PUBLIC MEETING

Utah Committee of Consumer Services

March 19, 2013

Welcome & Business

Case & Legislation Updates

Case Updates

- Wexpro II
  - Hearing held Jan. 31 & briefs filed. Awaiting Order.
- CPCN for Sigurd-Red Butte Line
  - Parties reached settlement that constructing the line is in the public interest
  - Specified that cost allocation and cost recovery would be addressed in future proceedings
  - Commission approved settlement
- RMP Voluntary Request for pre-approval of long-term natural gas contracts
  - Office and Division filed testimony, UAE intervened
  - Parties have reached a settlement in principle

Case Updates

- Manti
  - Commission granted reconsideration for limited purpose of timeframe for payback of excess USF distributed
  - Manti has hired new experts
  - Next proceeding will consider financial health of the Company, based on correct allocation of costs between telecom and cable
- EBA/RBA
  - Company filed 2012 true-up on March 15th
  - EBA Request: $17M (collected over two years = 0.5% increase)
  - RBA Request: $ 3.3 M credit (0.03 % increase since it replaces a $4 M credit)

Case Updates

- Voluntary Request for pre-approval of Jim Bridger environmental upgrades
  - Commission denied Sierra Club's request for stay
  - Parties filed rebuttal and sur-rebuttal testimony
    - RMP testimony included additional study and explanation to respond to OCS concerns
    - OCS testimony indicated that analytical record was sufficient, but opposed pre-approval because of uncertainty associated with delay in EPA decision
    - Division recommended conditional approval
    - WRA and Sierra Club continued to oppose
  - Commission established deadlines for legal brief (March 27), comments about EPA draft decision (April 5) and reply comments (April 19)

Legislation: Items of Note

- HB202: Energy Conservation Code Amendments
  - Reflects compromise position advancing the energy code
- HB284: Net Metering Billing Cycles
  - Allows different annual billing cycles for different classes for purposes of net metering
  - Will facilitate participation of irrigation customers in net metering
- SB275: Energy Amendments
  - Last-minute substitute removed cap on amount to include in rates
  - Commission process expected to start soon
- HB110: Electric Energy Efficiency and Conservation Tariff
  - Not introduced; discussions will continue
- SB199: Energy Revisions
  - Pro-nuclear bill never introduced after it became clear it wasn't necessary to fix the problems claimed by certain nuclear developers
- Questions on other items from tracking list?

Rocky Mountain Power Irrigator Load Control Tariff

RMP Irrigator Load Control Program

- RMP has long history running irrigator load control programs
- RMP identified problems with existing program
  - Free riders
  - Capacity available to be controlled as compared to total capacity enrolled in the program
  - Lack of available data
- RMP pursued a new program
  - RFI results showed that contractor-run program would be more cost-effective than a company-run program
  - RFP resulted in selection of a new program provider
  - RMP signed contract with the new provider in early December and then approached the DSM Steering Committee with the details
  - Despite several meetings, the Steering Committee and RMP did not reach resolution on proper treatment of the new program

Office Reaction to Proposal

- Generally supportive of parameter changes
  - Remedies design problems
  - Provides greater benefit to system – overall cost effective
- RMP initially filed request for the new program without an accompanying tariff
  - Office argued strongly that a tariff was necessary for proper oversight of this regulated program; other parties agreed
  - Office, DPU, and RMP eventually agreed upon appropriate tariff terms
- Current irrigator customers have concerns that the new program does not have sufficient benefits to warrant participation
  - Concerns may have been mitigated with earlier outreach to the customers
  - Bottom line: participation is dependent on the economics as seen from the perspective of individual potential participants

Current Status

- Office filed supportive comments:
  - Emphasized the need for the tariff to maintain Commission oversight
  - Noted that the Commission may want to have the pricing parameters filed with them
  - Noted concerns about whether the parameters would induce adequate pumper participation
  - Noted some process improvements that could be made
- DPU recommended approval and no other party participated
- Commission approved the program
  - Indicated they would address the process concerns in the next docket of this nature
  - Did not address the issue of having pricing parameters filed with them
  - Did not address the concerns about adequate pumper participation

Rocky Mountain Power Methodology for Calculating Avoided Cost

Public Utility Regulatory Policies Act of 1978

- Oil crises in 1973 and 1979 brought awareness of the need to develop alternative energy sources
- Section 210 of PURPA encourages decentralized electricity production from renewable energy sources and cogeneration
- Electric utilities must buy power from qualifying facilities (QFs) at the utility's avoided cost
- Small power producers qualify as a QF if:
  - No larger than 80 MW
  - 75% of its fuel is from biomass, waste and/or renewable resources (sun, wind, water or geothermal)
- QFs are exempt from much of the financial and rate regulation applied to electric utilities

Energy Policy Act of 2005 – EPAct 2005

- Utilities asserted that with energy markets in place, QF status under PURPA was no longer required
- Section 1253 eliminates a utility's requirement to purchase QF power if the utility can demonstrate that QFs can sell their power in a competitive wholesale market
  - Qualifying markets only exist in parts of the U.S. (the six existing RTOs and ERCOT)
- The required competitive wholesale power markets do not exist in the west.

PURPA – QF Avoided Costs

- PURPA Guidelines for QF Rates
  - Rates paid to QFs will be just and reasonable to the electric consumers of the electric utility
  - Rates paid to QFs will not exceed the incremental cost to the electric utility of alternative electric energy
- Full-Avoided-Cost Rule involves both energy and capacity:
  - Energy costs are the variable costs associated with production of electric energy (kilowatt-hours). They represent the cost of fuel and some operating and maintenance expenses.
  - Capacity costs are the costs associated with providing the capability to deliver energy. They consist primarily of the capital costs of facilities.

PURPA – QF Avoided Costs

- PURPA is federal law, but state utility regulatory commissions set rates paid to QFs based on PURPA guidelines
  - In the 1980's, some state Commissions set avoided costs too high which encouraged excessive QF development
- The Utah Public Service Commission sets avoided cost rates after a consideration of the cost data submitted by the utility.

  (Quarterly Schedule 38 filings)

Avoided Cost in Utah – Background

- Pre-2003 History: Minimal QF development in Utah during the 1980s and 1990s because of utility's excess capacity/energy situation. The exception was the Sunnyside "Coal Waste" Project in the late 1980s, where developers secured a favorable QF contract with Utah Power.

- 2003 Avoided Cost Case:
  - For thermal (non-wind) QF projects between 1-100 MWs, the Commission set capacity rates on a IRP proxy method (next avoidable IRP resource) and set energy rates using a Partial Displacement Differential Revenue Requirement (PDDRR) Method. Since the PDDRR method is based on cost differences in GRID runs with and without the QF, a more precise indication of the utility's actual avoided energy cost is obtained.
  - For wind QF projects > 3 MWs. the Commission set capacity and energy rates using a "market price proxy" method for wind QFs up to the utility's IRP target MW level. For wind QFs exceeding IRP targets, the avoided cost method was the same as for non-wind QFs.

QF Avoided Costs - Case Overview

- RMP Request:
  - Stay of Market Proxy Indicative Pricing for Wind Qualifying Facilities (QFs)
  - Changes to the two methods of pricing and clarification on REC ownership
- Current Pricing Methods (established in 2005)
  - Market Proxy – winning bid on most recent RFP (currently: 2009 Dunlap Wind Project located in SE WY)
  - PDDRR – Proxy/Partial Displacement Differential Revenue Requirement (based on next deferrable resource in IRP)
- PSC established two schedules
  - Motion to Stay on expedited schedule – hearing held 12/12/2012
  - Other issues – three rounds of testimony and hearing on 6/6/2013

Phase 1: Motion to Stay

- RMP asserts that Market Proxy pricing in Utah should no longer be used because:
  - The Proxy no longer reflects the current market price for wind energy.
  - The Company does not need wind resources until 2018 and only for other state's RPS requirements (no need in the state of Utah).
  - Retail customers should not pay wind QF prices that exceed current avoided costs.
- OCS Position:
  - Wind costs are declining and the 2009 Market Proxy now reflects costs above current market costs
  - Ratepayers would be harmed (pay too much) if avoided costs were based on a 2009 market proxy
  - Support RMP's motion to stay the use of the market proxy method

Phase 1: Motion to Stay -- continued

- Other parties' positions
  - Renewable advocates and wind developers opposed the stay
  - DPU proposed a compromise position
- Commission Order (December 20, 2012) denied RMP's motion to stay the use of the Market Proxy
  - Suspending the use of the Market Proxy would be an extreme response in light of insufficient evidence on declining wind costs
  - Wind provides additional value to ratepayers in the form of a hedge against fuel price risk and environmental risk
  - Any potential pricing harm to ratepayers will be mitigated because it is unlikely that all 5 projects in the queue will be able to negotiate a PPA by the end of Phase 2
  - A new method may be determined soon - with the conclusion of Phase 2 in June 2013 – addressing issues raised in Phase 1

Phase 2: Changes to Avoided Cost Methodology

RMP's January 31, 2013 Direct Testimony:

- Discontinue the Market Proxy method for wind
  - Costs for the Dunlap market proxy are outdated
  - Next wind in IRP is in 2018 and to meet RPS in other states (no need for wind located in Utah), wind for RPS is not "cost effective"
- Use the Proxy/PDDRR method instead but update some issues related to renewable resources
  - Capacity contribution for intermittent resources – update with current info
  - What proxy resource to use for the Proxy/PDDRR method – from IRP
  - Review of integration costs to be included in Proxy/PDDRR calculation – same as IRP & general rate cases
- Who owns the RECs generated by a renewable QF
  - PURPA requires the utility to purchase the renewable power therefore the utility (RMP) should own the REC & no buyback be allowed by the QF

Phase 2: OCS Issues

- Current Market Proxy price (Dunlap) is out of date
- Are Company's wind integration costs reasonable?
- Is it appropriate to use wind integration costs for solar?
- Is the Company's calculation for wind's capacity contribution (4.1%) reasonable? Should we separate West & East balancing areas?
- Do we exclude wind for other state's RPS, potential QFs and for "green future" from the avoided cost analysis?
- Is the Company's proposed Proxy/PDDRR method for wind reasonable? Produces a levelized cost of $37.43/MWh. A LBNL study shows levelized PPA prices in 2011 & 2012 were in the $30 to $40/MWh range.
- Who should own the RECs? Ratepayers or the QFs?

Docket No. 12-035-100 - Schedule

Phase 1 – Order Denying Motion to Stay Market Proxy Method Issued December 20, 2012

Phase 2 – Changes to Renewable Avoided Cost Pricing

January 31, 2013	Direct Testimony filed by Company
March 29, 2013	Direct Testimony – Other Parties
May 15, 2013	Rebuttal Testimony
May 30, 2013	Sur-Rebuttal Testimony
June 6 & 7, 2013	Hearing

Telecom Policy Objective

Background

- The Committee currently has ten policy objectives that serve as guiding principles for the work of the Office
- The Committee has had a series of background presentations and discussions regarding telecom policy over the last several meetings
- Staff has drafted a policy objective with the intent to capture the views regarding the use of UUSF for high cost support

Proposed Policy Objective*

The Committee of Consumer Services supports the Utah Universal Public Telecommunications Service Support Fund (also known as the Utah USF) as a mechanism to ensure that basic telephone service is available throughout all geographic regions of the state of Utah at reasonable rates. The Committee supports the Office advocating positions to help ensure proper use of these public funds including that basic telephone service should not subsidize other products or services and that the Utah USF funds are otherwise being used efficiently.

*This slide contains the final version, incorporating the changes made by the Committee during the meeting.

Lifeline Issues

- The Committee did not coalesce around specifics regarding the use of UUSF for Lifeline
- FCC changes have been impacting Lifeline provision and certification of eligibility
- Additional study and evaluation is necessary before defining a policy objective
- Current use of UUSF for provision of Lifeline:
  - Wireless Carriers: $ 0 (No wireless providers of Lifeline service in Utah have requested state USF to augment the Federal USF contribution.)
  - Wireline Carriers: $520,000 – 550,000 (estimate for next 12 – month period)
  - Note: New re-certification procedures required by the FCC have resulted in 49% of last year's Lifeline recipients (of wireline carriers in Utah) being denied continued participation in the program.

Electric Generation Options

Introduction

- Today's Presentation
  - Present key characteristics of primary new resource options.
  - Discuss challenges of evaluating resource options on a comparable basis.
  - Graph showing resource comparisons.
- Purpose
  - Respond to interest expressed on the subject by Committee members.
  - Provide background for IRP Discussion at next Committee meeting.

Key Characteristics – Conventional Coal

- High capital costs and typically low variable (fuel, O&M) costs.
- Large in size, built to meet base-load energy needs and tend to be located in more remote areas (often near coal mines) requiring long transmission lines to deliver power to loads in urban areas.
- Low operating costs and long start-up times; conventional coal plants operate at high capacity factors (80% – 90%) and are only taken off-line for maintenance or forced outages (equipment failure).
- Produce more emissions (CO_2, SO_2, and NOx) than any other generation resource. There are also costs of reclaiming lands that have been mined for coal.
- However, more stringent emissions standards and potential carbon tax impact the economic viability of conventional coal plants.
  - Older plants require retrofits, conversion to natural gas
  - Some new plants have been cancelled – new EPA carbon rules may prohibit any future, new conventional coal

Coal w/Carbon Capture and Sequestration

- Coal with carbon capture and sequestration technology (CCS) has higher capital costs compared to conventional coal. Estimates of cost differences range between 30-40% higher for CCS.
- Less CO_2 emissions than conventional coal plants. However, carbon capture lowers plant output by about 25% and increases water use by about 23% compared to conventional coal.
- By 2006, "clean coal" technologies were receiving a lot of attention in the industry and politically. A number of experimental stations were supported with DOE R&D funds.
- CCS has not yet been demonstrated to be commercially viable at a utility scale coal station.
- Need appropriate underground geological formation to sequester CO_2.

Natural Gas: Combined Cycle Combustion Turbine

- Medium capital and low-medium variable (fuel, O&M) costs.
- Variability in natural gas prices results in fuel price risk. Some utilities have hedged this risk, which at times results in additional costs to customers.
- Operational flexibility. Typically, CCCTs are dispatched as an intermediate plant to meet daily swings in customer loads. Can be operated in a base-load mode as needed. Capacity factors tend to range from 25% - 75%.
- Much lower emissions (CO_2, SO_2 and NOx) than conventional coal plants.
- Easier access to fuel (build near pipeline or extend pipeline as compared to near coal or rail.)
- Smaller plant footprint than coal.
- Lower emissions allows CCCTs to be sited closer to load centers. This may reduce transmission costs.
- The current resource of choice for many utilities because of relatively low costs, low emissions and operational flexibility.

Natural Gas: Combustion Turbine Peaker

- Low capital and high variable costs. Owing to their poor heat rate, simple or single cycle CTs are less efficient than CCCTs and therefore more costly to operate.
- Volatility in natural gas prices results in fuel price risk. Utilities have hedged this risk, resulting in additional costs to customers.
- Dispatched primarily to meet summer or winter peak loads. Have low capacity factors; normally between 5% - 20%.
- Fast start-up times. CT plants can be dispatched quickly to follow changes in loads.
- Low emissions allows CT plants to be sited closer to load centers (based on natural gas availability.) This reduces transmission costs.

Geothermal Resources

- High capital cost and zero fuel costs. Risk associated with well development costs can be an issue at unproven geothermal sites.
- Base-load Resource; capacity factors can be 90% or higher.
- New development limited to specific regions that supply the necessary steam temperatures to operate the plant. Various sites in the West, including California, Nevada, Oregon, Idaho, Utah and Washington.
- May require incremental transmission investment to deliver geothermal output from remote areas to load centers.
- No emissions as steam is the primary fuel.

Hydro Resources

- Medium – high capital and no fuel costs. Hydro represents more of a legacy resource versus new resource option.
- Large amounts of relatively cheap electricity can be generated from a moderately sized hydro station.
- Generation output varies due to wet/dry precipitation cycles, irrigation needs and environmental requirements. In some hydro facilities, water can be stored on a limited basis (lakes/reservoirs) and used to meet peak period demands.
- Costs associated with hydro relicensing has been an ongoing issue, resulting in restrictions on output on certain dams, equipment retrofits and removal of dams.

Wind Resources

- Medium capital costs, zero fuel costs. Despite declining capital costs in recent years, the industry still heavily relies on the production tax credit (subsidy) to spur new investment.
- Intermittent resource. Wind resources cannot be dispatched to meet swings in loads. For example, the wind speeds may be highest at night when demand is low and the energy is least needed.
- Wind integration costs. Since wind output varies by season and across hours, gas resources or market contracts are relied on to "back up" wind resources. This results in wind integration costs and estimates have recently ranged from $2.50/MWh (PacifiCorp) to $33/MWh (Idaho Power).
- The highest quality wind resources tend to be located far from load centers and power markets. Thus, new transmission investment (i.e., Gateway Project) may be needed to move wind output to load centers and markets.
- No fuel price variability; no emissions. However, there are environmental issues involving noise, aesthetics and impacts on birds/bats.

Solar Thermal

- Extremely high capital costs; no fuel costs.
- Quasi-intermittent resource. Dependent on energy from the sun to produce electricity. Unlike wind, the heat energy produced from solar thermal can be stored for later use in meeting demand.
- Best sites are desert areas in Southwest U.S. Flat land and sunny weather are key factors in locating this technology.
- New transmission investment may be required to bring electricity produced by solar thermal plants to load centers.
- No emissions.
- Solar thermal has promise; not yet commercially viable at utility scale level.

Solar Photovoltaic (PV)

- High capital costs compared to most other resources, but costs have been falling recently. No fuel costs.
- Proven technology; Solar PV can be installed on rooftops of homes and businesses in urban areas. May result in transmission cost savings.
- Payback time required to recoup investment costs may prevent wider penetration of PV systems.
- Utah experience indicates maximum output from PV systems occurs before the peak period of the day. This is contrary to conventional wisdom that there is a strong correlation between peak output from PV systems and peak demand.
- Intermittent resource and requires integration costs similar to wind.

Conventional Nuclear

- High capital and maintenance costs. Low fuel costs. Uses large amounts of water.
- Large in size w/significant output from a single nuclear station. Requires a 10-15 year lead time to design, permit and build.
- Operates as a base-load resource. Nuclear plants normally run at high capacity factors (over 80%).
- Located close to load centers (New England, Midwest, etc.). Accidents are infrequent, but potentially dangerous and costly. Fukushima nuclear disaster estimated to cost $257 billion.
- Decommissioning a nuclear power station is difficult and expensive.
- Storage of used nuclear fuel can be a challenge. Long-term disposal of nuclear waste is still unresolved.
- Nuclear plants are potential targets for terrorist attacks.

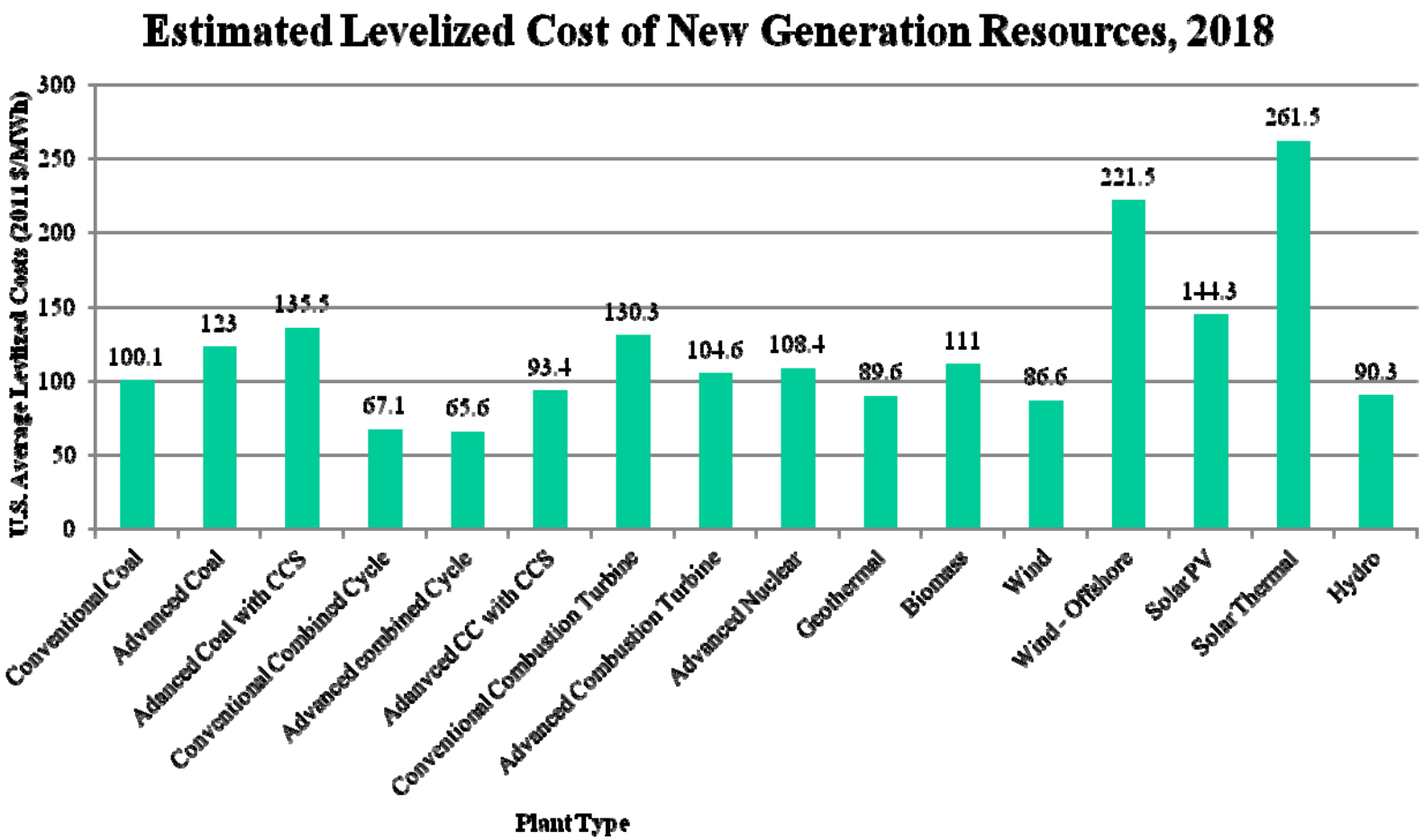
Other Technologies

- Fuel Cells
- Biomass
- Modular Nuclear
- Fast Neutron Nuclear
- Wave Technology
- Hot Dry Rock (5 KM Deep)
- Electric Storage

Challenges in Comparing Resource Options

- Cost studies must consider capital and variable (fuel, O&M) costs of resources
  - Some resources have high upfront capital costs but relatively low overall costs.
  - Costs can vary from early years to later years.
  - Resources have different expected life spans (e.g., Wind – 25 years, CCCT – 40 years)
  - Solution: Compare "all-in" levelized costs over a set period of time.
- Cost studies rely on different modeling assumptions and data
  - Some studies use actual data and others use forecasted data.
  - Data components and assumptions may not be uniform across studies.
  - Advocates of certain resources are often more optimistic about efficiency improvements, fuel cost projections and changes in environmental regulations.
  - Incremental transmission costs are rarely included in these cost studies, but could significantly impact the relative cost-effectiveness of resource options.
  - Assumptions may differ as to other resource characteristics (water requirements, access to fuel and transportation sources, the expected performance of a geothermal, wind or solar resource)

Levelized Cost Comparison of Resource Options



Source: Energy Information Administration http://www.eia.gov/forecasts/aeo/er/electricity_generation.cfm

Resource Selection

- In addition to cost comparisons, "Best" resource choice depends on many factors:
  - Current mix of resources (Coal, CCCTs, CTs, Hydro, Wind, etc.).
  - Short and long-term demand and energy forecasts.
  - Composition of the resource deficit (e.g., energy rather than capacity needs could be driving resource selection).
  - Assessment of risks attendant to certain resources (fuel price risk, carbon tax risk, hydro relicensing, etc.).
  - Compliance with requirements issued by federal and state regulatory agencies. These can involve emissions and haze standards, renewable portfolio standards, state and federal legislation, etc.
  - Operational differences among resources (ability to provide voltage support, spinning and non-spinning reserves, and fast ramping rate to respond to rapid changes in demand)

Other Business

Adjourn