	1.12	4.15	0.22	2.12	2.82	52.71
LCOE@Load ($/MW.h) =			45.35	1.16	1.23	4.56	0.24	2.33	3.11	57.98

Levelized Cost of Energy
Conawapa Generating Station

Current Dollar Year:	2012	
Discount Rate:	5.05	%
Service Life:	67	yrs
Time to First Power:	13	yrs
Nominal Capacity:	1485	MW
Net Summer Capacity:	1395	MW
Net Winter Capacity:	1300	MW
Capacity Factor:	57	%
Auxiliary Power:	0	%
N to S Trans. Adjustment:	10	%
Capital Tax:	0.5	%
Water Rental Rate:	3.3426	$/MW.h
Heat Rate:	N/A	Btu/kW.h

With Transmission	2012$	2014$	
Base Estimate:	5493	5704	$Million
Overnight Capital Cost:	3699	3841	$/kW
LCOE@Gen.:	58.00	60.23	$/MW.h
LCOE@Load:	63.80	66.26	$/MW.h

Without Transmission	2012$	2014$	
Base Estimate:	5483	5694	$Million
Overnight Capital Cost:	3692	3834	$/kW
LCOE@Gen.:	57.91	60.14	$/MW.h
LCOE@Load:	63.70	66.15	$/MW.h

			Generation (Millions of $CDN)							
Fiscal Year	Years to Earliest ISD	Average Net Energy (GW.h)	Generating Station	Trans. Station	Trans. Line	Capital Tax on GS	Capital Tax on TL & TS	Water Rentals	Fixed O&M	TOTAL COST
2012/13	-13	0	0.00		0.00	0.00	0.00	0.00	0.00	0.00
2013/14	-12	0	0.00		0.00	0.00	0.00	0.00	0.00	0.00
2014/15	-11	0	30.53		0.00	0.15	0.00	0.00	0.00	30.69
2015/16	-10	0	84.24		0.00	0.57	0.00	0.00	0.00	84.82
2016/17	-9	0	175.50		0.00	1.45	0.00	0.00	0.00	176.95
2017/18	-8	0	204.18		0.00	2.47	0.00	0.00	0.00	206.65
2018/19	-7	0	245.42		0.00	3.70	0.00	0.00	0.00	249.12
2019/20	-6	0	251.31		0.00	4.96	0.00	0.00	0.00	256.27
2020/21	-5	0	692.73		0.00	8.42	0.00	0.00	0.00	701.15
2021/22	-4	0	1112.09		0.52	13.98	0.00	0.00	0.00	1126.59
2022/23	-3	0	998.48		1.03	18.97	0.01	0.00	0.00	1018.50
2023/24	-2	0	713.03		2.06	22.54	0.02	0.00	0.00	737.64
2024/25	-1	0	493.81		4.64	25.01	0.04	0.00	0.00	523.50
2025/26	0	2200	324.35		2.06	26.63	0.05	5.63	13.77	372.50
2026/27	1	6600	119.46			27.23	0.05	16.59	13.98	177.31
2027/28	2	7000	37.70			27.41	0.05	17.26	13.70	96.13
2028/29	3	7000				27.41	0.05	16.94	13.91	58.32
2029/30	4	7000				27.41	0.05	16.63	13.74	57.83
2030/31	5	7000				27.41	0.05	16.32	13.70	57.48
2031/32	6	7000				27.41	0.05	16.01	13.47	56.94
2032/33	7	7000				27.41	0.05	15.71	13.05	56.23
2033/34	8	7000				27.41	0.05	15.42	13.05	55.93
2034/35	9	7000				27.41	0.05	15.13	13.09	55.69
2035/36	10	7000				27.41	0.05	14.85	15.71	58.03
2036/37	11	7000				27.41	0.05	14.57	12.92	54.96
2037/38	12	7000				27.41	0.05	14.30	12.92	54.69
2038/39	13	7000				27.41	0.05	14.03	12.92	54.42
2039/40	14	7000				27.41	0.05	13.77	12.92	54.16
2040/41	15	7000				27.41	0.05	13.52	12.92	53.91
2041/42	16	7000				27.41	0.05	13.26	12.29	53.02
2042/43	17	7000				27.41	0.05	13.02	12.29	52.77
2043/44	18	7000				27.41	0.05	12.77	12.29	52.53
2044/45	19	7000				27.41	0.05	12.54	12.29	52.29
2045/46	20	7000				27.41	0.05	12.30	15.08	54.85
2046/47	21	7000				27.41	0.05	12.07	12.29	51.83
2047/48	22	7000				27.41	0.05	11.85	12.29	51.60
2048/49	23	7000				27.41	0.05	11.63	12.29	51.38
2049/50	24	7000				27.41	0.05	11.41	12.29	51.17
2050/51	25	7000				27.41	0.05	11.20	13.96	52.63
2051/52	26	7000				27.41	0.05	10.99	13.96	52.42
2052/53	27	7000				27.41	0.05	10.78	13.96	52.21
2053/54	28	7000				27.41	0.05	10.58	13.96	52.01
2054/55	29	7000				27.41	0.05	10.39	13.96	51.81
2055/56	30	7000				27.41	0.05	10.19	15.08	52.74
2056/57	31	7000				27.41	0.05	10.00	12.29	49.76
2057/58	32	7000				27.41	0.05	9.82	12.29	49.57
2058/59	33	7000				27.41	0.05	9.63	12.29	49.39
2059/60	34	7000				27.41	0.05	9.45	12.29	49.21
2060/61	35	7000				27.41	0.05	9.28	12.29	49.03
2061/62	36	7000				27.41	0.05	9.10	12.29	48.86
2062/63	37	7000				27.41	0.05	8.93	27.21	63.61
2063/64	38	7000				27.41	0.05	8.77	12.29	48.52
2064/65	39	7000				27.41	0.05	8.60	27.21	63.28
2065/66	40	7000				27.41	0.05	8.44	15.08	50.99
2066/67	41	7000				27.41	0.05	8.29	27.21	62.96
2067/68	42	7000				27.41	0.05	8.13	12.29	47.89
2068/69	43	7000				27.41	0.05	7.98	27.21	62.66
2069/70	44	7000				27.41	0.05	7.83	12.29	47.59
2070/71	45	7000				27.41	0.05	7.68	27.21	62.36
2071/72	46	7000				27.41	0.05	7.54	12.29	47.30
2072/73	47	7000				27.41	0.05	7.40	27.21	62.08
2073/74	48	7000				27.41	0.05	7.26	12.29	47.02
2074/75	49	7000				27.41	0.05	7.13	27.21	61.80
2075/76	50	7000				27.41	0.05	6.99	15.08	49.54
2076/77	51	7000				27.41	0.05	6.86	28.88	63.21
2077/78	52	7000				27.41	0.05	6.74	13.96	48.17
2078/79	53	7000				27.41	0.05	6.61	28.88	62.96
2079/80	54	7000				27.41	0.05	6.49	13.96	47.92
2080/81	55	7000				27.41	0.05	6.37	28.88	62.72
2081/82	56	7000				27.41	0.05	6.25	12.29	46.00
2082/83	57	7000				27.41	0.05	6.13	12.29	45.89
2083/84	58	7000				27.41	0.05	6.02	12.29	45.77
2084/85	59	7000				27.41	0.05	5.90	12.29	45.66
2085/86	60	7000				27.41	0.05	5.79	15.08	48.34
2086/87	61	7000				27.41	0.05	5.69	12.29	45.44
2087/88	62	7000				27.41	0.05	5.58	12.29	45.34
2088/89	63	7000				27.41	0.05	5.48	12.29	45.23
2089/90	64	7000				27.41	0.05	5.37	12.29	45.13
2090/91	65	7000				27.41	0.05	5.27	12.29	45.03
2091/92	66	7000				27.41	0.05	5.18	12.29	44.93
2092/93	67	4800						3.48		3.48
2093/94	68	400						0.28		0.28
PV =		71288	3492.63	0.00	5.82	352.19	0.58	135.12	148.57	4134.92
LCOE@Gen. ($/MW.h) =			48.99	0.00	0.08	4.94	0.01	1.90	2.08	58.00
LCOE@Load ($/MW.h) =			53.89	0.00	0.09	5.43	0.01	2.09	2.29	63.80

Levelized Cost of Energy

Wind 100 MW Low Capital Cost Stage I Transmission

Current Dollar Year:	2012	
Discount Rate:	5.05	%
Service Life:	20	yrs
Time to First Power:	5	yrs
Nominal Capacity:	100	MW
Net Summer Capacity:	10	MW
Net Winter Capacity:	0	MW
Capacity Factor:	40	%
Auxiliary Power:	0	%
N to S Trans. Adjustment:	0	%
Capital Tax:	0.5	%
Water Rental Rate:	0	$/MW.h
Heat Rate:	N/A	Btu/kW.h

With Transmission	2012$	2014$	
Base Estimate:	171	177	$Million
Overnight Capital Cost:	1707	1773	$/kW
LCOE@Gen.:	65.65	68.17	$/MW.h
LCOE@Load:			$/MW.h

Without Transmission	2012$	2014$	
Base Estimate:	151	157	$Million
Overnight Capital Cost:	1507	1565	$/kW
LCOE@Gen.:	60.49	62.81	$/MW.h
LCOE@Load:			$/MW.h

			Generation (Millions of $CDN)							
Fiscal Year	Years to Earliest ISD	Average Net Energy (GW.h)	Generating Station	Trans. Station	Trans. Line	Capital Tax on GS	Capital Tax on TL & TS	Wind Integration	Fixed O&M	TOTAL COST
2012/13	-5	0	0.00	0.00		0.00	0.00	0.00	0.00	0.00
2013/14	-4	0	0.00	0.00		0.00	0.00	0.00	0.00	0.00
2014/15	-3	0	4.50	0.00		0.02	0.00	0.00	0.00	4.52
2015/16	-2	0	143.21	20.00		0.74	0.10	0.00	0.00	164.05
2016/17	-1	0	3.03			0.75	0.10	0.00	0.00	3.88
2017/18	0	351				0.75	0.10	2.96	4.60	8.42
2018/19	1	351				0.75	0.10	2.96	4.60	8.42
2019/20	2	351				0.75	0.10	2.96	4.60	8.42
2020/21	3	351				0.75	0.10	2.96	4.60	8.42
2021/22	4	351				0.75	0.10	2.96	4.60	8.42
2022/23	5	351				0.75	0.10	2.96	4.60	8.42
2023/24	6	351				0.75	0.10	2.96	4.60	8.42
2024/25	7	351				0.75	0.10	2.96	4.60	8.42
2025/26	8	351				0.75	0.10	2.96	4.60	8.42
2026/27	9	351				0.75	0.10	2.96	4.60	8.42
2027/28	10	351				0.75	0.10	2.96	4.60	8.42
2028/29	11	351				0.75	0.10	2.96	4.60	8.42
2029/30	12	351				0.75	0.10	2.96	4.60	8.42
2030/31	13	351				0.75	0.10	2.96	4.60	8.42
2031/32	14	351				0.75	0.10	2.96	4.60	8.42
2032/33	15	351				0.75	0.10	2.96	4.60	8.42
2033/34	16	351				0.75	0.10	2.96	4.60	8.42
2034/35	17	351				0.75	0.10	2.96	4.60	8.42
2035/36	18	351				0.75	0.10	2.96	4.60	8.42
2036/37	19	351				0.75	0.10	2.96	4.60	8.42
2037/38										
2038/39										
2039/40										
2040/41										
2041/42										
2042/43										
2043/44										
2044/45										
2045/46										
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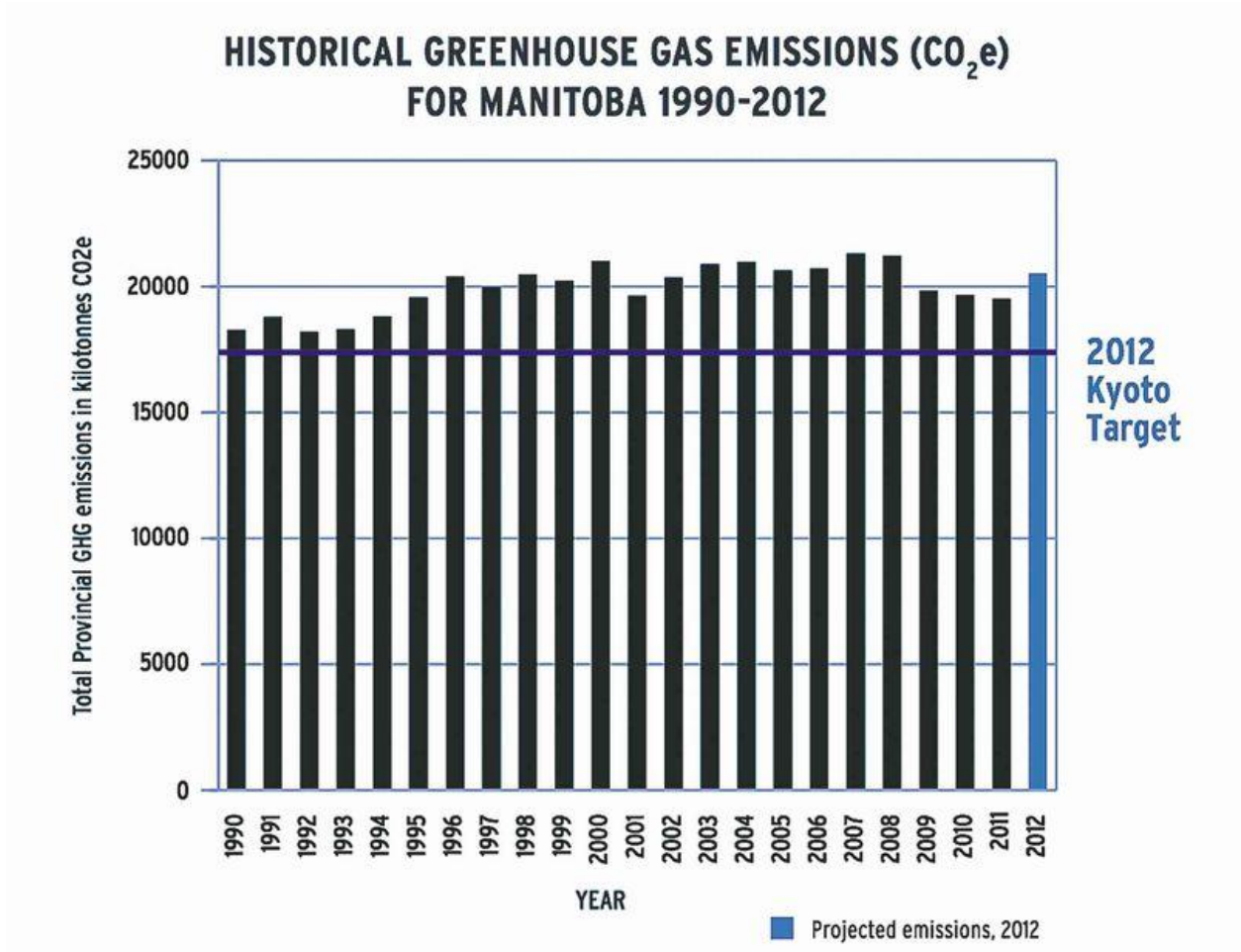
2090/91										
2091/92										
2092/93										
2093/94										
PV =		3573	130.10	17.25	0.00	8.96	1.19	30.19	46.87	234.56
LCOE@Gen. ($/MW.h) =			36.41	4.83	0.00	2.51	0.33	8.45	13.12	65.65
LCOE@Load ($/MW.h) =			36.41	4.83	0.00	2.51	0.33	8.45	13.12	65.65

http://www.winnipegfreepress.com/local/provinces-carbon-emissions-jump-248318151.html

Province's carbon emissions jump

Now farther than ever from long-abandoned Kyoto goal

By: Mary Agnes Welch
Posted: 03/4/2014 1:00 AM



A Manitoba government graphic shows the fluctuations in Manitoba's greenhouse gas emissions since 1990.

RELATED ITEMS

1. **ARTICLES**
   - **Blame U.S. carbon emissions on coal**

Enlarge Image

Transportation emissions, which make up more than 40 per cent of Manitoba's greenhouse gas emissions, have risen consistently since 1990. (WAYNE GLOWACKI / WINNIPEG FREE PRESS FILES) Photo Store

The province's greenhouse gas emissions spiked in 2012 after five years of small but steady declines.

That moves Manitoba even further away from its original Kyoto targets, now long abandoned.

The new data, contained in an annual climate change progress report released with little fanfare last week, peg Manitoba's 2012 carbon emissions at 20,500 kilotonnes. That's a five per cent increase over 2011, and it's the first year-over-year increase since 2006.

Emissions data, which are complicated to track, are typically two years old when they're finally tallied and made public. The province's latest figures are projections. Official data for 2012 will be released by Environment Canada this spring.

Conservation Minister Gord Mackintosh, whose department is now crafting a next-generation climate action plan, said Manitoba's emissions spike is due to the rebound in agriculture following the 2011 flood. The transportation sector also saw an increase in emissions. Cars, trucks and rail lines create more than 40 per cent of the province's greenhouse gases. Transportation emissions have increased steadily since 1990.

Mackintosh repeated what's become the province's good-news emissions talking point: Since 2000, Manitoba's population has increased by 11 per cent, the economy has grown by nearly a third but emissions are down two per cent.

"We know these reductions are not enough," said Mackintosh. "We have to recalibrate our efforts."

Curt Hull of Climate Change Connection said Manitoba frequently highlights the wrong figures in order to paint a rosy picture of progress on climate change.

To avert global disaster, the increase in the average global temperature must remain within 2 C, scientists say. That means humans must cap their carbon emissions at about 565 gigatons between now and mid-century, no matter how much the population or the global economy grows.

Hull said focusing on per capita emissions or economic growth instead of total tonnes distorts the real picture.

"We end up patting ourselves on the back for taking baby steps," said Hull. "It prevents us from taking the real quantum leap away from fossil fuels."

Conservative MLA Shannon Martin, the opposition critic for conservation and water issues, said the NDP's promise to shrink greenhouse gases was a glib one, with little follow-through. He declined to say how the Tories would combat climate change, but said the party would set realistic and attainable targets.

Over the next year, the province is expected to release its next climate action plan, one that focuses on developing green jobs. The NDP's original promise -- made in 2008 and enshrined in legislation -- to meet the now-obsolete Kyoto targets has since been abandoned. The province is still 3,300 kilotonnes shy of achieving the Kyoto goals.

Manitoba Wildlands director Gaile Whelan Enns said the province's latest progress report is short on details and specific data, a problem that plagues much of the way emissions are estimated and modelled across the country, especially when it comes to small industrial emitters.

"We do not do our own counting," said Whelan Enns. "We might find a lot more opportunities for reductions... We might find we're doing a whole lot better."

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Copenhagen Accord

From Wikipedia, the free encyclopedia

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The **Copenhagen Agreement**[1] is a document that delegates at the 15th session of the Conference of Parties (COP 15) to the United Nations Framework Convention on Climate Change agreed to "take note of" at the final plenary on 18 December 2009.

The Accord, drafted by, on the one hand, the United States and on the other, in a united position as the BASIC countries (China, India, South Africa, and Brazil), is not legally binding and does not commit countries to agree to a binding successor to the Kyoto Protocol, whose round ended in 2012.[2]

Summary[edit]

The Accord

- Endorses the continuation of the Kyoto Protocol.
- Underlines that climate change is one of the greatest challenges of our time and emphasises a "strong political will to urgently combat climate change in accordance with the principle of common but differentiated responsibilities and respective capabilities"
- To prevent dangerous anthropogenic interference with the climate system, recognizes "the scientific view that the increase in global temperature should be below 2 degrees Celsius", in a context of sustainable development, to combat climate change.
- Recognizes "the critical impacts of climate change and the potential impacts of response measures on countries particularly vulnerable to its adverse effects" and stresses "the need to establish a comprehensive adaptation programme including international support"
- Recognizes that "deep cuts in global emissions are required according to science" (IPCC AR4) and agrees cooperation in peaking (stopping from rising) global and national greenhouse gas emissions "as soon as possible" and that "a low-emission development strategy is indispensable to sustainable development"
- States that "enhanced action and international cooperation on **adaptation** is urgently required to... reduc[e] vulnerability and build.. resilience in developing countries, especially in those that are particularly vulnerable, especially least developed countries (LDCs), small island developing states (SIDS) and Africa" and agrees that "developed countries shall provide adequate, predictable and sustainable financial resources, technology and capacity-building to support the implementation of adaptation action in developing countries"
- About **mitigation** agrees that developed countries (Annex I Parties) would "commit to economy-wide emissions targets for 2020" to be submitted by 31 January 2010 and agrees that these Parties to the Kyoto Protocol would strengthen their existing targets. Delivery of reductions and finance by developed countries will be measured, reported and verified (MRV) in accordance with COP guidelines.
- Agrees that developing nations (non-Annex I Parties) would "implement mitigation actions" (Nationally Appropriate Mitigation Actions) to slow growth in their carbon emissions, submitting

these by 31 January 2010. LDS and SIDS may undertake actions voluntarily and on the basis of (international) support.

- Agrees that developing countries would report those actions once every two years via the U.N. climate change secretariat, subjected to their domestic MRV. NAMAs seeking international support will be subject to international MRV
- Recognizes "the crucial role of reducing emission from deforestation and forest degradation and the need to enhance removals of greenhouse gas emission by forests", and the need to establish a mechanism (including REDD-plus) to enable the mobilization of financial resources from developed countries to help achieve this
- Decides pursue opportunities to use markets to enhance the cost-effectiveness of, and to promote mitigation actions.
- Developing countries, especially these with low-emitting economies should be provided incentives to continue to develop on a low-emission pathway
- States that "scaled up, new and additional, predictable and adequate **funding** as well as improved access shall be provided to developing countries... to enable and support enhanced action"
- Agrees that developed countries would raise funds of $30 billion from 2010-2012 of new and additional resources
- Agrees a "goal" for the world to raise $100 billion per year by 2020, from "a wide variety of sources", to help developing countries cut carbon emissions (mitigation). New multilateral funding for adaptation will be delivered, with a governance structure.
- Establishes a Copenhagen Green Climate Fund, as an operating entity of the financial mechanism, "to support projects, programme, policies and other activities in developing countries related to mitigation". To this end, creates a High Level Panel
- Establishes a Technology Mechanism "to accelerate **technology** development and transfer...guided by a country-driven approach"
- Calls for "an **assessment** of the implementation of this Accord to be completed by 2015... This would include consideration of strengthening the long-term goal", for example to limit temperature rises to 1.5 degrees