November 13th, 2017

Delivered Via Email

Mario Bohorquez
Illinois Power Agency
160 N. LaSalle Street, Suite C-504
Chicago, IL 60601

Introduction

Carbon Solutions Group (CSG) would like to thank the Illinois Power Agency (IPA) for the opportunity to comment on the Draft Long Term Renewable Resources Plan (LTRRP).

CSG is a REC marketer and aggregator. We have been active participants in the Illinois REC market for a number of years. We have also served as a stakeholder and winning bidder/aggregator in the Supplemental Photovoltaic Procurement, Utility Distributed Generation Procurement, and the Utility Scale REC Procurement. We have worked closely with installers, system owners, and other market participants across a wide range of system sizes and geographical areas.

CSG's Approach to the Public Comment

CSG would like to commend IPA for their efforts on the Draft LTRRP. We greatly appreciate the Agency's thoroughness and openness when developing this plan. In general the Draft plan does a fantastic job of outlining what we believe will be a series of successful procurements and programs. We are excited for the future that this plan outlines and looking forward to participating in the resultant markets for years to come.

CSG's stance is first and foremost as an environmental markets advocate. As a business that is wholly dependent upon a strong regulatory infrastructure and long term program viability we comment in an effort to cure the market of unintended consequences and help steer it towards incentivizing renewables in a manner consistent with the intent of the legislation in the most cost-effective manner possible.

We also hope to offer insight on the administrative processes involved in administering of the LTRRP. Our approach is to advocate for an open, efficient, and effective market that reaches the goals outlined in the Future Energy Jobs Act (FEJA).

2. Legislative/Regulatory Requirements of the Plan

CSG agrees with the procurement targets the IPA outlines in the Draft Plan. We appreciate the detail and clarity in this initial section.

2.4.1

CSG agrees with the Agency's interpretation of 50% in this section. We the support the use of of "at least 50%" to apply to the quantity of RECs Procured.

4. Renewable Energy Credit Eligibility

Carbon Solutions Group reiterates our support for spot procurements as a cost effective method for supporting renewable facilities which contribute unique benefits to Illinois' ratepayers, but also suggest that additional duration is considered beyond the spot procurement of current year vintages.

Tax reform, the recent DOE fuel security NOPR and the solar trade case are three examples of potential sources of volatility in the price of developing new renewables in the near term future. In order to continue to provide a balance of new renewables development and the lesser priority components of the law CSG comments that a multi-year laddering approach with 5 (five) additional months of banking might be in order. As such, perhaps the full requirements for the 2017-18 energy year could be procured with 33% of the following energy year (2018-19), 15% of requirements of the next (2019-20) and 5% of the fourth year (or some strategy of the like).

This type of strategy will ensure some continuity in the remaining ARES REC market as the limited number of buyers now have little reason to proactively seek compliance RECs due to lack of banking value. As such, they are incentivized to wait out the generators and bid a very low price just before compliance is due. The lack of urgency to hedge risk is detrimental to the market, contributes to illiquidity and does nothing to foster REC generators confidence in the REC market as a tool for building, owning and operating renewables. Although, this is likely not a significant concern today as most facilities historically have been built based on the advantageous tax structure afforded by the existing Federal tax code these dynamics are currently very much in flux. Finding any marginal method for incentivizing liquidity and hedging of risk serves to develop the market for environmental assets; as such it bolsters the market's confidence in regulatory programs such as the Future Energy Jobs Bill.

Multi-year procurements of current energy year (+5 months) vintage RECs would provide continuity in a market that has quickly lost it with the erosion of the ARES market. CSG makes this particular comment from the perspective of an environmental markets advocate in the hopes that when marginal decisions can be made to bolster the overall strength of environmental financial markets that they can be highlighted by participants such as us and perhaps ultimately be implemented if deemed logical by stakeholders.

Vintage Requirement for Spot Procurement RECs - CSG would support a slight modification to include an additional five (5) month window in the vintages allowed for a given delivery year. This would slightly increase the available pool and would give the IPA a higher likelihood of potentially reaching RPS thresholds in a cost effective manner. For example Delivery year 2017-18 would allow the use of RECs generated during the period of 1/1/17 to 5/31/18. Delivery year 2018-19 would allow the use of RECs generated during the period of 1/1/18 to 5/31/19.

4.1 Adjacent State Requirement

CSG applauds IPA's innovative method for screening the inclusion of adjacent state facilities. However, IPA's analysis includes RECs sited in Iowa and Wisconsin that are unretired in tracking systems (MRETS/GATS) which may not actually meet proposed requirements. When each facility on the tracking systems are analyzed using the scoring model it appears that only a fraction of the facilities that generated this identified surplus would actually reach the 60-point threshold. The geographic location of resources within each state skews the availability of RECs towards PJM sited facilities and away from MISO sited facilities.

The load breakdown in Illinois is ~45% PJM and 55% MISO (according to 2015 EIA DOE retail sales data). As such, we suggest that perhaps that the targeted renewable energy supplied to follow a similar breakdown in order to have a more consistent impact on the entire Illinois grid. The current scoring threshold would result in REC supply being derived ~87% from PJM (for wind and non-wind RECs).

In order to make for a more equitable allocation of resiliency, reliability and fuel diversity benefits to customers located in MISO CSG suggests one subtle revision to the scoring model and further definition of what constitutes the geographical location of a wind facility.

The challenge here is due to the location of the wind resources in MISO. Most of the wind resources are found in North Central Iowa and Western Missouri; whereas the model only reaches Eastern Iowa & Missouri. Reducing the qualification threshold from **60 points to 55 points** would extend qualification coverage further west into Iowa and Missouri, north into Wisconsin and Michigan and east into Indiana. However, in terms of reaching additional facilities (and therefore tapping the natural resource availability and providing equitable resiliency, reliability and fuel diversity benefits to MISO customers) only Iowa would be impacted in any material way for wind energy and Wisconsin to a slight extent for hydro. Solar energy would be impacted fairly uniformly across the adjacent states. Table 1.0 below shows that a reduction in the threshold score (from 60 to 55) would likely increase the supply of wind RECs from MISO from ~2.1M/year to ~4.0M/year. This is an important added supply of liquid and potentially available RECs because the majority PJM sited wind RECs are likely already spoken for by compliance buyers in PA, NJ, OH, MD, MI, DC, VA and DE. So, although there is nearly 6M RECs per year in Illinois sited wind RECs in PJM the cost to ratepayers would be substantially higher (if these RECs were to be reappropriated at all from the ownership of buyers simply looking to make retirements in PJM states.)

The second recommendation that CSG would make is that the definition of the geographic location of the facility may not be easily discernible, as many wind farms are located across multiple municipalities. Therefore, CSG comments that the definition of the geographic location of the wind farm be the closest (to Morris, IL) border of a county in which any turbine associated with the wind farm is located. As such the distance used in the formula would be the shortest distance from Morris, IL to the border of the county in which the majority of the wind facility is located.

Table 1.0 - Wind Resource Supply by State (MISO)

Wind Resource Supply By State				
	MW Available (60 or Greater)	**MW Available (55 or Greater)**	**MW Available (50 or Greater)**	**MW Available (45 or Greater)**
MISO (IL)	632	632	632	632
MISO (WI)	48	155	155	155
MISO (IA)	47	580	1,574	2069
MISO (MO)	-	-	451	451
Total (MW)	**727**	**1,367**	**2,812**	**3,306**
	MWh/Year (60 or Greater)	**MWh/Year (55 or Greater)**	**MWh/Year (50 or Greater)**	**MWh/Year (45 or Greater)**
MISO (IL)	1,894,950	1,894,950	1,894,950	1,894,950
MISO (WI)	144,624	464,513	464,513	464,513
MISO (IA)	142,166	1,740,046	4,723,174	6,206,399
MISO (MO)	-	-	1,353,000	1,353,000
Total (MWh/Yr)	**2,181,740**	**4,099,509**	**8,435,637**	**9,918,862**

The table above represents likely non-rate recovery wind facilities on MISO (according to MRETS & PJM GATS facility listings). This product (MISO wind) is by far the most representative of where an adjustment of the threshold score would impact available RECs. For perspective we can consider that there are 3,179 MW of existing Illinois sited PJM wind capacity. As such, elevating the MISO, adjacent state supply from **95MW** (48MW WI + 47MW IA) to **735MW** (155MW WI + 580MW IA) would be a comparatively modest increase. Furthermore, we anticipate that the five (5) million unretired wind RECs in Iowa and Wisconsin may not have been adjusted for their specific geographic location within the states. In a less extensive review of hydro facilities in Wisconsin we found that a very small minority of the those facilities would both score >60 and pass the non-rate recovery requirement (probably less than 25MW or 100,000 RECs/Year).

Finally, it is important to consider that just because a REC becomes Illinois qualifying doesn't necessarily mean that it would be made available for sale into the market as many compliance entities in Minnesota and Wisconsin have internal policies which prohibit or restrict sale of RECs in favor of banking for later years of the program. Northern States Power (Xcel - Minnesota / North Dakota) is a utility that has both PUC imposed restrictions on sale of RECs, as well as internal strategies with a preference towards banking.

As such, CSG strongly advocates for a reduction in the public benefit formula threshold from 60-points to 55-points, as this would likely allow for the envisioned supply of non-rate recovery RECs. Finally, we would like to reiterate that the mileage input be the the shortest line between the county in which any turbines are located and Morris, IL. For instance, in the case of an Indiana wind farm this would be a straight line between the North and Westernmost border of Montgomery County and Morris, IL.

<u>Section Summary: Carbon Solutions Group</u>

- CSG suggests that the definition of geographical location for wind farms should be the most proximate border (to Morris, IL) of a county in which wind turbines associated with the wind farm exist.

- CSG suggests that the public benefit scoring threshold for qualification should be reduced from 60 to 55 points.

- CSG contributes our opinion that the benchmark price for spot procurements should take into considering the unique specifications required under Illinois law relative to other regional markets.

- CSG suggests that an additional five (5) month window be allowed for spot procurements of RECs from existing facilities

- CSG re-asserts its support for spot procurements on an ongoing basis.

5. Competitive Procurement Schedule

<u>5.4. Revised REC Eligibility</u>

“For Spot Procurements, such as those proposed in Section 5.9 below, there will not be the same level of initial screening of eligibility because the Spot Procurements are not unit-specific, but the procurement rules and contracts will clearly state that the obligation and responsibility (and potentially penalties) of delivering eligible RECs (as coded eligible in GATS or M-RETS) will reside with the winning suppliers.”

CSG supports this interpretation which ensures that the procurement will have the most access to supply which will in turn reduce costs to the ratepayer. CSG reiterates our previous comments with regard to the importance of the rolling procurement of existing RECs both spot and forward.

<u>Consistent Short-Term Procurements (Hybrid Duration) to Complement Multi-Year Procurements</u>

CSG believes that both short-term and multi-year procurements have their place in the context of a robust and successful LTRRP. A consistent short-term procurement strategy could be designed to complement the IFP and ABI’s. Short-term procurements would enable the development and inclusion of technologies besides wind and solar such as hydro, biogas and biomass which would result in more baseload renewable capacity; thereby enhancing grid reliability. Also, with the majority of these other renewables types being smaller and more resource driven in their location they would also arguably contribute to more grid resiliency. By this we mean that these other renewables are more likely to be located near their feedstock and their load which likely means at the outer nodes of the electric distribution system.

Constructing a market mechanism in the form of hybrid-duration procurements would provide liquidity and support for various “odd-lott” projects and REC sources that would complement the structured, but homogenous supply provided by long-term supply contracts.

Other markets such as PJM and NEPOOL have greatly benefited on the expectation of forward markets, but not necessarily from a long-term off-take from the ultimate consumer of the RECs. Long-term procurements have many risks that can be mitigated by short-term procurements over which IPA would reserve the right to determine the best implementation strategy based on market circumstances.

Benefits & Rationale for Hybrid Duration Procurements

1) Reduced market risks to ratepayers

- Federal tax rates – Lower tax rates would likely result in less new renewables build all else equal given the impact of tax credits on finance of new projects. This could make it more expensive for a typical wind or solar resource to be built in a given year for certain types of investment grade investors. This may necessitate the development of projects which rely on unique niches or circumstances such as state tax incentives/abatements, novel renewable waste feedstocks, etc. Short term procurements could benefit these projects which may require support from RECs, but not necessarily 15 years worth. This is an important way that short term procurement could contribute to cost-effective acquisition of renewable resources.

- Current ramp-down of ITC & PTCs – Similar impact as tax rates above.

- Low REC prices in PJM – Similar impact as tax rates above, but could provide for demand volatility if PJM becomes supply constrained in 2020 and beyond.

- Ohio Wind setback reduction (State Regulatory Changes)– This is an example of state regulatory uncertainty that is in flux right now that could produce year to year supply volatility on PJM/MISO. Excess supply in Ohio could allow for more cost effective Illinois and adjacent state resources to become available with very little notice. Having a mechanism for Illinois to take advantage of these short term changes in market dynamics would be beneficial to ratepayers.

- Higher interest rates – Similar impact as tax rates above.

2) Reduced project risk to ratepayers

There could be a balancing of REC price with delivery risk. Existing projects have very little risk of delivery.

3) Enhanced grid resiliency

Short term procurements could be used to identify projects that have additional ancillary benefits which contribute to grid resiliency.

4) Enhanced grid reliability

Short term procurements of to be determined duration would be able to focus more effectively on smaller projects from technologies which are potentially less intermittent in nature than wind & solar.

5) Incent technologies besides wind and solar

Balance other technologies such as hydro, biogas, etc. with wind/solar.

6) Incent project developers with a higher tolerance for risk

Aggregation of small projects is key and it's very challenging from a credit standpoint for small projects to bid into these procurements for long duration.

Smaller projects from other technologies don't often have the ability to participate in procurements in order to build the projects. The projects are often built based on unique circumstances and end of up having a higher tolerance for risk than large wind and large solar projects. These small projects should not be penalized for their tolerance for risk.

One might say that if they build the project without RECs then they didn't need RECs in the first place. This is in fact not true because perhaps they had a lower return on investment threshold and a higher tolerance for risk than a large scale solar and wind developer.

So, the net result is that you have these smaller, riskier projects that are outside the norms and that likely cannot compete in the LTRP with the large wind and solar developer for which the regulation was crafted. There should still be a market for them on an ongoing basis to bid into in order to compensate them for their tolerance of risk.

7) Increased participation from projects/developers with less than investment grade credit

However with the development of a liquid forward market would come with listing of an exchange traded product on an exchange such as ICE. This would draw market participants in the form of market makers; many of which would be investment grade.

Buying strips forward at minimum leads to incentivized development. In this way some of the long term risk could be passed from the state and utilities to market participants who have a much larger portfolio of risks and are in fact investment grade.

8) Incented development of projects with less sophistication than those participating in the long-term procurements

Sources of Hybrid-Duration Procurement RECs

The diversity of the sources of RECs which would be available in a short-term procurement environment and which would complement long-term sources is worth highlighting.

1. Distributed generation projects which over generate
2. LTRRP projects which over generate
3. Supplemental PV systems rolling off original contracts
4. Adjustable block projects which over generate
5. Existing wind and solar projects in Illinois and adjacent states
6. New & existing projects with a higher tolerance for risk
7. New & existing projects from alternate technologies (small hydro, biogas, biomass, landfill gas)

Mechanism for Administering Hybrid-Duration REC Procurements

The mechanism that we would propose for a complementary short-term procurement process would be as such:

Contract Duration – IPA would reserve the right to procure between one and five year contracts based on market conditions. CSG would initially propose three-year procurements. Should serve as a market-centric mechanism for filling the gaps in the long term procurement. IPA should reserve the right to determine duration of contracts and other procurement specific details.

Non-Identified Systems – IPA would reserve right to procure contracts which involved solely non-identified systems or a mix of non-identified and identified.

A strategy for balancing long and short-term procurements would be to allow short term procurements to be bid in without the explicit identification of systems. This way whatever the mismatching of supply with demand might be there would be an inherent market mechanism in the form of an incentive to aggregate the odd lot, mostly smaller generators (diversifying risk). This way the unique and not well formed supply could be met with a consistent buyer ready to provide liquidity for both existing facilities, as well as new.

Limited Banking Allowed – CSG proposes that banking would be allowed in the early years (just as it is currently allowed for ARES compliance) and that after RY19 banking would fall in line with the practice ultimately established under the LTRP, but still for no more than 3 years. This will likely be necessary in the early stages of the program before confidence is built in the market that the process will result in consistent pricing and demand for new and existing projects.

Adjacent states limited to PJM/MISO sited – As we discuss in the next section we believe that procurement of adjacent states should be limited to facilities sited within or interconnected to PJM/MISO.

Design should allow attainment of RPS% goals if capital is available – Whatever the ultimate format is chosen the possibility that % RPS requirements should be reachable is key to implementing a procurement strategy which acknowledges the full intent of the regulations and all the priorities therein.

Carve Outs for Facilities Which Meet Resiliency & Reliability Goals – Specifically, CSG proposes to carve out a category which might incent smaller systems (which might contribute to enhanced resiliency) and facilities with higher capacity utilization factors (which might contribute to enhanced reliability).

5.6 Benchmarks

CSG would like to contribute some ideas based on our experience in the markets for “like products in the region.” At first consideration it might seem reasonable to set a benchmark for wind RECs at the current level of the most liquid regional REC market (PJM GATS Tri-Qualify). These RECs are largely comprised of wind RECs and are used for compliance in PJM states such as Pennsylvania, New Jersey, Maryland, Ohio, Delaware, Michigan and Washington D.C. However, we assert the benchmark price should be substantially higher than the current PJM REC levels when the actual specification of Illinois qualifying RECs is considered.

Substantially Similar Technology

The Illinois wind and solar procurement should consider taking into consideration the actual weighted average price of wind and solar RECs in the regional market. In markets such as Minnesota, Wisconsin & Michigan the value of renewableness is not easily observed in the REC markets as the majority of compliance comes from utility owned wind assets or long-term wind PPAs. However, we can observe that historically the cost of renewableness in a structure such as these can range from $8.00 - $35.00/MWh.

The PJM (plus Ohio, Delaware, Washington DC) market can offer further anecdotal evidence in the form of data derived from PJM GATS retirement reports and a relatively liquid market for RECs. In the analysis we introduce here we’ve taken a typical price for the 12 months preceding the compliance date for these major REC markets and derived an average cost per REC for wind, solar, wind/solar and non-wind RECs based on the publically available retirement reports published on the PJM GATS tracking website.

Table 1.1: Quantity & Cost of Wind, Solar & Non-Wind RECs in PJM

	Wind RECs (MWh)	Solar RECs (MWh)	Wind + Solar RECs (MWh)	Non-Wind RECs (MWh)	$/Wind + Solar REC ($/MWh)	$/Non-Wind REC ($/MWh)
Pennsylvania	3,953,679	582,149	4,535,828	16,098,483	$ 6.19	$ 1.75
New Jersey	6,509,830	2,251,068	8,760,898	3,109,648	$ 51.99	$ 4.33
Maryland	2,339,596	411,787	2,751,383	6,378,430	$ 7.35	$ 4.74
Ohio	808,637	128,095	936,732	1,842,371	$ 6.14	$ 2.00
Delaware	612,775	89,650	702,425	0	$ 7.02	0
Washington DC	451,608	62,173	513,781	1,062,584	$ 59.24	$ 1.60
Total	14,676,125	3,524,922	18,201,047	28,491,516	$ 29.94	$ 2.71

The table above shows the actual spend by compliance entities in each state RPS in PJM (besides Michigan which recently increased its RPS % requirement, while at the same time reducing its bankability duration - both factors expected to exert bullish impacts on price of qualifying RECs). Although the definitions for Class 1/Tier 1 and Class 2/Tier 2 differ by state the tracking system data allows for the segmentation by technology type (and thus allows grouping by wind, solar, non-wind). We've then taken the available market pricing average and derived a total dollar value allocation by state and renewables type. The takeaway here is that a substantially similar wind + solar only REC in PJM would be expected to cost $29.94/REC on average and the equivalent non-wind REC would be expected to cost $2.71/REC. A similar analysis of MISO would reveal lower prices, but also a substantially lower amount of available supply so that a supply weighted price across both tracking systems (MRETS & PJM GATS) would reveal a wind + solar price of ~$20.00/REC and a Non-Wind price of $2.35/REC.

Same or Substantially Similar Vintage

Allowing only the current year vintage to be used for compliance in a given compliance year is a very unique specification. The New Jersey Class 2 market is probably the most prominent market which allows no banking. This has had the effect of elevating the New Jersey Class 2 market to the highest price of any of the Class 2 / Tier 2 PJM markets (Maryland, Pennsylvania and Washington DC also have Class 2 / Tier 2 markets which each allow three (3) year banking).

The effect of no banking (single year vintage eligibility) on pricing is very substantial as it has led to an average of ~10x pricing in New Jersey Class 2 relative to the other PJM markets historically. The effect of placing so much demand on a single vintage at the same time that the product has other uses has a very significant impact on the negotiating dynamics between the buyer and the seller in an over the counter (relatively illiquid) market.

As such it is Carbon Solutions Group's recommendation that 17-month vintage periods be allowed if IPA believes that it is within its regulatory purview to allow it.

Same or Substantially Similar Quantity

Typically lot sizes are 10,000 - 25,000 RECs. In a market that is oversupplied a buyer would typically get a discount for larger lot sizes as the seller would prefer not to be in the market as often. However, in an undersupplied (or tight supply market) the buyer would prefer not to be in the market as often and so would pay a premium for a larger lot size.

As such to acquire a substantially similar quantity such as the 1,000,000 plus necessary to satisfy the RPS percentage standards it would be expected that there would be a premium paid relative to the other markets for the Illinois qualifying RECs. In effect, to acquire a lot size this large it takes an active aggregation process and this in turn should justify a premium price relative to PJM Class 1 / Tier 1 RECs of the same vintage.

Same or Substantially Similar Contract Length & Structure

Structurally, the procurement would be buying very similarly to a typical PJM/MISO REC transaction. However, the additional requirements that the facilities are non rate-recovered and that the facilities positively impact Illinois public interest is unique.

Non-Rate Recovery - Approximately 50% of facilities on MRETS & GATS are rate recovered. No other PJM state requires this distinction and serves as another factor which should cause the benchmark in Illinois to be higher than the surrounding regional markets.

Public Interest - The benchmark would be most affected by the public interest criteria component of the Illinois regulations. This criteria ensures that real energy and environmental impacts must be delivered by facilities in order to qualify for the Illinois RPS and is a first of its kind innovation in environmental markets. While CSG believes that it's a master stroke in terms of environmental market regulation; the impact on facility qualification is considerable and shouldn't be underestimated when setting the benchmark for the renewables products.

5.9. Spot Procurement

CSG agrees with IPA's assessment, spot procurement will not cause a budget constraint. We think the intent of the law is to run a spot procurement in order to attempt to hit the % renewables target. Potential budget shortfall in later years is an an unknown whereas the need to attempt to hit % RPS when budget is available is a certainty today.

The cost of solar is likely to continue to drop over time, the cost of wind is likely to drop over time, with the price of storage dropping over time, and price volatility of natural gas over time are all likely to make renewables development. Price of competitively procured wind and solar will likely drop over time. Which will help the IPA hit targets in a cost effective manner.

CSG agrees with the IPA's assertion: "The Agency believes that it is obligated to seek to procure RECs from new or existing generating facilities to meet the 13% goal for the 2017-2018 delivery year. Furthermore, a similar provision (14.5%) exists for the 2018-2019 delivery year (with the portion of load to which RPS requirements apply for non-eligible retail customers increasing to 75%), and then increasing by 1.5 percentage points each year thereafter for all retail load (other than the ARES carve-out discussed in Section 3.3.)"

Section 6- Adjustable Block

6.3 Block Structure

Structure after Initial Blocks are Filled

We agree with the Agency's assessment that if demand is strong and funds are available the procurements should continue. Due to the unexpected speed that targets have been hit in other states we think there is a possibility the MW targets for the first 3 blocks are hit. We urge the IPA to outline what happens in the event that these blocks are exceeded before the plan is revisited to help maintain market stability and consistency. We comment on the method for this in a later section.

Pertinent Statutory Language:

"This goal is not a cap; if demand for new projects is strong enough, and funding available, there is no barrier (other than the monetary RPS budget discussed in Section 3.17) for going beyond that level."

Groups A and B

CSG fully supports the IPA's approach to split up the REC pricing blocks by utility territory. This keeps the program simple and easily navigable. We think that breaking it up into further blocks would only add complication and hinder market growth. The one exception to this is that we are aware that there may be some smaller Municipal Utilities and or Co-ops that fit better in a different block than they were assigned in the Draft Plan. We urge the IPA to make these switches where they make sense, but keep the program limited to groups A and B.

Allocation of Undefined 25%

FEJA leaves 25% of the ABI capacity unallocated and up to the agency to decide. We fully agree with the Agency's approach to split this capacity equally among the three blocks to start. This will enable the largest capacity possible at the launch of the program and is the most fair way to allocate this capacity. We agree that if certain market segments are lagging behind or shooting ahead that some of this capacity may need to get reallocated.

This approach also allows for a variety of business models to be successful. Some segments of the market will be slower to take off than others, especially because of the sales cycle and extra sales force that is needed for smaller system sizes. We believe that it will be difficult to even assess if a segment is doing well or lagging behind until 12 months after the program launch so the best approach is to give the maximum opportunity to each segment and allow businesses to develop to fill the demand.

If a market segment is truly lagging behind when the IPA reassesses the plan it would not be detrimental to reallocate the 25% by removing it from a lagging sector, because the lagging sector would be slow to use that capacity anyway. However, it could be detrimental by not allocating the additional 25% at all and limiting the capacity available for all market segments.

Small, Large, and Community Categories

CSG fully supports the IPA's decision to keep the block sizes simple and easily navigable. Adders for the large DG and Community Solar categories are sufficient to drive participation from various system sizes. Creating specific carve out requirements for a subsegment of either of these categories would create more complications and limit the market's ability to expand where it is most successful.

4% Decline Between Blocks

We fully support the 4% decline between blocks. These are easy, predictable, and small enough steps to avoid boom and bust cycles. It will help create and maintain consistency in the market.

Initial Blocks will Open for 60 days

CSG mostly supports the IPA's decision to manage the initial influx of systems by keeping block one in each category open for the first 60 days. We believe that the strict requirements placed on projects entering the blocks will limit the initial projects to only systems that have a high likelihood of being installed. However, we would like to urge the IPA to not leave the initial 60 days open to accept an unlimited amount of capacity. As the IPA notes in the Draft Plan, several other states have had a massive inflow of systems upon program opening.

We recommend that after 200% of the first block's capacity has been filled that the program continue to accept systems, but that the newly accepted systems will start to use up capacity from the next block in line (and the third block if needed). In the event that there is such a large influx of systems the budget will quickly become a constraint. We suggest the IPA adopt a series of priorities or tie breakers to select the systems that receive the first payments. These priorities should mirror the priorities established in the statute.

We propose that the following factors be considered as priorities in the event that there are enough systems accepted into the program that there are budget constraints on REC payments:

- DG- systems that are energized get priority
- Community Solar- Systems with higher subscriber rates get priority
- Community Solar- Systems with higher percentages of residential subscribers get priority

Whether these factors are needed in the first 60 days of the program opening, or later in the process, we believe that clear rules on how payment and spots in the program are allocated will help to create and maintain stability in the market.

In the event that the full first block is filled in the initial 60 days of the program opening, we recommend that the subsequent block open immediately, and that the 14 day period before the next block does not apply in this case.

14 Days after Block is Full

CSG supports the IPA's decision to keep blocks open for 14 days after the capacity has been reached. This is yet another measure incorporated by the IPA that will help maintain market stability. We would like to recommend or clarify that any project submitted to the Program Administrator in this 14 day period gets the REC price of the closing block, regardless of if they have an approved contract by the ICC in this period.

Redline Language:

"For each Block 1, all projects submitted within 60 days of the program opening will be included in that Block 1 regardless of if the block volume is used up. For subsequent blocks (and for each Block 1 if it is not filled in the first 60 days), the block will be held open for 14 days after the block volume is used up. Any projects that are submitted into the block during that 14 day period and are subsequently approved will receive the REC price from the just filled block, even if Commission Approval of the contract occurs after the 14 day period. The Agency will announce when a block has been filled and when the closing date will be."

6.4 REC Pricing Model

CSG would like to thank the IPA for its open and transparent approach to pricing RECS. We greatly appreciate the REC models published by the IPA and found them very helpful. We support this open approach and believe it will reach a REC price that creates an effective market. We are not offering any specific inputs on the CREST model except the points listed below. However, we are aware of many other market participants that will be commenting on specific inputs in the model that have more expertise than we do. We are confident that the IPA will use this input wisely and arrive at a REC price that is effective.

The following inputs are not included in the CREST model and will have real ongoing costs to the project so we recommend that they be included.

- Cost of capital for the 10% collateral required for systems in the ABI. Most systems will end up putting up cash or having cash withheld from their initial REC payment to cover this. This will alter the payback period for nearly all systems and have an impact on the IRR achieved. We are not making a specific recommendation to the IPA on the cost of capital they should use, but this is a cost that should be included in the model.

- The cost of ongoing REC reporting and delivery is not included in this model. There is an extra administrative cost to comply with the ongoing delivery requirements of this program. Again it is difficult to make a specific suggestion on this cost because it is highly variable based on other factors that are included in other sections of our comment. We would be more than happy to help the IPA establish this cost once the other variables are settled if extra input is desired.

- The cost of managing the risk of a system underperforming. We strongly recommend - later in our comments - ways to limit this cost and risk, but as the Draft Plan is currently written there is no limit to the collateral that can be reclaimed by the utilities (except the contracted value). This risk needs to be mitigated for at least the first 90% of the life of program contracts. CSG believes that there are ways that Vendors can mitigate this risk, but the less limited this risk is, the more expensive it will be to mitigate.

6.5 Adders

CSG supports the IPA's plan with regards to adders. We fully support the decision to limit them to size and residential participation based adders for Large DG and community solar. This will help to keep the program simple to understand and predict. We also support the decision to use adders only and not create carve outs. This will allow the market to select segments that work best and not slow down growth in other segments with overly specific carve outs. We also agree that there is no need for adders for systems under 10kW or for other types of systems such as carports.

We also recognize that there may be some need to alter the specific values and size ranges to which each adder is attributed. We are aware of other market participants commenting on these issues and support changes and tweaks as the Agency sees fit as long as the overall structure remains the same.

6.5.1 Co-Location

CSG supports the Agency's plan with regard to co-location with a few specific clarifications and exceptions.

We understand the need for the following provision in the Draft Plan: "the Agency reserves the right to revise the incentive amounts paid for the original system", however, we ask for this incentive revision to be taken from REC payments due to the system owner and not from REC collateral. The Vendor may have no knowledge of a pre-existing system at the time of the system owner's application and a modified REC payment is the best way to apply this revision.

CSG supports the decision to count capacity based on all arrays at a single location, with a few exceptions. We suggest that the IPA exempt older systems from this qualification and limit the rule to other systems with REC contracts under the LTRRP. We understand the purpose of limiting co-location to prevent gaming of the program, however, older systems built with DG or SPV contracts could not have known about the ABI Program at the time of construction. When system owners add on capacity with a new array they are truly building a new solar system and have the same costs as other new systems with the same capacity. Because of this they should be treated as a separate new array and receive the REC pricing that corresponds to the new additional capacity.

Suggested Language:

"The total capacity of ~~a~~ system's under the Adjustable Block Program at a customer's location will be considered a single system. (For example, three 100 kW systems at a single location will be considered a 300 kW system.)"

6.6. Payment Terms

CSG generally agrees with the payment terms in the Draft Plan. We agree with the timing of the payments, and the payment amounts as outlined in the plan for systems that are generating RECs at the contracted rate. We also agree that there is no flexibility allowed within the statute for systems under 10kW. However, for systems that are over 10kW and underperforming relative to their contracted REC quantities we recommend that the amount of contracted RECs is modified to be based off of actual performance, not off of the original contracted quantity. Systems that underperform in the first 5 years are highly unlikely to catch up and start producing more RECs in years 6-15. Because of this we recommend that if a system produces less than 90% of its contracted RECs in years 1-5 the contracted quantity of RECs is reduced based on actual production. This will benefit the utilities by giving them more predictable REC deliveries. It will also benefit the system owners and Vendors by reducing the amount of potential collateral draw.

Suggested Language:

"For systems over 10 kW and community solar projects, it is not clear from the law how exactly the "subsequent 4-year period" would be calculated, and whether the frequency of payments should be annually, quarterly, or monthly. The Agency recommends payments in equal 20% amounts on an annual basis. For example, if the first payment is made on September 1, 2018 (upon interconnection and energization), assuming continued compliance with contractual requirements, the next payments would occur on September 1, 2019, September 1 2020, September 1, 2021, and September 1, 2022 respectively. This would be five payments that bookend a four-year period of time.

Systems over 10kW that under deliver RECs in years 1-5 of the contract by more than 10% the contracted REC quantity will have the contracted quantity of RECs modified to reflect the system's actual performance up to the end of year 4. The final REC payment for the under delivering system will equal the contracted REC price times the remaining unpaid contracted RECs (new contract quantity minus # of REC paid for in payments 1-4)"

6.7. Contracts

CSG supports the use of standard contracts between Approved Vendors and the contracted utility. This approach has been simple and effective in the DG and SPV procurements and we expect it to continue to be so. We look forward to the opportunity to engage in the contract comment process and suggest that the ABI standard contracts will be more complex than the previous procurement contracts and may require a longer period for comments or additional rounds of comments.

We also have specific recommendations to make in regards to the Approved Vendor role that should be reflected in the standard contracts. We address this in the Section 6.9 of our comments.

6.8. Adjustments to Block Prices

CSG fully supports the IPA's decision to wait at least six months after program launch before making changes. Business models will take time to develop and stabilize and changes earlier than that will cause instability and confusion in the market.

The Draft Plan states that "the Agency will post an announcement to its website regarding the proposed changes and will hold either a stakeholder meeting, or an online webinar to provide an opportunity for stakeholder input." We thank and fully support the IPA's openness to continued stakeholder involvement and appreciate the opportunity to give input in regards to future changes.

6.8.1. Net Metering Cap Adjustment

Although we agree with the IPA that it is unlikely that the NEM cap is hit before fall of 2019, if measured by installed systems we think it is possible that systems enough systems will have applied to the ABI Program and been accepted to reach the NEM cap once they are all completed. This will put many systems in the position where their REC prices were set before the NEM cap was hit, but net metering is no longer available to them when their systems are energized.

We recommend that the systems that fall into this middle area be granted the higher of the following two REC prices: REC pricing on their original contract or REC pricing after the NEM Cap and DG Rebate changes have been applied. Having surety on this issue before the cap is hit will give more clarity in the market and protect consumers down the road when the cap is hit.

6.9 Approved Vendors

CSG appreciates the Agency's approach to Approved Vendors especially the flexibility of business models and approaches allowed. We agree in general with the role and this section as it is outlined in the Draft Plan, but we have suggestions to improve this role on several parts of this section.

Vendor Application before Program Opens

We support the agency's decision to open up the application process for Preferred Vendors before the program opens. We think that 2 months will be sufficient time for the application process to take place. However, given the complexity of this role and the responsibility that comes with it we suggest the IPA considers some sort of comment or stakeholder process on this procedure. We feel it will help alleviate issues down the road and make the program opening operate much smoother.

Suggested Language:

"The Agency intends to open the registration and training process for Approved Vendors approximately two months prior to the opening of programs. The IPA will hold a public comment period or workshop involving the Program Administrator on the Approved Vendor approval and registration process."

Annual Approval for Vendors

We support annual approval renewal for Approved Vendors.

REC Delivery Risk

We understand that the IPA's influence in this program, although very substantial, has to work through the mechanisms that are allowed to them. One of the main methods of enforcing the rules of the ABI Program is through the contract with Approved Vendors and the utilities. Because of this the program rules put a lot of onus on the Approved Vendors to enforce the program rules with their system owners and installers. This can be an efficient and effective method of administering the ABI, but there are some elements of this role that fall outside of the control of the Approved Vendor. This creates risk that the Vendor's need the ability to mitigate. **The biggest risk the Vendor is taking on is the need to continue to deliver RECs long after system owners have been paid for their production. Mitigating, limiting, or transferring this risk to the parties that have control over the system's performance is one of the most important aspects of the success of this program.**

We agree that the Approved Vendor is the correct party to be contractually responsible for ensuring REC delivery throughout the life of the contract. We simply want to ensure that Vendors have the tools necessary to enforce contracts between system owners and the Vendor to make sure that the RECs are available to the Vendor so they can be delivered to the utility. CSG has many ideas and suggestions proposed throughout our comments to help alleviate these risks and reduce the cost of the role played by Approved Vendors. Below are our suggestions to the IPA on this topic.

Collateral Cap

We explain this point further in a later section, but it is important enough to restate in this section. It is important for there to be a limitation on the liability that the Vendor is taking on when signing the contract with the utility. The easiest and most efficient way to do this is to cap the collateral for each system at the 10% that is required under the Draft Plan.

Adding Other Roles Under the Contract in Addition to the Vendor

The consumer protection section of the Draft Plan states "Requiring clear and consistent information on the relationship between the end customer, the installer/developer, and the Approved Vendor is critical to ensuring that the fiscal risks and controls of this program are properly and prudently managed." The distinction drawn in this section between developer/installer and Approved Vendor is a critical one. One way to transfer the REC delivery risk is to reassign some of the responsibilities under the contract from the vendor, to the "Installer/Developer" and the "End Customer" (System Owner).

These distinct roles are especially important for smaller installers and non-vertically integrated companies. For instance, if an installer uses a REC aggregator to manage their customers' systems' RECs, that aggregator is not actually involved in the building of the system in any way, and it is difficult for the aggregator to ensure the warranty on the physical system over the lifetime of the contract.

Recommended Split:

Approved REC Vendor

1. REC Delivery Responsibilities:
    a. Sign REC Contract
    b. Register systems in tracking system
    c. Deliver RECs
    d. Submit Annual Reports
    e. Collect and pay fees to get into ABI
2. Disclose to the Agency names and other information on installers and projects, while otherwise maintaining confidentiality of information.
3. Facilitate the transfer of documents from installer/developer to Program Administrator.

Installer/Developer

1. Installation Marketing and Quality:
    a. Document that all installers and other subcontractors comply with applicable local, state, and federal laws and regulations, including for example, maintaining Distributed Generation Installer Certification (this can be facilitated by the Vendor)
    b. Provide samples of any marketing materials or content used by the Approved Vendor, and/or their subcontractors/installers and affiliates, to the Agency for review, as requested (this can be facilitated by the Vendor)
    c. Provide warranty and ensure performance of system

System Owner

1. Submit Meter Readings to the Approved Vendor
2. Maintain regular operation of system and perform maintenance not due to faulty equipment or installation; seek and pay for repair of system when in disrepair in a timely fashion

Failure to comply with #1 or #2 would result in the loss of collateral and refund of previously paid REC funds.

We also understand that the Agency and or utility may not be able to directly contract with system owners or installers or include them directly in the contract. If this is the case we simply suggest that the Agency explicitly allow the Vendor to indemnify themselves from the risks created by failures on the part of a system owner or installer/developer that were out of the Vendor's control.

6.10. Program Administrator

CSG fully supports the IPA's use and selection of a program administrator. This method and selection has been very beneficial in the past. From previous experience working with Program Administrators in the REC procurement process we have a few suggestions that may help reduce administrative burden and make the program run more efficiently.

BETA Access to Vendor Portal

We anticipate that the document transfer between Approved Vendors and the Program Administrator will have several parallels with the process used in the DG and SPV procurements where Bidders identified systems to the Program Administrator. Although overall this process worked very well, there were a few issues with the formatting of documents and system information transfer that added to the administrative workload of all parties. Because of this we suggest to the Agency allows for earlier contact between the Program Administrator and the Vendors to comment on and streamline the process. This could be in the form of BETA access to the Administrator's portal, screenshots of the portal, sample Excel files, or other similar process. We believe that this engagement would increase the program's efficiency and reduce the administrative cost for all parties.

Suggested Language:

"Establishing an online portal for Approved Vendors to submit projects (and providing technical support to Approved Vendors) and collecting application fees. To the extent that it is possible, some or all current Approved Vendors will be granted BETA access to the portal, or given screenshots early in the development process to give feedback to the Approved Vendor on the administrative process of the necessary system identification and document transfer."

Block Status Dashboard

CSG suggests that the Block Status Dashboard maintained by the Program Administrator includes distinctions between capacity that has applied to the program, been approved, and been energized. There could be large jumps in allocated capacity after ICC approvals and this detail will be helpful to maintain continuity in the market.

Suggested Language:

"Maintaining an online dashboard to show block status. This dashboard will show block status broken down by capacity pending approval, approved, and energized"

6.11. Program Launch

CSG fully supports the IPA's decision to open the application process for Approved Vendors before the general opening of the program.

6.12.1. Technical System Detail

CSG strongly agrees that stringent system requirements are necessary to preclude speculative systems, however some requirements listed in the Draft Plan ineffective at precluding speculative systems and excessively costly and time consuming. CSG recommends eliminating the requirements listed below to increase administrative efficiency without decreasing the likelihood of precluding speculative systems.

Suggested Changes

- Number (quantity) of panels, and inverters, wattage of panels. array location (roof or ground mount), tilt, orientation, and shading percentage: most of this additional information is necessary for PJM-EIS GATS approval and will be readily available at no additional cost.

- Single-line or three-line diagrams: this is included in the Interconnection Application where needed anyway. This increases paperwork and soft costs, but does not help to ensure that the array will actually be installed.

- Net metering application approval letter (if applicable): This is redundant with interconnection approval or other comparable document.

- Site Map: This can easily be provided for systems that will not be built, and is an extra document to be created and transferred to and evaluated by the Administrator.

- Shading study: This is expensive and many smaller installers do not have the ability to provide one. We do not think it is necessary for any size project, but certainly not needed for systems under 25kw. Additionally, it does not help to ensure the project will be built - it is just extra paperwork.

Suggested Language:

"The technical system requirements are:

- *Information about the system location, and size, including but not limited to:*
  - ~~*Single-line or three-line diagrams*~~
  - *A description of the technical specifications of the main system components, including the make, and model, number (quantity) of panels, and inverters, wattage of panels. array location (roof or ground mount), tilt, orientation, and shading percentage.*
  - ~~*Site map or other project details*~~
- *Proof of site control and/or host acknowledgement*
- *Estimate of annual production using PV Watts or a similar tool*
- *For systems over 25 kW, a signed Interconnection Agreement*
- *For systems over 25 kW, evidence of having obtained all non-ministerial permits.*
- ~~*Shading study*~~

For systems that have been energized prior to application, the following information will also be required:

- *GATS or M-RETS approval including unit ID*
- *Certificate of Completion of Interconnection or comparable document*
- ~~*Net metering application approval letter (if applicable)*~~
- *Photographic documentation of the installation"*

6.12.2 Metering Requirements

CSG supports the metering requirements listed in the Draft Plan. They have been effective and not overly burdensome on installers or system owners. We also support the IPA's decision to allow for meter readings as infrequently as annually.

6.13. Customer Information Requirements/Consumer Protections

CSG agrees that effective consumer protection requirements are vital for the success of the program. We support the consumer protections that the IPA has in place with the following clarifications and recommendations.

System Size Cutoff

In regards to the agency's request at the end of this section we recommend that systems over 100kW do not require the same consumer protections as smaller systems. Systems in this size range require a large financial investment and the associated contracts are generally reviewed by legal counsel.

Contracts

To minimize administrative workload and increase timing and efficiency we recommend that the IPA provide a list of items that need to be covered in contract and an example contract instead of requiring that an approved contract is used. This method was used for Letters of Intent for the SPV and DG procurements and worked very well.

Suggested Language:

"A copy of the contract for the power purchase agreement, lease, or sale and a list of contract requirements will be provided by the Agency. Vendors may use model leases and model power purchase agreements ("PPAs") provided by the Solar Energy Industries Association ("SEIA")289, or other standard contracts that have been approved by the Agency, or any other contract that meets the stipulations provided by the Agency."

Disclosure Form

CSG understands the need for a disclosure form to be provided to the system owner. However, we would like to clarify and suggest that there is no requirement for a copy of this disclosure form to be provided to the Agency or Administrator for each system. It should simply be a contract requirement for the Vendor that such a contract was provided to each system owner.

6.13.2. Monitoring of Consumer Complaints

CSG is in favor of the Program Administrator monitoring consumer complaints. We request an appeals process for Preferred Vendors, Developers, and Installers be created as part of this process.

6.14.1. Batches

CSG supports the Draft Plan's method of batching systems. This sounds very similar to the approach used for the SPV and DG procurements. This system was effective and easy to navigate. We also support that the REC pricing given to a system is based on when the system is submitted to the Program Administrator.

We also agree that vendors with high failure rates should need to submit extra information when submitting systems or blocks. We would like to add in the stipulation that if the high failure rate is due to a particular installer or developer, and not the vendor, then the extra information is only required from systems developed by the installer or developer with the high failure rate. This extra information should be required even if that installer or developer uses a different Vendor to submit their systems.

We would also like to request that batches of systems can be a mix of systems in different size classes and in different service territories. This will allow for a more diverse variety of business models to serve as Vendors.

6.14.2. Systems Below 25kW

CSG understand the Agency's decision to not require systems under 25kW be energized when applying to a block. However, we noticed some problematic language in this section that may have unintended consequences. The Draft Plan states in regards to already energized systems, "but the Approved Vendor will have to assume the risk that the system may not meet the required terms and conditions and could be rejected and thus not be included in a contract for the purchase of the system's RECs. A system that is rejected could be resubmitted at a later date if the deficiencies are cured, but the Agency cautions that some deficiencies may be difficult or impossible to cure (particularly when related to ensuring consumer protections from the beginning of the project's life)."

This statement is problematic for a number of issues and we suggest that the Agency grants flexibility to previously installed systems whenever possible. We understand the Agency's desire to keep the rules consistent and protect consumers, but barring systems from participating in the ABI for failure to comply with requirements that were not yet outlined when they were built, could cause significant financial hardship for the system owners. In cases where systems that are already energized that otherwise qualify for the ABI are rejected for the reasons listed in the plan, the consumer protection provisions serve to actively harm consumers.

It is our understanding that there are many systems that have been installed or will be installed between June 1st, 2017 and implementation of the LTRRP that fully expect to participate in the the ABI Program. These systems cannot yet have a contract with an Approved Vendor as the process to become an Approved Vendor does not even exist yet. If these systems cannot participate they will not have very limited avenues to receive payment for the RECs they produce.

Because of these reasons we strongly recommend that the Agency shows leniency where possible with existing systems complying with the provisions of the LTRRP. We think that a designated period of time to bring these systems into compliance with all of the rules of the Plan would be sufficient to both protect system owners and ensure that the goals of the program are met.

6.14.3. Batch Size

CSG supports the IPA's decision to set block sizes at 100kW and the subsequent increase where applicable, except where noted below. We would like to further recommend that the IPA make the clarification that there is the flexibility to mix different size categories within individual batches.

Block Size in the 14 Day Period

In the 14 days following a block filling up there will be a rush to get systems in. This puts vendors that have already submitted 5 blocks of 100kW's at a distinct disadvantage and it could potentially result in some systems receiving a lower REC price. Because of this we would recommend that the in the 14 days following a block filling up Vendors only need 100kW of systems to submit a block to the program administrator.

Suggested Language:

“Each batch must contain at least 100 kW of proposed projects, and may be as large as 2 MW. A batch could contain a single 100 kW or larger project. In order to minimize contractual volume as the program expands, once an Approved Vendor has successfully submitted five batches, the minimum size of a batch for that Approved Vendor will increase to 250 kW, except for blocks submitted within the 14 day period following a block filling up.”

6.14.4. Batch Review

CSG supports the provisions in the batch review process.

6.14.5. Converting System Size to REC Quantities

CSG believes that using a more dynamic REC calculation, such as NREL’s PV Watts calculator, would lead to more optimal results for all parties. While previous procurements have utilized a standard capacity factor, the length of the contract increases the need for more accurate projections over the contract term.

There are several issues with fixed capacity factors with regards to accurately projecting RECs over the contract term.

Issues with a fixed capacity factor:

- Shading and/or suboptimal direction will lead to underperformance.
- Vendors who operate in the northern half of the state will be at a disadvantage and could have systems that generally underperform, leading to higher contract risk.
- Systems in the southern half of the state could be undercompensated.
- Data from current SREC procurements is already being corrected.

Benefits of a more dynamic REC projection:

- Systems are more likely to perform as contracted, lessening the likelihood of a collateral draw.
- Should average out with the same number of RECs procured by the utility, just more appropriately contracted on a system by system level.

That said, the Agency could use capacity factors for budget and quantity predictions, but a more dynamic projection would be best for actual contracts.

6.14.6. Batch Contract Approval

CSG supports the 10% collateral requirement for ABI systems. However, we would like to make a suggestion on the timing it is required.

We recommend that the IPA extend the 14 business day requirement. This is sufficient time to transfer cash for collateral, but it is not enough time to reliably get a letter of credit or amend a letter of credit amount. We suggest the IPA extend this timeline to at least 30 business days for Letters of Credit. We also would like to confirm that the cash collateral is held in a utility account and not in a state held fund. If the cash is held in a state fund, then the timing extension for the letter of credit is even more important.

"A collateral requirement equal to 10% of the total contract value will be required in the form of either cash or a letter of credit with the utility within 14 business days of Commission approval of the contract."

6.15.1. Development Timeline

We support the timelines set by the IPA. We also agree with that projects that are not completed on time should be allowed to resubmit, but should be counted like a new system in the currently open block.

6.15.2. Extensions

CSG supports all of the provisions in this section, but wishes to ask for clarification on two points. The first is to confirm that the $25/kW extension fee is refunded when project is energized. And the second: will the funds from this fee will be held in a state or an utility account?

6.15.3. Project Completion and Energization

6 Month Status Update

Systems under 25kW do not have same development hurdles as larger systems. The requirement for a 6 month status update on these systems just creates more administrative burden on Program Administrator and Vendor without passing on any useful information to the Agency or Administrator.

Suggested Language:

"The Approved Vendor will provide the Agency an update on each project over 25kW in nameplate capacity that is under development but not yet energized at least every six months and will inform the Agency of any significant changes to the system"

Information Required Upon Energization

We support the information required upon energization with the exception of the Net Metering Agreement. We explain this exception in the System Requirements Section. We would also request for there to be an option to upload the required documents directly to the Administrators Portal to the extent it is possible.

System Size that Changes Price Category

We agree with the Agency's decision to allow systems to resubmit into the program if the final system size difference pushes them to a different price bracket. We also understand the need to repay the application fee for these systems. However, we do not think that this instance should result in a forfeit of collateral. This would be unduly burdensome on the system owner or project developer.

Suggested Language:

"An Approved Vendor would have the option of canceling and resubmitting a system if the final size is larger than the proposed system in order to align the REC quantities. However, the resubmittal will be at the price of the Block open at the time, not the original submittal. A new application fee will be required because the Agency will need to review the system design which would be different from what was originally submitted (e.g., because of the change in system size). This would not result in the loss of collateral associated with the original system, instead the collateral would be transferred to cover the new contract for the system."

6.15.5. REC Delivery

CSG would like to request that the REC delivery obligations are averaged out over a period of time. The ability for utilities to draw on collateral annually is too frequent and does not allow for differences in weather year over year. Because of this we suggest the IPA change this period to three years.

Suggested Language:

“In the event of failure to remedy the RECs not being delivered , the utility may, at its discretion, call on the ongoing performance collateral it holds from the Approved Vendor if systems have under delivered on a three year rolling average.”

6.16. Ongoing Performance Requirements

We appreciate that REC delivery obligations be managed on a portfolio level. This is the best approach to ensure that deliveries are met and helps Vendors to mitigate the risk of underperforming systems. We would like ask for a few clarifications on how this section is defined.

We suggest that the IPA defines portfolio level to include all systems in all contracts held by a Vendor. This large pool helps to mitigate delivery risk.

We also suggest that the vintage or production year is kept open. This approach was taken in the Initial Forward Utility Scale Procurement and is necessary to hitting delivery targets that are fixed year over year. This is especially important as systems are likely to over-deliver in the early contract years and under-deliver in later contract years. Keeping this as open as possible it will greatly reduce the cost of administering these contracts and managing the delivery risk.

6.16.1. Credit Requirements

While CSG understands that some collateral is necessary to ensure the delivery of RECs required under the program, the uncapped performance requirement is very problematic for Approved Vendors. The credit requirement section gives the utility the option to draw on credit up to the system’s full contract value. This in combination with all of the delivery requirements for the Vendors and very little ability for the Vendor to recoup lost funds leave Vendors with little recourse for systems that underperform. Without including a cap on the amount of collateral needed for any individual system it could result in the negation of up-front REC payments. Some or all of the REC payments would need to be held by the Vendor and paid over time to ensure system owner’s continued to report meter reads for the duration of the contract. We do not believe that this is the situation that the legislation was intended to create, but for small system owners and system owners with bad credit, there will be few other options to ensure the delivery requirements are met.

In addition this provision could severely limit the businesses that could act as Vendors and would strongly favor large vertically integrated companies. For these reasons we urge the Agency to limit the collateral that can be drawn for any one system to 10% that is initially collected.

Suggested Language:

"Failure to deliver RECs will result in the utility drawing on the collateral to be compensated for undelivered RECs that were paid for. ~~After any such drawing the Approved Vendor will need to increase its collateral to bring it backup to the 10% of remaining value within 90 days. If the amount of collateral is insufficient to compensate the utility, the Approved Vendor will be required to make an additional payment to the utility for the remaining balance~~."

6.17. Annual Report

CSG recommends that the Agency allow for the option for the Approved Vendor to keep their annual report confidential. These reports will contain information that could be used by competitors and it could be detrimental to the Approved Vendors to have these reports made public.

Section 7- Community Renewable Generation Projects

7.3.1. Co-Location Standard

We commend the IPA for their approach to limiting co-location of community solar projects. We agree that limiting these to 2MW per location is the intent of the law and that the provisions in the Draft Plan serve to meet the legislative intent.

Conclusion

Carbon Solutions Group appreciates the opportunity to participate in this comment process. We would like thank the IPA again for their efforts in getting this program up and running. We are looking forward to more opportunities to participate as a stakeholder in this process and participate in the new market.

Sincerely,

Dylan DeBiasi
Carbon Solutions Group
1130 W Monroe
Chicago, IL 60607