SNL Energy
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Environment Canada to tighten clean air guidelines for ozone, soot

by Jonathan Crawford

Environment Canada on May 24 announced that it plans to ratchet up its national ambient air quality standards for ground-level ozone and fine particulate matter in 2015 and 2020, as well as add a new long-term exposure limit.

"We are implementing a new system to improve outdoor air quality for all Canadians, in collaboration with the provinces and territories," Environment Minister Peter Kent said in a statement. "These new air quality standards are proof of our commitment to environmental protection, today and for generations to come."

The standards, which are voluntary, were developed by Environment Canada in coordination with Health Canada, the provinces, territories and several stakeholder groups under the new Air Quality Management System.

The changes include first-ever national annual fine particulate matter standards, which were set at 10 micrograms per cubic meter and are to take effect in 2015. That standard will tighten further in 2020 to 8.8 micrograms per cubic meter.

Short-term fine particulate matter limits, for periods of 24 hours, are set to be tightened to 28 micrograms per cubic meter in 2015, and then to 27 micrograms per cubic meter in 2020, down from the current standard of 30 micrograms per cubic meter. The 8-hour ozone standard, currently at 65 parts

Continued on p 9

In this Issue

Click on headline to advance to story

SaskPower expects 30% savings in carbon capture following Boundary Dam project

by Jonathan Crawford

SNL Energy recently interviewed Mike Monea, SaskPower's president of carbon capture and storage initiatives, about the company's Boundary Dam integrated carbon capture and storage project. The Boundary Dam project in Estevan, Saskatchewan, is slated to go fully online in April 2014, making it the first of its kind in the world to go commercial.

The $1.24 billion post-combustion CCS project, which received $240 million from the federal government, is designed to capture up to 90% of CO2 emissions from the 110-MW coal-fired Boundary Dam unit 3, totaling about 1 million tonnes per year. The greenhouse gas will be used for enhanced oil recovery, or EOR, with the remainder to be permanently stored in a deep underground saline formation.

The provincial government-owned SaskPower is the principal supplier of electricity in Saskatchewan, serving almost half a

Continued on p 8

Ontario to comply with WTO ruling, expands feed-in tariff program

by Michael Lustig

Having lost an appeal of a World Trade Organization ruling directing it to modify its feed-in tariff, or FIT, program for renewable energy, the province of Ontario will make legislative changes to comply. It also on May 30 proposed an expansion of the contracting program and an enlarged role for municipalities.

In separate complaints filed in September 2010, the European Union and Japan claimed Ontario's feed-in tariff program, under which developers of renewable energy projects are awarded long-term power supply contracts, was unfair because it required that certain percentages of components in wind (50% for projects larger than 10 kW) and solar (60%) energy facilities be manufactured in Ontario. That provision was added to the program to spur development of manufacturing jobs in the province, but the WTO concluded it discriminated against other countries that could export such components to Ontario.

According to a May 29 article by The Canadian Press, Energy Minister Bob Chiarelli said the province will be proposing legislation on the domestically produced content provision to comply with the WTO ruling that should be enacted by early next year.

Meanwhile, on May 30, Chiarelli outlined a number of changes to the FIT program aimed at expanding the role of municipalities.

That's been a big push of Ontario's Liberal-led government lately. Earlier in May, Chiarelli directed resource planning agencies to revise procedures giving municipalities and communities a greater voice in the development of future energy plans. Specifically, local communities are also to be given greater say in the siting of energy production facilities.

"These changes will give communities and municipalities a stronger voice, more options and new tools when it comes to renewable energy," Chiarelli said in a statement regarding the FIT program changes.

One of the changes is that projects larger than 500 kW will be awarded through a competitive procurement process. "It will require energy planners and developers to work directly with municipalities to identify appropriate locations and site requirements for any future large renewable energy project," the Ministry of Energy said.

Rules for the small FIT program, covering projects between 10 kW and 500 kW, will be revised to give priority to projects led by or partnered with municipalities. Also, the energy ministry will work with municipalities to determine a property tax rate for wind turbine towers, and will provide funding assistance to municipalities to help them develop energy plans for the communities.

The province will also acquire by 2018 another 900 MW under the FIT program, with annual procurement targets of 150 MW through the small FIT program and 50 MW through the micro-FIT (less than 10 kW) program beginning in 2014, the energy ministry said. This fall, the Ontario Power Authority will seek 70 MW for small FIT and 30 MW for micro-FIT contract awards.

As of Jan. 31, the Ontario Power Authority had executed 1,728 contracts with FIT project developers, mostly for rooftop solar projects. Those executed contracts comprised more than 4.5 million kW, with about 372,600 kW — mostly wind — already in commercial operation.

The Canadian Wind Energy Association and Canadian Solar Industries Association, in separate statements, endorsed the FIT program changes.

COMPANY REFERENCED IN THIS ARTICLE:

Ontario Power Authority

Industry Document: Ontario Working With Communities to Secure Clean Energy Future

Industry Document: FIT Contracts and Large FIT Applications as of January 31, 2013

Industry Document: Wind Industry Welcomes Ontario's Continued Commitment to a Clean Energy Future

Industry Document: Ontario Minister of Energy Offers Stability to Solar Industry

E-mail this story.

Fortis, CH Energy offer more customer benefits to win merger approval in New York

by Nazia Qureshi

Fortis Inc. and CH Energy Group Inc. are offering more incentives to customers of Central Hudson Gas & Electric Corp. in an effort to secure approval of their proposed merger from New York regulators.

The joint announcement came after the administrative law judges on May 3 recommended that the New York State Public Service Commission reject Fortis' proposed acquisition of CH Energy and its utility Central Hudson Gas & Electric, suggesting that further "positive benefit adjustments" were needed beyond those outlined in a January merger settlement agreement to balance an "extraordinarily intense degree of public opposition" to the deal.

In a May 30 letter to the PSC, the companies proposed that customers will receive \$49.25 million of real, tangible, hard-dollar benefits, which can be used by the PSC to cover previously incurred storm costs, to invest in economic development, to support low income programs and to implement other rate-mitigation measures.

"The unique Fortis federation model ensures Central Hudson will remain a locally run company with customers receiving the benefits offered by this transaction," Barry Perry, Fortis' CFO and vice president of finance, said. "We look forward to receiving the commission's approval in order to begin providing those benefits to Central Hudson customers."

The enhancements include that the freeze in customer delivery rates will be extended by an additional year, which implies that rates will not change for a three-year period from July 1, 2012, through July 1, 2015. Central Hudson Gas & Electric will make \$215 million in capital expenditures during this period, including an estimated \$50 million, which will have a "storm hardening" effect on its infrastructure without any increase in utility delivery rates.

The companies said the effective four-year "no layoff" commitment has also been made to nonunionized employees. With the PSC oversight, \$5 million will be allocated toward economic development and low-income programs. The companies said the commitment to continue Central Hudson Gas & Electric's strong community relations support will be at least doubled from five years to at least 10 years.

Central Hudson Gas & Electric's name, headquarters and staff will all remain unchanged by becoming part of the Fortis federation model of operating utilities. Further, the minimum number of independent Central Hudson Gas & Electric's directors who reside or do business within the service territory will also be increased to two members.

"No alternate transaction could likely ensure that Central Hudson would remain an independently operated company," CH Energy Chairman Steven Lant said. "Absent Fortis, our customers will be deprived of nearly \$50 million in benefits and we will need to seek near-term delivery rate increases in order to fund our capital investments. That undesirable and uncertain alternative must be avoided."

Moreover, customers will benefit through Fortis' strong credit rating, greater scale and access to capital to finance an estimated \$600 million in infrastructure investments during the next five years, the companies said.

Fortis and CH Energy requested the PSC to approve the merger transaction at its next scheduled meeting on June 13.

COMPANIES REFERENCED IN THIS ARTICLE:

Central Hudson Gas & Electric Corp.	
CH Energy Group Inc.	**CHG**
Fortis Inc.	**FTS**

PR: Fortis and Central Hudson Offer Enhancements to Merger Proposal

E-mail this story.

IESO-N-0008057

Embedded generation, conservation driving down Ontario's peak demand

by Michael Lustig

Increased quantities of distribution-connected solar capacity, combined with conservation efforts, will reduce summer peak electricity demand in Ontario, the province's grid operator said in its latest outlook.

"Ontario's power system has changed dramatically over the past number of years, with a much greater diversity of generators and new forms of supply — such as solar generation and demand response — entering the market," Independent Electricity System Operator President and CEO Bruce Campbell said in a news release May 24 accompanying the release of the IESO's "18-Month Outlook," covering June 2013 through November 2014.

During this next period, the province's remaining two large coal-fired power plants, Ontario Power Generation Inc.'s Lambton and Nanticoke facilities, are scheduled to shut down, removing about 3,000 MW of currently operating capacity from the grid. Three wind farms and a biomass unit are expected to enter commercial operation by the end of June, but in the first three quarters of 2014, about 3,000 MW of new capacity, mainly wind, but also grid-connected solar, the converted-to-biomass Atikokan plant and the first addition at the Lower Mattagami hydro plant, are all expected to be in service.

The IESO's most recent previous outlook, released in late February, also predicted more than 3,000 MW of new capacity coming online once the coal units are shut down.

This shift in resources, which also will incorporate 1,700 MW of embedded solar generation, is driving the IESO to revise its operating procedures. By fall, the grid operator is expected to be able to dispatch grid-connected renewable resources. By the end of the year, a five-minute forecast for variable generation is expected to be introduced into the real-time scheduling process.

One consequence of the additional renewable energy capacity, plus increased availability of nuclear power now that Bruce Power has restarted its four Bruce A units, is that the IESO anticipates more periods of surplus baseload generation, when there is more power available than there is demand to consume it.

Surplus baseload generation periods mainly occur in off-peak hours in spring and fall, but the IESO predicts overall demand in Ontario will decline this year by 0.4%. Demand in 2012 was boosted by an extra day due to leap year, but the IESO expects any increase in consumption this year brought on by economic and population growth to be offset by growth in embedded generation and continued conservation efforts.

COMPANIES REFERENCED IN THIS ARTICLE:

Bruce Power

Independent Electricity System Operator

Ontario Power Generation Inc.

Industry Document: 18-Month Outlook

Industry Document: IESO 18-Month Outlook Points to Reliability, Rapid Growth in Renewables and New Approaches to System Operations

E-mail this story.

Nova Scotia Power wins approval of revised capital spending plan

by Michael Lustig

Nova Scotia regulators approved Nova Scotia Power Inc.'s revised annual capital expenditure plan for 2013, allowing the utility to spend $246 million on its power generation, transmission and distribution systems.

The Nova Scotia Utility and Review Board's decision, issued May 27, explored some of the reasons Nova Scotia Power gave in February for reducing its spending plan, known as the ACE plan, from its original proposal of $336.9 million.

The annual plan covers spending on new, carry-over and routine capital items. Nova Scotia Power's reductions came through deferring some projects to future years and changing cost structures of others to reduce capital costs this year.

"NSPI stated that the proposed reduction is based on the progress it had made in recent years with respect to generation portfolio transformation and improved customer reliability," the board said in its order. Nova Scotia Power has been reducing its use of coal-fired power and adding other fuels, including gas and wind, to its supply mix.

Within Nova Scotia Power's existing generation fleet are seven combustion units totaling 222 MW that run on light fuel oil. Those units are all about 40 years old and used infrequently, just to meet

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peak demand needs. In previous testimony, Nova Scotia Power indicated that those units could serve as backup generation for wind, which would mean they would be running more often and cost more money. The board noted that Nova Scotia Power, in its integrated resource plan and in an upcoming wind integration study, is examining the future of the combustion units, and restricted the utility's spending on the units to only engineering planning studies.

Many of the deferred projects, the board said, quoting prior Nova Scotia Power testimony, represent "a low short-term risk to reliability or efficiency." No spending considered routine, which totaled $87.8 million, was deferred. Those routine projects, and another 59 individual projects totaling $51.2 million, are projects that require board approval.

The board asked for some additional explanation from Nova Scotia Power on growth of routine expenditures, which totaled $45.8 million in the utility's 2007 budget.

Some intervenors, while pleased with Nova Scotia Power's cost-cutting efforts, still objected to such a drastic revision to the spending plan with relatively short notice. The ACE plan was first submitted to provincial regulators in November 2012, three months before the revision.

Regulators cautioned Nova Scotia Power, an Emera Inc. subsidiary, to pay attention to the affordability of its capital plan for ratepayers.

"The board considers that NSPI is taking the issue of affordability seriously, perhaps more than it has ever done," the review board said in the order. "It has gone beyond lip service but, in the board's view, it must still be kept at the forefront of NSPI's capital planning. The board agrees that the company must balance this with its requirement to serve and the need for reliability. The board directs NSPI to continue to report in future ACE plan applications on how it addresses affordability, and to do so in greater detail where practicable." (M05339)

COMPANIES REFERENCED IN THIS ARTICLE:

Emera Inc. **EMA**

Nova Scotia Power Inc.

Regulatory Filing: Nova Scotia Power Inc.

E-mail this story.

MISO finds large-scale grid expansion in northern area would not make economic sense

by Esther Whieldon

The Midcontinent Independent System Operator Inc. is slated to publish a report in June that will find a large-scale expansion of regional transmission facilities in MISO's northern footprint would not be cost effective from a production cost-savings perspective.

The so-called Northern Area Study explored whether there might be an economic reason to build major regional transmission facilities in the northern parts of MISO's market footprint given the potential for new generation imports from Canada, the expected retirement of generation units and the possibility of increased or decreased industrial customer electricity demand, according to a May 17 draft report on the study. The study made no conclusion as to whether any local reliability related transmission upgrades will be needed in the northern area.

For the study, MISO reviewed 38 potential mitigation plans and identified three sets of projects that were most likely to pass muster.

But a review of those three sets, or portfolios, found that although the upgrades would mitigate between 50% and 100% of expected area congestion, produce "synergic" economic benefits and "nearly equalize northern area locational marginal prices," or LMPs, those benefits would not sufficiently exceed the projects' costs. The costs were expected to range from $285 million to $894 million.

MISO also found that a portfolio of high-voltage, direct-current lines would be the "most effective at mitigating Lake Michigan congestion" but would "require significant additional upgrades to uphold reliability." New high-voltage lines in the Upper Peninsula would change the operating schemes of the area and require additional reliability upgrades and operational studies, the draft report said.

Synergic benefits occur when a portfolio of projects perform as a single interrelated system in which the segments, in effect, double-up to relieve the same problems.

Locational marginal pricing is a method of determining electricity prices at specific locations. LMPs represent the cost of the physical power and the price of delivering it to customers. As congestion is mitigated in an area, the difference between the energy and congestion cost components of LMP equalize — in a congestion-free system, the only remaining LMP differences would be from line losses.

The study shows there are economic benefits of "equalizing Michigan locational marginal prices with the rest of the footprint; however, options' adjusted production cost benefits do not exceed costs," the draft report said.

Several factors would further reduce the economic worth of the transmission projects. They include low natural gas prices, decreased forecast demand growth rates and MISO's existing plans for a number of so-called multivalue transmission projects.

Also, one of the key reasons for the study — the expected retirement of We Energies' Presque Isle Power Plant in Marquette, Mich. — is no longer a concern. "The retirement of this plant was expected to cause area reliability issues," the draft "Northern Area Study" report said. But then in November 2012, Wolverine Power Coop and We Energies — the trade name of Wisconsin Energy subsidiaries Wisconsin Electric Power Co. and Wisconsin Gas LLC — announced an agreement that would keep the Presque Isle Power Plant operational by adding emission controls to the plants' units in order to comply with environmental requirements.

Although the study did not find a need for any economic-driven transmission upgrades in the Northern area, the results of the study may provide a prioritized and shortened list of transmission options for future similar studies, the draft report said.

Moreover, a pair of transmission options considered in the Northern Area Study — upgrades to the 230-kV Hankinson-Wahpeton and 115-kV Big Stone-Morris transmission segments — is being further analyzed in MISO's Market Efficiency Planning Study.

The Market Efficiency Planning Study evaluates transmission-related market inefficiencies and identifies potential solutions on both a local transmission flowgate level and through larger-scale projects. The current study is expected to be completed mid-June.

A flowgate is a point on the grid where two or more transmission systems interconnect and where there is often congestion. Flowgates are also monitoring points for grid operators.

The Northern Area Study examined the benefit of upgrading the Big Stone-Morris line to 300 megavoltamperes and replacing the Wahpeton wave trap, which would allow the line rating for the

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Hankinson-Wahpeton 230-kV line to increase to a thermal capacity of 409 MVA.

The Northern Area Study found that upgrading the Hankinson-Wahpeton line, which runs from southeastern North Dakota to the North Dakota/Minnesota border, and the Big Stone-Morris facilities, which start near the South Dakota/Minnesota border and extend north into Minnesota, would mitigate expected transmission congestion from wind generation on the borders between the Dakotas and Minnesota.

The study also found that MISO could see some economic benefits from new potential Manitoba Hydro tie lines with minimal incremental transmission investment. The tie lines are part of Manitoba Hydro's plans to connect two proposed generation projects to the transmission system.

The Northern Area Study was triggered, in part, by Manitoba Hydro's plans to install two hydropower plants. They are the 695-MW Keeyask Generation Project and the 1,485-MW Conawapa Generating Station, both of which would be in Manitoba. The Conawapa and Keeyask units would be phased in from 2019 through 2027, MISO said. Together, they would increase the import potential into MISO by about 1,100 MW, while the remaining capacity would serve Manitoba Hydro's load, MISO said.

The Keeyask Project is a collaborative effort between Manitoba Hydro and four Manitoba First Nations, working together as the Keeyask Hydropower Limited Partnership, according to Manitoba Hydro's website.

Manitoba Hydro's preferred development plan is to build the Keeyask hydropower station and a new 500-kV transmission line from Manitoba to MISO, with a projected in-service date of 2020, followed by construction of the Conawapa hydro station, MISO said in a recent transmission planning status report. Manitoba Hydro has indicated that the earliest possible in-service date for the Conawapa unit is 2025.

MISO is performing a Manitoba Hydro Wind Synergy Study and an analysis of the Manitoba-MISO Transmission Service Request to determine the full economic potential and reliability impacts of the Manitoba-to-MISO tie lines and the planned hydropower projects.

The Manitoba Hydro Wind Synergy Study is reviewing the potential for using the Manitoba Hydro system to provide additional operational reserves. One objective of the study is to determine the value of increasing hydro storage and transmission to facilitate the integration of wind generation, MISO said in its monthly status report. MISO expects to complete that study in late December.

COMPANY REFERENCED IN THIS ARTICLE:

Midcontinent Independent System Operator Inc.

Misc: MISO

Regulatory Filing: MISO

Presentation: MISO

E-mail this story.

Financing sought for Muskrat Falls; Nova Scotia begins hearing on transmission segment

by Michael Lustig

Nova Scotia regulators began hearings May 28 on local utility Nova Scotia Power Inc.'s participation in the Maritime Link, a high-voltage, direct-current transmission line intended to deliver power to the province from the planned Muskrat Falls hydro facility in Labrador.

Meanwhile, the Newfoundland and Labrador government has begun a request for financing process.

The entire project has three main components: the 824-MW hydroelectric facility, located on the lower Churchill River; the Labrador-Island Transmission Link, roughly 1,100 kilometers of HVDC line from the power plant site across the island of Newfoundland, including a 35-km underwater link between the Canadian mainland and Newfoundland, and 250 km of 315-kV line connecting the Muskrat Falls site with the existing Churchill Falls hydro site; and the Maritime Link, about 500 km of HVDC line from Newfoundland to Nova Scotia, including a 180-km underwater segment.

Nalcor Energy, an entity owned by the government of Newfoundland and Labrador, is the chief developer of the overall project. Nova Scotia Power is buying 20% of the hydro plant's output and its parent company, Emera Inc., is paying 20% of the overall project costs, though its ownership interests will be only in the transmission portions.

The Canadian federal government has pledged to guarantee up to $6.3 billion in debt for financing the project, estimated at $7.6 billion. Nalcor and Emera aim to finance 60% to 70% of the overall costs by selling long-term debt.

On May 27, the government of Newfoundland and Labrador said it was issuing a request for financing, seeking proposals for the purpose of raising debt financing for the project. Money raised will go directly to the Nalcor subsidiaries responsible for the project. The provincial government has already approved participation in the project.

On May 28, the Nova Scotia Utility and Review Board began what is expected to be about three weeks of hearings on the $1.52 billion Maritime Link segment. The issue for the board to determine is whether the Maritime Link represents the least-cost option for Nova Scotia Power in obtaining its future power supply. In earlier testimony, some parties, among them representatives of Nova Scotia's consumer and small business advocates, argued against the Maritime Link, but the provincial government is fully behind it.

"Over the next three weeks, Nova Scotians will get the opportunity to better understand how the Maritime Link project will improve the energy and economic future of the entire province," Mat Whynott, ministerial assistant for energy, said in a statement on behalf of Energy Minister Charlie Parker. A decision is expected in July. (Matter No. M05419)

COMPANIES REFERENCED IN THIS ARTICLE:

Emera Inc. EMA

Nalcor Energy

Nova Scotia Power Inc.

Industry Document: Government of Newfoundland and Labrador Moves Forward on Financing of the Muskrat Falls Project

Industry Document: UARB Hearing Begins for Maritime Link Project

E-mail this story.

Conn. House passes renewable energy bill

by Kelly Harrington-Andrejasich

The Connecticut House of Representatives on May 28 passed its version of a bill that would allow larger hydropower resources count toward the state's renewable portfolio standard.

The bill is largely similar to a version passed by the Senate in early May but contains language that the state look to other renewables first before allowing large-scale hydro to count under the RPS. State Rep. Lonnie Reed described the change to other lawmakers as a "four-part trigger that must be met before large-scale hydro can be considered to play a small 1% role in the Connecticut renewable portfolio."

The House bill essentially requires the Department of Energy and Environmental Protection to first issue an RFP for resources such as wind to make up any renewable shortfall before letting hydropower count.

Chris Phelps, director of Environment Connecticut, said the move modestly strengthens the bill but not dramatically. "That's better than the Senate bill, but doesn't change the fundamental weaknesses of the bill," he said. That weakness is opening the door to giving broad discretion to reduce Connecticut's RPS targets in the future and offset it with hydropower, he said.

That was an opinion shared by others.

In a statement posted on the Connecticut Fund for the Environment Facebook page, CFE energy fellow Mark LeBel said the bill still dilutes the RPS by allowing large-scale hydro to count as a Class I renewable resource. "If this version of the renewables bill becomes law, the environmental community and clean energy businesses will have to work hard to protect the environmental benefits of Class I for years to come," he said.

Lori Brown, executive director of the Connecticut League of Conservation Voters, said the trigger is inadequate and written in such a way that it will be pulled, allowing large-scale hydro to displace other renewables. "We were all on board for so many good parts of the bill," she said of a coalition of environmental, religious and labor advocates.

Phelps said Environment Connecticut has supported a part of the bill dealing with solicitation for long-term contracts for renewables. "We think that's the best way to get new renewables built, but also to do so in a cost-effective manner," he said.

New England Power Generators Association President Dan Dolan said that while the House bill strengthens the trigger for making large-scale hydro RPS eligible, it does not change language allowing procurement for large-scale hydro. "Even under the House version, starting this July, the DEEP commissioner can go out and procure large-scale hydro for up to 5% of the state's load," he said.

NEPGA and others have argued that the bill will benefit Hydro-Québec at the expense of Connecticut businesses and resources.

New Hampshire Gov. Maggie Hassan has asked Connecticut Gov. Dannel Malloy to oppose the bill.

The Senate is expected to agree with the House version and send the bill to the governor. The legislative session is scheduled to end at midnight June 5.

COMPANY REFERENCED IN THIS ARTICLE:

Hydro-Québec

Industry Document: Amendment to Subst. Senate Bill No. 1138

E-mail this story.

IESO-N-0008057

First Nation deciding next step after losing effort to stop work on Quebec line

by Michael Lustig

A First Nation community in Quebec said it is deciding what to do next following a Superior Court of Quebec decision rejecting its motion to stop preparatory work for the development of a transmission line related to Hydro-Québec's Romaine hydro project.

Hydro-Québec is building four units of varying sizes but totaling 1,550 MW of generating capacity overall, along the Romaine River in eastern Quebec. The first of the four units (Romaine 2) is expected to be in service by the end of 2014, according to a timeline on Hydro-Québec's website, with all four complete by 2020.

The Romaine project also includes about 500 kilometers of new 315-kV and 735-kV transmission lines. The southern portion includes a 735-kV line from Romaine 2 to Arnaud, 267 km to the west, due to be finished in 2014, plus a line linking the Romaine 1 and 2 stations. The northern portion, due to be finished in 2017 includes a segment linking the Romaine 3 and 4 stations and a segment from Romaine 4 west to Montagnais.

Development work is underway on these transmission lines, some of which would run through the traditional territory of the Innu Takuaikan Uashat mak Mani-utenam band. The band, referred to as ITUM, in 2010 sought an injunction, amended in January 2013, stopping preparatory work such as clearing of trees and construction of a temporary service road over a 45-km stretch for the Romaine 4-Montagnais line. They argued the deforestation would cause their community irreparable harm.

In 2011, Hydro-Québec and the Innu Nation signed a 50-year agreement providing cash payments and construction contracts in exchange for dropping legal objections to the Romaine project.

On May 27, the Superior Court of Quebec, Montreal District, issued a decision rejecting the request for an injunction. In its decision, the court said the ITUM's Aboriginal title is not yet clearly established, and noted the benefits, from jobs created during construction and future economic gains, to both local communities and to the province as a whole from construction of the Romaine project.

ITUM Chief Mike McKenzie said in a statement May 30 that the band will first organize a community meeting to decide next steps. "Solutions will need to be found to ensure that our rights are respected, that we play our rightful role in the management of both development and the protection of our traditional territory and that we as a people gain access to the necessary tools to achieve our progress goals," he said.

COMPANY REFERENCED IN THIS ARTICLE:

Hydro-Québec

Industry Document: Québec is Not "Maître Chez Nous" - Itum's Reaction to the Court's Rejection of a Safeguard Order Seeking To Halt Hydro-Québec's Work On The Northern Line of the La Romaine Hydroelectric Project

E-mail this story.

NB Power intends to increase rates by 2%

by Janna Estares

NB Power on May 27 confirmed its intention to increase rates in all classes by 2% on Oct. 1, following a 40-month rate freeze that started in June 2010.

Under the proposed Electricity Act, the company may increase rates by up to 2% on Oct. 1, 2013, and Oct. 1, 2014, according to a news release. Under the current rules, NB Power is permitted to increase rates up to 3% before going in front of the Energy and Utilities Board.

"Even with the positive financial results of the past few years, this rate increase is required to address the impact of rising fuel costs, and to contribute to our goal of reducing the debt of the corporation by $1 billion over the next ten years," NB Power President and CEO Gaëtan Thomas said.

The October rate increase provisions allow NB Power to stay on track to meet its debt reduction target, the company said. Further, the provisions provide the Energy and Utilities Board and NB Power with the necessary time to prepare for a hearing on rates in fiscal year 2015/2016.

Based on the proposed Electricity Act, starting in fiscal 2015/2016, NB Power will be required to make an annual rate application to the board for increases, decreases or maintenance of rates on the company's revenue requirement. The revenue requirement will be part of a rolling 10-year strategic, financial and capital investment plan that will be submitted to the board on an annual basis.

Operational update

NB Power also provided an update on several initiatives undertaken by the company since October 2010 to streamline operations and improve productivity. Among other things, NB Power said it eliminated 300 positions and reduced operation costs by $47 million annually.

"NB Power is a smaller, more productive, more efficient organization than it was three years ago," Thomas said. "We have eliminated 300 positions, frozen salaries, successfully reduced our operating costs by $47 million annually and had record earnings in this three-year period."

COMPANY REFERENCED IN THIS ARTICLE:

NB Power

PR: NB Power confirms two percent rate increase for October 1, 2013

E-mail this story.

SaskPower to have 1st CCS project *continued*

million customers and operating about 3,500 MW of generating capacity from coal, hydro, natural gas and wind power. Below is an edited version of a recent interview with Monea at the 12th Annual Conference on Carbon Capture Utilization & Sequestration in Pittsburgh. This is the first in a two-part series.

SNL Energy: You said that in building SaskPower's Boundary Dam CCS project you have identified cost savings of up to 30%. Please explain.

Mike Monea: I guess since this is the world's first, it means it will be the most expensive carbon capture plant. When you are building the first, you have to over-design your equipment, and we've done that. For example, our absorber has 40% extra capacity in order to make sure that we have enough contact in order to take out the CO2. Secondly, when we started designing this plant, we didn't have any regulations. And now the federal government of Canada has posted 420 metric tonnes per GWh as the emissions threshold. Well, our plant is going to be 140 tonnes of CO2 per GWh, so it is much cleaner than the regulations require.

So with all the findings that our engineers have on changing the design of the plant, which you can only come across when you are building it — including building a bigger plant and maybe building a plant that is more tailored to regulation rather than making it ultra-clean — you have these cost savings. So we are very optimistic that we can hit 20% to 30% reduction when we build our next plant.

Stepping back, what does your project mean for the entire race to commercialize CCS?

Well, the significance for me is, if you look at what people are guessing as the cost of capturing carbon, that is all it is, is a guess. There is so much swing in estimating what the capture costs, that it makes the numbers senseless. So what Boundary Dam will do will remove that. It will be the first plant — the most expensive plant — but it will define what the capture costs are for a post-combustion coal unit.

What are the costs?

Our plant is a bit unique. It is not for everyone. We have some unique variables. On a $1.242 billion project we got $240 million from our federal government as a grant, which is unique. We also have revenue that comes from two streams. One is the sale of CO2 and unfortunately we can't say what that price is because of nondisclosure agreements with our offtakers, and also we sell the SO2, sold into sulfuric acid, and fly ash. So that is the revenue stream we wrap back into the overall economics. What we use is a cost per megawatt-hour for capturing carbon. What we feel is that it's below what the Electric Power Research Institute is predicting ... the price of capturing carbon, which is the $60 to $70 range.

You mentioned there are some obvious advantages to your specific situation. Please explain.

We are lucky because we have oil fields around our plant, and oil companies that will pay a modest fee to take the CO2 and store it. So it is important to bring in a revenue stream for the lifecycle costs of Boundary Dam 3. But for the province, it is hugely important because it is developing an oil resource that may not otherwise be able to be developed by using CO2. So the government likes it, they get taxes pumped back into provincial infrastructure. Oil companies like it because they like more money. So it is a great win-win. Some places don't have EOR so they will use storage. If we can keep driving the costs down, that's great. By the time we are done with our next set of plants, hopefully we'll have another 20% savings. So it reduces the cost of capturing carbon. We have no value for carbon in Saskatchewan. Alberta has a $15 value on their carbon that will escalate. All we can do is sell whatever we have.

There are so many favorable conditions for this project to come to fruition, from the revenue streams to the government support. Is it a fair statement to say that without these conditions, this project doesn't go forward?

The sale of CO2 is important, yes. It brings in a revenue stream. We may have gone ahead anyway. We know exactly what the cost is on a megawatt-hour, etc. And this is just my personal opinion, and not the company's, but I think that had we not been successful in negotiating the CO2 contract, I think we could have built a case to still go ahead. It would have been a very expensive plant. But we probably would have built it to, again, answer that question — "Can this thing work?" — with the hope that we would find that CO2 sale in the future. I am from the oil and gas industry, and I know the need for CO2 is huge, it's high. I've worked as a CO2 expert in my past life, so I knew the value, and I was lucky enough to convince people that if we couldn't get it now, we might get it in a couple of years. So I would've worked very hard to build that business case to see if we could get our board to approve that. Didn't need it. But the project was that important to us.

So you see CCS become increasingly commercially viable. Explain.

As far as we're concerned, we know that we'll have no government subsidies for our next plant. The savings that we found would replace a government subsidy. So with EOR, and our savings, the plant is economical. We'll build another one for sure. If you take EOR from that equation and have no value of carbon, it just adds to the costs on a megawatt-hour what your plant will run at. We can have very low-emission coal as a fuel for power in the future for 100 years at least. So the cost will just keep getting better.

What's the cost to ratepayers?

We are a power utility. We wrap the costs, that are called lifecycle costs. So we take all the costs for 45 years or the life of the plant, and it's all rolled in together. What we will have is a small one-time rate increase to pay for the plant over those years. We don't know of what magnitude. It will depend on how efficient our plant is. We can't really speculate on that now. But whether we put in a natural gas, combined-cycle plant, or put in a clean coal plant, there will be some kind of rate increase associated with a new plant.

COMPANY REFERENCED IN THIS ARTICLE:

SaskPower

E-mail this story.

Canada to tighten ozone rules *continued*

per billion, is to be tightened to 63 ppb in 2015, and then to 62 ppb in 2020.

The "health-based" standards were set by the federal government under the Canadian Environmental Protection Act, 1999.

Ground-level ozone, a component of smog, and fine particulate matter, or soot, stem from nitrogen oxide emissions and other pollutants that are released largely by coal-fired power plants and cars and trucks. "The quality of the air we breathe can have a direct impact on our health," said Health Minister Leona Aglukkaq in a statement. "These new air quality standards are an important part of Health Canada's mandate to protect the health of Canadians."

While it is not clear how the provinces will implement the voluntary guidelines or how the nation's approximately two dozen coal-fired plants will be affected, Sierra Club Canada's John Bennett said he expects "absolutely nothing" to change. At issue, he said, is a lack of proper enforcement mechanisms and incentives and a federal environmental agency that he said has been deprived of necessary resources under the Harper administration.

"It is hard to see that this announcement is anything more than an announcement," Bennett, executive director of the group, said May 28. The provincial governments' ownership of many of the public utilities has also created a conflict of interest, he added.

As a point of comparison, the U.S. EPA is revising its primary annual standard for fine particulate matter to 12 micrograms per cubic meter, annual mean, averaged over three years. The EPA left unchanged the daily primary standard for fine particles, which is at 35 micrograms per cubic meter, 98th percentile, averaged over three years. The EPA is widely expected to strengthen the current 8-hour primary ozone standard of 75 parts per billion to a level in a range 60 ppb and 70 ppb.

Those differences in the standards, Environment Canada said, stem from the fact that the U.S. population is about 10 times larger than Canada's and that the U.S. has a different regulatory and governmental framework. And while the standards are voluntary in Canada, the U.S. federal government can impose penalties on states for failure to comply.

Industry Document: Harper Government Delivers on Clean Air Commitments for Canadians

Industry Document: Canadian Ambient Air Quality Standards

E-mail this story.

States in Brief

Dollar amounts shown in U.S. dollars.

Can electric utilities and distributed generation co-exist?

With the idea of distributed generation increasing in popularity across the U.S., electric utilities should be spearheading the conversation on how to make it a sustainable part of the energy system of the future, Duke Energy's chief integration and innovation officer recently opined.

NH Senate approves bill that would tighten RGGI emissions cap

In a vote of 14-10 on May 23, the New Hampshire Senate approved recently a bill that would allow for changes to the Northeast's carbon cap-and-trade compact, the Regional Greenhouse Gas Initiative.

New Mexico Gas deal offers TECO foothold in Southwest, more regulated earnings

TECO Energy executives said the planned acquisition of New Mexico Gas will allow the Florida-based company to increase the proportion of its earnings mix coming from regulated businesses, and provides a foothold in the American Southwest.

FERC accepts MISO proposal to give state regulators more say in transmission cost allocation

FERC on May 23 accepted a plan by the Midcontinent ISO and a group of its transmission-owning members to give the Organization of MISO States "enhanced authority" for determining how the costs of certain new transmission projects are allocated.

PJM's lower auction prices leave analysts scratching their heads about new generation

A dramatic uptick in generation imports and new and repowered gas-fired units combined with a lackluster energy demand forecast to create the perfect storm for PJM's most recent forward capacity auction, pushing prices in much of the region to a level even more bearish than analysts predicted.

DC Circuit rejects Kan. coal plant appeal, potentially delaying project

The U.S. Court of Appeals for the District of Columbia Circuit dismissed an appeal from Sunflower Electric Corp., a move that could lead to significant delays for the proposed 895-MW expansion of the Holcomb power plant, one of only a handful of new coal-fired generation projects planned in the U.S.

FERC's Wellinghoff tenders resignation, effective when replacement takes helm

FERC Chairman Jon Wellinghoff has tendered his resignation to President Barack Obama but plans to stay on at the agency until the next head of FERC has been nominated and/or confirmed, Wellinghoff told SNL Energy late May 28.

Electric utilities eyeing distributed solar power

Some of the largest utilities in the U.S. have or are considering moving into distributed solar power generation, despite the inherent risk distributed power seems to pose to their business models.

DOE's Office of Fossil Energy on progress with carbon capture technology

The U.S. Department of Energy's Office of Fossil Energy recently talked with SNL Energy about the agency's efforts to commercialize carbon capture and storage technology, which is seen as essential in preserving coal-fired power generation in the future.

CRS report: RGGI 'carbon tax' generates $1.2B in revenue, encourages shift to gas

The Regional Greenhouse Gas Initiative was created as a cap-and-trade program to curb power plant carbon dioxide emissions, but since RGGI went into effect in 2009 it has functioned more like a carbon tax, according to a new Congressional Research Service report.

NJ BPU approves PSE&G's $446M solar development plan

The New Jersey Board of Public Utilities approved a plan for PSE&G to spend $446 million on solar power. The company will invest about $199 million through its Solar Loan III program and $247 million on its Solar 4 All distributed power program.

Miss. PSC monitor skeptical of May 2014 completion date for Ratcliffe IGCC project

The latest report by the independent monitor of construction progress for Mississippi Power Co.'s Plant Ratcliffe project doubts that the plant will begin operation by its scheduled date of May 2014.

Wall Street weighs in on Berkshire acquisition as NV Energy stock soars

Without any further words from MidAmerican Energy Holdings and NV Energy the day after the Berkshire Hathaway subsidiary announced it will acquire the Nevada-based utility for about $5.6 billion in cash, Wall Street analysts generally responded positively to the deal May 30.

API warns tighter ozone standards could be 'costliest EPA regulations ever'

In the event the EPA opts to set its ozone standard to 60 parts per billion, the most stringent level under consideration, 97% of the population could find itself in nonattainment areas subject to onerous new emissions reduction requirements, the API said in a May 30 conference call.

EIA analyst: Va. solar feed-in tariff unlikely to drive wider market penetration

Energy Information Administration analyst Gwen Bredehoeft said May 30 that a solar feed-in tariff that Dominion Virginia Power is initiating is "pretty small" and is unlikely to increase solar penetration in the state's power market.

Appalachian Power to convert portion of Va. coal-fired plant to gas

American Electric Power Co. Inc. subsidiary Appalachian Power Co. asked regulators in Virginia and West Virginia for approval of a $65 million plan to convert two of the three 237.5-MW coal-fired units at its Clinch River plant in Russell County, Va., to natural gas.

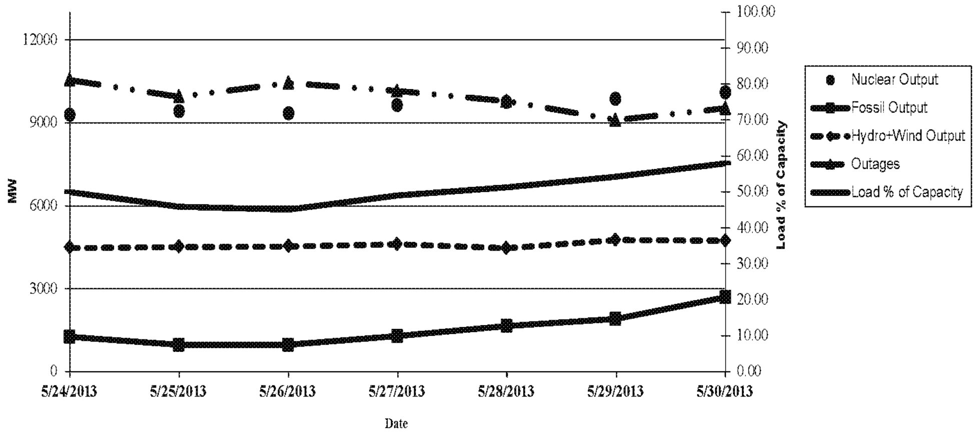
NV Energy deal spurs interest in expansion of Western energy imbalance market

MidAmerican Energy Holdings' planned acquisition of NV Energy is being seen as great news for the eventual creation of a Western energy imbalance market that expands on one proposed by the CAISO and PacifiCorp.

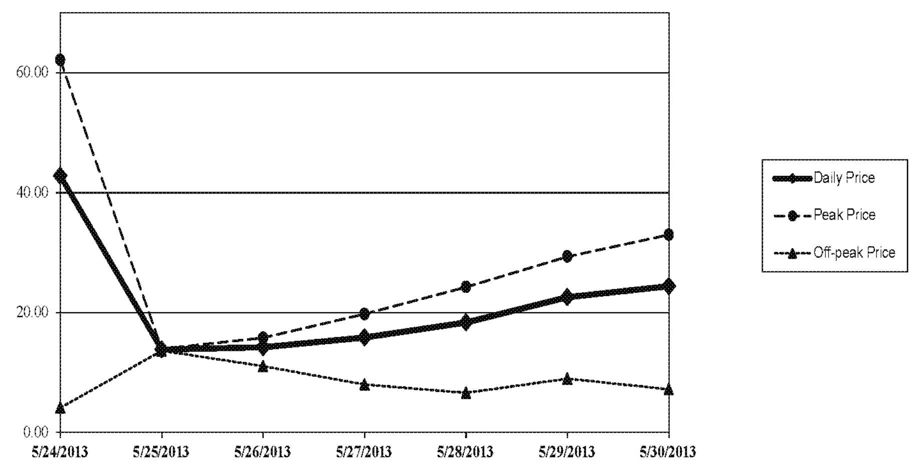
Markets Page ($/MWh) Week ending 5/31/13

Analysis of Ontario IESO Data

IESO Generation



IESO Settlement Prices $



Explanation of Ontario IESO data

The top line graph with the title "IESO Generation" shows 7 or 8 days worth of historical capacity information from the IESO's web site.

The following data streams are expressed in MW for each day and are keyed to the MW scale on the left hand side of the graph: Nuke Total Capacity, Fossil Total Capacity, Hydro Total Capacity and outages.

The capacity figures for each type of generation represent capacities actually in service for that day. The outage data represents actual outages.

The data stream "Load % of Capacity" is keyed to the percentage scale on the right hand side of the graph. It expresses the day's load as a percentage of the total capacity of the provincial system.

The bottom line graph with the title "IESO Settlement Price" shows the average daily IESO settlement price.

Alberta Forward Price Estimates

Term	5/27/13	5/28/13	5/29/13	5/30/13	5/31/13
Day-Ahead	34.00	39.00	38.00	37.00	60.00
Jun-13	88.50	88.25	89.50	87.25	84.00
Jul-13	98.25	98.00	94.50	91.50	89.75
Aug-13	93.50	93.25	92.00	89.00	88.00
Sep-13	90.50	90.25	90.00	88.00	87.50
Oct-13	69.00	68.75	69.50	68.00	67.00
Nov-13	70.00	69.75	70.50	69.00	67.25
Q4 2013	65.50	65.25	65.75	65.00	64.50
Cal 2014	55.00	54.75	55.00	54.75	54.50
Cal 2015	49.00	49.00	49.25	49.00	49.00

Source: Chase Energy Canada Limited, (403) 512-3071.
For information, contact: http://www.chaseenergy.com. Estimates are for flat products.

Alberta Electric System Operator

Date	Daily Average (C$/MWh)
5/30/2013	45.64
5/29/2013	32.76
5/28/2013	30.40
5/27/2013	37.30
5/26/2013	27.08
5/25/2013	25.50
5/24/2013	22.34
5/23/2013	25.66

Source: Alberta Power Pool

IESO-N-0008057