Chapter 7
PORTFOLIO MODELING

Update on Portfolio Modeling

Since 2003, a robust modeling and analytical capability has been developed and maintained by NorthWestern. This capability has been centered around the Power Costs, Inc. (PCI) suite of integrated software modules called GenTrader®. NorthWestern has two fully dedicated computer servers in Butte that are used for the GenTrader® application through remote desktop application. Using this standalone capability and support provided by PCI analysts and specialists, NorthWestern relies on this platform to vigorously evaluate existing and potential new resource alternatives using this industry tested and widely employed product.

GenTrader® is a not a push-of-the-button, answer to resource portfolio modeling nor is it a solutions database that answers resource questions from a predetermined set of algorithms. It does not make any independent assumptions about the future costs of carbon, the timing of legislative changes, the costs of future electric generation technologies, or the success or failure of energy conservation programs. It is a thorough and efficient evaluation engine that allows NorthWestern to evaluate complex sets of user-defined resource model inputs to arrive at correct economic results. NorthWestern has used PCI with confidence because it performs its analysis with precision and accuracy while honoring all of the input variables defined specifically for NorthWestern in Montana. That said, NorthWestern will evaluate alternative modeling methodologies during the planning interim.

The creation of the 20-year portfolio models used in the Plan requires the development of considerable input data. This input, described and documented throughout the Plan, includes:

1. Hourly load forecasts
2. Market forecasts for fuel & electricity
3. Cost and energy output for all existing resources in the portfolio

4. Projected cost and associated energy savings from DSM programs
5. New resource cost & production characteristics
6. Implied market volatility values
7. Numerical recognition of estimated carbon costs

All of the above referenced inputs are defined and controlled by NorthWestern during the modeling process. The only decisions made by the software are economic decisions where, in the presence of supply alternatives defined for a portfolio, the least cost option is always selected. Decisions made by the model, for example, can consist of market purchase instead of a gas unit dispatched to serve load or the execution of a pre-defined contract purchase.

To understand how GenTrader® functions, a simple overview of the model architecture and logic is presented. The 20-year hourly load forecast (including losses and excluding future DSM energy savings) creates the obligation to be served in GenTrader®. From this load obligation we apply (subtract) the existing Supply portfolio of resources (ex Colstrip 4, QF, and other existing supply resources) and future DSM energy savings. For modeling purposes DSM is treated as an energy purchase. The remainder is the unfilled supply obligation or need. It is this need that must be filled with energy purchases or the output of generating assets to achieve load – resource balance; the goal of the load-serving obligation.

GenTrader® is comprehensive in terms of its capability to model and solve complex energy generation, purchase, and sale calculations. Models are constructed and executed in two modes; intrinsic and stochastic modes. Each model type serves different purposes in the evaluation of resource and portfolio alternatives.

Intrinsic modeling is analogous to a simple spreadsheet model where inputs are defined and not allowed to change. In the intrinsic model the value of resources and the market costs for energy and fuel are predetermined, and the model run produces a single set of outcomes for the portfolios that have been defined. When comparing intrinsic portfolio results for a particular study case, for example a specific market case, each portfolio and its associated resource mix can be compared to determine how each one performed relative to one another under the same fixed set of market conditions. Based solely on this scenario, one can ascertain the least cost portfolio under a prescribed set of market assumptions.

By constructing multiple intrinsic scenarios and assigning weight or significance to each scenario, an outcome can be derived from the intrinsic analysis that captures a blended intrinsic economic outcome (cost) for each portfolio in each scenario to inform how resources perform across the different scenarios. It is this information that will be presented in the intrinsic modeling section for the cases NorthWestern developed for the 2009 Plan.

Cost, however, is not the only factor to consider when evaluating resource alternatives. The measurement of risk is a key element that must be considered. The 2009 Plan considers different elements of risk and includes stochastic modeling to provide a quantitative treatment of supply risk. Risk is defined as the relative uncertainty associated with an outcome or value. Here we define risk that is associated with the estimated future cost of the Supply portfolio.

Planners, regulators, and stakeholders understand that there are risks associated with energy. By definition, commodities such as electricity and natural gas have inherent risks in the form of price uncertainties that must be understood and addressed. NorthWestern addresses risk through stochastic modeling and the use of stochastic model results to quantitatively assess risk relative to total portfolio cost.

In the stochastic modeling section, the concept of the efficiency frontier will be introduced and developed. By using the numerical results of the stochastic cases, an efficiency frontier can be constructed that plots portfolio cost versus portfolio risk. Through the careful evaluation of these plots and the underlying data, conclusions can be reached regarding those portfolios that achieve balance between the two numeric parameters and those that do not.

Both the intrinsic and stochastic methods are widely used in utility resource planning. In previous resource plans NorthWestern has relied on these techniques to support its quantitative assessment of cost and risk. It is important to remember that modeling involves multiple estimates and assumptions in an attempt to simulate and predict the future performance of NorthWestern's energy supply and portfolio management activities. Understanding and acknowledging costs and risks is an important step toward mitigating customer exposure to the risk in the form of reliability and market price excursions.

As explained in previous plans, the modeling of supply resources in GenTrader® and the resulting performance of resources will differ when and if those resources are actually placed into service. One reason that we know that operating performance will vary from estimates is that the model has perfect knowledge of the market, the load, and the capability of generating units to supply power. Simulation programs such as GenTrade®r are powerful tools in the examination of future portfolio performance, however, they do not guarantee that resources will be run or perform as modeled. Although GenTrader® executes precisely and accurately, the results of both the intrinsic and stochastic models should be viewed and interpreted with an understanding that the outcomes are a function of the precision and accuracy of the inputs and assumptions that drive the model.

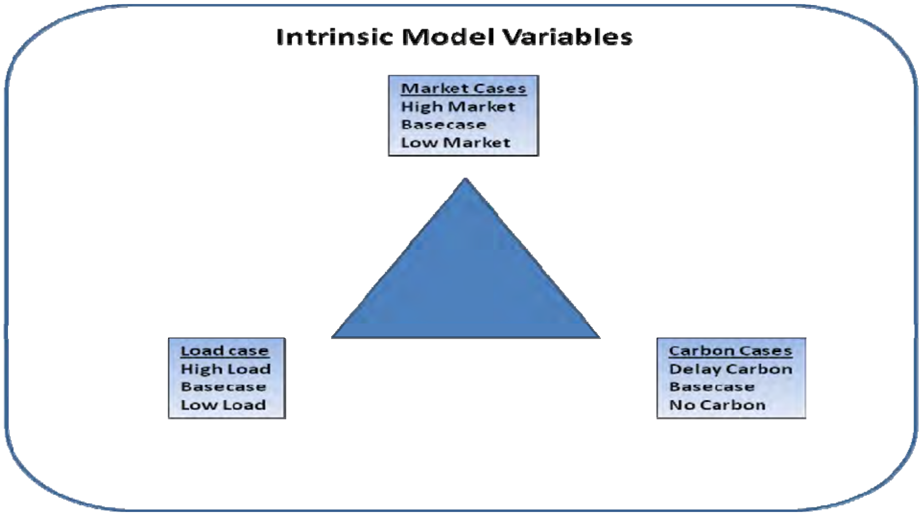
Intrinsic Portfolios

Intrinsic models of Supply portfolios are the first component of modeling performed in the planning process. The number of intrinsic models presented in the 2009 Plan is reflective of NorthWestern's deliberate attempt to model supply options that may materialize. For example, NorthWestern considers gas-fired generation as a prime candidate for development and inclusion in the Supply portfolio. With relatively short construction time, competitive total construction cost, operational flexibility, low risk (with the exception of fuel price risk), gas-fired generation is clearly a viable option for NorthWestern. Soon NorthWestern will have a 2-plant fleet of gas-fired resources including Basin Creek and Mill Creek totaling approximately 200 megawatts of on-system gas-fired capacity. The addition of Mill Creek and its subsequent operation will create a foundation of knowledge within the NorthWestern organization to draw upon for future assessments of gas-fired generation options.

During 2009 and 2010 Supply staff prepared and executed numerous portfolios in GenTrader® that have not been incorporated into the Plan. Some of this preliminary work was directed at tuning the model and used for checking and validating input data, the performance of the models, and model results. Some of these preliminary results were shared and discussed with ETAC to inform progress on the modeling and to demonstrate differences in portfolio costs caused by different generation technologies. Multiple refinements have been applied to the early models and the reader is cautioned that, when reviewing information in the ETAC section of Volume 3, inputs and model results in some instances have changed from the time they were originally presented to ETAC.

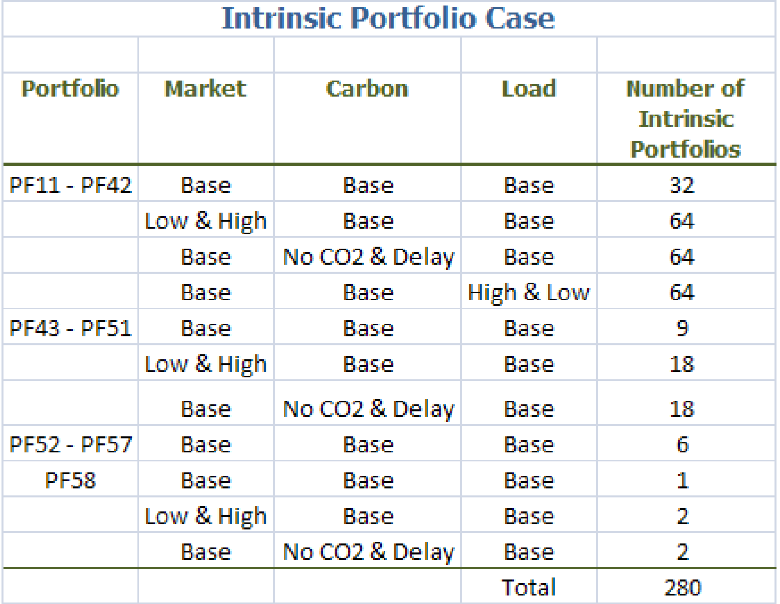
Multiple scenarios have been used to assess intrinsic portfolio performance under different conditions. The scenarios defined for the 2009 Plan are derived from the base case assumptions developed for market prices, carbon cost, and load described more fully elsewhere in the Plan. Using the three basecase intrinsic inputs as a starting point and adding two variant cases for each parameter pair yields nine (9) potential intrinsic case variables. If used in combination there are 27 possible permutations of load, market, and carbon. Figure 25 below illustrates the 9 intrinsic inputs that can be selected during a model run:

Figure 25



Vast numbers of intrinsic models do not necessarily lead to better results or improved decision making. NorthWestern elected to focus on a subset of all the possible intrinsic combinations to provide an adequate range of intrinsic model results to inform the Plan. Therefore, NorthWestern selected the following intrinsic model combinations as illustrated in Table 35:

Table 35



Intrinsic Portfolio Case

Portfolio	Market	Carbon	Load	Number of Intrinsic Portfolios
PF11 - PF42	Base	Base	Base	32
	Low & High	Base	Base	64
	Base	No CO2 & Delay	Base	64
	Base	Base	High & Low	64
PF43 - PF51	Base	Base	Base	9
	Low & High	Base	Base	18
	Base	No CO2 & Delay	Base	18
PF52 - PF57	Base	Base	Base	6
PF58	Base	Base	Base	1
	Low & High	Base	Base	2
	Base	No CO2 & Delay	Base	2
			Total	280

The intrinsic cases described above include special purpose cases (PF52 – PF58) that have been constructed to evaluate the impact that certain input parameters and assumptions have on portfolio costs. These cases include wind power (PF52 – PF57) at different penetration levels and wind integration costs at different levels, and a Colstrip 4 dispatch case (PF58) where economic dispatch logic instead of base load / must-run logic is employed using all the market and carbon cases. These cases were designed as sensitivity cases to inform planning under specific and isolated conditions. No probability of occurrence is assigned to any of these cases or the model results. Importantly, sensitivity results, when viewed in isolation can be interpreted differently. For instance, when intermittent power is added in the absence of operational or other resource changes, the results may not account for other portfolio cost changes that may occur. As explained in Chapter 3, NorthWestern is sensitive to the addition of any resource that delivers energy in light load hours and energy resources that are intermittent.

Intrinsic Model Results

The 2009 Plan presents the results of updated electric generation resources that have been identified as possible candidates for the portfolio. NorthWestern has carefully considered and narrowed the list of resources, using both internal and external reviews, for modeling to focus on resources that it would actually consider as plausible resource additions. Natural gas-fired resources have been identified as top candidates for additional evaluation and potential future inclusion in the resource portfolio in addition to the continued use of term and short-term market purchases. Gas-fired resources have attributes that can offer advantages over other resource types:

1. Gas-fired resources can be strategically sited and operated in Montana or other location
2. Construction and lead times for units are relatively short and manageable
3. Proven technology(s) with known costs and known operational performance
4. Gas resources can be sized to meet needs through single or multi-unit installations
5. Combustion unit type options; reciprocating and turbines with or without heat recovery
6. Construction, operation, and technological risk is low
7. Emissions and environmental hazards are manageable
8. Operational flexibility and dispatchability
9. Offer lower carbon emissions, w/o the addition of CCS, than coal-fired options

While reviewing the analysis resulting from the sensitivity variations is informative and beneficial to the decision process, it can be challenging to distill the results into an actionable summary, particularly when so many different portfolios are run and results tend to be tightly grouped numerically. Similar to the 2007 Procurement Plan, a weighted scale was devised to weight the output results from the different sensitivity runs in a manner to create a combined portfolio metric that could be compared against other portfolios. In keeping with the concern regarding higher markets and higher costs associated with new carbon and GHG regulations, NorthWestern has selected weightings highlighting those risks. Since there is no quantitative data set allowing for a purely objective computation of the likelihood of the different scenarios, NorthWestern Energy posed this question to ETAC for input and a decision. Based on direct feedback from the ETAC, the weightings for the various results were set at the following levels in Table 36:

Table 36

Scenario Weighting

Scenario	Weight
Base Case	40%
Delay Carbon Cost	10%
High Wholesale Market	30%
No Carbon Cost	10%
Low Wholesale Market	10%

These weightings have been applied to the model outputs of the different intrinsic model runs in order to produce the single metric, or set of metrics for comparative purposes. For example, the weightings could be applied to the 20-year levelized cost of the portfolios as well as the carbon emission rates for the portfolios to provide a family of results for each portfolio. This kind of scenario testing is one way to incorporate a risk-adjusted result to feed into the ultimate decision process. The stochastic modeling also provides a risk-adjusted result for shorter-term price volatility and its impact on the portfolios.

The results for all intrinsic models are presented in Table 37. Each portfolio contains the existing resource stack that was described in Chapter X, a new thermal resource(s), an amount of potential wind or new biomass, and totals for the installed capacity additions for both new thermal units and new resources overall. The exceptions are the market portfolio PF11 and portfolios 25 and 26 that do not add any new thermal units and instead add wind power at a reduced level and 50 to 75MW of biomass. Results of the intrinsic models have been converted to a 20-year levelized cost basis ($/MWh) for each of the five (5) cases evaluated. The basecase is defined for all three variables; carbon, market, and load. The additional cases (low market, high market, no carbon penalty, and delay carbon penalty) employ the basecase load and are executed independent of one another. The top 10 ten performing portfolios in each of the 5 intrinsic cases have been highlighted in Table 37 to illustrate how the different technologies performed across all cases.

Table 37

20-Year Levelized Portfolio Costs (top 10 shaded)

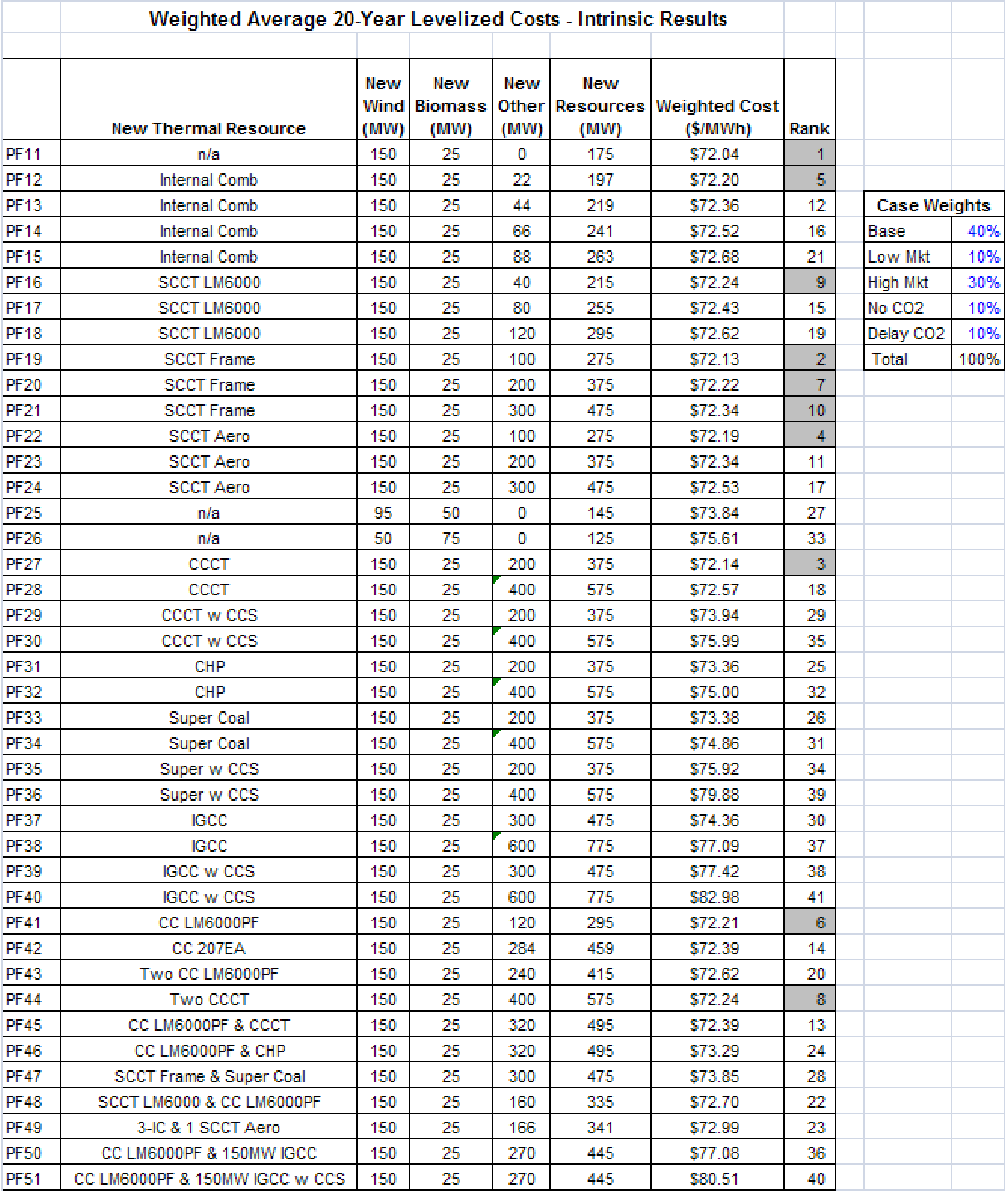
		(MW)				Levelized Cost ($/MWh)				
	New Thermal Resource	**New Wind**	**New Biomass**	**New Thermal**	**New Resources**	**Base Case**	**Low Market**	**High Market**	**No CO2 Penalty**	**Delay CO2 Penalty**
PF11	n/a	150	25	0	175	$70.11	$62.88	$81.72	$62.05	$69.90
PF12	Internal Comb	150	25	22	197	$70.40	$63.21	$81.55	$62.38	$70.18
PF13	Internal Comb	150	25	44	219	$70.69	$63.55	$81.39	$62.70	$70.47
PF14	Internal Comb	150	25	66	241	$70.98	$63.88	$81.22	$63.03	$70.75
PF15	Internal Comb	150	25	88	263	$71.27	$64.21	$81.06	$63.36	$71.03
PF16	SCCT LM6000	150	25	40	215	$70.53	$63.36	$81.35	$62.52	$70.31
PF17	SCCT LM6000	150	25	80	255	$70.95	$63.84	$80.98	$62.99	$70.71
PF18	SCCT LM6000	150	25	120	295	$71.36	$64.31	$80.62	$63.47	$71.12
PF19	SCCT Frame	150	25	100	275	$70.69	$63.52	$80.64	$62.68	$70.43
PF20	SCCT Frame	150	25	200	375	$71.26	$64.15	$79.59	$63.32	$70.97
PF21	SCCT Frame	150	25	300	475	$71.83	$64.79	$78.59	$63.96	$71.51
PF22	SCCT Aero	150	25	100	275	$70.86	$63.88	$80.31	$63.01	$70.63
PF23	SCCT Aero	150	25	200	375	$71.60	$64.89	$78.94	$63.97	$71.35
PF24	SCCT Aero	150	25	300	475	$72.36	$65.89	$77.64	$64.93	$72.09
PF25	n/a	95	50	0	145	$71.95	$64.87	$83.35	$63.93	$71.77
PF26	n/a	50	75	0	125	$73.77	$66.91	$84.88	$65.85	$73.62
PF27	CCCT	150	25	200	375	$71.27	$66.88	$77.92	$64.57	$71.11
PF28	CCCT	150	25	400	575	$72.75	$71.20	$74.47	$67.41	$72.64
PF29	CCCT w CCS	150	25	200	375	$72.69	$67.11	$81.06	$66.18	$72.15
PF30	CCCT w CCS	150	25	400	575	$75.42	$71.48	$80.57	$70.46	$74.55
PF31	CHP	150	25	200	375	$72.49	$68.10	$79.14	$65.79	$72.33
PF32	CHP	150	25	400	575	$75.19	$73.63	$76.91	$69.85	$75.08
PF33	Super Coal	150	25	200	375	$72.24	$66.66	$80.61	$64.31	$72.01
PF34	Super Coal	150	25	400	575	$74.51	$70.57	$79.66	$66.72	$74.28
PF35	Super w CCS	150	25	200	375	$74.57	$68.71	$83.47	$67.69	$74.10
PF36	Super w CCS	150	25	400	575	$79.11	$74.63	$85.32	$73.42	$78.39
PF37	IGCC	150	25	300	475	$73.60	$68.84	$80.36	$66.04	$73.30
PF38	IGCC	150	25	600	775	$77.49	$75.18	$79.41	$70.43	$77.12
PF39	IGCC w CCS	150	25	300	475	$76.22	$70.74	$84.40	$69.74	$75.67
PF40	IGCC w CCS	150	25	600	775	$82.51	$78.76	$87.27	$77.60	$81.62
PF41	CC LM6000PF	150	25	120	295	$70.84	$64.33	$80.19	$63.26	$70.62
PF42	CC 207EA	150	25	284	459	$71.67	$65.43	$78.67	$64.35	$71.44
PF43	Two CC LM6000PF	150	25	240	415	$71.34	$65.38	$78.90	$67.50	$71.33
PF44	Two CCCT	150	25	400	575	$71.94	$69.20	$75.37	$67.21	$72.07
PF45	CC LM6000PF & CCCT	150	25	320	495	$71.61	$67.16	$77.08	$67.32	$71.69
PF46	CC LM6000PF & CHP	150	25	320	495	$72.52	$68.06	$77.98	$68.23	$72.59
PF47	SCCT Frame & Super Coal	150	25	300	475	$72.81	$67.29	$79.58	$68.09	$73.09
PF48	SCCT LM6000 & CC LM6000PF	150	25	160	335	$71.02	$64.40	$80.04	$67.43	$71.00
PF49	3-IC & 1 SCCT Aero	150	25	166	341	$71.50	$64.61	$80.01	$67.82	$71.48
PF50	CC LM6000PF & 150MW IGCC	150	25	270	445	$75.96	$70.67	$82.90	$71.50	$76.13
PF51	CC LM6000PF & 150MW IGCC w CCS	150	25	270	445	$79.14	$73.50	$86.78	$75.56	$79.10
PF52*	PF11 with 75MW wind -$12.84 WIC	75	25	0	100	$69.83				
PF53*	PF11 with 225MW wind -$12.84 WIC	225	25	0	250	$70.11				
PF54*	PF11 no new wind - Generic Renewable	0	25	0	25	$69.54				
PF55*	PF11 with $20 Wind Integration Cost	150	25	0	175	$71.13				
PF56*	PF11 with $30 Wind Integration Cost	150	25	0	175	$72.55				
PF57*	PF11 with $8 Wind Integration Cost	150	25	0	175	$69.43				
PF58	PF11 with Colstrip 4 Dispatched	150	25	0	175	$70.53	$63.34	$81.97	$62.30	$70.26

*Modeled for PF11 sensitivity - not considered in the ranking.

The detailed intrinsic model output supporting the information in Table 37 are organized and presented in Volume 3, Chapter 7. Graphical and tabular data have been organized to aid the detailed review of individual portfolios and the resources comprising each portfolio.

In order to capture the results of all the intrinsic portfolios into a single, comparable value, the scenario weightings described above were applied to the five 20-year levelized costs and summed to determine a weighted 20-year levelized cost for portfolios PF11 through PF51 and PF58. The rank of each portfolio (excluding PF58) from least to highest cost is shown in the right most column of Table 38 with the top 10 highlighted. All of the top 10 portfolios include market purchases in combination with varying amounts of both existing and new gas-fired resources.

Table 38



Weighted Average 20-Year Levelized Costs - Intrinsic Results

	New Thermal Resource	New Wind (MW)	New Biomass (MW)	New Other (MW)	New Resources (MW)	Weighted Cost ($/MWh)	Rank
PF11	n/a	150	25	0	175	$72.04	1
PF12	Internal Comb	150	25	22	197	$72.20	5
PF13	Internal Comb	150	25	44	219	$72.36	12
PF14	Internal Comb	150	25	66	241	$72.52	16
PF15	Internal Comb	150	25	88	263	$72.68	21
PF16	SCCT LM6000	150	25	40	215	$72.24	9
PF17	SCCT LM6000	150	25	80	255	$72.43	15
PF18	SCCT LM6000	150	25	120	295	$72.62	19
PF19	SCCT Frame	150	25	100	275	$72.13	2
PF20	SCCT Frame	150	25	200	375	$72.22	7
PF21	SCCT Frame	150	25	300	475	$72.34	10
PF22	SCCT Aero	150	25	100	275	$72.19	4
PF23	SCCT Aero	150	25	200	375	$72.34	11
PF24	SCCT Aero	150	25	300	475	$72.53	17
PF25	n/a	95	50	0	145	$73.84	27
PF26	n/a	50	75	0	125	$75.61	33
PF27	CCCT	150	25	200	375	$72.14	3
PF28	CCCT	150	25	400	575	$72.57	18
PF29	CCCT w CCS	150	25	200	375	$73.94	29
PF30	CCCT w CCS	150	25	400	575	$75.99	35
PF31	CHP	150	25	200	375	$73.36	25
PF32	CHP	150	25	400	575	$75.00	32
PF33	Super Coal	150	25	200	375	$73.38	26
PF34	Super Coal	150	25	400	575	$74.86	31
PF35	Super w CCS	150	25	200	375	$75.92	34
PF36	Super w CCS	150	25	400	575	$79.88	39
PF37	IGCC	150	25	300	475	$74.36	30
PF38	IGCC	150	25	600	775	$77.09	37
PF39	IGCC w CCS	150	25	300	475	$77.42	38
PF40	IGCC w CCS	150	25	600	775	$82.98	41
PF41	CC LM6000PF	150	25	120	295	$72.21	6
PF42	CC 207EA	150	25	284	459	$72.39	14
PF43	Two CC LM6000PF	150	25	240	415	$72.62	20
PF44	Two CCCT	150	25	400	575	$72.24	8
PF45	CC LM6000PF & CCCT	150	25	320	495	$72.39	13
PF46	CC LM6000PF & CHP	150	25	320	495	$73.29	24
PF47	SCCT Frame & Super Coal	150	25	300	475	$73.85	28
PF48	SCCT LM6000 & CC LM6000PF	150	25	160	335	$72.70	22
PF49	3-IC & 1 SCCT Aero	150	25	166	341	$72.99	23
PF50	CC LM6000PF & 150MW IGCC	150	25	270	445	$77.08	36
PF51	CC LM6000PF & 150MW IGCC w CCS	150	25	270	445	$80.51	40

Case Weights	
Base	40%
Low Mkt	10%
High Mkt	30%
No CO2	10%
Delay CO2	10%
Total	100%

Intrinsic Analysis Conclusions

Results of the intrinsic analysis have undergone both internal and external review; including review by ETAC. NorthWestern has considered comments and criticisms regarding the construction of the portfolios, the results of the modeling, and the conclusions that can be reasonably drawn from the analysis.

Intrinsic model results general observations include:

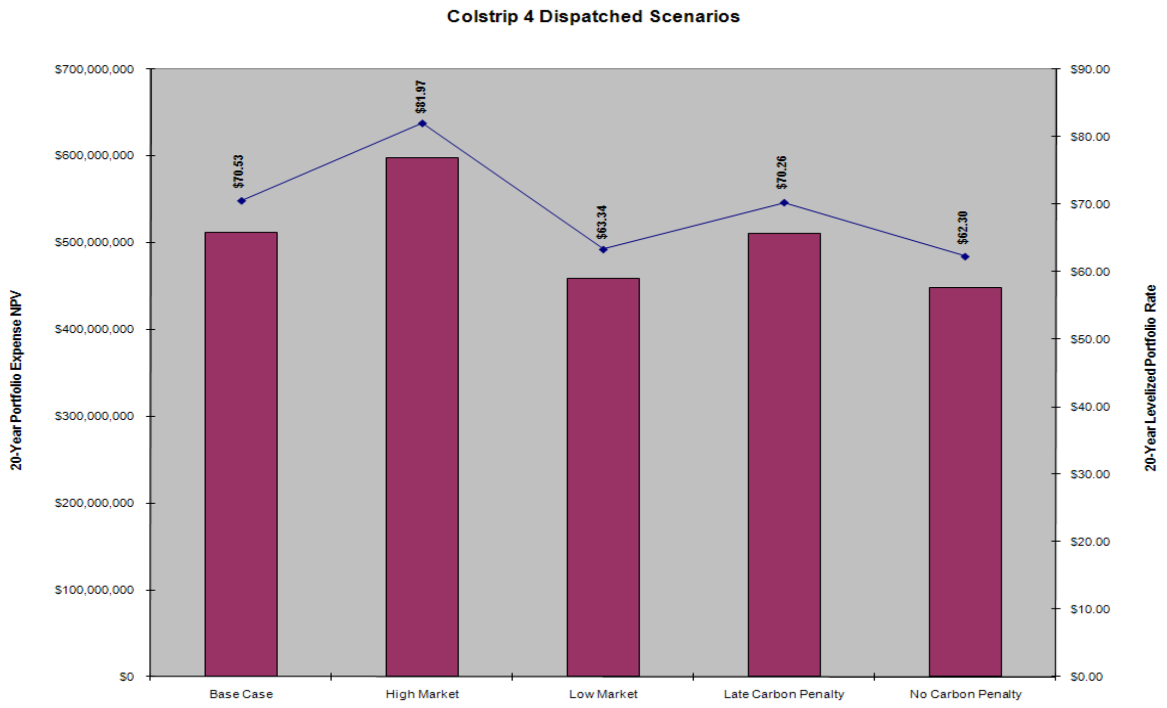
- For all intrinsic cases with the exception of the high market case, the addition of thermal resources to the portfolio adds cost to the base portfolio (PF11) which does not have new thermal resources
- The top 5 performing intrinsic portfolios, employing 4 different gas combustion technology/configurations, are separated by a 20-year weighted cost of $0.16/MWh. This level of cost seperation points strongly to additional investigation to better define costs and operational input assumptions to achieve a higher level of cost differentiation.
- Although PF27 (200MW CCCT) only ranks in the top 10 in the high market case, its weighted average ranking is 3rd overall because it performs well due to the weighting assigned to each of the intrinsic cases.
- The addition of small increments of gas-fired resource and the resulting portfolio cost is heavily influenced by the relative volume of market purchases
- The coal combustion and IGCC portfolios (with and without carbon capture) did not perform as well as the portfolios employing gas-fired technology; capital cost figures prominently even when costs are levelized and compared to resources installed sooner
- Economic performance of individual gas-fired technologies is sensitive to size and number of units included
- Portfolio cost is sensitive to both the amount of installed wind capacity and wind integration cost

Wind integration cost sensitivity cases (PF52 – PF57) were designed to test the impact of different levels of integration cost for the total amount of wind included in PF11. The wind integration costs (WIC) that have been employed in all other portfolios is based on the assumed rate of $12.84 per MWh beginning in 2010 and escalating at 2.5% per year over the 20-year planning horizon. The $12.84 per MWh has been suggested as a rate using the Mill Creek generating station and an 18% of installed capacity allocation methodology. This rate and the allocation of costs from Mill Creek do not represent approved values from the Montana Public Service Commission and is reflective of a $6.37 per dkt gas price. The WIC sensitivity cases of $8, $20, and $30 per MWh were selected to test a range of costs and should not be construed as rates that were derived from an analysis of Mill Creek or any other source of regulation service. A WIC of $30/MWh applied to PF11 raises the levelized portfolio cost to $72.55/MWh; a value higher than the levelized cost of the top 10 performing portfolios in the basecase scenario that uses a $12.84/MWh WIC. Clearly, the WIC must be considered in conjunction with wind project additions and any other potential cost impacts associated with increased wind penetration levels on NorthWestern's system. Results of the ongoing transmission system modeling by GENIVAR are expected to provide specific answers to questions regarding wind integration requirements and regulation allocation to wind projects.

Increments of wind (75MW, 225MW, 0MW) were added to PF11 (replacing the original 150MW of new wind) to create portfolios 52 through 54. As installed wind capacity increases, so do portfolio costs. Importantly, as wind is added in the models, the changes to portfolio costs were considered under static conditions. This means that operational and market constraints were not added; the models were simply allowed to run using the same logic as contained in PF11. Additionally, it is important to recognize that there are timing differences, in terms of the year in which the incremental volumes of wind capacity are put into the portfolio. The detailed model results in Volume 3 demonstrate the volume and timing of resource additions for all portfolios. Wind resources are not added in the same manner as the majority of the thermal resources that are necessarily added according to unit size. For PF53 that adds 225MW of new wind, the schedule of new wind additions occurs through 2017. The impact of nominally levelizing the annual portfolio costs serves to reduce the cost impact relative to PF52 and PF54 while coincidentally producing the same levelized portfolio cost as PF11 that includes wind resource additions of 150MW. Delay timing of additional wind resources because of renewable portfolio standard needs is coupled with the need to better understand the impacts of incremental wind power additions.

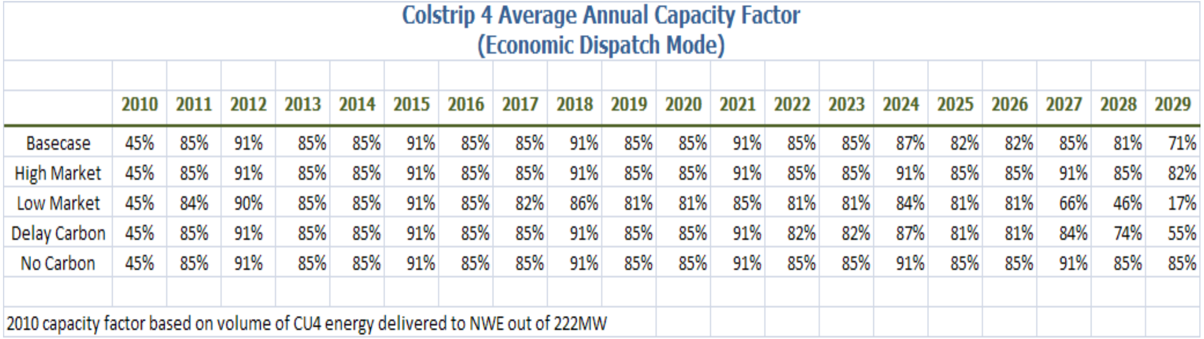
During the review of intrinsic model results, questions arose concerning the treatment of Colstrip 4 with regard to assessing its long-term contribution to the Supply portfolio. Specifically, questions were posed concerning the baseload/must run status of Colstrip without recognizing the total dispatch cost including carbon costs, compared to alternative sources. The suggestion to simulate Colstrip 4 in an economic dispatch mode to determine the timing and magnitude (if any) of reduced energy delivery was considered and a special Colstrip 4 case (PF58) was run. Portfolio 58 employs the same input parameters as PF11 with exception of the unit definition for Colstrip 4. The dispatch decision for Colstrip 4 is based upon the variable cost plus the cost for carbon as specifically determined for each of the intrinsic model cases. Figure 26 illustrates the intrinsic results of PF58:

Figure 26



To help explain how Colstrip 4 performed in economic dispatch mode a key indicator of performance is the average annual capacity factor. Table 39 demonstrates the annual capacity for Colstrip 4 when run in economic dispatch mode over the 20-year planning horizon

Table 39



Colstrip 4 Average Annual Capacity Factor
(Economic Dispatch Mode)

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Basecase	45%	85%	91%	85%	85%	91%	85%	85%	91%	85%	85%	91%	85%	85%	87%	82%	82%	85%	81%	71%
High Market	45%	85%	91%	85%	85%	91%	85%	85%	91%	85%	85%	91%	85%	85%	91%	85%	85%	91%	85%	82%
Low Market	45%	84%	90%	85%	85%	91%	85%	82%	86%	81%	81%	85%	81%	81%	84%	81%	81%	66%	46%	17%
Delay Carbon	45%	85%	91%	85%	85%	91%	85%	85%	91%	85%	85%	91%	82%	82%	87%	81%	81%	84%	74%	55%
No Carbon	45%	85%	91%	85%	85%	91%	85%	85%	91%	85%	85%	91%	85%	85%	91%	85%	85%	91%	85%	85%

2010 capacity factor based on volume of CU4 energy delivered to NWE out of 222MW

In economic dispatch mode Colstrip 4 generally produces at baseload forecast levels of annual energy output until the mid to late 2020s when economic dispatch generally begins to lower the annual volume of output. According to the results of all the dispatch model simulations, Colstrip 4 produces at or near current levels for at least another 15 years. The dispatch scenario that demonstrates the greatest single year change to Colstrip 4 annual capacity factor is the low market case. In 2029 the dispatch rate changes to 17% as a function of increasing carbon costs, decreasing carbon allowances, and depressed market prices relative to Colstrip 4 variable costs. The low market case was assigned a 10% weighting as opposed to the basecase that employs a 40% weighting and dispatching at capacity levels in excess of 80% through 2028.

According to the simulation results, the basecase and no carbon cases produce nearly identical results. That is, for these cases that employ very different carbon cost assumptions, Colstrip 4 in economic dispatch mode, produced at nearly identical levels of output until late in the 2020s. This suggests that the baseload/must run logic employed for Colstrip 4 is a reasonable assumption to use in the 2009 planning work.

Load sensitivity cases have been included to test a range of plausible retail loads for the intrinsic models. The high and low load cases resulted from the application of different rates of growth above and below the annual growth rates that were determined for the base case 20-year forecast. A probability of occurrence is not assigned to either of the alternative load cases. Figure 27 and Table 40 are provided to demonstrate the difference between the three load forecast cases. Additional information concerning the derivation of the base case load forecast and the sensitivity cases can be found in Volume 3 Chapter 6.

Figure 27

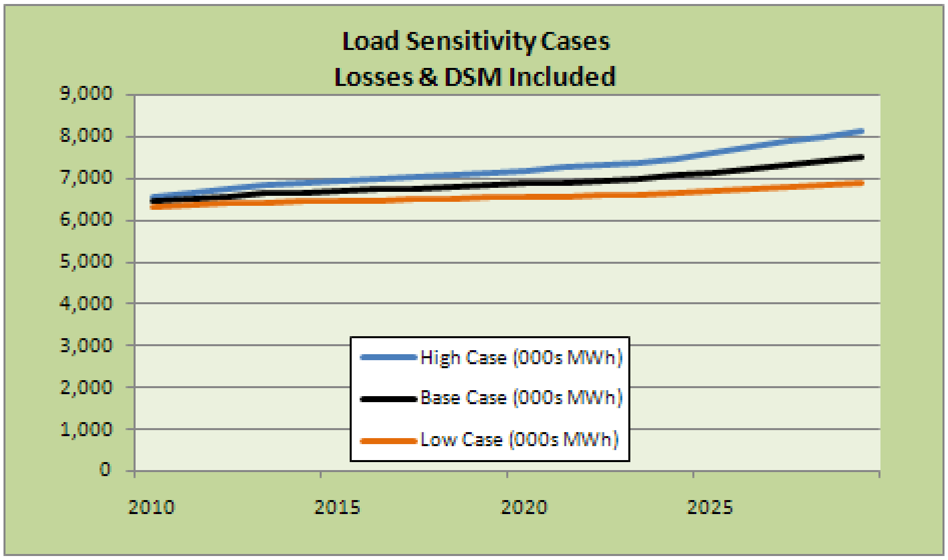
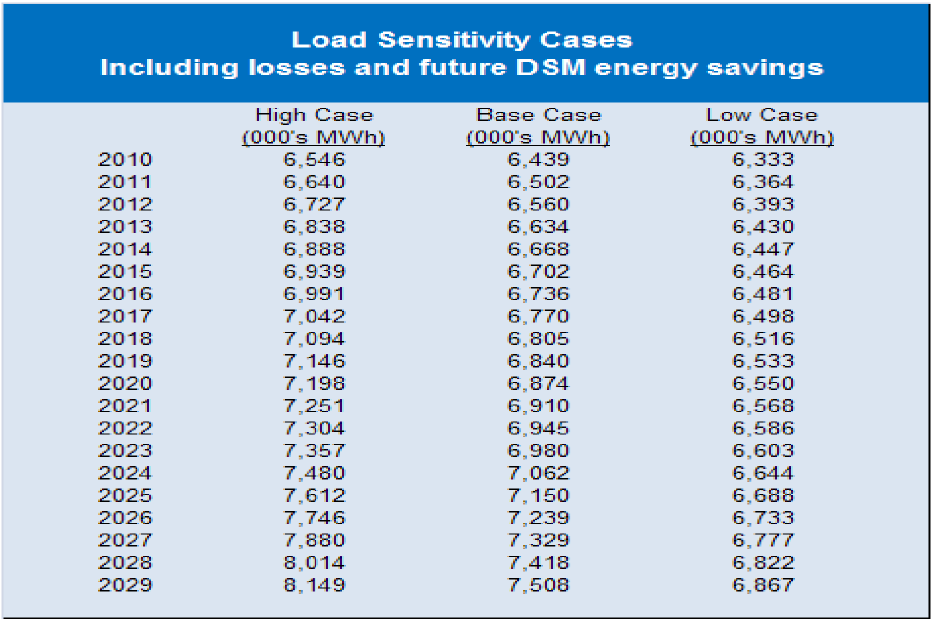


Table 40



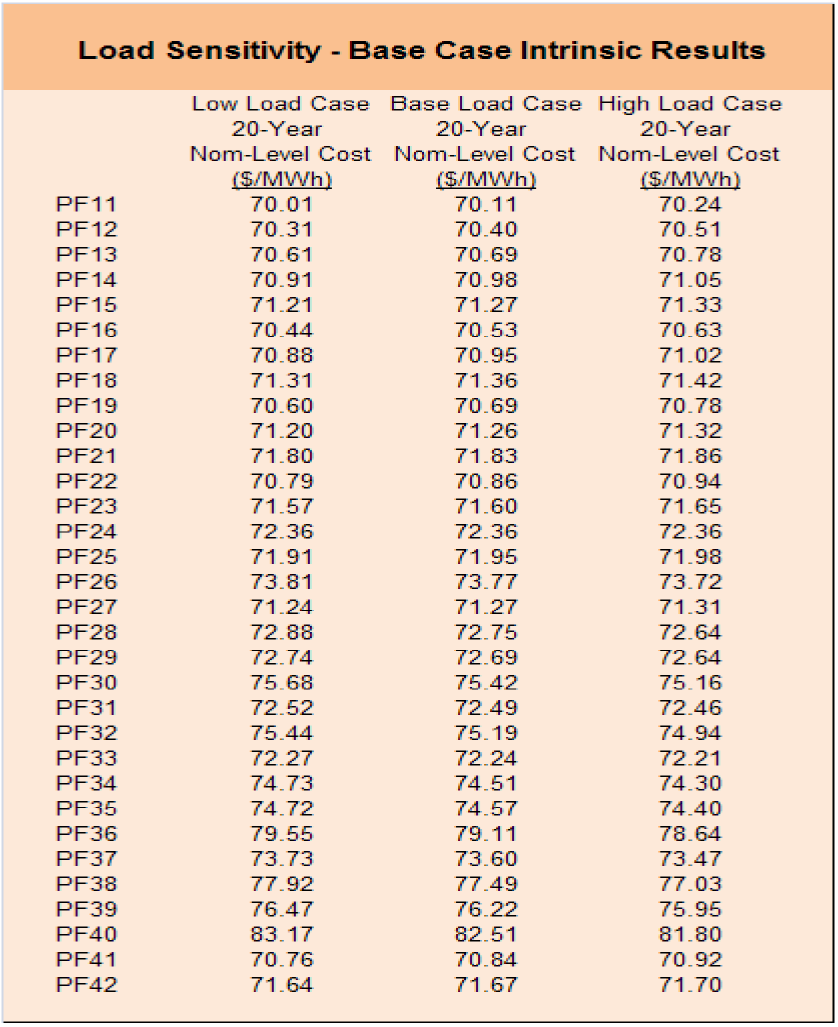
Load Sensitivity Cases
Including losses and future DSM energy savings

	High Case (000's MWh)	Base Case (000's MWh)	Low Case (000's MWh)
2010	6,546	6,439	6,333
2011	6,640	6,502	6,364
2012	6,727	6,560	6,393
2013	6,838	6,634	6,430
2014	6,888	6,668	6,447
2015	6,939	6,702	6,464
2016	6,991	6,736	6,481
2017	7,042	6,770	6,498
2018	7,094	6,805	6,516
2019	7,146	6,840	6,533
2020	7,198	6,874	6,550
2021	7,251	6,910	6,568
2022	7,304	6,945	6,586
2023	7,357	6,980	6,603
2024	7,480	7,062	6,644
2025	7,612	7,150	6,688
2026	7,746	7,239	6,733
2027	7,880	7,329	6,777
2028	8,014	7,418	6,822
2029	8,149	7,508	6,867

The difference between the three load cases grows over time. Because the evaluation of the intrinsic modeling results are compared on a nominally levelized basis ($/MWh) the effects of materially different loads in the out years of the three load cases is diluted through discounting and levelization.

Results of the load sensitivity intrinsic models for PF11 – 42 are presented in Table 41. By observation it is evident that portfolio cost change due to changing the load assumption is relatively small when compared to the total cost. These results are consistent with load sensitivity analyses that have been performed in previous resource plans. For both the low and high load cases, the calculated difference to the base case is less than a one percent (1%) change to the 20-year nominally levelized cost.

Table 41



Load Sensitivity - Base Case Intrinsic Results

	Low Load Case 20-Year Nom-Level Cost ($/MWh)	Base Load Case 20-Year Nom-Level Cost ($/MWh)	High Load Case 20-Year Nom-Level Cost ($/MWh)
PF11	70.01	70.11	70.24
PF12	70.31	70.40	70.51
PF13	70.61	70.69	70.78
PF14	70.91	70.98	71.05
PF15	71.21	71.27	71.33
PF16	70.44	70.53	70.63
PF17	70.88	70.95	71.02
PF18	71.31	71.36	71.42
PF19	70.60	70.69	70.78
PF20	71.20	71.26	71.32
PF21	71.80	71.83	71.86
PF22	70.79	70.86	70.94
PF23	71.57	71.60	71.65
PF24	72.36	72.36	72.36
PF25	71.91	71.95	71.98
PF26	73.81	73.77	73.72
PF27	71.24	71.27	71.31
PF28	72.88	72.75	72.64
PF29	72.74	72.69	72.64
PF30	75.68	75.42	75.16
PF31	72.52	72.49	72.46
PF32	75.44	75.19	74.94
PF33	72.27	72.24	72.21
PF34	74.73	74.51	74.30
PF35	74.72	74.57	74.40
PF36	79.55	79.11	78.64
PF37	73.73	73.60	73.47
PF38	77.92	77.49	77.03
PF39	76.47	76.22	75.95
PF40	83.17	82.51	81.80
PF41	70.76	70.84	70.92
PF42	71.64	71.67	71.70