

COMMITTEE WORKSHOP
BEFORE THE
CALIFORNIA ENERGY RESOURCES CONSERVATION
AND DEVELOPMENT COMMISSION

In the Matter of:)
)
Preparation of the 2007) Docket No.
Integrated Energy Policy) 06-IEP-1C
Report (2007 IEPR))
_____)

CALIFORNIA ENERGY COMMISSION
HEARING ROOM A
1516 NINTH STREET
SACRAMENTO, CALIFORNIA

MONDAY, MAY 7, 2007

1:00 P.M.

Reported by:
Peter Petty
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COMMISSIONERS PRESENT

Jackalyne Pfannenstiel, Presiding Member

James D. Boyd (in audience)

Jeffrey Byron, Associate Member

John L. Geesman, Associate Member

PUC COMMISSIONERS PRESENT

Dian Grueneich

CEC ADVISORS PRESENT

Melissa Jones

Tim Tutt

CEC STAFF and CONTRACTORS PRESENT

Linda Kelly

John Sugar

Lorraine White

ALSO PRESENT

Kim Crossman, United States Environmental
Protection Agency (US EPA)

Snuller Price, Energy and Environmental Economics,
Inc. (E3)

Eric R. Wong, Cummins Power Generation, on behalf
of the California Clean Distributed Generation
Coalition (CCDGC)

Don Schoenbeck, Cogeneration Association of
California and the Energy Producer and Users
Coalition (CAC/EPUC)

ALSO PRESENT (CONTINUED)

Nora E. Sheriff, Cogeneration Association of
California and the Energy Producer and Users
Coalition (CAC/EPUC)

Susan M. Buller, Pacific Gas & Electric Company
(PG&E)

Janice Lin, StrateGen Consulting,
on behalf of VRB Power Systems

Keith Davidson, DE Solutions

Chuck Whitaker, BEW Engineering (BEW)

Joseph Heinzmann, FuelCell Energy

Les Guliassi, Pacific Gas & Electric Company (PG&E)

Fred Skillman, Pacific Gas & Electric Company
(PG&E)

Andrew McAllister, California Center for
Sustainable Energy (via telephone)

Gary Schoonyan, Southern California Edison

Ellen M. Petrill, Electric Power Research
Institute

Bob Burt, Insulation Contractors Association

Bill Karambelas, FuelCell Energy

Jane Turnbull, League of Women Voters

Alex Kim, San Diego Gas & Electric,
also representing SoCal Gas

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1 P R O C E E D I N G S

2 1:07 p.m.

3 MR. SUGAR: Presiding today is
4 Commissioner Jackalyne Pfannenstiel. We have both
5 the Integrated Energy Policy Report Committee, the
6 Electricity Committee, and joining us today is
7 Commissioner Grueneich from the California Public
8 Utilities Commission. Do you have any comments?

9 PRESIDING MEMBER PFANNENSTIEL: Thank
10 you, John.

11 Good afternoon. I just want to thank
12 people for joining us for this subject matter
13 workshop. As John said it's a joint proceeding
14 between two of the Energy Commission's policy
15 committees, the Integrated Energy Policy Report
16 Committee, for which John is the Presiding
17 Commissioner, and the Electricity Committee, for
18 which Commissioner Byron is presiding.

19 Commissioner Geesman sits on both of those
20 committees. And we are delighted to have
21 Commissioner Grueneich of the PUC here with us.

22 I think it is very important that we are
23 looking at these issues jointly between the two
24 commissions. We both have certain implementation
25 and policy responsibilities and I think it is

1 really a very, very strong signal that we are
2 together in hearing from the staff and from the
3 parties in these matters.

4 With that, Commissioner Byron, do you
5 have any opening comments?

6 ASSOCIATE MEMBER BYRON: Thank you, yes.
7 You know, having only been on the Commission here
8 for less than a year it is very clear that there
9 has been strong and consistent support in both the
10 Integrated Energy Policy Reports and by my fellow
11 commissioners for distributed generation. And I
12 certainly want to echo and add my support for
13 those recommendations. I am glad to see this
14 workshop today and I thank the staff very much for
15 putting it on. I thank Commissioner Grueneich for
16 being here.

17 I was reminded that five years ago that
18 I was before this Commission making a presentation
19 on the DG strategic plan. So I understand very
20 much the effort that it takes to be here and for
21 your providing input. I want to let you all know
22 that we appreciate that very much and we welcome
23 it, that's why we're here.

24 We are seeing something interesting in
25 the last couple of, number of months. I am

1 beginning to see that there is new interest in,
2 excuse me, new interest in distributed generation
3 projects in publicly-owned utility service
4 territories. And I think that is really
5 intriguing given the lower rate structure and the
6 competitive aspect of DG having to compete in
7 those territories and it is beginning to work.

8 So I am very interested in making sure
9 that we address some of those impediments that
10 we're talking about and I hope that we get to
11 those today. I note that our investor-owned
12 utilities have had a rather mixed track record
13 when it comes to distributed generation so let's
14 get the issues out on the table and let's have a
15 good, candid discussion around that today.

16 Thank you, John.

17 PRESIDING MEMBER PFANNENSTIEL:

18 Commissioner Grueneich, do you have any comments?

19 CPUC COMMISSIONER GRUENEICH: Thank you.
20 Mainly I just want to say how pleased I am to be
21 here and to thank both Chair Pfannenstiel as well
22 as the other commissioners for inviting me to be
23 here.

24 That we have really been working hard
25 over the last couple of years to show that the two

1 energy agencies in the state are working together
2 trying to set common goals and really trying to
3 identify where there are barriers that need to be
4 overcome.

5 That I have been a strong supporter of
6 distributed generation, combined heat and power,
7 over my 30 years in the energy business. I
8 believe that it is a very important tool in the
9 tool chest that we have here in California, both
10 to ensure that our energy supply is economic as
11 well as to now meet our global warming goals.

12 We obviously have a number of cases
13 going on at the PUC that are addressing some of
14 these issues. I am particularly interested in
15 understanding what are the issues or barriers that
16 are not being addressed in those cases so that
17 collectively we can understand what additional
18 steps we need to be taking.

19 And then to the extent that anyone has
20 any observations or thoughts on how our new law,
21 AB 32, on global warming and the possibility of
22 setting up the cap and trade system may impact
23 some of the issues we are discussing today I'd be
24 interested.

25 But we are collectively, again, between

1 the two commissions having a specific effort on AB
2 32. So if that's not an issue people are prepared
3 to discuss today that's fine but we will be moving
4 into a very new era, I think, as we implement AB
5 32. So I am interested in how that will affect us
6 as we're looking at establishing some of the
7 policies that we are addressing today. Thank you.

8 PRESIDING MEMBER PFANNENSTIEL: Thank
9 you, Dian.

10 Commissioner Geesman.

11 ASSOCIATE MEMBER GEESMAN: Thank you,
12 Madam Chair, and thank you, Dian, for coming
13 today. You have been one of the pioneers in this
14 area since the state first got involved in
15 promoting distributed generation in the late
16 1970s.

17 I think one of our critical tasks in the
18 2007 IEPR cycle is to try and bring a pretty
19 strong dose of reality to the rhetoric that this
20 subject area has either benefitted from or been
21 burdened by from state policy makers over the
22 course of the last 20 years.

23 I think we have held ourselves out to a
24 much higher level of performance than we have
25 actually been able to achieve. I think that there

1 is an ongoing schizophrenia in state policy
2 between what we say we want to do and what we
3 actually allow to happen. That tension, I think,
4 is embodied in full force in the draft decision in
5 the CPUC's SRAC case.

6 And I don't want to, and traditionally
7 the Energy Commission has avoided trying to
8 second-guess rate making decisions. But I think
9 that in reviewing the draft decision it is pretty
10 clear that at least the administrative law judge
11 is on a different page from the Energy Commission
12 and its 2005 Integrated Energy Policy Report.

13 And I think that probably the most
14 frustrating aspect of that to me was our efforts
15 to promote a focus on the combined thermal load
16 and electrical load and the efficiency benefits to
17 be gained from that combined perspective seem to
18 have been missed entirely in the draft decision.

19 It is not clear where the climate
20 warriors were in reviewing some of the elements of
21 the draft decision. So I think we have got a lot
22 of work to do to try and bring the reality of
23 state policy into adjustment with the rhetoric
24 that we all like to engage in.

25 And I look forward to this cycle, Madam

1 Chair, in providing that.

2 PRESIDING MEMBER PFANNENSTIEL: Thank
3 you, Commissioner Geesman.

4 John, back to you.

5 MR. SUGAR: Thank you. Our first
6 speaker is Ms. Kim Crossman from EPA. Would you
7 care to use the podium here?

8 MS. CROSSMAN: I'd like to use this if
9 it's okay.

10 Good afternoon. Thank you very much to
11 all of the Commissioners who invited me here today
12 and thank you very much to the California Clean
13 Energy Stakeholders who I have the pleasure to
14 visit with today.

15 My name is Kim Crossman. I am the team
16 leader for the Environmental Protection Agency's
17 combined heat and power partnership program and I
18 am here to give a brief introduction to CHP. Why
19 the EPA actively supports the deployment of clean,
20 distributed generation such as CHP and some of the
21 issues that are being faced right now in this very
22 interesting time of change nationwide and
23 epitomized in what is going on here in California.

24 So the EPA Combined Heat and Power
25 Partnership is a voluntary program. We were

1 formed to foster the use of highly efficient CHP
2 as part of the EPA's suite of clean energy
3 programs to address the environmental impacts of
4 energy production and usage.

5 In the past five years or so we have
6 worked on about 250 CHP projects with our partners
7 all over the country for a grand total of 3500 new
8 megawatts of CHP nationwide since 2001. These
9 projects represent over 10 million tons of CO2
10 emissions reductions cumulatively during that time
11 period.

12 Our program is fuel and technology
13 neutral. We work with multiple types of CHP
14 applications, multiple fuel types and in multiple
15 areas all over the country. I would say that a
16 lot of the time that we have been running we have
17 not done a ton of work inside of California
18 because we have got partners who are industry
19 partners who have been successful in this state.
20 But right at this moment California is making some
21 decisions that will impact the ability to deploy
22 new CHP here so I am happy to be here.

23 Combined heat and power. I was under
24 the impression there might be other DG folks in
25 the audience who are not CHP people so please

1 forgive me if this is a little basic. Combined
2 heat and power is a highly efficient energy
3 system. It is located at or near a building or
4 facility and it generates electrical and/or
5 mechanical power and recovers waste heat for use.
6 That's more of a topping cycle idea, there are
7 other, you know. CHP is at least two useful
8 outputs from one fuel input, really, when we come
9 down to it.

10 So the benefits of CHP. And part of
11 this presentation was based on my recent review of
12 the latest and greatest version of AB 1613 where
13 suddenly the words, environmentally beneficial,
14 cost-effective, and technologically feasible came
15 up over and over and over in our latest draft of
16 that. So the benefits are that well-sited and
17 sized systems reduce all pollutants, including
18 greenhouse gas emissions.

19 Technically these are fully
20 commercialized technologies and proven
21 applications nationwide and worldwide. This is
22 not new or emerging. And economically once again,
23 where the systems are installed in the right spot
24 in the right application we get powerful energy
25 savings and we also have reliability benefits that

1 can avoid the catastrophic losses associated with
2 utility outages.

3 But then of course all benefit
4 statements are dependant on a baseline, you know.
5 It's better than what, is the question. So I'm
6 going to talk a little bit about the environmental
7 benefits.

8 This slide has been trotted out probably
9 1,000 times in the last five years, everywhere I
10 go where we talk about CHP. And the idea here is
11 that through using the waste heat from power gen
12 we are going to be significantly more efficient.
13 And in the case of this slide, have significant
14 CO2 emissions reductions.

15 Part of that is in the efficiency of the
16 system in general. You know, a 31 percent
17 efficient grid versus a 70 percent efficient CHP
18 system. Now this is broad, nationwide averages
19 we're talking about here. Part of it is also the
20 avoidance of transmission of distribution and the
21 losses associated with that. So you combine both
22 of those and we end up with CO2 emissions
23 reductions.

24 Now California is really its whole own
25 situation because CO2 performance is a combination

1 of fuel and conversion efficiency. And from what
2 I'm reading right now the CO2 performance that's
3 being discussed and implemented through
4 legislation in various places here is talking
5 about new, gas-fired, combined cycle central
6 plants, central utility plants, and 80 percent
7 efficient gas blowers. So we're not talking about
8 beating a 31 percent efficient grid and an 80
9 percent efficient boiler, okay. It's a higher
10 standard than that is what's being discussed.

11 The question is, can CHP do that? And
12 the answer is, yes it can. In order to do so the
13 systems need to be thermally base-loaded, sized
14 correctly as has been discussed repeatedly through
15 various legislation, sized to meet the thermal
16 demand and however much power you produce to go
17 with that, is what ends you up with the most
18 efficient system where you can actually get the
19 CO2 emissions reductions.

20 In order to do that analysis, when the
21 power is used on-site the benefits of the T&D
22 losses, not incurring T&D losses, absolutely
23 should be included in looking at the benefits of a
24 distributed generation system. And then biomass-
25 fueled CHP, regardless of system efficiency, will

1 be an improvement over the carbon baseline that's
2 being discussed. Fuel cell projects as well are
3 very, very low in emissions just kind of
4 automatically.

5 So the EPA/CHP partnership has been
6 administering the Energy Star CHP awards for the
7 last five years and those awards are identical to
8 what is being proposed in California as a
9 performance standard. We compare a CHP system to
10 state of the art, combined cycle, central gen,
11 gas-fired and an 80 percent efficient boiler. And
12 lately we give them the T&D as long as they are
13 using the power on-site. And we have found 22
14 winners over the last five years who applied for
15 and were able to achieve this performance
16 standard.

17 I'm sure there are many more in the
18 country, they just haven't applied for awards at
19 this time. But I guess the bottom line is we know
20 that CHP can do this. And CalTech is an example
21 of a plant in California that did achieve and
22 exceed this emissions and efficiency standard and
23 won an award from us in '04. So we administer
24 these awards.

25 One of the things I'm touching on here

1 is that we have got some things to offer and I'm
2 not going to labor over that but my program is
3 here with some services.

4 Technologically feasible. All of these
5 technologies, turbines, microturbines, engines,
6 boilers, are fully commercial, proven, with over
7 95 percent availability. All of them are
8 available from multiple manufacturers today. Fuel
9 cells and gasifiers are in the process of becoming
10 commercialized right now.

11 Some products are available. All of the
12 heat recovery and thermal technologies are proven
13 and available today. The controls and switch
14 gear are proven and available today. So that is
15 one of the advantages that CHP has as a front
16 guard of distributed generation in terms of
17 commercial status and cost competitiveness.

18 We do maintain catalogs with all of the
19 current status of technologies and are about to
20 publish a biomass catalog in a couple of weeks
21 that will have all of those as well.

22 So technologically feasible. The thing
23 is that CHP is not a technology. This is an
24 application and we just need to put it where it
25 makes sense, where it's actually thermally

1 baseloaded, matched to the site and the size that
2 the site needs. We have a strong CHP industry in
3 California that has continued to operate through
4 the ups and the downs of the policy environment
5 that have been experienced here over the last
6 probably 15 or 20 years at least.

7 And CHP is already in California. I
8 don't know how long I want to spend on this
9 because this actually comes from a CEC report so I
10 imagine you all probably know this. But average
11 plants in California, about ten megawatts is the
12 average capacity size. Most of the installed
13 capacity is greater than 20 megawatts. This is
14 for very simple reasons that CHP becomes more
15 cost-effective, cost-competitive with the larger
16 systems. Smaller systems, higher costs to develop
17 so that just leads to larger systems in general.

18 Most of the existing capacity is in
19 industrial applications. Very small commercial
20 and institutional is only about one-seventh of the
21 installed capacity currently. But when you look
22 at sites and the number of sites that are deployed
23 right now more than two-thirds of the sites are in
24 commercial and institutional applications today.

25 And we've got various sectors and size

1 ranges that have had success in doing this and
2 it's schools and colleges and hospitals, waste
3 water. You know, these classic, easy, low-hanging
4 fruit applications and then some that are a bit of
5 a stretch that are doing well in California in
6 hotels and health clubs and nursing homes.

7 And a lot of those projects really came
8 about in the last five years under the self-gen
9 incentive program because the incentive that was
10 provided there made the difference in terms of the
11 hurdle rate for the investment.

12 So there's still a lot of technical
13 potential in California. We would say that two-
14 thirds of the opportunity is in commercial and
15 institutional applications but we're talking about
16 sites when we say that. There's still a
17 substantial opportunity in industrial systems as
18 well but a lot of the potential is in these
19 smaller systems.

20 So cost-effectiveness is part of the
21 test that I have seen in various pieces of
22 legislation. And, you know, I think the message
23 here is that CHP is generally installed to be as
24 efficient as possible because that's where the
25 investment makes sense. You know, you wouldn't be

1 throwing away a portion of the system's
2 production. You would size the system to utilize
3 the maximum amount of power and heat from the
4 system.

5 And typically the best investments have
6 been, at least in the last five years, where you
7 can offset retail power at the site and use all
8 the power on the site. It just helps with the
9 payback. That's not to say that there aren't
10 substantial opportunities still in industrial
11 applications where they would be producing excess
12 power and looking -- well, where they could
13 produce excess power if they had the ability to
14 sell it. But low-hanging fruit, again, would be
15 where you are using all your power and heat on-
16 site.

17 One of my points I would like to make
18 here is that the cost-effectiveness test is really
19 up to the site at this point to decide. If they
20 are investing in an on-site power and heat system
21 the question of what their hurdle rate, you know,
22 what this system has to do economically, from
23 anything that I have ever seen, is up to the site
24 to decide. You know, they may have a ten year
25 investment criteria, they may have a two year

1 investment criteria. And it depends on what
2 problems it solves for them and whether they go
3 ahead or not.

4 So what makes CHP possible in California
5 even in a schizophrenic environment is that in
6 general we do still have a favorable spark spread
7 here. It's not ideal. Gas is high and the
8 investments get more and more marginal and we see
9 a slowdown. But essentially if you take into
10 account the thermal, you know, we can generate
11 power for about five cents with \$8 gas. So that's
12 you know, a two second version of CHP economics.

13 So market factors affect everything.
14 And part of the problem actually is volatility,
15 it's a huge piece of it, and uncertainty. And I
16 don't think we can change that by waving a magic
17 wand right now. That we are in a changing
18 environment and it is very difficult for the
19 private sector to make investment decisions in a
20 changing environment.

21 But part of what helps about having
22 clear policies in place is that demonstrates to
23 those investors that even in a changing
24 environment the powers that be support what they
25 are trying to do and will lead them, are going to

1 help them go in the right direction. So that is
2 one of the benefits, even of small incentives or
3 even of efforts such as this.

4 So market opportunities, I've already
5 talked about this a little bit. There are a lot
6 of emerging opportunities and if we are really
7 looking for deployment, if and when there is some
8 kind of a standard or some kind of a goal set up
9 in the state to get more CHP. Going after it on a
10 sector-specific basis is a good way to approach it
11 and is one of the things my program does.

12 So the impact of enabling policies on
13 cost-effectiveness and customer acceptance. You
14 know, there's a couple of different classes of
15 ways we can craft policies that help to get good
16 CHP deployed. Incentives provide capital
17 recovery, they reduce operating costs, they add
18 revenues streams and they increase customer
19 acceptance.

20 It's back to what I just mentioned.
21 That even a small incentive to an end-user -- you
22 know, there are other states where they're going
23 to get \$3,000 if they do this, you know, on a
24 \$500,000 system. But the effect on the customer
25 of knowing that someone has said there is a public

1 benefit to doing this project and we recognize
2 that through a small incentive, or any incentive,
3 it does help, even if it doesn't change the
4 investment decision. You know, it doesn't reduce
5 your payback by more than a few months.

6 Grants are fantastic and we did see a
7 lot of CHP get deployed in the state while the
8 self-gen incentive program was available for CHP
9 projects. Gas incentives such as you currently
10 have in place on the cogen transportation rate
11 reduce operating costs throughout the life of the
12 project and I found to be an excellent mechanism
13 to help get these projects deployed, especially
14 thermally base-loaded projects.

15 And then this potential for
16 environmental revenue streams is really an
17 emerging area that may really help projects a lot.

18 To go along with that we had talked
19 about barriers and the other bundle of policies
20 that are very, very important have to do with
21 removing the unintended barriers and streamlined
22 or simplified interconnection, output-based
23 emission standards, fair and justifiable standby
24 rates and having other sorts of policies recognize
25 and reward the public benefits of clean DG when

1 being considered are very, very important here.

2 In a lot of ways what they will do is
3 provide an added level of certainty to the people
4 who are trying to develop these projects. That
5 there is not just this question of well okay,
6 we've got this great project and it's got a five
7 year payback and that works for you. And you're
8 going to go forward with it except we can't
9 quantify how much time or how much cost is going
10 to be involved in getting your interconnection.
11 It could be \$10,000 in three months or it might be
12 \$2 million in two years, and you'll just have to
13 wait and see. That is the kind of barrier that
14 absolutely kills projects. And any kind of
15 certainty we can add in there is very helpful.

16 I'm going to give a couple of examples
17 of some of the incentives and how they actually
18 affect people's ability to do a project. And this
19 is an example of some cogen gas rates. One is
20 from California and the other one is from New York
21 State. And this is just, you know, we're modeling
22 a system that's a 925 kW thermally baseloaded
23 system at a hospital.

24 The PG&E gas transportation rate -- now
25 these are from 2004 and I'm not sure I have the

1 latest, greatest rate but what I am trying to show
2 on the sensitivity will show up regardless.

3 The boiler transportation rate, the gas
4 without a CHP system, 75 cents NMM BTU in summer,
5 99 cents in winter. The CHP transportation rate,
6 15 cents NMM BTU. So that boiler no longer needs
7 any gas. You're paying for a CHP system that
8 provides you with all of your thermal energy and
9 an additional incremental amount of power on top
10 of that.

11 So we can see, you know, what is the
12 difference in terms of payback on a project. The
13 bottom line is tracking on gas rates, And this
14 was \$4 low. This is definitely a few years old.
15 I don't know if anyone expects a \$4 gas rate any
16 time again. But at the time I think we were at
17 about \$6 when we ran this analysis.

18 And, you know, basically with the CHP
19 discount that curve flattens out. Your
20 sensitivity to gas rate increases is much lower.
21 And it's because you're offsetting purchased fuel
22 for a boiler. So where you would have bought fuel
23 for your boiler that would have gone up anyway at
24 this point you're buying an incremental additional
25 amount of CHP fuel at a lower rate. And this

1 helps a lot in terms of that investor risk.

2 Key Span in New York State has also got
3 a boiler, a CHP gas transmission rate in place and
4 this one has even a larger impact. Now our
5 overall project economics are looking a lot better
6 in New York because believe it or not they
7 actually have higher utility rates. So this is,
8 you know, we're down in this range of two or three
9 years or so on a payback with the cogen gas rate.

10 But once again we can see the effect
11 here is to level off the risk. It's to reduce a
12 little bit of the risk for the end user to reward
13 the fuel efficiency. Because when it really comes
14 down to it combined heat and power is a fuel
15 efficiency measure, natural gas efficiency.

16 Environmental revenue streams, I'm going
17 to cover this in about two minutes because this is
18 completely emerging and I just want to point out
19 the effect on a project economics of some of these
20 revenue streams. And, you know, we could be
21 talking about basic emissions programs. NOx
22 trading, offsets, emission reduction credits. We
23 can also be talking about portfolio standards and
24 RECs. And in some places where CHP has been put
25 into people's RPS they now have REC-like, tradable

1 -- I think they're calling them white tags in some
2 places, the name is still emerging.

3 And we are about to publish a major
4 report going through all of these types of
5 environmental revenue streams and the impact they
6 can have on projects. So we looked at both, you
7 know, a renewable project, a landfill gas project,
8 and a CHP plant. And baseline economics, you
9 know, based on today's situation. You know, we've
10 got about a six-and-a-half year payback on these
11 systems. The cost to produce power on the
12 systems, you know, ranging in the CHP systems to
13 about six to seven cents or six to eight cents.

14 So the value of the revenue streams is
15 really going to vary like crazy. Every state will
16 be different, every single trading program will be
17 different, it depends on what you're doing at the
18 site. If you were by any chance shutting down an
19 oil-fired boiler and putting in a gas-fired CHP
20 system there's obviously a lot of potential upside
21 there. But I think --

22 Let's just get to the bottom line. You
23 know, emission reduction credits, you know, can
24 range, they can be fairly high. These are, these
25 are annual values. And this is based on a

1 modeled, giant report and these are just the
2 outcomes. When we get into things like the RECs
3 and, you know, you see the impact on a landfill
4 methane project of RECs is a massive \$1.4 million
5 potential. I think that's based on New Jersey or
6 something.

7 But then even on the gas-fired CHP where
8 it's recognized we're talking about some
9 different, some environmental revenue streams. I
10 would say that, you know, a \$45,000 environmental
11 revenue is not going to make or break a project.
12 But what it does do is it tells the investor this
13 is a recognized public benefit that we are willing
14 to put our money behind. And therefore they can
15 have more certainty in going forward.

16 So that is a quick run-through and I
17 thank you all very much. And a thank you to the
18 Commissioners for giving me this opportunity.

19 PRESIDING MEMBER PFANNENSTIEL: Thank
20 you, Ms. Crossman.

21 Are there questions from the dais? Yes,
22 Commissioner Geesman.

23 ASSOCIATE MEMBER GEESMAN: Thank you for
24 being here. In recent years we have seen a pretty
25 aggressive return of standby rates and demand

1 charges. You mentioned that you maintain a
2 database of best practices. Would that database
3 have information as to best or better practices
4 regarding standby and demand charges?

5 MS. CROSSMAN: Yeah, we have sort of two
6 different approaches to that. I maintain a
7 database of exactly what's happening in every
8 single state, so we've got that. That's the, you
9 know, where are we now question.

10 But we also have a group that does
11 nothing but work with utility commissions and with
12 best practices. We have a fact sheet on our
13 website that's updated with about five or six
14 different major policies that help or hurt clean
15 DG. We update that probably once a month, my
16 colleague does. That tells us exactly, you know,
17 here are some examples of what's happening and
18 what's being done in all these states and even
19 gives a compendium of where each state is right
20 now. So all of that is available right now.

21 And we are also happy to work with
22 people to just ad hoc provide any kind of
23 information.

24 ASSOCIATE MEMBER GEESMAN: Thank you
25 very much.

1 PRESIDING MEMBER PFANNENSTIEL: Other
2 questions?

3 ASSOCIATE MEMBER BYRON: Excuse me,
4 Madam Chairman.

5 PRESIDING MEMBER PFANNENSTIEL: Yes.

6 ASSOCIATE MEMBER BYRON: I just noticed
7 that Commissioner Boyd may have snuck in here in
8 the back momentarily. Commissioner, you have been
9 a big proponent of DG for a long time. I know you
10 may not be able to stay very long. Did you want
11 to add anything while you were here?

12 COMMISSIONER BOYD (FROM THE AUDIENCE):
13 No, I am just a big proponent of it.

14 (Laughter.)

15 ASSOCIATE MEMBER BYRON: Okay.

16 Kim, I'm really glad that you made all
17 the effort to be here. And I noticed you flew out
18 a day early too so you wouldn't, so you'd be here.
19 I think you had a problem at the ARB when you came
20 out recently.

21 I think it is really interesting that
22 the EPA is involved in this activity and we talked
23 briefly about this. Can you briefly describe why
24 the EPA is spending taxpayer money on this issue.

25 MS. CROSSMAN: Well it's because we can

1 measure the emissions reductions associated with
2 clean DG. I mean, there are a suite of reasons, a
3 suite of public policy reasons why this kind of
4 thing makes sense. And our colleagues over at the
5 Department of Energy also spend money and time
6 working on this because they care about, you know,
7 load pockets and they care about other benefits to
8 the grid and other things along those lines.

9 For EPA we are kind of a one trick pony
10 agency. We care about emissions reductions and
11 this is a big part of our global warming strategy
12 in the agency. CHP is sustainable in the sense
13 that it is cost-effective. It gets us the
14 emissions reductions. And we can do that without
15 causing too much heartache or headache. On a
16 voluntary basis help people look at this and help
17 them do it.

18 And then at the end of the year I can
19 measure what that looks like in terms of a
20 reduction and what it means in terms of cars taken
21 off the road or acres of trees planted.

22 ASSOCIATE MEMBER BYRON: You had
23 mentioned that you thought our policies were
24 somewhat schizophrenic here in the state. Maybe
25 they're paranoia based.

1 (Laughter.)

2 ASSOCIATE MEMBER BYRON: But I was
3 wondering if you could give us a sense, with your
4 perspective, of all the different states that
5 you're working with. Is there one or two things
6 in particular that we should be concentrating our
7 efforts on to correct in California in order to
8 open up distributed generation and CHP?

9 MS. CROSSMAN: I think that you're
10 facing -- back to Commissioner Grueneich's mention
11 of AB 32. I think you are facing an interesting
12 moment where the criteria pollutant thought
13 process, the current air regulation scheme and
14 controlling greenhouse gas emissions, are not the
15 same thing. And I think that there is going to be
16 some challenges in terms of marrying up those
17 types of regulations and how you actually reduce
18 greenhouse gas emissions.

19 And I see that both of your agencies,
20 commissions, as well as ARB are going to have a
21 lot of work to do to figure out how to do that in
22 a way that makes sense. And it is going to have a
23 huge impact down the road. You know, I would say
24 that because I'm from EPA. We're watching very
25 closely and are very, very interested.

1 On just a straightforward side. If in
2 fact clean distributed generation is a piece of
3 the picture here I think the two things I would
4 hope is that if efficiency has incentives and
5 renewables have incentives and demand response
6 have incentives in this state, and clean DG is
7 recognized as another piece of the solution within
8 those same bundles, I would hope that it would
9 also be considered that it would be helpful to
10 have incentives in place.

11 There's been great work done on, you
12 know, in the past the standby issue was handled
13 well. I would hope that there would be continuing
14 through process given to that as well.

15 It's interesting, it's like things move
16 in the right direction for a couple of years and
17 then they just move right back. I think to grow
18 and maintain an industry that can do this in the
19 state. It would be helpful to have some kind of a
20 clear direction. And that's more of a process
21 answer than a, you know, prescription. A self-gen
22 incentive program? Okay.

23 ASSOCIATE MEMBER BYRON: Thank you.

24 MS. CROSSMAN: You're welcome.

25 PRESIDING MEMBER PFANNENSTIEL: Thank

1 you very much. Thank you for both being here and
2 for your very useful insights.

3 Now I turn it back to John.

4 MR. SUGAR: Thank you. And what I will
5 do is in the interest of time present the
6 conclusions of the roadmap so we can present
7 discussion.

8 Again, we have blue cards at the back.
9 Following this I'd like to go through and if you
10 do have a blue card, if you'd like to speak,
11 please put it out where I can get to it and then
12 we can get those up to the Chairman to move
13 discussion along.

14 The DG and cogeneration vision for 2020
15 in the roadmap report called for California's
16 portfolio mix to be diversified with central
17 generation, demand response, energy efficiency,
18 distributed generation and cogen. The vision
19 included a market that allows DG and cogeneration
20 to compete with central plants on an equal footing
21 and it foresaw that DG and cogeneration would
22 provide over 25 percent of the state's peak
23 demand.

24 For those of you who have read through
25 the report you have seen that the forecast

1 includes a change of technologies over time with
2 photovoltaics growing significantly, combined heat
3 and power increasing some. Over time DG
4 technologies taking a larger portion of the total
5 from large cogeneration projects.

6 In the vision customers would have
7 multiple options including distributed generation
8 and cogeneration as part of their resource
9 strategies. DG and cogeneration would be integral
10 to utility procurement, transmission and
11 distribution planning and operations, and it
12 foresaw a distributed generation industry that was
13 robust, filling utility and customer needs.

14 Large cogeneration would be readily,
15 would readily participate in the wholesale power
16 market. There would be transparent, dynamic rates
17 in place which would account for the environmental
18 attributes of distributed generation, locational
19 benefits and costs and time-dependant benefits of
20 these technologies. The renewable portfolio
21 standard would be satisfied without additional or
22 the need for additional incentives and DG
23 permitting would be efficient and environmentally
24 responsible.

25 Now the overall strategies to attain

1 this vision that were in the report include
2 supporting incentives in the near term, having a
3 transition to new market mechanisms over the
4 longer term, and then in the long term reducing
5 remaining institutional barriers to distributed
6 generation.

7 Near term incentives would include tax
8 credits for capital expense for renewable and
9 clean DG, continued self-generation incentive
10 programs and emerging renewable program efforts,
11 supporting renewable and clean DG systems with
12 low-interest loans and providing value for
13 environmental attributes in the near term
14 including production tax credits for criteria
15 pollutants and CO2 emission reductions.

16 The transition to new market mechanisms
17 would include development of renewable and CHP-
18 distributed generation, expanding it with a
19 portfolio standard, establishing market mechanisms
20 to allow DG to compete with central plants and
21 traditional transmission and distribution, and
22 creating access to emissions markets to include an
23 appropriately valued DG and cogeneration.

24 Reducing remaining institutional
25 barriers would include instituting an analytical

1 framework for distributed generation and cogen for
2 assessing the costs and the benefits, developing
3 rate designs allowing distributed generation and
4 cogen to be effectively integrated into the
5 electric power system, promoting distributed
6 generation through rules and standards development
7 and instituting an environmentally responsible
8 permitting process.

9 And then within that there were
10 specifics into which I do not intend to go. And
11 as soon as I find the escape button -- well maybe
12 the simplest thing to do is just go to the end.

13 So to start off our first speaker is
14 Snuller Price from E3 to discuss pricing.

15 CPUC COMMISSIONER GRUENEICH: Excuse me.
16 I have a question about the staff report. Would
17 this be appropriate?

18 I think you had it up on a slide a
19 figure, at least in the staff report it's Figure 6
20 on page 25. It's the curve, the upward curve. On
21 the left hand side I'm just -- I want to make sure
22 I understand. Looking at the blue, the
23 photovoltaics. That's the portion that would be
24 covered under what we call our California Solar
25 Initiative and previously A Million Solar Roofs.

1 MR. SUGAR: Yes.

2 CPUC COMMISSIONER GRUENEICH: Am I
3 correct?

4 MR. SUGAR: I believe so.

5 CPUC COMMISSIONER GRUENEICH: Do we have
6 a number then for looking at where we are now in
7 our baseline to where the 2020 vision would be for
8 essentially the non-solar portion of what the
9 delta change would be? In other words I'm trying
10 to figure out, you know, how much of a hill we
11 need to go up. Do we have those numbers either in
12 the report or if there would be an opportunity to
13 have them provided?

14 MR. SUGAR: They are not in the report.

15 CPUC COMMISSIONER GRUENEICH: Okay.

16 MR. SUGAR: We can look those numbers up
17 and get them to you.

18 CPUC COMMISSIONER GRUENEICH: Okay,
19 great. Thanks.

20 MR. PRICE: Good afternoon, thanks for
21 having me. In the next -- My name is Snuller
22 Price. I'm a partner with Energy and
23 Environmental Economics and I was asked to say a
24 few things about the DG roadmap vision on the
25 tariffs.

1 So I think as John laid out we are going
2 to have a few topics. My goal is to spend five
3 minutes or so to sort of give the group my
4 reaction to what was in the DG roadmap for retail
5 rates and tariffs and a quick reaction to it to
6 sort of start discussion in this topic area.

7 I borrowed from one of the tables that
8 you'll find in the report that talks about, what's
9 the situation with the rate structures, at least
10 in 2005, and then what is the vision for 2020?

11 In the roadmap the situation that's laid
12 out is sort of the current situation for rates for
13 DG are that energy prices are not transparent and
14 they inhibit customer response to actual costs.
15 That the current rate structure is based on sort
16 of a controlled average pricing. It doesn't
17 include locational environmental pieces. That
18 it's difficult for DG to participate in the
19 wholesale power markets and it's difficult for
20 cogen to execute new contracts with utilities.

21 That's the situation as it's
22 characterized. And then looking ahead to 2020 the
23 goal is to make rate structures more transparent,
24 connected to markets, take extra analities and
25 internalize them in rates so that you can get

1 credit for improvements in environmental impacts
2 as well as T&D constraints, and to allow customers
3 to more easily participate in the wholesale energy
4 markets. That's just the quote, the table from
5 the DG roadmap.

6 When I read through the DG roadmap I
7 tried to take all that and sort of summarize it
8 into, well what does this mean. This little
9 diagram is, I think, what I got anyway, one vision
10 of what's in there. And maybe during the
11 discussion other people can have their input on
12 what they thought it meant.

13 I think the idea is on the left hand
14 side I've got adding different components together
15 to get to the DG retail rate. There are dynamic
16 prices perhaps from the MRTU that's coming up,
17 there are some capacity costs, there are CO2
18 offsets or environment, and there are other
19 components sort of bundled together, okay.

20 Because we've got dynamic prices in here
21 we have some more intelligent metering, I'm
22 thinking AMI. And I'm thinking that the meter is
23 smart enough so that you can, you can go either
24 way. So you can buy energy at a cost that's the
25 sum of these things or you can sell. And if the

1 market prices are right then you can buy or sell
2 and you can go either way.

3 Now there are -- If you notice the rate
4 there are sort of two categories. There are these
5 sort of energy-related components, which is energy
6 losses, as Kim had mentioned. Environment. There
7 are sort of these energy-related costs and those
8 are represented by the MRTU.

9 There is also generation capacity,
10 transmission and distribution capacity and fixed
11 costs that also need to be collected. And I'm
12 going to talk a bit about that because I think
13 that's going to be really the crux.

14 But the concept is, if you get all of
15 these pieces right and all of the costs right then
16 you can have a market where the owner of the DG is
17 actually looking at what's there in terms of
18 market signals and they can participate in the
19 market by buying or selling. So think that's the
20 vision looking ahead 2020 for what we could do
21 with the retail rates.

22 Now how do we get there? And this was
23 really intended to sort of kick off discussion.
24 What are the issues that we have going from what
25 we have now towards something that looks like

1 this? And I think that the big one to me is how
2 do we allocate fixed costs and rates? So it is
3 very difficult to have your AMI meter there
4 sitting there and be able to buy and sell at the
5 same price all the time and still collect your
6 fixed costs.

7 So how are we going to do that? And
8 included in that I can include generation
9 capacity, transmission and distribution capital
10 costs. And then rate forms that have those costs
11 that vary with, you know, how those costs are
12 incurred are often and have long been considered
13 anti-DG.

14 And everybody in this room knows the
15 discussions there but fixed customer charges,
16 demand charges, ratcheted demand charges. There
17 are a lot of other ways to take and put fixed
18 costs on those and to collect those. So I think
19 that that's going to be a major issue in terms of
20 how do you do the DG retail rates.

21 And then the second piece, which is
22 related is, how do the distributed generators sell
23 capacity back? What are the rules going to be for
24 a distributed generator to be able to get a
25 capacity payment and how are those going to be

1 structured. You get into the issues of
2 reliability, you get into issues of who controls
3 the dispatch of the generator. You get into
4 issues like physical assurance on how reliable is
5 the generator in order to be able to get a credit
6 back for your capacity piece.

7 And also with that I think that an
8 important issue is that the opportunity sell back
9 capacity depends a lot on where you're at. So if
10 you're a generator that's going to be sited in a
11 new development that's completely greenfield there
12 might be a significant amount of capacity that you
13 could sell and earn versus a constrained area, a
14 load pocket where you could probably provide value
15 to an unconstrained area where there really isn't
16 a capacity constraint and you're not really going
17 to get a local capacity value. So there's going
18 to be big differences in terms of the value of DG
19 by area.

20 So with those two lively issues I guess
21 the last one that I sort of threw out there is
22 applicability of the rates and whether or not
23 we're talking about retail rates for just
24 distributed generators or whether we're talking
25 about rates for all customers, okay. So what's

1 sort of the scope of the idea in terms of getting
2 from here to there.

3 If we've got -- You could make an
4 argument if we've got all the costs right and
5 we've got the right incentives to invest in DG
6 then why wouldn't we use that same rate to give
7 customers the right incentive to buy into energy
8 efficiency or into any other capital purchases?
9 So why would they necessarily be DG rates? Of
10 course when you broaden the scope you've got a lot
11 of other issues about bill impacts for large
12 numbers of customers, et cetera.

13 So those are the three sort of
14 discussion items that I took away from looking at
15 the DG roadmap.

16 And I think with that should I turn it
17 back to --

18 PRESIDING MEMBER PFANNENSTIEL:
19 Questions from the dais first.

20 MR. PRICE: Questions.

21 PRESIDING MEMBER PFANNENSTIEL:
22 Commissioner Geesman.

23 ASSOCIATE MEMBER GEESMAN: Snuller, I
24 wonder if you could go back to, I think it was
25 your second slide.

1 MR. PRICE: This one?

2 ASSOCIATE MEMBER GEESMAN: No. You were
3 just on it.

4 MR. PRICE: Sorry.

5 ASSOCIATE MEMBER GEESMAN: That one.

6 Could I rewrite that second bullet so that rather
7 than rates signal customers it said, costs signal
8 regulators to make the right choices about utility
9 procurement. Because it seems to me that we
10 authorize the utilities to procure electricity.
11 The stuff that they're procuring today is pretty
12 profoundly inefficient, pretty profoundly carbon-
13 unfriendly or climate change unfriendly. They're
14 doing it in all of our names.

15 We have had nominal policies for 25
16 years to promote a different way of looking at
17 things. Our current system fails to properly
18 integrate thermal loads with electrical loads.
19 We've got this distorted policy configuration
20 where we try and fit square pegs into round holes
21 and pretend that every cogenerator or every
22 distributed generator is a merchant power plant.

23 Shouldn't there be more of a burden on
24 regulatory policy than the way you're second
25 bullet frames it?

1 MR. PRICE: Perhaps. I guess the
2 regulatory policy could be to develop the rates
3 and so that you're trying to get all of the right
4 economic signals in the rates and do that. Or
5 perhaps what I'm kind of hearing from you is more
6 of a portfolio-type approach where you're just
7 asking for a particular, you know, a different mix
8 of resources to be purchased.

9 And I think that's a choice, you can go
10 either way. Either a portfolio approach where
11 you're going to be, you know, by this type, you
12 know. And depending on how, how scripted you want
13 to be you could be very specific about what should
14 be in that portfolio. Or you can be much broader
15 in terms of, you know, let's set prices at cost
16 and allow more flexibility.

17 I don't know if that makes sense to you.

18 ASSOCIATE MEMBER GEESMAN: I just wonder
19 if we'd been a bit more consistent over the last
20 couple of decades about encouraging this focus on
21 efficiency in this effort to combine thermal and
22 electrical loads would we find ourselves in the
23 situation that we are today where the ISO suggests
24 a massive increase in locational capacity
25 requirements in Southern California. Or where the

1 CPUC directs Edison, go out and build peakers,
2 build them fast, build them expensive.

3 It seems to me when we make choices like
4 that every day or every year the notion that it's
5 just a function of finding the right flavor of
6 cheese to put in front of the mouse and then get
7 the mouse to do what would be in the mouse's best
8 interest to me seems an over-simplification.

9 But thank you for bearing with me.

10 PRESIDING MEMBER PFANNENSTIEL: You know
11 in your last point in the issues down the road,
12 what is your point of view? Do you think there
13 should be DG-specific rates or rates that are
14 designed according to the sort of principles that
15 were inherent in what you're describing that then
16 would be applicable to all customers?

17 MR. PRICE: The economist in me would
18 love to say we should get the rates, you know, to
19 be dynamic and reflect as closely as we can the
20 real marginal costs. But, you know, I think that
21 there are a lot of tradeoffs in rate design,
22 complexity being one of them, understanding bill
23 impacts.

24 And so I think it would be very
25 difficult to get there with the rates that I'm

1 talking -- the concept of the rates that I'm
2 talking about for all customers. And maybe 2020
3 is a long time and maybe we could do that. But I
4 think it's a pretty -- it's a lofty goal but I
5 think difficult to get there.

6 PRESIDING MEMBER PFANNENSTIEL: But you
7 would think that DG customers would be better able
8 to handle those other, complexity and other public
9 policy issues?

10 MR. PRICE: I think so.

11 PRESIDING MEMBER PFANNENSTIEL: Thank
12 you.

13 Any other questions?

14 Thank you very much.

15 MR. SUGAR: Our next speaker is Eric
16 Wong from Cummins Power Systems.

17 MR. WONG: Good afternoon, my name is
18 Eric Wong. I am here on behalf of the California
19 Clean Distributed Generation Coalition, I serve as
20 its chair. I am happy to address the joint panel
21 of the Commissioners of the Energy Commission and
22 the Public Utilities Commission.

23 What I've just handed out to you, I
24 don't have a slide. I chose not to have a slide.
25 Sometimes people get, especially after lunch they

1 get a little bit glazed after looking at the
2 screen for so long, I do. I am going to walk
3 somewhat quickly through these.

4 What we have here is based upon our
5 written comments which were submitted last week of
6 the top seven concerns of the clean DG coalition.
7 I'm going to do this in a reverse order, in a
8 descending order, and I'm going to start with
9 number seven and work my way down.

10 Number seven is, integrate CHP storage
11 and renewable technologies. I'm actually checking
12 some of my editorial comments here. It should be
13 supported by both commissions and the Clean DG
14 Coalition urges both commissions to support the
15 demonstration of a micro-grid in California in
16 2007 or 2008.

17 And the reason for this is pretty
18 straightforward. Micro-grids can increase the
19 penetration of CHP and renewable technologies.
20 And later today during a comment period one of the
21 members of the coalition will be speaking more on
22 storage technologies with you and how that can
23 serve as a glue for CHP renewables and advanced
24 storage technologies in micro-grid situations.

25 Number six, CHP should not be subject to

1 non-bypassable charges and standby reservation
2 charges. I think I'm going to be answering some
3 of the questions that were posed by the panel of
4 Commissioners earlier. In the context of being
5 virtually identical to energy efficiency and
6 demand side management resources the mini-grid
7 environmental benefits and the state's
8 pronouncement that CHP is a preferred resource,
9 CHP should not be subject to such charges.

10 Number five, I'm going to get into
11 incentives for CHP. I don't believe this has been
12 brought before, before any of the commissions.
13 Gas procurement for customer-sited CHP should be
14 done by utilities on the same basis as is done by
15 utilities for their own power plants.

16 One of the biggest challenges to
17 customer-owned, customer-sited CHP is the
18 volatility in gas prices. So what I am proposing
19 here is something for brainstorming. I think this
20 is something that we can certainly engage in as a
21 colloquy of people here.

22 The next incentive I address is the
23 SGIP, which has been talked about before. As many
24 of you are following the legislative action on
25 this, it has been stripped out of the SGIP bill,

1 AB 1064. We would like to see it be reinstated
2 somehow into, into the program for combustion-
3 based combined to end-power.

4 The question earlier about what other
5 states are doing in terms of incentive programs
6 and I'm going to point you to Connecticut and
7 their energy independence law of 2005. There are
8 some excellent examples in that of various
9 incentive payment programs. There are three that
10 are worth noting. The one-time capacity payments
11 to CHP for congestion relief, there is incentive
12 payments to CHP that are part of resource
13 adequacy, and lastly there is incentive payments
14 to the utility for education and assistance
15 programs to get CHP to participate in resource
16 adequacy.

17 Number four, working my way down. CHP
18 is a baseload resource providing reliable capacity
19 and energy is indisputable and should be
20 explicitly included in utilities' resource
21 adequacy requirements and the long-term
22 procurement process. The CEC has done several
23 seminal reports quantifying the economic potential
24 of CHP. Utility forecasts must assume a
25 reasonable economic penetration of CHP over the

1 playing horizon and explicitly include CHP
2 megawatts as meeting resource adequacy
3 requirements.

4 Number three, CHP's reduced carbon
5 impact compared to central station power plants
6 merits evaluation in tariffs and/or to be a
7 commodity in greenhouse gas trading programs.
8 Natural gas combined cycle power plants have an
9 efficiency range in the high 40s to the mid-50
10 percent. CHP units regularly exceed these ranges
11 for central station power plants. Not only is CHP
12 a far superior way of conserving natural gas
13 resources but the carbon impact for greenhouse
14 gasses is unmatched. CHP therefore comports
15 squarely with the state's greenhouse gas goals.

16 Number two, this is just a one-liner.
17 The Coalition, the Clean DG Coalition seeks
18 completion of the cost benefit methodology by the
19 PUC in its rulemaking at the earliest practicable
20 date. This proceeding began in 2004 and was
21 suspended I believe in 2005. We would like to see
22 that completed as soon as possible.

23 Item number one, my last point. A CHP
24 portfolio standards should be adopted. A CHP
25 portfolio standard by the state of California

1 would elevate the importance of the technology in
2 the eyes of the nation and other states.

3 Greenpeace International and the American Council
4 for an Energy Efficient Economy, excuse me, all
5 strongly support CHP. The Sierra Club lists CHP
6 in its portfolio of preferred resources for the
7 transition to a clean energy future.

8 Long a leader on energy issues we urge
9 the California Energy Commission and the Public
10 Utilities Commission to lead once again.

11 That's the basis of my remarks, thank
12 you.

13 PRESIDING MEMBER PFANNENSTIEL: Thank
14 you.

15 Are there questions? Yes, Commissioner
16 Grueneich.

17 CPUC COMMISSIONER GRUENEICH: You
18 mentioned the Connecticut law. Do you have any
19 information as to how it has been implemented? I
20 think it says or your notes stated that it was
21 passed in 2005. Do we have any information as far
22 as any payments that have been made last year or
23 this year to date and, you know, how well its
24 doing?

25 MR. WONG: Commissioner Grueneich, I do

1 not have that at my fingertips. I'd be happy to
2 provide that later.

3 CPUC COMMISSIONER GRUENEICH: Okay.

4 MR. WONG: I don't know if anyone --

5 CPUC COMMISSIONER GRUENEICH: Because,
6 you know, it is very intriguing and it would be
7 interesting to see if it is getting payments out
8 there and then what that's doing in terms of
9 getting actual projects developed.

10 I was also quite intrigued with your
11 item seven and I read your comments on my train
12 ride here this morning. In the specific comments
13 it talked about suggesting that the PUC move
14 expeditiously in the PIER program and other
15 initiatives to have a micro-grid in operation at
16 the earliest possible date. Can you give us any
17 sense of what would be needed to, you know, if
18 collectively we said that was a good use of the
19 PIER money what it would take to make that happen?

20 MR. WONG: I can, there's two parts.
21 Are you speaking just strictly for the PUC or
22 both?

23 CPUC COMMISSIONER GRUENEICH: We don't,
24 we don't run the PIER program. So it says, the
25 PIER program and other initiatives so I'm fairly

1 indifferent. I was looking at the PIER program.
2 If there's a PUC initiative that would be pulling
3 this together I'm interested in that as well.

4 MR. WONG: Right. From the PIER program
5 I understand that the Energy Commission is moving
6 fairly, I was going to say rapidly. But they're
7 taking steps to have a micro-grid in California, a
8 demonstration. I believe Navigant Consulting is
9 doing this for the PIER program. And there may be
10 someone else on the staff that can speak with a
11 lot more detail on that.

12 I've been contacted, I'm sure they've
13 contacted a lot of other industry people. Cummins
14 Power Generation as well as other members of the
15 Clean DG Coalition are fully capable of having a
16 micro-grid work. The interesting or the most
17 challenging part of it is having the power
18 electronics to make sure our loads and resources
19 are balanced and there's no back feeds into the
20 utility distribution system.

21 Which leads us back to the other side of
22 the coin, Commissioner Grueneich, and that is what
23 the PUC must do, or at least consider, and that
24 would be the over the fence from a resource,
25 distributed generation resource is combined heat

1 and power going across the street or over the
2 fence. And that invokes I think it's Section
3 2185.5 of the PUC Code which talks about
4 prohibitions about going beyond over the fence.

5 So you can do it to the left or right on
6 the same side of the street but in a true micro-
7 grid you may have a distribution feeder circuit
8 that goes much farther than that. And the PUC
9 would have to, at least in my opinion for the
10 demonstration, waive that requirement.

11 CPUC COMMISSIONER GRUENEICH: I haven't
12 dealt with it for a couple of years. My memory is
13 that's in statute, the over the fence requirement.
14 I know you're not a lawyer, not to put you on the
15 spot, but I'm interested if any of my Energy
16 Commission colleagues have a sense. In order to
17 do a demonstration of a micro-grid do we perhaps
18 collectively have to look at some exemption from
19 the existing law?

20 ASSOCIATE MEMBER GEESMAN: I don't think
21 we've identified that as a barrier to the PIER
22 effort.

23 CPUC COMMISSIONER GRUENEICH: Okay.

24 ASSOCIATE MEMBER GEESMAN: We may very
25 well need to dig into it further but I don't think

1 that's been seen as an impediment.

2 CPUC COMMISSIONER GRUENEICH: Okay. So
3 is it that we don't have any impediment or that
4 there is? Again, you may not know. But if there
5 is an impediment because of the over the fence
6 restriction that would be one that the PUC could
7 lift if it were done, closer working together on
8 the PIER program between the Energy Commission and
9 the PUC.

10 ASSOCIATE MEMBER GEESMAN: I think
11 that's right, I think that's right.

12 CPUC COMMISSIONER GRUENEICH: Okay.
13 Well let me just say on behalf of my agency, if
14 there is anybody at the CEC who is working on the
15 PIER program, because I am very interested in
16 making sure that there is better coordination
17 between the CEC and the PUC on the use of PIER
18 monies, let me know if there is something we
19 should be doing because we'll certainly step up to
20 the plate if we can.

21 PRESIDING MEMBER PFANNENSTIEL: Anything
22 else? Thank you very much.

23 MR. WONG: Thank you.

24 MR. SUGAR: Our next speaker Don
25 Schoenbeck.

1 MR. SCHOENBECK: Good afternoon, I'm Don
2 Schoenbeck. I'm here on behalf of CAC and EPUC.
3 I do not have a slide presentation either. I was
4 flying in from Boston last night and my flash
5 drive crashed. So the presentation is gone but I
6 do have a few points to make.

7 But first let me say who I am here on
8 behalf of. The Cogeneration Association of
9 California and the Energy Producer and Users
10 Coalition is made up of very large industries.
11 More specifically it includes the companies of
12 British Petroleum, Chevron/Texaco, ConocoPhillips,
13 Exxon and Shell. These are obviously companies
14 that have a great deal of CHP already operating in
15 the state. Collectively it's in excess of 1500
16 megawatts of CHP facilities.

17 I think much more important than that
18 though is the additional potential these companies
19 have to offer to the state. This potential is in
20 excess of 1,000 megawatts. What you heard earlier
21 from Kim Crossman is how important it is to do a
22 thermal matching in the -- in sizing for CHP to
23 maximize the benefit, to maximize the efficiency.

24 For my clients, to give you an example,
25 if they would size their CHP facility to match

1 their electrical load the resulting installation
2 or system would be approximately 50 to 100
3 megawatts. On the other hand since they are so
4 energy intensive, so thermally intensive, if they
5 would size the CHP facility to match their thermal
6 system it would be in the range of 200 to 500
7 megawatts.

8 Now everyone would agree that it's much
9 more efficient to build a larger system. You get
10 far more greenhouse gas reductions, you get a much
11 more reliable system. But there is a risk that
12 comes with building the thermally matched system
13 and that's to get sufficient revenue to pay back
14 the capital cost and the operating cost of this
15 much larger system.

16 So that's effectively the essence of my
17 talk is that for CHP, the CHP industry, size
18 matters. As the projects get larger the effective
19 heat rates get smaller. For our clients if they
20 would do a 50 to 75 megawatt installation the
21 effective electric heat rate would be in the range
22 of 11,000 BTUs per kilowatt hour.

23 To the extent they can build a combined
24 cycle plant with the technology in excess of 250
25 megawatts that heat rate would go down to 7,000

1 just on an electrical basis. Once you acknowledge
2 the thermal credits from the steam load you get
3 effective heat rates much closer to the 5,000 BTU
4 per kilowatt hour range for a new repower of an
5 existing CHP facility.

6 What this means, since we all know in
7 greenhouse emissions the amount of emissions you
8 could add is directly correlated, the amount of
9 fuel that's burned. To the extent you can put in
10 a more efficient CHP system the whole state is
11 better off.

12 Now the roadmap report for the most part
13 focuses on distributed generation and uses a
14 somewhat arbitrary cutoff line that it be
15 connected to the distribution system or that it be
16 less than 20 megawatts. I'd like to simply point
17 out that with respect to the size that it's really
18 an arbitrary value.

19 And if you look at transmission
20 customers on the utility systems in this state for
21 both PG&E and SCE where they have collectively in
22 the range of 300 transmission customers their
23 average size load on the transmission system is
24 less than four megawatts for PG&E and just five to
25 six megawatts for SCE.

1 So to say that just because you're
2 connected to the transmission system does not
3 necessarily mean you're going to be a 20 megawatt
4 project or larger if you want to achieve your goal
5 of trying to gain 5400 megawatts that the roadmap
6 says is your target by the year 2020.

7 So what do you need to do in this state
8 to actually get there? We think, in fact, that
9 you do need to incent CHP facilities and there are
10 several things that need to be done. First of all
11 you have to create a sink, that is a must-take
12 obligation, for the surplus power that goes beyond
13 the needs of the site. This is absolutely
14 required.

15 What goes hand in hand with that is also
16 that the revenue streams be assured from the
17 surplus power and that the contract have a term
18 that's sufficient enough to recover the capital
19 costs of these very expensive installations. And
20 I think you saw in Ms. Crossman's chart how the
21 payback period for these systems at very high gas
22 prices is many years out into the future. So you
23 need a contract for ten years that can provide an
24 assured revenue stream so it can be financable and
25 built.

1 Just as important I think the revenue
2 stream should reflect the local, occasional
3 benefits from transmission and distribution,
4 capital expenditures, as well as any cost or
5 credit of any greenhouse gas or environmentally
6 regulated obligation.

7 In at least one instance one of our
8 clients was almost successful in being a winning
9 participant in a utility RFO but for the fact that
10 the utility would not allow any pass-through of
11 additional environmental rules and the associated
12 costs, should they occur, during the term of that
13 contract. So it's very important that any such
14 costs, such as a carbon tax that comes into being,
15 can be passed through in these types of contracts.

16 I think just as important there needs to
17 be no NBCs or non-bypassable charges assessed to
18 the load. This is a state where ever since the
19 energy crisis it has been proposing such charges
20 and that needs to be relooked at and we'd
21 certainly recommend the NBCs be dropped.

22 And finally there is another part of the
23 roadmap that talks in terms of for larger cogens
24 they should be able to participate in the market.

25 I can stand before you today and say

1 these are some of the most sophisticated
2 companies. But when it comes down to the
3 operational level they don't want to be market
4 participants. They simply want to run their core
5 business, be able to sell -- be able to have the
6 utility take the surplus power that they do not
7 need and go about their business. So therefore we
8 think the utilities should continue to be the
9 scheduling coordinator and be the interface
10 between their entity and the ISO.

11 So those are my thoughts and thank you
12 very much for allowing me to appear before you
13 today.

14 PRESIDING MEMBER PFANNENSTIEL: Thank
15 you for coming and sharing your thoughts with us.
16 Are there questions from here? Yes.

17 CPUC COMMISSIONER GRUENEICH: What is
18 the approximate current amount of large
19 cogeneration in California?

20 MR. SCHOENBECK: If you're talking about
21 -- the numbers I have are a little bit different
22 than what Ms. Crossman showed. I have about 150
23 megawatts of generation that's come through the
24 SGIP program. With respect to the contractual
25 cogeneration that SCE has and PG&E has that's more

1 in the range of 4,000 megawatts for just those
2 utilities. So in other words, Commissioner
3 Grueneich, I don't have a statewide number.

4 CPUC COMMISSIONER GRUENEICH: Because,
5 again, I'm on the chart in the staff report, Table
6 7, which breaks out the 2020 vision. And it shows
7 for large, total large generation under division
8 in 2020 will be 11,200 megawatts. So I was just
9 wondering if you had a number that will compare to
10 what we have now.

11 MR. SCHOENBECK: The number I have as of
12 January 2007 was for the SGIP program. It's for
13 just about 150 megawatts from 284 contracts. And
14 this is where I do not have a statewide figure.

15 CPUC COMMISSIONER GRUENEICH: Okay.

16 MR. SCHOENBECK: For just PG&E and SCE I
17 have 4,625 megawatts of CHP for just those two
18 investor-owned utilities.

19 PRESIDING MEMBER PFANNENSTIEL: Go up to
20 the microphone if you'd like to comment.

21 MS. SHERIFF: Nora Sheriff, also on
22 behalf of CAC and EPUC. My understanding is that
23 the existing, large cogeneration facilities, that
24 is as they have been defined, facilities above 20
25 megawatts, 8,155 megawatts. So the 2020 vision

1 statement sees a goal of an additional 3,045
2 megawatts for large cogeneration facilities.

3 CPUC COMMISSIONER GRUENEICH: Thank you.

4 MR. SCHOENBECK: And I just say that's
5 defined as the over-20 in another 2,000 megawatts
6 of the under-20 so you get to the 5400 for
7 combined CHP. And of course in our view every
8 megawatt of CHP is good, whether it's from a one
9 megawatt facility or a 500 megawatt facility.

10 That's why we feel they all should be in
11 the load right after the demand reduction programs
12 and the energy efficiency programs. They should
13 basically be the first resource of choice.

14 CPUC COMMISSIONER GRUENEICH: And I have
15 one other question to follow up on my opening
16 remarks. That if we do end up developing a cap
17 and trade system under AB 32 in California in
18 theory there is an economic value.

19 And I'm focusing again specifically in
20 the large cogeneration projects because of the
21 increased efficiency and therefore the carbon
22 emission offsets. At least in theory there will
23 be a market that will develop and there will be
24 traders who will come in and provide both economic
25 value and the ability to be marketing those

1 emission offsets.

2 Is that something that is seen by the
3 clients that you deal with, the members of your
4 organization, that holds some promise in the
5 future for promoting? Again I am focusing on the
6 large cogeneration. Or is it viewed as the market
7 is just not going to provide the type of certainty
8 that's needed and a more traditional command and
9 control would be appropriate for providing the
10 incentives. Do you have any thoughts one way or
11 another of how we essentially start to layer in AB
12 32 in a cap and trade world into some of these
13 policies?

14 MR. SCHOENBECK: Well I may not be the
15 best person to answer this but I'll certainly give
16 my perspective. I think with respect to the RECs
17 there is obviously a possibility there. You saw,
18 again, from Ms. Crossman's slide there is a
19 significant financial potential impact.

20 I think in general what we have heard,
21 and actually in talking with some of the CPUC
22 staff on the very issue of how RECs should be
23 handled we took the position that as long as the
24 cost and the credits are equally considered we
25 would not have a problem with that type of

1 approach. But certainly the RECs should be
2 considered as part of a program because they are,
3 they could be a financial, a significant amount of
4 financial money.

5 PRESIDING MEMBER PFANNENSTIEL: Thank
6 you.

7 I think now the idea is to see if there
8 is discussion specifically on this section. I
9 have one blue card for somebody who asked to speak
10 on the section on the tariffs and that is Susan
11 Buller from PG&E.

12 MS. BULLER: Is this mic on?

13 PRESIDING MEMBER PFANNENSTIEL: The
14 green light needs to be illuminated.

15 MS. BULLER: Can you hear me? Can you
16 hear me now? Okay. Hi, I'm Susan Buller from
17 PG&E and I wanted to applaud the California Energy
18 Commission on a couple of topics.

19 First of all to just put this report
20 forward because this is a very timely area that a
21 lot of people are looking at and it is time to pay
22 some thoughtful attention to that and I appreciate
23 it happening now.

24 The second thing is, and following on
25 some of the things that the prior speaker was

1 talking about, PG&E, I appreciate him queuing up
2 the size issue because it has been PG&E's position
3 for quite some time that we could use a lot of
4 clarity around the issue of size of distributed
5 generation. And I appreciate the fact that the
6 report in fact called that out and did take some
7 steps in that direction and we applaud the CEC for
8 that reason.

9 PG&E would like to point out that there
10 are some things, for example, interconnection
11 issues that can be dramatically simplified for
12 smaller DG but can't be for larger DG. And that
13 there are more sophisticated customers when you're
14 looking at a larger DG unit that you may not
15 expect to find when you're trying to penetrate the
16 smaller customer market with smaller distributed
17 generation units.

18 So there are all kinds of physical and
19 policy and safety and reliability and political
20 reasons why you are going to want to have separate
21 policies for separate sizes. And PG&E in fact
22 would suggest that there might be three levels you
23 would want to look at.

24 And whether it's distribution versus
25 transmission or whether it's over 10 or under 10

1 or over 20 or under 20 I don't think that's nearly
2 as important as having a certain amount of clarity
3 just so people understand and know.

4 But we would also like to introduce the
5 idea of yet a third size that could be considered
6 some kind of micro-distributed generation because
7 we think both the California Energy Commission,
8 the Legislature and the CPUC have already led the
9 way along that by having various policies that cut
10 off at one megawatt or 1.5 megawatt or 5 megawatts
11 for the various existing subsidies that are
12 already in place. And so we would encourage the
13 idea of maybe a tri-level set of clarity around
14 distributed generation.

15 The second point I wanted to talk about
16 was the fact that there are various subsidies, as
17 we all know, that exist for distributed generation
18 today. Most of them are based on various size
19 issues. And that I'd like to underscore something
20 that the gentleman from Cummins Engineering called
21 for, which is some closure at the CPUC about the
22 benefit cost analysis that should precede, PG&E
23 believes, any additional subsidies that are
24 received by cogeneration.

25 The third point I wanted to make was to

1 address the fact there's discussion in the report,
2 there's discussion in a lot of previous reports,
3 I've been here before and listened to members of
4 the cogeneration community talking about what the
5 market barriers are. And I would just like to
6 call for the Commission to address market barriers
7 appropriately. That you do not overcome a market
8 barrier that needs to have an educational element
9 added to it by simply throwing more money at it.

10 That if the issue is customers don't
11 understand something then the response is
12 education. If the issue is customers have
13 difficulty with the Cal-ISO tariff then the
14 solution is to address the Cal-ISO tariff, not
15 just to just indiscriminately raise incentives for
16 customers.

17 What you will eventually do when you do
18 that is end up having a counterproductive thing
19 where you are incenting exactly not the sort of
20 combined heat and power you want. So I am
21 basically just expressing a call for identifying
22 what the market barriers are and then addressing
23 those.

24 And then the final point I wanted to
25 call to -- and I think everyone is on board with

1 this idea. But clean, when we talk about clean we
2 really need to be clear about what that means.
3 And at a minimum PG&E would suggest that combined
4 heat and power or distributed generation not be
5 considered clean unless it is at least as
6 environmentally beneficial as the alternative
7 would be.

8 Are there any questions about any of the
9 four points that I --

10 PRESIDING MEMBER PFANNENSTIEL: Yes,
11 Commissioner Geesman.

12 ASSOCIATE MEMBER GEESMAN: I'd actually
13 commend you for the way you framed that. We might
14 come to some different conclusions, I suspect,
15 than you do but --

16 MS. BULLER: What a surprise.

17 ASSOCIATE MEMBER GEESMAN: In terms of
18 what the alternative would be, what are you
19 thinking of there?

20 MS. BULLER: What I'm thinking of in --
21 And I'm not an engineer so boy am I going to blow
22 it here. What I'm thinking of is what is the next
23 conventional power source that would be brought on
24 line. So I think what I'm talking about, and
25 anyone from any one of the utilities or even

1 anyone from the DG community can correct this, is
2 a combined-cycle. And if you're looking at CHP
3 you're thinking about in conjunction with a
4 boiler. And you look at the relative efficiency
5 of a combined-cycle, today's combined-cycle with a
6 boiler and compare that with the proposed CHP.

7 ASSOCIATE MEMBER GEESMAN: But you're
8 thinking the alternative should be a new plant as
9 opposed to displacing some of the old jalopies
10 that we currently rely upon.

11 MS. BULLER: Correct.

12 ASSOCIATE MEMBER GEESMAN: Okay. I
13 wonder how you would feel if given your company's
14 knowledge of your customers and historic
15 commitment to service to your customers' needs if
16 we imposed the requirement on you and said, you
17 have to procure X amount of DG over the next
18 period of time and we set some criteria for what
19 that DG was to look like and left the details in
20 your hands. Wouldn't that be more efficient than
21 trying to figure out the right flavor cheese?

22 MS. BULLER: Well, until I see the
23 cheese it's going to be very hard for me to answer
24 that because it's a relatively hypothetical
25 question.

1 ASSOCIATE MEMBER GEESMAN: Less so than
2 you might imagine.

3 (Laughter.)

4 MS. BULLER: You're probably right.

5 PG&E supports distributed generation as
6 one of the choices that our customers ought to
7 have available to them. PG&E has supported most
8 of the legislation. I want to say all but I am
9 not absolutely certain, most of the legislation in
10 recent years. We supported the California Solar
11 Initiative. We're working very, very hard to
12 improve our interconnection process for our
13 customers.

14 We're working very hard to implement the
15 SGIP program and the California Solar Initiative
16 and we're very proud of both of those efforts and
17 we have supported most legislation. And in fact
18 without actually having looked at, you know, until
19 I see language I can't say for sure but PG&E
20 probably would support the extension of the SGIP
21 program, the continuation of it, to support CHP.

22 ASSOCIATE MEMBER GEESMAN: I see your
23 ads here, you're also a big supporter of the
24 renewable portfolio standard.

25 MS. BULLER: Correct.

1 ASSOCIATE MEMBER GEESMAN: Is this any
2 different than really just a subset or add-on to
3 the renewable portfolio standard?

4 MS. BULLER: It is and it isn't. At
5 some point you have to take into account that you
6 want to deliver cost effective energy to your
7 customers. So you at all times are going to be
8 balancing customers who can participate with
9 customers who can't.

10 ASSOCIATE MEMBER GEESMAN: Seventy-five
11 out of 80 of the renewable portfolio standard
12 contracts have come in below the market price
13 reference so that program seems pretty well
14 buffered against non-cost effective expenditures.

15 MS. BULLER: That is not my area of
16 expertise. I'm aware of the fact that so far it
17 has come in. I am also aware that the next one is
18 not going to be as easy. I mean, there was a
19 certain amount because of the newness of the
20 program, a certain amount of low-hanging fruit.
21 I'm not sure how long that is going to be
22 available.

23 Now I've just completely stopped my
24 brain. Ask me another question, John.

25 ASSOCIATE MEMBER GEESMAN: Let me come

1 back to what you think the benchmark should be.

2 MS. BULLER: Okay.

3 ASSOCIATE MEMBER GEESMAN: This new
4 combined cycle. That's the same as we use in the
5 market price reference, isn't it?

6 MS. BULLER: I think so, yes.

7 ASSOCIATE MEMBER GEESMAN: So it would
8 seem a logical extension then of that program
9 design.

10 MS. BULLER: I think as long as you are
11 focusing on whether something is cost-effective
12 you are not going to go too far wrong.

13 ASSOCIATE MEMBER GEESMAN: Thank you.

14 ASSOCIATE MEMBER BYRON: If I may,
15 Ms. Buller.

16 MS. BULLER: Sure.

17 ASSOCIATE MEMBER BYRON: One of the
18 recommendations that was put forward by Eric Wong
19 I had not seen before and I was just wondering if
20 maybe you had a response on behalf of your
21 utility. Gas procurement for customer-sited CHP
22 should be done by utilities on the same basis as
23 is done by utilities for their own options
24 provided to CHP. Is that something that might be
25 workable?

1 MS. BULLER: That's something that I
2 don't know enough about, gas procurement, to be
3 ready to answer but what I could do is get back to
4 you.

5 ASSOCIATE MEMBER BYRON: Okay. Well, I
6 can appreciate --

7 MS. BULLER: Or Les could get back to
8 you.

9 ASSOCIATE MEMBER BYRON: I can
10 appreciate you don't, you don't have the ability
11 to answer.

12 MS. BULLER: Right.

13 ASSOCIATE MEMBER BYRON: But
14 theoretically wouldn't it make sense that that
15 would be the same sort of, that they could have
16 the same sort of advantage that your existing
17 generating capacity does with regard to gas
18 procurement?

19 MS. BULLER: And again I am not, I don't
20 know enough about how PG&E does gas procurement to
21 know what the pluses and minuses of doing it on
22 behalf of our customers would be. I think that's
23 what the recommendation was and I am not sure how
24 the market would play out or what the impact would
25 be. It sounds reasonable but that's not the same

1 thing as sure. I am not in a position to say sure
2 today on that point.

3 ASSOCIATE MEMBER BYRON: Thank you.

4 PRESIDING MEMBER PFANNENSTIEL: Thank
5 you.

6 Are there others who have given me blue
7 cards who would like to speak on this subject of
8 tariffs and charges? Then come on up.

9 MS. LIN: Good afternoon. My name is
10 Janice Lin, I am the managing partner of StrateGen
11 Consulting. We're a strategic consulting firm
12 that advises renewable energy and clean DG
13 clients. And I am here on behalf of VRB Power
14 Systems, which is an advanced energy storage
15 manufacturer and member of the California Clean
16 Coalition and member of the Solar Energy
17 Industries Association.

18 I have just a few slides and I'll try to
19 go through it quickly because I know you have a
20 full agenda. Thanks very much for allowing me to
21 make some remarks today.

22 The first thing I'd like to do is just
23 mention that the subject of what I'd like to
24 comment on is why advanced energy storage should
25 be an integral component of California's DG policy

1 roadmap. I read through the document and noticed
2 it wasn't explicitly in there.

3 Advanced energy storage, let me define
4 that by suggesting it's a class of energy storage
5 technologies that are commercially available today
6 that weren't necessarily commercially available
7 five years ago and represent scalability from
8 serving as small as residential customers up to
9 large industrial customers, have a very long life
10 span commensurate with renewables with solar and
11 can be discharged on a daily basis. So lots of
12 duty cycles.

13 Many California DG projects are
14 photovoltaics. My background specifically was in
15 photovoltaics. And as we all know, during summer
16 the California peak is highly coincident with
17 solar. However, peak load isn't fully shaped
18 during the late afternoon when solar output begins
19 to decline.

20 This is what, this is a typical day in
21 the summer of Cal-ISO and this is what the curve
22 would look like as a result of the implementation
23 of the CSI. And what I'd like to show you is what
24 the same curve would look like hypothetically if
25 we had five kilowatt hours of storage installed

1 for every kilowatt of solar. And what you see
2 here is a pretty dramatic flattening of the
3 system-wide peak. The net impact is there would
4 be more energy usage at night but less peak demand
5 during the day.

6 In fact, energy storage systems can be
7 implemented alongside solar, distributed wind and
8 other DG technologies such as combined heat and
9 power. It can be a useful vessel to capture
10 excess electricity. For example, from combined
11 heat and power. It can also be installed on a
12 stand-alone basis and the usage would be basically
13 to charge every night, discharge during the day on
14 peak.

15 The reason I think that we are partnered
16 with the California Clean DG Coalition and the
17 Solar Energy Industries Association is that one of
18 the great benefits of storage with these
19 distributed technologies is it has the ability to
20 improve the value proposition for those
21 technologies. For example in the case of solar it
22 enables the end-user to capture demand charges all
23 throughout the peak window, which may be as late
24 as seven or eight o'clock at night.

25 So some of the benefits of using

1 advanced energy storage to reduce peak demand
2 include system energy costs to the extent that
3 there is lower cost marginal power that can be
4 procured at night, stored and discharged during
5 the day. There is definitely a cost savings.

6 Air quality. At the California Energy
7 Commission's electricity and air quality
8 conference last fall it was stated that shifting
9 power demand off-peak can reduce the use of older,
10 dirtier peaking plants and result in better air
11 quality.

12 There is a system infrastructure benefit
13 in that the existing T&D infrastructure can be
14 better utilized, have a better load factor. In
15 fact, advanced energy storage is pretty
16 dispatchable on demand so it can be used as
17 alternative to spending reserve.

18 And then finally with respect to
19 distributed systems. There is other value streams
20 that an end-use customer can capture such as the
21 better, greater ability to participate in DR
22 programs, the ability to have UPS and backup
23 capability as well. And as was discussed by Snu
24 and others, the magnitude of these benefits will
25 depend on where the system is sited, the available

1 tariff, et cetera.

2 There are a number of energy storage
3 systems that are commercially available today.
4 Here is a full list from the Energy Storage
5 Association. These two types here, there's
6 several types of flow batteries and a sodium-
7 sulfur battery that are commercially available and
8 these two classes of storage technologies are
9 probably well-suited for distributed application.

10 Advanced energy storage can be sited for
11 any size. In the example of vanadium redox flow
12 batteries, capacity and power are independent of
13 one another. The battery can be as small as five
14 kW and up to ten megawatts on the capacity side.
15 And the duration, the number of hours of storage,
16 really depends on the tank size. So that builds
17 in tremendous flexibility into the system at any
18 one customer.

19 Here is a case study of a customer in
20 PG&E territory. This is the Santa Rita Jail in
21 Alameda County. And what I wanted to show you,
22 this is a cloudy spring day. For those of you who
23 may not be aware of this, Santa Rita Jail already
24 has a megawatt of solar installed on its rooftop.
25 And what you're seeing here is a load profile, and

1 this is modeled off of real data, that shows what
2 would be the impact of advanced energy storage at
3 this large, municipal customer.

4 The net result would be their load to
5 PG&E would be the sum of the yellow plus this blue
6 bit. This is where the battery will be charging.
7 The aquamarine is the solar system discharging
8 during the middle of the day and then the battery
9 discharging alongside the solar. So the net load
10 profile of this customer, it's no longer a peak,
11 it's a trough in the middle of the day. Imagine
12 if there were hundreds of customers all over
13 California of this size that had this load shape
14 that also had dispatchable power by Cal-ISO.

15 As you can imagine with every new or
16 emerging technology, and I would say storage is in
17 the early commercialization period, it's not the
18 lowest cost technology available out there. It's
19 in the same set of technologies as fuel cells and
20 solar.

21 And when we looked at where would be a
22 good home for this technology within the
23 California programs we felt that advanced energy
24 storage met all of the self-generation incentive
25 program requirements. It has a large market

1 potential. It has significant and reliable on-
2 peak demand reduction potential. It has a very
3 long equipment life commensurate with solar and
4 photovoltaics. Financial assistance is required.

5 It's practical and safe to install.
6 There's plenty of systems installed worldwide to
7 demonstrate its safety and efficacy. The
8 technology has zero emissions and it can comply
9 with the current program requirements with
10 basically changes to four paragraphs in the
11 handbook. And the important thing to underscore
12 is that unlike other eligible peak load reduction
13 technologies, advanced energy storage is
14 dispatchable and can provide system control
15 benefits from a central location.

16 So in closure I'd just like to encourage
17 all of you to consider the introduction of
18 advanced energy storage into California's DG
19 policy roadmap. There's lots of places that
20 storage can be used throughout California's
21 electric infrastructure at substations and
22 substation backup applications. That would be
23 utility application for T&D asset optimization.
24 There's lots of examples there. This is primarily
25 a utility application as well.

1 But we're particularly excited about
2 distributed customer sited applications because
3 that is where there is the greatest opportunity to
4 capitalize on many different value streams and
5 solve a number of problems that end users face.
6 And then, of course, storage can also be used on
7 energy farms, wholesale wind and solar plants.

8 Thank you.

9 PRESIDING MEMBER PFANNENSTIEL: Thank
10 you.

11 CPUC COMMISSIONER GRUENEICH: Thank you
12 very much. Do you feel that this technology is
13 captured within the series of recommendations that
14 are included within the staff report or are there
15 additional recommendations that you would suggest
16 that would need to be made in order to ensure
17 development of advanced energy storage?

18 MS. LIN: Well, I think that certainly
19 the staff report commented intensively about the
20 benefits and the need for peak load reduction.
21 And advanced energy storage I don't believe was
22 specifically cited in the report nor is it
23 specifically cited as an eligible, sort of a
24 distributed generation technology.

25 And I know in some of the PUC filings

1 they are starting to define distributed generation
2 a little more broadly as a class of distributed
3 energy resources of which energy storage is key.
4 So I would encourage that to considering
5 broadening the definition and thinking about
6 including this technology in some of the incentive
7 programs going forward.

8 PRESIDING MEMBER PFANNENSTIEL: Thank
9 you.

10 Is there anybody else who has given me a
11 blue card who would like to speak to this subject
12 specifically?

13 MR. DAVIDSON: Hi, I'm Keith Davidson
14 with DE Solution, an engineering consulting
15 organization that primarily caters to the combined
16 heat and power community. We're a member of the
17 California Clean DG Coalition and we also, you
18 know, work with a number of manufacturers and
19 equipment suppliers to the combined heat and power
20 industry.

21 I wanted to echo a couple of other, a
22 couple of comments that have previously been made.
23 One of them by John Schoenbeck with, you know, on
24 the non-bypassable surcharges that combined heat
25 and power users get saddled with.

1 And I also want to go back to some
2 comments that Kim made about combined heat and
3 power as efficiency. It's the most efficient way
4 you can use natural gas. It affords many, many of
5 the same benefits that you get from energy
6 efficiency or renewables. It's a much nearer term
7 technology and we feel that combined heat and
8 power, just like energy efficiency, just like
9 demand response, just like if a customer decides
10 they want to shut down part of their operation,
11 that those measures should not be saddled with
12 non-bypassable surcharges such as is placed on
13 combined heat and power.

14 And I'm not really an expert on some of
15 the net metering rates but my understanding of the
16 net metering rates that apply basically to
17 renewables, and I think also natural gas fuel
18 cells below one megawatt, that they also are
19 exempt from non-bypassable surcharges for
20 electricity that they generate. Please correct me
21 if I'm wrong. So that's one comment.

22 The second comment I wanted to make had
23 to deal with the importance of the incentive,
24 continuation of the incentive for combined heat
25 and power. There's a -- You know, and I agree

1 with Susan that, you know, that there ought to be,
2 you know, we ought to be focused on, you know, on
3 cost-effectiveness and economics.

4 But I submit that there is a different
5 rate of return or a different set of economics
6 that are applied from the utility and from the PUC
7 perspective than from a small commercial business
8 or a small industrial would use to invest their
9 own money into what they would call a non-core
10 investment.

11 And that there is definitely, you know,
12 probably a two, maybe a three-year payback gap
13 that exists between what a lot of end users are
14 willing and can justify paying and what is, you
15 know, and what utilities justify as prudent for
16 their expenditures. So we look at the incentive
17 as one mechanism that kind of bridges that gap.

18 And as Kim pointed out, there's
19 incentives for energy efficiency, there's
20 incentives for demand response, there's incentives
21 for renewables. And I don't, I don't, I can't
22 come up with a reason why there shouldn't be a
23 continuation of incentives for combined heat and
24 power. Thank you.

25 PRESIDING MEMBER PFANNENSTIEL: Thank

1 you. Should we move to the next subject.

2 MS. WHITE: Commissioner, I just wanted
3 to make an announcement in response to
4 Commissioner Grueneich's questions on the micro-
5 grid. Thursday's workshop, it's an IEPR-related
6 workshop on the distribution system planning.
7 We'll actually be discussing the PIER work on the
8 micro-grid. And that is currently scheduled for
9 the afternoon on Thursday.

10 And Linda Kelly, if there's any specific
11 questions about the scope of that discussion is
12 available to answer any questions. But I just
13 wanted to let everyone know that the distribution
14 system workshop Thursday we'll be discussing the
15 micro-grid topic.

16 PRESIDING MEMBER PFANNENSTIEL: Thanks,
17 Lorraine.

18 MS. WHITE: You're welcome.

19 PRESIDING MEMBER PFANNENSTIEL: John.

20 MR. SUGAR: Just wondered if there was
21 anyone on the telephone who have expressed
22 interest in speaking to this? No.

23 PRESIDING MEMBER PFANNENSTIEL: So we'll
24 move on to the discussion of interconnection
25 issues.

1 MR. WHITAKER: Well good afternoon. I
2 am also very happy to be here to speak to the
3 Commissioners on the topic of Rule 21, which has
4 in our estimation been a very valuable success.
5 In particular successful coordination between the
6 Energy Commission and the PUC in achieving some
7 goals that were established a while ago and coming
8 to some fruition on those.

9 I want to start out by talking about the
10 current list of participants in Rule 21. This was
11 a recently reestablished list that Chuck Solt, one
12 of our colleagues on the project, had gotten from
13 those who have been on the mailing list for a long
14 period of time who said yes, we do want to
15 continue being involved in Rule 21.

16 So you can see there's a variety of
17 participants, both in terms of the numbers of
18 organizations and in the individuals involved in
19 that. One hundred thirty people feel it was
20 important to be at least kept informed of what is
21 going on in the process. Seventy-one different
22 organizations representing the broad variety of
23 the industry.

24 We also have our support team and I
25 wanted to at least recognize those folks and the

1 team that were not able to be here today. Chuck
2 Solt is here with Lyndh & Associates. I'm
3 actually here speaking for Jose Palomo who had
4 other obligations today and he is the CEC staff
5 person who has been leading this for the past
6 year. Before him Dave Michel and of course Scott
7 Tomashefsky who started off the project.
8 Reflective has been the prime contractor on this
9 and we've been working with him along with a
10 number of other contractors in maintaining the
11 forward progress of the activities.

12 Some time ago Scott Tomashefsky wrote
13 his guiding principles on how we should move
14 forward on developing Rule 21 and these are
15 presented here. That basically what we develop
16 should be very clear and transparent in terms of
17 who has written it and what it's intended to be
18 applied to.

19 The rules were intended to be technology
20 neutral except when differences are fully
21 justified. And I'd like to take this point to
22 raise the issue of sizist endeavors. You will
23 notice in Rule 21 that kilowatts or megawatts
24 rarely enters into the discussion because it turns
25 out it's rarely the issue of concern. It's

1 usually something like current or voltage level or
2 various other things.

3 And kilowatts tends to be a convenience
4 that people use but it's really not the issue.
5 And so I would suggest, being an engineer, that if
6 you do need to come up with criteria for
7 establishing demarcations that it be tied to a
8 specific issue. At least if those demarcations
9 are technically oriented. And that's a goal that
10 we have strived to maintain in the rule.

11 The rules are supposed to be uniform
12 throughout the state and I think at this point, at
13 least among the three IOUs and many of the munis
14 that have adopted some or all of the Rule 21
15 requirements, that they are fairly uniform.

16 And the last goal was that the utilities
17 be compensated for any, for any services that they
18 have to provide to support DG.

19 So in terms of accomplishments that
20 we've achieved since the process started in 2000
21 we have a literally consensus-based
22 interconnection rules. It's been adopted by the
23 three IOUs and a number of the munis, as I
24 mentioned.

25 Based on a cost effectiveness study that

1 was performed a year or so or two years ago we
2 have an estimated reduction in the cost of
3 interconnection per interconnection of about
4 \$6400. And the time to interconnect has gone down
5 from just under a year to a little over three
6 months. So fairly significant reductions in both
7 the time and cost for this process.

8 The work group has done a number of
9 technical and policy-related activities. We have
10 published what we call a supplemental review
11 guideline, which is a series of technical
12 requirements or guidance for the utility
13 protection engineers on how to apply, what issues
14 to address when our initial review process is not,
15 is somehow exceeded.

16 And that has been very useful in a
17 process of basically training both sides of the
18 issues here, the utilities and the DG providers
19 and the manufacturers. What the various issues
20 are and how those issues can be addressed. So
21 we've tried to bring those things to light in the
22 supplemental review guideline.

23 We also have an interconnection
24 guidebook which is almost the soccer mom's version
25 of Rule 21. Not exactly but it's intended to be

1 more for the user who is trying to apply Rule 21
2 and what kinds of issues they will run into and
3 how they go through that process.

4 We have had a very active coordination
5 process and involvement in the development of
6 relevant IEEE and UL standards. And that has been
7 also I think a key success and our participation
8 has been very much underscoring what's going on in
9 those areas. We also had a very successful
10 monitoring program where we monitored a number of
11 DG systems and have quite a mountain of data
12 showing the performance and the actual --
13 essentially the lack of impact that these DG had
14 on the system during their operation.

15 We have a -- Under Rule 21 we have
16 developed a certification process to simplify
17 moving forward with various DG projects.
18 Especially for the smaller systems it makes a lot
19 of sense to have the equipment tested in advance
20 so that they don't have to be tested in each
21 application. And right now we have about a dozen
22 different products on the Rule 21 list.

23 And we have a very, as I mentioned a
24 very effective working group. We have met 78
25 times over the I think it's actually seven-plus

1 years that the process has been, has been going
2 on. Many times in this very room.

3 The current issues that we're looking
4 at, we have issues with multiple tariffs and
5 combined technologies and this has recently been
6 resolved from the policy group. On the technical
7 side, which I actually represent and help
8 facilitate the technical part of the working
9 group, we have a number of ongoing issues that
10 we've been working on.

11 We recently resolved or have been
12 working secondary spot networks as a key issue and
13 that was part of a report that was published last
14 year. The request from the PUC in terms of
15 specific activities that we should undertake. And
16 that report basically said that we need to
17 continue evaluating this issue. We actually
18 developed some ideas. Those ideas are being
19 implemented in IEEE right now but that's still an
20 ongoing process in terms of network systems.

21 One of the issues that has just come up,
22 and this gets back to the sizes issue, people want
23 to apply Rule 21 on transmission interconnection.
24 And there's reasons to do that and there's reasons
25 why you have to be careful about doing that. So

1 we have that as a task right now, to see how that
2 might actually go about at least in terms of the
3 technical requirements and how you apply those
4 rules that we've developed for Rule 21.

5 We have some revisions to do. IEEE has
6 continued to develop a number of standards and we
7 have some revisions to do to the document to
8 accommodate what has occurred and what is now part
9 of the IEEE series. And in particular we have
10 some certification and test standards that we need
11 to revise the document to take on.

12 And lastly here, this was a comment from
13 Jose. That the PIER research objectives have been
14 achieved and the CEC is now looking for a
15 custodian to take on the process.

16 My personal perspective is that there is
17 a number of things, especially on the technology
18 side, that have people still interested in
19 participating, still interested in having some
20 organization that can continue to put these issues
21 on the floor in front of both a group of utilities
22 and DG providers in an open forum where we can
23 discuss them. It has been a very effective tool
24 for dealing with issues in the past, which
25 certainly have been the simpler of the issues.

1 And those going forward will be probably more
2 difficult and more in need of exactly this kind of
3 forum to resolve.

4 And I think that is pretty much the end
5 of my presentation. I have some additional slides
6 here from a presentation I gave last week to the
7 DER integration PAC. This just shows a series of
8 IEEE standards that are currently under
9 development to deal with DG interconnection and
10 certification and various specific technical
11 issues.

12 We have UL 1741, which is a test
13 standard for equipment that has now been broadened
14 to cover -- It started out, as many of these
15 things started out interestingly, as PV standards
16 for PV interconnection and have broadened
17 themselves to cover all forms of DG. In
18 particular this has utility compatibility and
19 interconnection issues that it addresses.

20 And I think I'll go ahead and skip
21 through these and see if you have any particular
22 questions.

23 PRESIDING MEMBER PFANNENSTIEL: Are
24 there questions? Melissa.

25 ADVISOR JONES: I have a question. In

1 what I have read about Rule 21 and heard about
2 Rule 21 it is always characterized that the policy
3 issues are actually determined by the Commissions
4 and that this is a technical type of organization.
5 Can you give me a flavor of what the kinds of
6 policy issues you're referring to are?

7 MR. WHITAKER: Well, things like what
8 sorts of rates should this entail. Let's see, how
9 should -- A lot of, a lot of the technical issues
10 like the combined. How do you deal with an
11 application where he has a combined or a non-net-
12 metered system and a net-metered system. It has
13 an existing gas-fired DG and PV. The technical
14 issues are pretty simple, you know. How you meter
15 that, there's a number of technically easy ways to
16 deal with that.

17 But the policy side is, well which do
18 you consider first and how do you, how do you
19 address that, that piece of the puzzle. All of
20 the application forms, all of the contracts, a
21 number of things. Someone help me here. What
22 else is there?

23 SPEAKER IN AUDIENCE: Metering.

24 MR. WHITAKER: Metering.

25 SPEAKER IN AUDIENCE: Metering is a

1 policy issue.

2 MR. WHITAKER: Metering is a policy
3 issue. The technical side can say, you know, this
4 is how you wire it up but yeah, what gets metered,
5 where you put the meter, what's included in the
6 metering, those kinds of things.

7 ADVISOR JONES: Okay, thank you.

8 PRESIDING MEMBER PFANNENSTIEL: Thank
9 you. Other questions? Yes.

10 ASSOCIATE MEMBER BYRON: Mr. Whitaker,
11 my recollection, and there's others maybe in the
12 audience that have been involved in Rule 21
13 activities or at least following them longer than
14 I have, was that seven or eight years ago the
15 biggest concern or the biggest issue we were
16 dealing with was safety around interconnection.
17 At least that's what many of the IOUs, most of the
18 IOUs were concerned about.

19 My sense is that we have addressed that
20 and a number of other issues in Rule 21 to date,
21 correct?

22 MR. WHITAKER: Well, I would
23 characterize it this way. It's not as though
24 there was a safety issue that is now solved.
25 Safety is an underlying issue. It's the primary

1 reason for all of the technical results that we
2 have come up -- all the technical requirements
3 deal with safety and reliability of the system.
4 So it hasn't gone away. And it's not as though we
5 have really eliminated technologies or
6 applications, we've just moved forward in a way
7 that everyone is comfortable with the safety
8 aspects of those applications.

9 ASSOCIATE MEMBER BYRON: Okay. And my
10 understanding is that about five years ago, maybe
11 six years ago, there was an agreement with the PUC
12 and the Energy Commission working collaboratively
13 that we would, if you will, undertake this effort
14 and fund it as well. And I think we have been
15 doing that for the last five or six years.

16 What is your sense of how much work
17 remains? Now I know you touched on this a little
18 bit but I'm getting a lot of feedback from the
19 investor-owned utilities that Rule 21 has run its
20 course, that we don't need it any longer. What is
21 your sense of what's left to be done and is there
22 an ongoing need for this, for this group?

23 MR. WHITAKER: Well my answer is yes and
24 in probably a different role. And I think if you
25 sit in the meetings you do get the same sense.

1 There are a number of people who feel, you know,
2 we've done our job, we had goals set out,
3 establish consistent rules across the state
4 meeting various requirements, addressing a
5 majority of the issues. And from that perspective
6 that job is done.

7 What we have done as a part of this
8 process is develop a process whereby people can
9 bring in issues. The technical side, the
10 protection engineers, we can talk about something
11 new at every meeting.

12 One of the things we have done recently
13 in the past two years or so is gone to quarterly
14 meetings, in part to reduce the burn rate on the
15 contracts that the support folks have had. And
16 that has really slowed down the work, especially
17 on the technical side. Because, you know, most of
18 what we have to do -- And it's the same on the
19 policy side as well. You sit in a room and you
20 argue about the issues and you discuss them and
21 you learn what is going on and, you know, it's
22 this learning process.

23 And with the quarterly meetings it has,
24 it has really slowed down the participation on the
25 technical side because you tend to lose interest.

1 When I brought this up at the previous meeting
2 earlier this year everyone in the room, including
3 the IOU engineers said, we should meet more often.

4 PRESIDING MEMBER PFANNENSTIEL: Yes,
5 Commissioner Grueneich.

6 CPUC COMMISSIONER GRUENEICH: You noted
7 that there is this issue of funding to continue
8 the Rule 21 working group after 2008. And I
9 believe it's because the PIER, the current PIER
10 money is ending. Is there any reason why there
11 couldn't be an augmentation of the PIER money? Or
12 is it a view of, the type of the work that will be
13 done post-2008 is a wholly different matter so it
14 wouldn't essentially come within the scope of
15 activities that will be encompassed under PIER?
16 Can you help me understand since this isn't an
17 area I'm familiar with.

18 MR. WHITAKER: Yes. I think the issue
19 has not grown new, it's grown a little bit more,
20 it's grown a bit larger recently. And that is
21 simply that PIER, the last letter is for research.
22 So the question has been, how is this a research
23 activity? And initially we had at least an
24 adjunct project where we were doing some field
25 monitoring that made the research part very

1 comfortable. And that has been more and more
2 difficult for people to address as we go on, how
3 this constitutes research.

4 We are involved with the standards
5 development side and a number of other things.
6 There are a number of areas where there's not
7 answers and where this group is very effective at
8 providing input and guidance. Whether or not
9 that's research, that's where the whole issue
10 lies.

11 ASSOCIATE MEMBER BYRON: That's correct,
12 Commissioner Grueneich. The difficulty is now
13 justifying this as continued research funding out
14 of PIER. And then of course the question is, are
15 there ongoing needs for Rule 21 and does the PUC
16 see needs for it as well as a forum for issue
17 resolution around interconnection.

18 The other issues that might come up
19 would be certification of new equipment and how
20 would that process continue. And I believe
21 there's also this concern about keeping the
22 investor-owned utilities within the state from
23 bifurcating the interconnection process. In other
24 words this keeps it consistent throughout the
25 state. Is that a fair read?

1 MR. WHITAKER: That's a very fair read.
2 In fact, many of our most contentious things have
3 been trying to, you know, to herd the cats and
4 keep everyone on the same path. Maybe that's a
5 mis-characterization but all of the utilities have
6 different systems and different perspectives. And
7 having them in a room, you know, trying to fight
8 to a single goal has been a very interesting set
9 of issues. And I think you do run the risk that
10 if they are allowed off on their own that you will
11 not necessarily come all to a common conclusion.

12 PRESIDING MEMBER PFANNENSTIEL: Thank
13 you. Yes.

14 MS. KELLY: My name is Linda Kelly, I'm
15 from PIER. I work in the distribution and
16 distributed energy resource program. I just
17 wanted to just clarify and support what Chuck
18 said.

19 PIER has been very supportive of this
20 work. And I think now the key thing is that we
21 have continued funding to make a smooth transition
22 that I think we would like to see happen where as
23 we gradually move, I think further and further
24 away from some of the research issues, we still
25 have time to develop due partners who can take

1 this forward in the next years as we develop the
2 technology and the standards work, which I agree
3 is very, very important.

4 But what we do is have a limited amount
5 of time. We have the funding that goes out for a
6 full year. So that gives us a chance, I think, to
7 develop new collaborative relationships with
8 somebody who could take this forward for us. So I
9 want to just, you know, just say PIER does support
10 this work and is looking for a smooth transition
11 to make sure that this important work continues.

12 PRESIDING MEMBER PFANNENSTIEL: Thank
13 you, Linda.

14 I have one blue card who indicates, the
15 person indicates she would like to speak to this
16 issue. Nora Sheriff.

17 MS. SHERIFF: Thank you. Nora Sheriff
18 for CAC and EPUC. I have two very brief, quick
19 points to make. First, my understanding is that
20 there are many existing Rule 21 interconnections
21 at the transmission level. So in terms of whether
22 or not Rule 21 could apply to the transmission
23 level interconnection, it has in the past.

24 And second, I just wanted to describe
25 one discouraging experience that an existing

1 cogeneration facility has had with PG&E in terms
2 of their Rule 21 interconnection. This facility
3 was looking at doing some upgrades to their
4 equipment, some maintenance work, and they're
5 already interconnected under Rule 21. And at one
6 point PG&E was saying, you have to file a new Rule
7 21 interconnection application for this
8 maintenance work.

9 And this isn't a large facility, not
10 even by PG&E's ten megawatt standard, it's a six
11 megawatt facility. And it's just been a very
12 long, discouraging and difficult process and we're
13 trying to work through it but it hasn't been
14 conducive to encouraging existing cogeneration to
15 perform maintenance and efficiency upgrades.

16 And I just wanted to make that point,
17 thank you.

18 ASSOCIATE MEMBER BYRON: If I may.

19 PRESIDING MEMBER PFANNENSTIEL: Thank
20 you for making the point.

21 ASSOCIATE MEMBER BYRON: If I may.

22 Ms. Sheriff, may I ask you a question about that?

23 Not necessarily getting into particular
24 cases but do you think Rule 21 would be able to
25 help situations -- if the Rule 21 working group

1 were to continue in some way would it be able to
2 help situations like this?

3 MS. SHERIFF: Well it might. You know,
4 CAC and EPUC have participated actively in the
5 Rule 21 working group. But when we have tried to
6 address these issues rather than hijack the entire
7 working group meeting to address the issue of a
8 single facility, you know, you try to address the
9 issue off-line. And we have still been faced with
10 reticence on the part of PG&E to work with us. We
11 had to bring it to a relatively high level within
12 the PG&E organization to get some understanding
13 that this should be a very simple matter. And it
14 was a very frustrating experience.

15 ASSOCIATE MEMBER BYRON: You used the
16 word hijacking the working group. But my sense is
17 that part of what they do is dispute resolutions
18 like this. Don't they, don't they provide some
19 consistency on interpretation of interconnection
20 that would help resolve these kinds of issues?

21 MS. SHERIFF: They do and that might. I
22 think this might have been a new issue in terms of
23 when you do maintenance to an existing facility.
24 The Rule 21 working group has primarily been
25 involved with new interconnections and this is an

1 existing facility.

2 ASSOCIATE MEMBER BYRON: Okay, thank
3 you.

4 MS. SHERIFF: Thank you.

5 PRESIDING MEMBER PFANNENSTIEL: Thank
6 you. Anybody else on this specific subject?

7 MR. HEINZMANN: I'd like to.

8 PRESIDING MEMBER PFANNENSTIEL: Okay.

9 MR. HEINZMANN: My name is Joe
10 Heinzmann, I'm with FuelCell Energy. In
11 particular on the interconnection items and also
12 with the Rule 21 group.

13 Part of the Rule 21 process was
14 establishing the certification procedure and then
15 the working group also provides the review of the
16 certification. And we'd want to ensure that if
17 the Rule 21 working group was discontinued that
18 the certification procedure would be continued in
19 some way. We want to make sure that's not dropped
20 off to the side. Thank you.

21 PRESIDING MEMBER PFANNENSTIEL: Got it,
22 thanks.

23 Les Guliasi, you're going to --

24 MR. GULIASI: Thank you, Chairman
25 Pfannenstiel and Commissioners.

1 I have with me today Fred Skillman who
2 is a member of --

3 PRESIDING MEMBER PFANNENSTIEL: Les,
4 please identify yourself for the record.

5 MR. GULIASI: I'm sorry. Les Guliasi
6 with PG&E. I have with me today a colleague, Fred
7 Skillman, who is actually a member of the Rule 21
8 working group. He is actually familiar with the
9 situation that we just heard about and I would
10 like for the benefit of the record for you to hear
11 from PG&E's perspective an explanation of that
12 situation. And certainly we'd be very happy to
13 take discussion off-line to see if there's any
14 further issue that we need to resolve.

15 PRESIDING MEMBER PFANNENSTIEL: Well my
16 preference is that we take discussion off-line but
17 I do think since it has been raised perhaps just
18 to mention a response. And then any further
19 discussion I think it does not belong here but
20 we'll --

21 MR. GULIASI: I agree, but I just wanted
22 this on the record. It will probably take 30
23 seconds, thank you.

24 MR. SKILLMAN: Good afternoon, my name
25 is Fred Skillman with PG&E. Just responding to

1 the comments of Ms. Sheriff as it pertains to this
2 particular interconnection, which I'll keep the
3 name of that customer.

4 PG&E had proposed a process to the
5 customer that would have saved them a considerable
6 amount of money. Being customer focused as we are
7 to all of our customers, and DG customers as well,
8 we had proposed a process that would have saved
9 them thousands of dollars. The customer had some
10 concerns about other agreements that they had with
11 PG&E and chose not to take that particular route.

12 So because of that and in the process
13 itself at the end of the day we're able to get the
14 issues resolved to the customers benefit. But I
15 just wanted to be able to state that PG&E was very
16 much customer focused in this and we offered an
17 avenue for them that would have saved them a
18 considerable amount to do the same work.

19 And as Les mentioned, if there is any
20 other details or others, if they'd like to discuss
21 those in detail off-line I'd be happy to address
22 those concerns. Thank you.

23 PRESIDING MEMBER PFANNENSTIEL: Yes,
24 Commissioner.

25 ASSOCIATE MEMBER BYRON: If I may.

1 Mr. Skillman, notwithstanding the issue that
2 you're discussing can you give me your sense as a
3 member of the Rule 21 working group of its value
4 in continuing in some capacity.

5 MR. SKILLMAN: I think the primary
6 benefit of the Rule 21 working group is that it is
7 the only form that exists that includes all
8 stakeholders in the community. As Mr. Whitaker's
9 presentation outlined, many different
10 organizations, the people that are involved there,
11 that's I think the primary benefit.

12 It is a forum and sometimes it can be
13 contentious but that's okay because the issues get
14 out on the table and they get resolved. We've
15 been dealing with for the last several months this
16 issue of funding. And there's essentially in our
17 next meeting, which is right here in this room on
18 the 15th of May, we're going to be discussing an
19 exit strategy as one of the agenda items.

20 But certainly having a forum that's
21 open, that's under the public auspices of the CEC,
22 is something that all stakeholders actually prefer
23 and PG&E supports that.

24 ASSOCIATE MEMBER BYRON: Thank you.

25 PRESIDING MEMBER PFANNENSTIEL: Thank

1 you.

2 Moving on then to the next area of
3 discussion, which is the DG goals and the roadmap.
4 I'll turn it back to John.

5 MR. SUGAR: If there is no question on
6 the phone then we'll --

7 MR. DAVIDSON: If it's all right I'd
8 like to make one more comment on the
9 interconnection issue.

10 PRESIDING MEMBER PFANNENSTIEL: You need
11 to come up to the microphone.

12 MR. DAVIDSON: My name is Keith Davidson
13 with DE Solutions and I'm going to represent
14 Tecogen. Tecogen is a packager of small combined
15 heat and power systems less than 100 kilowatts in
16 size and simplified interconnection is critical to
17 their business viability in California.

18 We just want to support the comment made
19 by FuelCell Energy that the certification process
20 needs to continue or perhaps there is some other
21 way like defaulting to the UL certification and
22 that enables the simplified interconnection
23 approach.

24 I also wanted to just mention a couple
25 of situations for -- this is combined heat and

1 power interconnecting with the grid. You can,
2 you've got a couple of choices. You can, you can
3 opt for the no export interconnection approach in
4 which case not only can you not export any power
5 back into the grid but you have to maintain a ten
6 percent purchase margin from the utility at all
7 times. And the other option is that you can go
8 through -- it requires additional costs for
9 metering -- is what they call inadvertent export,
10 which allows you to push a certain amount of
11 electrons back into the grid for which you are
12 given no value.

13 And to us this does not, this doesn't
14 seem very rational. There's already been
15 exceptions made for all of the net metering
16 technology. It's not a safety issue. And that we
17 feel that some form of, you know, net metering or
18 compensation of selling excess electricity back to
19 the grid, particularly when the thermal load there
20 is there and justifies the production of
21 additional kilowatts over and above what the, what
22 the facility needs. Thank you.

23 PRESIDING MEMBER PFANNENSTIEL: Thank
24 you.

25 I understand there is somebody on the

1 phone who wants to speak to this issue. John
2 Bonk-Vasko.

3 MR. McALLISTER: Yes. Actually this is
4 Andrew McAllister. I am here with John Bonk-Vasko
5 who is our self-gen program manager. We are with
6 the California Center for Sustainable Energy,
7 which is the new name of the San Diego Regional
8 Energy Office. So I just wanted everybody to have
9 that on their radar screens that we have changed
10 our name. So CCSE or something like that will be
11 appearing rather than SDREO in future documents
12 and proceedings, et cetera.

13 I thought the roadmap was a beautiful
14 report and we just had one question about the
15 definition of DG. In particular that it excludes
16 non-CHP digester gas and landfill gas. And it
17 just brought up the question for us because, you
18 know, the self-gen program does provide incentives
19 to projects and one of the renewable, one of the
20 renewable fuels that's eligible, those aren't
21 included in the Level 2 incentives for the self-
22 gen program. And particular, for example,
23 municipal wastewater treatment plants that would
24 have digester gas available to do on-site
25 generation that generally is not CHP. So how

1 would that fall under the definition of DG in the
2 sort of newer or updated definition in the
3 roadmap?

4 PRESIDING MEMBER PFANNENSTIEL: John,
5 would you like to answer?

6 MR. SUGAR: Well that's an issue for
7 discussion today, probably under DG goals and the
8 roadmap or public comment. We have had a number
9 of people comment in the background that the
10 definition of distributed generation is narrower
11 in the report than many parties would like to see.

12 PRESIDING MEMBER PFANNENSTIEL: Okay, so
13 we'll move into that area now. And, Nora, were
14 you going to lead this discussion on the DG goals
15 and roadmap?

16 MS. SHERIFF: Good afternoon. Again my
17 name is Nora Sheriff, I'm here on behalf of CAC
18 and EPUC. And just briefly to add to the names of
19 the member companies of CAC and EPUC, we also have
20 Valero, Era and Occidental.

21 Now I am going to talk about a 2007 plan
22 for cogeneration. And I'm calling this a 2007
23 plan to underscore the need for action now. The
24 time for the Energy Commission to act is now.

25 If the Energy Commission wants to make

1 its 2020 vision for cogeneration, that is the
2 retention of existing, large cogeneration
3 facilities of 8,155 megawatts, and the
4 encouragement of the development of new, large,
5 cogeneration facilities, that is 3,045 megawatts
6 by 2020, you need to act now. As Commissioner
7 Geesman said in the beginning of the afternoon,
8 you need to bring a strong dose of reality to the
9 rhetoric that is present.

10 Why do you have to act now? Because you
11 have large industrial sites that are looking at
12 expansion. They are considering these expansions
13 because they have increased thermal needs. If you
14 asked a refinery manager what size cogen would
15 optimally match your thermal need he would say,
16 500 megawatts. What size cogent facility would
17 meet your electrical needs, between 50 to 70
18 megawatts might be your answer.

19 And size matters in terms of the
20 efficiencies that you get, the greenhouse gas
21 emissions reductions that you achieve. You need
22 to be looking at these larger facilities. That's
23 why there's a goal of 3,000 megawatts of new
24 facilities by 2020.

25 The state needs to encourage sizing to

1 meet thermal demand. And this is a key point The
2 thermal demand is going to be met with or without
3 the byproduct of electricity. That means that
4 there is an opportunity now to incent new, large
5 cogeneration facilities. But if you don't take
6 away the regulatory uncertainty these facilities
7 are going to meet their increased thermal demand
8 with boilers, or with smaller size cogeneration
9 facilities and boilers.

10 Now the roadmap addresses three areas of
11 uncertainty that can impact the sizing of
12 cogeneration facilities. Sales of excess power to
13 the interconnected utility, the interface with the
14 California ISO tariffs. And the roadmap also says
15 they want to eliminate departing load charges by
16 2011. I am going to address the first and the
17 last of these areas.

18 In terms of excess power sales to the
19 utility the 2005 IEPR was fairly clear in terms of
20 the Energy Commission's intent that all
21 cogeneration, regardless of size, was beneficial
22 and should be in the loading order.

23 The roadmap, however, provides
24 definitions of DG and large cogeneration and small
25 cogeneration that might lead some to argue that

1 large cogeneration, facilities above 20 megawatts
2 in size, are not in the loading order. And this
3 could lead to continued utility pushback from
4 sales, from purchases of excess power from large
5 cogeneration facilities.

6 So what can the Energy Commission do
7 now? You can confirm that cogeneration of all
8 sizes should be considered to be in the loading
9 order by clarifying the roadmap and its
10 definitions. And you can also clarify that again
11 in the 2007 IEPR. And then at the Public
12 Utilities Commission addressing the question of
13 need for utility procurement in the ongoing long-
14 term procurement plan proceeding R0602013. The
15 Energy Commission can participate actively in
16 workshops, hearings and briefing on this issue.

17 And just to give you a point of
18 reference, PG&E has said in their testimony that
19 the cogeneration that is in the loading order is
20 limited to ten megawatts and PG&E has forecasted
21 28 megawatts a year of new installation of
22 cogeneration.

23 Now if you contrast that with the 2020
24 vision of 3,000 megawatts of new cogeneration and
25 large facilities above 20 megawatts you are not

1 going to get there with PG&E's forecast and PG&E's
2 definition.

3 Southern California Edison limits
4 cogeneration that is in the loading order to
5 facilities less than five megawatts and Edison's
6 forecast for new cogeneration is 25 megawatts a
7 year. So we would like the Energy Commission to
8 actively participate in the long-term procurement
9 plan proceeding to help make the 2020 vision
10 become a reality for large cogeneration.

11 And finally on the departing load issue.
12 The roadmap calls for the elimination of departing
13 load charges by 2011. However, as currently
14 adopted by the Public Utilities Commission
15 departing load charges could extend into the 2030s
16 and now cover close to 6,300 megawatts of ongoing
17 utility normal course of business procurement.

18 There is no way to quantify these new
19 departing load charges and the significance of
20 this cannot be understated. This has a
21 phenomenally chilling impact on the development of
22 new cogeneration facilities.

23 What can the Energy Commission do? You
24 can promote the roadmap goal of eliminating
25 departing load charges by 2011 by participating in

1 track three of the long-term procurement plan at
2 the PUC. That's R0602013. And you can also
3 support EPUC's petition to modify D0412028 and
4 R040403 where we argue that cogeneration should be
5 exempt from the new utility procurement departing
6 load charges. Thank you.

7 PRESIDING MEMBER PFANNENSTIEL: Thank
8 you.

9 Are there questions from the dais of
10 Ms. Sheriff? Dian.

11 CPUC COMMISSIONER GRUENEICH: Yes. I
12 think you have properly identified that a number
13 of the issues that are in the staff report are
14 teed up for decision by the PUC and especially in
15 the long-term procurement plan. That while I
16 haven't read the filings that you've noted it
17 sounds like that issue of where to put changes in
18 the loading order have been teed up.

19 So I just want to reiterate what you
20 said, which is for anybody who is interested in
21 any of the issues that are pending before the PUC,
22 please come and please participate because we will
23 e getting decisions out on these matters. And if
24 you do have a particular viewpoint you want to
25 make sure that we know and take into account when

1 we make our decision please come and participate.

2 PRESIDING MEMBER PFANNENSTIEL: Yes,
3 Commissioner Byron.

4 ASSOCIATE MEMBER BYRON: Ms. Sheriff,
5 good comments. I think I'll hold off on asking
6 some questions after our second presenter but
7 thank you very much for your comments.

8 MS. SHERIFF: Thank you.

9 PRESIDING MEMBER PFANNENSTIEL: And the
10 next presenter is Les Guliasi.

11 MR. GULIASI: Thank you and good
12 afternoon. I'm Les Guliasi with PG&E. I want to
13 thank the Commission for the opportunity to be
14 included in today's program. Particularly to
15 Commissioner Byron for resurrecting this important
16 topic and for John Sugar for presiding today and
17 Gabe Taylor for organizing today's workshop.

18 ASSOCIATE MEMBER BYRON: Mr. Guliasi.

19 MR. GULIASI: Yes.

20 ASSOCIATE MEMBER BYRON: If I just make
21 correct you. I did not resurrect this topic.
22 This is an IEPR topic. It's been on the agenda
23 every time it's on the cycle. I'm just adding my
24 support for it.

25 PRESIDING MEMBER PFANNENSTIEL: But he

1 is championing it.

2 MR. GULIASI: Yes, thank you. And I'm
3 surprised that no one brought up today the most
4 important energy topic that was in today's
5 headlines since we're talking about DG and that is
6 harnessing the jet stream.

7 (Laughter.)

8 Well my objective today is implied in
9 the little title that I attached to my
10 presentation. What I am here to do is offer a
11 commentary and a critique of the roadmap and the
12 vision for distributed generation and
13 cogeneration. I want to do this by posing some
14 questions about the assertions and the assumptions
15 embedded in the report with the hope of
16 stimulating some further discussion and a
17 constructive dialogue.

18 I am not here today necessarily to
19 advocate a particular point of view and I am
20 especially not here today to advocate a utility
21 point of view, although I have to say in full
22 disclosure that contrary -- well first of all that
23 if some things do creep through I'm only human.
24 But I do want to say at the outset that contrary
25 to popular belief utilities in general, I think,

1 and certainly PG&E in particular, is not
2 philosophically opposed to distributed generation,
3 nor are we opposed to cogeneration or what we call
4 combined heat and power.

5 I agree with the report's assertions
6 that there are institutional and historical
7 barriers to the deployment and development of DG
8 and CHP and it is important to penetrate these
9 assumptions and these assertions and to put all
10 the cards on the table and to target solutions
11 where they're needed.

12 Utilities, and my utility PG&E in
13 particular, support distributed generation as one
14 service option among many available to customers
15 to address their energy needs. Distributed
16 generation and cogeneration should be components
17 of an environmentally sound energy policy,
18 especially insofar as they promote technological
19 efficiency for society.

20 So herein lies the first question that I
21 want to pose and it's a question of definition.
22 In previous policy debates about distributed
23 generation and combined heat and power we were
24 very sloppy in our use of terms. We had no clear
25 definition and we mostly talked past one another

1 out of individual self-interest.

2 So I was happy to see that at the outset
3 this report took a step at making some clear
4 definitions for distributed generation and
5 combined heat and power, with clear operational
6 definitions with respect to size, technology and
7 location. So my question is, are these
8 definitions adequate? Do they need more
9 refinement or can we agree with them and just move
10 on to have constructive conversation.

11 Now I said a moment ago that the
12 utilities support distributed generation as an
13 option for customers to meet their energy needs.
14 And I would include cogeneration along with
15 distributed generation as a tool for customers.

16 But utilities in addition to being
17 service providers to end-use or retail customers
18 are also in the procurement business. We buy
19 power in the wholesale market for retail
20 distribution and sales. So from that perspective
21 the picture looks a bit different from the
22 procurement side.

23 Instead of dealing with retail customers
24 and providing them with a service option to meet
25 their needs, in procurement you're looking for a

1 good deal, usually price, for a product that meets
2 your portfolio needs. And again here you're
3 acting on behalf of retail customers. You're a
4 middle man seeking products at a reasonable price
5 to fit into a portfolio of products and services
6 that you deliver to the retail customer.

7 So my next question is in reading the
8 report, what is the over-arching policy objective
9 that we're striving for in promoting distributed
10 generation and combined heat and power? I would
11 recommend that a chapter be added to the report to
12 place the DG roadmap in a broader social context
13 and explicate the public policy objectives that we
14 are trying to achieve.

15 Oftentimes DG and CHP are advocated for
16 energy supply diversity, for energy reliability,
17 to promote efficiency, for technological
18 advancement, for cost or for environmental
19 benefits. So the question is, what are we trying
20 to achieve? It's important that this report
21 provides some broader social context to understand
22 what we're trying to achieve here in promoting
23 distributed generation and combined heat and
24 power.

25 As the report somewhat implies and

1 almost states, all electrons are not created equal
2 and it is important that we understand what the
3 origin of these electrons are and place them in a
4 larger social context.

5 I want to say a couple of words about
6 the process that led to the report, particularly
7 the vision for 2020 and the visioning process.

8 Exercises like the one used to develop
9 the vision for 2020 are generally self-contained
10 exercises. By that I mean they adhere to an
11 internal logic and often sort of trap themselves
12 in a set of scenarios that they create. And you
13 can see on page 13 the four scenarios that the
14 report identifies.

15 The scenarios themselves may offer the
16 use of a construct to help us classify in broad
17 distinctions but ultimately we must recognize that
18 these scenarios are depictions or representations
19 of reality, they are not reality itself. the
20 scenarios are internally and logically consistent
21 but they are lacking in practical terms. Reality
22 is made up more or less by a jumble of the
23 elements that we see contained in each of the
24 scenarios but reality isn't so neat. I'm just
25 going to give a couple of examples.

1 The roadmap talks about the regulatory
2 framework but it doesn't make clear that it's the
3 regulatory framework that governs the investor-
4 owned utilities. What about publicly-owned
5 utilities and a policy framework for the whole
6 state? Is the vision for 2020 adequate or is it
7 limited by its own construction? Should it be
8 expanded or modified to encompass a broader
9 definition of regulatory regime and should it
10 strive to take a broader, statewide perspective.

11 I think in the interest of time I won't
12 talk much about the issue of incentives and
13 subsidies but just in brief, we have to, again we
14 have to target our solutions where they're needed
15 and not just apply blanket peanut butter-like
16 spreading of solutions across technologies and
17 across industries.

18 Distributed generation is a market with
19 nascent technologies and here incentives may be
20 important. Combined heat and power is a more
21 mature industry with well understood technologies
22 and proven technologies, often with large and
23 sophisticated players. I would submit that
24 incentives are not necessarily needed in this
25 market.

1 As Mr. Schoenbeck from CAC and EPUC said
2 a little bit earlier in his remarks, his clients
3 design and sign a cogeneration system which
4 results in a heat rate of about 5,000. Well in a
5 market where the target you have to beat is about
6 7,000 or 8,000 heat rate these facilities ought to
7 be quite competitive and they ought to do well in
8 the utility solicitation. And with a long-term
9 contract in hand they should have an abundant
10 revenue stream to make a good payback for their
11 investment.

12 We just heard a moment ago from the
13 other representative from CAC and EPUC and she
14 talked about the vision to achieve a large number
15 of megawatts in a relatively short period of time.
16 Well the question that I have is, if we're going
17 to put these new thousands of megawatts into the
18 system where's the baseload demand to support this
19 huge increase in baseload production?

20 This Commission is responsible for
21 looking at supply and demand. I think we ought to
22 take into consideration forecast and demand when
23 we talk about forecasts, excuse me, projections
24 and production. I'm just looking over my notes
25 here to see if I can sort of cut some of this down

1 in the interest of time.

2 The vision for 2020 on page 20 talks
3 about mandatory targets such as a market
4 penetration of 26 percent of total peak load
5 demand being met by DG and large cogen with a mix
6 of technologies and fuels.

7 Okay, this seems to be a reasonable
8 approach and perhaps it's wise public policy. But
9 we're left with little explanation in the report
10 as to exactly where this number came from and the
11 analysis to support it. It seems to be based in
12 part on a reasonable projection of today's
13 technologies and market penetration. But we don't
14 know much about the vision or what the vision is
15 based on. Nor do we have much explanation in
16 terms of the analysis behind that target.

17 So the next question I have is similar
18 to the question I posed before about the visioning
19 process. Is the vision adequate or do we need
20 further analysis, or at a minimum, further
21 explanation of the assumptions that led to a
22 conclusion? And a conclusion in a report that
23 could likely lead to a policy recommendation.

24 So I think there's some more work that
25 needs to be done just to provide some further

1 analysis or explanation about some of the
2 recommendations that we see in the report.

3 And the final thing I want to raise has
4 to do with the strategy or the pathway to attain
5 the vision as laid out. And here in chapter four
6 of the report you really finally get to the meat
7 of the issue. And as John Sugar outlined in one
8 of his slides, there are three elements of the
9 strategy. They being to support incentives in the
10 near term, to transition to new market mechanisms
11 and to reduce remaining institutional barriers.
12 There is even a very useful time line that I
13 identifies steps that we need to take between now
14 and 2020 to achieve our vision.

15 So I think the greatest value in this
16 report lies in chapter four but from my
17 perspective that is really only the starting
18 point. In fact we don't really know what the end
19 game is because we can't know the future, by
20 definition.

21 So my final question is, what do we do
22 next? If we accept that this report and today's
23 workshop is the beginning who will map out the
24 times and places for taking the next steps. Who
25 is in charge? Who will gather the troops? Who

1 will ensure that we get the right stakeholders
2 present? And what are we going to do to ensure
3 that we have a full, statewide policy in place?

4 Division is a good guide and it could
5 guide our actions and the pathway can serve as a
6 checkpoint along the journey. Now we need to
7 start the engines and head down the course. That
8 concludes my remarks, thank you.

9 PRESIDING MEMBER PFANNENSTIEL: Thank
10 you, Less. Questions? Commissioner Byron.

11 ASSOCIATE MEMBER BYRON: Mr. Guliasi,
12 I'm glad to see that you're human.

13 (Laughter.)

14 MR. GULIASI: Some things did leak
15 through I guess.

16 ASSOCIATE MEMBER BYRON: Yes, I think
17 they did.

18 MR. GULIASI: I couldn't help myself.

19 ASSOCIATE MEMBER BYRON: But that's
20 okay. You asked a question, what is the objective
21 in promoting DG and CHP in the larger context of
22 things. Can I ask for your view on that?

23 MR. GULIASI: Well I think I laid out
24 some of them sort of rhetorically when I talked
25 about what we typically hear about the value of

1 CHP and DG. And certainly I'll just repeat them.
2 I think these are certainly some of the elements,
3 there may be others.

4 But we talk about increasing the
5 diversity of supply. Certainly there is
6 reliability. We need to have a reliable supply of
7 energy. We need it time-specific and we need it
8 for the long-term. Efficiency. Again, I think a
9 lot of the underpinning here about the value has
10 to do with efficiency. Economic efficiency,
11 social efficiency, technological efficiency. So
12 to the extent that those issues are squarely on
13 the table, fine.

14 We talk about technological advancement.
15 On the DG side we see all sorts of new
16 technologies emerging and we ought to support
17 those technologies. We have the whole overlay of
18 what to do to reduce greenhouse gas emissions and
19 these new technologies need to be front and center
20 when we begin to address that whole issue of
21 greenhouse gas reductions.

22 Cost is an important consideration. You
23 know, we have the whole spectrum of issues related
24 to environmental benefits.

25 There may be other criteria but at least

1 those are the ones that came to mind when I was
2 thinking about the report over the last few days.
3 But we need -- My point was we really need clearly
4 to identify what those benefits are from a public
5 policy perspective and design our actions to
6 achieve those broader objectives.

7 ASSOCIATE MEMBER BYRON: You know, I'm
8 reminded of comments that I made five years ago
9 before this Commission as well and in some ways
10 they haven't, they haven't changed much. In my
11 mind it comes down to customer choice.

12 It's interesting to me that where we
13 have customers that are willing to invest money in
14 the generation business and to not receive, not
15 necessarily benefit for it but it's characterized
16 as a negative. I'm not saying this properly. But
17 everything that they are trying to do is a problem
18 for our investor-owned utilities. Where is the
19 thank you in that for them, if you will?

20 And I'm struck because in recent years,
21 in the last year or so, I have seen a couple of
22 projects in the public, the publicly-owned utility
23 sector. And in fact I think we have maybe one or
24 two POU members here that might be able to speak
25 to this different thinking if you will, Les.

1 Whereas POU rates on the average are about 40
2 percent less than investor-owned rates and we
3 wouldn't expect distributed generation to compete
4 very well in those service territories.

5 But we're finding a completely different
6 response on the part of the publicly-owned
7 utilities working with their members. I'm sorry,
8 with their customers trying to figure out tariffs
9 that work. And I'm just struck by the difference
10 of approach that those utilities are taking versus
11 the investor-owned utilities. So maybe that
12 something to do with your humanity that you
13 referred to earlier. If there is any publicly-
14 owned utilities that are here and would like to
15 speak to that a little bit I'd appreciate that.

16 But I would just emphasize that I think
17 it really comes down to customer choice and it
18 needs to go a lot further than just speaking
19 positively towards distributed generation and CHP.
20 What do customers want and need and understanding
21 why they need it? Those are the over-arching
22 policy issues that -- that's the over-arching
23 policy issue that I think we're interested in
24 addressing.

25 MR. GULIASI: I agree with you. I

1 think, you know, customer choice is an important
2 consideration. And if you recall from the
3 discussions or the debates about the restructuring
4 of the electricity industry, PG&E was one of the
5 few who sided with customers and decided that we
6 should do everything we could to enable customers
7 to make their own choices about their power needs.

8 So what I said at the outset was that
9 insofar as, yo know, DG in particular was
10 concerned we see that as an important option for
11 customers to help them to manage their energy
12 needs. And even on the CHP side.

13 I just want to say parenthetically that
14 on something that the report talks about that -- I
15 had it included in my notes but I just skipped
16 over it in the interest of time. Transparency is
17 important here. We have -- You know, the Rule 21
18 working group has made a great deal of progress
19 and you saw some of the statistics about reducing
20 the amount of time for interconnections and the
21 cost of interconnections. That from our
22 perspective is one important example of putting
23 the customer first.

24 But the tariffs are complicated, overly
25 complicated. They are written in regulatory

1 jargon, they are not easily understood. I think
2 that they should all be rewritten along the same
3 lines that the SEC asked corporations to rewrite a
4 lot of their shareholder documents so that people
5 could understand them, people could understand
6 them in plain English. So transparency is
7 important. That's just a parenthetical remark.

8 But in reflecting on your thought about
9 customer choice I think you have to, you know, ask
10 yourself, at what point does a customer stop being
11 for the moment a customer that is receiving a
12 product or a service from a utility and at what
13 point is that customer now a supplier. It's a
14 whole different arrangement, it's a whole
15 different relationship.

16 ASSOCIATE MEMBER BYRON: Well in fact
17 that raises another question I was going to ask
18 Ms. Sheriff, and I believe Don Schoenbeck got into
19 this as well. For the most part, as I understand
20 it, your customers are not interested in being
21 suppliers. I believe, I believe that you said
22 something to that effect.

23 MS. SHERIFF: That is correct. We
24 don't, we're not interested in --

25 PRESIDING MEMBER PFANNENSTIEL: If

1 you're --

2 ASSOCIATE MEMBER BYRON: If you'd step
3 up to the podium I'd appreciate it. But let me
4 just ask my question. Has there been any effort
5 to work with the investor-owned utilities in maybe
6 some sort of private/private partnership here? I
7 was going to say private/public but that really
8 doesn't apply.

9 MR. SCHOENBECK: As far as I'm aware
10 there has not been a private partnership between
11 some of the large CHP facilities in the state and
12 the IOUs with respect to this issue.

13 But what I was saying in my remarks,
14 they do not want to deal -- our clients, and there
15 is one exception that is a market participant with
16 respect to the ISO and does do the scheduling of
17 an incremental amount of power that is not sold
18 through a bilateral contract. What comes from
19 that is almost a daily administrative burden on
20 that CHP facility to deal with the ISO.

21 From our perspective for the
22 cogeneration facilities that have been in place
23 for 20 years and delivering their power at their
24 traditional interconnection point they have not
25 had that administrative headache of dealing with

1 the Cal-ISO.

2 So that is why we have taken the
3 position we have in saying that the utilities are
4 a much larger system so they can accommodate the
5 CHP facilities and deliver them into a coordinated
6 interface with the ISO. So we just see that being
7 a much more cost-effective measure than making
8 every CHP its own scheduling coordinator and
9 having to have an operator desk, you know, 24/7 to
10 deal with the ISO.

11 So it would be a natural partnership.
12 That's one we need the IOUs to step forward with.

13 ASSOCIATE MEMBER BYRON: Thank you.

14 PRESIDING MEMBER PFANNENSTIEL: Thank
15 you. We have a number of -- Thanks, Les.

16 I have a number of blue cards from
17 people who would like to speak to this issue so
18 why don't we work through them. Starting with
19 Gary Schoonyan from Edison.

20 MR. SCHOONYAN: Thank you. My name is
21 Gary Schoonyan representing Southern California
22 Edison Company. I put a few brief slides here and
23 we did file a number of, a number of comments with
24 regards to some of the concerns that we had and
25 some of the focus that we felt that the roadmap

1 needed to take.

2 I am not going to go through. I mean,
3 we basically discussed every one of the
4 recommendations and had some comments on that, I'm
5 not going to go through those. Nor am I going to
6 go through some of the things that have already
7 been discussed. I think Mr. Guliasi talked about
8 resource planning, the concerns and the issues of
9 that. The need for -- you know, why do you need
10 incentives if you've got a 5,000 effective heat
11 rate, for one. Those sorts of things.

12 But I did want to just -- One of the
13 things that I felt and Edison felt was missing in
14 the report is that there wasn't any -- some clear
15 objectives and clear goals with regards to
16 performance of the facilities. There was a lot of
17 discussion and talk about how much benefits these
18 facilities provide to the system. And believe me,
19 some of these facilities provide significant
20 benefits to the system and we aren't going to
21 argue that and we'll demonstrate some of the
22 historical overview of that.

23 However, we believe a sound CHP policy,
24 and DG policy but particularly CHP policy, is one
25 that reduces overall fuel consumption, reduces

1 overall emissions since they're basically
2 inversely proportional to efficiency. That
3 basically the non-participants, electric rate
4 payers are held harmless.

5 We are providing significant incentives
6 in many instances for these projects. I've
7 testified before this forum as well as the EAP
8 forum and indicated that given those incentives,
9 given the significant efficiencies associated with
10 these projects if they're designed and operated
11 correctly, there are significant benefits.

12 Rate payers that paid into this should
13 receive some of those benefits, or at least be
14 held harmless. There should be no degradation of
15 system reliability and there should be the
16 development of clear design and performance
17 requirements for the systems.

18 One of the other things that at least in
19 going through the roadmap that we saw that failed
20 to exist was sort of an inventory of the
21 incentives that exist today. Now granted not all
22 projects have access to all these incentives. I'm
23 not suggesting that they do. But in essence
24 between the DG and the CHP there are significant
25 incentives already available to them. And we

1 heard today about an additional incentive or
2 benefit, namely the air credits associated with
3 the project.

4 Our comments, basically that we believe
5 that actual performance -- from what we've seen
6 the actual performance of the near-80 systems, CHP
7 systems on our system, only five percent have
8 shown or have met the 80 percent claimed
9 efficiency that developers and advocates have
10 basically put forth. And since emissions are
11 inversely proportional to the efficiency in many
12 instances existing CHP despite the claims have
13 actually increased emissions compared to the CCGT
14 and the current higher efficiency industrial
15 boilers.

16 What is needed in the roadmap and going
17 forward is clear design and performance criteria
18 that attempt to match the size and operate the CHP
19 systems to meet the on-site thermal and electrical
20 load. You need to have provisions in place to
21 monitor the performance.

22 And as discussed before, the export of
23 electrical energy should be incidental. A lot of
24 these projects export a significant amount of
25 power to the grid and apply with all local air

1 quality standards.

2 And again, the performance and the
3 design for new CHP systems in particular just --
4 they need. It's a very important part of the
5 system design. And to the extent that the roadmap
6 comes up with design criteria, operational
7 criteria for these we'll get all the benefits that
8 are claimed, as well the state should.

9 I won't spend much time on this. The
10 vast majority of the projects that exist for
11 potential CHP are topping cycle projects. You
12 produce the electrical energy followed by
13 recovering the waste heat to basically displace
14 other natural gas-fired energy requirements.

15 And the one thing I want to bring up
16 with this slide is, and I posed it as a final
17 question in my comments that I filed late last
18 week, is since the vast majority of the projects
19 actually benefit through the reduction of natural
20 gas shouldn't natural gas be a key provider of the
21 incentives to get this stuff going forward? Why
22 should it all fall on the shoulders of electric
23 rate payers?

24 I mentioned the industry. I just quoted
25 several organizations that have talked about the

1 efficiencies. Eighty percent, some in excess of
2 90 percent total efficiency. The American Council
3 of Energy Efficient Economy talks about CHP
4 systems exceeding 80 percent. The CCA (sic)/EPUC
5 basically uses 80 percent. If you go on the
6 website of the Energy Commission and you look at
7 their example you talk about 85 percent as being
8 the total efficiency associated. And as I've
9 mentioned, that does not come close to meeting
10 what historical performance that Edison has seen.

11 And Edison has purchased a lot of
12 cogeneration. I mean we've purchased well over
13 ten billion kilowatt hours a year from a number of
14 different projects. And if you take a look at
15 where these projects actually perform at only
16 three out of the close to 60 projects actually
17 even meet or exceed the 80 percent efficiency
18 requirement.

19 If you take a look at a CCGT with a good
20 industrial boiler nowadays you're probably talking
21 about 80 percent, maybe a little bit below 80.
22 No, pardon me, 70 percent, a little bit below 70
23 percent, 66 to 70 percent. So that would
24 basically fall right about in here. Anything
25 below that the system can basically provide more

1 efficient use of the fuel than moving forward with
2 something like this.

3 And these sorts of considerations we
4 could be taking into account. We're looking for
5 reduced natural gas use, we're looking for reduced
6 greenhouse gas emissions. Let's make sure that
7 the criteria that we have going forward to meet
8 those, actually we obtain those benefits.

9 Thank you.

10 PRESIDING MEMBER PFANNENSTIEL: Thank
11 you, Gary.

12 Questions? Discussion?

13 Interesting information. Yes, we have
14 somebody who'd like to speak to that. Kim.

15 MS. CROSSMAN: Hi, thank you. Regarding
16 the industry standard of 80 percent efficient.
17 Industry standard says cogeneration ranges between
18 60 to 85 percent efficient. A blurb that's a
19 leftover on the US CHPA website that refers to
20 over 90 percent efficient systems I could have
21 sworn was removed about a year and a half ago.

22 There is a tendency sometimes in the
23 industry to overstate benefits when you're trying
24 to promote something. But the system I referred
25 to earlier that won that Energy Star award at

1 CalTech is a 70 percent efficient system and
2 exceeds the performance of a combined cycle gas
3 turbine and an 80 percent efficient boiler. So
4 very, very few systems will exceed 80 percent.
5 Only the largest really will get there.

6 And the one other comment I would make
7 is when considering what is beneficial, although I
8 talked about being able to beat a new combined
9 cycle gas turbine and an 80 percent efficient
10 boiler. With some systems I think some
11 consideration probably needs to be given to
12 whether that is in fact the baseline that we're
13 actually trying to beat in California. You know,
14 what is the existing efficiency of the gen. It is
15 in fact all combined cycle, brand new gas turbines
16 or not. Thank you.

17 PRESIDING MEMBER PFANNENSTIEL: That's a
18 very good point, thank you for raising it.

19 MR. SCHOENBECK: I'd just like to make
20 one quick comment too on doing energy efficiencies
21 between CHP facilities and utility facilities
22 because you see it all the time in the wars we've
23 been having for years.

24 I've known Gary for many, many years and
25 I've always really liked him but I think you have

1 to be careful. And you do need to compare an
2 apple to an apple and you need to compare the same
3 technology. And what you see happening you see
4 utilities saying, the state of the art 1,000
5 megawatt combined cycle plant could give me a heat
6 rate of 6500. And I'll compare that to my
7 existing CHP fleet, which is 1985 vintage and has
8 basically heat rates of 12,000.

9 So in my mind that comparison can be
10 made but you have to realize what's being done.
11 And similarly you can look at it the other way
12 around. A more new, CHP facility can compare it
13 to the old 9600, 10,000 gas and oil plants that
14 Edison used to own.

15 I think the most appropriate comparison
16 is have it be the same technology, the same
17 vintage of technology, so by default CHP will
18 always win. You can take a combined cycle plant
19 like La Paloma and have a heat rate of 7,000. If
20 you take that same combined cycle plant and put it
21 in a CHP system it will have a substantially
22 reduced rate. So for the same technology of the
23 same vintage CHP will always win. Thank you.

24 PRESIDING MEMBER PFANNENSTIEL: Thank
25 you.

1 I have some blue cards, others. Ellen
2 Petrill.

3 MS. PETRILL: Hi. Thank you for the
4 opportunity to comment on the distributed
5 generation roadmap. My colleague, David Timson
6 and Dan Rastler and I wrote these comments and
7 we're pleased to be here to comment.

8 So EPRI's vision of the future grid
9 comprises diverse assets including large and small
10 scale, both supply and demand. So we agree that
11 distributed generation has a role in the
12 electricity system of the future and there is a
13 need to focus policy on increased DG penetration.

14 And EPRI commends CEC for looking out to
15 the 2020 time frame for DG penetration and
16 considering what needs to be done today to achieve
17 the goals of the roadmap.

18 We agree with the three element strategy
19 of the roadmap and we agree with helping the
20 penetration along with incentives is necessary for
21 the near term because the most significant
22 benefits of DG will become more evident and
23 monetizable as the penetration increases. So at
24 some point, and we don't know exactly when, market
25 mechanisms can be developed that in fact pay for

1 the value that diverse, distributed generation
2 will provide.

3 So we'd like to offer the following
4 additional comments. Number one, win/win outcomes
5 should be the focus of any DG policy that strives
6 to increase DG penetration. EPRI has undertaken
7 several studies of the microeconomics of DG
8 deployment and the costs and benefits that accrue
9 to site owners, rate payers and utility
10 shareholder and society in general. And our
11 studies have shown that there are scenarios under
12 which all three parties benefit from the
13 deployment. We call these win/win scenarios.

14 Win/win scenarios exist for both
15 customer-owned on-site generation and utility-
16 owned on-site generation. And while there are
17 some cases for win/win outcomes today these
18 opportunities are somewhat difficult to find due
19 to limited monetization of benefits in the market
20 and the cost of DG technologies.

21 However, as DG penetration increases the
22 macroeconomics of DG will improve due to an
23 increased ability to account for benefits of DG
24 such as reliability. Win/win opportunities will
25 become more prevalent.

1 So we recommend moving toward win/win
2 outcomes in the future but not to be trapped in
3 today's economic environment. In many cases
4 incentives will be needed in the near term to
5 achieve win/win outcomes until market mechanisms
6 can become sustainable.

7 Number two, utilities are critical to
8 integrating DG. We recommend that the roadmap
9 give more focus to the role of the electric
10 utility in achieving the roadmap goals. As
11 distribution system managers electric utilities
12 are in the right role to deploy distributed
13 generation to benefit the site owner as well as
14 other rate payers and society.

15 This will be true for cases where
16 utilities own and operate the on-site generator as
17 well as cases where customers own and operate the
18 generator to power their own loads and/or sell
19 power into the wholesale market.

20 To expect that utilities will encourage
21 increased DG penetration means that there must be
22 a benefit to rate payers and utility shareholders
23 such as incentives in the near term and monetized
24 benefits through market mechanisms in the longer
25 term. Again, this is the win/win outcome.

1 Furthermore while we agree that market
2 mechanisms are critical to achieving sustainable
3 DG penetration the mechanism should not focus on
4 competing with central stations and transmission
5 and distribution systems but on complementing
6 these assets.

7 Number three, pilots should lead the
8 way. We recommend that pilots be used to test
9 mechanisms to increase DG penetration. Achieving
10 the DG and cogen deployment goals of the roadmap
11 is likely to result in major changes in utility
12 planning and in the business relationships between
13 the utility and its customers. So we think that
14 these should be tested on a pilot scale so we can
15 identify the successes and build on those and
16 address the challenges.

17 So we recommend that in the near term
18 incentive period the focus should be placed on
19 testing and piloting new market mechanisms that
20 result in win/win outcomes. And these market
21 mechanisms will likely require new utility or
22 customer business models and probably regulatory
23 structures as well.

24 In addition the pilot programs we think
25 should consider advanced technologies such as

1 integrating CHP systems with energy efficiency and
2 PV and electricity storage as we heard about today
3 with a smart grid, for example, and integrating
4 these technologies so you can aggregate the
5 benefits and monetize the values.

6 We also think that other aspects should
7 be piloted like two-way power flows, intentional
8 islanding and micro-grids.

9 You may know that EPRI is working with
10 the Energy Commission and the State of
11 Massachusetts through our DER partnership on a DOE
12 States Technology Advancement Collaborative or
13 STAC project to develop and test business and
14 regulatory models that incentivize utilities to
15 encourage DG on their systems.

16 The pilot projects that we're planning
17 in Massachusetts and California will be a step in
18 this pilot process. We're working with Jose
19 Palomo, Linda Kelly and John Sugar on this project
20 and many other stakeholders in this room and we
21 appreciate their working with us.

22 Number four. Spark spread is an
23 important driver. We were surprised to find that
24 in figure B1 on page 30 of the roadmap the DG and
25 cogen scenario drivers, it suggested that the

1 spark spread is a relatively low impact factor.
2 Whereas in the studies that EPRI has done we have
3 found that spark spread is the most sensitive
4 factor in the microeconomic analysis. And it's
5 the factor we found that determines whether net
6 operating benefits are available to cover the
7 capital costs. So we recommend that you take
8 another look at the relative impact of spark
9 spread and give it a little bit more visibility.

10 Number five, consider standby generation
11 for peaking. We noted that there is an absence of
12 standby generation in the roadmap and we know that
13 there are other states that are looking at using
14 standby. Oregon, for example, employs customer-
15 sited standby generators for peaking under various
16 business arrangements. So the installed capacity
17 in California of standby generators are estimated
18 at 10,000 megawatts. This is an enormous untapped
19 resource which could go far to meet the demand
20 increase that is outlined in the roadmap of 14,000
21 megawatts growth between 2004 and 2020.

22 Because this capacity is already in
23 place and has been cost-justified for other
24 reasons it is a very low cost electricity capacity
25 for peaking purposes. You would have to do a

1 couple of other things. You'd have to install
2 switch gear and controls to allow the generators
3 to be dispatched during peak periods but this
4 equipment is commercially available and no further
5 development is likely to be required.

6 And in addition, of course this is very
7 important, you'd have to install combustion
8 controls and exhaust gas treatment to reduce the
9 exhaust emissions to acceptable levels of which is
10 typically diesel engines. And exhaust gas
11 treatment systems are not yet commercially proven
12 but there are technologies under development for
13 vehicles which could be readily applicable to
14 stationary diesel generators.

15 Nonetheless these costs are likely to be
16 much less than comparable costs for new generating
17 capacity to meet peak loads. So we recommend that
18 the use of customer-sited standby generators be
19 part of the roadmap.

20 And number six, standardized CHP
21 solutions might be something to consider.
22 Finally, EPRI suggests that penetration of CHP
23 could be improved by developing standardized CHP
24 solutions for key market segments. As with the
25 state's leadership in the specification of energy

1 efficiency for new buildings and new homes,
2 similar specifications and standard sized CHP
3 packages could be specified for new building
4 construction.

5 So thank you for the opportunity to
6 comment and we look forward to working with the
7 Energy Commission to bring the roadmap to
8 fruition.

9 PRESIDING MEMBER PFANNENSTIEL: Thank
10 you, Ellen.

11 Are there questions?

12 Thanks very much for being here. I'm
13 sorry, Dian.

14 CPUC COMMISSIONER GRUENEICH: I just
15 wanted to say that unfortunately I'm going to have
16 to take off now so I do apologize that I won't be
17 able to stay until the end. But again I want to
18 thank the Energy Commission for offering to have
19 me here today. I've learned a lot.

20 And I did want to also note, I think
21 he's here, Andy, Andy Schwartz, President Peevy's
22 advisor is also here. And between the two of us
23 and Jay Morse from our staff we'll certainly take
24 back today some of the things that we've heard.

25 Because I think that there's been some

1 very valuable input to some of our pending
2 matters. The issue of the continuation of the
3 Rule 22 (sic) working group seems to be an area
4 that we can work on, even in advance of whatever
5 formal documents will come out so that we do have
6 some assurance that this type of collaborative
7 group can continue.

8 So thank you again for letting me be
9 here and listen.

10 PRESIDING MEMBER PFANNENSTIEL: Thank
11 you, Dian, thanks for participating.

12 We have our next speaker, Bob Burt.

13 MR. BURT: Since this is an IEPR
14 workshop I had come planning to seek your advocacy
15 for an unusual approach to using offsets to deal
16 with global warming. But in view of the lateness
17 of the hour and the fact that I suspect very few
18 people here have a passing interest in that
19 subject I am willing to defer and put my stuff in
20 writing. Thank you.

21 PRESIDING MEMBER PFANNENSTIEL: Thank
22 you. Questions? No?

23 ASSOCIATE MEMBER BYRON: No.

24 PRESIDING MEMBER PFANNENSTIEL: Bill
25 Karambelas.

1 MR. KARAMBELAS: My name is Bill
2 Karambelas, I am the vice president of FuelCell
3 Energy. The comment was going to be on action
4 item number two under tariffs and was already
5 covered by Eric Wong. It had to do with natural
6 gas and the ability to move that possibly into the
7 rate base. Excuse me. So I will step down
8 because it's already been covered. Thank you.

9 PRESIDING MEMBER PFANNENSTIEL: Thank
10 you, sir. On the phone I believe we have Jane
11 Turnbull from the League of Women Voters. Jane.

12 ASSOCIATE MEMBER BYRON: She's in
13 person.

14 PRESIDING MEMBER PFANNENSTIEL: I'm
15 sorry, I thought you were --

16 MS. TURNBULL: I'm behind the podium.
17 Thanks Commissioners, I am pleased to be here.

18 I would like to first of all endorse
19 what Les Guliassi had to say in terms of asking
20 that a preface statement be laid out in terms of
21 the policy objectives that are being sought.

22 The League has been a supporter of DG
23 and CHP for as long as I can remember, largely
24 because we support the more efficient use of our
25 natural resources and also the potential for

1 mitigating pollutants.

2 Commissioner Grueneich did raise the
3 issue of how is this going to fit into a cap and
4 trade system and I think it's a great question and
5 I trust it will fit in but getting there is going
6 to be an interesting process.

7 We also feel that the potential
8 improvements to the whole reliability of the
9 electric system that can come out of this are very
10 significant and certainly ought to be included.

11 But Commissioner Byron, you raised the
12 issue of customer choice. And I have to address
13 that because that was a question that we asked
14 League members all around the state a little over
15 a year ago in terms of, was that a value that
16 should be sought in terms of energy policy and we
17 got a resounding no on the grounds that the
18 customers who want to choose are the ones that are
19 going to benefit. And there really continues to
20 be a concern out there in terms of what the impact
21 of policy decisions are going to be on the core
22 customers. So I do raise that.

23 I also think there is an issue of
24 fairness in terms of departing load costs. We
25 have a lot of load serving entities out there, not

1 just the IOUs, and I think there is a basic, level
2 playing field that is attempted to be established
3 in the tariff development process and hopefully
4 that level playing field will still be a goal out
5 there.

6 We also like the ideal of a more
7 transparent tariff process. Thank you.

8 PRESIDING MEMBER PFANNENSTIEL: Jane,
9 let me just ask. Does the League normally get
10 involved in rate design issues? For example, the
11 issues that were raised earlier about demand
12 charges and specific rates.

13 MS. TURNBULL: We usually don't get
14 involved in evidentiary hearings at the PUC. We
15 are in a position to talk in terms of policy on
16 the broader issue. We don't have the depth to
17 work in terms of the individual rate cases.

18 PRESIDING MEMBER PFANNENSTIEL: The
19 policy issues on rate design, have you taken those
20 on? Are you talking about cost allocations and
21 cost responsibility? Is there a position?

22 MS. TURNBULL: That is an area that we
23 are concerned about and we are certainly very
24 interested in the dynamic rate structures that are
25 coming up. We think they are very exciting but

1 they have to be done the right way.

2 PRESIDING MEMBER PFANNENSTIEL: That's
3 the challenge, thank you. Other questions?

4 Thank you, Jan.

5 And we have Alex Kim from SDG&E and
6 SoCal Gas Company.

7 MR. KIM: Thank you. I'm Alex Kim from
8 San Diego Gas and Electric. I'm here representing
9 both San Diego Gas and Electric and SoCal Gas.
10 I'll make my comments brief because I know we're
11 running late. And we will be filing our comments
12 as well so they'll be publicly available.

13 But I did want to say that first of all
14 we do commend the Commission for implementing and
15 creating this DG policy roadmap, we do believe
16 it's needed, and that SDG&E and SoCal Gas strongly
17 support cost-effective distributed generation. We
18 also believe that continuing to provide incentives
19 in the midterm, replacing those with market
20 mechanisms in the long term is a very good
21 strategy.

22 There are a couple of things, omissions,
23 that we feel are on the roadmap and one of them is
24 that cost-effectiveness is not addressed in the
25 division statement. Nowhere is cost-effectiveness

1 mentioned. Also the regional circumstances are
2 not addressed. What are they, how are the
3 different regional areas affected. And lastly the
4 procurement obligations. Increasing net metering
5 is inconsistent with moving forward towards the
6 new market mechanisms.

7 A couple of recommendations that I just
8 want to address here. Like I said, we'll be
9 filing our comments later. But one o them is --
10 and this was addressed, a question I guess that
11 was raised by PG&E. And one thing that we feel is
12 needed is to develop a comprehensive and detailed
13 plan that addresses these issues that are not
14 addressed in the roadmap. And that all
15 stakeholders should be considered and
16 participating when developing these strategies.

17 I think what was discussed initially
18 about the interconnection group. A forum like
19 that where you have all stakeholders involved is a
20 great forum in which this roadmap can also be
21 worked out.

22 And again, reinstating CHP and the SGIP.
23 We do believe that is a good, that is needed right
24 now, as was mentioned earlier by somebody. The
25 payback that customers are looking for are two to

1 three years. And one of the reasons why CHP has
2 not grown probably as significantly in our area is
3 the fact that our customers are requiring a much
4 quicker payback and maybe in the short term
5 reinstating the incentives in SGIP is needed.

6 And lastly that other factors including
7 impacting customer decisions to adopt DG such as
8 better site selection, performance requirements,
9 many of the factors that were addressed today
10 regarding customer decisions. Why does a customer
11 make a decision to include distributed generation
12 or to purchase distributed generation is not also
13 addressed in the roadmap and we would strongly
14 recommend that it does be addressed. Thank you.

15 ASSOCIATE MEMBER BYRON: Mr. Kim?

16 MR. KIM: Yes.

17 ASSOCIATE MEMBER BYRON: I want to make
18 sure I understood something you said. Did you say
19 expanding net metering is inconsistent with market
20 mechanisms. Is that what I understood you --

21 MR. KIM: Correct. With new market
22 mechanisms, correct.

23 ASSOCIATE MEMBER BYRON: I hadn't
24 considered that. Could you explain what you mean
25 by that, please.

1 MR. KIM: Sure. I think, I think what
2 the intent, at least our understanding of what the
3 intent of the roadmap was, was to move away toward
4 incentives -- away from incentives I should say.
5 And net energy metering is an incentive. And so
6 we believe that moving away from that or
7 continuing that as described in the roadmap is not
8 really moving towards new market mechanisms.

9 ASSOCIATE MEMBER BYRON: Thank you.

10 PRESIDING MEMBER PFANNENSTIEL: Thank
11 you.

12 MR. KIM: Thank you.

13 PRESIDING MEMBER PFANNENSTIEL: That
14 completes the blue cards I have. Is there anybody
15 on the phone who would like to make comments?

16 Then let me turn it back to John.

17 MR. SUGAR: For just a moment, please.
18 I'd like to note that I erred on the workshop
19 notice and gave a very short period for comments
20 and wondered if the Committee would be willing to
21 entertain extending the comment period for the
22 next week or two so that parties an docket
23 material as a result of our discussions today.

24 PRESIDING MEMBER PFANNENSTIEL: I'm
25 sorry, until when?

1 MR. SUGAR: Two weeks from now. That
2 would be about the 21st.

3 PRESIDING MEMBER PFANNENSTIEL: And
4 what's the IEPR Committee --

5 ASSOCIATE MEMBER BYRON: Yes, we welcome
6 the comments of individuals that are here and I
7 think expanding it, if we can afford the
8 additional time, would be really worthwhile.

9 MR. SUGAR: Great.

10 ASSOCIATE MEMBER BYRON: Notwithstanding
11 all the great comments we've received already.

12 MR. SUGAR: Yes, and we will be posting
13 those, thank you.

14 PRESIDING MEMBER PFANNENSTIEL: Are
15 there final concluding comments, Commissioner
16 Byron?

17 ASSOCIATE MEMBER BYRON: I think I'll
18 pass.

19 PRESIDING MEMBER PFANNENSTIEL: I have
20 no other than to say that today was a very meaty
21 afternoon. It was a lot of interesting, but I
22 think more than that, informative and very useful
23 information presented.

24 I think some of the disagreements were
25 valuable for us because they help us on the policy

1 decision-making that we need to do. It's not
2 quite as straightforward as each of the individual
3 sides would have us believe. But I do think, even
4 having said that, there's a great deal of
5 convergence of opinion on DG and cogeneration.

6 I think that the areas where there are
7 policy disagreements are important ones but not
8 that many of them. And I think that this is a
9 good way of getting started to resolve them.

10 With that, nothing further, we'll be
11 adjourned.

12 (Whereupon, at 4:25 p.m., the Committee
13 workshop was adjourned.)

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CERTIFICATE OF REPORTER

I, PETER PETTY, an Electronic Reporter, do hereby certify that I am a disinterested person herein; that I recorded the foregoing California Energy Commission Committee Workshop; that it was thereafter transcribed into typewriting.

I further certify that I am not of counsel or attorney for any of the parties to said workshop, nor in any way interested in outcome of said workshop.

IN WITNESS WHEREOF, I have hereunto set my hand this 16th day of May, 2007.

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