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September 14, 2012

To: Mike Wallerstein, Hearing Officer, Massachusetts D.P.U. 11-75

From: Dr. Jonathan Raab, Mediator, Distributed Generation Interconnection Working Group

Subject: Proposed Changes to the Uniform Standards for Interconnecting Distributed Generation

The attached Final Report from the Massachusetts Distributed Generation Interconnection Working Group delineates all of the Working Group's recommendations for changes to the *Uniform Standards for Interconnection Standards for Distributed Generation*. The Report represents an intensive effort over a four-month period by the Massachusetts distribution utilities, MA DOER, MA CEC, and representatives of distributed generators and customers to seek improvements in the interconnection process.

The Working Group Report includes a multitude of recommendations that, taken together, should help to improve the interconnection process in Massachusetts. These improvements include:

1) A multi-faceted utility timeline assurance and enforcement strategy that provides all parties with confidence that the utilities will be able and incented to deploy all necessary resources;
2) A more clear-cut and definitive process for utilities to withdraw project applications when applicants miss deadlines to provide information or other documents, thus freeing up feeders for other applicants and potentially reducing utility workload (aka stale project management);
3) Additional time within the Standard Track for "Complex" applications that will require more analysis and hence more time than a typical Standard Track project;
4) Utility-run tracking system to monitor both utility and customer timelines, from the application submittal through the application process and construction/interconnection, with transparency for each customer, and enhanced monthly reporting to DOER on timelines;
5) A uniform utility-published Technical Standards Manual that is periodically updated and into which non-utility parties have a formal process for providing input;
6) Revisions to the technical screens and Supplemental Review time budget to potentially allow more projects to qualify for both the Simplified and Expedited tracks; and
7) A required Pre-Application Report for applicants over 500 kW to the Expedited and Standard tracks to help applicants prioritize among potential locations and DG configurations (and to reduce the number of speculative applications).

It is notable that the extensive package of recommendations in this Report, when taken together, is being made by a consensus of this diverse group of stakeholders (except for one of the recommendations). Although all the parties recommend the addition of a new Penetration Test as a way of potentially allowing more projects to remain in the Expedited Track instead of being placed in the Standard Track (which takes longer), the stakeholders disagreed on whether the new screen should be based on 67% of minimum load or 100% of minimum load. An explanation of both of these approaches, along with a list of the supporters of each, can be found in Appendix C of the Report.

Finally, because we were not able to translate the myriad of recommendations into a redlined tariff within the allotted time, the Working Group proposes to submit a fully-vetted redlined tariff to the DPU on-or-before October 31, 2012. Concurrently, the distribution companies have agreed to begin work on the enhanced timeline tracking systems and monthly DOER reporting approach, as described in the Report.

On a personal note, I want to convey that the Working Group representatives and alternates worked diligently over the summer to first, better understand the root challenges in the existing interconnection processes and procedures, and then to creatively come up with better approaches and resolve differences.

Please let us know if there are any questions or concerns.

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Proposed Changes to the Uniform Standards for Interconnecting Distributed Generation in Massachusetts

Submitted to:

MASSACHUSETTS DEPARTMENT OF PUBLIC UTILITIES IN COMPLIANCE WITH DPU ORDER 11-75

by the

MASSACHUSETTS DISTRIBUTED GENERATION INTERCONNECTION WORKING GROUP

SEPTEMBER 14, 2012

Facilitated/Mediated by Dr. Jonathan Raab, Raab Associates, Ltd.

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Appendices

SECTION 1: INTRODUCTION, BACKGROUND, AND OVERVIEW

A) Introduction and Process Overview

The Massachusetts Distributed Generation Interconnection Working Group ("Working Group") was initiated at the request of the Massachusetts Department of Public Utilities ("DPU") through Order 11-75. In that Order, the DPU detailed its expectations for the Working Group as follows:

> "The original DG Collaborative established uniform standards for the interconnection of distributed generation in the wake of the restructuring of the electric industry. D.T.E. 02-38, at 1-2. Building on this foundation, the goal of the Working Group here is to determine what changes should be implemented to ensure an efficient and effective interconnection process that will foster continued growth of distributed generation in Massachusetts. The Department notes that the Working Group should not endeavor to recreate or reconvene the DG Collaborative, but rather should focus on the issues that need to be addressed in order to update the existing generation interconnection framework." [D.P.U. 11-75-A, at 4]
>
> "The goal of the Working Group is to reach consensus on distributed generation issues. However…consensus may not be attainable on some issues and additional Department process may be necessary, including a possible adjudicatory proceeding." [D.P.U. 11-75-A, at 5]
>
> "The Working Group should consider the issues presented in the DG Report, DOER Petition, comments filed in this proceeding, and any other related issues determined relevant by the Working Group…Accordingly the Working Group is directed to (1) determine what issues should be resolved regarding the current distributed generation interconnection standards and application procedure to ensure an efficient and effective interconnection process, and (2) deliberate with the goal of reaching a consensus on a resolution of such issues for Department review and approval." [D.P.U. 11-75-A, at 7]

Over twenty agencies, companies, and organizations actively participated throughout the four-month facilitated Working Group process. These participants are listed below in four separate clusters:

- DG Providers,
- Utilities,
- State Agencies, and
- Customers/Cities.

Appendix A presents a full roster of all the participants from each organization that participated in the Working Group.[1]

MA DG Working Group Representation

Utilities	DG Providers
National Grid NSTAR WMECO Unitil	**DG Solar:** Borrego Solar, Blue Wave Capital, Spire Solar Systems, DG Cleanpower, SEBANE/SEIA, Exelon/Constellation Energy, My Generation Energy **DG CHP:** Source One/Veolia Energy, Northeast Clean Heat and Power Initiative, US Clean Heat & Power Association, The E-Cubed Company, Prime Solutions, Harvard
State Agencies	**Customers/Cities**
Dept. of Energy Resources MA Clean Energy Center	CLC/CVEC

The Massachusetts Clean Energy Center provided funding for the facilitated Working Group process. Dr. Jonathan Raab facilitated/mediated the process, with assistance from Susan Rivo also from Raab Associates, Ltd. and Walker Larsen from CLF Ventures. The Working Group's first meeting was held on May 31, 2012. Both the National Renewable Energy Laboratory (NREL) and the Interstate Renewable Energy Council (IREC) participated in the process as outside experts and provided technical assistance on a wide range of issues.

The Working Group met in plenary for ten days of meetings over the course of four months. In addition, two Subcommittees (one focusing on technical issues and the other focusing on process, timeline, and fee issues) met consistently throughout this period to develop detailed proposals for review by the full Working Group during its plenary sessions.

With this Report, the Working Group has completed its recommendations on issues identified by the Commission in DPU 11-75, as well as on additional but related issues identified by the Working Group

[1] In addition to the organizations in the table that actively participated in the Working Group process as Representatives or Alternates and are signatories to the full Report, the following other organizations also support this Report in full, and their preference on the one undecided issue is shown in Appendix C: Interstate Renewable Energy Council, Inc., and the City of Boston; The Attorney General's office was not a formal Member of the Working Group but participated in most meetings as active observers. The AG is not a signatory of this Report.

participants. These recommendations, when taken together as a package, represent a consensus of the diverse members of this Working Group, except for one issue as explained in Section 2 and Appendix C of this Report. This Report also includes a transition plan and a strategy for ongoing collaboration within the next 12 months and beyond to ensure that the plan is implemented, and that evolving technical standards are vetted with non-utility stakeholders.

B) Summary of Findings and Recommendations

The Working Group wishes to prominently emphasize two necessary characteristics of an efficient and effective interconnection process that will foster continued growth of distributed generation in Massachusetts:

1) Customers applying to the interconnection process must know how long the steps in the process over which the interconnecting utility has control will take, and what the utilities' technical interconnection standards will be, and those expectations must be reliably adhered to by the interconnecting utility; and
2) The interconnecting utilities, if they are to reliably adhere to those expectations, must be given sufficient time and sufficient resources to deliver.

Despite the presence of specific, enforceable timelines in the Uniform Standards for Interconnecting Distributed Generation, and despite the fact that the utilities have been increasing their staff and outside contractors to handle the increased workload, those timelines have not been consistently adhered to in the interconnection process – neither the utilities nor customers have consistently adhered to them – and the utilities have not been required to implement a system for transparently tracking compliance with each step of the tariff timelines. You can't improve what you don't measure. Furthermore, the technical interconnection standards used by all the utilities are not transparently available to customers, and resolution of technical disputes is currently managed on an ad hoc basis between the utilities and their customers.

By the same token, the timelines in the uniform standards were agreed to by the utilities in 2002 and 2003, when they received far fewer interconnection applications, and most applications were smaller and proposed less complicated grid impacts than many of the applications received today. Accordingly, the current tariff timelines do not allow the utilities sufficient time to process the larger, more complex interconnection applications that they receive. Under the current strain of application volume and time pressure, the Working Group acknowledges that the utilities have done their best to serve the interests of their customers.

Many of the recommendations that follow are intended to address those two fundamental challenges, and the Working Group requests that the DPU keep that framework in mind when considering this Report and throughout any and all follow-up actions it takes. It is the considered opinion of the Working Group that a better process – one that will "ensure an efficient and effective interconnection process that will foster continued growth of distributed generation in Massachusetts" – must:

1) Allow sufficient time and sufficient resources for the utilities to process all interconnection applications;
2) Enforce the timelines in the tariff on both the utility and customer side, which cannot be done without tracking performance against the timelines in the tariff; and
3) Include a more transparent set of interconnection technical standards into which non-utility parties have a process for input.

Accordingly, key changes recommended by the Working Group in this Final Report include:

1) A multi-faceted utility timeline assurance and enforcement strategy that provides all parties with confidence that the utilities will be able and incented to deploy all necessary resources;
2) A more clear-cut and definitive process for utilities to withdraw project applications when applicants miss deadlines to provide information or other documents, thus freeing up feeders for other applicants and potentially reducing utility workload (aka stale project management);
3) Additional time within the Standard Track for "Complex" applications that will require more analysis and hence more time than a typical Standard Track project;
4) Utility-run tracking system to monitor both utility and customer timelines from the application submittal through the application process and construction/interconnection, with transparency for each customer, and enhanced monthly reporting to DOER on timelines;
5) A uniform utility published Technical Standards Manual that is periodically updated and into which non-utility parties have a formal process for providing input;
6) Revisions to the technical screens and Supplemental Review time budget to potentially allow more projects to qualify for both the Simplified and Expedited Tracks; and
7) A required Pre-Application Report for applicants over 500 kW to the Expedited and Standard Tracks to help applicants prioritize among potential locations and DG configurations (and reduce the number of speculative applications).

In addition, technical resources are important for all parties to participate effectively in future discussions of DG interconnection processes and discussions. The Working Group recommends that state agencies, utilities and non-utility stakeholders explore ways to continue increasing the engineering resources (employees and contractors) available to utilities, state agencies and other stakeholders. The current high level of public support for DG and the current level of DG development call for funding of neutral third party resources with distribution planning and engineering expertise who can participate in discussions of interconnection policies and practices and on the role of DG in distribution planning in order to provide independent advice to all parties, as well as providing or supporting ombudsperson functions to facilitate individual interconnections.

C) Report Structure

Section 2 of this Report lays out the Working Group's recommendations for the application review process, including revised screens and screens for a new "complex project" category in the Standard Track, and recommendations for a group/cluster study process. Section 3 provides recommendations for application and construction timelines, including timelines for “complex” projects and cluster studies. Section 4 outlines recommended measures to ensure adherence to timelines for both utilities and DG applicants. Section 5 covers application fee updates. Section 6 outlines recommendations for a new Pre-Application Report process. Section 7 outlines the recommendations for each utility to implement an application tracking and reporting process that includes a utility-run timeline tracking system to track both customer and utility project application and construction related timelines. Section 8 describes technical issues, including recommendations for a process to create a Uniform Technical Standards Manual and set up a Technical Standards Review Group. Section 9 describes recommendations for other issues, including a potential Ombudsperson and application training. Section 10 concludes the Report with a transition strategy and recommendations for ongoing collaboration.

Section 2: Application Review Process: Tracks and Revised Screens

The Working Group recommends changing several screens in the Simplified and Expedited Tracks as well as increasing the number of engineering review hours within the Expedited Track, with the express purpose of allowing more projects to remain in these tracks and hence move more rapidly through the interconnection process. The Working Group also recommends additional time for more complex projects within the Standard Track. Lastly, the Working Group recommends the addition of a Group (aka Cluster) Track for multiple applications on feeders that are relatively saturated with distributed generation such that extensive upgrades would be necessary. The initial approach recommended for the Group Track should allow the utility to study multiple projects at once and delineates a study and construction cost allocation approach.

A) Simplified Track

The Working Group recommends increasing the 10 kW single phase maximum size to 15 kW and leaving the three phase maximum size at 25 kW. Moreover, the Working Group recommends keeping projects that fail screen #5 in the Simplified Track rather than moving them to the Expedited Track, but allowing the utilities to have a total of 20 days to review those applications rather than 15 days.

B) Simplified and Expedited Track/Screen #2

The Working Group recommends changing one of the existing screens: *Is the aggregate generating Facility capacity on the circuit less than 7.5% of circuit annual peak load?* to potentially allow more DG thru the Simplified and Expedited Tracks, as follows: *Is the aggregate generating Facility capacity less than 15% of feeder/circuit annual peak load and, if available, line segment?*

C) Simplified Spot Network Track/Screens

Utilities are studying area networks to develop the data needed to come up with appropriate and safe screens for area networks. For now, the Working Group recommends that the simplified spot network screens also apply to area networks (if other screens are passed) as long as the applicant has interval meter data for an appropriate time period, and where there is available minimum load data, for area networks. The Working Group further recommends removing the requirement that the system be less than or equal to 15 kW, as long as the less than 1/15 of Customer's minimum load screen requirement is met.

The Working Group also recommends continuing to monitor and track IEEE 1547 and national best practices, and for the Massachusetts utilities to continue to study and experiment on area networks (e.g., NSTAR's current Boston pilot project). It further recommends incorporating networks and IEEE handling of networks into the new Uniform Technical Standards Manual discussed in Section 8.

D) Expedited Track Screens

The Working Group recommends adjusting the Expedited Track screens to allow more applications to remain in the Expedited Track instead of going through the longer Standard Track. Specifically the Working Group recommends adding three Supplemental Review screens to the interconnection process and increasing the amount of engineering hours allowed for Supplemental Review before a project is moved from the Expedited to the Standard Track from 10 hours to 30 hours.

The three screens to be added to the Supplemental Review section of the Expedited Track are:

A) Penetration Test
B) Power Quality and Voltage Tests
C) Safety and Reliability Tests

However, the utilities and non-utility Working Group members disagree on whether the minimum load screen under the Penetration Test should be 67% or 100%. See Appendix C for a brief description of their respective positions on this issue.

The Supplemental Review consists of Supplemental Review Screens A through C. If any of the Screens are not passed, a quick review of the failed Screen(s) will determine the requirements to address the failure(s) or that an Impact Study is required. In certain instances, the Distribution Provider may be able to identify the necessary solution and determine that Detailed Studies are unnecessary. Some examples of solutions that may be available to mitigate the impact of a failed Screen are:

1. Replacing a fixed capacitor bank with a switched capacitor bank
2. Adjustment of line regulation settings
3. Simple reconfiguration of the distribution circuit

Screen A: Penetration Test

Where 12 months of line section minimum load data is available, can be calculated, can be estimated from existing data, or determined from a power flow model, is the aggregate Generating Facility capacity on the Line Section less than (67 or 100)% of the minimum load for all line sections bounded by automatic sectionalizing devices upstream of the Generating Facility?

- If yes (pass), continue to Screen B.

- If no (fail), a quick review of the failure may determine the requirements to address the failure; otherwise either a Group Study or an Impact Study is required. Continue to Screen B.

Note 1: The type of generation will be taken into account when calculating, estimating, or determining circuit or Line Section minimum load relevant for the application of this screen.

Solar generation systems with no battery storage use daytime minimum load (i.e. 10 am to 4 pm for fixed panel systems and 8 am to 6 pm for PV systems utilizing tracking systems), while all other generation uses absolute minimum load.

Note 2: Distribution Provider will not consider as part of the aggregate generation for purposes of this screen Generating Facility capacity known to be already reflected in the minimum load data.

Significance: Penetration of Generating Facility installations that does not result in power flow from the circuit back toward the substation will have a minimal impact on equipment loading, operation, and protection of the Distribution System.

Screen B: Power Quality and Voltage Tests

In aggregate with existing generation on the line section,

a) Can it be determined within the Supplemental Review that the voltage regulation on the line section can be maintained in compliance with current voltage regulation requirements under all system conditions?

b) Can it be determined within the Supplemental Review that the voltage fluctuation is within acceptable limits as defined by IEEE 1453 or utility practice similar to IEEE1453?

c) Can it be determined within the Supplemental Review that the harmonic levels meet IEEE 519 limits at the Point of Common Coupling (PCC)?

- If yes to all of the above (pass), continue to Screen C.
- If no to any of the above (fail), a quick review of the failure may determine the requirements to address the failure; otherwise a Group or Impact Study is required. Continue to Screen C.

Significance: Adverse voltages and undesirable interference may be experienced by other Customers on Distribution Provider's Distribution System caused by operation of the Generating Facility(ies).

Screen C: Safety and Reliability Tests

Does the location of the proposed Generating Facility or the aggregate generation capacity on the Line Section create impacts to safety or reliability that cannot be adequately addressed without a Group or Impact Study?

- If yes (fail), review of the failure may determine the requirements to address the failure; otherwise a Group or Impact Study is required.
- If no (pass), Supplemental Review is complete.

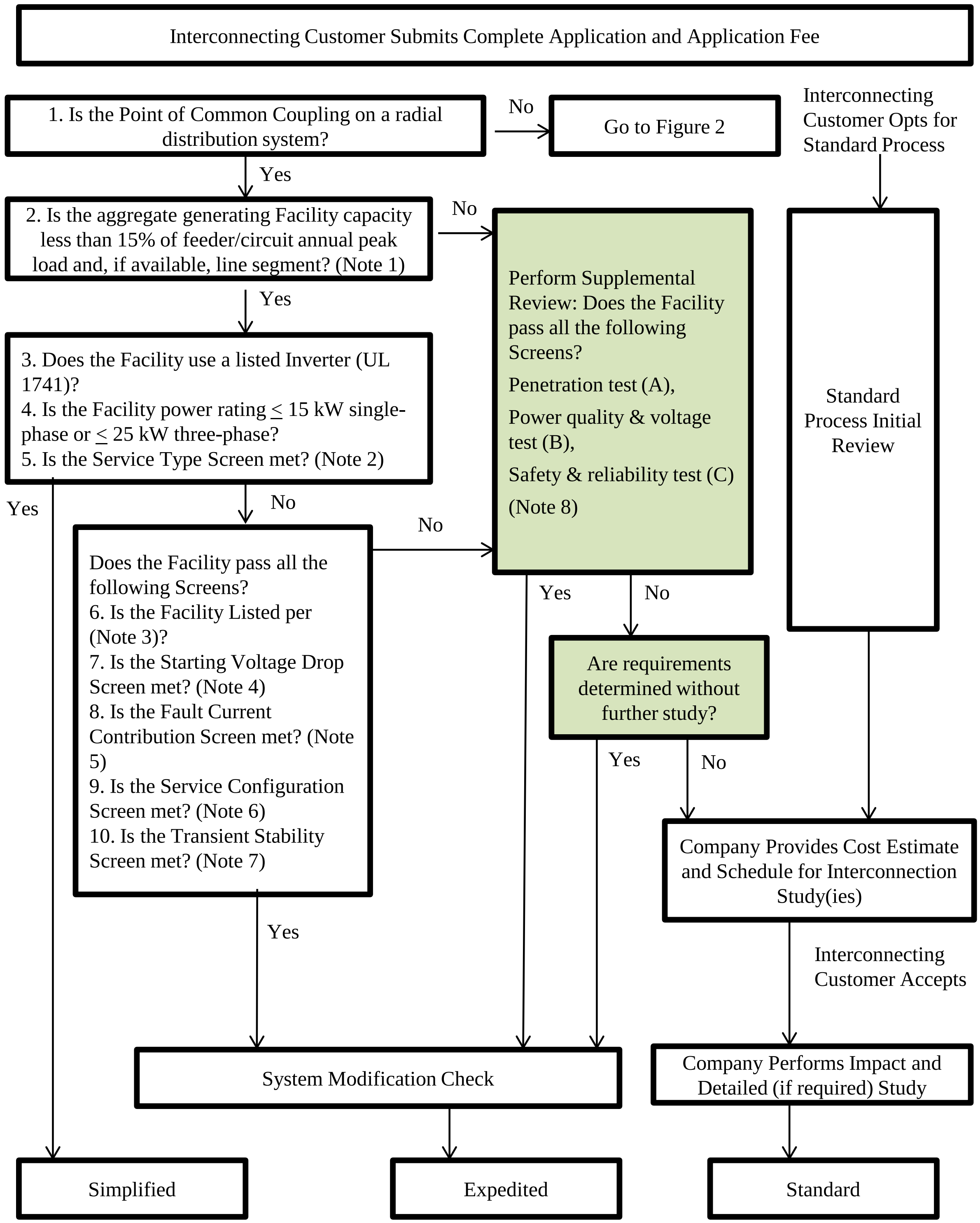
Significance: In the safety and reliability test, there are several factors that may affect the nature and performance of an Interconnection. These include, but are not limited to:

1. Generation energy source
2. Modes of synchronization
3. Unique system topology
4. Possible impacts to critical load customers
5. Possible safety impacts

The specific combination of these factors will determine if any system study requirements are needed. The following are some examples of the items that may be considered under this screen:

1. Does the Line Section have significant minimum loading levels dominated by a small number of customers (i.e. several large commercial customers)?
2. Is there an even or uneven distribution of loading along the feeder?
3. Is the proposed Generating Facility located in close proximity to the substation (i.e. <2.5 electrical line miles), and is the distribution line from the substation to the customer composed of large conductor/cable (i.e. 600A class cable)?
4. Does the Generating Facility incorporate a time delay function to prevent reconnection of the generator to the system until system voltage and frequency are within normal limits for a prescribed time?
5. Is operational flexibility reduced by the proposed Generating Facility, such that transfer of the line section(s) of the Generating Facility to a neighboring distribution circuit/substation may trigger overloads or voltage issues?
6. Does the Generating Facility utilize UL 1741/IEEE 1547 Certified anti-islanding functions and equipment?

Figure 1 – Schematic of Massachusetts DG Interconnection Process



The Working Group also recommends raising the Supplemental Review time allowed within the Expedited Track from 10 hours to 30 hours. Thus projects would be allowed to stay in the Expedited Track and not sent to the Standard Track if more than 10 hours of engineering review time is required.

For Interconnection Applications that fail Supplemental Review, the Company shall provide the specific screen failed, including the technical reason, the data and the analysis supporting the Supplemental Review results in writing and provide the Interconnecting Customer the option to attend a Supplemental Review results meeting. Failing a screen or exceeding 30 hours of engineering time are the only methods for a project to move from the Expedited Track to the Standard Track.

Within 5 Business Days of the Interconnecting Customer's request for a Supplemental Review results meeting, the Company shall contact the Interconnecting Customer and offer to convene a meeting at a mutually acceptable time to review the Supplemental Review screen analysis and related results to determine what modifications, if any, may permit the DG to be connected safely and reliably without an Impact Study and entering the Standard Process.

E) Complex Projects Within Standard Track

The Working Group discussed at length how to handle the increase of complex projects or projects seeking interconnection at challenging locations that require more studies and study time than initially contemplated when the Standard Track and its timelines were designed. The Working Group agreed to maintain the Standard Track, but to allow for additional utility review time in certain circumstances. See Section 3 for details.

F) Accelerating Interconnection Service Agreement Signing

The Working Group recommends adding language to the tariff that allows applicants to request and sign an Interconnection Service Agreement (ISA) at the end of the Impact Study rather than waiting until after the Detailed Study. If the applicant goes with this option they agree to accept the +/-25% construction cost estimates emanating from the Impact Study. They also will have to wait for a detailed construction schedule until after the utility completes its design engineering work (as discussed in Section 3 under Construction Timelines).

G) Group (aka Cluster) Study

The Working Group recommends that a new Group (aka Cluster) Study process be initiated on feeders with multiple applications where system upgrades would be extensive. Given the complexities of establishing this new study process, the Working Group recommends that the details of when and how this would be initiated be worked out by the Working Group during the transition period (see Section 10). Until a Group study process can be created, the Working Group recommends that the utilities continue to offer optional Group Studies when projects are identified as conducive to Group Studies by the utilities and/or Group Studies are proposed by applicants. The Working Group, however, has agreed on how costs associated with studies and system upgrade construction for Group Studies should be initially allocated among customers (See Section 5).

Section 3: Application and Construction Timelines

In this section the Working Group recommends changes to timelines for Complex projects within the existing Standard Track and timelines for the new Group Study process. It also recommends clarifying language and some modifications to witness tests, construction timelines, and the Simplified Track, as well as new language regarding force majeure.

A) Simplified Track

The Working Group recommends keeping the total utility review time at 15 days but allowing the utilities 5 extra days for applications that fail Screen #5 in order to keep those applications in the Simplified Track rather than moving them to the Expedited Track.

B) Expedited Track

The Working Group does not propose any changes to the Expedited Track timelines, except to clarify the timing in the Witness Test (see below in this section).

C) Complex Projects in Standard Track

The Working Group recommends adding additional time within the Standard Track for "Complex" projects or projects proposing to interconnect in challenging places. These types of projects typically require more extensive system upgrades that necessitate more study time than Standard Track timelines afford. Therefore for these types of projects the Working Group recommends:

A) If any Sub-Station modifications are needed (i.e., adding or replacing equipment)—a total time in business days for the utility to complete the Impact Study for each application of 75 days in 2013; 75 days in 2014; 70 days in 2015; 60 days in 2016 and thereafter
B) If system modifications from the Impact Study indicate likely to cost over $200,000 in EPS upgrades (See Appendix D for diagram on what constitutes EPS upgrades) not including service upgrades for the customer site — a total time in business days for the utility to complete the Detailed Study for each application of 75 days in 2013; 75 days in 2014; 70 days in 2015; 60 days in 2016 and thereafter). (See page 18 in this Report for illustrative costs)
C) If upgrade is estimated to be over $1 million in EPS upgrade costs, timeline for both the Impact and Detailed Studies will be by mutual agreement. The timeline will then still be tracked.
D) If the utility discovers that the upgrade will be under $1 million, the application will revert to the timelines under 1 and/or 2 above.
E) Utilities will inform applicants within 20 days into Impact study whether time extensions are needed applying 1 and/or 2, or 3 above. However, at any time during the Impact Study the utility discovers that the upgrade will be over $1 million, than the Detailed Study timeline will be by mutual agreement.

D) Group (aka Cluster) Study

The Working Group recommends that the timeframes for Group Studies be determined along with other design issues during the Transition planning period (See Section 10), but for now the timelines for any Group studies initiated in the interim should be determined by mutual agreement.

E) Construction Timelines

The Working Group recommends that there should continue to be clear construction timelines with milestones included in the ISA (except in the case where Applicant requests an ISA after the Impact Study and before a Detailed Study, in which case the construction schedule is added after the utility completes its design engineering). The Working Group further recommends that the timelines be tracked using the utility-run timeline tracking system just as with the interconnection steps (See Section 7). While the Working Group recognizes that there are many reasons that construction schedules may slip on both the applicant and utility side, milestones should only be missed for reasonable cause.

If a utility misses a milestone it will inform both the applicant and the DPU including the reason and a proposed new schedule. If the customer misses a milestone, the utility will follow the same protocols for Customer Adherence to time schedules described below in Section 4.

The Working Group also recommends that construction time guidelines for different upgrade costs and timeframes be included in the Technical Manual referenced in the tariff, and periodically updated, with stakeholder input and review (see below on page 18 for illustrative example from January 2011 as presented at the current Multi DG Workshops—note costs and times are subject to change, and if multiple upgrades are required some can be done concurrently so timelines not necessarily additive).

Distribution EPS Upgrade Item	Upper End Order-of-Magnitude Cost	Upper End Duration Scheduling
Voltage Regulator changes/phase	**$50k**	**6 months**
Capacitor Bank moves or new	**$17k**	**3 months**
Pole Top Recloser move/addition	**$80k**	**6 months**
Re-conductor 3-phase Line (includes pole replacements)	**$450k/mi.**	**12 months**
Convert from 1 to 3-phase Line (includes pole replacements)	**$400k/mi.**	**12 months**
Express 3-phase Feeder (open wire configuration)	**$600k/mi.**	**18 months**
Express 3-phase Feeder (lashed cable configuration)	**$750k/mi.**	**18 months**
Customer 3-phase Transformer change/addition (Pole or Pad)	**$45k**	**3 months**
Supply Station Transformer	**$4M**	**24 months**
DTT transmit addition to supply station	**$300k**	**11 months**
Communications media equipment additions to support DTT equipment at supply station	**$100k**	**6 months**
EMS-RTU (status & control) addition at DG site or supply station	**$80k**	**6 months**
Metering PTs & CTs at DG site (excludes structure)	**$15k**	**8 months**
Plus Company labor for acceptance review DG Customer's design, compliance verification activities, and project management	**$100k**	**Dependent on DG Customer**

F) Force Majeure

The Working Group recommends that for force majeure (as defined below) that the utility timeline requirements would be suspended for that period (for the utility, customer, or both depending on who is impacted by the force majeure). There should be notice when force majeure events occur. Volume of applications would not be considered force majeure. Also, the Working Group agrees to recommend deleting language in the current tariff about complying with timelines only under "normal work conditions."

Force Majeure: For purposes of this Agreement, "Force Majeure Event" as defined by Section 16 of the current ISA means any event:

a. that is beyond the reasonable control of the affected Party; and

b. that the affected Party is unable to prevent or provide against by exercising commercially reasonable efforts, including the following events or circumstances, but only to the extent they satisfy the preceding requirements: acts of war or terrorism, public disorder, insurrection, or rebellion; floods, hurricanes, earthquakes, lightning, storms, and other natural calamities; explosions or fire; strikes, work stoppages, or labor disputes; embargoes; and sabotage. If a Force Majeure Event prevents a Party from fulfilling any obligations under this Agreement, such Party will promptly notify the other Party in writing, and will keep the other Party informed on a continuing basis of the scope and duration of the Force Majeure Event. The affected Party will specify in reasonable detail the circumstances of the Force Majeure Event, its expected duration, and the steps that the affected Party is taking to mitigate the effects of the event on its performance. The affected Party will be entitled to suspend or modify its performance of obligations under this Agreement, other than the obligation to make payments then due or becoming due under this Agreement, but only to the extent that the effect of the Force Majeure Event cannot be mitigated by the use of reasonable efforts. The affected Party will use reasonable efforts to resume its performance as soon as possible. In no event will the unavailability or inability to obtain funds constitute a Force Majeure Event.

Changes in local, state or federal laws, regulations or policy relating to distributed generation or distributed generation price changes will <u>not</u> constitute an event of force majeure, but if they have substantial impact on a utility's ability to meet timelines such changes should constitute a mitigating factor in the measurement or enforcement of utility timelines, for example through a Service Quality Metric.

G) Witness Test

The Working Group recommends adding language to the Tariff to clarify Witness Test procedures and timelines as follows:

a) Simplified: Leave Language as is Section 3.1 (Item F)
b) Expedited: Add new section for Expedited—Identical Language as Simplified
c) Standard: (Replace Section 3.3.i with the following) The Company will require a witness test of the Facility for compliance with the relay settings as approved by the Company. The Interconnecting Customer will provide a proposed witness test and the requisite supporting documentation for review by the Company once they have completed the installation of the facility. Utility will have 8 business days to approve the witness test once they have all the information needed from the Customer. The utility will then inform the Customer when they have approved test procedures. Once the test has been approved by the Company, the Interconnecting Customer will call to arrange for the Witness Test. The Interconnecting Customer has no right to operate in parallel until a Witness Test has been passed. The Company is obligated to complete this Witness Test within 10 business days or by mutual agreement upon receipt of the request for a witness test as outlined above.

Section 4: Adherence to Utility and Applicant Timelines

In this section the Working Group recommends strategies and requirements to enhance adherence to timelines during the application and construction phases of distributed generation interconnection—on both the applicant/customer and utility sides.

A) Applicant/Customer Adherence (aka Stale Project Management)

The Working Group recognizes the need to remove stale projects that have exceeded their timelines to provide utilities with requested information or decisions to proceed. Stale projects can hold up other projects behind them in a queue on a particular feeder. However, even when there is not a queue, stale projects still require utility tracking and periodic attention, and also can give the misconception that many projects are actively awaiting interconnection. For all these reasons, the Working Group proposes a process that includes an initial withdrawal of stale projects, as well as an on-going customer timeline compliance process to deal with applicants who miss their deadlines, as outlined below.

1) Initial Withdrawal Process
    a. For all applicants where the utility is waiting to hear from the customer at any level at any stage (in application and construction process) for more than 30 business days
    b. Utility contacts applicant (email and letter and/or phone if no email address)—customer of record, alternative contact, and a most recent point of contact
    c. Include in communication to applicant: "Haven't heard from you in over 30 business days, if we don't hear from you in 30 business days, we will consider your application withdrawn (and if you want to continue at a later date, you will need to reapply)." If applicant responds, the applicant follows the ongoing process below. If not, the application is considered withdrawn and any fees paid are not refunded.
    d. Also in communication to applicant indicate removal has been authorized by the DPU
    e. Utilities already have the authority in the original tariff to remove applicants from queue. However the Working Group recommends replacing "may" with "shall" to remove the discretion
2) On-Going Customer Timeline Compliance (for all projects whether in a queue or not)
    a. Request from utility to applicant for information or signature will include customer deadline from tariff
    b. If miss deadline, send email that missed deadline and will be given 10 business days to cure or request an extension
    c. If request extension, granted one extension equal to timeline/deadline of step. In addition:
        i. For non-solar applications additional extensions allowed for cause by mutual agreement with utilities
        ii. For solar applications:
            1. Two times prior to the distribution company's provision of an Interconnection Service Agreement to the Customer (or prior to completion of the Detailed Study if customer elects to accelerate execution of the

Interconnection Service Agreement pursuant to Section 2(E) of the Report), the Customer may request an additional extension period of 30 Business Days if a Customer cannot meet a request for information related to the engineering studies and reviews being performed by the distribution company within the customer deadline timeframe because the information requested is held by a third party (i.e., equipment manufacturer) and such information cannot be obtained by such Customer despite reasonable efforts to do so. There shall be no additional fee for an extension under this provision.

2. One time, during any course of the interconnection process, a Customer may request an additional extension period of six months for legal challenges related to a Facility. The Customer shall submit a Certification that a governmental permit or approval for the Facility is subject to a legal challenge prior to the Customer deadline or during the initial extension period and the legal challenge remains pending. This additional extension period for legal challenges terminates at the end of the legal challenge or six months after the first day of this additional extension period for the legal challenge, whichever comes first. There is no additional fee for an extension under this provision.
3. One time, during any course of the interconnection process, a Customer of a Public Facility may seek an additional extension period of six months by certifying to the distribution company one or more of the following: (1) a town meeting vote required for the Public Facility; (2) special legislation required in relation to the Public Facility; or (3) any approval for the Public Facility necessary under Article 97 of the Massachusetts Constitution. The additional extension period for Public Facilities shall terminate at the end of the governmental process specified above or six months after the first day of the additional extension period for Public Facilities, whichever comes first. There is no additional fee for an extension under this provision.

iii. The following definitions shall apply to this provision:

1. "Certification" means a written statement based on knowledge, information, and belief that the relevant claims are true.
2. "Public Facility" means any Facility (1) that is owned or operated by a municipality or other governmental entity; or (2) that is sited on land of a municipality or other governmental entity; or (3) of which for purposes of Net Metering qualifies as a net metering facility of a municipality or other governmental entity.

d. If there is a clock stoppage for a customer request for extension near the end of the utility's timeline for completing a step, the utility can get an extension (e.g., within 1/3 of the end of step timeline, the utility gets an additional number of days to complete the step, equal to1/3 of the total utility timeline for that step). Utilities will keep track of extension dates.

e. Projects that do not meet extended timelines will be considered withdrawn and need to reapply, and any fees paid will not be refunded.
f. Customers will have 20 business days to sign an Interconnection Service Agreement (ISA) provided by the utility or provide comments to the utility on the ISA, or the project will be considered withdrawn and will need to reapply. Further, any fees paid will not be refunded. If the customer provides comments, the customer and the utility will have 30 business days to resolve issues presented in the comments. After 30 days, if there is no resolution and no request from the customer for ADR, the application will be considered withdrawn and the customer will need to reapply. Further, any fees paid will not be refunded.
g. Customers shall not be required to pay any costs related to distribution company infrastructure upgrades or system modifications upon execution of the Interconnection Service Agreement (or once they get the Construction schedule). Customers shall have 120 business days from the date of execution of an ISA to pay 25 percent of those costs. If a Customer pays such cost within the 120 business day timeline, the Customer shall have an additional 120 business days from the date of first payment to pay the remainder of the costs. If customer payment is not received within 60 business days from signing the ISA, the Utility has the right to reassess construction costs and timelines. In the event that the Customer fails to pay the distribution company within the timeline required by this provision (or within any extension to such timeline as authorized under Section 4(A)(2)(c)(ii)(2) and (3) above, the distribution company will require the Customer to reapply for interconnection. Further, any fees paid will not be refunded. The construction schedule will commence once the applicant’s financial commitment/payment has been made in full.

3) Timeline (after DPU approval)
    a. Initial Withdrawal—Begin right after DPU approval (2-3 months to complete)
    b. On-Going Customer Timeline Compliance—Concurrently with tracking system implementations

B) Utility Adherence (aka Assurance and Enforcement) to Timelines

The Working Group recommends a suite of measures to ensure and enforce utility compliance with tariff timelines.

A) Service Quality Metrics:

The Working Group believes that it is appropriate to explore the design of a service quality metric associated with enforcing timelines established in the Standards for Interconnection of Distributed Generation through a proceeding at the D.P.U. Moreover, the Working Group agrees to the inclusion of such a metric in the context of such proceeding and to have the metric be approved for effect as of January 1, 2014. The Working Group believes that the specific design of such metric must be based on the Department's articulated principles and protocols for establishing benchmarks based on objective and prospective empirical data and overall metric weighting, along with the clear recognition of the need for both utility and developers' mutual adherence to interconnection timelines. These and other aspects of a metric, including, but not limited to, whether a potential service quality metric should include penalties and offsets based on 12 months performance in calendar year 2014 against a reasonable benchmark as determined by the Department, should be discussed in the context of the aforementioned D.P.U. proceeding. Nothing contained within this Report precludes the discussion and analysis of other comparable proposals relating to enforcing interconnection timelines in the context of this proceeding.

B) Refunding application fees for Expedited and Standard processes for non-compliance with timelines

1) Within 30 business days after the ISA has been delivered or, pursuant to timeline, any time after when the ISA should have been delivered but has not been delivered, the customer may allege that the project's applicable interconnection timeline(s) had been exceeded and that the non-compliance with the timeline is due to the utility's actions or inaction.
2) The utility will have 15 business days to review the customer's documentation of timeline non-compliance and make a determination as to whether it adhered to the timelines. In communicating its determination to the customer, the utility shall provide its reasoning behind the determination.
3) The customer has 10 business days to appeal the utility determination through the appropriate mechanism (DPU customer complaint procedure, ADR, Ombudsperson, etc.).
4) If utility has not complied with the timelines, the utility will process a refund of the customer's application fee within 30 business days following the final determination of non-compliance.
5) Nothing in the stale project management provisions above prevents a customer from pursuing application fee refund as set out in the interim application fee refund language.
6) The refunding of application fees for expedited and standard process fees is an interim measure which shall expire on the implementation of a SQ metric in the calendar year in which penalties and offsets are applicable.

C) Process at DPU/ADR Process/Ombudsperson (technical and other issues only) —See Ombudsperson in Section 9 for details.

D) Missed Deadline Notification and Timeline Revision
   a. A customer may request review of timelines in the process at anytime or if deadline is missed at each stage
   b. Utility will provide a written (email) response to the request within 10 business days detailing the reason for the missed timeline and the expected date the process step will be completed

c. The DPU (through the Ombudsperson or otherwise) can at any time request additional information as to the specific missed timeline or a pattern of missed timelines

E) Annual Reporting and Review of Utility timeline compliance based on tracking system (at least until SQM kicks in)—Filed by utilities April 1 each year analyzing and summarizing data in monthly reporting to DOER plus any necessary additional information (e.g., Simplified Track data) including,

a. Percent of compliance of total timeline with each track
b. Compliance with each step in timeline
c. Number times ADR initiated and resolution
d. Number of times customer requested review of the timeline and application fee was refunded
e. Any additional DPU requirements

Section 5: Fees

The Working Group recommends continuing to not have an application fees for the Simplified Track. It also recommends updating the Fees for the Expedited and Standard Tracks to account for increased labor costs since the tariff was first put in place and anticipated review times. We also lay out a cost allocation approach for a new Group Study process. Actual costs will still be charged for Impact Studies and Detailed Studies. The changes recommended only apply to new applications following the DPU's approval.

A) Required Pre-Application Report Fees (Expedited and Standard Tracks Only)

The Working Group recommends that there be no fee for the Pre-Application Report recommended to be required for all Expedited and Standard Track applications over 500 k. However, the anticipated cost was taken into account when setting the proposed new application fees for the Expedited and Standard Tracks.

B) Simplified Track

The Working Group recommends that there continue to be no fee for Simplified Track applications.

C) Expedited and Standard Tracks

The Working Group agrees that current Expedited and Standard Track application fees are in need of updating and do not appear to be fully covering utility costs to review applications. The Working Group recommends that the utilities should increase the application fees for the Expedited and Standard Track processes to $4.50/kW with a $300 minimum and a $7,500 maximum, and that the rate for Supplemental Review engineering hours be increased from $125/hour (set in 2003) to $150/hour.

D) Group (Cluster) Study and Upgrade Cost Allocation

The Working Group recommends that the cost allocation for study and upgrade costs when a Group (cluster) Study is initiated should be as follows:

- I) Study Cost Allocation—by MW
- II) Upgrade Cost Allocation
    - a. Lines—Share common segments pro rata by MW, unique segments covered by that DG provider
    - b. Other equipment—Share common upgrades pro rata by MW, unique upgrades by that DG provider
    - c. If one or more DG applicant drops out, then remaining applicants share any additional restudies required
    - d. If new DG added to circuit within 5 years, need to share costs from prior DG (consistent with utility line extension policy). However, new applicants through the Simplified Track process would be exempted from this requirement.

Section 6: Pre-Application Report Requirements

The Working Group recommends adding a new required Pre-Application Report for all applicants going through the Expedited and Standard Tracks that are over 500 kW, and optional for applicants under 500 kW. The intent of this Report is to provide applicants with some basic information about the location at which they are potentially interested in connecting to the distribution system, so that they can get an initial sense of whether the particular location is practical for their project. The Pre-Application Report could also help applicants prioritize among various locations and possible distributed generation configurations they are considering. The Working Group believes that this could minimize the number of speculative applications, and increase the likelihood of viable applications.

Utilities would have 10 business days to provide the Pre-Application Report. There would be no fee for this service (however costs are reflected in the application fees). Applicants over 500 kW would not be able to submit their actual application in the Expedited and Standard Tracks until a Pre-Application Report is received.

Each Pre-Application Report will carry the following disclaimer: "Be aware that this Pre-Application Report is simply a snapshot in time and is non-binding. System conditions can and do change frequently."

Applicants would need to provide the following information to the utility through the statewide online application and tracking system:

1) Project Contact Information
   Name:
   Address:
   Phone:
   Email:
2) Location (street address with nearby cross streets, town)
3) Generation Type: (solar, wind, CHP, other)
4) Size (AC kWs)
5) Single or three phase generator configuration
6) Stand-alone (no on-site load, not including parasitic load – Y or N)
7) If existing service--include customer account number, site minimum and maximum (if available) current or proposed electric loads in kWs
8) Is new service needed?

The “Pre-Application Report” provided by the utility will include the following.

1) Circuit voltage
2) Circuit name
3) Voltage at proposed location
4) Single or three phase available near site
5) If single phase – distance from three phase service
6) Aggregate connected DG (kW) on circuit
7) Submitted complete applications of DG (kW) on circuit that have not yet been interconnected
8) Area network, or spot network or radial
9) Snap-shot within ¼ mile (or otherwise identify feeders within ¼ mile)
10) Other potential constraints or critical items that may jeopardize project

Section 7: Information Tracking and Reporting

The Working Group recommends that each distribution company establish its own timeline tracking system for applications. The timeline tracking system would track both the utility and customer time within each stage in the application, construction, and witness test as well as the overall utility time elapsed for the application and construction processes. This timeline tracking system would be used for multiple purposes including but not limited to informing applicants about where they stand in the application process, enforcing the stale project management procedures, monthly reporting to DOER, and for any Service Quality Metrics put in place by the D.P.U.

The Utilities shall use the Utility DG Interconnection Tracking and Reporting Template established by the Working Group and referenced as an Excel file in Appendix B, or an equivalent approved by DPU and DOER, to track each interconnection project. Modifications to the template shall be made only by mutual agreement of the Utilities, non-utility stakeholders, and DOER. The Utilities shall begin implementing the Tracking and Reporting system as follows:

> For the monthly DOER Report for November 2012 all new applications received from November 1 forward, and for all existing applications that begin a new interconnection step in the tariff.

The Utilities shall file a Monthly Report by the 15th of the following month to DPU and DOER beginning for the November 2012 time period, by providing the Utility DG Interconnection Tracking and Reporting file showing all entries for all projects being tracked. It is important to recognize that setting up their internal reporting systems will likely take a number of months before it is fully operational. The utilities accept their obligation to document the DG Interconnection timelines in the tariff as they apply to each project, as needed. The expected time that complete and accurate data could be derived from the reporting would be 6-8 months from the issuance of the Report.

The Utilities shall make available to any applicant upon request within 3 business days the complete record of the Utility DG Interconnection Tracking and Reporting file pertaining to the applicant's DG interconnection project.

Over the six months following the Working Group's Final Report filing to the DPU, the Utilities shall work with DOER, the DPU, and non-utility stakeholders to review the Utility DG Interconnection Tracking and Reporting System and identify issues and opportunities to improve upon the application, timeline assurance, and reporting process. The group shall assess and make recommendations to the DPU by April 1, 2013 on how to best overcome identified limitations and inefficiencies, including, but not limited to, the establishment of a centralized on-line application and reporting process considering both the benefits and costs of having such a centralized process administered by a third-party.

Section 8: Technical Standards Manual and Technical Standards Review Group

One month after the Working Group files its Report with the DPU, the Utilities will commence analyzing their Company-specific technical standards to identify areas of commonality and difference related to DG interconnection. The Utilities will also identify and analyze any barriers, including but not limited to business practices and structure, industry standards, and legal impediments, to developing a common Technical Standards Manual for Massachusetts. Any such common Technical Standards Manual will be subject to a Utility's uncontroverted ability to continue to apply a Company-specific technical standard that deviates from a common technical standard followed by one or more of the other Utilities. After the expiration of a six-month initial review period following the filing of Working Group Report, the Utilities will present their initial findings at the next regularly scheduled (or the initial) meeting of the Technical Standards Review Group. The Utilities will also propose a schedule, including timelines, for addressing, to the extent possible, outstanding analyses, barriers, etc. identified by the Utilities during the initial six-month review. For the benefit of DG applicants and customers, there will be a common statewide governing Manual that shows all the interconnection standards including wherever there are differences among the utilities (including links to any individual company specifications). The statewide governing Technical Standards Manual and individual utility manuals should be updated concurrently.

The Technical Standards Review Group should be composed of 7 members - one representative each from the four Utilities and three non-utility representatives who are engineers with electric supply systems experience with DG interconnection expertise. The Technical Standards Review Group will meet semi-annually to discuss, among other topics, the Technical Standards Manual which encompasses both common and Company-specific technical standards for DG interconnection. Each member will be able to add agenda items. The Utilities have the final decision as to DG interconnection technical standards (both common and Company-specific), and ultimate control over the Technical Standards Manual. Differences of opinion regarding technical standards will be recorded in the minutes of the meeting in which they were raised. The Utilities have the absolute right to update and modify the Technical Standards Manual to account for changes in accepted industry practices, evolving standards, etc. The Utilities will provide notice and an explanation of the update/modification to the Technical Standards Review Group. A special meeting of the Technical Standards Review Group shall be held if two of the three non-utility members request it--during which the Utility representatives will explain the update/modification. These meetings will be open to public as observers only (public can raise issues through the 7 members).

The Technical Review Group will begin to meet in January 2013 and will begin discussion of at least the following issues:

1) DTT and anti-islanding,
2) Limit of 3 MW/MVA on 13-15 kV feeders and related capacity limits,
3) RTUs,
4) External disconnect switches for small generators,
5) Interconnection practices in other states, and
6) Witness testing protocols

Section 9: Other Issues (ADR, Ombudsperson, Applicant Training and Certification)

A) Alternative Dispute Resolution Process (ADR)

The Working Group acknowledges that the ADR process for DG at the DPU has largely been untested over the past decade. As such, the only change related to the ADR process that we are recommending is the addition of an Ombudsperson as described below.

B) Ombudsperson

The Working Group recommends that the DPU, in consultation with the Working Group, name a staff DG Ombudsperson with technical expertise and authority to effectively carry out the following duties;

1. ADR;
    a. Ombudsperson role -- The Ombudsperson would hear the complaints of parties that reach the end of Step 9.1 Good Faith Negotiation without resolution. The Ombudsperson would a) be easily accessible; b) review the written documentation from Step 9.1; c) conduct independent interviews/ investigations as deemed necessary; d) offer independent problem-solving assistance from a third-party vantage. The Working Group recommends that the DPU explore whether communications with the Ombudsperson can be confidential or whether the Ombudsperson should be housed outside the DPU or both.
    b. Ombudsperson's judgments -- The intent of the Ombudsperson is to help resolve issues as expeditiously as possible. The Ombudsperson could a) propose a solution (non-binding); or b) render a judgment about whether the issues are best resolved through i) an informal settlement; ii) other alternative means (e.g., informal negotiation with an expert third party); or iii) continued use of the ADR process. If the latter, the Ombudsperson could also advise whether the dispute should pursue Step 9.2 Mediation/ Informal Arbitration, or go directly to 9.3 Departmental Hearing.
    c. Ombudsperson Complaint Process
        i. Customer would file complaint on a technical issue within the process to the Ombudsperson and the utility. The utility would have 10 business days to respond to the customer and DPU.
        ii. If the utility response does not have specific technical background as per good utility practice, then the matter would be taken up by the Ombudsperson
        iii. The Ombudsperson would respond in 20 business days and their response must conform to good utility practice.
        iv. The decision of the Ombudsperson can be appealed through the normal complaint appeal process at the DPU
        v. Include comment/complaint form
2. Reporting -- Quarterly Reports will be issued to the DPU summarizing the actions of the Ombudsperson; specific attention will be given to reoccurring issues for both utilities and

developers. An Annual Report will be issued summarizing the interconnection process, highlighting areas of concern.

3. Technical Standards – Ombudsperson will participate in the review and modification of the Technical Standards Manual and be an ex officio member of the Technical Standards Review Group.

C) Training

The Working Group recommends changing the monthly distribution company "briefing" sessions into more of a "training" that may or may not include some form of applicant certification. The trainings would provide an opportunity for applicants and utilities to interact, and could be a mandatory part of the application process. This could also link into any future online application process that requires applicants to take and pass a "how to apply for interconnection" test before submitting the online application. Details will be worked out in the on-going collaborative process during the transition period (See Section 10).

Section 10: Transition Tasks and Plan

Working Group is recommending the following transition strategy over the next year to assist in the implementation of the recommendations in this Report. The Working Group will meet monthly during the transition period to work on the tasks as outlined below.

A) Transition Tasks (with estimated timeframe)

1. Redline tariff and application (file with DPU by October 31st)
2. Establish DG Technical Standards Review Group (See Section 8 for details) (first meeting January 2013)
3. Initial information tracking and reporting (2 months)
4. Ongoing upgrades to information tracking and reporting (6-8 months)
5. Consider central administrator and potential online application for tracking and application process (6 months)
6. Review of insurance and tax markup – See Appendix E (2 months)
7. Trouble-shoot during implementation of initial applicant withdrawal (4 months)
8. Develop on-going trainings including online modules (6 months)
9. Consider using outside engineers during application and construction (1 year)
10. Consider accessible geographic mapping that will show feeders/circuits and DG activity (including names of sub-stations, circuits served) (1 year)
11. Group Studies process (6-12 months)
12. Standardized customer/utility communication (including step notification, information requests, initial screen report, and signatures) (12 months)

Appendix A: Working Group Membership and Participation

MA DG Working Group - Active Representatives and Alternates

Organization	Representative	Alternate
DG Providers – Solar		
Blue Wave Capital	Eric Graber-Lopez	
Borrego Solar	Dan Berwick	Ryan Burrowbridge
Exelon/Constellation	Scott Edwards	Robert Flottemesch
My Generation Energy	Michael Stone	
SEBANE/SEIA	Francis Cummings	
Spire Solar Systems*		Michael O’Dougherty
DG Providers—CHP		
Northeast Clean Heat and Power Initiative, US Clean Heat & Power Association	Bill Pentland	Ruben Brown (E-Cubed, LLC)
Harvard	Douglas Schmidt	
Prime Solutions/NECHPI/USCHPA		Henrietta de Veer
Source One/Veolia	Reid Sprite	Larry Plitch
Utilities		
National Grid	Tim Roughan	Kevin Kelly
NSTAR	George Moskos	Michael Brigandi
WMECO/NU***	Cynthia Janke	Donald Wells
Unitil	Gary Miller	John Bonazoli
End Users/Cities/Towns		
CLC/CVEC	Joseph Soares	Rebecca Zachas
State Agencies		
MA CEC**	Nils Bolgen	Martha Broad
MA DOER****	Gerry Bingham	Dwayne Breger

*Erik Hoagland was the alternate for Solar Spire Systems until 8.20.12
**Peter McPhee attended one meeting as an alternate for MA CEC
***Jennifer Schilling was the alternate for WMECO/NU after 8.31.12
****Courtney Feeley Karp was the third alternate for MA DOER until mid-August 2012
Note: The Attorney General's office was not a formal Member of the Working Group but participated in most meetings as active observers. They are not signatories of this Report.

Representatives and Alternates

(This sign-in list does not include attendance at the Technical and Process Subcommittee Meetings.)

Sign in Sheet MA DG Collaborative Working Group Plenaries				5.31	6.13	6.28	7.12	8.1	8.23	9.5	9.6	9.10	9.11
Adamson	Dan	SEIA (alt)	DG-Solar							X	X		
Berwick	Dan	Borrego Solar	DG Solar		X	X		X	X	X	X	X	
Bingham	Gerry	MA DOER	State Agency	X	X	X	X	X	X	X	X	X	X
Bolgen	Nils	MA CEC	State Agency	X	X	X				X	X	X	X
Bonazoli	John	Unitil (alt.)	Utilities	X		X	X	X	X	X	X	X	X
Breger	Dwayne	MA DOER (alt.)	State Agency	X	X	X	X	X	X	X	X	X	X
Brigandi	Michael	NSTAR (alt.)	Utilities	X	X	X	X	X	X			X	X
Broad	Martha	MA CEC (alt.)	State Agency										
Brown	Ruben	E Cubed LLC (alt.)	DG-CHP										
Burrowbridge	Ryan	Borrego Solar (alt.)	DG-Solar	X	X		X						X
Cummings	Fran	SEBANE/SEIA	DG-Solar	X	X	X	X	X	X	X	X	X	X
de Veer	Henrietta	Prime Solutions (alt)	DG-CHP		X	X	X	X	X			X	X
Edwards	Scott	Exelon/Constellation	DG-Solar	X	X	X		X					
Flottemesch	Robert	Exelon/Const. (alt.)	DG-Solar	X		X			X	X	X	X	X
Feeley Karp	Courtney	DOER	State Agency	X	X		X	X					
Graber-Lopez	Eric	Blue Wave Capital	DG-Solar				X	X					
Hoagland	Erik	Spire Solar Systems (alt)	DG-Solar	X	X	X	X						
Janke	Cynthia	WMECO	Utilities		X	X		X					
Kelly	Kevin	NGRID (alt.)	Utilities	X	X	X			X	X	X	X	X
McLaren	Robert	NuGen Capital (alt.)	DG-Solar	X									
McPhee	Peter	MassCEC (alt)	State Agency				X						
Miller	Gary	Unitil	Utility		X				X	X	X	X	X
Moskos	George	NSTAR	Utilities	X	X	X	X			X	X		
O'Dougherty	Michael	Spire Solar Systems (alt)	DG-Solar	X					X	X	X	X	X

(This sign-in list does not include attendance at the Technical and Process Subcommittee Meetings.)

Sign in Sheet MA DG Collaborative Working Group Plenaries				5.31	6.13	6.28	7.12	8.1	8.23	9.5	9.6	9.10	9.11
Pentland	Bill	NECHPI/USCHPA	DG-CHP			X	X	X	X		X		X
Plitch	Larry	Source 1/Veolia (alt.)	DG-CHP	X	X	X	X	X					
Roughan	Tim	NGRID	Utilities	X	X	X	X	X	X	X	X	X	X
Ruiz	Kially	Aquinergy	DG-Wind	X									
Schmidt	Douglas	Harvard	DG-CHP		X	X	X					X	X
Smith	Mary	Harvard (alt.)	DG-CHP										
Soares	Joe	CLC/CVEC	Cust/Cities	X		X	X	X	X	X	X	X	X
Sprite	Reid	Source One/ Veolia Energy	DG-CHP		X	X	X	X	X	X	X	X	X
Stone	Michael	My Generation Energy, Inc.	DG-Solar	X	X	X	X	X	X	X	X	X	X
Wells	Donald	NU (alt.)	Utilities	X									
Zachas	Rebecca	BCK Law P.C.	Cust/Cities	X	X		X	X	X		X		X
Other Working Group Participants													
Sign in Sheet MA DG Collaborative WG Plenaries				**5.31**	**6.13**	**6.28**	**7.12**	**8.1**	**8.23**	**9.5**	**9.6**	**9.10**	**9.11**
Ahirrao	Vishal	NGRID	Utilities	X									
Argo	Liz	Argo Consulting	Other/Cons	X	X								
Bachman	Roberto	SolarFlair Energy	DG-Solar	X									
Baker	Ed	UTC Power	DG-CHP	X									
Beck	Don	Keegan Werlin for NSTAR	Other/Law				X						
Bhumgara	Rayo	Sustainable Strategies 2050	DG-Solar	X			X						
Boecke	Donald	NSTAR	Utilities	X									
Brazo	Shawn	Prime Solutions	DG-Solar			X							
Busch	Joe	Borrego Solar	DG-Solar		X								
Cox	Roger	NGRID	Utilities	X									
DaSilva	John	Aegis Energy Services	DG-CHP	X									

DeVillars	John	Blue Wave Capital	DG-Solar	X									
DiNapoli	John	Unitil	Utilities	X									
Dunn	Hayley	ISO-NE	Other				X						
Eidelman	Audrey	BCK Law P.C.	Cust/Cities							X		X	
DeVillars	John	BlueWave	DG-Solar	X									
Feraci	Joseph	NSTAR	Utilities		X	X	X	X		X	X	X	X
Fitzpatrick	Joseph	DG Clean Power	DG-CHP	X									
Forrest	Dave	ISO-NE	Other				X						
Foster	John	Advanced Energy	DG-Solar	X									
Fox	Kevin	IREC	Other				X						
Fuller	Peter	NRG Energy	DG-Solar	X									
George	Caleb	NGRID	Utilities						X				
Grace	Bob	SEA	Other/Cons		X								
Greenblatt	Beth	Beacon Integrated	Other/Cons	X									
Greenwood	Daniel	SolarFlairEnergy	DG-Solar	X									
Gudell	Jan	NSTAR	Utilities	X									
Habib	Jack	NSTAR/WMECO	Other/Law		X	X				X	X	X	X
Hawes	Peter	Borrego Solar	DG-Solar	X									
Jones	Keith	NSTAR	Utilities		X		X						
Keeffe	Andrea	NGRID	Utilities		X	X	X			X	X	X	X
Kelley	Paul	NSTAR	Utilities	X									
Krathwohl	Eric	Rich May	Other/Law			X							
Krich	Abigail	Boreas Renewables	DG-Wind	X									
Kuriakose	Alex	NGRID	Utilities	X									
LaBrake	Neil	NGRID	Utilities	X	X		X	X		X	X	X	X
Larsen	Walker	CLFCLF	Other	X	X	X	X	X	X	X	X	X	X
Ledgerwood	Bruce	LEAN	Cust/Cities	X									
Medeiros	Ron	NE Clean Energy	DG-Solar	X									

Melnick	**Leah**	**SEA**	**Other/Cons**	**X**	**X**								
Newman	**Joe**	**NGRID**	**Utilities**	**X**									
Oppenheim	**Jerry**	**LEAN**	**Cust/Cities**							**X**	**X**		
Phelps	**Nathan**	**DPU**	**State Agency**	**X**									
Plett	**Frederick**	**MA AGO**	**State Agency**	**X**									
Raab	**Jonathan**	**Raab Associates**	**Other**	**X**	**X**	**X**	**X**	**X**	**X**	**X**	**X**	**X**	**X**
Rabadjija	**Neven**	**NSTAR**	**Utilities**	**X**	**X**			**X**	**X**	**X**		**X**	**X**
Ritter	**Jason**	**Borrego Solar**	**DG-Solar**	**X**									
Robinson	**Camal**	**NGRID**	**Utilities**					**X**	**X**		**X**		
Schroeder	**Erica**	**IREC**	**Other**	**X**		**X**		**X**	**X**	**X**	**X**	**X**	**X**
Sins	**Jack**	**Unison Energy**	**DG-CHP**	**X**					**X**				
Skulley	**Brooke**	**NGRID**	**Utilities**	**X**									
Smith	**Daniel**	**Siemens**	**DG-Solar**	**X**									
Sterritt	**Justin**	**MA EOHED**	**State Agency**	**X**									
Tosches	**Jamie**	**MA AGO**	**State Agency**	**X**	**X**			**X**	**X**	**X**	**X**		
Walsh	**Kevin**	**MA AGO**	**State Agency**		**X**	**X**		**X**	**X**	**X**	**X**		
Walker	**Jim**	**Solar PV Grid Tie Ameresco**	**DG-Solar**	**X**									
Wallerstein	**Mike**	**MA DPU**	**State Agency**	**X**									
Webster	**Raquel**	**NGRID**	**Utilities**						**X**				
Wheeler	**Lorraine**	**Redstoke, LLC**	**Other/Cons**	**X**	**X**	**X**							
Winter	**Danielle**	**NSTAR/WMECO**	**Other/Law**						**X**		**X**	**X**	**X**
This sign-in list does not include attendance at the Technical and Process Subcommittee Meetings.													

Appendix B: Monthly Reporting Requirements Template

Use the following link to see the actual template. The template contents are summarized below.

https://sites.google.com/site/massdgic/Home/ma-dg-working-group

Category/Stage	Required Data Entry
Application and Site Information	Company Name City/Town Facility ID (if any) ZIP Code Design Capacity (kW) Fuel Type (Solar, Wind, etc) Circuit Name
Application Receipt	Date Application Received Date Application Deemed Complete Total Time Lapsed (Workdays) calculated value Customer Time Lapsed (Workdays) enter workdays of "clock" stoppage by Customer Utility Time Lapsed (Workdays) enter workdays without "clock" stoppage
Screen Review	Date Review of Screens Study Begun Date Review of Screens Study Completed Total Time Lapsed (Workdays) calculated value Customer Time Lapsed (Workdays) enter workdays of "clock" stoppage by Customer Utility Time Lapsed (Workdays) enter workdays without "clock" stoppage
Supplemental Review	Date Supplemental Review Begun Date Supplemental Review Complete Total Time Lapsed (Workdays) calculated value Customer Time Lapsed (Workdays) enter workdays of "clock" stoppage by Customer Utility Time Lapsed (Workdays) enter workdays without "clock" stoppage
Standard Process Initial Review	Date Standard Process Initial Review Begun Date Standard Process Initial Review Complete Total Time Lapsed (Workdays) calculated value Customer Time Lapsed (Workdays) enter workdays of "clock" stoppage by Customer Utility Time Lapsed (Workdays) enter workdays without "clock" stoppage
Impact Study	Date Impact Study Begun Date Impact Study Sent Total Time Lapsed (Workdays) calculated value

	Customer Time Lapsed (Workdays) enter workdays of "clock" stoppage by Customer Utility Time Lapsed (Workdays) enter workdays without "clock" stoppage
Detailed Study	 Date Detailed Study Begun Date Detailed Study Sent Total Time Lapsed (Workdays) calculated value Customer Time Lapsed (Workdays) enter workdays of "clock" stoppage by Customer Utility Time Lapsed (Workdays) enter workdays without "clock" stoppage
ISA and Pre-Construction Information	 Date Interconnection Service Agreement Sent Estimated In-Service Date System Modification Required Expedited/Standard / Complex Project** Construction Commitment Date
Construction	 Date Construction Begun Date Construction Completed Total Time Lapsed (Workdays) calculated value Customer Time Lapsed (Workdays) enter workdays of "clock" stoppage by Customer Utility Time Lapsed (Workdays) enter workdays without "clock" stoppage
Witness Test	 Date Witness Test Scheduled Date Witness Test Completed
Authorization and Misc Information	 Authorization to Interconnect NOTES Date of Info Request Comm/Indus/Res/Muni Net Metered? (Y/N)

Appendix C: Penetration Test, Minimum Load Screen Positions

Utility Position

The 100% minimum load screen that has been proposed for use in CA and by SEIA to FERC, is not currently is use anywhere in the continental US. NJ recently decided not to implement this screen in recent interconnection proceedings that took place in the winter and spring of 2012 for many of the reasons cited here. The review of the minimum load on a feeder is currently undertaken in an impact study and is reviewed concurrently with other aspects of determining the impacts on the local distribution system from a proposed DG project. Using a 100% minimum load as a screen versus part of an impact study greatly reduces the utility's flexibility in managing customer loads during normal and abnormal operation of the distribution system. The CA Rule 21 settlement was a negotiated process and the CA utilities gained significant concessions on stale project management and financial security as part of the agreement to begin to use the 100% minimum load screen that were not part of this consensus document. The utilities recommend using vetted technical standards such as IEEE 1547 "Standard for Distributed Resources Interconnected with Electric Power Systems".

The utilities are obligated by law to maintain the safety, security and reliability of the electric power system (EPS). Accordingly, the utilities must rely on proven technical and engineering assumptions when making decisions pursuant to this obligation. The utilities have not been presented either in the context of the Working Group, or from industry sources, with technical and engineering justifications supporting the viability of the 100% minimum load-to-generation screen.

In order to maintain reliability of the system, the utilities support an aggregate inverter-based DG AC rating less than 67% of feeder (or line section) minimum load as a penetration screen test to initially check if the DG addition will have minimal impact on equipment loading, operation, and protection of the Distribution System as detailed in the Sandia Report SAND2012-1365, February 2012 "Suggested Guidelines for Anti-Islanding Screening" by M. Ropp, Northern Plains Power Technologies and A. Ellis, Sandia National Laboratories. The utilities understanding is that this 67% screen was derived from IEEE 1547 "Standard for Distributed Resources Interconnected with Electric Power Systems". The technical paper is credible being distributed to those listed in the report, being provided to over 20 utilities, and being presented in two IEEE forums in mid-2012. In addition, the analysis is supported by studies of over a dozen large PV DG interconnections in National Grid's Massachusetts service territory and for those of other utilities. The 67% screen is the first of a set of screens to determine is a risk of islanding condition exists that warrants additional protective measures. See Figure 2 in the report.

- If aggregate inverter-based DG AC rating is less than 67% of feeder minimum load, then no further study becomes necessary since the 67% allows for differing impedances of varying manufactured inverters to interact on the feeder as well as some small amount of rotating generators (i.e. less than limits in screens 3 and 4). Experience in studies have shown that at above 67%, run on times can result that exceed the 2-second anti-islanding requirement in IEEE 1547 and UL 1741.

- Where the first screen exceeds 67%, a second screen to compare the inverter and feeder reactive power should be used. The 2nd screen leads to the 3rd if the combination of load and inverter reactive power is within 1% of the feeder reactive power for any expected value of real power level at which inverter-to-load matches.

- The 3rd screen reviews if there are existing rotating generators greater than 25% of all DG on the same feeder as the inverters.

There are two more screens used in the Sandia Report SAND2012-1365, February 2012 "Suggested Guidelines for Anti-Islanding Screening", but at least the 2nd and 3rd are necessary after the first to determine if there is a risk of islanding concern to be further studied.

Note that the inverter's internal anti-islanding scheme will keep changing the system voltage or frequency in the islanded condition (Sandia Frequency Shift Method and Sandia Voltage Shift Method). Hence, the voltage and frequency cannot remain unchanged even when the load matches the generation. However, this is not true for rotating generators as they only have simple under/over voltage and frequency relays which cannot change the system voltage or frequency. If there are other types of generators, the screening fails and the project will require further study in detail.

The utilities propose the following recommended penetration test screen <u>for inverter-based DG</u> applications:

<u>Penetration Test</u>:

- ➢ The inverter-based DG AC rating in aggregate is less than 67% of feeder (or line section) minimum load without any rotating generators? Yes/No
- ➢ If "no", impact study required.
- ➢ Existing rotating generators are less than 25% of all DG on the same feeder as the inverters and all DG in aggregate is less than 67% of feeder (or line section) minimum load? Yes/No

If "no", impact study required.

<u>For other DG type</u> applications, the utilities propose to continue with the IEEE 1547 recommended practice as follows for a penetration test screen and open to revision at a future date as more experience develops:

<u>Penetration Test</u>:

- ➢ Rotating machine DG AC rating is less than 33% of feeder (or line section) minimum load? Yes/No
  If "no", impact study required.

Non-Utility Position (including all the non-utility Representatives and Alternates in the Working Group plus the Interstate Renewable Energy Council and the City of Boston)

100% of minimum load is a safe and reliable penetration screen in the context of the package of three screens that the Working Group report recommends for a robust and transparent Supplemental Review.

Use of a 100% of minimum load screen is supported by the February 2012 Updating Interconnection Screens for PV Integration by NREL, USDOE, Sandia and EPRI [http://www.nrel.gov/docs/fy12osti/54063.pdf]. This landmark report was prepared by independent technical experts and subject to extensive peer review, including utility engineers from Pacific Gas and Electric, Southern California Edison, San Diego Gas and Electric and Sacramento Municipal Utility District. The report is the cornerstone of new and innovative interconnection approaches that reduce the time and costs associated with the interconnection of DG systems in higher penetration areas while maintaining safety and reliability and protecting the grid.

FERC is considering updating its Small Generator Interconnection Procedure (SGIP) to include a supplemental review process with a 100% of minimum load penetration screen. FERC has very actively engaged on this issue, seeking comments and interventions, and in July 2012 conducting an all-day Technical Conference that repeatedly addressed the 100% of minimum load screen. SEIA, USCHPA and other DG advocates participating in the FERC proceeding are hopeful that FERC will issue a proposed rule this fall and a final rule in early 2013.

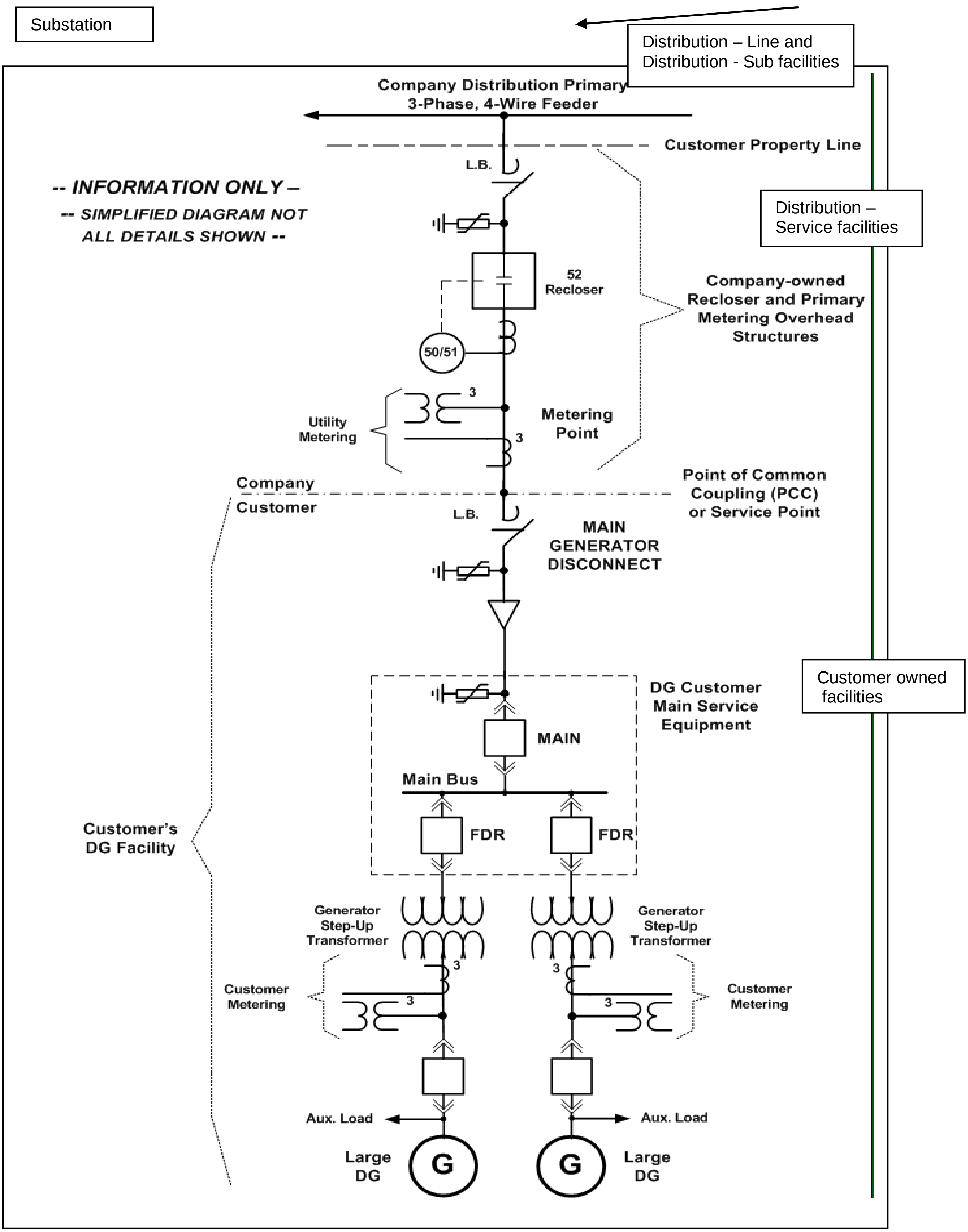
The 100% minimum load screen also reflects emerging best practices nationwide, and is already being used by a number of utilities in California (FERC Technical Conference Transcript July 17, 2012). The three investor-owned utilities in the U.S. with the most DG interconnection experience (PG&E, SCE and SDG&E) have agreed to a revised distribution-level interconnection procedure (California Rule 21) that includes a nearly identical supplemental review procedure to the one agreed upon by the Working Group for Massachusetts. In particular, the revised Rule 21 supplemental review process includes a 100% of minimum load penetration screen. The revised Rule 21 was developed through a settlement process, informed by the NREL screens report, and agreed to in March 2012 by SEIA, IREC, all three California investor-owned utilities, and a broad range of California DG stakeholders. The Settlement was recently included without modification in a Proposed Decision by a California Public Utility Commission (CPUC) Administrative Law Judge and is scheduled for a full CPUC vote on September 13.

The Working Group has agreed upon adoption of the three screens A, B and C verbatim from the California Settlement (where they are N, O and P), except for use of Massachusetts terminology. The only question is whether to retain the 100% value used in the CA settlement, or to replace it with a lower, more conservative percentage. The package of 3 screens which will now constitute the Supplemental Review process provide adequate opportunity for utilities to protect the Distribution System without reducing the 100% percentage value in the Penetration screen A. Specifically, Supplemental Review screens B and C should effectively address any outstanding concerns utilities may have about a DG

Facility that is below the 100% threshold in screen A but requires further consideration of power quality and voltage and/or safety and reliability, including anti-islanding concerns.

In addition to benefitting generators by minimizing their review time and costs, the use of 100% for the minimum load screen should significantly mitigate utility workloads for impact studies by enabling more DG applications to go through the Expedited Process rather than the Standard Process. Without this mitigation, it may be substantially more difficult for the other improvements in this Working Group report to ensure timeline adherence and an efficient and effective interconnection process that will foster continued growth of distributed generation.

Appendix D: Complex project break down of costs



Appendix E: Insurance and Tax Mark-Up

The Working Group agreed that a number of items need to continue to be addressed by the stakeholders after the filing of this Report. Primary among those issues are the following and the way the group plans for those issues to be addressed:

1) DOER Recommendation TC-11 (in KEMA Report cover letter): Insurance requirements – Prohibit requirements for additional insurance (DOER/IREC)

DOER believes additional insurance requirements are not necessary because the interconnection process adequately protects customer and utility property and adequately addresses electrical safety. DOER asserts that FERC and other states do not have these additional insurance requirements.

Mass utilities believe that additional insurance is appropriately required to address potential third-party claims against utilities for damages caused by underinsured DG facilities.

The Utilities and DOER agreed there was not adequate time in the DG Working Group schedule to adequately address this issue. The Utilities and DOER agreed to convene a discussion with respective insurance experts and legal counsel to discuss resolution of this issue. DOER and the utilities will submit an update on these discussions no later than two months after the filing of the DG Working Group Report (or November 11, 2012). <u>The review/update on such discussions may include proposals for revisions to the existing tariff.</u>

2) DOER Recommendation TC-17 (in KEMA Report cover letter): Interconnection Costs: Review requirement of the tax markup on upgrades for public entities. (state customer)

DOER believes that there should be a waiver of the DPU-mandated "tax adder" carrying charge imposed by utilities on customers who contribute (i.e. pay for) assets that ultimately become a part of utility plant (such as interconnection upgrades) for DG facilities owned by public entities, such as state hospitals, state universities, etc.

The Utilities believe that there should be no such waiver, since any amounts not collected from customers causing the imputed tax are ultimately recovered from other customers.

The Utilities and DOER agreed there was not adequate time in the DG Working Group schedule to adequately address this issue. The Utilities and DOER agreed to convene a discussion with tax and legal experts to discuss resolution of this issue. DOER and the utilities will submit an update on these discussions no later than two months after the filing of the DG Working Group Report (or November 11, 2012). <u>The review/update on such discussions may include proposals for revisions to the existing tariff.</u>