

Building Science Innovator's Critique of Entergy New Orleans's 2015 Integrated Resource Plan

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Building Science Innovators [BSI] is submitting, for review by the New Orleans City Council, both a critique of Entergy New Orleans' [ENO] 2015 Draft Integrated Resource Plan [IRP] and recommendations designed to enhance both the result and process used to get that result. This document is the critique. Recommendations are in a separate document entitled *BSI's Recommendations for an IRP for ENO*.

Critique of the Key Assumptions and Conclusions of ENO's 2015 Draft IRP

BSI's critiques (in italics) follow each item of the IRP's core assumptions and conclusions (in bold).

- 1. ENO employed Aurora Software to model its current and future economic operating conditions. Although created by a third party, the software's input and conclusions were handled and presented to the IRP meetings by ENO personnel.**

*BSI was concerned about the limitations of this software, but is now ultimately more concerned about the quality of its application within this IRP.*¹

- Judging from the parts of the model unaccounted for, BSI suspected that the Aurora software lacked important features: Can it 1) do a risk analysis? or 2) model batteries, whether installed on the customer or utility side of the meter? However, following review of some published IRPs of other utilities² and an extensive conversation with Aurora's technical support³, BSI's concerns reversed. Risk analysis is a mature and significant feature (albeit slightly restricted for some clients⁴) of the software. Although, battery storage is not a trivial input in the latest version, after application of modest computer skills, battery storage can be modelled within Aurora.*
- BSI found multiple questions about the way the Aurora software was used in the IRP. Besides for not including batteries and no automated risk analysis, ENO 1) made the assumption that the soonest a new PV system could go on-line was 4 years after approval,⁵ 2) used a 25% capacity factor for PV instead of the 33% used by Tucson Electric Power, 3) assigned zero value to off-peak PV produced energy, and 4) combined the Combustion Turbine [CT] option with three other mixes of renewable energy; but did not do the same for the Combined Cycle Gas Turbines [CCGT]. Finally, ENO may have further discouraged appreciation of the PV choice by not publishing the graphic that showed how much better a PV system would be in the "Generation Shift" scenario.*

¹ One of BSI's principals holds a Ph.D. in mathematics from University of CA, Berkeley, and is an expert in mathematical modeling; he is also a RESNET-Certified Energy Rater Trainer.

² <https://www.tep.com/doc/planning/2014-TEP-IRP.pdf> Tucson Electric Power's 2014 IRP.

³ Personal Communication with Brian Mills, Market Research & Analysis, Lead, EPIS, Inc. 8/18/15.

⁴ http://pse.com/aboutpse/EnergySupply/Documents/IRP_2013_AppK.pdf Puget Sound Electric 2013 IRP.

⁵ http://www.entergy-louisiana.com/content/irp/2015_Louisiana_Draft_IRP.pdf.

- *BSI also notes that ENO's IRP, published as it was before the recent EPA Clean Power Plan announcement, could only conjecture that the Generation Shift option was a viable scenario, today however, economic biases against CO2 production is that much more likely and can be more surely depended upon to encourage more PV generation in future IRPs.*

2. ENO will have a 300 MW shortfall of peaking power within a few years and has concluded that this problem will be most economically resolved by building a new generating station.

Although, ENO evaluated six sets of generation options to meet the 300 MW shortfall (however based on the unrealistic generation capability of wind in or near New Orleans and the other two options that contain hybrid pairing with CT), BSI believes these three options stand out as the most realistic ones.

Option A. 300 MW Combustion Turbine [CT], to run on natural gas

Option B. 300 MW Combined-Cycle Gas Turbines set [CCGT], to run on natural gas

Option C. 1,200 MW Solar System, which did not include batteries.

While BSI agrees that it is time to shut down the Michoud Gas Powered Plant, BSI does not agree that building new generating stations is more economical than doing what ENO is already doing: that is, buying energy from MISO.

i) ENO has been purchasing power from MISO whenever it was cheaper.

BSI points out that, in the recent past, ENO has often purchased peaking power from MISO that Michoud could have provided, because it was more economical to do so.

ii) ENO did not "prove" its assertion that building a plant is cheaper than buying from MISO.

The IRP presenters did not dispute the fact that MISO power would be available and sufficient to meet ENO's needs, but argued that this option would be more expensive than building its own generator. Although this contention was supported by use of the Aurora software, it was not proven, partly because batteries were not included in the modeling.

iii) ENO did not consider using batteries to store cheaper, non-peaking MISO energy to provide power during peaking hours.

ENO personnel pointed out that the solar option was somewhat more undesirable than options A and B partly because the excess energy it would produce could not be reliably sold at a profit through MISO. BSI believes that this and one of the previous statements are somewhat in contradiction because one states that MISO's power is too expensive for ENO to buy, and the other says that MISO prices will be too low (to help justify the building of a solar power plant). This can only be explained by recognizing that the wholesale price of power is highly time-dependent. Given that fact, it is even more significant and perplexing that ENO refused to consider batteries in the IRP because batteries can potentially eliminate that problem.

iv) Batteries alone are all you need. No peaking plants are needed.

In fact, consider this quote:

“Utilities and energy project developers are now considering batteries as alternatives to traditional grid infrastructure, such as substation upgrades and natural gas-fired “peaker” power plants that only run a few days a year, according to industry executives who spoke at the Utility of the Future conference in Washington D.C. last week. Once the price of energy storage goes below US \$300 per kilowatt-hour, batteries could transform how power is delivered, they said.”⁶

*This assertion only assumes the economics of batteries when installed on the utility side of the meter; if installed on the consumer side, the economics greatly improves — sufficiently to allow \$400/kWh batteries — which were commonly available a year ago.⁷ Moreover, Tesla came out with the **Tesla Wall** within the past six months, which sells for \$300/kWh if under 100 kWh, and even cheaper if larger.*

3. **Since a few years after Hurricane Katrina, ENO’s Demand-Side Management [DSM] program has displaced around 2 MW of peak demand per year. It is projected to further reduce peak demand by another 40 MW in the next 20 years at a cost near \$1/W.⁸ DSM’s success at reducing the demand of its customers has been linear with ENO investment; that is, more demand reduction in the future can be expected to pay back at no better or poorer than the same \$/W as previous investments. Thus, ENO contends that into the future, its DSM activity cannot displace a 300 MW generation shortfall fast enough to substantially alleviate the need for installing more generating capacity. In other words, ENO does not believe that it can reduce the demand of its customers sufficiently or fast enough to avoid building a power plant.**

BSI contends that ENO’s conclusion is incorrect because ENO’s DSM is not sufficiently exploiting all opportunities to lower demand. Short descriptions of the categories of missing opportunities are presented here. Examples and further explanation of these categories are provided after the Critique section, i.e., within the Elaboration of Recommendations section.

Perhaps the biggest problem is the fact that ENO controls the DSM done on its behalf. Perhaps the second biggest problem is that the DSM plan was designed by out-of-state building scientists.

In addition to these two, ENO’s DSM program

- 1) underpays the consumer for energy-efficiency retrofits,*
- 2) does not exploit the full range of cost-effective retrofits,*
- 3) only awards success by “deemed savings” and provides no award for performance-assured savings — which can be much greater and have a lower cost per W of reduced demand,*
- 4) only promotes energy-efficiency by direct and shared investment in a building: this is too restrictive and impedes invention and market transformation,*

⁶ LaMonica, Martin. "Time to Swap Power Plants for Giant Batteries? Almost." *Spectrum.ieee.org*. IEEE, 10 June 2014. Web. 13 Aug. 2015. <<http://spectrum.ieee.org/energywise/energy/the-smarter-grid/time-to-swap-power-plants-for-giant-batteries>>.

⁷ <http://www.eeba.org/Data/Sites/1/conference/2014/presentations/Katz-Inverted-Demand-Compliant-Construction.pdf>

⁸ Graphics on pages 8 and 14 of the 2015 IRP Modeling Overview section assert that over the next 20 years, the DSM program is estimated to reduce around 40 MW of demand at a cost of around \$40 million.

- 5) *fails to address any of the 3, major, split-incentive problems, e.g., the tenant-landlord problem*
- 6) *ignores retrofits in existing buildings that save much energy by focusing upon much more economically-significant problems like moisture control or worker productivity,*
- 7) *takes no steps to repair or circumvent broken building codes; faulty DOE, EPA or FEMA decisions; short-sighted manufacturers' activities or industry standards that impede energy-efficiency,*
- 8) *fails to employ highly cost-effective retrofits that lower peak demand and raise kWh use,*
- 9) *fails to employ time-of-use pricing or any other kind of Demand Response (DR) which cause retail rates to reflect wholesale prices—these can be cheaper in \$/W than standard DSM programs,*
- 10) *restricts customers from selling the spinning reserve service to ENO or MISO,*
- 11) *restricts customers from selling the frequency regulation service to ENO or MISO,*
- 12) *restricts customers from selling electricity at near wholesale prices during peak times,*
- 13) *sets the demand charges on commercial and industrial customers far too low, and*
- 14) *provides no incentive to help customer's buildings have more reliable electricity by purchasing their own battery back-up power supply; moving toward such a situation will lower the need for utility reserve margins and placing more batteries in the system facilitates all of the above means of lowering demand and the costs of the utility.*

4. **At the last two IRP public meetings, BSI publicly pointed out that, although called a Demand Side Management program, like most DSM programs in the United States, ENO's DSM should be more accurately called an Energy Efficiency Program, because it really "buys" reduced kWh consumption instead of more directly buying reduced demand, i.e., measured in W. Nevertheless, such DSM programs are typically substantial and cost-effective from both the customer's and utility's points of view, even though load reduction only occurs as a by-product of pursuing energy efficiency. However, as is explained above in number 3, ENO's DSM does this at \$1/W, the best value as measured in dollars/W for money administered by ENO presented anywhere in the IRP.**

The reason for this disparity of names and meanings is a natural consequence of the challenging goals of customers, regulators and the utility. Since retail customers are the only entity ultimately paying for energy, in fact, residential customers' bills only depend upon time-of-use-independent energy consumption measured in kWh, and most DSM programs are at least partially financed by contributions from customers for installations into their buildings, most successful DSM plans must achieve substantial reduction in energy consumption to harvest substantial customer participation. However, the utility's desire to earn a profit from new electricity generator construction strongly depends upon its ability to convince the regulator of a projected shortfall in generation to meet demand and, thereafter, get approval to construct another generator. Generator size is measured in kW not kWh. The regulator, in trying to balance these goals, requires the utility to try to reduce demand but both the regulator and the utility find that selling reduced kW demand doesn't garner nearly as much customer participation as compared to selling reduced kWh consumption. Fortunately, this gambit works because there are a wealth of "energy-efficiency" measures that have great impact on demand, e.g., changing commercial lighting from fluorescent to LED.

5. **BSI agrees and extends a comment made by the Alliance for Affordable Energy that: unlike the poorly named DSM program reviewed in the IRP process, ENO actually has a pure demand-side**

management method but refused to discuss it in the IRP, use it or expand it. It has the potential to reduce demand at lower \$/W costs.

BSI believes that unlike ENO's DSM plan, a process focused upon demand response [DR] will reduce demand at less than \$1/W, i.e., lower than ENO's current process. DR is growing in popularity and effectiveness among utilities in the United States. DR can be done with a variety of tools. One of which, real-time pricing, is so popular in New York that customers actually pay ComEd to get access to it.

*This issue was brought up by the Alliance for Affordable Energy's Executive Director, Casey DeMoss, in a public statement period at the end of the last public meeting. Her paraphrased statement effectively said: **Although ENO provides interruptible rates (allowing the utility to temporarily turn off service and thereby reduce demand) to its industrial customers, and some of such customers avail themselves of the discount this rate provides, ENO has never interrupted these customers' electricity supply.** ENO's IRP does not consider the potential of reducing the need for peaking plants with this already-in-place, real-time, demand-side management mechanism. Neither has ENO's IRP examined the potential effect of encouraging more of its customer base to accept this kind of service or, for that matter, any other kind of Demand Response [DR] program.*

To compare the cost-effectiveness of this means of demand side management to typical energy efficiency programs note:

- *The most recent head of the Federal Energy Regulatory Commission [FERC], Jon Wellinghoff, resigned his appointment and took up the business of promoting Demand Response full time.*
- *"Despite barriers to widespread participation in demand response programs, the FERC's 2012 State of the Markets Report notes a substantial increase in capacity enrolled in demand response programs, rising from 3 gigawatts (GW) of capacity in 2007 to 12 GW in 2012. The report states that demand response programs are becoming an increasingly important resource for grid operators during periods of system stress."⁹*
- *"Most electricity customers see electricity rates that are based on average electricity costs and bear little relation to the true production costs of electricity as they vary over time. Demand response is a tariff or program established to motivate changes in electric use by end-use customers in response to changes in the price of electricity over time, or to give incentive payments designed to induce lower electricity use at times of high market prices or when grid reliability is jeopardized. • Price-based demand response such as real-time pricing (RTP), critical-peak pricing (CPP) and time-of-use (TOU) tariffs, give customers time-varying rates that reflect the value and cost of electricity in different time periods. Armed with this information, customers tend to use less electricity at times when electricity prices are high. • Incentive-based demand response programs pay participating customers to reduce their loads at times requested by the program sponsor, triggered either by a grid reliability problem or high electricity prices."¹⁰*

⁹ "Best Practices: Demand Response." *Research Reports*. Energy Research Council, n.d. Web. 13 Aug. 2015. <<http://energyresearchcouncil.com/best-practices-demand-response.html>>.

¹⁰ United States. Cong. House. U.S. Department of Energy. *Benefits of Demand Response in Electricity Markets and Recommendations for Achieving Them*. 109th Cong. Washington: GPO, 2006. Print.

6. BSI asserts that rooftop solar has displaced 9 MW of demand, i.e., more than half of that effected by ENO's DSM process and did this at no cost to ENO or to any but a few of its rate-payers. Moreover, both the number of installations and the effect of each installation on peak demand can be very cost-effectively and significantly enhanced. Therefore building a solar plant comparable to Option C could be similarly inexpensive and does not need to be nearly as big as ENO contends.

Although an ENO presenter said New Orleans has 30 MW of PV, "Shining Cities 2015" reported 36 MW.¹¹ Given that ENO believes that only 25% of the output of a solar system displaces peak power, 9 MW is used.

However, the actual amount of peak power displaced by a PV system depends upon how batteries are integrated into these systems—as is shown in the Solar City graphic within the comments regarding the 14th assertion, the peaking power displaced is typically around 150% of the solar array size. Compare that to 25% demand reduction ENO assigns to a PV system without batteries!

BSI believes that the 36 MW of PV installations realized in New Orleans occurred despite the fact that about 90% of New Orleans buildings' owners and occupants consider themselves ineligible.¹² There would have been much more residential solar if there were no solar siting issues associated with

- i) shading trees,*
- ii) inappropriate roofs,*
- iii) aesthetic concerns,*
- iv) the Central Business District—where electricity may not run backwards,*
- v) tenant-landlord situations, or*
- vi) capital accumulation which was hampered because of recovery from Katrina early on and recovery from the 2008-2009 recession during the second half.*

BSI notes that 36 MW of rooftop solar implies that the number of installations is around 2%-4% of the number of residences in New Orleans. BSI argues that, if we can avoid the above barriers, New Orleans could easily have ten times as much installed PV.

Solar farms and other creative solutions to these problems have, by-in-large, not been significantly explored in New Orleans; however, looking to other cities and states — many solutions have been employed; such programs described in the Shining Cities 2015 reference given above. And that ignores the push from demand charges. Commercial customers would be much more interested in installing PV integrated with batteries if the demand charge was much closer to the real cost of new peaking plants, i.e., which should be around \$25 kW/month¹³; instead of the paltry demand charge of \$3/KW/month currently set within ENO commercial rates. In fact, a reason Solar City doesn't do business in our marketplace is precisely because of Entergy's unrealistically low demand charges. Moreover, in the

¹¹ Burr, Judee, Lindsay Hallock, and Rob Sargent. *Shining Cities: Harnessing the Benefits of Solar Energy in America*. N.p.: Environment America, 2015. Print.

¹² Design Decisions for Utility-Sponsored Community Solar, <http://innovation.luskin.ucla.edu/content/guide-design-decisions-utility-sponsored-community-solar>, May, 2015. 75% is sited in this report, but New Orleans has two more, significant impediments.

¹³ According to Steven Fenrick, chief economist at Power Systems Engineering; Personal communication 2014

current utility paradigm, the utility has nothing to gain to help solve these problems. However, BSI has come up with additional solutions for these problems as well.

7. **ENO decided that 1.2 GW of Solar is an appropriate “match” for the 300 MW available from either Option A or Option B by presuming a 25% capacity factor [CF]. That is, because solar power is a non-dispatchable electricity producer, it cannot be throttled like a gas plant and therefore will not, on average, produce power at times only coincident with the times of near peak demand even though a large percentage of its output occurs at such times. ENO assigned this 25% CF in order to account for this problem so that Option A and Option B can be effectively compared to Option C.**

A substantial part of the remaining 75% of the time, the solar plant can be expected to produce energy and power; however, ENO claims that this power has negligible economic value to ENO. BSI challenges this claim; see critique of assertion 2.

Moreover, the recent EPA rule 111d – Clean Power Plan provides the opportunity to trade pollution credits between utilities. This trade is not based upon kW of generator size but instead upon kWh of production. Therefore a PV plant’s off peak production would be very valuable indeed.¹⁴

8. **Options A, B and C were compared in four feasible economic scenarios.**

9. **ENO’s IRP data shows that CCGT, i.e., Option B, was calculated to be the most favorable in every scenario except the most extreme case, (called the Generation Shift scenario) where multiple price supports for solar and against fossil fuels were aggregated: these include continuing tax subsidies for solar construction and new carbon taxes are imposed—in that scenario, Solar, i.e., Option C was calculated to be most favorable.**

BSI finds fault in the timing of when these plants could be brought on line and begin generating electricity. In the model, none of the three options begin contributing energy until 2019. It can be presumed that a 300 MW plant (either CT or CCGT) could take as long as three years to complete construction. However, a solar plant, such as that in option C, could be installed and brought on line sooner and begin reducing the 300 MW power gap faster than options A or B.

10. **In every scenario, each of the power supply options were further analyzed by component costs: e.g., construction costs, fuel costs, etc. The solar option, i.e., Option C, had the lowest costs in every category except for construction within every scenario where it showed the highest cost. This means that if the solar option had substantially lower capital costs it would have been recognized as the best option for every scenario.**

ENO calls capital costs for new investments: “Non-Fuel Fixed Costs of Incremental Additions” on page 14 of [the Modeling Overview Section](#). It shows that the solar plant is projected to cost around \$1.6B or

¹⁴ <http://www.epa.gov/airquality/cpp/fs-cpp-overview.pdf>

\$1.25/W but this is not even that good of a deal since ENO projects that only 25% of this capacity is really useful; so the “real cost”/W is four times that, or \$5/W.

Although given out of order, this assertion supports the first asserted deficiency of ENO’s DSM plan. Given that solar power generation costs around \$5/W (according to ENO’s figures), why is ENO only willing to buy DSM at \$1/W?

11. **ENO’s IRP assumed or calculated that any power or energy produced by the 1.2 GW solar plant in excess of the 300 MW needed for peaking power would be modelled by the Aurora software to have negligible economic value because it would not contribute to the peaking needs of ENO and could not be reliably sold to MISO at profitable prices or economically employed within Entergy. This means that ENO personnel may have biased the calculation against the solar option by discounting the value of its off-peak power production.**

As already stated as a critique of ENO’s assertion 2 that it needs to build a 300 MW generator to meet a shortfall of supply to meet demand, ENO finds that buying from MISO is too expensive at peak times of the day but available prices for sales to MISO will be too low outside of peak demand times.

12. **Despite BSI’s open and repeated assertions at almost all of the public IRP meetings that batteries should be included in the IRP and the best place to install them is on the customers’ side of the meter (this comment was also made at the first public IRP meeting), ENO did not consider employing batteries in the IRP at all: neither on the consumer side of the meter nor on the utility side.**

BSI published Inverted Demand Compliant Construction [IDCC] as a talk at the national conference of EEBA in September, 2014.¹⁵ Clearly, that talk’s contents and assertions were well known to BSI before the beginning of ENO’s 2015 IRP cycle, which began in June 2014. IDCC recommends the installation of batteries in all buildings and shows that the recommended battery-back-up, power supply system will pay for itself better than a PV system as long as most of the economic activities and problems of consumers and the utility are utilized. Among the many assets, Inverted Demand completely removes all demand of a building during peak times.

13. **A few months before the end of the 2015 IRP process, ENO announced the construction of a 1 MW solar plant which will integrate batteries.**

BSI is not surprised that ENO decided to build an exploratory, 1 MW Solar plant with integrated batteries even though its own IRP ignores batteries. The efficacy of batteries is made abundantly clear by the adjacent

¹⁵ <http://www.eeba.org/Data/Sites/1/conference/2014/presentations/Katz-Inverted-Demand-Compliant-Construction.pdf>

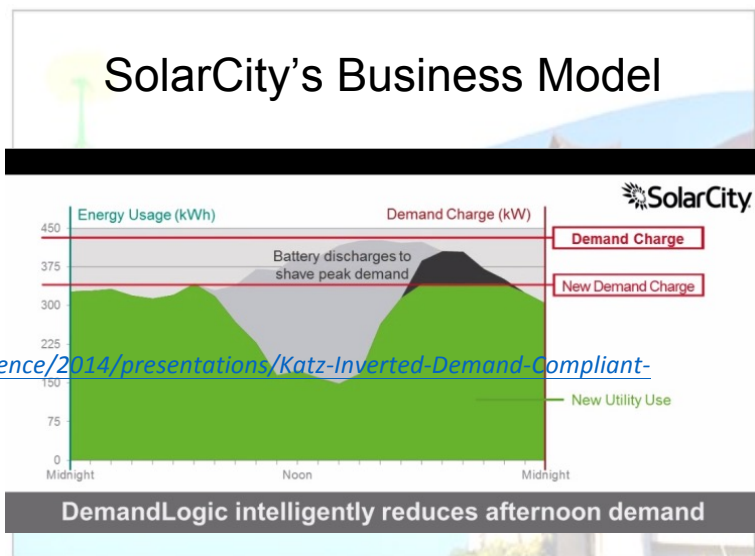


image taken from Solar City's website where it points out that a commercial building can economically avoid much of its demand charges by installing both solar and batteries because the combination allows battery charging in the late morning in order to offset the need for higher demand in the afternoon.

14. Without performing a calculated risk analysis, ENO concludes that, a 300 MW combustion turbine, CT, i.e., option A, is the best choice based upon risk. ENO was publicly informed regarding BSI's stated concern about the lack of a calculated risk analysis at the last public IRP meeting and more than a month earlier, at the 2nd-to-last public IRP meeting.

ENO, as a part of Entergy, has a special responsibility to do calculated risk analysis as much as or more than any utility in the US. This is the case because in the late 1970's and early 1980's Middle South Utilities (the former name of Entergy) was severely economically thwarted during the construction of the Waterford III nuclear powered electricity generator. Cost overruns effected a many-fold underestimate of the eventual price of construction of Waterford III. Among the unforeseen and not considered risks were: rising cost of capital and interest rates and great construction delays from increased regulation following the 3-Mile Island Disaster. Although these two planning issue oversights may have been forgivable and deemed within normal business practice, the mere question about whether it is more prudent to build a small number of large plants instead of a large number of small plants was never questioned. Literature on the last issue had been published before the mid 1970's. That literature asserted that the added reliability from a large number of small plants, shorter transmission lines, greater confidence that demand will rise to meet supply, and less need for extra power to meet a smaller reserve margin, provide more than enough ameliorating effects to balance the lower marginal cost of generation typically found in larger plants. Thus, ENO has no business doing any IRP work without doing a calculated risk analysis. Furthermore, BSI finds it grossly inappropriate for ENO to not do a risk analysis AND blithely assert that some unperformed risk analysis would pick option A despite the fact that the Aurora software never finds A the best choice for any scenario.

15. Implicitly, ENO and the New Orleans City council assert that the rate structure of ENO is as good as it should be in order to appropriately discourage increased demand at peak times. The current equipment for metering electricity consumption cannot be cost-effectively improved.

BSI contends that ENO's commercial demand charge is unreasonable too low — which therefore shifts costs onto other customers; since the largest set of customers are the residents, it is highly likely that this causes residential customers to subsidize commercial customers.

ENO's demand charges for commercial customers are as low as \$3/KW/month. Compare that to what is common in California; there it ranges from \$10 to \$23/KW/month. The lower value is only available to customers with a renewable energy system.¹⁶

Although some may think that California's commercial rates are unreasonably high, consider an assertion by Steven Fenrick of Power Systems Engineering, \$25/KW/month is a very good approximation of the true cost of peak power that should be allocated to commercial customers.¹⁷

¹⁶ Personal Communication with Brian Ward, energy consultant working for Solar City — August, 2015.

¹⁷ Personal Communication, Steven Fenrick, utility economist, Power Systems Engineering — March, 2014.

As stated below regarding process, the California Public Utilities Commission not only accepts public comments but pays intervenors for quality contributions to the rate-making process, and CPUC has been doing this for decades. Thus, it is highly likely that the CPUC has developed equitable rates, that is, rates that do not unfairly burden other rate classes.

Demand charges should be converted to Utility Peak Demand Charges. Utility Peak Demand for a building is the maximum measured KW consumption rate during any consecutive 15-minute period within the utility's 3 to 6 hour peak demand time of any day for a month of readings. This is only possible with smart meters.

BSI contends that ENO should be distributing smart meters to its customers and in particular, these meters should be able to measure electricity flows in both directions and report them at least once every five minutes.

Smart meters that make measurements every five minutes allow the utility and the customer to accurately track retail electricity consumption or sales of power produced by the customer with the needed temporal resolution sufficient to allow tracking of the time-varying price of wholesale electricity. MISO sells electricity within the wholesale marketplace with prices that vary every 5 minutes; this is called the 5-minute real-time price.

Over 50 million smart meters have been deployed in the US. The cost of purchase and installation of each smart meter is less than \$500.

Only by the use of smart meters can the City Council of New Orleans expect to meter "peak power" demand and consumption in a manner that is responsive to wholesale electricity price. ENO can only provide rates and subsidies explicitly focused upon Utility Peak demand side management, i.e., actually focused upon avoiding the utility's peak demand.

16. **ENO contends that community solar cannot be executed without placing an undue burden upon non-participants and, most particularly, on the low-income, non-participants.**

BSI contends that for almost all practical purposes and ways of perceiving this problem, ENO is wrong. However, assuming that this potentially real but very minor problem is deemed to be significant, a mechanism has already been implemented to over-compensate for this concern.

The following quote from a May 2015 publication implicitly defines Community Solar, presents arguments for it and outlines how it is financed and administered.

"Since 2010, residential solar installations have added more than 2,500 megawatts of clean energy- enough to power more than two million homes for a year. Yet nearly 75% of residential rooftop space is prohibited from participating in individual programs such as net metering due to structural constraints or ownership issues. Community solar aims to resolve this impediment, providing restricted residents access to solar in a virtual fashion. An administrating entity will cover the cost of installing a large solar array and recoup these

*costs by allowing co-investors to buy into the project. Co-investing participants then receive the benefits from their share's solar energy production. "*¹⁸

This same report points out that i) there are Community Solar [CS] programs in 19 states including Washington, D.C. and ii) D.C.'s CS regulation requires that instantaneous excess generation is not "stored for future use" by the owners of the CS, but instead is given to the low-income community. These last two clauses are decisions made by utility regulators based upon due consideration for the passing the non-participant test.¹⁹ The first indirectly asserts that in over 18 jurisdictions, the regulator decided that the costs thrown onto non-participants either didn't exist or was negligible. The second sentence states that in DC, the regulators decided that whether or not negligible, DC's regulators decided to provide a consideration for low-income people that would defeat this argument. For the average net-metering customer, less than 10% of the energy generated by a PV system goes to the grid. This 10% gift to the low-income community is small enough to keep from spoiling the economics for ratepayers who will buy into a CS system in order to gain virtual net-metering.

Although the report is focused upon Utility-Sponsored, Community Solar, the Utility does not wind up owning the solar plant; i.e., the solar plant does not wind up in the rate base, it is owned by the tens to hundreds of individual residents who finance their shares. Neither does the original sponsorship have to be a utility; the economics of CS is well enough explained to outline a plan for a private investor to sponsor and own the whole project. Moreover, since CS programs described in this report go all the way back to 2005, most of the currently existing CS projects have significantly higher capital costs than a new CS system owner would have to pay today; namely, about \$2.5 / W was the stated capital cost in the example given in the guide while ENO's IRP predicts that they could build their utility-scale PV power plants at half that price.

¹⁸ Design Decisions for Utility-Sponsored Community Solar, <http://innovation.luskin.ucla.edu/content/guide-design-decisions-utility-sponsored-community-solar>, May, 2015.

¹⁹ Ratepayer Impact Test (RIM). Originally known as the Non-Participant Test, RIM is also known as the "no losers test." The RIM tests from the viewpoint of a utility's customers as a whole, measuring distributional impacts of conservation programs. The test measures what happens to average price levels due to changes in utility revenues and operating costs caused by a program. A benefit/cost ratio less than 1.0 indicates the program will influence prices upward for all customers. For a program passing the TRC but failing the RIM, average prices will increase, resulting in higher energy service costs for customers not participating in the program. http://www.cadmusgroup.com/wp-content/uploads/2012/11/TRC_UCT-Paper_12DEC11.pdf; also see, https://beopt.nrel.gov/sites/beopt.nrel.gov/files/help/Ratepayer_Impact_Measure_Test.htm.