BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. GNR-E-02-01

EXHIBIT NO. 201
July 24, 2002

WITNESS: CLINT KALICH, AVISTA CORPORATION

Long-Term Physical Electric Resource Picture (aMW) -- CONFIDENTIAL

Last Updated July 12, 2002	Notes	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
REQUIREMENTS											
System Load	1	964	998	1,037	1,067	1,100	1,135	1,173	1,209	1,243	1,264
Contracts Out	2	88	40	40	40	39	39	39	40	40	39
Total Requirements		1,052	1,038	1,077	1,107	1,139	1,175	1,213	1,249	1,283	1,303
RESOURCES											
Hydro	3	550	550	551	561	560	559	558	546	535	489
Contracts In	4	204	184	182	182	132	132	132	132	57	57
Base-Load Thermal	5	355	360	357	360	367	365	367	367	365	367
Total Resources		1,109	1,094	1,090	1,103	1,060	1,056	1,057	1,046	957	914
Surplus (Deficit)		57	56	13	(4)	(80)	(119)	(156)	(203)	(326)	(389)

CONTINGENCY PLANNING											
Confidence Interval	6	(153)	(153)	(153)	(153)	(153)	(153)	(153)	(153)	(153)	(153)
Peaking Units	7	164	167	167	167	167	167	167	167	167	167
Surplus (Deficit) net position		68	70	28	10	(66)	(105)	(141)	(189)	(312)	(375)

Notes:

1. Load estimates are from the July 2001 load forecast plus the adjustment to reflect the net Potlatch load (38. aMW). Potlatch load and generation based on 5 years of historic data.
2. Includes PacifiCorp Exchange Delivery and Sale, Nichols Pumping, BPA-WNP#3 Delivery and Canadian Entitlement Return contracts.
3. Average (60-year) hydro generation for system hydro (Clark Fork and Spokane River projects) and contract hydro (mid-Columbia) based on NWPP 2000-01 Headwater Benefits Study. Contract hydro numbers reflect the proposed Priest Rapids and Wanapum contract extensions beginning in 2005.
4. Includes small power contracts, Upriver, Black Creek, Enron 2004-2006 25 MW Flat, El Paso 2004-2006 25 MW Flat, Duke 2004-2006 75 MW Flat, El Paso 2007-2010 75 MW Flat, PacifiCorp Exchange Return, CSPE, BPA-WNP#3 Receipt and TransAlta contracts. BPA Residential Exchange is zero, assumes contract monetization.
5. Includes base load thermal plants of Colstrip, Coyote Springs II (50% ownership, including duct burner), and Kettle Falls.
6. The confidence interval represents the 12-month average of reserve energy necessary to ensure nomore than a 10 percent probability of loads exceeding, and/or hydro underperforming, during a given month.
7. The Peaking Units (Boulder Park, Kettle Falls CT, Northeast, and Rathdrum) energy numbers reflect "full availability" adjusted for forced outage and maintenance. Northeast is also limited to 2,000 hours of operation per year.

Non-Fueled Resources - 2007 Deficit Year

CONTRACT LENGTH (YEARS)	ADJUSTABLE PLUS NON-ADJUSTABLE COSTS (m/kWh)					
	ON-LINE YEAR					
	2002	2003	2004	2005	2006	2007
1	27.02	28.24	29.51	30.83	32.22	65.92
2	27.60	28.84	30.14	31.50	48.34	67.63
3	28.18	29.45	30.78	42.00	54.80	69.36
4	28.76	30.06	38.46	48.02	58.85	71.10
5	29.34	36.05	43.65	52.24	61.94	72.85
6	34.21	40.50	47.60	55.58	64.54	74.60
7	38.04	44.07	50.83	58.40	66.88	76.36
8	41.24	47.08	53.62	60.91	69.05	78.12
9	44.02	49.73	56.11	63.20	71.10	79.88
10	46.49	52.13	58.39	65.35	73.07	81.64
11	48.74	54.33	60.52	67.38	74.99	83.40
12	50.83	56.39	62.53	69.33	76.85	85.16
13	52.79	58.34	64.46	71.22	78.68	86.92
14	54.65	60.19	66.31	73.05	80.48	88.67
15	56.42	61.98	68.10	74.83	82.25	90.41
16	58.13	63.70	69.84	76.58	83.99	92.14
17	59.77	65.38	71.53	78.29	85.71	93.87
18	61.36	67.00	73.19	79.97	87.41	95.58
19	62.91	68.58	74.80	81.62	89.09	97.28
20	64.41	70.13	76.39	83.25	90.75	98.97

Fueled Resources - 2007 Deficit Year

CONTRACT LENGTH (YEARS)	NON-ADJUSTABLE LEVELIZED AVOIDED COSTS (m/kWh)					
	ON-LINE YEAR					
	2002	2003	2004	2005	2006	2007
1	27.02	28.24	29.51	30.83	32.22	14.47
2	27.60	28.84	30.14	31.50	23.73	14.72
3	28.18	29.45	30.78	26.30	21.06	14.96
4	28.76	30.06	27.21	23.83	19.84	15.19
5	29.34	27.45	25.17	22.44	19.21	15.43
6	27.36	25.79	23.88	21.59	18.86	15.66
7	26.02	24.67	23.03	21.04	18.68	15.89
8	25.06	23.89	22.45	20.69	18.60	16.12
9	24.37	23.33	22.04	20.47	18.58	16.35
10	23.86	22.93	21.76	20.33	18.62	16.57
11	23.48	22.63	21.57	20.26	18.68	16.79
12	23.19	22.42	21.45	20.23	18.76	17.00
13	22.99	22.28	21.37	20.24	18.87	17.22
14	22.83	22.18	21.33	20.28	18.98	17.43
15	22.73	22.12	21.33	20.33	19.11	17.63
16	22.66	22.09	21.34	20.40	19.24	17.83
17	22.62	22.08	21.38	20.48	19.37	18.03
18	22.60	22.09	21.43	20.57	19.51	18.22
19	22.60	22.12	21.49	20.67	19.65	18.41
20	22.62	22.17	21.56	20.78	19.79	18.59

Generating Resources Advisory Committee (GRAC)
Northwest Power Planning Council - 5th Power Plan

Member	Organization	Note
Rob Anderson	Bonneville Power Administration	
Peter Blood	Calpine Corporation	
John Fazio	Northwest Power Planning Council	Vice-Chairman
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Mike Hoffman	Bonneville Power Administration	
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Mike Mikolaitis	Portland General Electric	
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Chris Taylor	Zilkha Renewable Energy	
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Sam Van Vactor	Economic Insight, Inc.	Consultant
Dick Winters	Avista Corp.	Electric/Gas Utility
Bill Wood	California Energy Commission	Public

DRAFT

Northwest Power Planning Council
New Resource Characterization for the Fifth Power Plan

Natural Gas Combined-cycle Gas Turbine Power Plants

July 15, 2002

This paper describes the technical characteristics and cost and performance assumptions to be used by the Northwest Power Planning Council for new natural gas combined-cycle gas turbine power plants. The intent is to characterize a reasonably typical facility, recognizing that actual facilities may differ from these assumptions. These assumptions will be used in our price forecasting and system reliability models and in the Council's periodic assessments of system reliability. The Council may also use these assumptions in the assessment of other issues where generic information concerning natural gas combined-cycle power plants is needed. Others may use the Council's technology characterizations for their own purposes.

A combined-cycle gas turbine power plant consists of one or more gas turbine generators equipped with heat recovery steam generators to capture additional, otherwise wasted heat from the gas turbine exhaust. Steam produced in the heat recovery steam generators is used to power a steam turbine generator. Use of the otherwise wasted heat in the turbine exhaust gas results in high thermal efficiency compared to other combustion-based technologies. Combined-cycle plants currently entering service can convert about 50 percent of the chemical energy of natural gas into electricity (HHV basis[1]). Additional efficiency can be gained in combined heat and power (CHP) applications (cogeneration), by bleeding steam from the steam generator, steam turbine or turbine exhaust to serve direct thermal loads.

A single-train combined-cycle plant consists of one gas turbine generator, a heat recovery steam generator and a steam turbine generator. Using "F-class" combustion turbines - the most common technology in use for large central station plants - this configuration can produce about 270 megawatts of capacity. Additional capacity can be gained by installing multiple trains at a site, or by using two or three gas turbine generator sets with heat recovery steam generators feeding a single, proportionally larger steam turbine generator. Other plant components include a switchyard for electrical interconnection, cooling towers for cooling the steam turbine condenser, a water treatment facility and control and maintenance facilities.

[1] The energy content of natural gas can be expressed on a higher heating value or lower heating value basis. Higher heating value includes the heat of vaporization of water formed as a product of combustion, whereas lower heating value does not. While it is customary for manufacturers to rate equipment on a lower heating value basis, fuel is generally purchased on the basis of higher heating value. Higher heating value is used as a convention in Council documents unless otherwise stated.

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Avista Corporation
Witness: Clint Kalich

Additional peaking capacity can be obtained by use of various power augmentation features, including inlet air chilling and duct firing. An additional 20 to 50 megawatts can be gained from a single-train plant by use of power augmentation features. Though the incremental thermal efficiency drops when using power augmentation features, the additional capacity can be valuable during peak load periods when electricity prices are high.

Gas turbines can operate on either gaseous or liquid fuels, however pipeline natural gas is the fuel of choice because of historically low and relatively stable prices and low air emissions. Though occasionally used as a backup fuel, distillate fuel oil is has become less common as backup fuel in recent years because of environmental concerns, the periodic testing required to ensure proper operation on fuel oil and increased turbine maintenance associated with fuel oil operation. It is now more common to ensure fuel availability by securing firm gas transportation.

The principal environmental concerns associated with gas-fired combined-cycle gas turbines are emissions of nitrogen oxides (NOx) and carbon monoxide (CO). Fuel oil operation may produce sulfur dioxide. "Low-NOx" combustors and high temperature selective catalytic controls allow NOx and CO emissions to be controlled to low levels. Water is required for cooling the steam condenser and may be an issue in arid areas. Water consumption can be reduced by use of dry (closed-cycle) cooling, though with cost and efficiency penalties. Gas-fired combined-cycle plants produce less carbon dioxide per unit energy output than other fossil fuel technologies because of the relatively high thermal efficiency of the technology and because of the high hydrogen-carbon ratio of methane (the primary constituent of natural gas).

Because of high thermal efficiency, low initial cost, reliability, relatively low gas prices and low air emissions, combined-cycle gas turbines have been the new resource of choice for bulk power generation for well over a decade. Combined-cycle power plants are an increasingly important element of the Northwest power system, currently comprising about 6 percent of installed capacity in the region - third following hydropower and coal steam plants. Completion of plants under construction will increase the fraction of gas-fired combined-cycle capacity to about 11 percent of total regional capacity.

The proposed reference plant is based on the General Electric 7FA gas turbine generator in 2 GT x 1ST configuration. The baseload output of this plant is assumed to be 540 megawatts. The incremental costs and performance of 70 MW of power augmentation using duct burners are provided in the table that follows. A firm gas transportation contract with capacity release capability is assumed, in lieu of backup fuel. Air emission controls include "low-NOx" burners, selective catalytic reduction for NOx control and an oxidation catalyst for CO control.

Table 1
Resource characterization: Natural gas combined-cycle gas turbine power plant

Facility description and basic assumptions		
Facility	Natural gas-fired combined-cycle gas turbine power plant. 2 GT x 1 ST configuration. 540 MW new & clean baseload output @ ISO conditions, plus 70 MW of capacity augmentation (duct-firing). No cogeneration. SCR for NOx control, CO catalyst for CO control. Wet mechanical draft cooling.	GRAC recommendation.
Fuel	Pipeline natural gas. Firm transportation contract with capacity release provisions. Seasonal variation in capacity release value.	Natural Gas Advisory Committee recommendations. See Appendix A for a summary of the gas price forecast and structure.
Technology base year	2002	GRAC recommendation
Price base year	2000	5th Plan price year.
Lead time	Development: 24 months Construction: 24 months	Estimate based on Council database of gas turbine power plants.
Service life	30 years	Consistent with capital replacement assumption.

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Avista Corporation
Witness: Clint Kalich

Technical Performance		
Net power	New & clean: 540 MW (baseload), 610 MW (peak) Lifetime average: 528 MW (baseload), 597 MW (peak)	Lifetime average based on 1 % degradation per year, 98.75% recovery at hot gas path inspection or major overhaul. GE data.
Scheduled outages	Scheduled outage factor: 5.8% (21 days/yr).	Based on a planned maintenance schedule of a 7-day annual inspection, a 14-day hot gas path inspection & overhaul every third year and a 42-day major overhaul every sixth year. In addition, allows for two 30-day maintenance outages and one six-month plant rebuild over 30-year plant life. Annual average rounded to nearest week. Planned maintenance intervals are GE baseline recommendations for baseload service.
Forced outages	Forced outage rate: 5% Mean time to repair: 24 hours	NERC Generating Availability Data System (GADS) weighted average equivalent forced outage rate for combined-cycle plants. Mean time to repair is GADS average for full outages.
Availability (lifetime average, busbar)	89.5%	(1-SOR)*(1-FOR). Derate additional 2.2% if using new & clean capacity.
Heat rate (HHV, net, ISO conditions)	New & clean (Btu/kWh): 6880 (baseload); 9500 (incremental duct firing); 7180 (full power) Lifetime average (Btu/kWh): 7030 (baseload); 9290 (incremental duct firing); 7340 (full power)	Baseload is current new & clean rating for GE 207FA. Lifetime average is new & clean value derated by 2.2%. Degradation estimates are from GE. Duct firing heat rate is GRAC recommendation.
Vintage performance improvement	2002-21 annual average: -0.5%.	Council estimate based on historical and potential improvements in gas turbine efficiency.
Seasonality (ambient air temperature sensitivity)	Factors at 20, 59 and 88 °F: Power output: 1.130, 1.000, 0.905 Heat rate: 0.992, 1.00, 1.007	

Costs		
Development & construction	Baseload configuration: $565/kW (overnight); 621 $/kW (all-in). Power augmentation configuration: $525/kW (overnight); 577 $/kW (all-in).	Excludes financing fees and interest during construction. Assumes "equilibrium" market conditions. Normalized cost of a single-train plant assumed to be 110% of example plant costs. Incremental cost of power augmentation using duct burners $225/kW. Values are based on new and clean rating. Council & GRAC estimate.
Capital replacement	$1.60/kW/yr[1]	Levelized equivalent of 10% of initial capital investment in Year 15. Value is based on new and clean rating.
Fixed operating costs	Baseload configuration: $7.25/kW/yr. Power augmentation configuration: $6.50/kW/yr.	Includes operating labor, routine maintenance, general & overhead, fees, contingency and an allowance for startup costs and average sales tax. Excludes property taxes and insurance (separately calculated in the Council's models). Normalized to full (peak) capacity. Normalized fixed O&M cost for a 1x1 plant assumed to be 167% of that for the example 2x1plant. Values are based on new and clean rating. Feasibility study and operator recommendation.
Variable operating costs	$2.80/MWh	Includes consumables, SCR catalyst replacement, makeup water and wastewater disposal costs, long-term major equipment service agreement, contingency and an allowance for sales tax. Excludes greenhouse gas offset fee (separately calculated in the Council's models). Feasibility study.
Interconnection and regional transmission costs	$15.00/kW/yr	Bonneville point-to-point transmission rate (PTP-02) plus Scheduling, System Control and Dispatch, and Reactive Supply and Voltage Control ancillary services, rounded. Omit for busbar calculations. Value is based on new and clean rating. Bonneville 2002 transmission tariff.
Regional transmission losses	1.9%	BPA contractual line losses. Omit for busbar calculations.
Vintage cost reduction	2002-21 annual average: -0.6%	Council estimate based on historical and potential improvements in gas turbine specific work.

Development, financing and capital-related costs		
Financing	Independent power producer	Assumptions provided separately
Tax depreciation	20 years	
Property tax	1.4%/yr of book value.	Average regionwide conditions. Council assumption.
Insurance	0.3%/yr of book value.	Feasibility study.
Emissions (Plant site, excluding gas production & delivery)		
Particulates (PM-10)	0.020 T/GWh	Grays Harbor (Satsop) Ph II application (Nov 2001).
SOx	0.004 T/GWh	$SO_2 + H_2SO_4$. Grays Harbor (Satsop) Ph II application (Nov 2001).
NOx	0.046 T/GWh	Grays Harbor (Satsop) Ph II application (Nov 2001).
CO	0.075 T/GWh	Grays Harbor (Satsop) Ph II application (Nov 2001).
Hydrocarbons/VOC	0.014 T/GWh	Permanent permit reqmts for recent CA peakers.
Ammonia	0.084 T/GWh	
CO_2	411 T/GWh (baseload operation) 429 T/GWh (full power operation)	Based on EPA standard fuel carbon content assumptions and lifecycle average heat rates.
Availability for future development		
Site Availability 2001 - 2020	Initially not limited.	Forecasted extent of future development will be tested in AURORA model runs. If this level significantly exceeds the inventory of currently or likely permitted sites in any load-resource area this issue will be revisited.

Natural Gas Advisory Committee (NGAC)
Northwest Power Planning Council - 5th Power Plan

Name	Affiliation	Sector
Rob Anderson	Bonneville Power Admin.	Electric Utility
John Bridges	TransCanada	Pipeline
Phil Carver	Oregon Office of Energy	Public
Kevin Christie	PG&E Gas Transmission NW	Pipeline
Colin Coe	Calpine	Electric Generation/Marketing
Jeffrey Currie	Goldman Sachs	Financial
Byron Defenbach	Intermountain Gas	Distribution
Cynthia Des Brisay	B.C. Gas	Distribution
Bill Donahue	Puget Sound Energy	Electric/Gas Utility
Randy Friedman	NW Natural Gas	Distribution
Rick Harper	Consultant	Consultant
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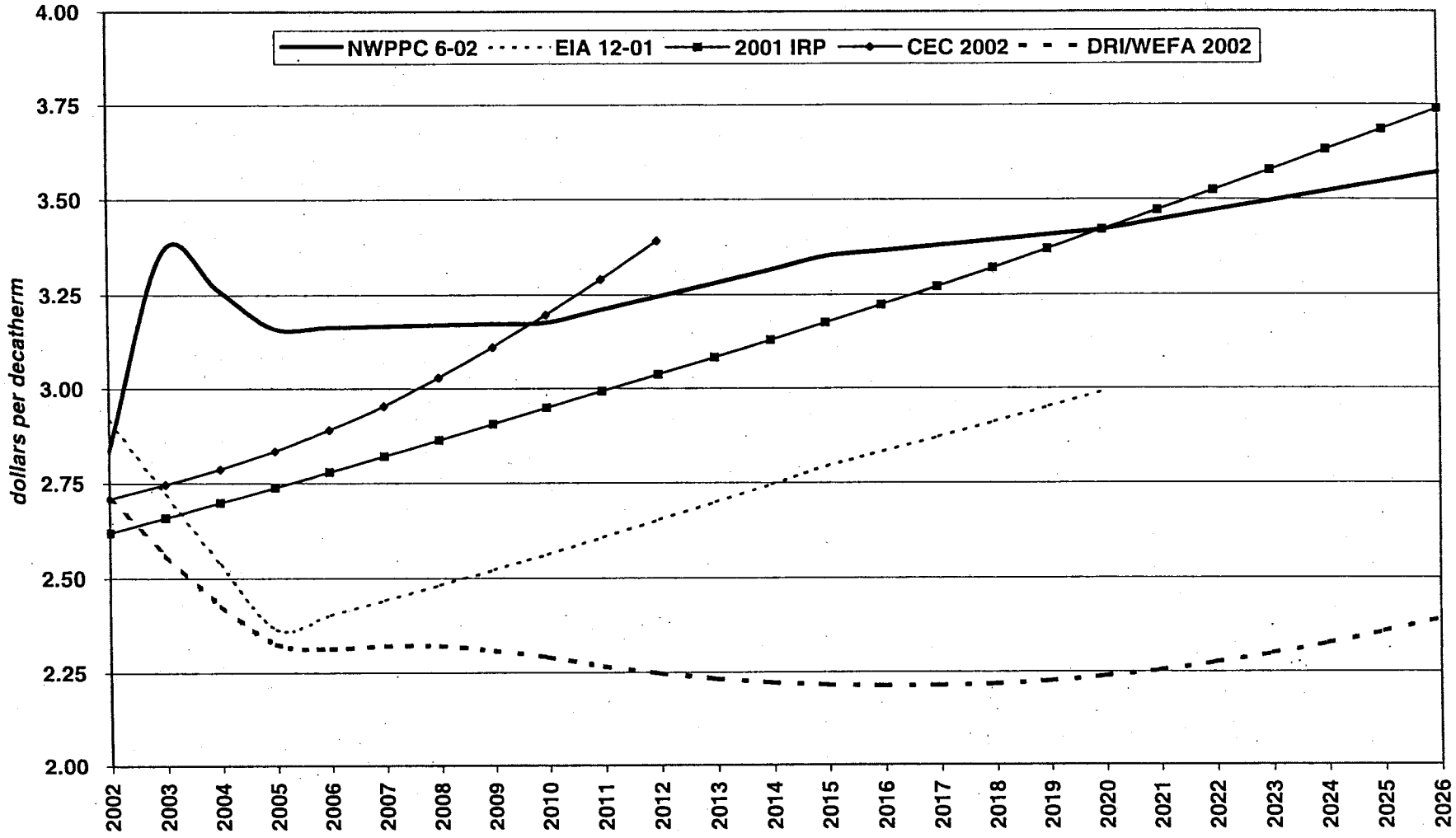
Peter Schwartz	Cascade Natural Gas	Distribution
Fred Scott	Engage Energy	Electric Generation/Marketing
Greg Staple	Westcoast Energy	Pipeline
Sam Van Vactor	Economic Insight, Inc.	Consultant
Dick Winters	Avista Corp.	Electric/Gas Utility
Bill Wood	California Energy Commission	Public

Natural Gas Price Forecasts
2002 Prices



Notes: EIA and DRI/WEFA based on Henry Hub less $0.40/dth basis discount for NW delivery; CEC forecast is @ Malin; prices are deflated using IPD of 2.4% per annum

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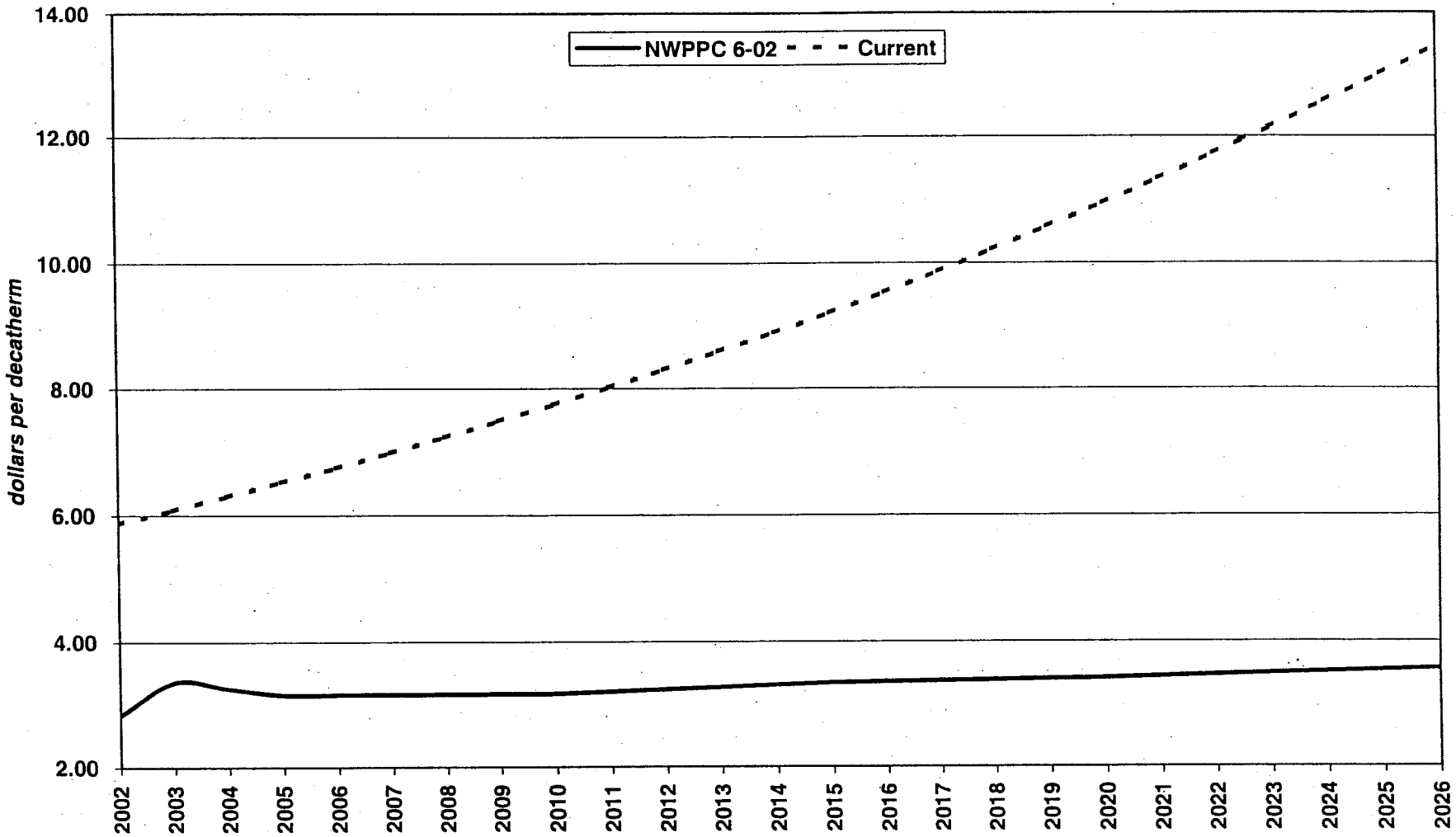
NWPPC and Current Avoided Cost Natural Gas Price Forecasts
2002 Prices



Notes: EIA and DRI/WEFA based on Henry Hub less $0.40/dth basis discount for NW delivery; CEC forecast is @ Malin; prices are deflated using IPD of 2.4% per annum

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Non-Fueled Resources - 2007 Deficit Year

CONTRACT LENGTH (YEARS)	NON-ADJUSTABLE LEVELIZED AVOIDED COSTS (m/kWh)					
	ON-LINE YEAR					
	2002	2003	2004	2005	2006	2007
1	22.12	24.37	29.56	29.56	29.56	39.72
2	23.20	26.85	29.56	29.56	34.42	40.19
3	25.14	27.68	29.56	32.66	36.34	40.65
4	26.11	28.09	31.79	34.42	37.51	41.11
5	26.68	30.04	33.28	35.64	38.39	41.61
6	28.42	31.45	34.40	36.58	39.14	42.12
7	29.75	32.57	35.30	37.40	39.83	42.63
8	30.84	33.49	36.10	38.13	40.47	43.15
9	31.75	34.31	36.82	38.80	41.07	43.67
10	32.57	35.04	37.48	39.43	41.65	44.17
11	33.30	35.71	38.10	40.03	42.20	44.65
12	33.98	36.34	38.69	40.58	42.71	45.11
13	34.60	36.93	39.23	41.10	43.21	45.56
14	35.19	37.48	39.75	41.60	43.68	46.00
15	35.74	38.00	40.23	42.07	44.13	46.43
16	36.25	38.48	40.69	42.52	44.57	46.85
17	36.73	38.94	41.13	42.96	44.99	47.26
18	37.18	39.38	41.56	43.38	45.41	47.66
19	37.61	39.80	41.96	43.78	45.81	48.05
20	38.02	40.20	42.36	44.18	46.20	48.44

Fueled Resources - 2007 Deficit Year

CONTRACT LENGTH (YEARS)	NON-ADJUSTABLE LEVELIZED AVOIDED COSTS (m/kWh)					
	ON-LINE YEAR					
	2002	2003	2004	2005	2006	2007
1	22.12	24.37	29.56	29.56	29.56	13.55
2	23.20	26.85	29.56	29.56	21.90	13.70
3	25.14	27.68	29.56	24.68	19.45	13.86
4	26.11	28.09	26.06	22.31	18.30	14.01
5	26.68	25.66	24.02	20.96	17.68	14.16
6	24.94	24.09	22.72	20.11	17.31	14.30
7	23.73	23.02	21.83	19.54	17.08	14.45
8	22.87	22.25	21.20	19.15	16.95	14.59
9	22.23	21.68	20.74	18.88	16.88	14.73
10	21.75	21.26	20.41	18.69	16.84	14.86
11	21.38	20.94	20.15	18.56	16.84	14.99
12	21.09	20.69	19.97	18.47	16.86	15.12
13	20.87	20.51	19.83	18.41	16.89	15.25
14	20.70	20.36	19.73	18.38	16.93	15.37
15	20.56	20.25	19.65	18.37	16.98	15.49
16	20.46	20.17	19.60	18.37	17.04	15.61
17	20.38	20.11	19.57	18.38	17.10	15.72
18	20.32	20.07	19.55	18.41	17.17	15.83
19	20.28	20.05	19.55	18.44	17.24	15.94
20	20.26	20.03	19.55	18.47	17.31	16.04

Avoided Cost Payment Comparison

Stayed versus Proposed Rates – 20 Year Contract Terms

Non-Fueled Project Rates

Year	Stayed ($/MWh)	Proposed ($/MWh)	Difference ($/MWh)	Energy (MWh)	Savings ($millions)
2002	64.41	38.02	26.39	87,600	2.31
2003	70.13	40.20	29.93	87,600	2.62
2004	76.39	42.36	34.03	87,600	2.98
2005	83.25	44.18	39.07	87,600	3.42
2006	90.75	46.20	44.55	87,600	3.90
2007	98.97	48.44	50.53	87,600	4.43
Average	80.65	43.23	37.42	87,600	3.28

Fueled Project Rates

Year	Stayed ($/MWh)	Proposed ($/MWh)	Difference ($/MWh)	Energy (MWh)	Savings ($millions)
2002	27.02	20.26	6.76	87,600	0.59
2003	28.24	20.03	8.20	87,600	0.72
2004	29.51	19.55	9.95	87,600	0.87
2005	30.83	18.47	12.36	87,600	1.08
2006	32.22	17.31	14.92	87,600	1.31
2007	14.47	16.04	(1.57)	87,600	(0.14)
Average	27.05	18.61	8.44	87,600	0.74