Net Metering Task Force, Group A- Utilities

1.20.15

9:00-10:30 a.m.

- Amy Rabinowitz, National Grid
- Brian Rice, Northeast Utilities
- Hayley Dunn, Northeast Utilities
- Richard Chin, Northeast Utilities
- Peter Zchokke, National Grid
- Ian Springsteel, National Grid
- Timothy Roughan, National Grid
- Carrie Brentlen, National Grid
- Laura Bickel – National Grid
- Camilo Sernac, National Grid
- Andy Belden, Meister Consultants Group
- Bob Grace, Sustainable Energy Advantage
- Kathryn Wright, Meister Consultants Group

Participants introduced themselves, and were informed the session would not be recorded. Participants were given the opportunity to provide additional written comments to supplement the call.

1. Stakeholder objectives and priorities from the Task Force process

What are your goals and objectives for the task force? Of those, what is your most important objective and why? To the extent that goals or objectives may conflict, how would you prioritize?

Participant 1: We will be providing written comments by Friday, which will summarize our comments. Supportive of clean energy goals state has and helping meet 1600MW goal and anything that comes beyond that, but we must not lose sight of how we hit the goals and cost-effectiveness, particularly for NEM and SRECs. How can we redefine them to be more cost effective to ensure rate fairness, transparency and make sure customers are not paying anything above market prices?

Participant 10: We will also submit written comments. The state needs sustainable renewable programs which can be enjoyed by all customers, not a few. Ideal programs would be fair, cost-effective and competitive.

2. Long term Massachusetts solar market goals

The current stated goal of the Massachusetts solar policies is to reach 1,600 MW of installed solar capacity in the 2020 timeframe. Please discuss your perspective on this MW goal, its timing, and the appropriate objectives for the state solar market beyond the timing and quantity of this goal.

Participant 10: We think 1600MW is an aggressive, but achievable goal. It represents ~4% of energy supply and ~12% of peak demand. A lot of this will be based on our company's ability to interconnect, overall development funding and the market. With the high incentive level we are going to achieve this goal early. Cited virtual net metering in particular because developers can choose the site location and then not contribute to system costs. The costs of the NEM and SREC programs need to be reduced to increase net benefits. We also need to reduce payments to solar developers and investors, particularly those from out of state.

Participant 1: Believes that Mass. is paying well above market prices. SRECs and NEM are nearly seven times more than wholesale power and four times more than wholesale renewable programs. Mass.'s program costs three times Conn.'s program, which participant's compnay also participates in. NEM customers are receiving $.50/kWh. There are better ways to structure the program- we need to develop an all-in cost per kWh of installed solar and accompanying cost-effectiveness goals. We've seen solar prices drop with increases in volume and manufacturing efficiencies and the level of incentives should be decreasing as well. Over the next few years, $7 billion will be paid above market costs to support solar development.

Participant 9: We looked at results under the ZREC program for 15-year contracts. CT has lower prices and lower NEM support. We also looked at other states. We compared this on a straight rate perspective. This is not apples to apples comparison, but if you were to do so, we find that the net cost of the ZREC program is less than MA no matter what perspective you take.

Participant 1: Agreed with Participant 9, and adds costs are high when compared with Rhode Island too.

Participant 9: We are looking at NEM around $0.15 credit plus basic service. The 2015 vintage for SREC-I is above 400 dollars. This gets us at or above $0.50/kWh, though in other years the amount has been lower.

3. Perspectives on current net metering approach

Solar PV systems in Massachusetts typically benefit from net metering with various system sizes and configurations receiving different net metering benefits. Additionally, volumetric caps to net metering have been revised through legislation on multiple occasions over the past several years. Please provide your perspective on the current Massachusetts net metering approach.

Participant 10: Current system is not well designed. There are two issues: cost shifts between customer classes and distributed generators (DG) only paying for a portion of their fixed costs. DG customers are receiving reliability services and the ability to transact and monetize solar energy. Other non-transmission and distribution costs are not being recovered or shifted to others, such as the renewable and efficiency funds as well as other programs. Once you add-in the VNEM concept these issues are made worse because it is a significant administrative burden for utilities. We have to transfer payments from generator to customer accounts which is not related to how power is being produced or used. There may also be an issue with community solar providers and ISO New England rules. There was a challenge regarding settlement at the DPU in 20011, with the result being that some suppliers are dropping customers since they can't serve them.

Participant 1: ISO defines a large unit SOGs as greater than 5MW. It's not clear how they should be treated who should take ownership of these units. For customer's that are interval-metered, suppliers are being billed based on generation. The net metering credit is a construct which creates a mismatch between the suppliers and what ISO needs to register in the system. Anyone bidding into basic service will bid at a higher rate to take into account this issue. We are receiving 1,000s of applications for PV interconnections, and will likely cause higher basic service charges in the future to account for this risk. In the smart grid pilot, 2,200 of 15,000 have left basic service because of costs. Now is the time to consider this issue. Community solar providers should be administered by ISO New England and regulated by FERC as retail providers.

Participant 10: The NEM construct may be appropriate for giving solar a jump-start, but it is not sustainable for a long-term program. If you have every customer net metering to zero out their bills, no one is paying for the costs of the system. All PV systems are receiving same net metering credit value. Using 2015 rates, it can be shown that VNEM costs customers more than NEM coincident with customer load. VNEM results in a 40% higher cost than most behind the meter systems. VNEM uses distribution system and provides less benefit.

4. Perspectives on current Massachusetts solar incentive model approach

Massachusetts solar installations typically benefit from a range of incentives, including SRECs, federal tax credits and net metering being major contributors to system economics. Please discuss your perspective on the current mix of incentives other than net metering (and virtual net metering) available to Massachusetts solar systems with a particular focus on the Massachusetts SREC incentive.

Participant 10: SREC obligations put a higher cost on IOU customers than it should. Prices are not declining with time even though PV is cheaper. SREC-II narrowed the floor and ceiling with declining price, but SREC values are still too high and volatile. This creates artificial risk and financing difficulties. If we introduced competition based on cost and total development, it would help developers. A fixed rate would give customers a hedge value and should lower costs. The SREC program is high cost/high risk and induces boom-bust cycles. This makes it hard for solar development costs to come down effectively. A competitively procured amount of solar PV production would be better.

Participant 1: SREC incentives exceed what's necessary to deploy solar in the state. CT, NJ and RI all have lower subsidies. We understand the need to provide price certainty, but believe transparency and competitiveness is key element. Having administratively set rates disrupts competition. We can still give appropriate incentives. Some amount of incentives should be set-aside and we should think about how much solar we can procure with a fixed budget. This is much like the CT approach.

Participant 1: In NJ, long-term contract support and banking have been able to augment the SREC program and stabilize market participants and the market, even without fixed floor. We think solar could be procured through RPS program without price support. Some market participants are sophisticated and should be able to manage this risk. We have seen this in NJ after the SREC program was changed. In the case of efficiency, incentives and rebates were introduced to jump start the market, but the goal was to reduce the incentives once the market is working. We need to think about how EE works and bring that to the next evolution of the SREC program.

5. Perspectives on other solar incentive models

Other states have implemented a range of incentive program types in order to grow their solar markets. Several program types that you may be aware of include (but are not limited to):

- *Standard offer incentive programs (aka. feed-in tariffs)*
- *Declining block incentive programs*
- *Competitive procurements (aka. auctions or solicitations)*

There are also many variations on these approaches, as well as co-policies. Are any of these incentive program types of particular interest to you? Please discuss your impressions of these or other incentive program types that you may be aware of, and whether we should focus on particular incentive types that are of interest to you. How do you think the effectiveness of these incentive program types vary for different solar installation types (e.g. residential vs. utility scale)? What options would you like to see the consulting team consider and analyze for Massachusetts?

Participant 1: It is more about what parameters are needed instead of focusing on a single program having looked at other states. A program should be fair, transparent, and appropriate to level of solar development in industry. DG should be incentivized based on known, measurable benefits and reevaluated and modified as policy goals are met. Externalities such as jobs and the environment should be treated consistently between the utility scale and DG. Any price above wholesale price should be regulated by DPU. We are supportive of the long-term contracting programs in CT. We also look to RPS programs to have transparent prices through bidding and no discrimination between project types. A tariff system would be easier administratively. We understand the difficulty of following bid schedule, and would be OK with a declining block incentive if the rates were set transparently and the schedule ends at 0. If RPS programs are retained, it should not have a floor, but instead should have these parameters.

Participant 10: In RI, renewable energy growth program is launched soon and will be ½ the cost of the MA program. All of the payments are under an approved tariff. Small and medium systems have a fixed –price performance based tariff. Non-residential systems receive a fixed payment for 20-years. Residential systems receive NEM credits and further incentives for performance. A public process sets rate annually based on the market and competitive procurements. Large solar systems must bid into a competitive procurement with a ceiling. During the last auction sizes ranged from 172kW to 1.25 MW. All-in $150-240/MWh bids. Most averaged $200/MWh. New York has used competitive solicitation for 200 kW and up. That program has provided awards worth the equivalent of SREC price of $50 for 10 years at a 10% discount rate. However, it doesn't provide hedge-value. NY is moving to PBI with a step schedule. This is less cost-effective compared to competitive model and insensitive to market changes and needed rates of return. Our view is that mix of PBI tariff and competitive process would be best.

6. **Perspectives on future use of net metering, as well as minimum bill provisions**
   During the past year, efforts have been made to revise the framework for net metering in Massachusetts including the addition of a minimum bill for all electricity ratepayers. Please discuss your perspective on the future use of net metering/virtual in Massachusetts and, to the extent you are able, what options or changes would you like to see and why?

Participant 10: Thinks a minimum bill would reduce inequities between ratepayers and would help NEM participants pay for their fixed costs and not impact EE incentives. This would not fully resolve all of the issues with cost-recovery and cross-subsidization, but it can transition us to a world where people pay for what they are using from the utility system.

Participant 1: We have indicated problems we see with the current structure. Rate design should function based on cost allocation, efficiency, continuity, and fairness. We feel that net metering violates most of these. Without proper cost-allocation, we can't meet state goals. We need new rate designs which disaggregate the benefits and costs of solar. We want to be able to get the data points we need to create a new rate design. This includes the power exported to our company, the power delivered to customers and the production of DG facilities. We need to recover fixed T&D costs at a level similar to non-DG customers. A separate generation transaction would be compensated – there are many different options. Another alternative is to develop valuation of solar methodology to compensate for energy being distributed. Then the incentives would come into play- we've discussed how they should be structured, and that they should decline over time. We also propose a new customer class with higher T&D customer charges, but it wouldn't be subject to net metering. The bottom line is that we need to address this in a comprehensive manner with a formal regulatory proceeding which can determine appropriate rate design and benefits of DG. Regulatory bodies were established to do this.

Participant 7: We believes that the minimum bill is one method of rate design. NEM should reflect the DPUs principles, costs should be properly allocated to customers, and it should have customer protection designed into it. Separation between delivery and export of power will enable a better rate design. VNEM needs to be re-evaluated entirely.

Participant 10: Seconds that DPU is the right forum to balance all needs for rate design. As with every other rate change, a minimum bill would have to be customer class specific.

Consultant: Do you have any feedback on if existing installations should be grandfathered for some period of time for rate changes?

Participant 1: It depends on what the rate design is and if it will accommodate existing facilities. Any design would have to take that into account. Difficult to explain without a specific example, but it should be a part of discussions.

Participant 10: Seconds Participant 1. Open to a transition, but hard to say more without specifics.

7. Perspectives on policy transitions

A. *At the 2nd Task Force meeting, it was suggested that analysis should account for* ***uncertainty costs****, (i.e., transition costs due to changing goals and programs.) Please discuss qualitatively the nature of these costs as you see them, and whether and how you might suggest such costs could or should be quantified.*

B. *Are there particular threshold milestones where it might make sense to consider policy transitions in order to minimize such costs? What other means are available to minimize such costs?*

Participant 1: It is difficult to know what kinds of costs there might be. The marketplace is full of uncertainty. Some of the players are becoming sophisticated and should be able to deal with change. Programs are not expected to be exactly the same forever. Any program change should incorporate transition into design. The cost of running the existing program would likely be more than the transition cost.

Participant 6: Unclear of what the definition of uncertainty cost is in the question. Costs are being incurred today for the program and the distribution grid. Program participants in the future may be uncertain about what their benefits will be from the utility and for their generation. Certainly, clarity from the DPU would help about where we are going in the future as well as a timeline so everyone is familiar with rate design and other changes. We want for customers to pay for the services provided by grid and be compensated for the services they provide. We need a framework, clarity, time and customer fairness. If VNEM is taken to the extreme no one is paying for the grid. This can't happen. Costs for one party are savings for another. Who is the right party to pay for the distribution grid?

Participant 5: The tighter the timeline, the less risk for all the parties involved and the more room for revisions.

8. Utility- specific questions

How would you propose a minimum bill calculation methodology be applied? What other models would you point to that are viable for achieving your objectives?

Participant 10: Minimum bill design to be addressed in the written comments.

Participant 1: We will provide written responses to questions and a separate attachment on the minimum bill. A minimum bill is less preferable than an appropriate rate design.

With respect to FCM revenues for current Class II and III systems, for which utilities secure certain rights under net metering tariffs, please describe your current practices, and future plans.

Participant 9: Haven't offered any NEM system into FCM. We don't control those assets so we aren't willing to assume risk of obligation of those systems. FCM value is still realized through a load reduction, perhaps not of quickly, but it is still there. We will continue to evaluate- if the risks could be addressed maybe it is an option.

Participant 1: To date, we have not taken advantage of this, but it is under consideration.

Are utility system integration costs for solar projects now fully borne by project owners?

Participant 4: Significant O&M costs, taxes, tree trimming, not being paid by customers even if they are paying upgrade costs. This can be up to 6% of the costs, annually. This is a cost not being borne by DG customers. 1,000 customers applying for interconnection- the $50-70 per meter costs are not being recovered since the simplified process has no fees. There are also costs from issues arising around Schedule Z for utility staff. A minimum 2-3 FTEs work on this issue and that number will grow.

Participant 1 - We will be providing data on O&M appropriate numbers.

What are the expected potential impacts of Grid Modernization/Time-Varying Rates efforts on net metering value and framework?

Participant 1: We are in the very early stages of thinking about implementation. Hard to assess the impacts without specifics.

Participant 6: We need to think holistically about costs incurred and recovery. What types of issues might arise from over or under recovering? What happens if customers over produce during a peak?

Participant 6: Our decision around TOU rates carries risks for the wholesale market. There is a disconnect between retail-TOU pilots and the way costs are incurred at the wholesale level.

Participant 5: We need to reflect on DG Forecast Working Group findings at ISO New England and the FCM for solar.

What are your experiences in other state solar markets with alternative incentive models or policies in place?

No further comments.

Please describe your past and expected future participation in SREC floor price auctions.

Participant 10: We haven't participated. We are in the market for SRECs prior to the auction and have typically gotten enough for load. To participate in the auction would be speculative since it would occur before the load was known.

Participant 9: Our experience is similar. Our only demand for SRECs is to serve basic service load. We have a process for serving basic service load, and we don't look at time horizons very far in the future. May be the case will be different in the future.

What information can you make available to the consulting team to help us assess the role of avoided T&D cost (if/where applicable) and avoided distribution losses resulting from installation of distributed solar generation?

Information will be provided.

9. Other topics

Are there any major topics or perspectives related to the Task Force's scope that we have not discussed today that you would like to comment on?

Participant 1: Recognizes there is a challenge to address everything through legislative process and report. We need regulatory proceedings, and to reflect value that grid provides to the DG. The value of these systems can increase with increased utility involvement in deployment. We believe we provide more services to DG, such as reliability and compensation for variable outputs, frequency regulation and redundancy services, voltage, and start-up power. This needs to be key element of rate design and as initial element of the analysis.

Participant 10: Recommended EPRI's paper on the Integrated Grid, and agreed with Participant 1 regarding the need to reflect the value of grid services. How will the consultant team get costs data from developers and host customers?

Net Metering Task Force Focus Group Interviews
Group B- Utility Customers and Customer Advocates
1.21.2015
3:00 p.m-4:30 p.m

- David Colton, Town Administrator, Easton
- Bob Rio, AIM Representative
- Andy Belden, Meister Consultants Group
- Bob Grace, Sustainable Energy Advantage
- Kathryn Wright, Meister Consultants Group

1. Stakeholder objectives and priorities from the Task Force process

What are your goals and objectives for the task force? Of those, what is your most important objective and why? To the extent that goals or objectives may conflict, how would you prioritize?

Participant 2- Would like to make sure the result continues to allow development of solar energy in the NEM/VNEM paradigm so that we can continue to reduce our costs of energy. Acknowledge that the subsidies need to be paid by someone. Regardless of what happens, public sector projects need to remain viable. As a secondary goal- alternative energy is important and we need to continue to diversify energy mix for well-being of planet. Third- Don't think we want to see change in the way that electricity is produced, generated and distributed. The separation of distribution and generation companies has been good for MA. We do not want distribution companies to gain more control over generation assets, even if they are distributed. Utilities have demonstrated that they are overstretched with their existing priorities.

Participant 1- The goal is to find the best way to have a solar program. That may or may not be NEM. We need to review rate and incentives structures to ensure they are proper and not overly generous. We need to stay on the trajectory of increased solar. Acknowledges who is paying for subsidies is a huge issue as well as freeridership. In general, people don't understand that the incentives are misaligned with the market. Our goal should be to look at the market and what it takes to develop solar and align incentives for people to install high-value installations. It is not clear what the implications for Massachusetts are or electric stability growth isn't managed.

2. Long term Massachusetts solar market goals

The current stated goal of the Massachusetts solar policies is to reach 1,600 MW of installed solar capacity in the 2020 timeframe. Please discuss your perspective on this MW goal, its timing, and the appropriate objectives for the state solar market beyond the timing and quantity of this goal.

Participant 1- Someone decided that 1600MW is the right number. It could be more or less. Getting to the goal doesn't bother me, but it needs to be clear that this goal has some resemblance of what you need to ensure system reliability and an appropriate fuel mix. The NEM legislation that references 1600MW doesn't mention 2020 so I don't think we are held to that standard. If the incentives are aligned and we get there before then, then that's OK. The location of solar and how we are using DG are more important than goal. Should consider incentives on a locational basis. An example, Nantucket Electric needs power. They have almost no back-up power in summer. Not sure what the attitude towards solar is in Nantucket, but solar could alleviate this problem. An installation is worth far more to society there. There are likely many other places where this is the case. For ISO New England, peak electricity needs are after the sun sets. Solar is not giving

us the full benefit we need. We'd better off orienting panels to pick up sun in later hours and incentivizing systems which provide maximum benefit to grid needs instead of maximizing production.

Participant 2- Agree with what was said, but also feels that the goal is too small. The program achieved the previous goal ahead of schedule. No one has demonstrated that there was negative impact from exceeding the previous goal. We've been very successful. Why are we setting this 1600MW goal? It's arbitrary. We can generate more solar power in a broad approach and include targeted installations. There's no need for one or the other or a real problem with exceeding the target.

Participant 1- The problem is that the program blew through the goal so fast, it signals that something isn't optimized. When you start getting to higher MW targets and higher costs, the grid might not be designed to handle that level of distributed power. The system has to be there to provide back-up service. In a perfect world would like to see system modernized, but that's not likely over the next few decades. Right now solar is not deferring generation or T&D. Cloudy days mean all of the solar users go back to drawing from the grid.

Participant 2- When I see there's that much work being completed, it is not necessarily a problem. That kind of program success is a good thing. Sure- maybe it needs to be directed and managed, and be used more efficiently, but we are not generating too much solar.

3. Perspectives on current net metering approach

Solar PV systems in Massachusetts typically benefit from net metering with various system sizes and configurations receiving different net metering benefits. Additionally, volumetric caps to net metering have been revised through legislation on multiple occasions over the past several years. Please provide your perspective on the current Massachusetts net metering approach.

Participant 1- It was a home run for us. The program should be kept.

Participant 2- On the 70% that you are not self-generating, it would be interesting to see how much extra you are paying on the 70% to get the lower rate on the 30%. You may pay additional fees on the 70% than the savings you receive from the 30%. Since you are offsetting such a large amount you are not likely to be generating overall savings. Might be more relevant for smaller systems

I am concerned that fixed costs of the system are not being served. I know people pursing CHP so they don't have to pay into adders and tariffs. Yet if CHP breaks down, they still need the grid. Any costs not paid by DG are picked up by everyone else. None of these customers are paying for EE programs, transmission, distribution, and low income programs. I know people that have gone completely off the grid, which has big implications in the short-term or long-term

Participant 1- Has always felt that the system of tariffs and rates are almost like the federal tax code. It's opaque. If we think that we as a society are moving towards RE and DG and that has an effect on distribution system, then that's a problem. We need to fix the tariffs. The system is creating disincentives for renewables

Participant 2- The utility system is 100-year old model. We have had piecemeal transformation.

Perspectives on current Massachusetts solar incentive model approach

Massachusetts solar installations typically benefit from a range of incentives, including SRECs, federal tax credits and net metering being major contributors to system economics. Please discuss your perspective on the current mix of incentives other than net metering (and virtual net metering) available to Massachusetts solar systems with a particular focus on the Massachusetts SREC incentive.

Participant 2- We have covered some of this. The system is a little bit complicated. Some municipal utilities have different ways of incentivizing solar. I don't know if it is better, but it is certainly simpler. My question is are we unjustly enriching the wrong people? Where do the benefits flow? We support members pursuing incentive programs, and our members comment that the system is confusing and it is always unclear if they are getting the best deal. It would be better in the long-run if MA was more similar to other states.

Participant 1 - Hoping to learn more about what's going on in other states through the task force process. In terms of the SREC program, the only thing I can say with confidence is that it is way too complicated.

Participant 2- I know that DPU is looking at TOU for basic service to push demand off-peak. I'm not a huge fan. Currently, solar is paid the basic service rate. Basic service is a price projection for next 3 o 6 months, while actual rate tends to be much lower. There is no reason why solar PV power being put into market should be compensated at a rate different from what it is worth, when you have to buy power at what it costs. You should get reimbursed for what the power is worth, and that would get rid of need for other programs.

4. Perspectives on other solar incentive models

Other states have implemented a range of incentive program types in order to grow their solar markets. Several program types that you may be aware of include (but are not limited to):

- *Standard offer incentive programs (aka. feed-in tariffs)*
- *Declining block incentive programs*
- *Competitive procurements (aka. auctions or solicitations)*

There are also many variations on these approaches, as well as co-policies. Are any of these incentive program types of particular interest to you? Please discuss your impressions of these or other incentive program types that you may be aware of, and whether we should focus on particular incentive types that are of interest to you. How do you think the effectiveness of these incentive program types vary for different solar installation types (e.g. residential vs. utility scale)? What options would you like to see the consulting team consider and analyze for Massachusetts?

Participant 2- Keep it simple. TOU rates, location-based compensation, or production-based compensation. Some municipal utilities compensate in this fashion, and it aligns the value of solar with its cost. The claim is that we are driving down the cost of solar, but there are protests when the incentive level is proposed to be dropped or needs to be dropped. It is unclear what's actually true, but if the incentives are aligned, like I said, I'm indifferent to the model.

5. Perspectives on future use of net metering, as well as minimum bill provisions

During the past year, efforts have been made to revise the framework for net metering in Massachusetts including the addition of a minimum bill for all electricity ratepayers. Please discuss your perspective on the future use of net metering/virtual in Massachusetts and, to the extent you are able, what options or changes would you like to see and why?

Participant 2- If people are compensated for the value of their power only, we wouldn't need a minimum bill, or if you are reimbursed your power costs only, then you would be paying for transmission and distribution costs only. National Grid and NSTAR are saying that someone has to pay for their back-up services, which means the transmission and distribution charge associated with your use of electricity.

Participant 1- There are a lot of elements and tariffs on the electric bill. The credit needs to only be for power portion, and then you can still fund these other programs. A possible exemption might be energy efficiency. The design of the incentive is to get people to use less traditional power, these programs aren't intend to make people use less solar or wind. Part of the incentive for solar should be that you might not have to pay that tariff. I'm not sure the credit should be stripped to just power.

Participant 2- We could have a different distribution tariff or schedule for on-site generation. Maybe you would pay a little less since you are not utilizing all of the programs. I tend to agree that just because you have solar or wind, that does not mean you should use less energy or pay into the efficiency fund. There are still environmental impacts from producing the systems. Our goal should be efficient use of energy period. If you have 5MW CHP system, and you briefly use the grid, you still have unlimited access to EE funds, even though they haven't paid very much into the system. Maybe we think about this further? We tend to look at these programs in a microcosm, but we need to look at all of the DG programs and their costs and think about reliability.

6. Perspectives on policy transitions

A. *At the 2nd Task Force meeting, it was suggested that analysis should account for* ***uncertainty costs****, (i.e., transition costs due to changing goals and programs.) Please discuss qualitatively the nature of these costs as you see them, and whether and how you might suggest such costs could or should be quantified. Are there particular threshold milestones where it might make sense to consider policy transitions in order to minimize such costs? What other means are available to minimize such costs?*

Participant 2- You can refer to my earlier comments. I have no problem grandfathering during the transition.

Participant 1- Agreed.

Stakeholder Specific

Please describe any concerns about low-income customer impacts and benefits of current Massachusetts solar policies. What changes could be implemented, consistent with overarching policy objectives, to mitigate these concerns?

Participant 1- Just an observation: Many low-income housing developments have ideal roofs for solar PV. The building uses practically little electricity and there's no incentive for the developer to pursue on-site energy. If there were, the energy could be used to reduce the low-income electric bills in the building, which would be a good thing. If we are incentivizing solar, then why not try to maximize benefit? Low-income customers are paying electric bills, they are subsidizing solar elsewhere and not being able to access programs seems unfair.

Participant 2- The incentives are completely misaligned for rentals.

Please describe any concerns about other customer impacts and benefits of current Massachusetts solar policies. What changes could be implemented, consistent with overarching policy objectives, to mitigate these concerns?

Participant 2- Cross subsidy is a problem to the extent that it is happening. Some people just aren't going be able to participate in the program and that is a problem

Participant 1- Even with ideal site conditions a system might not be cost-effective. It's not for everyone.

What are the expected potential impacts of Grid Modernization/Time-Varying Rates efforts on net metering value and framework?

Participant 2- This is what I discussed earlier. There is a loophole since that excludes competitively bid customers. Participant doesn't understand why solar wouldn't be subject to the same system as other generators. Has no problem paying solar generators a lot of money in the summer. We need to align TOU and smart grid with right incentives to build solar systems not for the sake of building them, but help solve reliability concerns.

Participant 1- I don’t have an opinion on this yet.

9. Other topics

Are there any major topics or perspectives related to the Task Force’s scope that we have not discussed today that you would like to comment on?

Participants offered no further comments.

Net Metering Task Force Focus Group Interviews
Group C- Solar Industry
1.20.2015
10:30 a.m.-12:00 p.m

- Bill Stillinger, PV Squared, Representing SEBANE
- Fred Zalcman, SunEdison, SEIA
- Janet Gail Besser, NECEC
- Lisa Podgurski, Representing urban solar installers
- Larry Aller, Next Step Living
- David O' Connor, SEBANE
- Kate Plourd, NECEC
- Geoff Chapin, Next Step Living
- Andy Belden, Meister Consultants Group
- Bob Grace, Sustainable Energy Advantage
- Kathryn Wright, Meister Consultants Group

Participants introduced themselves, and were informed the session would not be recorded. Participants were given the opportunity to provide additional written comments to supplement the call.

1. Stakeholder objectives and priorities from the Task Force process

What are your goals and objectives for the task force? Of those, what is your most important objective and why? To the extent that goals or objectives may conflict, how would you prioritize?

Participant 7: There is a document that lays out many of the objectives we have discussed as a solar industry coalition. It does a good job of capturing goals and priorities of several of the members. Provided consultant with documents via e-mail. The primary goal should be to ensure balanced growth of MA solar market for 1600MW and beyond. We should also support continued job growth in cost-effective way.

Participant 5: We need to get a good report and recommendations to the legislature to address net metering and solar incentives so we can hit the 1600MW goal in a timely fashion. We need to encourage other DG as well. Recognizes that utilities have raised concerns about distribution impacts, and the Participant is open to understanding and addressing their concerns. However in the long or shorter-term, there should not be caps. The incentives should be set-up to compensate for distribution impacts only. Hopes to find a win-win solution where EDCs can be partners in supporting DG.

Participant 4: The document Participant 7 referred to does lay out goals and objectives. If I were to prioritize, it would be to create a long-term sustainable market place for solar in the Commonwealth and break the cycle where we return to legislature to raise caps. This creates a lot of market risk for solar developers who are looking for stable, scalable market.

Participant 6: Seconds Participant 4. We can't keep returning to legislature if we want to have steady job industry growth. Maybe we should just remove the cap to prevent going through this cycle again.

Participant: We have simple feedback. We must ensure that the consultants and Task Force do what the legislature prescribed, except the March 31st deadline, which may have to be adjusted. The operating words from the legislature of a stable and sustainable market are important to everyone on this phone call.

2. Long term Massachusetts solar market goals

The current stated goal of the Massachusetts solar policies is to reach 1,600 MW of installed solar capacity in the 2020 timeframe. Please discuss your perspective on this MW goal, its timing, and the appropriate objectives for the state solar market beyond the timing and quantity of this goal.

Participant 1: 1600MW by 2020 has been discussed as a standard/goal we are moving towards, but given what's likely to happen with ITC expiration in 2017, this will not be linear process. We will walk most of the path before 2017, presuming no changes. How can we get to a point where the market is close to goal by end of 2016? We can get the rest of the way with lower incentive rate. For longer-term objectives, it would be ideal to have a stable policy approach and trajectory that initially provides a similar level of value to market participants and then have smooth transition to a stand-alone market after achievement of the goal. This would be similar to what was achieved in CA, but MA is at an earlier stage of market. Perhaps, in the 2025 to 2030 timeframe.

Consultant - What specifically do you mean when you refer to CA?

Participant 1- They took 8-years with their declining block schedule, and it stepped down over time. They still have net metering in place, which is important. The declining block drove significant market volume to develop the stand-alone market. MA is earlier on trajectory. The first step is getting to 1600MW goal without disrupting the market. Anything after 2016 has a 20-30% incentive cost due to expiration of federal tax credits.

Participant 7- Agrees with much of what Participant 1 stated. But, the end state should be self-sustaining market for solar. DOER has avoided boom-bust seen in other SREC markets. There has been more stable growth. Over the next two years, steady state growth is projected to 1600MW. Hopes to see reasonable industry (e.g. 15-30% CAGR) and job growth. We can reevaluate at the 1600MW point and see where solar is relative to grid parity. What incentives will be needed to get the rest of the way? Perhaps value of solar rates rather than incentives.

Participant is more focused on the transition to a new policy environment, and that we not further destabilize market by creating new constructs. Under SREC-II there are some markets where unfettered growth is possible, but most of growth in the market was under the managed growth sector, which is capped. Participant would suggest removing the cap on it before expiration of the ITC.

Participant 1: We will make a lot of progress towards the 1600MW is two years if the market is not interrupted. I think we are both focusing on allowing the market to continue to function without interruption and uncertainty through the end of 2016.

Participant 7- I would agree with that.

3. Perspectives on current net metering approach

Solar PV systems in Massachusetts typically benefit from net metering with various system sizes and configurations receiving different net metering benefits. Additionally, volumetric caps to net metering have been revised through legislation on multiple occasions over the past several years. Please provide your perspective on the current Massachusetts net metering approach.

Participant 1- Generally, we think the current NEM system is OK. A residential carve-out is a good idea, but community solar needs a carve-out too. We think community solar is a democratization of solar, and it should be a real priority. It fits new administration's goal of energy justice.

Participant 4- Agrees, and is supportive of the current NEM policy. We recognize that as solar penetration increases, different compensation schemes may be required based on a fair evaluation of system costs and benefits. This might be higher than retail value. With larger systems and VNEM systems, there's the loss of the distribution component. We will need to see where system is relative to utility distribution system load and where the value is created. Locational effects need to be accounted for in the next paradigm- currently all systems are treated equally.

Participant 6- In terms of NEM, we need to have it in MA, and we need to look at the caps. VNEM assures long-term stabilization of job and solar industry growth, which we need to keep in the mix.

Participant 5- Agrees with earlier statements. It would be useful to hear from consultants as to how policies in other states have dealt with utility concerns about distribution costs, and how to incentivize market as cost-effectively as possible. There are implications for the utility concerns about the distribution systems and our desire to remove caps.

Participant 7- Cap discussions in the legislature have been ongoing for several years. Utilities have traditionally made arguments that caps are technical caps for integration reasons. With 4185, the utilities were willing to remove the cap if they got a minimum bill. If we could get an idea of what is technically feasible for a solar penetration level from the utilities, it would be helpful. Minnesota said DG could serve 40% of retail load without major system impacts. In Massachusetts, we would be at less than 6%. It seems that this is an opportunity to explore technical constraints, if there are any.

4. Perspectives on current Massachusetts solar incentive model approach

Massachusetts solar installations typically benefit from a range of incentives, including SRECs, federal tax credits and net metering being major contributors to system economics. Please discuss your perspective on the current mix of incentives other than net metering (and virtual net metering) available to Massachusetts solar systems with a particular focus on the Massachusetts SREC incentive.

Participant 5- We have a variety of members with many business models. Our members favor many different models, so we won't weigh in on one. A key thing to consider for the task force and consulting team is if there are some models which are more efficient at achieving the same level of solar development? For all models, transition costs should be taken into account.

Participant 4- Our members were skeptical of the SREC program at first, and were concerned about the availability of long-term SREC off-taker agreements and incorporation of financial risk in the market. We have seen maturation of the market over past several years, financiers are getting more comfortable, long-term SRECs available and customers understand the market better. In total, many policy paradigms could support solar, but I think the MA model is promoting solar and delivering it. There may be tweaks to make the program more cost-effective.

Participant 1- The current SREC policy was positive even before there was an increase in natural gas generation. SREC-II was much better than the first SREC-I model due to increased certainty. Let's not change it by introducing risk and discouraging investors. SunRun and others pulled out dramatically when the program changed. We need to have clear market signals to make investors confident in the market.

5. Perspectives on other solar incentive models

Other states have implemented a range of incentive program types in order to grow their solar markets. Several program types that you may be aware of include (but are not limited to):

- *Standard offer incentive programs (aka. feed-in tariffs) – administratively set*
- *Declining block incentive programs – volume-based*
- *Competitive procurements (aka. auctions or solicitations) – competitive bids*

There are also many variations on these approaches, as well as co-policies. Are any of these incentive program types of particular interest to you? Please discuss your impressions of these or other incentive program types that you may be aware of, and whether we should focus on particular incentive types that are of interest to you. How do you think the effectiveness of these incentive program types vary for different solar installation types (e.g. residential vs. utility scale)? What options would you like to see the consulting team consider and analyze for Massachusetts?

Participant 3 - A lot of the prior comments answered this question. SREC-II seems to be working. Any changes to that system have to be done carefully and not destabilize the current knowledge base and certainty in contracting. Earlier NY, CT, and RI solicitation programs were mentioned. Those would be drastic changes for MA, which I'm not in favor of.

Participant 4- From our organization's perspective, all of these incentive programs have strengths and weaknesses. Without breaking it down further, we are generally more in favor of the incentive delivery mechanisms where the market is more or less continually open (declining blocks or SRECs). This means the market is not tethered to utility or a central administrator's solicitation process. There is a continuous business cycle, and developers are continuously selling projects. Greater transparency regarding incentive price is also helpful.

Participant 5- Many of our companies operate in different states. As you think about the analysis, stay focused on what's effectively delivering solar in different states.

Participant 7- Echoes previous comments. An open market that is not tied to a procurement schedule is key. Generally, other models only make sense to consider post 1600MW and not within the next two years where we could not change without significant cost. There has been in-depth work by the legislature and others to balance and achieve goals MA has for solar in the current program. We would be putting that goal achievement at risk. How much total uncertainty can the market absorb? The ITC will cause change in how tax equity participates. It will use a lot of bandwidth just dealing with that change. PBIs are like an SREC market with a firm floor. If there was a firm committed floor, then it is just about setting appropriate prices. As an additional thought for the legislature, reducing permitting, inspection and maybe interconnection costs could be an incentive for the market as well. A lot of the soft costs on residential side are due to massively fragmented requirements city-by-city in the state. If there's a way to consolidate, it might be worth putting on radar screen.

6. **Perspectives on future use of net metering, as well as minimum bill provisions**
   During the past year, efforts have been made to revise the framework for net metering in Massachusetts including the addition of a minimum bill for all electricity ratepayers. Please discuss your perspective on the future use of net metering/virtual in Massachusetts and, to the extent you are able, what options or changes would you like to see and why?

Participant 5- To the extent NEM can continue it should since it has supported development of solar. There are two concerns with that: cost effectiveness and distribution impacts. The QPQ of removing the cap is addressing the distribution concerns. We should work to resolve concerns.

Participant 1- A minimum bill that can be increased over time will make it hard to sell solar. It would need to be small and capped, otherwise it could kill the motivation to go solar. The biggest impact is in the summer, so the bill would need to be calculated fairly. Does not see a minimum bill as 100% necessary, but understands we need something.

Participant 7- An increasing minimum bill will destroy market security. It is unclear that a minimum bill will result in meaningful revenue to the utilities. The most at-risk members of the community may be impacted by a minimum bill, since low-income and elderly consumers are actively trying to reduce their bills. Overall the current NEM program is the best option that we have for progress through the end of 2016. The market will continue to evolve, and we will need a fair and balanced process of calculating the benefits and costs solar provides to the grid. It takes time. It was done well in Austin and Minnesota. Open to having a discussion on next generation approaches, but the process needs to be inclusive.

Participant 4- We supported 4185 last year, which did include consideration of minimum bills. Our support is contingent on an overall valuation of cost and benefits solar provides to customer, utility, grid, other ratepayers and society at large. Supports the notion of gradualism- any minimum bill has to be modest in amount relative to what customers are paying today. We are supportive of the concept if it's a trade for uncapping net-metering.

7. **Perspectives on policy transitions**
   A. *At the 2nd Task Force meeting, it was suggested that analysis should account for* ***uncertainty costs****, (i.e., transition costs due to changing goals and programs.) Please discuss qualitatively the nature of these costs as you see them, and whether and how you might suggest such costs could or should be quantified.*

B. *Are there particular threshold milestones where it might make sense to consider policy transitions in order to minimize such costs? What other means are available to minimize such costs?*

Participant 1- In any new market you will have less investment until the transition plays out, raising the cost of capital. Transitions need to be smoother. Once we pass 1600MW and the ITC fades, we need something to support the market to ease transition. It should not be radically different from the options in market now- we need companies and jobs not to be cut.

Participant 4- To the extent we do experience another change in the incentive delivery mechanism, we will need time for industry to adjust. Robust grandfathering is necessary to the extent investment decisions have been made based on the current market system.

Participant 7- Delays are a risk of transition since people will wait to see what will happen. SREC-II was not a major transition, but market grew 70% in 2013, and 2% in 2014. Without long-term visibility, any delays between now and the end of 2016 has a pretty clear cost. Any project delayed either loses 20% from the commercial ITC expiring or on residential side it loses 30% of its value. This is why it is of fundamental importance that the market be able to run through the end of 2016, unless we have some option that will provide 20-30% of the value of the system as an incentive. The transition needs to be a similar policy so the market can adjust. Any new program creates additional administrative burden.

Participant 3 - Grandfathering is fundamental to any contemplated change and as well as a long lead time.

Participant 4- It really is critical for customers now enrolled in NEM to continue to benefit from that arrangement. CA agreed that customers will continue to get NEM credits for the useful life of the system. This is critical for the market.

8. Stakeholder Group Specific

How (if at all) are FCM revenues currently monetized under the current policy environment? Do you have suggestions for improvements?

Participant 4- From our perspective, if the system is NEM, then the utility has the right to the capacity payment. But, for the most part, the utilities have not bid those assets in. There has been reluctance because of the capacity values to date. Utilities are also uncomfortable being subject to performance penalties from assets they don't own or control. This is detrimental to ratepayers- Close to 1000MW of solar is not being offered into capacity market. There could be a cost-sharing arrangement with developers to de-risk project from utility standpoint, or for developers to bid the projects in.

Participant 7- This is not relevant for residential. From our experience to date it is not something that has emerged as a revenue stream or service from a residential purchase. I am not familiar with everything the third-party market does. There may be early efforts on the third-party ownership side, but I haven't seen anything. The current market structure prohibiting pursuit of this, and customer knowledge of the FCM is low or non-existent.

Consultant – If obstructions were removed would FCM be of interest or are the risks too prohibitive?

Participant 4- We may be bidding resources in the next auction- so not at all. Right now, capacity rights belong to the utility- it is unclear if the utility may exercise those rights with more generation online or higher FCM prices.

What are your experiences in other state solar markets with alternative incentive models or policies in place?
No additional comments beyond earlier discussion.

What are the expected potential impacts of Grid Modernization/Time-Varying Rates efforts on net metering value and framework?

Participant 5- We sees significant opportunities to support DG deployment with TOU rates, and support TOU rates being made available. We need to send signals about the locational value of distributed resources. TOU can be a way to show

that value. The value of solar and DG will be more available to system operators. This is something to keep in mind as policy changes, but not a near-term solution

Participant 7- Agreed. On residential side, TOU rates can expand the power and effectiveness of the solar market, but if done wrong way it could damage it. If customers can opt-in or opt-out of TOU rates, it could open up west-facing rooftop systems which have been previously unviable. If it's a mandated change with no grandfathering, it hurts customers who built their systems based on another rate structure.

9. Other topics

Are there any major topics or perspectives related to the Task Force's scope that we have not discussed today that you would like to comment on?

Participant 3- Must take public comment into account. There is a huge interest in preserving and expanding community-shared solar and equitable treatment for customers that are located in municipal power systems. No suggestions on how to move forward, but these have emerged as important.

Participant 7- During the analysis for SREC-II, there was a discussion of different program options. When thinking about residential customer-owned systems, having a more guaranteed value stream has no impact on their cost of capital. Their cost of capital is determined by their credit score. This is just to remind the team to be aware that investments to increase SREC cash flow security don't necessarily benefit residential solar. In the third-party market there are efforts by those players to line-up financing against those revenue streams.

Participant 5 - Look at solar incentive models that work for variety of ownership structures.

Net Metering Task Force Focus Group Interviews
Group D - Legislators
1.9.2015
10:30 a.m.-12:00 p.m.

Attendees:

- Christina Fisher –Senator Downing's Office
- Eric Krathwohl – Appointee of Senator Bruce Tarr
- Stolle Singleton – Appointed by House Minority Leader, Bradley Jones
- Andy Belden, Meister Consultants Group
- Kathryn Wright, Meister Consultants Group
- Bob Grace, Sustainable Energy Advantage

Participants introduced themselves, and were informed the session would not be recorded. One of the participants noted that they would have to leave the call early. Participants were given the opportunity to provide additional written comments to supplement the call.

1. Stakeholder objectives and priorities from the Task Force process

What are your goals and objectives for the task force? Of those, what is your most important objective and why? To the extent that goals or objectives may conflict, how would you prioritize?

Participant 3: The task force should find an ideal mix of solar incentives to meet state goals with a caveat that any incentives should be distributed equitably so there's no burden on non-participating ratepayers. There is a balance between meeting the goal and fairly distributing costs.

Participant 1: Shares similar view to Participant 3. Personally and through conversations with an elected official, the task force needs to define clear costs and benefits of future solar development. Personal opinion of reading of legislation seems like the primary goal of the task force is to figure out the best way to hit 1600 MW. Hopes task force can set up policy market or framework for market to continue to provide benefits going forward in the long-term that is clear and consistent to minimize boom-bust cycles seen previously in renewable markets.

2. What issues and concerns have your constituents expressed to you regarding the current net metering and/or solar policies?

Beyond the goal of meeting a solar target, what are any other policy objectives that are important for a solar and net metering program to provide?

Participant 2: Constituency consists of communities in Western Massachusetts that are active in solar market, and they felt that they were left out of the conversations during the last legislative session. They were also unsure about the minimum bill. The length and content of the final discussions about the bill also caused confusion. Constituents prefer to keep existing policies in place.

Participant 3: Emphasized the need for balancing incentives and costs, and a better understanding of ratepayer impacts. Balance of incentives and ratepayer impacts are needed. Low-income individuals also need to be able to access solar DG programs through avenues like virtual net metering.

Participant 1: Based on personal conversations with the community, there is more interest in more solar. Participant's state legislator would like to see more fairness, and recognizes growing interest in community solar. Programs need to

be available to more people. Other goals to consider include economic development and jobs. The MassCEC has shown growth in employment in the clean tech sector in the state. Have to consider this issue- was not sure if the report to the taskforce will include impacts from additional solar development, but it is important.

3. Long term Massachusetts solar market goals

The current stated goal of the Massachusetts solar policies is to reach 1,600 MW of installed solar capacity in the 2020 timeframe. Please discuss your perspective on this MW goal, its timing, and the appropriate objectives for the state solar market beyond the timing and quantity of this goal.

Participants did not have comments on this question

4. Perspectives on current net metering approach

Solar PV systems in Massachusetts typically benefit from net metering with various system sizes and configurations receiving different net metering benefits. Additionally, volumetric caps to net metering have been revised through legislation on multiple occasions over the past several years. Please provide your perspective on the current Massachusetts net metering approach.

Participant 3: Believes that volumetric caps are necessary under the current structure since participating and non-participating ratepayers are funding incentive programs. Unless the structure is readjusted then the cap can't be adjusted or lifted. This could be done by changing the credit level, for instance potentially crediting solar production at the wholesale rate. A minimum bill could also be explored to recover appropriate costs from solar customers. Does not think the current structure is ideal.

Participant 1: Agrees that the current structure is not ideal. Caps have created boom-bust cycles and rushes to the queue without having viable projects. Programs fill up quickly and then development cycle halts. Can we eliminate caps? Studies are needed on DG and distribution system impacts as well as appropriate pricing for incentives. To the extent the net metering task force study and report could help refine these questions- it would be helpful. People are OK with paying their costs- a minimum bill might work. Virtual net metering has also been important driver for many projects. This needs to stay in place.

Participant 2: After listening to public comments, thinks virtual net metering is of significant concern across constituencies.

5. Perspectives on current Massachusetts solar incentive model approach

Massachusetts solar installations typically benefit from a range of incentives, including SRECs, federal tax credits and net metering being major contributors to system economics. Please discuss your perspective on the current mix of incentives other than net metering (and virtual net metering) available to Massachusetts solar systems with a particular focus on the Massachusetts SREC incentive.

Participant 3: Refrained from commenting since Participant was unclear of the program's performance.

Participant 1: The consultants may be able to help clarify. SREC-I and SREC-II have been critical to solar development. When SREC-I was depleted and SREC-II was not yet in place, development virtually halted. Everyone was waiting on the policy changes. Believes the current targeting strategy to encourage higher-value installations makes sense. The federal

tax credit will expire soon- unless replaced, there will be a void. Unsure of how and if the state can deal with that in advance, but the loss of the incentive will have impact on development.

Participant 2: Had to leave the call.

6. Perspectives on other solar incentive models

Other states have implemented a range of incentive program types in order to grow their solar markets. Several program types that you may be aware of include (but are not limited to):

- *Standard offer incentive programs (aka. feed-in tariffs)*
- *Declining block incentive programs*
- *Competitive procurements (aka. auctions or solicitations)*

There are also many variations on these approaches, as well as co-policies. Are any of these incentive program types of particular interest to you? Please discuss your impressions of these or other incentive program types that you may be aware of, and whether we should focus on particular incentive types that are of interest to you. How do you think the effectiveness of these incentive program types vary for different solar installation types (e.g. residential vs. utility scale)? What options would you like to see the consulting team consider and analyze for Massachusetts?

Participant 3: Interested in declining block incentives to encourage solar at lower cost. Wondered if it was possible to adapt California and New York models for Massachusetts. Inquired on how competitive procurement applies to small-scale solar projects?

Participant 3: Standard-offer contracts offer price certainty, but setting appropriate price over time is difficult.

Participant 1: Expressed general familiarity with models, but not enough to comment specifically. Looks to consultants for guidance on these topics.

7. Perspectives on future use of net metering, as well as minimum bill provisions

During the past year, efforts have been made to revise the framework for net metering in Massachusetts including the addition of a minimum bill for all electricity ratepayers. Please discuss your perspective on the future use of net metering/virtual in Massachusetts and, to the extent you are able, what options or changes would you like to see and why?

Participant 3: Would be supportive of a minimum bill if an ideal price can be identified that supports solar development without cost shifts. Will the consulting identify an appropriate amount? Participant heard there was limited quantitative analysis on the bill during the last session.

Participant 1: Net metering and virtual net metering are key to solar development. It seems likely that a reasonable rate could be set. The legislation could develop a framework to be administered by DOER to adjust the bill over time. development, but needs to not be burdensome. Unsure if minimum bill would be helpful or appropriate.

NMTF Consultant: Can we get feedback on degree to which grandfathering is appropriate for those who invested in solar?

Participant 1: Would have a problem applying new charge to those who've made investments from a legal and fairness perspective.

Participant 3: It makes a difference if it's a rate adjustment vs. minimum bill. Grandfathering a rate adjustment would seem more fair if the rate reflects the cost

Participant 1: Agreed. Looking at it as a homeowner with solar, to the extent that bills are offset, Participant would find it fair to charge for use of distribution system. The rate just needs to be correct. Will there be an analysis of the net metering credit rate in other states?

8. Perspectives on policy transitions

A. *At the 2nd Task Force meeting, it was suggested that analysis should account for* ***uncertainty costs****, (i.e., transition costs due to changing goals and programs.) Please discuss qualitatively the nature of these costs as you see them, and whether and how you might suggest such costs could or should be quantified.*

B. *Are there particular threshold milestones where it might make sense to consider policy transitions in order to minimize such costs? What other means are available to minimize such costs?*

Participant 3: There will be costs to a transition, but the current system also has costs as well, and the state still has a target to achieve.

Participant 1: To the extent possible, we must avoid having multiple transitions. If the taskforce can establish a framework for a longer timeframe, it would add some certainty. Policy changes lower investor confidence. How do you quantify initial policy transition cost? Unclear if that analysis is feasible.

Participant 3: Seconds Participant 1. Need to develop longer term, predictable model for future for investor confidence and market development.

Other topics

Are there any major topics or perspectives related to the Task Force's scope that we have not discussed today that you would like to comment on?

Participant 3: There've been recent reports about solar reaching grid parity in certain sectors. How have incentives impacted this? Has this or should this be discussed at the meetings?

Participant 1: Taskforce already has a lot on its plate, and doesn't have anything to add. Heard solar has reached grid parity in utility-scale projects, but since we are focused on smaller systems shouldn't influence conversation or actions much.

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Net Metering Task Force Focus Group Interviews
Group F- Non-Task Force Members
1.15.2015
10:30 a.m.-12:00 p.m

Attendees

- Emily Rochon, MassSolar, Boston Community Capital
- Nathan Phelps, Vote Solar
- Todd Ford, Hampshire COG
- Craig Wetmore, Bluewave
- Becky Merola, Noble Solutions
- Jason Prince, Karbone
- Stephen Eisenberg, SREC Trade
- Stephen Pratt-Oro, Eastern Bank
- Andy Belden, Meister Consultants Group
- Kathryn Wright, Meister Consultants Group
- Bob Grace, Sustainable Energy Advantage

Participants introduced themselves, and were informed the session would not be recorded. Participants were given the opportunity to provide additional written comments to supplement the call.

1. Stakeholder objectives and priorities from the Task Force process

What are your goals and objectives for the task force? Of those, what is your most important objective and why? To the extent that goals or objectives may conflict, how would you prioritize?

Participant 5: The objective is to develop sustainable policy for solar now and in the future. Policies should be substantive enough to include technologies and reach 1,600MW goal.

Participant 4: Agreed with Participant 5, and added than an explicit effort be made to include low-income communities and ratepayers, and creating a sustainable market beyond 1,600MW.

Participant 7: Agreed with previous statements. The Net Metering Task Force (NMTF) also needs to ensure development is completed as cost-effectively as possible. It helps everyone if solar is subsidized as efficiently as possible, and puts less of a burden on ratepayers.

Participant 1: The NMTF needs to take current market infrastructure into consideration from the financing of installations to service providers. The structure of the market, be it net metering or the SREC program, should change such that it does not impact market development or cause a market disruption. The policy also needs to be as cost-effective as possible. Current market has enabled Massachusetts to become market leader in solar and has led to a number of clean energy jobs in the state.

Participant 8: Coming from the perspective of the retail electric market, existing retail contracts need to be acknowledged and considered before changing the RPS.

Participant 2: Cautions and reminds NMTF that wind energy projects in the state are not currently on track. Continued incentives for solar become more important since other renewable energy projects are not performing as well.

Participant 9: Agreed with comments about stability. State needs to live with this model for a long time and aim for market stability. Encourage NMTF to observe the leadership role of municipalities have taken and seek to retain that leadership

Participant 6: The market needs stability, and existing projects and projects in pipeline should be grandfathered.

2. Long term Massachusetts solar market goals

The current stated goal of the Massachusetts solar policies is to reach 1,600 MW of installed solar capacity in the 2020 timeframe. Please discuss your perspective on this MW goal, its timing, and the appropriate objectives for the state solar market beyond the timing and quantity of this goal.

Participant 4: 1,600MW is too small in light of the diverse market that SREC-II is trying to foster. Given the MWs developed in the previous years, DOER has had to throttle the managed growth sector. This impacts economic growth. 1,600MW is only 4% of electricity consumption in state. Need to think about the next stage of the market. Task force also needs to take into account the impacts of the Investment Tax Credit (ITC) expiration.

Participant 9: The target is fine, but it is only one piece of the pie. Much of the money associated with solar development in past few years has flowed out of the state. Need to incentivize jobs and business within the Commonwealth instead of supporting the multi-national companies which have entered the market.

Participant 7: 1,600MW is not enough of a high ceiling for development. The key idea is to foster development where it is cost-effective, and developers can build what they can to respond for the benefits of the GWSA and ratepayers. Fears that 1,600MW target throttles development instead of encouraging. Needs to be clear if it is a binding constraint or an aspirational goal.

Participant 6: Agreed with previous statements. Noted that as we consider other questions, that the stated goal acts as a cap. 1,600MW is too small. Incentives should be a matter of right for developers that deliver solar instead of facing caps.

Participant 5: 1,600MW is the next interim objective, but not the goal. More development can benefit all ratepayers.

Participant 6: MW goals and program caps create unintended dynamics. There is positive intent to spur development, but can lead to boom-bust cycles, and doesn't allow for smooth continuation of market development. Seeing that with managed growth sector of SREC-II program. In other states, the solar carve-out is a percentage of retail load served

3. Perspectives on current net metering approach

Solar PV systems in Massachusetts typically benefit from net metering with various system sizes and configurations receiving different net metering benefits. Additionally, volumetric caps to net metering have been revised through legislation on multiple occasions over the past several years. Please provide your perspective on the current Massachusetts net metering approach.

Participant 5: Before any discussion starts, we need better information. A cost benefit analysis is the first step, then we can evaluate NEM and NEM vs. other policies. Also need to consider NEM in the context of the current rate design. If the rate design changes, is NEM still appropriate?

Participant 4: Agreed with Participant 5. As it stands now that caps are created by statute and we have to return to legislature to raise cap. This creates uncertainty. Should be addressed by removing cap entirely or removing for smaller

projects. Move from a 25 kW exemption to 1MW exemption. Virtual Net Energy Metering (VNEM) needs to be evaluated not just in terms of utility costs, but to insure that all ratepayers can access solar.

Participant 7: Agrees with comments on VNEM. NEM and VNEM has been fundamental to development of solar in the state. This has to be taken into consideration in the cost-benefit analysis. VNEM allows concerns with NEM to be addressed by allocating credits to wider population. Have seen issues in Minnesota where cost-benefit analysis has made utilities reluctant to adopt. Need to look at benefits with MA in mind. Need policy not to stop and start as we have seen with PTC elsewhere.

Participant 1: When H4185 was being debated some of the benefits that DG is providing to the grid, like capacity, were not focused on. Wants to make sure consulting group considers benefits, and the need for additional grid supply projects with traditional generators coming offline. This benefits ratepayer base as well.

4. Perspectives on current Massachusetts solar incentive model approach

Massachusetts solar installations typically benefit from a range of incentives, including SRECs, federal tax credits and net metering being major contributors to system economics. Please discuss your perspective on the current mix of incentives other than net metering (and virtual net metering) available to Massachusetts solar systems with a particular focus on the Massachusetts SREC incentive.

Participant 4: SREC-II added the tiered SREC factor to favor projects over others, such as projects in low-income communities and housing developments. This has created a major market where there previously was none. But, the SREC-II process can be too rigid. Under SREC-I, we completed a shared solar project, which sold power to assisted living, center, housing project and local business. SREC-II can't look at this project with different actors and assign it appropriate value. Unintentionally excludes interesting projects- you don't get as good of an incentive. Stifling innovation. Would be nice to address this inflexibility.

Participant 9: SRECs have driven the Massachusetts market. The Commonwealth shouldn't be wedded to this policy, but should not exclude it as an option. Should use this opportunity to test out other models, but the status quo may not be the best option. Not being able to secure financing for future value of RECs is a problem.

Participant 7: Need to make sure we have an efficient subsidy regime. Believes market mechanism is the most efficient way to achieve that. Administratively-set incentives haven't worked because they aren't responsive to market forces. From the market-makers perspective, and in response to previous comment, there have been long-term hedges in the Massachusetts market. SRECs in Mass are supported by policy features- dynamic demand calculation, floor, and auction. This means the SRECs are less volatile, and thus long-term SREC hedges are provided. People have been able to get financing. SRECs and NEM are broad policies but have to look at Massachusetts context. SRECs has encouraged development efficiently here. Market will do well if stability and path forward is clear.

Participant 10: Capital costs for Massachusetts are in the higher-range from a cash equity and tax equity perspective. This is partially because of the SREC market- thus would encourage other models. Capital costs are less in other places where incentive regime is simpler (i.e. California). In practice Massachusetts is 300-400 basis points higher because of the uncertainty of SREC transactions. Some companies can operate, but it's a heavier lift.

Participant 6: Likes SREC program. Long-term SREC pre-sales are significantly below spot prices. From our perspective- there are downside and upsides. Upsides: Does benefit local vendors and in-state/in-market actors. Downsides: SREC program opacity, even the auction and market are downside to program. Value leakage from developers/ratepayers over to brokers, etc. (i.e. Attorneys who are now needed soft costs under SREC program).

Participant 9: Need to differentiate large-scale SREC process vs. residential projects. To individuals - SREC market swings wildly and homeowners have no market power. Need some more protection for residential scale SRECs holder to keep small-scale SREC market viable for homeowners.

Participant 1: In the consulting report for SREC-II, the way the incentive flows from buy-side to sell-side means that one-side of the market can be more incentivized than the other. But it's a market-based mechanism so it can be responsive. Price is influenced by other factors not just solar supply in the market, but electricity costs, other incentives. If the value of the incentive is fundamentally too low, projects will slow down, and the SREC price will increase since there won't be enough to meet demand. No legislative process to go through make changes. Understands that these price swings have happened in large drops- think there's elements to adjust volatility to adjust the market.

Going back to the 4185 process: If we used declining block incentives, solar would be in its own incentive program separate from other renewables. Market should be used to incentivize renewables just like the electricity market uses competition. Ultimately SREC-I and SREC-II will turn to Class-I RECs- its the same type of program as opposed to something radically different.

5. Perspectives on other solar incentive models

Other states have implemented a range of incentive program types in order to grow their solar markets. Several program types that you may be aware of include (but are not limited to):

- *Standard offer incentive programs (aka. feed-in tariffs)*
- *Declining block incentive programs*
- *Competitive procurements (aka. auctions or solicitations)*

There are also many variations on these approaches, as well as co-policies. Are any of these incentive program types of particular interest to you? Please discuss your impressions of these or other incentive program types that you may be aware of, and whether we should focus on particular incentive types that are of interest to you. How do you think the effectiveness of these incentive program types vary for different solar installation types (e.g. residential vs. utility scale)? What options would you like to see the consulting team consider and analyze for Massachusetts?

Participant 5: Feed in tariffs don't do much to change the customer's interactions with electricity. Seen as financial investment. Declining block- great for financing and helps reduce soft costs. Sets market expectation for value of solar will be lower and heading toward parity. Competitive procurement- should only be used for utility-scale solar, not appropriate for DG or customer-sited solar.

Participant 4: Agrees with Participant 5's thoughts on competitive procurement. Many ways to incentivize solar, but unless we see something better than SRECs, prefer current system. Would say stay away from buy-all and sell-all transfers hedge value from customer to ratepayer. Participant has sold net metering credits/electricity for low-cost electricity over the years. Savings and hedge value in combination is appealing. If you remove the hedge, takes away incentive for low-income communities to go solar.

Participant 6: If it's a goal of the program to incent in-market vendors and program, the tariff would eliminate local market in favor of larger companies. Under the procurement model a developer trying to contract would not want to have bids from unbuilt projects. Doesn't think solar would grow under this model.

Participant 1: Procurements are at specific point in time. If you don't have everything in place at time of procurement, you have to wait. Competitive procurements have their own administrative cost burden. Notes per SREC fees for open markets is less than costs for competitive procurement. If the administrator of the program is an IOU or specific provider, they may manage market for long-time – this is not competitive. If there is something wrong with the

administrator of the program, then not much you can do. In SREC states, brokers competes with other service providers to manage SRECs.

Participant 7: Agrees previous comments. Competition is the name of the game. Administratively set rates are problematic. Declining block is great because acknowledges declining installed costs of solar over time, but many other factors to take into consideration as well. SREC-II mechanism has declining auction-price. Current system also assumes decreasing costs and has some of benefits of a declining block program. Competitive procurement is new can of worms. Stability is the crux to continue development. Utility-scale systems just figured out the new SREC market- revamping again, will have bad short to mid-term implications. In summary, markets are more efficient with competitive mechanisms.

6. **Perspectives on future use of net metering, as well as minimum bill provisions**
   During the past year, efforts have been made to revise the framework for net metering in Massachusetts including the addition of a minimum bill for all electricity ratepayers. Please discuss your perspective on the future use of net metering/virtual in Massachusetts and, to the extent you are able, what options or changes would you like to see and why?

Participant 4: Grandfathering goes without saying. We can't treat existing systems differently from how they've been treated; it disrupts financial stability and market security. 4185: Differentiated between NEM and VNEM, and somehow distinguished that VNEM electricity was worth less. This is too broad a distinction. A behind-the-meter triple-decker solar installation in Dorchester would be worth less under 4185. No proof that VNEM systems provide less value to the grid. Many low-income communities live in shared-multi-family housing. Treating VNEM and NEM projects separately brings up questions access. Maybe look at size limitations? Not appropriate to assume all VNEM projects are being over-subsidized, but maybe some of the larger projects are. Large here meaning multi-MW. 4185 proposed a lower incentive value based on electricity prices with additional cash to ensure projects would be developed. A lot of the affordable housing developments are limited in the amount of cash they can receive. Third-party providers would not be able to give cash for solar. Have to be careful about changes to the policy which might destroy certain market segment.

Participant 4 submitted comments on minimum bill submitted at hearing.

Participant 5: Need to discuss what the problem is right now or if there is one, then we can discuss solutions. Minimum bills are a solution to a problem, but we aren't sure what problem we are addressing. Structure: Should only cover the fixed costs to serve that customer. Excludes electric distribution system costs.

Participant: In 4185 discussions over the summer, benefits facilities provided were discounted. Many of these facilities cannot participate in capacity market. Agreed with Participant 5 on minimum bills. There may be other models out there, but unsure what they are. As retail electricity sales go down, utilities will hurt. How do we incentivize IOUs appropriately to maintain grid services going forward? Need to think about using EDC infrastructure as a platform to innovate onto.

7. **Perspectives on policy transitions**
   A. *At the 2nd Task Force meeting, it was suggested that analysis should account for* ***uncertainty costs****, (i.e., transition costs due to changing goals and programs.) Please discuss qualitatively the nature of these costs as you see them, and whether and how you might suggest such costs could or should be quantified.*
   B. *Are there particular threshold milestones where it might make sense to consider policy transitions in order to minimize such costs? What other means are available to minimize such costs?*

Participant 5: Determine the risk and the value of uncertainty in the transition. Installed costs would increase based on uncertainty of a policy transition. This would vary based on the clarity of the transition plan. With perfect information, the transition should be painless. However, with an abrupt transition, uncertainty costs will be much higher. Other costs should include lost jobs.

Participant 10: During SREC I to SREC II transition, we saw capital providers leave the market. The ones remaining can charge a premium for their financial services. From the financing perspective, you could figure out the cost based on few equity providers in the market. We can put something together. If capital costs rise, then installed costs are impacted by X%.

Participant 6: The assumption Participant 10 is making is that at some cost of capital, good projects can still get done. But, in our observations, if cost of capital goes up, projects don't happen. Market disruption means you don't get all the benefits of the program until certainty is restored. You probably won't get much development.

Participant 4: From a non-profit developer perspective, increased project lead times, lead to more costs. Does not impact ratepayers directly, but reduces savings to end-users. If you spend 10% more on soft costs, then instead of selling cheaper electricity, you have to sell it at a higher price for the costs to pencil.

Participant 7: Seems counter-intuitive: SREC criticisms are based on market volatility. Yet changing the program will cause more instability. Higher cost of capital are being exacerbated by talking about changing the policy. If there had to be a transition, the earlier comments make sense. Look at the transition from SREC-I and SREC-II. Price point was at the ACP is because development stopped because of the uncertainty.

With regards to quantification: Quantify impacts with proxies such as jobs, or electric prices, gas price volatility. There are usually milestones to consider a transition. The time is not now. 1,600MW is an interim target. Let SREC-II play out- the rules recently changed. Suggests removing managed growth and net metering caps. Will hit the interim target before 2020, under these conditions. Give enough lead-time to market about what transition period will be.

Participant 4: If we play out the legislative and regulatory process, realistically the rules would be changed by 2017, which only leaves 3 years. SREC-II is sunsetting at 1,600MW. Keep calendar in mind for the transition.

Participant 1: If you cut-off SREC-II before the interim target, there will be consequences: Will push market into a sunset period sooner. Currently an increase in prices for 2015 and 2016 vintages of SREC-I. SREC-II will push price up faster market thinks it is ending

8. Other topics

Are there any major topics or perspectives related to the Task Force's scope that we have not discussed today that you would like to comment on?

Participant 5: Cost benefit analysis is extremely important. To the maximum extent possible we need to quantify benefits of solar. If help is needed, they have examples from other states.

Participant 4: Significant loss of generation assets is coming. We are either paying more for natural gas or for transmission lines. Solar is the only renewable resource in MA that has the potential to grow quickly and offset some of this need. The cost of not building solar is not zero.

Participant 9: Focus on retaining as much of the positive economic impact within the Commonwealth.