Meeting Summary
NorthWestern Energy Electric Technical Advisory Committee
Helena, Montana
November 17, 2017

Attendance

Those participating in or attending the Electric Technical Advisory Committee (ETAC) meeting in person or via the web and by teleconference included:

Name	Organization
Beki Brandborg	ETAC Facilitator
Chuck Magraw	Natural Resources Defense Council
Brian Fadie	Montana Environmental Information Center (MEIC)
Frank Bennett	NorthWestern Energy (NWE)
John Bushnell	NWE
Jeff Blend	Montana Department of Environmental Quality (DEQ)
Luke Hansen	NWE
Joe Stimatz	NWE
Diego Rivas	NW Energy Coalition
Brian Dekiep	Northwest Power and Conservation Council
Mike Dalton	Montana Public Service Commission (MPSC)
Jamie Stamatson	Montana Consumer Counsel (MCC)
Will Rosquist	MPSC
Mike Babineaux	NWE
Jonathan Pytka	NWE
Ella Caillouette	NWE (via phone)
Bill Thompson	NWE (via phone)
Sarah Norcott	NWE (via phone)
Danie Williams	NWE
Eric Sayre	NWE
Larry Nordell	MCC
Paul Schultz	MCC

<u>Agenda:</u>

1. Update on CREP RFP – Ella Caillouette

2. NEM Study update – Danie Williams / Sarah Norcott

3. Update on Variable Energy Resource (VER) integration study – Casey Johnston

4. Mountain West update – Joe Stimatz

5. Update on QF dockets / RFP – John Bushnell

6. Process Check / Timeline – Discussion (Timeline attached)

7. Comments on NorthWestern's 2015 Resource Plan 6 month Check-in.
   a. Discussion of comments
   b. ETAC recommendations to NorthWestern

8. Future Meeting Dates
   a. November 29, 2017 – Technology Forum – Butte GO
   b. December 21, 2017 – Butte GO
   c. January 25, 2018 – Location to be determined

Meeting

1. <u>Update on CREP RFP</u>

By law, NorthWestern is required to acquire CREP resources. The current deficit is 41 MW. June 28 was the deadline for the CREP RFP bids. 11 proposals were received. Each proposal was evaluated by an independent evaluator. After the initial screening, 6 projects were removed, and the rest were evaluated for an avoided cost to determine cost effectiveness. These projects had avoided costs ranging from $5 to $139 dollars above the cost effectiveness amount. This process was very similar to the RFPs done in prior years.

Question: What were these evaluated against?
Answer: Just an avoided cost comparison including our total current portfolio.

Question: What was the proxy resource to determine what the base AC was to evaluate against?
Answer: CREP resources were evaluated in our portfolio model to determine avoided energy costs. We included the Commission's findings on 15 year term from the QF and MTSUN proceedings.

Question: I would be interested to see a resource that would pass that test?
Answer: It could have been any of the resources, but the prices they bid in at were not competitive.

Question: What were the 5 that passed the initial screening?
Answer: Wind Build-Transfer, Solar, Solar/Battery, Two other Wind (45 MW)

Question: In the past, some projects did not move forward because they would not be in operation in the particular compliance year. Was that a factor this time for some of these?
Answer: We did not cut any projects because they would not reach COD early enough.

Question: Which project was the best performing (i.e., the one that was $5 above the portfolio cost)?
Answer: Proposal 8 (wind combination PPA) was the closest.

Question: Are you continuing conversations with them?
Answer: We are not engaging any of the bidders because none were cost effective

Question: What do we think that the PSC will do?
Answer: If things go as they have historically, the commission will approve the waiver.

Comment: I would encourage NWE to continue negotiating with the closest bidder.
Answer: We will do some follow-up on this.

Question: If the CREP RFP went out earlier in the year next year, would this help?
Answer: Perhaps.

Question: When you determine the cost-effective rate for each of these resources, do you provide them with the cost-effective rate and see if they can meet it?
Answer: This question involves specific details about negotiation and may be project specific.

2. NEM Study update

HB 219 passed, which requires NWE to do a study of the cost and benefits of net metering. The PSC sent out a Notice of Commission Action. NorthWestern asked for feedback at the September ETAC meeting. We selected Navigant to do the study. NREL is looking at a low, medium, and high adoption rates for residential and non-residential sectors. We will supply information to NREL for this. We held a kick-off with Navigant and NREL in Butte earlier this month. We are moving quickly since we have to file in April.

Question: What is Navigant's level of experience on this?
Answer: They did similar studies for NV Energy, NWPCC, and one in California.

Question: Were there many that bid into this process?
Answer: No, not many had experience with solar PV and net metering.

Question: What is their methodology?
Answer: Through the PSC, we are required to use the NARUC methodology and cost benefit categories. We can distribute some information on this.

Question: What were Navigant's thoughts on the timeline?
Answer: They were selected for the VER study, so they have already been given some data that overlaps with this study. They thought that we have been moving at a good rate to date.

Question: Were there any requirements that they thought were not useful? Or any above the minimum study requirements that we have decided to look at?
Answer: At this point, we do not know. Navigant has not expressed any concerns on this yet. We had a call with NREL and Navigant at the same time to make sure that all of us are on the same page regarding input data and analysis.

Question: There was debate about the various cost-effectiveness tests, and Commission limited it to include the Utility Cost Test. Did you discuss including the Total Resource Cost Test?
Answer: We may decide later, after we have the required information, if we have time to do this.

Question: The quality/availability of the input data would be prohibitive to getting to the bottom of the cost/benefit analysis. Can you make available an assessment of the quality of the input data?
Answer: As part of the study requirements, Navigant is tasked with how they would improve this study in the future. So this is where that assessment could be included.

Question: Will you be able to incorporate the results of this study into the overall planning process or is it an island?
Answer: We anticipate that we will, because the results will set the growth rate that we use. The purpose of this study is to establish if we need a separate rate class. The results will likely impact the rate case filing more than the plan. It will depend on what kind of detail we get out of the study.

4. Mountain West update

Mountain West is a group of around 11 entities in Colorado and Wyoming, with some reaching into other states as well. The group self-selected the idea to create a market in the West. After considering a number of possibilities, Mountain West has decided to join SPP. Now that it appears that SPP will be established in the WECC, NorthWestern is considering whether it would make sense to pursue membership. Market development in the WECC has received a lot of attention recently, with the EIM developing and California making efforts to expand its full market. We may be past the point where a day-ahead market in WECC is a foregone conclusion. Mountain West plans to go live in October 2019.

Question: Are they a regional transmission organization currently?
Answer: No, but they plan to join SPP, which is an RTO.

The intention is that SPP would operate a single market, optimizing across the DC ties. SPP would operate separate East and West Balancing Authority Areas and will be the Reliability Coordinator for the entire footprint.

Question: What is the peak load for all of those utilities?
Answer: About 21,000 MW of generating capacity, so the peak load is in that ballpark.

Q: What is the total intertie capacity?
A: 800 MW.

Q: Are the interties owned/operated by WAPA?
A: I do not know.

Q: Are they all in the WECC?
A: Yes.

Q: It is the intertie issue leading to the creation of two BAs?
A: Yes.

The same staff at SPP will be coordinating planning for the East and West. In terms of making decisions about future upgrades to the interties, that will have to get worked out in the future.

There are approximately 30 SPP committees/working groups. These meetings are open to the public. The Colorado PUC expressed concern that they will have a hard time understanding how SPP works due to the large number of meetings.

In 2019, Mountain West will hit the trials phase, like NorthWestern did when our South Dakota group transitioned. SPP handled this very well, offering a trial period of several months.

Question: Is there a timeline for NorthWestern's evaluation of joining SPP in Montana?
Answer: No. This has our attention, but we have not determined how we will evaluate it In comparison to other alternatives.

Question: Who will make these decisions?
Answer: Each member will individually need to evaluate if they want to join.

Question: How much influence will the state PUCs have, given that this is under FERC jurisdiction?
Answer: I do not know.

NorthWestern discussed a map showing the combined footprint of SPP plus Mountain West. SPP has 66,000 miles of transmission; Mountain West has 16,000. This will be a pretty sizable increase for SPP. But the footprint is not indicative of the transmission layout. NorthWestern has some connectivity to WAPA, but mostly it is from the south through PacifiCorp.

Question: For you to participate, you would have to buy firm transmission capacity through Yellowtail?
Answer: That might be a mechanism.

Question: But to participate, you would have to have firm transmission?
A: Yes, either firm transmission to the market or direct connectivity to the market.

We are likely not going to model this in the plan, but we will think about the probability of joining, timing, alternatives, and California's effect on these.

Question: The impact on NorthWestern's bottom line will be a key factor in deciding whether to join. Our concern is about the impact on the customers. How do these interact?
Answer: Whether it will pencil out to be a win-win, at this point, I do not know. There are some benefits to joining for both customers and shareholders. And another key factor is the possibility of being isolated if everyone else joins. This was an important reason why we decided to join SPP in South Dakota.
Comment: The risk of cost-allocation and cost-recovery will be a factor.

Question: What did the EIM study find and was it released?
Answer: The EIM study found that there would be some benefits, but compared to the costs these would be marginal. Startup costs were estimated around $10-11 million in total, with ongoing operations costs of $1.1 million per year. Base case gross benefits were estimated at $1.8 million per year, so net benefits, not including amortization of startup costs, would be around $700,000. Eventually EIM may make sense. But with all of the other moving pieces (California ISO, Mountain West), the case was not compelling. I cannot remember if we ever released the full study. We did present results from the study to the PSC. E3 was there. CAISO was there as well presenting information. We can get you what we have made public.

Question: If you decide to go SPP, you would go day ahead, real time, all that. If you go the other way, California has the duck curve and net-load issues. Do they have those same concerns in SPP?
Answer: The major difference is solar - they do not have as much solar in SPP. Negative prices in the middle of the day in California benefit those that do not experience the same load shape. SPP has a lot of wind, as does Mountain West, but theirs is a bigger footprint and therefore more diverse than California's solar/load profile. SPP optimizes resources, and dispatch is very efficient. There would be some benefit to our customers if both Montana and South Dakota only had to deal with one market, but in the grand scheme of things this is not a huge dollar amount.

Question: In the 2018 plan, will NorthWestern provide a cost-benefit comparison between joining and not joining the market?
Answer: We may or may not have a cost-benefit analysis. We will likely present a qualitative analysis. We do not know if we can model it or if we will have enough information to model it yet.

Question: In terms of the impact to NorthWestern's bottom line, will this require modeling?
Answer: Yes. For EIM, we had a consultant model it. I doubt that we will have this for the next plan.
Comment: The more detail that you can give in the plan, the better.

Ascend Analytics mentioned in a previous meeting that Montana is closer to the California market than the SPP market. If NorthWestern makes a decision to look at SPP, this underlying analysis would change. We have always referenced Mid-C prices, but that would change if we look at SPP.

Question: Could you provide periodic updates (every meeting)?
Answer: We do not think that there will be significant changes or news that frequently. The beginning of the year would be a good check-in point, based on activities.

The Colorado PUC has quite a bit of information on their website about SPP and Mountain West.

5. Update on QF dockets / RFP

The QF dockets are still on-going, and there is still discussion about symmetry. There are no orders on reconsideration yet. Orders on reconsideration will be out by the end of the month.

NorthWestern will make a decision on whether to continue the flexible capacity RFP. The decision will be influenced by the orders on reconsideration, particularly the PSC's decision on the term length. The RFP was not set up for these shorter timeframes.

Question: Would the bids be stale, if you continue with the RFP?
Answer: Yes.

Question: If NorthWestern changes the RFP or if the PSC changes the period, would the bids have to be re-evaluated over 15 years (if that is what they decide)?
Answer: There is nothing that would restrict us from looking over shorter time periods.

With 185 MW by the end of the summer (Stillwater, Crazy Mountain, Big Timber), we are not sure where we stand going forward. These projects are curtailable must-take (they would be fully compensated if we curtailed them).

Question: Is this the sole factor - the orders for reconsideration?
Answer: There are other factors as well. But the PSC's actions are the primary input.

Question: If you were to open up a new RFP with shorter terms, how would you evaluate it differently?
Answer: That is something we discussed a few years ago. We opened this RFP up for 20 years so that we could have a more apples-to-apples comparison. We would have to assess what the market would be to compare PPAs and/or shorter projects to longer ones. We thought it was going to be a challenge just to deal with different ownership types.

Question: Isn't this built into the model, regarding contracts expiring?
Answer: Yes, but the nature of the evaluation is different for the planning model vs an RFP. The RFP parties are more interested in how we treat their projects and what we assume around them.

Comment: The plan considers long-term resources, and the RFP would consider short-term resources. All of our plans until the 2015 plan showed market as the least-costly resource.
Question: And those were energy-based plans?
Answer: Yes.

Question: Is your concern that bidders will not think that the process is fair? Do potential bidders not submit bids because they feel that a black box model is used to evaluate the bids?
Answer: That is how we would evaluate bids, and we are always subject to criticism.

Question: Is this novel? Do other utilities run RFPs with no contract term?
Answer: Sometimes, and sometimes they split the RFP up into separate components.
Comment: MDU has combined RFPs, and they use their planning model to evaluate bids.
Comment: This might be something worth looking into.

6. Process Check / Timeline – Discussion

The group reviewed a timeline handout.

Question: How are doing on our timeline?
Answer: There are a lot of things that we are doing. We are moving along. We need to get going on our resource definitions – what does wind, solar, batteries cost. The VER/load variability study will be

discussed at the next meeting. We are holding a public forum on November 29th to discuss resource technologies. We will have a follow-up meeting in the spring.

Question: Should we review the timeline once a month?
Answer: Yes.

Question: Regarding resource costs, are you looking at this over the planning horizon?
Answer: We have different forecasts that we use.

Question: Has ETAC traditionally addressed these?
Answer: We present the fuel price forecast and the coal price forecast.
Comment: There is a lot of homework that ETAC may need to do to flesh out some of these items. We have had modeling sub-groups in the past.

Ascend is running the model to make some presentations for ETAC. Their work is on-going after the recent software upgrade.

We used Ascend's optimal expansion module before as a one-off, but we are looking at licensing it and running it ourselves for this plan.

Comment: You are currently in the modeling phase. I would like the company to take a crack at defining the objective function that PowerSimm will use for the next plan. Please describe the mathematical function in a way that the PSC can understand. What are the inputs? How are they used? How are the constraints modeled? Why are they there? NorthWestern needs to describe this in words so that others can actually understand. Also, how does PowerSimm treat periods during which NorthWestern is long? What constraints are in the model? Are the resources in the model justified by the market? This could be a separate chapter but would be really important.

Comment: One of the constraints on the objective function is the resource adequacy constraint. In the last plan, the model was structured so that it did not try to build everything at once but instead tried to reach resource adequacy after 10 years. This may be good but what about letting the model build to whatever the adequacy standard is? First we have to decide on the standard. Then we let the model build to meet it. Then use the action plan to take what the model wants and come up with steps for how we can actually reach that goal.
Comment: The company used the 10-year horizon because it would front-load the building.
Comment: Yes, let the model do what it wants to do. Use the action plan to determine how to address what the model wants.
Question: Is 10 years or some other time the right choice? That is up for discussion.

Question: Regarding Mountain West, would that affect PowerSimm modeling?
Answer: It would. The modeling assumptions would need to be discussed/decided. We are not sure how successful we would be at modeling this yet. What resource adequacy level would we use? For example, in South Dakota we need to add a planning reserve margin on top of our actual capacity need.

Question: Will there be an opportunity for ETAC to see what some of that thinking is? It seems that a parallel path with a regional market should be considered?
Answer: Yes. We will share our thoughts as we go forward. We just have not formed them yet. We will address what we think will be concerns regarding the timing, resource selections, etc.

Question: Whatever resource the model picks at the beginning, the assumption is that it will pick all of these to be the same (the cheapest resource)?
Answer: Yes.
Comment: But start from this, and then move in the other direction.

Question: If you are using the optimal capacity expansion approach to planning, you feed the model the resource choices that it has and identify future conditions. Then the model tells you which portfolio best meets the condition. Is this correct?
Answer: For optimal expansion, we try to identify the cheapest resources to acquire. We switch the resources out for comparison scenarios. The standard PowerSimm software does not do this. Instead, we must use Ascend's optimal expansion module.

Question: Does the module do the resource expansion, and PowerSimm models the portfolio?
Answer: Yes.

Question: So you give the optimal expansion model the list of resources to pick from and the standards to achieve and it gives you the portfolio? You then put that into PowerSimm and it gives you the total portfolio cost and risk?
A: Yes.
Comment: It would be helpful to include these steps in the chapter that explains the overall modeling in layman's terms.

Question: Is the optimal expansion module deterministic?
Answer: We do not have that answer. We hired Ascend to run it last time. We are considering licensing it and running it ourselves for the next plan.

Comment: It might be worthwhile to do a workshop on this. (Others agreed.)

Comment: The build-out constraints are put into the optimal expansion module. The module picks our optimal portfolio. Then we would use PowerSimm to look at what would happen if we added 100 MW more of wind, for example.

Comment: Good point on the constraints built into the model. How do we treat variable market prices with excess renewable excess? We have always assumed that we can move as much energy as we need. But at what price is this going to be at now?

Comment: Think about contouring your resources to your load obligation. The PSC believes that being long is not in the customers' best interest. Maybe you should tailor the portfolio to minimize being in the long position. There is also a risk-premium related to being long in many hours.

Question: Going back to the EIM, and considering the concerns being expressed here about all of the excess wind on the system, should the EIM analysis be revised or updated now?
Answer: That study had some additional wind assumed in it, but perhaps it should be updated.

Question: A bunch of these tasks are designated as October, November, January, and February. Is our current status on these satisfactory?

Answer: We are just getting into the meat of these. For example, the Hydro optimization is fairly complete but has not been presented yet. The Hydro upgrades timeline may be extended due to internal restructuring. We will keep you informed. We will look at resource definitions on the 29th and will contract with HDR for the battery, solar, and everything else.

Question: What is your expectation for that process?
Answer: We will get the information back from HDR and communicate it to ETAC. At that time, there will be homework to do.

Question: Will you be completing the South Dakota resource definitions prior to this?
Answer: Yes. And the thought is that rather than contracting with HDR twice, we will try to accomplish this all in one study and have them give us the differences between Montana and South Dakota, which plays out in gas turbines, for example.

Question: On the thermal resource side, there was an appendix on infrastructure costs with a build-out. Which consultant group was used for that?

Answer: We are not redoing or furthering that study this time around. For this plan, we are putting in high-level numbers and a reference to the RFP. If you do not think that the costs are adequate we can discuss further. You will have another chance to take a look at this.

Comment: Modeling these costs in more detail may be beneficial.
Answer: Yes, but these studies are very expensive. And you still must use an RFP process to determine the resource, so all of the costs would change based on that. We used internal resources to develop the infrastructure costs.

Question: Are there different studies this time?
Answer: This time we will model batteries, so we will look at HDR for costs and help with modeling.

Comment: Batteries are tricky, because of their multiple uses. So what is the plan?
Answer: Puget Sound did some modeling on that. We do not have a robust ancillary services market, making forecasting really hard. We can use proxy costs from our current resources.

Question: Regarding regional activity, what are we looking at there?
Answer: We had a chapter on that in the last plan. And we will do it again in the next plan. We will have a discussion of our peak versus the region's peak as well as the Council's work. There will also be an LOLP analysis and how it is different from the region.

Question: What about the natural gas and electricity price forecasts?
Answer: We will do a preliminary forecast in February and an update in April if there are significant changes.

Question: What about the load forecast?
Answer: We will discuss Todd's results.

Question: Is the end of February going to be the presentation to ETAC with comments?
Answer: Yes. We will start modeling using our preliminary numbers in March/April, but they would be subject to change based on ETAC comments.

If you have any further comments, you can share them through email. We will add into this timeline what we be doing with the optimal expansion module.

3. Update on Variable Energy Resource (VER) integration study

Postponed until next ETAC meeting.

7. Comments on NorthWestern's 2015 Resource Plan 6 month Check-in

We will be having a technology forum on November 29th in response to some of the comments that we received about the 2015 plan and public participation.

Comment: A new document was posted to this docket. It was from a law firm representing the Hardin Generating Station (Rocky Mountain Power). That facility is in need of a buyer and was hoping that NorthWestern could purchase it. The previous owners are out.

Comment: There are knowledgeable people who seem willing to comment and potentially participate in ETAC. What is the process for deciding who participates or is involved in the planning process? How is ETAC's membership determined?
Response: ETAC members can read all of the comments from the public and can incorporate those ideas into their own comments during meetings.

Question: Why did you contact the NWPCC instead of EnerNOC for this generation technology meeting? EnerNOC presented on this topic to the PSC.
Answer: NWPCC studied demand response in its Seventh Plan.

Question: What trends do you see in the comments?
Answer: A number of parties commented that they would be interested in participating in this process if they were allowed to. Also, comments were received suggesting more participation, more openness, more competitive procurement.

Question: What will the PSC do with these comments?
Answer (from PSC): We have worked on summarizing the comments, but what we will do with them is uncertain. There may be a work session to discuss what to do with them, but this has been on the back burner.

Question: After reading these comments, were they helpful to anyone? Are they useful to consider?
Comment: The majority of the comments were focused on the closed-door policy of ETAC meetings and how this is handled differently in other states. The Commission's rules want NorthWestern to use a group of technically-proficient people to help with planning. Another prong of those rules states that the

company should use the public to help with planning. The question as to whether these rules are being followed can be discussed. It is doubtful at this point that the Commission staff will be making any recommendations based on these comments.

Comment: It would behoove NWE to try to loop the public into this process of reviewing and commenting on the draft prior to filing the final plan. Letting the public comment on the draft might help alleviate the concern that some folks and the PSC have with the exclusive nature of ETAC.

Comment: That is a good idea. Depending on the content of the public meetings, that could help to address the point of having public involvement.

Question: Variable resource technologies have a nameplate capacity but do not compare to DGGS. How do we solve this issue where the nameplate capacity of new technologies is not a fair representation of what they can do?
Answer: Regarding comments that we did not scale up potential resources to reach economies-of-scale for wind or solar, NorthWestern did not explore these fully. As far as the capacity contribution of these, we have fairly good direction from the PSC as to what these resources can contribute capacity-wise.
Question: How do we address this in the plan?
Answer: There will be a section for this in the plan.

Question: In PowerSimm, do you define a capacity contribution for wind or solar? When you scale up the size of the resource, is it a uniform scaling up of the profile or is there any geographic diversity? Would this affect the outcome if we modeled some diversity?
Answer: We have just scaled up in the past, but we will discuss this in future ETAC meetings as part of the resource definitions.

Question: On the public meeting issue, these meetings are closed?
Answer: We have not invited the public to these meetings.

Question: How could we open the meetings up to the public?
Answer: There would be some trade-offs in terms of what information NorthWestern would be able to share in the meetings. And it would change the nature of the meetings, since anything said by the PSC, Council, and DEQ, for example, would be recordable and could be quoted in a newspaper.

Comment: Responding to the earlier question of who would want to attend if they could, the responses to the six month update show that there are people that want to attend. As an example, Idaho Power has public meetings, and representatives from Boise State University and the City of Boise attend these meetings. NorthWestern's process is the outlier in terms of other regional ETAC processes. Groups such as MREA, for example, are not invited. They have expertise that they could bring free of charge to diversify the knowledge in the room.

Question: What would NorthWestern not be comfortable talking about in front of others? For example, would you have been as open about the CREP RFP?
Answer: CREP RFP respondents have all been notified and this information may already be public.

Comment: I would not object to a professional association representing wind developers, for example, instead of individual wind developers. If there were members of the public or reporters present it would change how I think about what I say in these meetings. Having said that, it would be worthwhile for NorthWestern to invest a little bit more in engaging its customers more broadly. Perhaps NorthWestern could go from town-to-town and invite communities to give feedback. These meetings could potentially be all over the place, but that is how I would handle this issue of increasing public involvement.
Response: That would mean that we would have to do 7-8 public meetings across our service territory. It may require coming back to check-in again and again and could become significant work. You do have to try to satisfy the desire of public involvement.

Question: How much do you think that the November 29th meeting will address this need?
Answer: I do not know. There should probably be more meetings later on in the process.

Comment: NorthWestern once had another process, it was called the public policy stakeholder group. It was another ETAC-type meeting with legislators and public leaders. The public did not attend these meetings. The company could use some improved customer relations, and this may help break that bubble.

Question: From the perspective of wanting to reach out to customers and receive feedback, what do you do with that feedback? You may have a few people make passionate arguments in a public meeting but what would we do with that?
Comment: For example, a bunch of people show up to say “No Coal” – how would you handle that?
Comment: The single biggest benefit would be food for thought for the next planning cycle.

Comment: The plan should show retail rate impacts corresponding to the various portfolios presented in the plan. NorthWestern should calculate how the different portfolios would affect customers’ rates. Such information would help people to understand the trade-offs that are faced.

Comment: On one hand, we are saying that no one is going to come and on the other we are saying that people will come with very passionate opinions. I think that it will be somewhere in between and that NorthWestern should be able to take in this feedback as part of the process.

We will have some discussion after the meeting on November 29th to talk about the feedback received. That meeting will start at 8:30 and go to about 1:00. Lunch on our own. ETAC will meet after lunch.

NorthWestern has compiled a list of questions that ETAC would like the presenters to address. This list was sent out to ETAC members. These questions will not be particularly applicable to DSM and DR.

Comment: Should NorthWestern ask what the public would like to see at the next meeting?
Answer: NorthWestern feels that there will be comments from the public at this meeting.

Question: Regarding the agenda for the meeting, is the intention that the Q&A session is for the public? Or for NorthWestern/ETAC to interact with the developers?
Answer: Each presenter will get 10 minutes. The hope is that they will address the questions already formulated by ETAC.

We will start ETAC at 2pm. There will be a discussion at that time about the morning meeting.

ETAC talked about the location of the December 21st and January 25th meetings and what the best method would be to get members preferred dates. On December 21st, NorthWestern would like to discuss the recent PSC decisions and how they will affect our planning.

8. Future Meeting Dates

a. November 29, 2017 – Technology Forum – Butte GO
b. December 21, 2017, 9:00am to 3:30pm – Helena
c. January 25, 2018 – Location to be determined

Comment: The update on Mountain West was helpful.

Comment: The timeline was useful to see, particularly because we are getting down to crunch time.

Comment: Regarding the Hardin announcement, a PSC Commissioner believes that NorthWestern should model this facility.
Response: We could model it if we had heat rate, variable costs, and other information.

Question: Can we get the meeting minutes sent to us via email?
Answer: We will send out a note saying that the minutes are posted.