TESTIMONY OF ALAN G. ISEMONGER ON BEHALF OF DYNEGY INC. CONCERNING GAS TRANSPORT RATES APPLICABLE TO THE MOSS LANDING POWER PLANT

Application 13 12 012

PG&E Gas Transmission and Storage Rate Case

August 11, 2014

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Introduction

Please state your name and business address.

My name is Alan Isemonger and my business address is 6049 Kenneth Avenue, Fair Oaks, California, 95628.

By whom and in what capacity are you employed?

I am the President of Energy Market Expertise LLC, a consulting firm with clients mainly in the wholesale electric power markets. I am here as an expert witness on behalf of Dynegy Inc.

Please describe your professional and educational background.

I have 19 years of experience as an economist and 16 years of experience in the wholesale electric power industry. I began my career in the wholesale power markets in 1998 when I worked at the British Columbia Hydro and Power Authority in Vancouver, British Columbia, a vertically integrated utility serving the bulk of the province. In 2000 I joined ZE Power Group, also in British Columbia, a consulting firm in the deregulated wholesale power industry with clients across Canada as well as in the western USA. My work with deregulated wholesale power markets dates back to this time, when I assisted clients with changes in market rules, assisted with rate cases before the British Columbia Utilities Commission, as well as performing due diligence for resource acquisitions and related tasks.

In 2002 I moved to the California Independent System Operator (CAISO), where I was initially employed in the Department of Market Analysis in the Market Investigations group in the aftermath of the energy crisis of 2001. In 2004 I moved into wholesale power market design and became familiar at that stage with the integrated nature of the wholesale power markets and the gas markets. In 2006 I was made a Manager in the Operations group where I was responsible for monitoring the performance of CAISO markets. I also managed part of an extensive Settlements function. In 2007 I managed the Congestion Revenue Rights group as the market transitioned from a zonal pricing system to a nodal system in April 2009, a responsibility

I retained until 2011. In August of 2011 I left the CAISO and founded Energy Market Expertise LLC, a consulting firm that specializes in the wholesale electric power markets, where I have been ever since. My clients generally are market participants in the wholesale power markets, generally in the West.

I received my undergraduate degree in Economics from the University of Natal Durban in 1991 and my Master's degree in Development Economics from the University of Leeds in 1993. I am the author or co author of 11 publications in refereed journals, of which the most recent six specifically deal with the design and functioning of wholesale electric power markets. I attach my resume as Appendix 1.

What is the purpose of your testimony?

The main purpose of my testimony is to explain how a change the Commission made in the rate structure for PG&E's gas transportation rates put Moss Landing Units 1 & 2 at a significant competitive disadvantage in relation to their market rivals and threatened to strand over a half billion dollars of investment in new generation infrastructure. This change occurred just after the plant entered service. I will discuss how a bill credit adopted in the Gas Accord III, IV, and V settlements has attempted to lessen the competitive disadvantage that Moss Landing Units 1 & 2 have suffered. I will also examine the commercial record of Moss Landing Units 1 & 2 and determine whether or not the bill credit accommodation that has been in place since Gas Accord III has served its purpose and proven to be an effective method of implementing the bill credit goals. I do this by examining the commercial operations of the plant and explaining how the bill credit functioned commercially, and why, most recently, it has failed to live up to its intended purpose. I then examine the proposed PG&E rates and explain why this rate case is so important for Dynegy, and further why, if it is adopted with little change, PG&E's gas transportation rate proposal for Electric Generation customers served by the local transmission system is particularly harmful to the commercial interests of the Moss Landing plant. I also detail some aspects of the rate case that have not been appropriately considered or studied. Thereafter I detail various alternatives which will allow the goals of the bill credit to be met either by other means or by changes to the bill credit mechanism. These alternatives will provide the Moss Landing plants with effective rates that will provide the Moss Landing units with a reasonable opportunity to compete in California energy markets.

Background

Please describe the characteristics and history of the plants at Moss Landing.

The Moss Landing power plant has four generation units on the site, Units 1, 2, 6, & 7. In terms of technology, Units 1 & 2 are a pair of Combined Cycle Gas Turbine (CCGT) generation sets. Each generation set consists of two gas turbines and a steam turbine with a capacity of 510MW, thus totaling 1020MW for Units 1 & 2. Units 1 and 2 went into commercial operation in July 2002. They are highly efficient with a capacity factor around 50% and are the subject of Dynegy's concern in this rate case application. In addition to Units 1 & 2, there are two other older units, namely Units 6 & 7. Totaling 1509 MW, these are 1960s era steam turbines. They have a low capacity utilization. This Moss Landing plant, in its entirety, was acquired by Dynegy in 2007 from LS Power[1].

What rate do Moss Landing Units 1 & 2 pay for service from PG&E?

Moss Landing Units 1&2 receive gas transportation service under PG&E's Schedule G EG from Line 301 G. Schedule G EG includes a Backbone level rate that is exempt from local transmission costs, and an "All Other Customers" (AOC) rate for non Backbone customers. Moss Landing Units 1 & 2 do not qualify for Backbone level service and pay the "All Other Customers" rate. This is a transportation charge, not a commodity charge. Moss Landing is also subject to other charges such as the G SUR and the customer access charge, but these latter charges are not the subject of concern in the instant testimony as they are the same for all generation units receiving service under the Schedule G EG rate.

Please describe the construction and rate history of Units 1 & 2.

When Moss Landing Units 1 & 2 were being planned and constructed, gas transportation rates were governed by the first Gas Accord. Gas Accord I required all on system end users, including Electric Generation (EG) customers, to pay both Backbone and local transmission charges. At

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[1] As a convenience the plant owner is generally referred to as Dynegy.

the time, PG&E's existing gas transportation system had ample underutilized pipeline capacity to serve the new units, due to the retirement of the previous Units 1 5 and the improved efficiency of the new Units 1 & 2. In addition, there was no economic advantage to constructing a lateral to the Backbone, about 24 miles away, because rates under the first Gas Accord required all on system end users to pay both Backbone transmission charges and local transmission charges, and there was no indication at that time that the Commission was inclined to adopt a Backbone level rate for EG customers. Thus, at the time Units 1 & 2 were planned and constructed the playing field was comparatively level, and in the absence of a commercial reason to construct a lateral to the Backbone, Moss Landing simply took gas transportation from PG&E using PG&E's facilities at the G EG rate.

However, 30 months after Units 1 & 2 went into service the rate structure started shifting dramatically. Beginning with the approval of Gas Accord III in December 2004, the Commission, for the first time, allowed certain customers to pay only the rate for Backbone level service and exempted qualifying end use customers from responsibility for local transmission charges. The implementation of the Backbone level rate gave those generation units that connected directly to the Backbone system a commercial advantage, as their transportation charges were reduced from the rate that the Moss Landing plant and all other similarly situated plants were paying. The Backbone only level customers paid the cost of the lateral pipeline or other facilities connecting them to the Backbone, although this cost was generally low as they were situated close to the Backbone. This decision also placed restrictions on the ability of customers to build new laterals to connect to Backbone service

In the negotiations of Gas Accord III, the resulting competitive disadvantage of paying the higher AOC rate was discussed and was mitigated for Moss Landing Units 1 & 2 by a $2 million annual bill credit included in the Gas Accord III settlement. This structure was then replicated in subsequent gas transportation rate case settlements. For Gas Accords III and IV (2005 through 2010) the bill credit was $2M/annum with annual escalation, and for Gas Accord V, it was $2.5M/annum, with annual escalation. For the first few years, this bill credit had the effect of giving Moss Landing Units 1 & 2 a reasonable opportunity to compete in electricity markets on the same basis assumed when the units were constructed.

Besides reducing Moss Landing's transport charge, what was the underlying policy concern that the bill credit addressed from Dynegy's perspective?

The genesis of the bill credit was linked to the formation of the Backbone rate as a separate rate for the Electric Generator class. Generation units that connected directly to the Backbone would not be responsible for the local transmission component of the revenue requirement and their rate would be commensurately lower. Prior to the introduction of the Backbone rate, all generation units paid the same rate regardless of their distance to the Backbone, so the gas price was the same across the entire PG&E gas service area. This was essentially a postage stamp rate. With the introduction of the Backbone rate, that changed, and there were broadly speaking two issues addressed by the bill credit approach.

1. The owners of plants like the Moss Landing plant had made substantive investments on a brownfield site under an existing regulatory regime that had postage stamp rates. The investment cycle in the electric generation industry is a long cycle, often 25 35 years depending on technology. If the price of gas transportation changed in comparison to its peers, that investment was extremely vulnerable. From an equity standpoint some accommodation needed to be made to ensure that such investments were not immediately displaced by a new class of generators connected to the Backbone, especially given the existing electric and gas transmission infrastructure at these existing plants. If Moss Landing had to pay significantly more than the Backbone units, even units of the same vintage and technology, its fundamental ability to compete in electricity markets would be compromised.
2. The gas market was so important to the wholesale electric market that changes in gas rates could disrupt not only investment decisions of generation owners but also the wholesale electric power market itself. The wholesale electric power market is both highly integrated with the natural gas transport infrastructure and also downstream of the gas market, even more so in California where natural gas plants

predominate and are generally on the margin. There was thus a recognition of this interaction as well as a desire to minimize that potential disruption.

The bill credit thus emerged as the vehicle to address these issues, and it is worth emphasizing that the bill credit had a policy purpose that was true then and remains valid. The passage of time has not changed these issues, and the Moss Landing plant is only 12 years through an industrial life that may last 25 35 years.

How did Dynegy negotiate the bill credit?

Dynegy negotiated as part of the multi party Gas Accord settlement process, and this remains Dynegy's preferred method of resolving issues such as these. All parties appeared to realize that Dynegy was a participant in competitive electricity markets and that its overarching goal was simply to maintain a reasonable opportunity to compete in those markets. The bill credit seemed to provide that opportunity. The revenue shortfall resulting from extending the bill credit to Moss Landing Units 1&2 was assessed partly to all Backbone shippers and partly to Backbone level customers (G EG and G NT). Dynegy did not seek an undue advantage, but was also concerned about maintaining the competitiveness of the Moss Landing units. This intention can be seen in the rates from the Gas Accord agreements and are shown in Table 1. These are the class average rates from the settlement accords.

Table 1: GA Rates and the Bill Credit

	Year	EGBB rate	EGDT Rate	Nominal Difference	Nominal Bill Credit
GA III	2005	0.045	0.193	0.148	$2M
	2006	0.045	0.193	0.148	$2M
	2007	0.045	0.193	0.148	$2M
GA IV	2008	0.116	0.249	0.133	$2M
	2009	0.116	0.249	0.133	$2M
	2010	0.116	0.249	0.133	$2M
GA V	2011	0.065	0.267	0.202	$2.5M
	2012	0.065	0.267	0.202	$2.5M
	2013	0.065	0.267	0.202	$2.5M
	2014	0.065	0.267	0.202	$2.5M
GA VI	2015	0.123	1.003	0.880	

As is clear from Table 1, as long as the nominal difference was 13 to 15c/dth Moss Landing Units 1 & 2 had a reasonable opportunity to compete. When Gas Accord V was negotiated and there was an increase in the rate difference, the value of the bill credit was also increased, in this case to $2.5M. The effect of the agreement was to provide the Moss Landing units a reasonable opportunity to compete in electricity markets, in recognition of their unique history in relation to the change in rate structure.

What was the net effect of the bill credit on the rates that the Moss Landing plant paid for gas transportation?

Initially the bill credit worked as intended. The bill credit was structured as a fixed dollar figure, whereas the rate that Dynegy paid for gas transportation services was a per dekatherm rate. These two methods need to be made comparable. The first step is to determine the gas consumption, or burn rate, of the Moss Landing units on an annual basis. This was calculated by averaging the burn rate for the last five years. The burn rate for 2014 was estimated by simply doubling the burn rate for the first six months. The average burn rate for Moss Landing Units 1 & 2 was found to be approximately 26M dth per annum.

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Thereafter one simply factors in the credit given the burn rate as shown in Table 2, which converts the lump sum payment into a dth value.

Table 2: Moss Landing Effective Bill Credit Per Dth[2]

Year	Credit	Burn	Credit/dth
2009	$(2,121,600)	[redacted]	0.087
2010	$(2,164,032)	[redacted]	0.092
2011	$(2,500,000)	[redacted]	0.196
2012	$(2,550,000)	[redacted]	0.080
2013	$(2,601,000)	[redacted]	0.077
2014	$(2,653,020)[3]	[redacted]	0.089

The value of the bill credit varies with production. If the Moss Landing 1&2 units do not run very often in a given year, the lump sum is spread over lower volumes and has a higher per dth value and vice versa. The average of the years considered is 0.104, or simply 10.4c. Going forward, a reasonable assumption based on the last five years of production data would be that the bill credit is worth 10.4c/dth.

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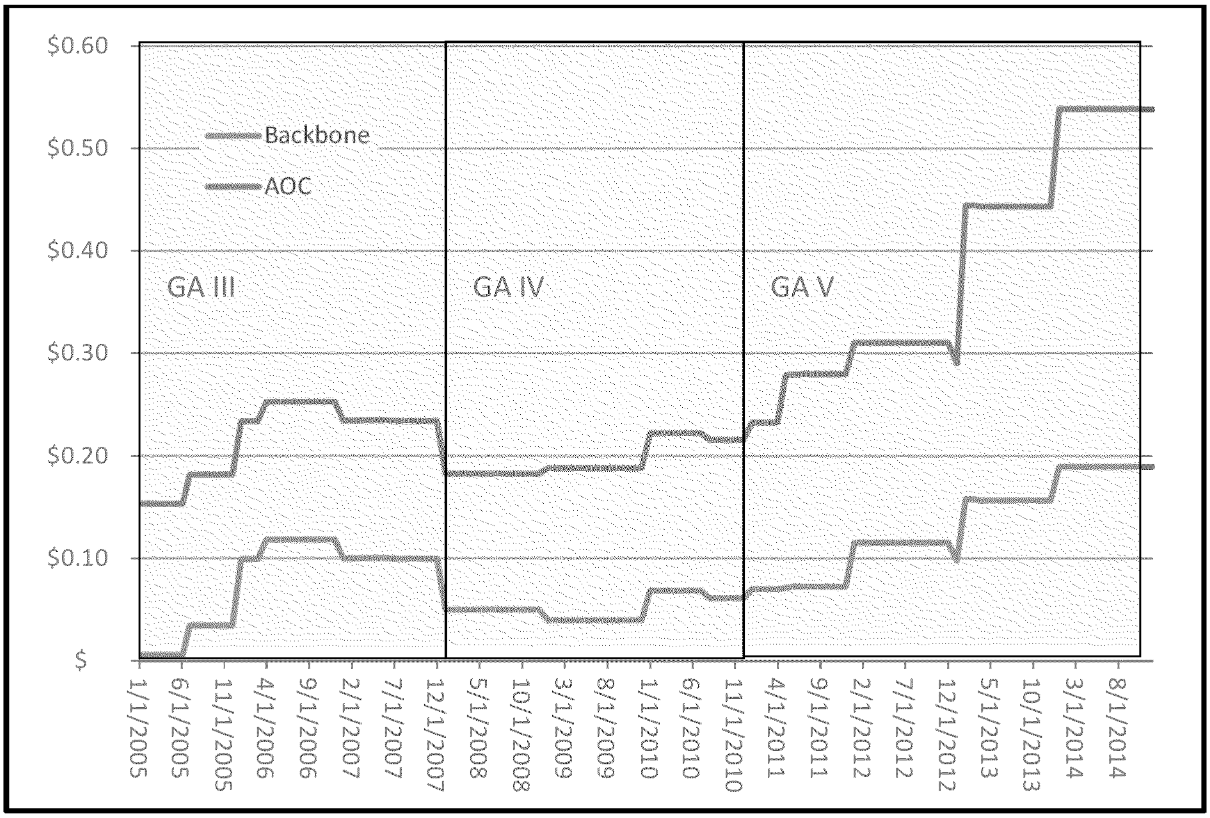
[2] For mathematical accuracy all calculations were made with actual production data. For confidentiality reasons these production figures have been obscured. Gas consumption for 2014 was estimated by doubling the value for the first six months.

[3] The credit for 2014 is $221,085/month, so this is simply that figure multiplied by 12.

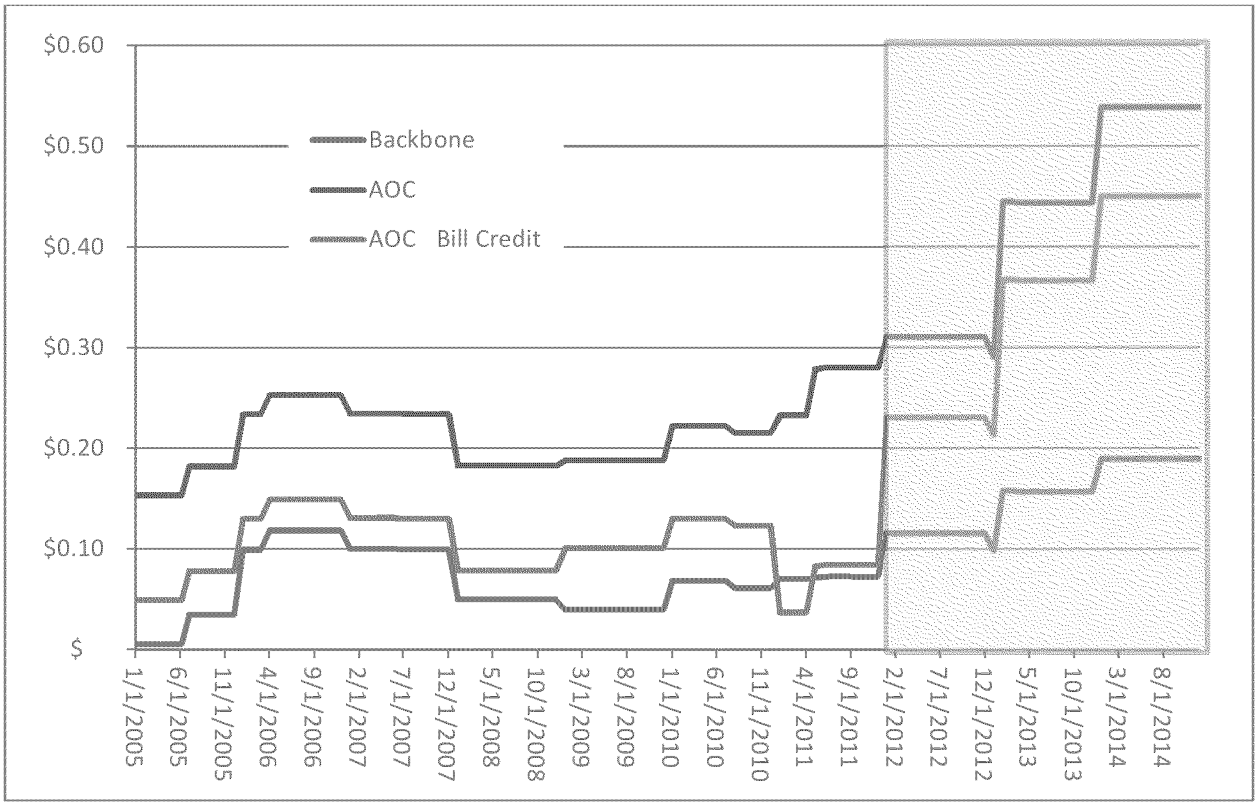
Using the G EG rates for Backbone customers and AOC customers downloaded from the PG&E website, it is possible to graph the rates of the Backbone users compared to the rates that Moss Landing Units 1 & 2 have faced. This is shown in Figure 1 where the rates are shown during the different Gas Accord periods. Even to the naked eye, there is rate separation evident in the last Gas Accord.

Figure 1: Gas Accord Rate Structure



To this graph one can add a further metric, which shows the net effect of the bill credit and this is shown in Figure 2. This is useful as the bill credit changes between Gas Accord IV and V and there is also a 2% adder to take into account.

Figure 2: Net Effect of Bill Credit

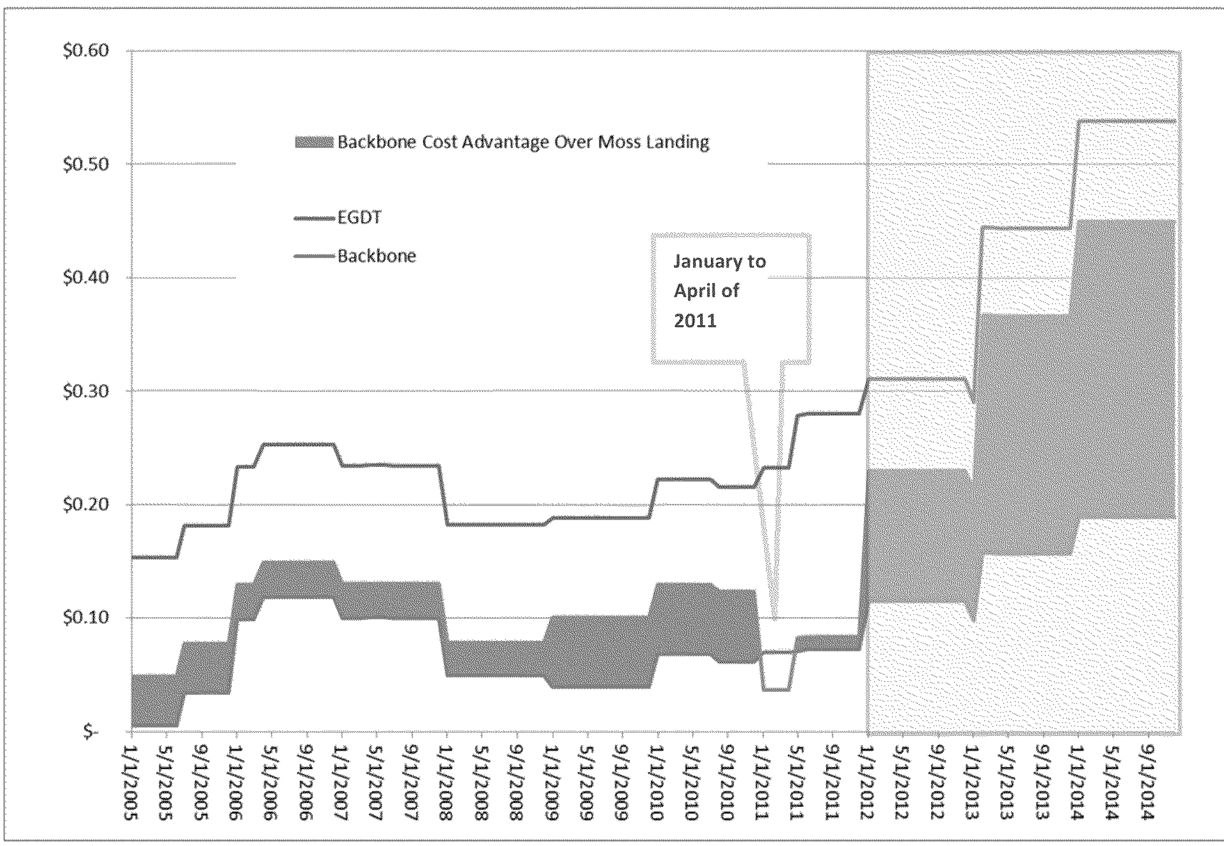


The net effect of the bill credit is seen in the green line entitled (AOC Bill Credit) in the legend. It illustrates that up until late 2011, the bill credit had the effect of allowing Dynegy a reasonable opportunity to compete against plants paying only the Backbone rate because its net gas transport cost tracked the Backbone rate closely. In the first four months of 2011 high hydro conditions led to a lower burn rate, and effectively a greater per Dth credit. That is, the effective transportation rate for Moss Landing Units 1 & 2 was low only because gas fired plants were not being dispatched much because of the availability of hydroelectric power. One can argue that some premium over the Backbone rate is appropriate for the effective rate after considering the bill credit, as Backbone generation plants have to build their own laterals or pay PG&E to build the lateral. Figure 2 shows that Dynegy had a reasonable opportunity to compete against the Backbone plants and that it did not receive a rate that was more favorable, on average, than the Backbone rate.

Did the Backbone units always have a cost advantage over Moss Landing 1 &2?

As shown in Figure 3 below, in this entire period from 2005 through 2014 the Backbone units have always had a competitive cost advantage over Moss Landing as they are paying the area below the blue line entitled "Backbone", whereas the Moss Landing Units 1&2 are paying that as well as the area shaded in green as shown in Figure 3. There is a single exception to this, and that is the period shown on the graph during the Winter of 2011. 2011 was an exceptionally high hydro year and in looking at the bill credit as a monthly value, this lumpiness resulted in a fleeting advantage over the Backbone units for four months as shown in Figure 3. In truth it was hardly an advantage as there was abundant hydroelectric power and gas plants weren't running much. The extent of the advantage that the backbone units had on an annual basis is also calculated in Table 3.

Figure 3: Backbone Competitive Cost Advantage Over Moss Landing 1&2



What happened to the bill credit after 2011?

In 2012 the effectiveness of the bill credit in keeping Moss Landing competitive breaks down, as shown in both Figure 2 and Figure 3 as the shaded area in light blue. The rapidly increasing green area showing the Backbone advantage also illustrates this. After the San Bruno incident, there was a case (R.11 02 019) that allowed for project funding of $769 million. This investment was primarily for projects on the local transmission and distribution portions of PG&E's system, and the resulting increase in the local transmission revenue requirement began a structural shift in the relationship between the Backbone rate and the AOC rate to which the Moss Landing plant was subject. As the bill credit was a lump sum and was not tied to the Backbone rate by tariff, Dynegy had little recourse. The details of this structural shift are shown in Table 3.

Table 3: Backbone Comparison Using Annual Production[4]

A	B	C	D	E	F	G	H	I	J	K	L
Yr	Avg BB	Avg AOC	Burn	BB*Burn	AOC*Burn	AOC Split BB	AOC Split Lat	Bill Credit	Net Lat Pay	Average	Avg Rate
05	$0.020	$0.167	[redacted]	$521,300	$4,353,700	$521,300	$3,832,400	$(2,000,004)	$1,832,396		
06	$0.114	$0.248	[redacted]	$2,954,250	$6,448,650	$2,954,250	$3,494,400	$(2,000,004)	$1,494,396		
07	$0.100	$0.234	[redacted]	$2,599,350	$6,093,750	$2,599,350	$3,494,400	$(2,000,004)	$1,494,396		
08	$0.050	$0.183	[redacted]	$1,297,400	$4,750,200	$1,297,400	$3,452,800	$(2,079,996)	$1,372,804		
09	$0.040	$0.188	[redacted]	$960,594	$4,571,943	$960,594	$3,611,348	$(2,121,600)	$1,489,748		
10	$0.065	$0.219	[redacted]	$1,532,987	$5,145,926	$1,532,987	$3,612,940	$(2,164,032)	$1,448,908		
11	$0.072	$0.264	[redacted]	$918,861	$3,455,432	$918,861	$2,536,571	$(2,500,000)	$36,571	$1,309,888	$0.056
12	$0.115	$0.311	[redacted]	$3,668,412	$9,870,382	$3,668,412	$6,201,969	$(2,550,000)	$3,651,969		
13	$0.152	$0.431	[redacted]	$5,134,988	$14,558,202	$5,134,988	$9,423,215	$(2,601,000)	$6,822,215		
14	$0.189	$0.539	[redacted]	$5,674,421	$16,133,451	$5,674,421	$10,459,030	$(2,653,020)	$7,806,010	$6,093,398	$0.192

[4] Average bill credit is estimated for 2005 to 2008, however it was set at $2M/annum. The details for 2014 in general assume that the first six months are the same as the last six months as production data for Dynegy only stretches back to 2009. The burn rate for 2005 2008 is assumed to be 26M dth as calculated earlier. This table represents the G EG rate. For confidentiality reasons the exact burn rate is obscured.

From left to right, columns B and C and D show the average Backbone and AOC transportation rates, followed by the average gas burn rate for Moss Landing Units 1 & 2. Columns E and F show the charges at the projected Backbone and AOC rates. Column G and Column H are together and they take the AOC charges (column F) and split it in two, into a Backbone portion and a Lateral portion (Column G is the same as Column E). Column H is termed the "Lateral" portion as this effectively is the charge to bring the gas from the Backbone to Moss Landing. Column I shows the bill credit and column J shows the Net Lateral Payment, which is simply the Lateral Payment offset with the bill credit.

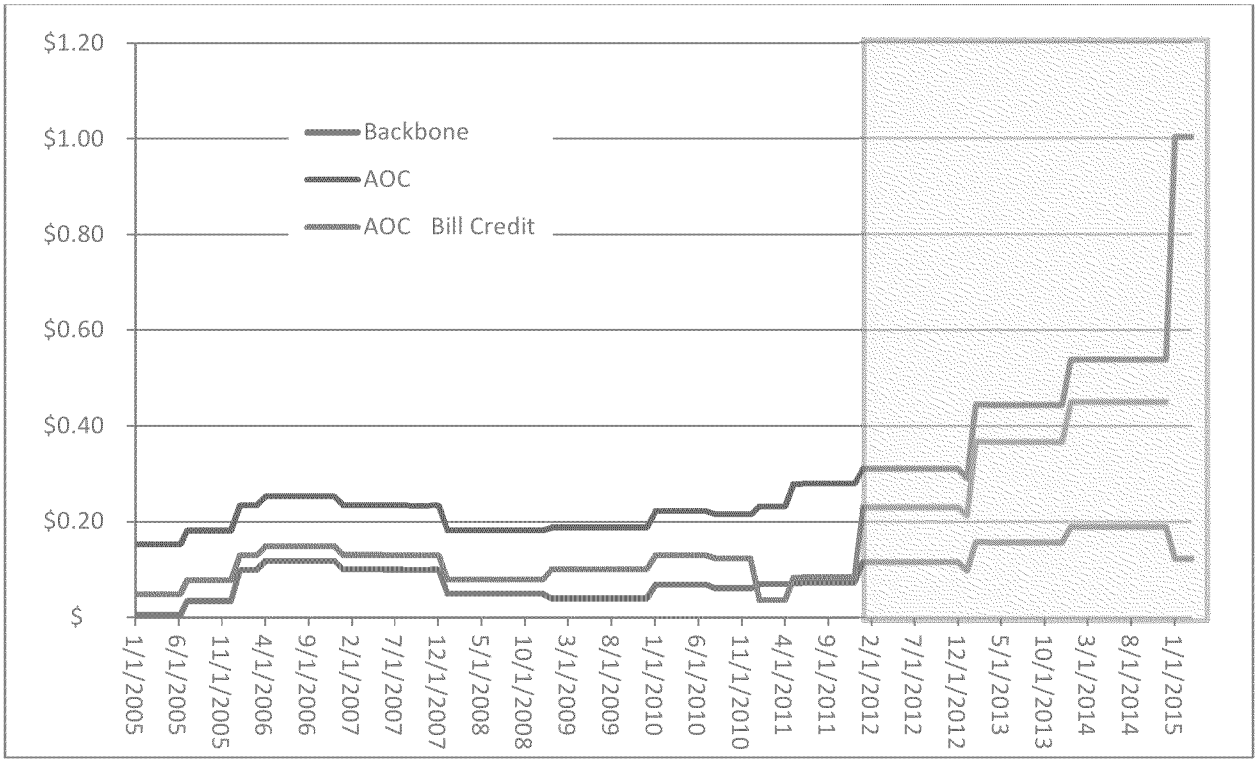
The final two columns, K and L, are the most important as they show that the period between Gas Accord III and the present consists of effectively two quite different periods for the Moss Landing plant. The first period, in green, is the period when the bill credit worked to reasonably offset the competitive disadvantage of the gas transportation rate change. This was before San Bruno, and before the Commission decision increasing rates in response to that event. During this time Dynegy paid $1.3M or about 5.6c/dth to bring gas from the Backbone to the Moss Landing plant. The second period, shown in very light orange, begins in 2012 and lasts through to present. Instead of paying $1.3M, Dynegy now paid $6m per annum on average during this period. Similarly, instead of paying 5.6c/dth Dynegy now pays 19.2c/dth. For the period 2012 2014, Dynegy rationally planned and budgeted for costs of about $1.3M per annum, or about $3.9M in total. Instead, Dynegy is projected to pay $18.3M over this period. This is $14.4M in excess of historical levels and negatively affected the ability of Moss Landing Units 1 & 2 to compete in the power markets.

What would Dynegy pay under the proposed PG&E rates[5]?

Under the PG&E proposal, the rate for the EGDT rate class rises to $1.003/Dth, while the rate for the Backbone rate class falls further to 12.3c/dth. Thus the rate separation widens dramatically. The simplest way to illustrate exactly how detrimental PG&E's proposed rate will be for Moss Landing is to reproduce Figure 2 from earlier and to model where the rates are headed under the PG&E proposal. Figure 4 is a reproduction with the proposed rates inserted for 2015. The bill credit is not modeled because it is not certain what it might be. As mentioned earlier, starting in 2012 the rate separation begins. For the last three years the traditional relationship between the Backbone rate and the rate that Dynegy pays dislocates entirely, rising to 20c, then 28c, and in 2014 to 35c. In 2015, it is proposed to be 88c. Note the change in scale from the previous graphs and the step change in the rate structure for the EGDT rate class.

[5] In the historical analysis of the commercial operations of the Moss Landing plant I have analyzed the G EG rates for Backbone and "All Other Customers" as Moss Landing pays the AOC rate. In PG&E's rate proposal it provides in Table 17 5 illustrative end use class average rates. In Table 17 5 lines 19 (Electric Generation – Distribution Transmission or EGDT) is the rate class to which Moss Landing belongs. Line 20 (Electric Generation – Backbone) is the corresponding Backbone rate. I have used these rates for the rate projections. The EGDT rate class includes some customers who have qualifying cogeneration load and are served under different schedules. The illustrative rates are also class averages and are thus not exactly the same. It seems that the Backbone customers most likely pay 2 3c more than the illustrative rates in Table 17 5, and the AOC customers 4 5c more. This small discrepancy does not change the import of the analysis.

Figure 4: New Rate Structure



How will this rate separation translate into actual payments for Dynegy?

In Table 4 below the payments are shown as calculated. This is simply the previous Table 3 with a new line for 2015. The figures for 2015 are the EGDT figures drawn from Table 17 5 of PG&E's rate proposal.

Table 4: Rate Projections

A	B	C	D	E	F	G	H	I	J	K	L
Yr	Avg BB	Avg AOC	Burn	BB*Burn	AOC*Burn	AOC Split BB	AOC Split Lat	Bill Credit	Net Lat Pay	Average	Avg Rate
05	$0.020	$0.167	[redacted]	$521,300	$4,353,700	$521,300	$3,832,400	$(2,000,004)	$1,832,396		
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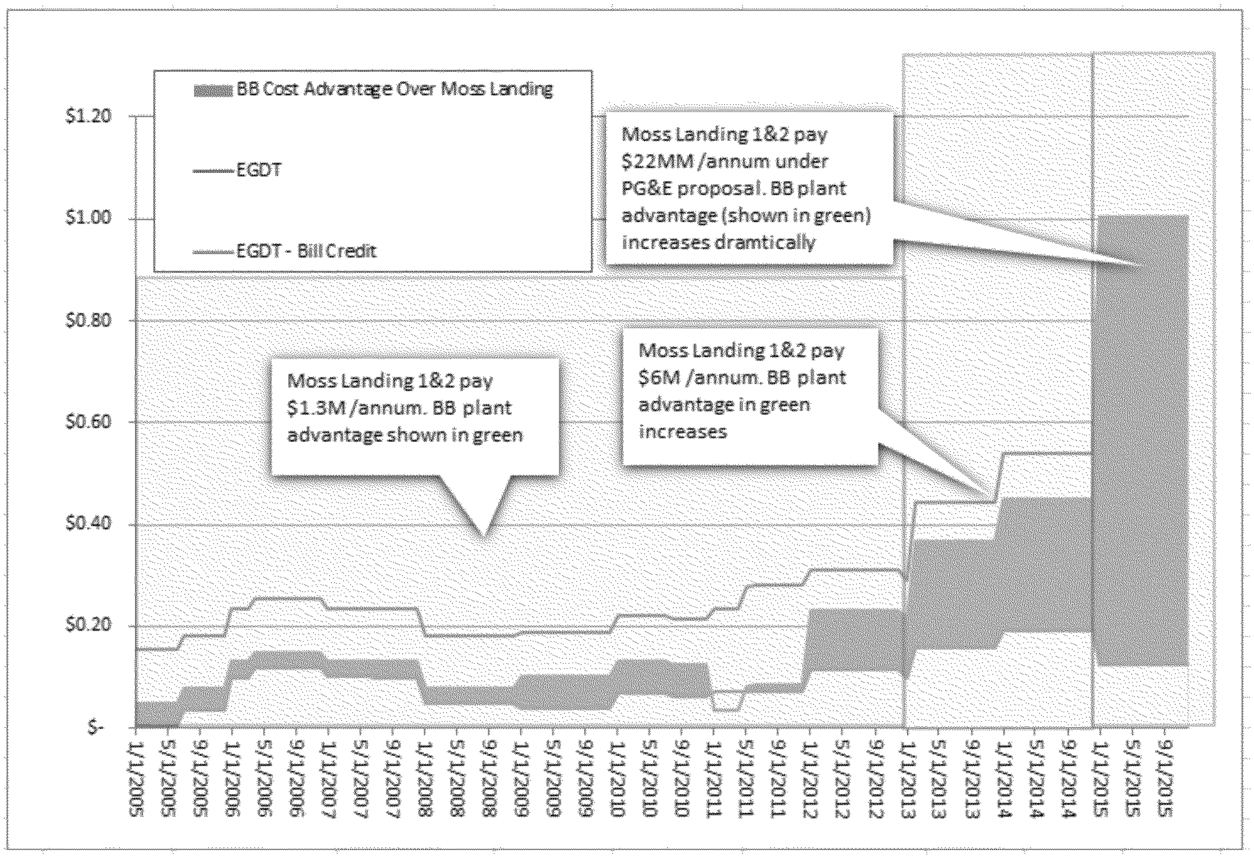
13	$0.152	$0.431	[redacted]	$5,134,988	$14,558,202	$5,134,988	$9,423,215	$(2,601,000)	$6,822,215		
14	$0.189	$0.539	[redacted]	$5,674,421	$16,133,451	$5,674,421	$10,459,030	$(2,653,020)	$7,806,010	$6,093,398	$0.192
15	$0.123	$1.003	[redacted]	$3,198,000	$26,077,999	$3,198,000	$22,879,999		$22,879,999	$22,879,999	$0.880

Assuming an average burn rate of 26M dekatherms (column D) Dynegy would pay $26M/ annum under the AOC rate. In the absence of a bill credit, Dynegy's payment to transport gas from the Backbone to the Moss Landing station will be almost $23M. *A service that previously cost $1.3M/annum will now cost $22.88M. A service that previously cost 5.6c/dth will now cost 88c/dth*. This increase for Dynegy is staggering. To put this in perspective, in 2013 the average Backbone rate for the G EG schedule was 15.2c, and the total annual revenue for the Backbone class was $19.1M for the entire class. Under this rate proposal the G EG Backbone rate will go down and the revenue for the class will most likely go down as well. Thus the entire class will likely pay less than $19.1M in 2014 and beyond. *Moss Landing's projected payment of $22.8M just for the lateral is more than the entire Backbone class will likely pay for gas transport*.

This can also be shown using a graph similar to Figure 3, and Figure 5 below shows the same three periods as Table 4, namely the period to 2012, 2012 2014 inclusive, and then the rate projection for 2015 onwards. Because there is no bill credit in the PG&E rate proposal, none is shown from 2015 onwards. Figure 5 shows this hugely increasing disparity between Backbone rates and the rates that Moss Landing 1 & 2 will pay under the PG&E rate proposal.

Figure 5: Backbone Competitive Advantage Under Proposed Rates



Do you think the structure of the bill credit was appropriate?

The recent divergence of Backbone and local transportation rates reveals that the structure of the bill credit as a lump sum, even if it is spread over 12 individual months, is no longer advisable given the sums of money involved. If a bill credit was going to be used as a vehicle to maintain a competitive balance in electric markets, then it needed to scale to usage and to the charge. Unfortunately no one realized this at the time and the bill credit remained a lump sum and as a consequence, Dynegy has paid a great deal more than expected.

How has the bill credit failed to maintain competitive balance?

Since Gas Accord V went into effect, there have been unforeseen events stemming from the San Bruno event. When the San Bruno event occurred, the Moss Landing plant and its competitors in the wholesale electric markets were quite differently situated. The position of

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Dynegy had always simply been to preserve the competitive position of the Moss Landing plant. The Moss Landing plant found itself in a different rate class to many of its peers, who now chose, or were allowed, to connect to the Backbone to take advantage of the lower Backbone rate. However, as long as the rates were relatively comparable, the Moss Landing plant could be reasonably competitive. And the rates were reasonably comparable once the bill credit was taken into account until the beginning of 2012. In recent years, the bill credit has been insufficient to prevent a clear degradation of Moss Landing's competitive position. An increase from around $1.3M to $7.8M (projected for 2014) and then to $22.88M (PG&E 2015 projection) is huge. An underlying goal of the bill credit was not only to keep Moss Landing competitive, but to offset to some extent the disruption to electric markets that might occur from optimizing gas transportation markets. Seeking an optimum balance of regulatory policies for gas transportation and for electric market competition is a worthy policy goal for the Commission. The bill credit, as a lump sum, is an unsophisticated method of preserving the competitive position of Moss Landing or other plants.

Effect on Moss Landing

If this rate increase is implemented without being substantially altered, what effect will it have on the competitiveness of the Moss Landing plant?

The worrisome aspect of this rate increase is that it is so wholly disproportionate. It has a staggering effect on the Moss Landing plant but much less of an effect on other participants, many of whom will benefit competitively from Moss Landing's increasing cost structure. The importance of this to Dynegy is best shown by examining how cost competitive the wholesale electric markets are.

1. Natural gas is literally the only variable input of any significance for a CCGT. CCGTs like Moss Landing produce electricity and their main variable cost is natural gas. In fact, natural gas is generally between 90 95% of the variable cost of production. CCGTs are effectively natural gas processors. This is fundamentally different to being a food processor for example, where there may be a variety of inputs.
2. Natural gas fired plants compete against each other. In California natural gas fired generators are generally on the margin and set the price. What this means is that competition from non natural gas fired generation is minimal. If the gas price rises, the wholesale electric prices will rise in tandem. There is very little competitive threat from competing fuel types such as nuclear, coal or hydroelectric power, especially in the wake of recent events such as Fukushima and the introduction of carbon constraints. Moss Landing's main competitive threat is simply its peers. There is some competitive threat from energy outside of the PG&E footprint, and outside of California, where gas may be cheaper, but that energy still has to be transported via transmission lines that have their own capacity limitations and costs of operation.
3. The products produced are characterized by very little differentiation. With some minor nuances, all power plants, especially the class of natural gas fired power plants, produce the exact same products, broadly energy and capacity. There is more differentiation as one drills down into product categories because prices vary somewhat by time and location, but generally the products produced by gas fired turbines are very similar.

4. Although technology is improving incrementally all the time, the technology is generally stable. CCGTs are the current technology of choice for fossil fueled plants.

In summary, for the class of CCGTs, the input is the same, the production technology is stable, and the output is almost undifferentiated. This is a competitive segment and consequently, natural gas fired plants are very sensitive to changes in natural gas prices and costs. It will be very difficult for the Moss Landing plant to compete under PG&E's proposed rates.

How does one quantify this difference?

The easiest way to visualize the effect on Dynegy itself is simply to calculate the change in bid cost for Moss Landing Units 1 & 2 due to the projected rate increase. A simple way to do this is to take the efficiency of the Moss Landing units measured by the heat rate, which is essentially a measure of how many dekatherms are needed to produce a MWh of energy, and multiply it by the price of the required dekatherm of energy. Like many of the plants of its configuration and age, Moss Landing Units 1 and 2 are relatively efficient, meaning that their heat rate is between 7.0 and 7.5 depending on the exact level of production. For simplicity, assume a heat rate of 7.2, meaning that the Moss Landing Units 1 & 2 need 7.2 dekatherms to produce 1 MWh. If gas is at $5 including transport costs, then the fuel cost of production is $36/MWh. There are other variable costs of production, essentially operations and maintenance, that typically amount to $2 $3/MWh for a Combined Cycle Gas Turbine like Dynegy's units at Moss Landing. Assuming a gas price of $5 and $3 of O&M, Dynegy will likely insert bids that are based on that cost calculation of around $39, as that is the bare minimum it needs to cover its variable costs.

Under the proposed rates the difference between the EGDT rate and the EGBB rate widens, as shown most recently in Table 4, to 88c. In terms of bid cost, this translates into a difference of (0.88 x 7.2 = $6.34). Thus a unit situated on the Backbone and paying the Backbone rate will have an advantage in the wholesale electric market of $6.34/MWh. It should be noted that prior to this rate case Dynegy was already working with a discrepancy of 33.4c as of January

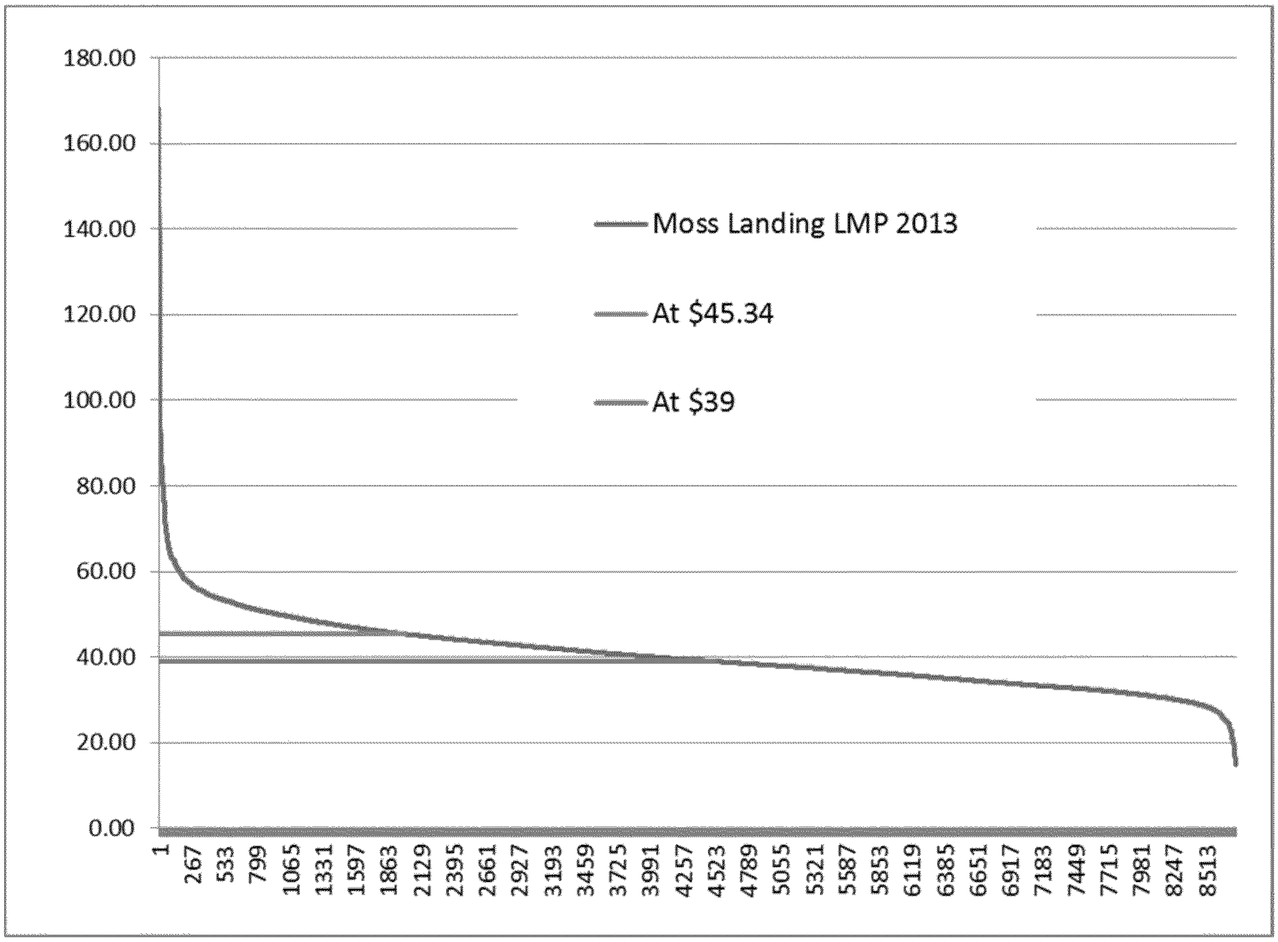
2014, which at a heat rate of 7.2 is $2.41/MWh. The disadvantage that Dynegy now faces, $6.34/MWh, is unexpected and significant.

How will this affect the Moss Landing plant's economic viability?

This is relatively easy to model using publicly available data. When Dynegy bids into the CAISO centralized market, it inserts bids that are fractionally higher than its variable costs. When the clearing price rises and matches or exceeds Dynegy's bid price, the unit is dispatched. The clearing price generally meets or exceeds Dynegy's bid price, and on occasion when it does exceed the bid price, Dynegy makes money in excess of its variable cost, often termed an infra marginal rent. The infra marginal rent is not profit, as it is in excess of the variable cost not the total cost, but is seen first and foremost as a contribution to fixed costs. Over the course of any period profit is only made when the sum of all revenues exceeds the sum of all costs. Dynegy is interested in having the lowest cost structure possible so as to maximize its infra marginal rents and try to earn a profit.

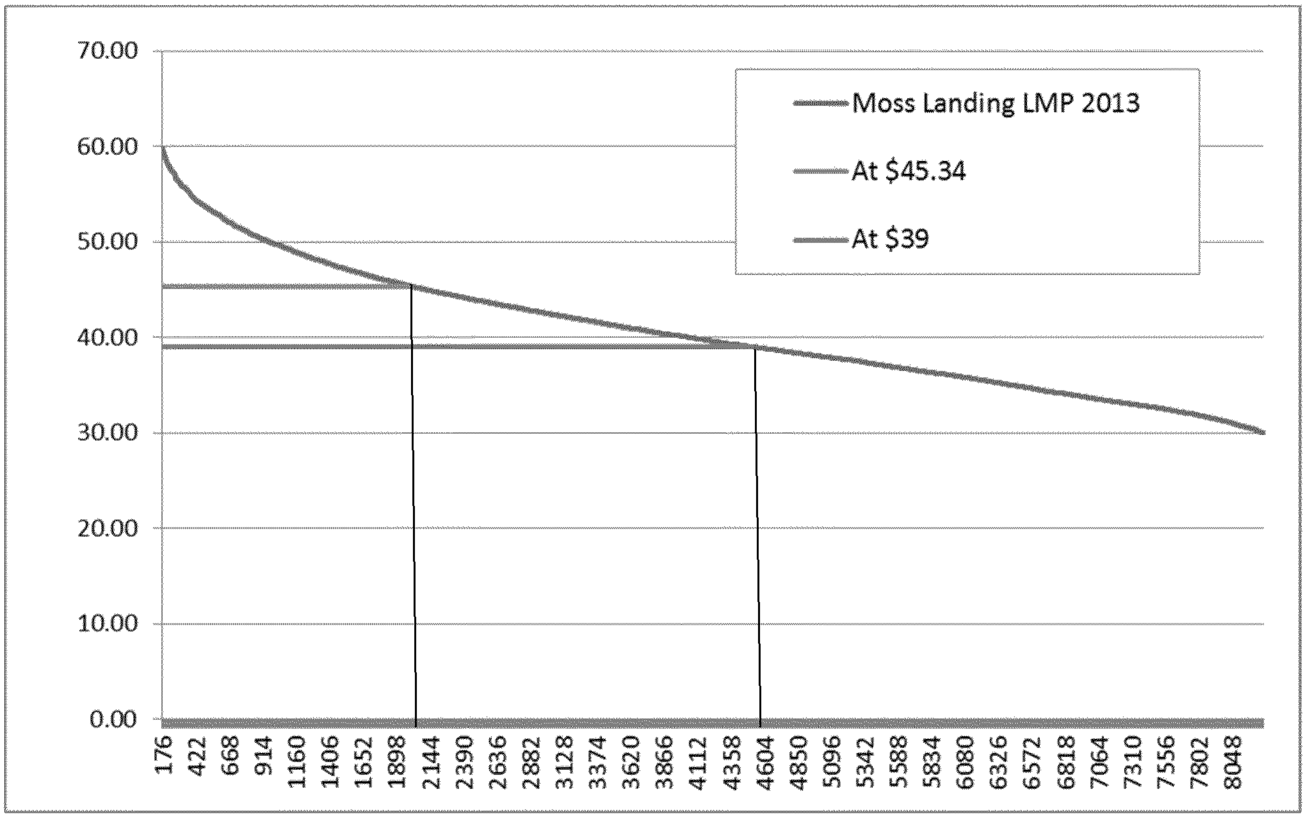
This can be demonstrated using a price duration curve. Most generating units bid into the CAISO day ahead market and these prices serve as a benchmark in California. Moss Landing receives the price at its delivery node, also commonly referred to as a pricing node (p_node). It actually has two delivery p_nodes, but for ease of illustration they are averaged as they seldom differ, being in the same switchyard. The price duration curve for the Moss Landing Units 1 & 2 delivery node, shown in Figure 6, consists of all of the hours for 2013, which is 8760 in total, ranked from highest to lowest, left to right.

Figure 6: Price Duration Curve for 2013



For ease of illustration this is reproduced in Figure 7 but just the particular part of the curve that is relevant. Figure 7 shows that a $6.34 difference in cost structure will mean that instead of running approximately 4500 hours per year (blue line) the plant will only run about 2000 hours (green line); the capacity factor halves. Further, the area between the two lines is a net loss of infra marginal rent to the Moss Landing plant. Exactly how much of that infra marginal rent is lost depends on the level of output, but assuming a range between minimum load and full output, the loss of revenue varies between $3M and $8.6M.

Figure 7: Truncated Price Duration Curve for 2013



If Dynegy pays 88c more than electric generators on the Backbone, why is that not simply reflective of the cost of transport from the Backbone to Moss Landing, and therefore a fully justifiable expense?

In analyzing the figures associated with this rate case, there seem to be a number of anomalies that are difficult to reconcile and for which there is no explanation given in the rate application. Earlier it was calculated that until the end of 2011 the annual payments for gas transportation to Moss Landing Units 1 & 2 from the Backbone was approximately $1.3M/annum or 5.6c/dth. Under PG&E's proposed rates, if there is no bill credit, Moss Landing Units 1 & 2 will pay $22.9M/annum for this service. In the industry there is a rule of thumb that the construction of a gas pipeline is approximately $1M/mile. Moss Landing is approximately 24 27 miles away from the Backbone depending on the route taken. For the amount of money from the increase in rates proposed by PG&E, Dynegy could almost build a new lateral every single year. PG&E proposes rates for Moss Landing that are difficult to reconcile with the actual cost of service that Moss Landing imposes on the natural gas network. I have not been able to definitively resolve this issue with the information on hand.

What other possible reasons are there for a discrepancy of this size?

A possible explanation for this level of discrepancy is that Dynegy is a cash cow within its rate class and is either supporting the other members of a poorly constituted rate class, or supporting other rate classes. A poorly constituted rate class in this scenario would be one in which there is a significant and permanent cross subsidization between members of the rate class. Rate classes are a commercial convenience for regulated entities that allow them to group classes of customers together so that not every customer is its own rate class. However, I am not able to satisfactorily explain the sizable discrepancy between the charges Moss Landing is projected to pay for gas transport and the burden it imposes on the gas transport network.

If there were a sizeable cross subsidization between Moss Landing and the other members of the rate class, then there would be some irony in this occurrence. One of the main reasons behind the wish to carve out separate Backbone and Local Transmission rates was the principle of cost causation, that entities with similar characteristics, such as generating units connected to the Backbone, should not be called upon to permanently cross subsidize members of another class. The costs that entities pay should approximate their burden on the system. In this the Backbone customers, as a class, seem to have been successful as their rates have stayed low even under PG&E's rate proposals. In contrast, the very occurrence that prompted the creation of a separate rate class for Backbone customers now seems to have been visited upon the Moss Landing plant as it now has a rate structure that is high and difficult to reconcile with the principles of cost causation. The same principles that applied to the creation of the Backbone level customers, namely cost causation, should be equally applicable to Moss Landing in this particular instance. Why is this cross subsidization not just as contradictory of the principles of cost causation?

When rates are low and do not vary much, entities seldom care much about which rate class they occupy. In this case however, rates are both increasing and separating, and in these situations the rate class becomes much more important. The Moss Landing plant needs to be charged a rate that approximates the burden it imposes on the system.

Why is PG&E's rate proposal so prejudicial to Dynegy?

This rate increase is prejudicial in two ways.

1. Most obviously it increases the rate that the Moss Landing units face and decreases the rates that Dynegy's competitors face. In essence, it deepens Dynegy's disadvantage. Many of Dynegy's peers are on the Backbone and their rates are declining, while Dynegy's rates are increasing. PG&E's rate increase is disruptive in that it reorders the competitive landscape amongst generators in a wholesale electric market that is narrowly competitive. If Dynegy were facing a rate increase that was significant but was equally spread across all rate classes, then this would be much less important to Dynegy. It is not the rate increase that is troublesome to Dynegy, it is the rate separation. With a higher cost structure, Moss Landing Units 1 & 2 will run less often. Dynegy will thus have less throughput over which to spread fixed costs and will have greater difficulty remaining profitable.
2. Backbone units will increase their capacity utilization factors and Moss Landing's capacity utilization factor will decrease. All of the Backbone units will profit from Moss Landing's increased cost structure. Included amongst the power plants that will benefit are PG&E's own power plants that are situated on the Backbone, namely Gateway, Colusa and Oakley if built. Competing against these power plants is particularly difficult as their costs are recovered in rates, so the plants are not reliant on infra marginal rents to cover their fixed costs[6]. They are super competitors generally and competing against them with a higher cost structure will be difficult. Dynegy does not believe that the PG&E proposal was purposefully structured to benefit utility owned generation at the

[6] It appears that PG&E owned units may not be subject to the G_SUR rate as well. See http://www.pge.com/tariffs/tm2/pdf/GAS_SCHEDS_G SUR.pdf

> expense of independently owned generation. There are many independent generators on the Backbone. However, the fact that the PG&E proposal has ended up harming some non utility generation and benefitting PG&E's plants is a complication that is best avoided.

Dynegy is an independent generator and is used to competing in wholesale electric markets. As long as Dynegy has the opportunity to compete on a level playing field against its peers, it has no qualms in dealing with the vicissitudes of competition. This change in rate structure has been disruptive to the Moss Landing plant in a manner that has not been shared by the industry. The disruption is narrowly focused on the Moss Landing plant and a few other smaller plants in Northern California.

Additionally, this change in rate structure contradicts one of the main functions of the Moss Landing bill credit, which was to ensure that the introduction of the Backbone rate did not create undue distortions in the emerging competitive wholesale electric markets by allowing the existing infrastructure investments to be outcompeted by emerging plants and a changed regulatory environment. Such a scenario risked stranding both gas and electric transmission assets and seemed irrational and inefficient given the existing infrastructure. This bill credit policy and historic accommodation does not seem to have factored into this rate proposal.

Effect on the Wholesale Power Market

Does the PG&E Rate Proposal Have Any Effect Beyond Impairing the Economics of Moss Landing?

The PG&E Rate Proposal will introduce distortions into the wholesale electric markets as a rate increase of this magnitude cannot help but have significant effects on the wholesale market. The exact nature of this effect is difficult calibrate without a series of studies. In the absence of a study sometimes it is only possible to determine the direction of change rather than to quantify the net effect. The fact that Moss Landing Units 1 & 2 are paying a rate that is seemingly in excess of the actual cost of transport results in a wave of inefficiencies that ripple through the wholesale electric power markets.

1. *Change in the dispatch order*. Moss Landing is contained within the CAISO footprint, which makes up approximately 90% of the wholesale electric market in California. Simplifying a little, the CAISO operates a single price auction for wholesale electricity in a variety of markets, principally the day ahead and real time markets. Under this construct, entities submit their bids to supply energy onto the grid and the market software produces a least cost dispatch subject to various constraints. In doing so it establishes a single price for energy across the entire footprint. The actual prices faced by entities are then the result of this energy price, plus an adjustment for losses and congestion. The method of least cost dispatch stacks the received bids in a merit order supply stack, and then simply runs up that stack until the required demand is met. The commitment and dispatch algorithm is a few orders of magnitude more complicated than that, however, no matter the complexity, the objective function remains the same, namely least cost dispatch. Faced with least cost dispatch, the most immediate effect is that the dispatch will migrate from units like Moss Landing to units on the Backbone. The first level effect is a dispatch order change. The direction of change is obvious, from generating units subject to the AOC rate to units that operate under the Backbone rate.

Congestion changes. In the short term, providing that all units stay in service, which is a reasonable assumption, the only change of any magnitude is a change in congestion. This issue is complex, but in broad brush strokes, it works as follows. Congestion on the transmission grid, by definition, occurs between generation points and the load centers. The presence of congestion simply means that low cost power is unable to travel to the load center to meet demand. Instead, it is halted at a constraint, and a more expensive generation unit on the other side of the constraint is dispatched. In the short term the rate increase that PG&E proposes will affect congestion, although the magnitude is difficult to discern. It will shift dispatch from the AOC units to the Backbone units.

This broadly is the effect. It is not certain what the net effect will be as some Backbone generators are close to the load centers, and some less so. Whether there is more congestion or less congestion is less important than the fact that the congestion market is now distorted by an artificially high cost structure for Moss Landing. This is an inefficiency due to a falsely high gas transport cost and is prima facie inappropriate regardless of which way the congestion prices move. The main feature of efficient pricing is that prices reflect true relative scarcities, not artificial scarcities. Prices should simply reflect costs appropriately so that sensible decisions can be made. Thus changes in congestion prices due to artificially high prices are prima facie wrong regardless of the direction in which they move.

2. If the dispatch is suppressed for those AOC units and thus inflated for the Backbone units, then in the short term it alters the dispatch pattern and in the long term it skews the investment incentives. Units on the Backbone will have higher dispatch levels and more of their power will flow to the load centers. This will eventually result in electric transmission line reinforcement over time, something that would not have happened had the dispatch order not been distorted. Changes in prices based on changing costs that are legitimate may be uncomfortable, but are not wrong. Changes in prices due to input prices that do not reflect relative scarcities always result in inefficiencies.

Other than a change in the dispatch order, how might the PG&E proposed rates impact the wholesale electric markets?

In the short term and presuming that all the units remain in service, the cost movements are as detailed above. In the longer term the effects become more uncertain. It stands to reason that all of the AOC units will become less profitable, and the Backbone units will become more profitable. At some stage the reduced revenue may result in the premature retirement of some of those units that are most sensitive to natural gas costs. In addition to stranding the existing local gas transmission capacity it may also require transmission upgrades to account for the lack of generation in the Moss Landing area. Given the competitiveness of the Backbone rate, it is unlikely that new construction would be willing to site in the local transmission area, leading to a hollowing out of the rate class.

Why Should PG&E, the CPUC and the Broader Electric Generation Community Care?

Earlier I detailed the effects of this rate case on Dynegy's commercial operations and in this most recent section I have detailed the effects on the wholesale power market. There are a number of reasons why PG&E, the CPUC, and the broader community should care about the events that have occurred with respect to the bill credit and the increase in rate structure.

1. Most obviously, the rates charged by PG&E must be fair, just, and reasonable and the burden of proving them so rests with PG&E. I contend that the proposed rates do not meet that threshold.
2. The bill credit that Moss Landing received at least until the end of 2011 has served to achieve two results that both merit Commission approval from a policy standpoint. The first was to respect the investment made at the Moss Landing site and not immediately shut it down as a result of a change in regulatory policy. In addition, there was also the benefit that optimizing gas transport rates by splitting out the Backbone rate should not unduly disrupt an emergent locational market. The wholesale electric market is closely integrated with the gas market and is very sensitive to changes in gas prices. These bill credit policy goals are worthy of embrace by the Commission and are not reflected in

the PG&E proposal, which, if adopted unchanged, will cause disruption to the electric market in some form.

3. The migration of electric generators from local transmission to the Backbone has its benefits for PG&E. Natural gas fired generators are intensive users of natural gas and it makes sense for them to be close to the larger Backbone pipes that are more easily able to provide the necessary quantity of gas. If this migration continues to play out though it is likely that over the construction cycle most every unit of size will migrate to the Backbone, thus stranding portions of the local transmission system. This does not make sense. The existing gas and electric infrastructure is in place and already partly depreciated. Stranding it would serve no purpose and serve no public good.
4. The events represented here also have broader significance for the Electric Generator community. Many of these generators take some level of service from PG&E and have a shared interest in receiving rates that are fair, just and reasonable. Moss Landing may be rendered less competitive, but few entities will take much comfort in the manner in which it is done. Although the Gas Accord settlements were in effect only for a few years at a time, their structure remained the same, creating the implicit expectation that things would persist in that manner. Neither Dynegy, nor PG&E, nor the CPUC seemed to realize that weaknesses in the bill credit approach would mean Dynegy has paid far more than it was intended to pay: $18.2M between 2012 2014 compared to the $1.3M/annum, or $3.9M that was the previous average. This is $14.3M more over the three year period. While PG&E may view this rate proposal as justified on other grounds, it has the effect of doubling down on the rate disparity paid by Dynegy.

Recommendations

What do you recommend concerning the competitiveness of the Moss Landing plant?

Moss Landing Units 1 & 2 should have a reasonable opportunity to compete with other generation plants. This basic principle has been the implicit policy of the bill credit since inception. There is no reason for it to change now. However, it is necessary that the method by which this policy is implemented and accomplished change. The Moss Landing plant paid an average premium of 5.6c/dth over the Backbone rate or $1.3M/annum for several years. This level of premium has precedent no matter what vehicle is used to get there and the Moss Landing plant should return to something approximating this level.

The best way to solve this issue is with a permanent solution. Although any solution that restores the competitiveness of the Moss Landing plant is better than none, the constant bill credit negotiations introduce an unneeded element of uncertainty for the Moss Landing plant. The Moss Landing plant has had a de facto different rate due to the bill credit. It should simply be made a de jure rate. Just as the Backbone units have rate stability, so should the Moss Landing plant also have rate stability for its most important input.

This outcome does not contradict the principles of cost causation; in fact the Moss Landing plant should receive rates that are more closely aligned with the cost of actual gas transport. The same principles of cost causation and inappropriate cross subsidization that led to the formation of the Backbone rate apply just as clearly in this case as they did then. The Moss Landing plant should not be a cash cow for the balance of the rate class, nor unduly cross subsidize its rate class.

What rate options would you recommend?

At a minimum I would recommend a rate that extends to the end of the industrial life of Moss Landing Units 1&2. As these units entered commercial operation in 2002 this would be around 2037, or the actual retirement of the plant, whichever is sooner. In terms of structure, I recommend the following alternative rate structures.

A Single EG Gas Transportation Rate

A single gas transportation rate for all electric generation customers promotes fair competition in electricity markets among electric generators, including PG&E, and does not distort the dispatch order of gas fired generation. It is the most elegant solution and in one stroke it solves a myriad of problems. At the same time, some companies have made a significant investment in privately owned and operated laterals to take advantage of the lower rate for Backbone level service that has been available for the last few years. No company should be unduly punished for decisions and investments made in reliance on the then prevailing regulatory structure.

Based on these principles, a gas transportation rate structure for all EG customers could include the following elements:

1. Except as described in 2), below, all EG customers will pay the same gas transportation rate, regardless of whether they receive service at the Backbone, local transmission, or distribution level.

2. The plants served by the private laterals that are more than one mile long will receive service at rates that reflect a reduced allocation of local transmission costs.

3. The total revenue responsibility of EG customers for local transmission costs remains the same.

The most equitable solution is this single rate. This, in effect, is a postage stamp rate for all electric generators. It is still likely that new generation will site close to the Backbone, as there are operational advantages, although the locational marginal prices in the wholesale electricity market also constrain the siting decision. A single electric generator gas transportation rate is simple, elegant, and conforms to the original policy goals that gave rise to the bill credit. It is simply a different method of implementing the same policy.

A New Rate Class Entitled Local Generation in the Transmission System

Since 2005, the Moss Landing unit has had a bill credit and a de facto different rate. A solution that is almost as optimal as the single EG rate would simply be to constitute a new rate class in recognition of the historical policy goals and the historical accommodation afforded the Moss Landing plant. This new rate class would include principally Dynegy's Moss Landing Units 1 and 2, as well perhaps as other units that might petition the CPUC for inclusion.

Although the single EG gas transportation rate is the preferred solution, there is a growing group of stakeholders associated with the Backbone units that are reluctant to support any measure that changes their current cost structure in any way. They want to build on the Backbone and have the simplicity of a single rate. This new rate class would recognize the historical accommodation made in Gas Accords III, IV, and V, and would make that accommodation permanent. If need be it could be grandfathered to include only the current power plants receiving the bill credit and could end when these plants retire. By setting a rate close to the historical rate of a 5.6c/dth premium above the Backbone rate, some rate certainty could be provided. This rate would apply regardless of the distance to the Backbone and would represent a premium to account for the fact that these entities did not build or pay for their own laterals. This new rate class would essentially codify the existing accommodations, but in a manner that was more permanent and less likely to result in the sort of unexpected developments that occurred with Moss Landing. In the absence of the single EG rate, this is the next best alternative.

Continuation of the Bill Credit

While the bill credit worked reasonably well until 2012, its structure became a large part of the reason why Dynegy is participating in this rate case. There is nothing wrong with the bill credit that cannot be fixed with a few adjustments. It has the advantage of both precedent and simplicity. Unfortunately its very simplicity was also its undoing and any solution that involves a bill credit should be restructured so that the Moss Landing plant does not have to revisit this occurrence. A restructured bill credit could have any one of these three elements.

1. A simple premium over the Backbone rate, similar to the historical rate of 5.6c/dth.
2. A payment of $1.3M/annum for transport regardless of volume.
3. A third alternative would be for Dynegy to pay the higher of $250K/annum or 5.6c/dth. This would guarantee PG&E $250K per annum for operations and maintenance regardless of volume. If the dollar figure is set too high though then it simply becomes a lump sum payment. A dollar figure to cover essential services would be appropriate.

Any one of these would work, and of these the first would be the simplest.

Purchase or Virtual Purchase of Line 301 G

Besides these abovementioned alternatives there are a number of more innovative methods that could also be used in place of the single EG rate, the new rate class, or a continuation of the bill credit. Using a purchase method, Dynegy would acquire an interest in one of the pipelines that serve the Moss Landing Power Plant, and that interest would serve as a lateral that would allow Moss Landing Units 1 & 2 to qualify for Backbone Level Service under Schedule G EG. The appropriate cost to Dynegy of this approach can be calculated from a few elements:

- Replacement cost, determined by multiplying a representative construction cost per mile times the distance in miles between the Moss Landing plant and PG&E's Backbone pipeline system
- Amortization period or useful life for depreciation purposes
- Cost of capital or allowed return
- Operations and Maintenance

Using the rule of thumb that construction costs for pipelines are about $1 million per mile, the 24 27 miles between Moss Landing and the Backbone, an amortization period of 25 years, a cost of capital of 12%, and a conservative estimate of $250,000 per year for the O&M, the full annual cost of a pipeline serving Moss Landing would be about $3.7 million. This of course is the cost of a brand new dedicated line. If Moss Landing were to purchase a share in the existing Line 301 G that serves Units 1 & 2 then it should be remembered that it is neither new nor dedicated.

Between 2005 2009, the highest use of Line 301 G's capacity by Units 1 & 2 was 70%; the average was 64%. If Dynegy acquires 70% of the capacity of Line 301 G, then a reasonable adjustment of the $3.7M would be ($3.7*0.7 = $2.6M). That would represent 70% of a brand new line. As the line is not new, and is most likely depreciated then an adjustment should be made to reflect that as well. A new line is more valuable than an old line and this is an old line, most likely dating to the original plant construction that has been depreciated by payments from the Moss Landing plant amongst others. It is not clear to me if there is any method by which one can choose a discount rate to reflect the age of the pipe, however a 50% discount results in an approximate annual payment of $1.3M, which is the historic cost to the Moss Landing plant for the period up to 2011.

This arrangement could be structured as an outright purchase, a virtual purchase, or a lease. If it was a virtual purchase Dynegy would pay an annual amount in exchange for Backbone level rates, but PG&E would retain ownership and the obligation to operate and maintain the pipeline. The payment made by Dynegy could be committed toward mitigating any detrimental effects on Local Transportation customers. This is perhaps more complicated than a bill credit, but it does have the advantage of being a more permanent solution and providing the rate certainty that every business prefers.

An Explicit Construction Alternative Modeled as a Long Term Contract

If none of the aforementioned alternatives is palatable, then there are a variety of possible construction alternatives by which the cost of service is explicitly linked to the cost of bypassing the local transmission system in a long term contract. There is no purchase, virtual or otherwise. In the virtual purchase alternative detailed earlier, the linkage to construction cost is used as a valuation method rather than a rate method, however the construction alternative can also be used simply as a rate method. This is a practice that needs to be approached with some caution for a few reasons.

1. If the CPUC were to approve a rate based on the construction alternative it would be the first time with respect to the Moss Landing plant. The rates set by the bill credit and the various Gas Accords were not based on construction cost, instead they simply sought to keep Moss Landing 1 & 2 reasonably competitive.
2. Validating a rate based on a construction alternative can open up a Pandora's box of issues as all manner of entities explore the option. Those able to acquire a commercial advantage then take it, and the rates for the class become more and more expensive as the lowest cost entities migrate to an individual rate. These arguments are well known and previous commission decisions have recognized the problems associated with bypass agreements. Nevertheless economic bypass does provide a cost basis that is occasionally useful despite its dangers.

This approach recognizes that if Duke, Dynegy's predecessor, had known that the Commission would adopt a rate option that would require Moss Landing 1 & 2 to pay roughly $22M per year more than their direct competitors for a substantial portion of the life of the plant, it would have made an economic decision to construct its own lateral to the Backbone at the same time that it constructed Units 1 & 2, to take advantage of the design and construction teams already assembled for work on the plant. As mentioned earlier, the annual cost of the lateral would have been projected to be about $3.7 million, yielding an annual economic benefit that would simply equal the distance between $3.7M and the projected payment, in this case $22M. Had Duke made that investment, Duke and Dynegy would have benefited by paying only the Backbone level service rate for gas transportation, but they also would have incurred the costs of owning, operating, and maintaining the line.

Faced with the prospect of having stranded pipeline capacity and stranded costs if Duke/Dynegy had actually constructed a redundant lateral pipeline, PG&E would have rationally responded by offering a discounted long term transportation contract or similar arrangement. A discounted rate contract for Units 1 & 2 could meet the three factors the Commission articulated for evaluating the anti bypass economic agreements in the early 1990s:

- **Whether bypass is imminent**. The Commission required a showing that the utility customer could realistically, physically bypass PG&E. In the case of Units 1 & 2, the construction of a new lateral in conjunction with the construction of the generating units was physically possible, and the logic of coordinating the construction of the units and the lateral would have led to an imminent threat of bypass of Lines 301 A and 301 G.
- **Whether bypass would be uneconomic**. Bypass is uneconomic when the customer's cost to bypass is more than the marginal cost of utility service. For Units 1 & 2, even though the cost to bypass was relatively low the marginal cost of utility service was even lower. Lines 301 A and 301 G were heavily depreciated, and compression and metering were included in the costs of constructing the generation units, *i.e.,* PG&E did not incur any costs of additional metering or compression to serve Units 1 & 2. PG&E could provide transportation service to Units 1 & 2 at a low rate and still receive a contribution to margin.
- **Whether the negotiated rates and terms of an agreement were reasonable.** The terms for a discounted gas contract for service to Units 1 & 2 would have to be reasonable.

This long term contract approach would establish what could be characterized as a yearly annual fee equal to the cost of new construction. The basis for the rate is simply the bypass construction cost, in this case $3.7M per annum.

Please summarize your testimony

In my testimony I have explained and mathematically validated the events that stretch back to Gas Accord III. Principally, my testimony reminds all parties of the policy goals inherent in the bill credit, namely non disruption to a significant investment at Moss Landing due to the creation of a new set of Backbone competitors and a changing regulatory structure; and non disruption of the electric market. These goals were implemented via the bill credit approach in all of the historic gas accords, however due to the simplicity of the implementation, in recent years the historic bill credit approach has not proven sufficiently robust to maintain competitive balance. Moss Landing has already suffered financial disruption and the wholesale market will see increasing changes that are plainly not efficient. The objectives underlying the bill credit approach remain valid but require a reinvigorated implementation under the current proposed rate structure.

Please summarize your recommendations

My primary recommendation is the establishment of a single, permanent, Electric Generation rate, which is the same across the entire PG&E service area. Such a postage stamp approach solves all of the problems detailed in my testimony. My second recommended alternative is the establishment of a new rate class, grandfathered if need be, that recognizes the historical accommodation represented by the bill credit and makes it more permanent. My third recommendation is the continuation of the bill credit approach, but in a manner that calibrates to the intended purpose of the bill credit, which was to maintain reasonable competitive parity to the Backbone rate. My fourth recommendation is to allow for the physical or virtual purchase of Line 301 G by Dynegy as a method to implement the original policy goals embodied by the bill credit. My fifth recommendation is to base the rate on the annualized cost of physically bypassing the local transmission system.

Does this conclude your testimony?

Yes.

ATTACHMENT

Alan G. Isemonger

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WORK EXPERIENCE

Energy Market Expertise LLC (August 2011 – present)

In August of 2011 I started up Energy Market Expertise LLC, a boutique consulting firm specializing in wholesale power markets in the WECC. In particular EME focuses on issues that pertain to the design, functioning and outcome of wholesale power markets, with a particular focus on financial outcomes and risk analysis. Recent work includes:

1. Assisting a market trader (primarily virtuals and FTRs) interpret market outcomes at the CAISO and providing support during their interactions with the CAISO
2. Data analysis of public CAISO data in support of a significant new storage facility in the West. Work consisted of analyzing revenue streams and valuing them.
3. Business analyst role; business gap analysis supporting the transition from the SPP Energy Imbalance Market (EIM) to the new Integrated Market for a substantive utility located within the SPP footprint. Work consisted of analyzing existing EIM business functionality, as well as the proposed new business functionality, and planning the business transition between them. This included the proposed FTR market (named TCRs in SPP), virtuals market, day-ahead and real-time markets, as well as the change in risk management due to the new business functions. Tasks consisted of requirements writing, and process and data mapping in support of transitioning the business to a fully nodal system.
4. Worked on a variable generation study looking at the challenges of integrating wind and solar power into the electric grid

Client references available on request.

Manager, Market Information @ CAISO (August 2006 – August 2011)

Over a period of about five years I worked in the operations group and was responsible for a number of different market functions, including some settlements functions and market validation functions, during the period when the California ISO switched from a zonal market model to a nodal market model. The two main responsibilities though were market performance monitoring and reporting, and managing the Congestion Revenue Rights (CRR) group. The market performance function was similar to market monitoring in that it was a wide-ranging, data-intensive, analytical function which attempted to discover anomalous results prior to them becoming significant issues. The CRR group (a.k.a. Financial Transmission Rights or FTRs) was a monthly and annual allocation and auction of transmission line capacity that allowed market entities to hedge their day-ahead congestion risk. These groups were my main responsibility. In addition I was also responsible for more broadly managing market issues as they emerged, as well as the usual day-to-day managerial functions such as recruitment and personnel management.

Market Design @ CAISO (September 2004 – August 2006)

As a product developer I designed products for the spot markets for the CAISO's impending LMP redesign. Responsibilities included the design of trading hubs, the trade in ancillary services, and design elements for the CAISO's PJM-style market power mitigation. Work consisted of initial design, stakeholder presentations, final formulation, tariff support and testimony support.

Market Monitoring @ CAISO (September 2002 – September 2004)

As a market monitor I analyzed unusual market behavior and outcomes by market participants. The work was generally empirical data analysis, but also consisted of submissions to regulatory authorities, tariff support, and analysis related to tariff negotiations. In addition I often generated weekly and monthly reports on the CAISO market. I specialized in congestion issues, but also monitored ancillary services, outages, and real-time market outcomes.

Economist @ ZE PowerGroup Inc. (November 2000 – September 2002)
As an economist I had a number of different responsibilities ranging from analysis of acquisition strategies, to rate case analysis, rate design and risk analysis. The work also included the generation of weekly and monthly reports on the deregulated electric utility industry in the WECC. In addition I also assisted municipal utilities respond to the deregulated environment by auditing their workflow processes to determine optimal resource deployment.

Economist @ BC Hydro (September 1998- November 2000)
As an economist I analyzed and monitored industrial client developments, such as mergers and acquisitions, assets sales etc. I also produced sectoral surveys of major industries for senior management, and planned and managed the switch from SIC (Standard Industrial Classification) to NAICS (North American Industrial Classification System).

Economist @ Economic Research Unit (July 1996 to September 1998)
As an economist I worked on a variety of trade and public policy projects mainly concerned with structural adjustment policies, trade switching and resultant revenue effects. The main clients were country governments in Southern Africa and aid organizations, such as USAid and the World Bank.

Economics Lecturer, University of Natal (July 1995 to June 1996)
Taught Economics at the undergraduate level.

EDUCATION

MA Development Economics: University of Leeds (England; Graduated 1993). Studied on scholarship
B. Social Science: University of Natal, (South Africa; Graduated 1991).
Received two full fee scholarships. Majored in Economics.

SKILLS

I have strong data processing skills in SAS and SQL, and am competent in the standard desktop business applications such as spread sheeting, and word processing. In addition I am intimately familiar with all aspects of the Software Development Life Cycle (SDLC) from the initial policy design to requirements gathering through to testing, simulation and deployment. I am also familiar with business process development and its requirements, such as audit trails and SSAE 16 (SAS 70 a.k.a. Sarbanes Oxley) requirements.

PERSONAL

Canadian citizenship and permanent resident of the USA.

Energy Publications - Journals

2009: Isemonger, A.G. "Market Redesign and Technology Upgrade: A Nodal Implementation" The Electricity Journal, Volume 22, Issue 8, October 2009, Pages 72-81. DOI:10.1016/j.tej.2009.08.005

2008: Isemonger, A. G. "The Evolving Design of RTO Ancillary Service Markets" Energy Policy 37 (2009), pp. 150-157, DOI:10.1016/j.enpol.2008.06.033

2007: Isemonger, A.G. "The Viability of the Competitive Procurement of Blackstart: Lessons from the RTOs" The Electricity Journal Volume 20, Issue 8, October 2007, Pages 60-67 doi:10.1016/j.physletb.2003.10.071

2007: Isemonger, A.G. "Some Guidelines for Designing Markets in Reactive Power",

The Electricity Journal, Volume 20, Issue 6, July 2007 pp35-45
DOI information: 10.1016/j.tej.2007.06.001
2007: Isemonger, A.G. "Conduct and Impact versus Direct Mitigation" The Electricity Journal, Volume 20, Issue 1, January-February 2007, Pages 53-62
doi:10.1016/j.tej.2006.11.010
2006: Isemonger, A.G. "The Benefits and Risks of Virtual Bidding in Multi-Settlement Markets," The Electricity Journal, Volume 19, Issue 9, November 2006, Pages 26-36.
doi:10.1016/j.tej.2006.09.010

Energy Publications - Conference Proceedings

2009: Kueck, J., Kirby, B., **Isemonger, A.G.**, Tufon C., Li, F. Li., "A Tariff for Reactive Power" Accepted Conference Proceedings for March 2009 Power Systems Conference & Exposition, Seattle WA.

Non-Energy Journal Publications

2000: Isemonger, A.G. "The Estimation of Intra-Industry Trade in South Africa" In Development South Africa, 17(1) March pp.53-63.ISSN 0376835X

1999: Isemonger, A.G. and Roberts, N.J. "Post-entry Gender Discrimination in the South African Labour Market" in the Journal for Studies in Economics and Econometrics, August 23(2) 1-25

1999: Holden, M.G. and Isemonger, A.G. "A Review of Trade Trends: South Africa and the Indian Ocean Rim" In Development Southern Africa, Autumn 16(1):89-105.issn 0376-835X

1997: Tewari, D.D. and Isemonger, A.G. "Joint Forest Management in South Gujarat, India: A Case of Successful Community Development" In Journal of Community Development, January 33(1):32-40.issn 0010-3802

1996: Tewari, D.D. and Isemonger, A.G. "Energy Use Patterns in World Agriculture: An Exploratory Analysis" In Pacific and Asian Journal of Energy, 6(2):75-82.