**Net Metering Solar Task Force Meeting**

**Thursday March 5, 2015**

**9:30am-12:30pm**

Task Force members in attendance: Dan Burgess, Angie O’Connor, Janet Besser, Fred Zalcman, Amy Rabinowitz, Bill Stillinger, Paul Brennan, Geoff Chapin, Camilo Serna, Bob Rio, David Colton, Lisa Podgurski, Liam Holland

Intro

Introduction by Dan Burgess, notes that the meeting is being blogged by NESEA. Task Force members introduce themselves.

Dan Burgess reviews the meeting agenda and notes that meeting minutes from the February meetings will be reviewed and voted on at next Task Force meeting.

Presentation of survey results by consultant team

The consultants note that the discussion today should be focused on which options to model. The current base case scenario will be modeled; the Task Force will choose two additional modeling options. Time and budget constraints necessitate simplicity in the selected models. The consultants note that the modeling options are focused on longer-term policy paths and explain that some choices are best treated as policy decisions rather than modeling decisions. After the Task Force decides on modeling options, there will still be decisions that need to be made regarding the running of the models selected.

Review of Policy Paths

The consultants lay out three potential paths based on Task Force members’ responses to the consultant survey.

Option A is a distribution company-centric option involving competitive solicitations.

Options B1 and B2 are “open” options that are incentive-focused. One of these options focuses on a more liberal net metering regime, the other focuses on a narrower net metering regime.

Option A

The proposed small solar type is a performance-based incentive (“PBI”) involving a cost-based, administratively-determined price or a declining block incentive with a built-in safety valve.

The proposed large solar type is a PBI involving competitive solicitations three times per year.

The proposed geographic distribution is either separate pools by utility or a uniform state-wide incentive.

The consultants note that the differentiation by market sector options yielded a wide range of opinions in the surveys. The consultants state that it will be difficult to model a lot of the variations suggested, so they suggest trying to keep the options simple enough to model while still addressing the concerns of the Task Force members. The proposals set forth by the consultants are an SREC II-based stratification or size stratification.

Discussion

Amy Rabinowitz: Where there are multiple suggestions in a single box on the consultant slide, will the Task Force be deciding on those today or modeling both options?

Bob Grace: The options presented are for Task Force members to discuss today.

The proposal for size-to-load net metering would involve a reduction in the value of excess net metering credits to the generation service rate or the wholesale rate using the current QF rate. The consultants note that the reduction in credit value could be made up for by the solar incentive.

Janet Besser: Can you model different net metering options for both policy paths?

Bob Grace: The intention of today’s meeting is to explore whether that’s where everyone wants to go.

Janet Besser: The group may want to look at what happens when you have a higher and a lower net metering value for each policy path.

Fred Zalcman: I would like to echo Janet’s comments regarding modeling different net metering values for each policy path. I would also like to clarify whether the generation rate would apply only to the monthly excess or to all kW hours produced by the system.

Bob Grace: That would be for the Task Force to decide.

Fred Zalcman: Would customers have a separate meter measuring all of the excess generation?

Bob Grace: I believe that there would be a need for a separate meter to measure net metering credits, so this scenario would result in a two-meter future.

Camilo Serna: It will be important to tease out the impacts from each of the changes in the models so that the Task Force can see what is driving the changes.

Bob Grace: I agree that it is important to make clear which choices are driving different outcomes in the models.

Paul Gromer: I would suggest keeping certain choices the same for all paths in order to simplify modeling.

Camilo Serna: We should not simplify every issue just for modeling purposes. The focus should be on addressing the important issues.

Amy Rabinowitz: Instead of modeling two different policy paths, can the consultants study each piece individually so that at the end of this process, the Task Force members have an understanding of how each piece impacts the different policy paths?

Bob Grace: We are limited by the budget and the timeline. Many of these options can be modeled so you can look at different variations, but what we are able to do really comes down to what we have to work with in terms of time and budget

Janet Besser: To clarify, the solar incentive would be consolidated in this model, so what would you be modeling?

Bob Grace: Competitive solicitation for the full amount, with net metering only contributing what’s needed (G rate vs. QF rate).

Janet: So you could net out any net metering rate?

Bob Grace: This is an area where we need to decide on some methods for the modeling.

Janet: So we could make a choice between netting out the net metering rate or adding it?

Bob Grace: Correct.

Continued Explanation of Option A

Virtual net metering credit structure would involve reducing the value to the QF rate. There would be no need to model type and size for virtual net metering. There would be no changes to the current net metering caps.

The timing of transition is set as 1/1/17, which, practically speaking, is as soon as possible. This would allow for simplification of modeling and allows for modeling of the declining block incentive as always declining. Nothing would prevent us from moving to a different date at a later time, but this date will be used for modeling purposes.

For targets and timelines, we can set specific targets annually or describe a set of targets by certain dates. We are not locked into the dates modeled, but setting dates across all models will be more informative. Another option would be a budget procurement approach such as 2,500 MW by 2025. We can set different numbers, but we recommend keeping an apple to apples comparison.

For the minimum bill modeling, there is agreement that there is general disagreement. There is general agreement that if there were a minimum bill imposed, the amount should be set in a D.P.U. proceeding. The impact of the minimum bill would be heavily dependent on the details, so the thought is to separate this issue from the policy paths for modeling purposes.

Discussion

Bill Stillinger: The legislation calls for the evaluation of minimum bill. What are the plans for providing information about this?

Dan Burgess: Can we get a quick update on Task 5?

Bob Grace: Task 5 provides insight into the minimum bill. Andy Belden is heading up this effort and is not here to speak to that. We do not have this part quite figured out yet, as the analysis of a minimum bill impact in great detail is beyond our level of capability. We are looking for suggestions as to how we can provide helpful information on the minimum bill.

Amy Rabinowitz: It seems that the minimum bill is a question of who pays, not what is being paid. What will you be modeling? Can you pick two or three numbers to model so that we can have some sense of what the impact of a minimum bill will be at different levels?

Bob Grace: Large data sets would be required to model this. We have not yet decided on a modeling approach.

Bob Rio: Aren’t there options that would preclude a minimum bill? Are there alternatives where a minimum bill discussion would not be necessary?

Bob Grace: If you are moving firmly away from net metering, perhaps a minimum bill would not be important in this column, but it will be relevant in the next column.

Janet Besser: In terms of timing of rate cases at the D.P.U., will any companies have rate cases before 1/1/17?

Amy Rabinowitz: For National Grid, yes.

Camilo Serna: I cannot answer that right now.

Continued Explanation of Option A

The disposition of RECs has not been discussed before, but will be critical in how any new regime works. For all models, it seems to make the most sense to look at a future in which we assume that all RECs are minted as class I RECs and sold back into the market.

Options B-1 and B-2

The proposed small solar type is an up-front expected production-based incentive (“EPBI”) model based upon expected production over some period of time. Functionally, this would work the same way as rebates.

The proposed small solar setting is a declining block with a safety valve.

The proposed large solar type is a PBI.

The proposed large solar setting is a declining block with a safety valve.

The geographic distribution would be separate pools by utility or a uniform, state-wide incentive.

Discussion

Janet Besser: With use of EPBIs for small solar, how hard would it be to also model straight PBIs?

Bob Grace: That information might come out in another model, but it is possible to model that.

Fred Zalcman: How will a safety valve play out in modeling results? Will the model assume that the safety valve gets triggered?

Bob Grace: We would assume that the safety valve would not get triggered, but it would be understood that the policy would have the ability to adjust if conditions warrant.

Fred Zalcman: So you will describe the safety valve mechanism, but will not factor it into the modeling results?

Bob Grace: Correct, there is not an obvious basis for modeling something else.

Fred Zalcman: I just want to throw out a third possibility from House Bill 4185 for geographic distribution. In that bill, there was a cost reconciliation mechanism to address a case where solar development ended up focused in single utility territory. If a uniform incentive were over-incentivizing certain customers, we might see uneven development.

Continued Explanation of Options B-1 and B-2

For net metering, we would keep the current framework for sized-to-load facilities.

For virtual net metering, the options are to keep the current framework and rates or to continue virtual net metering on a narrower basis involving a move to the QF rate with exceptions for certain project types.

The options for net metering size limitations are to cap projects at 2 MW or to keep the current size limits.

The proposal for net metering caps for modeling purposes is to align the caps to match the 1,600 MW target, as opposed to setting the caps at a percentage of peak load.

The proposed options for the timing of the policy transition are 1/1/17 or once 1,600 MW is reached.

Discussion

Janet: So there is no proposal for modeling a scenario with no net metering caps in place?

Bob Grace: That is up to the Task Force members.

Janet Besser: Would the current caps remain in place until 1/1/17 when the new regime takes over? Is this a long-term decision for beyond 1/1/17?

Bob Grace: That would be a good topic for the Task Force to consider.

Continued Explanation of Options B-1 and B-2

The proposals for targets and timelines are to set a target of 2,500 MW with no hard timeline, or to calibrate the modeled incentives to match the goal of 2,500 MW by 2025, or whatever other target we dictate, as best as possible. This would allow for an “apples to apples” comparison.

Discussion

Camilo Serna: I just want to clarify that it wasn’t just the utilities that supported the utility-centric approach set forth in Option A. Do we need to get to one option or two options for modeling?

Bob Grace: The intent was to pick from among the options presented and walk away with two cases to model.

Janet Besser: It would be helpful if during the next step of this discussion we walked through the choices to be made.

Dan Burgess: We will now take 15 minutes to hear brief public comments.

Summary of Public Comments

Haskell Werlin, Solar Design Associates of Harvard MA: There was an $800 million number put forth by Amy Rabinowitz at the public hearing, we would like to know where that number came from. Also, a study just came out of Maine that put value of solar at $0.33 per kWh. We would be interested in having the consultants look at that study.

Doug Pope: The Task Force has not yet decided on long-term goals. We are calling for 20 percent of generation from solar by 2025 and encourage the Task Force to recommend this as a goal to the legislature. ISO‑NE came out with publications that stated that it is retiring 8,300 MW. We’d advocate that 5,000 MW be set as a baseline. Barry Bluestone has stated that solar installations would have a 1.2 percent multiplier effect. We have billions of dollars potentially coming down from Maine in hydro or wind, and Massachusetts ratepayers would pay 46 percent of these costs based on consumption. These costs need to be factored into value of solar. The Task Force needs to consider logical long-term goals. Option B-2 would be our preferred option.

Cathy Doyle, Fireflower Alternative Energy: The ever-changing rules of the game have made it difficult for solar investors by creating a lack of predictability. I request that the Task Force create a product that is easier for people to digest so that people can participate without major impacts on running their day-to-day businesses. What are the parameters against which the costs for solar DG are being measured?

Darien Crimmin, Wynn: I recently went to the White House to speak about solar on affordable housing. Virtual net metering allows the benefits of offsite solar to be applied to low income customers. Do not kill virtual net metering. Massachusetts needs to continue to be a hub of innovation.

John Murphy, Nexamp: There needs to be a distinction between the incentive program and the net metering program. The process would be simplified if we were able to first decide what we want to do with net metering. I echo Darien’s sentiments.

David Lowe, MA Climate Action Network: Is there an analysis of local economy and jobs that will come from these policies?

Discussion of Policy Options to Model

Bob Grace: Once we have a decision, there will be other issues to decide, such as the cutoff between large and small solar for modeling distinctions, the PBI philosophy, the size of declining block steps, etc.

Camilo Serna: Can you explain the nature of the analysis? How will you look at different incentive levels? How will you determine price of competitive solicitation, etc.?

Bob Grace: This is not fully decided yet. We will develop a forecast for inputs into the analysis. We will look at the rate structure in different utility territories and focus on rate classes with largest impacts. The distribution of costs of installations will be based on data available from the SREC program, which is self-reported data. For competitive solicitations, we will use a range of data sets, working our way up the distribution curve. The approach will differ for different paths. For the declining block incentive or standard offer, we will need to decide on an aggressive or conservative pricing structure.

Bill Stillinger: What is your definition of PBI with a safety valve? Is it your intention to model the definition proposed by the group in the survey results?

Bob Grace: I think so. The safety valve issues will not show up in the modeling. The modeling will be consistent with what the “cluster” suggested. The models are distinct from what the group may suggest to the legislature.

David Colton: I want to explain what virtual net metering means to us. In the past year, our facility generated about $300,000 in credit, property taxes, and lease payments. Municipalities are generally large consumers of electricity. The effect of that money will not begin to solve all problems, but its effect on the fiscal condition of the town and its economy is huge. That money goes to local economy, teachers, cops, firefighters, etc. This money allows towns to improve their services to residents. I would be opposed to any modeling of any system that does away with virtual net metering. Secondly, if it is our goal to constrain the development of solar in Massachusetts, we ought to do so with competitive bidding and let the utilities be gatekeepers. This is not conducive to innovation or speed. Competitive bidding is a cumbersome process, and in many cases, just scares people away and makes things more complicated than they need to be. I do not have a high degree of confidence that this will work.

Fred Zalcman: Moving away from posing questions to the consultant and resolving the question at hand. We have a deadline. Although it is not SEIA’s preferred model, what the consultants have presented does fairly represent a range of possibilities. It is important to determine the impacts of net metering. So, we should model constrained and unconstrained scenarios. SEIA wants to see uncapped net metering in the EDC model, especially if the net metering rate is constrained. Lots of considerations are not strictly captured in costs and benefits. An open versus closed market matters. EDC as a gatekeeper has important ramifications for the solar industry that is not captured in cost-benefit analysis. A cost-benefit analysis does not capture low income concerns either. The report should include a qualitative analysis on these issues.

Geoff Chapin: Virtual net metering is really important. It is a key policy to reach renters, middle and low income customers, and customers with a roof that isn’t suitable for solar. The benefit of solar should be available to everyone. It should be democratized. Hundreds of communities across the state benefit from virtual net metering. It is a moral imperative.

Amy Rabinowitz: National Grid wouldn’t use either of these models precisely as a policy choice, but they offer a good range of possibilities. They will yield good data and we can reserve value judgments for later.

Bob Rio: If we get to 100 percent renewables under the current system, nobody will be left to pay the bill. The current system overly rewards producers. Somebody has to pay the subsidies. There shouldn’t be a cap on solar at all, but under the current system that is not sustainable. If we get the program right, and the incentives right, we won’t need caps. We can have solar grow without subsidy. We don’t want the system to collapse. We want to keep growth going in a sustainable way.

Angie O’Connor: We appreciate public comments and will take them into consideration. We want to see the no cap option modeled as an important data point. I was a selectman in a small town on the north shore and can appreciate the value of virtual net metering to municipalities, also to community shared solar and to low income customers.

Camilo Serna: The Task Force must understand the cost side of the equation. Today we pay 55-60 cents per kWh for solar. We need to know what solar is actually worth. Is it 33 cents, like the results of the recent Maine study? We should be able to get to a more cost effective system. We want to look at a model with no caps. We want to have the data to point the best way forward. We want to see what factors are driving the impacts and the costs.

Janet Besser: 3 comments. 1) Look at a model with no caps, in A if you keep the current caps, you will not see the impacts of the competitive solicitation. 2) Some of the public comments surround the value of solar and the Maine study. When would it be appropriate to study the value of solar or the value of distributed generation. It would be informative. It should happen soon. 3) With the $800 million National Grid number, a significant portion ($500-600 million) of that is for energy efficiency. We should look at the costs of the supply portion of the bill in the larger context. Good job by the consultant to build two scenarios that will cover the range.

Bob Rio: I want to address the $800 million number. Everyone may have it wrong. Amy, would you please explain?

Amy Rabinowitz: The total cost to customers includes the commodity portion of the bill (which is 2/3 of bill) and the distribution work. The distribution side has about an $800 million annual revenue requirement. The whole gamut of renewable energy and energy efficiency is beginning to approach the $800 million revenue requirement. At some future point, the distribution portion of the bill will have to be doubled to pay for these programs. National Grid wants to achieve these goals at the lowest cost that we can.

Janet: The commodity portion of the bill is 2/3. Transmission distribution SBC accounts for the rest. We want to do this in a cost effective way.

Dan Burgess: We have one hour to go. We will edit the policy paths in real time. We are open to suggestions but want to go number by number to see where we have agreement. We will take one vote at the end.

Bill Stillinger: What is the nature of the final vote?

Dan Burgess: A yes no vote on the two scenarios.

Bob Grace: I propose a slight variation: we need to narrow down options as we go.

Janet Besser: On line 3 is it easy to model small solar with PBI and EPBI?

Bob Grace: Yes. We are capable of it, but it is not in the budget.

Fred Zalcman: Why did we exclude EPBI from the EDC model?

Bob Grace: We were following the survey results and looking to capture the diversity of interests.

Fred Zalcman: Why not just do EPBI across the board?

Dan Burgess: Any concerns with that?

Camilo Serna: It is important to model both PBI and EPBI so we can compare.

Janet Besser: I agree with Camilo.

Dan Burgess: We need to make a decision in line 4.

Janet Besser: I propose DBI w/ safety valve across the board.

Dan Burgess: Any concerns? Seeing none, onto line 5. Any issues keeping PBI for both? Seeing none. Onto 6. Solar Large. Any discussion?

David Colton: I want to renew my objection to competitive solicitation.

Janet Besser: It is just for modeling.

Dan Burgess: 7, geographic distribution?

Fred Zalcman: I prefer a third option which is incentives vary across different utility service territories but MW apply against a state wide block and there is a reconciliation at the end. Because the required incentive is driven by the retail rate, the required incentive will vary among the utility service territories. Each utility would have different PBIs. But then, when the companies submit for rebates, each counts against a statewide block.

Janet Besser: Does that mean development will not be proportional statewide? Do some ratepayers pick up the costs of developing outside of their territory?

Fred Zalcman: The costs are spread. Costs are borne by each utility according to their load, even if the development does not match that.

Amy Rabinowitz: Say there is a lot more development in National Grid territory. Are you suggesting some periodic true-up so that customers pay an equal dollar value across the state? If so, I support it as a policy option and as a modeling decision. It would show the impacts on different utility customers.

Bob Grace: Does levelized cost impact adequately describe your position?

Camilo Serna: Balancing costs between service territories is tricky. It could be done based on dollars, on size or some other way. The concept is good that all Massachusetts customers are paying the same to support the development solar, however the implementation is complicated.

Dan Burgess: Can we model that Bob?

Bob Grace: I think it is doable.

Janet: Re-raising the question of whether you look at the incentive as the total incentive to build solar, where the net metering payment is netted out, or the incentive an incremental payment that is above net metering? And, as you look at modeling a PBI, does that even matter? Do you need that answer to model it?

Bob Grace: I don’t have a definitive answer. In column A, if we have the net metering revenue as a given, then what bidders need will be incremental to whatever they get from the solicitation. Either bid all in for what you need, or bid what you need excluding net metering. Either way, I think we can model it.

Amy Rabinowitz: It seems from Janet’s question that it is important to know where the payment is coming from. That matters to cover the cost.

Bob Grace: Are we talking about the 4185 path?

Fred Zalcman: In a competitive solicitation, the developer will take into account the net metering revenue and their bid will be whatever additional dollars they need to make the project pencil out. Under declining block, it is more or less the same.

Bob Grace: I think of that as a straw man, if you assume net metering revenue then the incentive is calculated on top of that. The rest is just the gap in the revenue requirement and it will be easy to fill in.

Angie O’Connor: It is not easy to transfer costs of net metering from one service territory to another.

Bob Grace: To clarify, the cost allocation is on the solar incentive side only, not the net metering side.

Dan Burgess: Is there general agreement on the third option?

Bob Grace: This gets a little complicated. But we understand how to model this.

Dan Burgess: Seeing no disagreement we will move onto 8.

Janet Besser: We should go with SREC II.

Bill Stillinger: We should say “based on SREC II”; some clarifications would be good.

Janet Besser: Size stratification is just from large to small. SREC II factors are a more thoughtful sensible way to drive solar development to markets that have more public policy value (like community shared solar and low income). “Based on SREC II” should explicitly include community shared solar and low income.

Dan Burgess: So based on SREC II for both models. Any concerns? Seeing none, on to net metering sized to load.

Bob Grace: Do we have the data from utility reconciliation filings to use as a basis?

Janet Besser: I am not sure how helpful it is to use the G rate when talking about sized to load net metering. Using retail rates would reduce the incentive level and would be an easier political sell.

Bob Rio: When net metering systems export, will they get the G rate, the power rate, or the basic service rate? Furthermore, is it only the excess generation, or is it whenever they export?

Bob Grace: We are just trying to create a framework that could be modeled. I believe the thinking is that net excess gets paid at the QF rate and onsite consumption can offset high and low load.

Camilo Serna: It is important to know where the payment is coming from, whether it is part of the competitive solicitation or net metering. We need to be able to count.

Janet Besser: To paraphrase Camilo, for a reduction in value of net metering credits for excess generation, we do an annual or month to month valuation of excess generation.

Bob Grace: We are trying to work on a whole cost to benefit framework. Oversized generators are split between two categories. Amount consumed on site nets the meter (at retail rate) and the exported power would be paid at a lower rate. So we use the current framework for all on-site load, and a different rate for everything excess.

Fred Zalcman: This is still not clear. Is it instantaneous excess or netted over some period? Is that period monthly or annually? Different answers yield very different results.

Bob Grace: We have a couple of choices. Billing year means we could have two net metering credit rates (one for offsetting the bill, and one for true export).

Bob Rio: Month to month offers simplicity. Different seasons of power prices can get very confusing.

Bob Grace: I suggest that we may need to figure out what we can do with the data in order to make the distinction. To make a clean analysis, we may need to divide up simply by whether it is allocated or if used on the host customer bill.

Amy Rabinowitz: I like differentiating between onsite load and exported energy. Even if the system is sized to load, it can export. We want to figure out the effects of not having virtual net metering.

Dan Burgess: Bob, please reiterate your proposal.

Paul Gromer: What I think Bob suggested is that any customer account gets their own generation at the retail rate. Anything they allocate.

Dan Burgess: For modeling purposes this makes sense.

Bob Grace: Sounds like we are on a QF rate for column A and need to figure out how to get down to two options on column B.

Fred Zalcman: If you roll forward the retail value you would impair the customer’s ability to bank their credits for a time when they need them.

Bob Rio: Identify the incentives and the costs with an eye towards the burden on the system. When you roll forward, you are not really reducing the burden on the system.

Dan Burgess: It seems we are revisiting number 9.

Camilo Serna: Maybe we shouldn’t include the credits in row 9?

Bob Grace: To be clear, nobody is talking about avoiding retail rates. Let’s then redefine that so we model column A at the roll forward rate is generation or QF rate and column B is the retail rate. Does that work?

Janet Besser: That works as a modeling exercise but it does significant harm to behind the meter net metering and NECEC could not support it. But go ahead and model it to see what the number is. Instantaneous is problematic.

Bob Rio: Doesn’t instantaneous avoid the conversation on a minimum bill?

Amy Rabinowitz: I don’t agree that it avoids the minimum bill conversation. To see what the answer is, if we drive Massachusetts down to the lowest subsidies, under that scenario, if the credit is tracked in the net metering or additive, we said net metering was netted out of the incentive.

Janet Besser: I disagree. I think we can figure out the policy choice, but as a modeling exercise we agree.

Fred Zalcman: Consistent with Janet, this would fundamentally change the economics of solar. The money has to come from somewhere. Without a value of solar study, we do not know for sure but the G rate significantly undervalues solar production.

Paul Brennan: I cannot ultimately say whether we would support it as a policy, but it is important to model it to see the data.

Paul Gromer: To be clear, we are not modeling the instantaneous excess, but the monthly excess?

Janet Besser: The G rate is just a higher number than the QF rate and while neither is a productive path to follow, you are just picking a number for modeling. Do modeling as described with G rate.

Dan Burgess: Onto line 10.

Bob Grace: Production rate, QF rate or G rate?

Amy Rabinowitz: QF rate is the correct rate.

Fred Zalcman: My concern there is that in a competitive bidding regime where different configurations are getting a different value for net metering, they are already at a disadvantage.

Bob Rio: Isn’t some of this argument going to be solved by the model?

Fred Zalcman: It is self evident that if you are paying less for electricity, you will get less development.

Bob Rio: I disagree.

Dan Burgess: For modeling purposes on 10 A, are there proposals to change from the QF rate?

Bob Grace: We can call this broadly the wholesale rate since QF is the monthly average wholesale rate.

Dan Burgess: There is agreement, moving to B current framework in rates. Then onto 11.

Janet Besser: Doesn’t 11 go away then?

Dan Burgess: Agreed, onto 12. But I just want to be clear how community shared solar is treated.

Janet Besser: It still gets full value as it does now. Does 12 also go away as a subset of 10? Just keep current. 13 is the tricky one.

Fred Zalcman: But for 11 and 12, it is not applicable because we are restricting the payment because we are not getting rid of virtual net metering, right?

Bob Grace: Right.

Janet Besser: On 13 do we want to model a scenario with no net metering caps? Not sure how it fits in, but that is data that we need to see.

Amy Rabinowitz: Would it be possible to model it both ways for both A and B? Not just looking at the growth of solar but the cost to customers? It is good to know how/where the money is flowing.

Camilo Serna: The options simplify all other elements, but we need to model that. It would be most helpful.

Janet Besser: Agreed.

Amy Rabinowitz: It would also be helpful to know how you came up with the numbers, what the projections are based on.

Bob Grace: So we are going to model both current caps and no caps on A? And on B it is not so simple based on the timing of the transition. We need to understand what B looks like.

David Colton: I agree that we should model it both ways but I can’t let Amy’s comment pass. We developed a 2 MW solar facility and that is the reason we are getting our money and our credits. We aren’t taking that money out of somebody else’s pockets.

Janet Besser: For 13B, no caps, and current caps. For 14, it should say 1/1/17. The alternative is that on 13, we say get to 1,600 MW with no caps, and then have a cap. So somehow we get to 1,600 MW by October of 2015, that would be one scenario, versus no cap played out to 1/1/17. But if it doesn’t matter, just say current cap versus no caps.

Bob Grace: Lots of folks have expressed an interest in keeping the current SREC system until we get to 1,600 MW.

Janet Besser: The group consensus is a no cap scenario and a “to 1,600 MW” scenario.

Bob Grace: So then, row 13 would be no caps or align to match reaching 1,600 MW, to enable the SREC II program, and when that is done you reach another world.

Janet Besser: Then, on 14, the B track would just read 1/1/17.

Bob Grace: So the transition would happen at 1,600 MW? Or on 1/1/17?

Fred Zalcman: I support a scenario with a longer runway.

Janet Besser: Now I understand what Fred is saying. It should say 1,600 MW.

Amy Rabinowitz: Wasn’t the task that the legislature gave us to get to 1,600 MW?

Dan Burgess: It said to get there and beyond. So we have to consider additional deployment.

Bob Grace: If you model this world without net metering cap, you would get more uptake earlier on. But if you truncate SREC II in 2017, the cost changes and the model must change with it. There are many moving parts that could obscure what you are trying to see.

Dan Burgess: We are short on time. Any changes needed on 13 and 14. Seeing none onto 15.

Bob Grace: For A, we must choose set targets (like RI) or set budgets (like CT).

Amy Rabinowitz: I prefer set budgets for the A Model.

Camilo Serna: I agree with Amy.

Dan Burgess: Any concerns?

Janet Besser: Don’t just look at the costs of the programs. Look at the benefits too. To the extent you set a budget, you commit to foregoing benefits of additional out of budget PV.

Bob Grace: In reality, there is a cost to a dynamic volatile market place. We could calibrate the budget to meet certain goals, such as 2,500 MW by 2025.

Janet Besser: But it is not clear how you set that budget.

Bob Grace: For any given budget, we can model how much supply in each category it can buy.

Janet Besser: A larger question is how we are assessing the value that we are not getting by choosing one level and not a higher level.

Liam Holland: There is something of a catch 22 here.

Bill Stillinger: We seem to be circling around a larger question. These scenarios will yield different levels of solar. How are we valuing costs and benefits?

Bob Grace: That’s not exactly right. We are going to get similar levels of solar at all options. We are looking more at the costs and timing of getting there.

Janet Besser: The straightforward analysis is to pick a target and then choose what track gets us there at a lower cost. I suggest we just go with it as written.

Dan Burgess: Okay, minimum bill we will take on in task five and disposition of SRECs has an agreement. Any further comments?

Bob Rio: For the solar people talking about reducing incentives, peace of mind is worth a lot. Certainty is worthwhile. Volatility is expensive. It is okay for some of the incentives to change, if it gives the industry certainty.

Dan Burgess: Any motions to put the modeling proposal, as written to a vote? Motion made. Any seconds? Motion seconded. It is time to vote. All those in favor of voting for the modeling proposal as written? [All task force members vote in favor.] Any opposed? [none opposed]. Any abstentions [none abstaining]. The motion passes unanimously. We will have more discussion on March 20th. This meeting is adjourned.