Ownership and Regional Economic Impact:
The Case of Wind Development in Minnesota

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July, 2010

Abstract: *The Upper Midwest is poised for a major investment boom in wind-powered electricity generation. Public policy currently favors corporate ownership structures for new investment in this field, but when wind development takes place under the aegis of an external corporate ownership group the local economic participation will generally be limited to a minor role. This study attempts to quantify the regional value-added and employment consequences of local- versus outside-ownership of wind-powered electricity generation. We employ a realistic pro forma model of a "flip" structure -- i.e. a local equity "community wind" group partnered with an external tax-motivated equity group -- for a modestly sized (9.9 MW) wind farm, using recent vendor-certified capital costs combined with additional financial estimates from industry participants, assuming a class four wind resource. The present value of the residuals (after tax profits) as well as the other O&M expenditures are annuitized and entered into a Minnesota state-level input-output model. We find that, respectively, under pessimistic and optimistic parameter assumptions in the community-wind group's pro forma, the impact on state-level value added is 3.1 and 4.5 times larger than the impact would be under an external ownership structure. The impact on employment is respectively 2.5 and 3.5 times larger than that generated by an external ownership structure.*

* Research support provided by The Bremer Foundation and The West Central (Minnesota) Sustainable Development Partnership. The author thanks John Ihle, Dan Juhl, and Lowell Rasmussen for generously sharing data and experience. Research assistance was provided by Dugan Flanders and Thompson Clifford.

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I. Introduction

With RES legislation growing in popularity across the U.S., current economics favor an immense build-out of wind over the course of the next decade.[1] A great deal of analysis has focused on the location of best wind resources, and upon the technology and infrastructure (transmission capacity, balancing generation, and possible storage media) that will be necessary to incorporate significant quantities of wind power into the generation mix.[2]

In practice, public policy has been an influential if not decisive factor in shaping both the volume of wind development and also the specific business organizational form that this development assumes.[3] Current policy, for example, favors firms with sufficiently large tax liabilities and with an established capital market presence. Smaller pools of local capital, organized as partnerships, cooperatives, municipals, non-profits, or LLCs, have a more difficult time taking advantage of the full range of existing public policy incentives. A recent survey found that only 4% of U.S. wind capacity is locally owned, in stark contrast, for example, to the northern European figures of 83% and 45% in Denmark and Germany, respectively.[4]

When wind development takes place under the aegis of an external corporate ownership group, the local economic participation will generally be limited to a minor role in construction (e.g. cement contracting), enhanced property tax collections, and a continuing stream of land-lease payments (often in the range of $3K - $4K per year). Compared to corporate projects, some research has suggested that locally-owned "community wind" projects will likely spend more locally on attorney fees, electrician services, and other construction-related outlays.[5] The largest effect, however, may be the residuals of the project, which would enter the local economy directly as income streams.[6]

1 Twenty-eight states and the District of Columbia have adopted Renewable Electricity Standards, while five more have adopted voluntary targets. (http://apps1.eere.energy.gov/states/maps/renewable_portfolio_states.cfm, last accessed June 21, 2010). See the [California] Renewable Electricity Transmission Initiative (2008) for a relative ranking of levelized renewable generation costs. NREL researchers recently estimated that in order to reach a national goal of 20% of electricity production from wind power by the year 2030, annual installations of new capacity will have to grow by 2018 to over 16 gigawatts per year, which was roughly the entire installed capacity in the U.S., as of 2008 (Laxon, Hand, & Blair, 2008).

2 One comprehensive example is the U.S. Department of Energy report 20% Windpower by 2030 (U.S. D.O.E., 2008).

3 Kildegaard (2007). Bolinger and Wiser (2004).

4 Windustry: http://www.windustry.com/communitywind (last accessed June 21, 2010). In Minnesota, the figure is 25%.

5 Grover (2005), Northwest Economic Associate (2003).

6 Lantz and Tegen (2008), Kildegaard and Myers-Kuykindall (2006).

Much of the best on-shore wind resource in the U.S. is located in the central Great Plains.[7] It is an open question as to whether or not the local communities there will embrace and promote the anticipated wind development, or whether local resistance will prove too strong -- as for example it has with respect to on-shore wind development in England. In the latter case, extensive research has established that successful local resistance is strongly related to an unacceptable balance between *local* costs and *local* benefits, despite a national policy that strongly promotes wind development.[8] In the socially conservative region of the U.S. Great Plains, it seems likely that political support for wind development traces more to the economic potential that it represents than to environmental sensibilities *per se*. A public policy that aims to encourage wind development in general might yet prove to be undermined by tax incentives and other policy provisions that strongly discourage local ownership.

Since ownership structure is an outcome significantly influenced by public policy, and potentially a determinant of community acceptance in this region poised for rapid wind development, this study investigates the consequences of ownership structure for local economies. Specifically, we conduct our analysis of Minnesota, where community wind is an established force in state policy and the policy developments relating to grid connection and tariffs are reasonably far along.

A few fairly modest attempts have been made to analyze the differential economic development consequences of locally-owned wind development.[9] This article pursues this question with some important enhancements: i) the cost data are actual and up-to-date, vendor-certified costs as of late 2009; ii) the power prices are consistent with power purchase agreements recently approved by the Minnesota Public Utilities Commission; iii) a fully-articulated financing model is included, complete with a tax equity partner and with supplementary bank financing; iv) the local ownership residuals (as well as the various O&M expenses) are inserted into a state-level input-output model to capture the effects of the project on the regional economy.

II. Ownership Structures

Capturing the federal tax incentives is a key element of project design, comprising as these do somewhere in the range of 30-40% of a project's overall revenue stream.[10] Bolinger et al. (2004) and

7 U.S. Department of Energy windmaps: http://www.windpoweringamerica.gov/wind_maps.asp (last accessed June 21, 2010).

8 Toke (2005); Devine-Wright (2005); Rogers et al. (2008); Hain et al. (2006)

9 Galluzzo (2005), Grover (2005), Kildegaard and Myers-Kuykindall (2006), Lantz and Tegen (2008),

10 The production tax credit (PTC) currently stands at $21/MWH, while the double declining depreciation allowance allows full write-down of the project's capital costs in just five years.

Kildegaard and Myers-Kuykindall (2006) describe various ownership structures for local capital to participate in wind development, the most successful of which in fact capture the majority of the federal incentives. Harper et al. (2007) survey and evaluate a variety of financing structures for larger projects, again with the capture of federal incentives being a principal objective.

One common structure involves a tax equity partner with sufficient tax appetite to consume the entire federal incentive. Frequently an ownership “flip” is arranged at a pre-determined moment, for example upon the expiration of the production tax credit (after 10 years), or after the tax equity partner has achieved a pre-negotiated after-tax internal rate of return on its original investment. After the flip takes place, majority ownership rights to the remaining cash flow devolve back to the local equity group.

In the analysis that follows we formally model an ownership structure in which an equity partner captures most (99%) of the tax incentives (depreciation, production tax credits, interest deductions) over the first 10 years of the project. For years 11-20 the ownership shares flip to 5% for the tax equity investor and 95% for the local investor.[11] The project’s total debt financing is calibrated to enable the tax-motivated equity partner to achieve a targeted after-tax internal rate of return (IRR) on its 99% equity stake. The term on the debt is chosen to maintain debt service coverage requirements at acceptable levels. Since the flow of benefits to the local equity group is extremely uneven (see below) over the project’s 20-year lifespan, we calculate and annuitize the net present value of these benefits.[12] The local ownership residuals of the project are subsequently entered into a state-wide input-output model, wherein the ultimate economic impacts are estimated and compared with projects employing exclusively non-local equity

III. <u>Pro Forma</u> Modeling

A 20-year *pro forma* model was created for a 9.9 MW project (6 x 1.65), incorporating the actual capital, development, and O&M costs from a current project at the University of Minnesota. These costs are presented in Tables 1-2.

We construct two scenarios (*optimistic* and *pessimistic*), with parameters reported in Table 3. The key differences include, respectively: 1) interest rates on bank debt; 2) requisite after-tax internal

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11 5% is the minimum IRS requirement for the tax partner’s continued participation. See Harper et al. (2007), esp. pp.69-70.

12 For example: if the after-tax net present value comes to $5 million, at a discount rate of 5%, this is equivalent to an 20-year annuity stream of $401,212.94 annually. In this case, we would use the annuity payment as a key input to the state-level input-output model.

rates of return; 3) discount rates applied to the ultimate net cash flows. These differences in free parameters lead to some key differences in endogenous variables, including: 1) levels of overall debt financing in the project; 2) capital contributions on the part of the tax equity partner; 3) debt maturities.[13] A screen-shot of the pro forma cash flow sheet (years 1-7) is presented as Table 4.

Figure 1 shows the annual after-tax, net profit share of the project accruing to the local ownership group. As with most flips, the local equity partner returns are much larger late than early.[14] Both scenarios share a common trajectory. Year 11 the local investor is assigned 95% of the project's operating cash (and attendant profit taxes), but the remaining years of debt service (two and five years, in *optimistic* and *pessimistic* respectively) ensure that the corresponding *net* cash distribution is much lower. After the debt is retired (year 12 or 15), the project's net cash equals its operating cash. With the ownership shares now flipped, distributions to the local investor rise much higher for the duration of the project.

Figure 2 focuses on the first decade, where it can be seen that the returns to the local investor are essentially identical across scenarios.[15] Since the numbers are in current, non-discounted dollars, one might visualize the benefits net of the opportunity cost of capital, by annuitizing (over 20 years) the initial local equity investment. For example, in the *optimistic* scenario, approximately $144,000 is initially invested; at a discount rate of 5% this equates to 20 annual payments of roughly $11,500. Figure 2 also graphs the *optimistic* and *pessimistic* scenarios after subtracting the opportunity cost of capital (O.C.C.). Over the first decade of the horizon, this correction appears to make a rather significant difference; however, as Figure 1 illustrates, in the 11th year the returns turn highly positive. After year 12 (*optimistic*) or 15 (*pessimistic*), the $11,500 correction is nearly two orders of magnitude below the benefit stream.

Figure 3 illustrates the uncorrected difference between net benefits in the two scenarios. The returns are essentially identical outside of years 11-15. For years 11-12, the *optimistic* scenario is impacted by assumption of 95% equity share (raising the tax liability), as well as full responsibility for the two remaining years of debt service. The 11th year shock to the *pessimistic* scenario is mitigated by

13 Debt maturities are set to ensure that the debt service coverage ratios never fall below 140%, and that the total local return never falls negative in any given year.

14 In practice, there are various methods employed to advance the return to the local investors. These may include for example an expense item through which the tax-motivated partner pays a "management fee" to the local partners. Alternatively, an upfront development fee may be paid to the local investors. Each of these strategies has specific legal and tax consequences, incorporation of which would add more heat than light to the analysis here. Presumably, financial instruments may be employed to shift the timing of cash flows in a straightforward manner.

15 A significant portion of the early returns take the form of tax benefits, resulting from the favorable depreciation allowance ("double declining balances method"). We assume that the local investors have sufficient tax appetite to make full use of the depreciation and production tax credits accruing to their 1% of the project.

the extended term of the loan, which lowers debt service on an annual basis. In year 13, the *optimistic* scenario is free and clear of debt obligations, and the net returns rise accordingly.

An alternative measure of the return on local equity is simply to calculate the internal rate of return (IRR) on a rolling basis. Figure 4 illustrates the paths for each scenario, plotting the IRRs for years 2-20. The IRRs reach zero (indicating full recuperation of the initial outlay) after 5 and 5.5 years, for *pessimistic* and *optimistic* scenarios, respectively. The IRRs reach the respective discount rates (6% and 5% respectively) between years 7 and 8 -- indicating a break-even after-tax net present value of zero. The IRRs grow sharply after year 10 (the flip year), and again after year 12 (*optimistic*) or 15 (*pessimistic*), at which point the debt is fully retired. At the project's conclusion, IRRs have reached 32% (*pessimistic*) and 37% (*optimistic*).

In present value terms, discounting future after-tax net proceeds from the project, the two scenario yields are presented in Figure 5.[16] Under the *pessimistic* scenario, the after-tax present value of the project comes to $3.876m.; the *optimistic* scenario comes to $7.027m. For a better sense of the average annual revenue, Figure 6 annuitizes the totals from Figure 5 for a 20-year lifespan of the project, at the previously-given after-tax rates of returns. The *pessimistic* scenario produces the equivalent of a 20-year annuity payment of $338k, while the *optimistic* scenario produces a 20-year annuity payment of $563k.

In addition to the two scenarios described above, we also model a third ("*non-local"*), corresponding to the impacts of wind development under external corporate ownership. For the non-local scenario we assume identical O&M streams, however the pre-multiplier income stimulus is limited to the after-tax land-lease payments, since the project's residuals accrue externally to the region.

The next section considers the state-wide economic impact, when these direct value-added effects are added to O&M spending streams, and subsequently allowed to operate through realistic local spending multipliers.

IV. Input-Output Analysis

In this section we use the outputs of the *pro forma* analysis as inputs to an economic impact analysis. Specifically, we plug the data from the *pro forma* analysis into a state-level (Minnesota)

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16 Since the annuity has a present value exactly equal to the local equity stake, subtracting the annuity payment from the gross, and then discounting the cash flow is identical to simply calculating the discounted present value of the gross cash flow, net of the initial equity investment.

input-output analysis,[17] using data and software from the Minnesota IMPLAN Group.[18]

There are two distinct categories of impacts, having to do in the first instance with capital expenditures and construction, and in the second with on-going operational expenditures and local re-circulation of profits from the project. Our analysis is exclusively concerned with the latter, which are the lasting effects.

Since both the net revenue stream accruing to local ownership and the expenditure stream associated with on-going O&M are variable, the local economic impact will differ from year to year. In principle these streams could be smoothed over the 20-year project life-span, either through contractual terms between the partners or through financial arrangements entirely separate from the partnership. The specific timing of impacts is of less interest here than the average magnitude of these impacts, so we proceed by effectively annuitizing both the expenditure and the net revenue streams, and using these as a point of departure for the input-output model. Figure 7 presents the annuitized values of the O&M expenditure streams under each scenario,[19] including the breakdown according to expenditure category. These expenditure categories are subsequently mapped to the industry/commodity categories of the IMPLAN database, as reported in Table 5.

Table 6 reports results from simulating the impact of each scenario on the two most obvious indicators: value added, and employment. Figures 8 and 9 present the findings graphically.[20] In terms of value added (including wages, profits, rents and taxes), the *optimistic* and *pessimistic* local ownership scenarios add an annual flow of $1.533m. and $1.05m., respectively, as compared with the outside ownership contribution of $344k. In terms of employment, the *optimistic* and *pessimistic* local ownership scenarios contributed an annual equivalent of 12.4 and 8.8 jobs, as compared with the

17 Miller and Blair (2009) is comprehensive reference for input-output modeling, including full development of social accounting matrices.

18 IMPLAN Professional® Version 2.0. Our model uses the full social account matrix (SAM) specification, including all household institutions of final demand, along with s*tate and local government* (both *education* and *non-education* spending). The regional purchase coefficients are estimated econometrically by IMPLAN, and we have specified that the model choose "average" (as opposed to "max" or "first") values for the RPCs. All direct increments to household spending are assigned to the SAM institution "Households $100-$150k." As per Table 5, land leases are discounted by the tax rates from Table 3, before incrementing final demand. Project residuals, however, are already calculated after-tax, hence may be added without tax discounting to final demand.

19 Note that the only difference between the scenarios with respect to O&M expenses is the discount rate applied to future cash flows. The pessimistic scenario models a higher discount rate, which on the expense side actually lowers the present value of future payments.

20 The IMPLAN model calculates three layers of effects: *direct*, *indirect*, and *induced*. The expenditure stimulus impacts the local economy *directly* through the purchase of local goods and services, and *indirectly* through the increased demand for intermediate inputs (necessary to meet this change in final demand). The re-spending of the income generated via direct and indirect effects *induces* another set of impacts, until the stimulus leaks out of the local economy via imports, taxes, and savings. For a detailed description see IMPLAN (2004).

outside ownership contribution of 3.5.

V. Conclusion:

This study attempts to quantify the regional value added and employment consequences of local- versus outside-ownership of wind-powered electricity generation. We have employed a standard “flip” model for developing a modestly sized wind park in collaboration with a tax-motivated partner. In collaboration with industry participants we have modeled optimistic and pessimistic assumptions about financing terms, in an attempt to realistically bracket the range of possible outcomes. The net present value of the residuals (accruing to the local ownership group) of this model, along with the on-going O&M expenditures, were subsequently inserted into an input-output model for the State of Minnesota, in order to quantify the direct and indirect consequences of higher local incomes and spending.

The analysis concludes that local ownership yields regional value added between 3.1 times (*pessimistic*) and 4.5 times (*optimistic*) higher than a project developed by non-local ownership. The employment impacts are, respectively, 2.5 and 3.5 times greater in the two local-ownership scenarios, relative to the non-local ownership baseline.

One over-arching cautionary note must be sounded: the “flip” model of local ownership depends fundamentally on the existence of tax appetite on the part of the tax-equity partner, which in turn depends directly on corporate profits. The pool of available tax-equity financing, moving forward, will depend critically on the strength of the recovery from the 2008-2009 recession.

These findings are not in and of themselves a rationale for “protectionism”. The key point is that -- as many have pointed out in the literature on wind development -- publicly provided incentives are in most cases not only influential but actually decisive factors in determining the quantity and nature (including ownership structure) of wind power development. Regional policy-makers have direct influence over the tariffs for different categories of wind development as well as the non-financial terms of access to the grid. In the interest of regional development (as well as clean energy) they may wish to consider how to use those instruments to counterbalance a federal policy strongly biased against local ownership.

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Tables

Table 1: Upfront costs

Capital		Per Turbine	9.9 MW Project
	Turbines and towers [a]	-x-	-x-
	Land Transport [a]	-x-	-x-
	Capitalized warranty [a]	-x-	-x-
	Total Capital Costs	**$2,739,000**	**$16,436,000**
Construction			
	Gen. conditions mob/demob.	$37,000	$222,000
	Foundation, conduit & transfer pad	$153,000	$918,000
	Crane, rigging, erection labor, turbine electrical labor	$250,000	$1,500,000
	Electrical wiring from generator to transformer	$167,000	$1,002,000
	FAA obstruction light	$3,000	$18,000
	Earthwork	$15,000	$90,000
	Access road and exterior improvements	$60,000	$360,000
	Total Construction Costs	**$685,000**	**$4,110,000**
Utility Construction Costs			
	Transformer	$20,000	$120,000
	Substation/interconnection	$17,500	$105,000
	Total Utility Construction Costs	**$37,500**	**$225,000**
Misc. Development Costs			
	Engineering/Project Planning	$140,000	$840,000
	Geotechnical Exploration	$5,000	$30,000
	Permitting	$8,000	$48,000
	Independent Testing & Inspection	$7,500	$45,000
	Interconnection studies	$100,000	$600,000
	Legal & Finance	$25,000	$150,000
	Total Misc. Development Costs	**$285,500**	**$1,713,000**
Total Investment	**TOTAL**	**$3,747,000**	**$22,484,000**

[a] Itemized costs redacted to comply with vendor's contractual non-disclosure agreement.

Table 2: Operating expenses

Operating Expenses	Per Turbine	Total	Years
Land Leases	$3,500	$21,000	1-20
Service Agreement Renewal*	$25,000	$150,000	6-20
Liability & Force Majeure Insurance*	$3,000	$18,000	1-20
Equipment and Loss of Profit Insurance*	$11,000	$66,000	6-20
Power Use*	$1,250	$7,500	1-20
Accounting/Auditing*	$833	$5,000	1-20
Property Tax	$6,426	$38,557	1-20
Total Expenses, Pre-inflation (Years 1-5)	**$15,010**	**$90,057**	**1-5**
Total Expenses, Pre-inflation (years 6-20)	**$51,010**	**$306,057**	**6-20**

* 3% annual inflation rate modeled

Table 3: Scenario assumptions

	Scenario	
Parameter:	*Optimistic*	*Pessimistic*
interest rate on bank debt	8%	10%
loan term (years)	12	15
after-tax IRR (tax investor)	8.5%	10%
discount rate	5%	6%
debt financing	36%	38%
equity financing	64%	62%
tax partner equity	$14.24m. (99%)	$13.89m. (99%)
local investor equity	$144k. (1%)	$140k. (1%)
	Parameter values constant across scenarios:	
project lifespan	20 years	
tax equity partner marginal tax rate[(a)]	40%	
local investor marginal tax rate[(a)]	35%	
production tax credit (PTC)	.021/kwh	
depreciation method	double declining balances (5 years)	
ownership "flip" after year	10	
pre- and post-flip shares:		
tax equity partner	.99/.05	
local investor	.01/.95	
power purchase agreement[(b)]	.068/kwh	
turbine efficiency[(c)]	39%	
turbine availability[(c)]	95%	
electricity sales	$2,184,924	

(a) Includes state and federal taxes.
(b) Based on power purchase agreements recently approved by the Minnesota Public Utilities Commission.
(c) Based on an average of four years of performance data for the Vestas V82 turbine installed on the campus of the University of Minnesota West Central Research and Outreach Center in Morris, Minnesota. This installation represents a class 4 wind resource, with average windspeeds at 50 meters between 7.0 and 7.5 meters per second. Much of the Great Plains, including western Minnesota, the Dakotas, Nebraska, and parts of Iowa, are categorized as class 4 or higher wind zones (U.S.D.O.E, 1986).

Table 4: *Pro Forma* screenshot (first seven years; optimistic scenario)

YEAR	0	1	2	3	4	5	6	7
Revenues								
kwh/yr		32,131,242	32,131,242	32,131,242	32,131,242	32,131,242	32,131,242	32,131,242
PPA Rate		$0.06800	$0.06800	$0.06800	$0.06800	$0.06800	$0.06800	$0.06800
Total Revenues		**$2,184,924**	**$2,184,924**	**$2,184,924**	**$2,184,924**	**$2,184,924**	**$2,184,924**	**$2,184,924**
Expenses								
Total Expenses		**$90,057**	**$90,972**	**$91,915**	**$92,886**	**$93,886**	**$94,915**	**$335,867**
Operating Cash		**$2,094,867**	**$2,093,952**	**$2,093,010**	**$2,092,039**	**$2,091,039**	**$2,090,009**	**$1,849,057**
Debt Service		**($1,074,075)**	**($1,074,075)**	**($1,074,075)**	**($1,074,075)**	**($1,074,075)**	**($1,074,075)**	**($1,074,075)**
Coverage Ratio		-1.95	-1.95	-1.95	-1.95	-1.95	-1.95	-1.72
Net Cash		**$1,020,792**	**$1,019,877**	**$1,018,935**	**$1,017,964**	**$1,016,964**	**$1,015,934**	**$774,982**
interest		**$647,545**	**$613,423**	**$576,570**	**$536,770**	**$493,786**	**$447,363**	**$397,226**
outstanding debt	**8094312.72**	**$7,667,783**	**$7,207,130**	**$6,709,626**	**$6,172,321**	**$5,592,032**	**$4,965,319**	**$4,288,470**
Taxable Income								
Operating Cash		2094866.966	2093951.966	2093009.516	2092038.792	2091038.947	2090009.106	1849057.259
Interest		-647545.018	-613422.622	-576570.435	-536770.072	-493785.681	-447362.538	-397225.544
Depreciation		-8993680.8	-5396208.48	-3237725.088	-2428293.816	-2428293.816		
TI		**-7546358.852**	**-3915679.136**	**-1721286.007**	**-873025.096**	**-831040.55**	**1642646.568**	**1451831.715**
Investor Return								
99% Investor		-7470895.263	-3876522.345	-1704073.147	-864294.845	-822730.145	1626220.102	1437313.398
Tax Rate		40%	40%	40%	40%	40%	40%	40%
Tax Savings		$2,988,358	$1,550,609	$681,629	$345,718	$329,092	($650,488)	($574,925)
Tax Credits		$668,009	$674,689	$681,435	$688,250	$695,132	$702,084	$709,105
Tot.taxSavings		$3,656,367	$2,225,298	$1,363,065	$1,033,968	$1,024,224	$51,596	$134,179
99% net cash		$1,010,584	$1,009,678	$1,008,745	$1,007,784	$1,006,794	$1,005,775	$767,232
Total Eq.Rtn	**$(14,245,990)**	**$4,666,951**	**$3,234,976**	**$2,371,810**	**$2,041,752**	**$2,031,019**	**$1,057,370**	**$901,412**
Local return								
1% Investor		**$75,464**	**$39,157**	**$17,213**	**$8,730**	**$8,310**	**($16,426)**	**($14,518)**
Tax Rate		**0.35**	**0.35**	**0.35**	**0.35**	**0.35**	**0.35**	**0.35**
Tax Savings		**$26,412**	**$13,705**	**$6,025**	**$3,056**	**$2,909**	**($5,749)**	**($5,081)**
Tax Credits		**$6,748**	**$6,815**	**$6,883**	**$6,952**	**$7,022**	**$7,092**	**$7,163**
Tot. Tax Savings		**$33,160**	**$20,520**	**$12,908**	**$10,008**	**$9,930**	**$1,342**	**$2,081**
1% Net Cash		**$10,208**	**$10,199**	**$10,189**	**$10,180**	**$10,170**	**$10,159**	**$7,750**
Total local Rt.	**$(143,899)**	**$43,368**	**$30,719**	**$23,097**	**$20,187**	**$20,100**	**$11,502**	**$9,831**

Table 5: O&M expenditures mapped to IMPLAN commodities/institutions

Pro Forma Expense	**IMPLAN Commodity (Institution)**
Land Leases	*Households $100-$150K* [a] *[disposable income]*
Service Agreement Renewal	*365 --- Commercial and Industrial Machinery Maintenance & Repair*
Liability and Force Majeure Insurance	*357 -- Insurance Carriers*
Equipment and Loss of Profit Insurance	*357 -- Insurance Carriers*
Power Use	*31 -- Electric Power*
Accounting/Auditing	*368 -- Accounting/Tax Preparation/Bookkeeping*
Property Tax	*12001 -- State & Local Government Non-Education (50%)* *12002 -- State & Local Government Education (50%)*
Net Return to Local Investors	*Households $100-$150K* [b] *[disposable income]*

[a] Land leases are discounted by the assumed tax rate (see Table 3) before being added as an increment to final demand.
[b] Net returns to local investors are already calculated after tax, and therefore need not be discounted before incrementing final demand.

Table 6: Comparative Economic Impacts

Variable:	Scenario:	**Project's Direct Contribution**			**Input-Output Model "Multiplier" Effects**				**(Scenario) / (Non-Local Scenario) Ratio**
		Annuitized Disposable Income	*Project Property Tax Payments*	*Land Lease Income (After-Tax)*	*Direct*	*Indirect*	*Induced*	*Total*	
In-State Value Added	*Pessimistic*	$338,000	$38,557	$13,650	$249,517	$101,300	$309,865	**$1,050,889**	3.1
...	*Optimistic*	$563,000	$38,557	$13,650	$348,737	$138,288	$431,328	**$1,533,560**	4.5
...	*Non-local*	$0	$38,557	$13,650	$106,092	$49,892	$135,866	**$344,057**	1.0
In-State Employment	*Pessimistic*	-	-	-	3.2	1.2	4.4	**8.8**	2.5
...	*Optimistic*	-	-	-	4.7	1.6	6.1	**12.4**	3.5
...	*Non-local*	-	-	-	1.0	0.6	1.9	**3.5**	1.0

Figures

Figure 1

Figure 2

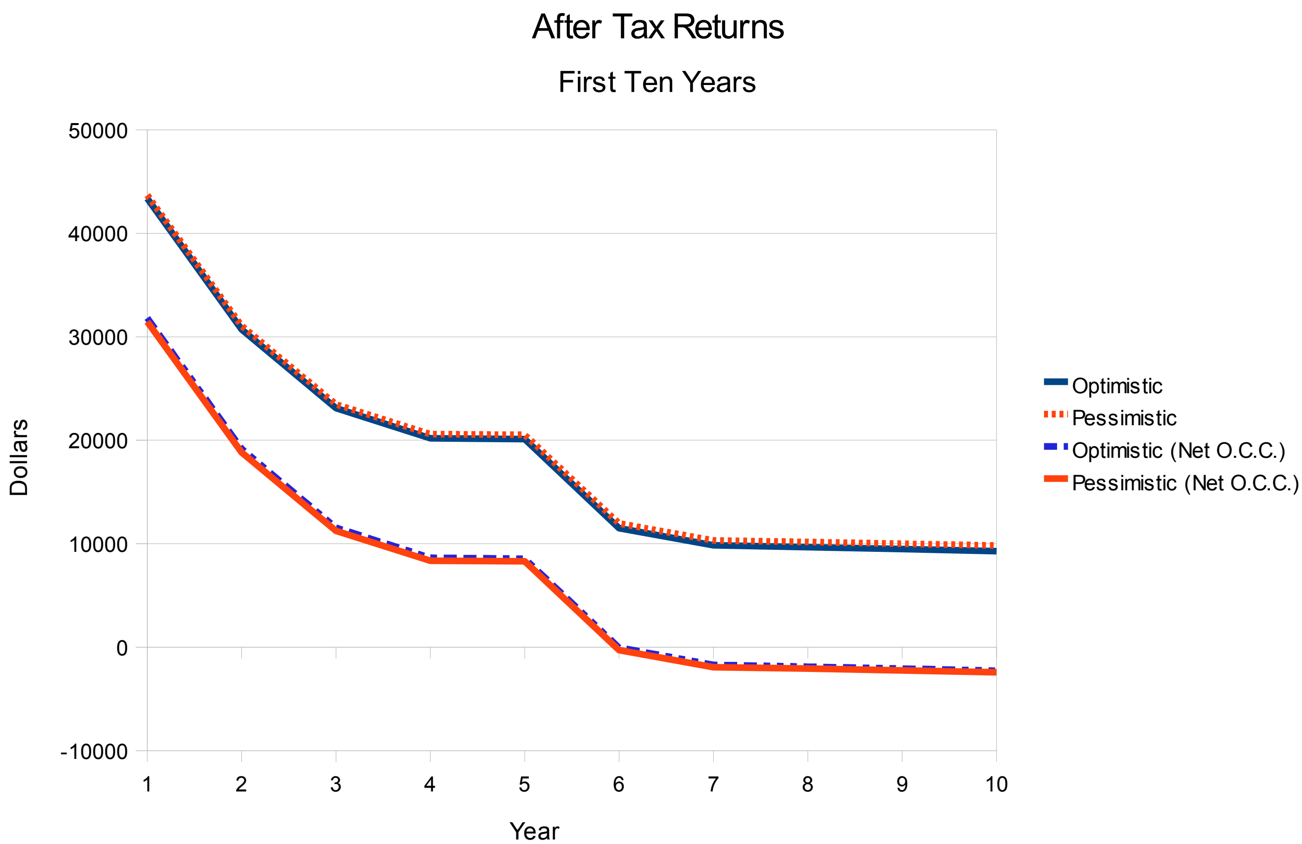
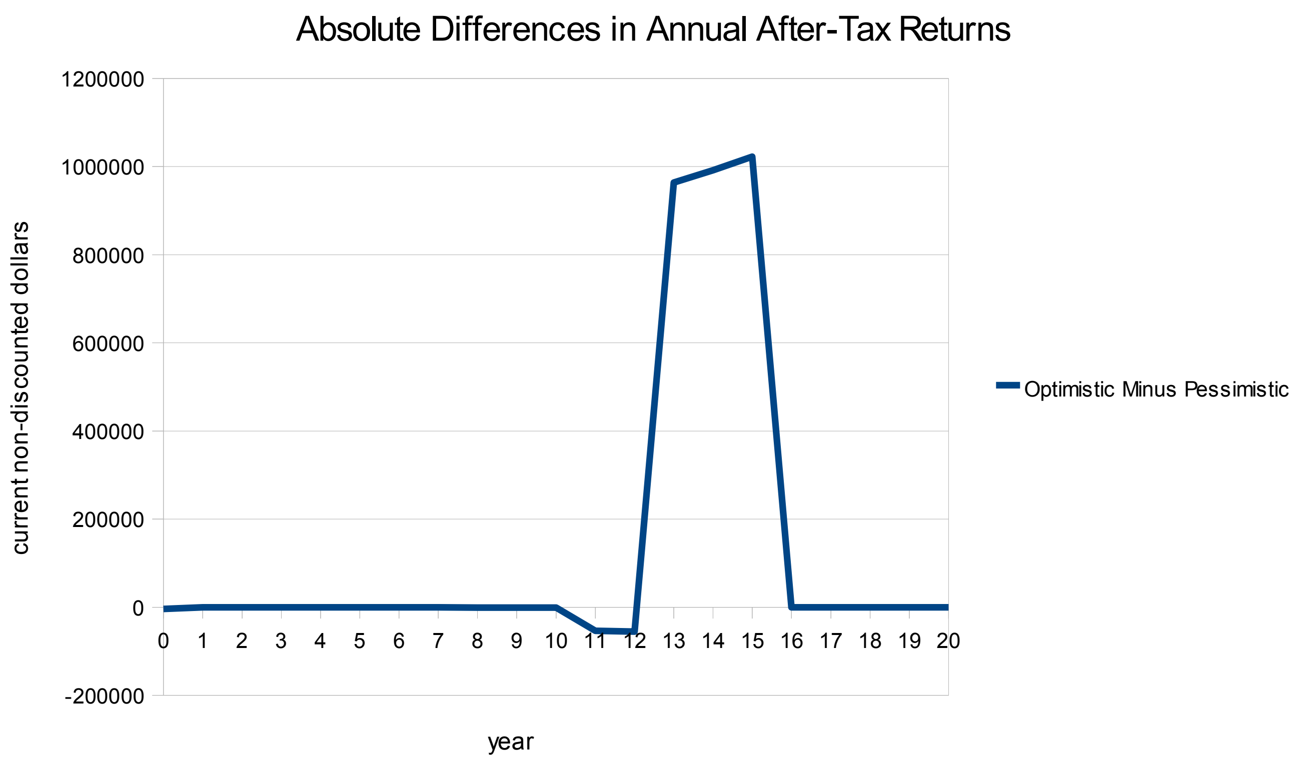

After Tax Returns
First Ten Years
50000
40000
30000
20000
10000
0
-10000
Dollars
1
2
3
4
5
6
7
8
9
10
Year
Optimistic
Pessimistic
Optimistic (Net O.C.C.)
Pessimistic (Net O.C.C.)

Figure 3



Absolute Differences in Annual After-Tax Returns
1200000
1000000
800000
600000
400000
200000
0
-200000
current non-discounted dollars
0 1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20
year
Optimistic Minus Pessimistic

Figure 4

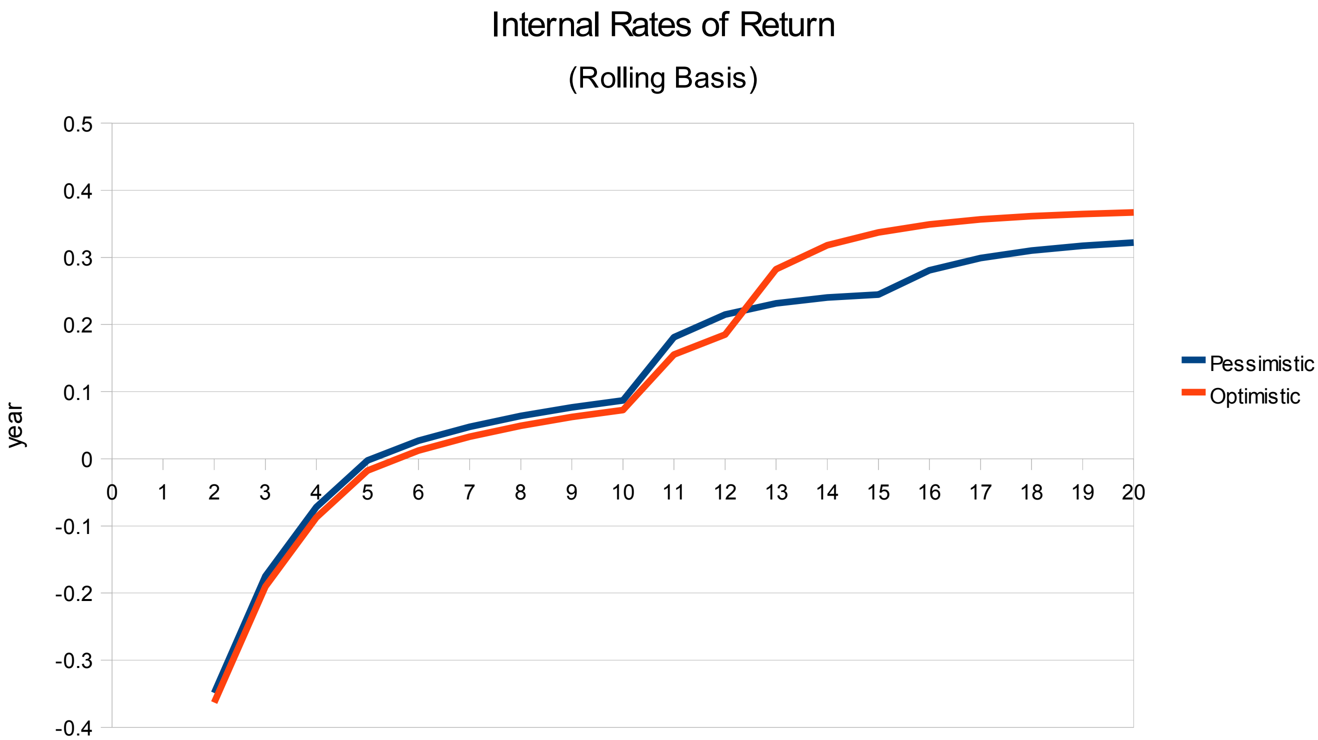

Internal Rates of Return
(Rolling Basis)
0.5
0.4
0.3
0.2
0.1
0
-0.1
-0.2
-0.3
-0.4
year
0 1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20
Pessimistic
Optimistic

Figure 5

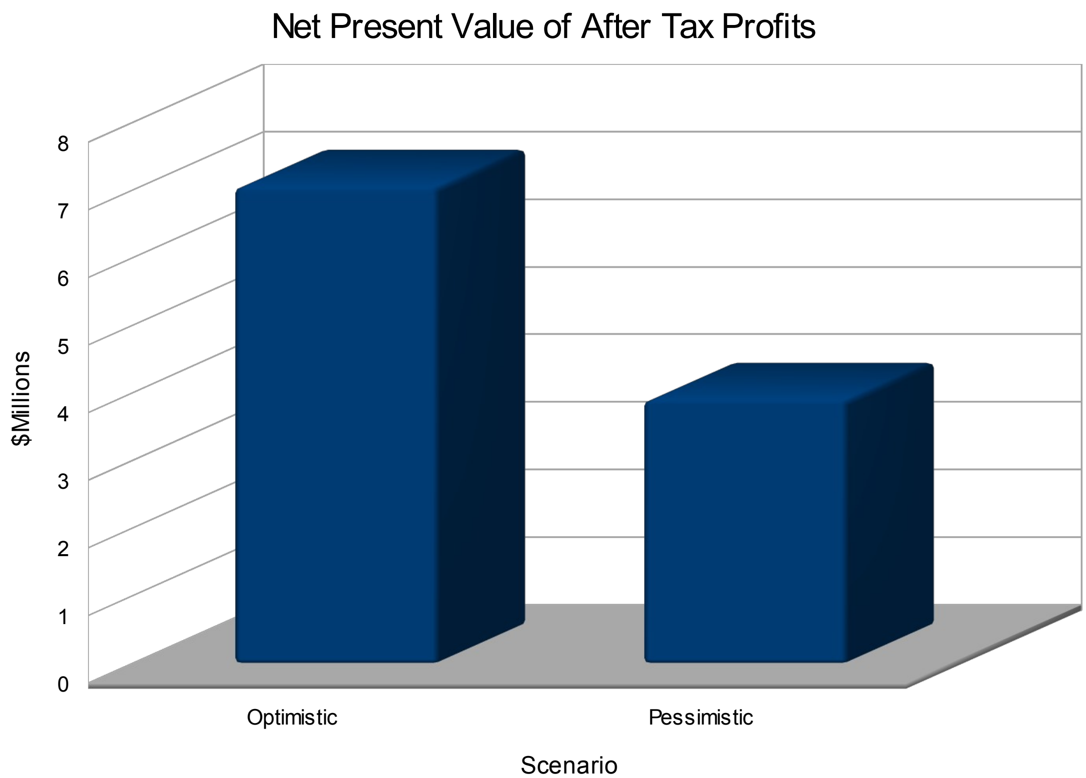
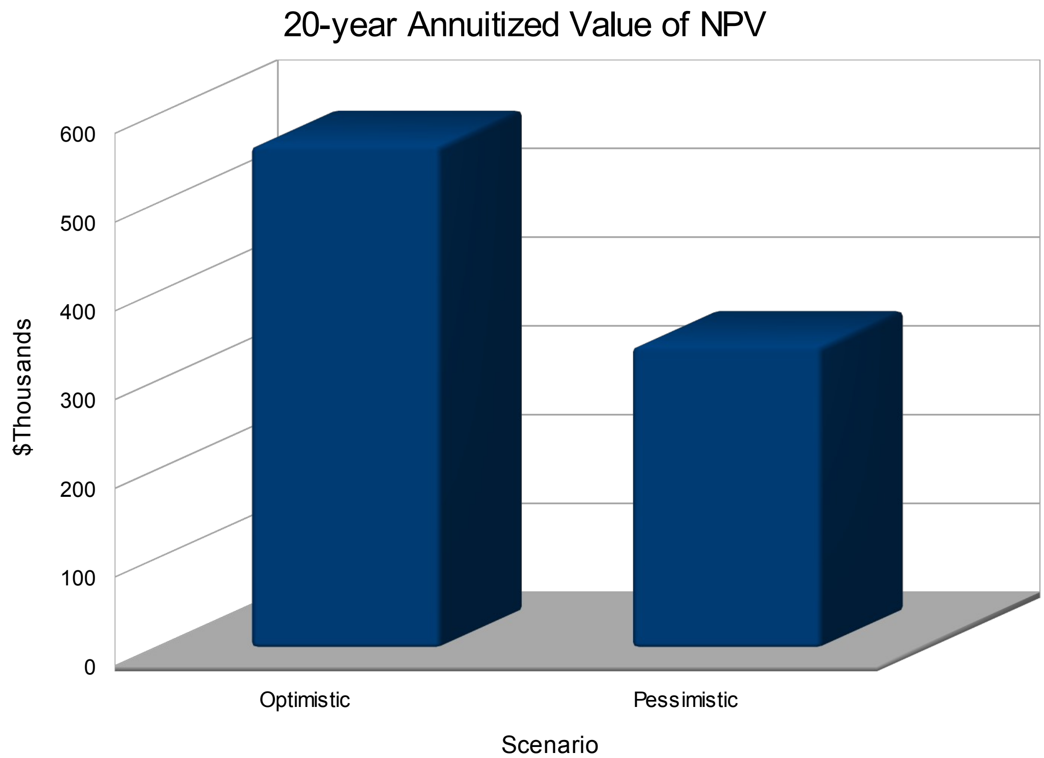
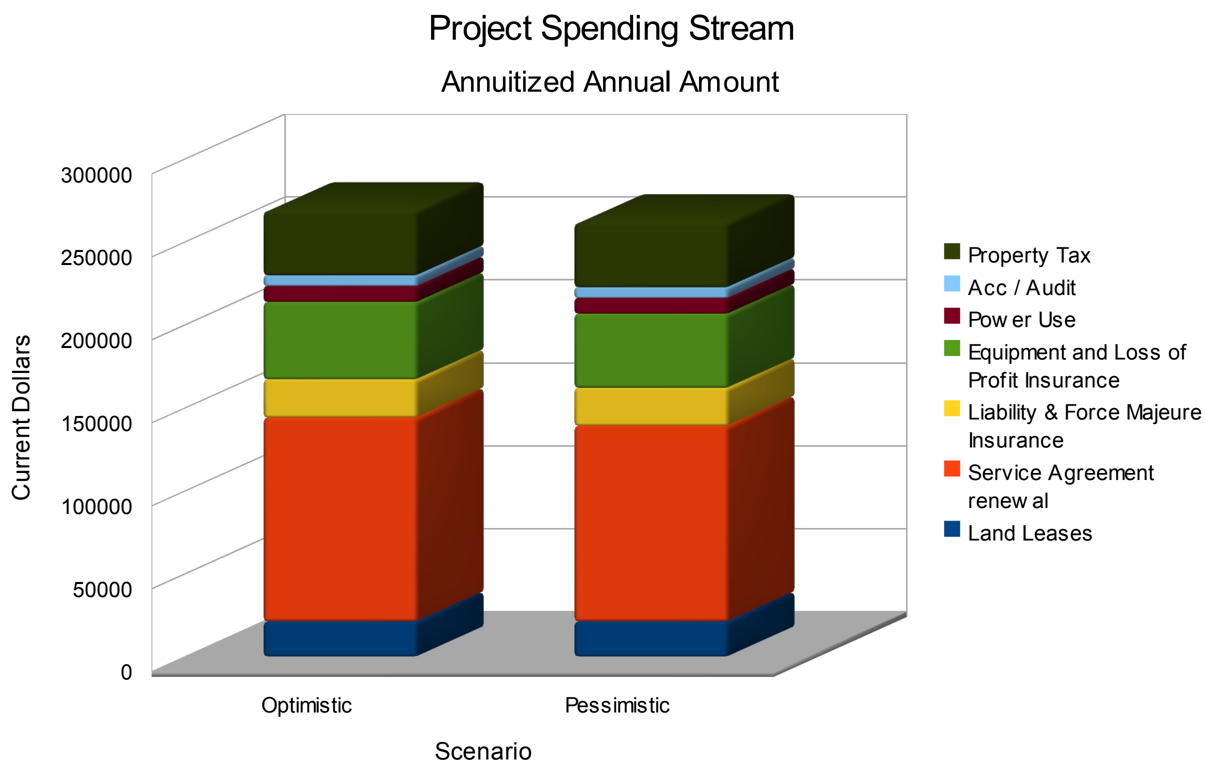

Net Present Value of After Tax Profits
$Millions
0
1
2
3
4
5
6
7
8
Optimistic
Pessimistic
Scenario

Figure 6



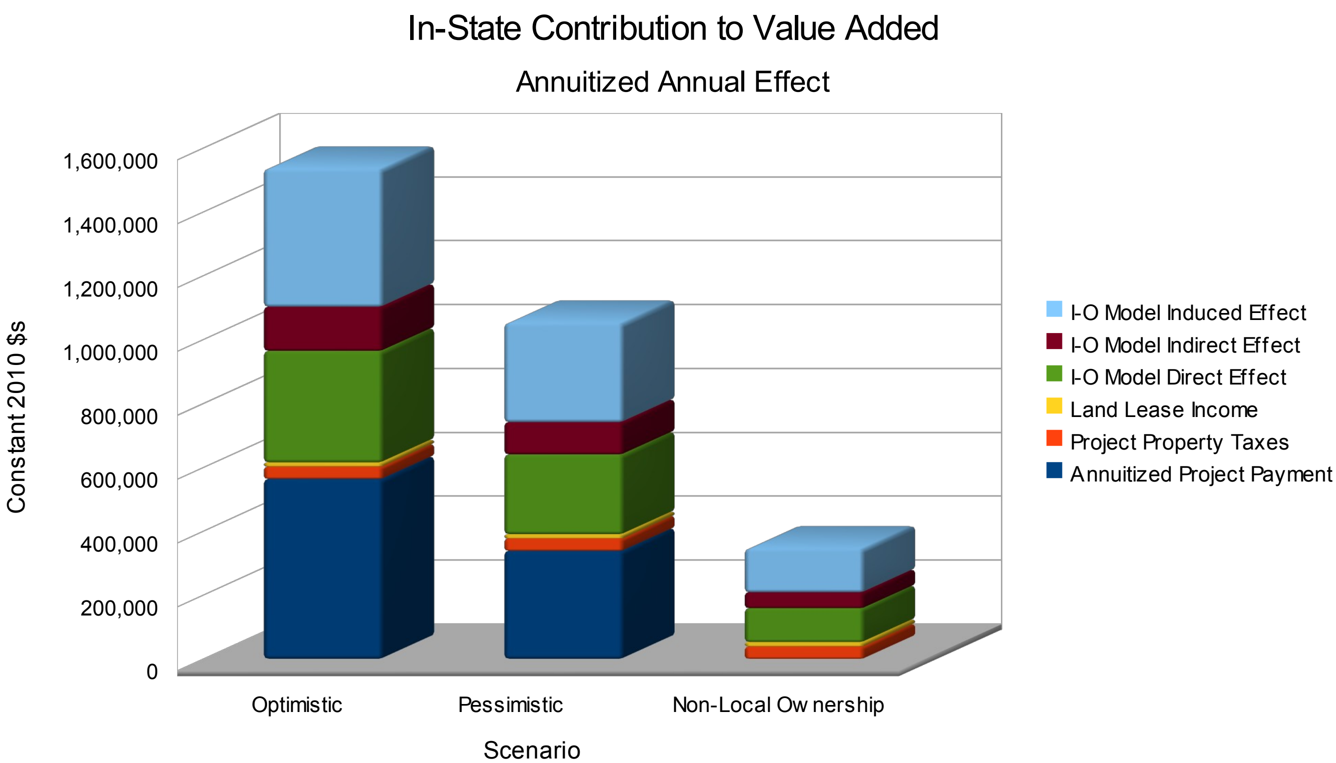
20-year Annuitized Value of NPV
$Thousands
600
500
400
300
200
100
0
Optimistic
Pessimistic
Scenario

Figure 7



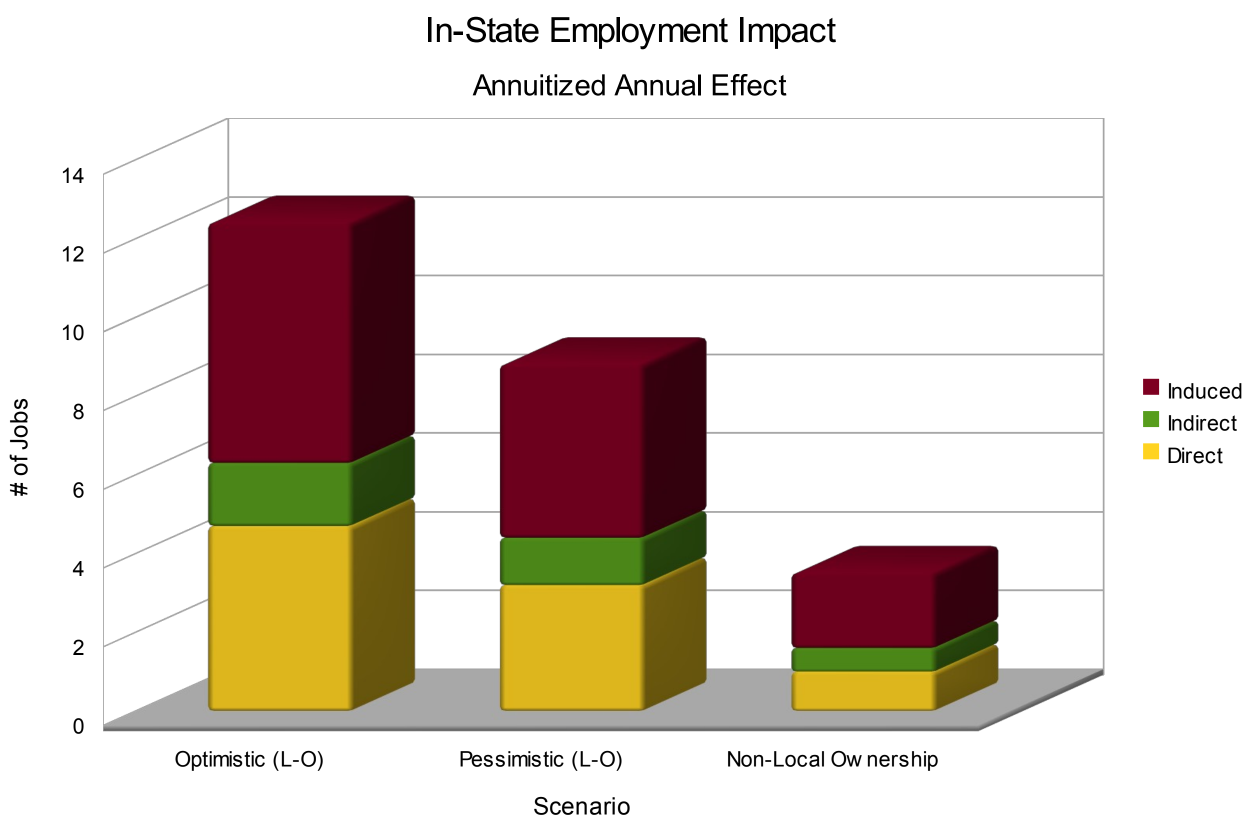
Project Spending Stream
Annuitized Annual Amount
Current Dollars
300000
250000
200000
150000
100000
50000
0
Optimistic
Pessimistic
Scenario
Property Tax
Acc / Audit
Pow er Use
Equipment and Loss of Profit Insurance
Liability & Force Majeure Insurance
Service Agreement renew al
Land Leases

Figure 8



In-State Contribution to Value Added
Annuitized Annual Effect
Constant 2010 $s
1,600,000
1,400,000
1,200,000
1,000,000
800,000
600,000
400,000
200,000
0
Optimistic
Pessimistic
Non-Local Ow nership
Scenario
I-O Model Induced Effect
I-O Model Indirect Effect
I-O Model Direct Effect
Land Lease Income
Project Property Taxes
Annuitized Project Payment

Figure 9


In-State Employment Impact
Annuitized Annual Effect
# of Jobs
14
12
10
8
6
4
2
0
Optimistic (L-O)
Pessimistic (L-O)
Non-Local Ow nership
Scenario
Induced
Indirect
Direct