FINAL DRAFT

IndeGO Benefits Report

IndeGO Benefit Analysis Work Group

Disclaimer

The results of this analysis of benefits were presented to the IndeGO Steering Committee at a meeting in Portland on May 26. There was no validation or acceptance of the findings or conclusions. This report is being circulated as information only, and should not be construed as a consensus.

Findings

Reduced staffing would result in estimated savings of $14 million per year. A potential additional savings or $4 million would be possible from eliminating the need of each participant to have 7 day scheduling coverage.

Elimination of multiple control centers would result in estimated savings of $2 million per year.

Coordinated transmission planning could result in an estimated benefit of $3 - $5 million per year.

Elimination of pancaking would result in reduced operating costs, and reduced costs from future generation capacity expansion. The net benefit to the WSCC region could be in the range of $100 million per year. Significant additional benefits could be shifted from California to the Northwest depending on reciprocity agreements.

Economic benefits from increased competition are also likely to occur. Removing grid operation from vertically integrated utilities eliminates transmission operation and scheduling as a tool for gaming bulk power markets. Analysis models are not available to estimate this benefit.

Conclusions

A few of the benefits identified in the findings above were relatively easy to estimate and easy for the IndeGO Benefits Analysis Group to agree on. Other items were more difficult. The findings were organized in increasing order of difficulty.

The benefits group agreed that there would be a benefit due to reduced staffing, and that the estimate above is reasonable. Not everyone agreed that there would be benefits from elimination of control centers, or that there would be a benefit to coordinated transmission planning. However, if a benefit was realized, the group agreed the amounts estimated were reasonable.

The benefits group agreed that there would be a benefit due to elimination of pancaking. The benefit was hard to estimate, and the group is not in agreement as to the amount of the benefit. A study with GE MAPS prepared by Pacificorp (Kurt Granat) estimated the benefit to be $8 - $16 million per year due to a more optimal dispatch. A study with PMDAM prepared by New Energy Associates, Inc. working on contract and in conjunction with BPA (Dennis Phillips) estimated the benefit to be approximately $100 million per year due to a more optimal dispatch, capacity sharing of existing and new resources, and reciprocity with the California ISO, Desert Star, and BC Hydro.

It was generally agreed that significant benefits could also accrue from removing grid operations from the regions vertically integrated utilities. IndeGO would eliminate the potential for transmission operation and scheduling to be used as a tool for gaming bulk power markets. The benefits work group did not analyze this. Analysis does not lend itself to tools and talent available in the time frame of the study.

Introduction

As the work to prepare the IndeGO proposal neared completion in March, 1998, costs were estimated to be $89 – 164 million in capital costs and $45 million in annual costs. Experience in California suggested these estimates may be low. Estimates of benefits were much less than $45 million per year.

At the request of Vicki VanZandt, an IndeGO Benefits Analysis Work Group was formed. Membership was open to anyone interested. Key participants have been Don Matheson - BPA, Dennis Phillips – BPA, Dave Gilman – BPA, Dennis Metcalf - BPA, Kurt Granat – PPL, Steve Walton – PPL, Kevin O"Mera – PPC, Ray Bliven – DSI's. Others have also provided input.

The group identified the following areas to study for potential benefits as a result of forming IndeGO:

1. Reduced staffing
2. Elimination of multiple control centers
3. Potential benefits from coordinated main grid transmission planning
4. Benefits from elimination of pancaking
   - A. Improved system dispatch from elimination of pancaking
   - B. Generation capacity benefits from elimination of pancaking

C. Benefits from Reciprocity with the California ISO and others
5. Economic benefits from a more competitive power market
6. Improved reliability due to coordinated grid operation
7. Coordinated unit commitment
8. Coordinated maintenance
9. Improved loss methodology

Using straightforward assumptions that could be agreed upon combined with engineering judgment Items 1, 2, and 3 were estimated. Item 4 was difficult to estimate. However, analysis was possible using market optimization or general equilibrium economic models such as GE MAPS or PMDAM. The results were subject to assumptions on time frame analyzed, resource cost, load growth, etc. Item 5 is an important consideration, but analysis tools and resources are not available to perform an analysis. The benefit analysis group believes the item has potentially significant benefits, but was not able to estimate the benefit. Items 6, 7, 8, and 9 were considered but not analyzed in depth. The group determined that these benefits would likely be realized with or without an IndeGO.

Reduced staffing

The IndeGO staffing and cost estimates were released with the Operations Report dated November 25, 1997. The estimate of $35 million per year is based on a projected staff of 276 people and an average salary of $90,000 per year plus 40% loading for fringe benefits.

There is considerable difference of opinion among members of the IndeGO steering committee regarding these figures. The estimates were based on an assumption that the IndeGO staff and infrastructure would be built on a “green field” basis without considering potentially lower cost alternatives. The estimates do not include the cost and staffing reductions that the transmission owners would be likely to experience as a result of the formation of IndeGO.

An informal survey of Steering Committee members was taken. The result is described in a memorandum dated December 12, 1997 by Bill Pascoe. Following is a quotation from the memorandum:

> An informal survey of Steering Committee members was taken to estimate the number of positions that would be eliminated by the transmission owners if IndeGO is formed. The total number of staff reductions was estimated to be about 150 (Does this include the Security Coordinators?) Assuming an average salary of $70,000 per year (and 40% loading for benefits) these savings represent about $15 million per year. Additional savings may be possible

> from reduced travel, office computing and office space requirements.

An IndeGO Costs draft work in progress was circulated February 26, 1998. The draft estimated "Avoided Costs." The draft estimated the total number of staff reductions to be 150. The average annual salary was estimated to be $66,500 (and 40% loading for benefits). The total savings would be $13.9 million per year.

Also, in the February 26, 1998 draft is a discussion of potential additional savings in staff reductions. It is estimated that each of the 21 MOU signatories could eliminate two additional staff positions required for 7 day scheduling coverage. That is an additional 42 positions for an additional savings of $3.9 million.

The Benefits Analysis Work Group has reviewed these estimates. The estimates appear conservative. Additional savings may be possible from reduced travel, office computing equipment and office space. 150 people with an average salary of $66,500 per year (and 40% loading for benefits) would provide a savings of $14 million per year. Relieving each participant from the need for 7 day scheduling coverage generates a potential additional savings of 42 positions or $4 million.

Elimination of multiple control centers

This was studied and reported prior to formation of the benefits study group. It was reported in a December 9, 1997 memorandum from Bill Pascoe. Following is a quotation from the memorandum:

> Operation of a single electrical control area by IndeGO would result in reduced generation costs. Currently, there are 14 control areas in the IndeGO area. Under reliability criteria observed throughout the electric power industry, power flows between control areas may not exceed established limits on either an actual or a scheduled basis. Due to the laws of physics and the resulting differences between scheduled and actual power flows, power transfers between control areas are sometimes limited by scheduled flows when actual power flows could be increased without exceeding the established limits. With a single IndeGO control area, it will be possible to increase actual power flows to established limits on all transmission lines within IndeGO without being restricted by scheduled flows. MAPS simulations indicate that eliminating scheduled flows within IndeGO would increase utilization of the grid and reduce generation running costs by about $2 million per year. However, this benefit would be diminished if some IndeGO

participants elect to continue to operate fully accredited control areas that must recognize scheduled flow limits.

The benefits study group reviewed the estimate. Consensus of the group is that IndeGO probably will not eliminate the existing 14 control areas. However, if the existing control areas are integrated into one control area, the estimated $2 million per year reduction in generation operating costs would be realized.

Potential benefits from coordinated main grid transmission planning

The average main grid transmission expansion cost is estimated to be $60 - $100 million per year over the next ten years. If coordinated transmission planning results in a 5% savings, the amount would be $3 - $5 million per year. Note that some of the planning committee expressed the opinion that there would be no significant savings over current planning. Details of this estimate are included in appendix A.

Benefits from the elimination of Pancaking

Under the present system, fees are charged when power flows from one utility's transmission system to another. Several fees (hops) may be required between generation and load. These hops are called pancaking, and thought of as friction limiting economic transactions. Under IndeGO the region is divided into 11 access pricing areas. The price for transmission service is a single price based on where the load is located. It is not based on how far power is transmitted or how many systems it crosses. Once the single access fee is paid, power can be transmitted from anywhere in the system.

Elimination of pancake transmission rates should result in a more optimal dispatch and consequently reduced fuel costs. Another benefit would be better capacity sharing. This would take on greater importance in the future as new resources are required to meet load growth.

GE MAPS was used to model the dispatch (fuel cost) savings resulting from elimination of pancaked rates and schedule flow limits within IndeGO. A base case dispatch was determined by running MAPS to represent the present situation. Two study cases were run. The dispatches of the study cases were compared with the base case dispatch to estimate benefits. The first study case was run with a hop charge of $2/MWh outside IndeGO, and $0/MWh inside IndeGO. That is, the friction within IndeGO was completely eliminated. The benefit in the case (determined by comparing the base case dispatch with the study case dispatch) was $8 million.

It is believed that in addition to the pancake fees, other sources of friction are introduced into the system. These additional sources of friction include the need for seller profit, and buyer savings. Also, the cost of information is greater as deals are further away. Another case was run with greater hop charges to account for the other sources of friction. In this case the hop charges were $3/MWh outside of IndeGO, and $0.5/MWh hop charges inside IndeGO. The case produced WSCC dispatch savings of $16 million. Details of the GE MAPS study are found in Appendix b.

The GE MAPS program was designed to economically dispatch a fixed set of resources and to compute transmission flows. The model's strength resides in its sophisticated power-flow logic and detailed representation of the grid. However these features are computer intensive and restrict the model's ability to simulate long-term uncertainty and system expansion impacts. As a result, GE MAPS only measured a single year's worth of fuel cost savings and ignored all resource deferral benefits. PMDAM was employed to estimate these benefits.

As in the GE MAPS analysis two study cases were run. The "no-IndeGo" base case was run with a $2/KWM demand charge and a $1/MWh on all major paths in the WSCC. The "IndeGo" case removed both charges from all paths within the IndeGo region and retained both tariffs on all inter-ISO paths. WSCC load growth averaged 1.75%.

The PMDAM model simulates minimizes each utility's revenue requirement over the 2001-2015 time period. PMDAM simulates least cost resource and contract dispatch on an hourly basis, maintenance scheduling and generation expansion. Each fifteen year simulation was repeated twenty times using randomly selected hydro inflows, fuel prices, daily loads and forced outage rates.

The PMDAM results indicate that system operation, resource expansion, and intertie utilization change significantly when pancaked tariffs are removed. Eliminating intra-regional trade barriers provides an economic incentive for IndeGo participants to trade between themselves. As a result, the IndeGo region firms increasing amounts of non-firm by purchasing energy from California and Desert Star. California meanwhile, is forced to build to meet its summer peak load. WSCC total capital and operating costs decrease by approximately $108 million/year as IndeGo's existing supplies of capacity and energy are more fully utilized (i.e. supply curve shifts right). However there are winners and losers. Indego participants benefit by $81 million/year, Desert Star benefits by $67 million/year, Canada benefits by $25 million/year and California customers incur an additional cost of $61 million/year (a more detailed explaination can be found in Appendix b).

The reader should note the caveats in Appendix C and interpret the results accordingly.

Economic benefits from a more competitive power market

Removing grid operations from the regions vertically integrated utilities eliminates transmission operation and scheduling as a tool for gaming bulk power markets. This is not amenable to study with market optimization or general equilibrium economic models.

This has not been studied, and no estimate of benefits are available. One approach to estimating these benefits would be a qualitative analysis of an area where deregulation is farther along than it is in the Northwestern United States. One such system may be the UK. Another approach would be to solicit proposals for analysis from industry experts.

Improved Reliability Due to Coordinated Grid Operation

There is considerable room for coordinated grid operation. With a single grid operator this would occur. Current activities including the WSCC security monitor should result in improved grid operation with or without IndeGO.

Coordinated unit commitment

Ramping thermal units up and down adds to the dispatch cost. With an ISO that serves a large territory it may be possible to save on unit commitment costs through regional coordination. This was considered by the Benefit Analysis Work Group. This was not studied since the group didn't believe that there were not significant benefit to be gained.

Coordinated maintenance

The Benefit Analysis Work Group considered this potential savings area. Discussions with maintenance people revealed that there is significant work in progress in this area at the present time. It is believed that any benefits can be realized with or without an IndeGO. Therefore, no estimate was prepared for this area.

Improved loss methodology

Currently wheeling losses are recovered using a pancaked, average loss methodology. An incremental loss methodology taking into account location and operating conditions would improve the efficiency of system dispatch and generation siting. The IndeGO pricing committee recognized that developing such a loss methodology would be time intensive and difficult to reach agreement on, so deferred work on it.

Appendices

Appendix A – Potential Benefits from Coordinated Transmission Planning
Submitted by Dave Gilman - BPA

One of the potential benefits of an ISO like IndeGO is better coordination of transmission expansion. This would result in the more efficient planning and construction of needed transmission facilities. The primary gain would be in main grid, high voltage facilities that affect multiple utilities. A reasonable level of savings would be a 5% reduction in the capital costs spent on new construction each year. A 5% saving translates into a reduction in capital costs of $3-5 million for the 1997 –2006 period. This is, of course, a rough estimate and would not be the same each year. Some of the IndeGO participants stated they would expect to see little change in planning as there is considerable coordination already and they do not expect there to be a need for significant main grid additions in the future due to distributed generation and improvements in technology.

A ball park estimate of the saving was determined based on the 1997 WSCC significant additions, which tabulated proposed additions for 1997-2006 period. As the savings are expected to be primarily high voltage lines only the miles of line 230 kV and above were used. The IndeGO area was approximated by using the added miles for the NW Power Pool and Rocky Mt. Power areas. The miles of line were converted to dollars by using typical BPA line costs and overheads, and an appropriate adder to include substation costs. As shown in the table, this resulted in a total 10-year cost of roughly a billion dollars or about 100 million per year. A significant portion of this cost is the SWIP project (Midpoint to Las Vegas) which is now on hold. If the cost of this project is removed, it results in an average cost of 60 million per year. At 5% of capital costs, the result is a potential saving of $3-5 million.

Appendix A Continued

ESTIMATE OF CAPITAL COST OF NEW TRANSMISSION IN INDEGO AREA
Based on WSCC Significant Transmission Additions for 1997-2006
Transmission line additions by miles of line with adder for substation facilities

Capital cost in $ millions

	~~NWPP~~		~~RMPA~~	
~~Line by voltage~~	~~Miles~~	~~Cost 1/~~	~~Miles~~	~~Cost 1/~~
230 kV	502	189	301	113
345 kV	196	148	141	106
500 kV	605	~~513~~	0	~~0~~
Total		**850**		**220**
	IndeGO Total =		**1070**	

1/ Capital cost is based on BPA typical line cost with 30% overhead.
An adder of 45% is used to reflect the cost associated substation facilities.

Estimate of per miles costs with overheads & substations
in ($000)

~~Cost per miles~~	~~BPA base~~	~~w OH~~	~~w Sub~~
230 kV	200	260	377
345 kV	400	520	754
500 kV	450	585	848

SWIP (Midpoint-Las Vegas) project is about 520 miles
Cost is 441 $ million

Appendix B – GE MAPS Estimate of Potential Benefits from Lower Cost Dispatch Submitted by Kurt Granat - PPL

Assumptions in IndeGO Draft MAPS runs

- **Starts WSCC MAPS Model as a base**
  - **MAPS data cooperatively developed over several years for use in WSCC**

- **Added new Company Areas in the Pacific Northwest and Colorado**
  - Added Details to capture wheeling that the WSCC model would miss.
  - **Northwest Additions**
    - Puget
    - Pac-W
    - PGE
    - WWP
    - Mid-Columbia
    - Seattle Area Publics
  - **Colorado Additions**
    - PSCo
    - WPE
    - CSU
    - WAPA
    - Tri-State
    - PRPA

- **Base Case**
  - **$2/MWh Wheeling to move power between Area Bubbles**

- **WSCC No Wheeling Charge Case**
  - **$0/MWh Wheeling to move between Area Bubbles**

- **WSCC w/ IndeGO Flow Limit Case**
  - **$0/MWh Wheeling to move between Area Bubbles**
  - **Internal IndeGO Scheduling limits turned off - Flow limits remain**

- **IndeGO Case**
  - **$2/MWh Wheeling to move between Area Bubbles outside of IndeGO** and across IndeGO Boarders
  - **$0/MWh Wheeling inside IndeGO Region**

- **Three ISO Case**
  - **IndeGO, California IGO, and Desert Star**
  - **$0/MWh Wheeling inside ISO's**
  - **$2/MWh to cross ISO Boarders**

Caveats for IndeGO Draft MAPS runs

What MAPS Measures

Only Variable Fuel and O&M Costs

Factors MAPS does not Model

MAPS is not a capacity expansion model and cannot capture capital deferments.

IndeGO will produce Market Prices that will make resource investments less assumption driven if there are real market signals to aid the cost calculation.

No changes were modeled in where Ancillary Services were carried for each area. With IndeGO pooling there may be efficiencies in the provision of Operating Reserves Voltage and Frequency Control and Load Following.

Uses WSCC MAPS Model as a base

Assumes "Expected" conditions

Median Water Conditions - High and Low conditions would be expected to yield more economy transfers.

Average plant outage draws – unusually high plant availability causes more bottlenecks while severe plant outages forces more transfers.

Operator Uncertainty vs Optimizing Model Certainty

For a given week MAPS minimizes costs knowing for each hour

All WSCC area loads

The maintenance and forced outages for all WSCC plants

The incremental plant loading and costs for all WSCC generating plants

The availability of all WSCC transmission paths that could move the power both on an actual flow basis and on a path scheduled basis.

Company Operators have information for only a portion of these items, and even Then with a considerable band of uncertainty (e.g. loads many be within 3%). With IndeGO's security function, flow scheduling, and market signals, IndeGO will Operate far closer to MAPS like conditions than the current market could. Essentially MAPS assumes every company for every hour has complete information on WSCC loads, available generation (including incremental costs), and available Transmission capacity (and costs). No company has this information. The current Spot market helps, but a broker's job becomes far simpler if there is a single agent With consistent rules booking the transmission system, just as rail shipping is much Easier if there is one gauge of tracks.

Thus, the Base case is over-optimized compared to the IndeGO case which Tends to reduce the benefits of IndeGO that MAPS produces.

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PacifiCorp ***Draft***

IndeGO MAPS Runs

WSCC MAPS Model

Dollars in Millions

		IndeGO
	$3/MWh	**$3/MWh outside $0.5/MWh inside**
Fuel Total $M	$ 5,460.3	$ 5,442.3
NonFuel Total $M	$ 2,020.7	$ 2,022.7
VOM Total $M	$ 7,481.0	$ 7,465.0
Saving from $3 Hop Case		$ (16.0)

klg 2/5/98

PacifiCorp
IndeGO MAPS Runs ***Draft***
WSCC MAPS Model
Dollars in Millions

	Transaction "Friction" Level per WSCC Hop						IndeGO
	$2/MWh	**$3/MWh**	**$4/MWh**	**$5/MWh**	**$6/MWh**	**$10/MWh**	**$3/MWh outside $0.5/MWh inside**
Fuel Total $M	$5,415.1	$5,460.3	$5,510.4	$5,566.9	$5,613.7	$5,750.1	$5,442.3
NonFuel Total $M	$2,028.2	$2,020.7	$2,015.2	$2,009.8	$2,004.8	$1,992.3	$2,022.7
VOM Total $M	$7,443.3	$7,481.0	$7,525.5	$7,576.6	$7,618.4	$7,742.4	$7,465.0
Increase From $2/MWh $M		$37.7	$82.2	$133.4	$175.2	$299.2	
							$(16.0) Saving from $3 Hop Case

PacifiCorp ***DRA***

IndeGO MAPS Runs

WSCC MAPS Model

Dollars in Thousands

	Base	**WSCC**	**WSCC**	**IndeGO**	**3 ISO Case**
	$2/MWh Wheel	$0/MWh Wheel	$0/MWh Wheel	$0/MWh IndeGO	IndeGO, IGO, Desert Star
			IndeGO Flow Limits	$2 elsewhere	$2 @ edges
Fuel	$ 5,415,052	$ 5,363,728	$ 5,362,271	$ 5,406,644	$ 5,388,061
Var. O&M	$ 2,028,219	$ 2,039,262	$ 2,038,594	$ 2,028,272	$ 2,032,330
Total	$ 7,443,271	$ 7,402,990	$ 7,400,865	$ 7,434,916	$ 7,420,391
Savings from Base		$ 40,281	$ 42,406	$ 8,355	$ 22,880

Appendix C

INDEGO ANALYSIS 5/25/98

- **General Background and Purpose of Analysis**

This analysis examines the regional costs and benefits of IndeGo. The analysis was requested by the IndeGo Benefits Workgroup and performed by New Energy Associates, Inc. working on contract and in conjunction with BPA staff (Dennis Phillips). This analysis was performed with the Power Market Decision Analysis Model, PMDAM.

- **Methodology and Modeling Assumptions**

An IndeGo case (idgmc) was compared against a "No" IndeGo base case (nidgmc). Both cases assume the existence of Desert Star and the CaISO. All cases assume zero demand and energy tariffs within each ISO. Both cases also assume all inter-ISO tariffs remain in place, (no-reciprocity).

Each case was simulated for the period 1998-2015. The simulation was performed by PMDAM which is a chronological, Monte Carlo optimizing model that simulates the long-term hourly operation, resource acquisition and marketing functions of each utility in the WSCC system PMDAM is an economic equilibrium model that balances the supply and demand of electricity products using marginal prices, system constraints and standard micro-economic pricing theory.

The objective of the simulation is to meet each utility's load and load growth at minimum cost. The individual utilities modeled are shown below. PMDAM acquires and operates a least cost portfolio of resources, power contracts and economy transactions. The transmission network is simulated as a transport model and accounts for ownership, marginal losses and transactions costs on all paths connecting WSCC control area bubble. PMDAM also maintains intertie flows and capacity transfers within line limits. Unlimited transfer capability and zero wheeling charges are assumed within a control area.

All 750 existing thermal units within the WSCC are modeled individually taking into account variable fuel costs, minimum operating levels, annual maintenance, forced outage rates, unit commitment and incremental heat rate curve data. In addition new resources are acquired when economic.

All resources, contracts and economy transactions are dispatched hourly. Each simulation consists of a 18 year, 12 month/year, 2 day/week, 2 hour/day, on peak and off peak "scenario" that randomly varies monthly hydro inflows, forced outage rates and daily load uncertainty. Long-term fuel prices and load growth were deterministically fixed at the expected growth rates for each utility.

Under the No-IndeGo scenario the following assumptions are made:
a) firm power trades pay pancaked $2/kwm transmission demand charge on all paths shown in WSCC control area diagram,
b) hourly or non-firm economy trades pay a pancaking 1 mill/kwh energy charge,
c) no demand or energy charges are assessed on any trades within a control area bubble,

Under the IndeGo scenario the following assumptions are made:
a) no transmission demand or energy charges paid within the IndeGo region,
b) IndeGo internal path capacity unconstrained
c) path losses internal to IndeGo estimated at 2%

Assumptions common to both scenarios:
a) $2/kwm demand and 1 mill energy charges paid for intertie usage between ISOs.
b) WSCC load growth averaged 1.75% per year during 2001-2015 period.
c) gas price forecast, (shown on following page)
d) combined cycle overnight capital cost $520/kw, $9.83/kwyr fixed o&m
e) combustion turbine overnight capital cost $320/kw, $2.03/kwyr fixed o&m.
f) transactions costs (and market efficiency) were held constant in both runs

Some caveats: This analysis contains the following errors and omissions:

a) the $2/kwm demand charge was double counted at COB and NOB which tends to over-estimate IndeGo benefits.

b) the 1.5 mill/kwh energy charge was only charged once on 2 wheel trades which tends to under-estimate IndeGo benefits. The benefits appear to be very sensitive to energy charges. Sensitivity runs would be desirable.

c) tariffs within a control area were assumed to be zero which tends to underestimate the benefits of IndeGo.

d) the unconstrained transmission capacity associated with the IndeGo scenario will tend to over-estimate IndeGo benefits. However this effect will probably have minimal impacts on the result since PMDAM is basically unconstrained, especially in the direction the IndeGo scenario shifts flows.

With these caveats in mind the results should be interpreted as an "upper" bound for evaluating IndeGo benefits using 1 mill energy and $2/kwm demand charges. If future simulations are required these problems will be corrected or minimized.

General Findings:

This analysis indicates that the global (WSCC wide) benefit of forming IndeGo is approximately $108 million per year. These benefits begin immediately as can be seen from the graph on the following page.

There are winners as well as losers. IndeGo participants benefit by $81 million per year, Desert Star benefits by $67 million per year, Canadian benefits by $25 million per year and California has a negative benefit of $64 million per year.

As a reality check these benefits are relatively small and certainly within the range of plausibility. The results indicate that removing intra-IndeGo tariffs increases economic efficiency by 1.2%, (i.e. when a $81 million per year decrease in cost is compared to the $6.5 billion per year wholesale market value of IndeGo’s entire 30,000 annual average megawatt load,(i.e. 30,000 at 25 mills/kwh).

A more detailed explanation can be seen in the simulation output. The simulation results indicate that the IndeGo region pursues a different and less costly long-term resource development and marketing strategy under the IndeGo scenario. The shift in strategy results when tariffs are removed within IndeGo.

The current tariff structure, outside of California, charges export and import tariffs on all inter-regional transactions and pancaked tariffs on all intra-IndeGo transactions. The California ISO charges "export" tariffs on all transactions exiting and wheeling through the ISO. However California does not charge import tariffs on power delivered within California.

As a result, one would expect the "no IndeGo" scenario to reach an economic equilibrium that places more emphasis on exporting power from IndeGo and Desert Star 's into California and less emphasis on trade within IndeGo and between Desert Star and IndeGo. Those expectations are borne out by the data.

In the "no" IndeGo scenario, California continues to emphasize imports as a means of meeting load growth and IndeGo continues to build in part to meet California demand.

Conversely, in the IndeGo scenario, the IndeGo region meets load growth by selling less power to California, purchasing more capacity and supplemental energy from Desert Star and building fewer resources.

Unpancaking tariffs also enhances IndeGo's access to cheap coal imports from the Desert Star region. Facing stiffer competition for its import energy from Desert Star and the IndeGo region, California builds more resources to meet its native load growth.

IndeGo's operating costs go down by $400 million per year and its net import costs go up by $499 million per year, as fewer resources, less exports and more imports are needed to meet load. These costs are more than offset by capital and fixed o&m savings of approximately $196 million per year.

California's operating costs go up by $338 million per year and its net import costs go down by $358 million per year, as more native generation is needed to offset the reductions in imports from IndeGo and Desert Star. However these small savings are offset by additional capital and fixed o&m costs of $85 million per year.

Desert Star's operating costs go up by $27 million per year and its net import costs go down by $93 million per year as the IndeGo region more successfully competes with California for a larger share of the Desert Star's surplus capacity a energy supplies.

Summary of Energy Transfers:

IndeGo Imports:

IndeGo imports 400-500 average annual megawatts of additional energy from Desert Star during the fall, winter and spring seasons. Initially Desert Star re-allocates an additional 200 average annual megawatts of its California sales into the IndeGo region. By 2015, Desert Star's exports to California decrease by 400 average annual megawatts in order to support the expanding markets within IndeGo. This provides benefits to Desert Star and to IndeGo and comes at a cost to California.

Initially IndeGo's imports from California decrease by approximately 400 annual average megawatts. However, over time, IndeGo will increasingly rely on California for fall and winter option energy to serve native load in average to low water years.

As IndeGo more successfully competes for Desert Southwest coal it is also taking advantage of California's increasing supply of fall and winter energy surpluses to meet a portion of its future load growth.

IndeGo Exports:

By far the most dramatic impact of this analysis is that IndeGo's total inter-regional energy exports decline by over 2500 average annual megawatts by 2015. Eliminating tariffs enables IndeGo participants to compete more effectively for IndeGo surplus energy.

As a result IndeGo participants firm non-firm by melding IndeGo's regional supply of surplus energy with California option energy and Desert Star coal. This reduces energy exports to California and lowers intertie loadings north to south. This firming non-firm strategy provides benefits to IndeGo and to Desert Star and comes at a cost to California.

Summary of Capacity Transfers:

IndeGo Imports:
Eliminating demand charges also increases trading opportunities between Desert Star and the IndeGo region. Initially IndeGo formation shifts the capacity supply curve within the IndeGo region to the right. This reduces IndeGo's demand for extra-regional capacity during the November to February period by approximately 1500 megawatts.

This decrease in extra-regional demand for capacity is short lived. Over time, as IndeGo's regional loads grow, fall and winter capacity demands are increasingly met by Desert Star. By 2015 IndeGo is purchasing an additional 3000 megawatts of winter peak capacity from Desert Star, California and Canada. Nearly 2000 megawatts of fall and winter capacity is purchased from Desert Star and wheeled directly into the IndeGo region. California benefits decrease and Desert Star benefits increase as Desert Star captures a greater share of this market.

IndeGo Exports:
During the summer and early fall IndeGo capacity exports to California decrease dramatically. IndeGo reallocates this capacity to meet regional loads. When trading barriers are removed within IndeGo, participants appear to compete more effectively for the region's summer capacity surplus.

California replaces IndeGo's summer capacity imports with new resource construction and approximately 1000 megawatts of additional August capacity purchases from Desert Star.

- **Parties Modeled in Analysis**

CANADA	**BC HYDRO and ALBERTA**
DESERT	**DESERT STAR ISO**
BPA	**BONNEVILLE POWER ADMINISTRATION**
CALIF	**CALIFORNIA ISO**
CHPD	**PUD NO. 1 OF CHELAN COUNTY**
CSU	**COLORADO SPRINGS UTILITIES**
GCPD	**PUD NO. 2 OF GRANT COUNTY**
IPA	**INTERMOUNTAIN POWER AGENCY**
IPC	**IDAHO POWER COMPANY**
MPC	**MONTANA POWER COMPANY**
OMON_1	**OTHER MONTANA**
OPNW_1	**OTHER PNW**
OUTH_1	**OTHER UTAH**
OWLM_1	**OTHER WAPA LM**
OWYO_1	**OTHER WYOMING**
PGE	**PORTLAND GENERAL ELECTRIC CO**
PP&L	**PACIFICORP**
PSCO	**PUBLIC SERVICE CO OF COLORADO**
PSP&L	**PUGET SOUND POWER & LIGHT CO**
SCL	**SEATTLE CITY LIGHT**
SPP	**SIERRA PACIFIC POWER COMPANY**
SRP	**SALT RIVER PROJECT**
TCL	**TACOMA DEPARTMENT OF PUBLIC UT**
WLM	**WAPA LOWER MISSOURI - LOVELAND**
WUC	**WAPA UPPER COLORADO - SALT LAKE**
WWP	**WASHINGTON WATER POWER COMPANY**

IndeGo benefits analysis. **DRAFT**

Date: May 26, 1998

Under the No-IndeGo scenario the following assumptions are made:
a) firm power trades pay pancaked $2/kwm tranmission demand charge on all paths shown in figure 1,
b) hourly or non-firm economy trades pay pancaked 1 mill/kwh energy charge,
c) no demand or energy charges are assessed on any trades within a control area bubble,

Under the IndeGo scenario the following assumptions are made:
a) no transmission demand or energy charges paid within the IndeGo region,
b) IndeGo internal path capacity unconstrained
c) path losses internal to IndeGo estimated at 2%

Assumptions common to both scenarios:
a) $2/kwm demand and 1 mill energy charges paid for intertie usage between ISOs.
b) WSCC load growth averaged 1.75% per year during 2001-2015 period.
c) gas price forecast, (shown on following page)
d) combined cycle overnight capital cost $520/kw, $9.83/kwyr fixed o&m
e) combustion turbine overnight capital cost $320/kw, $2.03/kwyr fixed o&m.
f) transactions costs (and market efficiency) were held constant in both runs

( )'s indicates negative benefit. Positive
2001 PV costs in millions (MM) 1998$$,assume 9% nominal discount rate, 3% annual inflation, 2001-1015 cost streams

	DELTA	***(No-IndeGo less IndeGo)***		
	2001 NPV@9%	**2001-2015 Annual Levelized**		
WSCC:	**$777**	**$96**	MM	capital costs
	$51	**$6**	MM	fixed o&m costs
	$170	**$21**	MM	operating costs
	($124.05)	**($15.39)**	MM	IndeGo loss adjustment
	$874	**$108**	MM	**total net costs**
IndeGo ISO:				
	$1,401	**$174**	MM	capital costs
	$176	**$22**	MM	fixed o&m costs
Note:Export Revenues D	**$3,222**	**$400**	MM	operating costs
& option purchases incr	**($4,025)**	**($499)**	MM	net import costs
	($124.05)	**($15.39)**	MM	IndeGo loss adjustment
	$650	**$81**	MM	**total net costs**
California ISO:	**($562)**	**($70)**	MM	capital costs
	($118)	**($15)**	MM	fixed o&m costs
	($2,721)	**($338)**	MM	operating costs
	$2,886	**$358**	MM	net import costs
	($515)	**($64)**		**total net costs**
Desert Star ISO:	**$0**	**$0**	MM	capital costs
	$0	**$0**	MM	fixed o&m costs
	($216)	**($27)**	MM	operating costs
	$752	**$93**	MM	net import costs
	$536	**$67**		**total net costs**
Canada:	**($62)**	**($8)**	MM	capital costs
	($7)	**($1)**	MM	fixed o&m costs
	($115)	**($14)**	MM	operating costs
	$387	**$48**	MM	net import costs
	$203	**$25**		**total net costs**