COLORADO PHOTOVOLTAIC SOLAR DEVELOPMENT CONSIDERATIONS

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Introduction[1]

This paper is designed to identify considerations relative to photovoltaic ("PV") [2] solar development in rural Colorado.

Economic circumstances bear significantly on potential PV opportunities. When we proposed this paper, we expected our focus would be on a particular development type -- larger (above 500 kilowatt ("kW")) applications structured around federal incentives and related credit. With the collapse of the credit markets in the fall of 2008, this model became far less practical. Therefore, we in part shifted focus and devoted less attention to this development type and related considerations (such as interconnection) and focused more on smaller applications, particularly applications we believe have a better near-term potential. Because of the significance of the credit crisis, we have generally outlined those effects on PV development.

Notwithstanding the effects of the credit crisis, the overall PV industry shows great promise, particularly given industry advances and continuing cost reductions. As we believe industry trends are worth noting, we have generally outlined those trends.

Notwithstanding the strong prospects for renewables, including PV, we also believe they are often oversold, and therefore have generally noted this observation.

As we (the authors of this paper) have experience related to wind development in rural Colorado and elsewhere, and as wind has a longer history than PV, we in part borrowed from these experiences and observations in determining what to address in this paper. One such observation is that the market is often not given due consideration. By example, there are dozens of wind developers in Colorado, and we estimate their +/- 15,000 megawatts ("MW") of projects are competing for a market of less than +/- 1500 MW of real, near-term opportunities. This necessarily means most of these projects will fail. Our hope is that Colorado PV projects will have a greater likelihood of success. Therefore, we devoted considerable attention to what we believe to be the potential market and market drivers for rural PV.

PV is not perfect, but neither is wind or conventional power. Because, we believe, informed decisions will yield better projects, we have identified certain advantages and disadvantages of PV, particularly considering rural Colorado applications.

Many PV development models are being pursued in Colorado and across the US. We have generally described some of these models, focusing on those that seem to best fit rural Colorado.

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[1] This paper is a resource, only. No part of this paper may be considered as accounting, investment, legal, tax or other advice, professional or otherwise. Anyone considering a solar project, in Colorado or elsewhere, should retain accounting, legal, and tax professionals, as well as other professionals experienced in the different facets of project development. Professional assistance is essential, and no part of this paper may be relied on as or substituted for such assistance. This paper includes numerous references to many concepts, resources, statutes, and websites. The authors assume and have no responsibility for any inaccurate, incomplete, incorrect, or outdated information set out in this paper. The resources referenced in this paper are subject to change at any time or become disabled or unavailable at any time. The authors and sponsors assume no responsibility related to these resources and no responsibility to update this paper. Further, the authors and sponsors in no way ensure or endorse any resource referenced in this paper and will have no responsibility with respect to any advice, information, program, or service referenced in this paper or provided by any resource referenced in this paper. The reader must evaluate all such resources. The authors especially thank John Cutler for the time he committed to this project. Without his research, this project would not have been possible.

[2] For a discussion of PV equipment and system components generally, see Appendix A.

As much of the background surrounding PV and possible enhancements is dense, we have covered these issues in Appendices A-D. We hope this allows for easier review, and still provides useful background.

As we have finished this project and made final edits, we have noted that it may be perceived as negative. This is a fair perception. However, the truth is that opportunities are not now great, and we believe it is more important to be objective than to suggest opportunities are better than now, actually exist. We also believe there is great value in providing "negative" information if that will cause a shift in focus to more appropriate projects, or cause the termination of a bad project. More appropriate projects and the elimination of bad projects will necessarily result in the development of better projects, that fit needs, and make economic sense. In all, this is best for the overall renewables industry and for rural Colorado.

<u>Effect of the current economic crisis on PV development</u>

Until the late summer, early fall of 2008, the renewables industry was robust, due in part to available credit.

With the collapse of the credit markets came a significant decline in PV development. Notwithstanding equipment availability (which, at times leading up to 2009 had been scarce), declining equipment costs, and ready power purchasers, capital to fund PV projects was significantly limited, if available.

Before the collapse, there were +/- 20 significant tax credit investors backing renewables projects, including PV projects.

After the collapse, more than 75% of the former go-to tax-credit investors were gone. And of those that remained, their tax liability was significantly reduced, resulting in a reduction of their tax-credit appetite.

Along with the reduction in the number of tax-credit investors and the reduction in the tax-credit appetite of those that remained came tightening of the debt markets. Lenders stopped lending. And those that were willing to lend had become more risk averse. Translation – capital for PV projects became more expensive.

In all, the credit markets came close to freezing. And to the extent they had not actually frozen, they had effectively done so by increasing the cost of capital by up to 600 basis points. So, to the extent capital was available to invest/lend, that capital was now too expensive.

The result – renewables projects died or stalled. And the most vulnerable were the largest projects, as these required the greatest amount of capital that was now in short supply.

It is impossible to forecast when the credit markets will improve. And it is further impossible to speculate as to the long-term importance of the credit markets to the viability of renewables deals, particularly PV deals.

Presumably, every project will take whatever benefit it can gain, such as a 30% investment tax credit. But there does come a point when tax credits are not necessary (which is, in fact, one of the aims of tax credits for the PV industry – to foster industry growth, stimulating competition, efficiencies, and technology and thus driving down cost). Unfortunately, we are not yet there, leaving us with an available (and certainly important, if not necessary) incentive that may be too difficult (or expensive) to use.

The aim of this paper is to identify factors to consider relative to PV project development, particularly in rural Colorado. The current state of the credit markets has to be a factor considered. The significance of this one factor may suggest that now is not the optimum time to pursue tax-credit models, especially tax-credit models involving larger developments.

When we first submitted our proposal for this paper to the Governor's Energy Office ("GEO"), we fully expected that tax-credit models would be a significant focus. Even after having started to prepare this paper, we hoped to see some signs of credit market recovery that would, in turn, mean expanded opportunities for tax-credit models. But instead of recovery signs, we continue to see uncertainty.

Trends suggest a good future for PV

While the current economic crisis has slowed PV development, PV's future appears bright.

PV is projected to grow at annual rates of 8% (commercial) to 25% (residential) for the next 21 years.[3] (The US PV market grew 33% in 2007 over 2006.[4]) According to a report from the Solar Energy Industries Association, total US capacity grew by 16% in 2008.[5] This represented an 81% increase in installed grid-tied PV in 2008 as compared to 2007, bringing total US installed grid-tied PV capacity to more than 1 gigawatt ("GW").

Worldwide PV installations reached a new high of 5.95 GW in 2008, a 110% percent increase over 2007. Europe accounted for 82% of world demand.[6] The PV industry generated $37.1 billion in global revenues in 2008, and PV developers raised over $12.5 billion in equity and debt, an 11% increase over the prior year.[7] The worldwide PV panel market is expected to increase dramatically in 2010, with an expected growth rate of 48%.[8]

Presumably, PV's future growth will be driven in part by decreasing PV costs. Decreasing PV costs are due largely to increasing efficiencies (i.e. more watts per module) and decreasing manufacturing costs (i.e. more modules for less money).

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[3] "Annual Energy Outlook 2009 with Projections to 2030"; Energy Information Administration Report DOE/EIA-0383(2009) at p.141.
[4] "2007 World PV Industry Report Hightlights," Solar Buzz; accessed at http://www.solarbuzz.com/Marketbuzz2007-intro.htm.
[5] "US Solar Industry; Year in Review 2008"; Solar Energy Industry Association at p.1.
[6] But note the number of European companies now descending on the US as the next, brightest (again, pardon the pun) solar market.
[7] "MarketBuzz 2009"; World PV Industry Report Summary; Solar Buzz; accessed at http://www.solarbuzz.com/Marketbuzz2009-intro.htm.
[8] "Solar panel market growth to slow in 2009, says analyst"; March 19, 2009; accessed at http://www.eetimes.com.

The recent boom revealed major bottlenecks in the silicon PV supply chain, which drove up PV prices. These higher prices caused massive investment in silicon production, and module prices dropped significantly, especially around the third quarter of 2008. US Manufacturers reported a 60% increase in module production in 2008 as compared to 2007.[9]

25 years ago, modules (the largest cost component of a PV system) cost $27/watt.[10] In 2008, this cost had dropped to as low as $4/watt.[11] And projections are that this cost may drop to $2.81/watt by 2016.[12] FirstSolar's[13] recent announcement that it had reduced its manufacturing costs below $1/watt[14] indicates these targets are achievable, and maybe understated.

While PV costs drop,[15] the cost of conventional power is expected to rise. Increasing worldwide demand on finite coal, natural gas, and uranium resources, as well as increased transport and plant capital costs, permitting hurdles, cap-and-trade costs, carbon taxes, .… all mean conventional power will cost more, especially if greenhouse gas policy is enacted.[16]

PV cost reductions and conventional power cost increases will converge at a point some refer to as "grid-parity" – the point in time when the cost of PV is the same as the cost of conventional power from the grid. Grid-parity timelines vary and depend on the region (and mostly the cost of conventional power for that region), the decline in the cost of PV, and the increase in the cost of the conventional power source.

There are projections of PV grid-parity as early as 2015.[17] In regions with a strong solar resource and high electricity costs (due, for instance, to a significant volume of electricity production from natural gas), grid-parity may come sooner. Southern California, for instance, will achieve grid-party before Colorado.

The date by which Colorado achieves grid-parity presumably will be further out, due primarily to the significant volume of coal in Colorado's system. But, as the cost of power produced from coal increases, and as PV costs decline, we should expect grid-parity in Colorado, as well.

After grid-parity, electricity consumers will have the option of offsetting some of the electricity they purchase from the grid for (what will presumably be, at least over time)

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[9] ***Id.*** at 5.
[10] "Photovoltaic Industry Statistics: Costs," Solar Buzz; accessed at http://www.solarbuzz.com/statscosts.htm.
[11] ***Id.***
[12] http://www.solarbuzz.com/ModulePrices.htm.
"Solar Module Price Highlights: May 2009," Solar Buzz; accessed at http://www.solarbuzz.com/moduleprices.htm.
[13] The world's largest module manufacturer.
[14] "First Solar Passes $1 Per Watt Industry Milestone" ; accessed at http://investor.firstsolar.com/phoenix.zhtml?c=201491&p=irol-newsArticle&ID=1259614&highlight=.
[15] *See* "Tracking the Sun; The Installed Cost of Photovoltaics in the U.S. from 1998-2007," Lawrence Berkeley National Laboratory; accessed at http://eetd.lbl.gov/ea/ems/reports/lbnl-1516e.pdf. (detailed review of PV-related cost decreases).
[16] *See e.g.* "Annual Energy Outlook 2009 with Projections to 2030"; Energy Information Administration Report DOE/EIA-0383(2009) at p. 53**.**
[17] "Solar Energy Industry Forecast: Perspectives on U.S. Solar Market Trajectory," US Department of Energy Solar Energy Technologies Program; accessed at http://www1.eere.energy.gov/solar/solar_america/pdfs/solar_market_evolution.pdf.

less-expensive power they produce. At the same time (if not earlier), utilities will have the option of meeting a portion of their load from PV.

When this point arrives, the number of PV installations could expand significantly. This expansion may present interesting opportunities for rural Colorado.

Limitations and oversale of renewables

All sources of renewable power present extraordinary, important opportunities. But, the benefits of renewables often overshadow the limits, and the promise of renewables seems to sometimes be exaggerated.

The truth is that (presently) renewables are expensive and depend on policy – tax credits, grants, and/or renewable portfolio standards ("RPS"). In most areas of the country, including Colorado, renewables cannot right now stand on their own as a viable economic enterprise without government incentives and mandates.

Unfortunately, a perception has been fostered that one kW of installed renewables capacity will displace one kW of conventional power capacity. This is not true, at least not yet.

One unfortunate effect of the oversale of renewables is the failure to identify appropriate markets for specific types of projects and the failure to match development models to existing circumstances (e.g. contractual relationships, economics, and infrastructure).

All of this does not mean renewables are not a viable and valuable resource. They already are, and they will continue to work better as costs come down, integration improves (possibly, through smart-grid options, forecasting improvements, and maybe also geographic resources diversity), and storage becomes feasible. Nevertheless, recognizing the limitations of renewables and the practical issues pertaining to generation and transmission of power from renewables are critical steps in considering development models for rural Colorado PV.

Colorado market drivers and the Colorado PV market, generally

Colorado's Renewable Energy Standard ("RPS") is the biggest driver of PV development in Colorado.

Colorado's RPS derives from Colorado's Constitutional Amendment 37 ("A37").

In November 2004, Colorado voters adopted Amendment 37 ("A37"). Generally, A37 required investor-owned utilities ("IOUs") serving more than 40,000 customers to generate or buy enough renewable energy (or renewable energy credits ("REC")) to meet 10% of their retail electricity sales. Until March 2007, all of Colorado's electric distribution cooperatives ("REA") were effectively excluded from A37.

In March 2007, House Bill 1281 became law. HB 1281 increased the renewable energy percentage requirement applicable to the IOUs and extended application of the RPS to the REAs and municipal utilities.[18]

Presently, Colorado's RPS requires the following renewables contributions:

For IOUs[19]

Percentage requirement of retail electricity sales	Year(s)
3%	2007
5%	2008-2010
10%	2011-2014
15%	2015-2019
20%	2020 and beyond

For REAs and municipal utilities[20]

Percentage requirement of retail electricity sales	Year(s)
1%	Years 2008-2010
3%	Years 2011-2014
6%	Years 2015-2019
10%	Years 2020 and beyond

Of the recognized renewable technologies from which Colorado utilities may source renewable energy, solar is the only technology for which a specific share of power generation is required.

Colorado's RPS requires that 4% of the renewable energy an IOU secures to meet its RPS come from solar electric technology. And of this 4%, one-half must come from customer-sited installations.[21]

Colorado's RPS does not require Colorado municipal utilities or REAs use any solar to meet their RPS obligation; however, as discussed below, incentives exist for REAs and municipal utilities to add PV to their systems.

Putting the IOU's PV requirement in context (such as, a context for evaluating market opportunities) requires, first, an understanding of the IOU's retail sales (as retail sales drive the IOU's gross renewable's requirement) which in turn drives their solar requirement.

In their 2009 RPS Compliance Plans, Public Service Company of Colorado ("PSCo") and Black Hills Energy ("Black Hills") (Colorado's two IOUs) estimated the solar RECs

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[18] Notably, the following focuses on analysis of the market drivers and the market related to PSCo, Black Hills, Tri-State Generation and Transmission, and the Colorado REAs. The following does not specifically address market drivers and/or conditions related to the various municipal utilities; however, hopefully the information below will provide some guidance relative to analyzing these opportunities.

[19] C.R.S. § 40-2-124(1)(c)(I).

[20] C.R.S. § 40-2-124(1)(c)(V).

[21] C.R.S. § 40-2-124 (1)(c)(II).

they will require through 2020 and 2019, respectively.[22] These figures are depicted in the tables below.

[22] PSCo 2009 RES Compliance Plan Table 4-1.

PSCo

Year	Estimated retail sales (in megawatt hours ("MWh"))	RPS Solar Requirement (in MWh)
2009	28,242,744	56,485
2010	29,312,756	58,626
2011	30,166,114	120,664
2012	30,967,265	123,869
2013	31,320,925	125,284
2014	31,546,194	126,185
2015	31,759,066	190,554
2016	32,143,892	192,863
2017	32,455,352	194,732
2018	32,781,065	196,686
2019	33,196,252	199,178
2020	33,637,545	269,100

Black Hills

Year	Estimated retail sales (in MWh)	RPS Solar Requirement (in MWh)
2009	1,940,893	3882
2010	1,994,246	3988
2011	2,065,239	8261
2012	2,116,993	8468
2013	2,165,836	8663
2014	2,217,137	8869
2015	2,267,918	13,608
2016	2,322,684	13,936
2017	2,374,029	14,244
2018	2,428,478	14,571
2019	2,483,239	14,899
2020	Not reported	Not reported

What will be required for the IOUs to meet their respective solar requirements varies, depending primarily on installed capacity (i.e. number of kW at the facility) and solar resource, particularly how often each facility will produce power at its rated capacity.[23]

For the sake of discussion, presume a one MW PV facility will produce electricity at its rated capacity 20% of the year.[24] From this, we can very generally calculate the MWh the facility will produce by multiplying the number of hours in a year (8760) times 20%, which equals 1752 MWh. This 20% may be generally referred to as the project's net capacity factor (or "NCF").

Applying these simplified rules to the IOUs' estimated solar requirements gives a general sense of the MW each IOU requires for each compliance year, as set forth in the tables below.

[23] Other factors will bear on this analysis, including actual production, PV equipment degradation and retiring of RECs.
[24] Solar panels are rated under ideal, laboratory conditions. In reality, there are cloudy and rainy days, nighttime and other factors contribute to actual output at less than ideal conditions.

Determining the IOUs' actual RPS solar requirement is not as simple as outlined above. A number of factors will bear on the requirement, some minimally, and some significantly.

Colorado Public Utilities Commission ("PUC") Rule 3654(f) states "[f]or purposes of compliance with the renewable energy standard, each kilowatt-hour of eligible energy generated in Colorado shall be counted as 1.25 kilowatt-hours of eligible energy." This 25% in-state REC bonus afforded domestic (i.e. within Colorado) generation will most significantly reduce the number of MW required. For instance, if all of the solar in an IOU's system is produced in-state (as is expected), then the hypothetical 1752 MWh produced by a single MW would (for RPS compliance purposes) increase to 2190 MWh. This would in turn reduce the number of MW required for each compliance year, as depicted in the fourth column in the tables above.

PSCo

Year	**RPS Solar Requirement (in MWh)**	**Estimated MW Requirement based on estimated 20% NCF**	**Estimated MW Requirement including 25% in-state bonus**
2009	56,485	32.24 MW	25.79 MW
2010	58,626	33.46 MW	26.77 MW
2011	120,664	68.87 MW	55.09 MW
2012	123,869	70.70 MW	56.56 MW
2013	125,284	71.50 MW	57.20 MW
2014	126,185	72.02 MW	57.61 MW
2015	190,554	108.76 MW	87.01 MW
2016	192,863	110.08 MW	88.06 MW
2017	194,732	111.14 MW	88.91 MW
2018	196,686	112.26 MW	89.81 MW
2019	199,178	113.68 MW	90.94 MW
2020	269,100	153.59 MW	122.87 MW

Black Hills

Year	**RPS Solar Requirement (in MWh)**	**Estimated MW Requirement (based on estimated 20% NCF)**	**Estimated MW Requirement (including 25% in-state bonus)**
2009	3882	2.21 MW	1.77 MW
2010	3988	2.27 MW	1.82 MW
2011	8261	4.71 MW	3.77 MW
2012	8468	4.83 MW	3.86 MW
2013	8663	4.94 MW	3.95 MW
2014	8869	5.06 MW	4.04 MW
2015	13,608	7.76 MW	6.21 MW
2016	13,936	7.95 MW	6.36 MW
2017	14,244	8.13 MW	6.50 MW
2018	14,571	8.31 MW	6.65 MW
2019	14,899	8.50 MW	6.80 MW

Acquisition of PV from a “community-based”[25] project would further reduce the number of MW required; however, at least presently it appears PSCo places little stock in this prospect, as its 2009 RPS Compliance Report lists no community-based bonus RECs through 2020.[26] Degradation of installed equipment and other factors will also bear on the number of installed MW required for a IOU to meet its solar requirement, but not in a significant way.

Looking at 2012 and 2015, it appears, these projections present little opportunity for rural PV development with PSCo. As one-half of the solar an IOU is required to add to its system must be customer-sited,[27] this leaves +/- 28 MW required for 2012 and +/- 43 MW required for 2015 PSCo RPS solar compliance purposes. Presumably, through its recently-closed January 9, 2009 RFP[28], PSCo secured sufficient PV opportunities to meet its requirements.[29]

Development opportunities with Black Hills appear to be similarly limited. As Black Hills' retail sales are much lower than PSCo's, its solar requirement is also much lower. And as PV projects have become bigger (in terms of installed MW), it could be that only one or a few projects would be necessary for Black Hills to meet its requirement.[30]

Opportunities with the REAs and/or Tri-State also are not extraordinary.

Tri-State is a generation and transmission provider. It has 44 REA member/owners. Of these, 18 are located in Colorado.

Tri-State's 2008 annual report[31] lists the 2008 retail sales for each of its members. The table below lists the REAs and their 2008 retail sales.

Colorado REAs	**2008 Retail Sales (in MWh)**
Delta Montrose Electric Association	626,646
Gunnison County Electric Association	123,593
Highline Electric Association	429,822
K.C. Electric Association	193,498
La Plata Electric Association	1,041,440
Morgan County Rural Electric Association	188,340
Mountain Parks Electric	295,122

[25] PUC Rule 3654(g) states “[f]or purposes of compliance with the renewable energy standard, each kilowatt-hour of eligible energy generated from a community-based project shall be counted as 1.5 kilowatt-hours of eligible energy.” PUC Rule 3652(c) defines “community-based project” to mean “a project located in Colorado and: (a) that is owned by individual residents of a community, a local nonprofit organization, a cooperative, a local government entity, or a tribal council; (b) whose generating capacity does not exceed thirty megawatts; and (c) for which there is a resolution of support adopted by the local governing body of each local jurisdiction in which the project is to be located.” As of the production of this paper, the issue of the meaning of this definition is before the PUC.

[26] PSCo 2009 RES Compliance Plan Table 4-4 p.9.

[27] PUC Rule 3654 (d) states “[o]f the eligible renewable energy amounts specified in rule 3654(a), each investor owned QRU shall derive at least four percent from solar electric generation technologies. At least one-half of this four percent shall be derived from on-site solar systems located at customers' facilities.”

[28] “Request for Non-Wind/Non-Dispatchable Resources.”

[29] In response to its January 2008 RFP for 25 MW of solar, PSCo had by April 2008 received 23 proposals totaling 400 MW. *See* 2009 PSCo Renewable Energy Standard Compliance Plan Volume 1 Section 5 pp.8-9.

[30] Notably, the town of Fowler, Colorado appears to be positioning itself to take advantage of any opportunities with Black Hills. *See* “Fowler looks at energy alternatives,” Fowler Tribune; accessed at http://www.fowlertribune.com/news/x289108759..

[31] *See* “Tri-State Generation and Transmission Association 2008 Annual Report” accessed at http://www.tristategt.org/Financials/documents/T-S-2008-annual-report.pdf.

Mountain View Electric	702,151
Poudre Valley Rural Electric Association	1,016,938
San Isabel Electric Association	377,006
San Luis Valley Rural Electric Cooperative	209,333
San Miguel Power Association	197,835
Sangre De Cristo Electric Association	103,766
Southeast Colorado Power Association	186,266
United Power	1,199,035
White River Electric Association	480,636
Y-W Electric Association	333,948
Total CO Tri-State Members	**7,705,375**

Based on the combined REAs' 2008 retail sales, we can generally determine a corresponding REAs/Tri-State renewables' requirement. This is shown in the table below.

Year	Estimated Energy Sales (in MWh)[32]	Renewables Requirement (in MWh)
2009	7,859,483	78,594.83
2010	8,016,672	80,166.67
2011	8,177,006	245,310.2
2012	8,340,546	250,216.4
2013	8,507,357	255,220.7
2014	8,677,504	260,325.1
2015	8,851,054	531,063.2
2016	9,028,075	541,684.5
2017	9,208,636	552,518.2
2018	9,392,809	563,568.5
2019	9,580,665	574,839.9
2020	9,772,279	977,227.9

Unlike with the IOUs, Tri-State and the REAs are not required to satisfy any part of their RPS requirement using solar. The potential for PV development with Tri-State and/or the REAs will therefore depend on other factors, such as contractual obligations, incentives, and project economics (the latter of which will include the economics of competing renewables technologies, like wind).

The potential for PV development with the REAs is limited by their contracts with Tri-State. The REAs have wholesale power contracts (often called "all-requirements contracts") with Tri-State. These contracts expire in 2040 (for two REAs) or 2050 (for 42 REAs) and require the REAs purchase 95% of their required electricity from Tri-State. The remaining 5% may come from generation owned or controlled by the REA.[33] These contracts limit the already-small market with the REAs by prohibiting self-generation or power purchase agreements (in excess of 5% of the REA's requirement) with independent power producers ("IPP"), such as a PV IPP.

[32] Based on 7,705,375 MWh sold by Colorado REAs in 2008, escalating 2% annually. From 2007 to 2008, Tri-State's members' sales increased 4.2%. *See* Tri-State 2008 Annual Report p.20. 2% annual escalation was inserted for the sake of a more conservative view and considering the recent economic downturn.
[33] *See* 2008 Tri-State Annual Report p.26.

The all-requirements contracts seem to present a dilemma for the REAs. How can they meet a 10% RPS and yet not violate their 5% cap on self-generation? If a solution were necessary (which presumes TriState does not satisfy some or all of the REAs' RPS obligations) PV presents a solution, albeit a self-limiting solution.

PUC Rule 3654(e)[34] allows REAs to triple count RECs the REA generates or causes to be generated "from solar electric generation technology" that started operating before July 1, 2015. Conceivably, 3654(e) allows REAs to meet their entire RPS requirement (10% of retail sales) by generating/securing 3.33% of their retail sales from PV. Hence the self-limiting aspect of PV opportunities with the REAs.

Even though PUC Rule 3654(e) is an attractive incentive, it is not without issues that require attention. Primarily, ambiguities in the rule may create uncertainty, which may create problems for financing or planning purposes. For instance, the rules do not expressly confirm that PV-generated electricity produced after July 1, 2015 at pre-cutoff facilities may be triple counted. Similarly, the rules do not address how REAs may treat modules replaced or upgraded at pre-cutoff facilities after July 1, 2015. Nor do the rules address how to treat expansion of pre-cutoff facilities. Some measure of certainty around these rules should enable further consideration of REA-based PV options.

Irrespective of the 3x REC incentive and any uncertainty regarding its application, whether the REAs will pursue PV (or any other renewables) is uncertain. Few REAs have participated in renewables projects to date. And for RPS compliance purposes, there is some indication that Tri-State will satisfy (at least some of) its members' RPS requirements. This is logical, especially considering Tri-State's resources and capabilities (particularly as compared to its members) and the all-requirements contracts. Based on these factors, it may be safe to presume Tri-State will assume responsibility for its members' RPS obligations. And Tri-State's actions/comments may bear this out.

In December 2007, Tri-State issued an RFP for renewables.[35] Part of the stated purpose of the RFP was to support Tri-State's Colorado and New Mexico members in meeting their RPS obligations.[36] In its 2008 annual report, Tri-State noted its expectation of announcing in the first quarter of 2009 its plans to move forward with one wind and one solar project, intended in part to help Tri-State's Colorado and New Mexico members meet their RPS requirements.

In March 2009, Tri-State announced its agreement with First Solar to build a 30 MW PV facility in New Mexico.[37] Presumably, the First Solar New Mexico project is the same

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[34] PUC Rule 3654(e) States: "For purposes of compliance with the renewable energy standard specified in rules 3654(b) and (c), for cooperative electric association QRUs and municipal QRUs, each kilowatt-hour of eligible energy generated from solar electric generation technology shall be counted as 3.0 kilowatt-hours of eligible energy, provided that the solar electric generation technology commenced producing electricity prior to July 1, 2015. For solar electric generation technology that commenced producing electricity on or after July 1, 2015, each kilowatt-hour of eligible energy generated from solar electric generation technology shall be counted as 1.0 kilowatt-hours of eligible energy for compliance purposes."

[35] Notably, the RFP required annual generation of no less than 15,000 MWh. *See* 2007 Tri-State Renewable Energy Supply RFP p.6 accessed at http://www.tristategt.org/rfp/Tri-State%202007%20Renewable%20RFP.pdf.

[36] *See* 2007 Tri-State Renewable Energy Supply RFP p.2.

[37] *See* **"**Tri-State and First Solar sign major development agreement 30-megawatt New Mexico solar facility among world's largest photovoltaic projects," Tri-State News Items, March 24, 2009 accessed at http://www.tristategt.org/NewsCenter/NewsItems/First-Solar-Cimmaron-I-announcement.cfm.

solar project referenced in Tri-State's 2008 annual report, suggesting Tri-State's near-term plan for Colorado is to move forward with a wind project. And depending on its size, this project alone could satisfy the REAs' RPS requirements for the near-term, or longer.

Overall, Tri-State's relationship with its REA members, its recent RFP, its 2008 annual report, and its recent award may give some insight in to Tri-State and REA PV opportunities.

- Tri-State's RFP expressly acknowledges its intent to help its members meet their RPS obligations. This may suggest limited opportunities with the REAs, which have yet to embark on significant renewables projects.
- Tri-State is a sophisticated organization ($2.5 billion in assets).[38] It has significant human and financial resources and significant experience negotiating power contracts. As compared to its members, it is in a better position to negotiate significant renewables contracts and to secure the best terms. This suggests that potential, significant PV opportunities would be negotiated with Tri-State, leaving small opportunities with the REAs.
- In its 2007 RFP, Tri-State set a floor for annual generation for projects bid of 15,000 MWh, suggesting +/- 8 MW of PV (presuming +/- 20% NCF) may be a good target size project for Tri-State. Also, Tri-State's RFP suggests that future awards may be competitively bid, which would increase the risk and cost of PV development directed at Tri-State.
- Tri-State's apparent decision to first participate in wind in Colorado and PV in New Mexico may suggest: (a) that for Tri-State and in Colorado, the (then-current) economics of wind were better than the (then-current) economics of PV; or, (b) the solar resource in New Mexico is sufficiently better than in Colorado. At the very least, Tri-State's apparent decision to pursue wind first in Colorado suggests wind (and not PV) was the more cost-effective option for TriState.

Overall, current market opportunities for rural Colorado with Tri-State and/or the REAs are uncertain. There is currently no solar obligation, and it is not clear where the opportunities lie. But, at least some opportunity exists, and these opportunities may be better than any near-term opportunities with PSCo or Black Hills.

Presumably, any current opportunities for larger developments will be with Tri-State (as demonstrated by Tri-State's New Mexico agreement with First Solar). These opportunities may improve over time (if and as the cost of PV declines and the cost of wind increases, both as discussed later in this paper). It appears that any smaller project opportunities may be with the REAs, and for reasons discussed later in this paper, now may be a good time to pursue these opportunities.

Thoughts on the Colorado PV export market

While the ability to export renewable power would certainly cement Colorado's place in the renewables' sector, and while export of renewables is a significant Colorado and national issue, export of Colorado-generated PV power seems relatively far off and therefore not worthy of consideration relative to near-term opportunities.

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[38] *See* 2007 Tri-State Renewable Energy Supply RFP p.8.

Wyoming is an example of a successful exporter of renewable power – namely wind power. Understanding how Wyoming is able to export its wind power suggests Colorado is not now positioned to export PV solar power.

Most of the wind energy Wyoming produces leaves the state. Wyoming is able to export this power because of its strong wind resource, transmission capability (whether available or to be constructed or upgraded), and willing offtakers.

The most significant of these factors is Wyoming's wind resource, which enables transmission and offtake opportunities.

With most renewables' projects, finance ultimately determines development. And for financiers to commit to a project, that project must deliver a certain minimum return. In the case of a wind project, that return requirement may range from 9 to 12%, or more. (In the case of PV projects, hurdle rates have been lower. Regardless, of two or more competing projects, the project that presents the best return potential will be the first built.)

Achieving a certain return threshold requires realizing a certain minimum revenue stream. Very generally, in the case of a renewables project revenue equals the amount of power sold (represented by the project's NCF) at a specified power price.

By example, assume an hypothetical 1 MW wind project. From the revenue standpoint, if this project has a 35% NCF this will allow the project owner to sell, at a levelized (levelized for the life of the power purchase agreement) price (say, $70/MWh), in any given year during the project's life, 3066 MWh. And for the sake of continuing this example, presume this level of production at this price allows the owner to achieve a 9% return.

In the case of renewables projects, NCF often has a disproportionately significant effect on return. A one point increase in NCF may increase returns by as much as one point. For instance, if the hypothetical 1 MW wind project returned 9% at 35% NCF, an increase in NCF to 36% would increase the return to 10% -- stated otherwise, a 2.8% increase in NCF could mean an 11% increase in return.

Back to Wyoming as an example of a successful exporter of renewable power, the wind resource is much richer than 35%, which is generally considered to be a good wind resource and that may exist in those states where Wyoming wind power is being shipped. However, a good Wyoming wind project will usually have an NCF in the range of 38 to as high as 45%. This richer resource means greater return potential. And this greater return potential means: a greater ability to transmit power over long distances (i.e. pay wheeling fees to move the power over a transmission provider's lines); a greater ability to construct transmission (i.e. to build or upgrade transmission to export the power to market); and, a greater ability to reduce the price at which power is sold (i.e. a greater ability to attract offtakers).

Unfortunately, the same likely is not true for Colorado PV export opportunities.

The Colorado solar resource is not better than that of those states that conceivably present export opportunities.[39] Arizona, California (southern California, specifically), New Mexico, and Nevada are generally regarded as having better solar resources than Colorado,[40][41] and these states present the most-attractive, conceivable export market, particularly due to their RPS requirements. And if the solar resource in these states is better, then the returns from projects located in these states will be higher, meaning that even without considering transmission (and the cost to build it and/or wheel power over it), projects in these states have a more likely opportunity to serve their native load than would projects in Colorado.

Regarding transmission, it is understood that there is no near term transmission opportunity in the case of what is regarded as the best Colorado PV resource area --- the San Luis Valley – if a transmission path from a solar resource area out state of exists anywhere.

In all, Wyoming's strong renewable resource and transmission capacity enable Wyoming's ability to export renewable power, while Colorado's lesser (relative to other areas) solar resource and absence of a transmission route out of state indicate no meaningful opportunity to move PV-generated electricity from Colorado out of state.

Even if we look beyond the biggest potential markets for PV-generated power of Arizona, California, and Nevada and look to our closer neighbors, we still likely will not find near-term opportunities.

All but two of Colorado's immediate neighbors lack an RPS (which are now the biggest drivers of renewables, including PV, development) -- Nebraska, Oklahoma, Utah, and Wyoming do not have a mandatory[42] RPS[43], much less an RPS that requires solar generation. New Mexico and Kansas are Colorado's only immediate neighbors with an RPS. And notably, New Mexico's RPS includes a significant solar carveout for its IOUs (the Kansas RPS does not include a solar carveout);[44] however, New Mexico's solar resource is as good if not better than Colorado's. This suggests that PV projects sited in New Mexico will realize greater returns than projects sited in Colorado and trying to serve New Mexico, irrespective of potential transmission and wheeling costs, which would further hamper moving Colorado-generated PV power to New Mexico.[45] The remaining southwestern states (Arizona, California, and Nevada) also have RPS legislation, but in these states, as well as in New Mexico, the resource is better than that of Colorado, limiting export potential.

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[39] Solar resource information is available from a variety of sources, such as: http://www.osti.gov/bridge/servlets/purl/10169141-YmPrJc/webviewable/10169141.pdf; http://firstlook.3tiergroup.com/.

[40] *See* "Comparison of Solar Power Potential by State," Official Nebraska Government Website accessed at http://www.neo.ne.gov/statshtml/201.htm.

[41] The fact of a better solar resource outside Colorado and within Arizona, California, New Mexico, and Nevada was anecdotally demonstrated by one consultant (who asked to remain anonymous) interviewed in connection with this paper who stated he was aware of 40,000 MW of solar projects being pursued in these four states.

[42] Note the distinction between a voluntary RPS or "goal" and a mandatory RPS like Colorado's.

[43] It is also worth noting that each of these states have rich wind resources. And given wind's current price advantage, greater power production, and greater power density, it seems as, if not more, likely that these states would pursue wind development before PV opportunities, particularly before PV opportunities based in Colorado.

[44] 20% of RPS requirement for IOUs *See* New Mexico Public Utilities & Utility Services Regulation §17.9.572.7.

[45] Maybe this is (partly) the reason for Tri-State's committing to purchase power from a 30 MW PV facility to be located in New Mexico.

Overall, export of Colorado-generated PV power may not now be the best focus for rural Colorado PV development. That said, policy development, resource planning, and renewables technology are dynamic. It is conceivable that a federal carbon tax or cap-and-trade system, a national RPS, improved transmission, and/or improved forecasting and resource planning would justify significant development of Colorado's rural PV solar potential based on export opportunities; however, these are big "ifs." Until one or more of these evolves, it seems Colorado's near-term focus relative to rural PV development should not be based on export potential.

PV solar advantages

As compared to other renewable resources, namely wind, PV has certain advantages.

Because it produces electricity when the sun is shining and when "peaking units" are most likely to be in use, PV should be able to offset the most-expensive conventional power sources.[46] Contrast wind, which tends to produce less electricity in the summer and during daylight hours.[47]

Also unlike wind, which depends on significant, new transmission for development of projects in the strongest resource areas, PV can be sited nearly anywhere, including on buildings and close to load. This means avoiding transmission costs (and the indeterminable delay associated with transmission buildout), as well as line losses that occur as electricity is moved over distances.

Also unlike wind, and as discussed above, PV installed costs continue to decline, while the installed costs of wind have steadily increased, and are projected to continue to increase.[48]

PV-related tax credits have greater certainty than wind. The Investment Tax Credit ("ITC")[49] can be captured up-front, while wind's Production Tax Credit ("PTC") depends on continued production. Further, the ITC has been extended until 2016, while the in-service deadline for the PTC is set to expire in 2012.[50] This longer-term extension should make planning and budgeting around PV projects simpler, and should mean greater cost certainty, as the various suppliers of PV-related equipment also will be better able to plan.

PV equipment warranties are usually longer-term than wind equipment warranties. PV inverter warranties may range from 10-15 years. Module warranties may be as long as

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[46] In its February 2009 report to the PUC titled " An Effective Load Carrying Capability Analysis for Estimating the Capacity Value of Solar Generation Resources on the Public Service Company of Colorado System" Xcel Energy Services, Inc. suggested amounts by which PV installed in the PSCo system should be considered relative to capacity reserves. This report may provide a sense of the value of PV relative to capacity reserves, particularly for the PSCo system, and may provide analogical information relative to the TriState or Black Hills systems.

[47] In Xcel's February 2009 report, it notes the poor correlation between Colorado wind generation and PSCo's peak load and the better correlation between Colorado solar generation and PSCo's peak load.

[48] *See* "Annual Report on U.S. Wind Power Installation, Cost, and Performance Trends: 2007," US Department of Energy, Energy Efficiency and Renewable Energy, May, 2008, at p. 21; accessed at http://www1.eere.energy.gov/windandhydro/pdfs/43025.pdf .

[49] Discussed in Appendix B.

[50] December 31, 2012 is the in-service deadline for the PTC for wind, however eligible taxpayers can claim the credit for 10 years. The in-service date for many other qualifying renewables is December 31, 2013. *See* "Renewable Electricity Production Tax Credit," Database of State Incentives for Renewables and Efficiency, accessed 6/3/09 at http://www.dsireusa.org/incentives/incentive.cfm?Inentive_Code=US13F&re=1&=1.

20 years. Contrast wind turbine generators, which may have less than a five-year warranty.[51]

Similarly, PV operations and maintenance costs are minimal. Unless tracking, PV includes no moving parts, reducing what may fail and therefore also what may require maintenance.

And for much of rural Colorado, PV enjoys a 3x REC multiplier.

The features outlined above make PV an attractive option, especially for rural Colorado, and especially for potential community development or ownership purposes.

Renewables supporters have advocated community ownership of wind. To date, approximately 8.5 MW of the over 1000 MW of wind installed in Colorado are community developed/owned. Wind is difficult to build and operate, policy has not driven community ownership[52], and economies of scale drive larger projects, all making community development and ownership of wind more difficult. PV, arguably, should be simpler to develop and operate and thus more appropriate for community development/ownership:

By example:[53]

- Financing for wind projects generally requires at least one year's wind data (with a minimum data collection and interpretation cost of +/- $50,000).
- Just the avian studies for wind projects may require 12-24 months of site surveys (and tens of thousands $$).
- Construction of a wind project will require large 300-600 ton cranes, which during peak demand periods have been in short supply.
- A cost-effective wind project (i.e. a project of sufficient size to realize economies of scale) will require considerable interconnection and transmission capacity – both of which are limited in Colorado.
- Rural communities do not require the volume of power that would be necessary to develop a cost-effective wind project.
- The REAs' all-requirements contracts limit the size project from which they can procure power, effectively prohibiting from REA consideration large-scale wind and its associated economies of scale.
- And thousands of MW of wind are already in development in Colorado, making for extraordinary competition.

PV has certain advantages over wind, and if PV costs continue to decline, while the costs of wind increase, PV options may become even more attractive.

PV solar disadvantages

PV shares certain disadvantages with wind – higher cost (to build) and intermittency (which, without storage or other advances, necessitates a firming resource).

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[51] "Wind Turbines: Designing with Maintenance in Mind," Hansen, Teresa; Power Engineering International; May 2007, accessed at http://pepei.pennnet.com/display_article/293559/6/ARCHI/none/none/1/Wind-Turbines:-Designing-With-Maintenance-in-Mind/.

[52] For instance, Colorado lacks a feed-in-tariff, and Colorado's 25% REC multiplier for "community-owned" projects has yet to stimulate community development and ownership.

[53] The following is based on discussions with various wind developers.

But PV costs more than wind (though this may be changing), produces less power (on a per-MW basis), and may be more prone to greater production fluctuations.

While a good Colorado wind project may have a 38% NCF, a good PV project may have a 20% NCF – almost 1/2 the production of a similarly-sized (i.e. same number of MW) wind project. To generate the same number of MWh, the size of the PV project must be increased. This is meaningful when considering payback or revenue, depending on the nature of the project. Further, understanding issues with the integration of wind is farther ahead than that of PV.[54]

Also, production fluctuations may be greater with PV than with wind. This is noteworthy relative to larger, utility-scale projects (that are intended to displace conventional power) and relative to commercial projects, particularly those associated with customers subject to demand charges.

A conventional power source delivers firm power -- there are no dips or peaks in production, and electricity is always available. The intermittent nature of renewables (e.g. PV and wind) causes large, long dips in production. In the case of PV, the greatest dip occurs at night, while the sun is not shining and thus there is no electricity production. When the sun is at its apex in the middle of the day, the project should produce at its maximum capacity.

But with all renewables, there may be dips within its production period. The greater the dips in production the greater the requirement for backup (dispatchable) power, which, to a utility purchaser, may mean additional cost to back up the project.

One report indicates the dips during the production period for certain PV projects were greater than those associated with certain wind projects, and further that unlike with wind it may not be possible to effectively overcome these dips through a geographically-diverse mix of projects.[55] If correct, then, in the case of the same size wind and PV projects, the PV project may require more dispatchable backup power and therefore effectively cost more to operate (or, the PV project will provide less in the way of capacity value). This is especially noteworthy in Colorado relative to utility-scale applications given the volume of coal-fired generation[56] (i.e. not dispatchable power), especially within the Tri-State system.

Production fluctuations are also noteworthy relative to consumers who pay demand charges (typically, commercial applications). In Colorado, demand charges are generally based on a consumer's greatest demand during a certain period (for instance, any 15 minutes) of a given month. Notwithstanding Colorado's 300 sunny days per year, it is unlikely that for every 15-minute-period in a given month, PV will limit demand from the grid. One instance of cloud cover could eliminate PV production, require consumption of

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54 See Quantifying Avoided Fuel Use and Emissions from Solar Photovoltaic Generation in the Western United States accessed at http://pubs.acs.org/doi/pdfplus/10.1021/es801216y?cookieSet=1
55 See The Character of Power Output from Utility-Scale Photovoltaic Systems accessed at http://maeresearch.ucsd.edu/kleissl/papers/CurtrightAptPV2008_PVIntermittencyAZ.pdf.
56 See Quantifying Avoided Fuel Use and Emissions from Solar Photovoltaic Generation in the Western United States

significant power from the grid, and thus set the demand charge at a rate that would have been charged irrespective of whether PV was installed.[57]

Development models

PV development can occur in a number of ways. Outlined below are certain models to consider relative to potential rural development.[58] This is not a comprehensive list, but is rather a sample of what seems appropriate for discussion, either because of its historic use or perceived, potential applicability. As a comprehensive analysis of each of these models is beyond the scope of this paper, we have focused on the more-obvious issues related to these models.

In addition to the models discussed below, individuals or businesses may wish to consider their own development (such as an application for a residence or small business). As with the commercial models discussed below, there may be various enhancements available in connection with these models, such as net metering (which is discussed in Appendix A), tax credits, USDA sources, and rebates (which are discussed in Appendix D). Here, too, we have identified the enhancements that appear to have the greatest potential application.

PPA model

The "PPA" (short for power purchase agreement) model grew to some prominence over the past several years, largely due to tax-credit-driven projects.

Given the contraction of the credit markets, the limited market for PV-generated electricity with the IOUs (especially in rural Colorado), the likely absence of a significant market with the REAs, limited availability (if any) of rebates, and the uncertain market with TriState, the PPA model may be of limited utility.

However, the capital markets (and investment tax credit appetites) should recover, energy prices should continue to rise, PV prices should continue to fall, and the demand for PV should continue to grow, especially considering the recent extension of the ITC and anticipated further understanding of integrating solar power – all meaning potentially better, long-term prospects for this development model than those that may now exist in Colorado.

At its most basic level, the PPA model involves development of a project and the sale of the power to a third party, such as an end user or utility. The recently-announced First

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57 Certainly, PV would still offset energy charges, which may make up one-half of a total monthly charge for electricity.

[58] Some of the other models being pursued include: (a) New Jersey's power pole project – As part of a larger 120 MW solar project, New Jersey's Public Service Electric and Gas is pursuing installation of PV panels on 200,000 utility poles. *See* http://news.tnanytime.org/energy/node/2095. (b) Solar roof leases – Utilities (including in California and North Carolina) are pursuing leases of rooftops for solar development, with the power to be sent to the grid, instead of being consumed on-site. In the summer and fall of 2008, similar projects were noted on the Front Range; however, it has been reported by one prospective lessee that the project stalled. Presumably, any similar opportunity pursued in rural Colorado would be in connection with TriState. However, given the fewer large rooftops in rural Colorado and the abundance of vacant land, it seems this model may not be the best option.

Solar / Tri-State New Mexico development and the PSCo / SunEdison San Luis Valley development are examples of PPA models involving utilities. The Denver Federal Center and DIA projects are examples of PPA models involving end users.

While a PPA project can theoretically be any size, transaction costs (i.e. accounting, consultant, and legal fees, which can exceed hundreds of thousands $$) have tended to drive larger projects – over time, financiers have reported minimum project sizes increasing from 150 kW, to 250 kW, to 400 kW. Projects can be developed as either ground-mounted or rooftop facilities.

With most PPA models, the development is structured to allow the developer (or, more commonly, a special purpose entity controlled by the developer's tax credit investor) to take advantage of available federal tax benefits. Hence, the present uncertain utility of this model.

PPA developments, whether customer-sited (i.e. located on the power purchaser's facility) or on owned or leased property, have historically included two basic elements – an agreement for the sale and purchase of power produced, likely on a take-or-pay basis (that is, the purchaser buys all of the power produced, irrespective of need) and a term of a minimum duration necessary to permit the tax-credit investor to realize the tax credit benefits (and avoid recapture penalties, as discussed in Appendix B), with project purchase option prices that decrease over time.

In the case of customer-sited arrangements (e.g. when the development is located on the power purchaser's roof), the agreement also will include concepts concerning: real property matters (such as license and easement rights necessary to locate and access the equipment); practical matters (such as repairs to the customer's facility); finance matters (authorizing collateralization of the agreement and associated revenue stream, as well as disclaimers by the owner of interest in the equipment, which is necessary to ensure the lenders' priority security interests); and, the sundry miscellaneous provisions typical in significant, commercial agreements. Even a small PV development may involve millions $$ of equipment and hundreds of thousands $$ in annual revenue, not to mention the value of the associated tax benefits.

From the end-users's perspective, PPA arrangements should be carefully considered. Mostly, in Colorado, these arrangements have been pursued with larger consumers, with projects in the +/- 100 kW size ranges that qualified for rebates with PSCo. The rebates were transferred from the customer to the developer in order to support power price reductions. The projects are/were sometimes promoted claiming fixed-price power and sometimes even a lower rate than is being charged for power from the grid. On review of these opportunities, unidentified mismatches between customer need and production may show an effectively-higher cost than the customer is actually paying pre-installation. Because of low returns, these contracts are structured as take-or-pay arrangements. Therefore, by example, if a customer has no consumption on weekends or holidays, the customer will nevertheless be obligated to purchase this power, effectively driving up the customer's overall energy costs. Also, if a customer is subject to a demand charge, it is unlikely the project will eliminate that charge, raising the effective cost of the project. Purchase options may give an impression of additional value (as ownership would eliminate continuing obligations to the developer); however, due largely to recapture issues and investor hurdle requirements, the prices built in to these options may be greater than the value of system and/or may drive up the effective cost beyond that which the customer would pay for power from the grid.[59] Certainly, end-user arrangements should be carefully considered, particularly if the economics are important.

From the developer's perspective, a single, customer-sited arrangement in rural Colorado will be difficult, even if the credit markets were to open up. On the Front Range, rebates drove much of this development, and without some, additional offset (that now appears to not exist), the economics will be difficult to overcome. Stating the obvious, enhancements, as may be or may become available, should be considered, noting that careful consideration will be necessary, as incentives may not be compatible.[60]

In the case of ground-mounted PPA developments (and the following would apply to other ground-mounted development models, as well), the project can be sited on property owned by the developer or on leased property.

Siting a project on property owned by the developer is the simpler approach. When developing on its own property, the developer's requirements generally will be limited to matters such as: zoning (as applicable); permitting (local, state, and federal, and environmental and wildlife, as applicable); title work, to ensure no competing or potentially-competing encumbrances (such as rights of way or mineral interests); and, securing subordinations or non-disturbance agreements from prior lien-holders.

Developing on leased land is more complicated. In addition to the issues outlined above, the developer must negotiate a lease of the property with the landowner. Considering the desired PPA term (at least 20 years), the developer will want minimum unrestricted use of the property for 20 years (starting on COD for the project), and maybe for as long as 40 or more years. The imposition on the land, the value of the equipment and revenue stream, and the required "bankability" of the overall project, including the lease, make these necessarily complicated agreements. Fortunately, the amount of property needed is minimal (+/- 3-10 acres/MW, depending on module type) and therefore it may be possible to avoid dealings with multiple landowners, which would further complicate the transaction.

In the case of a project pursuing a utility PPA, proximity to transmission and interconnection will be key to any large, ground-mounted project.[61] But not just any transmission or interconnection will do. The point of interconnection must be as close as possible to the project site and must be of a size sufficient to handle the power from the project. Similarly, the transmission must be of sufficient size and have sufficient capacity to move the power. These are significantly-complex issues and will certainly require specialized interconnection and transmission consultants and personnel. This, plus land costs, plus modeling requirements, plus tax-credit components, plus resource assessment, plus transaction costs, plus interconnection costs; … all mean significant financial and human resources are necessary to legitimately pursue larger, ground-

[59] Customer-sited PPA arrangements also may unduly restrict the customer's real property requirements. These projects require certain returns, and this certainty depends on continued operation, which depends on some minimum measure of site control, which may be inconsistent with the customer's need for flexibility.

[60] For instance, due to the ownership requirement, USDA 9007 resources may be incompatible with use of the ITC in connection with a PPA-modeled project, although in theory the ITC should be available to the owner, if the owner's own resources are not so great as to prevent availability of the 9007 resources.

[61] Each mile of transmission may add over $100,000 to the development costs, and this number will be higher depending on right of way issues and line voltages.

mounted developments intended for utility power purchase arrangements (presuming opportunities exist).

If the use of Stimulus funds is considered, then one other issue to review, especially relative to ground-mounted projects, is compliance with the National Environmental Policy Act ("NEPA").[62] Generally, use of federal funds or federal land may trigger NEPA application. Federal agencies (like the Department of Energy ("DOE")) are directed by NEPA to evaluate the environmental impacts of certain projects.[63] The agencies have developed procedures for these evaluations.[64] Depending on the nature of the project, the evaluation may require preparation of an "environmental assessment" (lower standard) or "environmental impact statement" (higher standard), unless the project fits within a defined "categorical exclusion" (lowest standard).[65] The Stimulus does not authorize any waiver of NEPA, although there is a requirement for expediting NEPA consideration. If NEPA applies,[66] and if the project does not fit within a categorical exclusion, then preparation of an environmental assessment or environmental impact statement may be necessary. Historically, this has meant additional cost and time, which may be considerable. Therefore, any project considering Stimulus funds, should consider NEPA issues early on, as well as what financial and timing impacts this may have. Notably, installation of PV equipment on a building, as opposed to installation on raw land, would presumably be more likely to qualify for a categorical exclusion, limiting potential NEPA issues (i.e. cost and time and litigation).

One ground-mounted opportunity that also may be worth considering would involve injecting power directly on to the distribution system. A similar project was proposed as part of a study for the predecessor to GEO, [67] and it may be that some analog of this study and/or model considered would be appropriate for rural Colorado consideration. Part of the appeal of this idea would be in (presumably) avoiding infrastructure costs, in having numerous injection points along the distribution system (which would allow for consideration of various sites, both building mounted and ground-mounted), and in allowing for somewhat larger projects (or aggregated projects) that would realize economies of scale. Aggregating several projects would further allow for realizing economies of scale. But, again, the utility of this model may depend on stabilization of the credit markets (if tax-credit equity were to be pursued), not to mention confirming a power purchase arrangement. Presumably, this idea would work best if the REAs were in a position to purchase the power; however, there are limitations to this, as discussed above. A better course may be to explore purchase opportunities with TriState, for instance, if developing within an REA territory. In this case, the developer would still be required to work closely with the REAs to address capacity, interconnection requirements, and wheeling fees (i.e. costs to use the REA's system). Also, unfortunately, it is not clear whether this arrangement would qualify for 3x REC treatment (if developed within an REA territory). The presumption should be that PV within the REA system would in fact qualify for this treatment, irrespective of whether TriState or the REAs purchase the power; however, this conclusion is not clear from the rules.

[62] *See* 42 USC 4321 et seq.
[63] *See* 42 USC 4322.
[64] DOE's procedures are codified at 10 CFR 1021.
[65] For DOE purposes, the level of review required is generally outlined in 10 CFR 1021 Appendices A,B,C, and D of Subpart D of Part 1021.
[66] Notably, it appears federal tax credits do not trigger NEPA.
[67] The Tom Wind study referenced here was accessed at http://www.colorado.gov/energy/images/uploads/pdfs/b6708bde95335b14a5a9ee1da6b306a7.pdf.

The United Power model, and possible variations

Colorado's United Power, a TriState REA, is pursuing a novel and noteworthy development model it refers to as "Sol Partners-Cooperative Solar Farm."[68]

Generally under this model, United Power procures and leases modules to its customers. The modules are maintained and operated at United Power's facility.

Similar to a model developed by the Sacramento Municipal Utility District,[69] customers pay an up-front charge. Here, the charge is $1050 to lease a 210 watt module for 25 years. The customer then receives a credit equal to the volume of power produced by its module.

United Power projects a 3% customer return, or approximately $32 per year per module in electricity bill credits.

It will be interesting to see how the United Power model fares in this economic climate. The first SMUD development sold out, but this was before the economic downturn and was within a community with higher electricity rates. In today's economy, a $1050 investment is significant, and a 3% return may not be sufficient. Regardless, United Power deserves credit for conceiving the first cooperative PV model of its kind.

Several aspects of this model are attractive and warrant consideration of the model (or variations of it) by other REAs, or even municipal utilities.

- The adoption of this model recognizes that for purposes of renewables, PV has advantages over wind with the REAs.
- Siting the system at United Power's facility is logical. United Power is in the electricity business and is therefore in a good position to maintain and operate the system.
- A lease structure recognizes the difficulty that surrounds customer ownership, tax credits, …, and by retaining ownership and maintaining and operating the

[68] *See* "Sol Partners-Cooperative Solar Farm," featured on the United Power web site accessed at http://www.unitedpower.com/solpartners.aspx#Q3d.

[69] In July 2008, the Sacramento Municipal Utility District ("SMUD") brought on-line a 1.2 MW PV solar project that is the first in the US to provide customers an opportunity to sell renewable power back to their utility without placing solar panels on their homes or businesses. SMUD agreed to purchase power under a 20 year agreement with enXco, the builder and owner of the 17,172 panel solar array. SMUD offers its customers the option to enroll in its "Solar Shares Program" whereby the customer agrees to pay an extra fee on its monthly electricity bills in exchange for a pro-rata "ownership" in the project and a right to share in payments (in the form of reduced electricity bills) for the solar power sold by the 1.2 MW solar array. The economics of the arrangement will depend on future energy prices. A customer using 6,000 kilowatt-hours a month would be charged an extra $10.75 per month added to the bill from SMUD. SMUD expects that, on average, at first the customer may get 2/3 of that monthly charge returned because of the solar power sales. As the cost of electricity increases, the customer may get more than the full fee back. SMUD hopes to expand the Solar Shares program in phases, depending on customer demand. *See* "SMUD Opens 1.2-MW Solar PV "customer-driven" array," July 14, 2008; accessed at http://www.uk.reuters.com/article/rbssIndustryMaterialsUtilitiesNewsdUKN1445852620080715; "Solar Shares: Solar for Everyone!"; SMUD.org webpage accessed at http://www.smud.org/en/community-environment/solar/pages/solarshares.aspx.

system, United Power has likely ensured REC ownership, and ensured application of the 3x multiplier.[70]

Likely, the greatest potential limiting features of the United Power model are cost (up-front cost) and payback (25 years, per United Power). But now (especially considering possibly-available Stimulus $$, as well as possibly-available USDA $$) may be the time to consider any alternative structure(s) or variations on the United Power model, with the overall idea being to increase the number of participants by lowering the cost of participation and/or shortening the payback period. Any additional funding that can be directed to this model will increase PV penetration and generate additional rural Colorado experience with PV.

As discussed below, there is now +/- $50 million in Stimulus $$ that may be put to energy projects in Colorado. Presumably, some of this could be put to funding REA PV options, similar to (but maybe not exactly like) the United Power model.

If the funding were rich enough (and/or if the REA can secure capital from other sources) then the REA could presumably absorb more (if not all) of the up-front cost of the systems, lowering (if not eliminating) the customer's up-front charge. This could have various positive effects.

By eliminating or lowering the customer's up-front charge, the REA could eliminate what may be the most significant barrier to participation. In exchange, the customer could pay an ongoing lease fee, which could be structured as a credit and/or as a percentage of what would otherwise be charged for the electricity produced, and this would give the REA a continuing revenue source.[71] Essentially, the REA would be in the PV equipment leasing business. And interestingly, at least on the surface, it seems this would not implicate any issues under the REAs' all-requirements contracts, as the REA would not be generating or purchasing electricity.

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[70] United Power's long-term ownership of the system may address one unclear question regarding the duration of the 3x REC multiplier. Again, the pertinent PUC Rule 3654(e) states:

> For purposes of compliance with the renewable energy standard specified in rules 3654(b) and (c), **for cooperative electric association QRUs** and municipal QRUs, **each kilowatt-hour of eligible energy generated from solar electric generation technology shall be counted as 3.0 kilowatt-hours of eligible energy, <u>provided that the solar electric generation technology commenced producing electricity prior to July 1, 2015</u>**. For solar electric generation technology that commenced producing electricity on or after July 1, 2015, each kilowatt-hour of eligible energy generated from solar electric generation technology shall be counted as 1.0 kilowatt-hours of eligible energy for compliance purposes.(emphasis added)

Partly, what is unclear is whether "the solar electric generation technology" is a direct or indirect reference. Is the PUC referring to the specific modules, inverters, and racking system installed before July 1, 2015 or to the type of system. If the PUC was referring to the specific equipment then United Power ownership becomes more important, because United Power, as Owner of the equipment, can to a large degree control continued operation of the equipment, and thus also continue generation of the RECs.

[71] The idea of a new REA revenue source is appealing, if within the scope of the REA's charter. Overall, in considering PV applications for rural Colorado, it came to mind that customer-owned PV could actually be considered competitive with the REAs. The REAs are in the business of selling electricity, and for some of the REAs, business is somewhat precarious. If a customer self-generates power, then there will be a reduction in REA revenue equal to the amount of power self-generated. Moreover, the volume of power self-generated will not likely cause a reduction in the amount of power produced within the TriState system, and thus TriState and/or the REA will nevertheless pay for the power that would otherwise be supplying what that single customer is self-generating. Certainly, this single, hypothetical REA customer is not likely to have an appreciable affect on overall REA economics; however, this example does present at least a theoretical dilemma, with renewables negatively affecting REA revenue, without reducing REA cost. Based on this (at least theoretical) affect, consideration was given to mitigation of the lost revenue to the REA. One option considered was to put the REAs in the PV business, such as through an equipment lease model, like that discussed here.

However, under this expanded scenario, the REA would certainly want to contract for ownership of all of the RECs, and likely this would be done in the context of the lease agreement, which may also include a maintenance component, as the REA(s) would want to ensure optimum operation of the system.

Ownership of all RECs will open up another potential cost offset and/or revenue source for the REA. Presuming the program was properly structured to qualify for the 3x multiplier,[72] the REA could pre-sell some of the RECs.[73] The presale revenue could be applied to offset system costs, lowering the customer's up-front cost. And a REC pre-sale structure could be designed to correspond to the REA's anticipated RPS obligation. For instance, more of the RECs produced could be sold in the early years of the program (generating more up-front $$ to offset equipment costs) and when the REA's RPS obligation is a lower percentage of its retail sales, and while equipment costs are higher. As equipment costs decline (as projected), the RPS requirement increases, and the cost of conventional power increases, the REA could find itself in a position of being able to retain all of the RECs, and ideally, at the end of the day, it would have in a place a self-sustaining program.

Overall, given that equipment costs are coming down and energy costs are going up, it seems that the economics of a program like the United Power program would be most successful in years to come, but presumably before 2015 and the expiration of the 3x REC multiplier. However, if Stimulus $$ is available now, it may be appropriate for the REAs to develop and submit for funding one or more pilot programs based on something like the United Power model.

CREBs model

In connection with the Stimulus, there now exists $2.4 billion in clean renewable energy bonding ("CREBs") authority available for allocation. Public power providers, government bodies and electric cooperatives may apply for an allocation, which is awarded to the smallest dollar projects first. The program is designed to provide qualified entities the equivalent of interest free financing. The program has certain advantages but also some limitations. For a more detailed discussion of the rules and regulations governing CREBs, see Appendix B

The transaction costs to fund a project using CREBs are high. One report estimated that a $10 million CREBs allocation would cost $3 million to complete, when considering transaction costs, the cost of securing voter approval and the discount to par that must be offered to sell the bonds. Given transaction costs, it may make the most economic sense to use CREBs to fund large projects. Under the CREBs allocation scheme, however, the smallest projects are funded first and the largest projects are funded only if there are sufficient allocations remaining after funding smaller projects. With the recent, increase in the funding authority available for CREBs, it is now more likely than before that large project could receive funding. Alternatively, issuers could combine multiple, related projects together into one bond offering in order to share transaction costs.

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[72] Admittedly, how to do this is uncertain, as there is little guidance within the PUC rules.

[73] By example, RECs were presold in connection with the Wray, Colorado school turbine. *See http://www.nativeenergy.com/pages/wray_school_district_wind_turbine/417.php.*

Massachusetts successfully pooled several PV projects together and financed the project with a combination of CREBs and government grants.[74] In 2006, Massachusetts' "Leading by Example" program, in collaboration with MassDevelopment and the Massachusetts Technology Collaborative, pooled together 12 PV installations on municipal buildings totaling 1 MW. They combined the projects in order to streamline transaction costs. Together, the 12 projects cost approximately $8.5 million, funded by $3.12 million in CREBS and the rest in the form of grants. The Massachusetts group also realized procurement cost savings by grouping their installations.

In addition to transaction costs, there are other challenges unique to CREBs when used to finance PV.[75] The issuance is usually not truly interest fee because the IRS uses a market rate for AA-rated corporate bonds to determine the tax credit offered to investors, and not all public entities can borrow at that rate. Further, the lack of familiarity in the markets may impair the ability of issuers to sell the bonds at par. Also, provisions in the federal laws creating the latest round of CREBs authority reduced the tax credit from 100% to 70% for the interest received from CREBs. The provisions in the federal laws establishing the most recent CREBs authority now requires that 100% of the proceeds be spent on a qualified project, leaving no room to finance the transaction costs; whereas before only 95% of the proceeds had to be spent on qualified projects. Lastly, the first principal payment is due in December of the year the CREBs are first issued, creating challenges for projects still under construction.

Notwithstanding the difficulties, the additional funds available suggest CREBs should be considered. And the Massachusetts example suggests one model for consideration. This model may be particularly appropriate for rural communities, especially if these communities are able to identify additional incentives, and maybe aggregate projects.

Conclusion

While opportunities for rural Colorado PV are not what we expected when we started this project, opportunities exist, and funding exists for these opportunities. The key is to match projects to the market and with available resources. We sincerely hope the information provided in this paper will help rural Colorado interests evaluate these opportunities and realize successful PV developments.

Update (August 27, 2009)

In the weeks after we submitted the final draft of this paper, we were asked to prepare an additional, brief section discussing recommendations for moving forward with rural Colorado PV development. It then seemed the focus of this summary would be very brief and limited, doing no more than highlighting development features to consider pursuing. But, since final submission and this request, the industry has changed (in many ways markedly), and more changes are expected. Based on these changes, we have expanded the scope of these recommendations.

For Colorado to enhance its rural PV development potential it should (likely, vigilantly) track development enhancements. Just in the past few weeks, at least three meaningful

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[74] "Solar Photovoltaic Financing: Deployment on Public Property by State and Local Governments," NREL Technical Report NREL/TP-670-43115; May 2008.

[75] *Id*.

opportunities for enhancing rural PV development have been announced (GEO's NEED Grant funding; DOE's community development grant; and, certain of DOE's loan guarantee programs). Any of these, but most particularly GEO's NEED Grant and DOE's community development grant, could significantly enable a project by providing critical funding. Vigilance in tracking these enhancements is likely necessary, as the window for securing these funding sources may be short.[76]

While tracking enhancements, developments themselves also should be tracked. Development announcements give a sense of industry trends and (maybe) of development features that can be employed in rural Colorado. Just in the past few weeks, several, new large-scale developments (mostly in California) have been announced. While these models may not fit Colorado, certain aspects of these developments (e.g. development on Federal land) are worth noting, and noting the features of all announced developments may help identify similar opportunities.

Some attention also should be directed to policy, particularly PUC policy surrounding the REC multiplier. Energy development likes (if not needs) certainty, and adding certainty to the uncertain features of the PUC's rules should enable more meaningful developer, offtaker, and financier consideration of this potentially-rich Colorado enhancement. GEO would be well-served by clarifying the uncertain points surrounding the REC multiplier.

Finally, in terms of developments themselves, even though recent announcements suggest consideration of much larger developments, it does not seem now is the time to pursue those developments in Colorado, particularly considering the condition of the credit markets, the absence of a meaningful export market, and the recent Tri-State and PSCo announcements and completed RFPs. Based on these circumstances, smaller developments may be most appropriate. Further, if the recently-announced enhancements are an indication of potential future benefits, then some focus on roof-mounted applications may be appropriate, as GEO's NEED grant and DOE funding will trigger NEPA consideration,[77]which may be easiest to avoid by siting applications on existing structures.[78] Focus should remain on the REC multiplier, which is an extraordinary incentive and may enable creative development structures. The focus on the REC multiplier, which necessarily means involving the REAs, also suggests focused consideration on USDA funding sources, and agricultural applications. Some union of the REC multiplier, USDA sources, and (by example) GEO NEED grant funding could facilitate a meaningful development. Presales of some of RECs also could be a component of these developments. Necessarily, these unions will involve the REAs and USDA. Starting with the REAs is necessary, as their involvement is most critical to capturing the REC multiplier. If a structure with the REAs is identified, then confirming USDA funding would be the next step, followed by involvement of any additional enhancements and/or REC presales.

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[76] A rural PV-related enhancements link on the GEO website could be quite useful.

[77] In the case of GEO's NEED Grant, "categorical exclusion" from NEPA is a predicate requirement to consideration, and it may be more difficult to ensure "categorical exclusion" in connection with a ground-mounted application.

[78] This is not to say ground-mounted applications should be avoided if considering funding derived from federal sources; however, NEPA application does present additional, potential delay, which means additional cost, and therefore should be carefully considered.

Appendix A

General explanation of PV systems

History of PV

A PV cell is a device that converts sunlight directly into electricity by the photovoltaic effect. The earliest recognition of the photovoltaic effect occurred in 1839. In 1883 the first solar cell was built. In 1954 the modern age of solar power began when Bell Laboratories, experimenting with semiconductors, accidentally found that silicon doped with certain impurities was sensitive to light. This eventually resulted in production of the first practical PV cells with a sunlight energy conversion efficiency of around 6%.[79]

How PV works

PV cells are made of semi-conducting materials similar to those used in computer chips. When sunlight is absorbed by the semi-conducting materials, the solar energy knocks electrons loose from their atoms, allowing the electrons to flow through the material producing a current. Assemblies of photovoltaic cells are used to make solar panels, solar modules, or photovoltaic arrays.[80]

PV systems can be used to provide power for almost anything. Generally, PV systems are installed on residences or commercial buildings. On the grandest scale, large-scale PV arrays function as a power plant.

PV equipment

PV panels or modules

There are a number of types of PV panels.[81]

Poly-crystalline block. Currently, poly-crystalline PV panels are the most common. Typically, each cell is cast from large blocks of silicon which may contain many small crystals. Although a little less efficient than single crystal PV, once set into a frame with 35 or so other cells, the practical difference in watts per square foot is minimal. Poly-crystalline PV resembles shattered glass and has a dark blue to almost black color. Overall efficiency averages about 11-13%.

Mono-crystalline. Mono-crystalline PV is made from a very pure single large crystal, cut from ingots. It is the most efficient type of PV panel but it is also the most expensive. Mono-crystalline PV boasts efficiency of approximately 12-15%. Typically, mono-crystalline PV is blue-grey in color and has fairly uniform consistency.

Bifacial mono-crystalline. A new form of PV panel recently introduced to the market uses mono-crystalline cells with glass on both sides so that it can collect energy from both sides of the PV panel. Collecting light from both sides of the bifacial panels increases the panel efficiency for about the same cost. Bifacial mono-crystalline panels have reported efficiency levels of up to 20%. It is common to install these panels in a

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[79] "Timeline of Solar Energy," accessed at http://www.Wikipedia.com.
[80] "Learning About Renewable Energy-Photovoltaics," accessed at http://www.NREL.gov.
[81] "Solar Panels," www.energybible.com; accessed at http://www.energybible.com/solar_energy/solar_panels.htm.

pole mounted PV array so that ambient light reaches the front and the back of the panel. Additionally, bifacial mono-crystalline panels can be installed on a roof that has a white matt or has been painted white to allow light to reflect on to the back of the panel. The durability of these panels has not yet been established but most carry 20-25 year warranties, similar to traditional panels. Bi-facial panels work well in pole mounted systems because each pole mount can usually only hold 9-12 PV panels. By using more efficient panels the cost tradeoff of the panels as compared with the cost of the tracking system is improved.

Poly-crystalline string ribbon. String ribbon PV cells are manufactured with a variation on the polycrystalline production process, using the same molten silicon but gradually drawing a thin strip of crystalline silicon out of the molten form between two strings. The photovoltaic strips are then assembled into a panel which attaches the same metal conductor strips to the electrical current. This technology saves on costs over standard polycrystalline and, in some cases, has higher efficiency levels than other polycrystalline technologies. Efficiency of String ribbon PV cells averages 11-14%.

Thin film or amorphous. Amorphous or "thin film" PV panels spread silicon directly on large plates, usually made of stainless steel or more flexible plastic materials to make very flexible PV panels. Thin film PV is cheaper than other forms of PV but is less efficient than mono crystalline or poly-crystalline PV panels, with overall efficiency on average in the range of just 5-6%. To obtain as many watts as the other types of PV panels thin film PV arrays must be much bigger in size. Because they can be put on to flexible backings, thin film PV is preferred in certain types of applications where flexibility is more critical than power.

Concentrating PV solar panels. Concentrating PV panels employ a lens or mirror to concentrate the sun's energy on to the individual cells. Concentrating PV uses lenses or mirrors to focus or increase the amount of sunlight on a PV panel. Concentrating PV panels decrease the number of panels needed to produce electricity and the amount of space needed for a PV installation. However, they work only with direct light to produce electricity, while stand-alone PV panels can use both direct and diffuse light. Locations may lack sufficient direct light throughout the year to make these systems practical. The complexity of their construction is another disadvantage because it makes these systems more difficult to build and install than conventional PV panels. Concentrating panels are also considerably heavier than conventional PV panels and have a number of moving parts which makes them more prone to malfunction than conventional panels. Concentrating PV is not commonly used in residential PV systems but is instead technology likely to be used on larger systems.

Group III-IV Technology Panels. Solar cells created with advanced technologies are often referred to as Group III and IV cells. Though these technologies are very efficient, with efficiencies as high as 25%, their current use is limited due to their very high costs.

Mounting systems[82]

A PV mounting system is used to hold the PV panels in place, secure them from wind damage, and lift them enough off the surface so that air circulates underneath the PV

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[82] "Solar Panel Mounting Systems," www.energybible.com; accessed at http://www.energybible.com/solar_energy/mounting_systems.htm

cells to keep them cool. Mounting systems can be designed for many locations. Pole mounted systems can also be modified to support both active and passive modules that allow the panels to more closely follow the sun. Fixed roof mounts are inexpensive and simple to install but do not allow for tracking of the sun like pole mounts. However, their low cost and simplicity more than compensates for the lack of tracking, which is why fixed roof mounts are so common.

Mounting PV panels on a roof is fairly simple. It is common to mount light aluminum rails on top of the roof tiles to serve as the base for the PV panels. Depending upon the roof pitch and roofing type the aluminum rails can be attached just to the roofing tile themselves or to the rafters. On most roof-mounting systems, the legs of the rails can telescope up or down so the PV panels can be positioned at the optimal angle to the sun, usually around 30 degrees. These roof mounted racks can withstand wind velocities up to 100 miles an hour.

Pole mounted systems are comprised of frames which mount the PV panel at the top of a pole. They tend to be used in situations where roof mounting is not an option. The pole is typically a 10 foot, 40 gage steel pipe which is cemented in the ground. To ensure strength and stability, about one third of the pipe is buried below the surface and most pole mounted systems can withstand 80 to 120 mile per hour winds. One advantage to pole mounting systems is that they allow the panels to be directed and pitched in order to catch the most sunlight and can be further enhanced with tracking systems which follow the natural track of the sun (*See* Tracking Systems).

Tracking systems[83]

Tracking systems are hardware devices usually used on pole mounted PV arrays to position the PV panels so that they follow the movement of the sun. A tracking system may boost the output of a PV system by up to 30% in the summer and 15% in the winter over non-tracking systems.

Tracking systems can be passive or active. Passive systems include a tracker that follows the sun from east to west without using any type of electric motor to power the movement. A passive system rotates from a combination of heat and gravity. Passive systems are ideal for remote off-the-grid scenarios or use with water pumping systems where peak demand is in the summer. The disadvantages of passive tracking systems are that they are somewhat susceptible to high winds which can throw the tracker off the proper direction and they can be somewhat sluggish in cold temperatures because they are mechanically rather than electronically driven.

Active tracking systems are powered by small electric motors and require a control module to direct them. Active systems require some electric power which can come from the PV panels themselves, depending upon the model, or an external source.

Tracking systems are also classified as to the number of axis they track against. A one axis system rotates only left to right rather than in an arch. A two axis tracking system tracks both left to right and up and down, allowing it more accurately to follow the arch of the sun throughout the day.

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[83] "Tracking Systems," www.energybible.com; http://www.energybible.com/solar_energy/tracking_systems.htm.

Tracking systems involve both initial cost and maintenance cost which may or may not be justified by the additional electric power they generate. Tracking systems require maintenance and add a good bit of complexity to the system simply because they have moving parts. Additionally, the sun's location in the sky varies more in the summer than in the winter so during many months the tracking system may be of little practical value. As an alternative to tracking systems, it may be more cost effective in small scale PV arrays to add one or more panels, increasing output for less cost and with less maintenance.

Inverters

The PV array is accompanied by a system of electrical wires and a box, called an inverter. The electric current created in the PV cell is a direct current (DC). The energy created may be stored in a battery bank (for significant additional cost) for later use or sent directly to the inverter. An inverter converts low voltage DC created by the PV array into higher voltage AC, which can be used for most conventional household appliances. Inverters are available in a wide range of wattage capabilities.[84]

PV systems can be "grid tied" or "off-grid." If the PV system is grid-tied, the electricity leaves the inverter and is either used by the home or business immediately or is sent to the grid. If the PV system is producing excess power, then the excess is sent through the utility meter to merge with the power in the grid. (*See* discussion below regarding "net-metering"). If the PV system is off-grid, then the system functions independently from the power grid. In this situation, excess power may be stored in batteries for later use. Off-grid systems are typically used in locations where connection to the grid is not possible. Some grid-tied systems use batteries to store power to provide backup for power failures.[85]

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[84] "Solar PV Electric," Solar Direct accessed 5/21/09 at http://www.solardirect.com/pv/inverts/inverters.htm.
[85] "Photovoltaics," Colorado Governor's Energy Office website; accessed 5/19/09 at http://www.colorado.gov/energy/index.php?/renewable/category/photovoltaics.

Appendix B
Primary federal incentives for PV

Commercial tax credit and accelerated depreciation

A 30% federal tax credit[86] (ITC) is available for solar equipment placed in service during the period 2006 through 2016[87]. The ITC is 30% of the "basis" a company invests in "eligible property" "placed in service" until 2016.[88] Thereafter the ITC will drop to 10% of the basis for the property put into service and the residential credit will drop to zero for property put in service after that date.[89]

The ITC can be claimed for "equipment which uses solar energy to generate electricity, to heat or cool (or provide hot water for use in) a structure, or to provide solar process heat, excepting property used to generate energy for the purposes of heating a swimming pool," [90] and "equipment which uses solar energy to illuminate the inside of a structure using fiber-optic distributed sunlight."[91]

Eligible equipment includes[92]:

- equipment such as collectors (to absorb sunlight and create hot liquids or air), storage tanks (to store hot liquids), rock beds (to store hot air), thermostats (to activate pumps or fans which circulate the hot liquids or air), and heat exchangers (to utilize hot liquid or air to create hot air or water)[93];
- equipment that is part of a solar heating or cooling system, but only if 75% of the energy used to run the system comes from the sun;[94] and
- pipes and ducts that are used exclusively to carry energy derived from solar energy.[95]

In most cases, property installed must be new to claim the credit.[96] The tax credit can only be claimed in the first year the eligible property is "placed in service."[97] Equipment is considered "placed in service" once it is in a condition or state of readiness and

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[86] A tax credit is a dollar-for-dollar reduction of the income taxes that the person claiming the credit would otherwise have to pay the federal government.
[87] IRC § 48.
[88] IRC § 48 (2)(A)(i)(II).
[89] IRC § 48 (2)(A)(ii).
[90] IRC § 48 (3)(A)(i).
[91] IRC § 48 (3)(A)(ii).
[92] IRS regulations explain that storage devices, power conditioning equipment and transfer equipment are examples of eligible equipment; but batteries can only be claimed when such devices store solar-generated electricity.[92] The commercial solar credit can be claimed on equipment in a solar system up to the transmission stage only. [92] No credit is allowed for radial lines or substations to transfer electricity to the grid. Additionally, passive solar systems do not qualify for the credit. 26 CFR §1.48-9(d)(2). IRS regulations define passive solar systems as ones that use "conductive, convective, or radiant energy transfer."
[93] 26 CFR § 1.48-9(d)(1). Equipment only can be claimed. If the system includes a building or is installed on a roof, a credit likely cannot be claimed on the cost of the building or the roof. However, structures that hold up photovoltaic panels may or may not be eligible equipment—they may be deemed part of the solar system eligible for a tax credit if the solar array is structured primarily for electricity generation and not for other uses.
[94] If less than 75% of the energy comes from sunlight then there is an allocation based on the mix of energy in the first year the equipment is put into service. 26 CFR § 1.48-9(d)(6).
[95] 26 CFR § 1.48-9(d)(4). Pipes and ducts that are used to carry both energy derived from solar and energy from other sources are eligible property if 75% of their use is related to solar derived energy and only the amount added to basis must be pro-rated based on the relative use by solar and non-solar sources.
[96] 26 CFR § 1.48-9(a)(3).
[97] 26 CFR § 1.46-3(d)(1).

availability for a specifically assigned function. Equipment will still be deemed in a state of readiness even if the taxpayer acquires or sets aside parts for use as replacements for a particular machine to avoid operational time loss or equipment in operation but is undergoing testing to eliminate any defects.[98]

If a project is expected to take at least two years to build then a taxpayer can elect to claim construction progress payments.[99] The amount that can be claimed for such progress payments depends upon complex rules that would require close review.

A Company's tax "basis" for purposes of the tax credit is the portion of its investment in eligible property. "Basis" is usually the cost of the equipment and installation.[100] Interest on loans to acquire the equipment and sales and use taxes are usually deducted when paid and are not included in basis. An election can be made to include interest in the basis and be later deducted over time as depreciation.[101] Incentives such as state rebates, buy-downs, grants or other incentives do not decrease the basis for the tax credit so long as the company pays federal income tax on the incentive. For those non-taxable incentives, the tax basis must be reduced.

Normally, basis is not affected by the fact that a taxpayer buys such equipment with borrowed funds.[102] However at-risk limitations may limit the credit claimed in situations where the taxpayer borrows on a non-recourse basis.[103] The at-risk limitations apply to individuals, individuals investing through a partnership or limited liability company treated as a partnership, S Corporations and closely-held corporations.[104] There are exceptions to the at-risk rules that often apply to most solar projects, however. It is important to note that the at-risk rules affect only the timing of the tax credit and not the amount of the credit. As the non-recourse loan is paid the taxpayer can claim a new credit calculated on the reduction in loan principal as the tax credit. Interest payments do not usually qualify for the credit.

The same solar equipment that qualifies for the ITC can usually be depreciated over five years on an accelerated basis.[105] If the 30% tax credit is claimed then the depreciable basis is reduced by ½ of the solar tax credit claimed, leaving only 85% of the equipment cost subject to depreciation[106]

Taxpayers can claim the ITC the first year the solar project is placed in service, however if the project is sold or the property is no longer "eligible property" for the credit within the next five years then the credit is subject to recapture at a rate of 20% per year.[107] The "unvested" portion of the credit will have to be reported as income in the year of the recapture event. Partners in a partnership face a particular risk of recapture if the

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[98] 26 CFR § 1.46-3(d)(2).
[99] 26 CFR § 1.46-5(b).
[100] 26 CFR § 1.46-3(c).
[101] Election is made pursuant to IRC § 266.
[102] The American Recovery and Reinvestment Act of 2009 removed a provision as of Dec. 31, 2008 that reduced basis for property financed in whole or in part by subsidized energy financing or with proceeds from private activity bonds.
[103] IRC §49. Non-recourse financing means that under the terms of the loan the only recourse of the lender is to foreclose on the equipment and has no claim against the borrower if it defaults.
[104] IRC §465 ."Closely-held" is defined as 5 or fewer individuals own at least 50% of the stock. IRC § 542(a)(2).
[105] IRC § 168(e)(3)(B)(vi)(l).
[106] IRC § 50 (c)(3)(a).
[107] 26 CFR § 1.47-1(h).

partner's share of taxable income during the four years following the first year the credit is taken drops to less than 2/3 of such partner's share of income in the first year.[108]

An ITC that cannot be used in the year claimed may be carried back one year and forward 20 years. If the unused credit is carried forward 20 years and the taxpayer is still unable to use it, then the taxpayer can deduct the unused credit in the last year of the carry-forward period.[109]

Because the ITC can only be claimed by the owner of the eligible property, various structures have been developed to allow those with tax liability to take advantage of the tax benefits. Two of these structures include:

Sale-leasebacks—In this structure, the owner sells the project to another company who can use the benefits and then leases it back, presumably sharing in the tax credit subsidy in the form of reduced rent for the equipment. The owner must sell the project within three months of the in-service date.[110] The lessor must lease-back the project to the same legal entity that placed the eligible equipment in service. The lessor claims the tax credits and depreciation unless it elects to pass the credits to the lessee. The lessor can elect to pass the tax credit to the lessee and claim only depreciation on the project.[111] The lessee must otherwise be eligible to claim the tax credit.[112] The lease should not have a term greater than 80% of the expected life or value of the project. Options to renew are not considered when determining the term of the lease for this purpose.[113]

Partnership flips -- Before the in service date, the developer can form a partnership with an equity investor who provides capital for the project, and who presumably also can take advantage of the tax benefits. As owner, the investor will receive the tax benefits and likely a large percentage of the returns, at least until the investor has received a specified target return. At that point, the partnership "flips" and the developer and investor's ownership percentages will adjust and/or the developer may have an option to purchase some or all of the investor's interests. Note that the flip should not occur before the project has been in service for 5 years or the tax credits will be subject to recapture. Also, partnership accounting rules might limit the parties' ability to allocate tax benefits to the investor to the extent provided for in the partnership agreement.

Residential tax credit

One tax credit applies to PV equipment for residential use. Taxpayers receive a tax credit for 30% of the cost of eligible solar electric property without a cap[114] . A taxpayer cannot spread out the cost of the equipment over a number of years to get more expenses under the cap.

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[108] 26 CFR § 1.47-6.
[109] 26 CFR §§ 1.46-1; 1.46-2.
[110] 26 USCA § 50(d)(4). For the remainder of the paper I.R.S. code section 26 of the USCA will be cited as "IRC".
[111] 26 CFR § 1.48-4.
[112] In the case where the project is sold and leased back and the lessor elects to leave the tax credit with the lessee, then the lessor can claim depreciation on the full cost of the project without any basis reduction. However, in that situation the lessee must report half of the credit it claims as taxable income over 5 years.
[113] 26 CFR § 1.48-4(a)(2).
[114] IRC 25D(a)(1).

The residential tax credit applies to spending for two different types of equipment: 1) "qualified solar electric property" which is "property which uses solar energy to generate electricity for use in a dwelling unit located in the US and used as a residence by the taxpayer[115]" and 2) "qualified solar water heating property" which is "property to heat water for use in a dwelling unit located in the US and used as a residence by the taxpayer if at least half of the energy used by such property for such purpose is derived from the sun."[116]

The residential tax credit can only be used for new equipment and can be taken only when originally installed.[117]To qualify for the residential credit, eligible equipment must be installed before 2016.[118] If equipment is installed in a new home, the date the taxpayer moves into the house is the date when such expenditures are deemed to be made.[119]

A taxpayer's cost of the equipment is the tax basis for purpose of the credit and the equipment cost includes the cost of contractor labor directly associated with its installation.[120] If a dwelling is occupied by more than one individual, then the maximum amount of expenditures that may be taken into account for purposes of the credit is $6,667 in the case of any qualified solar water heating property expenditures.[121]

As with the commercial tax credit, certain grants and rebates may reduce the tax basis of the equipment. Rebates that homeowners receive from a utility for the installation of solar equipment should reduce the basis of the equipment for purposes of the residential tax credit.[122]

New markets tax credits

The New Markets Tax Credit ("NMTC") program was created by Congress in December 2000 to provide tax credits to subsidize investments in businesses and real estate developments serving low-income communities that are typically underserved by investors and lenders.[123] The program has been approved to provide approximately $16 billion in tax credits through 2008 and the Emergency Economic Stabilization Act of 2008 provided for an additional $3.5 billion for fiscal year 2009. The Stimulus increases to $5 billion the amount available for allocation in both 2008 and 2009.[124]

NMTCs are available for equity investments in entities called Community Development Entities[125] ("CDE") that are organized to serve or provide investment capital for low-

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[115] IRC 25D(d)(2).
[116] IRC 25D(d)(1).
[117] IRC § 25D(e)(8)(A).
[118] IRC § 25D(g).
[119] IRC § 25D(e)(8)(B).
[120] IRC § 25D(e)(1). Labor costs that may be added to basis include onsite preparation, assembly, original installation of the property and piping or wiring to interconnect such property to the dwelling unit.
[121] IRC § 25D(e)(4)(A)(i).
[122] IRC § 25D(e)(9).
[123] IRC § 45D(a)(1) provides a new markets tax credit on certain credit allowance dates described in § 45D(a)(3) with respect to a qualified equity investment in a qualified community development entity.
[124] The 1.5 Billion increase in authorized funds for 2008 is available to CDEs who submitted an allocation with respect to calendar year 2008 and either did not received an allocation in 2008 or received an allocation less than the full amount requested. Stimulus Act §1403(b)
[125] The Community Development Financial Institutions Fund ("CDFI") certifies CDEs, allocates tax credit authority to them and, together with the IRS, monitors their investments to ensure compliance with the NMTC restrictions. CDEs have been formed by a wide variety of institutions, including community development corporations and other local nonprofits, small

income communities or low-income persons. Once designated as a CDE, an organization can apply for tax credit authority. Allocations can be awarded to CDEs in any location so long as the investments are made in qualifying low-income communities. The allocation process is competitive and each year CDEs apply for a far greater amount of tax credit authority than the NMTC program is authorized to award. The NMTC program was designed to aid both urban and rural low-income communities but it has been used more widely in larger urban areas. In more recent years, Congress has specifically instructed the CDFI Fund to change its allocation process to better target rural areas.[126]

CDEs that are awarded tax credits must allocate them within five years of the award. [127] The CDEs then negotiate with investors to trade the tax credits for cash investment in the CDE. In return, the investor receives a credit worth 39% of the investment made in the CDE. The credit is a dollar-for-dollar reduction in tax liability, so it covers only taxes owed to the government, and the value of the credit is spread over seven tax years (5% over the first 3 years and 6% over the last 4 years).[128] The capital provided to the CDE by the investors is referred to as "qualified equity investments[129]" ("QEIs") from which the CDEs make "qualified low-income community investments" ("QLICIs") which are generally made in the form of loans or investments with better-than-market terms to business in low-income areas.[130] The CDEs must use substantially all of the funds (generally 85% of the proceeds) as QLICIs and such requirement must be satisfied for each annual period in the 7-year credit period[131].

Investments must be made in "Qualified Active Low-Income Community Businesses."[132] Historically, a majority of the investments using NMTC have been real estate developments, although many other types of investments have been made.

Low-income communities that qualify for the investment of funds include a population census tract if any of the following apply: (1) the poverty rate is at least 20%; (2) if the tract is not located within a metropolitan area, the median family income is not more than 80% of statewide median family income; and (3) if the tract is located within a metropolitan area, the median family income is not more than 80% of the greater of the

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business investment companies, real estate development companies, venture capital firms, insured depository institutions, investment banks and governmental entities. See IRC § 45D(c)(2).

[126] Federal Reserve Bank of San Francisco, Community Development Investment Center Working Paper 2008-04 "Addressing the Prevalence of Real Estate Investments in the New Markets Tax Credit Program", Hanson Fall 2008.

[127] IRC § 45D(b)(1)(C).

[128] IRC § 45D(a)(2).

[129] IRC § 45D(b).

[130] The qualified low income community investments must be in one of four eligible investment types: (1) loans to or investments in Qualified Active Low-Income Community Business (defined further); (2) financial counseling and other services; (3) loans to or investments s in other CDEs, provided that those fund are in turn used to finance investments identified in (1) or (2); or (4) purchase of qualifying loans from other CDEs. See IRC § 45D(d)(1). For the definition of a "Qualified Active Low-Income Community Business" see IRC § 45D(d)(2).

[131] IRC § 45(b)(3). 26 CFR § 1.45D-1(c)(5) provides for methods to calculate whether the substantially-all requirement is satisfied.

[132] To be a "Qualified Active Low-Income Community Business the "qualified business" must generally meet all of the following: (1) at least 50% of the total gross income of such entity is derived from the active conduct of a qualified business within any low-income community; (2) a substantial portion of the use of the tangible property of such entity (either owned or leased) is within a low income community; (3) a substantial portion of the services performed by its employees are performed in an low-income community; (4) less than 5% of the average of the unadjusted bases of the property is collectibles other than collectibles held primarily for sale; and (5) less than 5% of the average of the aggregated unadjusted bases of property held by an entity is nonqualified financial property. IRC § 45D(d)(2).

statewide median family income or the metropolitan area median family income.[133] The allocation process is competitive and in order to be allocated funds an area must usually have other higher distress criteria such as high poverty rate, high unemployment, or lower than median income. In any one year, approximately ten percent of the requested money is actually allocated.

The IRS reserves the right to recapture the value of the tax credits should any one of three things happen: (1) if the CDE loses designation as a CDE, (2) if the CDE fails to invest substantially all of the QEI proceeds as QLICIs; or (3) if the investor redeems its QEI before the end of the seven-year holding period. If any one of the three things happen then the IRS recaptures the credits, the investors lose their right to claim remaining tax credits they have received, and the investors must pay back credits used in prior tax years, plus a penalty and interest.[134]

According to the CDFI Fund, many Colorado counties are within qualifying NMTC Census Tracts.[135]

CDEs may have difficulty establishing how the project will benefit low-income communities and/or low-income persons, particularly if the renewable energy leaves the community in which it was created (such as a ground mounted solar field that connects into the electric grid). The applicant could point out the community benefits from the project such as the labor required to build, assemble, manage, maintain, and run the project, the source of the hardware used and the other positive impacts the project may have on the local community.

Using NMTC to fund renewables projects, and combining them with ITCs, is an emerging practice and involves some uncertainty as to the receptiveness by the CDI Fund to allocate money to CDEs interested in such projects and the potential for a ruling by the IRS to reduce ITCs applicable to the project as a result of the NMTC funding mechanism.

Due to high transaction costs, projects of only certain sizes would be attractive to CDEs.

Some CDEs that focus on alternative energy projects in Colorado and nationally are[136]:

- American Community Renewable Energy Fund, LLC (New Orleans, LA)
- Banc of America CDE, LLC (Washington, DC)
- Boston Community Capital, Inc. (Boston, MA)
- Colorado Growth and Revitalization Fund, LLC (Denver, CO—Colorado Housing and Financing Authority)
- Rural Development Partners, LLC (Mason City, IA)

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[133] IRC § 45D(e). This section was amended by Section 223 of the American Jobs Creation Act of 2004 (P.L. 108-357, 118 Stat. 1418) to expand the definition of "low income communities" to include census tracts in High Migration Rural Counties with a median family income at or below 85% of the applicable area median family income.
[134] IRC § 45D(g); 26 CFR §1.45D-1(e).
[135] See the CDFI Fund website "www.cdfifund.gov" for a document titled "List of Qualifying Census Tracts in Non-Metropolitan Counties for qualifying Colorado counties.
[136] From the 2008 NMTC Program Profiles of Allocatees listed on the CDFI Fund Website; accessed at http://www.cdfifund.gov.

Clean renewable energy bonds (CREBs)

Clean renewable energy bonds ("CREBs") are an interest free financing instrument available to certain qualified issuers[137] and is an incentive available for entities that cannot utilize PTCs or MACRS depreciation. CREBs are typically not available as financing tools for private developers and investor owned utilities that are able to take advantage of PTCs and MACRS depreciation.

A CREB is a special type of bond, known as a "tax credit bond," that offers qualified entities the equivalent of an interest-free loan for financing qualified energy projects for a limited term. CREBs may be purchased and held by any taxpayer.[138] It is important to note that CREBs act as a construction financing tool rather than as a production credit like other incentives.

The first CREBs were created under the Energy Tax Incentives Act of 2005 ("2005 Energy Act") which authorized $800 million for CREBs and delegated authority to the Treasury Secretary and IRS for allocating such funds over the period January 1, 2006 through December 31, 2007.[139] The 2005 Energy Act was originally amended to permit an additional $400 million of tax credit CREB bonds through December 31, 2008.

The Stimulus allocated an additional $800 million in new CREBs[140] ("NCREBs") and extended the deadline for previously reserved allocations for CREBs until December 31, 2009.[141] The Stimulus authorized an additional $1.6 billion in clean renewable energy bond authority bringing the total national bond volume authority to $2.4 billion.

The IRS recently issued Notice 2009-33 providing interim guidance on the NCREBs program rules and application process and changes from prior CREB allocations. NCREBs are very similar to the original CREBs with some notable differences described below. For the remainder of the discussion "CREBs" shall mean to refer to both NCREBs and CREBs unless specifically noted.

To obtain an allocation of bond volume authority for CREBs, a qualified issuer is required to submit an application to the IRS who allocates CREBs on a project-by-project basis beginning with the project(s) for which the smallest dollar amount of volume authority has been requested, and continuing with the project(s) for which the next smallest dollar amount of such limitation has been requested until the total amount of volume authority has been allocated.[142] The application deadline for CREBs was July 13, 2007 and the IRS is no longer accepting applications for CREBs. The deadline for those entities who received an allocation to issue CREBs was extended to December 31, 2009 by the 2008 Emergency Act.

Under the NCREBs program public power providers, government bodies, and electric cooperatives are each reserved an equal (33 1/3 %) share of the most recent allocation.[143] The allocation of the NCREBs is such that for public power providers their

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[137] The 2005 Energy Act CREBs program is codified in Section 54 of the Internal Revenue Code of 1986.
[138] IRC § 54(a).
[139] IRC §54(f).
[140] IRC § 54C(c)(2).
[141] IRC § 54(m).
[142] I.R.S. Notice 2005-98; Notice 2007-26. The Notices state that for purposes of the allocation rules, all qualified projects located at the same site and owned by the same qualified borrower are treated as a single project.
[143] IRC § 54C(c)(2).

1/3 share will be equally shared by all qualifying projects proportionate to the amount requested,[144] and for electric cooperatives and for other governmental projects the Treasury can elect any allocation methodology it chooses[145] but will likely continue to use a "smallest to largest" methodology used for the original CREBs.

Investors in CREBs bonds may take a dollar for dollar quarterly tax credit, whereas the 2008 Emergency Act reduces the tax credit for NCREBs to only 70% of what it would have been otherwise.[146] Lastly, issuers of CREBs must use 95% of the proceeds for qualifying renewable energy resource facilities[147] but issuers of NCREBs must use 100% of the proceeds for qualifying renewable energy resource facilities.[148]

Entities qualified to issue CREBs[149] include governmental bodies,[150] mutual or cooperative electric companies[151] and clean energy bond lenders[152]— namely, the National Rural Utilities Cooperative Finance Corporation and Cobank. NCREBs may also be issued by public power providers.[153] In addition to the requirement that CREBs be issued by a "qualified issuer," a CREB-financed project must be owned by a qualified borrower. "Qualified borrowers" include any mutual or cooperative electric company and any governmental body for one or more qualified renewable energy facilities.[154] Public power providers are "qualified borrowers" for NCREBs.[155] In some instances, an entity can lend to itself if it qualifies as both an issuer and borrower under the CREBs rules. Projects that qualify for the PTC generally qualify for CREB financing, including solar facilities.[156] Note that projects located at the same site and owned by the same qualified borrower will be treated as a single project.[157]

To obtain an allocation of bond volume, a qualified borrower is required to submit an application to the IRS by the applicable deadline.[158] There is no application fee, however there may be preparation costs involved. The application deadline for CREBs was July 13, 2007. The application deadline for NCREBs is August 4, 2009. The form of application can be found in IRS Notice 2009-33.

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[144] IRC § 54C(c)(3)(A).
[145] IRC § 54C(c)(3)(B).
[146] IRC §54C(b).
[147] IRC § 54(h).
[148] IRC § 54C(a)(1).
[149] IRC § 54(j)(4); IRC § 54C(d)(6) "NCREBs".
[150] IRC § 54(j)(3) defines a "governmental body" as any State, territory, possession of the United States, the District of Columbia, Indian tribal government and any political subdivision thereof. See also IRC § 54C(d)(3) "NCREBs".
[151] IRC § 54(j)(1) defines a "cooperative electric company" as a mutual or cooperative electric company described in Section 501(c)(12) or Section 1381 (a)(2)(C), or a not-for-profit electric utility which has received a loan or a loan guarantee under the Rural Electrification Act. See also IRC § 54C(d)(4) "NCREBs".
[152] IRC § 54(j)(2); IRC § 54C(d)(5) "NCREBs".
[153] IRC § 54C(d)(2). "Public power provider" means a State utility with a service obligation, as such terms are defined in section 217 of the Federal Power Act.
[154] IRC § 54(j)(5). See also IRC § 54C(a)(1) "NCREBs".
[155] IRC § 54C(d)(2).
[156] IRC § 45(d)(4) defines "solar facilities" as a facility that uses solar energy to produce electricity. See also IRC § 54C(d)(1) "NCREBs".
[157] I.R.S. Notice 2007-26. Each application must: (1) identify the qualified borrower expected to own the project, (2) if any of the bonds are expected to be issued as pooled financing bonds, demonstrate that the qualified issuer will enter into a written loan commitment with each qualified borrower prior to the issue date of the bond issue, (3) describe in detail the project to be financed with the proceeds of the bonds, (4) demonstrate that the project will constitute a qualified project, and (5) contain a detailed description of the plan of financing[157]. Issuers are required to obtain a certification of an independent licensed engineer stating that the project is a qualified project and certifying as to the project's technical viability**.**
[158] I.R.S. Notice 2007-26. The Notice provides detailed guidance regarding CREB volume authority allocations and the specifics for volume authority applications.

Once approved, the electric cooperative or cooperative lender ("CREBs Issuer") issues the CREBS and sells them to the bondholders. In contrast to a conventional bond where the issuer pays interest to the bondholder, with a tax credit bond the issuer does not make interest payments but instead the federal government provides a tax credit to the bondholder. The maximum term of the bonds is calculated through a formula that is dependent upon interest rates and, based on current interest rates, the maximum term of a CREB is about 15 years.[159] The interest rate on CREBS is set by the Treasury daily and when the bondholder purchases the bond, the credit rate is locked in for the term of the bond.[160] Principal on the bond is repaid in equal annual amounts.[161]

Once approved, an issuer has up to two years to issue the bonds. Once issued, qualified borrowers are subject to several spending requirements.[162] A qualified issuer of CREBs must reasonably expect: (1) that at least 95% of the proceeds of the issue will be spent for one or more qualified projects within the 5 year period beginning on the date of issuance (and 100% with NCREBs), (2) to enter into a binding commitment within 6 months of the date of issue with a third party to spend at least 10% of the proceeds of the issue or in the case of an issue the proceeds of which are to be loaned to two or more qualified borrowers, such binding commitment will be incurred within the six-month period beginning on the date of the loan of such proceeds to a qualified borrower, and (3) the projects will be completed with due diligence and the proceeds of the issue will be spent with due diligence.[163]

If less than 95% of the proceeds are spent at the end of the 5 year period (or any extension thereof), then the qualified issuer must redeem all of the nonqualified bonds within 90 days of the end of such period.[164] NCREBs must be spent 100% for one or more qualified projects.[165] Additionally, you may use CREBs to refinance existing debt in some circumstances and may be used to reimburse expenditures related to qualified projects in certain circumstances.[166]

USDA's 9007 program

USDA's 9007 program may offer opportunities for rural PV development.

Generally, Section 9007 offers financial assistance in the form of grants, direct loans, and loan guarantees for renewable energy systems and energy efficiency programs for agricultural producers and rural small businesses. Participation requires navigating fairly considerable regulation. But as the available support may be considerable, the associated "red tape" may be worth the effort.

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[159] The maximum term of CREBs is the term that the Secretary of the Treasury estimates will result in the present value of the obligation to repay the principal on the bond being equal to 50% of the face amount of such bond. IRC § 54(e)(2).
[160] IRC §54(b)(3).
[161] IRC §54(l)(5).
[162] There are arbitrage restrictions that apply to the investment of CREBs proceeds, as well. See IRC § 54(i) and I.R.S. Notice 2007-26.
[163] IRC § 54(h)(1). If requested prior to the expiration of the 5 year period, the Secretary of the Treasury may extend such period if the qualified issuer establishes that the failure to satisfy the 5 year requirement is due to reasonable cause and the related projects will proceed with due diligence.[163] While there are strict spending requirements and deadlines with CREBs there are no placed-in-service date requirements for CREBs as with the PTC.
[164] IRC § 54(h)(3).
[165] IRC. § 54C(a)(1).
[166] See IRC § § 54(d)(2)(B) & 54(d)(2)(C).

Program participation is only open to “agricultural producers” and “rural small businesses,” both of which terms are defined.[167] As a first step, an interested party should confirm it fits within the scope of the authorized applicants.

“Agricultural producer” means “[a]n individual or entity directly engaged in the production of agricultural products, including crops (including farming); livestock (including ranching); forestry products; hydroponics; nursery stock; or aquaculture, whereby 50 percent or greater of their gross income is derived from the operations.”[168]

“Rural small business” is defined in two parts – “rural” and “small business.”

The regulations define “rural” as “[a]ny area other than a city or town that has a population of greater than 50,000 inhabitants and the urbanized area contiguous and adjacent to such a city or town according to the latest decennial census of the United States.”[169]

The regulations define “small business” as an entity considered a small business in accordance with the Small Business Administration's (“SBA”) small business size standards by the North American Industry Classification System (“NAICS”) found in Title 13 CFR part 121. A private entity, including a sole proprietorship, partnership, corporation, cooperative (including a cooperative qualified under section 501(c)(12) of the Internal Revenue Code), and an electric utility, including a Tribal or governmental electric utility, that provides service to rural consumers on a cost-of-service basis without support from public funds or subsidy from the Government authority establishing the district, provided such utilities meet SBA's definition of small business. These entities must operate independent of direct government control. With the exception of the entities described above, all other non-profit entities are excluded.[170]

Determining “small business” status is beyond the scope of this paper. Therefore, anyone considering a 9007 application based on rural small business status should consult with the USDA to confirm satisfaction of the basic eligibility requirements.[171] That said, the SBA regulations apply to a variety of business categories, including manufacturers, retailers, and wholesalers,[172] meaning any number of rural Colorado small businesses may be eligible for 9007 opportunities.

In addition to the business qualifying as either an “agricultural producer” or “rural small business,” the project must also qualify.

Generally, and for purposes of an hypothetical rural PV project, qualification requires: (a) the purchase of a commercially available PV system; (b) the PV project have “technical merit,” as determined by the regulations; (c) applicant ownership and control of the project and its associated revenues and expenses, including operations and maintenance; (d) applicant site control; and, (e) sufficient owner resources to satisfy operations and maintenance requirements.[173] Further, in the case of grants, the

[167] The complete applicant eligibility requirements are listed at 7 CFR §4280.107.
[168] 7 CFR § 4280.103.
[169] 7 CFR § 4280.103.
[170] *See* 7 CFR § 4280.103.
[171] Considering the breadth of the 9007 regulations, working with the USDA in connection with any 9007 application seems essential.
[172] *See* 13 CFR § 121.201.
[173] *See* 7 CFR § 4280.108.

applicant must demonstrate "financial need," which means demonstrating an inability to finance the project on its own or with commercially available resources, without grant assistance, or that the project cannot achieve sustainable income and cashflows without grant assistance.[174]

Beyond these general requirements, the regulations impose more considerable, additional application requirements. The nature and volume of these more considerable application requirements depend on project cost – simplified applications apply to projects with a gross cost of less than $200,000, while the more onerous requirements apply to applications for projects with gross costs in excess of $200,000. Either way, but especially in the case of larger projects, the 9007 application requirements are considerable. And in the case of either small or large projects, the application requirements cannot be regarded as "paperwork."

The regulations detail project scoring guidelines.[175] Therefore, applications should be presented (and in fact projects should be developed from inception) considering these scoring parameters. The most significant one feature to note within the project scoring guidelines is "replicability."

The sheer volume of the 9007 application requirements suggests project aggregation -- multiple applicants working together (probably with USDA) and with one project integrator.

On their face, the 9007 project requirements *seem* to eliminate certain project enhancements, such as: (a) third-party, tax-credit driven models, as applicant ownership of the project is required, while the tax rules would require tax-credit investor ownership during the recapture period to take advantage of the ITC; and, (b) financial enhancements based on non-profit status (e.g. CREB's)[176], given the broad prohibition against non-profit participation.[177]

Technical interpretation of the 9007 regulations would certainly eliminate application of certain project concepts, as well as eliminate certain projects that fail to meet the very broad regulatory requirements; however, the regulations incorporate broad "exception" authority, allowing exceptions "on a case-by-case basis" "to any requirement or provision" of the regulations "that is not inconsistent with any authorizing statute or applicable law." What this means for any one project is unclear. It seems safe to presume, however, that an applicant could rely on this broad exception authority in connection with requesting a minor deviation from the regulatory requirements. Regardless, the right project may very well compel seeking exception authority in connection with a substantive deviation. Working directly and early with USDA in connection with a request for exception authority for a substantive deviation seems essential.

[174] *See* 7 CFR § 4280.103.
[175] *See* 7 CFR § 4280.112(e).
[176] Rural REA participation in both 9007 and CREBs programs may be possible, given the rural REA's apparent inclusion within the scope of small businesses.
[177] *See* 7 CFR § 4280.103.

Appendix C
Other state and federal incentives for PV

Net metering[178]

Solar net metering requires an electric company to pay a consumer for any excess electricity the consumer's PV system produces.

Currently, PV systems that generate up to 2 MW in capacity are eligible for net metering in IOU service territories. Municipal utilities and REAs subject to lesser maximums as described below. Electricity generated at a customer's site can be applied toward meeting an RPS.

Colorado's net-metering rules require that any customer net excess generation ("NEG") in a given month is applied as a kilowatt-hour (kWh) credit to the customer's next bill. If in a calendar year a customer's generation exceeds consumption, the utility must reimburse the customer for the excess generation at the utility's average hourly incremental cost for the prior 12-month period.

If a customer-generator does not own a single bi-directional meter, then the utility must provide one. Systems over 10 kW in capacity require a second meter to measure the output for the counting of RECs. Customers accepting IOU incentive payments must surrender all RECs for the next 20 years. REAs and municipal utilities may develop their own incentive programs at their discretion.

As of March 2008, municipal utilities with more than 5,000 customers and REAs must offer net-metering. The new law allows residential systems up to 10 kW in capacity and commercial and industrial systems up to 25 kW to be credited monthly at the retail rate for any net excess generation their systems produce. Co-ops and municipal utilities are authorized to exceed these minimum size standards.

A recent law signed in April 2009 made several changes to the net metering rules for IOUs as they apply to PV systems. These changes include changing the maximum system size from 2 MW to 120% of the annual consumption of the site; redefining a site to include all contiguous property owned by the consumer; and allowing system owners to make a one-time election in writing to have their annual net excess generation carried forward as a credit from month to month indefinitely, rather than being paid annually at the average hourly incremental cost for that year. This law takes effect September 1, 2009.

Additional state sources

The following additional sources may provide enhancements for PV projects:

- Colorado Clean Energy Fund[179]

[178] Information largely from "Colorado-Net Metering," Database of State Incentives for Renewables and Efficiency (DSIRE), accessed 5/21/09 at http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=CO26R&state=CO&CurrentPageID=1.

[179] The Clean Energy Fund was created in 2007. It allows the Governor's Energy Office to distribute funds designed, in part, to assist in advancing renewable energy development in Colorado. The fund uses revenue from the Limited Gaming Fund that would have otherwise been transferred to the General Revenue Fund and does not include sunset provisions.

- Colorado Clean Energy Development Authority[180]

Stimulus $$

The American Recovery and Reinvestment Act of 2009 ("ARRA") enacted February 17 of this year directs $787 billion into the US economy, $43 billion of which is designated for energy programs. Colorado expects to receive $3 billion from the ARRA, without taking into account tax relief for individuals and businesses. In all, Colorado could receive more than $7 billion over the next three years from the ARRA.

According to Recovery.gov, Colorado has been allocated $49,222,000 for state energy programs. GEO is overseeing and tracking the use of these discretionary funds, which must be obligated by September 30, 2010 and must be spent by March of 2012. In the Governor's report entitled "The American Recovery and Reinvestment Act; What it means for Colorado" dated May 8, 2009, the following goals are listed for these funds:

- work with utility companies to increase energy efficiency to reduce energy costs and consumption for consumers, businesses, and government;
- reduce reliance on imported energy;
- improve the reliability of electricity and fuel supply and delivery of energy services; and,
- reduce the impact of energy production and use on the environment.

Rural interests considering PV projects and interested in Stimulus funds should begin to consider pursuing these funds.[181]

These opportunities are evidence of the dynamic nature of the renewable industry and of funding sources. These opportunities should be tracked for the purpose of identifying enhancements to funding potential projects.

Additional federal sources

- USDA Rural Development Electric Program[182]
  USDA Natural Resources Conservation Service; NRCS Colorado Environmental Quality Incentive Program ("EQIP")[183]

Presumably, money allocated to the Clean Energy Fund could be used to enhance projects like those described in this paper. The Governor's Energy Office awards funds in connection with its "New Energy Economy Development ("NEED") grant program.

[180] The Clean Energy Development authority was created in 2007. Its purpose, in part, is to increase the use of clean energy by assisting with financing options. The Authority can issuance bonds, make guaranties, make loans, and enter other financing agreements. The law that created the Authority does not allocate funds to the Authority or specify a source for Authority funds. Nevertheless, options with the Authority should be considered given the Authority's broad purpose.

[181] GEO's plan for a portion of the Stimulus funds is available at http://www.colorado.gov/energy/images/uploads/pdfs/GEO_ARRA_Program_Goals_and_Objectives.pdf

[182] *See* www.rurdev.usda.gov/rd/pubs/pa1789.htm.

[183] A broad description of USDA's Natural Resources Conservation Services conservation programs is available at http://www.nrcs.usda.gov/programs. Certain of these programs may present opportunities for funding for PV systems. By example, while not a strong fit, the 2009 application for "Conservation Innovation Grants" includes as a technical review group "On-Farm Energy Resources." Work with an NRCS office is suggested if considering PV opportunities.

Appendix D
Economic analysis
Simple PV purchase and installation

In order to determine the cost of purchasing and installing a PV system and the number of years it will take to recoup the system costs, many factors should be considered. The following provides basic considerations.

At a very basic level, the payback period = Total PV costs/total estimated annual energy savings, as further defined below[184]

Total PV Costs= (PV system cost after incentives) + (Maintenance costs x Equipment lifetime)

Total Est. Annual Energy Savings= (Annual system kWh production) x (Your electric rate cost per kWh)

Total PV Costs

PV Equipment and Installation. The basic cost of a PV system includes the costs of the PV system itself and installation. The cost of a PV system will depend on a number of factors, including system size and the energy efficiency of your home, whether the home is under construction and whether the PV is integrated into the roof or mounted on top of an existing roof. The cost also varies depending on the PV system rating, size, manufacturer, retailer and installer.

Small-scaled PV systems with built-in inverters that produce about 600 watts of power may cost about $10 per watt ($6,000). These small systems will offset only a small fraction of an electricity bill. A 2-kW system that will offset the needs of an energy-efficient home may cost $8 to $10 per watt ($16,000-$20,000). At the high end, a 10-kW system that will completely offset the energy needs of a conventional home may cost $7 to $8 per watt ($70,000-$80,000). These costs include the cost of the PV modules, the inverter, PV array support structures, electrical cabling, equipment and installation. Additional costs to consider include permitting, borrowing costs, inflation, potential increases to property taxes and insurance as a result of the PV system.

Maintenance. Studies report maintenance costs vary with systems size and suggest 2% of total hardware costs may be a good estimate for annual maintenance charges.[185]

Equipment Life. While PV module warranties may be as long as 20 years and inverter warranties are typically 10-15 years, it may be reasonable to estimate the PV equipment lifetime to be 25 - 30 years. Of course, the actual life could vary significantly from these estimates depending on the individual PV system

Rebates and incentives reduce system costs

[184] "Simple Calculation for Solar PV Payback," GoGreenSolar.com; accessed 5/31/2009 at http://www.blog.gogreensolar.com/2009/04/simple-calculation-for-solar-pv-payback.html.
[185] *See* "Photovoltaic Economics" Atomstromfreie Website powered by Greenpeace Energy; accessed at http://www.pvresources.com/en/economics.php.

The cost of a system is reduced by federal tax credits and any rebates that might be offered. PV qualifies for a 30% tax credit for commercial and residential installations until 2016.[186] The costs qualifying for the federal tax credit for residential PV are no longer capped. The tax basis or qualifying cost of the PV for purposes of the credit is reduced by certain grants, rebates and other incentives.[187]

PSCo and Black Hills administer their own rebate programs. Territories outside these service areas may obtain rebates from other sources, including GEO.

PSCo. The Solar Reward Program[188] provides up to a $3.50-per-watt (DC) incentive for customers who install grid-connected PV systems of between .5 kW to 100 kW. The incentive is structured as a $2/watt Standard Rebate Offer and a $1.50-per-watt Solar On-Site REC payment (for .5-10kW systems) or a monthly payment of $115 per MWH of energy produced (for 10.1kW-100kW systems). For large commercial systems over 100 KW PSCo accepts requests for proposals and there is a $200,000 rebate cap.

Black Hills. Black Hill's On-Site Solar PV Rebate Program[189] provides an incentive of $2 per watt DC of installed PV capacity combined with a payment for the RECs associated with the PV system. Rebates are given for newly installed PV with up to 100 kilowatts of capacity. Rebates for PV systems up to 10 kW are $2 per DC watt, and a one-time REC payment is currently set at $2.50 per DC watt. Rebates and REC payments for PV systems greater than 10kW and up to 100kW are $2 per DC watt, with an annual REC payment of $115 for every MWh of actual metered output of the system.

GEO. GEO is currently providing matching grants to establish solar rebate programs throughout the state in areas outside the service territories of PSCo and Black Hills.[190] Unfortunately, the application deadline has passed for the most recent funding deadline and renewal or extension of the rebate program has not yet been announced at this time. The Colorado Solar Energy Industries Association administers the grant program and it is available for rebate on both residential and small business systems through program partners in the certain territories. If available, the program partners offer rebates of up to $9,000 for residential systems and up to $15,000 for small business systems (cost of the rebate split between GEO and the local program partner). There is also a rebate program of up to $3,000 to re-commission existing, orphan solar systems. Only grid tied, net metered systems are eligible.

Estimated Annual Energy Savings

The total estimated energy produced by a PV system = the PV systems rated capacity * 80% capacity factor[191] * 5.5[192] (estimated the average daily hours of sun in your area, which may be higher or lower).

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[186] IRC §§ 48 and 25D.
[187] IRC § 25D(e)(9).
[188] *See* Xcel Energy rebate program website accessed at http://www.xcelenergy.cm/residential/renewableEnergy/Solar_Rewards/Pages/home.aspx.
[189] *See* Black Hills Energy rebate program website accessed at http:// www.blackhillspv.programprocessing.com.
[190] *See* the Colorado Governor's Energy Office website at http://www.colorado.gov/energy/index.php?/renewable/solar-rebate-program/ and the Colorado Solar Energy Industries Association website accessed at http://www.coseia.org/newsite/index.php?id=96 for information on the rebate program.
[191] Solar panels are rated under ideal, laboratory conditions. In reality, there are cloudy and rainy days and other factors contribute to actual output at less than ideal conditions. A 20% capacity reduction is common in the industry but the actual results may vary depending on each particular situation. *See* www.energybible.com/solar_energy/calculating_payback.html.

Review of recent electricity bills should give you a good idea of your average electricity cost and usage. In Colorado, typical electricity costs in 2008 were $00.89 per kWh for residential customers and $00.73 per kWh for commercial customers.[193] Keep in mind that electricity costs are likely to rise in the future.[194]

PV payback calculators

The following online PV payback calculators may provide a simpler method of estimating any savings from a PV system or its payback period:

- www.infinitepower.org/calc_pv.htm
- www.builditsolar.com/Projects/PV/pv.htm
- www.solar-estimate.org
- www.BPSolar.cleanpowerestimator.com/pbsolar.htm

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[192] Per NREL map of "Photovoltaic Solar Resource"; most of Colorado receives an average of 5.5-6 hours of sun per day; parts of southern Colorado receive an average of 6-6.5 hours of sun per day. See map accessed at http://www.nrel.gov/gis/images/map_pv_us_annual10km_dec2008.jpg.

[193] "Average Retail Price of Electricity to Ultimate Customers by End-Use Sector, by State,"Energy Information Administration, Official Energy Statistics from the US Government; accessed 5/28/09 at http://www.eia.doe.gov/electricity/epm/table5_6_b.htm.

[194] A conservative estimate would be a 4% per year increase in electricity costs. *See* "Calculating Payback for a photovoltaic system," www.energybible.com; accessed 5/31/09 at http://www.energybible.com/solar_energy/calculating_payback.html.

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